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Department of Environmental Protection

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# Draft for Public Hearing and Comment

# Prevention of Significant Deterioration Permit

# Fact Sheet

## Canal Unit 3
## 9 Freezer Road
## Sandwich, MA

## Transmittal No. X269143
## Application No. SE-16-015

## January 5, 2017

MassDEP is hereby issuing this Prevention of Significant Deterioration ("PSD") Permit Fact Sheet, concurrently with the Draft PSD Permit for Canal Unit 3 ("Project")[1] MassDEP based its permit decisions on the information and analysis provided by the NRG Canal 3 Development, LLC (hereinafter referred to as the "Applicant" or "Canal 3") and MassDEP's own technical review. This Fact Sheet documents the information and analysis MassDEP used to support its PSD Permit decisions. It includes a description of the proposed Project, the applicable PSD regulations, and an analysis demonstrating how the Applicant complied with all applicable PSD requirements.

## I. General Information

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|---|---|
| Name of Source: | Canal Generating Station |
| Location: | Sandwich, Massachusetts |
| Applicant's Name and Address: | NRG Canal 3 Development, LLC<br>9 Freezer Road<br>Sandwich, MA 02563 |
| Application Prepared By: | Tetra Tech, Inc.<br>160 Federal St., 3rd Floor<br>Boston, MA 02110 |

Prevention of Significant Deterioration Application

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|---|---|
| Transmittal Number: | X269143 |
| Application Number: | SE-16-015 |

Massachusetts Department of Environmental Protection ("MassDEP")

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MassDEP administers the federal PSD Program pursuant to the "Agreement for Delegation of the Federal PSD program by Environmental Protection Agency ("EPA") to MassDEP" (PSD Delegation Agreement) between MassDEP and the United States EPA ("USEPA"), Region 1, dated April 11, 2011. The PSD Delegation Agreement directs that all Permits issued by

[1] Hereinafter the new installation, the subject of this Plan Approval, will be termed the 'Project,' and the existing and new installations together will be termed the 'Facility.'

MassDEP under the Agreement follow the applicable procedures in 40 CFR 52.21 and 40 CFR Part 124 regarding permit issuance, modification and appeals.

On February 18, 2016, the Applicant submitted an initial Application to MassDEP requesting a PSD Permit for construction of one (1) new, simple-cycle electric generating combustion turbine with a nominal electrical output of 350 megawatts (“MW”). The Project will be located on approximately 12 acres within the existing 29-acre Canal Generating Station site on Freezer Road, Sandwich, Massachusetts. The Applicant submitted a revised application on October 27, 2016. MassDEP considered the Application for the PSD Permit to be complete. Today, MassDEP issued this PSD Fact Sheet and a Draft PSD Permit for a 30-day public comment period as required by the PSD Delegation Agreement and 40 CFR 124 - Procedures for Decision Making.

The Project is also subject to the MassDEP Plan Approval and Emission Limitations requirements at 310 CMR 7.02 and Emission Offsets and Nonattainment Review at 310 CMR 7.00: Appendix A (“Appendix A”). MassDEP is issuing a proposed Air Quality Plan Approval under these regulations concurrent with this PSD Fact Sheet and Draft PSD Permit.

Finally, based on information in the record, MassDEP has determined that there is a potential condition of air pollution that could be caused by the Project in the absence of a GHG emission limit.[2] Therefore, MassDEP has included in the Plan Approval requirements that create annual declining $CO_{2e}$ limits on all sources of greenhouse gas included in the Project. MassDEP did not include the declining CO2e limits in the Draft PSD permit because it is a state-only requirement. The requirements are designed so the Project will not emit GHG emissions that may cause or contribute to a condition of air pollution, or cause damage or threat of damage to the environment, as required by the state Clean Air Act, M.G.L. c. 111, §§ 142A-142E, MassDEP air regulations, 310 CMR 7.00, and M.G.L. c. 21A, § 2 and 8.

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2 By adopting the GWSA, the Legislature has made a determination on behalf of the Commonwealth that without a significant reduction in the current level of GHG emissions by 2020 and an even more significant reduction by 2050, there will be significant harm to human health and the environment. The federal government has concurred that GHG emissions are air pollutants that endanger human health and the environment. On April 2, 2007, in a landmark decision pressed by the Commonwealth of Massachusetts as well as other states, the Supreme Court determined that GHGs, including carbon dioxide, are air pollutants covered by the Clean Air Act. *See* Massachusetts v. EPA, 549 U.S. 497 (2007). The Supreme Court required EPA, under Section 202(a) of the federal Clean Air Act (CAA), to determine if GHGs threaten public health and welfare, that is, make what is called an “endangerment” finding. On December 7, 2009, the EPA Administrator signed an endangerment finding regarding greenhouse gases under section 202(a) of the Clean Air Act that found that the current and projected concentrations of GHGs endanger the public health and welfare of current and future generations. 74 Fed. Reg. 66,496 (2009). The Administrator determined that greenhouse gas pollution threatens Americans' health and welfare by leading to long lasting changes in our climate that can have a range of significant negative effects on human health and the environment.

The Permittee shall comply with the declining annual $CO_{2e}$ limits by either controlling the Project's operations to limit actual $CO_{2e}$ emissions below the applicable year's $CO_{2e}$ limit, or use over-compliance credits created when the Project's actual annual project-wide emissions of $CO_{2e}$ are less than the Project's applicable year's $CO_{2e}$ limit.

The requirements are also designed so the Project will help achieve the 2020 mandate to reduce GHG emissions by 25% from 1990 emission levels, and the 2050 mandate for an 80% reduction from 1990 emission levels as required by the Global Warming Solutions Act ("GWSA"), M.G.L. c. 21N, and as emphasized by the decision by the Supreme Judicial Court in *Kain v DEP*, 474 Mass. 278 (2016) ("*Kain*"). To demonstrate compliance with the declining annual $CO_{2e}$ limits, MassDEP has incorporated monitoring, recordkeeping and reporting requirements into the Plan Approval.

Furthermore, MassDEP was directed by Governor Baker to finalize regulations, effective on or before August 11, 2017, to impose annual declining GHG emission limits on multiple sectors in the Commonwealth (see Executive Order 569)[3]. On December 16, 2016, MassDEP proposed for public hearing and public comment regulations to meet Section 3(d) requirements, Executive Order 569 and the *Kain* decision. In the proposed regulations, MassDEP takes into account GHG emissions from existing and new facilities in the electric generation sector.

MassDEP has designed the declining GHG emissions limit in this Plan Approval to balance the need to restrict GHG emissions from the Project, which could cause a condition of air pollution and jeopardize meeting the GWSA goals, against the important need to support intermittent renewable power and ensure grid reliability. In structuring the declining GHG emissions limit in the Plan Approval, MassDEP took into account the proposed Project's efficiency and quick-start capabilities. These capabilities will facilitate the integration and operation of intermittent renewables (such as wind and solar) into Massachusetts and New England. Supporting intermittent renewable resources at an increasing rate into the ISO-New England electricity grid will be key to the Commonwealth's ability to achieve the long-term GWSA goals of an 80% reduction in GHG emission from 1990 levels by 2050. As part of that effort and under the mandates of the GWSA, Massachusetts must demonstrate a reduction in GHG emissions from electricity imported into Massachusetts from the ISO-New England region as well as from electricity generated within the Commonwealth. *See* M.G.L. c. 21N, § 2.

## II. PROJECT LOCATION

3 http://www.mass.gov/governor/legislationexecorder/execorders/executive-order-no-569.html

NRG Canal owns two non-contiguous tracts of land, which total approximately 88 acres in the Town of Sandwich. The 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 Project site will be located on approximately 12 acres of the eastern portion of this 52-acre 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 property.

Directly north of the 52-acre property is the Cape Cod Canal, which has recreational walkways/bike paths located directly next to and on each side of the Canal. The Canal Generating Station has a docking facility located on the south side of the Canal for the docking of the vessels, including oil delivery barges. The area directly north of the Canal, across from the Canal Generating 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 Marine, 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 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 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 property. Eversource owns an electrical substation, located south of the railroad ROW. Undeveloped wooded areas south of the 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 Stop & Shop supermarket, CVS Pharmacy, Citizen's Bank, Eastern Bank, Bobby Byrnes Restaurant, Café 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 property.

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

Air quality at the Project location is classified as "attainment" for sulfur dioxide ("$SO_2$") and nitrogen dioxide ("$NO_2$"), and "unclassifiable/attainment" for carbon monoxide ("CO"), lead ("Pb"), particulate matter with an aerodynamic diameter of 10 microns or less ("$PM_{10}$"), particulate matter with an aerodynamic diameter of 2.5 microns or less ("$PM_{2.5}$"). Therefore, the Project is located in a PSD area for these pollutants.

The project location is also classified as unclassifiable/attainment for ozone. Because Massachusetts is located in the Ozone Transport Region, Emission Offset and Nonattainment Review requirements at 310 CMR 7.00: Appendix A apply statewide for projects emitting oxides of nitrogen (NOx) and volatile organic compounds (VOC) as ozone precursors, instead of PSD review.

The purposes of the PSD program are to: [4]

1. protect public health and welfare;
2. preserve, protect, and enhance the air quality in national parks, national wilderness areas, national monuments, national seashores, and other areas of special national or regional natural, recreational, scenic, or historic value;
3. to insure economic growth will occur in a manner consistent with preservation of existing clean air resources;
4. to assure that emissions from any source in any State will not interfere with any portion of the applicable implementation plan to prevent significant deterioration of air quality in any other State; and
5. assure that any decision to permit increased air pollution in any area to which PSD applies is made only after careful evaluation of all the consequences of such a decision and after adequate procedural opportunities for informed public participation in the decision making process.

MassDEP is issuing a Proposed Comprehensive Plan Application Approval for the Project under the preconstruction plan approval requirements at 310 CMR 7.02, including the Emission Offset and Nonattainment Review requirements at 310 CMR 7.00: Appendix A concurrently with the Draft PSD Permit. As mentioned above, Appendix A applies because the entire Commonwealth

[4] 42 U.S.C. § 7470 – Congressional declaration of purpose.

of Massachusetts, including Barnstable County, is in the Ozone Transport Region and is required to comply with Nonattainment Review requirements under 42 U.S.C. § 7511c.

## III. Proposed Project

The Applicant is proposing to install one General Electric ("GE") 7HA.02 natural gas- and ultra-low sulfur diesel fuel ("ULSD") -fired combustion turbine generator ("CTG") with an evaporative inlet air cooler, tempering air fans, and its associated exhaust stack. The CTG is a simple-cycle unit wherein the thermal energy from combustion of fuel is converted to mechanical energy in the turbine, which drives an integral compressor and electric generator. There is no supplementary waste heat recovery for combined cycle power generation.

Proposed air pollution control equipment includes a dry-low- $NO_x$ combustor and a selective catalytic reduction ("SCR") module complete with ammonia ("$NH_3$") injection skid to reduce $NO_x$ emissions, and an oxidation catalyst to control CO and VOC emissions. Electrical equipment includes a two-winding main generator step-up transformer, an auxiliary transformer, and electric switchgear.

The Project also includes construction of a new 3,590-foot on-site natural gas pipeline, conversion of an existing 5,700,000-gallon aboveground storage tank and associated 1,800,000-gallon day tank to hold ULSD, and use of two (2) existing fully diked aqueous $NH_3$ storage tanks, each with a capacity of 60,000 gallons. The aqueous $NH_3$ storage tanks will be enclosed in a single structure.

Continuous emissions monitoring system ("CEMS") will sample, analyze and record fuel firing rates as well as $NO_x$, CO, and $NH_3$ emissions concentration levels. The combustion turbine will discharge exhaust gases through a 220-foot tall, 25-foot diameter stack constructed of steel.

Ancillary equipment at the proposed Project includes two stationary ULSD-fired reciprocating internal combustion engines (RICE):

- One (1) 500 kilowatt ($kW_{electric}$),581 kW (mechanical) emergency generator engine (Caterpillar C15 or equivalent); and
- One (1) 101 kW (mechanical) (135 BHP) fire pump engine (John Deere / Clarke JU4H-UFAD5G or equivalent).

The Project is designed to respond to a projected shortfall in peak electric generation capacity for Southeastern Massachusetts/Rhode Island. The Applicant submitted a capacity bid for the Project in the most recent Independent System Operator – New England ("ISO-NE") forward capacity auction (FCA #10), which took place on February 10, 2016. The Project's bid was accepted. Therefore, the Applicant is obligated to make the Project available to supply electricity by June 1, 2019.

The Applicant has proposed to limit the Project to operating no more than 4,380 hours per year, and limiting ULSD firing to no more than 720 hours per year. The total quantity of natural gas fired will be limited to 14,554,740 MMBtu (50°F full-load firing rate times 4,380 hours). The total quantity of ULSD fired will be limited to 2,499,120 MMBtu (0°F full-load firing rate times 720 hours).

The Applicant assumed 180 starts firing natural gas and 80 starts firing ULSD to determine potential emissions and for air quality dispersion modeling, but the proposed Project will not be restricted on the number of starts.

The rated gross electric power output of the proposed CTG varies from approximately 319 MW during warm weather (90°F), to an estimated 368 MW at 0°F. The CTG's maximum heat input ratings are approximately 3,425 million British thermal units per hour (MMBtu/hr)[5] while firing natural gas and 3,471 MMBtu/hr while firing ULSD (at 0°F). These heat input ratings are equivalent to maximum firing rates of 3,256,000 standard cubic feet per hour (scf/hr) while firing natural gas (assuming 1,000 Btu HHV/scf) and 24,793 gallons per hour (gal/hr) while firing ULSD (assuming 140,000 Btu HHV/gal).

The emergency generator engine and the fire pump will each be limited to no more than 300 hours of operation per consecutive 12-month period. Each engine is also subject to the operating limitations specified in 40 CFR part 60 subpart IIII for emergency engines.

The existing Canal Generating Station power generation equipment consists of two (2) steam electric units, designated as EU-1 and EU-2. EU-1 is a Babcock & Wilcox boiler rated at 5,083 MMBtu/hr energy input firing No. 6 fuel oil with No. 2 fuel oil as a startup fuel. EU-2 is a Babcock & Wilcox boiler firing No. 6 fuel oil as the primary fuel with 5,682 MMBtu/hr energy input rating, and natural gas as a backup fuel with 5,973 MMBtu/hr energy input rating. EU-2 can be started on either No. 2 fuel oil or natural gas. Each boiler supplies steam to a separate electric steam turbine generator with a nominal electric generating capacity of 560 MW.

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[5] Higher heating value (HHV) at 100% load, 59°F, 60% relative humidity.

## IV. PSD PROGRAM APPLICABILITY AND REVIEW

MassDEP administers the PSD program in accordance with the provisions of the April 11, 2011 PSD Delegation Agreement between MassDEP and EPA which states that MassDEP agrees to implement and enforce the federal PSD regulations in 40 CFR 52.21.[6]

Review considerations with respect to 310 CMR 7.00: Appendix A Emission Offsets and Nonattainment Review (Appendix A) are not part of the PSD Review Process and are therefore not addressed in this Fact Sheet. MassDEP provides its evaluation of Emission Offsets and Nonattainment Review for the Project, as required by Appendix A, in the Proposed major-Comprehensive Plan Approval ("CPA"), which is being issued by MassDEP concurrently with the draft PSD Permit and this PSD Fact Sheet.

The PSD regulations at 40 CFR 52.21 require that a major new stationary source of an attainment pollutant, or major modification to an existing major stationary source of an attainment pollutant, undergo a PSD review and that a PSD permit be granted before commencement of construction. 40 CFR 52.21(b)(1) of the federal PSD regulations defines a "major stationary source" as either (a) any of 28 designated stationary source categories with potential emissions of 100 tons per year ("tpy") or more of any regulated attainment pollutant, or (b) any other stationary source with potential emissions of 250 tpy or more of any regulated attainment pollutant. The existing station is covered by the designated source category of fossil fuel-fired steam electric plant of more than 250 MMBtu/hr heat input and has potential emissions of 100 tons per year or more of $NO_x$, CO, $PM_{10}$, $PM_{2.5}$, and $SO_2$ emissions; therefore, it is an existing major source.

The Project is being evaluated under the PSD Program as a modification of an existing major source. As such, a PSD applicability determination must be made for each PSD pollutant. PSD review applies to each PSD pollutant emitted in excess of a defined Significant Emission Rate, i.e. a major modification. Further, if greenhouse gas ("GHG") emissions expressed as carbon dioxide ("$CO_2$") equivalent (or "$CO_2e$") are greater than 75,000 tpy for a project that is subject to PSD review, then GHG are also included as a PSD pollutant.

For a project that is subject to PSD review and approval, the Applicant must apply for and obtain a PSD Permit that meets regulatory requirements including:

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

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

## V. PSD APPLICABILITY

The Project is considered a major modification as defined by EPA's PSD program. Potential emissions from the Project are significant for six (6) different PSD pollutants: $NO_x$, PM, $PM_{10}$, $PM_{2.5}$, sulfuric acid ("$H_2SO_4$"), and GHG. Table 1 shows potential emissions from the proposed new equipment at the site. Table 2 shows total project potential to emit relative to the significance thresholds for PSD regulated pollutants.

**Table 1. Project-Wide Annual Potential Emissions (tons per year/tpy)**

| Pollutant | CTG(1) | Emergency Generator Engine(2) | Emergency Fire Pump Engine(2) | 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 | $1.1 \times 10^{-3}$ | $2.7 \times 10^{-4}$ | 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(3) |
| $H_2SO_4$ | 12.0 | $8.7 \times 10^{-5}$ | $2.1 \times 10^{-5}$ | 12.0 |
| $NH_3$ | 50.3 | N/A | N/A | 50.3 |
| Pb | 0.004 | $2.4 \times 10^{-6}$ | $5.6 \times 10^{-7}$ | 0.004 |
| $CO_2e$ | 932,325 | 123 | 29 | 934,041(4) |
| Fluorides | None expected | None expected | None expected | None expected |

| **Table 1. Project-Wide Annual Potential Emissions (tons per year/tpy)** | | | | |
|---|---|---|---|---|
| **Pollutant** | **CTG[1]** | **Emergency Generator Engine[2]** | **Emergency Fire Pump Engine[2]** | **Project Totals** |
| $H_2S$ | None expected | None expected | None expected | 0.0012[4] |
| Total Reduced Sulfur (including $H_2S$) | None expected | None expected | None expected | 0.0012[4] |
| Reduced Sulfur Compounds (including $H_2S$) | None expected | None expected | None expected | 0.0012[4] |

| **Table 2. Prevention of Significant Deterioration Regulatory Threshold Evaluation** | | | |
|---|---|---|---|
| **Pollutant** | **Project Annual Emissions (tpy)** | **PSD Significant Emission Rate (tpy)** | **PSD Review 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 |
| GHG (as $CO_2$e) | 934,041 | 75,000 | Yes |
| Fluorides | None expected | 3 | No |
| $H_2S$ | 0.0012 | 10 | No |
| Total Reduced Sulfur (including $H_2S$) | 0.0012 | 10 | No |
| Reduced Sulfur Compounds (including $H_2S$) | 0.0012 | 10 | No |

**Table 1 and 2 notes:**

1. Emissions are based on 4,380 hours of steady-state operation per 12-month rolling period (50% capacity factor) at 50°F ambient temperature (3,323 MMBtu/hr, HHV), including 720 hours of ULSD firing per 12-month rolling period at 0°F ambient temperature (3,471 MMBtu/hr, HHV), 3,660 hours of natural gas firing, and the added emissions associated with 180 startup / shutdown cycles on natural gas and 80 startup / shutdown cycles on ULSD.
2. The emergency diesel generator and fire pump emissions are each based on 300 hours per unit, per 12-month rolling period, including maintenance and periodic readiness testing, while firing ULSD.
3. Emissions include working and/or breathing losses associated with the ULSD oil tanks of one ton per year.
4. Includes allowance for 1,561 tpy $CO_2$e from methane leaks and 3 tpy $CO_2$e from potential $SF_6$ leaks. Since natural gas may contain trace quantities of $H_2S$ or other reduced sulfur compounds, an allowance for up to 0.0012 tpy of $H_2S$ or other reduced sulfur compounds from natural gas is included.

**Table 1 and 2 Key:**

| | |
|---|---|
| CTG | = Combustion Turbine Generator |
| tpy | = tons per year |
| PM | = Total Particulate Matter |
| $PM_{10}$ | = Particulate Matter less than or equal to 10 microns in diameter |
| $PM_{2.5}$ | = Particulate Matter less than or equal to 2.5 microns in diameter |
| $SO_2$ | = Sulfur Dioxide |
| NOx | = Nitrogen Oxides |
| CO | = Carbon Monoxide |
| VOC | = Volatile Organic Compounds |
| $H_2SO_4$ | = Sulfuric Acid |
| $H_2S$ | = Hydrogen Sulfide |
| Pb | = Lead |
| GHG | = Greenhouse Gases |
| $CO_{2e}$ | = Greenhouse Gases expressed as Carbon Dioxide equivalent and calculated by multiplying each of the six greenhouse gases (Carbon Dioxide, Nitrous Oxide, methane, Hydrofluorocarbons, Perfluorocarbons, Sulfur Hexafluoride) mass amount of emissions, in tons per year, by the gas's associated global warming potential published at Table A-1 of 40 CFR Part 98, Subpart A and summing the six resultant values. |
| Max | = Maximum |
| °F | = degrees Fahrenheit |
| % | = percent |
| MMBtu/hr | = million British thermal units per hour |
| HHV | = higher heating value |
| ULSD | = Ultra Low Sulfur Diesel Fuel Oil containing a maximum of 0.0015 weight percent sulfur |
| N/A | = Not Applicable |

## VI. BACT ANALYSIS

As required by the Federal PSD Program at 40 CFR 52.21(j)(3), a major modification shall apply best available control technology for each regulated NSR pollutant for which it would result in a significant net emissions increase at the source. This requirement applies to each proposed emissions unit at which a net emissions increase in the pollutant would occur as a result of a physical change or change in the method of operation in the unit. Therefore, the Project is required to apply BACT for the NOx, PM, $PM_{10}$, $PM_{2.5}$, $H_2SO_4$, and GHG emissions from the CTG, the emergency generator engine, and the emergency fire pump engine.

BACT is defined as:

> "an emissions limitation … based on the maximum degree of reduction of each pollutant subject to regulation under [the Clean Air] Act which would be emitted from any proposed major stationary source or major modification which the Administrator, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such source or modification through application of production processes or available methods, systems and techniques … for control of such pollutant." 40 CFR 52.21(b)(12); 42 U.S.C. § 7479.

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

Top-down BACT analysis follows a five-step methodology:

1. Identify all control technologies. Identify all possible control options, including inherently lower emitting processes and practices, add-on control equipment, or a combination of inherently lower emitting processes and practices and add-on control equipment.

2. Eliminate technically infeasible options. Eliminate technically infeasible options based on physical, chemical, and engineering principles.

3. Rank remaining control technologies by control effectiveness. Rank the remaining control options by control effectiveness, expected emission reduction, energy impacts, environmental impacts, and economic impacts.

4. Evaluate most effective controls and document results. Determine the economic, energy, and environmental impacts of the control technology on a case-by-case basis.

5. Select BACT. Select the most effective control option not rejected in the above analyses as BACT.

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

**1. Combustion Turbine**

In order to identify BACT for a dual-fueled simple-cycle CTG, the Applicant evaluated numerous sources of information. These sources included both state and federal resources of publicly available air permitting information. The Applicant evaluated the following sources of information to determine BACT:

- EPA's RACT, BACT and LAER Clearinghouse ("RBLC") and Control Technology Center;
- Federal, state and local new source review permits and associated inspection/performance test reports

According to the Application, the Project is designed to compete in the capacity and energy markets as a generator with particular value related to its quick-start capability and relatively high efficiency. As such, the Project is capable of providing up to 350 MW of electricity in 10 minutes. The Applicant demonstrated that combined-cycle turbine technology is not capable of achieving this level of quick start. Therefore, MassDEP determined that the BACT analysis need not include an analysis of combined-cycle technologies that would redefine the source. However, for the sake of completeness, this BACT analysis considers certain other technologies as being hypothetically available.

1.1. Fuels

The choice of fuels used to fire the simple-cycle combustion turbine is a major element of the BACT analyses for each pollutant. The fuel choice will affect the emission limits that represent BACT for each pollutant. MassDEP must weigh the same factors when addressing the fuel choice as a control option for each pollutant. Rather than including a fuel choice control option in the BACT analysis for each individual pollutant, this Fact Sheet discusses the fuel choice analysis for the Project, which applies to the emission limits chosen to represent BACT for each pollutant.

The Applicant has proposed to burn primarily natural gas in the combustion turbine. As a back-up fuel, the Applicant has proposed to burn ULSD for up to the equivalent of 720 hours per 12-month rolling period. While ULSD is the cleanest burning fossil fuel other than natural gas, pollutant emission rates of $NO_x$, PM, $PM_{10}$, $PM_{2.5}$, and GHG that result from burning ULSD are higher than from burning natural gas. Emissions of $H_2SO_4$ mist are expected to be lower while burning ULSD. The Applicant is proposing a 50% capacity factor, operating up to 4,380 hours per 12-month rolling period, 720 hours of which could be ULSD.

**Step 1: Identify all control technologies**

The Applicant identified the following possible fuels for the Project:

- 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.

**Step 2: Eliminate technically infeasible options**

The Project is designed to operate as an on-demand peaking power source that can start and reach full (100%) load within 10 minutes, which requires that a source of fuel be available at all times. Gas transmission operators refer to this as “No Notice Service.”

The Applicant demonstrated that natural gas as the sole fuel, based on securing a dedicated pipeline supply, is not technically feasible. Although the existing Canal Station currently connects to Algonquin Gas Transmission, LLC (“AGT”), No Notice Service is fully subscribed by local gas distribution companies and not commercially available for the Project.

The Applicant demonstrated that natural gas as the primary fuel with LNG as backup is not technically feasible because the Facility area is insufficient to accommodate an appropriate LNG facility.

Therefore, natural gas as the primary fuel with ULSD as backup is the sole technically feasible option for the Project.

**Step 3: Rank remaining control technologies**

Natural gas as the primary fuel with ULSD as backup is the sole technically feasible option for the Project.

**Step 4: Evaluate most effective controls and document results**

The Applicant proposes limitations on the operating hours and restrictions on when ULSD as a backup fuel can be fired. The Applicant presented the ULSD restrictions for Pioneer Valley Energy, which is the most recent PSD approval issued for a dual-fuel electric generating unit in Massachusetts. The approval limited ULSD firing up to 1,440 hours per 12-month rolling period and imposed restrictions on when ULSD can be fired. These restrictions include curtailment by pipeline operator, failure of equipment required for the combustion turbine to operate on natural gas, commissioning and start-up testing on ULSD, and the necessity to maintain an appropriate turnover of the on-site fuel oil delivery.

**Step 5: Select BACT**

The Applicant plans to participate in the “Ten-Minute Non-Spinning Reserve” (“TMNSR”) market which includes resources in ISO-NE’s Real Time Operation with the ability to start-up in 10 minutes. The Applicant demonstrated that natural gas cannot be procured within the 10-minute timeframe necessary to dispatch the unit for the TMNSR market.

Upon review, MassDEP has determined that the emission limits associated with the use of natural gas with ULSD backup represents BACT for the Project. The Project will be restricted to the equivalent of a 50% capacity factor or 4,380 operating hours per 12-month rolling period and no more than 720 operating hours per year on ULSD.

MassDEP will restrict the use of ULSD in the PSD Permit to when any of the following conditions apply:

a) 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.
b) When the operator of the natural gas transmission line issues a critical notice that disallows increases in nominations from where gas is received on their pipeline system to the point of delivery for the Project.
c) 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.
d) 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.
e) 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.
f) During commissioning when the combustion turbine is required to operate on ULSD pursuant to the turbine manufacturer's written instructions.
g) For emission testing purposes as specified in the Project's Air Plan Approval or as required by MassDEP or other regulatory agencies with relevant authority.
h) During routine maintenance if any equipment requires ULSD operation.
i) 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 six-month 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 0°F firing rate on ULSD.

Operations pursuant to conditions (g), (h) and (i) are not allowed on any day when the air quality index for the area including Sandwich, MA is, or is forecast to be, 101 or greater. This limitation does not apply to conditions (a) through (f).

### 1.2. $NO_x$

In addition to the requirement to apply BACT for $NO_x$, the Project is also subject to the determination of Lowest Achievable Emission Rate ("LAER") for $NO_x$ because potential $NO_x$ emissions exceed the major source threshold at 310 CMR 7.00: Appendix A, Emission Offsets and Nonattainment Review. The LAER analysis is described in the proposed Comprehensive Plan Approval ("CPA").

**Step 1: Identify all control technologies**

The Applicant identified the following possible control options for $NO_x$:

1. Selective Catalytic Reduction (SCR);
2. Dry-Low $NO_x$ (DLN) Combustion;
3. Water ($H_2O$) or steam injection;
4. Selective Non-Catalytic Reduction (SNCR);
5. Oxidation/absorption technology using hydrogen ($H_2$) or methane ($CH_4$) as a reactant, such as EMx™ systems.
6. Good combustion practices.

**Step 2: Eliminate technically infeasible options**

The BACT analysis concluded that SNCR is not technically feasible because the proposed CTG will not be able to achieve the optimum exhaust gas temperature range to achieve the $NO_x$ reduction.

The BACT analysis concluded that EMx™ systems are not technically feasible because the technology has never been installed on a simple-cycle and for the size of combustion turbine proposed for the Project.

**Step 3 and 4: Rank remaining control technologies by control effectiveness**

The Applicant concluded that SCR, DLN combustion, $H_2O$ injection, and good combustion practices are technically feasible technologies and proposed to use all four technologies to control $NO_x$ emissions from the Project. Accordingly, the BACT analysis did not consider the competing impacts and benefits among these technologies.

**Step 5: Select BACT**

The Applicant presented available data on simple-cycle $NO_x$ combustion turbine emissions limits from the information resources listed above. Based on these data, the Applicant's analysis concluded that the lowest $NO_x$ emission limit for a gas-firing simple-cycle combustion turbine is

2.5 parts per million volume dry corrected (ppmvdc) when firing on natural gas and 5.0 ppmvdc when firing on ULSD.

The Applicant identified that the value of 2.5 ppmvdc of $NO_x$ is determined as the lowest limit identified for a simple-cycle CTG for natural gas firing. The following facilities are permitted for $NO_x$ emission limit of 2.5 ppmvdc:

- Carlsbad Energy Center, Carlsbad, California – 6 units rated at 88 MW each, natural gas-fired simple-cycle CTG permitted April 17, 2015.
- El Paso Montana Power, El Paso, Texas – 4 units rated at 88 MW each, natural gas-fired simple-cycle CTG permitted April 2, 2013.
- Pio Pico Energy Center, Otay Mesa, California – 3 units rated at 100 MW each, natural gas-fired simple-cycle CTG permitted November 19, 2012.
- PSEG Fossil-Kearny Generating Station, Hudson, New Jersey – 6 units rated at 45 MW each, natural gas-fired simple-cycle CTG permitted October 27, 2010.
- TID Almond 2 Power Plant, Modesto, California – 3 units rated at 58 MW each, natural gas-fired simple-cycle CTG permitted February 16, 2010.

For ULSD firing, the Applicant identified that the value of 3.5 ppmvdc of $NO_x$ is the lowest permitted for any size CTGs firing ULSD. However, the emission limit of 3.5 ppmvdc of $NO_x$ for ULSD firing permitted for GE LMS-100 CTG at Gowanus Generating Station, New York, has not been demonstrated in practice since the proposed facility has yet to be constructed. Troutdale Energy Center in Multnomah, Oregon is permitted at 3.8 ppmvdc for oil firing for two GE LMS-100 units; however, the project is currently undergoing a contested Oregon Department of Energy sitting process and has not commenced construction.

In summary, the Applicant proposed a $NO_x$ emission limit of 2.5 ppmvd on natural gas and 5.0 ppmvd on ULSD for the combustion turbine. Upon review, MassDEP determined that 2.5 ppmvd at 15% $O_2$ firing natural gas and 5.0 ppmvd at 15% $O_2$ firing ULSD represent BACT. This BACT determination is based on the use of SCR, dry low $NO_x$ burners, water injection, and good combustion practices.

### 1.3. $PM/PM_{10}/PM_{2.5}$

The BACT analysis reviewed emission limits and control technologies for PM using conservative assumption that all PM emissions are 2.5 microns aerodynamic particle diameter or less. The analysis found that potential control options included fabric filtration, electrostatic precipitation, and/or wet scrubbing. As with all of the pollutants considered for the BACT analysis, the use of clean fuels and good combustion control is another option for emissions control. Post combustion control technologies are not technically feasible for CTGs since the large amount of excess air inherent to combustion turbine technology would create an unacceptable amount of backpressure for turbine operation. The Applicant concluded that the sole technically feasible control option for PM emissions is to fire clean-burning fuels and use good combustion practices.

The Applicant identified a value of 0.03 pound per million British thermal unit ("lb/MMBtu") as the lowest permitted PM emissions for an oil-firing in simple-cycle turbine (Southern Power – Dahlberg Generating Facility, Jackson, Georgia – 756 MW simple-cycle CTGs permitted May 14, 2010). The Applicant found that there are differences in PM emissions limits among various projects since the emissions are based on different manufacturer's guarantee and not emissions produced by turbine models. The analysis found that there are no H-class CTGs permitted in simple-cycle configuration, hence there are no comparable permitted PM emission to assess the BACT limits.

Upon review, MassDEP determined that the following PM/$PM_{10}$/$PM_{2.5}$ emission limits represent BACT:

- 0.012 lb/MMBtu, not to exceed 18.1 lb/hr on when operating at reduced load, from 75% load down to MECL on natural gas. MECL is the Minimum Emission Compliance Load, as determined by the stack $NO_x$ and CO monitoring data, which ranges between 30 and 40% load based on ambient temperature.
- 0.0073 lb/MMBtu, not to exceed 18.1 lb/hr when operating above 75% load on natural gas.
- 0.046 lb/MMBtu, not to exceed 65.8 lb/hr, when operating at reduced load, from 75% load down to MECL on ULSD. MECL is the Minimum Emission Compliance Load, as determined by the stack $NO_x$ and CO monitoring data, which ranges between 30 and 40% load based on ambient temperature.
- 0.026 lb/MMBtu, not to exceed 65.8 lbs/hr above 75% load on ULSD.

### 1.4. $H_2SO_4$

Emissions of $H_2SO_4$ are formed from the oxidation of sulfur in the fuel. Most of the sulfur in the fuel will oxidize to $SO_2$. However, small amounts of sulfite ($SO_3$) are generated by the oxidation of the fuel sulfur in the combustion turbine, the SCR catalyst, and the oxidation catalyst. The $SO_3$ can react with water in the flue gas to form $H_2SO_4$.

The Applicant concluded that post-combustion control options such as dry or wet scrubbers are not technically feasible for the Project because the back pressure such post-combustion control options would impose on the CTG exhaust.

$H_2SO_4$ emissions will be controlled by limiting the sulfur content of the fuel and applying good combustion practices. Natural gas, the primary fuel, is naturally low in sulfur and ULSD is the lowest sulfur content fuel oil commercially available. The Applicant has proposed a sulfur content limit of 0.5 grains per 100 cubic feet (gr/100 scf), consistent with USEPA's definition of "pipeline natural gas[7]."

The Applicant has proposed the use of Ultra Low Sulfur Distillate with a sulfur content not to exceed 0.0015% by weight to achieve BACT for sulfuric acid mist emissions. Upon review, MassDEP determined that $H_2SO_4$ emission limits of 0.0016 lb/MMBtu firing natural gas and 0.0018 lb/MMBtu firing ULSD represent BACT.

## 1.5. Greenhouse Gas Emissions

Under the PSD regulations, GHG includes six compounds or chemical groups: carbon dioxide, methane, nitrous oxide, hydrofluorocarbons, perfluorocarbons, and sulfur hexafluoride ("$SF_6$"). Nitrous oxide emissions from uncontrolled and SCR controlled combustion turbines are inherently low. Hydrofluorocarbons, perfluorocarbons and sulfur hexafluoride are not products of combustion and will not be emitted by the combustion turbine. Accordingly, PSD applicability is based on a $CO_2$ equivalent determined by multiplying each pollutant's mass emissions by its global warming potential. For the combustion turbine, the main constituent of GHG emissions is $CO_2$ at 930,931 tpy. Other GHG emissions at the Project are methane and nitrous oxide emitted from the CTG stack (1,394 tpy GHG as $CO_2e$), GHG emissions as $CO_2e$ from the emergency diesel generator (123 tpy) and emergency diesel fire pump (29 tpy), fugitive emissions from natural gas leaks at 1,561 tons $CO_2e$ methane per year and switchgear insulating gas leaks at 3 tons $CO_2e$ $SF_6$ per year. The Project's potential GHG emissions are 934,041 tons $CO_2e$ per year.

$SF_6$ emissions are subject to and will be managed in accordance with MassDEP's Regulations "Reducing Sulfur Hexafluoride Emissions from Gas-insulated Switchgear" at 310 CMR 7.72 and in accordance with the requirements of the Air Plan Approval. Good combustion practices will minimize methane emissions. Natural gas leaks will be minimized by monitoring in accordance with manufacturer's recommendations and industry guidelines. Any leaks identified during

[7] Pursuant to 40 CFR 72, Subpart A – Acid Rain Program, General Provisions, §72.2 – Definitions.

monitoring will be repaired. The GHG BACT analysis focused on $CO_2$ emissions as the primary GHG component.

**Step 1: Identify all control technologies**

The Applicant identified the following potential control options for controlling $CO_2$:

1. Carbon capture and sequestration (CSS);
2. Low emitting fuels;
3. Generating efficiency;
4. Alternative electric generation technologies; and
5. Good combustion practices.

**Step 2: Eliminate technically infeasible options**

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 second step is to transport the captured $CO_2$ to a suitable storage location. Currently, there is no pipeline to transport captured $CO_2$ from the Project site to a known sequestration site in northern Michigan. This location, which is in the development phase, is over 600 miles from the Project site and is not currently operational. The Applicant concluded that CCS is not technically feasible.

Combined-cycle systems can also be considered a "process modification" relative to the proposed simple-cycle system. In a combined-cycle system, waste heat is recovered from the fuel gas in the form of steam using a heat recovery steam generator. This steam is then used to generate additional power in a steam turbine. A combined cycle system has greater efficiency of power generation per unit of fuel combusted than a simple-cycle unit. In the absence of a thermal load, a steam condenser (normally either air cooled condensers or wet cooling towers for new facilities) is necessary to condense the steam as part of the combined-cycle process. Converting this Project to combined-cycle would change the fundamental nature of the Project, and is not feasible for the Project to serve its design function as a quick-starting TMNSR peaking unit.

New "quick-start" combined-cycle systems (a.k.a "flex plants") allow a certain portion of the turbine output to be available in 10 minutes, while the steam-cycle portion of the combined cycle system warms up. However, to bring 300 MW or more to the grid in 10 minutes (the project's intended capability for the Real Time/TMNSR market), a "quick-start" combined-cycle plant with capacity of approximately 600 MW, or two F-class turbines, is necessary. 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 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, while costing substantially more than the proposed H-class simple cycle unit. Either one or two "quick-start" F-class combined cycle units is considered commercially infeasible since they would represent fundamental change to the project.

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.

**Step 3 and 4: Rank remaining control technologies by control effectiveness**

The Applicant identified the following potential control options, ranked in order of effectiveness and viability:

1. Low emitting fuels; and,
2. Generating efficiency.

**Step 5: Select BACT**

The Applicant proposed low emitting fuels and energy efficiency as GHG emissions control technologies. The H-Class CTG has the greatest energy efficiency of any available comparably sized CTG. Based upon the Project design, and adding a performance plus degradation margin of 7.1% for the life of the Project, the net heat rates are 9,897 British thermal units per kilowatt-hour (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 emission rate of 1,178 lb $CO_2e$/MW-hr (gross) at full load ISO conditions for natural gas firing.

The Applicant identified a permitted GHG emission limit of 1,232 lb $CO_2e$/MW-hr for various configurations of natural gas-fired simple-cycle CTG at NRG Cedar Bayou, Hill County, Texas, permitted on September 15, 2015. An emission limit of 1,276 lb $CO_2e$/MW-hr was set on May 12, 2014 in the permit for the three- simple-cycle-CTG project (214 MW per unit for GE 7FA units) natural-gas fired Indeck Wharton Energy Center project at Wharton, Texas.

A simple-cycle CTG project was recently approved by Exelon for West Medway in Massachusetts. The West Medway project consists of two GE LMS-100 turbines. For full-load ISO conditions with gas and ULSD firing, Exelon proposed GHG BACT as 1,151 lb $CO_2$/MW-hr (gas) and 1,551 lb $CO_2$/MW-hr (ULSD), both on a gross energy basis. These emission factors include a 9.5% degradation allowance.

Exelon's proposed GHG BACT emissions factors 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 to reach the Project's rated power output capacity would be at least 30% greater than using an H-class simple-cycle unit. There are other disadvantages of an LMS-100 at the Facility: Three LMS-100 units (300 MW), including a collector bus switchyard, would occupy approximately 9 acres. The single 7HA.02 (no switchyard needed) will only occupy about 6 acres. The LMS-100 would also require additional silencing to achieve comparable sound emission levels. In summary, a single H-class heavy-duty simple-cycle unit is preferable to two aero derivative units to meet the Project objectives.

Upon review, MassDEP determined that GHG emission limits of 1,178 lb/MW-hr (gross) firing natural gas and 1,673 lb/MW-hr (gross) firing ULSD, at full-load ISO conditions represent BACT.

1.6. <u>Startup and shutdown</u>

During startup and shutdown, CTG operating conditions result in higher emissions factors and emission rates of $NO_x$, PM, $PM_{10}$, and $PM_{2.5}$ relative to steady-state operation.

The oxidation catalyst and SCR, require minimum operating temperatures that may not be reached during initial startup or when the CTG is below its minimum rated operating load.

There are no known add-on air pollution control technologies to limit startup / shutdown emissions beyond those already addressed (above) 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. A simple cycle turbine warms up quickly and the 7HA.02 turbine exhaust normally reaches 800°F within 5 minutes of startup, which is well within the range of an oxidation catalyst for effective CO removal. The oxidation catalyst is therefore expected to reach a normal operating temperature soon after startup. BACT for CO emissions during startup is, therefore, use of an oxidation catalyst, which reaches its normal operating temperature soon after startup (less than 30 minutes).

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 directly to the atmosphere. BACT for $NO_x$ emissions during startup consists of initiating $NH_3$ injection as soon as the SCR catalyst reaches its minimum operating temperature and other SCR design criteria are met.

The mass emission rates for startup and shutdown are based on data provided by General Electric, derived from test cell operation of units similar to the model proposed for the project.

The Applicant defined a startup event as the time from initial combustion through achieving steady-state emissions performance and the capability of complying with the BACT emissions limits established for steady-state operation. A shutdown event was defined as the time from initiating controlled shutdown of the CTG until fuel flow is shut off. According to the vendor data, startup events will last 10 – 30 minutes and shutdown events will last 8 – 14 minutes depending on the fuel. Based on the emissions data from the vendor, the Applicant proposes the following startup/shutdown mass emission rates for the CTG:

**Table 3**

**Proposed Startup and Shutdown Emission Rates**

| Event | Fuel | $NO_x$ (lb/event) | $PM/PM_{10}/PM_{2.5}$ (lb/event) |
|---|---|---|---|
| Startup | Natural Gas | 151 | 9.1 |
| | ULSD | 219 | 48.2 |

| Table 3 (continued) | | | |
|---|---|---|---|
| **Proposed Startup and Shutdown Emission Rates** | | | |
| **Event** | **Fuel** | **$NO_x$ (lb/event)** | **$PM/PM_{10}/PM_{2.5}$ (lb/event)** |
| Shutdown | Natural Gas | 7 | 4.2 |
| | ULSD | 8 | 12.8 |

**Table 3 Key:**

PM = Total Particulate Matter
$PM_{10}$ = Particulate Matter less than or equal to 10 microns in diameter
$PM_{2.5}$ = Particulate Matter less than or equal to 2.5 microns in diameter
$NO_x$ = Nitrogen Oxides
lb = pound
ULSD = Ultra Low Sulfur Diesel Fuel Oil containing a maximum of 0.0015 weight percent sulfur

Upon review, MassDEP has determined to include the Applicant's proposed start-up and shut down emission rates and the proposed maximum number of start-up and shut down episodes in the calculation of long-term (consecutive 12-month-period) BACT emissions limitations.

## 2. Emergency Generator and Emergency Fire Pump Engines

The Project includes an emergency generator engine; its primary purpose is to be able to shut the plant down safely in the event of an electric power outage. The proposed emergency generator engine will be a 581 kW (mechanical) CAT C-15 (or equivalent) ULSD-fired engine with a standby electrical generating capacity of 500 kW (nominal). Use of the emergency engine will be limited to emergencies, readiness testing, maintenance, emissions testing, and as otherwise allowed under 40 CFR part 60 subpart IIII.

The BACT analysis for both engines included a fuel selection BACT and a BACT analysis for NOx, PM, $SO_2$/Sulfuric Acid Mist, and GHG emissions.

### 2.1. Fuels

The BACT analysis for the emergency generator engine asserted that ULSD is the only feasible option for the engines due to the requirement for the engine to have a fuel supply that is directly available without interruption. The Facility area is insufficient to accommodate the size of the

LNG facility needed in order to have an uninterrupted fuel supply for the emergency generator engine. ULSD is the fuel of choice due to its ability to be stored in a small tank adjacent to the engines.

Upon review, MassDEP determined that the fuel selection of ULSD, with a sulfur content of no more than 15 ppm by weight, represents BACT for the engine.

2.2. $NO_x$

With respect to $NO_x$ emissions from the emergency generator engine, the Applicant identified two candidate technologies. These two technologies are selective catalytic reduction (SCR) and the use of a low-$NO_x$ engine design. The BACT analysis found that SCR is not technically feasible for emergency stationary RICE. The Applicant proposed an emergency generator engine that complies 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 $NO_x$.

MassDEP determined that the $NO_x$ emissions limit imposed for 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 $NO_x$, represents BACT for the emergency generator engine.

2.3. $PM/PM_{10}/PM_{2.5}$

The Applicant identified low-emissions engine design and diesel particulate filter (DPF) as technically feasible control technology options for the emergency generator engine. 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.

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 at 40 CFR 89. MassDEP Air Quality Regulations at 310 CMR 7.26(42) also require new emergency engines to meet the applicable emission limitations for non-road engines at 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.

The top level of control would be the installation of a low-PM (Tier 4) engine with a DPF. The top level of control demonstrated in practice was found to be compliance with the Tier 4

Alternate FEL Cap limit for generator engines at 40 CFR 1039.104(g), Table 1, which is 0.1 grams/kW-hr of PM.

An economic analysis of the cost effectiveness for emission control was conducted, which found that the cost effectiveness for an active DPF is almost $1,000,000 per ton of PM/$PM_{10}$/$PM_{2.5}$ controlled, and therefore not economically feasible.

The Applicant proposes the emissions limits associated with the use of clean fuels and good combustion control as BACT, consistent with 40 CFR 89 Tier 4 Alternate FEL cap engine standards for the emergency generator engine, MassDEP BACT guidance, and with past MassDEP BACT determinations for similar emission units.

After review, MassDEP concurs that the emission limits imposed for the latest available model-year NSPS-compliant emergency stationary CI RICE represent BACT for these emissions.

2.4. $\underline{H_2SO_4}$

The only control technology identified for $H_2SO_4$ from the emergency generator engine is the use of clean fuels. No other control technologies were identified and therefore, the BACT analysis was truncated. The Project will use 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.

After review, MassDEP agrees that emissions limits reflecting the use of ULSD represent BACT.

2.5. GHG

The Applicant did not identify any technically feasible control technology to reduce GHG emissions from the emergency fire pump engine. The Applicant proposes restriction on operating hours, which will limit the emergency generator engine to no more than 300 hours per year.

Upon review, MassDEP determined the emergency generator engine emissions limits in Table 4a, below, represent BACT.

| Table 4a | | | | |
|---|---|---|---|---|
| **Emergency Diesel Generator Engine BACT Emission Limits** | | | | |
| **Pollutant** | **EPA Tier 4 Standard[1] (g/kW-hr)** | **Emissions (lbs/hr)** | **Emissions (lb/MMBtu)** | **TPY** |
| $NO_x$ | 3.5 | 4.48 | N/A | 0.67 |
| $PM/PM_{10}/PM_{2.5}$ | 0.1 | 0.17 | | 0.03 |
| $SO_2$ | N/A | 0.0075 | $1.5 \times 10^{-3}$ | $1.1 \times 10^{-3}$ |
| $H_2SO_4$ | N/A | $5.78 \times 10^{-4}$ | $1.2 \times 10^{-4}$ | $8.7 \times 10^{-5}$ |
| $CO_2e$ | N/A | 819 | 162.85 | 123 |

**Table 4a notes:**

1. Tier 4 Alternate Federally Enforceable Limits (FEL) Cap limit for generator engines under 40 CFR 1039.104(g) Table 1.

**Table 4a Key**:

| | |
|---|---|
| BACT | = Best Available Control Technology |
| EPA | = Environmental Protection Agency |
| NOx | = Nitrogen Oxides |
| PM | = Total Particulate Matter |
| $PM_{10}$ | = Particulate Matter less than or equal to 10 microns in diameter |
| $PM_{2.5}$ | = Particulate Matter less than or equal to 2.5 microns in diameter |
| $H_2SO_4$ | = Sulfuric acid (mist) |
| g/kW-hr | = gram per kilowatt-hour |
| lbs/hr | = pounds per hour |
| lb/MMBtu | = pounds per Million British Thermal Unit |
| tpy | = tons per consecutive 12-month period |
| N/A | = Not Applicable |

## 3. Emergency Fire Pump Engine

The Project includes two (2) emergency fire pumps. One will be electrically driven, the other will powered by an engine that operates on ULSD fuel, exclusively. The proposed emergency fire pump engine will be a 135-brake horsepower John Deere/Clarke JU4H-UFAD5G (or equivalent) engine. Use of the engine will be limited to emergencies, periodic readiness testing, maintenance, emissions testing, and as otherwise allowed under 40 CFR part 60 subpart IIII.

The BACT analysis for the fire pump engine included a fuel selection BACT and a BACT analysis for $NO_x$, PM, $SO_2$/Sulfuric Acid Mist, and GHG emissions.

### 3.1. Fuels

The BACT analysis for the fire pump engine asserted that ULSD is the only feasible option for the engine due to the requirement for the engine to have a fuel supply that is directly available without interruption. The Facility area is insufficient to accommodate the size of the LNG facility needed in order to have an uninterrupted fuel supply for the engine. ULSD is the fuel of choice due to its ability to be stored in a small tank adjacent to the engine.

Upon review, MassDEP determined that the fuel selection of ULSD, with a sulfur content of no more than 15 ppm by weight, represents BACT for the emergency fire pump engine.

### 3.2. $NO_x$

With respect to $NO_x$ emissions from the emergency fire pump engine, the Applicant identified two candidate technologies. These two technologies are selective catalytic reduction (SCR) and the use of a low-$NO_x$ engine design. The BACT analysis found that SCR is not technically feasible for emergency stationary RICE. The Applicant proposed an emergency fire pump engine that complies with the Tier 3 standards for the fire pump engine (referenced by 40 CFR 60 Subpart IIII for emergency engines).

Based on MassDEP review, fire pump engines selection is constrained to an engine that complies with the applicable emission standards in Table 4 of 40 CFR 60 Subpart IIII. There is limited opportunity for owners to deviate from the standard offerings for either emergency or non-emergency stationary CI RICE, without jeopardizing the required manufacturer certifications.

Therefore, MassDEP determined that the $NO_x$ emissions limit imposed by the latest available model-year New Source Performance Standard (NSPS)-compliant emergency stationary CI fire pump engine represent BACT.

### 3.3. PM/$PM_{10}$/$PM_{2.5}$

The Applicant identified low-emissions engine design and diesel particulate filter (DPF) as 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.

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

An economic analysis of the cost effectiveness for emission control was conducted, which found that the cost effectiveness for an active DPF is almost $700,000 per ton of PM/PM10/PM2.5 controlled, and therefore not economically feasible.

The Applicant proposes 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.

After review, MassDEP has determined that 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, represents BACT for PM emissions.

### 3.4. $H_2SO_4$

The only control technology identified for $H_2SO_4$ from the emergency fire pump is the use of clean fuels. No other control technologies were identified and therefore, the BACT analysis was truncated. The Project will use 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.

After review, MassDEP has determined that emissions limits reflecting the use of ULSD represent BACT.

## 3.5. GHG

The Applicant did not identify any technically feasible control technology to reduce GHG emissions from the emergency fire pump engine. The Applicant proposes restriction on operating hours, which will limit the engine to operate no more than 100 hours per year for readiness testing purposes in accordance with the regulations at 40 CFR 60 Subpart IIII, and will operate no more than 300 hours per year in total.

Upon review, MassDEP determined the emergency fire pump engine emissions limits in Table 4b, below, represent BACT.

| Table 4b<br>Emergency Fire Pump Engine BACT Emission Limits | | | | |
|---|---|---|---|---|
| **Pollutant** | **EPA Tier 3 Standard (g/kW-hr)** | **Emissions (lbs/hr)** | **Emissions (lb/MMBtu)** | **Emissions (tpy)** |
| $NO_x$ and NMHC | 4.0[(1)] | 0.89 | N/A | 0.13 |
| $PM/PM_{10}/PM_{2.5}$ | 0.3 | 0.074 | | 0.01 |
| $SO_2$ | N/A | 0.0018 | $1.5 \times 10^{-3}$ | $2.7 \times 10^{-4}$ |
| $H_2SO_4$ | N/A | $1.38 \times 10^{-4}$ | $1.2 \times 10^{-4}$ | $2.1 \times 10^{-5}$ |
| $CO_2e$ | N/A | 195 | 162.85 | 29 |

**Table 4b notes:**

1. Tier 3 limit and 40 CFR 60 Subpart IIII for fire pump engines limit $NO_x$ + NMHC to 4.0 g/kW-hr. Mass emission limits in this row (for $NO_x$) assume all 4.0 g/kW-hr are $NO_x$.

**Table 4b Key**:

| | |
|---|---|
| BACT | = Best Available Control Technology |
| EPA | = Environmental Protection Agency |
| $NO_x$ | = Nitrogen Oxides |
| NMHC | = Non-Methane Hydrocarbons |
| PM | = Total Particulate Matter |
| $PM_{10}$ | = Particulate Matter less than or equal to 10 microns in diameter |
| $PM_{2.5}$ | = Particulate Matter less than or equal to 2.5 microns in diameter |
| $H_2SO_4$ | = Sulfuric acid (mist) |
| g/kW-hr | = gram per kilowatt-hour |

| | |
|---|---|
| lbs/hr | = pounds per hour |
| lb/MMBtu | = pounds per Million British Thermal Unit |
| tpy | = tons per consecutive 12-month period |
| N/A | = Not Applicable |
| $CO_2$e | = Greenhouse Gases expressed as Carbon Dioxide equivalent and calculated by multiplying each of the six greenhouse gases (Carbon Dioxide, Nitrous Oxide, methane, Hydrofluorocarbons, Perfluorocarbons, Sulfur Hexafluoride) mass amount of emissions, in tons per year, by the gas's associated global warming potential published at Table A-1 of 40 CFR Part 98, Subpart A and summing the six resultant values. |

## VII. MONITORING AND TESTING

The Applicant will be required to install, calibrate, certify, maintain, and continuously operate a continuous emission monitoring system ("CEMS") for measuring emissions of $NO_x$. The system will consist of a probe, analyzer and data acquisition system and will include a diluent monitor ($O_2$) and fuel flow monitors. The systems will comply with USEPA Regulations at 40 CFR 60 Appendixes B ad F, all applicable portions of 40 CFR 72 and 75 and MassDEP Regulations at 310 CMR 7.32 and 310 CMR 7.70.

Pursuant to 40 CFR 75.13 and 40 CFR 75 Appendix G, the Applicant will monitor $CO_2$ emissions. To obtain $CO_2$ mass emissions on an hourly basis, the Applicant will use EPA methods contained in 40 CFR 75.

The Applicant is required to monitor and keep records of the sulfur content of the natural gas and ULSD combusted in the combustion turbine as required by 40 CFR 60 Subpart KKKK.

The Applicant will also be required to conduct stack emission tests for $NO_x$, $H_2SO_4$ and total PM emissions within 180 days after initial firing of the combustion turbine to determine the compliance status with the emission limits. The Applicant is also required to repeat the initial compliance tests for PM and $H_2SO_4$ every five years.

## VIII. AIR QUALITY IMPACT ANALYSIS

The Applicant is required to demonstrate, using air quality dispersion modeling, that the increase in emissions as a result of the Project, in conjunction with background air quality and other emissions, will not cause or contribute to a violation of any National Ambient Air Quality Standards ("NAAQS") or any applicable PSD increment. The EPA has promulgated NAAQS for six air contaminants known as criteria pollutants for the protection of public health and welfare. The criteria pollutants are: nitrogen dioxide ("$NO_x$"), sulfur dioxide ("$SO_2$"), particulate matter ("PM"), carbon monoxide ("CO"), ozone ("$O_3$") and lead ("Pb"). The NAAQS include both primary and secondary standards of different averaging periods. The primary standards protect public health and the secondary standards protect public welfare, such as damage to property or vegetation.

A PSD increment is the maximum allowable increase in concentration that is allowed to occur above a baseline concentration for a pollutant and averaging period. The baseline concentration must be determined for each pollutant and, in general, is the ambient concentration existing at the time that the first complete PSD permit application affecting the area is submitted. Significant deterioration is said to occur when the amount of new pollution would exceed the applicable PSD increment. It is important to note, however, that the air quality cannot deteriorate beyond the concentration allowed by the applicable NAAQS, even if not all of the PSD increment is consumed.[8]

The Applicant conducted refined dispersion modeling analyses to predict the impacts of the Project's emissions of PSD pollutants on ambient concentrations, and determine whether the project will comply with NAAQS and PSD Increments. These analyses were conducted in accordance with EPA's "Guideline on Air Quality Models" (November 2005) as described in the Air Quality Modeling Protocol submitted to MassDEP on October 13, 2015. The Applicant used the EPA-recommended AERMOD model (AERMOD version 15181, AERMAP version 11103 and AERMET version 15181) to perform the dispersion modeling. The Applicant conducted dispersion modeling in a manner that evaluated emissions from a range of operating conditions in an effort to identify the worst-case operating conditions, that is, those that result in the highest ambient impact for each pollutant and averaging period.

To conduct dispersion modeling, the Applicant is required to input meteorological data relevant to the Project area. An applicant can either establish an on-site meteorological station to gather one year of data or propose to use five years meteorological data from a source where the applicant believes data is representative to its proposed site. The Applicant used five years (2008 through 2012) of site-specific data from the nearby Telegraph Hill monitor (approximately 2.9 miles to the south-southeast of the Project) along with concurrent surface observations from Barnstable Municipal Airport and upper air data from Chatham Municipal Airport. AERMET (version 15181) and AERSURFACE (version 13016) were used to prepare the meteorological files.

The Applicant characterized land use within a 3-kilometer radius of the Facility as rural. Therefore, the Applicant used rural dispersion coefficients in the dispersion modeling.

[8] https://www.epa.gov/nsr/prevention-significant-deterioration-basic-information

The modeling analyses included emissions from all proposed combustion equipment, that is; the new combustion turbine, the emergency generator engine, and the emergency fire pump engine, plus the existing sources at the Canal Generating Station, all operating simultaneously. The Applicant determined emission rates at three combustion turbine operating loads (30-40%, 75%, and 100 percent loads) each at five ambient operating temperatures (0°F, 20°F, 50°F, 59°F and 90°F) at steady state conditions while firing natural gas and ULSD. For each turbine load, the highest pollutant-specific emission rate coupled with the lowest exhaust temperature and exhaust flow rate was utilized. The Applicant also evaluated emissions from a combustion turbine start-up/shut down condition.

A. Significant Impact Analysis

To identify new pollution sources with the potential to alter significantly ambient air quality, EPA adopted "significant impact levels." If the predicted impact of the new or modified emission source is less than the Significant Impact Level ("SIL") for a particular pollutant and averaging period, and the margin between background ambient air quality and the NAAQS is greater than the SIL, then no further evaluation is needed for that pollutant and averaging period. However, if the predicted impact of the new or modified source is equal to or greater than the SIL for a particular pollutant and averaging period, then further impact evaluation is required. This additional evaluation must include measured background levels of pollutants, and emissions from both the proposed new or modified source and any existing emission sources that may interact with emissions from the proposed new emissions source (referred to as cumulative modeling).

The PSD regulations addressing SILs for $PM_{2.5}$ were partially vacated and remanded in the January 22, 2013 decision of the U.S. Court of Appeals for the DC Circuit (No. 10-413, *Sierra Club v. EPA*). 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[9]).

[9] USEPA 2014. Guidance for PM2.5 Permit Modeling. (EPA-454/B-14-001). USEPA, Office of Air Quality Planning and Standards, Research Triangle Park, NC 27711.

Table 5 presents the difference between the NAAQS and the representative monitored background concentration, compared to the SILs. The Applicant demonstrated that all averaging periods for each pollutant have a margin between the monitored value and the NAAQS that is greater than the respective SIL; therefore, the Applicant concluded that the use of the SILs as *de minimis* levels for all pollutants is appropriate.

**Table 5**

**Margin between the Monitored Air Quality Concentration 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 |
| $PM_{10}$ | 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 |

**Table 5 Key**:

NAAQS = National Ambient Air Quality Standards
SILs = Significant Impact Levels
$\mu g/m^3$ = microgram per cubic meter
$SO_2$ = Sulfur dioxide
$NO_2$ = Nitrogen dioxide
$PM_{10}$ = Particulate Matter less than or equal to 10 microns in diameter
$PM_{2.5}$ = Particulate Matter less than or equal to 2.5 microns in diameter

**Table 6**

**Results of Significant Impact Level Analysis**

| Pollutant | Averaging Period | Max. Predicted Project Impact ($\mu g/m^3$) | SIL ($\mu g/m^3$) | Greater than SIL? |
|---|---|---|---|---|
| $SO_2$ | 1-Hour(1) | 0.61 | 7.8 | No |
| | 3-Hour | 0.64 | 25 | No |
| | 24-Hour | 0.40 | 5 | No |
| | Annual | 0.0037 | 1 | No |
| $PM_{10}$ | 24-Hour | 11.98 | 5 | **Yes** |
| | Annual | 0.06 | 1 | No |
| $PM_{2.5}$ | 24-Hour(2) | 8.25 | 1.2 | **Yes** |
| | Annual(3) | 0.05 | 0.3 | No |
| $NO_2$(4) | 1-Hour(1) | 53.35 | 7.5 | **Yes** |
| | Annual | 0.71 | 1 | No |

**Table 6 Notes**:

1. High daily maximum 1-hour concentrations averaged over 5 years.
2. High maximum 24-hour concentrations averaged over 5 years.
3. Maximum annual concentrations averaged over 5 years.
4. $NO_2$ estimated by assuming 75% conversion of $NO_x$ to $NO_2$ for annual concentrations and 80% conversions of $NO_x$ to $NO_2$ for 1-hour concentrations.

**Table 6 Key**:

| | |
|---|---|
| Max. | = Maximum |
| SILs | = Significant Impact Levels |
| $\mu g/m^3$ | = microgram per cubic meter |
| $SO_2$ | = Sulfur dioxide |
| $NO_2$ | = Nitrogen dioxide |
| $PM_{10}$ | = Particulate Matter less than or equal to 10 microns in diameter |
| $PM_{2.5}$ | = Particulate Matter less than or equal to 2.5 microns in diameter |
| % | = percent |

## B. Background Air Quality

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 $PM_{10}$, $PM_{2.5}$, and $NO_2$.

The Applicant presented monitored ambient quality concentrations collected at the Shawme Crowell Monitoring Station in Shawme Crowell State Park, Sandwich, approximately 1 mile southwest of the Project site. The station measures concentrations of $SO_2$, $NO_2$, $PM_{10}$, and $PM_{2.5}$. The Shawme-Crowell monitor is a source-specific location designed to capture impacts from the existing Station, which was cumulatively modeled with the Project. A summary of the background air quality concentrations based on the latest three years (2012-2014) of existing monitoring data is presented in Table 7.

**Table 7**

**Monitored Ambient Quality Concentrations and Selected Background Levels**

| Pollutant | Averaging Period | Year 2012 | Year 2013 | Year 2014 | Background Air Quality (μg/m$^3$) | NAAQS (μg/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 |
| $PM_{10}$ (μg/m$^3$) | 24-Hour | 23 | 18 | 20 | 23 | 150 |
| | Annual | 9 | 9 | 9 | 9 | 50 |
| $PM_{2.5}$ (μg/m$^3$) | 24-Hour | 12 | 10 | 10 | 11 | 35 |
| | Annual | 5 | 5 | 4 | 5 | 12 |

**<u>Table 7 Key</u>:**

NAAQS = National Ambient Air Quality Standards
μg/m$^3$ = microgram per cubic meter
$SO_2$ = Sulfur dioxide
$NO_2$ = Nitrogen dioxide
$PM_{10}$ = Particulate Matter less than or equal to 10 microns in diameter
$PM_{2.5}$ = Particulate Matter less than or equal to 2.5 microns in diameter
ppb = parts per billion
ppm = parts per million

In accordance with the PSD regulations and EPA guidance, MassDEP determined that the data from the monitoring site is representative of background conditions at the Project site for $PM_{2.5}$ and other PSD pollutants and that preconstruction monitoring is not required.

C. Cumulative Dispersion Modeling

The Applicant used dispersion modeling to assess the air quality impacts from the entire Facility, including the existing emission sources and all proposed new sources. The Applicant added these impacts to background air quality. Table 8 shows the cumulative impact of both the new and existing sources at the Canal Generating Station when added to background air quality. Based on the results of the cumulative Facility impact analysis, the Project's worst-case emissions from the proposed new sources in combination with emissions from the existing Facility sources do not result in predicted concentrations that exceed the applicable NAAQS.

For the pollutants and averaging periods that have maximum predicted impacts greater than SILs (see Table 6), cumulative modeling is required. The Applicant found that there were no additional sources required for cumulative NAAQS modeling analysis. Table 8 shows the cumulative design value modeled concentrations of the new Project and existing Canal Generating Station combined with appropriate ambient background concentrations, and comparisons with the corresponding NAAQS. Based on these results, the predicted total ambient criteria pollutant concentrations are below the NAAQS for all pollutants.

**Table 8**

**Results of Cumulative Impact Analysis**

| Criteria Pollutant | Averaging Period | Predicted Facility Impact ($\mu g/m^3$) | Background ($\mu g/m^3$) | Predicted Facility Impact plus background ($\mu g/m^3$) | NAAQS ($\mu g/m^3$) | Less than NAAQS? |
|---|---|---|---|---|---|---|
| $SO_2$ | 1-Hour | 128.33 | 22 | 150.33 | 196 | Yes |
| | 3-Hour | 133.79 | 58 | 191.79 | 1,300 | Yes |
| | 24-Hour | 45.92 | 12 | 57.92 | 365 | Yes |
| | Annual | 4.20 | 5 | 9.20 | 80 | Yes |
| $PM_{10}$ | 24-Hour | 8.71 | 23 | 31.71 | 150 | Yes |
| | Annual | 1.01 | 9 | 10.01 | 50 | Yes |
| $PM_{2.5}$ | 24-Hour | 3.87 | 11 | 14.87 | 35 | Yes |
| | Annual | 0.79 | 5 | 5.79 | 12 | Yes |
| $NO_2$(1) | 1-Hour | 91.23 | 40 | 131.33 | 188 | Yes |
| | Annual | 10.04 | 15 | 25.04 | 100 | Yes |

**Table 8 Note:**

1. $NO_2$ estimated by assuming 75% conversion of $NO_x$ to $NO_2$ for annual concentrations and 80% conversions of $NO_x$ to $NO_2$ for 1-hour concentrations.

**Table 8 Key:**

| | |
|---|---|
| NAAQS | = National Ambient Air Quality Standards |
| $\mu g/m^3$ | = microgram per cubic meter |
| $SO_2$ | = Sulfur dioxide |
| $NO_2$ | = Nitrogen dioxide |
| $PM_{10}$ | = Particulate Matter less than or equal to 10 microns in diameter |
| $PM_{2.5}$ | = Particulate Matter less than or equal to 2.5 microns in diameter |

## D. PSD Increment Analysis

The PSD increment analysis requires additional modeling if the maximum modeled concentration of a pollutant due to emission increase from the proposed Project exceeds the applicable SIL (see Table 6). Therefore, the Applicant was required to model PSD increment consumption for 24-hour $PM_{10}$ and 24-hour $PM_{2.5}$. There are no $PM_{10}$ or $PM_{2.5}$ increment-consuming sources already in the baseline area.

Table 9 shows the results of the PSD increment analysis for $PM_{10}$ and $PM_{2.5}$, which includes impacts from the new turbine, emergency generator and emergency fire pump engine. The results indicate that the operation of the proposed Project is protective of the PSD increments.

**Table 9**

**Modeled Results Compared to the PSD Increments**

| Pollutant | Averaging Period | Modeled Concentration ($\mu g/m^3$) | PSD Increment ($\mu g/m^3$) | Less than PSD Increment? |
|---|---|---|---|---|
| $PM_{10}$ | 24-Hour | 8.53 | 30 | Yes |
| $PM_{2.5}$ | | 8.53 | 9 | Yes |

**Table 9 Key:**

| | |
|---|---|
| $\mu g/m^3$ | = microgram per cubic meter |
| PSD | = Prevention of Significant Deterioration |
| $PM_{10}$ | = Particulate Matter less than or equal to 10 microns in diameter |
| $PM_{2.5}$ | = Particulate Matter less than or equal to 2.5 microns in diameter |

## E. Secondary $PM_{2.5}$ Impacts

The previously mentioned EPA *Guidance for $PM_{2.5}$ Permit Modeling* provides guidance on demonstrating compliance with the NAAQS and PSD increments for $PM_{2.5}$ specifically with regard secondary formation of $PM_{2.5}$ resulting from emissions of $PM_{2.5}$ precursor pollutants. In the Guidance, EPA has defined four Assessment Case categories based on the magnitude of a project's potential emissions of direct $PM_{2.5}$ and precursors for potential secondary $PM_{2.5}$ formation, $NO_x$ and $SO_2$ (in tons per year). The Assessment Case categories identify assessment approaches that are available and appropriate for each case. The Project falls into Case 3 because direct $PM_{2.5}$ emissions are greater than 10 tons per year (TPY) and $NO_x$ and/or $SO_2$ emissions are greater than 40 tpy. Accordingly, the Applicant conducted a Case 3 qualitative assessment of potential secondary formation of $PM_{2.5}$, which is appropriate 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. The Applicant's qualitative assessment followed the example in Appendix D of the Guidance, which involves calculating an equivalent secondary $PM_{2.5}$ to primary $PM_{2.5}$ ratio. The ratio is 1.01 based on projected $PM_{2.5}$, $NO_x$ and $SO_2$ emissions. Based on the results of this assessment, the secondary $PM_{2.5}$ impact associated with the Project's precursor emissions will not cause or contribute to a violation of the 24-hour or annual $PM_{2.5}$ NAAQS. See Table 10, below.

**Table 10**

**Total $PM_{2.5}$ (Primary + Secondary) Impacts Comparison to the NAAQS and PSD increments**

| Averaging Period | New Source Primary $PM_{2.5}$ Conc. (μg/m$^3$) | Primary plus Secondary $PM_{2.5}$ Conc. (μg/m$^3$) | Monitored Background (μg/m$^3$) | Existing Source Contribution (μg/m$^3$) | Total $PM_{2.5}$ Impact (μg/m$^3$) | Standard (μg/m$^3$) | Less than Standard? |
|---|---|---|---|---|---|---|---|
| **NAAQS** | | | | | | | |
| 24-Hour | 2.43 | 2.45 | 11 | 3.87 | 17.32 | 35 | Yes |
| Annual | 0.05 | 0.051 | 5 | 0.79 | 5.84 | 12 | Yes |
| **PSD Increments** | | | | | | | |
| 24-Hour | 8.53 | 8.62 | N/A | N/A | 8.62 | 9 | Yes |
| Annual | 0.06 | 0.061 | N/A | N/A | 0.061 | 4 | Yes |

**<u>Table 10 Key</u>**:

| | |
|---|---|
| $\mu g/m^3$ | = microgram per cubic meter |
| PSD | = Prevention of Significant Deterioration |
| NAAQS | = National Ambient Air Quality Standards |
| $PM_{2.5}$ | = Particulate Matter less than or equal to 2.5 microns in diameter |

## F. AIR TOXICS ANALYSIS

The Applicant conducted an air quality impact assessment of the non-criteria pollutants (air toxics) emitted from the proposed Project and existing Canal Generating Station. Provision IV.C. of MassDEP's 2011 PSD Delegation Agreement with the USEPA allows MassDEP to implement rules or policies, which are more stringent than the federal PSD program, provided it is clearly documented that said requirements are not derived from federal PSD requirements. The air toxics analysis is not required by federal PSD Regulations at 40 CFR 52.21, but is a MassDEP requirement for PSD applications set forth in MassDEP policy "Air Toxics Implementation Update," dated August, 1989.

To obtain the predicted concentration of each pollutant across all operating loads, the Applicant utilized AERMOD and scaled the concentrations by the appropriate pollutant emission rates. The worst-case impacts were compared to applicable thresholds, according to the MassDEP's guidelines for 24-hour Threshold Effects Exposure Limit (TEL) and annual Allowable Ambient Limit (AAL). The results concluded that air quality impacts from the non-criteria emissions are below the threshold levels of the corresponding AALs and TELs. See Tables 5-16 and 5-17 of the PSD application Supplement No. 1 for the complete modeled results.

## G. IMPAIRMENT TO VISIBILITY, SOILS AND VEGETATION AND IMPACT ON GROWTH

### Visibility

Federal Land Managers (FLMs) recommend that an Applicant for a PSD permit conduct a screening analysis to determine if the proposed Project has the potential to adversely impact a Class I area, described in the *Federal Land Managers' Air Quality Related Values Work Group Phase 1 Report – Revised* (National Park Service, 2010).

This guidance document references an emission/distance (Q/D) ratio of 10, below which a proposed source is not likely to 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 $NO_x$, $SO_2$,

$H_2SO_4$, and PM emissions expressed in tpy, based on maximum short-term (24-hour) emissions levels. The Applicant determined that 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 Facility to the closest Class I area in km. The closest Class I area is the Lye Brook Wilderness Area in southern Vermont, approximately 250 km northwest of the Facility. The resulting Q/D ratio is 2.9, which is below the recommended screening ratio of 10.

Based on the results of this analysis, Mr. Ralph Perron, Air Quality Specialist of United States Forest Service Eastern Regional Office, the responsible FLM, concurred that a Class I Air Quality Related Values (AQRV) analysis is not required for the Project. This was documented in an email message by Mr. Perron dated October 26, 2015.

**Soils and Vegetation**

The PSD regulation requires analysis of air quality impacts on sensitive vegetation types, with significant commercial or recreational value, or sensitive types of soil. The Applicant evaluated impacts on sensitive vegetation by comparison of predicted Project impacts with screening levels presented in *A Screening Procedure for the Impacts of Air Pollution Sources on Plants, Soils and Animals* (EPA, 1980). As an indication to whether emissions from the Project will significantly impact the surrounding vegetation (i.e., cause acute or chronic exposure to each evaluated pollutant), the modeled emission concentrations were compared against both a range of injury thresholds found in the guidance, as well as those established by the NAAQS secondary standards. Since the NAAQS secondary standards were set to protect public welfare, including protection against damage to crops and vegetation, comparing modeled emissions to these standards provides some indication of whether potential impacts are likely to be significant. Table 11 lists the results of the potential soil and plant concentrations (based on maximum annual concentrations) and compares them to the corresponding screening concentration criteria. The results show that the concentrations are below the screening criteria.

**Table 11**

**Soils Impact Screening Assessment**

| Pollutant | Max. Deposited Conc. (ppmw) | Soil Screening Criteria (ppmw) | Percent of Soil Screening Criteria | Plant Tissue Concentration (ppmw) | Plant Screening Criteria (ppmw) | Percent of Plant Screening Criteria |
|---|---|---|---|---|---|---|
| Arsenic | $2.07 \times 10^{-5}$ | 3 | 0.0007% | $2.89 \times 10^{-6}$ | 0.25 | 0.0012% |
| Cadmium | $2.3 \times 10^{-6}$ | 2.5 | 0.0001% | $2.46 \times 10^{-5}$ | 3 | 0.0008% |
| Chromium | $9.26 \times 10^{-3}$ | 8.4 | 0.1102% | $1.85 \times 10^{-4}$ | 1 | 0.0185% |

| Table 11 (continued) | | | | | | |
|---|---|---|---|---|---|---|
| **Soils Impact Screening Assessment** | | | | | | |
| **Pollutant** | **Max. Deposited Conc. (ppmw)** | **Soil Screening Criteria (ppmw)** | **Percent of Soil Screening Criteria** | **Plant Tissue Concentration (ppmw)** | **Plant Screening Criteria (ppmw)** | **Percent of Plant Screening Criteria** |
| Lead | $1.4x10^{-3}$ | 1,000 | 0.0001% | $6.3x10^{-4}$ | 126 | 0.0005% |
| Mercury | $4.59x10^{-6}$ | 455 | 0.0000% | $2.29x10^{-6}$ | N/A | N/A |
| Nickel | $4.24x10^{-3}$ | 500 | 0.0008% | $1.91x10^{-4}$ | 60 | 0.0003% |
| Selenium | $1.15x10^{-4}$ | 13 | 0.0009% | $1.15x10^{-4}$ | 100 | 0.0001% |

**Table 11 Key**:
Max. = maximum
Con. = concentration
ppmw = parts per million weight
N/A = not applicable
% = percent

## Impact on Growth

During the 21-month construction period for the Project, the number of workers will include up 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.

The Applicant stated 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.

## IX. MASS EMISSION LIMITS

To ensure that the Applicant does not exceed the NAAQS or PSD increment during operation of the Project, a PSD permit must contain enforceable permit terms and conditions to ensure that the Project does not exceed the mass flow rates for each modeled pollutant. MassDEP has established mass emission limits for each PSD pollutant in the PSD Permit. Stack tests will confirm whether $NO_x$, PM, and $H_2SO_4$ mist emissions are in compliance with mass emission limits. The Applicant will be required to install CEMS for $NO_x$ and will document compliance with $NO_x$ emissions limits on a 1-hour basis. The Applicant will also monitor other combustion parameters to indicate compliance with PM and $H_2SO_4$ mist emission limits. The Applicant will determine compliance with the annual $CO_2$ emission limit by calculating $CO_2$ emissions using the procedures in 40 CFR 98.

## X. ENVIRONMENTAL JUSTICE

Environmental justice (EJ) is the fair treatment and meaningful involvement of all people regardless of race, color, national origin, or income with respect to the development, implementation and enforcement of environmental laws, regulations and policies.

On February 11, 1994, Executive Order 12898 was issued to direct Federal agencies to incorporate achieving environmental justice into their mission. MassDEP has the obligation under the provisions of the April 11, 2011 PSD Delegation Agreement to implement and enforce the federal PSD regulations at 40 CFR 52.21.

The terms of the PSD Delegation Agreement require MassDEP to demonstrate that the PSD permit does not violate EPA's Environmental Justice (EJ) policy and guidelines. The Delegation agreement explicitly says:

> MassDEP will follow EPA policy, guidance, and determinations as applicable for implementing the federal PSD program, whether issued before or after the execution of this Delegation Agreement, including…Federal Actions to Address Environmental

Justice in Minority Populations and Low-Income Populations, Exec. Order 12,898, 59 Fed. Reg. 7,629 (Feb. 16, 1994). ("Executive Order" or "EJ 12898")[10].

EJ 12898 states in relevant part that each Federal agency shall make achieving environmental justice part of its mission by identifying and addressing, as appropriate, disproportionately high and adverse human health or environmental effects of its programs, policies, and activities on minority populations and low- income populations. Exec. Order 12898, § 1-101, 59 Fed. Reg. 7, 629 (Feb. 16, 1994).

Federal agencies are required to implement this order consistent with, and to the extent permitted by, existing law. To comply with this requirement, EPA adopted its Environmental Justice Policy that describes environmental justice as the fair treatment and meaningful involvement of all people regardless of race, color, national origin, or income, with respect to the development, implementation, and enforcement of environmental laws, regulations, and policies. Fair treatment means no group of people should bear a disproportionate share of the negative environmental consequences resulting from industrial, governmental and commercial operations or policies. Meaningful involvement means:

- People have an opportunity to participate in decisions about activities that may affect their environment and/or health
- The public's contribution can influence the regulatory agency's decision
- Community concerns will be considered in the decision making process
- Decision makers will seek out and facilitate the involvement of those potentially affected.

MassDEP understands that the Executive Order and EJ Policy requirements pertain to MassDEP as EPA's delegated permitting authority with respect to the PSD review process for the Project.

The USEPA has developed EJSCREEN, an environmental justice mapping and screening tool, which provides demographic and environmental information for a selected area. The potential EJ communities are identified as areas that should be more fully evaluated.

EJSCREEN results identify the Otis Air National Guard Base, located to the southwest of the Project, as a minority and low-income area. EPA guidance states that screening results should be supplemented with additional information and local knowledge to get a better understanding of the issues in a selected location.[11]

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[10] https://ceq.doe.gov/nepa/regs/eos/ii-5.pdf
[11] https://www.epa.gov/ejscreen/what-ejscreen

As noted in the PSD application, a review of housing on the Base indicates there is only one home in the northeast section of the Base that is within 5 miles of the Project, with the remaining housing located in the extreme southern portions of the Base, which is beyond 5 miles from the Project. Additionally, the Barnstable County Correctional Facility is located within the southwest portion of the Base, and is also beyond 5 miles from the Project.

The demographics of the area are classified by census tract. The presence of this correctional facility in this tract (Barnstable County, Census Tract 141) is driving the classification of the Base as minority (52%) and low-income (55%).

Based on a review of census data and the housing in Census Tract 141 of Barnstable County, there are no affected Environmental Justice Communities within 5 miles of the proposed Facility.

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 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 and more than 5 miles from the Project site. For 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, 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.

Based on its review of the PSD application, MassDEP analysis of environmental justice issues determined that MassDEP has complied with the Executive Order and EJ Policy because there are no affected environmental justice communities within five miles of the Project. The Project’s emissions will not have a disproportionally high and adverse human health or environmental effects on minority and low income populations. Furthermore, MassDEP has found no indication that the Project will not extend fair treatment and meaningful involvement to all people regardless of race, color, national origin, or income with respect to the preconstruction environmental review process for the project.

Even though the Project is not subject to the requirements of EOEEA’s Environmental Justice Policy, Canal 3 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 expansion of the Facility. 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 Proposed Facility, 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 at www.canalnewgeneration.com 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.
- **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.

## XI. NATIONAL HISTORIC PRESERVATION ACT, ENDANGERED SPECIES ACT, TRIBAL AND OTHER CONSULTATIONS

MassDEP received a letter dated November 30, 2016 from EPA Region 1 indicating that the Applicant had satisfied the consultation responsibilities under the PSD Delegation Agreement between EPA and MassDEP. The following sections describe how Exelon met the National Historic Preservation Act, Endangered Species Act, and Tribal consultation requirements identified in the PSD Delegation Agreement and describe other consultations.

### *A. National Historic Preservation Act Consultation*

The Applicant sent a notification letter regarding the submittal of the PSD air permit application to the Massachusetts Historical Commission, as identified by the PSD Delegation Agreement and required by the National Historic Preservation Act consultation requirements. The Applicant also sent notification letters to the Tribal Historic Preservation Officers of the Wampanoag Tribe of Gay Head (Aquinnah) and the Mashpee Wampanoag Tribe.

The Massachusetts Historical Commission (MHC) did request a copy of the PSD Application, as did the Mashpee Wampanoag Historical Preservation Office. The Mashpee Wampanoag Historical Preservation Office requested further detail on potential archaeological impacts of the Project. The Applicant provided the Mashpee Wampanoag Historical Preservation Office further detail on how the Project is located within an area that was previously disturbed in association with the construction of the Cape Cod Canal as well as construction of the existing Canal Station. The presence of any intact below-ground archaeological resources has been determined to be highly unlikely due to the extent of the prior site disturbance. The MHC reviewed a 1998 archaeological investigation and determined that the proposed activities were "unlikely to affect significant historic or archaeological resources…"

### *B. <u>Endangered Species Act Consultation</u>*

The Applicant sent a notification letter regarding the submittal of the PSD air permit application to the U.S. Fish and Wildlife Service ("FWS"), as identified by the PSD Delegation Agreement. Additionally, the Applicant sent a notification letter to the National Marine Fisheries Service.

Neither Agency responded to the notification letters.

### *C. <u>Tribal Consultation</u>*

The Applicant sent letters of notification regarding the submittal of the PSD air permit application to the Mashpee Wampanoag Tribe and the Wampanoag Tribe of Gay Head (Aquinnah).

As noted above, the Mashpee Wampanoag Historical Preservation Office did request a copy of the PSD Application as well as further detail regarding potential archaeological impacts.

### *D. <u>Class I Area Modeling</u>*

The Applicant completed a Request for Applicability for Class I Area Modeling Analysis Document with regard to Class I areas in Vermont and New Hampshire and submitted it to the Eastern Regional Office of the US Forest Service. An Air Quality Specialist of United States Forest Service Eastern Regional Office, responded that the Forest Service would not be requesting Air Quality Related Values analyses of the Proposal.

### *E. <u>Magnuson-Stevens Fishery Conservation and Management Act</u>*

EPA Region 1 staff reviewed the proposed project and concluded that the Magnuson-Stevens Act requirements do not apply.

## XII. COMMENT PERIOD, HEARINGS AND PROCEDURES FOR FINAL DECISIONS

All persons, including the Applicant, who believe any condition of the Draft PSD Permit is inappropriate is required to raise all issues and submit all available arguments and all supporting material for their arguments in full by the close of the public comment period, 5:00 PM on Thursday, February 9, 2017 to Thomas Cushing of MassDEP at the address listed in Section XIII of this Fact Sheet.

Notice is also hereby given that MassDEP will hold a public hearing to receive public comments on the Draft PSD Permit as well as the Proposed Air Quality Plan Approval before issuing any PSD Permit and Air Quality Plan Approval. The public hearing will be held:

Date: February 8, 2017

Time: 7:00 PM

Location: Sandwich Town Hall, 130 Main St., Sandwich, MA

Persons can arrange to view copies of the Draft PSD Permit, this PSD Fact Sheet, the Proposed Air Quality Plan Approval and Exelon's applications at MassDEP's Southeast Regional Office located at 20 Riverside Drive, Lakeville, MA between 9:00 AM to 4:00 PM by calling the Southeast Region Records Coordinator at 508-946-2772. Copies of these materials are also available on MassDEP's website at:
http://www.mass.gov/eea/agencies/massdep/news/comment/.

Copies of the Draft PSD Permit, this PSD Fact Sheet, the Proposed Air Quality Plan Approval and the Applicant's applications are available for review at the Sandwich Town Clerk's Office located at 130 Main Street, Sandwich, MA and at the Sandwich public library.

Note: the notification below will appear in the PSD Permit. MassDEP is providing the notification in this PSD Fact Sheet so that interested persons will understand the applicable appeal process for any PSD Permit that may issue following the Public Hearing and Comment Period.

Along with the PSD Permit, MassDEP is notifying each person of their right to appeal the issuance of any Final PSD Permit, in accordance with 40 CFR 124.15 and 124.19 as follows:

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

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

3. If any person appeals the Permit to the EAB, the effective date of the Permit is suspended until the appeal is resolved.

## XIII. MassDEP CONTACTS

Any person may obtain additional information concerning the Draft PSD Permit between the hours of 9:00 AM and 4:00 PM, Monday through Friday, excluding holidays from:

Thomas Cushing, Permit Chief
Bureau of Air and Waste
Massachusetts Department of Environmental Protection
Southeast Regional Office
20 Riverside Drive
Lakeville, MA 02347
508-946-2824
Thomas.Cushing@state.ma.us