Prevention of Significant Deterioration Permit Application

Canal Unit 3

Canal Generating Station
Sandwich, MA

Updated through Supplement No. 2

November 2016

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ACRONYMS/ABBREVIATIONS

Acronyms/Abbreviations	Definition
°F	degrees Fahrenheit
%	percent
AAL	Allowable Ambient Limit
AGT	Algonquin Gas Transmission, LLC
amsl	above mean sea level
AP-42	Compilation of Air Pollutant Emission Factors
ARM	Ambient Ratio Method
BACT	Best Available Control Technology
bhp	brake horsepower
Btu/kW-hr	British thermal units per kilowatt-hour
CAIR	Clean Air Interstate Rule
Canal 3	NRG Canal 3 Development LLC
CCS	carbon capture and sequestration
CEMS	continuous emissions monitoring systems
CF	capacity factor
CFR	Code of Federal Regulations
CH_4	methane
CI	compression ignition
CMR	Code of Massachusetts Regulations
CO	carbon monoxide
CO_2	carbon dioxide
CO_{2e}	carbon dioxide equivalents
the Court	United States Court of Appeals for the District of Columbia Circuit
CSAPR	Cross-State Air Pollution Rule
CTG	combustion turbine generator
DPF	diesel particulate filter
DLN	dry-low-NO_x
EAB	Environmental Appeals Board
EEA	Massachusetts Executive Office of Energy and Environmental Affairs
EJ	***Environmental Justice***
FCA	***Forward Capacity Auction***
FCM	***Forward Capacity Market***
FERC	***Federal Energy Regulatory Commission***

Acronyms/Abbreviations	Definition
FLM	Federal Land Manager
GE	General Electric
GEP	Good Engineering Practice
GHG	greenhouse gases
g/hp-hr	grams per horsepower-hour
g/kW-hr	grams per kilowatt-hour
gr/100 scf	grains per 100 standard cubic feet
the Guidance	USEPA's Guidance for $PM_{2.5}$ Permit Modeling
HAPs	hazardous air pollutants
HHV	higher heating value
H_2	hydrogen
H_2O	water
hp	horsepower
H_2SO_4	sulfuric acid
ISO	International Organization for Standardization
ISO-NE	Independent System Operator – New England
km	kilometer
kW	kilowatts
kWe	kilowatts (electrical)
LAER	Lowest Achievable Emission Rate
lbs	pounds
lb CO_2/MW-hr	pounds of carbon dioxide per megawatt-hour
lb/hr	pounds per hour
lb/MMBtu	pounds per million British thermal units
lb/MW-hr	pounds per megawatt-hour
LNG	liquefied natural gas
MACT	Maximum Achievable Control Technology
MassDEP	Massachusetts Department of Environmental Protection
MassDOT	***Massachusetts Department of Transportation***
MCPA	Major Comprehensive Plan Approval
MECL	***Minimum Emissions Compliance Load***
MMBtu/hr	million British thermal units per hour
MRCSP	Midwest Regional Carbon Sequestration Partnership
MW	megawatt
MW-hr	megawatt-hour

Acronyms/Abbreviations	Definition
N_2	nitrogen
N_2O	nitrous oxide
NAD	North American Datum
NED	National Elevation Data
NESHAPs	National Emissions Standards for Hazardous Air Pollutants
NAAQS	National Ambient Air Quality Standards
ng/J	nanograms per Joule
NH_3	ammonia
NLCD92	United States Geological Survey National Land Cover Data 1992
NMHC	non-methane hydrocarbons
NNSR	Nonattainment New Source Review
NO_2	nitrogen dioxide
NO_x	nitrogen oxides
NRG	NRG Canal LLC
NSPS	New Source Performance Standards
NSR	New Source Review
O_2	oxygen
O_3	ozone
OTR	Ozone Transport Region
Pb	lead
PM	particulate matter
PM_{10}	particulate matter with a diameter equal to or less than 10 microns
$PM_{2.5}$	particulate matter with a diameter equal to or less than 2.5 microns
ppmvdc	parts per million by volume, dry basis, corrected to 15% O_2
ppmw	parts per million by weight
PRIME	Plume Rise Model Enhancements
PSD	Prevention of Significant Deterioration
the Project	proposed installation of a GE 7HA.02 or equivalent simple-cycle combustion turbine
PTE	potential to emit
Q/D	emissions/distance
RACT	Reasonably Available Control Technology
ROW	***Right-of-Way***
RBLC	RACT/BACT/LAER Clearinghouse
SCR	selective catalytic reduction

Acronyms/Abbreviations	Definition
SEMA/RI	***Southeast Massachusetts/Rhode Island***
SENE	***Southeastern New England***
SER	Significant Emission Rate
SF_6	sulfur hexafluoride
SIA	Significant Impact Area
SIP	State Implementation Plan
SIL	Significant Impact Level
SMC	Significant Monitoring Concentration
SO_2	sulfur dioxide
SO_3	sulfur trioxide
SO_4	sulfate
the Station	Canal Generating Station
SUSD	startup and shutdown
TEL	Threshold Effects Exposure Limit
TMNSR	Ten-Minute Non-Spinning Reserve
tpy	tons per year
ULSD	ultra-low sulfur distillate
USACE	***United States Army Corps of Engineers***
USEPA	United States Environmental Protection Agency
USGS	United States Geological Survey
UTM	Universal Transverse Mercator
VOC	volatile organic compounds

1.0 INTRODUCTION

NRG Canal 3 Development LLC (Canal 3) is proposing to construct a new, highly efficient, fast-starting, approximately 350-megawatt (MW)[1] peak electric generating unit (the Project) at the existing Canal Generating Station (the Station) located at 9 Freezer Road in Sandwich Massachusetts. The proposed new unit for the Project will consist of a simple-cycle combustion turbine fired with natural gas as the primary fuel, with limited firing of ultra-low sulfur distillate (ULSD) as backup fuel. The combustion turbine generator (CTG) will operate no more than 4,380 hours per year, with ULSD firing limited to 720 hours per year.

NRG Canal LLC (NRG) operates the existing Station, which consists of two steam-electric generating units, each with a nominal generating capacity of 560 MW. Units 1 and 2 were originally constructed to fire No. 6 fuel oil as the sole fuel; Unit 2 was modified in 1996 to allow firing of either No. 6 fuel oil or natural gas. The Station also includes ancillary emission sources including two auxiliary boilers capable of firing natural gas or distillate oil, an emergency diesel-fired generator engine, a fuel-gas heater and other minor emission sources. The Station is an existing major source for emissions of nitrogen oxides (NO_x), volatile organic compounds (VOC), sulfur dioxide (SO_2), carbon monoxide (CO), particulate matter (PM), particulate matter with a diameter equal to or less than 10 microns (PM_{10}), particulate matter with a diameter equal to or less than 2.5 microns ($PM_{2.5}$); and Hazardous Air Pollutants (HAPs).

Air emissions from the proposed Project will consist primarily of products of combustion from the CTG. Barnstable County is designated as attainment with respect to the National Ambient Air Quality Standards (NAAQS) for all criteria pollutants with the exception of ozone (O_3); Barnstable County is a moderate nonattainment area for the 1997 O_3 standard. Based upon the potential to emit (PTE) estimates provided in Section 2, the Project is subject to Prevention of Significant Deterioration (PSD) review for emissions of NO_x, PM, PM_{10}, $PM_{2.5}$, greenhouse gases (GHG) and sulfuric acid (H_2SO_4). In addition, the Project is also subject to Major Comprehensive Plan Approval (MCPA) pursuant to 310 Code of Massachusetts Regulations (CMR) 7.02(5). In accordance with the Massachusetts Department of Environmental Protection's (MassDEP's) Nonattainment New Source Review (NNSR) permitting program, the Project is also subject to NNSR for emissions of NO_x, pursuant to 310 CMR 7.00, Appendix A.

Canal 3 is hereby applying for a PSD Permit as required pursuant to 40 Code of Federal Regulations (CFR) 52.21. MassDEP is the responsible agency for reviewing and issuing the PSD Permit, pursuant to the PSD Delegation Agreement between the United States Environmental Protection Agency (USEPA) Region 1 and MassDEP dated April 2011. The MCPA/NNSR Application, including the NNSR permit requirements required pursuant to 310 CMR 7.02(5), is being provided as a separate document.

1.1 REGULATORY OVERVIEW

The Project is subject to PSD review for NO_x, PM, PM_{10}, $PM_{2.5}$, GHG and H_2SO_4. To satisfy PSD review requirements, the Project will employ Best Available Control Technology (BACT) emission controls for all pollutants subject to PSD review. The BACT NO_x emission controls for the CTG will include dry-low-NO_x (DLN) burners and selective catalytic reduction (SCR) to control NO_x emissions; water (H_2O) injection will also be used to control NO_x when firing ULSD. Emissions of PM, PM_{10}, $PM_{2.5}$, and H_2SO_4 will be controlled by the use of low-sulfur fuels with natural gas as the primary fuel for the CTG. GHG emissions will be minimized by the use of a high efficiency simple-cycle combustion turbine fired with natural gas as the primary fuel, with limited firing of ULSD as backup fuel. The Project will comply with the National Ambient Air Quality Standards (NAAQS) and all applicable New Source Performance Standards (NSPS) and National Emission Standards for Hazardous Air Pollutants (NESHAPs).

[1] The gross electrical output of the CTG will vary from approximately 330 MW at higher ambient temperatures to approximately 365 MW at very low temperatures.

The Project will also apply Lowest Achievable Emissions Rate (LAER) for NO_x and BACT for all MassDEP-regulated pollutants, as required pursuant to 310 CMR 7.02(5) and Appendix A. Demonstration of LAER and MassDEP BACT are contained in the MCPA Application, which is being provided as a separate document.

1.2 APPLICATION OVERVIEW

1.2.1 Application Organization

This PSD Permit application is divided into six sections. Section 1 provides an overview of the Project and regulatory requirements. Section 2 provides a detailed description of the proposed Project, including estimated emissions. Section 3 provides a detailed review of applicable PSD Permit requirements. Section 4 provides the PSD BACT control technology evaluation. An air quality modeling analyses demonstrating compliance with NAAQS, PSD Increments, and other PSD modeling requirements is provided as Section 5. Section 6 provides references.

Emission calculation spreadsheets providing supporting calculations for the application are provided in Appendix A. Appendix B presents summary tables supporting the PSD BACT analyses. Appendix C presents the results of the request for determination of applicability for the Class I Area Modeling Analysis and Federal Land Manager Determination.

1.2.2 Application Contacts

To facilitate agency review of this application, individuals familiar with the Project and this application are identified below.

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2.0 PROJECT DESCRIPTION

2.1 PROJECT SUMMARY

The Project site is located on an approximately 12-acre site (Project site) within the larger Station property (Property) in Sandwich, Barnstable County, Massachusetts (Figure 2-1). The Project plans to use a General Electric (GE) 7HA.02 combustion turbine, or a comparable unit, operating in simple-cycle mode to provide electric power during periods of peak demand. The CTG generating system will primarily include: one GE 7HA.02 CTG, or a comparable turbine; an evaporative inlet air cooler; an SCR system with an ammonia (NH_3) injection skid; an oxidation catalyst; tempering air fans; an exhaust stack; a two-winding main generator step-up transformer; auxiliary transformer; and electrical switchgear. The Project will also include two ancillary emission sources, a 500-kilowatt (electrical) (kWe) emergency diesel generator engine (581-kW [mechanical]) and a 135-brake-horsepower (bhp) emergency diesel fire pump engine.

Natural gas for the Project will be delivered via the existing Algonquin Gas Transmission, LLC (AGT) lateral that currently serves the existing Station. A new 3,590-foot on-site natural gas pipeline will be constructed from the existing natural gas pipeline on the Property to the new gas compressor building. ULSD for the Project will be stored in an existing 5,700,000-gallon aboveground storage tank and associated 1,800,000-gallon day tank; both tanks currently hold No. 6 fuel oil and will be converted to hold ULSD prior to operation of the Project. Two existing fully diked aqueous NH_3 storage tanks, each with a capacity of 60,000 gallons will provide aqueous NH_3 for the SCR system.

The purpose of the Project is to respond to a projected shortfall in peak electric generation capacity for Southeastern Massachusetts/Rhode Island. Canal 3 submitted a capacity bid for the Project in the Independent System Operator – New England's (ISO-NE's) most recent forward capacity auction (FCA #10), which took place on February 10, 2016. The Project's bid was accepted and the Project is obligated to be able to supply electricity by June 1, 2019. The Project will provide needed highly efficient, fast-starting, peak electric generation for Southeastern Massachusetts/Rhode Island. With the ability to start up in 10 minutes, this flexible, fast-starting CTG will also provide critical backup support to the region's increasing renewable energy sources. Further, with a simple-cycle turbine having dual-fuel capability, the Project will provide increased reliability to the ISO-NE system. The reasons why the simple-cycle dual-fuel turbine alternative is the best option to meet the Project's purpose are discussed in more detail in Sections 4.2.1 and 4.2.6.

The proposed Project is intended to operate primarily during periods of peak demand providing additional needed electric generating capacity to ISO New England's Southeast Massachusetts/Rhode Island (SEMA/RI)[2] load zone. ISO-NE ensures sufficient electric generating capacity throughout the region by administering a Forward Capacity Market (FCM). The FCM includes an annual Forward Capacity Auction (FCA) in which suppliers compete for the opportunity to provide capacity to meet forecasted demand three years in the future. Qualified suppliers with the lowest price offers "clear" the auction and qualify for potential capacity payments. In February 2015, the results of FCA9 demonstrated a shortfall of 238 MW of generation capacity in the SEMA/RI load zone. In response to this shortfall, the Project decided to participate in FCA10 (held on February 8, 2016) and cleared the market with a capacity supply obligation starting on June 1, 2019.

Suppliers that clear in a Forward Capacity Auction undertake an obligation to produce power whenever called upon by ISO-NE. In 2015, ISO-NE added a Pay-for-Performance requirement to the Forward Capacity

[2] On November 10, 2015, ISO-NE made a filing at the Federal Energy Regulatory Commission (FERC) with specific information related to FCA #10. Within that filing, they confirmed that only two capacity zones will be modeled in FCA #10: Southeastern New England (SENE) and Rest of Pool (ROP). SENE is a new capacity zone that includes two zones previously known as SEMA/RI and Northeast Massachusetts (NEMA).

Market to address recent winter reliability issues experienced when natural gas supplies to the region were curtailed. Under this new Pay-for-Performance design, capacity resources that are unable to fully respond within 30 minutes of a dispatch order suffer financial penalties in the Forward Capacity Market. Pay-for-performance penalties to generators can actually exceed their total revenues from the capacity market and therefore serve as a significant incentive for these resources to be fully available throughout the year. As a result, to be economically viable generating resources relying on natural gas pipelines with a history of winter curtailments must also have a reliable backup fuel supply.

The Project will receive natural gas from the Algonquin Gas Transmission (AGT) lateral serving Cape Cod. While there is normally sufficient capacity on this system to serve the Project at full load, there are times (such as during severe cold snaps) when natural gas supplies are insufficient to meet Project needs without disrupting service to downstream commercial and residential customers. As described in Section 5.2.1, during these times the Project will operate on its backup fuel supply (ULSD) until normal conditions are restored on the pipeline.

In addition, the Project may elect to participate as a Fast Start Generator in ISO New England's Forward Reserve Market. This market ensures that the electric grid has enough quick start capacity to respond to the largest single contingency on the system (e.g., the instantaneous loss of a major transmission line or on-line generating facility). When operating in the reserve market, the Project would have to start up and reach full load within as little as 10 minutes of receiving a dispatch signal from ISO- NE. Since the AGT G lateral does not currently have the ability to provide sufficient No Notice fuel without disrupting service to downstream customers, the Project would also have to start up on its backup ULSD fuel supply in this circumstance as well.

2.2 SITE DESCRIPTION

NRG Canal owns two non-contiguous tracts of land, which total approximately 88 acres. The Station Property consists of a 52-acre tract north of a railroad right-of-way (ROW), owned by Massachusetts Department of Transportation (MassDOT) and operated by Cape Cod Central Railroad. The proposed nominal 350 MW CTG will be located on approximately 12 acres on the eastern portion of this 52-acre Station Property. A separate 36-acre tract southern area is located to the south of the railroad ROW. The majority of the existing Canal Generating Station is located on the 52-acre Station Property, Major components associated with existing Canal Station include: two steam-electric generating units; a 498-foot exhaust stack; eight aboveground storage tanks; two NH3 storage tanks; and appurtenant structures and infrastructure. Two aboveground oil storage tanks are located on the 36-acre tract south of the railroad ROW. Natural gas service is provided by an existing Algonquin Gas Transmission (AGT) pipeline, which is located under the Cape Cod Canal and is accessed at the western end of the 52-acre Station property.

Directly north of the 52-acre Station Property is the Cape Cod Canal, which has recreational walkways/bike paths located directly next to and on each side of the Canal. Canal Station has a docking facility located on the south side of the Canal for the docking of vessels, including oil delivery barges. The area directly north of the Canal, across from Canal Station, is primarily undeveloped. Scusset Beach State Reservation, which includes a campground and beach on Cape Cod Bay, is located to the northeast of the Project site, north of the Canal. On the South side of the Canal, the Town of Sandwich Marina, the Cape Cod Canal Visitors Center, and the United States Army Corps of Engineers (USACE) Sandcatcher Recreation Area are located to the east of the Project site. Farther east is an area of mixed use development. Several seasonal restaurants, including the Pilot House Restaurant and Lounge, Joe's Lobster Market, and Seafood Sam's Restaurant are located to the east of the Project site, on the south of the Cape Cod Canal, along with the Global Companies LLC fuel oil tank farm, and a United States Coast Guard Station. A more densely developed residential area is located farther east, extending to Scusset Harbor.

Immediately south of the Station Property is an active railroad ROW, used by the Cape Cod Scenic Railroad and a small number of freight trains. The nearest residence to the Station Property is located on Freezer Road, adjacent to and just south of the railroad tracks. Two additional single-family homes are located on Briarwood Avenue, south of the Station Property. Eversource owns an electrical substation, located south of the railroad ROW. Undeveloped wooded areas south of the Station Property extend to Tupper Road. To the east of Freezer Road, north of Tupper Road, are The Shipwreck Ice Cream and Marylou's Coffee.

South of Tupper Road, commercial development extends to Old King's Highway (Route 6A). This area includes a Super Stop & Shop, CVS Pharmacy, Citizen's Bank, Eastern Bank, Bobby Byrnes Restaurant, Cafe Chew, and the Post Office. Farther south, across Old King's Highway, is a mix of commercial and residential uses. Shawme-Crowell State Forest is approximately 1 mile south of the Station Property.

West of the Station Property is undeveloped wooded land in the Town of Bourne. Farther west is a mix of commercial and residential land uses along Old King's Highway.

The Massachusetts Executive Office of Energy and Environmental Affairs (EEA) has developed an Environmental Justice (EJ) Policy, and has identified EJ neighborhoods as areas with annual median household income equal to or less than 65% of the statewide median or populations 25% or greater of individuals classified as minority, foreign born, or lacking English language proficiency. The purpose of an EJ analysis is to determine whether the construction or operation of a proposed facility would have a significant adverse and disproportionate burden on an Environmental Justice community. Based on the determination of EJ areas as done by EEA, there are no mapped Environmental Justice communities within 5 miles of the Canal Generating Station. The closest EEA-mapped EJ area is to the west, in Onset MA, approximately 7.5 miles from the Project site.

2.3 SIMPLE-CYCLE COMBUSTION TURBINE

The Project will utilize a GE 7HA.02 CTG, or comparable unit. The CTG will operate in simple-cycle mode where the thermal energy from combustion of fuel is converted to mechanical energy, which drives an integral compressor and electric generator; there is no supplementary waste heat recovery. Simple-cycle operation allows for the CTG to respond quickly to the needs of the ISO-NE regional transmission system during times of peak energy demand. The reasons for selection of the H-Class turbine over an alternative simple cycle turbine are also addressed in Section 4.2.6.

2.3.1 Combustion Turbine Operation

The CTG is composed of three major sections: the compressor; the combustor, and the power turbine, as described below.

- In the compressor section, ambient air is drawn through a filter (which under certain meteorological and unit load conditions includes the operation of an evaporative cooler or inlet air heater) to clean (and cool or heat) the air. The air is then compressed and directed to the combustor section.
- The primary fuel that will be utilized by the CTG is natural gas, with limited firing of ULSD as a back-up fuel. The CTG will utilize DLN combustors to control NO_x formation during natural gas firing by pre-mixing fuel and air immediately prior to combustion. During ULSD firing, H_2O will be emulsified with the fuel and injected into the combustor to minimize peak flame temperature and reduce NO_x formation.
- In the combustor section, the fuel or fuel/H_2O mixture is introduced to air and combusted. Hot gases from combustion are diluted with additional air from the compressor section and directed to the power turbine section at high temperature and pressure.
- In the power turbine section, the hot exhaust gases expand and rotate the turbine blades, which are coupled to a shaft. The rotating shaft drives the compressor and the generator, which generates electricity.

Figure 2-2 presents the Site Plan and General Arrangement, Figure 2-3 presents an Elevation View, and Figure 2-4 presents a Process Flow Diagram.

The maximum electrical output of the CTG varies with temperature. At lower temperatures, the density of the compressor inlet air is higher and mass flow through the turbine is higher, which results in higher electrical output. In warm weather when air density is lower, an evaporative cooler is utilized to cool the combustion air in order to achieve greater electrical output. The gross electrical output of the CTG will vary from approximately 330 MW at higher ambient temperatures to approximately 365 MW at very low ambient temperatures. The net electrical output of the CTG will be slightly less due to internal (plant) loads from auxiliary equipment associated with the Project. The CTG will have a heat input rate while firing natural gas of approximately 3,256 million British thermal units per hour (MMBtu/hr) (higher heating value [HHV]) at 100 percent (%) load, 59 degrees Fahrenheit (°F) and 60% relative humidity. At the same conditions while firing ULSD, the CTG will have a firing rate of approximately 3,303 MMBtu/hr (HHV).

After passing through the combustion turbine, the hot exhaust gases will be sent through an oxidation catalyst and SCR to control NO_x, CO and VOC emissions. The temperature of the exhaust at the control equipment will be approximately 900°F. The exhaust stack will be constructed of steel and is proposed to be 220 feet tall, with a 25-foot diameter. With the base of the exhaust stack proposed at 16 feet (amsl), the top of stack is proposed at elevation of 236 feet amsl.

2.3.2 Air Pollution Control Equipment

The emission control technologies proposed for the CTG include DLN combustors, SCR to control NO_x emissions, and an oxidation catalyst to control CO and VOC emissions. When firing ULSD, H_2O injection will also be used to minimize NO_x emissions upstream of the SCR. DLN combustors are integrated within the CTG; the SCR and oxidation catalyst will be located within an integral separate housing. Due to the elevated temperature of the exhaust gas from the CTG (>1,100°F), a tempering air system will be employed to inject ambient air into the exhaust gas and lower its temperature to the proper operating temperature (nominally 900°F) at the SCR and oxidation catalyst.

The DLN combustors control NO_x formation during natural gas firing by pre-mixing fuel and air immediately prior to combustion. Pre-mixing inhibits NO_x formation by minimizing both the flame temperature and the concentration of oxygen (O_2) at the flame front. During ULSD firing, H_2O will be emulsified with the fuel and injected into the combustor, effectively mixing with the combustion air. By injecting H_2O into the combustion zone, the peak flame temperature will be minimized resulting in lower thermal NO_x formation.

CO and VOC formation will be minimized by combustor design and good combustion practices to ensure complete combustion of the fuel. ***Good combustion practices, or good combustion controls, as referred to throughout this document, refers to maintaining the appropriate air to fuel mixtures, air/fuel contact and combustion residence times to achieve proper combustion in accordance with the manufacturer's combustor design. This includes limiting residual emissions of CO and VOC while also limiting NOx formation in accordance with the combustor design.*** Emissions of SO_2, PM/PM_{10}/$PM_{2.5}$, and H_2SO_4 will be minimized through use of natural gas as the primary fuel; limited firing of ULSD with a maximum sulfur content of 15 parts per million by weight (ppmw) will also minimize emissions of these pollutants.

2.3.2.1 Selective Catalytic Reduction

SCR, a post-combustion chemical process, will treat exhaust gases downstream of the CTG. The SCR process will use 19% aqueous NH_3 as a reagent. Aqueous NH_3 will be injected into the flue gas stream upstream of the SCR catalyst, where it will mix with NO_x. The catalyst bed will be located in an integral separate housing along with the oxidation catalyst. The temperature of the SCR will be maintained within its designed operating zone by the introduction of ambient air into the exhaust gas from the CTG to cool the exhaust gas. The temperature-controlled exhaust gases with the injected NH_3 will pass over the catalyst and the NO_x will be reduced to nitrogen gas (N_2) and H_2O. The SCR system will reduce NO_x concentrations to 2.5 parts per million by volume dry basis corrected to

15 percent O_2 (ppmvdc) during natural gas firing and 5.0 ppmvdc during ULSD firing, across all steady-state operating loads and ambient temperatures.

A small amount of NH_3 will remain un-reacted through the catalyst, which is called “ammonia slip.” The ammonia slip will initially be limited to 5.0 ppmvdc at all load conditions and ambient temperatures for both fuels, with an optimization goal of 2.0 ppmvdc for natural gas firing. For ULSD firing, the proposed BACT limit is 5.0 ppmvdc.

2.3.2.2 Oxidation Catalyst

An oxidation catalyst system will be located within the same housing as the SCR to control emissions of CO and VOC. Exhaust gases from the CTG will flow through the catalyst bed where the CO and VOC will oxidize to form carbon dioxide (CO_2) and H_2O. The oxidation catalyst system will reduce CO concentrations to 4.0 ppmvdc in the exhaust gas during natural gas firing and 5.0 ppmvdc during ULSD firing, across all steady-state operating loads and ambient temperatures. VOC will be limited to 2.0 ppmvdc for both fuels.

2.4 ANCILLARY SOURCES

2.4.1 Emergency Diesel Generator

The purpose of the emergency diesel generator is to provide power to critical equipment in the event of a power failure, including the distributed control system, combustion turbine turning gear, combustion turbine lube oil pumps, as well as lighting and communication systems. ***The emergency diesel generator will not provide black-start capability for the new CTG unit.*** The emergency diesel generator will be rated at approximately 500 kWe (581 kW mechanical) and will be fired with ULSD. The engine will be a Tier 4 engine that will satisfy the emissions requirements of 40 CFR 1039.104(g), Table 1 and 40 CFR 60 Subpart IIII. Tier 4 refers to the fourth tier in a sequence of USEPA emission standards for nonroad diesel engines. Some of the Tier 1-4 designations are also used for certain requirements for stationary engines. The Tier 4 limit under 40 CFR 1039.104(g) is an alternate limit which applies to a percentage of a manufacturer’s engine family that does not require SCR for compliance. The emergency diesel generator will be a package unit that will contain a ULSD tank. Operation of the emergency generator engine will be limited to no greater than 300 hours per year.

2.4.2 Emergency Diesel Fire Pump

Two fire pumps will be provided to ensure 100% backup of the fire protection system water supply. One fire pump will be driven by an electric motor and the other will be driven by a diesel engine. Each pump will be capable of delivering total system requirements at design pressure and flow rate with any one pump out of service. The diesel-engine-driven fire pump will be rated at 135 bhp and will be fired with ULSD. The engine will be a Tier 3 engine that will satisfy the emissions requirements of 40 CFR 60 Subpart IIII. Fuel supply for the fire pump will be located in a tank adjacent to the pump. Operation of the emergency fire pump engine will be limited to no greater than 300 hours per year.

2.5 EMISSIONS SUMMARY

2.5.1 Combustion Turbine

Table 2-1 presents a summary of the proposed limits for candidate PSD pollutants emitted from the CTG at steady-state full-load operation. Startup/shutdown (SUSD) emissions are presented in Table 2-2. The limits incorporate BACT requirements as discussed in Section 4.0. Calculations for emission rates for all steady-state operating conditions and ambient temperatures are provided in Appendix A.

Table 2-1: Summary of Proposed Emission Limits for the CTG (Steady-State Full-Load Operation) [a]

Pollutant	Natural Gas Firing			ULSD Firing			Basis
	lb/MMBtu[b]	ppmvdc	lb/hr[c]	lb/MMBtu[b]	ppmvdc	lb/hr[c]	
NO_x	0.0092	2.5	31.5	0.0194	5.0	67.3	BACT/LAER
VOC	0.0026	2.0	8.9	0.0027	2.0	9.4	BACT
CO	***0.0079***	***3.5***	***25.9***	0.0118	5.0	41.0	BACT
$PM/PM_{10}/PM_{2.5}$ ***>=75% load***	0.0073[d]	n/a	18.1	***0.026[d]***	n/a	***65.8***	BACT
$PM/PM_{10}/PM_{2.5}$ >= MECL[d] but < 75% load	***0.012***	***n/a***	***18.1***	***0.046***	***n/a***	***65.8***	***BACT***
SO_2	0.0015	n/a	5.14	0.0015	n/a	5.21	BACT
H_2SO_4	0.0016	n/a	5.48	0.0018	n/a	6.25	BACT
GHG as CO_2e	1,178 lb/MW-hr (gross)[e]	n/a	407,575	1,673 lb/MW-hr (gross)[e]	n/a	565,252	BACT

[a] Project may exceed these limits during defined periods of startup, shutdown and malfunction.
[b] lb/MMBtu = pounds per million British thermal units. Emission rates are based on HHV of fuel.
[c] Maximum mass emission rate across all steady-state loads and ambient temperatures.
[d] ***Minimum Emissions Compliance Load (MECL), ranges from 30 -40% load based on fuel and ambient temperature.***
[e] BACT for GHGs is expressed as an efficiency based limit at International Organization for Standardization (ISO) conditions (base load, 59°F, 1 atmosphere pressure, and 60% relative humidity), gross output basis.

Project SUSD scenarios are presented in Table 2-2. Emissions during startup may, for some pollutants, result in an increase in short-term (pounds per hour [lb/hr]) emission rates. Potential annual emissions estimates for the proposed Project, as provided in Section 2.5, include emissions from SUSD.

Table 2-2: Proposed Provisional Startup and Shutdown Emission Limits for the Combustion Turbine

	Fuel	NO_x (lb/event)	CO (lb/event)	VOC (lb/event)	$PM/PM_{10}/PM_{2.5}$ (lb/event)
Startup	Natural Gas	151	130	9	9.1
	ULSD	219	163	12	48.2
Shutdown	Natural Gas	7	133	25	4.2
	ULSD	8	25	3	12.8

The SUSD limits in Table 2-2 are proposed as provisional limits since actual experience in the first year of operation may indicate a change in these limits is necessary. Short-term SUSD emission limits will be evaluated after a year of actual operation and revised values may be proposed if needed

2.5.2 Ancillary Sources

Table 2-3 provides emissions from the Project's ancillary equipment (emergency diesel generator and emergency diesel fire pump). Emissions of air contaminants from this equipment have been estimated based upon vendor emission guarantees, USEPA emission factors, mass balance calculations, and engineering estimates.

Table 2-3: Emissions from Ancillary Equipment

Pollutant	Emergency Generator (lb/hr)	Emergency Fire Pump (lb/hr)
PM_{10}	0.17	0.074
$PM_{2.5}$	0.17	0.074
SO_2	0.0075	0.0018
H_2SO_4	$5.78x10^{-4}$	1.38×10^{-4}
NO_x	4.48	0.89
CO	4.48	1.113
VOC	0.24	0.29
Pb	$1.60x10^{-5}$	3.76×10^{-6}
CO_{2e}*	819	195

* carbon dioxide equivalent

2.6 PROJECT POTENTIAL ANNUAL EMISSIONS

Potential annual emissions from the proposed Project were estimated using the following worst-case assumptions for any rolling 12 months of operation. However, as discussed in Section 3.3.4, under applicable NSPS Subpart TTTT requirements, operation over three years (based on 3-year rolling average) will not exceed a 40% capacity factor (CF). ***Compliance with this three-year rolling average 40% capacity factor is determined in accordance with Subpart TTTT, based on net electric output (actual net-electric sales divided by potential net-electric generation if the unit had operated for 8,760 hours in each year).***

The operation of the new CTG will be limited as follows on a rolling 12-month (R12M) basis.

- Operation of the CTG ***(all fuels) limited to*** 4,380 hours (50% CF) per ***R12M.***
- ULSD firing limited to 720 hours per ***R12M***.
- ***Total quantity of natural gas fired limited to 14,554,740 MMBtu (50º F full-load firing rate times 4,380 hours);***
- ***Total quantity of ULSD fired limited to 2,499,120 MMBtu (0º F full-load firing rate times 720 hours)***
- ***Incorporation*** of SUSD events, based on a conservative scenario (180 SUSD cycles on natural gas and 80 SUSD cycles on ULSD). ***The actual number of SUSD events is not specifically limited, but SUSD emissions will be tracked and included in total emissions to ensure the R12M emission limits are not exceeded.***

Potential annual emissions for the proposed Project are summarized in Table 2-4.

Table 2-4: Summary of Potential Annual Emissions (tons per year)

Pollutant	CTG	Emergency Generator Engine	Emergency Fire Pump Engine	Project Totals
PM	60.4	0.03	0.01	60.5
PM_{10}	60.4	0.03	0.01	60.5
$PM_{2.5}$	60.4	0.03	0.01	60.5
SO_2	11.1	$1.1x10^{-3}$	$2.7x10^{-4}$	11.1
NO_x	103.5	0.67	0.13	104.3
CO	***94.0***	0.67	0.17	***94.8***
VOC	23.3	0.04	0.04	***24.4***[b]
H_2SO_4	12.0	$8.7x10^{-5}$	$2.1x10^{-5}$	12.0
NH_3	50.3	---	---	50.3
Pb	0.004	$2.4x10^{-6}$	$5.6x10^{-7}$	0.004
CO_{2e}[a]	932,325	123	29	***934,041***[c]
Formaldehyde (max HAP)	1.6	$6.0x10^{-5}$	$2.1x10^{-4}$	1.6
Total HAP	3.9	$1.3x10^{-3}$	$7.2x10^{-4}$	3.9

[a] GHGs expressed as carbon dioxide equivalents, based on global warming potential of each individual GHG.

[b.] ***Includes 1.0 tpy VOC emissions from ULSD working and breathing losses.***

[c.] ***Includes allowance for 1,561 tpy CO_2e from methane leaks and 3 tpy CO_2e from potential SF_6 leaks.***

3.0 REGULATORY APPLICABILITY EVALUATION

This section identifies the federal regulations that may apply to the proposed Project and discusses how the Project will comply with all applicable requirements.

The federal regulations reviewed here include: New Source Review (NSR); NAAQS; NSPS; NESHAPs; the Acid Rain Program; the Title V Operating Permit Program; and NO_x Budget Program requirements. Applicable Massachusetts regulations are discussed in the MCPA/NNSR Application, which is being filed separately.

3.1 NEW SOURCE REVIEW

NSR applies to proposed new major sources of air pollutants. The NSR program for major sources includes two distinct permitting programs, PSD permitting for projects located in areas designated as unclassified or attainment with the NAAQS, and NNSR permitting for projects located in areas designated as nonattainment with the NAAQS. As an area may be in attainment with one or more NAAQS, but in nonattainment with one or more other NAAQS at same time, an individual project may be subject to both PSD and NNSR permitting depending upon its potential emissions. The federal PSD permit program under 40 CFR 52.21 applies to subject sources in Massachusetts and the program is administered by the MassDEP under the PSD Delegation Agreement. All of Massachusetts was recently designated as attainment with respect to the 2008 8-hour O_3 standard, with the exception of Dukes County. However, all of Massachusetts is within the OTR as designated by the Clean Air Act. New major sources or major source modifications in the Northeast Ozone Transport Region (OTR) are subject to the provisions of NNSR that apply to moderate O_3 nonattainment areas. Also, 40 CFR 81 still retains a Moderate Nonattainment designation for all of Massachusetts for the 1997 8-hour O_3 standard. The MassDEP has adopted, under 310 CMR 7.00, Appendix A, permitting requirements for new sources and modifications of existing major sources that correspond to the provisions of NNSR for serious ozone nonattainment areas, so these provisions of 310 CMR 7.00, Appendix A, control the NNSR permitting requirements for the Project.

Under the NNSR program, a project located in an area designated as nonattainment for O_3 must satisfy NNSR requirements for NO_x and/or VOC emissions if it exceeds the NNSR thresholds. For a facility that is an existing NNSR major source for both NO_x and VOC emissions, a modification of that facility that results in a net increase in NO_x and/or VOC emissions above their respective Significant Emission Rate (SER) triggers NNSR permitting requirements. The NNSR SER threshold under 310 CMR 7.00, Appendix A, for both NO_x and VOC emissions is 25 tons per year (tpy).

The Station is an existing PSD major source for emissions of NO_x, VOC, SO_2, PM, PM_{10}, and $PM_{2.5}$, since potential emissions of these pollutants from the existing Station exceed the applicable PSD major source threshold of 100 tpy for steam-electric generating facilities. Therefore, a modification of the Station (for purposes of PSD review) that results in a net increase in any PSD pollutant above its respective PSD SER triggers PSD permitting requirements.

Table 3-1 presents a comparison of the Project's potential emissions with the applicable PSD SERs. As summarized in Table 3-1, the Project exceeds the PSD SER for NO_x, $PM/PM_{10}/PM_{2.5}$, H_2SO_4, and GHG emissions. Therefore, the Project is subject to PSD review for NO_x, $PM/PM_{10}/PM_{2.5}$, H_2SO_4, and GHGs.

Table 3-1: Summary of Project Emissions and Applicable PSD Thresholds

Pollutant	Project PTE (tpy)	PSD SER (tpy)	PSD Applies? (Yes/No)
PM	60.5	25	Yes
PM_{10}	60.5	15	Yes
$PM_{2.5}$	60.5	10	Yes
SO_2	11.1	40	No
NO_x	104.3	40	Yes
CO	***94.8***	100	***No***
VOC	***24.4***	40	No
H_2SO_4	12.0	7	Yes
Pb	0.004	0.6	No
GHGs[a]	932,477	75,000	Yes

[a] GHGs are expressed as CO_{2e}. Note that as of a June 23, 2014 Supreme Court Decision, GHG emissions cannot determine major source status. USEPA issued a Policy Memo dated July 24, 2014, indicating that it intends to apply the current GHG SER threshold for requiring PSD BACT review for GHG for "anyway" sources (sources that are subject to PSD review for criteria pollutants).

Under the PSD regulations, subject sources must satisfy the following requirements:

- demonstration of BACT controls;
- an ambient air quality modeling analysis demonstrating compliance with NAAQS and PSD Increments;
- additional air quality impact analyses on secondary growth, visibility impairment, soils and vegetation, and other air quality related values at PSD Class I Areas; and,
- demonstration of compliance with federal Environmental Justice (EJ) requirements.

The PSD BACT analysis is provided in Section 4.0. The modeling analysis along with the additional impacts analyses and EJ demonstration are provided in Section 5.0.

3.2 AMBIENT AIR QUALITY STANDARDS

The USEPA has developed NAAQS for six air contaminants, known as criteria pollutants, for the protection of public health and welfare. These criteria pollutants are SO_2, PM, nitrogen dioxide (NO_2), CO, O_3, and lead (Pb). PM is characterized according to size; PM having an effective aerodynamic diameter of 10 microns or less is referred to as PM_{10}, or "respirable particulate." PM having an effective aerodynamic diameter of 2.5 microns or less is referred to as $PM_{2.5}$, or "fine particulate"; $PM_{2.5}$ is a subset of PM_{10}.

The NAAQS have been developed for various durations of exposure. The NAAQS for short-term periods (24 hours or less) typically refer to pollutant levels that cannot be exceeded except for a limited number of cases per year. The NAAQS for long-term periods refer to pollutant levels that cannot be exceeded for exposures averaged typically over one year. The NAAQS include both "primary" and "secondary" standards. The primary standards are intended to protect human health and the secondary standards are intended to protect the public welfare from any known or anticipated adverse effects associated with the presence of air pollutants.

One of the basic goals of federal and state air pollution regulations is to ensure that ambient air quality, including consideration of background levels and contributions from existing and new sources, is in compliance with the NAAQS. Toward this end, for each criteria pollutant, every area of the United States has been designated as one of the following categories: attainment; unclassifiable; or nonattainment. In areas designated as attainment, the air quality with respect to the pollutant is equal to or better than the NAAQS. These areas are under a mandate to maintain, i.e., prevent significant deterioration of, such air quality. In areas designated as unclassifiable, there are limited air quality data, and those areas are treated as attainment areas for regulatory purposes. In areas designated as nonattainment, the air quality with respect to the pollutant is worse than the NAAQS. These areas must take actions to improve air quality and achieve attainment with the NAAQS within a certain period of time.

If a new major source or a major modification of an existing major source of air pollution is proposed, it must undergo NSR. There are two NSR programs, one for sources being built in attainment/unclassifiable areas, and one for sources in nonattainment areas. The NSR program for sources in attainment/unclassifiable areas is known as the PSD Program. The NSR program for sources being built in nonattainment areas is known as the NNSR Program.

The Project location is presently classified as “attainment” for SO_2 and NO_2, and “attainment/unclassifiable” (combined definition) for CO, Pb, and all particulates. Thus, emissions of these pollutants are evaluated under the PSD program. Except for Dukes County, all of Massachusetts was reclassified as attainment with respect to the 2008 8-hour O_3 standard on May 21, 2012. However, 40 CFR 81 still retains a moderate nonattainment designation for the 1997 8-hour O_3 standard. Also, due to the federal Clean Air Act requirements for the OTR, which includes all of Massachusetts, as well as the MassDEP NNSR provisions of 310 CMR 7.00, Appendix A, all of Massachusetts is still treated as an O_3 nonattainment area for NSR purposes.

To identify new emission sources with the potential to have a significant impact on ambient air quality, the USEPA and MassDEP have adopted significant impact levels (SILs) for the criteria pollutants. Applicants for new major sources or major modifications of existing major sources are required to perform dispersion modeling analyses to predict air quality impacts of the new or modified sources in comparison to the SILs. If the predicted impacts of the new or modified sources are less than the SIL for a particular pollutant and averaging period, then the impacts are considered “insignificant” for that pollutant and averaging period. However, if the predicted impacts of the new or modified sources are greater than the SIL for a particular pollutant and averaging period, then further impact evaluation is required. This additional evaluation must consider measured background levels of pollutants and emissions from both the proposed new sources and existing interactive sources. Further, in areas attaining the NAAQS, air quality is not permitted to degrade beyond specified levels, called PSD Increments, as a result of the cumulative impacts of “PSD Increment consuming” sources. In general, sources constructed or modified after pollutant and area-specific “baseline dates” consume PSD Increment.

Table 3-2 presents the NAAQS ***and MAAQS*** as well as the corresponding SIL and PSD increment values for the various criteria pollutants and averaging periods.

Section 5.0 of this application presents a detailed evaluation of the Project’s compliance with the applicable ambient air quality standards.

Table 3-2: National *and Massachusetts* Ambient Air Quality Standards

Pollutant	Averaging Period	NAAQS/MAAQS[a] (µg/m³)[b]		Significant Impact Level (µg/m³)	PSD Increment (µg/m³)
		Primary	Secondary		
NO_2	Annual[c]	100	Same	1	25
	1-hour[d]	188	None	7.5	Not yet proposed
SO_2	Annual[c,e]	80	None	1	20
	24-hour[e,f]	365	None	5	91
	3-hour[f]	None	1,300	25	512
	1-hour[g]	196	None	7.8	None
$PM_{2.5}$	Annual[h]	12	Same	0.3	4
	24-hour[i]	35	Same	1.2	9
PM_{10}	Annual[j]	50	Same	1	17
	24-hour[k]	150	Same	5	30
CO	8-hour[f]	10,000	None	500	None
	1-hour[f]	40,000	None	2,000	None
O_3	8-hour[k]	137	Same	None	None
	1-hour[l]	235	Same	None	None
Pb	***Rolling*** 3-month[c]	0.15	Same	None	None

[a] The MAAQS were last amended in April 1994, prior to promulgation of the NAAQS for 1-hr NO_2, 1-hr SO_2, $PM_{2.5}$, and 8-hr O_3. Therefore, these standards are only NAAQS.

[b] µg/m³ = micrograms per cubic meter

[c] Not to be exceeded.

[d] To attain this standard, the 3-year average of the 98th percentile of the daily maximum 1-hour average at each monitor within an area must not exceed 100 parts per billion (ppb) (188 µg/m³).

[e] The 24-hour and annual average primary NAAQS for SO_2 have been revoked. However, these standards remain in effect until one year after an area is designated for the new 1-hour standard, and they also remain in effect as MAAQS.

[f] Not to be exceeded more than once per year.

[g] To attain this standard, the 3-year average of 99th percentile of the daily maximum 1-hour average at each monitor within an area must not exceed 75 ppb (196 µg/m³).

[h] To attain this standard, the 3-year average of weighted annual mean $PM_{2.5}$ concentrations at community-oriented monitors must not exceed 12 µg/m³.

[i] To attain this standard, the 3-year average of 98th percentile of 24-hour concentrations at each population-oriented monitor within an area must not exceed 35 µg/m³.

[j] MAAQS only. NAAQS for annual PM_{10} and 1-hr O_3 no longer exist. Annual PM_{10} is not to be exceeded based on 3 year average. 1 hour O_3 is based on expected number of days in exceedance < one per year.

[k] ***To attain this standard, the 3-year average of the fourth highest daily maximum 8-hour average ozone concentrations measured at each monitor within an area over each year must not exceed 0.070 ppm.***

[l] To attain this standard, ***the number of days per calendar year, with maximum hourly average concentration greater than 0.12 ppm, must not exceed 1***.

3.3 NEW SOURCE PERFORMANCE STANDARDS

The NSPS (40 CFR 60) are technology-based standards applicable to new and modified stationary sources. NSPS have been established for approximately 70 source categories. Based upon a review of these standards, several subparts are applicable to the proposed Project. The Project's compliance with each of these standards is presented in the following sections.

3.3.1 40 CFR 60 – Subpart A – General Provisions

Any source subject to an applicable standard under 40 CFR 60 is also subject to the general provisions under Subpart A. Because the Project is subject to other Subparts of the regulation as set forth below, the requirements of Subpart A will also apply. The Project will comply with the applicable notifications, performance testing, recordkeeping and reporting outlined in Subpart A.

3.3.2 40 CFR 60 – Subpart KKKK – Stationary Combustion Turbines

Subpart KKKK places emission limits on NO_x and SO_2 from new combustion turbines. The proposed CTG will be subject to this standard. For new CTGs with a rated heat input greater than 850 MMBtu/hr, NO_x emissions are limited to the following:

- 15 ppmvdc for natural gas and 42 ppmvdc for oil; or
- 54 nanograms per Joule (ng/J) of useful output (0.43 pounds per megawatt-hour [lb/MW-hr]) for natural gas and 160 ng/J or useful energy output (1.3 lb/MW-hr) for oil.

Additionally, SO_2 emissions must meet one of the following:

- emissions limited to 110 ng/J (0.90 lb/MW-hr) gross output; or
- emissions limited to 26 ng/J (0.060 lb/MMBtu).

As described in Section 2.0, the proposed Project will use DLN combustors and an SCR system to control NO_x emissions to 2.5 ppmvdc during natural gas firing. H_2O injection and SCR will be used to control NO_x emissions to 5.0 ppmvdc during ULSD firing. SO_2 emissions will be limited to 0.0015 lb/MMBtu when firing both pipeline-quality natural gas and ULSD. As such, the Project will meet the emission limits under Subpart KKKK.

3.3.3 40 CFR 60 – Subpart IIII – Stationary Compression Ignition Internal Combustion Engines

Subpart IIII is applicable to owners and operators of stationary compression ignition (CI) internal combustion engines that commence operation after July 11, 2005. Relevant to the proposed Project, this rule applies to the emergency generator engine and emergency fire pump engine.

For model year 2010 and later, fire pump engines with a displacement less than 30 liters per cylinder and an energy rating between 100 and 175 horsepower (hp), Table 4 of Subpart IIII provides the following emission limits:

- 4.0 grams per kilowatt-hour (g/kW-hr) (3.0 grams per horsepower-hour [g/hp-hr]) of NO_x + VOC
- 5.0 g/kW-hr (3.7 g/hp-hr) of CO
- 0.30 g/kW-hr (0.22 g/hp-hr) of PM

The Project will install a fire pump meeting these emission standards.

To comply with Subpart IIII, new emergency stationary CI engines with a displacement less than 30 liters per cylinder must meet the emission standards per 40 CFR 60.4205(b). To meet these limits and satisfy BACT requirements, the proposed 581-kW (mechanical) new emergency stationary CI engine will meet USEPA's Tier 4 limits under 40 CFR 1039.101, Table 1 and 40 CFR 1039.104(g), Table 1 as follows:

- 3.5 g/kW-hr (2.6 g/hp-hr) of NO_X
- 0.19 g/kW-hr (0.14 g/hp-hr) of VOC
- 3.5 g/kW-hr (2.6 g/hp-hr) of CO
- 0.1 g/kW-hr (0.07 g/hp-hr) of PM (filterable)

3.3.4 40 CFR 60 – Subpart TTTT – Greenhouse Gas Emissions from New Stationary Sources: Electric Utility Generating Units

Subpart TTTT for GHG emissions from electric generating units (including combustion turbines) was promulgated by USEPA on August 4, 2015. A natural gas-fired combustion turbine with an annual capacity factor (on a three-year rolling basis) that exceeds the combustion turbine's "design efficiency," expressed as a percent, as defined in the rule, is considered a "baseload" unit. The applicable standard for baseload combustion turbine is 1,000 pounds of CO_2/MW-hr gross energy output (lb CO_2/MW-hr) or 1,030 lb CO_2/MW-hr net energy output. The "design efficiency" is the rated efficiency of the turbine at ISO conditions, net basis.

The "design efficiency" value for an H-class turbine in a simple-cycle configuration is nominally 40%. Accordingly, if the Project were to operate, on a rolling three-year average, at a capacity factor in excess of 40%, the Project would need to meet the 1,000 lbs CO_2/MW-hr gross – 1,030 lb CO_2/MW-hr net energy output standards. However, as long as the Project operates as a non-base-load facility (i.e., its annual capacity factor is equal to or less than the Unit's 40% design efficiency) then the Project is subject to different requirements, as described below.

Under Subpart TTTT, non-baseload, multi-fuel combustion turbines must comply with a mass-based standard, which is expressed in the units of lbs of CO_2 per MMBtu heat input. For multi-fuel units like the proposed Project, compliance must be demonstrated with a sliding scale standard in the range of 120-160 lbs CO_2/MMBtu, where the specific limit is calculated based on the percent of the rolling 12-month heat input that is natural gas and ULSD, respectively. Compliance with this limit can be demonstrated using the respective carbon contents of natural gas and ULSD. As a multi-fuel non-baseload unit, the Project could be operated up to 4,380 full-load hours in any specific 12-month period with up to 720 full-load hours in this 12-month period on ULSD, and maintain compliance with the sliding scale multi-fuel lbs CO_2/MMBtu requirement.

The Project will comply with a maximum three-year rolling average capacity factor of no more than 40% so as to qualify as a non-baseload unit under Subpart TTTT. In any single 12-month period, the operation of the Project may be as much as 4,380 hours (50% CF) to accommodate projected worst-case operating scenarios. However, for any 12-month period that the Project operates at a 50% CF, the Project will be required to operate at an average capacity factor of 35% in the following 2 years, in order to comply with the 3-year rolling average 40% CF limit.

3.4 NATIONAL EMISSION STANDARDS FOR HAZARDOUS AIR POLLUTANTS (40 CFR 61 AND 63)

There are no 40 CFR 61 standards applicable to the proposed Project. Current USEPA Compilation of Air Pollutant Emission Factors (AP-42), other applicable emission factors, and vendor information were reviewed in determining if the proposed Project will be subject to a standard under 40 CFR 63. The existing Station is a major source of HAP emissions and, therefore, the Project is considered a major source under 40 CFR 63.

3.4.1 40 CFR 63 – Subpart YYYY – Stationary Combustion Turbines

The Station is an existing major source of HAP emissions; therefore, the Project has been evaluated with respect to Subpart YYYY for Stationary Combustion Turbines, which was promulgated on March 5, 2004. In April 2004, USEPA proposed to "delist" natural gas-fired combustion turbines from the NESHAPs program. In August 2004, USEPA stayed (indefinitely) the combustion turbine NESHAPs for natural gas-fired turbines (including any unit which fires oil less than 1,000 hours per calendar year) pending a final decision on delisting; no final delisting decision has been made. Since the Project is proposing to fire no more than 720 hours of oil in any calendar year, ***the operating, monitoring and reporting requirements of*** Subpart YYYY do not apply ***as long as the stay is in effect. The initial notification requirements of Subpart YYYY under 40 CFR 63.6145 still do apply. It is also noted that*** the Project will be equipped with lean pre-mix combustors for natural gas firing that effectively limit products of incomplete combustion such as formaldehyde. In addition, the oxidation catalyst system will be effective at limiting formaldehyde emissions on both natural gas and ULSD.

3.4.2 40 CFR 63 – Subpart ZZZZ – Reciprocating Internal Combustion Engines

The emergency generator diesel engine and emergency diesel fire pump engine are subject to the NESHAPs under 40 CFR 60 Subpart ZZZZ. These NESHAPs generally apply, with the same requirements for new emergency generators, regardless of major or minor HAP source status. For new emergency units, the NESHAPs requirements are satisfied if the units comply with the NSPS under 40 CFR 60, Subpart IIII. As stated in Section 4.3, the Project will purchase emergency generator and fire pump engines that comply with NSPS Subpart IIII.

3.5 ACID RAIN PROGRAM

Title IV of the Clean Air Act Amendments of 1990 required USEPA to establish a program to reduce emissions of acid rain-forming pollutants, called the Acid Rain Program. The overall goal of this program is to achieve significant environmental benefits through reduction in SO_2 and NO_x emissions. To achieve this goal, the program employs a market-based approach for controlling air pollution. Under the market-based aspect of the program, affected units are allocated SO_2 allowances by the USEPA, which may be used to offset emissions, or traded under the market allowance program. In addition, in order to ensure that facilities do not exceed their allowances, affected units are required to monitor and report their emissions using a Continuous Emissions Monitoring System (CEMS), as approved under 40 CFR Part 75.

The Project is subject to the Acid Rain Program based on the provisions of 40 CFR 72.6(a)(3) because the CTG is considered a “utility unit” under the program definition and does not meet the exemptions listed under paragraph (b) of this Section. The Project will be required to submit an Acid Rain Permit application at least 24 months prior to the date on which the affected units commence operation. The Project will submit an Acid Rain Permit application in compliance with these requirements prior to this deadline.

3.6 NO_X AND SO_2 BUDGET PROGRAMS

On March 10, 2005, USEPA issued the Clean Air Interstate Rule (CAIR), which required reductions in emissions of NO_x and SO_2 from large fossil fuel-fired electric generating units on a state-specific basis using a cap-and-trade system. The rule provided an annual emissions budget and/or an ozone season emission budget for certain affected states. Massachusetts was subject to ozone-season NO_x requirements under CAIR, but was not subject to any annual NO_x or SO_2 requirements under CAIR.

On July 11, 2008, the United States Court of Appeals for the District of Columbia Circuit (the Court) issued an opinion vacating and remanding CAIR. However, on December 23, 2008, the Court granted rehearing only to the extent that it remanded the rules to USEPA without vacating them. The December 23, 2008 ruling left CAIR in place until the USEPA issued a new rule to replace CAIR, in accordance with the July 11, 2008 provisions.

On July 6, 2011, the USEPA issued the Cross-State Air Pollution Rule (CSAPR), which replaced CAIR. However, Massachusetts was not subject to any requirements under CSAPR. After legal delays, CSAPR officially replaced CAIR, effective January 1, 2015.

While Massachusetts is not subject to CSAPR, and CAIR is no longer in effect, Massachusetts is prevented from “backsliding” under the Clean Air Act. As a result, the MassDEP has indicated that it will implement regulations to maintain the historical CAIR restrictions on ozone-season NO_x emissions. At this time, replacement regulations for CAIR have not been promulgated.

The Project will comply with the rules in effect when the Project becomes operational.

3.7 ACCIDENTAL RELEASE PROGRAM

Section 112r of the Clean Air Act governs the storage and handling of certain chemicals. Aqueous NH_3 will be used as the reagent for the SCR systems for controlling NO_x emissions. Aqueous NH_3 at a concentration of 19% by weight will be supplied from the two existing 60,000-gallon storage tanks. Facilities that store aqueous NH_3 solutions containing less than 20% ammonia by weight are not subject to the accidental release requirements under Section 112r. However, Section 112r includes a general-duty clause covering the storage of all chemicals of all quantities. To address the general-duty clause, an analysis of potential impacts from a hypothetical worst-case ammonia spill is provided in the MCPA/NNSR Application, which is being submitted separately.

3.8 TITLE V OPERATING PERMIT PROGRAM

USEPA has delegated MassDEP authority to administer the Title V Operating Permit Program (40 CFR 70), under its regulations at 310 CMR 7.00: Appendix A. The Station is an existing major source and is operating under Title V Operating Permit Application No. 4V95058 and SE-13-022. In accordance with 310 CMR 7.00, Appendix A, an application for a significant modification of the Title V Operating Permit must be submitted to the MassDEP no later than nine months prior to the planned modification. NRG will submit an application for a significant modification of the Title V Operating Permit within the required timeframe.

4.0 BEST AVAILABLE CONTROL TECHNOLOGY ANALYSIS

Pollutants subject to PSD review are required to determine BACT as defined by the PSD regulations at 40 CFR 52.21. As discussed in Section 3.1, BACT is required for emissions of NO_x, $PM/PM_{10}/PM_{2.5}$, H_2SO_4 and GHG because the Project's potential emissions exceed the PSD SER thresholds. The BACT analysis set forth below was conducted using a top-down approach consistent with PSD BACT requirements.

4.1 BACT ANALYSIS APPROACH

A top-down analysis was employed that satisfies the requirements of the federal PSD regulations and accompanying policies. In accordance with 40 CFR 52.21, PSD BACT is defined as the following:

> "…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."

USEPA has also issued the "Top Down BACT Policy" (1987) and draft "New Source Review Workshop Manual, Prevention of Significant Deterioration and Nonattainment Area Permitting" (October 1990). In those documents, the USEPA describes a five-step "top-down" process to identify BACT. This five-step process has been followed to identify BACT for all pollutants subject to PSD and 310 CMR 7.02 BACT. The top-down BACT process involves the following five-steps:

(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.

Following is a description of the steps followed for each BACT subject pollutant for each emission source.

4.1.1 Step 1: Identification of Control Technology Options

The first step in a BACT analysis is the identification of available control technologies, including an evaluation of transferable and innovative control measures that may not have been previously applied to the source type under analysis. For emission sources with a large number of recent control technology determinations, such as those proposed for the Project, available control technologies can be identified from various agency reviews of these projects. A review was conducted of recent technical determinations made by USEPA and various state air agencies to identify available control technology options for each proposed emission source and each subject pollutant.

4.1.2 Step 2: Identification of Technically Infeasible Control Technology Options

Once all control technology options are identified, each is evaluated to determine if it is technically feasible for the proposed emission source. This determination is made on a case-by-case basis in accordance with USEPA and MassDEP guidance. A control option may be shown to be technically infeasible by documenting that technical difficulties would preclude the successful use of the control option on the emissions unit under review. Per USEPA guidance, a permit requiring the application of a technology is sufficient justification to assume the technical feasibility of that technology. Following this guidance, this analysis has focused on technologies that have been demonstrated in practice based upon recent determinations and reviewed alternative technologies to assess their capability to achieve a greater emission reduction than the approved technologies.

4.1.3 Step 3: Ranking of Technically Feasible Control Technology Options

After technically infeasible control technologies have been eliminated, the remaining control options are ranked by control effectiveness. The minimum requirement for a BACT proposal is an option that meets federal NSPS limits or other minimum state or local requirements, such as MassDEP emission standards.

4.1.4 Step 4: Evaluation of Most Effective Controls

The USEPA's draft "New Source Review Workshop Manual, Prevention of Significant Deterioration and Nonattainment Area Permitting" states that:

> "…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."

In USEPA's guidance document "PSD and Title V Permitting Guidance for Greenhouse Gases" (March 2011), it states that "the top-ranked option should be established as BACT unless the permit applicant demonstrates to the satisfaction of the permitting authority that technical considerations, or energy, environmental, or economic impacts justify a conclusion that the top-ranked technology is not 'achievable' in that case." Accordingly, an evaluation of energy, environmental, or economic impacts is applied only when an applicant wants to demonstrate that the top-ranked option is not achievable.

Based upon this guidance, when the top-case BACT option was determined to be achievable and was selected for the Project, an evaluation of energy, environmental, or economic impacts in general was not considered. The only exception to this is that any collateral environmental impacts associated with a proposed top-case option are addressed only to the extent to determine if such collateral impacts would be unacceptable, and thus rule out a proposed top-case option as BACT.

In order to identify the most effective control for each subject emission source and pollutant, a search was performed of the USEPA's RBLC database, limits in State Implementation Plans (SIPs) as well as permits issued by the MassDEP and other states, to the extent available. Information was compiled for each emission source, focusing on projects permitted in the last five years. Older precedents were included on a pollutant-specific basis to identify the most stringent permitted emission levels achieved in practice. Appendix B provides a summary of BACT precedents identified for large simple-cycle combustion turbine projects.

4.1.5 Step 5: Selection of BACT

If there is only a single technically feasible option, or if the top-ranked control option is proposed, then no further analysis was conducted other than a check of any unacceptable collateral environmental impacts as discussed above. If two or more technically feasible options were identified, and the most stringent (top) level of control was not proposed, the next three steps (as presented below) were applied to demonstrate that the economic, energy, and environmental impacts of the top-ranked option justified not selecting this option as BACT.

4.1.5.1 Economic Impacts

The economic analysis consists of evaluating the cost-effectiveness of a control technology, on a dollar-per-ton-of-pollution-removed basis. Annual emissions with a control option are subtracted from base-case emissions to calculate tons of pollutant controlled. The base case may be uncontrolled emissions or the maximum emission rate allowed by regulation (such as an NSPS limit). Annual costs are calculated by the sum of operation and maintenance costs plus the annualized capital cost of the control option. Operating and maintenance costs may take into account a reduction in the output capacity or reliability of a unit. The cost-effectiveness (dollars per ton of pollutant removed) of a control option is the annual cost (dollars per year) divided by the annual reduction in pollutant emissions (tpy). If the calculated cost effectiveness is deemed too high, then a control option may be eliminated from the remainder of the BACT analysis for economic reasons. If the most effective control option is proposed, or if there are no technically feasible control options, an economic analysis is not required.

4.1.5.2 Energy Impacts

The consumption of energy by the control option itself is a quantifiable energy impact. These impacts can be quantified by either an increase in fuel consumption due to reduced efficiency or fuel consumption to power the control equipment.

4.1.5.3 Environmental Impacts

The environmental impact analysis concentrates on other impacts such as solid or hazardous waste generation, discharges of polluted water from a control device, visibility impacts, or emissions of additional regulated or unregulated pollutants. Collateral increases or decreases in air pollutant emissions of other criteria or non-criteria pollutants may occur with a control option and should be evaluated. These additional impacts are identified and qualitatively and/or quantitatively evaluated as appropriate.

4.2 COMBUSTION TURBINE

4.2.1 Fuels

The first step in evaluating BACT is to evaluate changes in raw materials where substitution to a lower emitting raw material may be technically feasible. For the Project, the “raw material” would be the fuel combusted in the combustion turbine. The selection of the lowest-emitting fuel for a combustion source affects emissions of multiple pollutants and, therefore, this review of available fuels is applicable for all BACT-subject pollutants for the Project.

4.2.1.1 Step 1: Identification of Control Technology Options

Available fuel choices for the CTG include the following:

- natural gas as the sole fuel, based on securing a dedicated pipeline supply;
- natural gas as the primary fuel with liquefied natural gas (LNG) as backup; and
- natural gas as the primary fuel with ULSD as backup.

4.2.1.2 Step 2: Identification of Technically Infeasible Control Technology Options

Natural gas is the cleanest burning fossil fuel and its selection as the primary fuel is the “top case” for emissions reductions that may be achieved through fuel choice. The design of the Project as an on-demand peaking power source that can start and reach full load within 10 minutes requires that a source of fuel be available at all times ("No Notice Service"). The Station currently connects to an AGT interstate natural gas pipeline. The AGT system is highly constrained particularly on its G Lateral where the Project will connect. This means that there is not always sufficient latent capacity to reliably support quick start capability at the Project. Although AGT does provide No-Notice Service (i.e., firm fixed-contract for uninterruptible supply available at a moment's notice) to some customers, it is fully subscribed by local gas distribution companies who use this service to supply existing firm downstream commitments. Natural gas as a sole fuel source is, therefore, deemed infeasible for purposes of BACT.

As stated above, the Station does not have a firm-fixed contract for an uninterruptible supply of natural gas. ISO-NE's recent *Winter Reliability Program Update* (September 2015)[3], noted that the region is increasingly reliant on resources with uncertain availability, and that natural gas generating units typically lack firm gas transportation or fuel storage.

In ISO-NE's *2015 Regional Electricity Outlook*[4], ISO-NE discusses the issue of natural gas supply constraints in the regional natural gas transmission system. ISO-NE notes that the natural gas pipeline system is reaching maximum capacity more often and when supplies become constrained, priority goes to residential and commercial customers. Given the location of the Project within New England's natural gas transmission system, it is anticipated that natural gas may not be available at all times based on the current gas pipeline infrastructure, especially (as described below) within 10-minutes of a dispatch notice from ISO-NE. As stated above, No Notice Service via the existing natural gas transmission system is not commercially available and, therefore, such service to the Project is deemed infeasible for purposes of BACT.

The Project's purpose as a source of peaking power supply when electric supplies are needed most by the regional transmission system eliminates the option of relying on interruptible gas as the sole fuel for the CTG. The Project could not fulfill its central function as a backstop for regional power supplies if it could only operate on interruptible gas. Therefore, using interruptible gas as the sole fuel was deemed infeasible and eliminated as an option for the Project. Dual-fuel capability for the Project is necessary because at times ULSD will be the only available fuel that can be relied upon when ISO-NE dispatches the Project within 10 minutes to maintain bulk power system reliability.

Securing a dedicated pipeline supply of natural gas to the Station is also not feasible for the Project. Due to regional gas pipeline constraints discussed in the ISO-NE reports referenced above, securing a dedicated pipeline supply of natural gas to the Station site would require major regional infrastructure system improvements that are well beyond the scope a single generation project could undertake. Contemplated and proposed upgrades to the interstate natural gas pipeline system serving New England are well documented by ISO-NE and others (Raab and Peterson, 2015). Proposed upgrades to the interstate gas pipeline system serving New England, which would enable dedicated natural gas supplies to be available for proposed generation facilities such as the Project, are well beyond the reasonable commercial feasibility of a single generation project to undertake. Therefore, while it is theoretically possible (at some speculative future date) to complete such upgrades to the interstate gas pipeline system serving New England, these upgrades are not achievable in any reasonable time frame to supply the Project with uninterruptable No Notice Service natural gas. Therefore, these interstate pipeline upgrades are deemed technically infeasible for purposes of BACT.

Another potential option that would create a dedicated supply of natural gas to the Project would be installation of LNG storage. Securing the necessary approvals and constructing this LNG storage at the Station site is also not technically feasible for the Project. A significant concern is the exclusion zone required around LNG storage tanks and whether sufficient space even exists for such an exclusion zone at the Station site. Construction and operation of LNG storage is a major undertaking that changes the fundamental nature of the Project. LNG delivery is typically by large specialized ocean vessels, which would require major infrastructure to unload such vessels and revaporize the LNG. The length of time alone to secure approvals for new LNG-related infrastructure, if they could even be

[3] http://www.iso-ne.com/static-assets/documents/2015/09/final_gillespie_raab_sept2015.pdf
[4] http://www.iso-ne.com/static-assets/documents/2015/02/2015_reo.pdf

obtained at all, would certainly not be possible in any reasonable timeframe that is consistent with this proposal to construct a peaking electric generation facility. Therefore, using LNG as a backup to pipeline natural gas is eliminated as technically infeasible for the Project.

Therefore, the only remaining technically feasible fueling option for the Project is the use of interruptible natural gas as the primary fuel with ULSD as the backup fuel.

4.2.1.3 Step 3: Ranking of Technically Feasible Control Technology Options

The sole technically feasible option for fuels is natural gas as the primary fuel with ULSD as backup fuel.

4.2.1.4 Step 4: Evaluation of Most Effective Controls

Limits achieved in practice for generating units that utilize ULSD as backup fuel include limiting the number of operating hours when the backup fuel can be fired and restrictions on when backup fuel can be fired. The most recent PSD approval issued for a dual-fuel electric generating unit in Massachusetts is for the Pioneer Valley Energy Center. This approval limited backup firing of ULSD to 1,440 hours per year and imposed the following restrictions on when ULSD can be fired:

i. The interruptible natural gas supply is curtailed at the Tennessee No. 6 gas terminal hub. A curtailment begins when the owner/operator receives a communication from the owner of the hub informing the owner/operator stating that the natural gas supply will be curtailed, and ends when the owner/operator receives a communication from the owner of the hub stating that the curtailment has ended.

ii. Any equipment (whether on-site or off-site) required to allow the turbine to utilize natural gas has failed;

iii. The owner/operator is commissioning the combined-cycle turbine and, pursuant to the turbine manufacturer’s written instructions, the owner/operator is required by the manufacturer to fire ULSD during the commissioning process;

iv. The firing of ULSD is required for emission testing purposes as specified in the PSD permit or as required by the Commonwealth of Massachusetts;

v. Routine maintenance of any equipment requires the owner/operator to fire ULSD; and,

vi. In order to maintain an appropriate turnover of the on-site fuel oil inventory, the owner/operator can fire ULSD when the age of the oil in the tank is greater than six months. A new waiting period for when oil can be used pursuant to this condition will commence once oil firing is stopped.

4.2.1.5 Step 5: Selection of BACT

The proposed fuel BACT for the Project is the use of natural gas as the primary fuel, with ULSD as backup. The selection of appropriate conditions on ULSD use is key to the fuels BACT determination.

Establishing appropriate restrictions on ULSD use, consistent with the provisions of BACT, requires that the basic relationship between power demand and fuel purchase be examined. In general, ISO-NE can procure power from generating units such as the Project based on either the “Day Ahead” market or the “Real Time” market. The “Day Ahead” market involves bidding power sales one day prior to when the power would be generated, which also allows fuel purchase arrangements to be made one day in advance. It is much more likely that gas supplies can be successfully arranged for the Project in the Day Ahead market. In contrast, the “Real Time” market functions on the same day the power is generated. Real Time operation includes resources known as “fast-start generators” participating in the “Ten-Minute Non-Spinning Reserve” (TMNSR) market. This market plays a significant role in ensuring the reliability of the bulk power system since resources with the ability to start-up in 10 minutes can respond quickly to unusual events including: (i) sudden unscheduled outages of both transmission and generation resources; (ii) severe weather events; and, (iii) unexpected losses of renewable resources such as solar or wind power. However, it will typically not be possible for a fast-start generator to purchase natural gas within 10 minutes of being notified of a dispatch by ISO-NE. Since the Project is planning to participate in the TMNSR market (an important regional system need), start up and operation of the Project in Real Time will typically require the use of ULSD until adequate supplies of natural gas can be secured.

Therefore, the proposed fuel BACT for the Project has been developed recognizing the important role Real Time dispatch of fast-start generators plays in maintaining the reliability of the bulk power system. Accordingly, natural gas will be fired in the proposed CTG at all times when it is available; however, natural gas will not typically be available within the 10 minute timeframe necessary to meet ISO-NE's TMNSR requirements. When natural gas is not available, the proposed CTG will start on ULSD and will switch over to natural gas as soon as reasonably possible. Given the time frame necessary to procure natural gas in real time, confirm its delivery on the pipeline and comply with the Real Time bidding requirements of ISO-NE, it is not expected that a swap over to natural gas will be possible in less than four hours from the initial dispatch instruction from the system operator. In order to ensure reliable annual service to the region as a fast-start generator, the Project is requesting up to 720 operating hours per year using ULSD.

Natural gas will be deemed unavailable when its supply and/or delivery cannot be contracted for within the timeframe necessary to start the unit or when emergency conditions or scarcity conditions are declared by ISO-NE. ULSD firing will also occur to ensure that the unit is properly maintained and the ULSD quality is high enough to support unit availability and to meet the BACT and LAER emission rates. It is proposed to limit the Project's use of ULSD to any of the following specific conditions:

i) When ISO-NE declares an Emergency as defined in ISO New England's Operating Procedure No. 21, No. 4, and No. 7, or declares a Scarcity Condition.

ii) When AGT issues a critical notice that disallows increases in nominations from where gas is received on its pipeline system to the point of delivery for the Project.

iii) When gas supplies cannot be procured or delivered at any price or are not available for purchase or delivery within the timeframe required to support operation of the Project. The Project will use all commercially reasonable efforts to switch to natural gas operation as soon as possible without jeopardizing the safety of equipment or operating personnel.

iv) If the Project is operating on natural gas and the supply or delivery is curtailed by the pipeline operator. In this situation, the Project will use all commercially reasonable efforts to switch back to natural gas operation as soon as it is again available without jeopardizing the safety of equipment or operating personnel.

v) Any equipment (whether on-site or off-site) required to allow the turbine to operate on natural gas has failed including a physical blockage of the supply pipeline;

vi) During commissioning when the combustion turbine is required to operate on ULSD pursuant to the turbine manufacturer's written instructions;

vii) For emission testing purposes as specified in the Project's permit or as required by the Commonwealth of Massachusetts;

viii) During routine maintenance if any equipment requires ULSD operation; and

ix) In order to maintain an appropriate turnover of the on-site fuel oil inventory, ULSD can be used when the age of the fuel in the tank is greater than six months. A new waiting period for when ULSD can be used pursuant to this condition will commence once ULSD firing is stopped. ***In addition, the use of ULSD burned pursuant to this condition (ix) will be limited to 4,000,000 gallons per rolling four -year period (rolling calendar years). This corresponds to 160 hours of 100% load operation over four years at the 0ºF firing rate on ULSD.***

Additionally, the Project agrees not to operate on ULSD pursuant to conditions (vii), (viii) and (ix) on any day when the air quality index for the area including Sandwich MA is, or is forecast to be, 101 or greater. ***Fairhaven MA, which is the current AQI tabulation/prediction site closest to Sandwich MA, may be used for the reference***

AQI value for this condition. AQI is made available through the AIRNow web site at http://airnow.gov/index.cfm?action=airnow.local_city&cityid=74 (or its successor). If the AQI is re-scaled, "101" in this condition shall be replaced by an equivalent value indicating air quality Unhealthy for Sensitive Groups or worse. This limitation does not apply to conditions (i) through (vi).

There are no unacceptable collateral environmental impacts associated with use of 720 hours per year of ULSD firing that would preclude its selection as BACT, in combination with use of natural gas as the primary fuel.

4.2.2 NO_x

4.2.2.1 Step 1: Identification of Control Technology Options

Process Modifications

The process is the proposed simple-cycle CTG. A modification to the process would be a change in the CTG design to limit the NO_x emissions from the unit. The Project is proposing to utilize DLN combustors during natural gas firing and H_2O injection during ULSD firing to minimize NO_x formation during the combustion process. A process modification available for small-scale combustion turbines is catalytic combustion. Kawasaki markets combustion turbines equipped with catalytic combustors named K-Lean™ (formerly XONON).

Add-on Controls

Available add-on controls to reduce NO_x from combustion sources include the following:

- *SCR*: This is a catalytic reduction technology using NH_3 as a reagent that has been successfully demonstrated on simple-cycle turbines. SCR is widely recognized as the most stringent available control technology for NO_x emissions from simple-cycle turbines.
- *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. DLN is generally used in combination with SCR.
- *H_2O or Steam Injection*: H_2O or steam injection has been historically used for both natural gas- and oil-fired turbines, but for new turbines, H_2O or steam injection is generally only used for liquid fuel firing. H_2O or steam injection is less effective than DLN, but DLN combustion cannot be used for liquid fuels.
- *SNCR*: This is selective non-catalytic reduction technology using NH_3 or urea as a reagent that is injected into the hot exhaust gases. SNCR is widely used as a retrofit technology for steam-generating boilers but has never been applied to control NO_x emissions from simple-cycle turbines.
- *EMx*™: This is an oxidation/absorption technology using hydrogen (H_2) or methane (CH_4) as a reactant.

4.2.2.2 Step 2: Identification of Technically Infeasible Control Technology Options

Kawasaki is the only manufacturer that offers catalytic combustors, and its largest combustion turbine is 18 MW. Due to this size limitation, K-Lean™ was determined to be technically infeasible for the Project.

SNCR and EMx™ were determined to be not technically feasible and unable to exceed the NO_x reduction achieved by SCR. SNCR requires an exhaust gas temperature between 1,600°F and 2,100°F[5] and typically achieves NO_x reductions of 50% or less. The exhaust gas temperature from the proposed CTG is less than 1100°F; therefore, SNCR is not technically feasible for the project. EMx™ utilizes a catalyst that is coated with potassium carbonate to react with NO_x to form CO_2, potassium nitrite and potassium nitrate; H_2 is used to regenerate the catalyst when it becomes saturated with the products of reaction. The maximum operating temperature range for EMx™ is 750°F with an optimal range between 500°F - 700°F. Unlike SCR, which is a passive reactor with a single reagent (NH_3),

[5] http://www.epa.gov/ttn/catc/dir1/fsncr.pdf

EMx™ is a complicated technology with numerous moving parts and multiple sections that are on or off-line at any given time due to the need to regenerate with H_2 in an O_2-free environment. This complexity reduces the reliability of EMx™ as compared to SCR. Furthermore, EMx™ technology: has never been installed on a turbine larger than 43 MW; has never been installed on a simple-cycle combustion turbine; and has not demonstrated NO_x emission levels lower than SCR. For these reasons, EMx™ was eliminated as technically infeasible for the Project.

A combination of DLN combustors during natural gas firing, H_2O injection during ULSD firing, and SCR is technically feasible for the proposed CTG and represents the top-level of control; therefore, these control technologies have been selected to achieve LAER and BACT for the Project.

4.2.2.3 Step 3: Ranking of Technically Feasible Control Technology Options

The technically feasible control options include DLN combustors during natural gas firing, H_2O injection during ULSD firing, and SCR for both fuels.

4.2.2.4 Step 4: Evaluation of Most Effective Controls

A search of the USEPA's RBLC and available permits for similar sources was conducted to identify the lowest permitted NO_x limits for natural gas and ULSD-fired simple-cycle CTGs. The details of this review are presented in Appendix B, Table B-1.

While a number of the simple-cycle CTGs shown in Table B-1 are permitted without SCR, there are simple-cycle CTGs permitted with SCR at 2.5 ppmvdc for natural gas firing. The value of 2.5 ppmvdc of NO_x is the lowest limit identified for a simple-cycle combustion turbine for gas firing. The lowest permitted NO_x emission limit for any size combustion turbine firing ULSD is 3.5 ppmvdc for a GE LMS-100 CTG at the Gowanus Generating Station. However, the LMS-100 peaking turbine at Gowanus Generating Station has not yet been constructed and it is not believed that this project is moving forward. Also, the Troutdale Energy Center in Multnomah, Oregon is permitted at 3.8 ppmvdc for oil firing for two GE LMS-100 units. The Troutdale project is currently undergoing a contested Oregon Department of Energy siting process, and has not commenced construction. Therefore, the emission levels for oil firing of 3.5 ppmvdc and 3.8 ppmvdc have not been demonstrated in practice. The simple-cycle CTGs permitted limits below 9 ppmvdc for natural gas firing and 42 ppmvdc for ULSD firing are all equipped with the same package of emission controls: DLN combustors or water injection for natural gas firing, water injection for ULSD firing, and SCR for both fuels.

A review of emission limits in SIPs did not identify any NO_x emission limits for combustion turbines that are more stringent than limits achieved in practice by recently permitted and operated simple-cycle CTGs subject to BACT and/or LAER requirements. Although not incorporated into the Massachusetts SIP, the MassDEP's established BACT Guidelines (June 2011) for new combustion sources include simple-cycle combustion turbines. The NO_x emission limits for simple-cycle combustion turbines in the MassDEP BACT guidelines is 2.5 ppmvdc for natural gas firing and 5.0 ppmvdc for ULSD firing.

4.2.2.5 Step 5: Selection of BACT

Canal 3 proposes that NO_x LAER and BACT be 2.5 ppmvdc for natural gas firing and 5.0 ppmvdc for ULSD firing consistent with the MassDEP BACT guidelines. The proposed limit for natural gas firing is equal to the lowest limit permitted for a simple-cycle CTG of any size. The proposed limit for ULSD firing represents an 88% reduction by the SCR (based upon a NO_x emission rate from the CTG of 42 ppmvdc) and the level deemed technically achievable given the size of the CTG and the required exhaust cooling system. These proposed limits will be achieved through the application of DLN burners during natural gas firing, H_2O injection during ULSD firing, and SCR for both fuels.

The proposed controls represent the top level of control and have been demonstrated to be achievable in practice. Pursuant to USEPA and MassDEP guidance, an evaluation of economic and energy impacts has not been conducted. With respect to potential collateral environmental impacts of SCR, one impact we have examined is the use and storage of aqueous NH_3 required for the SCR. As documented in Section 5.0, the predicted ambient air quality impacts for (unreacted) NH_3 "slip" emissions from the stack are well below the MassDEP air toxics guidelines.

Aqueous NH_3 will be stored in two existing 60,000-gallon aboveground tanks located within individual concrete dikes, each designed to contain of the total volume of each tank. Passive evaporative controls are used inside the dike to control evaporation in the unlikely event of a release. As documented in the MCPA/NNSR application, evaluation of a hypothetical worst-case release indicates that NH_3 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. Therefore, the any collateral environmental impacts of SCR are considered to be acceptably mitigated.

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

4.2.3.1 Step 1: Identification of Control Technology Options

Process Modifications

The process is the proposed simple-cycle CTG; CTGs have inherently low PM emission rates. Emissions of PM from combustion can occur as a result of trace inert solids contained in the fuel and products of incomplete combustion, which may agglomerate or condense to form particles. PM emissions from CTGs equipped with SCR can also result from the formation of ammonium salts due to the conversion of SO_2 to sulfur trioxide (SO_3), which is then available to react with NH_3 to form ammonium sulfates. All of the PM emitted from simple-cycle gas turbines is conservatively assumed to be less than 2.5 microns in diameter. Therefore, PM, PM_{10} and $PM_{2.5}$ emission rates are assumed to be the same.

Add-on Controls

This evaluation did not identify any PM/PM_{10}/$PM_{2.5}$ post-combustion control technologies available for simple-cycle combustion turbines. 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 an unacceptable amount of backpressure for turbine operation. There are no known simple-cycle turbine facilities that are equipped with a post-combustion particulate control technology.

4.2.3.2 Step 2: Identification of Technically Infeasible Control Technology Options

The only known control option for particulate matter from combustion turbines is to fire clean-burning fuels and ensure good combustion practices.

4.2.3.3 Step 3: Ranking of Technically Feasible Control Technology Options

The firing of natural gas as the primary fuel, limited firing of ULSD, and good combustion practices are the only technically feasible controls.

4.2.3.4 Step 4: Evaluation of Most Effective Controls

The results of the search of the RBLC and other available permits for PM/PM_{10}/$PM_{2.5}$ BACT/LAER precedents are presented in Appendix B, Table B-3. Based on this search, use of clean-burning fuels and good combustion practices are the most stringent available technologies for control of simple-cycle gas turbine particulate emissions.

A review of Table B-3 indicates that the majority of the limits are presented in the units of lb/hr. In order to compare these limits across a range of turbine sizes, the equivalent full load emission rates in lb/MMBtu were estimated based on available data for each turbine.

One limit in the RBLC (Pio Pico) is presented in the units of lb/MMBtu, at 0.0065 lb/MMBtu for natural gas firing. The natural gas-fired limits (converted to lb/MMBtu at full load) range from 0.004 – 0.04 lb/MMBtu, with the bulk of the limits in the 0.005-0.012 lb/MMBtu range. Since most of these limits are expressed in lb/hr, the equivalent lb/MMBtu would increase under part-load conditions.

There are seven projects listed in Table B-3 with BACT determinations for oil firing in simple-cycle turbines. Two of these (in Florida) have PSD BACT stated in terms of the fuel sulfur content (ULSD). Two others (Troutdale and Dahlberg) have the PM BACT limit expressed in lb/hr, with a calculated lb/MMBtu for full load of 0.03 lb/MMBtu. The other three (Wolverine, Dayton, and Braintree) have specific PM limits in lb/MMBtu for oil firing. Since Wolverine is a black-start turbine for a coal-fired power plant, it is not clear if part-load conditions were taken into account for the limit of 0.03 lb/MMBtu. Dayton's limit of 0.026 lb/MMBtu is qualified as strictly a filterable PM limit by USEPA Method 5, which means this value should be at least doubled to compare it to the other limits that are assumed to include both filterable and condensable fractions since they typically include $PM_{2.5}$. The Braintree limit of 15.0 lb/hr and 0.05 lb/MMBtu includes part-load firing, since at full load for the Trent 60, the calculated value would be 0.0275 lb/MMBtu. Note there actually is an eighth duel-fuel project listed in Table B-3 (VMEU Howard Down), but the PM limit listed in RBLC appears to only be the natural gas-fired limit for the Trent 60.

It is important to recognize that the differences in $PM/PM_{10}/PM_{2.5}$ emission limits among various projects are largely due to different emission guarantee philosophies of the various suppliers, and are not believed to be actual differences in the quantity of $PM/PM_{10}/PM_{2.5}$ emissions inherently produced by the turbine models. 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 inclusion of condensable particulate emissions in permit limits in the last decade.

A review of emission limits in SIPs did not identify any $PM/PM_{10}/PM_{2.5}$ emission limits for combustion turbines more stringent than limits achieved in practice by recently permitted and operated simple-cycle CTGs subject to BACT and/or LAER requirements. The MassDEP BACT guidelines do not provide $PM/PM_{10}/PM_{2.5}$ limits as there are no technically feasible add-on pollution controls, and these limits are typically based upon vendor performance guarantees.

4.2.3.5 Step 5: Selection of BACT

Canal 3 is proposing the $PM/PM_{10}/PM_{2.5}$ BACT emission rate to be the CTG vendor performance emissions guarantees, consistent with other permitted projects. As there are no H-class CTGs permitted in simple-cycle configuration, there are no comparable permitted projects against which to assess these proposed BACT limits.

The Project is proposing BACT $PM/PM_{10}/PM_{2.5}$ limits for natural gas firing of ***0.0073*** lb/MMBtu, not to exceed 18.1 lb/hr, ***at 75% load or greater, and 0.012 lb/MMBtu, not to exceed 18.1 lb/hr at less than 75% load down to MECL.*** The 0.012 lb/MMBtu value is set to cover part-load operation on natural gas when the $PM/PM_{10}/PM_{2.5}$ lb/MMBtu emission rate is higher than at full load. At the natural gas firing full-load maximum case for lb/hr of $PM/PM_{10}/PM_{2.5}$ of 18.1 lb/hr, the corresponding lb/MMBtu rate for this case is 0.0057 lb/MMBtu. These limits compare favorably with the other natural gas-firing PM BACT precedents in Table B-3.

For ULSD firing, the proposed $PM/PM_{10}/PM_{2.5}$ BACT limits are ***0.026 lb/MMBtu, not to exceed 65.8 lb/hr, at 75% load or greater, and*** *0.046 lb/MMBtu, not to exceed 65.8 lb/hr* ***< 75% load down to MECL*** . BACT will be achieved with the most stringent available particulate control technologies, which are good combustion practices and natural gas as the primary fuel with limited firing of ULSD as backup fuel. The limits of 0.046 lb/MMBtu and 65.8 lb/hr are the vendor performance data on ULSD to allow the operating flexibility to run down to 30% load. At full load, the maximum PM emissions on ULSD will be 65.8 lb/hr and 0.02 lb/MMBtu. The value of ***0.026*** lb/MMBtu ***for 75% load and above*** compares favorably with the lb/MMBtu full-load-equivalent values found in the RBLC for recent BACT determinations, given the different guarantee approaches of different turbine suppliers.

The proposed controls represent the top level of control and have been demonstrated to be achievable in practice. Pursuant to USEPA and MassDEP guidance, an evaluation of economic and energy impacts has not been conducted. There are no unacceptable collateral environmental impacts associated with the proposed $PM/PM_{10}/PM_{2.5}$ BACT.

The proposed opacity limit for the CTG for natural gas firing (above MECL) is an opacity level of 5%, with 5-10% opacity allowed for up to 2 minutes per hour. This gas-firing opacity limit is consistent with other

recent MassDEP Plan Approvals and PSD permits for combustion turbine units. The proposed opacity limit for the CTG for ULSD (above MECL) is an opacity level of 10%. This is the lowest opacity level guarantee available from GE for the 7HA.02 CTG while firing ULSD. The proposed opacity BACT during startup/shutdown is compliance with the MassDEP opacity/smoke regulations under 7.06(1)(a and b), which is 20% opacity with short exceptions allowed up to 40% opacity.

4.2.4 H_2SO_4

4.2.4.1 Step 1: Identification of Control Technology Options

Process Modifications

Emissions of H_2SO_4 are formed from the oxidation of sulfur in the fuel. Normally, all sulfur compounds contained in the fuel will oxidize, with the vast majority initially oxidizing to SO_2 and a smaller percentage to SO_3. Additionally, a portion of the fuel sulfur that initially oxidizes to SO_2 will be subsequently oxidized to SO_3 by the SCR and oxidation catalyst. Due to the high temperature of the CTG exhaust in simple-cycle mode, a relatively significant percentage of the SO_2 is expected to oxidize to SO_3 while passing through the SCR and oxidation catalyst. After being formed, SO_3 and sulfate (SO_4) react to form H_2SO_4 and sulfate particulate. There are no process modifications available to reduce SO_2 and H_2SO_4 emissions from the CTG without compromising the ability to achieve BACT for NO_x and CO and MassDEP BACT for VOC.

Add-on Controls

This evaluation does not identify and rank control technologies as there are no simple-cycle gas turbine post-combustion control technologies available for H_2SO_4. Post-combustion H_2SO_4 control technologies, such as dry or wet scrubbers that 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 an unacceptable amount of backpressure for turbine operation. Furthermore, the low concentrations of H_2SO_4 in the exhaust gas would make further reductions very difficult, if not impossible, to achieve. Canal 3 is not aware of any simple-cycle gas turbine facilities that are equipped with any post-combustion H_2SO_4 control technologies.

4.2.4.2 Step 2: Identification of Technically Infeasible Control Technology Options

The only known control option for H_2SO_4 from combustion turbines is to fire clean-burning fuels and ensure good combustion practices.

4.2.4.3 Step 3: Ranking of Technically Feasible Control Technology Options

The firing of pipeline-quality natural gas and ULSD as the sole fuels is the only technically feasible control option.

4.2.4.4 Step 4: Evaluation of Most Effective Controls

The results of the search of the RBLC and other available permits for H_2SO_4 BACT precedents are presented in Appendix B, Table B-4. This search confirms that the only technology identified for control of H_2SO_4 from combustion turbines is use of low-sulfur fuel. The limits in Table B-4 indicate BACT emissions for H_2SO_4 have been typically expressed as a fuel sulfur content limit. A relatively wide range of fuel sulfur content limits were found. The lowest sulfur content in natural gas identified is 0.2 grains per 100 standard cubic feet (gr/100 scf) for the Indeck Wharton project in Texas. This sulfur content limit is well below USEPA's sulfur content limit of 0.5 gr/100 scf for pipeline-quality natural gas as defined in the Acid Rain Program under 40 CFR 72.2. The natural gas sulfur content limit for all other projects identified in Table B-4 is at or above 0.5 gr/100 scf. The lowest oil sulfur content limit identified is 15 ppmw, equivalent to 0.0015 percent by weight (ULSD).

4.2.4.5 Step 5: Selection of BACT

For the sulfur content of natural gas, the USEPA definition of "pipeline natural gas" in 40 CFR 72.2 stipulates a maximum sulfur content of 0.5 gr/100 scf. Canal 3 has reviewed actual sulfur content data from the natural gas supplier and proposes a limit of 0.5 gr/100 scf consistent with USEPA's definition of "pipeline natural gas." The backup fuel will be ULSD, which has the lowest sulfur of any available fuel oil at 15 ppmw.

The proposed H_2SO_4 BACT emission rates are 0.0016 lb/MMBtu firing natural gas and 0.0018 lb/MMBtu firing ULSD taking into account a conservative (high) conversion rate of SO_2 to SO_3 by the pollution controls necessary to meet BACT/LAER requirements for NO_x, CO and VOC emissions. ***These H_2SO_4 rates are based on performance data provided by General Electric Company for the 7HA.02 CTG for the Canal 3 configuration.***

The proposed controls represent the top level of control and have been demonstrated to be achievable in practice. Pursuant to USEPA and MassDEP guidance, an evaluation of economic and energy impacts has not been conducted. There are no unacceptable collateral environmental impacts associated with the proposed H_2SO_4 BACT.

4.2.5 GHGs

4.2.5.1 Step 1: Identification of Control Technology Options

The principal GHGs associated with the Project are CO_2, CH_4, and nitrous oxide (N_2O). Because these gases differ in their ability to trap heat, 1 ton of CO_2 in the atmosphere has a different effect on global warming than 1 ton of CH_4 or 1 ton of N_2O. For example, CH_4 and N_2O have 25 times and 298 times the global warming potential of CO_2, respectively. GHG emissions from the proposed Project are primarily attributable to combustion of fuels in the simple-cycle gas turbine. There will also be minor fugitive releases of natural gas (primarily CH_4) from valves and flanges associated with the natural gas piping, and of sulfur hexafluoride (SF_6) from the circuit breakers in the substation. By far the greatest proportion of potential GHGs emissions associated with the Project are CO_2 emissions associated with combustion of natural gas and ULSD in the simple-cycle turbine. Trace amounts of CH_4 and N_2O will be emitted during combustion in varying quantities depending on operating conditions, and even more insignificant amounts of SF_6 will be released from the circuit breakers. Even after adjusting for global warming potential, emissions of CH_4, N_2O, and SF_6 are negligible when compared to total CO_2 emissions. As such, BACT for the CTG focuses on the options for reducing and controlling emissions of CO_2.

Process Modifications

CO_2 is a product of combusting any carbon-containing fuel, including natural gas and ULSD. All fossil fuel contains significant amounts of carbon. During complete combustion, the fuel carbon is oxidized into CO_2 via the following reaction:

$$C + O_2 \rightarrow CO_2$$

Full oxidation of carbon in fuel is desirable because CO, a product of partial combustion, has long been a regulated pollutant and because full combustion results in more useful energy. In fact, emission control technologies required for CO emissions (oxidation catalysts) increase CO_2 emissions by oxidizing CO to CO_2. Recent BACT determinations for simple-cycle CTG projects have focused on reducing emissions of CO_2 through high-efficiency power generation technology and use of cleaner-burning fuels. Since emissions of CO_2 are directly related to the amount of fuel combusted, an effective means of reducing GHG emissions is through efficient power generation combustion technologies. By utilizing more efficient technology, less fuel is required to produce the same amount of output electricity. The Project is proposing to use an H-class combustion turbine, which is the most efficient combustion turbine in its size range that is commercially available. The proposed Project will have a "Design Base Heat Rate" (new and clean) of approximately 9,241 British thermal units per kilowatt-hour (Btu/kW-hr) (gross), HHV while firing natural gas at full load at ISO conditions, evaporative cooler off. While firing ULSD, this "Design Base Heat Rate" (new and clean) is 9,590 Btu/kW-hr (gross). The emphasis on GHG reductions via efficient combustion is reflected in the recently issued BACT determinations for similar simple-cycle CTG projects as summarized in Table B-5.

Combined-cycle technology can also be considered a type of "process modification," albeit a process modification that changes the fundamental nature of the Project. With combined-cycle technology, a heat recovery steam generator is installed and waste heat is recovered from the fuel gas in the form of steam. This steam is then directed to a steam turbine, which is then used to generate additional power. This increases the efficiency of power generation per unit of fuel combusted. A cooling technology (normally either air cooled condensers or wet cooling towers for new facilities) must also be incorporated to condense the steam as part of the combined-cycle process. However, as discussed below, converting this Project to combined-cycle would change the fundamental nature of the Project, and is not feasible in order for the Project to serve its design function as a quick-starting TMNSR peaking unit.

Another effective method used to reduce GHG emissions is the use of inherently low-emitting fuels. The Project's simple-cycle CTG will combust natural gas as the primary fuel, which is the lowest GHG-emitting fossil fuel. Firing of ULSD as the backup fuel will be limited to no more than 720 hours per rolling 12-month period pursuant to the restrictions defined in Section 4.2.1.5.

Add-on Controls

There are limited post-combustion options for controlling CO_2. The USEPA has indicated in the document, *PSD and Title V Permitting Guidance for Greenhouse Gases* (USEPA, 2011), that carbon capture and sequestration (CCS) should be considered in BACT analyses as a technically feasible add-on control option for CO_2. Currently, there are no CTG projects utilizing CCS, and although theoretically feasible, this technology is not commercially available. However, this control option is discussed in greater detail below.

CCS is a relatively new technology which requires three distinct processes:

1. isolation of CO_2 from the waste gas stream;
2. transportation of the captured CO_2 to a suitable storage location; and,
3. safe and secure storage of the captured and delivered CO_2.

The first step in the CCS process is capture of the CO_2 from the process in a form that is suitable for transport. There are several methods that may be used for capturing CO_2 from gas streams, including chemical and physical absorption, cryogenic separation, and membrane separation. Exhaust streams from simple-cycle combustion turbines have relatively low CO_2 concentrations. Only physical and chemical absorption would be considered technically feasible for a high-volume, low-concentration gas stream.

The next step in the CCS process is transportation of the captured CO_2 to a suitable storage location. Currently, development of commercially available CO_2 storage sites is in its infancy. The nearest geological formation that is capable of storing CO_2 is located in New York, more than 200 miles from the Project. However, a carbon storage facility does not exist at this location. New York is an area where the suitability of geological formations for CO_2 storage is being studied by the Midwest Regional Carbon Sequestration Partnership (MRCSP), which is funded by the Department of Energy. While several CO_2 sequestration demonstrations have been initiated under this program, much further development is needed before a commercially available CO_2 sequestration site becomes available near the Project site. Currently, the closest MRCSP CO_2 sequestration site in the development phase is in northern Michigan, over 600 miles from the Project site by land; although this location is not currently operable.

4.2.5.2 Step 2: Identification of Technically Infeasible Control Technology Options

Converting the Project to combined-cycle technology is not feasible to allow the Project to serve its design function as a quick-starting peaking unit. A simple-cycle peaking turbine is not the same "source type" as a conventional combined-cycle unit for BACT purposes. A conventional combined-cycle unit has longer startup times and ramp up rates, and is disadvantaged with respect to the TMNSR market due to the need to warm up the steam-related combined-cycle components. Therefore, conventional combined-cycle technology has been determined to be technically infeasible since it changes the fundamental nature of the Project to a different source type. USEPA top-down BACT guidance and a recent USEPA Environmental Appeals Board (EAB) decision both recognize the fundamental difference between simple-cycle and combined-cycle turbines for the purposes of BACT determinations. The USEPA's draft "New Source Review Workshop Manual, Prevention of Significant Deterioration and Nonattainment Area Permitting" contains the following passage at page B.61 when presenting a sample BACT analysis: "*Due to the lag time required to bring a heat recovery steam generator on line, it is not technically feasible to use a HRSG at the facility. Use of an HRSG in this instance was shown to interfere with the performance of the unit for peaking service, which requires immediate response times for the turbine*." In additional, the EAB Decision in the matter of the Pio Pico Energy Center (PSD Permit No. SD 11-01, PSD Appeal Nos. 12-04 through 12-06, decided August 2, 2013) addressed (among other matters) a challenge that USEPA Region IX clearly erred in eliminating combined-cycle gas turbines in Step 2 of its BACT analysis for greenhouse gases, or that the issue otherwise warrants review or remand. In particular, the EAB concluded that the Region did not define "source type" too narrowly in Step 2. Therefore, this EAB finding supports the fact that simple-cycle and conventional combined-cycle units are fundamentally different source types for purposes of BACT determinations, and conventional combined-cycle technology may be eliminated at Step 2 for a simple-cycle project.

It is recognized that new "quick-start" combined-cycle technologies have been developed (a/k/a "flex plants") that will allow a certain portion of the turbine output to be available in 10 minutes, while the steam-cycle portion of the combined cycle unit warms up. However, in order to be able to bring 300+ MW to the grid in 10 minutes, the total size of the "quick-start" combined-cycle plant would need to be on the order of 600 MW. Two F-class turbines would be needed to accomplish the same function in the Real Time/TMNSR market. In addition to being substantially larger and more expensive than a single H class simple cycle unit, such a two-unit combined-cycle plant would still operate in a fundamentally different manner.

A single "quick start" F-class combined-cycle unit would have a nominal output of 300 MW, approximately the same size as the Project, but would only be able to provide approximately 150 MW in 10 minutes. The single F-class "quick start" unit would cost substantially more than the proposed H-class simple cycle unit, but would only provide about half as much power in 10 minutes as the proposed Project. Either one or two "quick-start" F-class combined cycle units is considered commercially infeasible since they would represent fundamental project changes and be highly unlikely to be selected in an ISO-NE FCA due to the substantially higher capital cost if used for peak-load service.

With respect to the technical feasibility of CCS, there are no simple-cycle facilities utilizing CCS and this technology is not considered available. As such, this technology has not been demonstrated in practice for simple-cycle facilities or any utility-scale power generating facility in the United States. However, for the purposes of this analysis, CCS is considered technically feasible in accordance with USEPA guidance.

4.2.5.3 Step 3: Ranking of Technically Feasible Control Technology Options

The technically feasible options, ranked in order or effectiveness and achievability, are as follows:

1. CCS;
2. low emitting fuels; and,
3. generating efficiency.

4.2.5.4 Step 4: Evaluation of Most Effective Controls

The results of the search of the RBLC and other available permits for GHG BACT precedents are presented in Appendix B, Table B-5. GHG BACT determinations in Table B-5 are expressed predominantly in units of lb CO_{2e} per MW-hr with two limits on a tpy basis. The energy-based limits are expressed as either "gross" or "net." Energy units (MW-hr or kW-hr) are more meaningful than mass emission limits since they relate directly to the efficiency of the equipment, which is enables comparison of energy efficiency between different projects. Mass emissions are specific to the fuel firing rate of a given project, the number of operating hours, and the carbon content of the fuel, but do not incorporate Project efficiency.

The GHG BACT emission rate must take into account both performance margin and degradation, as follows:

- performance margin accounts for the possibility that the equipment as constructed and installed may not fully achieve the optimal vendor-specified design performance; and,
- degradation accounts for the normal wear and tear of the combustion turbine over its useful life and particularly between maintenance overhauls.

The proposed Project performance margin and degradation factors for the GHG BACT are as follows:

- a performance design margin of 5.0 percent (reflected in GE performance guarantee); and,
- an equipment degradation margin of 2.0 percent.

The adjustment factors have a compounding affect so the overall degradation applied from new and clean condition is 7.1% [1.05 × 1.02 = 1.071].

In addition to proposing an H-class CTG that provides the highest efficiency of any available comparably sized CTG, the Project will also be designed to maximize generation efficiency by minimizing other sources of internal power consumption. Certain equipment, such as the SCR and oxidation catalysts, do result in pressure drop (and reduced power output). However, the SCR and oxidation catalysts are necessary in order to meet BACT/LAER requirements for criteria pollutants. Within the competing design and operational requirements, the Project will be designed to maximize net generation to the grid. ***Appendix D provides an assessment of balance of plant efficiency measures.***

The lowest GHG BACT emission limit (gas firing) in Table B-5 is 1,232 lb CO_{2e}/MW-hr (gross) for the NRG Cedar Bayou Project. For ULSD firing, the lowest rate in Table B-5 for oil alone is 1,741 lb/MW-hr for the Exelon Perryman Project.

Another simple-cycle peaking project has recently been proposed (but not yet permitted) in Massachusetts, which is the Exelon West Medway Project. This project is based on two GE LMS-100 turbines. For full-load ISO conditions with gas and ULSD firing, the proposed GHG BACT for the West Medway LMS-100 units is 1,151 lb CO_2/MW-hr (gas) and 1,551 lb CO_2/MW-hr (ULSD), both on a gross energy basis. These limits are stated to include a 9.5% degradation allowance.

A review of emission limits in SIPs did not identify any GHG emission limits for combustion turbines that are more stringent than limits achieved in practice by recently permitted and operated simple-cycle CTGs subject to BACT requirements. The MassDEP BACT guidelines do not provide GHG limits for a simple-cycle CTG.

4.2.5.5 Step 5: Selection of BACT

Each of the three technically feasible options in Step 3 can be used in tandem and, therefore, the top-level of control would be the application of all three technologies. However, CCS is eliminated as a BACT option due to its economic, energy and environmental impacts as demonstrated in the following discussion. Canal 3 is proposing to implement the remaining two control technologies for GHG emission reduction, high-efficiency generating technology and low-carbon fuels. The Project will utilize an H-class CTG that provides the highest efficiency of any available comparably sized CTG. Based upon the Project design, and adding a reasonable performance plus degradation margin of 7.1% for the life of the Project, the CTG will meet a net heat rate of 9,897 Btu/kW-hr (gross) at full-load ISO conditions for natural gas firing, and 10,271 Btu/kW-hr (gross) at full-load ISO conditions for ULSD firing. This is equivalent to a GHG BACT emission rate of 1,178 lb CO_{2e}/MW-hr (gross) at full load ISO conditions for natural gas firing, which compares favorably with the other permitted GHG BACT limits in Appendix B, Table B-5. For ULSD firing, taking into account performance degradation, the proposed GHG BACT emission rate is 1,673 lb CO_{2e}/MW-hr (gross) at full load ISO conditions. This value generally compares favorably with the oil-fired project values in Table B-5.

The proposed GHG BACT for the LMS-100 units at West Medway are approximately 2% lower than the proposed Project limits on gas and 7% lower than the proposed Project limits on ULSD. However, the LMS-100 does not offer the economy of scale that an H-class turbine provides as the initial capital cost of using LMS-100 technology will be at least 30% greater than using an H-class simple-cycle unit. There are other disadvantages of an LMS-100 project at this site as well. The LMS-100 is also not a very space-efficient machine. Three LMS-100 units (300 MW), including a collector bus switchyard, would occupy some 9 acres. The single 7HA.02 (no switchyard needed) only occupies about 6 acres. The LMS-100 also requires additional silencing to produce comparable noise levels and also needs H_2O injection for NO_x control for both natural gas and ULSD firing. All these factors make the H-class simple-cycle unit a better selection for the Project at this location to meet the peak power needs of southeastern Massachusetts.

CCS Economics Impacts

The capital expenditure required to capture CO_2 from the exhaust and compress it to the pressure required for transport and sequestration is prohibitive. The Report of the *Interagency Task Force on Carbon Capture and Storage* (ITF, 2010) indicates that it costs approximately $105 per ton of CO_2 captured to install and operate a post-combustion system on a new installation to capture and compress CO_2 for transport and sequestration. Applying this factor to the 932,325 tpy of CO_2 potentially emitted from the Project's simple-cycle gas turbine results in an estimated annual cost of over $97,000,000 per year; which is clearly prohibitive.

If the Project were to use the northern Michigan sequestration site at some point in the future should it become operable, captured CO_2 would have to be transported by pipeline. Pipelines are the most common method for transporting large quantities of CO_2 over long distances. There are currently approximately 3,600 miles of existing pipeline located in the United States, but none of these pipelines currently go from Massachusetts towards Michigan. As such, a CO_2 transportation pipeline would need to be constructed from the Project location to the northern Michigan location. The cost for permitting and constructing this pressurized pipeline would be economically prohibitive and impractical.

CCS Energy Impacts

CCS systems impose a very large parasitic load, which reduces the overall efficiency of the Project. The *Interagency Task Force on Carbon Capture and Storage* (ITF, 2010) estimates that the overall generating efficiency would be reduced by as much as a third. This would reduce the overall output of the plant by more than 100 MW. This reduction in efficiency would yield a cost to generate that would make it uneconomical to operate in the competitive ISO-NE market.

CCS Environmental Impacts

The reduction in overall plant output would not result in a ton per year reduction in any other pollutants that are subject to BACT. As a result, the emissions of every non-GHG BACT subject pollutant would increase by 50% on a lb/MWh basis. This increase in criteria pollutant emissions is clearly counterproductive for BACT for criteria pollutants.

As demonstrated above, even if it were commercially available, the economic, energy and environmental impacts to install and operate a CCS system would be unacceptable and, therefore, CCS was eliminated as a BACT option for the Project.

4.2.6 Summary of Proposed CTG Steady-State BACT Emission Rate Limits

Table 4-1 summarizes the proposed LAER/BACT emission limits and associated control technology for the proposed CTG.

Table 4-1: Proposed PSD BACT Emission Limits for the Combustion Turbine

Pollutant	Fuel	Emission Rate (lb/MMBtu)	Emission Rate (ppmvdc)	Control Technology
NO_x	Natural Gas	0.0092	2.5	DLN and SCR
	ULSD	0.0194	5.0	Water Injection and SCR
$PM/PM_{10}/PM_{2.5}$ ***>=75% Load***	Natural Gas	***0.0073***	18.1 lb/hr	Good combustion controls and low sulfur fuels
	ULSD	***0.026***	***65.8*** lb/hr	
$PM/PM_{10}/PM_{2.5}$ < 75% Load and >=MECL	***Natural Gas***	***0.012***	***18.1 lb/hr***	***Good combustion controls and low sulfur fuels***
	ULSD	***0.046***	***65.8 lb/hr***	
H_2SO_4	Natural Gas	0.0016	n/a	Low sulfur fuels
	ULSD	0.0018	n/a	
GHG[1]	Natural Gas	1,178 lb/MW-hr	n/a	High efficiency generation and low emitting fuels
	ULSD	1,673 lb/MW-hr	n/a	

[1] At full load ISO conditions, gross energy basis.

4.2.7 Startup and Shutdown Operations

During SUSD operation, pollutant emissions may be above steady-state emissions rates, especially emissions of NO_x, CO and VOC. During SUSD, combustion conditions are less than ideal resulting in higher emissions of pollutants based upon proper combustor design and operation. In addition, the control technologies employed to meet the BACT emission limits, in particular the oxidation catalyst and SCR, require minimum operating temperatures that may not be met during initial startup or when the CTG is below its minimum rated operating load.

There are no control technologies to limit SUSD emissions beyond those already established as the BACT control technologies for steady-state operation. The oxidation catalyst is a passive reactor and will control emissions of CO whenever it is operating above its minimum operating temperature. When the SCR catalyst is below its minimum operating temperature, NH_3 is not injected as it would not react with NO_x and be emitted as slip. To minimize NO_x emissions during startup, Canal 3 will initiate NH_3 injection as soon as the SCR catalyst reaches its minimum operating temperature and other SCR design criteria are met.

To establish BACT emission rate limits for SUSD operation, emissions data from the vendor are relied upon as the vendor has performance data from test cell operation for the selected make and model CTG. Provided in Table 4-2 are the vendor-specified emissions of NO_x, CO, VOC and $PM/PM_{10}/PM_{2.5}$ during SUSD operation. The emissions are presented in terms of pounds emitted per startup and shutdown event. A startup event is defined as the time from initial combustion through achieving the BACT emission rate limit. A shutdown event is defined as the time from initiating turndown of the CTG until fuel flow is shutoff. Short-term startup and shutdown emission limits will be evaluated after a year of actual operation and revised values may be proposed if needed.

Table 4-2: Proposed Provisional Startup and Shutdown Emission Limits for the Combustion Turbine

	Fuel	NO_x (lb/event)	CO (lb/event)	VOC (lb/event)	$PM/PM_{10}/PM_{2.5}$ (lb/event)
Startup	Natural Gas	151	130	9	9.1
	ULSD	219	163	12	48.2
Shutdown	Natural Gas	7	133	25	4.2
	ULSD	8	25	3	12.8

4.3 EMERGENCY GENERATOR ENGINE

4.3.1 Fuels

4.3.1.1 Step 1: Identification of Control Technology Options

The raw material for the emergency generator engine is the fuel. It is critical for the emergency generator engine to have its own stand-alone fuel source in the event that the emergency includes disruption of fuel from an outside source, such as natural gas. The primary purpose of the emergency generator is to be able to shut the plant down safely in the event of an electric power outage. Generator engines are available that can fire natural gas or diesel; to incorporate a stand-alone fuel source, the available fuel options are LNG and ULSD.

4.3.1.2 Step 2: Identification of Technically Infeasible Control Technology Options

Use of interruptible natural gas is not feasible for an emergency engine that must be able to operate during an emergency. LNG storage was eliminated as technically infeasible per the analysis in Section 4.2.1.2.

4.3.1.3 Step 3: Ranking of Technically Feasible Control Technology Options

The sole stand-alone fuel source available for the emergency generator engine is ULSD.

4.3.1.4 Step 4: Evaluation of Most Effective Controls

Under 310 CMR 7.05, all distillate oil sold in Massachusetts as of July 1, 2018 must be ULSD, having a maximum sulfur content of 0.0015% sulfur by weight (15 ppmw). Also, existing emergency diesel generators installed in Massachusetts after March 1, 2006, are required to use ULSD under the provisions of 310 CMR 7.26(42). Therefore, use of ULSD in emergency generators in Massachusetts is common practice.

4.3.1.5 Step 5: Selection of BACT

The emergency generator engine will be fired with ULSD having a sulfur content no greater than 15 ppmw.

4.3.2 NO_x

4.3.2.1 Step 1: Identification of Control Technology Options

Process Modifications

Low-NO_x engine design is the only known process modification that can be made to reduce NO_x emissions from a diesel engine.

Add-on Controls

SCR is a technically feasible option to control NO_x emissions from non-emergency diesel engines.

4.3.2.2 Step 2: Identification of Technically Infeasible Control Technology Options

Tier 4 engine design (Alternate FEL Cap limit for NO_x under 40 CFR 1039.104(g)) is technically feasible. SCR is considered technically infeasible for an emergency diesel generator since it has not been demonstrated in practice to our knowledge. However, since SCR is technically feasible for non-emergency diesel engines, SCR has been carried into Step 3 to show it is not cost effective as well for this application.

4.3.2.3 Step 3: Ranking of Technically Feasible Control Technology Options

SCR can normally achieve 90% remove of NO_x emissions, However, for an emergency generator that is used primarily for short periods of testing and facility shutdown in an actual emergency, the ability of the SCR to control emissions in practice will be significantly reduced since the engine/SCR takes time to warm up to achieve appreciable NO_x control.

4.3.2.4 Step 4: Evaluation of Most Effective Controls

Stationary internal combustion engines are subject to 40 CFR Part 60, Subpart IIII and 40 CFR 63, Subpart ZZZZ. These regulations require a new emergency engine to meet the applicable emission standards under 40 CFR 89. MassDEP regulations under 310 CMR 7.26(42) also require new emergency engines to meet the applicable emission limitations for non-road engines under 40 CFR Part 89 at the time of installation. A review of emission limits in SIPs did not identify any NO_x emission limits for new emergency engines that are more stringent than the limits provided in 40 CFR 89.

A review of recent NO_x emission limits for emergency generator diesel engines installed as part of major source generating projects, as summarized in Table B-6 in Appendix B, show that all of these engines were required to meet the applicable emission limitations, or equivalent, for non-road engines under 40 CFR Part 89 as required by 40 CFR 60, Subpart IIII. No limits were found that required installation of add-on controls for emergency generator diesel engines.

Emergency engines are now commercially available and that meet the Tier 4 Alternate FEL Cap limit for generator engines under 40 CFR 1039, Table 3, which is 3.5 grams/kW-hr of NO_x.

4.3.2.5 Step 5: Selection of BACT

The top level of control demonstrated in practice is determined to be compliance with the Tier 4 Alternate FEL Cap limit for generator engines under 40 CFR 1039.104(g), Table 1, which is 3.5 grams/kW-hr of NO_x. Canal 3 is proposing to install an engine that meets this limit. This limit will be lower than any other emergency engine recently permitted.

Economic Impacts

Since SCR is technically feasible for non-emergency generators, an economic analysis of its cost effectiveness was conducted and is presented in Appendix A. The SCR has been conservatively assumed to control 90% of the potential NO_x emissions, although this degree of control is unlikely due to the intermittent operation of the emergency engine, primarily for periodic readiness testing. The calculations indicate that the cost effectiveness of an SCR is over $60,000 per ton of NO_x controlled at maximum allowable operation of 300 hours per year; this cost is considered excessive. So in addition to being technically infeasible for this emergency application, SCR is also not cost effective. There are no collateral energy or environmental issues with a Tier 4 generator that would indicate selection of SCR as BACT, given the unfavorable economics.

The proposed controls represent BACT and is the most stringent level of control actually demonstrated in practice.

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

4.3.3.1 Step 1: Identification of Control Technology Options

Process Modifications

Low-PM engine design is the only known process modification that can be made to reduce PM emissions from a diesel engine.

Add-on Controls

A diesel particulate matter filter (DPF) is a technically feasible option to control PM emissions from diesel engines.

4.3.3.2 Step 2: Identification of Technically Infeasible Control Technology Options

Low-PM engine design and a DPF are both technically feasible, although application of a DPF is unusual for an emergency diesel engine.

4.3.3.3 Step 3: Ranking of Technically Feasible Control Technology Options

An active DPF can achieve up to 85% particulate removal (CARB Level 3), so it is more effective than the Tier 4 Alternate FEL Cap engine design, which is based on low-emission engine design.

4.3.3.4 Step 4: Evaluation of Most Effective Controls

Stationary internal combustion engines are subject to 40 CFR Part 60, Subpart IIII and 40 CFR 63, Subpart ZZZZ. These regulations require a new emergency engine to meet the applicable emission standards under 40 CFR 89. MassDEP regulations under 310 CMR 7.26(42) also require new emergency engines to meet the applicable emission limitations for non-road engines under 40 CFR Part 89 at the time of installation. A review of emission limits in SIPs did not identify any PM emission limits for new emergency engines that are more stringent than the limits provided in 40 CFR 89.

A review of recent PM emission limits for emergency generator diesel engines installed as part of a major source simple-cycle generating project, as summarized in Table B-6 in Appendix B, show that most of these engines were required to meet the applicable emission limitations for non-road engines under 40 CFR Part 89 as required by 40 CFR 60, Subpart IIII. No limits were found that required installation of add-on pollution controls for emergency generator diesel engines.

The Moxie Patriot Project has a PM limit of 0.02 grams/hp-hr, which corresponds to 0.027 grams/kW-hr. It is suspected that this is an RBLC entry error as the limit is inconsistent with known PM emissions from diesel engines.

4.3.3.5 Step 5: Selection of BACT

The top level of control would be the installation of a low-PM (Tier 4) engine with a DPF. However, a DPF was eliminated due to economic impacts as described below. The top level of control demonstrated in practice is determined to be compliance with the Tier 4 Alternate FEL Cap limit for generator engines under 40 CFR 1039.104(g), Table 1, which is 0.1 grams/kW-hr of PM. Canal 3 is proposing to install an engine that meets this limit.

Economic Impacts

Since a DPF is technically feasible, an economic analysis of the cost effectiveness for emission control was conducted. This economic analysis is presented in Appendix A. This analysis indicates that the cost effectiveness for an active DPF is nearly $1,000,000 per ton of PM/$PM_{10}$/$PM_{2.5}$ controlled. This cost is excessive, even if the emergency generator runs the maximum allowable amount of 300 hours per year (unlikely).

There are no energy or environmental issues with a Tier 4 generator engine that would indicate selection of a DPF as BACT, given the unfavorable economics.

The proposed controls represent BACT and is the most stringent level of control actually demonstrated in practice.

4.3.4 H_2SO_4

The only control technology for reducing H_2SO_4 emissions from the emergency generator engine is to utilize low-sulfur fuels. No other control technologies are available for the control of H_2SO_4 from an emergency engine and, therefore, the five-step BACT process was truncated. The Project will utilize ULSD with a maximum sulfur content of 15 ppmw, which is the lowest sulfur fuel available and represents the top level of control for H_2SO_4 from an emergency engine. The proposed H_2SO_4 BACT limit is based on 5% conversion of fuel sulfur to SO_3/H_2SO_4, with the molecular weight correction from the SO_2 limit of 0.0015 lb/MMBtu. This results in H_2SO_4 emissions of 0.00012 lb/MMBtu.

4.3.5 Greenhouse Gases (GHGs)

The GHG BACT discussion in Section 4.2.7 describes the difficulties in controlling GHG emissions from the primary source of emissions from the Project, which is the CTG. The emergency generator engine is an insignificant source of GHG emissions at 123 tpy, which represents approximately 0.01% of the Project's GHG emissions. There are no technically feasible means of reducing GHG emissions from the emergency generator engine other than restricting operating hours. The emergency generator engine will operate no more than 300 hours per year. This restriction will limit annual GHG emissions to 123 tpy, which is consistent with the limits for other emergency generator engines listed in Table B-6 in Appendix B. ***The proposed BACT limits for GHG as CO_2e for the emergency generator are 819 lb/hr and 162.85 lb/MMBtu.***

4.4 EMERGENCY FIRE PUMP ENGINE

4.4.1 Fuels

4.4.1.1 Step 1: Identification of Control Technology Options

The raw material for the emergency fire pump engine is the fuel. It is critical for the emergency fire pump engine to have its own stand-alone fuel source in the event that the emergency includes disruption of fuel from an outside source, such as natural gas. The purpose of the emergency fire pump is to provide firefighting capability during a fire onsite. Fire pump engines are available that can fire natural gas or diesel; to incorporate a stand-alone fuel source, the available fuel options are LNG and ULSD.

It is important to note here as well that two fire pumps will be provided for the Project to ensure 100% backup of the fire protection system water supply. One fire pump will be driven by an electric motor and the other will be driven by a diesel engine. Each pump will be capable of delivering total system requirements at design pressure and flow rate with any one pump out of service. Therefore, the diesel fire pump is essentially a backup unit that would typically be used in a fire fighting emergency if there is also a simultaneous loss of electric power.

4.4.1.2 Step 2: Identification of Technically Infeasible Control Technology Options

Use of interruptible natural gas is not feasible for an emergency fire pump engine that must be able to operate during an emergency. LNG storage was eliminated as technically infeasible at the Facility per the analysis in Section 4.2.1.2.

4.4.1.3 Step 3: Ranking of Technically Feasible Control Technology Options

The sole stand-alone fuel source available for the emergency diesel fire pump is ULSD.

4.4.1.4 Step 4: Evaluation of Most Effective Controls

Under 310 CMR 7.05, all distillate oil sold in Massachusetts as of July 1, 2018 must be ULSD having a maximum sulfur content of 0.0015% sulfur by weight (15 ppmw). Also, existing emergency diesel engines installed in

Massachusetts after March 1, 2006, are required to use ULSD under the provisions of 310 CMR 7.26(42). Therefore, use of ULSD in emergency engines in Massachusetts is common practice.

4.4.1.5 Step 5: Selection of BACT

The emergency diesel fire pump engine shall be fired with ULSD having a sulfur content no greater than 15 ppmw.

4.4.2 NO_x

4.4.2.1 Step 1: Identification of Control Technology Options

Process Modifications

Low-NO_x engine design is the only known process modification that can be made to reduce NO_x emissions from a diesel engine. Low-NO_x engine design for a 135-bhp emergency diesel fire pump engine is a Tier 3 engine rated at 4.0 grams/kW-hr NO_x and VOC combined.

Add-on Controls

SCR is a technically feasible option to control NO_x emissions from non-emergency diesel engines.

4.4.2.2 Step 2: Identification of Technically Infeasible Control Technology Options

Tier 3 engine design is technically feasible.   SCR is considered technically infeasible for an emergency diesel fire pump since it has not been demonstrated in practice to our knowledge. However, since SCR is technically feasible for non-emergency diesel engines, SCR has been carried into Step 3 to show it is not cost effective as well for this application.

4.4.2.3 Step 3: Ranking of Technically Feasible Control Technology Options

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 diesel fire pump that is used primarily for short periods of testing and limited use in actual emergencies, the ability of the SCR to control emissions will be significantly reduced since the engine/SCR takes time to warm up to achieve appreciable NO_x control.

4.4.2.4 Step 4: Evaluation of Most Effective Controls

Stationary internal combustion engines are subject to 40 CFR Part 60, Subpart IIII and 40 CFR 63, Subpart ZZZZ. These regulations require a new emergency fire pump engine to meet the applicable emission standards under NSPS Subpart IIII, Table 4. MassDEP regulations under 310 CMR 7.26(42) also require new emergency engines to meet the applicable emission limitations for non-road engines under 40 CFR Part 89 at the time of installation. The applicable limits under NSPS Subpart IIII, Table 4 are equal to or more stringent than 40 CFR 89. A review of emission limits in SIPs did not identify any NO_x emission limits for new emergency engines that are more stringent than the limits provided in NSPS Subpart IIII, Table 4.

A review of recent NO_x emission limits for emergency fire pump diesel engines installed as part of major source simple-cycle generating projects, as summarized in Table B-7 in Appendix B, show that most of these engines were required to meet the applicable emission limitations for non-road engines under 40 CFR 60, Subpart IIII. No limits were found that required installation of add-on pollution controls for emergency fire pump diesel engines.

4.4.2.5 Step 5: Selection of BACT

The top level of control actually demonstrated in practice is determined to be compliance with the applicable limits under 40 CFR Part 60, Subpart IIII and firing of ULSD that meets the requirements of 40 CFR 80, Subpart I. The applicable limit for a 135-bhp emergency fire pump engine is USEPA's Tier 3 limit under NSPS Subpart IIII, Table 4, which is 4.0 grams per kW/hp-hr of NO_x and non-methane hydrocarbons (NMHC) combined.

Economic Impacts

Since SCR is technically feasible for non-emergency units, an economic analysis of the cost effectiveness for emission control was conducted. This economic analysis is presented in Appendix A. This analysis indicates that the cost effectiveness of SCR is over $100,000 per ton of NO_x. This cost is excessive, even if the emergency diesel fire pump runs the maximum allowable amount of 300 hours per year (unlikely). So in addition to being technically infeasible for this emergency application, SCR is also not cost effective.

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

The proposed controls represent the top level of control and have been demonstrated to be achievable in practice.

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

4.4.3.1 Step 1: Identification of Control Technology Options

Process Modifications

Low-PM engine design is the only known process modification that can be made to reduce PM emissions from a diesel engine. Low-emission engine design for a 135-bhp emergency diesel fire pump engine is a Tier 3 engine rated at 0.30 grams/kW-hr PM.

Add-on Controls

DPF is a technically feasible option to control PM emissions from diesel engines.

4.4.3.2 Step 2: Identification of Technically Infeasible Control Technology Options

Low-PM engine design and DPF are both technically feasible, although application of a DPF is unusual for an emergency diesel engine.

4.4.3.3 Step 3: Ranking of Technically Feasible Control Technology Options

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.

4.4.3.4 Step 4: Evaluation of Most Effective Controls

Stationary internal combustion engines are subject to 40 CFR Part 60, Subpart IIII and 40 CFR 63, Subpart ZZZZ. These regulations require a new emergency fire pump engine to meet the applicable emission standards under NSPS Subpart IIII, Table 4. MassDEP regulations under 310 CMR 7.26(42) also require new emergency engines to meet the applicable emission limitations for non-road engines under 40 CFR Part 89 at the time of installation. The applicable limits under NSPS Subpart IIII, Table 4 are equal to or more stringent than 40 CFR 89. A review of emission limits in SIPs did not identify any PM emission limits for new emergency engines that are more stringent than the limits provided in NSPS Subpart IIII, Table 4.

A review of recent PM emission limits for emergency fire pump diesel engines installed as part of major source simple-cycle generating projects, as summarized in Table B-7 in Appendix B, show that most of these engines were required to meet the applicable emission limitations for non-road engines under 40 CFR 60, Subpart IIII. No limits were found that required installation of add-on pollution controls for emergency fire pump diesel engines.

Several engines have PM limits that do not match Subpart IIII. Towantic Energy Center has a CO limit expressed in lb/hr which corresponds to 0.17 gram/kW-hr. This is more stringent than the Subpart IIII limit of 0.3 grams/kW-hr. The Moxie Patriot and Moxie Liberty Projects have a PM limit of 0.09 grams/hp-hr, which corresponds to 0.12 grams/kW-hr which is also more stringent than the Subpart IIII limit. For these limits that are more stringent than the Subpart IIII limit, we suspect that vendor data may have been used which did not exactly match Subpart IIII values. But we suspect for regulatory compliance purposes use of Subpart IIII certifications will be all that is required.

4.4.3.5 Step 5: Selection of BACT

The top level of control would be the installation of both a low-PM engine with DPF. However, DPF was eliminated due to economic impacts as described below. The next level of control was determined to be compliance with the applicable limits under 40 CFR Part 60, Subpart IIII and firing of ULSD that meets the requirements of 40 CFR 80, Subpart I. The applicable limit for a 135-bhp new emergency fire pump engine is USEPA's Tier 3 limit under NSPS Subpart IIII, Table 4, which is 0.30 grams per/kW-hr.

Economic Impacts

Since a DPF is technically feasible, an economic analysis of the cost effectiveness for emission control was conducted. This economic analysis is presented in Appendix A. This analysis indicates that the cost effectiveness of an active DPF is nearly $700,000 per ton of PM/$PM_{10}$/$PM_{2.5}$. This cost is excessive, even if the emergency diesel fire pump engine were to run the maximum allowable amount of 300 hours per year (unlikely).

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

The proposed controls represent the top level of control that have been demonstrated to be achievable in practice.

4.4.4 H_2SO_4

The only control technology for reducing H_2SO_4 emissions from the emergency fire pump engine is to utilize low sulfur fuels. No other control technologies are available for the control of H_2SO_4 from an emergency fire pump engine; therefore, the five-step BACT process was truncated. The Project will utilize ULSD with a maximum sulfur content of 15 ppmw, which is the lowest sulfur fuel available and represents the top level of control for H_2SO_4 from an emergency fire pump engine. The proposed H_2SO_4 BACT limit is based on 5% conversion of fuel sulfur to SO_3/H_2SO_4, with the molecular weight correction from the SO_2 limit of 0.0015 lb/MMBtu. This results in H_2SO_4 emissions of 0.00012 lb/MMBtu.

4.4.5 GHGs

The GHG BACT discussion in Section 4.2.7 describes the difficulties in controlling GHG emissions from the primary source of emissions from the Project, which is the CTG. The emergency fire pump engine is an insignificant source of GHG emissions at 29 tpy, which represents approximately 0.003% of the Project's GHG emissions. There are no technically feasible means of reducing GHG emissions from the emergency fire pump engine other than restricting operating hours. The emergency fire pump engine will operate no more than 100 hours per year for readiness testing purposes in accordance with NSPS Subpart IIII, and will operate no more than 300 hours per year in total. These restrictions will limit annual GHG emissions to 29 tpy, which is consistent with the limits for other emergency fire pump engines listed in Table B-7 in Appendix B.

4.4.6 Ancillary Source BACT Summary

Table 4-3 summarizes the proposed PSD BACT emission limits and associated control technology for the Project's ancillary emission sources.

Table 4-3: Proposed BACT Emission Limits for the Emergency Engines

Pollutant	Emergency Generator	Emergency Fire Pump
NO_x	3.5 grams/kW-hr[1]	4.0 grams/kW-hr[1] (NO_x and NMHC)
PM	0.10 grams/kW-hr[1]	0.30 grams/kW-hr[1]
H_2SO_4	0.00012 lb/MMBtu	0.00012 lb/MMBtu
GHGs ***as CO_2e***	***819 lb/hr*** ***162.85 lb/MMBtu***	***195 lb/hr*** ***162.85 lb/MMBtu***

[1] Proposed emission limits in accordance with applicable 40 CFR 1039 or 40 CFR 60 Subpart IIII emission test cycle as demonstrated by manufacturer's certification.

5.0 AIR QUALITY IMPACT ANALYSIS

As described in Section 3.1, the Project will be a major modification under PSD rules for NO_x, $PM/PM_{10}/PM_{2.5}$, H_2SO_4, and GHGs. As such, the Project is required to demonstrate compliance with NAAQS and PSD Increments. As there are no NAAQS for H_2SO_4, it is evaluated as an air toxic. All applicable air toxics, including H_2SO_4, have been evaluated per MassDEP's air toxics policy. SO_2 will also be evaluated to demonstrate compliance with the NAAQS and for use in the impacts to soils and vegetation analysis. There are no air quality modeling requirements for GHGs.

Air quality dispersion modeling uses mathematical formulations to simulate how a pollutant emitted by a source will disperse in the atmosphere to predict concentrations at downwind receptor locations. An evaluation of the potential impacts of the proposed Project's air emissions on ambient air quality has been conducted using USEPA's regulatory model, AERMOD (15181). The air quality dispersion modeling analyses for the Project have been conducted as specified in the Air Quality Dispersion Modeling Protocol, submitted to and approved by MassDEP. These procedures are in accordance with 40 CFR 51 Appendix W USEPA's *Guideline on Air Quality Models* (USEPA, 2005), *Modeling Guidance for Significant Stationary Sources of Air Pollution* (MassDEP, 2011), the AERMOD Implementation Guide (USEPA, 2015), and supplemented by additional agency guidance.

The dispersion modeling for the Project evaluates worst-case operating conditions to predict the appropriate maximum ground-level concentration for each pollutant and averaging period. The appropriate maximum concentrations from the worst-case scenarios are compared to the corresponding SILs. If the maximum concentration is below the corresponding SIL, then compliance is demonstrated and no additional analysis is necessary. However, if any maximum predicted concentration is equal to or greater than its corresponding SIL, a cumulative impact analysis must be conducted with other major emission sources in the area, as identified by the MassDEP.

As discussed in the following sections, the modeling analysis demonstrates that the proposed Project will not cause or significantly contribute to an exceedance of any NAAQS, PSD Increment, or MassDEP non-criteria pollutant threshold.

5.1 SOURCE PARAMETERS AND EMISSION RATES

The proposed Project will include one new combustion turbine and ancillary equipment (specifically, one new emergency generator and one new fire water pump). In addition to modeling impacts from the Project, the modeling analysis includes consideration of cumulative impacts from the existing Station sources. Table 5-1 lists the physical stack characteristics for each source that was included in the modeling.

Table 5-1: Stack Characteristics for the Proposed Project and the Existing Canal Generating Station

Source	Status	UTM E[1] (m)	UTM N[1] (m)	Base Elevation (m)	Stack Height (ft)	Stack Diameter (ft)
Canal 3 CTG	Proposed	374,636.75	4,625,364.08	4.88	220	25
Emergency Gen.	Proposed	374,636.50	4,625,375.45	4.88	25	0.75
Fire Water Pump	Proposed	374,802.48	4,625,326.75	4.88	25	0.33
Canal Unit 1,2	Existing	374,565.91	4,625,318.96	3.66	498	25.5
Emergency Gen 1	Existing	374,393.38	4,625,435.85	3.66	14.4	0.66
Emergency Gen 2	Existing	374,608.72	4,625,460.22	3.66	14.4	0.66
Fire Water Pump	Existing	374,397.46	4,625,433.02	3.66	14.1	0.33
Gas Heater	Existing	373,685.91	4,625,564.01	3.66	15	1.6

[1] Universal Transverse Mercator Zone 19, based on North American Datum 83.

Modeling for the Project was conducted in a manner that utilizes the worst-case operating conditions for the proposed new combustion turbine in combination with the ancillary sources impacts in an effort to predict the highest impact for each averaging period. The Project is requesting a permit that will allow up to 4,380 hours per year of operation for the new simple-cycle turbine. Turbine operation could range from up to 4,380 hours per year on natural gas alone to 3,660 hours per year on natural gas and 720 hours per year on ULSD. However, the modeling analysis presented herein conservatively assumes the CTG will operate up to 1,440 hours per year on ULSD and 2,940 hours per year on natural gas. ***Also, the modeling analyses presented herein conservatively assumes CTG CO emission rates for natural gas firing of 4.0 ppm instead of the 3.5 ppm now proposed as the gas-firing permit limit.*** The proposed GE 7HA.02 turbine is rated at a maximum capacity of 3,425 MMBtu/hr at 0°F while firing natural gas and 3,471 MMBtu/hr at 0°F while firing ULSD. The emissions will exit to the atmosphere through a 220-foot tall stack with an inside exit diameter of 25 feet. Since proposed new combustion turbine emission rates and flue gas characteristics for a given turbine load vary as a function of ambient temperature, data were derived for the following ambient temperatures and load scenarios:

- three operating loads (Base [100%], Mid [~75%], and Min [30-40%]); and,
- five ambient temperatures (90°F, 59°F, 50°F, 20°F, and 0°F).

In order to calculate conservatively ground-level concentrations, a composite "worst-case" set of emission parameters was used in the modeling. For each turbine load, the highest pollutant-specific emission rate coupled with the lowest exhaust temperature and exhaust flow rate was selected. Tables 5-2 and 5-3 summarize the worst-case emission parameters over the three operating loads for natural gas and ULSD firing, respectively.

Table 5-2: Worst-Case Operational Data for the Proposed Simple-Cycle CTG firing Natural Gas

Parameter		Load Value		
		Base	Mid	Min
Exit Temperature (°F)		750.0	750.0	750.0
Exit Velocity (feet/sec)		128.29	107.94	75.30
Pollutant Emissions (lb/hr)	SO_2	5.14	4.11	2.80
	PM_{10}	18.10	16.60[2]	15.60[2]
	$PM_{2.5}$	18.10	16.60[2]	15.60[2]
	NO_X	31.51	25.24	17.19
	CO[1]	30.82	24.69	16.82

[1] ***Conservatively based on 4.0 ppm CO, although Project will meet 3.5 ppm.***

[2] ***Manufacturer guarantees for part load conditions revised to 18.1 lb/hr. The min load case is controlling for gas portion of annual impacts but overall calculated impacts remain conservative because ULSD operation is now limited to 720 hours per year (at a lower emission rate) and annual PM_{10}/$PM_{2.5}$ impacts have been calculated based on 1440 hours per year of ULSD operation.***

Table 5-3: Worst-Case Operational Data for the Proposed Simple-Cycle CTG firing ULSD

Parameter		Load Value		
		Base	Mid	Min
Exit Temperature (°F)		750.0	750.0	750.0
Exit Velocity (feet/sec)		122.74	104.18	74.59
Pollutant Emissions (lb/hr)	SO_2	5.21	4.17	2.66
	PM_{10}	86.7[1]	90.6[1]	96.3[1]
	$PM_{2.5}$	86.7[1]	90.6[1]	96.3[1]
	NO_X	67.35	53.96	34.34
	CO	40.96	32.82	20.89
	Pb	***1.1E-02***	***8.7E-03***	***5.5E-03***

[1] ***Project will now meet 65.8 lb/hr for all cases.***

The proposed combustion turbine will be operated as a peaking unit; therefore, in addition to estimating the steady-state operational impacts, the proposed new combustion turbine's SUSD conditions were also included in the AERMOD operating scenario modeling for the pollutants that have short-term standards (SO_2, PM_{10}, $PM_{2.5}$, NO_2, and CO). SUSD modeling was not conducted for annual averaging periods. The vendor data suggest that startup events will last only 10-30 minutes and shutdown events will last only 8-14 minutes, depending on the fuel. Therefore, the modeling for SUSD is composed of a representative hourly profile of emissions that accounts for a startup or shutdown within 1 hour. For longer averaging periods (i.e., 24-hour) a limited number of startups and shutdowns were considered in a day as it is unreasonable to expect that the turbine will startup and shutdown 24 hours per day. Since the SUSD emissions occur under different exhaust parameters (which are different from exhaust parameters for steady-state operations), the hourly profile of emissions for a SUSD hour was modeled assuming co-located stacks.

For the 1-hour, 3-hour, and 8-hour averaging periods, two co-located stacks were used. (This is just a calculation technique and does not mean two or three stacks are being constructed, as discussed below; only a single physical stack for the new CTG is being constructed.) Stack 1 consists of the startup stack and is modeled with the total emissions from a single startup event. Stack 2 consists of the normal operation stack representing the balance of the hour that the turbine is not operating in startup mode. The emissions for Stack 2 are scaled based on the portion of the hour that the turbine is operating under normal conditions. With the exception of CO during shutdown from natural gas firing, startup emissions are always higher with lower plume rise, as shown in Table 5-4. Therefore, for CO, natural gas startup, the shutdown emission rate was conservatively used with the startup stack parameters.

For the 24-hour averaging period, three co-located stacks were used in the modeling. Stack 1 consists of the startup stack and is modeled with the total emissions from a single startup event. Stack 2 consists of the shutdown stack and is modeled with the total emissions from a single shutdown event. Stack 3 consists of the normal operation stack representing the balance of the hour that the turbine is not operating in startup or shutdown mode. The emissions for Stack 3 are scaled based on the portion of the hour that the turbine is operating under normal conditions (both minimum and maximum load conditions were evaluated). As noted above, since the turbine will not be starting up and shutting down every hour of the day, the modeling assumed a maximum of six startup and six shutdown events per day. The daily emissions were scaled accordingly to account for this assumption. For the remainder of the day, it was assumed the turbine is at normal load operations.

For all averaging periods (except annual), the modeled concentrations from all three stacks are combined to determine the total hourly modeled concentration.

Table 5-4: Startup/Shutdown Data for the Proposed Simple-Cycle Combustion Turbine

Parameter		Natural Gas		ULSD	
		Startup	Shutdown	Startup	Shutdown
Exit Temperature (°F)		680	750	680	750
Exit Velocity (feet/sec)		35.73	44.24	35.73	44.24
Pollutant Emissions (lb/hr)	SO_2	0.25	0.05	0.24	0.04
	PM_{10}	2.28	1.05	12.05	3.2
	$PM_{2.5}$	2.28	1.05	12.05	3.2
	NO_X	151	7	219	8
	CO	130	133	163	25

The Project will also include a ULSD-fired emergency generator and a ULSD-fired emergency fire pump, which are each expected to operate approximately 1 hour/week per unit for maintenance and 300 hours/year per unit. Therefore, the modeled short-term emissions (24-hour or less) were normalized to reflect 1 hour of operation within the averaging period for the assessment of short-term modeled averaging periods. The modeled annual emission rates for these emergency sources were normalized based on the 300 hours per year for the assessment of annual modeled averaging periods. Additionally, for the 1-hour NO_2 and SO_2 modeling, per USEPA guidance for modeling intermittent sources (USEPA, 2011), these emission rates are annualized (i.e., based on 300 hours per year). Source parameters and emissions rates for the ancillary equipment are provided in Table 5-5.

No modifications of the existing Station sources are proposed. The source parameters and emission rates for the existing combustion equipment are presented in Table 5-6. Emission rates are based on the existing permit limits, i.e., maximum allowable emissions.

Worst-case turbine operating conditions were determined based on AERMOD-predicted concentrations for comparison with the SILs, which included the Project emission sources. The worst-case operating condition was based on the operating scenario that results in the highest predicted ground-level air quality impacts. The operating scenarios resulting in the highest predicted concentrations for each pollutant for each averaging period are summarized in Table 5-7.

5.2 AIR QUALITY MODEL SELECTION AND OPTIONS

The USEPA-recommended AERMOD modeling system was used to conduct the dispersion modeling for this analysis. The current versions of the models (AERMOD v15181, AERMET v15181, and AERMAP v11103) were used to model both criteria pollutants and air toxics.

The AERMOD model is a steady-state plume model that incorporates air dispersion based on planetary boundary layer turbulence structure and scaling concepts. AERMOD includes the treatment of both surface and elevated emission sources in areas of simple and complex terrain. The model can assess sources in either rural or urban settings and calculate concentrations for every hour of meteorological data at user-defined receptors that are allowed to vary with terrain. The AERMOD model has incorporated the latest USEPA building downwash algorithm, the Plume Rise Model Enhancements (PRIME), for the improved treatment of building downwash. PRIME can also account for the stack placement relative to the building, thereby allowing the estimation of impacts in the cavity region near the stack.

AERMOD is designed to operate with two preprocessor executables: AERMET processes meteorological data for input to AERMOD, and AERMAP processes terrain elevation data and generates receptor information for input to AERMOD. The AERMOD model was selected for the air quality modeling analysis because of several model features that properly simulate the proposed Project dispersion environments, including the following:

- ability to model multiple sources;
- ability to calculate simple, complex, and intermediate terrain concentrations;
- ability to estimate cavity impacts;
- use of representative historical hourly average meteorological data; and,
- processing for concentration averaging periods ranging from one hour to one year, as well as 5-year averaging (which is necessary for comparison with the NAAQS).

A complete technical description of the AERMOD model may be found in the User's Guide for AERMOD (USEPA, 2004a). Modeling was performed with all regulatory default options in AERMOD set. The chemical conversion of NO_X into NO_2 is an important factor when assessing NO_2 concentrations. The Ambient Ratio Method (ARM) in AERMOD was used to determine the NO_2 impacts for the Project. Specifically, the USEPA Tier 2 methodology for estimating NO_2 concentrations from total NO_x emissions was implemented. ARM assumes a 75% conversion of NO_x to NO_2 on an annual basis and an 80% conversion of NO_x to NO_2 on a 1-hour basis.

Table 5-5: Source Parameters and Emission Rates for the Proposed Ancillary Equipment

Source	Exit Temp. (°F)	Exit Velocity (fps)	Emission Rates (lb/hr)											
			NO_x		CO		PM_{10}		$PM_{2.5}$		SO_2			
			1-hr	Ann	1-hr	8-hr	24-hr	Ann	24-hr	Ann	1-hr	3-hr	24-hr	Ann
Emergency Engine[1]	887.1	139.3	0.338	0.338	4.49	0.561	0.012	0.010	0.012	0.010	0.00026	0.0026	0.00032	0.00026
Fire Water Pump[1]	809.0	127.0	0.031	0.031	1.11	0.139	0.0031	0.0025	0.0031	0.0025	6.18e-5	0.0006	7.53e-5	6.18e-5

[1]For the emergency engine and fire water pump the short-term modeled emission rates are normalized to operate 1 hour within the averaging period. For 1-hour NO_2, 1-hour SO_2 and other pollutant's annual averaging periods, the modeled emission rates were normalized based on 300 hours per year.

Table 5-6. Source Parameters and Emission Rates for the Existing Canal Generating Station Equipment

Source	Exit Temp. (°F)	Exit Velocity (fps)	Emission Rates (lb/hr)												
			NO_x		CO		PM_{10}		$PM_{2.5}$		SO_2				*Pb*
			1-hr	Ann	1-hr	8-hr	24-hr	Ann	24-hr	Ann	1-hr	3-hr	24-hr	Ann	*24-hr*
Canal Unit 1, 2	338.5	116	3112.1	3112.1	10859.3	10859.3	333.2	333.2	333.2	333.2	6728.7	6728.7	6728.7	6728.7	***0.109***
Emergency Gen 1[1]	900	152	0.60	0.60	3.81	0.48	0.05	0.044	0.05	0.044	0.0002	0.0021	0.0003	0.0002	***1.28e-5***
Emergency Gen 2[1]	900	152	0.60	0.60	3.81	0.48	0.05	0.044	0.05	0.044	0.0002	0.0021	0.0003	0.0002	***1.28e-5***
Emerg. Fire Pump[1]	900	267	0.27	0.27	1.75	0.22	0.02	0.019	0.02	0.019	0.0031	0.0299	0.0037	0.0031	***5.63e-6***
Gas Heater	600	8.5	0.64	0.64	0.48	0.48	0.079	0.079	0.079	0.079	0.033	0.033	0.033	0.033	***2.94e-6***

[1]For the emergency engine and fire water pump the short-term modeled emission rates are normalized to operate 1 hour within the averaging period. For 1-hour NO_2, 1-hour SO_2 and other pollutant's annual averaging periods, the modeled emission rates were normalized based on 300 hours per year.

Table 5-7: Results of Proposed Turbine Operating Condition Analysis

Pollutant	Averaging Period	Fuel	Worst-Case Operating Condition[(1)]
SO_2	1-hr[2,3]	ULSD	Base Load
	3-hr[3]	ULSD	Base Load
	24-hr[4]	ULSD	Base Load
	Annual[2,5]	2940 hours NG 1440 hours ULSD	Minimum Load
PM_{10}	24-hr[4]	ULSD	Startup/shutdown to minimum load
	Annual[5]	2940 hours NG 1440 hours ULSD	Minimum Load
$PM_{2.5}$	24-hr[4]	ULSD	Startup/shutdown to minimum load
	Annual[5]	2940 hours NG 1440 hours ULSD	Minimum Load
NO_2	1-hr[2,3]	ULSD	Startup/shutdown to minimum load
	Annual[5]	2940 hours NG 1440 hours ULSD	Minimum Load
CO	1-hr[3]	ULSD	Startup/shutdown to base load
	8-hr[3]	ULSD	Startup/shutdown to minimum load
Pb	***Rolling 3-month[6]***	***ULSD***	***Base Load***

[1]Worst-case operating conditions were determined based on AERMOD modeled concentrations for SILs analysis, which include the project emission sources: simple cycle turbine; fire pump; and, emergency generator, unless noted.
[2]Emergency equipment was included using modeled emission rates that were normalized based on 300 hours per year.
[3]Startup/shutdown conditions for 1-hr, 3-hr, and 8-hr model runs are conservatively defined as 30-min startup and 30-min of normal operations (minimum load for 1-hr NO_2, 8-hr CO and base load for 1-hr CO).
[4]Startup/shutdown conditions for 24-hr model runs refine emissions to six 30-minute startups, six 8-minute shutdowns, and 22-minute minimum load.
[5]Annual average modeling does not evaluate startup/shutdown conditions.
[6] Rolling 3-month average modeling does not evaluate startup/shutdown conditions.

5.3 URBAN/RURAL CLASSIFICATION FOR MODELING

One of the factors affecting input parameters to dispersion models is the presence of either a rural or urban setting near the Project site. Use of the urban options in AERMOD (URBANOPT) depends upon the land use characteristics within 3 kilometers (km) of the source being modeled (Appendix W to 40 CFR Part 51) (USEPA, 2005). Factors that affect the decision if an area is urban, and thus the use of the URBANOPT options in AERMOD, include the extent of vegetated surface area, the water surface area, types of industry and commerce, and building types and heights within this area. Per USEPA guidance, the Auer method of meteorological land use typing scheme was applied to determine whether urban or rural dispersion should be used in the modeling. The Auer land use types are defined in Table 5-8 (Auer, 1978). If the land use types I1, I2, C1, R2 and R3 account for 50% or more of the area within 3 km of the source, then the URBANOPT option could be used in the modeling analysis.

Figure 5-1 shows the 3-km radius around the Project. Observation of the aerial map shows that the area within a 3-km radius of the Project is predominantly rural; therefore, the URBANOPT options were not used in the AERMOD modeling.

Table 5-8: Identification and Classification of Land Use

Type	Use and Structures	Vegetation
I1	Heavy Industrial Major chemical, steel and fabrication industries; generally 3-5 story buildings, flat roofs	Grass and tree growth extremely rare; <5% vegetation
I2	Light-Moderate Industrial Rail yards, truck depots, warehouses, industrial parks, minor fabrications; generally 1-3 story buildings, flat roofs	Very limited grass, trees almost absent; <5% vegetation
C1	Commercial Office and apartment buildings, hotels; >10 story heights, flat roofs	Limited grass and trees; < 15% vegetation
R1	Common Residential Single family dwellings with normal easements; generally one story, pitched roof structures; frequent driveways	Abundant grass lawns and light-moderately wooded; >70% vegetation
R2	Compact Residential Single, some multiple, family dwellings with close spacing; generally <2 story, pitched roof structures; garages (via alley), no driveways	Limited lawn sizes and shade trees; < 30% vegetation
R3	Compact Residential Old multi-family dwellings with close (<2m) lateral separation; generally 2 story, flat roof structures; garages (via alley) and ashpits, no driveways	Limited lawn sizes, old established shade trees; < 35% vegetation
R4	Estate Residential Expansive family dwellings on multi-acre tracts	Abundant grass lawns and lightly wooded; > 95% vegetation
A1	Metropolitan Natural Major municipal, state or federal parks, golf courses, cemeteries, campuses, occasional single story structures	Nearly total grass and lightly wooded; > 95% vegetation
A2	Agricultural; Rural	Local crops (e.g.,corn, soybean); > 95% vegetation
A3	Undeveloped; Uncultivated; wasteland	Mostly wild grasses and weeds, lightly wooded; > 90% vegetation
A4	Undeveloped Rural	Heavily wooded; > 95% vegetation
A5	Water Surfaces: Rivers, lakes	

5.4 GOOD ENGINEERING PRACTICE STACK HEIGHT ANALYSIS

A Good Engineering Practice (GEP) stack height analysis was performed based on the proposed Project design to determine the potential for building-induced aerodynamic downwash for all modeled stacks. The analysis procedures described in USEPA's *Guidelines for Determination of Good Engineering Practice*

Stack Height (USEPA, 1985), Stack Height Regulations (40 CFR 51), and current USEPA Model Clearinghouse guidance were used.

The GEP formula height is based on the observed phenomena of disturbed atmospheric flow in the immediate vicinity of a structure resulting in higher ground-level concentrations at a closer proximity to the building than would otherwise occur. It identifies the minimum stack height at which significant aerodynamic downwash is avoided.

GEP stack height is defined as the greater of 65 meters or the formula height. The formula height, as defined by USEPA, is:

$$H_{GEP} = H_b + 1.5L$$

where: H_{GEP} = GEP formula height;

H_b = Height of adjacent or nearby building or structure; and

L = Lesser of height or maximum projected width of adjacent or nearby building or structure, i.e., the critical dimension.

A structure is determined to be “nearby” if the stack is within 5L from the edge of the structure.

The latest version of the USEPA Building Profile Input Program (BPIP-PRIME) was run for all stacks and buildings in the vicinity of the Project to create the building parameter inputs to AERMOD. BPIP-PRIME addresses the entire structure of the wake, from the cavity immediately downwind of the building, to the far wake. Figure 5-2 shows the stack locations as well as the structure footprints and heights input into BPIP-PRIME. A GEP formula height of 491.4 feet (149.8 meters) was calculated for the new turbine stack with the combined structure of the boiler buildings #1 and #2 at the existing Station as the controlling structure. Stack heights for each source modeled are provided in Table 5-1. Each of the stacks modeled are equal to or below its GEP height and, therefore, exhaust emissions have the potential to experience the aerodynamic effects of downwash. As such, wind-direction-specific building parameters generated by BPIP-PRIME were input into AERMOD to account for potential downwash from nearby structures in the dispersion calculations.

5.5 RECEPTOR LOCATIONS FOR MODELING

The receptor grid selected for the AERMOD modeling is sufficient to capture maximum modeled impacts. A nested Cartesian grid was extended out from the Property fence line based on the following spacing and distances:

- at 25-meter intervals along the fence line;
- at 50-meter intervals extending out to 1 km;
- at 100-meter intervals from 1 km to 3 km;
- at 250-meter intervals from 3 km to 5 km;
- at 500-meter intervals from 5 km to 10 km; and,
- at 1,000-meter intervals from 10 km to 20 km.

In addition to the gridded receptors, discrete receptors are placed at locations of schools, daycare centers, hospitals, and nursing homes within 5 km of the Project. Specifically those locations include:

Three identifiable sensitive receptors within 1 km of Canal Generating Station:

1. Dieu's Daycare - Day Care Center (14 Moody Dr. Sandwich, MA)
2. Radius HealthCare Center - Nursing Home (37 MA-6A Sandwich, MA)
3. Sandwich Schoolhouse Preschool (38 Route 6A, Sandwich, MA)

Between 1 km and 5 km from Canal Generating Station, there are 11 identifiable sensitive receptors:

1. Bridgeview Montessori School (885 Sandwich Rd. Sagamore, MA).
2. Ella F Hoxie School (30 Williston Rd. Sagamore Beach, MA)
3. Henry T. Wing School (33 Water St. Sandwich, MA)
4. Sandwich Community School-Early Learning (4 Beale Ave. Sandwich, MA)
5. Little Owl Day Care - Day Care Center (67 Main St. Sandwich, MA)
6. Sandwich Village Preschool - Preschool (159 Main St. Sandwich, MA)
7. Cape Winds Rest Home - Retirement Home (125 Main St. Sandwich, MA)
8. Decatur House Inc - Assisted Living Facility (176 Main St. Sandwich, MA)
9. Joyful Noise Preschool (136 Main St, Sandwich, MA)
10. Rainbow Preschool (80 Old Plymouth Rd, Sagamore Beach)
11. Bourne/Sandwich I Preschool and Borne Sandwich II Preschool (90 Adams St, Sagamore, MA)

The receptor coordinates used in the modeling analysis are in Universal Transverse Mercator (UTM) Zone 19, based on North American Datum (NAD) 83. A total of 8,589 receptors were included in the modeling. The full receptor network is depicted in Figure 5-3 and a close-up of the near field receptors is shown in Figure 5-4.

AERMAP (version 11103) (USEPA, 2004b), AERMOD's terrain preprocessor program, was used to calculate terrain elevations and critical hill heights for each model receptor using National Elevation Data (NED). The 1 arc-second (~30-meter resolution) NED dataset was downloaded from the United States Geological Service (USGS) website (http://seamless.usgs.gov/).

5.6 METEOROLOGICAL DATA FOR MODELING

The meteorological data utilized in the modeling analysis were described in detail in the Modeling Protocol approved by MassDEP. Meteorological data required for AERMOD include hourly values of wind speed, wind direction, and ambient temperature. Five years (2008-2012) of site-specific meteorological data from the nearby Telegraph Hill monitor (approximately 2.9 miles to the south-southeast of the proposed Project) were used in the modeling analyses, along with concurrent surface observations from Barnstable Municipal Airport and upper air data from Chatham Municipal Airport. The meteorological data were processed with AERMET (USEPA, 2004c), the meteorological preprocessor for AERMOD, based on USEPA guidance (USEPA, 2013a), 40 CFR Part 51 Appendix W, the AERSURFACE user's guide (USEPA, 2013b), and other USEPA publications.

The five-year data period selected for this analysis spans the calendar years 2008-2012 because the latest five years (through 2014) from Telegraph Hill had periods that were well below the data completeness requirements for modeling. In particular, data recovery of wind direction for the first quarter of 2013 was less than 60% due to an outage at the tower. However, data for the five consecutive years of 2008–2012 meets data completeness requirements and, therefore, were chosen for this modeling analysis.

The Telegraph Hill monitor records some key measurements at a height much higher than the typical airport 10-m (33-ft) level:

- wind speed at 145 feet;
- wind direction at 145 feet;
- sigma theta at 145 feet;
- temperature at 10 feet; and,
- relative humidity at 10 feet.

The Telegraph Hill data were supplemented, as appropriate, with concurrent surface observations (not including wind data) from Barnstable Municipal Airport (to substitute for missing data) and upper air observations from Chatham Municipal Airport (for upper air data as required by the AERMOD modeling system). The Telegraph Hill Station base of 64.3 meters was used for the potential temperature profile.

AERMET requires specification of site land use characteristics including surface roughness (z_o), albedo (r), and Bowen ratio (B_o). USEPA has developed the AERSURFACE (v13016) tool to determine the site characteristics based on digitized land cover data. AERSURFACE supports the use of land cover data from the USGS National Land Cover Data 1992 archives (NLCD92) (http://edcftp.cr.usgs.gov/pub/data/landcover/states/). The NLCD92 archive provides data at a spatial resolution of 30 meter based on a 21-category classification scheme applied over the continental United States.

AERSURFACE was applied for surface roughness, based on the 1-km radius circular area centered at the Telegraph Hill monitor. The 1-km radius was divided into sectors for the AERSURFACE analysis; each chosen sector has a mix of land uses that is different from that of other selected sectors. Three sectors used for this analysis are: 80˚ – 170˚, 170˚ – 345˚, and 345˚ – 80˚. The determination of the Bowen ratio and albedo are based on a mean value (i.e., no direction or distance dependency) for a representative domain defined by a 10 km by 10 km region centered on the measurement site. For Bowen ratio, the land use values are linked to three categories of surface moisture corresponding to average, wet, and dry conditions. The surface moisture condition for the site may vary depending on the meteorological data period for which the surface characteristics are applied. AERSURFACE applies the surface moisture condition for the entire data period. Therefore, if the surface moisture condition varies significantly across the data period, then AERSURFACE can be applied multiple times to account for those variations. The surface moisture condition for each month was determined by comparing precipitation for the period of data to be processed to the 30-year climatological record, selecting "wet" conditions if precipitation is in the upper 30th-percentile, "dry" conditions if precipitation is in the lower 30th-percentile, and "average" conditions if precipitation is in the middle 40th-percentile. The 30-year precipitation data set used in this modeling was taken from the National Climatic Data Center for Chatham, MA (USC00191386). The monthly designations of surface moisture input to AERSURFACE are summarized in Table 5-9.

Table 5-9: AERSURFACE Bowen Ratio Moisture Condition Designations

Month	Bowen Ratio Category				
	2008	2009	2010	2011	2012
January	Average	Average	Average	Wet	Average
February	Wet	Dry	Average	Average	Dry
March	Average	Average	Wet	Dry	Dry
April	Average	Average	Dry	Average	Dry
May	Wet	Average	Average	Dry	Wet
June	Dry	Average	Average	Average	Dry
July	Average	Wet	Average	Wet	Average
August	Average	Wet	Wet	Average	Average
September	Wet	Average	Wet	Dry	Average
October	Average	Wet	Wet	Wet	Average
November	Average	Dry	Average	Average	Dry
December	Wet	Average	Average	Dry	Wet

There were no months during the 2008-2012 time period in which there was measurable snow depth on the ground for more than 50% of the winter months. As such, all winter months were modeled as "winter no snow."

A composite wind rose for the five years of meteorological data used in the modeling analysis is presented in Figure 5-5. The winds are predominantly from the southwest.

5.7 BACKGROUND AIR QUALITY DATA

Air quality data collected from the closest, representative, available monitoring stations to the Project site were used to characterize ambient air quality conditions near the proposed Project. Background air quality levels characterize the existing ambient air quality in the vicinity of the proposed Project. NRG operates an ambient air quality monitoring station, Shawme Crowell Monitoring Station, in Shawme Crowell State Park located approximately 1 mile southwest of the Project site. This monitoring site was put into operation to provide data of the existing air quality conditions in the vicinity of the Station. This monitor measures concentrations of SO_2, NO_2, PM_{10}, and $PM_{2.5}$. For background concentrations of CO ***and Pb (lead)***, the Francis School monitor in East Providence (EPA AQS ID 440071010), which is located 43.6 miles to the west-northwest of the Project site, was used. Data from both of these monitoring sites represent conservative estimates of the existing ambient air quality. The Shawme-Crowell monitor is a source-specific location designed to capture impacts from the existing Station, which was cumulatively modeled with the Project. The East Providence site is conservative because it is affected by more development, since it is located in a more urban environment than Sandwich. A summary of the background air quality concentrations based on the latest three years (2012-2014) of existing monitoring data is presented in Table 5-10. ***The Pb (lead) data are for 2013–2015.***

As shown in Table 5-10, ambient concentrations of SO_2, NO_2, PM_{10}, and $PM_{2.5}$ measured at the Shawme-Crowell monitor are well below the NAAQS. Ambient concentrations of CO at the closest measurement location in East Providence are also well below the NAAQS.

Table 5-10: Monitored Ambient Air Quality Concentrations and Selected Background Levels

Pollutant	Averaging Period	2012	2013	2014	Background Air Quality ($\mu g/m^3$)	NAAQS ($\mu g/m^3$)
SO_2 (ppb)	1-Hour	11	9	5	22	196
	3-Hour	22	14	5	58	1,300
	24-Hour	5	4	5	12	365
	Annual	1	2	2	5	80
NO_2 (ppb)	1-Hour	22	20	22	40	188
	Annual	8	8	7	15	100
CO (ppm)	1-Hour	1.5	2.0	1.6	2,346	40,000
	8-Hour	1.0	1.3	1.2	1,495	10,000
PM_{10} ($\mu g/m^3$)	24-Hour	23	18	20	23	150
	Annual	9	9	9	9	50
$PM_{2.5}$ ($\mu g/m^3$)	24-Hour	12	10	10	11	35
	Annual	5	5	4	5	12
Lead (Pb) (µg/m3)	***3-Month***	***0.01***	***0.01***	***0.01***	***0.01***	***0.15***

In January 2013, a Court ruling held that use of the $PM_{2.5}$ SIL alone cannot be used to demonstrate compliance with NAAQS. The Court decision does not preclude the use of the SILs for $PM_{2.5}$ entirely, but requires that monitoring data be evaluated to ensure that predicted impacts that are less than the SIL do not result in total concentrations (existing ambient plus project-related contributions) that exceed the NAAQS. Therefore, if there is a sufficient margin (greater than the SIL value) between the representative monitored background concentration in the area and the $PM_{2.5}$ NAAQS, then USEPA believes it would be sufficient to conclude that a proposed source with an impact less than the SIL value will not cause or contribute to a violation of the NAAQS and to forego a more comprehensive modeling analysis for that pollutant for that averaging period (USEPA, 2014). MassDEP believes that this methodology can be extended to all NAAQS pollutants and averaging periods. Table 5-11 presents the difference between the NAAQS and the representative monitored background concentration, compared to the SILs. As shown in Table 5-11, all averaging periods for each pollutant have a margin between the monitored value and the NAAQS that is greater than the respective SIL; therefore, use of the SILs as *de minimis* levels for all pollutants is appropriate.

Table 5-11: Margin between the Monitored Air Quality Concentrations and the NAAQS Compared to the SILs

Pollutant	Averaging Period	Background Concentration ($\mu g/m^3$)	NAAQS ($\mu g/m^3$)	Delta Concentration (NAAQS –Background) ($\mu g/m^3$)	Significant Impact Level ($\mu g/m^3$)
SO_2	1-Hour	22	196	174	7.8
	3-Hour	58	1,300	1,242	25
	24-Hour	12	365	353	5
	Annual	5	80	75	1
NO_2	1-Hour	40	188	148	7.5
	Annual	15	100	85	1
CO	1-Hour	2,346	40,000	37,654	2,000
	8-Hour	1,495	10,000	8,505	500
PM_{10}	24-Hour	23	150	127	5
	Annual	9	50	41	1
$PM_{2.5}$	24-Hour	11	35	24	1.2
	Annual	5	12	7	0.3

(Note: Pb does not have a Significant Impact Level so it is not listed in the Table.)

5.8 AIR QUALITY MODELING RESULTS

5.8.1 Significant Impact Level Analysis

The modeled concentrations for criteria pollutants predicted using AERMOD for the proposed Project sources were compared to the applicable SILs. The modeling evaluated a range of operating loads (including SUSD) to assess the proposed Project's impact. SUSD conditions were not evaluated for annual average modeling because these conditions are only expected to last for a short amount of time (less than 30 minutes). The maximum modeled criteria pollutant concentrations are compared to the SILs in Table 5-12. All maximum impacts are predicted at the Station fence-line or within 700 meters of the fence-line for a few pollutants/averaging periods. The results show that maximum modeled concentrations of SO_2) and CO for all averaging periods, and annual NO_2, $PM_{2.5}$, and PM_{10} are below their corresponding SILs. Maximum modeled concentrations of 24-hour average $PM_{2.5}$ and PM_{10}, and 1-hour NO_2 are above their corresponding SILs (shown in bold in Table 5-12). Therefore, cumulative modeling (see Section 5.8.2) was required for these pollutants/averaging period combinations. Figure 5-6 presents the Significant Impact Area (SIA) for 24-hr PM_{10}, 24-hr $PM_{2.5}$ and 1-hr NO_2. The SIA: for 24-hour PM_{10} extends to 1,115 meters; for 24-hour $PM_{2.5}$ extends to 2,903 meters; and, for 1-hour NO_2 extends to 4,750 meters from the Project stack location.

Table 5-12: Proposed Canal 3 Project Maximum AERMOD Modeled Results Compared to Significant Impact Levels

Pollutant	Avg. Period	Form	Max. Modeled Conc. (µg/m^3)	SIL (µg/m^3)	% of SIL	Period	Receptor Location[4] (m) (UTME, UTMN, Elev.)
SO_2	1-hr	H1H[1]	0.61	7.8	8%	2008-2012	374615.32, 4625525.14, 3.16
	3-hr	H1H	0.64	25	3%	04/28/11 hr 15	374615.32, 4625525.14, 3.16
	24-hr	H1H	0.40	5	8%	04/28/11 hr 24	374615.32, 4625525.14, 3.16
	Annual	H1H	0.0037	1	0%	2011	375250.00, 4626000.00, 4.00
PM_{10}	24-hr	H1H	**11.98**	5	240%	04/28/11 hr 24	374615.32, 4625525.14, 3.16
	Annual	H1H	0.06	1	6%	2011	375250.00, 4626000.00, 4.00
$PM_{2.5}$	24-hr	H1H[2]	**8.25**	1.2	687%	2008-2012	374615.32, 4625525.14, 3.16
	Ann.	H1H[3]	0.05	0.3	16%	2008-2012	374615.32, 4625525.14, 3.16
NO_2 [5]	1-hr	H1H[1]	**53.35**	7.5	711%	2008-2012	374425.63, 4625515.76, 2.95
	Annual	H1H	0.71	1	71%	2009	374603.87, 4625282, 3.62
CO	1-hr	H1H	197.57	10%	9%	07/18/10 hr 22	374900.00, 4625300.00, 4.71
	8-hr	H1H	45.31	9%	9%	11/10/10 hr 08	374517.68, 4625306.81, 3.12

Note: Impacts denoted in bold font are above the SILs.
[1] High 1st High daily maximum 1-hr concentrations averaged over 5 years.
[2] High 1st High maximum 24-hour concentrations averaged over 5 years.
[3] Maximum annual concentrations averaged over 5 years.
[4] All modeled concentrations depicted in this table occur on the facility fence line or within 700-meters of the facility fence line.
[5] NO_2 estimated by assuming 75% conversion of NO_X to NO_2 for annual concentrations and 80% conversion of NO_X to NO_2 for 1-hour concentrations.
Note: Pb does not have a Significant Impact Level so it is not listed in the Table.

5.8.2 NAAQS Compliance Demonstration

Since the proposed Project is a modification of the existing Station, a compliance demonstration was conducted to ensure that the combined emissions from the existing Station and the proposed new Project will not cause or contribute to a NAAQS violation (MassDEP, 2011).

For the pollutants and averaging periods that have maximum predicted impacts greater than the SILs (24-hour $PM_{2.5}$**,** 24-hour PM_{10} and 1-hour NO_2), cumulative modeling is required. MassDEP modeling guidance indicates that sources within 10 km of the Station that emit significant $PM_{2.5}$, PM_{10}, and NO_x emissions (i.e., > 10 tpy $PM_{2.5}$, >15 tpy PM_{10}, >40 tpy NO_x, based on actual emissions) should be included in the cumulative modeling. A search for facilities was conducted using these criteria and no sources were found within 10 km that satisfy the criteria. Therefore, there are no nearby sources beyond those existing sources at the Canal Generating Station to include in a cumulative modeling analysis. MassDEP has concurred with the finding of no additional sources required for a cumulative NAAQS modeling analysis.

The cumulative design value modeled concentrations of the new Project and existing Station were combined with appropriate ambient background concentrations and then compared with the NAAQS. Table 5-13 demonstrates that the predicted total ambient criteria pollutant concentrations (modeled plus background) are below the NAAQS for all pollutants. For reference, the maximum impact from the new sources and existing sources are also shown separately in Table 5-13. Note that these individual concentrations represent their relative maximum impact (in the form of the standard) and are not paired in time and space; therefore, these concentrations do not sum to the "AERMOD Total Modeled Concentration" shown in the table, which reflects the maximum in the form of the standard of the combined impacts (new plus existing) paired in time and space.

5.8.3 PSD Increment Analysis

To ensure that air quality in areas that are in attainment of the NAAQS is not allowed to be significantly degraded from existing levels, USEPA has established PSD Increments. PSD Increments reflect the maximum increase in pollutant concentrations that is allowed to occur above a baseline concentration for a subject pollutant. The baseline concentration for each pollutant and averaging period is defined as the ambient concentration existing at the time that the first complete PSD permit application affecting the area is submitted to the regulatory agency. Significant deterioration is said to occur when the amount of new pollution would exceed the applicable PSD Increment. Modeling to demonstrate that allowable increments are not exceeded must include existing sources that are both within the baseline area and were constructed after the PSD baseline date (consume increment). In addition, credit may be taken for sources that have added controls or stopped operating after the PSD baseline date (expand increment). The existing Station sources do not consume increment because they were in operation prior to the baseline dates and are considered part of the baseline concentration.

If the maximum modeled concentration of a pollutant due to the emission increase from the proposed Project are below the applicable SILs, the predicted emissions from the proposed modifications are considered to be in compliance with the PSD Increments for that pollutant. Therefore, for this Project, PSD Increment modeling is required for short-term particulates (24-hour PM_{10} and $PM_{2.5}$). A PSD Increment has not been established for 1-hour NO_2.

Canal 3 has conferred with MassDEP to determine that the $PM_{2.5}$ minor source baseline date has not yet been established for the baseline area (Barnstable County). The PSD Permit application for this Project will establish the baseline date for $PM_{2.5}$ when it is determined to be complete. Therefore, because the baseline has not been previously established for $PM_{2.5}$, there are no other $PM_{2.5}$ increment-consuming sources in the baseline area to include in the $PM_{2.5}$ PSD Increment modeling.

The baseline for PM_{10} is tracked by town in Massachusetts. The only other potential increment consuming project, the SEMASS Resource Recovery Facility, is located approximately 23 km from the Station in Rochester, Massachusetts. The Project's SIA for 24-hr PM_{10} extends only approximately 1 km, which does not reach into the town of Rochester. Therefore, there are no other facilities included in the PSD Increment modeling for PM_{10}.

Table 5-14 presents the results of the PSD Increment analysis for $PM_{2.5}$ and PM_{10}. The analysis includes impacts from the new turbine, emergency generator and the fire water pump. The results indicate that the operation of the proposed Project is protective of the PSD Increments.

Table 5-13: AERMOD Model Results for the New Project and Existing Station Compared to the NAAQS

Pollutant	Avg. Period	Form	AERMOD Modeled Max. Concentration (μg/m³) (6)		AERMOD Total Modeled Conc. (μg/m³)	Back-ground Conc. (μg/m³)	Total Ambient Conc. (μg/m³)	NAAQS (μg/m3)	% of NAAQS	Period (7)	Receptor Location (m) (7)
			New Sources	Existing Sources							(UTME, UTMN, Elev.)
SO_2	1-hr	H4H[1]	0.49	128.20	128.33	22	150.33	196	77%	2008-2012	375700.00, 4626300.00, 4.35
	3-hr	H2H	0.61	133.70	133.79	58	191.79	1300	15%	06/26/08 hr 12	375400.00, 4626300.00, 4.01
	24-hr	H2H	0.26	45.87	45.92	12	57.92	365	16%	07/08/08 hr 24	375800.00, 4626300.00, 0.51
	Annual	H1H	0.004	4.20	4.20	5	9.20	80	12%	2011	376000.00, 4626700.00, 0.00
PM_{10}	24-hr	H2H	8.53	6.40	8.71	23	31.71	150	21%	12/15/08 hr 24	374615.32, 4625525.14, 3.16
	Annual	H1H	0.06	1.00	1.01	9	10.01	50	20%	2009	373682.47, 4625526.98, 3.77
$PM_{2.5}$	24-hr	H8H[2]	2.43	3.87	3.87	11	14.87	35	42%	2008-2012	373682.47, 4625526.98, 3.77
	Annual	H1H[3]	0.05	0.79	0.79	5	5.79	12	48%	2008-2012	373713.42, 4625597.92, 4.23
NO_2(5)	1-hr	H8H[4]	44.28	91.23	91.23	40	131.33	188	70%	2008-2012	373682.47, 4625526.98, 3.77
	Annual	H1H	0.71	10.03	10.04	15	25.04	100	25%	2009	373682.47, 4625526.98, 3.77
CO	1-hr	H2H	195.16	666.81	678.94	2,346	3,024.94	40000	8%	04/11/08 hr 11	374300.00, 4626700.00, 1.71
	8-hr	H2H	42.25	159.51	167.86	1,495	1,662.86	10000	17%	09/22/10 hr 16	375900.00, 4626400.00, 0.00
***Pb*[8]**	***3-month***	***H1H***	***8.51E-04***	***1.43E-03***	***2.28E-03***	***0.01***	***0.012***	***0.15***	***8%***	***03/08/12***	***376500.00, 4627100.00, 0.00***

1 High 4st High daily maximum 1-hr concentrations averaged over 5 years.
2 High 8th High 24-hour concentrations averaged over 5 years.
3 Maximum annual concentration averaged over 5 years.
4 High 8th High daily maximum 1-hr concentrations averaged over 5 years.
5 NO_2 estimated by assuming 75% conversion of NO_X to NO_2 for annual concentrations and 80% conversion of NO_X to NO_2 for 1-hour concentrations.
6 Modeled concentrations depict impacts from New Sources and Existing Sources relative to their own maximum modeled concentrations. Therefore the total of the New Sources + Existing Sources does not add up to the "AERMOD Total Modeled Concentration" depicted in this table.
7 The period and receptor location correspond to the AERMOD Total Modeled Concentration value.
8 Pb impacts are conservatively based on the maximum 24-hr AERMOD modeled concentrations. The "AERMOD Total Modeled Concentration" for Pb is conservatively the sum of the maximum concentrations for the New and Existing source, and the period and receptor are based on the existing source impact.

Table 5-14: AERMOD Model Results Compared to the PSD Increments

Pollutant	Avg. Period	Form	Modeled Conc. (µg/m^3)	PSD Increment (µg/m^3)	% of Increment	Period	Receptor Location (m) (UTME, UTMN, Elev.)
PM_{10}	24-hr	H2H[1]	8.53	30	28%	11/11/10 hr 24	374517.68, 4625306.81, 3.12
$PM_{2.5}$	24-hr	H2H[1]	8.53	9	95%	11/11/10 hr 24	374517.68, 4625306.81, 3.12

[1] High 2nd High concentration over 5 years.

5.8.4 Secondary $PM_{2.5}$ Assessment

In May 2014, USEPA released "*Guidance for $PM_{2.5}$ Permit Modeling"* (the Guidance), which provides guidance on demonstrating compliance with the NAAQS and PSD Increment for $PM_{2.5}$ specifically with regard to consideration of the secondarily formed $PM_{2.5}$. In the Guidance, USEPA has defined four "Assessment Case" categories based on a project's potential emissions of direct $PM_{2.5}$ and precursors for potential secondary formation, NO_x and SO_2 (in tpy). The Assessment Case categories identify assessment approaches that are available and appropriate for each case.

The current USEPA dispersion model recommended for near-field $PM_{2.5}$ modeling, AERMOD, does not explicitly account for potential secondary formation of $PM_{2.5}$. Therefore, in addition to the direct $PM_{2.5}$ dispersion modeling analysis, the potential for secondary formation of $PM_{2.5}$ from significant precursor emissions should be assessed in accordance with the Guidance.

Based on the information in Table III-1 of the Guidance, the Project falls into Assessment Case 3[6]. Accordingly, a Case 3 hybrid qualitative/quantitative assessment of potential secondary formation of $PM_{2.5}$ is appropriate.

Based upon the Guidance, a hybrid qualitative/quantitative assessment is deemed appropriate for evaluation of the Project's potential secondary $PM_{2.5}$ because the underlying refined air quality modeling provides a well-developed analysis of both the current background concentrations and the Project's primary $PM_{2.5}$ emissions. Accordingly, a hybrid qualitative/quantitative assessment of the emission source and the atmospheric environment in which the source is located is presented.

A quantitative estimate of the projected secondary formation of $PM_{2.5}$ is developed based on the approach described in Appendix D of the Guidance, which incorporates a regional average offset ratio. This assessment supports a determination that secondary $PM_{2.5}$ impacts associated with the source's precursor emissions will not cause or contribute to a violation of the 24-hour or annual $PM_{2.5}$ NAAQS.

Regional $PM_{2.5}$

Particulate matter in the atmosphere is made up of different chemical species (nitrates, sulfates, organic matter, elemental carbon, etc.). NO_x as a gas is considered a precursor pollutant because NO_x emissions can convert to nitrates, a particulate, in the atmosphere. Similarly, SO_2 as a gas can be converted to sulfates in the atmosphere. These conversions involve highly complex shifting between gaseous, liquid and solid phases. They are dependent on atmospheric conditions such as temperature, sunlight, relative humidity, and the presence of reactive gases such as O_3, hydrogen peroxide, and NH_3. The formation of secondary $PM_{2.5}$ takes time to occur and, therefore, generally materializes considerably downwind of the precursor emission source. The sulfate formation is considered a stable product; however, the nitrate process is reversible. Equilibrium is established between nitric acid, NH_3 and ammonium nitrate.

[6] Assessment Case 3 applies when direct $PM_{2.5}$ emissions are ≥ 10 tpy and NO_x and/or SO_2 emissions are ≥ 40 tpy.

As a general matter, the composition of $PM_{2.5}$ varies by season and location across the United States. Nitrates make up a small fraction of the $PM_{2.5}$ in the Northeast. The percentage of nitrates in $PM_{2.5}$ is almost negligible during the summer, increases somewhat in the spring and fall, with the highest percentage of nitrates seen during the winter season. Even during the winter, sulfates and organic matter dominate the $PM_{2.5}$ composition in the Northeast.

For the proposed Project, the background $PM_{2.5}$ monitoring data considered in the air quality analysis are from the Shawme Crowell Monitoring Station located in Shawme Crowell State Park. This monitoring station was specifically established to characterize air quality in the vicinity of the Station. There are co-located $PM_{2.5}$ monitors operating at that monitoring station. Figures 5-7 and 5-8 show a seven-year trend of measured annual $PM_{2.5}$ at the Shawme Crowell site and a 10-year trend at other monitoring locations across the state, respectively. The $PM_{2.5}$ monitoring data show improvement in the ambient air quality on an annual basis over recent years. The same trend is found at other monitoring locations throughout Massachusetts.

A recent Harvard School of Public Health study (Masri, et al., 2015) found that regional sources accounted for 48% of the $PM_{2.5}$ measured at a Boston monitoring site. Hence, the representative background monitoring data for $PM_{2.5}$ used in the modeling analysis adequately accounts for secondary contribution from background sources in the region. On the basis of measured data, there is no indication that secondary formation of $PM_{2.5}$ from existing sources in the region is currently causing or contributing to an exceedance of the $PM_{2.5}$ NAAQS on a short-term or annual basis.

Figure 5-9 presents the recent trend of annual NO_2 measurement from Shawme Crowell monitor. The long-term trend of annual NO_2 monitoring data across Massachusetts, as presented on Figure 5-10, shows a pronounced downward trend in concentrations over time. However, as concentrations have decreased to low levels, the trend has stabilized over the past few years across the state as well as at the Shawme Crowell site.

Summary of Primary $PM_{2.5}$ Emissions and Modeling

AERMOD air quality modeling of the primary $PM_{2.5}$ emissions from the proposed Project demonstrates that the predicted 24-hour and annual impacts plus ambient background concentrations are well below the respective NAAQS.

Air quality modeling of the direct $PM_{2.5}$ emissions from the Project plus the ambient background concentration results in a total 24-hour concentration that is approximately 38% of the 24-hour $PM_{2.5}$ NAAQS. The modeled 24-hour impact from the Project represents only approximately 7% of the NAAQS, while the monitored background alone comprises 31% of the NAAQS. On an annual basis, the annual average direct $PM_{2.5}$ modeled impact plus the monitored background accounts for approximately 42% of the annual NAAQS. The modeled concentration attributable to the Project alone accounts for less than 1% of the NAAQS, while the monitored background accounts for more than 41% of the NAAQS.

Therefore, for both the 24-hour standard and the annual standard, there is a very considerable margin allowing for the formation of secondary $PM_{2.5}$ from precursor emissions before an exceedance of the NAAQS would be predicted.

A cumulative modeling analysis was also conducted for direct $PM_{2.5}$ impacts including the proposed Project as well as sources at the existing Station. Air quality modeling of the direct $PM_{2.5}$ emissions from the future Canal Generating Station (new and existing sources) plus the ambient background concentration results in 24-hour impacts that are approximately 42% of the 24-hour $PM_{2.5}$ NAAQS and 48% of the annual $PM_{2.5}$ NAAQS. The monitored background data may also already include the impacts of the existing Station that was also explicitly modeled, so there is some degree of conservative double counting in the analysis. Even with the addition of the direct impacts from the existing Station, there is still a substantial margin available to accommodate any potential secondary formation of $PM_{2.5}$ without approaching the health-protective NAAQS.

Assessment of Secondary $PM_{2.5}$ Emissions

Because the Project is subject to NNSR, it must apply LAER for NO_x. The proposed Project's NO_x emissions are minimized through the use of DLN burners and SCR. SO_2, PM_{10}, and $PM_{2.5}$ emissions will be controlled through the use of clean-burning fuels.

An estimate of the projected secondary formation of $PM_{2.5}$ was developed based on the example described in Appendix D of the Guidance, which incorporates a regional average offset ratio. The method divides the projected emissions by a national ratio of 40 for SO_2 and 200 (eastern states value) for NO_x to determine the total equivalent $PM_{2.5}$ emissions. Then, the ratio of the total equivalent $PM_{2.5}$ emissions is divided by the primary $PM_{2.5}$ emissions and the result is used to scale the total modeled primary $PM_{2.5}$ impact to account for the secondary formation of $PM_{2.5}$.

Hence, for the proposed Project:

$$\text{Total Equivalent } PM_{2.5} \text{ (tpy)} = PM_{2.5} + SO_2/40 + NO_x/200$$

$$\text{Total Equivalent } PM_{2.5} \text{ (tpy)} = 99.6 + 11.2/40 + 117.2/200 = 100.5 \text{ tpy}$$

$$\text{Total Equivalent } PM_{2.5} \text{ /Primary } PM_{2.5} \text{ ratio} = 100.5 \text{ tpy} / 99.6 \text{ tpy} = 1.01$$

Table 5-15 presents the total $PM_{2.5}$ impacts (24-hour and annual) including the primary modeled $PM_{2.5}$ (from Table 5-13), the estimated secondary $PM_{2.5}$ formed from precursor emissions, and the ambient monitored background. Using the estimation technique provided by USEPA, the secondary formation of $PM_{2.5}$ (from SO_2 and NO_x) is approximately 0.02 µg/m^3 on a 24-hour basis, or approximately 0.06% of the 24-hour NAAQS, and 0.001 µg/m^3 on an annual average basis, or approximately 0.01% of the annual NAAQS.

Also presented in Table 5-15 is a comparison of the total $PM_{2.5}$ impacts (24-hour and annual) including the primary modeled $PM_{2.5}$ and the estimated secondary $PM_{2.5}$ formed from precursor emissions compared to the PSD Increments. The total $PM_{2.5}$ impacts demonstrate compliance with both the 24-hour and annual average NAAQS and the 24-hour and annual average PSD Increments.

Table 5-15: Total $PM_{2.5}$ (Primary + Secondary) Impacts Comparison to the NAAQS and PSD Increments

Avg. Period	New Source Modeled Primary $PM_{2.5}$ Conc. (µg/m^3)	Equivalent Ratio	Primary plus Secondary $PM_{2.5}$ Conc. (µg/m^3)	Monitored Back-ground (µg/m^3)	Existing Source Contrib.(1) (µg/m^3)	Total $PM_{2.5}$ Impact (µg/m^3)	Standard (µg/m^3)	% of Standard
NAAQS								
24-Hour	2.43	1.01	2.45	11	3.87	17.32	35	49.5%
Annual	0.05	1.01	0.051	5	0.79	5.84	12	48.7%
PSD Increments								
24-Hour	8.53	1.01	8.62	N/A	N/A	8.62	9	96%
Annual	0.06	1.01	0.061	N/A	N/A	0.061	4	1.5%
[1] includes existing Station units								

It should be noted that this analysis is very conservative because the maximum secondary $PM_{2.5}$ impacts will not occur at the same location and time as the maximum direct $PM_{2.5}$ impacts. This is due to the fact that the secondary chemical reactions take time to occur, so the secondary $PM_{2.5}$ impacts would be expected to occur at a greater distance away from the Project than the predicted direct $PM_{2.5}$ impacts.

Based on these factors, the above assessment, which has been made in accordance with USEPA Guidance, demonstrates that the $PM_{2.5}$ NAAQS and PSD Increments will be protected, taking into account both primary $PM_{2.5}$ impacts and potential contributions from secondary $PM_{2.5}$ due to precursor emissions from the proposed Project.

5.8.5 PSD Pre-Construction Monitoring Requirements

The PSD regulations require that a PSD permit application establish existing air quality levels. The determination of existing air quality levels can be satisfied by air measurements from an existing representative monitor, by an on-site monitoring program, or by demonstrating that modeled impacts are *de minimis,* as defined by Significant Monitoring Concentrations (SMC). Due to its proximity to the Project, data from the Shawme Crowell Monitoring Station can be used to fulfill the PSD pre-construction monitoring requirement for PM_{10}, $PM_{2.5}$, SO_2, and NO_2.

O_3 is a secondary, regional-scale pollutant and not modeled for single-source applications. As such, regional monitoring data are considered sufficient to establish existing O_3 levels without the need for pre-construction monitoring.

5.8.6 Air Toxics Analysis

An air quality impact assessment of the non-criteria pollutants (air toxics) emitted from the proposed Project and existing Station sources was conducted. The highest 24-hour and annual normalized AERMOD predicted concentrations were determined across all operating loads and then scaled by the appropriate pollutant emission rates to obtain the predicted concentration of each pollutant. The worst-case impacts were then compared to applicable thresholds. Table 5-***16*** presents the maximum predicted non-criteria pollutant air quality impacts for those pollutants for which MassDEP has a guideline 24-hour Threshold Effects Exposure Limit (TEL). The modeled impacts from the proposed Project alone as well as the combined impacts from the proposed Project plus the existing Station are presented. Similarly, Table 5-***17*** presents the maximum predicted non-criteria pollutant air quality impacts for those pollutants for which MassDEP has a guideline annual Allowable Ambient Limit (AAL). The results show that air quality impacts from the non-criteria emissions are well below the threshold levels of the corresponding MassDEP AALs and TELs.

Table 5-*16*: Non-Criteria Pollutant Modeled Concentrations from Proposed Project and Existing Canal Sources for Comparison to Massachusetts TELs

Pollutant	AERMOD Maximum 24-Hr Concentration (µg/m^3)		MassDEP 24-hr TEL (µg/m^3)	Proposed Project % of TEL	Proposed Project plus Existing % of TEL
	Proposed Project Only[(1)]	Proposed Project plus Existing[(2)]			
Acetaldehyde	1.23E-02	2.44E-02	30	0%	0%
Acrolein	1.88E-03	3.06E-03	0.07	3%	4%
Ammonia	1.92E+00	2.14E+00	100	2%	2%
Antimony	0.00E+00	3.28E-03	0.02	0%	16%
Arsenic	1.26E-05	1.01E-03	0.003	0%	34%
Benzene	1.94E-02	3.61E-02	0.6	3%	6%
Beryllium	0.00E+00	2.78E-05	0.001	0%	3%
1,3-Butadiene	4.38E-03	5.00E-03	1.2	0%	0%
Cadmium	1.40E-06	1.20E-03	0.002	0%	60%
Chromium (metal)	5.62E-03	7.72E-03	1.36	0%	1%
Chromium (VI) Compounds	9.77E-07	2.43E-04	0.003	0%	8%
Copper	0.00E+00	1.84E-03	0.54	0%	0%
o-Dichlorobenzene	0.00E+00	1.04E-03	81.74	0%	0%
p-Dichlorobenzene	0.00E+00	1.04E-03	122.61	0%	0%
Ethylbenzene	7.96E-03	8.00E-03	300	0%	0%
Formaldehyde	6.51E-02	1.70E-01	2	3%	8%
Hydrogen Chloride	0.00E+00	2.26E-01	7	0%	3%
Hydrogen Fluoride	0.00E+00	2.49E-02	0.68	0%	4%
Lead	8.51E-04	2.28E-03	0.14	1%	2%
Mercury (elemental)	2.79E-06	2.99E-04	0.14	0%	0%
Mercury (inorganic)	2.79E-06	2.99E-04	0.14	0%	0%
Naphthalene (including 2-methylnaphthalene)	9.91E-03	1.25E-02	14.25	0%	0%
Nickel (metal)	2.58E-03	5.73E-02	0.27	1%	21%
Nickel Oxide	3.28E-03	7.29E-02	0.27	1%	27%
Phosphoric Acid	0.00E+00	1.90E-02	0.27	0%	7%
Propylene Oxide	2.75E-02	8.39E-02	6	0%	1%
Selenium	6.98E-05	5.21E-04	0.54	0%	0%
Sulfuric Acid	4.82E-01	2.43E+00	2.72	18%	89%
Toluene	3.42E-02	4.76E-02	80	0%	0%
1,1,1-Trichloroethane	0.00E+00	1.50E-04	1038.37	0%	0%
Vanadium	0.00E+00	2.18E-02	0.27	0%	8%
Vanadium Pentoxide	0.00E+00	3.90E-02	0.14	0%	28%
Xylenes (m-,o-,p- isomers)	1.72E-02	2.18E-02	11.8	0%	0%

[1] Proposed Project alone impacts were based on either 24-hrs/day of operation on gas or ULSD for CT3, plus 24-hrs/day of operation for the fuel heater and 1-hr/day for the emergency engine and fire water pump.
[2] Project impacts where then also combined with existing sources assuming oil firing in Canal Units 1 and 2.

Table 5-*17*: Non-Criteria Pollutant Modeled Concentrations from Proposed Project and Existing Canal Sources for Comparison to Massachusetts AALs

Pollutant	AERMOD Annual Concentrations (µg/m³)				MassDEP Annual AAL (µg/m³)	Proposed Project % of AAL	Proposed Project plus Existing % of AAL
	Proposed Project Only[1]		Proposed Project plus Existing[2]				
	NG Only	NG + Oil	NG Only	NG + Oil			
Acetaldehyde	3.17E-04	2.84E-04	1.50E-03	1.47E-03	0.4	0%	0%
Acrolein	4.46E-05	3.93E-05	1.88E-04	1.82E-04	0.07	0%	0%
Ammonia	1.71E-02	1.73E-02	3.32E-02	3.34E-02	100	0%	0%
Antimony	0.00E+00	0.00E+00	2.35E-04	2.35E-04	0.02	0%	1%
Arsenic	3.47E-08	7.21E-08	8.37E-05	8.37E-05	0.0003	0%	28%
Benzene	6.55E-04	6.89E-04	2.36E-03	2.40E-03	0.1	1%	2%
Beryllium	0.00E+00	0.00E+00	2.71E-06	2.71E-06	0.0004	0%	1%
1,3-Butadiene	1.15E-05	2.41E-05	7.20E-05	8.46E-05	0.003	1%	3%
Cadmium	3.85E-09	8.01E-09	1.53E-04	1.53E-04	0.0002	0%	76%
Chromium (metal)	1.55E-05	3.23E-05	2.59E-04	2.76E-04	0.68	0%	0%
Chromium (VI) Compounds	2.70E-09	5.61E-09	2.35E-05	2.35E-05	0.0001	0%	23%
Copper	0.00E+00	0.00E+00	1.83E-04	1.83E-04	0.54	0%	0%
o-Dichlorobenzene	0.00E+00	0.00E+00	1.47E-04	1.47E-04	81.74	0%	0%
p-Dichlorobenzene	0.00E+00	0.00E+00	1.47E-04	1.47E-04	0.18	0%	0%
Ethylbenzene	8.04E-05	5.40E-05	8.33E-05	5.69E-05	300	0%	0%
Formaldehyde	9.02E-04	9.09E-04	1.34E-02	1.34E-02	0.08	1%	17%
Hydrogen Chloride	0.00E+00	0.00E+00	1.62E-02	1.62E-02	7	0%	0%
Hydrogen Fluoride	0.00E+00	0.00E+00	1.79E-03	1.79E-03	0.34	0%	1%
Lead	2.35E-06	4.88E-06	1.36E-04	1.39E-04	0.07	0%	0%
Mercury (elemental)	7.70E-09	1.60E-08	3.69E-05	3.69E-05	0.07	0%	0%
Mercury (inorganic)	7.70E-09	1.60E-08	3.69E-05	3.69E-05	0.01	0%	0%
Naphthalene (including 2-methylnaphthalene)	8.88E-05	1.16E-04	3.46E-04	3.73E-04	14.25	0%	0%
Nickel (metal)	7.11E-06	1.48E-05	4.06E-03	4.07E-03	0.18	0%	2%
Nickel Oxide	9.05E-06	1.88E-05	5.17E-03	5.18E-03	0.01	0%	52%
Phosphoric Acid	0.00E+00	0.00E+00	1.36E-03	1.36E-03	0.27	0%	1%
Propylene Oxide	2.89E-03	2.86E-03	8.39E-03	8.37E-03	0.3	1%	3%
Selenium	1.93E-07	4.00E-07	3.41E-05	3.43E-05	0.54	0%	0%
Sulfuric Acid	8.72E-03	8.72E-03	1.74E-01	1.74E-01	2.72	0%	7%
Toluene	5.72E-04	4.64E-04	1.90E-03	1.80E-03	5.31	0%	0%
1,1,1-Trichloroethane	0.00E+00	0.00E+00	1.07E-05	1.07E-05	1038.37	0%	0%
Vanadium	0.00E+00	0.00E+00	1.71E-03	1.71E-03	0.27	0%	1%
Vanadium Pentoxide	0.00E+00	0.00E+00	3.04E-03	3.04E-03	0.03	0%	10%
Xylenes (m-,o-,p- isomers)	3.30E-04	2.77E-04	7.76E-04	7.23E-04	11.8	0%	0%

[1] Annual Project impacts includes the greater of either 4380 hours of gas firing or 2940 hours gas firing and 1440 hours ULSD firing for the CT plus 300 hours for the emergency engine and fire water pump.
[2] For these two cases, annual Project impacts where then also combined with existing sources assuming oil firing in Units 1 and 2.

5.8.7 PSD Class I Area Analyses

PSD Class I Areas are specifically designated pristine locations (e.g., National Parks, Wildlife Refuges, and Wilderness Areas) that are afforded additional protection by the Clean Air Act. The closest PSD Class I area is more than 250 km from the Station. The Federal Land Managers (FLMs) recommend a screening approach to determine if a proposed source will potentially have an adverse impact on a Class I area, described in the *Federal Land Managers' Air Quality Related Values Work Group Phase 1 Report – Revised* (NPS, 2010).

The guidance references an emissions/distance (Q/D) ratio of 10, below which a proposed source will likely not have an adverse impact on a Class I Area and, therefore, a full Class I Area impact analysis is not warranted. The "Q" in the Q/D is the sum of SO_2, NO_X, H_2SO_4, and PM emissions expressed in tpy, based on maximum short-term (24-hour) emission levels. Conservatively, the total sum of these short-term emissions, based on firing ULSD, is 720.38 tpy. The "D" in the Q/D is the distance from the source to the closest Class I area in km. The closest Class I area is Lye Brook Wilderness Area, located in southern Vermont just over 250 km northwest of the Station. The resulting Q/D ratio is 2.9, well below the recommended screening ratio of 10. As a result, no further Class I Area analyses have been conducted.

Canal 3 sent a request to the FLM requesting a Class I Area analysis determination. The FLM is in agreement with screening analysis Canal 3 presented above. The form submitted and response email confirming that a Class I Area analysis is not required for this Project are presented in Appendix C.

5.8.8 Impacts to Soils and Vegetation

The USEPA guidance document for soils and vegetation, *A Screening Procedure for the Impacts of Air Pollution Sources on Plants, Soils, and Animals* (USEPA, 1980) and related technical publications established a screening methodology for comparing air quality modeling impacts to vegetation sensitivity thresholds.

For assessing impacts to soils, the USEPA provides a method that evaluates trace element contamination of soils. Since plant and animal communities can be affected before noticeable accumulation occur in the soils, the approach used here evaluates the way soil acts as an intermediary in the transfer of a deposited trace element to plants. For trace elements, the concentration deposited in the soil is calculated from the maximum predicted annual ground-level concentrations, conservatively assuming that all deposited material is soluble and available for uptake by plants. The amount of trace element potentially taken up by plants is calculated using average plant to soil concentration ratios. The calculated soil and plant concentrations are compared to screening concentrations designed to assess potential adverse effects to soils and plants.

Table 5-19 presents the results of the potential soil and plant concentrations (based on maximum annual concentrations) and compares them to the corresponding screening concentration criteria. Only pollutants that will be emitted from the Project and that have a screening concentration are presented. A calculated concentration in excess of either of the screening concentration criteria is an indication that a more detailed evaluation may be required. However, as shown in Table 5-***18***, calculated concentrations as a result of operation of the Project are all well below the screening criteria.

As an indication of whether emissions from the proposed Project will significantly impact (i.e., cause acute or chronic exposure to each evaluated pollutant) any surrounding vegetation with commercial or recreational value, the modeled emission concentrations are compared against both a range of injury thresholds found in the guidance and appropriate literature, as well as those established by the NAAQS secondary standards. Since the NAAQS secondary standards were set to protect public welfare, including protection against damage to crops and vegetation, comparing modeled emissions to these standards will provide some indication if potential impacts are likely to be significant. Tables 5-***19*** through 5-***22*** list the Project impact concentrations of NO_2, CO, SO_2, PM_{10}, and formaldehyde and compare them to the vegetation sensitivity thresholds and NAAQS secondary standards. For averaging periods for which concentrations were not predicted, the concentration for the next shortest averaging period is conservatively used. All pollutant concentrations are well below the vegetation sensitivity thresholds.

Table 5-1*8*: Soils Impact Screening Assessment

Pollutant	Maximum Project Deposited Soil Concentration (ppmw[a])	Soil Screening Criteria (ppmw)	Percent of Soil Screening Criteria	Plant Tissue Concentration (ppmw)	Plant Screening Criteria (ppmw)	Percent of Plant Screening Criteria
Arsenic	2.07E-05	3	0.0007%	2.89E-06	0.25	0.0012%
Cadmium	2.30E-06	2.5	0.0001%	2.46E-05	3	0.0008%
Chromium	9.26E-03	8.4	0.1102%	1.85E-04	1	0.0185%
Lead	1.40E-03	1,000	0.0001%	6.30E-04	126	0.0005%
Mercury	4.59E-06	455	0.0000%	2.29E-06	NA	NA
Nickel	4.24E-03	500	0.0008%	1.91E-04	60	0.0003%
Selenium	1.15E-04	13	0.0009%	1.15E-04	100	0.0001%

[a] ppmw = parts per million wet

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

Table 5-*19*: Predicted Air Quality Impacts Compared to NO_2 Vegetation Impact Thresholds

Averaging Period	Maximum Project Impacts (µg/m³)	Threshold for Impact to Vegetation (µg/m³)	Applicability
1-hour	53.35	66,000[a]	Leaf Injury to plant
2-hour		1,130[b]	Affects to alfalfa
4-hour		3,760[c]	Protects all vegetation
8-hour		3,760[c]	Protects all vegetation
1-month		564[c]	Protects all vegetation
Annual	0.71	94[c], 100[d]	Protects all vegetation
		190[e]	Metabolic and growth impact to plants

[a] "Diagnosing Injury Caused by Air Pollution", EPA-68-02-1344, Prepared by Applied Science Associates, Inc. under contract to the Air Pollution Training Institute, Research Triangle Park, North Carolina. 1976.

[b] "Synergistic Inhibition of Apparent Photosynthesis Rate of Alfalfa by Combinations of SO_2 and NO_2" Environmental Science and Technology, vol. 8(6): p.574-576, 1975. The limit is based on a concentration in ambient air of 0.6 ppm NO_2 (1,130 µg/m³) which was found to depress the photosynthesis rate of alfalfa during a 2-hour exposure.

[c] *A Screening Procedure for the Impacts of Air Pollution Sources on Plants, Soils, and Animals,* EPA 450/2-81-078, Research Triangle Park, NC. 1980.

[d] Secondary National Ambient Air Quality Standard (µg/m³) which is a limit set to avoid damage to vegetation resulting in economic losses in commercial crops, aesthetic damage to cultivated trees, shrubs, and other ornamentals, and reductions in productivity, species richness, and diversity in natural ecosystems to protect public welfare (Section 109 of the Clean Air Act). These thresholds are the most stringent of those found in the literature survey.

[e] "Air Quality Criteria for Oxides of Nitrogen," EPA/600/8-91/049aF-cF.3v, Office of Health and Environment Assessment, Environmental Criteria and Assessment Office, USEPA, Research Triangle Park, NC. 1993.

Table 5-*20*: Predicted Air Quality Impacts Compared to CO Vegetation Impact Thresholds

Averaging Period	Maximum Project Impacts ($\mu g/m^3$)	Threshold for Impact to Vegetation ($\mu g/m^3$)	Applicability
1-hour	197.57	40,000[a]	Protects all vegetation
8-hour	45.31	10,000[a]	Protects all vegetation
Multiple day		10,000[b]	No known effects to vegetation
1-week		115,000[c]	Effects to some vegetation
Multiple week		115,000[d]	No effect on various plant species

[a] Secondary NAAQS ($\mu g/m^3$) which is a limit set to avoid damage to vegetation resulting in economic losses in commercial crops, aesthetic damage to cultivated trees, shrubs, and other ornamentals, and reductions in productivity, species richness, and diversity in natural ecosystems to protect public welfare (Section 109 of the Clean Air Act). These thresholds are the most stringent of those found in the literature survey.

[b] "Air Quality Criteria for Carbon Monoxide," EPA/600/8-90/045F (NTIS PB93-167492), Office of Health and Environment Assessment, Environmental Criteria and Assessment Office, USEPA, Research Triangle Park, NC. 1991. Various CO concentrations were examined the lowest of these was 10,000 $\mu g/m^3$. Concentrations this low had no effects to various plant species. For many plant species, concentrations as high as 230,000 $\mu g/m^3$ caused no effects. The exception was legume seedlings which were found to experience abnormal leaf growth when exposed to CO concentrations of only 27,000 $\mu g/m^3$. Also related to this family of plants, CO concentrations in the soil of 113,000 $\mu g/m^3$ were found to inhibit nitrogen fixation. It is clear that ambient CO concentrations as low as 10,000 $\mu g/m^3$ will not affect vegetation.

[c] "Diagnosing Injury Caused by Air Pollution," EPA-68-02-1344, Prepared by Applied Science Associates, Inc. under contract to the Air Pollution Training Institute, Research Triangle Park, North Carolina. 1976. A CO concentration of 115,000 $\mu g/m^3$ was found to affect certain plant species.

[d] "Polymorphic Regions in Plant Genomes Detected by an M13 Probe," Zimmerman, P.A., et al. 1989. Genome 32: 824-828. 115,000 $\mu g/m^3$ was the lowest CO concentration included in this study. This concentration was not found to cause a reduction in growth rate to a variety of plant species.

Table 5-*21*: Predicted Air Quality Impacts Compared to SO_2 and PM_{10} Vegetation Impact Thresholds

Averaging Period	Maximum Project Impacts ($\mu g/m^3$)	Threshold for Impact to Vegetation ($\mu g/m^3$)	Applicability
SO_2			
1-hour SO_2	0.61	131[a]	Suggested worst-case limit
3-hour SO_2	0.64	390[b]	Protects SO_2 sensitive species
3-hour SO_2		1,300[c]	Protects all vegetation
24-hour SO_2	0.40	63[d]	Insignificant effect to wheat and barley
Annual SO_2	0.0037	130[b]	Protects SO_2 sensitive species
Annual SO_2		18[e]	Protects all vegetation
PM_{10}			
24-hour PM_{10}	11.98	150[c]	Protects all vegetation
Annual PM_{10}	0.06	50[c]	Protects all vegetation
Annual PM_{10}		579[f]	Damage to sensitive species (fir tree)

a. "Crop and Forest Losses due to Current and Projected Emissions from Coal-Fired Power Plants in the Ohio River Basin," Loucks, O.L., R.W. Miller, et al. 1980. The Institute of Ecology. In this publication, the authors propose 1-hour thresholds from 131 to 262 $\mu g/m^3$.

b. "Impacts of Coal-fired Power Plants on Fish, Wildlife, and their Habitats," Dvorak, A.J., et al. Argonne National Laboratory. Argonne, Illinois. Fish and Wildlife Service Publication No. FWS/OBS-78/29. March 1978. This document indicates the lowest 3-hour SO_2 concentration expected to cause injury to sensitive plants growing under compromised conditions is approximately 390 $\mu g/m^3$. Similarly, a threshold of 130 $\mu g/m^3$ is suggested for chronic exposure.

c. Secondary National Ambient Air Quality Standard ($\mu g/m^3$) which is a limit set to avoid damage to vegetation resulting in economic losses in commercial crops, aesthetic damage to cultivated trees, shrubs, and other ornamentals, and reductions in productivity, species richness, and diversity in natural ecosystems to protect public welfare (Section 109 of the Clean Air Act). These thresholds are the most stringent of those found in the literature survey.

d. "Concurrent Exposure to SO_2 and/or NO_2 Alters Growth and Yield Responses of Wheat and Barley to Low Concentrations of O_3," (New Phytologist, 118 (4). 1991. pp. 581-592). This paper indicates exposure to 63 $\mu g/m^3$ of SO_2 during the growing season had insignificant effects to wheat but did affect the weight of barley seeds.

e. *A Screening Procedure for the Impacts of Air Pollution Sources on Plants, Soils, and Animals,* EPA 450/2-81-078, Research Triangle Park, NC. 1980

f. "Responses of Plants to Air Pollution," Lerman, S.L., and E.F. Darley. 1975. "Particulates," pp. 141-158 (Chap. 7). In J.B. Mudd and T.T. Kozlowski (eds.). Academic Press. New York, NY. Results of studies conducted indicated concluded that particulate deposition rates of 365 grams per square meter per year ($g/m^2/yr$) caused damage to fir trees, but rates of 274 g/m^2/year and 400 to 600 $g/m^2/yr$ did not cause damage to vegetation. 365 $g/m^2/yr$ translates to W579 $\mu g/m^3$, using a worst-case deposition velocity of 2 cm/s.

Table 5-*22*: Predicted Air Quality Impacts Compared to Formaldehyde Vegetation Impact Thresholds

Averaging Period	Maximum Project Impacts ($\mu g/m^3$)	Threshold for Impact to Vegetation ($\mu g/m^3$)	Applicability
Repeated 4.5 hour	0.322 [a]	18 [b]	Sensitive species affected
5-hour		840[c]	Signs of injury to sensitive species (alfalfa)
5-hour		367[d]	Signs of injury to pollen tube length (lily)
Repeated 7-hour		78[e]	Stimulated shoot growth (beans)

[a] The maximum 1-hour predicted formaldehyde concentration is used as a conservative surrogate for the longer averaging periods.

[b] "Formaldehyde-Contaminated Fog Effects on Plant Growth," Barker J.R. & Shimabuku R.A. (1992). In Proceedings of the 85th Annual Meeting and Exhibition, Air and Waste Management Association, pp. 113. 92150.01. Pittsburgh, PA. The authors examined the effects on vegetation grown in fog with formaldehyde concentrations of 18 and 54 $\mu g/m^3$. Exposure rates were 4.5 hours per night, 3 nights/week, for 40 days. The growth rate of rapeseed was found to be affected in this study. However, slash pine grown under the same conditions showed a significant increase in needle and stem growth. No effects were observed in wheat or aspen at test concentrations.

[c] "Investigation on Injury to Plants from Air Pollution in the Los Angeles Area," Haagen-Smit AJ, Darley EE, Zaitlin M, Hull H, Noble WM (1952). Plant physiology, 27:18–34. The authors found a 5-hour exposure to 700 ppb caused mild atypical signs of injury in alfalfa, but no injury to spinach, beets, or oats.

[d] "Effects of Exposure to Various Injurious Gases on Germination of Lily Pollen," Masaru N, Syozo F, Saburo K (1976). Environmental Pollution, 11:181–188. The authors fund a significant reduction of the pollen tube length of lily following a 5-hour exposure to ambient formaldehyde concentrations of 367 ppb.

[e] "Formaldehyde exposure affects growth and metabolism of common bean," Mutters RG, Madore M, Bytnerowicz A (1993). Journal of the Air and Waste Management Association, 43:113–116. The authors found that repeated exposure of sensitive plants to ambient formaldehyde concentrations of 78 $\mu g/m^3$ could cause plant shoots to grow faster than the roots. It is pointed out that this effect would not be a problem except for crops growing in a water starved condition.

5.8.9 Growth

During the 21-month construction period for the Project, the number of workers will range from approximately 1 to 150 workers. For 13 months, less than 100 workers will be on-site. For approximately eight months (March 2018 to October 2018), more than 100 workers are expected to be on-site. The peak period of construction activity will occur from June 2018 to July 2018, with approximately 150 workers traveling to and from the Project site. The Station expansion will not require a significant addition of new full-time employees.

It is expected that a significant construction force is available and is supported by the fact that within New England significant construction activities have already occurred. Therefore, it is expected that because this area can support the Project's construction from within the region; new housing, commercial and industrial construction will not be necessary to support the Project during the construction period.

If any new personnel move to the area to support the Project, a significant housing market is already established and available. Therefore, no new housing is expected. Further, due to the small number of new individuals expected to move into the area to support the Project and the significant level of existing commercial activity in the area, new commercial construction is not foreseen to be necessary to support the Project's expanded work force. In addition, no significant level of industrial related support will be necessary for the Project, thus industrial growth in the area is not expected.

Thus, no new significant emissions from secondary growth during either the construction phase or operations are anticipated.

5.8.10 Environmental Justice

In 1994, a Presidential Executive Order (E.O. 12898) was signed to "focus federal attention on the environmental and human health effects of federal actions on minority and low-income populations with the goal of achieving environmental protection for all communities." MassDEP has the obligation under the provisions of the April 11, 2011 PSD Delegation Agreement between MassDEP and USEPA to "identify and address, as appropriate, disproportionately high and adverse human health or environmental effects of federal programs, policies, and activities on minority and low-income populations."

The Massachusetts Executive Office of Energy and Environmental Affairs (EEA) has established Environmental Justice (EJ) neighborhoods, which identify areas with minority populations and low-income populations in Massachusetts. In addition, the USEPA has developed EJSCREEN, an EJ screening and mapping tool. The potential EJ communities are identified as areas that should be more fully evaluated. Figure 5-11 presents the EJ communities identified from both the Massachusetts and Federal databases in the vicinity of the Station. Based on the MassGIS database there are no EJ communities identified within 5 miles of the Station; however, the EJSCREEN results identify the Otis Air National Guard Base, located to the southwest of the Project, as a minority and low-income area.

USEPA indicates that the EJSCREEN results should be supplemented with local knowledge to better understand the issues in a selected location. As noted in Figure 5-11 the Otis Air National Guard Base spans a large area to the southwest of the Project. Approximately half (northern section) of the Base is within 5 miles of the Project site. A review of housing on the Base indicates one home in the northeast section of the Base (within 5 miles) with the remaining housing located in the extreme southern portions of the Base (beyond 5 miles). The Barnstable County Correctional Facility is located within the southwest portion of the Base, outside the 5 mile radius. As the demographics of the area are classified as census tracks (population 1,284), the presence of this correctional facility in this tract is driving the classification of the Base as minority (52%) and low-income (55%). Massachusetts did not identify the Otis Air National Guard Base as an EJ area. For the reasons stated, Canal 3 feels that the portion of the Otis Base within 5 miles of the Station should not be considered an EJ community.

The purpose of an EJ analysis is to determine whether the construction or operation of a proposed facility would have an adverse and disproportionate burden on an EJ community. The maximum predicted ambient air quality impacts of the proposed Project as presented in Table 5-12 above are all located within 0.25 miles of the proposed Project stack location. These maximum impact locations are much closer to the Project site than the Barnstable County Correctional Facility, which is in the southwest portion of the Otis Air National Guard Base, more than 5 miles from the Project site. As discussed in Section 5.8.1 above, for those pollutants for which the Project has impacts above the SILs, the Significant Impact Area in all cases is within 3 miles of the proposed Project site. Therefore, it is clear the Project will not have a disproportionately high impact on minority and low-income populations, which are located well outside the area of maximum predicted impacts as well as the SIA for those pollutants which have impacts above the SILs.

Even though the Project is not subject to the requirements of EEA's Environmental Justice Policy, the Project has developed a comprehensive communications plan that includes a number of approaches designed to keep local residents, abutters, businesses and Town of Sandwich officials updated on significant construction milestones and schedules related to the Project. These approaches include:

- ***Electronic mail - As part of public outreach during the permitting process, the Company developed e-mail lists to reach specific targeted audiences, including direct abutters, nearby neighbors within 1 mile, local businesses and key external stakeholders. These lists will be used to deliver targeted traffic and construction messages to affected audiences during the construction phase of the Project.***
- ***Mailings – as part of initial communications announcing and describing the Project, the Company developed and utilized mailing lists to communicate information on public hearings related to the***

Project. Those lists will be utilized to provide traffic, parking, delivery and construction related updates and notifications during the next phase of Project development.

- ***Website – The Company has established a website that will be updated as appropriate. From the website, visitors will see the latest information, and can download a printable fact sheet. The website has a provision for visitors to sign up for periodic emails, as well as renderings of how the station will look before and after completion of the Project. The website is being promoted through local media via announcements, emails and phone calls to working journalists and media outlets as well as advertising in selected local publications. The website URL is: www.canalnewgeneration.com***
- ***Routine updates with Town of Sandwich officials – The Company has established routine communication networks with local officials including traffic, fire, police and others regarding the Project particularly concerning traffic management, construction, delivery, noise and all other potential issues of concern to the Town and residents during the construction phase.***

6.0 REFERENCES

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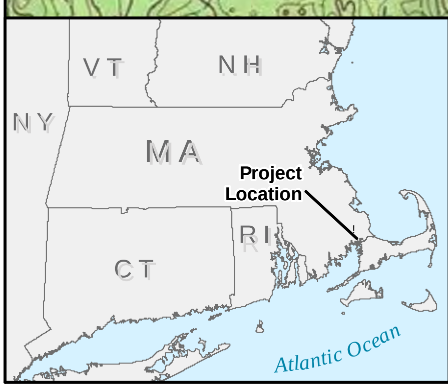
FIGURES



Legend

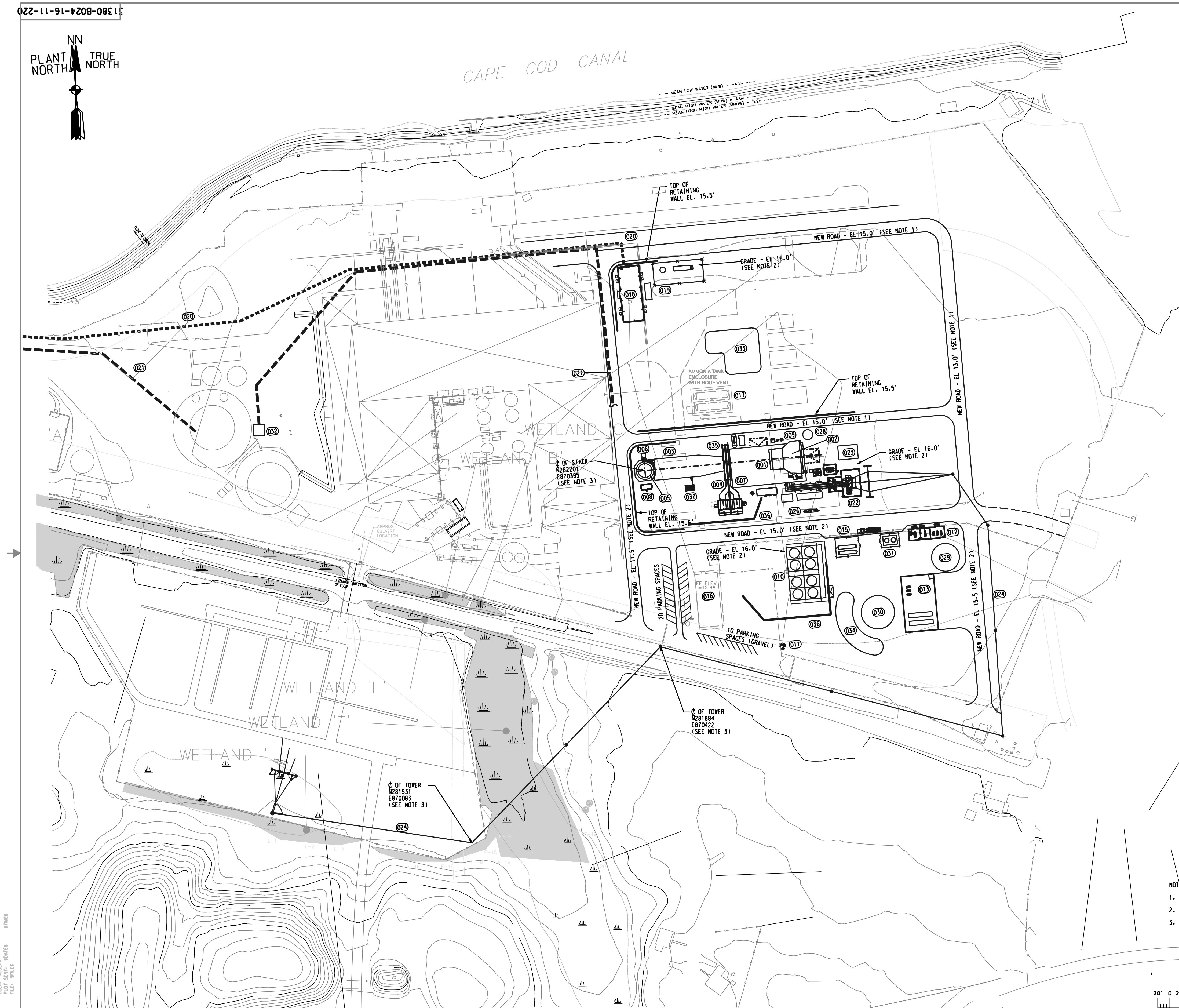
Property

Facility Site

0 500 1,000 2,000
Feet

Figure 2-1
Site Location

NRG Canal 3 Development LLC
Sandwich, Massachusetts



LEGEND

001 GAS TURBINE GE 7HA.02 (w/ACOUSTICAL ENCLOSURE)
002 GENERATOR
003 SCR/CO2 CATALYST (w/ACOUSTICAL SHROUD)
004 TEMPERING/PURGE FANS
005 STACK
006 EMERGENCY DIESEL GENERATOR
007 LUBE OIL SKID
008 CEMS
009 COMPRESSED AIR SYSTEM
010 COOLING FAN MODULE
011 EXISTING WELL
012 SERVICE WATER/FIRE PROTECTION PUMP HOUSE
013 DEMINERALIZED WATER SYSTEM
014 DELETED
015 HYDROGEN STORAGE AREA
016 EXISTING TRAINING BLDG. / NEW CONTROL RM.
017 EXISTING AMMONIA STORAGE AREA
018 GAS COMPRESSOR
019 GAS PRE-HEATER AREA
020 NEW GAS LINE
021 NEW FUEL OIL LINE
022 GENERATOR STEP-UP TRANSFORMER (GSU)
023 POWER DISTRIBUTION CENTER (PDC)
024 TRANSMISSION LINES
025 DELETED
026 OIL WATER SEPARATOR
027 DELETED
028 EVAPORATOR COOLER BLOWDOWN COLLECTION TANK
029 SERVICE WATER/FIRE WATER TANK
030 DEMINERALIZED WATER TANK
031 CO2 STORAGE AREA
032 FUEL OIL PUMP HOUSE
033 INFILTRATION BASIN 1
034 INFILTRATION BASIN 2
035 UNDERGROUND 4,000 GALLON CT WATER-WASH TANK
036 ACOUSTICAL WALL
037 AMMONIA VAPORIZATION SKID

NOTES:

1. ROAD MAY NEED TO BE ADJUSTED AFTER SURVEY LOCATION OF RAILWAY TRACKS.
2. ELEVATIONS MAY NEED SOME ADJUSTMENT AS MORE INFORMATION BECOMES AVAILABLE.
3. THE LOCATION OF THE STACK IS BASED ON THE MASSACHUSETTS STATE PLANE SYSTEM, (NAD27, DATUM) FOR THE HORIZONTAL COORDINATES. THE GRID PRESENTED WAS CREATED FROM IMAGE FILES RECEIVED FROM NRG. COORDINATE LOCATION REQUIRES RECHECK WHEN SURVEY DATA IS OBTAINED. MORE DETAILED DESIGN OF THE SITE ARRANGEMENT INCLUDING FACILITY PLACEMENT, GRADING AND DRAINAGE WILL REQUIRE TOPOGRAPHIC SURVEY WITH TIES TO THE PROPERTY AND EASEMENTS.

20' 0 20' 40' 60' 80'
SCALE: 1" = 60'

REVISION APPROVAL RECORD				REV	
DISCIPLINE	BY	DATE	DISCIPLINE	BY	DATE
ARCH.			MECHANICAL		
BUILDING SERVICES			PIPING		
CIVIL			PROCESS		
ELECTRICAL			QA / QC		
ENVIRON.			STRUCTURAL		
GEN. ARRANG.					
I & C					

REV NO	DATE	REVISIONS	BY	CHKR
A	5/14/15	ISSUED FOR ENF PERMITTING	RLR	MD
B	5/18/15	REVISED GRADING	RLR	MD
C	6/9/15	ADDED FUEL OIL PUMPHOUSE; DELETED FUTURE ITEMS	TJK	RLR
D	10/05/15	DELETED WATER TREATMENT BUILDING, ADJUSTED AND RELOCATED INFILTRAION BASIN 1, RELOCATED INFILTRATION BASIN 2	RST	RLR
E	10/07/15	INCORPORATED CLIENT COMMENTS	RST	RLR
F	11/18/15	INCORPORATED CLIENT COMMENTS	RST	RLR
G	11/23/15	INCORPORATED CLIENT COMMENTS	RST	RLR

DRAWING STATUS				
ISSUED	REV	DATE	SDE	PEM
PRELIMINARY	F	11/23/15	PKS	PKS
APPROVED FOR CONSTRUCTION				

NOT APPROVED FOR CONSTRUCTION UNLESS SIGNED AND DATED. DESTROY ALL PRINTS BEARING EARLIER DATE AND/OR REV.NO.

PROJECT NO.: 31380

DRAWN: RLR DATE: 4/23/15

CHECKED: MD DATE: 5/14/15

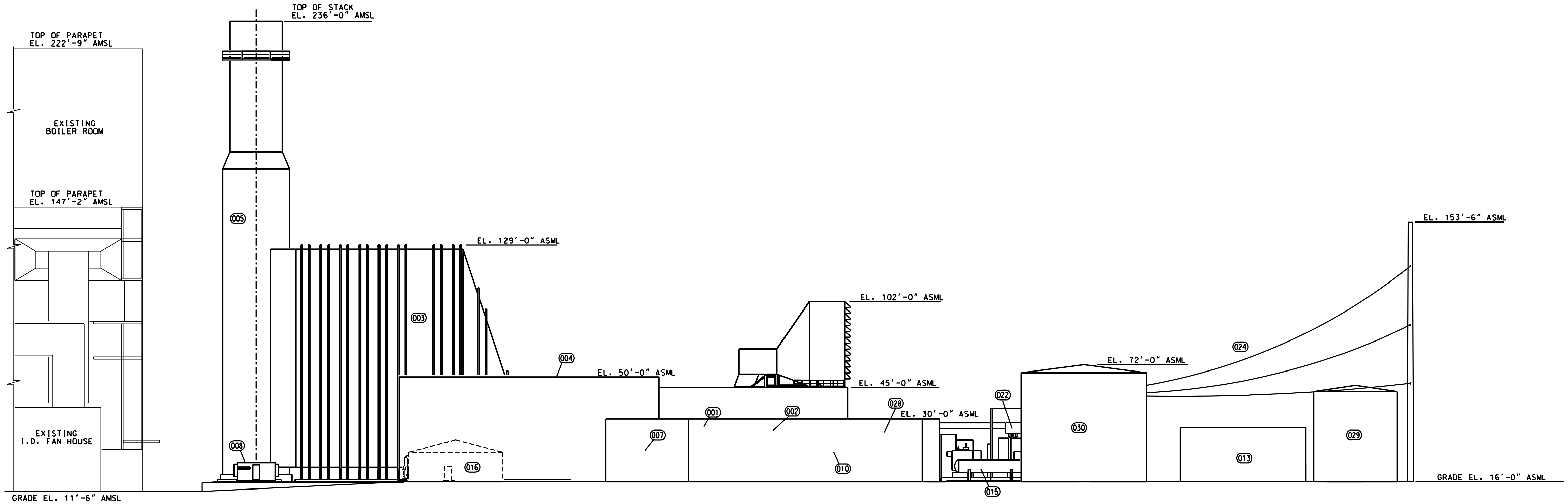
SCALE: 1" = 60'-0"

Figure 2-2
Site Plan and General Arrangement

NRG Canal 3 Development LLC
Sandwich, Massachusetts

Simple Cycle Stack West.dgn

...\31380-B024-Sketch 2 Plot Plan West_RG.dgn 11/23/2015 3:16:31 PM



ELEVATION LOOKING NORTH

LEGEND
001 GAS TURBINE GE 7HA.02
002 GENERATOR
003 SCR/CO2 CATALYST
004 TEMPERING/PURGE FANS
005 STACK
007 LUBE OIL SKID
008 CEMS
010 COOLING FAN MODULE
013 DEMINERALIZED WATER SYSTEM
014 DELETED
015 HYDROGEN STORAGE AREA
016 EXISTING TRAINING BLDG. / NEW CONTROL RM.
022 GENERATOR STEP-UP TRANSFORMER (GSU)
024 TRANSMISSION LINES
028 EVAPORATOR COOLER BLOWDOWN COLLECTION TANK
029 SERVICE WATER/FIRE WATER TANK
030 DEMINERALIZED WATER TANK

10' 0 10' 20' 30'
SCALE: 1" = 20'

REVISION APPROVAL RECORD			REV		
DISCIPLINE	BY	DATE	DISCIPLINE	BY	DATE
ARCH.			MECHANICAL		
BUILDING SERVICES			PIPING		
CIVIL			PROCESS		
ELECTRICAL			QA / QC		
ENVIRON.			STRUCTURAL		
GEN. ARRANG.					
I & C					

REV NO	DATE	REVISIONS	BY	CHKR
A	6/10/15	ISSUED FOR REVIEW	TJK	RLR
B	6/16/15	CHANGED STACK ELEVATION	TJK	RLR
C	10/05/15	CHANGED STACK ELEVATION. DELETED WATER TREATMENT BUILDING	RST	RLR
D	10/07/15	INCORPORATED CLIENT COMMENTS	RST	RLR
E	11/18/15	INCORPORATED CLIENT COMMENTS	RST	RLR

DRAWING STATUS				
ISSUED	REV	DATE	SDE	PEM
PRELIMINARY	E	11/18/15	PKS	PKS
APPROVED FOR CONSTRUCTION				

NOT APPROVED FOR CONSTRUCTION UNLESS SIGNED AND DATED. DESTROY ALL PRINTS BEARING EARLIER DATE AND/OR REV.NO.

PROJECT NO.: 31380
DRAWN: TJK DATE: 6/10/15
CHECKED: DATE:
SCALE: 1" = 20'-0"

Figure 2-3
Elevation View

NRG Canal 3 Development LLC
Sandwich, Massachusetts

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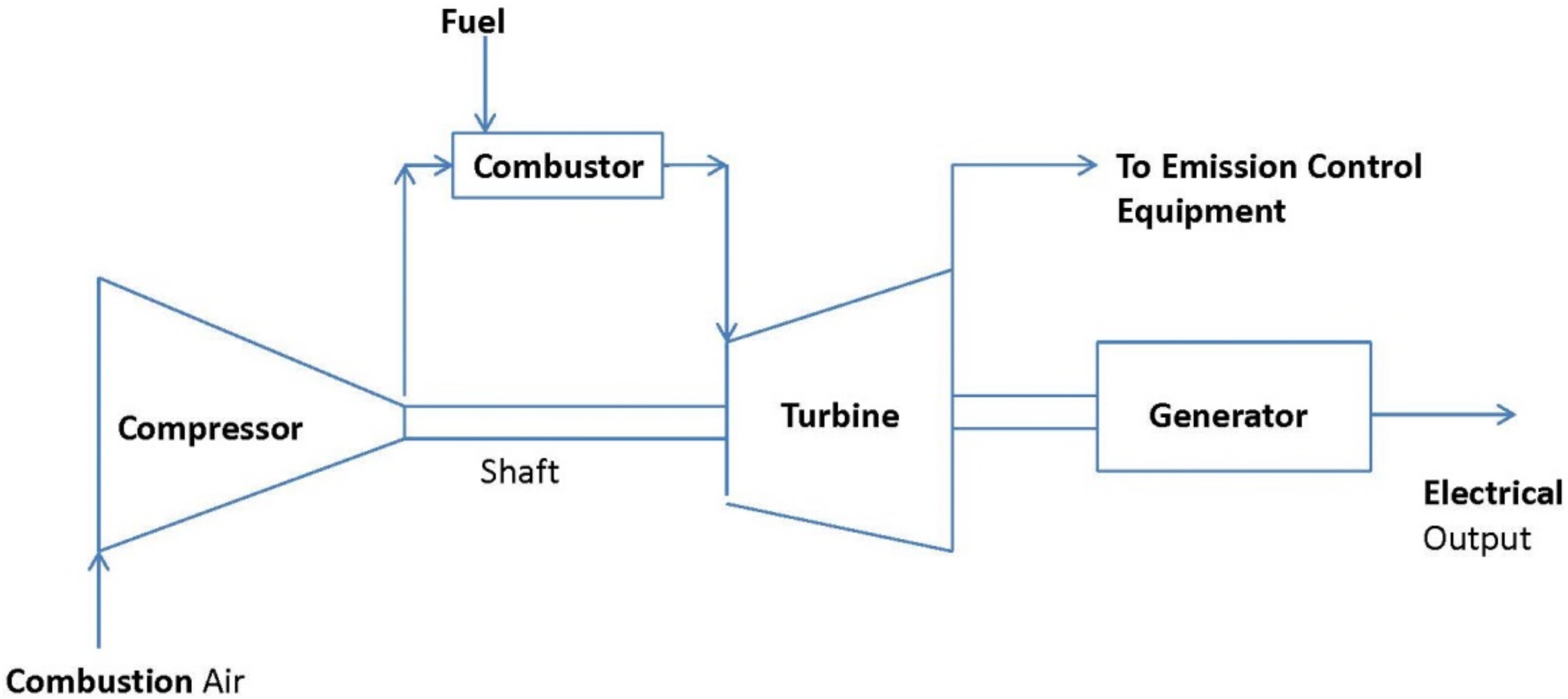


Figure 2-4
Process Flow Diagram

NRG Canal 3 Development LLC
Sandwich, Massachusetts

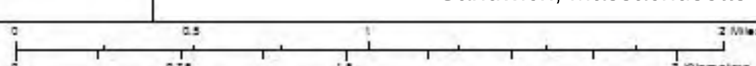
Legend

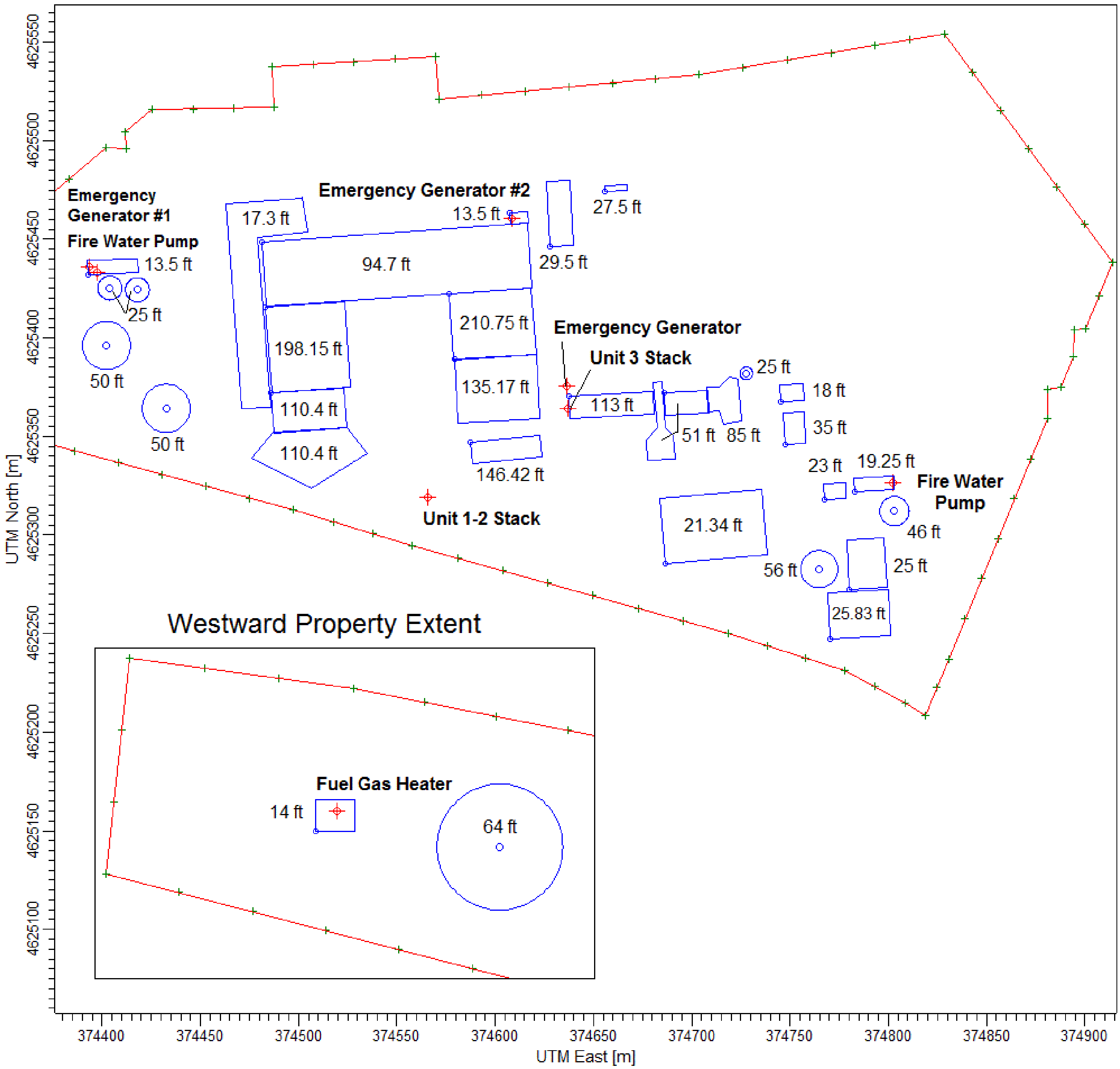
★ Canal Generating Station

Figure 5-1
Land Use Around Canal Generating Station

NRG Canal LLC
Sandwich, Massachusetts

Scale



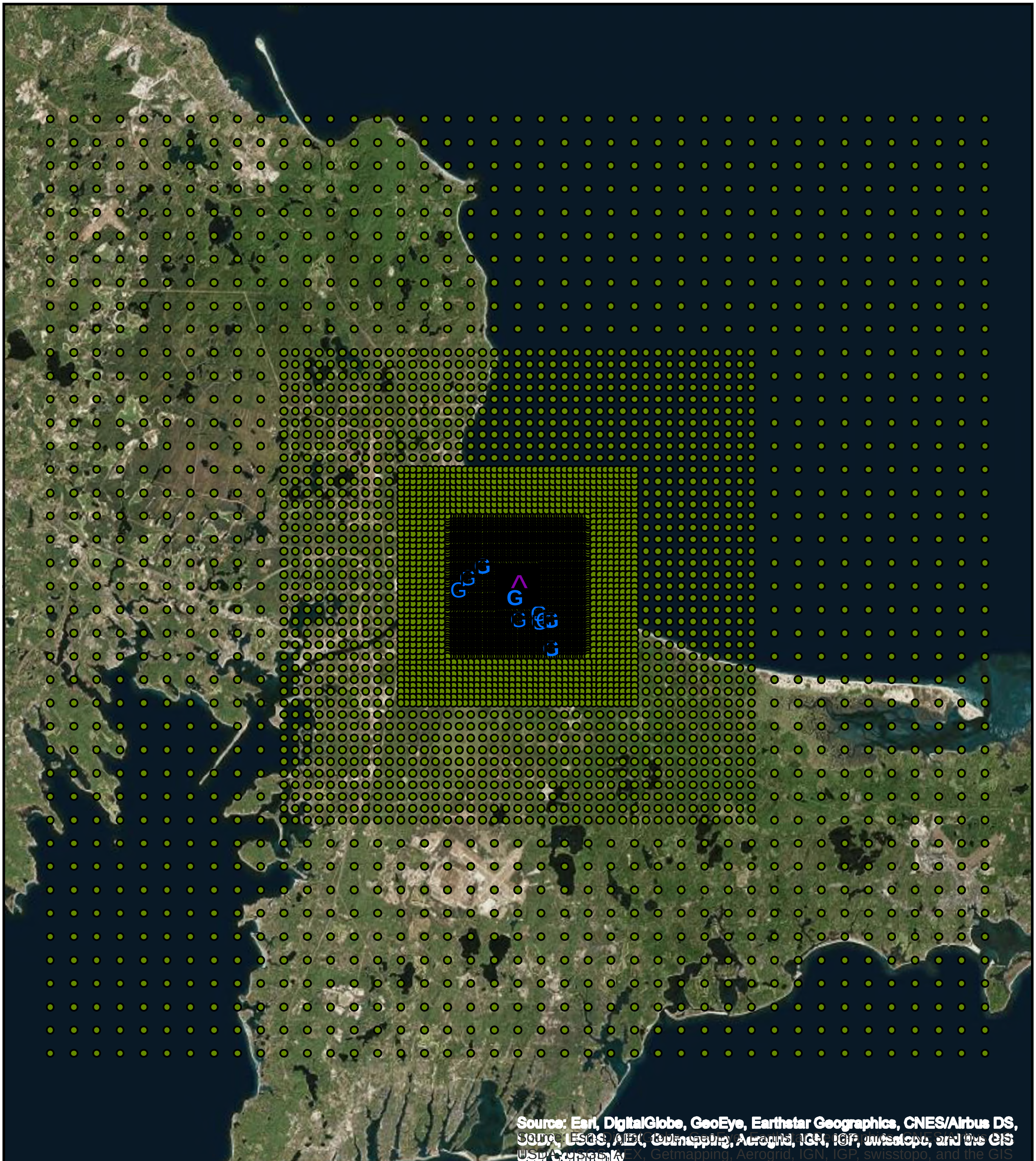


Legend

Structures/Building Footprints shown in blue
Stack locations shown in red
Facility Fence line shown in red
Fence line receptors shown in green

Figure 5-2
Structure Footprints and Heights Entered in BPIP-Prime

NRG Canal LLC
Sandwich, Massachusetts



Locator Map

Legend

Canal Generating Station

Sensitive Receptors

Cartesian Receptors

Fence Line Receptors

Fence Line

Scale

0 3.75 7.5 15 Miles

0 5 10 20 Kilometers

Figure 5-3

Full Receptor Grid Used for AERMOD Modeling

NRG Canal LLC

Sandwich, Massachusetts

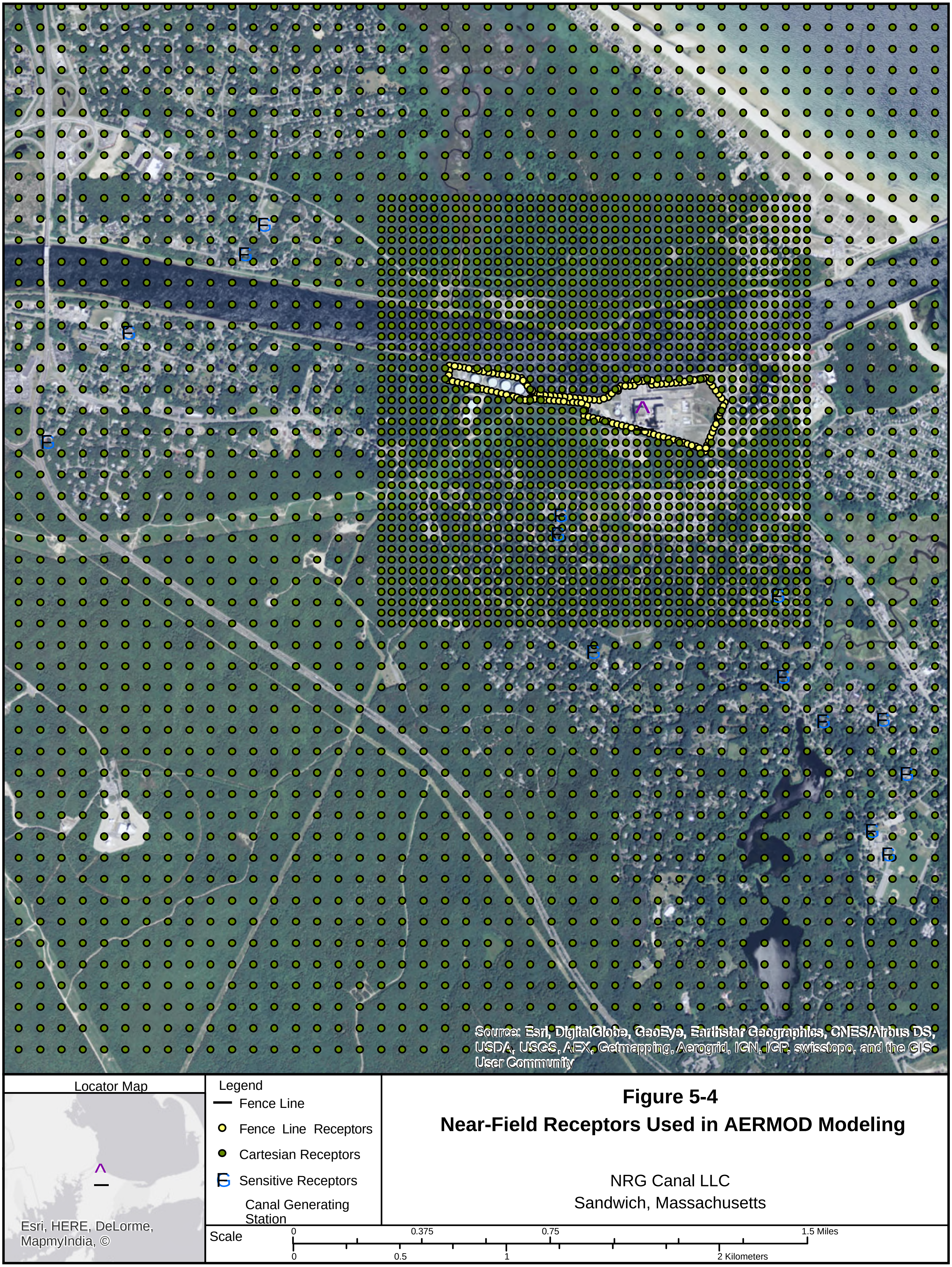


Figure 5-4
Near-Field Receptors Used in AERMOD Modeling

NRG Canal LLC
Sandwich, Massachusetts

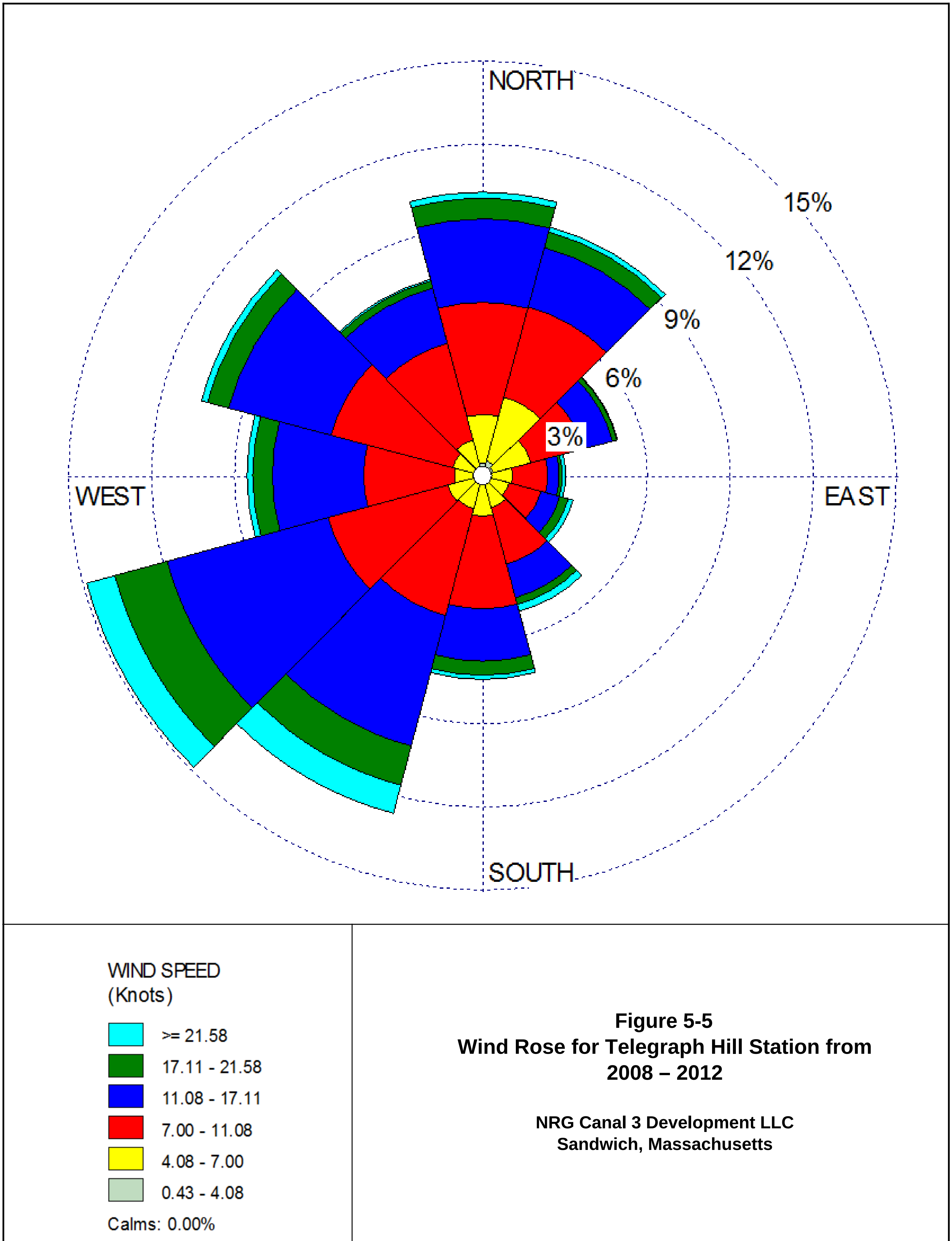


Figure 5-5
Wind Rose for Telegraph Hill Station from 2008 – 2012

NRG Canal 3 Development LLC
Sandwich, Massachusetts

Locator Map

Legend

- NO2 1-hour SIA
- PM2.5 24-hour SIA
- PM10 24-hour SIA
- Canal Generating Station

Figure 5-6

Significant Impact Areas for Short-term PM_{10}, $PM_{2.5}$, and NO_2

NRG Canal 3 Development LLC

Sandwich, Massachusetts

Scale: 0 – 1 – 2 – 4 Miles; 0 – 1.5 – 3 – 6 Kilometers

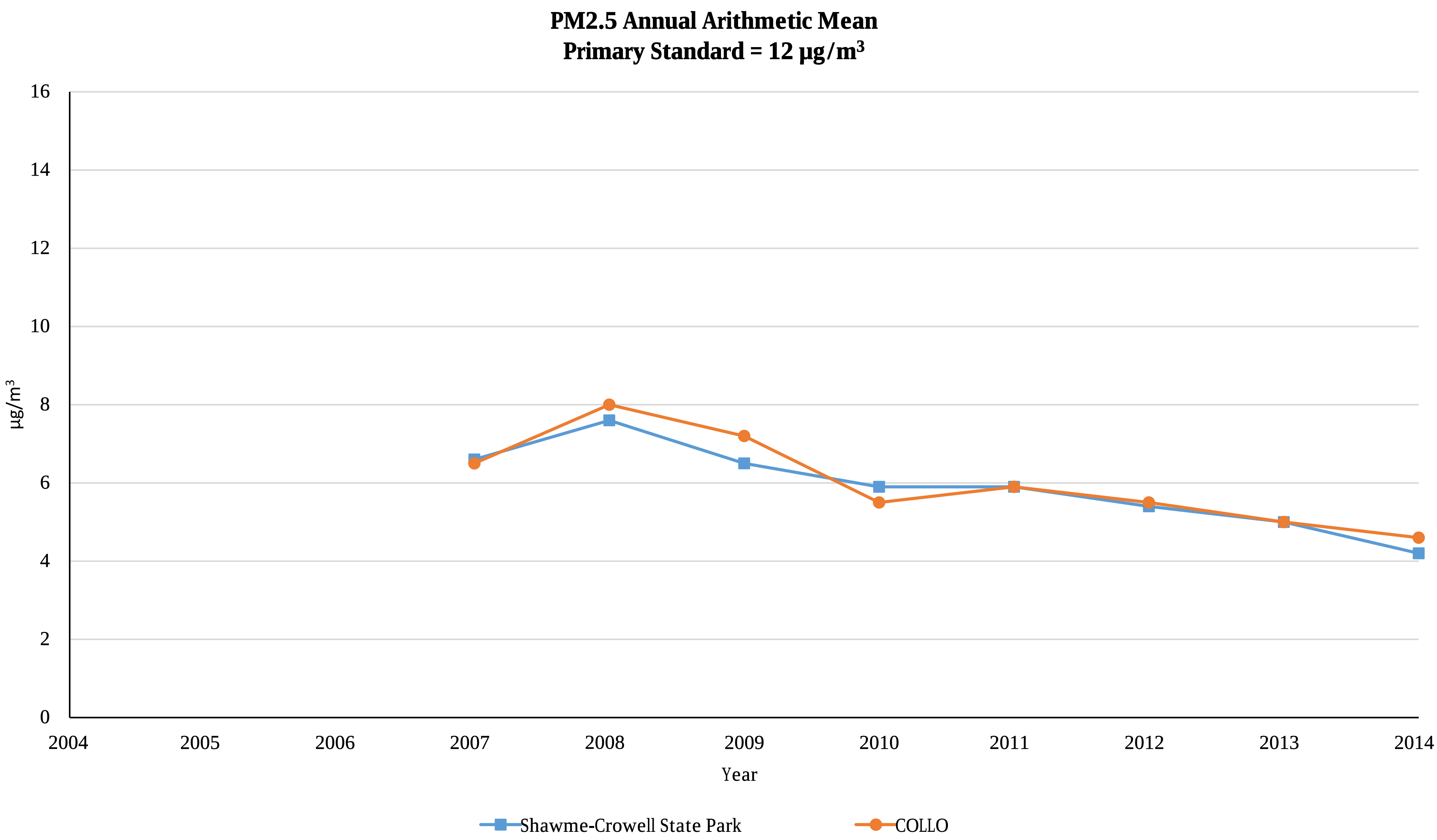


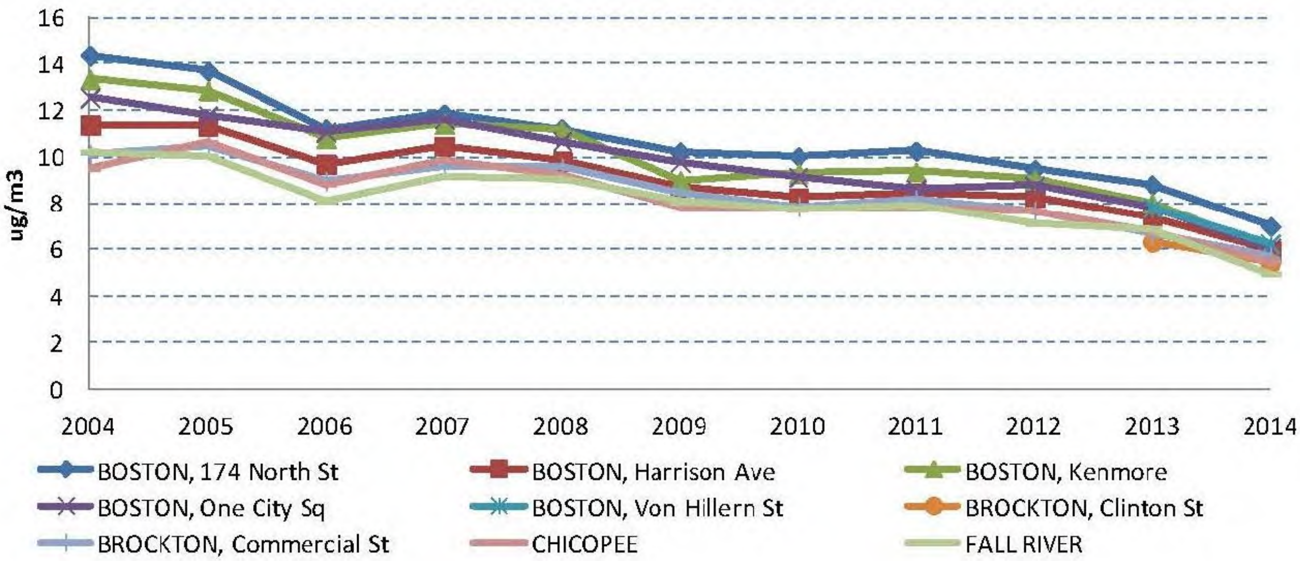
Figure 5-7
$PM_{2.5}$ Monitoring Data Trend Measured at the Shawme Crowell State Park (µg/m^3)

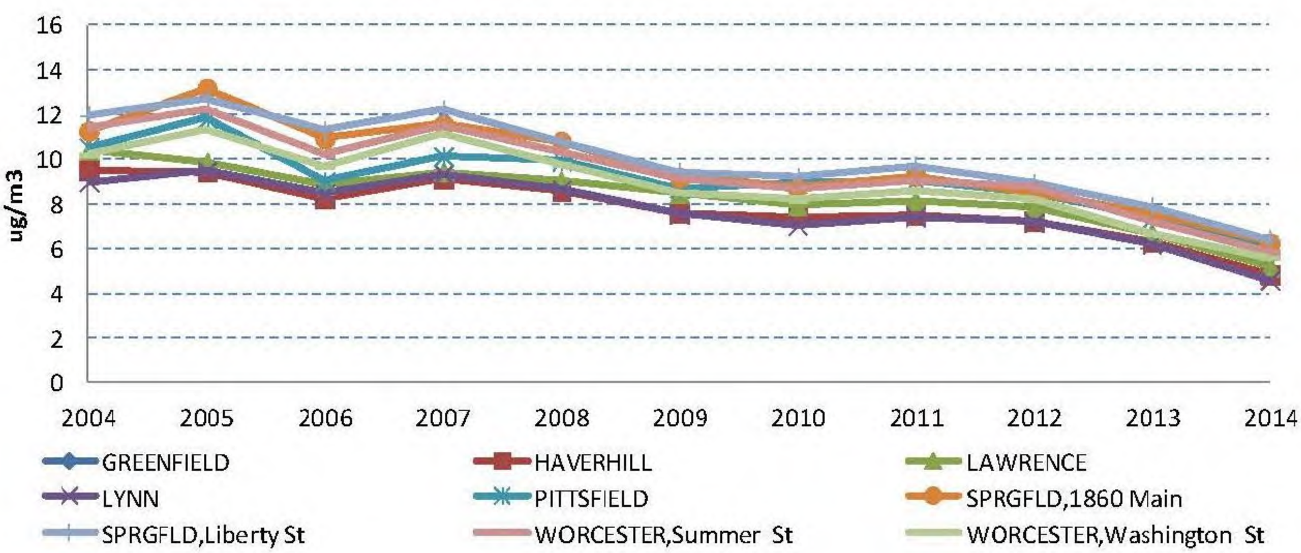
NRG Canal 3 Development LLC
Sandwich, Massachusetts

$PM_{2.5}$ FRM Trends

Long-term trends for each $PM_{2.5}$ FRM site are shown below using the annual arithmetic mean as an indicator. The data shows an overall downward trend.

Figure 8
$PM_{2.5}$ FRM Trends 2004-2014
Annual Arithmetic Mean
Primary Standard = 12 $\mu g/m^3$





(Source: Massachusetts 2014 Air Quality Report)

Figure 5-8
$PM_{2.5}$ Monitoring Data Trend in Massachusetts
($\mu g/m^3$)

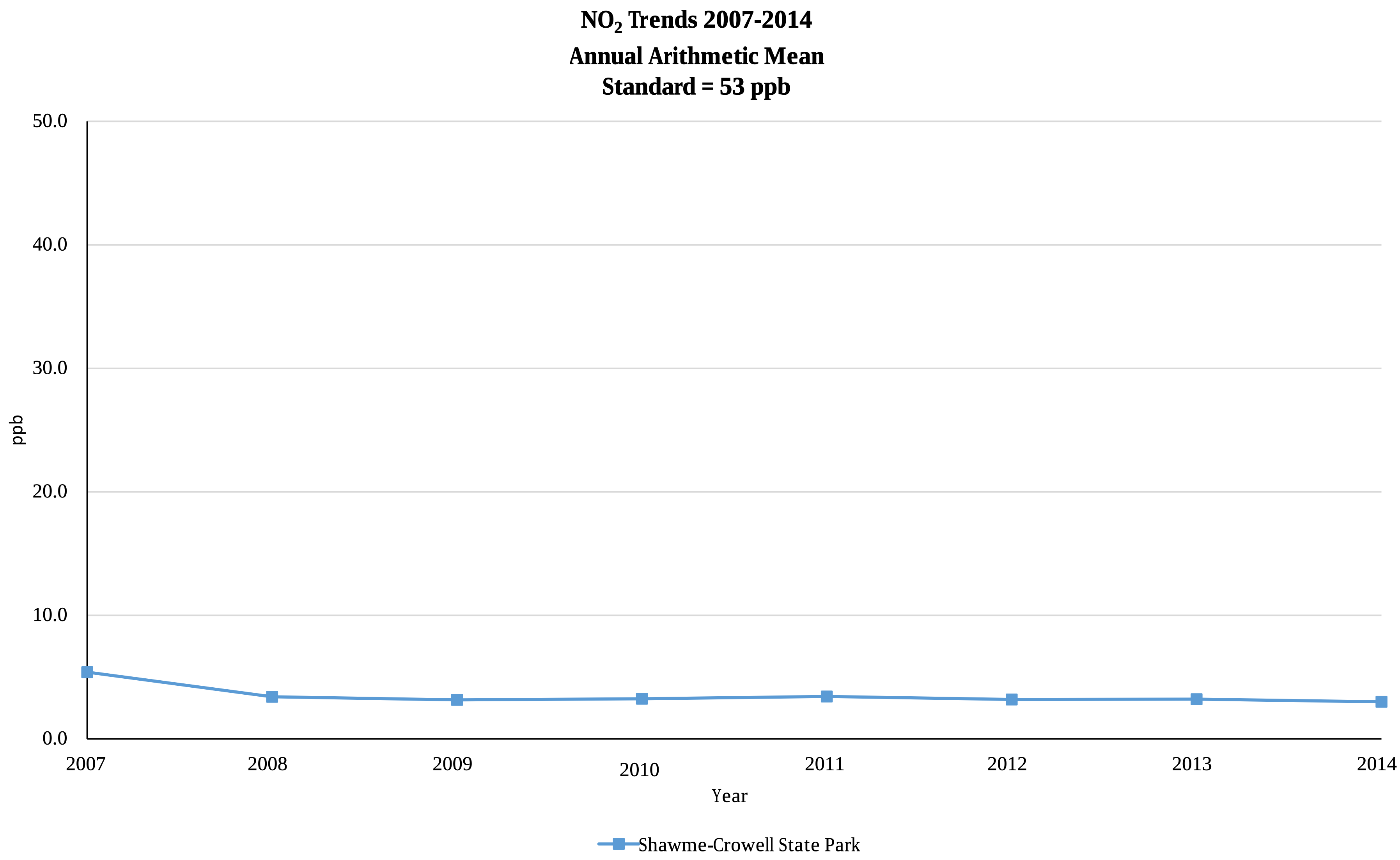


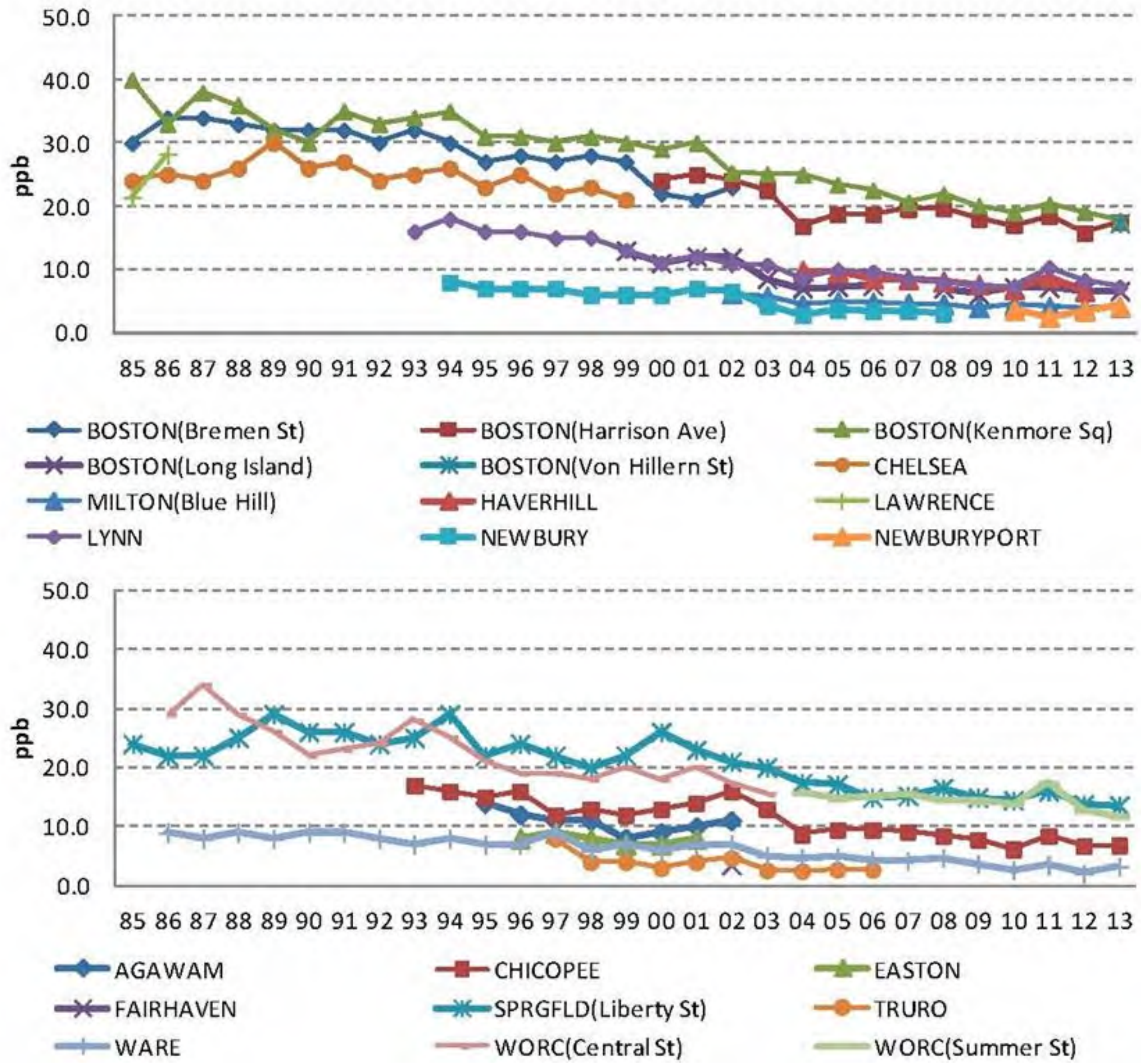
Figure 5-9
NO_2 Monitoring Data Trend Measured at the Shawme Crowell State Park (ppb)

NRG Canal 3 Development LLC
Sandwich, Massachusetts

NO$_2$ Trends

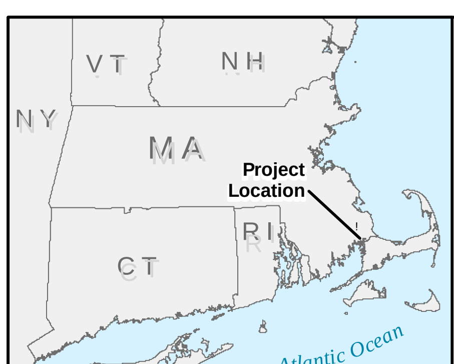
The long-term trends of the annual arithmetic means for each NO_2 site are shown below. The trend has been stable the last few years and downward for the entire period. Massachusetts is below the annual standard.

Figure 5
NO_2 Trends 1985 – 2013
Annual Arithmetic Mean
Standard = 53 ppb



(Source: Massachusetts 2013 Air Quality Report)

Figure 5-10
NO_2 Monitoring Data Trend in Massachusetts (ppb)



Legend

Project Area
5-mile Buffer

State EJ Criteria
Minority
Income
Minority and Income

Potential Federal EJ Areas, identified by EJScreen Tool
Minority and Income

0 0.5 1 2 Miles

Figure 5-11
Environmental Justice Analysis

NRG Canal 3 Development LLC
Sandwich, Massachusetts

APPENDIX A: EMISSION CALCULATIONS

Appendix A, Table A-1
Combustion Turbine Exhaust Data for GE7HA.02
Natural Gas Firing

OPERATING POINT		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16
Case Description		Unfired	Unfired	Unfired	Unfired	Unfired	Unfired	Unfired	Unfired	Unfired	Unfired	Unfired	Unfired	Unfired	Unfired	Unfired	Unfired
SITE CONDITIONS																	
Ambient Temperature	°F	90	90	90	90	59	59	59	50	50	50	20	20	20	0	0	0
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	14.7	14.7	14.7
Ambient Relative Humidity	%	56	56	56	56	60	60	60	60	60	60	66	66	66	40	40	40
Evaporative Cooler state (On or Off)		On	Off	Off	Off	Off	Off	Off	Off	Off	Off	Off	Off	Off	Off	Off	Off
Gas Turbine Load	%	BASE	BASE	75%	38%	BASE	75%	30%	BASE	75%	30%	BASE	75%	30%	BASE	75%	40%
GT Diluent Injection Type		None	None	None	None	None	None	None	None	None	None	None	None	None	None	None	None
GT Diluent Injection Flow (per GT)	10^3 lb/hr	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Fuel Type		NG	NG	NG	NG	NG	NG	NG	NG	NG	NG	NG	NG	NG	NG	NG	NG
HHV	BTU/lb	23882	23882	23882	23882	23882	23882	23882	23882	23882	23882	23882	23882	23882	23882	23882	23882
LHV	BTU/lb	21515	21515	21515	21515	21515	21515	21515	21515	21515	21515	21515	21515	21515	21515	21515	21515
Fuel Mol. Wt.	lb/mole	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16
Fuel Bound Nitrogen	Wt %	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Fuel Sulfur Content	ppmw	16.9	16.9	16.9	16.9	16.9	16.9	16.9	16.9	16.9	16.9	16.9	16.9	16.9	16.9	16.9	16.9
GT Heat Consumption (HHV Basis)	MMBTU/hr	3272	3150	2485	1609	3256	2580	1489	3323	2628	1513	3414	2714	1574	3425	2743	1869
Attemperated Flue Gas Temperature	°F	900	900	900	900	900	900	900	900	900	900	900	900	900	900	900	900
Attemperated Flue Gas Flow	ft3/sec	75,001	73,343	60,043	44,682	72,353	59,784	41,547	72,985	60,099	41,708	72,246	59,983	42,114	70,783	59,555	46,558

Stack Emissions

NOx (ppmvdc design BACT)	ppmvdc	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5
	lb/MMBtu	0.0092	0.0092	0.0092	0.0092	0.0092	0.0092	0.0092	0.0092	0.0092	0.0092	0.0092	0.0092	0.0092	0.0092	0.0092	0.0092
	lb/hr	30.10	28.98	22.86	14.80	29.95	23.73	13.70	30.58	24.17	13.92	31.41	24.97	14.48	31.51	25.24	17.19
CO (ppmvdc design BACT)	ppmvdc	***3.5***	***3.5***	***3.5***	***3.5***	***3.5***	***3.5***	***3.5***	***3.5***	***3.5***	***3.5***	***3.5***	***3.5***	***3.5***	***3.5***	***3.5***	***3.5***
	lb/MMBtu	***0.0079***	***0.0079***	***0.0079***	***0.0079***	***0.0079***	***0.0079***	***0.0079***	***0.0079***	***0.0079***	***0.0079***	***0.0079***	***0.0079***	***0.0079***	***0.0079***	***0.0079***	***0.0079***
	lb/hr	***25.8***	***24.9***	***19.6***	***12.7***	***25.7***	***20.4***	***11.8***	***26.3***	***20.8***	***12.0***	***27.0***	***21.4***	***12.4***	***27.1***	***21.7***	***14.8***
Particulates (GE data)	lb/hr	18.1	**18.1**	**18.1**	**18.1**	**18.1**	**18.1**	**18.1**	**18.1**	**18.1**	**18.1**	**18.1**	**18.1**	**18.1**	**18.1**	**18.1**	**18.1**
	lb/MMBtu	0.0055	**0.0057**	**0.0073**	**0.0112**	**0.0056**	**0.0070**	**0.0122**	**0.0054**	**0.0069**	**0.0120**	**0.0053**	**0.0067**	**0.0115**	**0.0053**	**0.0066**	**0.0097**
SO2	lb/MMBtu	0.0015	0.0015	0.0015	0.0015	0.0015	0.0015	0.0015	0.0015	0.0015	0.0015	0.0015	0.0015	0.0015	0.0015	0.0015	0.0015
	lb/hr	4.91	4.73	3.73	2.41	4.88	3.87	2.23	4.99	3.94	2.27	5.12	4.07	2.36	5.14	4.11	2.80
VOC (ppmvdc design BACT)	ppmvdc	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0
	lb/MMBtu	0.0026	0.0026	0.0026	0.0026	0.0026	0.0026	0.0026	0.0026	0.0026	0.0026	0.0026	0.0026	0.0026	0.0026	0.0026	0.0026
	lb/hr	8.51	8.19	6.46	4.18	8.46	6.71	3.87	8.64	6.83	3.93	8.88	7.06	4.09	8.90	7.13	4.86
Exhaust Velocity*	feet/sec	135.93	132.93	108.82	80.98	131.14	108.35	75.30	132.28	108.93	75.59	130.94	108.72	76.33	128.29	107.94	84.38
Exhaust Temp *	deg F	750	750	750	750	750	750	750	750	750	750	750	750	750	750	750	750

*Note : Exhaust temperature and velocity incorporate a temperature loss in the stack of 150 deg F from the attempered SCR temp of 900 deg F based on Babcock & Wilcox *Steam.*

Updated information for Supplement No. 1 is shown in boldface and italics

Appendix A, Table A-2
Combustion Turbine Exhaust Data for GE7HA.02
ULSD Firing

OPERATING POINT		17	18	19	20	21	22	23	24	25	26	27	28	29	30	31	32
Case Description		Unfired	Unfired	Unfired	Unfired	Unfired	Unfired	Unfired	Unfired	Unfired	Unfired	Unfired	Unfired	Unfired	Unfired	Unfired	Unfired
SITE CONDITIONS																	
Ambient Temperature	°F	90	90	90	90	59	59	59	50	50	50	20	20	20	0	0	0
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	14.7	14.7	14.7
Ambient Relative Humidity	%	56	56	56	56	60	60	60	60	60	60	66	66	66	40	40	40
Evaporative Cooler state (On or Off)		On	Off	Off	Off	Off	Off	Off	Off	Off	Off	Off	Off	Off	Off	Off	Off
Gas Turbine Load	%	BASE	BASE	75%	37.5%	BASE	75%	30%	BASE	75%	30%	BASE	75%	30%	BASE	75%	40%
GT Diluent Injection Type		Water	Water	Water	Water	Water	Water	Water	Water	Water	Water	Water	Water	Water	Water	Water	Water
GT Diluent Injection Flow (per GT)	10^3 lb/hr	220.9	220.8	152.4	101.7	230.4	163.5	114.8	236	167	119.3	234.1	171.3	125.8	232.3	172.8	119.8
Fuel Type		DO	DO	DO	DO	DO	DO	DO	DO	DO	DO	DO	DO	DO	DO	DO	DO
HHV	BTU/lb	19581	19581	19581	19581	19581	19581	19581	19581	19581	19581	19581	19581	19581	19581	19581	19581
LHV	BTU/lb	18300	18300	18300	18300	18300	18300	18300	18300	18300	18300	18300	18300	18300	18300	18300	18300
Fuel Mol. Wt.	lb/mole	138	138	138	138	138	138	138	138	138	138	138	138	138	138	138	138
Fuel Bound Nitrogen	Wt %	≤ 0.015%	≤ 0.015%	≤ 0.015%	≤ 0.015%	≤ 0.015%	≤ 0.015%	≤ 0.015%	≤ 0.015%	≤ 0.015%	≤ 0.015%	≤ 0.015%	≤ 0.015%	≤ 0.015%	≤ 0.015%	≤ 0.015%	≤ 0.015%
Fuel Sulfur Content	ppmw	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15
GT Heat Consumption (HHV Basis)	MMBTU/hr	3293	3202	2519	1543	3303	2615	1427	3371	2660	1455	3447	2748	1515	3471	2782	1770
Attemperated Flue Gas Temperature	°F	900	900	900	900	900	900	900	900	900	900	900	900	900	900	900	900
Attemperated Flue Gas Flow	ft3/sec	70,682	69,528	57,868	44,211	68,439	57,479	41,157	69,012	57,677	41,438	68,231	57,700	41,773	67,721	57,617	45,197

Stack Emissions

NOx (ppmvdc design BACT)	ppmvdc	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0
	lb/MMBtu	0.0194	0.0194	0.0194	0.0194	0.0194	0.0194	0.0194	0.0194	0.0194	0.0194	0.0194	0.0194	0.0194	0.0194	0.0194	0.0194
	lb/hr	63.89	62.11	48.87	29.93	64.08	50.72	27.68	65.40	51.61	28.23	66.86	53.30	29.39	67.35	53.96	34.34
CO (ppmvdc design BACT)	ppmvdc	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0
	lb/MMBtu	0.0118	0.0118	0.0118	0.0118	0.0118	0.0118	0.0118	0.0118	0.0118	0.0118	0.0118	0.0118	0.0118	0.0118	0.0118	0.0118
	lb/hr	38.86	37.78	29.72	18.21	38.97	30.85	16.84	39.78	31.39	17.17	40.67	32.42	17.88	40.96	32.82	20.89
Particulates (GE data)	lb/hr	65.8	65.8	65.8	65.8	65.8	65.8	65.8	65.8	65.8	65.8	65.8	65.8	65.8	65.8	65.8	65.8
	lb/MMBtu	0.0200	0.0205	0.0261	0.0426	0.0199	0.0252	0.0461	0.0195	0.0247	0.0452	0.0191	0.0239	0.0434	0.0190	0.0237	0.0372
SO2	lb/MMBtu	0.0015	0.0015	0.0015	0.0015	0.0015	0.0015	0.0015	0.0015	0.0015	0.0015	0.0015	0.0015	0.0015	0.0015	0.0015	0.0015
	lb/hr	4.94	4.80	3.78	2.31	4.95	3.92	2.14	5.06	3.99	2.18	5.17	4.12	2.27	5.21	4.17	2.66
VOC (ppmvdc design BACT)	ppmvdc	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0
	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	0.0027	0.0027	0.0027
	lb/hr	8.89	8.64	6.80	4.17	8.92	7.06	3.85	9.10	7.18	3.93	9.31	7.42	4.09	9.37	7.51	4.78
Exhaust Velocity*	feet/sec	128.11	126.02	104.88	80.13	124.04	104.18	74.59	125.08	104.54	75.10	123.66	104.58	75.71	122.74	104.43	81.92
Exhaust Temp *	deg F	750	750	750	750	750	750	750	750	750	750	750	750	750	750	750	750

*Note : Exhaust temperature and velocity incorporate a temperature loss in the stack of 150 deg F from the attemperated SCR temp of 900 deg F based on Babcock & Wilcox *Steam.*

Appendix A, Table A-3
Emergency Diesel Generator Data

Emergency Diesel Generator							
Permitting Design based on Caterpillar Tier 4 Alternate FEL C-15 ATAAC engine-generator set							
Engine mechanical power output			779	bhp			
Engine mechanical kW			581	kWm			
Engine Heat Input rating			5.03	MMBtu/hr			
SO2 is based on ULSD							
		Tier 4	Tier 4		**Full load**		
		1039.101	1039.104				
		Table 1	Table 1				
		g/kWhr	g/kWhr		**lb/hr**		
NOx			3.5		**4.48**		
CO		3.5			**4.48**		
PM Part 1039			0.10		**0.13**		
PM with condensables			0.132		**0.17**		
SO2 (lb/MMBtu)		0.0015			**0.0075**		
VOC		0.19			**0.24**		
Exhaust Parameters per Caterpillar Spec Sheet flow & temp							
Flow (acfm)	3842.2						
Temperature (F)	942.1						
Stack Diameter		9	inches				
Stack Height		25	feet				
Exit Temp with temp loss		887.1	F				
Velocity with temp loss		139.3	fps				

Appendix A, Table A-4
Emergency Diesel Fire Pump Data

Emergency Fire Pump					
Permitting Design based on Jon Deere/Clarke JU4H-UFAD5G (135 bhp)					
Maximum engine mechanical kW			101	kWm	
Engine Heat Input rating			1.20	MMBtu/hr	
SO2 is based on ULSD					
		Tier 3			**Full load**
		g/kWhr			**lb/hr**
NOx		4.0			**0.89**
CO		5.0			**1.113**
PM Subpart IIII		0.3			**0.067**
PM with condensables		0.332			**0.074**
SO2 (lb/MMBtu)	0.0015				**0.0018**
VOC		1.3			**0.29**
Exhaust Parameters per Clarke Spec Sheet flow & temp					
Flow (acfm)	694				
Temperature (F)	864				
Stack Diameter		4	inches		
Stack Height		25	feet		
Exit Temp with temp loss		809	F		
Velocity with temp loss		127.0	fps		

Appendix A, Table A-5 - Canal Unit 3 Project Potential Emissions

	Combustion Turbine at 100% Load		Combustion Turbine Starts			Turbine Emissions (tons/year)	Ancillary Sources (tons per year)	Total Canal 3 Project Emissions (tons per year)	Major Modification Threshold (tons/year)	Threshold Type	Major Modification? (Yes/No)
	50 deg F	0 deg F									
	Gas	ULSD		Gas	ULSD						
Hours per year	3660	720	Number of SUSD cycles per year	180	80						
MMBtu/hr	3323	3471									
NOx	0.0092	0.0194	lbs/SUSD cycle	158	227	103.5	0.8	**104.3**	25/40	NNSR/PSD	Yes
CO	***0.0079***	0.0118	lbs/SUSD cycle	263	188	***94.0***	0.8	***94.8***	100	:PSD	***No***
VOC	0.0026	0.0027	lbs/SUSD cycle	34	15	23.3	0.08	***24.4***	25	NNSR	No
SO2	0.0015	0.0015	lbs/SUSD cycle	0.46	0.42	11.1	1.40E-03	**11.1**	40	PSD	No
PM/PM-10	18.1 lb/hr	***65.8 lb/hr***	lbs/SUSD cycle	13.3	61	***60.4***	0.04	***60.5***	25/15	PSD	Yes
PM-2.5	18.1 lb/hr	***65.8 lb/hr***	lbs/SUSD cycle	13.3	61	***60.4***	0.04	***60.5***	10	PSD	Yes
NH3	0.0068	0.0072	lbs/SUSD cycle	--	--	50.3	--	**50.3**	--	--	
H2SO4	0.0016	0.0018	lbs/SUSD cycle	0.49	0.50	12.0	1.1E-04	**12.0**	7	PSD	Yes
Pb	0.00E+00	3.13E-06	lbs/SUSD cycle	0.00E+00	8.73E-04	0.004	3E-06	**0.004**	0.6	PSD	No
Formaldehyde	0.00022	0.00023	lbs/SUSD cycle	0.07	0.06	1.6	2.7E-04	**1.6**	Canal Station is already a Major HAP Source		
CO2e	119.0	162.85	lbs/SUSD cycle	36,418	45,435	932325	152	***934,041***	75,000	PSD	Yes

Notes:
1. Turbine PTE is based on design emission rates in lb/MMBtu as shown except for particulates.
2. PM/PM-10/PM-2.5 emissions are based on the maximum GE lb/hr case for each fuel.
3. Annual emissions for steady-state conditions are based on the 100% load natural gas firing rate or emissions at 50 deg F (3660 hours) and the 100% load ULSD firing rate or emissions at 0 deg F (720 hours) (see also notes 4 & 5).
4. Startup/shutdown (SUSD) cycles are included on top of the steady-state emissions based on GE SUSD emission data and the number of SUSD cycles on each fuel as shown.
5. For CO, VOC and SO2, which have higher SUSD cycle emissions on gas compared to ULSD, the annual emission are based on the maximum of 4380 hours on gas and 260 SUSD cycles on gas, or the approach described in notes 4 & 5.
6. Total Canal VOC emissions includes 1.0 tpy VOC emissions from ULSD working and breathing losses (see pages B-15 through B-28).
7. Total Canal GHG Project Emissions includes allowance for 1,561 tpy CO2e from methane leaks and 3 tpy CO2e from potential SF6 leaks (see page B-29).
8 . Updates for Supplement No. 1 in bold/italics
9 . Updates for Supplement No. 2 highlighted

Table A-6
HAP Emissions
Combustion Turbine

	Units	Dual Fuel	Gas Only	
50 deg F Base Load Heat Input (Gas)	MMBtu/hr, HHV	3323	3323	
0 deg F Base Load Heat Input (ULSD)	MMBtu/hr, HHV	3471		
Annual Operation	Hours on Gas	3660	4380	
Annual Operation	Hours on Oil	720		
SUSD Gas	MMBtu	306	306	
SUSD ULSD	MMBtu	279		
SUSD Gas	Number per year	180	260	
SUSD ULSD	Number per year	80		

HAP Emissions - Turbine

	Turbine Factor (Gas)	Turbine Factor (Oil)	All Gas HAP Annual	Gas/Oil HAP Annual
Air Toxic	**lb/MMBtu**	**lb/MMBtu**	**tons/yr**	**tons/yr**
1,3 Butadiene	4.30E-07	1.60E-05	3.15E-03	2.28E-02
Acetaldehyde	4.00E-05		2.93E-01	2.44E-01
Acrolein	6.40E-06		4.68E-02	3.91E-02
Benzene	1.20E-05	5.50E-05	8.78E-02	1.43E-01
Ethylbenzene	3.20E-05		2.34E-01	1.95E-01
Formaldehyde	2.20E-04	2.30E-04	1.61E+00	1.63E+00
Naphthalene	1.30E-06	3.50E-05	9.51E-03	5.21E-02
PAH	2.20E-06	4.00E-05	1.61E-02	6.39E-02
Propylene Oxide	2.90E-05		2.12E-01	1.77E-01
Toluene	1.30E-04		9.51E-01	7.94E-01
Xylenes	6.40E-05		4.68E-01	3.91E-01
Arsenic		4.62E-08		5.82E-05
Cadmium		5.13E-09		6.47E-06
Chromium		1.24E-05		1.57E-02
Lead		7.69E-07		9.70E-04
Manganese		2.82E-07		3.56E-04
Mercury		1.03E-08		1.29E-05
Nickel		1.48E-06		1.87E-03
Selenium		2.56E-07		3.23E-04
Total HAP	5.37E-04	3.91E-04	3.93	3.78

Table A-7 Emergency Diesel Generator
HAP Emissions

	Units	
Engine Size	kW (mechanical)	581
Maximum Heat Input	MMBtu/hr	5.03
Number of Engines		1
Annual Hours of Operation		300

Emissions Emergency Generator

			HAP
Air Toxic	**lb/MMBtu**	**lb/hr**	**ton/yr**
1,3 Butadiene			
Acetaldehyde	2.52E-05	1.27E-04	1.90E-05
Acrolein	7.88E-06	3.96E-05	5.95E-06
Anthracene	1.23E-06	6.19E-06	9.28E-07
Benzene	7.76E-04	3.90E-03	5.85E-04
Benzo(a)anthracene	6.22E-07	3.13E-06	4.69E-07
Benzo(a)pyrene	2.57E-07	1.29E-06	1.94E-07
Formaldehyde	7.89E-05	3.97E-04	5.95E-05
Naphthalene	1.30E-04	6.54E-04	9.81E-05
PAH	2.12E-04	1.07E-03	1.60E-04
Toluene	2.81E-04	1.41E-03	2.12E-04
Xylene (Total)	1.93E-04	9.71E-04	1.46E-04
Arsenic	4.62E-08	2.32E-07	3.49E-08
Cadmium	5.13E-09	2.58E-08	3.87E-09
Chromium	1.24E-05	6.24E-05	9.36E-06
Lead	7.69E-07	3.87E-06	5.80E-07
Manganese	2.82E-07	1.42E-06	2.13E-07
Mercury	1.03E-08	5.18E-08	7.77E-09
Nickel	1.48E-06	7.44E-06	1.12E-06
Selenium	2.56E-07	1.29E-06	1.93E-07

Total HAPs		5.19E-03	1.30E-03

Table A-8 Emergency Diesel Fire Pump
HAP Emissions

	Units	
Engine Size	Horsepower	135
Maximum Heat Input	MMBtu/hr	1.20
Number of Engines		1
Annual Hours of Operation		300

Emissions Emergency Diesel Fire Pump

			HAP
Air Toxic	**lb/MMBtu**	**lb/hr**	**ton/yr**
1,3 Butadiene	3.91E-05	4.69E-05	7.04E-06
Acetaldehyde	7.67E-04	9.20E-04	1.38E-04
Acrolein	9.25E-05	1.11E-04	1.67E-05
Anthracene	1.87E-06	2.24E-06	3.37E-07
Benzene	9.33E-04	1.12E-03	1.68E-04
Benzo(a)anthracene	1.68E-06	2.02E-06	3.02E-07
Benzo(a)pyrene	1.88E-07	2.26E-07	3.38E-08
Formaldehyde	1.18E-03	1.42E-03	2.12E-04
Naphthalene	8.48E-05	1.02E-04	1.53E-05
PAH	1.68E-04	2.02E-04	3.02E-05
Toluene	4.09E-04	4.91E-04	7.36E-05
Xylene (Total)	2.85E-04	3.42E-04	5.13E-05
Arsenic	4.62E-08	5.54E-08	8.32E-09
Cadmium	5.13E-09	6.16E-09	9.23E-10
Chromium	1.24E-05	1.49E-05	2.23E-06
Lead	7.69E-07	9.23E-07	1.38E-07
Manganese	2.82E-07	3.38E-07	5.08E-08
Mercury	1.03E-08	1.24E-08	1.85E-09
Nickel	1.48E-06	1.78E-06	2.66E-07
Selenium	2.56E-07	3.07E-07	4.61E-08

Total HAP		2.86E-03	7.16E-04

TABLE A-9 500 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 1039.104(g) (tpy) 0.67
SCR Control Efficiency (%) 90%

Equipment Cost (EC)		(Factor)	
a.	SCR Capital Cost Estimate (Per Milton Cat)		$100,000
b.	Instrumentation (0.10A)		Included
c.	Taxes and Freight	(EC*0.05)	$5,000
Total Equipment Cost (TEC)			**$105,000**
Direct Installation Costs			
a.	Foundation	(TEC*0.08)	$8,400
b.	Erection and Handling	(TEC*0.14)	$14,700
c.	Electrical	(TEC*0.04)	$4,200
d.	Piping	(TEC*0.02)	$2,100
e.	Insulation	(TEC*0.01)	$1,050
f.	Painting	(TEC*0.01)	$1,050
Total Direct Installation Cost			**$31,500**
Indirect Installation Costs			
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 (TCC)			**$165,900**

Capital Recovery		**$27,042**
Direct Operating Costs		
a.	Ammonia	$868
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		**$2,308**
Indirect Operating Costs		
a.	Overhead (60% of OL+ML)	$576
b.	Property Tax: (TCC*0.01)	$1,659
c.	Insurance: (TCC*0.01)	$1,659
d.	Administration: (TCC*0.02)	$3,318
Total Indirect Operating Cost		**$7,212**
Total Annual Cost		**$36,562**
NOx Reduction (tons/yr)		**0.60**
Cost of Control ($/ton - NOx)		**$60,634**

Catalyst Replacement is not included since the emergency generator will only operate a maximum of 300 hours in any year

Note 1: SCR capital cost scaled from estimate for 750 kW emergency generator unit.

Note 2: 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 A-10 500 KW EMERGENCY GENERATOR
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 (includes condensables, tpy) **0.03**
DPF Control Efficiency (%) **85%**

Equipment Cost (EC)		(Factor)	
a.	DPF Capital Cost Estimate (per Milton Cat)		$60,000
b.	Instrumentation (0.10A)		Included
c.	Taxes and Freight	(EC*0.05)	$3,000
Total Equipment Cost (TEC)			**$63,000**
Direct Installation Costs			
a.	Foundation	(TEC*0.08)	$5,040
b.	Erection and Handling	(TEC*0.14)	$8,820
c.	Electrical	(TEC*0.04)	$2,520
d.	Piping	(TEC*0.02)	$1,260
e.	Insulation	(TEC*0.01)	$630
f.	Painting	(TEC*0.01)	$630
Total Direct Installation Cost			**$18,900**
Indirect Installation Costs			
a.	Engineering and Supervision	(TEC*0.1)	$6,300
b.	Construction/Field Expenses	(TEC*0.05)	$3,150
c.	Construction Fee	(TEC*0.1)	$6,300
d.	Start up	(TEC*0.02)	$1,260
e.	Performance Test	(TEC*0.01)	$630
Total Indirect Installation Cost			**$17,640**
Total Capital Cost (TCC)			**$99,540**

Capital Recovery		**$16,225**
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)	$995
c.	Insurance: (TCC*0.01)	$995
d.	Administration: (TCC*0.02)	$1,991
Total Indirect Operating Cost		**$4,269**

Total Annual Cost	**$21,214**
PM Reduction (tons/yr)	**0.0216**
Cost of Control ($/ton - PM)	**$984,110**

Note 1: DPF capital cost scaled from estimate for 750 kW emergency generator unit.

TABLE A-11 101 kWm 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) **0.13**
SCR Control Efficiency (%) **90%**

Equipment Cost (EC)		(Factor)	
a.	SCR Capital Cost Estmate (per Milton Cat)		$30,930
b.	Instrumentation (0.10A)		Included
c.	Taxes and Freight	(EC*0.05)	$1,546
Total Equipment Cost (TEC)			**$32,476**
Direct Installation Costs			
a.	Foundation	(TEC*0.08)	$2,598
b.	Erection and Handling	(TEC*0.14)	$4,547
c.	Electrical	(TEC*0.04)	$1,299
d.	Piping	(TEC*0.02)	$650
e.	Insulation	(TEC*0.01)	$325
f.	Painting	(TEC*0.01)	$325
Total Direct Installation Cost			**$9,743**
Indirect Installation Costs			
a.	Engineering and Supervision	(TEC*0.1)	$3,247.64
b.	Construction/Field Expenses	(TEC*0.05)	$1,624
c.	Construction Fee	(TEC*0.1)	$3,248
d.	Start up	(TEC*0.02)	$650
e.	Performance Test	(TEC*0.01)	$325
Total Indirect Installation Cost			**$9,093**
Total Capital Cost (TCC)			**$51,313**

Capital Recovery		**$8,364**
Direct Operating Costs		
a.	Ammonia	$168
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		**$1,608**

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)	$513
c.	Insurance: (TCC*0.01)	$513
d.	Administration: (TCC*0.02)	$1,026
Total Indirect Operating Cost		**$2,628**

Total Annual Cost	**$12,601**
NOx Reduction (tons/yr)	**0.12**
Cost of Control ($/ton - NOx)	**$107,697**

Note 1: SCR capital cost scaled from estimate for 371 emergency diesle fire pump.

Note 2: 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 A-12 101 kWm 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 (includes condensables, tpy) 0.011
DPF Control Efficiency (%) 85%

Equipment Cost (EC)		(Factor)	
a.	DPF Capital Cost Estmate		$16,375
b.	Instrumentation (0.10A)		Included
c.	Taxes and Freight	(EC*0.05)	$819
Total Equipment Cost (TEC)			**$17,193**
Direct Installation Costs			
a.	Foundation	(TEC*0.08)	$1,375
b.	Erection and Handling	(TEC*0.14)	$2,407
c.	Electrical	(TEC*0.04)	$688
d.	Piping	(TEC*0.02)	$344
e.	Insulation	(TEC*0.01)	$172
f.	Painting	(TEC*0.01)	$172
Total Direct Installation Cost			**$5,158**
Indirect Installation Costs			
a.	Engineering and Supervision	(TEC*0.1)	$1,719.34
b.	Construction/Field Expenses	(TEC*0.05)	$860
c.	Construction Fee	(TEC*0.1)	$1,719
d.	Start up	(TEC*0.02)	$344
e.	Performance Test	(TEC*0.01)	$172
Total Indirect Installation Cost			**$4,814**
Total Capital Cost (TCC)			**$27,166**

Capital Recovery		**$4,428**
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)	$272
c.	Insurance: (TCC*0.01)	$272
d.	Administration: (TCC*0.02)	$543
Total Indirect Operating Cost		**$1,375**

Total Annual Cost	**$6,523**
PM Reduction (tons/yr)	**0.0094**
Cost of Control ($/ton - PM)	**$697,610**

Table A-13 ULSD Storage Working/Breathing Loss Summary

	ULSD Storage VOC Working and Breathing Losses		
	ULSD Throughput		
	Rolling 12-month Throughput 720 hours at 3471 MMBtu/hr		
=	(720 hours)(3471 MMBtu/hr)(1,000,000 Btu/MMBtu)/{(19,581 Btu/lb)(7 lb/gal)}		
=	18,232,835	gallons	
	round up to 18,240,000 gallons rolling 12-month throughput		
	Tanks		
	Main Storage Tank (Facility Designation ESCO-1)		
	5.88 million vertical fixed roof tank per Table B-16 Tanks Output		
	All ULSD is delivered into the 5.88 MMgal tank and then transferred into the		
	day tank prior to combustion.		
	Day Tank (Facility Designation FDT1)		
	1.8 million vertical fixed roof tank per Table B-17 Tanks Output		
	All ULSD transferred from the 5.88 MMgal tank passes through the		
	day tank prior to combustion.		
	Summary of Total VOC Working and Breathing Losses		
			VOC (lb/year)
	Main Storage Tank (Table B-16, Sheet 6 of 7)		1310.41
	Day Tank (Table B-17, Sheet 6 of 7)		676.23
		Total (lbs/year)	1986.64
		Total (tons/year)	1.0

TABLE A-14

TANKS 4.0.9d
Emissions Report - Detail Format
Tank Indentification and Physical Characteristics

Identification

User Identification:	ESCO-1
City:	Sandwich
State:	Massachusetts
Company:	Canal Generating
Type of Tank:	Vertical Fixed Roof Tank
Description:	5.88 MM gallon No.2 fuel oil tank

Tank Dimensions

Shell Height (ft):	65.00
Diameter (ft):	136.00
Liquid Height (ft) :	52.50
Avg. Liquid Height (ft):	45.50
Volume (gallons):	5,705,059.76
Turnovers:	3.20
Net Throughput(gal/yr):	18,240,000.00
Is Tank Heated (y/n):	N

Paint Characteristics

Shell Color/Shade:	Gray/Light
Shell Condition	Good
Roof Color/Shade:	Gray/Light
Roof Condition:	Good

Roof Characteristics

Type:	Cone
Height (ft)	4.25
Slope (ft/ft) (Cone Roof)	0.06

Breather Vent Settings

Vacuum Settings (psig):	-0.03
Pressure Settings (psig)	0.03

Meterological Data used in Emissions Calculations: Providence, Rhode Island (Avg Atmospheric Pressure = 14.7 psia)

TABLE A-14

TANKS 4.0.9d
Emissions Report - Detail Format
Liquid Contents of Storage Tank

ESCO-1 - Vertical Fixed Roof Tank
Sandwich, Massachusetts

Mixture/Component	Month	Daily Liquid Surf. Temperature (deg F) Avg.	Min.	Max.	Liquid Bulk Temp (deg F)	Vapor Pressure (psia) Avg.	Min.	Max.	Vapor Mol. Weight.	Liquid Mass Fract.	Vapor Mass Fract.	Mol. Weight	Basis for Vapor Pressure Calculations
Distillate fuel oil no. 2	Jan	44.28	38.87	49.69	52.63	0.0037	0.0031	0.0045	130.0000			188.00	Option 1: VP40 = .0031 VP50 = .0045
Distillate fuel oil no. 2	Feb	46.15	39.78	52.51	52.63	0.0040	0.0031	0.0050	130.0000			188.00	Option 1: VP40 = .0031 VP50 = .0045
Distillate fuel oil no. 2	Mar	50.99	43.41	58.56	52.63	0.0047	0.0036	0.0062	130.0000			188.00	Option 1: VP50 = .0045 VP60 = .0065
Distillate fuel oil no. 2	Apr	56.67	47.56	65.78	52.63	0.0058	0.0042	0.0079	130.0000			188.00	Option 1: VP50 = .0045 VP60 = .0065
Distillate fuel oil no. 2	May	62.20	51.94	72.46	52.63	0.0070	0.0049	0.0097	130.0000			188.00	Option 1: VP60 = .0065 VP70 = .009
Distillate fuel oil no. 2	Jun	67.02	56.20	77.85	52.63	0.0083	0.0057	0.0114	130.0000			188.00	Option 1: VP60 = .0065 VP70 = .009
Distillate fuel oil no. 2	Jul	69.42	58.95	79.89	52.63	0.0089	0.0063	0.0120	130.0000			188.00	Option 1: VP60 = .0065 VP70 = .009
Distillate fuel oil no. 2	Aug	67.92	58.27	77.57	52.63	0.0085	0.0062	0.0113	130.0000			188.00	Option 1: VP60 = .0065 VP70 = .009
Distillate fuel oil no. 2	Sep	63.37	54.62	72.13	52.63	0.0073	0.0054	0.0096	130.0000			188.00	Option 1: VP60 = .0065 VP70 = .009
Distillate fuel oil no. 2	Oct	57.20	49.71	64.68	52.63	0.0059	0.0045	0.0077	130.0000			188.00	Option 1: VP50 = .0045 VP60 = .0065
Distillate fuel oil no. 2	Nov	51.44	45.85	57.02	52.63	0.0048	0.0039	0.0059	130.0000			188.00	Option 1: VP50 = .0045 VP60 = .0065
Distillate fuel oil no. 2	Dec	46.02	41.12	50.92	52.63	0.0039	0.0033	0.0047	130.0000			188.00	Option 1: VP40 = .0031 VP50 = .0045

TABLE A-14

TANKS 4.0.9d
Emissions Report - Detail Format
Detail Calculations (AP-42)

ESCO-1 - Vertical Fixed Roof Tank
Sandwich, Massachusetts

Month:	January	February	March	April	May	June	July	August	September	October	November	December
Standing Losses (lb):	32.4962	37.2690	57.8992	82.7669	114.5091	134.6700	142.6834	126.1480	97.1184	70.4200	40.9204	30.8042
Vapor Space Volume (cu ft):	303,850.6523	303,850.6523	303,850.6523	303,850.6523	303,850.6523	303,850.6523	303,850.6523	303,850.6523	303,850.6523	303,850.6523	303,850.6523	303,850.6523
Vapor Density (lb/cu ft):	0.0001	0.0001	0.0001	0.0001	0.0002	0.0002	0.0002	0.0002	0.0002	0.0001	0.0001	0.0001
Vapor Space Expansion Factor:	0.0390	0.0464	0.0554	0.0668	0.0749	0.0785	0.0755	0.0694	0.0632	0.0541	0.0398	0.0348
Vented Vapor Saturation Factor:	0.9959	0.9956	0.9948	0.9936	0.9922	0.9909	0.9903	0.9907	0.9919	0.9935	0.9947	0.9956
Tank Vapor Space Volume:												
Vapor Space Volume (cu ft):	303,850.6523	303,850.6523	303,850.6523	303,850.6523	303,850.6523	303,850.6523	303,850.6523	303,850.6523	303,850.6523	303,850.6523	303,850.6523	303,850.6523
Tank Diameter (ft):	136.0000	136.0000	136.0000	136.0000	136.0000	136.0000	136.0000	136.0000	136.0000	136.0000	136.0000	136.0000
Vapor Space Outage (ft):	20.9167	20.9167	20.9167	20.9167	20.9167	20.9167	20.9167	20.9167	20.9167	20.9167	20.9167	20.9167
Tank Shell Height (ft):	65.0000	65.0000	65.0000	65.0000	65.0000	65.0000	65.0000	65.0000	65.0000	65.0000	65.0000	65.0000
Average Liquid Height (ft):	45.5000	45.5000	45.5000	45.5000	45.5000	45.5000	45.5000	45.5000	45.5000	45.5000	45.5000	45.5000
Roof Outage (ft):	1.4167	1.4167	1.4167	1.4167	1.4167	1.4167	1.4167	1.4167	1.4167	1.4167	1.4167	1.4167
Roof Outage (Cone Roof)												
Roof Outage (ft):	1.4167	1.4167	1.4167	1.4167	1.4167	1.4167	1.4167	1.4167	1.4167	1.4167	1.4167	1.4167
Roof Height (ft):	4.2500	4.2500	4.2500	4.2500	4.2500	4.2500	4.2500	4.2500	4.2500	4.2500	4.2500	4.2500
Roof Slope (ft/ft):	0.0600	0.0600	0.0600	0.0600	0.0600	0.0600	0.0600	0.0600	0.0600	0.0600	0.0600	0.0600
Shell Radius (ft):	68.0000	68.0000	68.0000	68.0000	68.0000	68.0000	68.0000	68.0000	68.0000	68.0000	68.0000	68.0000
Vapor Density												
Vapor Density (lb/cu ft):	0.0001	0.0001	0.0001	0.0001	0.0002	0.0002	0.0002	0.0002	0.0002	0.0001	0.0001	0.0001
Vapor Molecular Weight (lb/lb-mole):	130.0000	130.0000	130.0000	130.0000	130.0000	130.0000	130.0000	130.0000	130.0000	130.0000	130.0000	130.0000
Vapor Pressure at Daily Average Liquid Surface Temperature (psia):	0.0037	0.0040	0.0047	0.0058	0.0070	0.0083	0.0089	0.0085	0.0073	0.0059	0.0048	0.0039
Daily Avg. Liquid Surface Temp. (deg. R):	503.9490	505.8167	510.6580	516.3404	521.8689	526.6921	529.0858	527.5876	523.0415	516.8663	511.1088	505.6926
Daily Average Ambient Temp. (deg. F):	27.8500	29.6000	37.4500	47.3500	57.3000	66.8500	72.6500	71.3000	64.0500	53.5500	43.9500	32.8000
Ideal Gas Constant R (psia cuft / (lb-mol-deg R)):	10.731	10.731	10.731	10.731	10.731	10.731	10.731	10.731	10.731	10.731	10.731	10.731
Liquid Bulk Temperature (deg. R):	512.3017	512.3017	512.3017	512.3017	512.3017	512.3017	512.3017	512.3017	512.3017	512.3017	512.3017	512.3017
Tank Paint Solar Absorptance (Shell):	0.5400	0.5400	0.5400	0.5400	0.5400	0.5400	0.5400	0.5400	0.5400	0.5400	0.5400	0.5400
Tank Paint Solar Absorptance (Roof):	0.5400	0.5400	0.5400	0.5400	0.5400	0.5400	0.5400	0.5400	0.5400	0.5400	0.5400	0.5400
Daily Total Solar Insulation Factor (Btu/sqft day):	598.0540	855.3599	1,180.5617	1,491.4863	1,761.1658	1,906.7927	1,869.6721	1,657.7358	1,339.8312	975.2880	615.8211	496.2103
Vapor Space Expansion Factor												
Vapor Space Expansion Factor:	0.0390	0.0464	0.0554	0.0668	0.0749	0.0785	0.0755	0.0694	0.0632	0.0541	0.0398	0.0348
Daily Vapor Temperature Range (deg. R):	21.6426	25.4610	30.3061	36.4473	41.0288	43.3027	41.8774	38.6010	35.0182	29.9384	22.3432	19.5987
Daily Vapor Pressure Range (psia):	0.0014	0.0019	0.0026	0.0038	0.0048	0.0056	0.0057	0.0051	0.0042	0.0032	0.0020	0.0014
Breather Vent Press. Setting Range(psia):	0.0600	0.0600	0.0600	0.0600	0.0600	0.0600	0.0600	0.0600	0.0600	0.0600	0.0600	0.0600
Vapor Pressure at Daily Average Liquid Surface Temperature (psia):	0.0037	0.0040	0.0047	0.0058	0.0070	0.0083	0.0089	0.0085	0.0073	0.0059	0.0048	0.0039
Vapor Pressure at Daily Minimum Liquid Surface Temperature (psia):	0.0031	0.0031	0.0036	0.0042	0.0049	0.0057	0.0063	0.0062	0.0054	0.0045	0.0039	0.0033
Vapor Pressure at Daily Maximum Liquid Surface Temperature (psia):	0.0045	0.0050	0.0062	0.0079	0.0097	0.0114	0.0120	0.0113	0.0096	0.0077	0.0059	0.0047
Daily Avg. Liquid Surface Temp. (deg R):	503.9490	505.8167	510.6580	516.3404	521.8689	526.6921	529.0858	527.5876	523.0415	516.8663	511.1088	505.6926
Daily Min. Liquid Surface Temp. (deg R):	498.5384	499.4514	503.0815	507.2286	511.6117	515.8664	518.6164	517.9374	514.2869	509.3817	505.5230	500.7929
Daily Max. Liquid Surface Temp. (deg R):	509.3597	512.1820	518.2345	525.4522	532.1261	537.5178	539.5551	537.2379	531.7960	524.3509	516.6946	510.5922
Daily Ambient Temp. Range (deg. R):	17.5000	17.4000	17.3000	19.3000	20.0000	20.1000	18.9000	18.8000	20.5000	21.1000	18.1000	16.8000
Vented Vapor Saturation Factor												
Vented Vapor Saturation Factor:	0.9959	0.9956	0.9948	0.9936	0.9922	0.9909	0.9903	0.9907	0.9919	0.9935	0.9947	0.9956
Vapor Pressure at Daily Average Liquid: Surface Temperature (psia):	0.0037	0.0040	0.0047	0.0058	0.0070	0.0083	0.0089	0.0085	0.0073	0.0059	0.0048	0.0039
Vapor Space Outage (ft):	20.9167	20.9167	20.9167	20.9167	20.9167	20.9167	20.9167	20.9167	20.9167	20.9167	20.9167	20.9167

TABLE A-14

Working Losses (lb):	17.4032	18.6334	22.1011	27.4480	33.1672	38.8403	41.6557	39.8936	34.5464	27.9428	22.5253	18.5516
Vapor Molecular Weight (lb/lb-mole):	130.0000	130.0000	130.0000	130.0000	130.0000	130.0000	130.0000	130.0000	130.0000	130.0000	130.0000	130.0000
Vapor Pressure at Daily Average Liquid Surface Temperature (psia):	0.0037	0.0040	0.0047	0.0058	0.0070	0.0083	0.0089	0.0085	0.0073	0.0059	0.0048	0.0039
Net Throughput (gal/mo.):	1,520,000.0000	1,520,000.0000	1,520,000.0000	1,520,000.0000	1,520,000.0000	1,520,000.0000	1,520,000.0000	1,520,000.0000	1,520,000.0000	1,520,000.0000	1,520,000.0000	1,520,000.0000
Annual Turnovers:	3.1972	3.1972	3.1972	3.1972	3.1972	3.1972	3.1972	3.1972	3.1972	3.1972	3.1972	3.1972
Turnover Factor:	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
Maximum Liquid Volume (gal):	5,705,059.7576	5,705,059.7576	5,705,059.7576	5,705,059.7576	5,705,059.7576	5,705,059.7576	5,705,059.7576	5,705,059.7576	5,705,059.7576	5,705,059.7576	5,705,059.7576	5,705,059.7576
Maximum Liquid Height (ft):	52.5000	52.5000	52.5000	52.5000	52.5000	52.5000	52.5000	52.5000	52.5000	52.5000	52.5000	52.5000
Tank Diameter (ft):	136.0000	136.0000	136.0000	136.0000	136.0000	136.0000	136.0000	136.0000	136.0000	136.0000	136.0000	136.0000
Working Loss Product Factor:	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
Total Losses (lb):	49.8994	55.9024	80.0003	110.2149	147.6764	173.5103	184.3391	166.0416	131.6649	98.3628	63.4457	49.3558

TABLE A-14

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TABLE A-14

TANKS 4.0.9d
Emissions Report - Detail Format
Individual Tank Emission Totals

Emissions Report for: January, February, March, April, May, June, July, August, September, October, November, December

ESCO-1 - Vertical Fixed Roof Tank
Sandwich, Massachusetts

	Losses(lbs)		
Components	Working Loss	Breathing Loss	Total Emissions
Distillate fuel oil no. 2	342.71	967.70	1,310.41

TABLE A-14

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TABLE A-15

TANKS 4.0.9d
Emissions Report - Detail Format
Tank Indentification and Physical Characteristics

Identification

User Identification:	FDT1
City:	Sandwich
State:	Massachusetts
Company:	Canal Generating
Type of Tank:	Vertical Fixed Roof Tank
Description:	1.8 MM gallon fuel oil storage tank

Tank Dimensions

Shell Height (ft):	48.00
Diameter (ft):	80.00
Liquid Height (ft) :	48.00
Avg. Liquid Height (ft):	28.00
Volume (gallons):	1,804,863.20
Turnovers:	10.11
Net Throughput(gal/yr):	18,240,000.00
Is Tank Heated (y/n):	N

Paint Characteristics

Shell Color/Shade:	Gray/Light
Shell Condition	Good
Roof Color/Shade:	Gray/Light
Roof Condition:	Good

Roof Characteristics

Type:	Cone
Height (ft)	2.50
Slope (ft/ft) (Cone Roof)	0.06

Breather Vent Settings

Vacuum Settings (psig):	-0.03
Pressure Settings (psig)	0.03

Meterological Data used in Emissions Calculations: Providence, Rhode Island (Avg Atmospheric Pressure = 14.7 psia)

TABLE A-15

TANKS 4.0.9d
Emissions Report - Detail Format
Liquid Contents of Storage Tank

FDT1 - Vertical Fixed Roof Tank
Sandwich, Massachusetts

Mixture/Component	Month	Daily Liquid Surf. Temperature (deg F) Avg.	Min.	Max.	Liquid Bulk Temp (deg F)	Vapor Pressure (psia) Avg.	Min.	Max.	Vapor Mol. Weight.	Liquid Mass Fract.	Vapor Mass Fract.	Mol. Weight	Basis for Vapor Pressure Calculations
Distillate fuel oil no. 2	Jan	44.28	38.87	49.69	52.63	0.0037	0.0031	0.0045	130.0000			188.00	Option 1: VP40 = .0031 VP50 = .0045
Distillate fuel oil no. 2	Feb	46.15	39.78	52.51	52.63	0.0040	0.0031	0.0050	130.0000			188.00	Option 1: VP40 = .0031 VP50 = .0045
Distillate fuel oil no. 2	Mar	50.99	43.41	58.56	52.63	0.0047	0.0036	0.0062	130.0000			188.00	Option 1: VP50 = .0045 VP60 = .0065
Distillate fuel oil no. 2	Apr	56.67	47.56	65.78	52.63	0.0058	0.0042	0.0079	130.0000			188.00	Option 1: VP50 = .0045 VP60 = .0065
Distillate fuel oil no. 2	May	62.20	51.94	72.46	52.63	0.0070	0.0049	0.0097	130.0000			188.00	Option 1: VP60 = .0065 VP70 = .009
Distillate fuel oil no. 2	Jun	67.02	56.20	77.85	52.63	0.0083	0.0057	0.0114	130.0000			188.00	Option 1: VP60 = .0065 VP70 = .009
Distillate fuel oil no. 2	Jul	69.42	58.95	79.89	52.63	0.0089	0.0063	0.0120	130.0000			188.00	Option 1: VP60 = .0065 VP70 = .009
Distillate fuel oil no. 2	Aug	67.92	58.27	77.57	52.63	0.0085	0.0062	0.0113	130.0000			188.00	Option 1: VP60 = .0065 VP70 = .009
Distillate fuel oil no. 2	Sep	63.37	54.62	72.13	52.63	0.0073	0.0054	0.0096	130.0000			188.00	Option 1: VP60 = .0065 VP70 = .009
Distillate fuel oil no. 2	Oct	57.20	49.71	64.68	52.63	0.0059	0.0045	0.0077	130.0000			188.00	Option 1: VP50 = .0045 VP60 = .0065
Distillate fuel oil no. 2	Nov	51.44	45.85	57.02	52.63	0.0048	0.0039	0.0059	130.0000			188.00	Option 1: VP50 = .0045 VP60 = .0065
Distillate fuel oil no. 2	Dec	46.02	41.12	50.92	52.63	0.0039	0.0033	0.0047	130.0000			188.00	Option 1: VP40 = .0031 VP50 = .0045

TABLE A-15

TANKS 4.0.9d
Emissions Report - Detail Format
Detail Calculations (AP-42)

FDT1 - Vertical Fixed Roof Tank
Sandwich, Massachusetts

Month:	January	February	March	April	May	June	July	August	September	October	November	December
Standing Losses (lb):	11.1997	12.8447	19.9549	28.5257	39.4659	46.4146	49.1766	43.4775	33.4722	24.2703	14.1032	10.6166
Vapor Space Volume (cu ft):	104,719.7550	104,719.7550	104,719.7550	104,719.7550	104,719.7550	104,719.7550	104,719.7550	104,719.7550	104,719.7550	104,719.7550	104,719.7550	104,719.7550
Vapor Density (lb/cu ft):	0.0001	0.0001	0.0001	0.0001	0.0002	0.0002	0.0002	0.0002	0.0002	0.0001	0.0001	0.0001
Vapor Space Expansion Factor:	0.0390	0.0464	0.0554	0.0668	0.0749	0.0785	0.0755	0.0694	0.0632	0.0541	0.0398	0.0348
Vented Vapor Saturation Factor:	0.9959	0.9956	0.9948	0.9936	0.9923	0.9910	0.9903	0.9907	0.9920	0.9935	0.9947	0.9957
Tank Vapor Space Volume:												
Vapor Space Volume (cu ft):	104,719.7550	104,719.7550	104,719.7550	104,719.7550	104,719.7550	104,719.7550	104,719.7550	104,719.7550	104,719.7550	104,719.7550	104,719.7550	104,719.7550
Tank Diameter (ft):	80.0000	80.0000	80.0000	80.0000	80.0000	80.0000	80.0000	80.0000	80.0000	80.0000	80.0000	80.0000
Vapor Space Outage (ft):	20.8333	20.8333	20.8333	20.8333	20.8333	20.8333	20.8333	20.8333	20.8333	20.8333	20.8333	20.8333
Tank Shell Height (ft):	48.0000	48.0000	48.0000	48.0000	48.0000	48.0000	48.0000	48.0000	48.0000	48.0000	48.0000	48.0000
Average Liquid Height (ft):	28.0000	28.0000	28.0000	28.0000	28.0000	28.0000	28.0000	28.0000	28.0000	28.0000	28.0000	28.0000
Roof Outage (ft):	0.8333	0.8333	0.8333	0.8333	0.8333	0.8333	0.8333	0.8333	0.8333	0.8333	0.8333	0.8333
Roof Outage (Cone Roof)												
Roof Outage (ft):	0.8333	0.8333	0.8333	0.8333	0.8333	0.8333	0.8333	0.8333	0.8333	0.8333	0.8333	0.8333
Roof Height (ft):	2.5000	2.5000	2.5000	2.5000	2.5000	2.5000	2.5000	2.5000	2.5000	2.5000	2.5000	2.5000
Roof Slope (ft/ft):	0.0600	0.0600	0.0600	0.0600	0.0600	0.0600	0.0600	0.0600	0.0600	0.0600	0.0600	0.0600
Shell Radius (ft):	40.0000	40.0000	40.0000	40.0000	40.0000	40.0000	40.0000	40.0000	40.0000	40.0000	40.0000	40.0000
Vapor Density												
Vapor Density (lb/cu ft):	0.0001	0.0001	0.0001	0.0001	0.0002	0.0002	0.0002	0.0002	0.0002	0.0001	0.0001	0.0001
Vapor Molecular Weight (lb/lb-mole):	130.0000	130.0000	130.0000	130.0000	130.0000	130.0000	130.0000	130.0000	130.0000	130.0000	130.0000	130.0000
Vapor Pressure at Daily Average Liquid Surface Temperature (psia):	0.0037	0.0040	0.0047	0.0058	0.0070	0.0083	0.0089	0.0085	0.0073	0.0059	0.0048	0.0039
Daily Avg. Liquid Surface Temp. (deg. R):	503.9490	505.8167	510.6580	516.3404	521.8689	526.6921	529.0858	527.5876	523.0415	516.8663	511.1088	505.6926
Daily Average Ambient Temp. (deg. F):	27.8500	29.6000	37.4500	47.3500	57.3000	66.8500	72.6500	71.3000	64.0500	53.5500	43.9500	32.8000
Ideal Gas Constant R (psia cuft / (lb-mol-deg R)):	10.731	10.731	10.731	10.731	10.731	10.731	10.731	10.731	10.731	10.731	10.731	10.731
Liquid Bulk Temperature (deg. R):	512.3017	512.3017	512.3017	512.3017	512.3017	512.3017	512.3017	512.3017	512.3017	512.3017	512.3017	512.3017
Tank Paint Solar Absorptance (Shell):	0.5400	0.5400	0.5400	0.5400	0.5400	0.5400	0.5400	0.5400	0.5400	0.5400	0.5400	0.5400
Tank Paint Solar Absorptance (Roof):	0.5400	0.5400	0.5400	0.5400	0.5400	0.5400	0.5400	0.5400	0.5400	0.5400	0.5400	0.5400
Daily Total Solar Insulation Factor (Btu/sqft day):	598.0540	855.3599	1,180.5617	1,491.4863	1,761.1658	1,906.7927	1,869.6721	1,657.7358	1,339.8312	975.2880	615.8211	496.2103
Vapor Space Expansion Factor												
Vapor Space Expansion Factor:	0.0390	0.0464	0.0554	0.0668	0.0749	0.0785	0.0755	0.0694	0.0632	0.0541	0.0398	0.0348
Daily Vapor Temperature Range (deg. R):	21.6426	25.4610	30.3061	36.4473	41.0288	43.3027	41.8774	38.6010	35.0182	29.9384	22.3432	19.5987
Daily Vapor Pressure Range (psia):	0.0014	0.0019	0.0026	0.0038	0.0048	0.0056	0.0057	0.0051	0.0042	0.0032	0.0020	0.0014
Breather Vent Press. Setting Range(psia):	0.0600	0.0600	0.0600	0.0600	0.0600	0.0600	0.0600	0.0600	0.0600	0.0600	0.0600	0.0600
Vapor Pressure at Daily Average Liquid Surface Temperature (psia):	0.0037	0.0040	0.0047	0.0058	0.0070	0.0083	0.0089	0.0085	0.0073	0.0059	0.0048	0.0039
Vapor Pressure at Daily Minimum Liquid Surface Temperature (psia):	0.0031	0.0031	0.0036	0.0042	0.0049	0.0057	0.0063	0.0062	0.0054	0.0045	0.0039	0.0033
Vapor Pressure at Daily Maximum Liquid Surface Temperature (psia):	0.0045	0.0050	0.0062	0.0079	0.0097	0.0114	0.0120	0.0113	0.0096	0.0077	0.0059	0.0047
Daily Avg. Liquid Surface Temp. (deg R):	503.9490	505.8167	510.6580	516.3404	521.8689	526.6921	529.0858	527.5876	523.0415	516.8663	511.1088	505.6926
Daily Min. Liquid Surface Temp. (deg R):	498.5384	499.4514	503.0815	507.2286	511.6117	515.8664	518.6164	517.9374	514.2869	509.3817	505.5230	500.7929
Daily Max. Liquid Surface Temp. (deg R):	509.3597	512.1820	518.2345	525.4522	532.1261	537.5178	539.5551	537.2379	531.7960	524.3509	516.6946	510.5922
Daily Ambient Temp. Range (deg. R):	17.5000	17.4000	17.3000	19.3000	20.0000	20.1000	18.9000	18.8000	20.5000	21.1000	18.1000	16.8000
Vented Vapor Saturation Factor												
Vented Vapor Saturation Factor:	0.9959	0.9956	0.9948	0.9936	0.9923	0.9910	0.9903	0.9907	0.9920	0.9935	0.9947	0.9957
Vapor Pressure at Daily Average Liquid: Surface Temperature (psia):	0.0037	0.0040	0.0047	0.0058	0.0070	0.0083	0.0089	0.0085	0.0073	0.0059	0.0048	0.0039
Vapor Space Outage (ft):	20.8333	20.8333	20.8333	20.8333	20.8333	20.8333	20.8333	20.8333	20.8333	20.8333	20.8333	20.8333

TABLE A-15

Working Losses (lb):	17.4032	18.6334	22.1011	27.4480	33.1672	38.8403	41.6557	39.8936	34.5464	27.9428	22.5253	18.5516
Vapor Molecular Weight (lb/lb-mole):	130.0000	130.0000	130.0000	130.0000	130.0000	130.0000	130.0000	130.0000	130.0000	130.0000	130.0000	130.0000
Vapor Pressure at Daily Average Liquid Surface Temperature (psia):	0.0037	0.0040	0.0047	0.0058	0.0070	0.0083	0.0089	0.0085	0.0073	0.0059	0.0048	0.0039
Net Throughput (gal/mo.):	1,520,000.0000	1,520,000.0000	1,520,000.0000	1,520,000.0000	1,520,000.0000	1,520,000.0000	1,520,000.0000	1,520,000.0000	1,520,000.0000	1,520,000.0000	1,520,000.0000	1,520,000.0000
Annual Turnovers:	10.1060	10.1060	10.1060	10.1060	10.1060	10.1060	10.1060	10.1060	10.1060	10.1060	10.1060	10.1060
Turnover Factor:	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
Maximum Liquid Volume (gal):	1,804,863.1957	1,804,863.1957	1,804,863.1957	1,804,863.1957	1,804,863.1957	1,804,863.1957	1,804,863.1957	1,804,863.1957	1,804,863.1957	1,804,863.1957	1,804,863.1957	1,804,863.1957
Maximum Liquid Height (ft):	48.0000	48.0000	48.0000	48.0000	48.0000	48.0000	48.0000	48.0000	48.0000	48.0000	48.0000	48.0000
Tank Diameter (ft):	80.0000	80.0000	80.0000	80.0000	80.0000	80.0000	80.0000	80.0000	80.0000	80.0000	80.0000	80.0000
Working Loss Product Factor:	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
Total Losses (lb):	28.6029	31.4781	42.0560	55.9737	72.6331	85.2549	90.8323	83.3711	68.0186	52.2131	36.6285	29.1682

TABLE A-15

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TABLE A-15

TANKS 4.0.9d
Emissions Report - Detail Format
Individual Tank Emission Totals

Emissions Report for: January, February, March, April, May, June, July, August, September, October, November, December

FDT1 - Vertical Fixed Roof Tank
Sandwich, Massachusetts

	Losses(lbs)		
Components	Working Loss	Breathing Loss	Total Emissions
Distillate fuel oil no. 2	342.71	333.52	676.23

TABLE A-15

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Table A-16 Compressor and Gas Insulated Switchgear Fugitive GHG Emissions

Reciprocating Compressor Fugitive Methane Emissions				
Use Table 3-5 of EPA Report:				
Report for Oil and Natural Gas Sector Compressors, Review Panel, April 2014, USEPA OAQPS				
Apply 50% margin to cover variabiity and other site fugitives, correct to short tons, GWP = 25				
75,809 MT of CH4 for 2008 total number of compressors reported				
GHG as CO2e = (75,809 metric tons of CH4 total)/(2008 compressors)(1.1023 short tons/MT)(25)				
= 1040.4 tons GHG as CO2e)(1.5) =	**1,561**	**tons of GHG as CO2e**		
Sulfur Hexafluoride (SF6) Gas Insulated Switchgear (GIS)				
Design basis for GIS is 25 pounds of SF6 with a maximum annual leakage rate of 1%				
GWP = 22,800				
GHG as CO2e = (25 pounds SF6)(1.0/100)(22,800)/(2000 lb/ton) =			**3**	**tons of GHG as CO2e**

APPENDIX B: BACT ANALYSIS SUPPORTING TABLES

Table B-1: Summary of Recent NOx PSD BACT and LAER Determinations for Simple-Cycle Generating Plants

Facility	Location	Permit Date	Turbine Make & Model (facilities designated as dual fuel or oil only are noted –otherwise emissions are gas-fired values)	Emission Limits NO_x (ppmvdc at 15% O_2)	Control(s)
Navasota South Union Valley Energy Center	Nixon County TX	12/9/2015	3 – GE 7FA.04 (183 MW each)	9.0 ppmvdc (3-hr rolling avg)	DLN Combustors
Navasota North Van Alstyne Energy Center	Grayson County TX	10/27/2015	3 – GE 7FA.04 (183 MW each)	9.0 ppmvdc (3-hr rolling avg)	DLN Combustors
Nacogdoches Power LLC	Nacogdoches County TX	10/14/2015	1 – Siemens F5 (232 MW)	9 ppmvdc	DLN Combustor
Shawnee Energy Center	Hill County, TX	10/9/2015	4- Siemens SGT6-5000F5 (230 MW each) or GE 7FA.05TP (227 MW each)	9 ppmvdc	DLN Combustors
Golden Spread Antelope Elk	Hale County, TX	5/12/2015	3 – GE 7F5	9 ppmvdc	DLN Combustors
Navasota South Clear Springs Energy Center	Guadalupe County, TX	5/8/2015	3 - GE 7FA.04 183 MW each	9.0 ppmvdc (3-hr rolling avg)	DLN Combustors
Duke Suwannee River Power Plant	Live Oak, FL	04/28/2015	2 – GE 7FA.03 (dual fuel)	15 ppmvdc (gas) (4-hr rolling avg.) 96 ppmvdc (gas <75%) (4-hr rolling avg.) 42.0 ppmvdc (oil) (4-hr rolling avg.) 96 ppmvdc (oil <75%) (4-hr rolling avg.)	DLN Combustors, water injection
Carlsbad Energy Center	Carlsbad, CA	04/17/2015	6 – GE LMS100 PA	2.5 ppmvdc (1-hour)	SCR
Indeck Wharton Energy Center	Wharton, TX	02/02/2015	3- Siemens SGT6-5000F (227 MW) or GE 7FA (214 MW)	9.0 ppmvdc (3-hr rolling avg)	DLN Combustors
NRG SR Bertron	Harris, TX	12/19/2014	2 - Siemens F5, GE 7FA or Mitsubishi G	9.0 ppmvdc (3-hr rolling avg)	DLN Combustors

Facility	Location	Permit Date	Turbine Make & Model (facilities designated as dual fuel or oil only are noted –otherwise emissions are gas-fired values)	Emission Limits	Control(s)
				NO_x (ppmvdc at 15% O_2)	
Black Hills - Pueblo Airport Generating	Pueblo, CO	12/11/2014 (update) 7/22/2010 (original)	3 – GE LMS100 PA	5.0 ppmvdc (1-hr avg.)	Good combustion, water injection, SCR
Tenaska Roan's Prairie Partners	Grimes, TX	09/22/2014	2 - GE 7FA.04, GE 7FA.05 or Siemens SGT6-5000F	9.0 ppmvdc (3-hr rolling avg)	DLN Combustors
Invenergy Ector County Energy Center	Ector, TX	08/01/2014	2 - GE 7FA.03 (165 MW) or 2 - GE 7FA.05 (193 MW)	9.0 ppmvdc (3-hr rolling avg)	DLN Combustors
NRG PH Robinson Electric Generating	Galveston, TX	05/20/2014	6 – GE 7EA	15.0 ppmvdc (3-hr rolling avg)	DLN Combustors
FP&L Lauderdale	Broward, FL	04/22/2014	5 - GE 7FA.04, GE 7FA.05 or Siemens SGT6-5000F (dual fuel)	9.0 ppmvdc (gas) (24-hr rolling avg) 42.0 ppmvdc (oil) (4-hr rolling avg)	DLN Combustors, water injection (oil firing)
Goldenspread Antelope Elk Energy	Hale, TX	04/22/2014	3 - GE 7FA.05	9.0 ppmvdc (3-hr rolling avg)	DLN Combustors
Troutdale Energy Center	Multnomah, OR	03/05/2014	2 - GE LMS-100 (dual fuel)	2.5 ppmvdc (gas) (3-hr rolling avg) 3.8 ppmvdc (oil) (3-hr rolling avg)	Good combustion, water injection, SCR
Guadalupe Power – Guadalupe Generating Station	Marion, TX	10/4/2013	2 - GE 7FA.05	9.0 ppmvdc (3-hr rolling avg.)	DLN Combustors
Basin EPC Lonesome Creek Generating Station	McKenzie, ND	09/16/2013	3 - GE LM6000 PF Sprint	5.0 ppmvdc (4-hr rolling avg)	Good combustion, SCR
Basin EPC Pioneer Generating Station	Williams, ND	05/14/2013	3 - GE LM6000 PF Sprint	5.0 ppmvdc (4-hr rolling avg)	Good combustion, water injection, SCR
Invenergy Thermal Development LLC - Ector County Energy Center	Ector, TX	05/13/2013	2 - GE 7FA.03 or GE 7FA.05	9.0 ppmvdc (3-hr rolling avg)	DLN Combustors

Facility	Location	Permit Date	Turbine Make & Model (facilities designated as dual fuel or oil only are noted –otherwise emissions are gas-fired values)	Emission Limits NOx (ppmvdc at 15% O_2)	Control(s)
El Paso – Montana Power Station	El Paso, TX	04/02/2013	4 – GE LMS100	2.5 ppmvdc	Good combustion, SCR
Montana-Dakota Utilities Co. R.M. Heskett Station	Morton, ND	02/22/2013	1 - GE Model PG 7121 (7EA)	9.0 ppmvdc (4-hr rolling avg., >50 MWE & >0°F) 96.0 ppmvdc (4-hr rolling avg., <50 MWE & <0°F)	DLN Combustors
Pio Pico Energy Center	Otay Mesa, CA	11/19/2012	3 - GE LMS100	2.5 ppmvdc (1-hr avg.)	Good combustion, water injection, SCR
NRG Cedar Bayou Electric Generation Station	Chambers, TX	09/12/2012	2 - Siemens Model F5, GE 7FA, or Mitsubishi G Frame	9.0 ppmvdc (3-hr rolling avg.)	DLN Combustors
Black Hills - Cheyenne Prairie Generating Station	Laramie, WY	08/28/2012	5 – GE LM6000 PF Sprint (3 operate in simple cycle & 2 in combined cycle)	5.0 ppmvdc (1-hr rolling avg.)	Good combustion, SCR
EFS Shady Hills	Pasco County FL	4/6/2012	2 - GE 7FA.05	9.0 ppmvdc (gas) 42 ppmvdc (oil)	DLN Combustors, water injection (oil)
Entergy Gulf States La Calcasieu Plant	Calcasieu, LA	12/21/2011	2 – unspecified turbines	17.5 ppmvdc	DLN Combustors
Wolverine Power	Presque Isle County MI	6/29/2011	540 MMBtu/hr oil-fired Black Start Turbine for Coal-Fired Power Plant	0.16 lb/MMBtu	No controls specified
Southwestern PSC – Cunningham Power Plant	Lea, NM	05/02/2011	2 – Westinghouse 501D5A	21.0 ppmvdc (w/o PA) 30.0 ppmvdc (with PA)	DLN Combustors Type K, Good Combustion
PSEG Fossil - Kearny Generating Station	Hudson, NJ	10/27/2010	6 – GE LM6000 sprint	2.5 ppmvdc (3-hr rolling avg.)	Good combustion, Natural gas, water injection, SCR
VMEU – Howard Down Station	Cumberland, NJ	09/16/2010	1 – Trent 60	2.5 ppmvdc (3-hr rolling avg.)	Good combustion, Natural gas, water injection, SCR
Black Hills - Pueblo Airport Generating	Pueblo, CO	07/22/2010	3 – GE LMS100PA	5.0 ppmvdc (1-hr)	Good combustion, water injection, SCR

Facility	Location	Permit Date	Turbine Make & Model (facilities designated as dual fuel or oil only are noted –otherwise emissions are gas-fired values)	Emission Limits NO$_x$ (ppmvdc at 15% O_2)	Control(s)
Southern Power – Dahlberg Generating Facility	Jackson, GA	05/14/2010	4 – Siemens SGT G-5000F Dual fuel	9.0 ppmvdc (gas) 42 ppmvdc (oil)	DLN Combustors, water injection (oil)
TID Almond 2 Power Plant	Modesto, CA	02/16/2010	3 – GE LM6000 PG Sprint	2.5 ppmvdc (1-hr)	Good combustion, water injection, SCR
Dayton Power & Light	Montgomery County OH	12/03/2009	4 dual fuel (gas/oil) turbines rated at 80 MW each	42 ppmvdc (gas/oil) (1-hr avg)	DLN (gas) and water injection (oil)
Gowanus Expansion	New York, NY	2009	1 – GE LMS100 Dual fuel	2.5 ppmvdc (gas) (1-hr) 3.5 ppmvdc (oil) (1-hr)	Good combustion, water injection, SCR
Braintree Electric – Watson	Braintree, MA	04/04/2008	2 – Trent 60 Dual fuel	2.5 ppmvdc (gas) (1-hr) 5.0 ppmvdc (oil) (1-hr)	Good combustion, water injection, SCR

Table B-2: Summary of Recent CO PSD BACT Determinations for Simple-Cycle Generating Plants

Facility	Location	Permit Date	Turbine Make & Model (facilities designated as dual fuel or oil only are noted –otherwise emissions are gas-fired values)	Emission Limits CO (ppmvdc at 15% O_2)	Control(s)
Navasota South Union Valley Energy Center	Nixon County TX	12/9/2015	3 – GE 7FA.04 (183 MW each)	9.0 ppmvdc (3-hr rolling avg)	DLN combustors, good combustion practices
Navasota North Van Alstyne Energy Center	Grayson County TX	10/27/2015	3 – GE 7FA.04 (183 MW each)	9 ppmvdc	DLN combustors, good combustion practices
Nacogdoches Power LLC	Nacogdoches County TX	10/14/2015	1 – Siemens F5 (232 MW)	9 ppmvdc	DLN combustor, good combustion practices
Shawnee Energy Center	Hill County, TX	10/9/2015	4- Siemens SGT6-5000F5 (230 MW each) or GE 7FA.05TP (227 MW each)	9 ppmvdc	DLN Combustors
Golden Spread Antelope Elk	Hale County, TX	5/19/2015	3 – GE 7F5	9 ppmvdc	DLN Combustors, good combustion
Duke Suwannee River Power Plant	Live Oak, FL	04/28/2015	2 – GE 7FA.03 Dual fuel	4.0 ppmvdc (gas) (1-hr) 8 ppmvdc (oil) (1-hr)	Good combustion
Carlsbad Energy Center	Carlsbad, CA	04/17/2015	6 – GE LMS100 PA	4.0 ppmvdc (1-hour))	Oxidation Catalyst
Indeck Wharton Energy Center	Wharton, TX	02/02/2015	3 - Siemens SGT6-5000F (227 MW) or GE 7FA (214 MW)	GE - 9.0 ppmvdc (3-hr rolling avg) Siemens - 4.0 ppmvdc (3-hr rolling avg)	DLN Combustors, good combustion
NRG SR Bertron	Harris, TX	12/19/2014	2 - Siemens F5, GE 7FA or Mitsubishi G	9.0 ppmvdc (1-hr)	DLN Combustors
Black Hills - Pueblo Airport Generating	Pueblo, CO	12/11/2014 (update) 7/22/2010 (original)	3 – GE LMS100 PA	10 ppmvdc (1-hr avg.)	Good combustion, water injection, oxidation catalyst
Tenaska Roan's Prairie Partners	Grimes, TX	09/22/2014	2 - GE 7FA.04, GE 7FA.05 or Siemens SGT6-5000F	9.0 ppmvdc (3-hr rolling avg)	DLN Combustors
Invenergy Ector County Energy Center	Ector, TX	08/01/2014	2 - GE 7FA.03 (165 MW) or 2 - GE 7FA.05 (193 MW)	9.0 ppmvdc (3-hr rolling avg)	DLN Combustors
NRG PH Robinson Electric Generating	Galveston, TX	05/20/2014	6 – GE 7EA	25.0 ppmvdc (3-hr rolling avg)	DLN Combustors
FP&L Lauderdale	Broward, FL	04/22/2014	5 - GE 7FA.04, GE 7FA.05 or Siemens SGT6-5000F Dual fuel	4.0 ppmvdc (gas) 9.0 ppmvdc (oil)	DLN Combustors
Goldenspread Antelope Elk Energy	Hale, TX	04/22/2014	3 - GE 7FA.05	9.0 ppmvdc (3-hr rolling avg)	DLN Combustors
Troutdale Energy Center	Multnomah, OR	03/05/2014	2 - GE LMS-100 Dual fuel	6.0 ppmvdc (gas & oil) (3-hr rolling avg)	Oxidation Catalyst
Guadalupe Power – Guadalupe Generating Station	Marion, TX	10/4/2013	2 - GE 7FA.05	9.0 ppmvdc (3-hr rolling avg.)	DLN Combustors

Facility	Location	Permit Date	Turbine Make & Model (facilities designated as dual fuel or oil only are noted –otherwise emissions are gas-fired values)	Emission Limits CO (ppmvdc at 15% O_2)	Control(s)
Basin EPC Lonesome Creek Generating Station	McKenzie, ND	09/16/2013	3 - GE LM6000 PF Sprint	6.0 ppmvdc (8-hr rolling avg)	Oxidation Catalyst
Basin EPC Pioneer Generating Station	Williams, ND	05/14/2013	3 - GE LM6000 PF Sprint	6.0 ppmvdc (8-hr rolling avg)	Oxidation Catalyst
Invenergy Thermal Development LLC - Ector County Energy Center	Ector, TX	05/13/2013	2 - GE 7FA.03 or GE 7FA.05	9.0 ppmvdc (3-hr rolling avg)	
El Paso – Montana Power Station	El Paso, TX	04/02/2013	4 – GE LMS100	6.0 ppmvdc	Oxidation Catalyst
Montana-Dakota Utilities Co. R.M. Heskett Station	Morton, ND	02/22/2013	1 - GE Model PG 7121 (7EA)	25.0 ppmvdc (4-hr rolling avg., >50 MWE) 27 tons (30-day rolling total, <50 MWE)	Good combustion
NRG Cedar Bayou Electric Generation Station	Chambers, TX	09/12/2012	2 - Siemens Model F5, GE 7FA, or Mitsubishi G Frame	9.0 ppmvdc (1-hr rolling avg)	Good combustion
Black Hills Power, Inc. - Cheyenne Prairie Generating Station	Laramie, WY	08/28/2012	5 – GE LM6000	6.0 ppmvdc (1-hr rolling avg.)	Oxidation Catalyst
EFS Shady Hills	Pasco County FL	4/6/2012	2 - GE 7FA.05 Dual fuel	9.0 ppmvdc (gas) 42 ppmvdc (oil)	Good combustion
Entergy Gulf States La Calcasieu Plant	Calcasieu, LA	12/21/2011	2 – unspecified turbines	15.0 ppmvdc	DLN Combustors
Wolverine Power	Presque Isle County MI	6/29/2011	540 MMBtu/hr oil-fired Black Start Turbine for Coal-Fired Power Plant	0.045 lb/MMBtu	No controls specified
Southwestern PSC – Cunningham Power Plant	Lea, NM	05/02/2011	2 – Westinghouse 501D5A	77.2 lb/hr (w/o power augmentation) 138.9 (w/ power aug)	Good Combustion
PSEG Fossil - Kearny Generating Station	Hudson, NJ	10/27/2010	6 – GE LM6000 sprint	5.0 ppmvdc (3-hr rolling avg.)	Oxidation Catalyst, Good combustion, Natural gas
VMEU – Howard Down Station	Cumberland, NJ	09/16/2010	1 – Trent 60	5.0 ppmvdc (3-hr rolling avg.)	Oxidation Catalyst, Good combustion, Natural gas
Black Hills - Pueblo Airport Generating	Pueblo, CO	07/22/2010	3 – GE LMS100PA	10.0 ppmvdc (1-hr)	Good combustion, Oxidation catalyst
Southern Power – Dahlberg Generating Facility	Jackson, GA	05/14/2010	4 – Siemens SGT G-5000F Dual fuel	9.0 ppmvdc (gas) (3-hr avg.) 30.0 ppmvdc (ULSD) (3-hr avg.)	Good Combustion
TID Almond 2 Power Plant	Modesto, CA	02/16/2010	3 – GE LM6000 PG Sprint	4.0 ppmvdc (3-hr avg.)	Good combustion, Oxidation catalyst
Dayton Power & Light	Montgomery County OH	12/03/2009	4 dual fuel (gas/oil) turbines rated at 80 MW each	20 ppmvdc (gas/oil) (3-hr avg)	Efficient combustion technology
Braintree Electric – Watson	Braintree, MA	04/04/2008	2 – Trent 60 Dual fuel	5.0 ppmvdc (gas & oil) (1-hr)	Good combustion, water injection, SCR

Table B-3: Summary of Recent Particulate Matter PSD BACT Determinations for Simple-Cycle Generating Plants

Facility	Location	Permit Date	Turbine Make & Model (facilities designated as dual fuel or oil only are noted –otherwise emissions are gas-fired values)	Emission Limits PM/PM_{10}/$PM_{2.5}$ (lb/MMBtu)	Control(s)
Navasota South Union Valley Energy Center	Nixon County TX	12/9/2015	3 – GE 7FA.04 (183 MW each)	8.6 lb/hr *(0.005 lb/MMBtu*	Pipeline quality natural gas
Navasota North Van Alstyne Energy Center	Grayson County TX	10/27/2015	3 – GE 7FA.04 (183 MW each)	8.6 lb/hr *(0.005 lb/MMBtu)*	Pipeline quality natural gas
Nacogdoches Power LLC	Nacogdoches County TX	10/14/2015	1 – Siemens F5 (232 MW)	12.09 lb/hr *(0.005 lb/MMBtu)*	Natural gas and good combustion practices
Shawnee Energy Center	Hill County, TX	10/9/2015	4- Siemens SGT6-5000F5 (230 MW each) or GE 7FA.05TP (227 MW each)	84.1 lb/hr *(0.04 lb/MMBtu)*	Natural gas and good combustion practices
Duke Suwannee River Power Plant	Live Oak, FL	04/28/2015	2 – GE 7FA.03 Dual fuel	2.0 gr. S/100 scf & 0.0015% sulfur fuel oil	Natural gas as primary fuel & ULSD
Black Hills - Pueblo Airport Generating	Pueblo, CO	12/11/2014	2 – GE LMS100	6.6 lb/hr *(0.008 lb/MMBtu)*	Natural gas as primary fuel
Tenaska Roan's Prairie Partners	Grimes, TX	09/22/2014	2 - GE 7FA.04, GE 7FA.05 or Siemens SGT6-5000F	9.3 lb/hr (GE) *(0.005 lb/MMBtu)* 10 lb/hr (Siemens) *(0.005 lb/MMBtu)*	Natural gas as primary fuel
Troutdale Energy Center	Multnomah, OR	03/05/2014	2 - GE LMS-100	9.1 lb/hr (gas) *(0.01 lb/MMBtu)* 22.74 lb/hr (oil) (*0.03 lb/MMBtu*)	Natural gas as primary fuel
Basin EPC Lonesome Creek Generating Station	McKenzie, ND	09/16/2013	3 - GE LM6000 PF Sprint	5.0 lb/hr (*0.012 lb/MMBtu*)	Natural gas as primary fuel
Basin EPC Pioneer Generating Station	Williams, ND	05/14/2013	3 - GE LM6000 PF Sprint	5.4 lb/hr (*0.012 lb/MMBtu*)	Natural gas as primary fuel
Montana-Dakota Utilities Co. R.M. Heskett Station	Morton, ND	02/22/2013	1 - GE Model PG 7121 (7EA)	7.3 lb/hr (*0.007 lb/MMBtu*)	Natural gas as primary fuel, and Good combustion
Pio Pico Energy Center	Otay Mesa, CA	11/19/2012	3 - GE LMS100	0.0065 lb/MMBtu (>80%) 5.5 lb/hr	Natural gas as primary fuel

Facility	Location	Permit Date	Turbine Make & Model (facilities designated as dual fuel or oil only are noted –otherwise emissions are gas-fired values)	Emission Limits PM/PM10/PM2.5 (lb/MMBtu)	Control(s)
Black Hills Power, Inc. - Cheyenne Prairie Generating Station	Laramie, WY	08/28/2012	5 – GE LM6000 (3 simple cycle and 2 combined cycle)	4.0 lb/hr (*0.010 lb/MMBtu*) 17.5 TPY	Natural gas as primary fuel, Good combustion
EFS Shady Hills	Pasco County FL	4/6/2012	2 - GE 7FA.05 Dual fuel	2.0 gr. S/100 scf & 0.0015% sulfur fuel oil	Good combustion
Entergy Gulf States La Calcasieu Plant	Calcasieu, LA	12/21/2011	2 – unspecified turbines	17 lb/hr (*0.009 lb/MMBtu*)	Natural gas as primary fuel, Good combustion
Wolverine Power	Presque Isle County MI	6/29/2011	540 MMBtu/hr Black Start Turbine for Coal-Fired Power Plant	0.03 lb/MMBtu (Oil)	No controls specified
Southwestern PSC – Cunningham Power Plant	Lea, NM	05/02/2011	2 – Westinghouse 501D5A	5.4 lb/hr	Natural gas as primary fuel, Good Combustion
PSEG Fossil - Kearny Generating Station	Hudson, NJ	10/27/2010	6 – GE LM6000 sprint	6.0 lb/hr (*0.012 lb/MMBtu*)	Good combustion, Natural gas
VMEU – Howard Down Station	Cumberland, NJ	09/16/2010	1 – dual fuel Trent 60 (590 MMBtu/hr gas; 569 MMBtu/hr oil)	5.0 lb/hr (*0.008 lb/MMBtu*)	Good combustion, Natural gas (RBLC only appears to list gas limits)
Black Hills - Pueblo Airport Generating	Pueblo, CO	07/22/2010	3 – GE LMS100PA	6.6 lb/hr (*0.008 lb/MMBtu*)	Good combustion
Southern Power – Dahlberg Generating Facility	Jackson, GA	05/14/2010	4 – Siemens SGT G-5000F	9.1 lb/hr (gas) (*0.004 lb/MMBtu*) 69.0 lb/hr (ULSD) (*0.03 lb/MMBtu*)	Natural gas as primary fuel, ULSD
TID Almond 2 Power Plant	Modesto, CA	02/16/2010	3 – GE LM6000 PG Sprint	2.5 lb/hr 0.75 gr-S/100 dscf	Good combustion, Natural gas
Dayton Power & Light	Montgomery County OH	12/03/2009	4 dual fuel (gas/oil) turbines rated at 80 MW each	0.026 lb/MMBtu (gas/oil)	Clean fuels (Test Method specified as Method 5 (normally filterable only)
Braintree Electric – Watson	Braintree, MA	04/04/2008	2 – Trent 60 Dual fuel	5.0 lb/hr, 0.02 lb/MMBtu (gas) 15.0 lb/hr, 0.05 lb/MMBtu (oil)	Good combustion, water injection, SCR

Table B-4: Summary of Recent H2SO4 PSD BACT Determinations for Simple-Cycle Generating Plants

Facility	Location	Permit Date	Turbine Make & Model	Emission Limits H_2SO_4 (lb/MMBtu)	Control(s)
Duke Suwannee River Power Plant	Live Oak, FL	04/28/2015	2 – GE 7FA.03	2.0 gr. S/100 scf & 0.0015% sulfur fuel oil	Natural gas as primary fuel & ULSD
Indeck Wharton Energy Center	Wharton, TX	02/02/2015	3- Siemens SGT6-5000F (227 MW) or GE 7FA (214 MW)	0.2 gr/S/100 ft3 nat gas	Natural gas as primary fuel
Tenaska Roan's Prairie Partners	Grimes, TX	09/22/2014	2 - GE 7FA.04, GE 7FA.05 or Siemens SGT6-5000F	0.5 gr/S/100 ft^3 nat gas	Natural gas as primary fuel
Invenergy Ector County Energy Center	Ector, TX	08/01/2014	2 - GE 7FA.03 (165 MW) or 2 - GE 7FA.05 (193 MW)	1.0 gr/S/100 ft^3 nat gas	Natural gas as primary fuel
NRG PH Robinson Electric Generating	Galveston, TX	05/20/2014	6 – GE 7EA	0.5 gr/S/100 ft^3 nat gas	Natural gas as primary fuel
FP&L Lauderdale	Broward, FL	04/22/2014	5 - GE 7FA.04, GE 7FA.05 or Siemens SGT6-5000F	2.0 gr/S/100 ft^3 (nat gas) 15 ppmw (oil)	Natural gas as primary fuel, oil ≤500 hrs/yr
Goldenspread Antelope Elk Energy	Hale, TX	04/22/2014	3 - GE 7FA.05	1.0 gr/S/100 ft^3 nat gas	Natural gas as primary fuel
Guadalupe Power – Guadalupe Generating Station	Marion, TX	10/4/2013	2 - GE 7FA.05	0.5 gr/S/100 ft^3 nat gas	Natural gas as primary fuel
Southwestern PSC – Cunningham Power Plant	Lea, NM	05/02/2011	unspecified turbines	5.25 gr S/100 scf 0.25 gr H_2S/100 scf	Natural gas as primary fuel, Good Combustion
TID Almond 2 Power Plant	Modesto, CA	02/16/2010	3 – GE LM6000 PG Sprint	0.75 gr-S/100 dscf	Natural gas as primary fuel
Dayton Power & Light	Montgomery County OH	12/03/2009	4 dual fuel (gas/oil) turbines rated at 80 MW each	0.0054 lb/MMBtu (gas/oil)	Low sulfur fuel oil

Table B-5: Summary of Recent GHG PSD BACT Determinations for Simple-Cycle Generating Plants

Facility	Location	Permit Date	Turbine Make & Model	Emission Limits	Control(s)
				GHG	
Navasota North Van Alstyne Energy Center	Grayson County TX	1/13/2016 (GHG)	3 - GE 7FA.04 183 MW each	1,461 lb CO2e/MWhr	Natural gas
Navasota South Union Valley Energy Center	Guadalupe County, TX	12/16/2015 (GHG)	3 - GE 7FA.04 183 MW each	1,461 lb CO2e/MWhr	Natural gas
Navasota South Clear Springs Energy Center	Guadalupe County, TX	11/13/2015 (GHG)	3 - GE 7FA.04 183 MW each	1,461 lb CO2e/MWhr	Natural gas
Shawnee Energy Center	Hill County, TX	11/10/2015 (GHG)	4- Siemens SGT6-5000F5 (230 MW each) or GE 7FA.05TP (227 MW each)	1,398 lb CO2e/MWhr	Natural gas
NRG Cedar Bayou	Hill County, TX	9/15/2015	2 CTGs - GE 7HA (359 MW) or GE 7FA (215 MW) or Siemens SF5 (225 MW) or MHI 501G (263 MW)	1232 lb CO2/MWhr	Natural gas; RBLC listed for simple and combined cycle mode; CO_2 emission rate is listed under simple cycle BACT
Golden Spread Antelope Elk	Hale County, TX	5/19/2015	3 – GE 7F5	1304 lb CO2e/MWhr	Natural gas, energy efficiency and good combustion practices
Duke Suwannee River Power Plant	Live Oak, FL	04/28/2015	2 – GE 7FA.03	1,409 lb CO2e/MW-hr (gas) 1,973 lb CO2e/MW-hr (oil)	Natural gas as primary fuel, good combustion
Indeck Wharton Energy Center	0Wharton, TX	5/12/2014 (GHG)	3- Siemens SGT6-5000F (227 MW) or GE 7FA (214 MW)	1,337 lb CO2/MW-hr (gross) (Siemens) 1,276 lb CO2/MW-hr (gross) (GE)	Natural gas as primary fuel, good combustion
Guadalupe Power – Guadalupe Generating Station	Marion, TX	12/02/2014 (GHG) 10/4/2013	2 - GE 7FA.05	1,293.3 lb CO2/MW-hr (gross)	Natural gas as primary fuel, good combustion
Tenaska Roan's Prairie Partners	Grimes, TX	09/22/2014 08/1/2014 (GHG)	2 - GE 7FA.04, GE 7FA.05 or Siemens SGT6-5000F	1,334 lb CO2/MW-hr (gross)	Natural gas as primary fuel, good combustion
Invenergy Ector County Energy Center	Ector, TX	08/01/2014	2 - GE 7FA.03 (165 MW) or 2 - GE 7FA.05 (193 MW)	1,393 lb CO2/MW-hr (gross)	Natural gas as primary fuel, good combustion

Facility	Location	Permit Date	Turbine Make & Model	Emission Limits	Control(s)
				GHG	
Exelon Perryman 6	MD	05/2014	1 - Pratt & Whitney FT4000 (120 MW)	1,394 lb CO2/MW-hr (gas, gross) 1,741 lb CO2/MW-hr (oil, gross)	Natural gas as primary fuel, good combustion
Goldenspread Antelope Elk Energy	Hale, TX	04/22/2014 06/02/2014 (GHG)	1 - GE 7FA.05	1,304 lb CO2/MW-hr (gross)	Natural gas as primary fuel, good combustion
Troutdale Energy Center	Multnomah, OR	03/05/2014	2 - GE LMS-100	1,707 lb CO2/Gross MWH (365-day rolling avg.)	Natural gas as primary fuel
Basin EPC Lonesome Creek Generating Station	McKenzie, ND	09/16/2013	3 - GE LM6000 PF Sprint	220,122 tons (12-mo. rolling avg.)	Natural gas as primary fuel, high efficiency turbines
Basin EPC Pioneer Generating Station	Williams, ND	05/14/2013	3 - GE LM6000 PF Sprint	243,147 tons (each unit) (12-mo. rolling avg.)	Natural gas as primary fuel, high efficiency turbines
Montana-Dakota Utilities Co. R.M. Heskett Station	Morton, ND	02/22/2013	1 - GE Model PG 7121 (7EA)	413,198 tons/12 mo. rolling total	Natural gas as primary fuel, good combustion
Pio Pico Energy Center	Otay Mesa, CA	11/19/2012	3 - GE LMS100	1,328 lb/MW-H (Gross Output)	Natural gas as primary fuel, good combustion
Black Hills - Cheyenne Prairie Generating Station	Laramie, WY	08/28/2012 09/27/2012 (GHG)	5 – GE LM6000 PF (3 in simple cycle & 2 in combined cycle)	1,600 lb CO2/MW-hr (gross)	Natural gas as primary fuel, good combustion

Table B-6: Summary of Recent PSD BACT Determinations for Emergency Generator Engines at Simple-Cycle Generating Plants

Facility	Location	Permit Date	Emergency Generator Size[1]	Emission Limits					
				NO_x	CO	VOC	PM	H_2SO_4	GHGs
Towantic Energy Center	Oxford, CT	11/30/2015	1500 kW	19.84 lb/hr (6.0 grams/kWh based on electrical kW)	2.14 lb/hr	0.53 lb/hr	0.15 lb/hr	0.02 lb/hr SO_2 $1.66x10^{-3}$ lb/hr H_2SO_4	163.6 lb/MMbtu
Carlsbad Energy Center	Carlsbad, CA	04/17/2015	779 hp (500 kW)	Subpart IIII	Subpart IIII	Subpart IIII	Subpart IIII	N/A	128 tpy
Moundsville Power	Moundsville WV	11/21/2014	1500 kW	Subpart IIII	Subpart IIII	Subpart IIII	Subpart IIII	N/A	2416 lb/hr 604 tpy
Tenaska Roan's Prairie Partners	Grimes, TX	09/22/2014	2,937 hp	Subpart IIII	Subpart IIII	Subpart IIII	Subpart IIII	N/A	156 tpy
Goldenspread Antelope Elk Energy	Hale, TX	04/22/2014 06/02/2014 (GHG)	1,656 kW	Subpart IIII	Subpart IIII	Subpart IIII	Subpart IIII	N/A	128 tpy
FP&L Lauderdale	Broward, FL	04/22/2014	4 – 3,100 kW	Subpart IIII	Subpart IIII	Subpart IIII	Subpart IIII	N/A	N/A
Footprint Power Salem Harbor	Salem MA	01/30/2014	750 kW	Subpart IIII	Subpart IIII	Subpart IIII	Subpart IIII	ULSD SO_2 0.0009 lb/hr H_2SO_4 *(0.0005 gram/kWhr)*	162.85 lb/MMBtu
Berks Hollow	Ontelaunee Twnshp, PA	12/17/2013	60 gal/hr (approx. 850 kW)	0.53 tpy	0.03 tpy	0.29 tpy	0.017 tpy	ULSD SO2 0.0001 tpy H2SO4	--

Facility	Location	Permit Date	Emergency Generator Size[1]	Emission Limits					
				NO_x	CO	VOC	PM	H_2SO_4	GHGs
Carroll County Energy	Washington Twp., OH	11/5/2013	1112 kW	Subpart IIII	Subpart IIII	Subpart IIII	Subpart IIII	ULSD SO_2 0.000132 H_2SO_4 grams/kWhr	433.96 tpy
Renaissance Power	Carson City, MI	11/1/2013	(2) – 1000 kW	Subpart IIII	Subpart IIII	Subpart IIII	Subpart IIII	ULSD SO_2	1731.4 tpy (both units)
Langley Gulch Power	Payette, ID	08/14/2013	750 kW	Subpart IIII	Subpart IIII	Subpart IIII	Subpart IIII	ULSD SO_2	--
Oregon Clean Energy	Oregon, OH	06/18/2013	2250 kW	Subpart IIII	Subpart IIII	Subpart IIII	Subpart IIII	ULSD SO_2 0.000132 H_2SO_4 grams/kWhr	878 tpy
Green Energy Partners / Stonewall	Leesburg, VA	04/30/2013	1500 kW	Subpart IIII	Subpart IIII	Subpart IIII	Subpart IIII	ULSD SO_2	Low carbon fuel and efficient operation
Hickory Run Energy LLC	New Beaver Twp., PA	04/23/2013	750 kW	6.0 gm/kWhr	0.4 gm/kWhr	Subpart IIII	0.02 tpy	ULSD SO_2	80.5 tpy
Brunswick County Power	Freeman, VA	03/12/2013	2200 kW	Subpart IIII	Subpart IIII	Subpart IIII	Subpart IIII	ULSD SO_2	Low carbon fuel and efficient operation
Moxie Patriot LLC	Clinton Twp PA	01/31/2013	1472 hp	4.93 gms/hp-hr	0.01 gms/hp-hr	0.13 gms/hp-hr	0.02 gms/hp-hr	ULSD SO_2	--
St. Joseph Energy Center	New Carlisle, IN	12/03/2012	(2) – 1006 hp	Subpart IIII	Subpart IIII	Subpart IIII	Subpart IIII	ULSD SO_2	--

[1] Generators are diesel generators except where noted.
[2] Limits obtained from agency permitting documents when not available in RBLC.

Table B-7: Summary of Recent PSD BACT Determinations for Emergency Fire Pump Engines at Simple-Cycle Generating Plants

Facility	Location	Permit Date	Emergency Generator Size[1]	Emission Limits					
				NO_x	CO	VOC	PM	H_2SO_4	GHGs
Towantic Energy Center	Oxford, CT	11/30/2015	350 hp	2.65 lb/hr	0.64 lb/hr	0.07 lb/hr	0.1 lb/hr	3.7×10^{-3} lb/hr SO_2 2.8×10^{-4} lb/hr H_2SO_4	163.6 lb/MMbtu
Duke Suwannee River Power	Live Oak, FL	04/28/2015	160 hp	Subpart IIII	Subpart IIII	Subpart IIII	Subpart IIII	N/A	N/A
Carlsbad Energy Center	Carlsbad, CA	04/17/2015	327 hp	Subpart IIII	Subpart IIII	Subpart IIII	Subpart IIII	N/A	128 tpy
Moundsville Power	Moundsville WV	11/21/2014	251 hp	Subpart IIII	Subpart IIII	Subpart IIII	Subpart IIII	N/A	309 lb/hr 77 tpy
Tenaska Roan's Prairie Partners	Grimes, TX	09/22/2014	575 hp	Subpart IIII	Subpart IIII	Subpart IIII	Subpart IIII	N/A	33 tpy
Invenergy Ector County Energy Center	Ector, TX	08/01/2014	250 hp	Subpart IIII	Subpart IIII	Subpart IIII	Subpart IIII	N/A	5 tpy
FP&L Lauderdale	Broward, FL	04/22/2014	300 hp	Subpart IIII	Subpart IIII	Subpart IIII	Subpart IIII	N/A	N/A
Footprint Power Salem Harbor	Salem MA	01/30/2014	371 hp	Subpart IIII	Subpart IIII	Subpart IIII	Subpart IIII	ULSD SO_2 0.0009 lb/hr H_2SO_4 *(0.0005 gram/kWhr)*	162.85 lb/MMBtu
Berks Hollow	Ontelaunee Twnshp,PA	12/17/2013	60 gal/hr (approx. 320 hp)	0.09 tpy	0.013 tpy	0.09 tpy	0.005 tpy	ULSD SO2 0 tpy H2SO4	--
Carroll County Energy	Washington Twp., OH	11/5/2013	400 hp	Subpart IIII	Subpart IIII	Subpart IIII	Subpart IIII	ULSD SO_2 0.000132 H_2SO_4 grams/kWhr	115.75 tpy
Consumers Energy Thetford Station	Thetford Twp, MI	7/25/2013	315 hp	Subpart IIII	Subpart IIII	Subpart IIII	Subpart IIII	--	15.6 tpy

Facility	Location	Permit Date	Emergency Generator Size[1]	Emission Limits					
				NO_x	CO	VOC	PM	H_2SO_4	GHGs
Oregon Clean Energy	Oregon, OH	06/18/2013	2250 kW	Subpart IIII	Subpart IIII	Subpart IIII	Subpart IIII	ULSD SO_2 0.000132 H_2SO_4 grams/kWhr	87 tpy
Green Energy Partners Stonewall	Leesburg, VA	04/30/2013	330 hp	Subpart IIII	Subpart IIII	Subpart IIII	Subpart IIII	ULSD SO_2	Low carbon fuel and efficient operation
Hickory Run Energy LLC	New Beaver Twp., PA	04/23/2013	450 hp	1.9 gm/bhp-hr	1.1 gm/bhp-hr	Subpart IIII	Subpart IIII	0.00012 grams/bhp-hr	33.8 tpy
Brunswick County Power	Freeman, VA	03/12/2013	305 hp	Subpart IIII	Subpart IIII	Subpart IIII	Subpart IIII	ULSD SO_2	Low carbon fuel and efficient operation
Moxie Patriot LLC	Clinton Twp PA	01/31/2013	460 hp	2.6 gms/hp-hr	0.1 gms/hp-hr	0.5 gms/hp-hr	0.09 gms/hp-hr	ULSD SO_2	--
St. Joseph Energy Center	New Carlisle, IN	12/03/2012	(2) – 371 hp	Subpart IIII	Subpart IIII	Subpart IIII	Subpart IIII	ULSD SO_2	172 tpy
Hess Newark Energy Center	Newark, NJ	11/01/2012	270 hp	Subpart IIII	Subpart IIII	Subpart IIII	Subpart IIII	ULSD SO_2	--

[1] Generators are diesel generators except where noted.
[2] Limits obtained from agency permitting documents when not available in RBLC.

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APPENDIX C: REQUEST FOR APPLICABLITY OF CLASS I AREA MODELING ANALYSIS AND FEDERAL LAND MANAGER DETERMINATION

Request for Applicability of Class I Area Modeling Analysis
Eastern Region, U.S. Forest Service

Facility Name (Company Name)	NRG Canal 3 Development LLC - Canal Generating Station
New Facility or Modification?	Modification
Source Type	1 new dual-fuel fired 350 MW simple-cycle combustion turbine
Project Location (County/State/ Lat. & Long. in decimal degrees)	Town of Sandwich, Barnstable County, Massachusetts (41.77 N and 70.51 W)

Application Contacts

Applicant		*Consultant*		*Air Agency Permit Engineer*	
Company	NRG Canal 3 Development LLC	**Company**	AECOM	**Agency**	Massachusetts DEP
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Address	9 Freezer Road Sandwich, MA 02563	**Address**	250 Apollo Drive Chelmsford, MA 01824	**Address**	One Winter Street Boston, MA 02108
Phone #	617-529-3874	**Phone #**	978-905-2166	**Phone #**	617-654-6580
Email	Shawn.Konary@nrg.com	**Email**	jeffrey.connors@aecom.com	**Email**	Glenn.pacheco@state.ma.us

Briefly Describe the Proposed Project

NRG Canal 3 Development LLC (NRG) proposes to construct a new approximately 350-MW dual-fuel fired simple cycle combustion turbine. The proposed new CT will be permitted to operate up to six months per year. Specifically, the new CT will be permitted to operate 4,380 hours per year on natural gas with up to 1,440 of those hours operating on the backup fuel, ultra-low sulfur diesel (ULSD). The Project will also include a new fuel-gas heater, ULSD-fired emergency generator, and ULSD-fired emergency fire water pump. The Project will be a modification of the existing Canal Generating Station, which is classified as a major source under both the Prevention of Significant Deterioration (PSD) and Non-Attainment New Source Review (NNSR) air permitting programs. The Project will be a major PSD modification for particulate matter with diameters less than 10 microns (PM_{10})/ particulate matter with diameters less than 2.5 microns ($PM_{2.5}$), nitrogen oxides (NO_x), carbon monoxide (CO), sulfuric acid mist (H_2SO_4) and greenhouse gases (GHG).

Proposed Emissions and BACT

Criteria Pollutant	***Proposed Emissions tons/year (max lb/hr from the new CT)***	***Emission Factor (AP-42, Stack Test, Other?)***	***Proposed BACT***
Nitrogen Oxides	117.2 (Gas = 31.51 lb/hr) (ULSD = 67.35 lb/hr)	Vendor Design	Natural Gas firing: 2.5 parts per million by volume in turbine exhaust, corrected to 15% O2 (ppmvdc); ULSD firing, 5.0 ppmvdc
Sulfur Dioxide	15.0 (Gas = 5.14 lb/hr) (ULSD = 5.21 lb/hr)	N/A	Natural Gas: 0.5 grains/100 scf of natural gas (0.0015 lb SO2/MMBtu heat input); ULSD: 15 parts per million sulfur by weight (0.0015 lb SO2/MMBtu heat input)
Particulate Matter	99.6 (Gas = 18.10 lb/hr) (ULSD = 96.30 lb/hr)	Vendor Design	Natural Gas: 0.01 lb/MMBtu heat input, not to exceed 18.1 lb/hr; ULSD: 0.07 lb/MMBtu heat input not to exceed 96.3 lb/hr

For Additional Information or Questions, Contact Ralph Perron
(802) 222-1444 or rperron@fs.fed.us

Volatile Organic Compounds	23.9 (Gas = 8.90 lb/hr) (ULSD = 9.37 lb/hr)	Vendor Design	Both Natural Gas and ULSD: 2.0 ppmvdc as methane
Sulfuric Acid Mist	12.4 (Gas = 5.48 lb/hr) (ULSD = 6.25 lb/hr)	Vendor Design	Natural Gas: 0.0016 lb/MMBtu heat input; ULSD: 0.0018 lb/MMBtu heat input not to exceed 96.3 lb/hr

Proximity to U.S. Forest Service Class I Areas

Class I Area	Lye Brook Wilderness	Presidential Range-Dry River Wilderness	
Distance from Facility (km)	250 km	265	

From:	Perron, Ralph -FS
To:	Connors, Jeffrey
Subject:	RE: Class I Area AQRV Request
Date:	Monday, October 26, 2015 10:21:29 AM
Attachments:	image001.png image002.png image003.png image004.png NRG-Canal PSD Permit Request for Determination-final-rev2.pdf

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Hi Jeff,

Thanks for the additional information on the modification of the NRG Canal 3 Development LLC - Canal Generating Station, located in the town of Sandwich, Barnstable County, Massachusetts.

Based on the proposed emissions of 117 tons per year Nitrogen Oxides, 15 tons per year Sulfur Dioxide, 100 tons per year PM10, 12 tons per year sulfuric acid mist, and distance of 250 km to the Lye Brook Class I Area in the Green Mountain Finger Lakes National Forest, the US Forest Service will not be requesting AQRV analyses of this project. Please keep us informed of any significant changes in this project, as well as any other proposal which may have an impact on the Lye Brook Class I area.

I have not measured the distances from this PSD location to Brigantine Class I area in NY, nor to Acadia NP Class I area, in Maine; let me know if you need contact names/emails for these locations.

Thanks

Ralph Perron
Air Quality Specialist

Forest Service
Eastern Regional Office

p: 603-536-6228
c: 802-222-1444
rperron@fs.fed.us

71 White Mountain Drive
Campton, NH 03223
www.fs.fed.us/air/

Caring for the land and serving people

From: Connors, Jeffrey [mailto:Jeffrey.Connors@aecom.com]
Sent: Wednesday, October 21, 2015 9:30 AM
To: Perron, Ralph -FS
Cc: Konary, Shawn (Shawn.Konary@nrg.com); Lipka, George (George.Lipka@tetratech.com); glenn.pacheco@state.ma.us; marc.wolman@state.ma.us; thomas.cushing@state.ma.us
Subject: RE: Class I Area AQRV Request

Ralph,

Per your request I have added the SO2 emissions to the attached form even though the project will not trigger PSD review for this pollutant.
The resultant Q/D changes slightly for both fuels.
The Q/D for gas is not slightly over 1 at 1.06 while the Q/D for ULSD is now 3.07.

Please let me know if you have any additional comments or questions.

Thanks,
-Jeff Connors
D 978.905.2166
M 978.660.4097

From: Perron, Ralph -FS [mailto:rperron@fs.fed.us]
Sent: Friday, October 16, 2015 5:32 PM
To: Connors, Jeffrey
Subject: RE: Class I Area AQRV Request

Hi Jeff,

Could you include the proposed sulfur dioxide emissions levels in the request for determination document? We use that value, in addition to the values you provided, to determine Q. To calculate Q for SO2, we use the same formula (annual emissions, in tons per year, based on 24-hour maximum allowable emissions).

Based on the FLAG 2010 Guidance, if PSD review is triggered for at least one pollutant, we review the sum of SO2, NOx, PM10, and H2SO4 annual emissions.

Thanks

Ralph Perron
Air Quality Specialist

Forest Service
Eastern Regional Office

p: 603-536-6228
c: 802-222-1444
rperron@fs.fed.us

71 White Mountain Drive
Campton, NH 03223
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Caring for the land and serving people

From: Connors, Jeffrey [mailto:Jeffrey.Connors@aecom.com]

Sent: Tuesday, October 13, 2015 4:53 PM
To: Perron, Ralph -FS
Cc: Konary, Shawn (Shawn.Konary@nrg.com); Lipka, George (George.Lipka@tetratech.com); glenn.pacheco@state.ma.us; marc.wolman@state.ma.us; thomas.cushing@state.ma.us
Subject: RE: Class I Area AQRV Request

Dear Ralph,

NRG Canal 3 Development LLC (NRG) proposes to construct a new approximately 350-MW dual-fuel (natural gas and ultra-low sulfur diesel) fired simple cycle combustion turbine at the existing Canal Generating Station in Sandwich, MA. The proposed new CT will be permitted to operate up to six months per year.

The proposed project is located just over 250 KM from the Lye Brook Wilderness and 265 KM from the Presidential Range-Dry River Wilderness Class I areas.

The FLAG 2010 guidance references a Q/D ratio of 10, at which below a proposed source will likely not have an adverse impact on a Class I area.
The Q in the Q/D is the sum of the short-term NO_x, H_2SO_4, and PM emissions expressed in tons/year. The project will not trigger PSD review for SO_2.
Conservatively, the total sum of these short-term emissions firing ULSD expressed in tons per year is 744 tons per year.
The D in the Q/D is the distance from the source to the closest Class I area.
In this case, the closest Class I area is Lye Brook Wilderness located in Vermont just over 250 km northwest of the Canal Generating Station.
Using Q=744 and D=250, the resultant Q/D ratio = 3.0.
This is far less than 10, the FLM suggested screening level.
In fact the Q/D ratio while firing natural gas, the primary fuel, is less than 1.0.

Given these low Q/D ratios, NRG requests a waiver from having to perform and AQRV analysis for regional haze and deposition at the Lye Brook Wilderness and Presidential Range-Dry River Wilderness Class I areas.

Attached is the completed “Request for Applicability of Class I Area Modeling Analysis” form that provides all the relevant information for the USFS to make their determination.

Please review the Project and inform us of your decision.
If you could provide a response in the next few weeks, that would be greatly appreciated.

Regards,

Jeff Connors
Technical Specialist, AQES, North
Environment
D 978.905.2166
M 978.660.4097
jeffrey.connors@aecom.com

AECOM

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-Jeff Connors
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From: Perron, Ralph -FS [mailto:rperron@fs.fed.us]
Sent: Thursday, September 10, 2015 4:18 PM
To: Connors, Jeffrey
Subject: RE: Class I Area AQRV Request

Hi Jeff,

Attached is the Request for Applicability of Class I Area Modeling Analysis form. If you can complete this for us, we can make a quick determination (on whether or not we'll request further analysis) using FLAG 2010 guidance (page 18 and 19: Agencies will consider a source locating greater than 50 km from a Class I area to have negligible impacts with respect to Class I AQRVs if its total SO2, NOx, PM10, and H2SO4 annual emissions (in tons per year, based on 24-hour maximum allowable emissions), divided by the distance (in km) from the Class I area (Q/D) is 10 or less. The Agencies would not request any further Class I AQRV impact analyses from such sources.

When a determination is made, would you like a response via email from me, or would you prefer an official correspondence letter from John Sinclair, Forest Supervisor of the Green Mountain and Finger Lakes National Forests, and Federal Land Manager for Lye Brook Class I area?

Ralph Perron
Air Quality Specialist

Forest Service
Eastern Regional Office

p: 603-536-6228
c: 802-222-1444
rperron@fs.fed.us

71 White Mountain Drive
Campton, NH 03223
www.fs.fed.us/air/

Caring for the land and serving people

From: Connors, Jeffrey [mailto:Jeffrey.Connors@aecom.com]
Sent: Wednesday, September 09, 2015 11:54 AM
To: Perron, Ralph -FS
Subject: Class I Area AQRV Request

Ralph,

My name is Jeff Connors and I work for AECOM in Chelmsford, MA.
We are working for a client in Massachusetts that is looking to install a new simple-cycle gas/oil-fired combustion turbine.

The project location is just over 250 km from Lye Brook, but will trigger PSD review for NOX and PM10, and PM2.5.
The project will not trigger for SO2.

In accordance with the FLM's FLAG 2010 Q/D guidance, we would like to submit an AQRV waiver request.

So my question, are you the correct contact person for directing this request too?
I got your contact information form the US Forest Service website as being the primary contact for Lye Brook Wilderness.

Thanks,

Jeff Connors
Technical Specialist, AQES, North
Environment
D 978.905.2166
M 978.660.4097
jeffrey.connors@aecom.com

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APPENDIX D: BALANCE OF PLANT GHG MITIGATION MEASURES

D.1 INTRODUCTION

The analysis of balance of plant efficiency measures includes evaluation of the principal components of the plant that constitute parasitic loads. A discussion of how efficiency has been incorporated into the design of the balance of plant systems is summarized in this Section.

This evaluation uses the base-case Project design parameters for natural gas firing at 50ºF and for ULSD firing at 0ºF. The GHG emissions for a Project "Base Case" are based on 3,500 hours per year of operation (average capacity factor of 40%), with 720 hours of these 3,500 hours on ULSD. This corresponds to the fuel inputs associated with the maximum rolling three-year average operating scenario for the Project to qualify as a non-baseload unit under 40 CFR 60 Subpart TTTT. The "Base Case" annual GHG emission under this scenario are 757,765 tpy.

The "Base Case" design parameters for the Project are provided below. These values do not have any manufacturer's margins or any degradation allowance included. Improvements to the balance of plant design that have been made and under study (above and beyond the "Base Case" design) are described in this Appendix.

Natural Gas Firing at 50ºF (3,187.21 MMBtu/hr HHV)

Output (gross): 346,314 kW

Output (net): 336,954 kW

Parasitic Load: 9,360 kW

Heat rate (gross, HHV basis): 9,203 Btu/kW-hr

Heat rate (net, HHV basis): 9,459 Btu/kW-hr

ULSD Firing at 0ºF (3461.73 MMBtu/hr HHV)

Output (gross): 363,320 kW

Output (net): 357,104

Parasitic Load: 6,216 kW

Heat rate (gross, HHV basis): 9,528 Btu/kW-hr

Heat rate (net, HHV basis): 9,694 Btu/kW-hr

D.2 EVAPORATIVE COOLING

The Project design includes evaporative cooling, which may be used at ambient temperatures above 59ºF. The evaporative cooler is a device that cools the inlet air to the combustion turbine by evaporating water into the air. Evaporation of liquid water requires energy, which is obtained from the inlet air resulting in a reduction in its temperature. The combustion turbine can fire more fuel and create more power when the inlet air is cooler (and thus denser). The heat rate of the GE 7HA.02 improves by approximately 0.5% at 80ºF for full load operation, which is representative of weather conditions when evaporative cooling would be used.

Based on plant performance data provided by GE, use of evaporative cooling will improve the plant heat rate by approximately 45 Btu/kW-hr (HHV basis) for natural gas firing. Evaporative cooling will normally be used when the average temperature is greater than 59°F. The vast majority of temperatures greater than 59°F will normally occur during the months of May through September. Based on the projected seasonal operation of the Project, it is expected that approximately 27% of Project operating hours will occur between May and September, and the ambient temperature exceeds 59°F for about 75% of the hours between May and September. Combining these expected values, it is expected that approximately 20% of plant operating hours will involve use of evaporative cooling.

With an improvement in heat rate of 45 Btu/kW-hr during use of evaporative cooling during 20% of operating hours, the overall average heat rate improvement for all hours is expected to be 9 Btu/kW-hr. To quantify the GHG mitigation, this heat rate mitigation is conservatively applied to only the natural gas-firing portion of the base case since the bulk of ULSD operation (for a base case ULSD firing amount of 720 hours per year) is expected to be occur during the colder months. The GHG mitigation of this reduction in heat rate is estimated as follows.

Natural Gas Firing at 50ºF (346,314 kW gross output, 2780 hours per year)

Heat rate improvement (HHV basis): 9 Btu/kW-hr = 0.009 MMBtu/MW-hr

(0.009 MMBtu/MW-hr)(119 lb GHG/MMBtu) = 1.07 lb GHG/MW-hr

GHG savings: (346,314 kW gross output)(2780 hours)(1.07 lb GHG/MW-hr)/(1,000 kW/MW)/(2,000 lb/ton)

= **515 tpy GHG**

D.3 EXHAUST GAS BACKPRESSURE

Backpressure is a term that is used for the friction and obstacles the exhaust flow encounters when flowing from the turbine outlet to the stack exit. Overcoming this friction and the obstacles to airflow consumes energy, which reduces the amount of electric power the turbine can produce. Minimizing friction and obstacles within other design constraints is an important aspect of gas turbine design.

The energy necessary to overcome friction and obstacles is accounted for in the gross power output values listed above. Friction is minimized by optimizing the gas path velocity, minimizing the number of bends in the gas path and avoiding sharp transitions for the bends that cannot be avoided. The Project exhaust flow path has only one necessary bend, which is the transition from the horizontal flow through the turbine to the vertical flow out the stack. A smooth bend has been designed for this transition. The exhaust velocities are optimized based on the SCR design and the selection of a 25-foot stack diameter to minimize friction losses to the extent practicable.

The air pollution control equipment, which includes the SCR and oxidation catalyst systems, are necessary exhaust path components to meet LAER and BACT requirements. However, these components do create additional backpressure. One design option that was considered, but is not included in the base-case design, is a low pressure drop SCR design that has been offered by GE. The current base-case SCR design has 20 inches of backpressure. GE does offer a 12-inch SCR backpressure design, but the equipment capital cost increase for this low backpressure pressure option is $3,800,000. The incremental installation costs would increase the low backpressure design penalty to approximately $4,500,000. The low backpressure pressure option would decrease the gas-firing heat rate by approximately 33 Btu/kW-hr net (i.e., the net heat rate for natural gas firing at 50ºF would improve from 9,459 Btu/kW-hr net to 9,426 Btu/net kW-hr net. However, this small heat rate improvement was determined to not warrant such a large capital cost addition ($4.5 million). Therefore, the base-case and as-proposed designs are based on the 20-inch backpressure SCR, as reflected by the gross power output and heat rate values above.

D.4 NATURAL GAS COMPRESSOR AND GAS REHEATING

D.4.1 Description of Base Case Natural Gas Compressor

The type of natural gas compressor assumed for the “Base Case” design is a reciprocating compressor. In a reciprocating compressor, an electric motor powers a crankshaft that moves pistons contained within cylinders. The power provided to the pistons compresses the natural gas inside the cylinder, and compressed natural gas is then discharged from the cylinders.

A reciprocating compressor was used for the Project “Base Case” in order to identify the parasitic load for a candidate compressor type. The final selection of the type of compressor will not occur until an EPC contractor has been selected, and the contractor has progressed with the engineering work and solicited bids for the equipment.

An alternate compressor design that can improve gas compressor efficiency is a positive displacement flooded screw compressor with a “slide valve.” This compressor option will be evaluated by the EPC contractor as part of identifying the optimal gas compressor for the Project.

D.4.2 Base Case Gas Compressor Parasitic Load

The kW of parasitic compressor work that was included in the ”Base Case” design was 2,720 kW. This value of 2,720 kW was actually used as a constant assumed parasitic load over all gas firing hours to account for either compression or dew point heating of the gas depending on the gas pipeline pressure. The gas compressor is only required when gas pipeline pressure drops below the minimum pressure required for the turbine. The refined analysis of average parasitic compressor load based on historical gas pipeline pressures is provided in Section D.4.3 below.

D.4.3 Gas Compressor Loads Based on Historical Pipeline Pressures

Historical hourly supply pressure data have been obtained from Algonquin Gas Transmission (AGT) for a two year period (June 2014 through May 2016). Based on these data, the average hours per year when the gas supply pressure falls below the minimum required for turbine operation (582 psig) is 2,435 hours per year. These 2,435 hours per year typically occur during daytime and evening hours when overall energy demands are greater. Therefore, since the hours per year when gas compression is required (2,435) is less than the total base case gas firing hours per year (2,780), we have conservatively assumed for purposes of the parasitic load analysis that gas compression will be required for 2,435 of the 2,780 base case gas firing hours.

Table D-1 provides a summary of the average kW parasitic gas compression average work (kW) and energy (MW-hr) based on the historical AGT gas pipeline supply pressures. This analysis incorporates the hourly actual gas pipeline pressure over the two-year period and predicts the actual parasitic load for each hour based on the compressor type.

Table D-1: Natural Gas Compressor Energy Analysis Based on Historical Gas Pipeline Supply Pressures

Compressor	Average Load over 2,780 hours of “base case” gas-firing (kW)	Annual MW-hrs for Gas Compression	Annual MW-hr savings for Mitigation Option
Reciprocating Compressor (Base Case)	448.0	1,245.5	--
Flooded Screw Compressor with Slide Gate (Mitigation Option under Consideration)	419.9	1,167.3	78.2

The GHG mitigation for the flooded screw compressor with the slide gate option is calculated as follows, using the “base case” gas-firing heat rate of 9,203 Btu/kW-hr (gross, HHV basis).

Natural Gas Firing at 50ºF (2,435 hours per year with gas compression)

Heat rate (gross, HHV basis): 9,203 Btu/kW-hr = 9.203 MMBtu/MW-hr

(9.203 MMBtu/MW-hr)(119 lb GHG/MMBtu) = 1,095.2 lb GHG/MW-hr

GHG savings: (78.2 MW-hrs/year)(1095.2 lb GHG/MW-hr)/(2000 lb/ton) = **43 tpy GHG**

D.4.4 Natural Gas Reheating

When natural gas pipeline pressures are above the upper limit of the optimal pressure for the combustion turbine, the pressure must be reduced. Reduction in gas pressure causes gas cooling, which can cause the gas to drop below its dew point and liquid water droplets can condense (depending on the gas moisture content). In cases when the potential exists for liquid water droplets to form, the gas must be heated above its dew point in order to protect the gas turbine components. Therefore, the Project “Base Case” design also includes an electric gas heater. The gas heater would normally not be used during periods of low gas pressure, since the compressor itself causes heating of the gas; however, some dew point heating can be needed at times of gas compression.

The Project “Base Case” parasitic load analysis used a constant parasitic load of 2,720 kW to account for all compression and/or dew point heating demand for the 2,780 hours of natural gas firing in the “Base Case”. These parasitic load calculations have been refined using historical hourly supply pressure data obtained from AGT. The average parasitic load for electric dew point heating has been calculated using this hourly AGT pressure data for the two year period June 2014 through May 2016. Based on these data, the average expected parasitic load for electric dew point heating is 547.2 kW over the 2,780 hours of base case gas firing.

Use of waste heat from the flue gas for dew point heating was evaluated and determined to not be justified on the basis of cost. Dew point heating using waste heat from the flue gas would require installation of a glycol heating loop to capture and transfer heat from the flue gas to the dew point heater. This glycol heating loop has been estimated to have an installed capital cost in excess of $1,000,000, which was determined to not be justified for the Project.

D.5 ELECTRIC MOTORS (ASIDE FROM GAS COMPRESSOR)

Aside from the natural gas compressor, the design electric motor load for the natural gas 50ºF case is 4,301 kW, and for the ULSD 0ºF case is 3,722 kW. The largest electric motor load is for the SCR dilution air fan (2,391 kW for the natural gas 50ºF case and 1,080 kW for the 0ºF ULSD case). The SCR dilution air fan is used to draw in ambient air to cool the flue gas to the maximum SCR operating temperature of 900ºF. Due to the lower turbine exhaust and ambient temperatures for the ULSD 0ºF case, less dilution air is needed for this case. In addition to this largest electric motor load, there are several dozen other electric motors used primarily to power various pumps and fans to provide system cooling and lubrication.

The base-case electric motor design is based on motors in compliance with the Energy Policy Act of 1992 (EPAct). EPAct established minimum efficiency levels for electric motors. The EPAct motor efficiencies have been used to establish the base-case parasitic loads identified above, A more efficient class of electric motors is available than specified in EPAct, NEMA premium high-efficiency motors. A review of Project electric motors indicates that an overall aggregate efficiency improvement of 1.05% can be achieved through specification of NEMA premium high-efficiency for all electric motors. The electric motors for all Project parasitic loads are proposed as NEMA premium high-efficiency motors. With an aggregate efficiency improvement of 1.05%, the as proposed electric motor load for the natural gas 50ºF case is reduced from 4,301 kW to 4,256 kW and ULSD 0ºF case is reduced from 3,722 kW to 3,683 kW.

One other design item with respect to control of electric motors related to efficiency is the potential use of variable frequency drives (VFD). VFD uses frequency and voltage to control electric motor at partial loads, which improves motor efficiency at partial loads. However, when ISO-NE dispatches the Project to operate, it is expected that Project operation will be either at or near full load, so electric motors will typically be running at full speed and a meaningful efficiency benefit of VFD is not expected. Therefore, VFD drives have not been incorporated into the as-proposed design. The use of all NEMA premium high efficiency motors typically operating at full speed when they operate is consistent with use of all reasonable measures to mitigate GHG emissions.

D.6 FUEL GAS PERFORMANCE HEATING

One additional balance of plant efficiency improvement measure that was considered was the inclusion of fuel gas performance heating using waste heat from the flue gas. Incoming natural gas (fuel gas) can be heated to 425°F in order to improve plant heat rate using waste heat from the flue gas. A net heat rate improvement of about 90 Btu/kWh-HHV at ISO conditions can be obtained by implementing performance fuel gas heating. This is conceptually similar to the dew point heating of natural gas discussed above, but the natural gas is heated to a more significant degree such that the plant heat rate is improved.

Use of waste heat for fuel gas performance heating was evaluated and also determined to not be justified on the basis of cost. Fuel gas performance heating using waste heat from the flue gas would require installation of the same glycol heating loop discussed above to capture and transfer heat from the flue gas. This glycol heating loop has been estimated to have an installed capital cost in excess of $1,000,000, which was determined to not be justified for the Project (either for dew point heating and/or for fuel gas performance heating).

D. 7 ELECTRIC TRANSFORMER

The electric transformer increases the voltage of the electricity as generated to the transmission voltage. When voltage is increased with transformers, a small fraction of the electric energy is lost in the form of heat. Transformer efficiency is related to a transformer design parameter known as impedance. The percentage impedance of a transformer is the voltage drop on full load due to the winding resistance and leakage reactance expressed as a percentage of the rated voltage. The normal design range of power plant scale transformers is 7-12%. The Project "Base Case" transformer design is based on an impedance of 9%. With an impedance of 9%, the Project "Base Case" transformer power loss for the natural gas 50ºF case is 1,749 kW, and for the ULSD 0ºF case is 1,776 kW.

If the design impedance is reduced, the transformer losses can be reduced. Lower impedance, however, results in higher available fault duty (short-circuit current). As part of the electrical interconnection process, a System Impact Study has been completed to evaluate the impact of the Project on the Eversource transmission system, including the short-circuit fault duty contribution from the Project. Based on using a 9% impedance GSU transformer, the System Impact Study found that the 345-kV circuit breakers in the adjacent Eversource substation reached 97% of their maximum short-circuit fault duty rating. Due to equipment and personnel safety issues associated with high voltage circuit breakers exceeding their maximum interrupting capability, lower impedance transformers have been found to be not feasible due to high secondary fault currents and the need for circuit breaker replacements. Lower impedance transformers have been dropped from consideration for GHG mitigation.

D.8 SCR AMMONIA VAPORIZATION

The Project "Base Case" design included an electric heater for vaporizing the aqueous ammonia solution used as the SCR reagent. The design parasitic load for this electrically heated ammonia vaporizer for the natural gas 50ºF case is 196 kW, and for the ULSD 0ºF case is 340 kW.

The Project has determined that it is feasible to use of hot CTG exhaust gas to vaporize ammonia in lieu of continuous use of an electric heater. Since the turbine exhaust gas temperature will be in excess of 1,200ºF, the use of hot exhaust gas to vaporize aqueous ammonia vaporizer will require the use of high alloy materials and/or a cooling air system. The overall GHG benefit of this reduction in parasitic load is as follows:

Natural Gas Firing at 50ºF (2780 hours per year)

Heat rate (gross, HHV basis): 9,203 Btu/kW-hr = 9.203 MMBtu/MW-hr

(9.203 MMBtu/MW-hr)(119 lb CO2e/MMBtu) = 1,095.2 lb CO2e/MW-hr

CO2e savings: (196 kW)(2780 hours)(1095.2 lb CO2e/MW-hr)/(1000 kW/MW)/

(2000 lb/ton) = **298.4** tpy CO2e

ULSD Firing at 0ºF (720 hours per year)

Heat rate (gross, HHV basis): 9,528 Btu/kW-hr = 9.528 MMBtu/MW-hr

(9.528 MMBtu/MW-hr)(162.85 lb CO2e/MMBtu) = 1,551.6 lb CO2e/MW-hr

CO2e savings: (340 kW)(720 hours)(1551.6 lb CO2e/MW-hr)/(1000 kW/MW)/

(2000 lb/ton) = **189.9** tpy CO2e

Total CO2e Savings for Both Fuels: **298.4** tpy + **189.9** tpy = **488.3** tpy CO2e

Under this scenario, the primary operational ammonia vaporization duty would be accomplished with the exhaust gas heated system. However, the Project would still include an electrically heated ammonia vaporizer in order for the unit to achieve rapid stack NO_x emissions compliance during startups. Accordingly, in order to adjust the projected CO2e savings for use of the electric vaporizer during startups, the total CO2e savings would be reduced by 3%. The final estimated value for CO2e savings from the inclusion of the exhaust gas heated ammonia vaporizer system is **474** tpy CO2e.

D.9 MISCELLANEOUS AUXILIARIES

The Project base-case design includes an allowance of 364 kW of parasitic losses for miscellaneous plant auxiliaries. These auxiliaries include an allowance for various minor components such as lighting (22 kW allowance), computer systems, lube oil heating and other small power consumption sources. The Project will review the design allowance and equipment specifications for miscellaneous auxiliaries and select the most efficient commercially available equipment and systems, including LED lighting.

D.10 SUMMARY OF PARASITIC LOAD ANALYSIS

The parasitic load evaluation and summary of balance of plant mitigation measures is provided in Table D-2 below.

Table D-2: Summary of Mitigation - Balance of Plant Efficiency Evaluation

<table>
<tr><th rowspan="2">Item</th><th rowspan="2">Natural Gas – 50ºF
2,780 hours/year</th><th rowspan="2">ULSD – 0ºF
720 hours/year</th><th colspan="2">CO_2e Emissions (tpy)</th><th colspan="2">Percent Reduction</th></tr>
<tr><th>Adopted</th><th>Under Study</th><th>Adopted</th><th>Under Study</th></tr>
<tr><td>Prime Mover – GE 7HA.02 CTG (or equivalent H-class turbine)</td><td>Gross Output 346,314 kW
Base Case</td><td>Gross Output 363,320 kW
Base Case</td><td colspan="2">757,765
(Base Case)</td><td colspan="2">--</td></tr>
<tr><td>Evaporative Cooling (adopted)</td><td>Heat rate improvement of 9 Btu/kW-hr
Equivalent reduction expressed as parasitic load reduction = 339 kW</td><td>Benefit conservatively ignored for ULSD firing</td><td>515</td><td></td><td>0.07%</td><td></td></tr>
<tr><td>Fuel Gas Performance Heating (not adopted)</td><td>Heat rate improvement of 90 Btu/kW-hr
Equivalent reduction expressed as parasitic load reduction = 3,420 kW</td><td>NA</td><td></td><td></td><td></td><td></td></tr>
<tr><td>Gas Compressor Selection (under study)</td><td>2,720 kW Base Case allowed for total parasitic load of gas compression and dew point heating
Revised analysis indicates 448 kW average expected load for 2,780 compression hours with base case compressor
419.9 kW average load with a mitigated flooded screw compressor</td><td>NA</td><td></td><td>43</td><td></td><td>0.006%</td></tr>
<tr><td>Gas Dew Point Heating Using Waste Heat (not adopted)</td><td>Base Case was 2,720 kW for parasitic load of both compression and dew point heating. Revised analysis indicates 547.2 kW average expected electric dew point load for 2,780 “base case” gas-firing hours.</td><td>NA</td><td></td><td></td><td></td><td></td></tr>
<tr><td>Electric Motors Aside from Gas Compressor NEMA (premium high efficiency motors adopted)</td><td>4,301 kW based on EPAct motors (Base Case)
With NEMA premium high efficiency motors the load is reduced to 4,256 kW</td><td>3,722 kW based on EPAct motors (Base Case)
With NEMA premium high efficiency motors the load is reduced to 3,683 kW</td><td>90</td><td></td><td>0.01%</td><td></td></tr>
<tr><td rowspan="2">Electric Transformer Loss (lower impedance transformers not adopted)</td><td>1,749 kW based on Z = 9</td><td>1,776 kW based on Z = 9</td><td rowspan="2"></td><td rowspan="2"></td><td rowspan="2"></td><td rowspan="2"></td></tr>
<tr><td colspan="2">Lower impedance transformers found to be not feasible due to high secondary fault currents and the need for circuit breaker replacements. Lower impedance transformers have been dropped from consideration for GHG mitigation.</td></tr>
</table>

Item	Natural Gas – 50°F 2,780 hours/year	ULSD – 0°F 720 hours/year	CO2e Emissions (tpy)		Percent Reduction	
			Adopted	Under Study	Adopted	Under Study
SCR Ammonia Vaporizer (adopted)	196 kW based on electric heater	340 kW based on electric heater	474		0.06%	
	Use of an electric ammonia vaporizer is required during startup, resulting in an average vaporizer load (spread over all operating hours) of 6 kW for gas firing and 10 kW for ULSD firing.					
Miscellaneous Auxiliaries (highest efficiency alternatives adopted)	364 kW	364 kW				
Total	Current total parasitic load for gas firing at full load 50 deg F incorporating all adopted measures = 448+ 547+4,256+1,749 +6+364-339 = 7,031 kW (25% improvement over Base Case value of 9,360 kW)	Current total parasitic load ULSD firing 0 deg F incorporating all adopted measures = 3,683+1,776 +10+364 = 5,833 kW (6% improvement over Base Case value of 6,216 kW)	1,079	43	0.14%	0.006%

The design data for the adopted efficiency improvement measures are as follows:

<u>Natural Gas Firing at 50°F (3,187.21 MMBtu/hr HHV)</u>

Output (gross): 346,314 kW

Output (net): **339,283** kW

Parasitic Load: **7,031** kW

Heat rate (gross, HHV basis): 9,203 Btu/kW-hr

Heat rate (net, HHV basis): **9,394** Btu/kW-hr

<u>ULSD Firing at 0°F (3461.73 MMBtu/hr HHV)</u>

Output (gross): 363,320 kW

Output (net): **357,487** kW

Parasitic Load: **5,833** kW

Heat rate (gross, HHV basis): 9,528 Btu/kW-hr

Heat rate (net, HHV basis): **9,684** Btu/kW-hr