New Nominal 44 MW Cogeneration Project

Massachusetts Institute of Technology

Major Comprehensive Plan Approval Application (310 CMR 7.02)

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Section 1.0

Introduction

1.0 INTRODUCTION

1.1 Project Overview – Combustion Turbine Expansion

The Massachusetts Institute of Technology (MIT) is located on 168 acres along the Cambridge side of the Charles River Basin. As part of its mission, MIT is determined to support its research and other world-changing activities with efficient, reliable power and utilities. MIT is committed to achieving this while reducing its greenhouse gas (GHG) emissions at least 32% by 2030. To this end, MIT is proposing to upgrade its on-campus power plant—a key step in developing an energy strategy that makes climate change mitigation a top priority.

The MIT Central Utilities Plant (CUP) currently provides electricity, heat, and chilled water to more than 100 MIT buildings through a combined heat and power (CHP) process, also known as cogeneration—a highly efficient method of generating electrical and thermal power simultaneously. The heat and electrical power it generates is used to maintain critical research facilities, laboratories, classrooms, and dormitories.

A cogeneration system has significant efficiency and environmental advantages, as described by the Massachusetts Department of Environmental Protection (MassDEP)[1]:

> *"In a combined heat and power (CHP) system, the engine or combustion turbine is connected to an electrical generator for electrical power production. The hot exhaust gasses from the engine or combustion turbine are directed through a heat recovery system, such as a boiler, to recover thermal energy for use in heating, cooling, or other uses. This approach eliminates the need for a second combustion unit and therefore eliminates the emissions such a combustion unit would produce. CHP systems make more efficient use of fuel, such as natural gas or fuel oil, than two, separate stand alone, combustion units, one for electricity and one for thermal energy such as steam thus reducing the net emissions of greenhouse gas and other air contaminants."*

Since 1995, the CUP has consisted of a Siemens (ABB) GT10A Combustion Turbine Generator (CTG), a heat recovery steam generator (HRSG), an electric generator rated at approximately 21 Megawatt (MW), and ancillary equipment, all located in Building 42. The CUP also houses five boilers, designated as Boilers Nos. 3, 4, 5, 7 and 9, an emergency

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1 Proposed Amendments to 310 CMR 7.00, March 2008

generator, and a number of cooling towers. Currently, the cogeneration system meets about 60% of campus electricity needs, and the steam generated from waste heat is used for campus heating and cooling (through steam-driven chillers).

MIT's proposed project would enable its power plant to meet nearly 100% of anticipated campus electric and thermal needs using cogeneration, enhancing on-campus power reliability in the event of a utility outage while also reducing MIT's GHG emissions by approximately 10%. The project involves retiring the plant's existing CTG (now reaching the end of its useful life) and installing two nominal 22 MW CTGs and two dedicated HRSGs designed with natural gas-fired duct burners. In addition, as part of the this project, MIT will eliminate the burning of No. 6 fuel oil in existing boilers, significantly lowering nitrogen oxides (NO_x) and regulated pollutant emissions.

Each of the new CTGs will fire natural gas purchased and delivered to the CUP under a firm gas contract. In the event that the natural gas supply is interrupted by the supplier or is otherwise unavailable to be combusted in the equipment, each CTG will be able to operate using ultra-low sulfur diesel (ULSD) as a backup fuel. Each CTG will exhaust to a HRSG. This system will be cleaner and more efficient overall when compared with the existing system. For example, the system's state-of-the-art emissions controls will include selective catalytic reduction (SCR) for NO_x control and an oxidation catalyst for the control of carbon monoxide (CO) and volatile organics (VOC). These controls are expected to reduce NO_x by 90% as compared to the existing CTG, which is not equipped with this technology.

Additional public and environmental benefits of MIT's proposed system are detailed in Section 1.3 (Project Benefits) below.

1.2 Project Overview – Other Proposed Changes

In addition to installing two new CTGs, MIT proposes the following other changes:

- Addition of a 2 MW ULSD-fired cold-start engine unit to provide emergency power to start the CTGs when grid electricity is unavailable.

- As mentioned above, existing Boilers Nos. 3, 4, and 5 will cease burning No. 6 fuel oil and will only burn natural gas, with ULSD as a backup fuel for up to the equivalent heat input of 48 hours per year for testing and up to the equivalent heat input of 168 hours per year including testing and periods when natural gas is unavailable.

  This fuel changeover will occur within 12 months of the startup of the new CTGs. This will allow for adequate time to finish construction and remove the existing No. 6 fuel oil tanks. The boilers will not fire No. 6 fuel oil after initial startup (first fire) of the new CTGs.

- Existing Boilers Nos. 7 and 9 will fire natural gas only, with ULSD as a backup fuel for up to the equivalent heat input of 48 hours per year for testing and up to the equivalent heat input of 168 hours per year including testing and periods when natural gas is unavailable. This represents a substantial reduction in the ULSD operating time limitation from the current operating permit limit of 720 hours per year.[2]

1.3 Project Benefits

This project has been proposed and designed to improve conditions and provide benefits to MIT and the surrounding community. The intent of the project is to increase the resiliency of the campus, safeguarding crucial research and public safety by enabling MIT to function during a power-loss event; to equip the MIT community with an efficient, reliable power source capable of supporting their groundbreaking work and experimentation; and to continue conserving energy and reducing MIT's impact on the environment.

The upgraded plant will provide a reliable source of energy that is more efficient than conventional energy sources — and that will lower both GHG and pollutant emissions, as mentioned above. In addition, the upgraded plant will improve campus resiliency by placing critical equipment above the flood level, safeguarding the system to ensure that it can provide energy to MIT's campus during a flooding event.

By providing the MIT campus with a reliable power source and improving its self-sufficiency, the project will reduce the burden on the community in a power-loss situation. As a further benefit, MIT is providing Eversource Energy (formerly NSTAR) with a location inside the plant for a regulator station that gives Eversource access to high-pressure gas. With this access, Eversource can continue providing service to this area of Cambridge even as it develops and expands. By allowing and hosting new Eversource equipment, the proposed project will also provide the City of Cambridge with a back-up gas supply for existing natural gas users, a significant public benefit.

The project is also expected to improve the surrounding community by enhancing the Albany Street streetscape, installing new lighting on public walkways, and installing new public seating.

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2 The original December 2015 application requested an increase in the allowable natural gas-fired operating hours for Boilers Nos. 7 and 9. MIT has withdrawn this request because further analysis of projected operations shows that the steam load will be more efficiently met using the new CHP units, and additional operation of Boilers Nos. 7 and 9 will not be needed. Specifically, projected future operation (for model year 2023) shows that the steam generated by the CTG and HRSG units will be 1,446,663 MMbtu/year, and the steam generated by existing boilers will only be 2,154 MMBtu/year.

A further benefit is the collection of rainwater on the roof of the expanded plant's new addition. This rainwater will be discharged to an existing holding basin (approximately 145,000 gallon capacity) located on the roof of Building N16. This water will be used in the facility's cooling towers and will not flow into the City of Cambridge storm water system. The reuse of storm water will reduce local flooding risks and the facility's burden on the City's water and storm water systems.

1.4 Outline of Application

The remainder of this application is organized as follows.

Section 2 provides a detailed description and estimate of emissions for the proposed CHP expansion.

Section 3 describes the Federal, state, and local air quality regulations applicable to the CHP expansion.

Section 4 is the Best Available Control Technology (BACT) Analysis for the CHP expansion.

Section 5 documents compliance with specific Major Comprehensive Plan Approval (MCPA) requirements.

Appendices include the application forms, supplemental information, calculation details, air quality dispersion modeling results, and Acentech's Noise Report.

Section 2.0

Project Description

2.0 PROJECT DESCRIPTION AND EMISSIONS

2.1 Description of Project Site

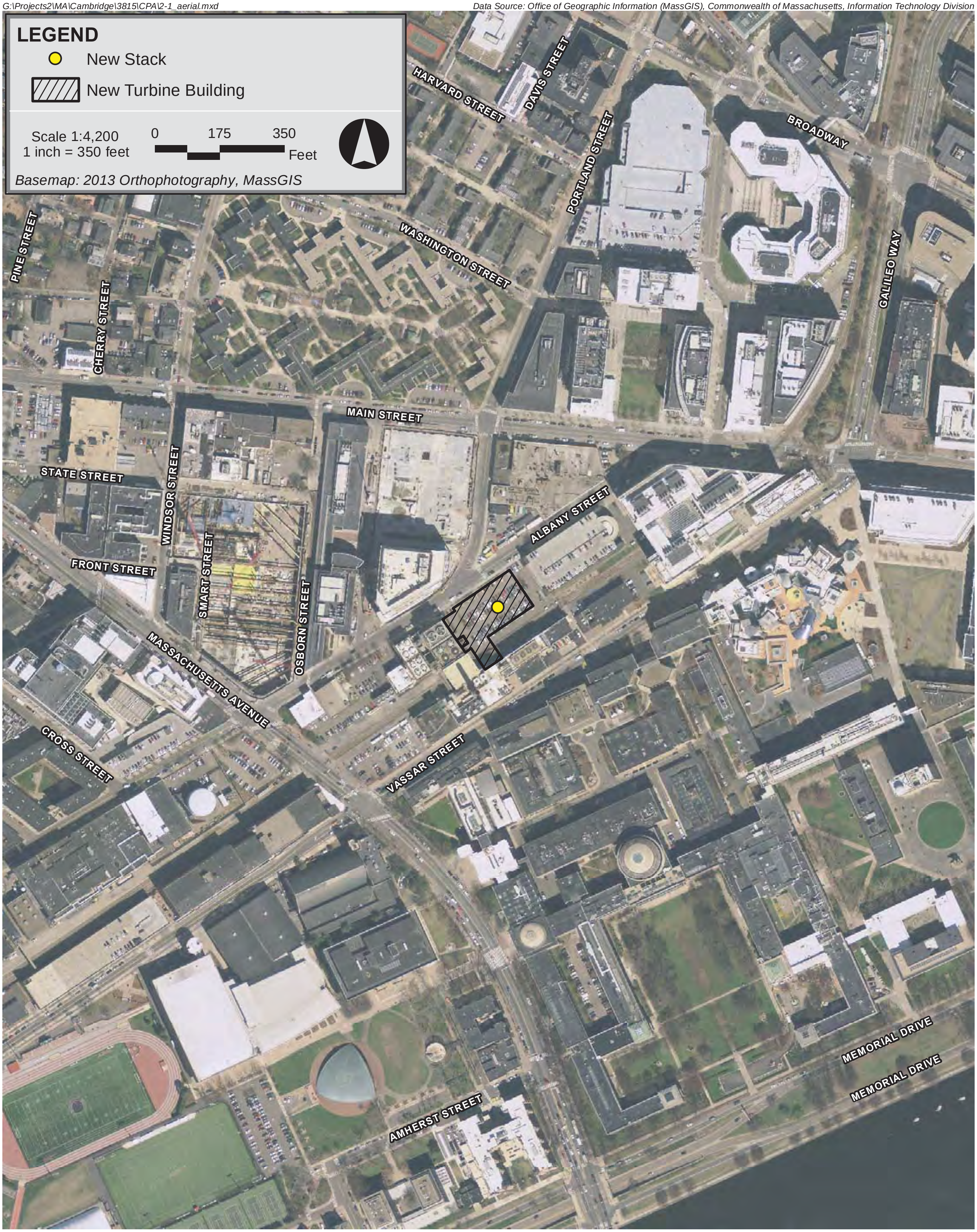
MIT is a world-class educational institution which admitted its first students in 1865. Teaching and research—with relevance to the practical world as a guiding principle—continue to be its primary purpose. MIT is independent, coeducational, and privately endowed. Its five schools and one college encompass numerous academic departments, divisions, and degree-granting programs, as well as interdisciplinary centers, laboratories, and programs whose work cuts across traditional departmental boundaries.

As an academic and research facility, MIT has steam and electricity reliability needs that exceed those of typical industrial facilities. The MIT CUP has been sized to provide near nearly 100% of the Institute's thermal and electrical needs during most operating and weather conditions. The thermal and electrical energy generated is used to maintain critical research facilities, laboratories, classrooms and dormitories in the event of a power outage, gas curtailment, or other emergency.

The Central Utility Plant (CUP) is housed in Building 42 (N16, N16A, N16C and 43 on MIT campus maps) which is located between Vassar Street and Albany Street in Cambridge, MA. The new CTGs would be housed in an addition to Building 42 to be built on the site of an existing parking lot along Albany Street between the cooling towers and an existing parking garage. The addition would be approximately 184′ x 118′ by 63′ above ground level (AGL) tall with two 167′ AGL high flues centrally co-located in a common stack structure. There will be a flue for each CTG vented through its respective Heat Recovery Steam Generator (HRSG). The cold-start engine will be roof-mounted and will have its own exhaust vent above its housing (93.5′ AGL). An aerial locus of the area around the new project is shown in Figure 2-1. The proposed new cogeneration addition and the proposed site for the new CTG stacks and new cold-start engine stack are shown.

Table 2-1 describes the key equipment at the CUP and lists the equipment designation abbreviations used in the operating permit (Application MBR-95-OPP-026).

Data Source: Office of Geographic Information (MassGIS), Commonwealth of Massachusetts, Information Technology Division



MIT Cogeneration Project Cambridge, Massachusetts

Figure 2-1

Aerial Locus Map

Table 2-1 Key Existing Equipment at the MIT Plant

Turbine No. 1	ABB GT10 (GT-42-1A) and Heat Recovery Steam Generator No. 1 (HRSG-42-1B) (collectively the Cogeneration Unit)
Boiler No. 3	Wickes 2 drum type R dual fuel (BLR-42-3)
Boiler No. 4	Wickes 2 drum type R dual fuel (BLR-42-4)
Boiler No. 5	Riley type VP dual fuel (BLR-42-5)
Generator No. 01	Emergency Diesel Generator Caterpillar No. 3516B 2MW (DG-42-6)
Boiler No. 7	Indeck Dual Fuel firing natural gas with ULSD backup (BLR-42-7)
Boiler No. 9	Rentech Boiler rated at 125 MMBtu/hr firing natural gas with Ultra Low Sulfur Diesel (ULSD) backup (BLR-42-9)
Cooling Towers	Wet mechanical towers Nos. 7,8,9,10, 11, 12, 13.

2.2 Project Description

The proposed project consists of two nominal 22 MW Solar Titan 250 CTGs fired primarily on natural gas. Backup ULSD will be used for up to the equivalent heat input of 48 hours per year for testing and up to the equivalent heat input of 168 hours per year including testing and periods when natural gas is interrupted by the supplier or is otherwise unavailable to be combusted in the equipment. Each CTG will exhaust to its own HRSG with a nominal 134 MMBtu/hr (HHV) gas-fired HRSG. The HRSG will include SCR for NO_x control and an oxidation catalyst for CO and VOC control.

Pending approvals, MIT intends to begin installing the new CTGs in 2019 and complete installation and shakeout in late 2019 or early 2020. The existing Siemens CTG will be fully retired following completion of installation and shakeout for both of the new units in 2020. At no time will the existing Siemens CTG be operating at the same time as the new Solar Titan 250 CTGs.

In addition to the two new CTGs, MIT plans to add a 2 MW ULSD-fired cold-start engine unit to be used to start the CTGs in emergency conditions.

As a result of this project, existing Boiler Nos. 3, 4, and 5 will cease burning No. 6 fuel oil and will burn only natural gas, with ULSD as a backup fuel for up to the equivalent heat input of 48 hours per year for testing and up to the equivalent heat input of 168 hours per year including testing and periods when natural gas is unavailable.

Also, existing Boilers Nos. 7 and 9 will fire natural gas only, with ULSD as a backup fuel for up to the equivalent heat input of 48 hours per year for testing and up to the equivalent heat input of 168 hours per year including testing and periods when natural gas is unavailable.

This is a substantial reduction in ULSD operating time from the current operating permit limit of 720 hours per year.

Technical specifications for the Solar Titan 250 CTG units are included in Appendix B – Part 1.

As an unrelated project, MIT has recently replaced cooling towers 3 and 4 with three new cooling towers (towers 11, 12, and 13). Cooling towers 1, 2, 5, and 6 are retired. Towers 7, 8, 9, and 10 will remain. The cooling tower replacements do not rely on the proposed project and vice-versa; the replacement cooling towers are not required for the proposed project to operate, and the proposed project does not need to be constructed for MIT to gain full use of the replacement cooling towers. Replacement of the cooling towers did not trigger Massachusetts plan approval thresholds (potential emissions less than one ton per year). The projects were funded and constructed separately. Based on a pre-application meeting with MassDEP on July 29, 2014, the changes to the cooling towers are addressed in the air quality dispersion modeling analysis for this project.

2.3 Source Emissions Discussion

The two new CTGs will emit products of combustion from the firing of natural gas or ULSD. Emissions are minimized through the use of clean burning fuels (natural gas with ULSD backup) and good combustion practices (Solar's *SoLoNOx* technology), in combination with post-combustion controls. Air emissions, including emissions from the natural gas-fired HRSG, are further reduced using Selective Catalytic Reduction (SCR) for post-combustion control of NO_x and an oxidation catalyst for post-combustion control of CO and VOC.

Because proposed ULSD use is very limited, the new CTGs have the opportunity to use dry low- NO_x combustors instead of water injection for natural gas firing. ULSD firing will make use of a separate combustor that uses water injection.

Emissions from the new cold-start engine will be minimized due to the anticipated low operating hours and burning of ULSD. .

The existing boilers will have the same short-term emission rates as currently permitted, with the same emissions controls.

Potential short-term and long-term emission rates of the project are summarized below.

Table 2-2 Proposed Emission Rates for CTGs

Pollutant	Emission Rate, Natural Gas-fired	Emission Rate, ULSD-fired	HRSG Emission Rate (Natural Gas only)	Control Technology
Nitrogen oxides (NO_x)	2.0 ppm	9.0 ppm	0.011 lb/MMBtu	SCR
Carbon Monoxide (CO)	2.0 ppm	7.0 ppm	0.011 lb/MMBtu	Oxidation Catalyst
Volatile Organic Compounds (VOC)	1.7 ppm	7.0 ppm	0.03 lb/MMBtu	Oxidation Catalyst
Particulate Matter ($PM/PM_{10}/PM_{2.5}$)	0.02 lb/MMBtu	0.04 lb/MMBtu	0.02 lb/MMBtu	Low ash fuels
Sulfur dioxide (SO_2)	0.0029 lb/MMBtu	0.0016 lb/MMBtu	0.0029 lb/MMBtu	Low sulfur fuels
Carbon Dioxide (CO_2e)[3]	119 lb/MMBtu	166 lb/MMBtu	119 lb/MMBtu	N/A
Ammonia (NH_3)	2.0 ppm	2.0 ppm	2.0 ppm	SCR

ppm = parts per million (dry volume, corrected to 15% oxygen)

lb/MMBtu = pounds per million British Thermal Unit

Short-term NO_x, CO, VOC, and NH_3 emission rates are for full-load, steady-state operations.

Table 2-3 Proposed Project Potential Emissions in Tons Per Year [From Table C-10 of Appendix C]

	CTGs & Duct Burners	Cold-start Engine	Total
NO_x	21.1	5.3	26.4
CO	15.1	0.33	15.4
VOC	20.9	0.17	21.0
$PM/PM_{10}/PM_{2.5}$	50.0	0.06	50.1
SO_2	7.0	0.004	7.0
CO_2e	294,970	480	295,450

CO_2e emission rates are rounded to the nearest ten tons.

Boilers Nos. 3, 4, 5, 7 and 9 are part of the project but have no emissions increase. As such, they are not included in the potential emissions from the project.

The basis for each proposed emission limit is described in Section 4, and a summary of the proposed emission limits and compliance mechanisms is in Section 4.11. CHP systems using CTGs are not "off-the-shelf" items but instead are more customized to the specific

3 CO2e emission factors are from 40 CFR Part 75 Appendix G

application. The published specifications sheets for the Solar Titan 250 are included in Appendix B – Part 1, and a vendor video is posted at https://www.youtube.com/watch?v=gfXKgG84lTk. Air emissions calculations to document the short-term emission rates (Tables C-1 and C-2), long-term emission rates (Table C-10), and stack exhaust parameters (Tables C-1, C-2, and C-3) for different conditions are in Appendix C.

Tables C-1 and C-2 in Appendix C calculate emission rates and exhaust parameters across a range of conditions. Key design inputs include CTG fuel input (MMBtu/hr) and exhaust flow (CTG outlet Flow Rate (ft3/min) at CTG Exhaust Temp. (°F)), provided by Solar for the ambient conditions (including elevation) and expected system back pressure associated with the HRSG, pollution control catalysts, ductwork, and stack. HRSG fuel input (MMBtu/hr) and stack exhaust temperature are calculated by Vanderweil Engineers based on the HRSG system specifications prepared by Vanderweil.

Detailed project design is continuing. Data provided by Solar and Deltak (HRSG vendor) in September 2016 for representative conditions show heat input data within 0.5% to 2% of the values in Appendix C (Tables C-1 and C-2) and exhaust flow data within 0.5 to 4.5% of the values in Appendix C (Tables C-1 and C-2). The current project design exhaust flows are higher than what was used in the air quality dispersion modeling (and therefore the modeled exhaust parameters have conservatively low exhaust flow and will tend to overstate impacts). MIT will operate the upgraded CUP in compliance with the proposed emission and operating limits in this application and will provide final design data prior to initiating construction.

In contrast, diesel engines such as the cold-start engine behave approximately the same irrespective of atmospheric conditions and the service they are placed in. They are relatively "off-the-shelf" items with published vendor specifications. MIT proposes to use the CAT Model DM8263 or equivalent as the cold-start engine; the published specification sheets for the CAT DM8263 are in Appendix B – Part 2.

2.4 Exhaust Design Configurations

Emissions from the existing Boilers Nos. 3, 4, and 5 are vented out the brick stack on the roof of the CUP. The existing CTG No. 1 stack and the emergency generator stack are also located on the roof of the existing CUP. Existing Boilers Nos.7 and 9 are located adjacent to Building N16A at 60 Albany Street, across the railroad tracks from the main CUP building. Exhaust from both Boiler No. 7 and Boiler No. 9 is combined and vents through a common stack.

The two new CTGs with HRSGs and nonpolluting ancillary equipment will be located in an addition to Building 42 to be built on the site of an existing parking lot along Albany Street between the cooling towers and an existing parking garage[4]. The project layout is shown in Figure 2-1. There will be two 167′ AGL high flues centrally co-located in a common stack structure. There will be a flue for each CTG vented through its respective HRSG system. The cold-start engine flue will be located atop its housing (93.5′ AGL).

2.5 Project Schedule

Pending approvals, MIT intends to begin installing the new CTGs and cold-start engine in 2019 and complete installation and shakeout in late 2019 or early 2020. The existing Siemens CTG will be fully retired following completion of installation and shakeout for both of the new units in 2020. The fuel switch for Boilers Nos. 3, 4, and 5 will occur within 12 months of the startup of the new CTGs.

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4 Ancillary equipment includes electrical switchgear and natural gas metering equipment. The electrical equipment will not contain any sulfur hexafluoride (SF_6).

Section 3.0

Applicable Regulatory Requirements

3.0 APPLICABLE REGULATORY REQUIREMENTS

Under federal and state air laws, the MassDEP and the EPA have promulgated air quality regulations that establish ambient air quality standards and emission limits. These standards and limits impose design constraints on new facilities and provide the basis for an evaluation of the potential impacts of proposed projects on ambient air quality. This section briefly describes these regulations and their relevance to the proposed expansion of the CUP. As discussed below, regulations and guidance apply to the project as a whole or to individual components of the project (the CTGs/HRSGs, the cold-start engine, the boilers).

Regulatory requirements are summarized in Table 3-1, below:

Table 3-1 Summary of Applicable Requirements

Regulatory Program	Applicability
Ambient Air Quality Standards and Policies	Applies and compliance is documented through air quality dispersion modeling in the air plan approval process
Prevention of Significant Deterioration (PSD) Review	Applies and is the subject of a separate PSD permit application
Non-Attainment New Source Review	Does not apply
New Source Performance Standards	The CTGs and the HRSGs are subject to 40 CFR 60 Subpart KKKK. The cold-start engine is subject to 40 CFR 60 Subpart IIII. Boilers Nos. 7 and 9 continue to be subject to 40 CFR 60 Subparts Dc and Db, respectively.
National Emission Standards for Hazardous Air Pollutants	Emergency Engine standards in Subpart ZZZZ applies to cold-start engine.
Emissions Trading Programs	The new CTGs are subject to 310 CMR 7.32 as applicable. The new units will not be subject to federal Clean Air Interstate Rule, the federal Acid Rain Program, or the Regional Greenhouse Gas Initiative.
Visible Emissions	Applies and will be complied with
Noise Control Regulation and Policy	Applies and is satisfied through the noise analysis in the air plan approval process
Air Plan Approval	Applies and is satisfied through the air plan approval application
Operating Permit	Applies and will be satisfied through an operating permit modification application after the air plan approval is issued
Compliance Assurance Monitoring	Does not apply
Massachusetts Environmental Policy Act (MEPA) Review	Applies and will be satisfied through separate filings to the MEPA office
Massachusetts Environmental Justice Guidance	Does not apply to the project, but must be followed by MassDEP in the Plan Approval process.

3.1 Ambient Air Quality Standards and Policies

The EPA has developed National Ambient Air Quality Standards (NAAQS) for six air contaminants, known as criteria pollutants, for the protection of public health and welfare. These criteria pollutants are SO_2; particulate matter having an aerodynamic diameter of 10 micrometers or less (PM_{10}); particulate matter having an aerodynamic diameter of 2.5 micrometers or less ($PM_{2.5}$); nitrogen dioxide (NO_2); carbon monoxide (CO); ozone (O_3); and lead (Pb).

The NAAQS consist of primary and secondary standards. Primary standards are intended to protect human health. Secondary standards are intended to protect public welfare from known or anticipated adverse effects associated with the presence of air pollutants, such as damage to property or vegetation. NAAQS have been developed for various durations of exposure. Massachusetts Ambient Air Quality Standards (MAAQS) are codified in 310 CMR 6 and generally follow the NAAQS but have not yet been updated to reflect the EPA's recent revisions to some NAAQS standards.

Table 3-2 summarizes the standards as currently presented by the EPA and MassDEP.

Table 3-2 National and Massachusetts Ambient Air Quality Standards (MAAQS), SILs, and PSD Increments

Pollutant	Averaging Period	NAAQS/MAAQS ($\mu g/m^3$)		Significant Impact Level ($\mu g/m^3$)	PSD Increments ($\mu g/m^3$)	
		Primary	Secondary		Class I	Class II
NO_2	Annual (1)	100	Same	1	2.5	25
	1-hour (2)	188	None	7.5	None	None
SO_2	Annual (1)	80	None	1	2	20
	24-hour (3)	365	None	5	5	91
	3-hour (3)	None	1300	25	25	512
	1-hour (4)	196	None	7.8	None	None
$PM_{2.5}$	Annual (1)	12	15	0.3	1	4
	24-hour (5)	35	Same	1.2	2	9
PM_{10}	Annual (6)	50	Same	1	4	17
	24-hour (7)	150	Same	5	8	30
CO	8-hour (2)	10,000	Same	500	None	None
	1-hour (2)	40,000	Same	2,000	None	None
Ozone	8-hour (8)	148	Same	N/A	None	None
Pb	3-month (1)	1.5	Same	N/A	None	None

(1) Not to be exceeded
(2) 98th percentile of 1-hour daily maximum concentrations, averaged over 3 years
(3) Not to be exceeded more than once per year.
(4) 99th percentile of 1-hour daily maximum concentrations, averaged over 3 years
(5) 98th percentile, averaged over 3 years
(6) EPA revoked the annual PM_{10} NAAQS in 2006.
(7) Not to be exceeded more than once per year on average over 3 years
(8) Annual fourth-highest daily maximum 8-hr concentration, averaged over 3 years. MAAQS is 235 $\mu g/m^3$.
Source: http://epa.gov/air/criteria.html

One of the basic goals of federal and state air regulations is to ensure that ambient air quality, including the impact of background, existing sources, and new sources, is in compliance with ambient standards. Toward this end, all areas of the country have been classified as an "attainment," "non-attainment", or "unclassified" area for a particular contaminant.

The City of Cambridge in Middlesex County is presently designated as unclassified (treated as attainment) or attainment for SO_2, CO, PM_{10}, $PM_{2.5}$, and Pb. The entire Commonwealth of Massachusetts, including Middlesex County, is classified as moderate non-attainment for O_3 (8-hr standard).

MassDEP regulates compliance with NAAQS and MAAQS through the Massachusetts Air Plan Approval process, discussed below. Compliance is required for the project as a whole.

3.2 Prevention of Significant Deterioration (PSD) Review

Prevention of Significant Deterioration review is a federally mandated program for review of new major sources of criteria pollutants or major modifications to existing sources. In Massachusetts, as of April 2011, MassDEP has "full responsibility for implementing and enforcing the federal PSD regulations."

The project as a whole triggers PSD Major Modification thresholds as follows:

- MIT is an existing major stationary source of air emissions per the federal PSD program at 40 CFR 52.21(b)(1)(i), with potential emissions of one or more PSD pollutants above 100 tons/year for a facility with combinations of fossil-fuel boilers totaling more than 250 MMBtu/hr heat input.

- The project per 40 CFR 52.21(b)(52) is the installation of the CTGs and associated HRSGs, the cold-start engine, and the change from No. 6 oil firing to ULSD firing in Boilers Nos. 3, 4, and 5. The restriction of ULSD operations in Boilers Nos. 7 and 9 is not a physical change or change in the method of operation. For purposes of PSD applicability review, to be conservative the project emission rates in Table 3-1 below include emissions from the recently-installed, unrelated cooling tower installation.

- Per 40 CFR 52.21(a)(2)(iv), a project is a major modification for a regulated New Source Review (NSR) pollutant if it causes two types of emissions increases - a significant emissions increase, and a significant net emissions increase.

- The project will create a significant emissions increase per 40 CFR 52.21(b)(23)(i) for CO_2e, PM_{10}, and $PM_{2.5}$. The emissions from the project are compared to PSD thresholds in Table 3-3.

- ♦ The project will also create a significant net increase for CO_2e, PM_{10}, and $PM_{2.5}$, as there are no contemporaneous emissions decreases that are enforceable as a practical matter per 40 CFR 52.21(b)(3)(vi).

Therefore, the project will be a major modification of an existing major source, subject to the requirement to obtain a PSD permit.

Table 3-3 Comparison of Project Emissions to PSD Triggers

Pollutant	Estimated Potential Emission Rates (tpy)	Significant Emission Rate (tpy)	Significant?
NO_x	26.4	40	No
CO	15.4	100	No
VOC	21.0	40	No
PM_{10}	51.0	15	Yes
$PM_{2.5}$	51.0	10	Yes
SO_2	7.0	40	No
CO_2e	295,450	75,000	Yes
Lead	Negligible	0.6	No
Fluorides	Negligible	3	No
Sulfuric Acid Mist	5.4	7	No
Hydrogen Sulfide	None expected	10	No
Total reduced sulfur	None expected	10	No
Reduced sulfur compounds	None expected	10	No

The project is not expected to emit any other regulated NSR pollutants as defined in 40 CFR 52.21 (b)(50); that is: pollutants with standards promulgated under Section 111 of the Clean Air Act Amendments of 1990 and not listed above, Class I or II ozone-depleting substances regulated subject to a standard promulgated under or established by Title VI of the Clean Air Act Amendments of 1990, and pollutants otherwise subject to regulation under the Clean Air Act Amendments of 1990 as defined in paragraph 40 CFR 52.21 (b)(49) and not listed above.

The PSD regulations define "minor source baseline date" at 40 CFR 52.21(b)(14)(ii) as "the earliest date after the trigger date on which… a major modification subject to 40 CFR 52.21… submits a complete application." Therefore, if the minor source baseline date has not been established for the baseline area, this application will establish the baseline date when it is determined to be complete. EPA has established increment standards for PM_{10} and $PM_{2.5}$. The project will comply with all applicable PSD requirements including demonstrating BACT and complying with all NAAQS and PSD increments.

3.3 Non-Attainment New Source Review

If an area is designated as "non-attainment" for a given contaminant and if the proposed facility is a major source of the non-attainment contaminant, a procedure known as Non-Attainment New Source Review (NSR) applies. The Non-Attainment NSR regulations have more stringent requirements than PSD review for source control and for securing emissions offsets.

As discussed in Section 3.1, above, the entire Commonwealth of Massachusetts is classified as a moderate non-attainment area for O_3 (8-hour standard) and attainment for all other criteria pollutants. Because O_3 is not directly emitted, it is considered a secondary pollutant that is photochemically produced as a function of both VOC and NO_x emissions. Therefore, VOC and NO_x are regulated as the precursors of O_3. Therefore, Non-attainment NSR relative to O_3 is required only for new major sources of VOC and/or NO_x or major modifications at existing major sources.

The MIT project as a whole does not trigger Non-attainment NSR because it does not meet the threshold requirement for major source modification. The project's potential NO_x emissions will be below the 310 CMR 7.00: Appendix A major source modification threshold of 25 tpy for an existing major source of NO_x. MIT maintains calculations to continuously document that this threshold is not exceeded. In order to ensure that CUP emissions do not exceed the threshold, MIT proposes a limitation during the first calendar year of operation for specific individual components of the project. Specifically, MIT proposes the following limitation for total emissions from the CTG and HRSG units:

Table 3-4 First-year Limitations on CTG/HRSG Units

Potential Emissions	Both CTGs & HRSGs
NO_x	10.55

MIT is not an existing major source of VOC. The project's VOC emissions potential is less than 25 tpy, which puts the project below the major modification threshold for both an existing major source of VOC and an existing minor source of VOC. Therefore, Non-Attainment NSR does not apply to VOC emissions in this case. Upon implementation of this project, MIT will become a major source of VOC emissions, and future projects will be subject to the 25 ton/year major modification threshold.

3.4 New Source Performance Standards

New Source Performance Standards (NSPS) regulate the amount of air contaminants that may be emitted from a given process. The EPA has established NSPS for various categories of new sources. Individual components of the project are subject to NSPS as described below.

- Each CTG/HRSG unit is subject to NSPS under 40 CFR 60 Subpart KKKK, Standards of Performance for Stationary Combustion Turbines.

- Subpart KKKK limits SO_2 to 0.060 lb/MMBtu heat input. The MIT project's proposed emission limits are well below this limit. As demonstrated in Sample Calculation C-2 of Appendix C, the proposed SO_2 limit for this project equates to 0.0029 lb/MMBtu, which is approximately half of the Subpart KKKK limit.

- Similarly, Subpart KKKK limits NO_x to 2.3 lb/MWH for natural gas-fired units and would limit this project to approximately 50.6 lb/hr of NO_x per CTG (based on 2.3 lb/MWH and a 22 MW nominal output per CTG) while firing natural gas. Again, the project's proposed limit is well below this limit, with a proposed NO_x limit under the same conditions of 3.2 lb/hr.

- Subpart KKKK limits NO_2 to 5.5 lb/MWH for distillate oil-fired units and would limit this project to approximately 121 lb/hr of NO_x per CTG (based on 5.5 lb/MWH and a 22 MW nominal output per CTG) while firing ULSD. The proposed NO_x limit for this project under the same conditions is 9.5 lb/hr, again well below NSPS limits.

New NSPS regulations on the Standards of Performance for Greenhouse Gas Emissions for Electric Generating Units were finalized by EPA on August 3, 2015. These regulations are found in 40 CFR 60, Subpart TTTT, and apply to any unit considered an electric generating unit (EGU) that does not meet the exemption criteria set forth in subpart TTTT. The rule's preamble states that to be considered an EGU, a unit must "(1) be capable of combusting more than 250 MMBtu/h (260 GJ/h) heat input of fossil fuel; and (2) serve a generator capable of supplying more than 25 MW net to a utility distribution system (i.e., for sale to the grid)." The project's proposed CTGs are nominally 22 MW, which means they fall below the limit described in point (2) of serving a generator capable of supplying greater than 25 MW net. In addition, the output of the CTGs is for MIT use only and will not be exported to the electric utility system. For both of these reasons, the proposed project is exempt and is not subject to the new NSPS rules set forth in 40 CFR 60, Subpart TTTT.

The new cold-start engine is subject to NSPS under 40 CFR 60 Subpart IIII (Standards of Performance for Stationary Compression Ignition Internal Combustion Engines). MIT will comply with this standard by purchasing a certified engine and by imposing annual operating hour limits and work practices. The cold-start engine will be certified per the MassDEP Environmental Results Program (ERP) and will comply with EPA standards for non-road engines as well as with the NSPS regulations at 40 CFR 60 Subpart IIII for stationary emergency engines.

The existing Boilers Nos. 7 and 9 are subject to NSPS under 40 CFR 60 Subpart Dc and Db, respectively. No new requirements are triggered.

Boilers Nos. 3, 4, and 5 predate the NSPS program, and the proposed operational changes (removal of No. 6 oil firing and establishment of ULSD as a backup fuel for up to the equivalent heat input of 48 hours per year for testing and up to the equivalent heat input of 168 hours per year including testing and periods when natural gas is unavailable) do not impact the status of these boilers vis-à-vis the NSPS program.

3.5 National Emission Standards for Hazardous Air Pollutants

Realizing that numerous pollutants do not meet the specific criteria for development of a NAAQS, Congress included Section 112 in the 1990 Amendments of the Clean Air Act to provide the EPA with a vehicle for developing standards for other potentially hazardous pollutants. These standards are the National Emission Standards for Hazardous Air Pollutants (NESHAPs), and the regulations that have been developed to enforce these standards are presented in 40 CFR Parts 61 and 63. Individual components of the project are subject to NESHAPs as described below.

EPA has finalized the NESHAP for Industrial/Commercial/Institutional Boilers and Process Heaters at Major and Area Sources. As defined by this NESHAP, MIT is an Area Source of hazardous air pollutants or HAPs (potential emissions <25 tons/year total HAPs, <10 tons/year each individual HAP) and must therefore comply with 40 CFR 63 Subpart JJJJJJ[5]. However, the proposed project's HRSG fires only natural gas, and the project will transform existing Boilers Nos. 3, 4, 5, 7, and 9 into "gas-fired boilers" as defined in 40 CFR 63.11237. Since Subpart JJJJJJ only applies to fuel types other than natural gas, the proposed project does not trigger a review under this NESHAP.

The new CTG/HRSG units are not subject to the NESHAP for Stationary Combustion Turbines (40 CFR 63 Subpart YYYY) as it only applies to major sources of HAPs. Based on tons of HAPs produced per year, the MIT facility does not meet the threshold to qualify as a major source.

Also, as an Area Source of HAPs, the cold-start engine is subject to the NESHAP for Stationary Reciprocating Internal Combustion Engines (40 CFR Part 63 Subpart ZZZZ). Per 40 CFR 63.6590(c)(1), the cold-start engine meets the requirements of Subpart ZZZZ for emergency engines by meeting the requirements of 40 CFR Part 60, Subpart IIII, "Standards of Performance for Stationary Compression Ignition Internal Combustion Engines."

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[5] The definition of gas-fired boiler in 40 CFR 63.11237 is: "any boiler that burns gaseous fuels not combined with any solid fuels and burns liquid fuel only during periods of gas curtailment, gas supply interruption, startups, or periodic testing on liquid fuel. Periodic testing of liquid fuel shall not exceed a combined total of 48 hours during any calendar year." MIT will meet this by limiting ULSD testing to 48 hours per year.

3.6 Emissions Trading Programs

The Clean Air Interstate Rule ("CAIR") was a federal regulatory program controlling emissions of ozone precursors and fine particulates in the eastern United States. Effective in 2009 and implemented in Massachusetts as 310 CMR 7.32, CAIR functioned as an emission trading program similar to the Acid Rain Program and the Regional Greenhouse Gas Initiative ("RGGI"). Under CAIR, qualifying Massachusetts emission sources needed to hold or procure sufficient "allowances" to cover actual NO_x emissions for the prior ozone season (May-September).

As of January 1, 2015, the Commonwealth of Massachusetts is no longer subject to the CAIR program or its replacement, the Cross-State Air Pollution Rule (CSAPR, aka "Transport Rule"), since it was determined not to contribute to air pollution in downwind states. However, the state is required to maintain its NO_x emission reductions and is working to develop a replacement program. This means Massachusetts is maintaining (at a minimum) certain requirements implemented under 310 CMR 7.28.

The proposed project's new CTGs meet the threshold (250 MMBtu/hr) for inclusion per 310 CMR 7.32 and are subject to the requirements of 310 CMR 7.28 that are currently in effect. Per MassDEP instructions[6], no ozone season NO_x allowance holding requirements are currently in effect, but the monitoring, reporting, and recordkeeping requirements of 310 CMR 7.32(8-9) continue to be in effect. MIT will comply with the applicable regulations at the time of operation by participating in the NO_x monitoring and reporting methods specified in 40 CFR 75, and MIT will also comply with the requirement to obtain allowances as needed in the event that a new state program is established.

Each of the proposed project's new CTGs is less than 25 MW, and therefore the project is not subject to the federal Acid Rain Program or the Regional Greenhouse Gas Initiative.

3.7 Visible Emissions

Massachusetts regulation 310 CMR 7.06 limits smoke to No. 1 on the Ringlemann Chart (except for six minutes in an hour up to No. 2 on the Chart) and limits opacity (excluding water vapor) to 20% (except for two minutes in an hour up to 40%). This applies to individual components of the proposed project: the CTGs/HRSGs, boilers, and cold-start engine. For these combustion sources, MIT will comply through the use of clean fuels and good operating practices.

[6] http://www.mass.gov/eea/docs/dep/air/approvals/cair-email.pdf, December 31, 2014

MIT intends to use Continuous Opacity Monitoring System (COMS) on the new CTG/HRSG units to demonstrate compliance with 310 CMR 7.04(2) (Smoke Density Indicators).

3.8 Short-term NO_2 Policy

On April 20, 1978, and in an update on November 3, 1980, MassDEP adopted a policy entitled "New Source Performance Criteria for Allowable Ambient NO_2 Concentrations." The policy applies only to new major sources or modifications to an existing source which would result in increased emissions of at least 250 tpy of NO_x. The proposed project's potential emissions are well below this threshold. Furthermore, the one-hour NO_2 NAAQS concentration limit is well above the project's permitted one-hour NO_2.

3.9 Noise Control Regulation and Policy

Per MassDEP's Noise Policy Interpretation, MassDEP regulates noise as a form of air pollution. The Policy Interpretation states:

> *"When reviewing applications for pre-construction approval of new sources of air pollution, MassDEP examines the potential increase in sound levels over ambient conditions and the impacts of noise at both the source's property line and at the nearest residence or other sensitive receptor (e.g., schools, hospitals) located in the area surrounding the facility and occupied at the time of the permit review."*[7]

MassDEP regulations, set forth in 310 CMR 7.10 and interpreted in the MassDEP Noise Policy 90-001, limit noise increases to 10 dBA over the existing L_{90} ambient level at the closest residence and at property lines. MassDEP also prohibits "pure tone" sounds, defined as any octave band level that exceeds the levels in the two adjacent octave bands by 3 dB or more. Noise considerations are discussed in an appendix to this application. The proposed project as a whole will comply with all components of the MassDEP Noise Policy 90-001 as indicated in Appendix E.

3.10 Air Plan Approval

The proposed project as a whole is subject to MassDEP Air Plan Approval (permit) requirements under 310 CMR 7.02. The purpose of Air Plan Approval review is to ensure that these new and modified sources will be in compliance with all applicable federal and DEP air regulatory requirements, including emission standards and ambient air quality criteria.

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[7] http://www.mass.gov/eea/agencies/massdep/air/programs/noise-pollution-policy-interpretation.html

This Air Plan Approval application covers the Project as a whole, even though some individual components would not trigger plan approval requirements. In particular, the cold-start engine is exempt per 310 CMR 7.02(2)(b)29 as a reciprocating engine subject to 310 CMR 7.26(42).

In addition to the federal and state limits and standards described above which are implemented through the MassDEP Air Plan Approval review, Massachusetts regulations require the application of Best Available Control Technology (BACT) for each regulated pollutant. Massachusetts BACT is based on the maximum degree of reduction of any regulated air contaminant that the MassDEP determines, on a case-by-case basis, is achievable taking into account energy, environmental, and economic impacts. A BACT determination can never result in a less stringent emission limitation than an applicable emission standard. Depending on the circumstances, BACT may parallel the emission standard or may be more stringent than the emission standard. BACT itself is a standard that balances emission control benefits with technical feasibility, other environmental impacts, and costs. Application of BACT is demonstrated in Section 4 of this application. The proposed project meets BACT.

Compliance with ambient air quality criteria is demonstrated in Appendix D.

3.11 Industry Performance Standards

The Massachusetts Industry Performance Standards in 310 CMR 7.26 apply to individual components of this project. The Engines and Turbines section at 7.26(43) and the Combined Heat and Power section at 7.26(45), which only apply to turbines smaller than 10 MW, do not apply to the proposed project. However, the project's cold-start engine is subject to the MassDEP ERP Standards for emergency engines and turbines at 310 CMR 7.26(42), which requires that affected emergency engines must comply with the applicable emission limitations set by the EPA for non-road engines (40 CFR Part 89 as in effect October 23, 1998) at the time of installation. MIT will obtain the appropriate engine supplier certification for this unit and will file the appropriate Environmental Results Program form within 60 days of the commencement of operation.

3.12 Fuel Switching

The conversion of Boiler Nos. 3, 4, and 5 from natural gas and No. 6 oil to natural gas with ULSD backup will result in an emissions improvement.

3.13 Operating Permit

MIT is subject to the operating permit requirements in 310 CMR 7.00, Appendix C. MIT has an operating permit (MBR-95-OPP-026 MM) pursuant to this program (sometimes referred to as a "Title V" permit because the program was originally initiated by Title V of the Clean Air Act Amendments of 1990). After receipt of an Air Plan Approval, MIT will apply to modify the operating permit to reflect the conditions of the Air Plan Approval. That modification will include the addition of the new equipment to the facility-wide emission limits.

3.14 Compliance Assurance Monitoring

The Compliance Assurance Monitoring requirements at 40 CFR 64 applies when an emission unit uses a control device to comply with certain emission limits, the potential emissions before control are above major source thresholds, and the operating permit does not specify a continuous compliance determination method, such as CEMS. While the new CTGs will use control devices (SCR and oxidation catalyst) to comply with NO_x, CO, and VOC emission limits, MIT will use a CEMS to continuously determine compliance. The Compliance Assurance Monitoring requirements therefore do not apply to the CTGs and HRSGs. The cold-start engine does not use control devices to comply with emission limits.

3.15 Massachusetts Environmental Policy Act

Per the Massachusetts Environmental Policy Act (MEPA) Office website, MEPA requires that state agencies study the environmental consequences of their actions, including permitting and financial assistance. It also requires them to take all feasible measures to avoid, minimize, and mitigate damage to the environment.

MEPA further requires that state agencies "use all practicable means and measures to minimize damage to the environment" by studying alternatives to the proposed project and developing enforceable mitigation commitments, which will become conditions for the project if and when it is permitted.

MIT's proposed project triggers review through the MEPA review process. MassDEP is precluded from issuing the MCPA until the MEPA review process has concluded, to ensure that MassDEP is aware of the environmental consequences associated with permit issuance. MIT has concluded the MEPA review process, per certificate EEA # 15453 issued July 1, 2016.

3.16 Massachusetts Environmental Justice Guidance

The Massachusetts Executive Office of Energy and Environmental Affairs (EEA), of which MassDEP is a part, has established an Environmental Justice Policy[8]. The policy instructs agencies to consider outreach efforts including scheduling public meetings or hearings at locations and times convenient for neighborhood stakeholders; translating public notices

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8 http://www.mass.gov/eea/docs/eea/ej/ej-policy-english.pdf, accessed 10/12/2016

into other languages; and offering interpreters and translated documents at public meetings. MIT has performed its own outreach efforts and will support MassDEP with outreach efforts related to the public hearing associated with this MCPA application.

The EEA has established environmental justice neighborhoods which identify areas with minority populations and low-income populations. Figure 3-1 identifies areas with minority populations and low-income populations in the vicinity of MIT. This MCPA application will assist MassDEP in promoting enforcement of the applicable health and environmental statutes in these areas, specifically the NAAQS.

3.16.1 Environmental Justice conclusions

As shown in the detailed sections below, MIT's proposed project will have no disproportionately high and adverse human health or environmental effects on areas with minority populations and low-income populations.

In fact, the project represents an environmental improvement for all nearby areas and populations, including areas with minority populations and low-income populations, as follows:

- The upgraded plant will use natural gas for all normal operations which is expected to lower MIT's regulated pollutant emissions. As shown in Table 3-5 in Section 3.16.2 below, air emissions impacts on all nearby communities, including EJ communities, are projected to improve over existing conditions

- The two new turbines will be cleaner and more efficient than the plant's current equipment. Their state-of-the-art emissions controls include two different catalysts that will reduce NOx (nitrogen oxides) emissions by 90% compared to the current system, which does not have this technology.

- MIT's new gas supply agreement with Eversource will enable the plant to run entirely on natural gas. This agreement will lead to further reduced emissions as the use of fuel oil is eliminated except for emergencies and testing.

- When in operation, the upgraded plant will produce electricity and relieve stress on the electric system across the City of Cambridge during periods of high demand. As a result, the likelihood of a power outage will decrease, as will the likelihood that emergency diesel generators (with more emissions and less dispersion) will be called into service in the area.

- As part of the proposed project, MIT will provide Eversource with a location inside the plant to install a new gas regulator station that will provide additional capacity and more reliable gas service to the Cambridge community

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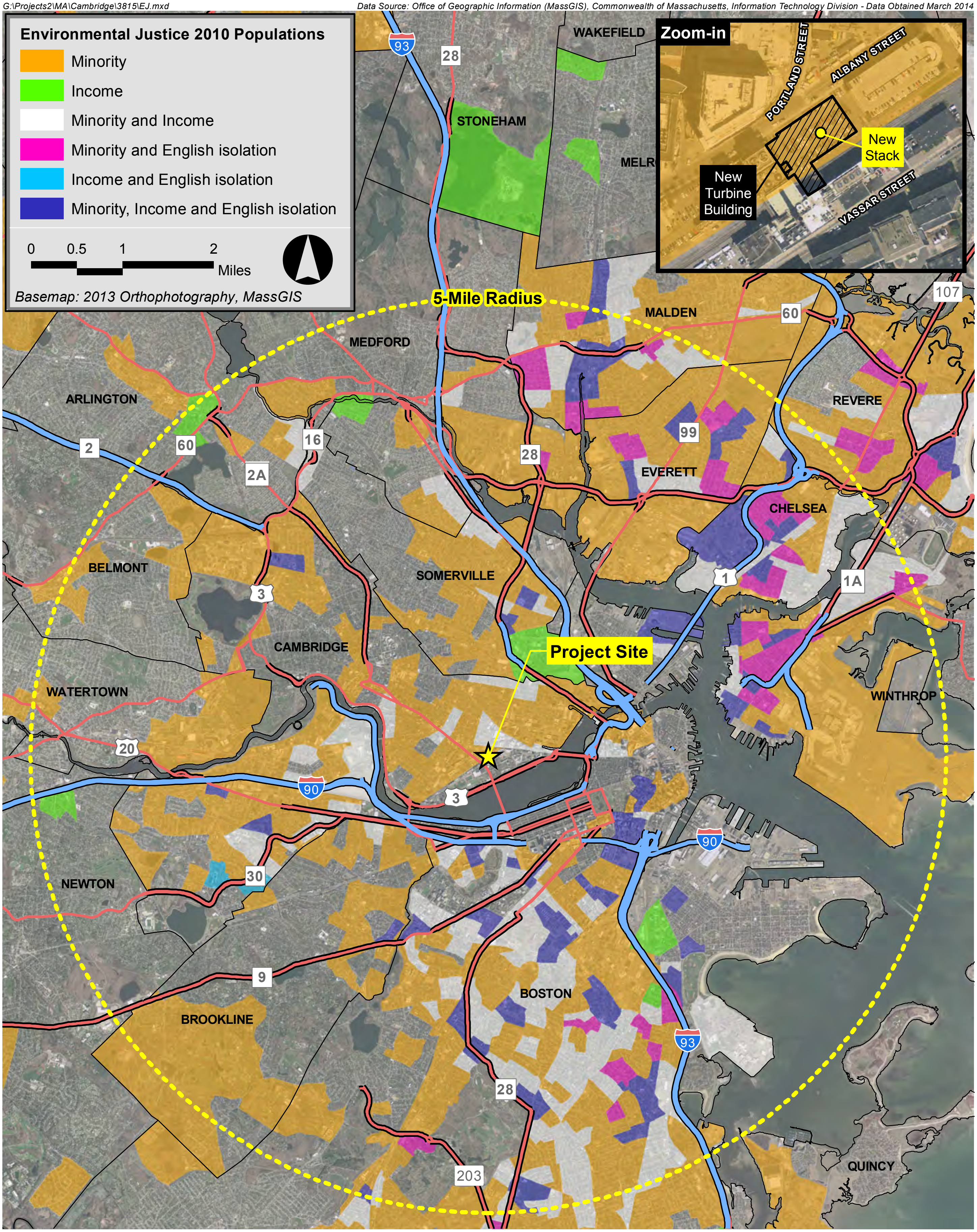
Data Source: Office of Geographic Information (MassGIS), Commonwealth of Massachusetts, Information Technology Division - Data Obtained March 2014



MIT Cogeneration Project Cambridge, Massachusetts

Epsilon ASSOCIATES INC.

Figure 3-1

Environmental Justice 2010 Populations

- ♦ The upgraded plant will have "black start" restoration capability as a primary design objective. By design, the CUP will be able to shed part or parts of its service load in the case of a loss of grid power, in order to keep critical loops powered and continue to operate. This capability will allow MIT to avoid and minimize the use of diesel generators, thereby reducing local emissions during emergencies.

3.16.2 The Impacts: Not Disproportionately High

As shown in Table 3-5 below, in terms of potential air emissions impacts on EJ communities, the proposed facility represents a clear improvement over existing conditions.

Table 3-5 Expected Actual Air Quality Improvement in EJ Areas

Parameter	Current	Proposed
Number of discrete EJ areas with modeled peak 24-hour impacts above the PM2.5 significant impact level[1], based on full load normal CUP operation.	112	37
Number of discrete EJ areas with modeled peak 1-hour impacts above the NO_2 significant impact level[1], based on full load normal CUP operation.	530	196
Square miles of EJ area with modeled peak 24-hour impacts above the PM2.5 significant impact level, based on full load normal CUP operation.	4.2	1.5
Square miles of EJ area with modeled peak 1-hour impacts above the NO_2 significant impact level, based on full load normal CUP operation.	41	12
Highest modeled 24-hour average PM2.5 impact averaged across the impacted EJ areas, based on full load normal CUP operation, in micrograms per cubic meter	2.7	2.5
Highest modeled 1-hour average NO_2 impact averaged across the impacted EJ areas, based on full load normal CUP operation, in micrograms per cubic meter	19	14

[1] Significant Impact Levels only indicate where additional modeling is needed to document that impacts are below health-based National Ambient Air Quality Standards. The project does not cause any violations of National Ambient Air Quality Standards at any location, inside or outside of EJ areas.

3.16.3 *Impacts Will Not Be Adverse*

The modeled ambient air impacts associated with MIT's expanded plant show that the project will improve air quality in the area. As part of the Massachusetts Environmental Policy Act (MEPA), MIT was asked by the Massachusetts Department of Public Health to more fully examine the impact on EJ populations. MIT performed AERMOD dispersion modeling using the current configuration of the CUP (Boilers Nos. 3, 4, and 5 burning No. 6 Fuel Oil; the existing turbine operating on fuel oil, and Boilers Nos. 7 and 9 burning ULSD) and compared these existing configurations to how the CUP is projected to typically operate after completion of this project: Boilers Nos. 3, 4, 5 burning natural gas, the two new CTG units burning natural gas, and Boilers Nos. 7 and 9 burning natural gas. Based on the description above, peak 24-hr $PM_{2.5}$ impacts and peak 1-hr NO_2 impacts will decrease by over 50% as a result of the project.

Table 3-6 documents the emission rates for each of these units under current operating conditions and the future projected actual emission rates. Figures 3-2 and 3-3 show the extent of the reduction in concentrations, overlaid on the surrounding EJ populations in the vicinity of the project.

Table 3-6 Population-weighted Predicted Impacts

Pollutant	Averaging Period	Pre-Project Maximum Concentration ($\mu g/m^3$)	Post-Project Maximum Predicted Concentration ($\mu g/m^3$)
$PM_{2.5}$	24-hour	27.6	11.5
NO_2	1-hour	68.3	32.1

The project impacts for all pollutants and operational scenarios are below the NAAQS[9] (as documented in Table D-16 of the modeling report). The NAAQS are considered protective of the health of sensitive populations such as asthmatics, children, and the elderly. The total impacts presented here are worst-case impacts; anticipated actual impacts are projected to decrease from present levels in all areas including Environmental Justice areas. Therefore, it has been demonstrated that no adverse impacts are expected within any Environmental Justice areas around MIT.

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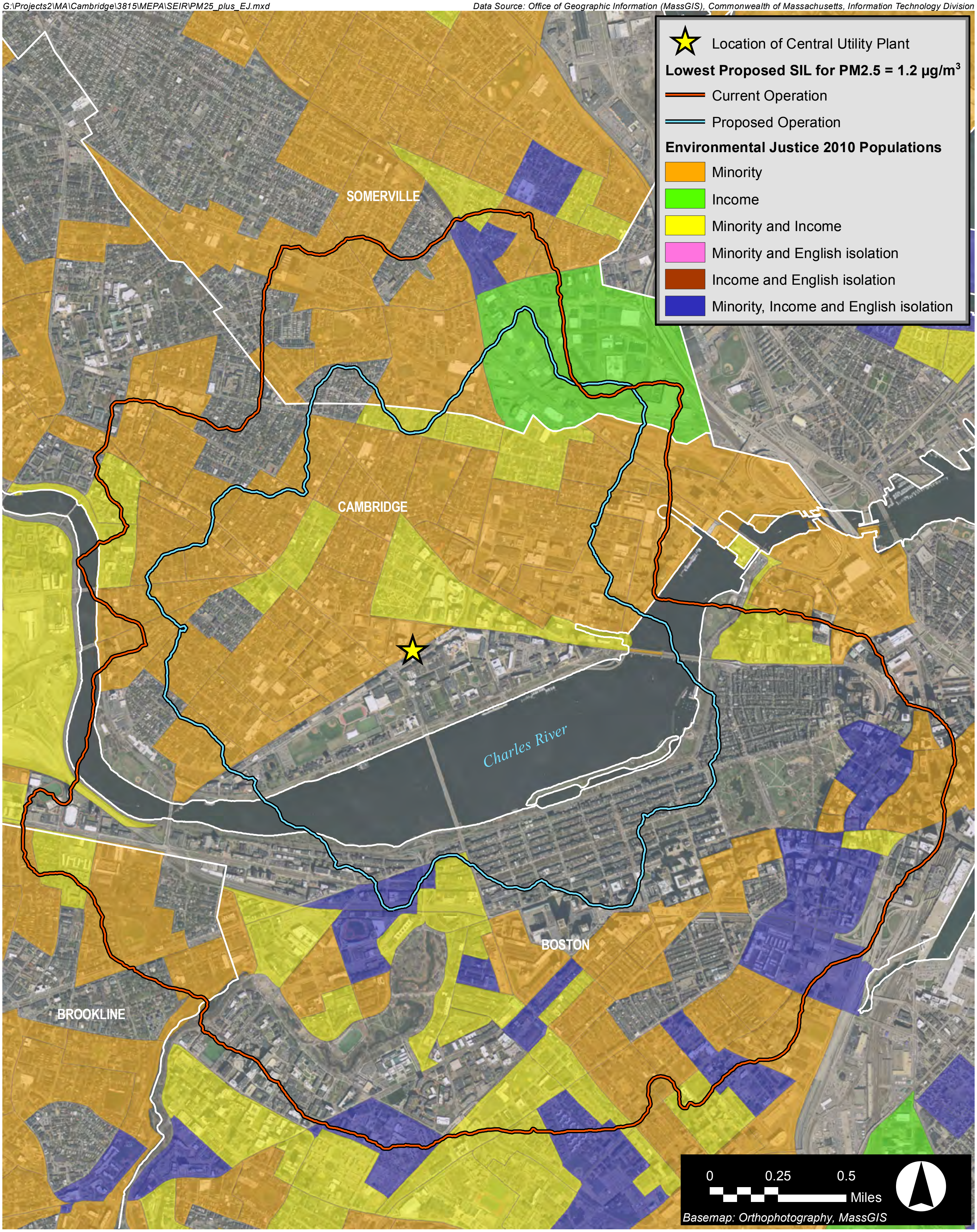
[9] The Clean Air Act required U.S. EPA to set NAAQS for wide-spread pollutants that were considered harmful to the public and environment. Separately, MassDEP has established health-based air guidelines - Ambient Air Limits (AALs) and Threshold Effect Exposure Limits (TELs) - that are used to evaluate potential human health risks from exposures to chemicals in air. In the separate MCPA application, MIT documents that the Project will not cause any exceedance of AALs or TELs.

Data Source: Office of Geographic Information (MassGIS), Commonwealth of Massachusetts, Information Technology Division



MIT CUP Second Century Project **Cambridge, Massachusetts**

Massachusetts Institute of Technology

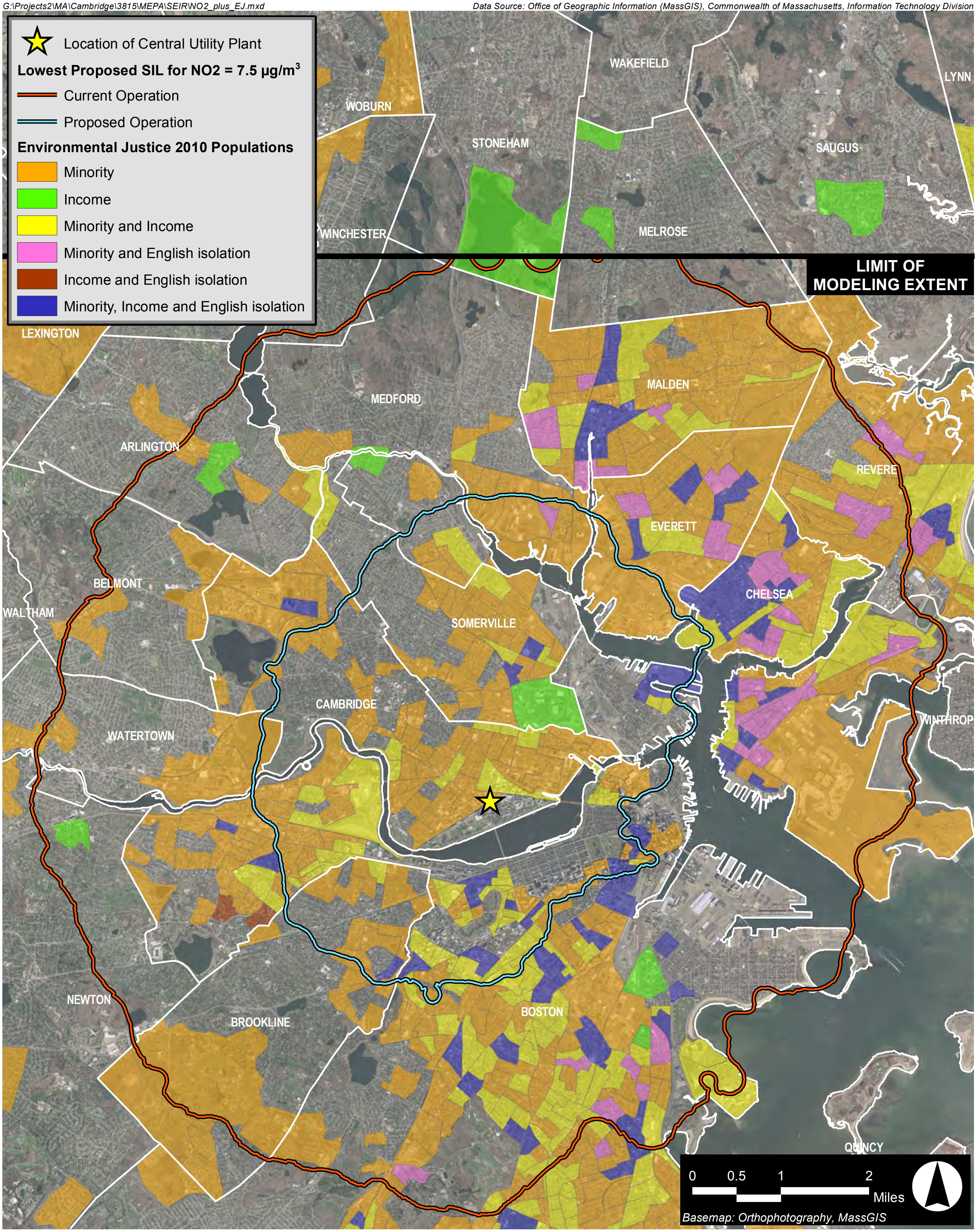
Epsilon Associates Inc.

Figure 3-2

Predicted 24-hour PM2.5 Concentration Contours (µg/m^3) and Environmental Justice Populations

G:\Projects2\MA\Cambridge\3815\MEPA\SEIR\NO2_plus_EJ.mxd

Data Source: Office of Geographic Information (MassGIS), Commonwealth of Massachusetts, Information Technology Division



MIT CUP Second Century Project **Cambridge, Massachusetts**

Massachusetts Institute of Technology

Epsilon Associates Inc.

Figure 3-3

Predicted 1-hour NO2 Concentration Contours (µg/m^3) and Environmental Justice Populations

3.16.4 The Public will Continue to be Informed of the Project

In order to reach and inform residents of Environmental Justice neighborhoods in the area, MIT will work with MassDEP to identify opportunities to ensure greater public participation through the review process. MIT expects that will include use of alternative media outlets such as community or ethnic newspapers, use of alternative information repositories, translation of materials, and interpretation services at public meetings. More specifically, MIT expects that public participation can be enhanced through the following actions:

- MIT will publish the Notice of Public Hearing and Public Comment Period on the Draft PSD Permit in English, Spanish, Portuguese, Chinese (Cantonese), and French.
- MIT will publish a one or two page summary of the project and the permitting process in English, Spanish, Portuguese, Chinese (Cantonese), and French.
- Interpreters will be provided at the Public Hearing.
- MIT will post electronic copies of the notice of Public Hearing and Public Comment Period, Proposed Plan Approval, Draft PSD Permit, Draft PSD Fact sheet, Revised CPA Application, and Revised PSD Application on its project website (powering.mit.edu).

As of this revised submittal, MIT has also conducted public outreach specifically related to the Massachusetts Environmental Policy Act (MEPA) process. Specifically, MIT submitted a Notification of Filing an Expanded Environmental Notification Form (EENF) under the Massachusetts Environmental Policy Act and Public Scoping in December of 2015, then submitted the EENF in December 15, 2015. Availability of the EENF was announced in the *Environmental Monitor* on December 23, 2015, in the *Boston Herald* on December 18, 2015, and in the *Cambridge Chronicle* on December 24, 2015.

Following notice in the *Environmental Monitor*, MIT published a two-page fact sheet describing the project and options for comment in four common non-English languages spoken in the areas adjacent to the project site. The fact sheet was published in English in the *Cambridge Chronicle* on January 7, 2016, in Spanish in *El Mundo Boston* on January 7, 2016, in Chinese in *Sampan* on January 8, 2016, and in Portuguese in *O Jornal* on January 8, 2016. All fact sheets and the EENF were sent to the Cambridge Public Library, Central Square Branch. As stated in the fact sheets, the MEPA Office accepted comments in all languages through January 22, 2016.

A public scoping session was held to hear comments on the proposed project from 6:00 to 8:00 p.m. on January 14, 2016, at MIT Building 4 Room 270 (182 Memorial Drive, Cambridge). At that public meeting, MIT provided interpretation services in Spanish, Portuguese, French, and Cantonese.

MIT submitted a Notification of Filing a Single Environmental Impact Report (SEIR) under Massachusetts Environmental Policy Act in May of 2016, and submittal of the SEIR was announced in the *Environmental Monitor* on May 25, 2016. MIT published the notification of the availability of the SEIR and a copy of the fact sheet in English in the *Cambridge Chronicle* on May 26, 2016, in Spanish in *El Mundo* on May 19, 2016, in Chinese in *Sampan* on May 27, 2016 and in Portuguese in *O Jornal* on May 20, 2016. The SEIR and translated fact sheets were provided to the Cambridge Public Library, Central Square Branch. Members of the public were also able request copies through the MEPA Office.

MIT has posted copies of the current CPA and PSD applications, the EENF, the SEIR, and translated fact sheets on its project website (powering.mit.edu). The project website also includes an overall project description, additional project information, and responses to frequently asked questions.

Section 4.0

Best Available Control Technology (BACT) Analysis

4.0 BEST AVAILABLE CONTROL TECHNOLOGY (BACT) ANALYSIS

The MIT CHP expansion will meet Massachusetts and federal BACT through the use of clean fuels (natural gas with ULSD backup), efficient combustion, and post-combustion controls (Selective Catalytic Reduction and oxidation catalyst). Different pollutants are subject to different BACT requirements. The applicable requirements are discussed in detail in this Section, followed by descriptions of how BACT is applied for each separate pollutant.

4.1 Massachusetts Best Available Control Technology (BACT) Requirement

The plan approval requirements at 310 CMR 7.02(5) require BACT. BACT is defined in 310 CMR 7.00 as follows:

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

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

MassDEP has a lengthy history of determining BACT for combustion sources of the size proposed for this project and has applicable regulations and guidance defining "top-case BACT." For pollutants where top-case BACT is proposed, a detailed, exhaustive top-down analysis would be "reinventing the wheel." This application presents a formal BACT analysis for PM, CO, VOC, and CO_2e, and relies on MassDEP guidance and information from other available resources for other pollutants. Also, a separate BACT analysis is provided for the proposed ULSD-fired cold-start engine.

4.2 PSD BACT

The PSD regulations include (at 40 CFR 52.21(j)(3)) a requirement to "apply best available control technology for each regulated NSR pollutant for which it would result in a significant net emissions increase."

With regard to the proposed project, this requirement applies to the CTG and HRSG units and the cold-start engine. Per 40 CFR 52.21(j)(3), BACT "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." Because there is no net emissions increase of $PM_{2.5}$, PM_{10}, and CO_2e from the boilers (and no physical change or change in the method of operation from Boilers Nos. 7 and 9), the requirement does not apply to the boilers.

Regarding Boilers Nos. 3, 4,, and 5, the change from No. 6 oil to ULSD will reduce emissions of CO_2e because ULSD has a lower carbon content. The EPA emission factors at 40 CFR 98 Table C-1 are as follows:

- No. 6 oil: 75.10 kg CO_2/MMBtu
- ULSD: 73.96 kg CO_2/MMBtu

EPA also states "Particulate matter will generally be reduced when a lighter grade of fuel oil is burned" (EPA AP-42 Compilation of Air Pollutant Emission Factors, Section 1.3.4; factors show a decrease in PM emissions of more than 75%). Between burning the lighter grade of fuel oil and dramatically restricting the amount of fuel oil burned (168 hours/year total), the fuel change will not create a net emissions increase of particulate matter in Boilers Nos. 3, 4, or 5.

The reasons listed above are sufficient to document that boiler emissions will not increase, and therefore BACT does not apply to Boilers Nos. 3, 4, or 5. Additional documentation of non-applicability is as follows: The PSD regulations' definition of "net emissions increase" does not apply in this context, as it is addressing source-wide applicability. A review of EPA's Applicability Determination Index[10] finds a single reference to 40 CFR 52.21(j)[11] and that reference states "This section clearly intends that technology review be assessed on an emissions unit rather than on a plant-wide basis." That said, on the basis of "each proposed emission unit" the definition of "net emissions increase" at 40 CFR 52.21(b)(3)(i)(a) refers to the "Actual-to-projected-actual applicability test for projects that only involve existing

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10 (https://cfpub.epa.gov/adi/index.cfm)

11 (https://cfpub.epa.gov/adi/pdf/adi-nsps-nb20.pdf)

emissions units" at 40 CFR 52.21(a)(2)(iv)(c). Following the procedures in the actual-to-projected-actual applicability test for projects that only involve existing emissions units, the baseline actual emissions (the average rate, in tons per year, at which the emissions unit actually emitted the pollutant during any consecutive 24-month period selected by the owner or operator within the 10-year period immediately preceding the date a complete permit application is received by the Administrator) for 1/1/13 – 12/31/2014 was 11.41 tons per year of PM_{10} and $PM_{2.5}$ total from all three boilers (3.21 tons per year from Boiler No. 3, 3.69 tons per year from Boiler No. 4, and 4.51 tons per year from Boiler No. 5). Of this, 10.0 tons/year were associated with No. 6 oil firing (calculations located in Table C-13 Appendix C). Projected actual emissions conservatively do not include any projected decrease in operation, although the analysis described in Section 4.9.4 shows a large predicted decrease in boiler use after installation of the new CTG/HRSG units. The projected actual emissions do account for the restriction to 48 hours of ULSD maintenance and testing, and the projection that no natural gas interruption will occur (so no ULSD use outside of maintenance and testing will occur). Replacing No. 6 oil with natural gas (and 48 hours of ULSD) provides a projected actual emission rate of 3.2 tons/year total from the three boilers (1.0 tons per year from Boiler No. 3, 1.0 tons per year from Boiler No. 4, and 1.2 tons per year from Boiler No. 5) (calculations located in Table C-13 Appendix C). Therefore, on an actual-to-projected actual basis, there is no net emissions increase at the existing Boilers Nos. 3, 4, and 5.

The PSD definition of BACT is similar to the Massachusetts definition.

> *"Best available control technology means an emissions limitation... based on the maximum degree of reduction... which the Administrator, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such source or modification through application of production processes or available methods, systems, and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of such pollutant."*

The pollutants subject to the PSD BACT requirement are $PM_{2.5}$, PM_{10}, and CO_2e. A formal top-down analysis is presented for particulate matter and CO_2e.

The objective of the project is to provide highly reliable and responsive electrical and thermal energy to the MIT campus. The basic design of the facility is the use of dual-fuel CTGs with HRSG systems (and supporting equipment) to provide the ability to balance thermal and electrical output to meet campus needs, to respond quickly to system upsets, and to start and operate independent of external energy supply during emergencies.

Per the EPA GHG Guidance: "clean fuels which would reduce GHG emissions should be considered, but EPA has recognized that the initial list of control options for a BACT analysis does not need to include 'clean fuel' options that would fundamentally redefine the source." Since "BACT should generally not be applied to regulate the applicant's purpose or objective for the proposed facility," this BACT analysis focuses on options that could be used with a system providing reliable and responsive electrical and thermal energy.

MIT proposes to burn natural gas, which is the cleanest fuel available that can provide a reliable energy supply to the MIT campus in the needed amounts. MIT is contracting for a firm, uninterruptable natural gas supply. However, to meet the objective of providing a highly reliable energy supply, the cogeneration system must have a backup fuel that can be stored onsite and called on reliably if natural gas cannot be used. MIT proposes to use ULSD as that backup fuel; ULSD is the cleanest available fuel that can be stored onsite in the quantities needed and called upon reliably in the absence of an external energy supply.

4.3 MassDEP Top Case BACT Guidance for CTGs and HRSGs

Where available, MIT proposes to use the MassDEP Top Case (BACT) Guidelines for Combustion Sources[12] to document BACT. As stated in the guidelines, "Use of the applicable Top Case BACT emissions limitations contained herein may preclude the need for applicants to prepare and submit a "top-down BACT analysis" for MassDEP's review, and will streamline the Air Quality permitting process for both the applicants and MassDEP."

Specifically, MIT proposes the emission rates in Table 4-1 below as top case BACT for normal operation (does not apply to transient operation or startup and shutdown scenarios which are discussed separately):

[12] http://www.mass.gov/eea/docs/dep/air/approvals/bactcmb.pdf, accessed 7/10/14

Table 4-1 Proposed Top Case BACT from MassDEP

Source	Fuel	Air Contaminant	Emission Limitations	Control Technology
Combustion Turbine (>10 MW)	Natural Gas	NO_x	2.0 ppmvd at 15 % O2	Dry Low NO_x Combustor, SCR, Oxidation catalyst, NO_x, CO, NH3 CEMS
		NH_3	2.0 ppmvd at 15 % O2	
		CO	2.0 ppmvd at 15 % O2	
		VOC	1.7 ppmvd at 15 % O2	
Combustion Turbine (>10 MW)	Ultra Low Sulfur Distillate Oil 0.0015 %	NH_3	2.0 ppmvd at 15 % O2	Low NO_x Combustor, SCR, Oxidation catalyst, NO_x, CO, NH3 CEMS
		CO	7.0 ppmvd at 15 % O2	
		VOC	7.0 ppmvd at 15 % O2	
Duct Burner (boiler >100 MMBtu/hr)	Natural Gas	NO_x	0.011 lb/MMBtu	Low NO_x burners, SCR, Oxidation catalyst, NO_x, CO CEMS
		CO	0.011 lb/MMBtu	
		VOC	0.03 lb/MMBtu	

MIT proposes to fire the HRSG using natural gas exclusively.

Top case BACT will be achieved and maintained through the use of efficient combustion controls which include following Standard Operating and Maintenance Practices (SOMP). The SOMP will be provided to MassDEP when available and will be provided prior to startup of the units.

Although sulfur dioxide (SO_2) is not specifically mentioned in the MassDEP guidance, MIT proposes the following as top case BACT for this pollutant:

- Sulfur dioxide BACT is met through the use of low-sulfur fuels (natural gas and ultra-low sulfur diesel) and efficient operation. MIT will track sulfur content through vendor-posted data and fuel receipts.

4.4 Proposed Variations from Top Case BACT

MIT proposes the following changes from Massachusetts guidance for Top Case BACT:

- MIT proposes a NO_x emission rate of 9 ppmvd at 15% O2 when firing ULSD, instead of the Massachusetts top case BACT guidance of 6 ppmvd at 15% O2. Designing the pollution control for the very limited amount of ULSD firing would cause problems with back pressure, which would reduce efficiency during all operating cases and require additional space. Considering that the difference between 9 ppmvd @ 15% O2 and 6 ppmvd @ 15% O2 equates to no more than

0.21 tons per year (3 ppmvd @ 15% O2 difference at 212 MMBtu/hr and 168 hours per year), it is reasonable to conclude that the energy and environmental impacts associated with the additional controls outweigh the emissions benefit.

- MIT proposes to meet other top case BACT guidance during full-load, steady state conditions. However, the CTGs must be able to quickly and reliably respond to changes in campus energy demand. Meeting the same limits as apply for full-load steady-state conditions will not be possible over the short term. When operating load is changing significantly, the CTGs, HRSGs, and catalyst controls can have difficulty keeping up with the changes while maintaining compliance with steady-state emission limits. MIT has worked with the equipment vendors to identify situations where the operating load ramp rate will exceed the control system's ability to maintain continuous compliance. MIT proposes that for the limited situations when the HRSG heat input is changing by more than 30 MMBtu in an hour, the following mass-based emission limits apply:

  - Proposed NO_x firing gas from the CTG of 4.0 lb/hr during transient operations.
  - Proposed CO firing gas from the CTG of 3.8 lb/hr during transient operations.
  - Proposed VOC firing gas from the CTG of 4.6 lb/hr during transient operations.
  - Proposed NH3 firing gas from the CTG of 1.8 lb/hr during transient operations.

MIT is proposing that these limits apply for the full hour in which transient operations occur for up to 20 occurrences per year.

4.5 Particulate Matter BACT for the CTGs and HRSGs

Because particulate matter emissions are subject to both federal and Massachusetts BACT requirements, this BACT analysis follows the federal guidance in the New Source Review Workshop Manual, Prevention of Significant Deterioration and Nonattainment Area Permitting, EPA Draft October 1990 document. Specific guidance from that document is included in boxes below, followed by MIT's analysis based on the guidance. The BACT analysis follows the guidance in the Northeast States for Coordinated Air Use Management (NESCAUM) BACT Guideline dated June 1991, as well as the referenced NSR Workshop Manual.

Available fuels and emission controls are the same for the CTGs and the HRSGs. Also, data on emission limits achieved-in-practice are generally based on total emissions from CTG and HRSG firing. This BACT analysis therefore applies to the combined emissions of the CTGs and the HRSGs.

4.5.1 BACT Applicability

…the BACT determination must separately address…, for each regulated pollutant… air pollution controls for each emissions unit or pollutant emitting activity subject to review.

While “particulate matter” is listed as a regulated pollutant, EPA rescinded the national ambient air quality standard for particulate matter in favor of a PM_{10} standard in 1987, and recent statutory and regulatory provisions impose controls and limitations on PM_{10}, not particulate matter.

Particulate matter consists of two broad categories: filterable PM and condensable PM. Based on recent guidance from the MassDEP on other projects, this analysis addresses total particulate, filterable plus condensable.

$PM_{2.5}$ is a subset of PM_{10}; there is very limited data on $PM_{2.5}$ emission limits achieved in practice, and there is considerable uncertainty regarding $PM_{2.5}$ test methods. Much or most of the filterable PM_{10} emissions will be 2.5 microns or smaller, and all of the condensable PM_{10} emissions are generally considered 2.5 microns or smaller. BACT techniques for $PM_{2.5}$ control will be the same as for PM_{10} control. For all of these reasons, this application makes the conservative assumption that all PM_{10} emitted from the CHP expansion is $PM_{2.5}$. The BACT emission rates reviewed in this analysis are for PM, PM_{10}, and $PM_{2.5}$. Throughout this application, the term PM refers to PM/PM_{10}/$PM_{2.5}$, filterable plus condensable.

4.5.2 Step 1— Identify All Control Technologies

The first step in a "top-down" analysis is to identify, for the emissions unit in question (the term "emissions unit" should be read to mean emissions unit, process or activity), all "available" control options. Available control options are those air pollution control technologies or techniques with a practical potential for application to the emissions unit and the regulated pollutant under evaluation.

Available control options are:

- Post-combustion control, including:
  - Fabric filtration
  - Electrostatic precipitation
  - Wet scrubbing
  - Cyclone or multicyclone collection
  - Side-stream separation

- The use of clean fuels and good combustion practices

This project will use natural gas as the primary fuel. Natural gas is the cleanest fuel that can be reliably supplied in the quantities required. ULSD will be used as a secondary fuel source in the unlikely event natural gas is not available. The CTG design will utilize Solar's SoLoNOx technology to ensure optimal combustion resulting in minimal CO emissions. Details of how this technology works is included in Appendix B – Part 1.

Air pollution control technologies and techniques include the application of production process or available methods, systems, and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of the affected pollutant.

With reference to the list above, MIT's proposed project includes fuel combustion techniques and the use of clean fuels (natural gas with ULSD backup), which can be considered "fuel cleaning or treatment."

This includes technologies employed outside the United States.

MIT is unaware of technologies employed outside the United States that are not employed inside the United States.

... in some circumstances inherently lower-polluting processes are appropriate for consideration as available control alternatives.

MIT's proposed use of clean fuels (natural gas with ULSD backup) can be considered an inherently lower-polluting process.

The control alternatives should include not only existing controls for the source category in question, but also (through technology transfer) controls applied to similar source categories and gas streams, and innovative control technologies.

With regard to MIT's proposed project, the source category in question is the production of electricity in a CTG. Existing particulate controls are limited to the use of clean fuels (natural gas with ULSD backup) and good combustion techniques (Solar's *SoLoNOx* technology which employs lean-premixed combustion to reduce NO_x emissions). Lean-premixed combustion reduces the conversion of atmospheric nitrogen to NO_x by reducing the combustion flame temperatures as NO_x formation rates are strongly dependent on flame temperature. Further reductions in emission are achieved by premixing the fuel and combustor airflow upstream of the combustor primary zone. The pre-mixing prevents stoichiometric burning locally with the flame, thus ensuring the entire flame is at fuel lean condition resulting in low emissions. (Appendix B – Part 1).

Technologies required under lowest achievable emission rate (LAER) determinations are available for BACT purposes and must also be included as control alternatives and usually represent the top alternative.

MIT has reviewed the EPA RACT/BACT/LAER Clearinghouse and other online data sources which include LAER determinations. The top control technology found is the use of clean fuels (natural gas with ULSD backup) and good combustion techniques.

4.5.3 Step 2 — Eliminate Technically Infeasible Options

In the second step, the technical feasibility of the control options identified in step one is evaluated with respect to the source-specific (or emissions unit-specific) factors.

Each identified control option is evaluated with respect to emissions unit-specific factors below.

- Post-combustion control: *technically infeasible*
- Use of clean fuels (natural gas with ULSD backup) and good combustion practices (Appendix B — Part 1): *technically feasible*

A demonstration of technical infeasibility should be clearly documented and should show, based on physical, chemical, and engineering principles, that technical difficulties would preclude the successful use of the control option on the emissions unit under review. Technically infeasible control options are then eliminated from further consideration in the BACT analysis.

With regard to MIT's proposed project, clear documentation of technical difficulties is demonstrated below for each technically infeasible control option:

- **Post-combustion control**. All available post-combustion controls have limits in terms of how clean an exhaust concentration they can achieve. The minimum outlet concentration achievable using post-combustion control is generally higher than the inlet concentration achievable using clean fuels (natural gas with ULSD backup). Therefore, the installation of post-combustion controls will not reduce particulate emissions.

For example, in cases where the level of control in a permit is not expected to be achieved in practice (e.g., a source has received a permit but the project was cancelled, or every operating source at that permitted level has been physically unable to achieve compliance with the limit), and supporting documentation showing why such limits are not technically feasible is provided, the level of control (but not necessarily the technology) may be eliminated from further consideration.

MIT has made a good faith effort to compile appropriate information from available information sources (per EPA guidance). Information sources considered included:

- EPA's RACT/BACT/LAER Clearinghouse and Control Technology Center - Information from the Clearinghouse[13] was reviewed. No facilities are identified that use post-combustion control on a CTG smaller than 25 MW that fires natural gas and/or distillate oil.

- Best Available Control Technology Guideline - South Coast Air Quality Management District - The Guideline[14] has no guidance for particulate matter;

- Control technology vendors - An online review of vendors[15] does not find any offering post-combustion control for particulate matter from CTGs firing natural gas or distillate oil;

- Federal/State/Local new source review permits and associated inspection/performance test reports - A good faith effort to review permits available online found information as presented in Table 4-2 below;

- Environmental consultants - Consultants at Epsilon Associates, Inc. reviewed available information on current and past projects;

- Technical journals, reports and newsletters, air pollution control seminars - A review of papers posted by the Air and Waste Management Association[16] found no recent papers associated with particulate emission rates achievable from gas and ULSD-fired CTGs; and

- EPA's policy bulletin board - A review of the online Office of Air and Radiation (OAR) Policy and Guidance[17] websites found no references to specific recent BACT emission limits or technologies for particulate matter from gas- and ULSD-fired CTGs. Particulate control from boilers was reviewed in the development of the National Emissions Standards for Hazardous Air Pollutants (NESHAP) rules for

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13 http://cfpub.epa.gov/rblc/ reviewed July 2014

14 http://aqmd.gov/home/permits/bact/guidelines reviewed March 2014

15 http://www.icac.com/?Publications, search March 2014 for particulate matter control equipment applicable to natural gas or ULSD combustion.

16 http://awma.org/search and http://portal.awma.org/store/, March 2014. Searches for "Particulate & Natural Gas" and "Particulate & Distillate." No applicable papers were identified.

17 http://epa.gov/ttn/oarpg/new.html and http://epa.gov/ttn/oarpg/ramain.html. reviewed March 2014

industrial, commercial, and institutional boilers under 40 CFR 63[18]. EPA concluded that, for boilers firing gaseous fuel with liquid fuel backup, "no existing units were using control technologies that achieve consistently lower emission rates than uncontrolled sources."

The EPA Clearinghouse was queried for CTGs firing natural gas or distillate oil, operating in combined-cycle or cogeneration mode, sized smaller than 25 MW. Facilities listed in the Clearinghouse as having only filterable particulate matter limits were excluded. Additional facilities were added based on Epsilon experience.

No projects comparable to MIT's proposed project were found that used post-combustion control. Key projects are summarized as follows:

Table 4-2 Summary of Available Data on PM CTG Emission Limits

Determination	PM emission limit	Converted
CARB Database determination for Los Angeles County Sanitation District, 9.9 MW Solar combustion turbine, combined cycle, firing landfill gas	5.7 lb/hr PM	~0.038 lb/MMBtu at full load
RBLC determination for Signal Hills Wichita Falls Power (TX), 20 MW turbine, combined cycle	1.04 lb/hr PM firing natural gas (type not specified, assume FILTERABLE)	~0.0052 lb/MMBtu at full load (type not specified, assume FILTERABLE)
RBLC determination for Maui Electric, 20 MW turbine, combined cycle	19.7 lb/hr PM firing No. 2 fuel oil	~0.099 lb/MMBtu firing No. 2 fuel oil
NYSDEC operating permit for Cornell University, 15 MW Solar turbine CHP	0.022 lb/MMBtu PM_{10} (filterable & condensable) firing natural gas, 0.04 lb/MMBtu firing ULSD (other limits also listed).	0.022 lb/MMBtu PM_{10} (filterable & condensable) firing natural gas, 0.04 lb/MMBtu firing ULSD
Conditional Approval for MassDEP operating permit for UMass Amherst, 10 MW Solar turbine CHP	0.03 lb/MMBtu PM10 firing natural gas); 0.036 lb/MMBtu PM10 firing diesel.	0.03 lb/MMBtu PM10 firing natural gas); 0.036 lb/MMBtu PM10 firing diesel.

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Table 4-2 Summary of Available Data on PM CTG Emission Limits (Continued)

Determination	PM emission limit	Converted
MassDEP operating permit for Gillette Boston, Solar Taurus 70 turbine CHP	3.4 lb/hr PM firing natural gas (with and without duct burning); 4.5 lb/hr PM firing ULSD.	The Gillette Boston application states the emission limits are based on 0.022 lb/MMBtu firing natural gas & 0.037 lb/MMBtu firing ULSD, but that does not appear to correspond to the rated capacity of the permitted equipment. Based on available equipment data, the calculated limits would be 0.017 lb/MMBtu firing natural gas with the duct burner and 0.053 lb/MMBtu firing ULSD.
MassDEP operating permit for UMass Medical Center, Solar Taurus 70 turbine CHP	1.9 lb/hr firing natural gas without duct burning; 2.34 lb/hr firing natural gas with duct burning; 2.88 lb/hr firing ULSD	~0.021 lb/MMBtu firing natural gas ~0.034 lb/MMBtu firing ULSD
MassDEP operating permit for MATEP, Alston turbine & HRSG	0.025 lb/MMBtu firing gas, 0.040 lb/MMBtu firing ULSD (interim limits)	0.025 lb/MMBtu firing gas 0.040 lb/MMBtu firing ULSD
MassDEP operating permit for Biogen, Solar Taurus 60 turbine & HRSG	0.028 lb/MMBtu PM firing natural gas (with and without duct burning); 0.056 lb/MMBtu PM firing ULSD	0.028 lb/MWh firing natural gas 0.056 lb/MWh firing ULSD
MassDEP operating permit for Harvard, Solar Taurus 70 turbine & HRSG (not yet constructed)	3.3 lb/hr firing natural gas with or without duct burning; 3.7 lb/hr firing ULSD	0.022 lb/MMBtu firing natural gas 0.04 lb/MMBtu firing ULSD
RBLC Draft Determination for Lenzing Fibers, Inc. (AL) 25 MW Gas Turbine with HRSG	0.0075 lb/MMBtu filterable PM firing natural gas	0.0075 lb/MMBtu filterable PM firing natural gas

4.5.4 Step 3 — Rank Remaining Control Technologies By Control Effectiveness

In step 3, all remaining control alternatives not eliminated in step 2 are ranked and then listed in order of overall control effectiveness for the pollutant under review, with the most effective control alternative at the top. A list should be prepared for each pollutant and for each emissions unit (or grouping of similar units) subject to a BACT analysis. The list should present the array of control technology alternatives and should include the following types of information:

- control efficiencies (percent pollutant removed);
- expected emission rate (tons per year, pounds per hour);
- expected emissions reduction (tons per year);
- economic impacts (cost effectiveness);
- environmental impacts (includes any significant or unusual other media impacts (e.g., water or solid waste), and, at a minimum, the impact of each control alternative on emissions of toxic or hazardous air contaminants);
- energy impacts.

With regard to MIT's proposed project, the only remaining control technology is the use of clean fuels (natural gas with ULSD backup) and efficient combustion. Requested data is summarized below.

Table 4-3 Summary of Particulate Matter Effectiveness of Clean Fuels (Natural Gas with ULSD Backup) and Efficient Combustion

Control efficiencies (percent pollutant removed)	Not applicable (inherently clean technology used)
Expected emission rate (tons per year, pounds per hour)	Per the calculations in Appendix C (Tables C-1, C-2, and C-10), potential emissions are 7.1 lb/hr firing gas, 11.9 lb/hr firing ULSD in each CTG (and gas in the HRSG), and 50 tons/year combined total. Expected emission rates are lower.
Expected emissions reduction (tons per year)	Not applicable (inherently clean technology used)
Economic impacts	In most cases, clean fuels (natural gas with ULSD backup) are more expensive than higher-polluting fuels. As of the time of this application, natural gas prices are low on an annual basis but high during peak winter use periods.

Table 4-3 Summary of Particulate Matter Effectiveness of Clean Fuels (Natural Gas with ULSD Backup) and Efficient Combustion (Continued)

Environmental impacts (includes any significant or unusual other media impacts (e.g., water or solid waste), and, at a minimum, the impact of each control alternative on emissions of toxic or hazardous air contaminants)	The use of clean fuels (natural gas with ULSD backup) can have lower water, wastewater, solid waste, and toxic/hazardous air impacts than higher-polluting fuels.
Energy impacts	Energy use is a function of system efficiency; the proposed CHP is an efficient CTG with heat recovery and low energy impacts.

4.5.5 Steps 4 and 5 — Select BACT

If the applicant accepts the top alternative in the listing as BACT, the applicant proceeds to consider whether impacts of unregulated air pollutants or impacts in other media would justify selection of an alternative control option. If there are no outstanding issues regarding collateral environmental impacts, the analysis is ended and the results proposed as BACT. In the event that the top candidate is shown to be inappropriate, due to energy, environmental, or economic impacts, the rationale for this finding should be documented for the public record. Then the next most stringent alternative in the listing becomes the new control candidate and is similarly evaluated. This process continues until the technology under consideration cannot be eliminated by any source-specific environmental, energy, or economic impacts which demonstrate that alternative to be inappropriate as BACT. The most effective control option not eliminated is proposed as BACT for the pollutant and emission unit under review.

Consistent with the analysis presented above, MIT proposes the use of clean fuels (natural gas with ULSD backup) and efficient combustion, achieving a total $PM/PM_{10}/PM_{2.5}$ emission rate of 0.02 lb/MMBtu firing gas and 0.04 lb/MMBtu firing ULSD as the top alternative for BACT. These limits are comparable to (and slightly lower than) recent projects of similar size (Cornell, UMass Amherst, Gillette, and Harvard). The proposed BACT emission limitations are the maximum degree of reduction achievable, taking into account the scarcity of comparable units with emission limits demonstrated-in-practice, the continued concerns with the accuracy and repeatability of the stack test method (EPA Method 202), and the limited technical opportunities to directly control and reduce particulate emissions.

4.6 Nitrogen Oxides (NO_x) BACT

While NO_x emissions are only subject to Massachusetts BACT requirements, this BACT analysis follows the federal guidance in the New Source Review Workshop Manual, Prevention of Significant Deterioration and Nonattainment Area Permitting, EPA Draft October 1990 document. Specific guidance from that document is included in boxes below, followed by MIT's analysis based on the guidance. The BACT analysis follows the guidance in the NESCAUM BACT Guideline dated June 1991, as well as the referenced NSR Workshop Manual.

4.6.1 BACT Applicability

> ...the BACT determination must separately address..., for each regulated pollutant... air pollution controls for each emissions unit or pollutant emitting activity subject to review.

NO_x is formed during the combustion process due to the reaction between nitrogen and oxygen in the combustion air at high temperatures ("thermal NO_x") and the reaction of nitrogen bound in the fuel with oxygen ("fuel NO_x"). Fuel NO_x is minimal from the combustion of natural gas or ULSD.

MIT proposes to meet DEP's top case BACT of 2.0 ppmvd @ 15% O2 for the CTG firing natural gas at 100% load by using selective catalytic reduction sized to consistently achieve the top case BACT outlet concentration. The proposed dry-low NO_x combustors will have elevated NO_x emissions at part-load and at low ambient air temperatures.

During ULSD firing, MIT proposes to meet a limit of 9.0 ppmvd at 15% O2. While this is higher than the MassDEP top case BACT guidance, proposed ULSD use is very limited and the higher emission limit avoids size constraint and back-pressure issues, which could otherwise cause technical feasibility problems as well as detrimental energy and environmental impacts.

4.6.2 Step 1 — Identify All Control Technologies

> The first step in a "top-down" analysis is to identify, for the emissions unit in question (the term "emissions unit" should be read to mean emissions unit, process or activity), all "available" control options. Available control options are those air pollution control technologies or techniques with a practical potential for application to the emissions unit and the regulated pollutant under evaluation.

Available control options are:

- Post-combustion control, including:
    - Selective Catalytic Reduction

- Selective Non-Catalytic Reduction
- EMx (SCONOX) Systems
- XONON Systems

♦ The use of clean fuels (natural gas with ULSD backup) and good combustion control, including:

- Dry Low-NO_x combustors
- Low-NO_x combustors with water injection ("wet combustors")

Air pollution control technologies and techniques include the application of production process or available methods, systems, and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of the affected pollutant.

With regard to the list above, MIT's proposed project includes fuel combustion techniques and the use of clean fuels (natural gas with ULSD backup), which can be considered "fuel cleaning or treatment."

This includes technologies employed outside the United States.

MIT is unaware of technologies employed outside the United States that are not employed inside the United States.

… in some circumstances inherently lower-polluting processes are appropriate for consideration as available control alternatives.

MIT's proposed use of a CHP can be considered an inherently lower-polluting process.

The control alternatives should include not only existing controls for the source category in question, but also (through technology transfer) controls applied to similar source categories and gas streams, and innovative control technologies.

With regard to MIT's proposed project, the source category in question is the production of electricity and thermal energy in a CTG.

Technologies required under lowest achievable emission rate (LAER) determinations are available for BACT purposes and must also be included as control alternatives and usually represent the top alternative.

MIT has reviewed the EPA RACT/BACT/LAER Clearinghouse and other online data sources which include LAER determinations. The top control technology found is the use of clean fuels (natural gas with ULSD backup) and good combustion techniques, combined with SCR.

4.6.3 Step 2–Eliminate Technically Infeasible Options

In the second step, the technical feasibility of the control options identified in step one is evaluated with respect to the source-specific (or emissions unit-specific) factors.

Each identified control option is evaluated with respect to emissions unit-specific factors below.

- Post-combustion control, including:
  - Selective Catalytic Reduction (SCR) *technically feasible*
  - Selective Non-Catalytic Reduction (SNCR) *technically infeasible*
  - EMx (SCONOX) Systems *technically infeasible*
  - XONON Systems *technically infeasible*
- The use of clean fuels (natural gas with ULSD backup) and good combustion control, including:
  - Dry Low-NO_x combustors *technically feasible*
  - Low-NO_x combustors with water injection ("wet combustors") *technically feasible*

A demonstration of technical infeasibility should be clearly documented and should show, based on physical, chemical, and engineering principles, that technical difficulties would preclude the successful use of the control option on the emissions unit under review. Technically infeasible control options are then eliminated from further consideration in the BACT analysis.

- SNCR uses the same chemical reduction principle as SCR, but without the catalyst. Instead, the combustion unit acts as a reactor chamber (and removal efficiencies are lower). With regard to MIT's proposed project, the effectiveness of SNCR would be limited because 1) on a CTG, there is insufficient reactor residence time, and 2) changes to load would make it difficult to maintain the proper temperature window. EPA's Air Pollution Control Technology Fact Sheet for SNCR[19] states that SNCR is "not applicable to sources with low NO_X concentrations such as gas turbines."

- Two other technologies were considered, but were determined to be not technically feasible for the proposed facility. These are: 1) Kawasaki's Catalytica's catalytic combustion-based technology, K-LeanTM (formerly XONON) for NO_x control, and 2) Emerachem's EMxTM (formerly $SCONO_x$) post-combustion system for NO_x control. Neither technology has a sufficient operating track record to be relied upon to support critical infrastructure on the MIT campus.

For example, in cases where the level of control in a permit is not expected to be achieved in practice (e.g., a source has received a permit but the project was cancelled, or every operating source at that permitted level has been physically unable to achieve compliance with the limit), and supporting documentation showing why such limits are not technically feasible is provided, the level of control (but not necessarily the technology) may be eliminated from further consideration.

The EPA Clearinghouse was queried for CTGs firing natural gas or distillate oil, operating in combined-cycle or cogeneration mode, sized smaller than 25 MW. Additional facilities were added based on Epsilon experience.

Key projects are summarized in Table 4-4 below:

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Table 4-4 Summary of Available Data on NO_x CTG Emission Limits

Determination	NO_x emission limit	Converted
RBLC determination for Signal Hills Wichita Falls Power (TX), 20 MW turbine, combined cycle	52.0 lb/hr	0.26 lb/MMBtu
NYSDEC operating permit for Cornell University, 15 MW Solar turbine CHP	15 ppmvd @ 15% O2 on natural gas below 0 °F 25 ppmvd @ 15% O2 on ULSD below 0 °F 2.5 ppmvd @ 15% O2 on natural gas above 0 °F 9 ppmvd @ 15% O2 on ULSD above 0 °F	0.055 lb/MMBtu on natural gas below 0 °F 0.097 lb/MMBtu on ULSD below 0 °F 0.0092 lb/MMBtu on natural gas above 0 °F 0.035 lb/MMBtu on ULSD above 0 °F
Conditional Approval for MassDEP operating permit for UMass Amherst, 10 MW Solar turbine CHP	19.0 lb/hr on natural gas or ULSD below 0 °F 2.56 lb/hr on natural gas above 0 °F 5.94 lb/hr on ULSD above 0 °F	0.148 lb/MMBtu on natural gas or ULSD below 0 °F 0.020 lb/MMBtu on natural gas above 0 °F 0.046 lb/MMBtu on ULSD above 0 °F
MassDEP operating permit for Gillette Boston, Solar Taurus 70 turbine CHP	1.5 lb/hr firing natural gas (with and without duct burning); 4.4 lb/hr PM firing ULSD.	0.020 firing natural gas with duct burning; 0.058 lb/MMBtu PM firing ULSD.
MassDEP operating permit for UMass Medical Center, Solar Taurus 70 turbine CHP	2 ppm firing natural gas without duct burning (0.93 lb/hr with duct burning); 1.82 lb/hr firing ULSD	0.014 lb/MMBtu firing natural gas with duct burning; 0.071 lb/MMBtu firing ULSD
MassDEP operating permit for MATEP, Alston turbine & HRSG	2.0 ppmvd @ 15% O2 firing natural gas 6.0 ppmvd @ 15% O2 firing ULSD	0.007 lb/MMBtu firing natural gas 0.022 lb/MMBtu firing ULSD
MassDEP operating permit for Harvard, Solar Taurus 70 turbine & HRSG (not yet constructed)	3.3 lb/hr firing natural gas with or without duct burning; 4.3 lb/hr firing ULSD	0.022 lb/MMBtu firing natural gas with duct burning 0.046 lb/MMMBtu firing ULSD
RBLC Draft Determination for Lenzing Fibers, Inc. (AL) 25 MW Gas Turbine with HRSG	4 ppm at 15% O_2 firing natural gas	0.015 lb/MMBtu firing natural gas
* CHP emission limit at 310 CMR 7.26()		

4.6.4 *Step 3–Rank Remaining Control Technologies By Control Effectiveness*

In step 3, all remaining control alternatives not eliminated in step 2 are ranked and then listed in order of overall control effectiveness for the pollutant under review, with the most effective control alternative at the top. A list should be prepared for each pollutant and for each emissions unit (or grouping of similar units) subject to a BACT analysis. The list should present the array of control technology alternatives and should include the following types of information:

- control efficiencies (percent pollutant removed);
- expected emission rate (tons per year, pounds per hour);
- expected emissions reduction (tons per year);
- economic impacts (cost effectiveness);
- environmental impacts (includes any significant or unusual other media impacts (e.g., water or solid waste), and, at a minimum, the impact of each control alternative on emissions of toxic or hazardous air contaminants);
- energy impacts.

With regard to MIT's proposed project, the only available control technology is the use of clean fuels (natural gas with ULSD backup), efficient combustion and SCR. Requested data is summarized below.

Table 4-5 Summary of NOx effectiveness of clean fuels, combustion and SCR Catalyst

Control efficiencies (percent pollutant removed)	Up to 92% to meet the 2 ppmvd emission limit
Expected emission rate (tons per year, pounds per hour)	Per the calculations in Appendix C (Tables C-1, C-2, and C-10), potential emissions are a maximum of 3.2 lb/hr firing gas, 9.5 lb/hr firing ULSD in each CTG (and gas in the HRSG), and 21.1 tons/year combined total. Expected emission rates are lower.
Expected emissions reduction (tons per year)	The SCR as proposed will remove approximately 92% of uncontrolled NO_x emissions, which will vary based on actual loads operated.
Economic impacts	The use of SCR is cost-effective for NO_x control.

Table 4-5 Summary of NOx effectiveness of clean fuels, combustion and SCR Catalyst (Continued)

Environmental impacts (includes any significant or unusual other media impacts (e.g., water or solid waste), and, at a minimum, the impact of each control alternative on emissions of toxic or hazardous air contaminants)	Spent SCR catalyst can be recycled or disposed of as solid waste (expected every 5 or 10 years). The use of dry-low NO_x combustion during gas firing reduces water use.
Energy impacts	Energy use is a function of system efficiency; the proposed CHP is an efficient combustion turbine with heat recovery and low energy impacts. The SCR adds some backpressure to the CHP system, resulting in a small energy impact.

4.6.5 Steps 4&5–Select BACT

> If the applicant accepts the top alternative in the listing as BACT, the applicant proceeds to consider whether impacts of unregulated air pollutants or impacts in other media would justify selection of an alternative control option. If there are no outstanding issues regarding collateral environmental impacts, the analysis is ended and the results proposed as BACT. In the event that the top candidate is shown to be inappropriate, due to energy, environmental, or economic impacts, the rationale for this finding should be documented for the public record. Then the next most stringent alternative in the listing becomes the new control candidate and is similarly evaluated. This process continues until the technology under consideration cannot be eliminated by any source-specific environmental, energy, or economic impacts which demonstrate that alternative to be inappropriate as BACT. The most effective control option not eliminated is proposed as BACT for the pollutant and emission unit under review.

The Solar Titan 250 dry low-NO_x CTG avoids water injection while on natural gas, and emits fewer products of incomplete combustion (CO and VOC) than a similar unit with water injection, while achieving the same full-load NO_x emission rates.

During oil firing, MIT proposes an emission limit of 9.0 ppmdv down to 50% load. Given that ULSD will be fired only when gas is unavailable, at most 168 hours per year, the difference between this limit and the MassDEP top-case BACT is 0.14 tons per year. The environmental impacts associated with using water injection (water use, higher products of incomplete combustion) outweigh the impacts associated with slightly higher NO_x emissions during limited ULSD operating hours.

4.7 Carbon Monoxide (CO) BACT

While CO emissions are only subject to Massachusetts BACT requirements, this BACT analysis follows the federal guidance in the New Source Review Workshop Manual, Prevention of Significant Deterioration and Nonattainment Area Permitting, USEPA Draft October 1990 document. Specific guidance from that document is included in boxes below, followed by MIT's analysis based on the guidance. The BACT analysis follows the guidance in the NESCAUM BACT Guideline dated June 1991, as well as the referenced NSR Workshop Manual.

4.7.1 BACT Applicability

> ...the BACT determination must separately address..., for each regulated pollutant... air pollution controls for each emissions unit or pollutant emitting activity subject to review.

Carbon monoxide (CO) is a product of incomplete combustion. MIT proposes to meet MassDEP's top case BACT of 2.0 ppmvd @ 15% O2 for the CTG firing natural gas at 100% load at 60°F ambient by using an oxidation catalyst sized to consistently achieve the Top-Case BACT outlet concentration.

Part load operation will be limited by MIT as needed to meet the annual potential to emit limit of 15.1 tpy proposed for the CTGs and HRSGs, including the HRSGs and operation down to 40% load. During oil firing, MIT is able to meet the top case BACT of 7.0 ppmdv down to 50% load.

4.7.2 Step 1–Identify All Control Technologies

> The first step in a "top-down" analysis is to identify, for the emissions unit in question (the term "emissions unit" should be read to mean emissions unit, process or activity), all "available" control options. Available control options are those air pollution control technologies or techniques with a practical potential for application to the emissions unit and the regulated pollutant under evaluation.

Available control options are:

- Post-combustion control, including:
  - Oxidation catalyst
- The use of clean fuels (natural gas with ULSD backup) and good combustion control

> Air pollution control technologies and techniques include the application of production process or available methods, systems, and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of the affected pollutant.

With regard to the list above, MIT's proposed project includes fuel combustion techniques, and the use of clean fuels (natural gas with ULSD backup), which can be considered "fuel cleaning or treatment."

> This includes technologies employed outside the United States.

MIT is unaware of technologies employed outside the United States that are not employed inside the United States.

> … in some circumstances inherently lower-polluting processes are appropriate for consideration as available control alternatives.

MIT's proposed use of clean fuels (natural gas with ULSD backup) can be considered an inherently lower-polluting process.

> The control alternatives should include not only existing controls for the source category in question, but also (through technology transfer) controls applied to similar source categories and gas streams, and innovative control technologies.

With regards to the proposed project, the source category in question is the production of electricity in a combustion turbine.

> Technologies required under lowest achievable emission rate (LAER) determinations are available for BACT purposes and must also be included as control alternatives and usually represent the top alternative.

MIT has reviewed the EPA RACT/BACT/LAER Clearinghouse and other online data sources which include LAER determinations. The top control technology found is the use of clean fuels (natural gas with ULSD backup) and good combustion techniques.

4.7.3 Step 2–Eliminate Technically Infeasible Options

> In the second step, the technical feasibility of the control options identified in step one is evaluated with respect to the source-specific (or emissions unit-specific) factors.

Each identified control option is evaluated with respect to emissions unit-specific factors below.

- Post-combustion control: *technically feasible*
- Use of clean fuels (natural gas with ULSD backup) and good combustion control: *technically feasible*

A demonstration of technical infeasibility should be clearly documented and should show, based on physical, chemical, and engineering principles, that technical difficulties would preclude the successful use of the control option on the emissions unit under review. Technically infeasible control options are then eliminated from further consideration in the BACT analysis.

- All identified control options are technically feasible

For example, in cases where the level of control in a permit is not expected to be achieved in practice (e.g., a source has received a permit but the project was cancelled, or every operating source at that permitted level has been physically unable to achieve compliance with the limit), and supporting documentation showing why such limits are not technically feasible is provided, the level of control (but not necessarily the technology) may be eliminated from further consideration.

The EPA Clearinghouse was queried for CTGs firing natural gas or distillate oil, operating in combined-cycle or cogeneration mode, sized smaller than 25 MW. Additional facilities were added based on Epsilon experience.

Key projects are summarized in Table 4-6 below:

Table 4-6 Summary of available data on CO turbine emission limits

Determination	CO emission limit	Converted
RBLC determination for Signal Hills Wichita Falls Power (TX), 20 MW turbine, combined cycle	32 lb/hr firing natural gas	1.60 lb/MWh 0.15 lb/MMBtu
NYSDEC operating permit for Cornell University, 15 MW Solar turbine CHP	10 ppm firing natural gas 30 ppm firing ULSD	0.40 lb/MWh firing natural gas (0.022 lb/MMBtu) 1.28 lb/MWh firing ULSD (0.071 lb/MMBtu)
Conditional Approval for MassDEP operating permit for UMass Amherst, 10 MW Solar turbine CHP	5 ppm firing natural gas 5 ppm firing diesel	0.28 lb/MWh (0.011 lb/MMBtu) natural gas 0.27 lb/MWh (0.012 lb/MMBtu) ULSD
MassDEP operating permit for Gillette Boston, Solar Taurus 70 turbine CHP	0.9 lb/hr firing natural gas (with and without duct burning); 2.2 lb/hr firing ULSD.	0.12 lb/MWh (0.005 lb/MMBtu) firing natural gas, 0.29 lb/MWh firing ULSD (0.012 lb/MMBtu)

Table 4-6 Summary of available data on CO turbine emission limits (Continued)

Determination	CO emission limit	Converted
MassDEP operating permit for UMass Medical Center, Solar Taurus 70 turbine CHP	2 ppm firing natural gas without duct burning; 0.92 lb/hr firing ULSD	0.051 lb/MWh (0.0045 lb/MMBtu) firing natural gas 0.12 lb/MWh firing ULSD (0.011 lb/MMBtu)
MassDEP operating permit for MATEP, Alston turbine & HRSG	1 ppm firing gas, 2.5 ppm firing gas with duct firing, 5 ppm firing ULSD	0.023 lb/MWh (0.0022 lb/MMBtu) firing natural gas 0.085 lb/MWh (0.0056 lb/MMBtu) firing natural gas with duct firing 0.12 lb/MWh firing ULSD (0.012 lb/MMBtu)
MassDEP operating permit for Harvard, Solar Taurus 70 turbine & HRSG (not yet constructed)	6 lb/hr firing natural gas with or without duct firing; 4.8 lb/hr firing ULSD	0.48 lb/MWh* (0.061 lb/MMBtu) firing natural gas 0.68 lb/MWh* (0.04 lb/MMBtu) firing natural gas with duct firing 0.57 lb/MWh* firing ULSD (0.051 lb/MMBtu)
RBLC Draft Determination for Lenzing Fibers, Inc. (AL) 25 MW Gas Turbine with HRSG	1.78 lb/hr firing natural gas	
* CHP emission limit at 310 CMR 7.26()		

4.7.4 Step 3–Rank Remaining Control Technologies By Control Effectiveness

In step 3, all remaining control alternatives not eliminated in step 2 are ranked and then listed in order of overall control effectiveness for the pollutant under review, with the most effective control alternative at the top. A list should be prepared for each pollutant and for each emissions unit (or grouping of similar units) subject to a BACT analysis. The list should present the array of control technology alternatives and should include the following types of information:

- control efficiencies (percent pollutant removed);
- expected emission rate (tons per year, pounds per hour);
- expected emissions reduction (tons per year);
- economic impacts (cost effectiveness);
- environmental impacts (includes any significant or unusual other media impacts (e.g., water or solid waste), and, at a minimum, the impact of each control alternative on emissions of toxic or hazardous air contaminants);
- energy impacts.

With regard to MIT's proposed project, the only available control technology is the use of clean fuels (natural gas with ULSD backup), efficient combustion and oxidation catalyst. Requested data is summarized in Table 4-7 below.

Table 4-7 Summary of CO effectiveness of clean fuels, efficient combustion and Oxidation Catalyst

Control efficiencies (percent pollutant removed)	Up to 96% to meet the 2 ppmvd emission limit
Expected emission rate (tons per year, pounds per hour)	Per the calculations in Appendix C (Tables C-1, C-2, and C-10), potential emissions are a maximum of 2.5 lb/hr firing gas (at 40% load), 5.3 lb/hr firing ULSD in each CTG (and gas in the HRSG), and 15.1 tons/year combined total. Expected emission rates are lower.
Expected emissions reduction (tons per year)	The oxidation catalyst as proposed will remove 94-96% of uncontrolled CO emissions, which will vary based on actual loads operated.
Economic impacts	In most cases, clean fuels are more expensive than higher-polluting fuels. As of the time of this application natural gas prices are low on an annual basis, but high during peak winter use periods.
Environmental impacts (includes any significant or unusual other media impacts (e.g., water or solid waste), and, at a minimum, the impact of each control alternative on emissions of toxic or hazardous air contaminants)	The use of clean fuels (natural gas with ULSD backup) can have lower water, wastewater, solid waste, and toxic/hazardous air impacts than higher-polluting fuels.
Energy impacts	Energy use is a function of system efficiency; the proposed CHP is an efficient combustion turbine with heat recovery and low energy impacts.

4.7.5 Steps 4&5–Select BACT

If the applicant accepts the top alternative in the listing as BACT, the applicant proceeds to consider whether impacts of unregulated air pollutants or impacts in other media would justify selection of an alternative control option. If there are no outstanding issues regarding collateral environmental impacts, the analysis is ended and the results proposed as BACT. In the event that the top candidate is shown to be inappropriate, due to energy, environmental, or economic impacts, the rationale for this finding should be documented for the public record. Then the next most stringent alternative in the listing becomes the new control candidate and is similarly evaluated. This process continues until the technology under consideration cannot be eliminated by any source-specific environmental, energy, or economic impacts which demonstrate that alternative to be inappropriate as BACT. The most effective control option not eliminated is proposed as BACT for the pollutant and emission unit under review.

Based on the review above, MIT proposes to meet DEP's top case BACT of 2.0 ppmvd @ 15% O2 during full-load, steady state conditions. MIT proposes the top-case BACT emission limit of 7 ppmvd @15% O2 firing ULSD.

4.8 Volatile Organic Compounds (VOC) BACT

While VOC emissions are only subject to Massachusetts BACT requirements, this BACT analysis follows the federal guidance in the New Source Review Workshop Manual, Prevention of Significant Deterioration and Nonattainment Area Permitting, USEPA Draft October 1990 document. Specific guidance from that document is included in boxes below, followed by MIT's analysis based on the guidance. The BACT analysis follows the guidance in the NESCAUM BACT Guideline dated June 1991, as well as the referenced NSR Workshop Manual.

4.8.1 BACT Applicability

...the BACT determination must separately address..., for each regulated pollutant... air pollution controls for each emissions unit or pollutant emitting activity subject to review.

Volatile Organic Compounds (VOCs) are products of incomplete combustion. MIT proposes to meet MassDEP's top case BACT of 1.7 ppmdv (0.0022 lb/MMBTU) for the CTG firing natural gas at 100% load at 60°F ambient by using an oxidation catalyst designed for 50% VOC removal.

4.8.2 Step 1–Identify All Control Technologies

The first step in a "top-down" analysis is to identify, for the emissions unit in question (the term "emissions unit" should be read to mean emissions unit, process or activity), all "available" control options. Available control options are those air pollution control technologies or techniques with a practical potential for application to the emissions unit and the regulated pollutant under evaluation.

Available control options are:

- Post-combustion control, including:
  - Oxidation catalyst
- The use of clean fuels (natural gas with ULSD backup) and good combustion control

Air pollution control technologies and techniques include the application of production process or available methods, systems, and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of the affected pollutant.

With regard to the list above, MIT's proposed project includes fuel combustion techniques, and the use of clean fuels (natural gas with ULSD backup) which can be considered "fuel cleaning or treatment."

This includes technologies employed outside the United States.

MIT is unaware of technologies employed outside the United States that are not employed inside the United States.

... in some circumstances inherently lower-polluting processes are appropriate for consideration as available control alternatives.

MIT's proposed use of clean fuels (natural gas with ULSD backup) can be considered an inherently lower-polluting process.

The control alternatives should include not only existing controls for the source category in question, but also (through technology transfer) controls applied to similar source categories and gas streams, and innovative control technologies.

With regard to the proposed project, the source category in question is the production of electricity in a combustion turbine.

Technologies required under lowest achievable emission rate (LAER) determinations are available for BACT purposes and must also be included as control alternatives and usually represent the top alternative.

MIT has reviewed the EPA RACT/BACT/LAER Clearinghouse and other online data sources which include LAER determinations. The top control technology found is the use of clean fuels (natural gas with ULSD backup) and good combustion techniques.

4.8.3 Step 2–Eliminate Technically Infeasible Options

In the second step, the technical feasibility of the control options identified in step one is evaluated with respect to the source-specific (or emissions unit-specific) factors.

Each identified control option is evaluated with respect to emissions unit-specific factors below.

- Post-combustion control: *technically feasible*

- ♦ Use of clean fuels (natural gas with ULSD backup) and good combustion control: *technically feasible*

A demonstration of technical infeasibility should be clearly documented and should show, based on physical, chemical, and engineering principles, that technical difficulties would preclude the successful use of the control option on the emissions unit under review. Technically infeasible control options are then eliminated from further consideration in the BACT analysis.

- ♦ All identified control options are technically feasible.

For example, in cases where the level of control in a permit is not expected to be achieved in practice (e.g., a source has received a permit but the project was cancelled, or every operating source at that permitted level has been physically unable to achieve compliance with the limit), and supporting documentation showing why such limits are not technically feasible is provided, the level of control (but not necessarily the technology) may be eliminated from further consideration.

The EPA Clearinghouse was queried for CTGs firing natural gas or distillate oil, operating in combined-cycle or cogeneration mode, sized smaller than 25 MW. Additional facilities were added based on Epsilon experience.

Key projects are summarized in Table 4-8 below:

Table 4-8 Summary of available data on VOC turbine emission limits

Determination	VOC emission limit	Converted
RBLC determination for Signal Hills Wichita Falls Power (TX), 20 MW turbine, combined cycle	0.87 lb/hr firing natural gas	0.044 lb/MWh 0.0042 lb/MMBtu
NYSDEC operating permit for Cornell University, 15 MW Solar turbine CHP	NA	NA
Conditional Approval for MassDEP operating permit for UMass Amherst, 10 MW Solar turbine CHP	0.5 lb/hr firing natural gas or 0.87 lb/hr firing diesel	0.045 lb/MWh (0.0041 lb/MMBtu) natural gas 0.079 lb/MWh (0.0074 lb/MMBtu) ULSD
MassDEP operating permit for Gillette Boston, Solar Taurus 70 turbine CHP	0.5 lb/hr firing natural gas or ULSD	0.067 lb/MWh (0.0027 lb/MMBtu) firing natural gas, 0.067 lb/MWh firing ULSD (0.003 lb/MMBtu)

Table 4-8 Summary of available data on VOC turbine emission limits (Continued)

Determination	VOC emission limit	Converted
MassDEP operating permit for UMass Medical Center, Solar Taurus 70 turbine CHP	2 ppm firing natural gas without duct burning; 0.21 lb/hr firing ULSD	0.029 lb/MWh (0.0026 lb/MMBtu) firing natural gas 0.028 lb/MWh firing ULSD (0.0025 lb/MMBtu)
MassDEP operating permit for MATEP, Alston turbine & HRSG	1 ppm firing gas, 2.5 ppm firing gas with duct firing, 7 ppm firing ULSD	0.013 lb/MWh (0.0013 lb/MMBtu) firing natural gas 0.049 lb/MWh (0.0032 lb/MMBtu) firing natural gas with duct firing 0.10 lb/MWh firing ULSD (0.0095 lb/MMBtu)
MassDEP operating permit for Harvard, Solar Taurus 70 turbine & HRSG (not yet constructed)	2 lb/hr firing natural gas with or without duct burning; 0.34 lb/hr firing ULSD	0.029 lb/MWh (0.02 lb/MMBtu) firing natural gas 0.23 lb/MWh* (0.013 lb/MMBtu) firing natural gas with duct firing 0.041 lb/MWh firing ULSD (0.004 lb/MMBtu)
RBLC Draft Determination for Lenzing Fibers, Inc. (AL) 25 MW Gas Turbine with HRSG	1.60 ppm firing natural gas	

4.8.4 Step 3–Rank Remaining Control Technologies By Control Effectiveness

In step 3, all remaining control alternatives not eliminated in step 2 are ranked and then listed in order of over all control effectiveness for the pollutant under review, with the most effective control alternative at the top. A list should be prepared for each pollutant and for each emissions unit (or grouping of similar units) subject to a BACT analysis. The list should present the array of control technology alternatives and should include the following types of information:

- control efficiencies (percent pollutant removed);
- expected emission rate (tons per year, pounds per hour);
- expected emissions reduction (tons per year);
- economic impacts (cost effectiveness);
- environmental impacts (includes any significant or unusual other media impacts (e.g., water or solid waste), and, at a minimum, the impact of each control alternative on emissions of toxic or hazardous air contaminants);
- energy impacts.

With regard to MIT's proposed project, the only available control technology is the use of clean fuels (natural gas with ULSD backup), efficient combustion and oxidation catalyst. Requested data is summarized in Table 4-9 below.

Table 4-9 Summary of VOC effectiveness of clean fuels, combustion and Oxidation Catalyst

Control efficiencies (percent pollutant removed)	Up to 50% control efficiency for VOC removal
Expected emission rate (tons per year, pounds per hour)	Per the calculations in Appendix C (Tables C-9 and C-10), potential emissions are 4.2 lb/hr firing gas, 5.8 lb/hr firing ULSD in each CTG (and gas in the HRSG), and 20.9 tons/year combined total. Expected emission rates are lower.
Expected emissions reduction (tons per year)	The oxidation catalyst as proposed will remove 50% of uncontrolled VOC emissions, which will vary based on actual loads operated.
Economic impacts	In most cases, clean fuels are more expensive than higher-polluting fuels. As of the time of this application natural gas prices are low on an annual basis, but high during peak winter use periods.
Environmental impacts (includes any significant or unusual other media impacts (e.g., water or solid waste), and, at a minimum, the impact of each control alternative on emissions of toxic or hazardous air contaminants)	The use of clean fuels (natural gas with ULSD backup) can have lower water, wastewater, solid waste, and toxic/hazardous air impacts than higher-polluting fuels.
Energy impacts	Energy use is a function of system efficiency; the proposed CHP is an efficient combustion turbine with heat recovery and low energy impacts.

4.8.5 Steps 4&5–Select BACT

If the applicant accepts the top alternative in the listing as BACT, the applicant proceeds to consider whether impacts of unregulated air pollutants or impacts in other media would justify selection of an alternative control option. If there are no outstanding issues regarding collateral environmental impacts, the analysis is ended and the results proposed as BACT. In the event that the top candidate is shown to be inappropriate, due to energy, environmental, or economic impacts, the rationale for this finding should be documented for the public record. Then the next most stringent alternative in the listing becomes the new control candidate and is similarly evaluated. This process continues until the technology under consideration cannot be eliminated by any source-specific environmental, energy, or economic impacts which demonstrate that alternative to be inappropriate as BACT. The most effective control option not eliminated is proposed as BACT for the pollutant and emission unit under review.

As described above, MIT proposes to meet DEP's top case BACT of 1.7 ppmdv (0.0022 lb/MMBTU) for the combustion turbine firing natural gas at 100% load at 60°F ambient by using an oxidation catalyst designed for 50% VOC removal. During oil firing, MIT is able to meet the top case BACT of 7.0 ppmdv down to 50% load.

4.9 Greenhouse Gas BACT

Similar to particulate matter, GHG emissions are subject to both federal and Massachusetts BACT requirements, so this BACT analysis follows the New Source Review Workshop Manual, and the NESCAUM BACT Guideline. In addition, this BACT analysis refers to the March 2011 EPA document "PSD and Title V Permitting Guidance for Greenhouse Gases.[20]"

Available fuels and emission controls are the same for the CTGs and the HRSGs. Also, data on emission limits achieved-in-practice tend to be based on total emissions from CTG and HRSG firing. This BACT analysis therefore applies to the combined emissions of the CTGs and the HRSGs in the proposed project.

4.9.1 BACT Applicability

...the BACT determination must separately address..., for each regulated pollutant... air pollution controls for each emissions unit or pollutant emitting activity subject to review.

The PSD regulations at 40 CFR 52.21(b)(49)(i) define GHG as a single pollutant, an aggregate of the following six gases: carbon dioxide (CO_2), nitrous oxide (N2O), methane (CH4), hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), and sulfur hexafluoride (SF6). Of these, HFCs, PFCs, and SF6 are not products of combustion and will not be emitted by the proposed expanded CUP. The N2O will be controlled as NO_x by the proposed project's SCR, and the CH4 will be controlled by good combustion practices. Therefore, this BACT analysis focuses on CO_2 emissions as the primary GHG component. Emissions calculations are as CO_2-equivalent, or CO_2e.

[20] EPA-457/B-11-001, http://www.epa.gov/nsr/ghgdocs/ghgpermittingguidance.pdf

4.9.2 Step 1 — Identify All Control Technologies

The first step in a "top-down" analysis is to identify, for the emissions unit in question (the term "emissions unit" should be read to mean emissions unit, process or activity), all "available" control options. Available control options are those air pollution control technologies or techniques with a practical potential for application to the emissions unit and the regulated pollutant under evaluation.

With regard to MIT's proposed project, available control options are:

- Carbon Capture Sequestration - (CCS)
- The use of clean fuels (natural gas with ULSD backup), good combustion practices (Appendix B — Part 1), and efficient operation

Air pollution control technologies and techniques include the application of production process or available methods, systems, and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of the affected pollutant.

With reference to the list above, MIT's proposed project includes fuel combustion techniques and the use of clean fuels (natural gas with ULSD backup), which can be considered "fuel cleaning or treatment."

This list includes technologies employed outside the United States.

MIT is unaware of technologies employed outside the United States that are not employed inside the United States.

...in some circumstances inherently lower-polluting processes are appropriate for consideration as available control alternatives.

With regard to MIT's proposed project, the use of clean fuels (natural gas with ULSD backup) can be considered an inherently lower-polluting process.

The control alternatives should include not only existing controls for the source category in question, but also (through technology transfer) controls applied to similar source categories and gas streams, and innovative control technologies.

In this case, the source category in question is the production of electricity in a CTG. Through technology transfer, controls applied to similar source categories (residual oil or solid fuel combustion) include the control options listed above.

Technologies required under lowest achievable emission rate (LAER) determinations are available for BACT purposes and must also be included as control alternatives and usually represent the top alternative.

MIT has reviewed the EPA RACT/BACT/LAER Clearinghouse and other online data sources which include LAER determinations. The top control technology found is the use of clean fuels (natural gas with ULSD backup) and good combustion techniques. For example, all the determinations in Table 4-6, (above) fire natural gas or distillate oil. Each has no GHG emission limit or has a GHG emission limit on a mass basis.

A RACT/BACT/LAER Clearinghouse search finds a single facility with GHG emission limits[21]. Midwest Fertilizer in Mount Vernon IN has two "open-simple cycle combustion turbines with heat recovery," each with a limit of 12,666 "BTU/KW-H, MINIMUM". It is not clear that this limit is comparable to the proposed project.

4.9.3 Step 2 — Eliminate Technically Infeasible Options

In the second step, the technical feasibility of the control options identified in step one is evaluated with respect to the source-specific (or emissions unit-specific) factors.

Each identified control option is evaluated with respect to emissions unit-specific factors below.

- Carbon Capture Sequestration: *technically infeasible*
- Use of clean fuels (natural gas with ULSD backup), good combustion control, and energy efficiency: *technically feasible*

A demonstration of technical infeasibility should be clearly documented and should show, based on physical, chemical, and engineering principles, that technical difficulties would preclude the successful use of the control option on the emissions unit under review. Technically infeasible control options are then eliminated from further consideration in the BACT analysis.

With regard to MIT's proposed project, clear documentation of technical difficulties is demonstrated below for each technically infeasible control option:

21 http://cfpub.epa.gov/rblc/index.cfm, Categories 16.210 and 16.290 (Small Combustion Turbines <25 MW, Combined Cycle and Cogeneration, natural gas and liquid fuel), pollutants CO2 or CO_2e over the last 10 years.

- **Carbon Capture Sequestration**. For CCS to be technically feasible, each of the following steps needs to be technically feasible: 1) capture; 2) compression; 3) transport; and 4) sequestration.

    1) **Capture.** Carbon capture is technically infeasible for the MIT project site. There is insufficient space for the required absorption system (more than 5 acres would be needed[22]). Also, the absorption process has not been demonstrated on a power generating unit beyond the pilot-scale or side-stream scale. Finally, the handling of the absorption media (which could be ammonia, monoethanolamine, or other amine solution) may not be feasible in an urban setting.

    2) **Compression.** Compressing the CO_2 to about 2,000 pounds per square inch for transport may or may not be technically feasible at the MIT site. There may or may not be space for the required equipment, and it may be impossible to operate the needed compressors and comply with Cambridge noise regulations.

    3) **Transport.** The transport of CO_2 from the MIT site is technically infeasible because the necessary approvals could not be obtained for a pipeline of pressurized gas or supercritical fluid CO_2 through Cambridge streets.

    4) **Sequestration.** Sequestration of CO_2 from the MIT site is technically infeasible. Sequestration is the injection and long-term storage of CO_2 in geologic formations such as coal seams and oil and gas reservoirs. There are no candidate geologic formations near enough to MIT to make the process feasible. As shown in Figure 4-1, the nearest potential geologic formation is at the Pennsylvania/New Jersey border over 200 miles away; proven CO_2 storage locations are much more distant. Sequestration has in any event not been demonstrated in practice for control of CO_2 from electric generation.

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[22] Sizing estimated from permits for CO_2 recovery plant at Indiantown Cogeneration, Florida Department of Environmental Protection Project Number 0850102-003-AC.

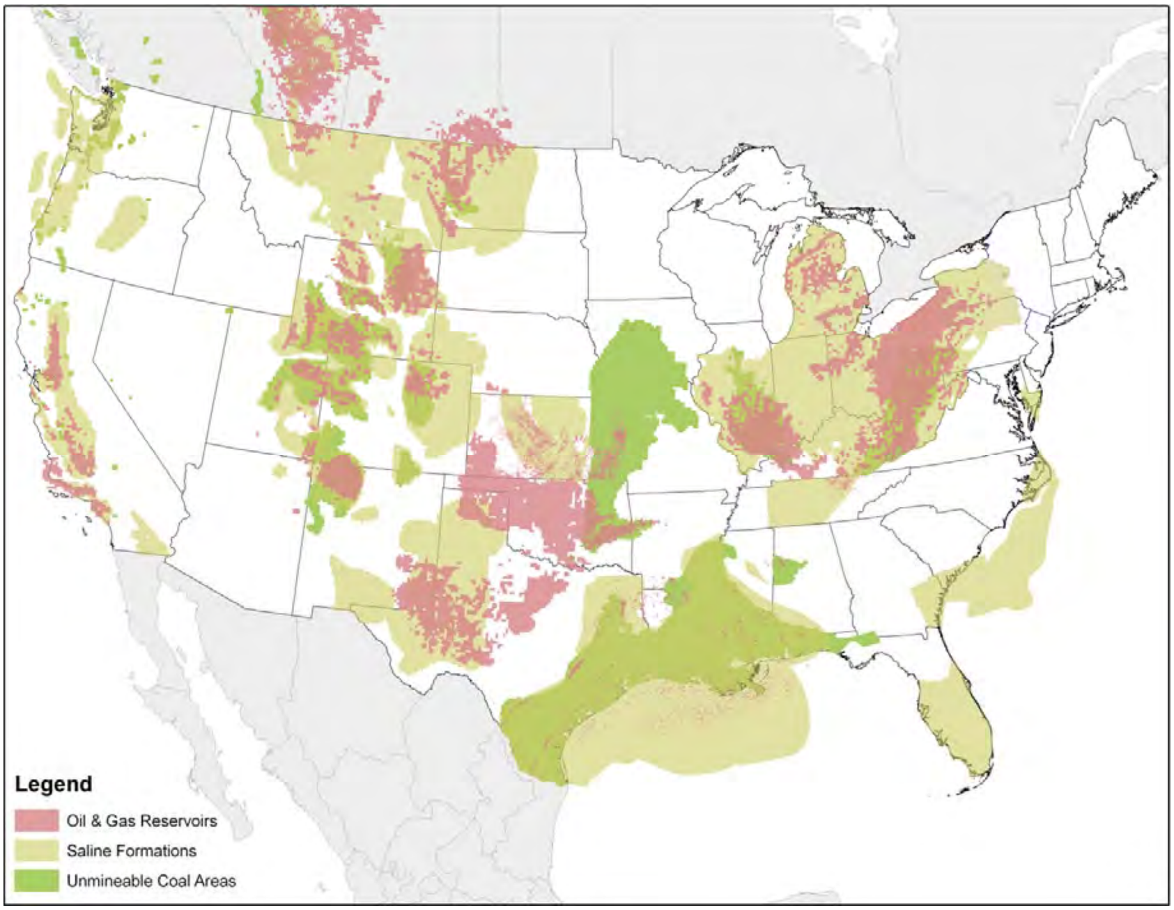

Figure 4-1 Potential CO2 Sequestration Sites

Source: http://www.epa.gov/climatechange/ccs/

Also, the EPA 2011 GHG guidance notes:

> …in cases where it is clear that there are significant and overwhelming technical (including logistical) issues associated with the application of CCS for the type of source under review (e.g., sources that emit CO_2 in amounts just over the relevant GHG thresholds…) a much less detailed justification may be appropriate and acceptable for the source. In addition, a permitting authority may make a determination to dismiss CCS for a small natural gas-fired package boiler, for example, on grounds that no reasonable opportunity exists for the capture and long-term storage or reuse of captured CO_2 given the nature of the project.

The proposed project's CTG and HRSG units emit CO_2 in amounts just over the relevant GHG thresholds and have a similar emission profile to a natural gas-fired package boiler.

Since most or all of the steps required for CCS are not technically feasible for the MIT project, CCS is not technically feasible.

- ♦ Use of clean fuels (natural gas with ULSD backup), good combustion control (as described in Appendix B — Part 1), and energy efficiency: Technically feasible.

4.9.4 Step 3 — Rank Remaining Control Technologies By Control Effectiveness

In step 3, all remaining control alternatives not eliminated in step 2 are ranked and then listed in order of overall control effectiveness for the pollutant under review, with the most effective control alternative at the top. A list should be prepared for each pollutant and for each emissions unit (or grouping of similar units) subject to a BACT analysis. The list should present the array of control technology alternatives and should include the following types of information:

- control efficiencies (percent pollutant removed);
- expected emission rate (tons per year, pounds per hour);
- expected emissions reduction (tons per year);
- economic impacts (cost effectiveness);
- environmental impacts (includes any significant or unusual other media impacts (e.g., water or solid waste), and, at a minimum, the impact of each control alternative on emissions of toxic or hazardous air contaminants);
- energy impacts.

With regard to MIT's proposed project, the only remaining control technology is the use of clean fuels (natural gas with ULSD backup) and efficient combustion. Requested data is summarized in Table 4-10 below.

Table 4-10 Summary of CO_2e Effectiveness of Clean Fuels (Natural Gas with ULSD Backup) and Efficient Combustion

Control efficiencies (percent pollutant removed)	Not applicable (inherently clean technology used)
Expected emission rate (tons per year, pounds per hour)	Per the calculations in Appendix C (Tables C-9 and C-10), potential emissions are 42,071 lb/hr firing gas, 51,167 lb/hr firing ULSD in each CTG (and gas in the HRSG), and 294,970 tons/year combined total.
Expected emissions reduction (tons per year)	Not applicable (inherently clean technology used)
Economic impacts	In most cases, clean fuels are more expensive than higher-polluting fuels. As of the time of this application, natural gas prices are low on an annual basis but high during peak winter use periods.
Environmental impacts (includes any significant or unusual other media impacts (e.g., water or solid waste), and, at a minimum, the impact of each control alternative on emissions of toxic or hazardous air contaminants)	The use of clean fuels (natural gas with ULSD backup) can have lower water, wastewater, solid waste, and toxic/hazardous air impacts than higher-polluting fuels.
Energy impacts	Energy use is a function of system efficiency; the proposed CHP is an efficient CTG with heat recovery and low energy impacts.

The MIT project is designed to provide BACT for GHG by optimizing equipment size and efficiency to provide the most efficient electrical and thermal generation across the range of MIT's projected loads.

As part of its evaluation, MIT performed an hour-by-hour model of CUP operation (including the proposed CTGs, associated HRSGs, and existing boilers) against projected MIT campus electric and thermal loads. This model was run for the entire project design period (2019-2030), with two different sets of assumptions for MIT campus electric and thermal loads. The model results consistently showed that a slightly smaller CTG model (Solar Titan 250) met MIT's needs with lower GHG emissions. Both CTG/HRSG combinations had similar full load electric and thermal efficiencies. The key difference was the ability of the smaller CTG to effectively meet MIT's energy needs for more hours of the year using fuel fired in the CTG , allowing more hours of true cogeneration (where fuel is fired in the CTG to generate electricity, and the hot exhaust is used to generate useful thermal energy). For the larger CTG configuration, there were more modeled hours when one CTG would be shut off and a larger portion of the campus energy needs would be met using grid electricity and duct firing.

Table 4-11 below provides an apples-to-apples comparison of the two CTG configuration options and annotation explaining how the slightly smaller CTG is a better fit to maximize efficient cogeneration.

Table 4-11 Comparison of CHP Configurations

CTG Model	Total Run Time (2 CTGs) (hrs/year)	Total Generated Electric (MWh/yr)	Total Purchased Electric (MWh/yr)	Total CTG Gas Usage (MMBtu/yr)	Total HRSG Gas Usage (MMBtu/yr)	Steam Generated by CTG & HRSG (MMBtu/yr)	Total Existing Boiler Gas Usage (MMBtu/yr)
Solar T250	14,219	273,964	85,882	2,537,725	324,375	1,446,663	2,154
GE LM2500	11,695	234,421	125,115	2,353,174	337,896	1,463,185	1,675
Notes	The T250 CTGs can remain operating for more hours of the year, generating more electricity.		This results in lower electricity purchases, and lower GHG emissions from grid electricity.	More fuel is fired in the CTGs, and less in the HRSGs, allowing for more cogeneration.		For both cases, the CTGs and HRSGs provide almost all the campus steam needs. Existing boilers remain for reliability, but generally do not run.	

Basis: Projected 2023 MIT loads, as modeled

A summary spreadsheet is provided in Appendix C [Table C-14] which follows a sample calculation provided by the Massachusetts Department of Energy Resources (DOER) for the Massachusetts Environmental Policy Act (MEPA) process. This calculation compares, for the same amount of electricity and useful heat, the CO2 emissions generated by the CHP versus the CO2 emissions that would be generated by the import of electricity from the distribution grid and creation of the useful heat with conventional natural gas boilers. Using the same emission factors as were used in the MEPA process, the calculations show a net GHG reduction of 67,254 tons per year for the Solar Titan 250 and 59,863 tons per year for the GE LM2500. Since the Solar Titan 250 had a greater reduction in GHG emissions, it is the better fit to maximize efficient cogeneration and minimize GHG emissions.

The thermal efficiency of the HRSG will be significantly higher than that of an equivalent stand-alone boiler. MIT expects a 95% thermal efficiency in the final design. As such, MIT expects to use the HRSGs to meet most of the campus thermal energy needs, keeping the existing boilers as backup units. The thermal efficiency of the final design will be a function of space constraints, the mechanical and structural considerations involved in integrating the HRSG with the rest of MIT's steam generation and supply equipment, catalyst placement requirements, etc.

4.9.5 Steps 4 and 5 — Select BACT

If the applicant accepts the top alternative in the listing as BACT, the applicant proceeds to consider whether impacts of unregulated air pollutants or impacts in other media would justify selection of an alternative control option. If there are no outstanding issues regarding collateral environmental impacts, the analysis is ended and the results proposed as BACT. In the event that the top candidate is shown to be inappropriate, due to energy, environmental, or economic impacts, the rationale for this finding should be documented for the public record. Then the next most stringent alternative in the listing becomes the new control candidate and is similarly evaluated. This process continues until the technology under consideration cannot be eliminated by any source-specific environmental, energy, or economic impacts which demonstrate that alternative to be inappropriate as BACT. The most effective control option not eliminated is proposed as BACT for the pollutant and emission unit under review.

Consistent with the analysis presented above, MIT proposes the use of clean fuels (natural gas with ULSD backup) and efficient combustion, achieving a total CO_2e emission of 42,071 lb/hr firing gas and 51,167 lb/hr firing ULSD in the CTG (and gas in the HRSG) as the top alternative for BACT.

As discussed in Section 1.1, this CHP project will promote very efficient fuel use by generating both electricity and useful heat. Per the Massachusetts Energy and Environmental Affairs website[23]:

> *"A Combined Heat and Power (CHP) system (or cogeneration) can effectively and reliably generate useful heat and electric power using less fuel than a typical system that generates power only. CHP systems offer tremendous opportunities for customers with predictable and consistent heat and power needs (particularly large commercial, industrial, and institutional facilities), providing potential for significant economic savings and reductions in fuel consumption and greenhouse gas emissions."*

4.10 Startup Periods, Shutdown Periods, and Fuel Changes

CTGs can experience increased emissions during startup periods, shutdown periods, and fuel changes because operations are not steady-state. Also, the SCR system needs a minimum operating temperature to effectively reduce NO_x. MIT will comply with BACT during startup periods and shutdown periods by employing good operating practices (by following the manufacturer's recommendations during startup and shutdown) and by

[23] http://www.mass.gov/eea/energy-utilities-clean-tech/energy-efficiency/ee-for-business-institutions/combined-heat-power/

limiting startup and shutdown time. Required startup and shutdown times are a function of equipment protection requirements (e.g. avoiding damage from rapid temperature changes) and emissions during startups and shutdowns will be minimized by following manufacturers' Standard Operating Procedures. Startups and shutdowns will be per manufacturers' specifications, but startups will not exceed 180 minutes in duration and shutdowns will not exceed 60 minutes for each episode as a worst case.

Additionally, NO_x emissions will be minimized during startup periods by injecting urea into the SCR system as soon as the catalyst reaches its minimum operating temperature and all system parameters are met. The oxidation catalyst will begin removing CO as it warms up, with increasing effectiveness as it comes up to temperature.

Given the brief and transient nature of startups and shutdowns, and the many project-specific details that affect startup and shutdown parameters, it is difficult to estimate startup and shutdown emission rates before project construction and operation. The equipment vendors working with MIT have made it clear that startup and shutdown emission rates will not be guaranteed under any circumstances.

Based on general vendor data with adjustments to reflect particulars for the MIT operation, emissions of NO_x and CO could be elevated during startups and shutdowns. Startup and shutdown emissions estimates are provided in Table 4-12 below:

Table 4-12 Startup and Shutdown Emissions Estimates

Operation during Startups with Natural Gas Firing Startup duration: < 180 minutes	
Pollutant	Emissions Estimate
NO_x	32 lb/event
CO	201 lb/event
Operation during startups Natural Gas Firing Shutdown duration: < 60 minutes	
Pollutant	Emissions Estimate
NO_x	12.4 lb/event
CO	26.3 lb/event
Operation during startups ULSD Firing Startup duration: < 180 minutes	
Pollutant	Emissions Estimate
NO_x	65 lb/event
CO	453 lb/event
Operation during shutdowns ULSD Firing Shutdown duration: < 60 minutes	
Pollutant	Emissions Estimate
NO_x	25 lb/event
CO	129 lb/event

MIT proposes to track NO_x and CO emissions during startups and shutdowns using CEMS and comply with the proposed long-term emission limits for the CTGs and HRSGs as provided in Table 4-14 (below) for all periods including startups and shutdowns. Other pollutant emission rates are not expected to be elevated relative to the proposed full-load steady-state emission rates in Table 4-13 (also below).

4.11 Proposed CTG & HRSG Emission Limits

MIT proposes combined, mass-based emissions limits that reflect BACT as described above, for the following reasons:

- Based on guidance in the NSR Workshop Manual, emission limits should be "enforceable as a practical matter." Because the HRSG emissions are entirely commingled with the CTG emissions, it is not practical to enforce separate permit limits.

- A well-designed CHP system is well matched to the electric and thermal loads it is serving, and lb/MWh limits, which are primarily intended to encourage electric power generation efficiency, would limit MIT's ability to operate the facility in the most efficient manner to serve the electric, chilled water, and thermal demands of the campus. A limit on lb/MWh that includes thermal energy output could be complicated to calculate and could serve to reduce overall CUP plant efficiency by restricting MIT's ability to operate its most efficient equipment as needed to respond to changing campus needs.

This is consistent with the plan approval recently issued by MassDEP for very similar projects (The Gillette Company, Boston, February 2, 2010 and Harvard University, Cambridge, October 29, 2013). The proposed emission limits and compliance mechanisms are summarized in Table 4-13, below. Supporting calculations are provided in Appendix C.

Table 4-13 Proposed Short-Term Emission Limits Per CHP Unit [Table C-1,C-2, and C-9 of Appendix C]

Operating Condition	Pollutant	Proposed Limit Per CHP Unit	Proposed Compliance Method
Natural gas, with or without duct firing	NO_x (with HRSG)	3.2 lb/hr normal operation / 4.0 lb/hr transient	CEMS, based on 1-hour average calculated hourly
	NO_x (without HRSG)	1.65 lb/hr	CEMS, based on 1-hour average calculated hourly
	CO (with HRSG)	2.5 lb/hr normal operation / 3.8 lb/hr transient	CEMS, based on 1-hour average calculated hourly
	CO (without HRSG)	1.00 lb/hr	CEMS, based on 1-hour average calculated hourly
	NH3 (with HRSG)	0.97 lb/hr normal operation / 1.8 lb/hr transient	CEMS, based on 1-hour average calculated hourly
	NH3 (without HRSG)	0.60 lb/hr	CEMS, based on 1-hour average calculated hourly
	VOC (with HRSG)	4.5 lb/hr normal operation / 4.6 lb/hr transient	Stack testing based on EPA Method 25A or other method approved by MassDEP, every 5 years.
	VOC (without HRSG)	0.48 lb/hr	Stack testing based on EPA Method 25A or other method approved by MassDEP, every 5 years.
	PM (with HRSG)	7.14 lb/hr	Stack testing based on EPA Method 5/202 or other method approved by MassDEP, every 5 years.
	PM (without HRSG)	4.47 lb/hr	Stack testing based on EPA Method 5/202 or other method approved by MassDEP, every 5 years.
	SO2 (with HRSG)	1.0 lb/hr	Initial calculations based on rated capacity, emission factor
	SO2 (without HRSG)	0.64 lb/hr	Initial calculations based on rated capacity, emission factor
	CO2e (with HRSG)	42,071 lb/hr	Initial calculations based on rated capacity, emission factor
	CO2e (without HRSG)	26,103 lb/hr	Initial calculations based on rated capacity, emission factor

Table 4-13 Proposed Short-Term Emission Limits Per CHP Unit [Table C-1,C-2, and C-9 of Appendix C] (Continued)

Operating Condition	Pollutant	Proposed Limit Per CHP Unit	Proposed Compliance Method
ULSD in CTG, with or without natural gas duct firing	NO_x (with HRSG)	9.5 lb/hr	CEMS, based on 1-hour average calculated hourly during normal operation
	NO_x (without HRSG)	8.02 lb/hr	CEMS, based on 1-hour average calculated hourly during normal operation
	CO (with HRSG)	5.3 lb/hr	CEMS, based on 1-hour average calculated hourly during normal operation
	CO (without HRSG)	3.80 lb/hr	CEMS, based on 1-hour average calculated hourly during normal operation
	NH_3 (with HRSG)	0.9 lb/hr	CEMS, based on 1-hour average calculated hourly during normal operation
	NH3 (without HRSG)	0.61 lb/hr	CEMS, based on 1-hour average calculated hourly during normal operation
	VOC (with HRSG)	6.0 lb/hr	Stack testing based on EPA Method 25A or other method approved by MassDEP, every 5 years.
	VOC (without HRSG)	2.01 lb/hr	Stack testing based on EPA Method 25A or other method approved by MassDEP, every 5 years.
	PM (with HRSG)	11.9 lb/hr	Stack testing based on EPA Method 5/202 or other method approved by MassDEP, every 5 years.
	PM (without HRSG)	9.17 lb/hr	Stack testing based on EPA Method 5/202 or other method approved by MassDEP, every 5 years.
	SO_2 (with HRSG)	0.7 lb/hr	Initial calculations based on rated capacity, emission factor
	SO_2 (without HRSG)	0.36 lb/hr	Initial calculations based on rated capacity, emission factor
	CO_2e (with HRSG)	51,167 lb/hr	Initial calculations based on rated capacity, emission factor
	CO_2e (without HRSG)	35,198 lb/hr	Initial calculations based on rated capacity, emission factor

Emissions of SO_2 and CO_2e will be limited through the use of clean fuels (natural gas with ULSD backup) and efficient operation. NO_x, CO, and NH_3 monitoring systems will be installed in accordance with 40 CFR 60 Appendix B and quality assured in accordance with Appendix F. Dedicated Continuous Opacity Monitoring System (COMS) will be installed to document compliance with opacity limits per 310 CMR 7.06.

MIT proposes that the short-term limits, above, exclude startup periods, shutdown periods, and fuel changes. MIT will not operate the CTG/HRSG at power generating loads below 40% of CTG rated capacity (50% on ULSD), excluding startup or shutdown periods or fuel changes. Emissions of other pollutants are not expected to be elevated relative to the proposed full-load steady-state emission rates in Table 4-13. Emissions of CO2e are directly related to fuel use and will be lower during startup and shutdown periods than during full-load operation.

For long-term emission rates, MIT proposes to restrict operation on ULSD up to the equivalent heat input of 168 hours per year (268,800 gallons per year per CTG (calculations in Table C-12 of Appendix C)) including testing and periods when natural gas is unavailable. Proposed long-term emission limits are summarized in Table 4-14, below. The proposed long-term emission rates include startup periods, shutdown periods, and fuel changes. The proposed long-term emission rates are based on a heat input of 1,094,825 MMBtu/12-month rolling period for the two HRSGs (4,380 hours/year full load equivalent).

Table 4-14 Proposed Long-Term Emission Limits for the CTGs and HRSGs

NO_x	21.1 ton/12-month rolling period, based on CEMS
CO	15.1 ton/12-month rolling period, based on CEMS
NH3	6.7 ton/12-month rolling period, based on CEMS
VOC	20.9 ton/12-month rolling period, based on stack test data and fuel use
PM	50 ton/12-month rolling period, based on stack test data and fuel use
SO_2	7.0 ton/12-month rolling period, based on emission factors and fuel use
CO_2e	294,970 ton/12-month rolling period, based on emission factors and fuel use

MIT requests that the approval avoid limits that are linked to energy production (pounds per megawatt-hour or lb/MWh limits). The MIT CUP supplies steam, chilled water, and/or electricity to over 100 buildings on campus. The proposed project is designed to be integrated operationally into the existing CUP system that provides steam, chilled water, and electricity through a variety of production equipment. The combustion equipment process flow diagram is included in Appendix B – Part 3. Imposing specific pounds per megawatt-hour (lb/MWh) limits on individual generating units would either ignore the useful heat generated by the CHP system or would require a real time analytical model to account for the thermal energy generated. During any period of time, and at any given moment of the day, there is a range of production equipment in service as required by ever-changing campus demand.

In summary, tracking lb/MWh emissions against a limit would be complicated and would yield data that would be subject to various inaccuracies and assumptions, limiting its value as an indicator of compliance. Electrical generation efficiency is only one element of a properly-designed CHP system. The overall CHP project efficiency is based on the combination of electric power and thermal heat.

4.12 BACT for Cold-Start Engine

Where available, MIT proposes to use the MassDEP Top Case (BACT) Guidelines for Combustion Sources to document BACT for the cold-start engine. As stated in the guidelines, "Use of the applicable Top Case BACT emissions limitations contained herein may preclude the need for applicants to prepare and submit a "top-down BACT analysis" for MassDEP's review, and will streamline the Air Quality permitting process for both the applicants and MassDEP."

Table 4-15 below contains the MassDEP Top Case BACT Guideline for Emergency IC Engines equal to or greater than 37 kw.

Table 4-15 Top Case BACT from MassDEP Guidance for Emergency IC Engines

Source	Fuel	Air Contaminant	Emission Limitations	Control Technology
IC Engines equal to or greater than 37 kw (Emergency Engines)	ULSD (0.0015%)	NO_x, PM, CO, VOC	Comply with applicable emission limitations set by US EPA for non-road engines at 40 CFR 89	N/A

MIT is proposing to install a 2 MW engine in order to meet the minimum requirements necessary to start up the CTGs during a black-out situation. The cold-start engine is intended to be used to provide power to one CTG and its supporting equipment during a black-out situation in order to start up the CUP facility. As such, the engine is required to output enough power to meet the requirements to get one CTG up and running. MIT determined that the minimum engine size required to perform this function was the 2 MW unit. This determination is based on the estimated electric loads for the different components that the engine would serve, which are listed in Appendix B — Part 2. The cold-start engine falls within the range of sources subject to the MassDEP Environmental Results Program (ERP) Standards for emergency engines and CTGs at 310 CMR 7.26(42). The ERP limitations for emergency engines and CTGs mandate compliance with the applicable emission limits set by the EPA for non-road engines (40 CFR 89), use of ULSD fuel and hours of operation limited to no more than 300 per 12-month rolling period. MIT will obtain the appropriate engine supplier certification for this unit. These design and operating restrictions constitute BACT pursuant to 310 CMR 7.02(5).

Specifically regarding BACT for PSD-applicable pollutants, the following Top-Down BACT analyses were performed:

4.12.1 Particulate Matter

Step 1: Identify Candidate Control Technologies

- Active Diesel Particulate Filter (DPF)
- Low PM engine design (an engine that complies with Tier 2 engine limitations set forth in 40 CFR 60 Subpart IIII)

Step 2: Eliminate Infeasible Technologies

With regard to MIT's proposed project, both of the technologies listed above are technically feasible, although it would be highly unusual to use a DPF for a cold-start engine.

Step 3: Rank Control Technologies by Control Effectiveness

An active DPF, which can achieve up to 85% removal of particulate matter (CARB Level 3), is more effective than the low emission engine design.

Step 4: Evaluate Controls

Since a DPF is technically feasible in the proposed project, an economic analysis of the cost effectiveness for emission control was conducted. This economic analysis is presented in Table C-11 of Appendix C. The capital cost estimate for an active DPF system is based on a budgetary quote from RYPOS for Exelon West Medway's 450 kW Emergency Diesel Generator[24], scaled according to *Plant Design and Economics for Chemical Engineers*[25]. The other factors are from the OAQPS Control Cost Manual. Appendix C (Table C-11) indicates that the cost effectiveness of an active DPF is approximately $730,000 per ton of PM/$PM_{10}$/$PM_{2.5}$. This is not a cost-effective approach for MIT's project, even if the cold-start engine runs the maximum allowable amount of 300 hours per year, which is unlikely.

Considering the unfavorable economics of the DPF, there are no energy or environmental benefits that would outweigh the economics and indicate the selection of a DPF as BACT.

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24 Exelon West Medway CPA Application, Application Number CE-15-016

25 M. Peters and K. Timmerhaus, Plant Design and Economics for Chemical Engineers, 3rd ed. New York: McGraw-Hill, 1980, p. 166.

Step 5: Select BACT

With respect to the selection of a PSD BACT for $PM/PM_{10}/PM_{2.5}$ for the cold-start engine, DPF is eliminated as a BACT on economic grounds with regard to the proposed project. As such, the low PM engine design (an engine that meets EPA non-road engine standards for a Tier 2 engine) is proposed as BACT for PM for this project.

4.12.2 Greenhouse Gas (GHG) Emissions

Step 1 – Identify All Control Technologies

- Post-combustion controls
- Use of clean fuels (ULSD) and good combustion control

Step 2 – Eliminate Infeasible Technologies

Post-combustion controls for carbon dioxide and other greenhouse gases are not technically feasible for an engine of this size (2 MW). These controls are designed for much larger systems and even then have many technical issues as described in section 4.9. For example, GHG emissions are mostly composed of carbon dioxide emissions which are directly proportional to the amount of fuel fired. Given the size of this unit, it would be hard to control GHG emissions, especially from a cold-start engine that is used infrequently.

The use of clean fuels (ULSD) and good combustion control is technically feasible with regard to MIT's proposed project. ULSD is the fuel of choice because it is the cleanest fuel that could be used for this project while still meeting the project's intended purpose as defined above in section 4.2. ULSD can be stored in a small tank adjacent to the engine, satisfying the requirement for the engine to have a fuel supply that is directly available without interruption. By comparison, propane may be a less reliable source. While propane can be stored locally, the operator would need to evaporate the propane before firing it in the emergency engine. Due to its size, the cold-start engine proposed for this project might need an external heat source to vaporize the propane to make it usable, especially in cold weather. Due to the possible need for an external heat source, propane would be a less reliable resource in an emergency. As such, MIT has proposed ULSD for the project's cold-start generator engine.

Step 3 – Rank Control Technologies by Control Effectiveness

The only technically feasible control option is the use of clean fuels (ULSD) and good combustion control.

Step 4 – Evaluate Controls

There is no need to analyze the controls because the only remaining technically feasible control is the use of a clean fuels (ULSD) and good combustion practices.

Step 5 – Select BACT

With regard to MIT's proposed project, BACT was determined to be the use of clean fuels (ULSD) and good combustion control. However, as discussed in Step 2 of the BACT process for GHG emissions from the cold-start engine, this does not have much of an impact on GHG emissions. This is primarily due to the fact that GHG emissions are largely carbon dioxide, which is produced proportionally to the amount of fuel fired. The cold-start engine will have very low run times and will be vendor-certified per the MassDEP Environmental Results Program (ERP). It will also comply with EPA standards for non-road engines (40 CFR 89) as well as with the NSPS regulations at 40 CFR 60 Subpart IIII for stationary emergency engines.

Appendix A

Permit Forms

Enter your transmittal number → X262144
Transmittal Number

Your unique Transmittal Number can be accessed online: http://mass.gov/dep/service/online/trasmfrm.shtml

Massachusetts Department of Environmental Protection

Transmittal Form for Permit Application and Payment

1. Please type or print. A separate Transmittal Form must be completed for each permit application.

2. Make your check payable to the Commonwealth of Massachusetts and mail it with a copy of this form to: DEP, P.O. Box 4062, Boston, MA 02211.

3. Three copies of this form will be needed.

Copy 1 - the original must accompany your permit application.
Copy 2 must accompany your fee payment.
Copy 3 should be retained for your records

4. Both fee-paying and exempt applicants must mail a copy of this transmittal form to:

**MassDEP
P.O. Box 4062
Boston, MA
02211**

*** Note:**
For BWSC Permits, enter the LSP.

A. Permit Information

BWP AQ03
1. Permit Code: 7 or 8 character code from permit instructions

PLAN APPLICATION MAJOR COMPREHENSIVE
2. Name of Permit Category

COMBINED HEAT AND POWER COMBUSTION TURBINE INSTALLATION
3. Type of Project or Activity

B. Applicant Information – Firm or Individual

Massachusetts Institute of Technology
1. Name of Firm - Or, if party needing this approval is an individual enter name below:

2. **Last Name** of Individual | 3. **First Name** of Individual | 4. MI

59 Vassar Street, Building 42C
5. Street Address

Cambridge | MA | 02139 | 617-253-4790 |
6. City/Town | 7. State | 8. Zip Code | 9. Telephone # | 10. Ext. #

Ken Packard
11. Contact Person

kpackard@MIT.EDU
12. e-mail address (optional)

C. Facility, Site or Individual Requiring Approval

Massachusetts Institute of Technology
1. Name of Facility, Site Or Individual

59 Vassar St., Building 42C
2. Street Address

Cambridge | MA | 02139 | 617-253-4790 |
3. City/Town | 4. State | 5. Zip Code | 6. Telephone # | 7. Ext. #

314888
8. DEP Facility Number (if Known)

9. Federal I.D. Number (if Known)

1191844
10. BWSC Tracking # (if Known)

D. Application Prepared by (if different from Section B)*

EPSILON ASSOCIATES
1. Name of Firm Or Individual

3 CLOCKTOWER PLACE SUITE 250
2. Address

MAYNARD | MA | 01754 | 978-461-6202 |
3. City/Town | 4. State | 5. Zip Code | 6. Telephone # | 7. Ext. #

AJ Jablonowski
8. Contact Person

N/A
9. LSP Number (BWSC Permits only)

E. Permit - Project Coordination

1. Is this project subject to MEPA review? ☒ yes ☐ no
If yes, enter the project's EOEA file number - assigned when an Environmental Notification Form is submitted to the MEPA unit:

15453
EOEA File Number

F. Amount Due

DEP Use Only

Permit No:

Rec'd Date:

Reviewer:

Special Provisions:

1. ☐ **Fee** Exempt (city, town or municipal housing authority)(state agency if fee is $100 or less).
There are no fee exemptions for BWSC permits, regardless of applicant status.
2. ☐ Hardship Request - payment extensions according to 310 CMR 4.04(3)(c).
3. ☐ Alternative Schedule Project (according to 310 CMR 4.05 and 4.10).
4. ☐ Homeowner (according to 310 CMR 4.02).

Check Number

$24,305
Dollar Amount

Date

Massachusetts Department of Environmental Protection
Bureau of Waste Prevention – Air Quality

CPA-FUEL (BWP AQ 02 Non-Major, BWP AQ 03 Major)

Comprehensive Plan Application for Fuel Utilization Emission Unit(s)

X262144
Transmittal Number

1191844
Facility ID (if known)

Use this form for:

- Boilers firing Natural Gas and having a heat input capacity of 40,000,000 British Thermal Units per hour (Btu/hr) or more.
- Boilers firing Ultra Low Sulfur Distillate Fuel Oil and having a heat input capacity of 30,000,000 Btu/hr or more.
- Emergency turbines with a rated power output of more than 1 Megawatt (MW) and/or in lieu of complying with 310 CMR 7.26(43) for engines or turbines as described at 310 CMR (43)2 and 3.
- Other Fuel Utilization Units as specified at 310 CMR 7.02(5)(a)2. See the instructions for a complete list.

Important: When filling out forms on the computer, use only the tab key to move your cursor - do not use the return key.

tab

return

Type of Application: ☐ BWP AQ 02 Non-Major CPA ☒ BWP AQ 03 Major CPA

A. Facility Information

Massachusetts Institute of Technology
1. Facility Name

59 Vassar St., Building 42C
2. Street Address

Cambridge
3. City

MA
4. State

02139
5. ZIP Code

314888
6. MassDEP Account # / FMF Facility # (if Known)

1191844
7. Facility AQ # / SEIS ID # (if Known)

4931/8221
8. Standard Industrial Classification (SIC) Code

611310
9. North American Industry Classification System (NAICS) Code

10. Are you proposing a new facility? ☐ Yes ☒ No - If Yes, skip to Section B.

11. List ALL existing Air Quality Plan Approvals, Emission Cap Notifications, and 310 CMR 7.26 Compliance Certifications and associated facility-wide emission caps, if any, for this facility in the table below. If you hold a Final Operating Permit for this facility, you may leave this table blank.

Table 1

Approval Number(s)/ 25% or 50% Rule/ 310 CMR 7.26 Certification	**Transmittal Number(s)** (if Applicable)	**Air Contaminant** (e.g. CO, CO2, NOx, SO2, VOC, HAP, PM or Other [Specify])*	**Existing Facility-Wide Emission Cap(s) Per Consecutive 12-Month Time Period** (Tons)
NOT APPLICABLE (FACILITY HOLDS FINAL OPERATING PERMIT TR. NO. X223574)			

*CO = carbon monoxide, CO_2 = carbon dioxide, NOx = nitrogen oxides, SO_2 = sulfur dioxide, VOC = volatile organic compoun
HAP = hazardous air pollutant, PM = particulate matter, specify if "Other"

A. Facility Information (continued)

12. Will this proposed project result in an increase in any facility-wide emission cap(s)? ☐ Yes ☒ No

    If Yes, describe:

B. Equipment Description

Note that per 310 CMR 7.02, MassDEP can issue a Plan Approval only for proposed Emission Unit(s) with air contaminant emissions that are representative of Best Available Control Technology (BACT). See Section D: Best Available Control Technology (BACT) Emissions and the MassDEP BACT Guidance.

1. Is this proposed project modifying previously approved equipment? ☐ Yes ☒ No

   If Yes, list pertinent Plan Approval(s):

2. Is this proposed project replacing previously approved equipment? ☒ Yes ☐ No

   If Yes, list pertinent Plan Approval(s): MBR-91-COM-027

3. Provide a description of the proposed project, including relevant parameters (including but not limited to operating temperature and pressure) and associated air pollution controls, if any:

   Two nominal 22 MW Combustion Turbines (CT) with supplemental duct fired (134 MMBTU/hr) Heat Recovery Steam Generators (HRSGs), and one 2 MW IC engine.

Netting & Offsets

4. Is netting being used to avoid 310 CMR 7.00: Appendix A? ☐ Yes* ☒ No

   *If Yes, attach a description of contemporaneous increases and decreases in applicable potential (or allowable) nonattainment pollutant emissions over a period of the most recent five (5) calendar years, including the year that the proposed project will commence operating. For each emission unit, this description must include: a description of the emission unit, the year it commenced operation or was removed from service, any associated MassDEP-issued Plan Approval(s), and its potential (or allowable) nonattainment pollutant emissions. In any case, a proposed project cannot "net out" of the requirement to submit a plan application and comply with Best Available Control Technology (BACT) pursuant to 310 CMR 7.02.

5. Is the proposed project subject to 310 CMR 7.00: Appendix A Nonattainment Review? ☐ Yes* ☒ No – Skip to 6

   *If Yes, pursuant to 310 CMR 7.00: Appendix A(6), federally enforceable emission offsets, such as Emission Reduction Credits (ERCs), must be used for this part of the application. Complete Table 2 on the next page to summarize either the facility providing the federally enforceable emission offsets, or what is being shut down, curtailed or further controlled at this facility to obtain the required emission offsets. Emission offsets must be part of a federally enforceable Plan Approval to be used for offsetting emission increases in applicable nonattainment pollutants or their precursors.

B. Equipment Description (continued)

Note: Complete this table if you answered Yes to Question 5. Otherwise, skip to Question 6.

Table 2

Source of Emission Reduction Credits (ERCs) or Emission Offsets	Transmittal No. of Plan Approval Verifying Generation of ERCs, if Any	Air Contaminant	Actual Baselines Emissions (Tons per Consecutive 12-Month Time Period)[1]	New Potential Emissions[2] (Tons per Consecutive 12-Month Time Period After Control)	ERC[3] or Emission Offsets, Including Offset Ratio & Required ERC Set Aside (Tons per Consecutive 12-Month Time Period)

[1] Actual Baseline Emissions means the average actual emissions for the source of emission credits or offsets in the previous two years (310 CMR 7.00: Appendix A).
[2] New Potential Emissions means the potential emissions for the source of emission credits or offsets after project completion (310 CMR 7.00: Appendix A).
[3] Emission Reduction Credit (ERC) means the difference between Actual Baseline and New Potential Emissions, including an offset ratio of 1.26:1 (310 CMR 7.00: Appendix B(3)).

6. Complete the table below to summarize the details of the proposed project.

Note: For additional information, see the instructions for a link to the MassDEP BACT Guidance.

Table 3

Facility-Assigned Identifying Number for Proposed Equipment (Emission Unit No.)	Description of Proposed Equipment Including Manufacturer & Model Number or Equivalent (e.g. Acme Boiler, Model No. AB500)	Manufacturer's Maximum Heat Input Rating in Btu/hr	Proposed Primary Fuel	Proposed Back-Up Fuel (if Any)
CTG 200 ☒ New ☐ Modified	COMBUSTION TURBINE: SOLAR TITAN 250 OR EQUAL	219,000,000	NATURAL GAS	ULTRA LOW SULFUR DIESEL
HRSG 200 ☒ New ☐ Modified	DUCT BURNER	134,000,000	NATURAL GAS	NONE
CTG 300 ☒ New ☐ Modified	COMBUSTION TURBINE: SOLAR TITAN 250 OR EQUAL	219,000,000	NATURAL GAS	ULTRA LOW SULFUR DIESEL
HRSG 300 ☒ New ☐ Modified	DUCT BURNER	134,000,000	NATURAL GAS	NONE

BOILER 3 ☐ New ☒ Modified	BOILER: WICKES TYPE R	116,200,000	NATURAL GAS	ULTRA LOW SULFUR DIESEL
BOILER 4 ☐ New ☒ Modified	BOILER: WICKES TYPE R	116,200,000	NATURAL GAS	ULTRA LOW SULFUR DIESEL
BOILER 5 ☐ New ☒ Modified	BOILER: RILEY TYPE VP	145,000,000	NATURAL GAS	ULTRA LOW SULFUR DIESEL
Emergency Generator ☒ New ☐ Modified	CAT 2 MW Emergency Diesel Generator	19,320,000	ULTRA LOW SULFUR DIESEL	NONE

B. Equipment Description (continued)

7. Complete the table below to summarize the burner details if the proposed project includes boiler(s).

Note: For additional information, see the instructions for a link to the MassDEP BACT Guidance.

Table 4

Emission Unit No.	**Burner Manufacturer & Model Number or Equivalent** (e.g. Acme Burner, Model No. AB300)	**Manufacturer's Maximum Firing Rate** (Gallons per Hour or Cubic Feet per Hour)	**Type of Burner** (e.g. Ultra Low NOx Burner)	**Is Emission Unit Equipped with Flue Gas Recirculation?**
HRSG 200	TBD	134,000 CF/HR	DUCT BURNER	☐ Yes ☒ No
HRSG 300	TBD	134,000 CF/HR	DUCT BURNER	☐ Yes ☒ No
BOILER 3	PEABODY	116,000 CF/HR	N/A	☐ Yes ☒ No
BOILER 4	PEABODY	116,000 CF/HR	N/A	☐ Yes ☒ No
BOILER 5	COEN	145,000 CF/HR	LOW NOx	☐ Yes ☒ No

B. Equipment Description (continued)

8. Complete the table below if the proposed project includes turbine(s).

Table 5		
Emission Unit No.	**Maximum Firing Rate** (Gallons per Hour or Cubic Feet per Hour)	**Maximum Output Rating** (Megawatts [MW] or Kilowatts [kW]; Indicate Unit of Measure)
CTG-200	219,000 CF/HR (GAS) 1,600 GAL/HR (ULSD)	22 MW
CTG-300	219,000 CF/HR (GAS) 1,600 GAL/HR (ULSD)	22 MW

Continue to Next Page ►

B. Equipment Description (continued)

9. Are you proposing an Air Pollution Control Device (PCD)? ☒ Yes* ☐ No

*If Yes, complete the table below to summarize the details of each PCD being proposed.

Note: If you are proposing one or more Air Pollution Control Devices (PCDs), you must also submit the applicable Supplemental Form(s). See Page 6 for additional information.

Table 6a

Description of Proposed PCD	Emission Unit No(s). Served by PCD	Air Contaminant(s) Controlled	Overall Control (Percent by Weight)
SCR ☒ New ☐ Existing	CTG-200 and 300; HRSG 200 and 300	VOC	
		CO	
		PM[1]	
		NO_x	92%
		NH_3	
		Other:	

[1] PM includes particulate matter having a diameter of 10 microns or less (PM_{10}) and particulate matter having a diameter of 2.5 microns or less ($PM_{2.5}$).

Note: If you are proposing more than two Air Pollution Control Devices (PCDs), complete additional copies of these tables.

Table 6b

Description of Proposed PCD	Emission Unit No(s). Served by PCD	Air Contaminant(s) Controlled	Overall Control (Percent by Weight)
OXIDATION CATALYST ☒ New ☐ Existing	CTG 300 HRSG 300	VOC	50%
		CO	94-96%
		PM[1]	
		NO_x	
		NH_3	
		Other:	

Table 6c			
Description of Proposed PCD	**Emission Unit No(s). Served by PCD**	**Air Contaminant(s) Controlled**	**Overall Control** (Percent by Weight)
LOW NOx BURNER ☐ New ☒ Existing	Boiler 5	VOC	
		CO	
		PM[1]	
		NO_x	
		NH_3	
		Other:	

B. Equipment Description (continued)

Supplemental Forms Required

If you are proposing one or more PCDs, you will also need to submit the applicable form(s) below.

If Your Project Includes:	You Must File Form(s):
Wet or Dry Scrubbers	BWP AQ Scrubber
Cyclone or Inertial Separators	BWP AQ Cyclone
Fabric Filter	BWP AQ Baghouse/Filter
Adsorbers	BWP AQ Adsorption Equipment
Afterburners or Oxidizers	BWP AQ Afterburner/Oxidizer
Electrostatic Precipitators	BWP AQ Electrostatic Precipitator
Selective Catalytic Reduction	BWP AQ Selective Catalytic Reduction
Sorbent/Reactant Injection	BWP AQ Sorbent/Reactant Injection

10. Is there any external noise generating equipment associated with the proposed project? ☒ Yes ☐ No – Skip to 12

Note: The installation of some fuel burning equipment can cause off-site noise if proper precautions are not taken. For additional guidance, see MassDEP's Noise Pollution Policy Interpretation.

11. Complete the table(s) below to summarize all associated noise suppression equipment, if any is being proposed, and attach a completed Form BWP AQ Sound to this application (unless MassDEP waives this requirement).

Table 7

Emission Unit No.	Type of Noise Suppression Equipment (e.g. Mufflers, Acoustical Enclosures)	Equipment Manufacturer	Equipment Model No.
CTG 200 and 300	Turbine Acoustical Enclosure	SOLAR OR EQUAL	TBD
CTG 200 and 300	Turbine Inlet Air Silencer	SOLAR OR EQUAL	TBD
CTG 200 and 300	Turbine Enclosure Intake Vent Silencer	SOLAR OR EQUAL	TBD
CTG 200 and 300	Turbine Enclosure Discharge Vent Silencer	SOLAR OR EQUAL	TBD

B. Equipment Description (continued)

12. Have you attached a completed Form BWP AQ Sound to this application? ☒ Yes ☐ No*

*If No, explain:

13. Describe the potential for visible emissions from the proposed project and how they will be controlled:

NATURAL GAS AND ULSD FIRING, NO VISIBLE EMISSIONS EXPECTED DURING NORMAL OPERATION. VISIBLE EMISSIONS DURING STARTUPS AND SHUTDOWNS WILL BE MINIMIZED BY FOLLOWING MANUFACTURERS' STANDARD OPERATING PROCEDURES.

14. Describe the potential for odor impacts from the proposed project and how they will be controlled:

NATURAL GAS AND ULSD FIRING, NO ODORS EXPECTED

C. Stack Description

Complete the table below to summarize the details of the proposed project's stack configuration.

Note: Discharge must meet Good Air Pollution Control Engineering Practice. When designing stacks, special consideration must be given to nearby structures and terrain to prevent emissions downwash and adverse impacts upon sensitive receptors. Stack must be vertical, must not impede vertical exhaust gas flow, and must be a minimum of 10 feet above rooftop or fresh air intake, whichever is higher. For additional guidance, refer to the MassDEP "Stack Design General Guidelines." See the instructions for a link.

Table 8

Emission Unit No.	**Stack Height Above Ground** (Feet)	**Stack Height Above Roof** (Feet)	**Stack Exit Diameter or Dimensions** (Feet)	**Exhaust Gas Exit Temperature Range** (Degrees Fahrenheit)	**Exhaust Gas Exit Velocity Range** (Feet per Second)	**Stack Liner Material**
HRSG 200	167	104	7.0	180-225	45-70	STEEL
HRSG 300	167	104	7.0	180-225	45-70	STEEL
Emergency Generator	93.5	30.5	2.0	752.1	81.1	STEEL

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D. Best Available Control Technology (BACT) Emissions

1. Complete the table(s) below to summarize the proposed project's BACT emissions.

Note: Complete a separate table for each proposed fuel to be used in each Emission Unit. For example, if one Emission Unit will be capable of burning two different fuels, you will need to complete two tables.

Table 9A

Emission Unit No. & Fuel Used	**Air Contaminant**	**Uncontrolled Emissions** (Pounds per Hour [lbs/hr], Pounds per 1 Million British Thermal Units [lb/MMBtu] or Parts per Million Dry Volume Corrected Basis [ppmvd@ %O_2 or CO_2])	**Proposed BACT Emissions** (lbs/hr, lb/MMBtu or ppmvd@ %O_2 or CO_2)	**Proposed Consecutive 12-Month Time Period Emissions Restrictions** (Tons, if Any)[5]	**Proposed Monthly Time Period Emissions Restrictions** (Tons, if Any)[5]	**Proposed Fuel Usage Limit(s)** (if Any)[5]
Unit No. CTG 200 or 300; HRSG 200 or 300 Fuel Used NATURAL GAS with Duct Burning	PM[1]	7.14 lbs/hr	7.14 lbs/hr	50.0 Tons (NG & ULSD)	N/A	N/A
	$PM_{2.5}$	7.14 lbs/hr	7.14 lbs/hr	50.0 Tons (NG & ULSD)	N/A	N/A
	PM_{10}	7.14 lbs/hr	7.14 lbs/hr	50.0 Tons (NG & ULSD)	N/A	N/A
	NO_x[2]	~24 lbs/hr	3.2-4.0 lb/hr	21.1 Tons (NG & ULSD)	N/A	N/A
	CO	~100-200 lb/hr	2.5-3.8 lb/hr	15.1 Tons (NG & ULSD)	N/A	N/A
	VOC	~10-20 lb/hr	4.5-4.6 lbs/hr	20.9 Tons (NG & ULSD)	N/A	N/A
	SO_2	1.0 lbs/hr	1.0 lbs/hr	7.0 Tons (NG & ULSD)	N/A	N/A
	HAP[3]	<0.5 lb/hr	<0.5 lb/hr	<10 Tons (NG & ULSD)	N/A	N/A
	Total HAPs[3]	<1.5 lb/hr	<1.5 lb/hr	<10 Tons (NG & ULSD)	N/A	N/A
	CO_2[4]	42,071 lbs/hr	42,071 lbs/hr	294,970 Tons (NG & ULSD)	N/A	N/A

[1]PM includes particulate matter having a diameter of 10 microns or less (PM_{10}) and particulate matter having a diameter of 2.5 microns or less ($PM_{2.5}$).
[2] NO_X emissions from this proposed project need to be included for the purposes of NO_X emissions tracking for 310 CMR 7.00: Appendix A, if applicable.
[3]Operating Permit facilities are required to track emissions of Hazardous Air Pollutants.
[4]Pounds of CO_2 per unit product (e.g. pounds CO_2 per megawatt, pounds CO_2 per 1,000 pounds of steam).
[5]Enter "N/A" if not requesting emissions restrictions and/or fuel usage limit.

D. Best Available Control Technology (BACT) Emissions (continued)

Table 9B

Emission Unit No. & Fuel Used	**Air Contaminant**	**Uncontrolled Emissions** (Pounds per Hour [lbs/hr], Pounds per 1 Million British Thermal Units [lb/MMBtu] or Parts per Million Dry Volume Corrected Basis [ppmvd@ %O_2 or CO_2])	**Proposed BACT Emissions** (lbs/hr, lb/MMBtu or ppmvd@ %O_2 or CO_2)	**Proposed Consecutive 12-Month Time Period Emissions Restrictions** (Tons, if Any)[5]	**Proposed Monthly Time Period Emissions Restrictions** (Tons, if Any)[5]	**Proposed Fuel Usage Limit(s)** (if Any)[5]
Unit No. CTG 200 or 300; HRSG 200 or 300 Fuel Used NATURAL GAS without Duct Burning	PM[1]	4.47 lbs/hr	4.47 lbs/hr	50.0 Tons (NG & ULSD)	N/A	N/A
	$PM_{2.5}$	4.47 lbs/hr	4.47 lbs/hr	50.0 Tons (NG & ULSD)	N/A	N/A
	PM_{10}	4.47 lbs/hr	4.47 lbs/hr	50.0 Tons (NG & ULSD)	N/A	N/A
	NO_x[2]	~24 lbs/hr	1.6 lbs/hr	21.1 Tons (NG & ULSD)	N/A	N/A
	CO	~100-200 lb/hr	1.0 lbs/hr	15.1 Tons (NG & ULSD)	N/A	N/A
	VOC	~1 lbs/hr	0.48 lbs/hr	20.9 Tons (NG & ULSD)	N/A	N/A
	SO_2	0.64 lbs/hr	0.64 lbs/hr	7.0 Tons (NG & ULSD)	N/A	N/A
	HAP[3]	<0.5 lb/hr	<0.5 lbs/hr	<10 Tons (NG & ULSD)	N/A	N/A
	Total HAPs[3]	<1.5 lb/hr	<1.5 lbs/hr	<10 Tons (NG & ULSD)	N/A	N/A
	CO_2[4]	26,103 lbs/hr	26,103 lbs/hr	294,970 Tons (NG & ULSD)	N/A	N/A

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D. Best Available Control Technology (BACT) Emissions (continued)

Table 9C

Emission Unit No. & Fuel Used	**Air Contaminant**	**Uncontrolled Emissions** (Pounds per Hour [lbs/hr], Pounds per 1 Million British Thermal Units [lb/MMBtu] or Parts per Million Dry Volume Corrected Basis [ppmvd@ %O_2 or CO_2])	**Proposed BACT Emissions** (lbs/hr, lb/MMBtu or ppmvd@ %O_2 or CO_2)	**Proposed Consecutive 12-Month Time Period Emissions Restrictions** (Tons, if Any)[5]	**Proposed Monthly Time Period Emissions Restrictions** (Tons, if Any)[5]	**Proposed Fuel Usage Limit(s)** (if Any)[5]
Unit No. CTG 200 or 300; HRSG 200 or 300 Fuel Used ULSD IN CTG 200 or 300, NATURAL GAS IN HRSG 200 or 300	PM	11.9 lbs/hr	11.9 lbs/hr	50.0 Tons (NG & ULSD)	N/A	37,632 MMBTU/yr ULSD per turbine
	$PM_{2.5}$	11.9 lbs/hr	11.9 lbs/hr	50.0 Tons (NG & ULSD)	N/A	N/A
	PM_{10}	11.9 lbs/hr	11.9 lbs/hr	50.0 Tons (NG & ULSD)	N/A	N/A
	NO_x	~41 lbs/hr	9.5 lbs/hr	21.1 Tons (NG & ULSD)	N/A	N/A
	CO	~36 lb/hr	5.3 lbs/hr	15.1 Tons (NG & ULSD)	N/A	N/A
	VOC	6.4 lbs/hr	6.0 lbs/hr	20.9 Tons (NG & ULSD)	N/A	N/A
	SO_2	0.8 lbs/hr	0.7 lbs/hr	7.0 Tons (NG & ULSD)	N/A	N/A
	HAP	<0.5 lbs/hr	<0.5 lbs/hr	<10 Tons (NG & ULSD)	N/A	N/A
	Total HAPs	<1.5 lbs/hr	<1.5 lbs/hr	<10 Tons (NG & ULSD)	N/A	N/A
	CO_2	51,167 lbs/hr	51,167 lbs/hr	294,970 Tons (NG & ULSD)	N/A	N/A

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D. Best Available Control Technology (BACT) Emissions (continued)

Table 9D

Emission Unit No. & Fuel Used	**Air Contaminant**	**Uncontrolled Emissions** (Pounds per Hour [lbs/hr], Pounds per 1 Million British Thermal Units [lb/MMBtu] or Parts per Million Dry Volume Corrected Basis [ppmvd@ %O_2 or CO_2])	**Proposed BACT Emissions** (lbs/hr, lb/MMBtu or ppmvd@ %O_2 or CO_2)	**Proposed Consecutive 12-Month Time Period Emissions Restrictions** (Tons, if Any)[5]	**Proposed Monthly Time Period Emissions Restrictions** (Tons, if Any)[5]	**Proposed Fuel Usage Limit(s)** (if Any)[5]
Unit No. CTG 200 or 300; HRSG 200 or 300 Fuel Used ULSD IN CTG 200 or 300, No Duct Burning	PM	9.17 lbs/hr	9.17 lbs/hr	50.0 Tons (NG & ULSD)	N/A	37,632 MMBTU/yr ULSD per turbine
	$PM_{2.5}$	9.17 lbs/hr	9.17 lbs/hr	50.0 Tons (NG & ULSD)	N/A	N/A
	PM_{10}	9.17 lbs/hr	9.17 lbs/hr	50.0 Tons (NG & ULSD)	N/A	N/A
	NO_x	~41 lbs/hr	8.02 lbs/hr	21.1 Tons (NG & ULSD)	N/A	N/A
	CO	~36 lb/hr	3.80 lbs/hr	15.1 Tons (NG & ULSD)	N/A	N/A
	VOC	~2.25 lb/hr	2.01 lbs/hr	20.9 Tons (NG & ULSD)	N/A	N/A
	SO_2	0.36 lbs/hr	0.36 lbs/hr	7.0 Tons (NG & ULSD)	N/A	N/A
	HAP	<0.5 lbs/hr	<0.5 lbs/hr	<10 Tons (NG & ULSD)	N/A	N/A
	Total HAPs	<1.5 lbs/hr	<1.5 lbs/hr	<10 Tons (NG & ULSD)	N/A	N/A
	CO_2	35,198 lbs/hr	35,198 lbs/hr	294,970 Tons (NG & ULSD)	N/A	N/A

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D. Best Available Control Technology (BACT) Emissions (continued)

Table 9E

Emission Unit No. & Fuel Used	**Air Contaminant**	**Uncontrolled Emissions** (Pounds per Hour [lbs/hr], Pounds per 1 Million British Thermal Units [lb/MMBtu] or Parts per Million Dry Volume Corrected Basis [ppmvd@ %O_2 or CO_2])	**Proposed BACT Emissions** (lbs/hr, lb/MMBtu or ppmvd@ %O_2 or CO_2)	**Proposed Consecutive 12-Month Time Period Emissions Restrictions** (Tons, if Any)[5]	**Proposed Monthly Time Period Emissions Restrictions** (Tons, if Any)[5]	**Proposed Fuel Usage Limit(s)** (if Any)[5]
Unit No. DG2-42 Fuel Used ULSD	PM	0.4 lb/hr	0.4 lb/hr	0.06 tpy	N/A	N/A
	$PM_{2.5}$	0.4 lb/hr	0.4 lb/hr	0.06 tpy	N/A	N/A
	PM_{10}	0.4 lb/hr	0.4 lb/hr	0.06 tpy	N/A	N/A
	NO_x	35.09 lb/hr	35.09 lb/hr	5.3 tpy	N/A	N/A
	CO	2.2 lb/hr	2.2 lb/hr	0.33 tpy	N/A	N/A
	VOC	1.13	1.13	0.17 tpy	N/A	N/A
	SO_2	0.029 lb/hr	0.029 lb/hr	0.004 tpy	N/A	N/A
	HAP	<0.1 lb/hr	<0.1 lb/hr	<0.01 tpy	N/A	N/A
	Total HAPs	<0.1 lb/hr	<0.1 lb/hr	<0.01 tpy	N/A	N/A
	CO_2	3184 lb/hr	3184 lb/hr	480	N/A	N/A

Note: Top-Case BACT is the emission rate identified via the MassDEP BACT Guidance or a pre-application meeting with MassDEP.

2. Are proposed BACT emission limits in the tables above Top-Case BACT as referenced in 310 CMR 7.02(8)(a)2.a? ☒ Yes ☐ No*

*If No, you must submit form BWP AQ BACT to demonstrate that this project meets BACT as provided in 310 CMR 7.02(8)(a)2 or 310 CMR 7.02(8)(a)2.c..

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E. Monitoring Procedures

Complete the table below to summarize the details of the proposed project's monitoring procedures.

Table 10

Emission Unit No.	Type or Method of Monitoring (e.g. CEMS[1], Fuel Flow)	Parameter/Emission Monitored	Frequency of Monitoring
CTG 200 and 300, HRSG 200 and 300	CEMS	NOx, CO, NH3	AVERAGED HOURLY
CTG 200 and 300, HRSG 200 and 300	FUEL FLOW	NATURAL GAS AND ULSD USAGE	AVERAGED HOURLY
CTG 200 and 300, HRSG 200 and 300	COMS	OPACITY	6-MINUTE AVERAGES

[1] CEMS = Continuous Emissions Monitoring System

F. Record Keeping Procedures

Complete the table below to summarize the details of the proposed project's record keeping procedures. Proposed record keeping procedures need to be able to demonstrate your compliance status with regard to all limitations/restrictions proposed herein. Record keeping may include, but is not limited to, hourly or daily logs, meter charts, time logs, fuel purchase receipts, CEMS records, etc.

Table 11

Emission Unit No.	Parameter/Emission (e.g. Temperature, Material Usage, Air Contaminant)	Record Keeping Procedures (e.g. Data Logger or Manual)	Frequency of Data Record (e.g. Hourly, Daily)
CTG 200 and 300, HRSG 200 and 300	CEMS	NOx, CO, NH3	AVERAGED HOURLY
CTG 200 and 300, HRSG 200 and 300	FUEL FLOW	NATURAL GAS AND ULSD USAGE	AVERAGED HOURLY
CTG 200 and 300, HRSG 200 and 300	COMS	OPACITY	6-MINUTE AVERAGES

Examples of emissions calculations for record keeping purposes:

NOx: {(0.085 pounds per 1,000,000 British thermal units (MMBtu)*(**X** cubic feet)*(1,000 Btu per cubic feet) + (0.10 pounds per MMBtu)*(**Y** gallons of fuel oil)*(130,000 Btu per gallon)}* 1 ton per 2000 pounds = NOx in tons per consecutive twelve month time period

CO: {(0.035 pounds per MMBtu)*(**X** cubic feet)*(1000 Btu per cubic feet) + (0.035 pounds per MMBtu)*(**Y** gallons of fuel oil)*(130,000 Btu per gallon}*1 ton per 2000 pounds = CO in tons per consecutive twelve month time period

VOC: {(0.035 pounds per MMBtu)*(**X** cubic feet)*(1000 Btu per cubic feet) + (0.035 pounds per MMBtu)*(**Y** gallons of fuel oil)*(130,000 Btu per gallon}*1 ton per 2000 pounds= VOC in tons per consecutive twelve month time period

SO_2: {(0.0015 lb per MMBtu)*(**Y** gallons of fuel oil)*(130,000 Btu per gallon)}*1 ton per 2000 pounds = SO_2 in tons per consecutive twelve month time period

Where: **X** = cubic feet of natural gas burned per consecutive twelve month time period
Y = gallons of ULSD oil burned per consecutive twelve month time period

G. Additional Information Checklist

Attach a specific facility description and the following required additional information that MassDEP needs to process your application. Check the box next to each item to ensure that your application is complete.

- ☒ Plot Plan
- ☒ Combustion Equipment Manufacturer Specifications, Including but not Limited to Emissions Data
- ☐ Combustion Equipment Standard Operating Procedures *[TO BE PROVIDED AT A LATER DATE]*
- ☐ Combustion Equipment Standard Maintenance Procedures, Including Cleaning Method & Frequency *[TO BE PROVIDED AT A LATER DATE]*
- ☒ Calculations to Support This Plan Application
- ☐ Air pollution control device manufacturer specifications, if applicable *[TO BE PROVIDED AT A LATER DATE]*
- ☐ Air pollution control device standard operating procedures, if applicable *[TO BE PROVIDED AT A LATER DATE]*
- ☐ Air pollution control device standard maintenance procedures, if applicable *[TO BE PROVIDED AT A LATER DATE]*
- ☐ BWP AQ BACT Form, if not proposing Top-Case BACT *[NOT APPLICABLE]*
- ☒ Air quality dispersion modeling demonstration documenting that National Ambient Air Quality Standards (NAAQS) are not exceeded
- ☒ Process flow diagram for the proposed equipment and any PCD, if applicable, including relevant parameters (e.g. flow rate, pressure and temperature)

Note: Pursuant to 310 CMR 7.02(5)(c), MassDEP may request additional information.

Continue to Next Page ►

H. Other Regulatory Considerations

Indicate below whether the proposed project is subject to any additional regulatory requirements.

310 CMR 7.00: Appendix A Nonattainment Review, or is netting used to avoid review under 310 CMR 7.00 Appendix A or 40 CFR 52.21? ☐ Yes ☒ No

40 CFR 60: New Source Performance Standards (NSPS)? ☒ Yes ☐ No

If Yes: Which subpart? **KKKK and IIII** Applicable emission limitation(s): **See Application Report Section 3.4**

40 CFR 61: National Emission Standards for Hazardous Air Pollutants (NESHAPS) ☐ Yes ☒ No

If Yes: Which subpart? Applicable emission limitation(s):

40 CFR 63: NESHAPS for Source Categories – Maximum Achievable (MACT) or Generally Available (GACT) Control Technology ☒ Yes ☐ No

If Yes: Which subpart? **ZZZZ** Applicable emission limitation(s): **See NSPS IIII**

[After approval, Boilers 3, 4, 5, 7, and 9 will no longer be subject to subpart JJJJJJ]

301 CMR 11.00: Massachusetts Environmental Policy Act (MEPA)? ☒ Yes ☐ No

If Yes: EOEA No.: **TBD**

Other Applicable Requirements? ☐ Yes ☒ No

If Yes: Specify:

Facility-Wide Potential-to-Emit Hazardous Air Pollutants (HAPS): ☐ Major* ☒ Non-Major

*A Major source has a facility-wide potential-to-emit of 25 tons per year or more of the sum of all hazardous air pollutants or 10 tons per year or more of any individual hazardous air pollutant.

Continue to Next Page ►

I. Professional Engineer's Stamp

The seal or stamp and signature of a Massachusetts Registered Professional Engineer (P.E.) must be entered below. Both the seal or stamp impression and the P.E. signature must be original. This is to certify that the information contained in this form has been checked for accuracy, and that the design represents good air pollution control engineering practice.

A.J. Jablonowski
P.E. Name (Type or Print)

A Jablonowski
P.E. Signature

PRINCIPAL
Position/Title

EPSILON ASSOCIATES, INC.
Company

12/16/2016
Date (MM/DD/YYYY)

39123
P.E. Number

Place P.E. Seal or Stamp Here.

COMMONWEALTH OF MASSACHUSETTS
ANDREW JABLONOWSKI
CHEMICAL
No. 39123
REGISTERED
PROFESSIONAL ENGINEER

J. Certification by Responsible Official

The signature below provides the affirmative demonstration pursuant to 310 CMR 7.02(5)(c)8 that any facility(ies) in Massachusetts, owned or operated by the proponent for this project (or by an entity controlling, controlled by or under common control with such proponent) that is subject to 310 CMR 7.00, et seq., is in compliance with, or on a MassDEP approved compliance schedule to meet, all provisions of 310 CMR 7.00, et seq., and any plan approval, order, notice of noncompliance or permit issued thereunder. This Form must be signed by a Responsible Official working at the location of the proposed new or modified facility. Even if an agent has been designated to fill out this Form, the Responsible Official must sign it. (Refer to the definition given in 310 CMR 7.00.)

I certify that I have personally examined the foregoing and am familiar with the information contained in this document and all attachments and that, based on my inquiry of those individuals immediately responsible for obtaining the information, I believe that the information is true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including possible fines and imprisonment.

Louis DiBerardinis
Responsible Official Name (Type or Print)

Louis DiBerardinis
Responsible Official Signature

Director, EHS Office
Responsible Official Title

Massachusetts Institute of Technology
Responsible Official Company/Organization Name

12/20/16
Date (MM/DD/YYYY)

This Space Reserved for MassDEP Approval Stamp.

K. Energy Efficiency Evaluation Survey

1. Do you know where your electricity and/or fuel and/or water and/or heat and/or compressed air is being used/consumed? ☒ Yes ☐ No

2. Has your facility had an energy audit performed by your utility supplier (or other) in the past two years?[1] ☒ Yes ☐ No

   a. Did the audit include evaluations for heat loss, lighting load, cooling requirements and compressor usage? ☒ Yes ☐ No

   b. Did the audit influence how this project is configured? ☒ Yes ☐ No

3. Does your facility have an energy management plan? ☒ Yes ☐ No

   a. Have you identified and prioritized energy conservation opportunities? ☒ Yes ☐ No

   b. Have you identified opportunities to improve operating and maintenance procedures by employing an energy management plan? ☒ Yes ☐ No

4. Has each emission unit proposed herein been evaluated for energy consumption including average and peak electrical use; efficiency of electric motors and suitability of alternative motors such as variable speed; added heat load and/or added cooling load as a result of the operation of the proposed process; added energy load due to building air exchange requirements as a result of exhausting heat or emissions to the ambient air; and/or use of compressors? ☒ Yes ☐ No

5. Has your facility considered alternative energy methods such as solar, geothermal or wind power as a means of supplementing all or some of the facility's energy demand? ☒ Yes ☐ No

6. Does your facility comply with Leadership in Energy & Environmental Design (LEED) Green Building Rating System design recommendations?[2] ☒ Yes ☐ No

[1]A facility wide energy audit would include an inspection of such things as lighting, air-conditioning, heating, compressors and other energy-demand equipment. It would also provide you with information on qualifying equipment rebates and incentive programs; analysis of your energy consumption patterns and written cost-savings recommendations and estimated cost savings for installing new, high-efficiency equipment.

[2]To understand the LEED Rating System, it is important to become familiar with its comprising facets. To be considered for LEED New Construction and Major Renovations, a building must meet specific prerequisites and additional credit areas within six categories:

- Sustainable Sites
- Materials and Resources
- Water Efficiency
- Indoor Environmental Quality
- Energy and Atmosphere
- Innovation and Design

BWP AQ Selective Catalytic Reduction

Submit with Form CPA-FUEL and/or CPA-PROCESS whenever construction, substantial reconstruction or alteration of a Selection Catalytic Reduction system is proposed unless exempt per 310 CMR 7.02(2)(b).

X262144
Transmittal Number

1191844
Facility ID (if known)

Important: When filling out forms on the computer, use only the tab key to move your cursor - do not use the return key.

A. Inlet Operating Conditions

1. Complete the table below with information on inlet gas flow(s).

Table 1a

Emission Unit No(s). Being Controlled	Average Inlet Gas Flow (Actual Cubic Feet Per Minute)	Inlet Temperature (Degrees Fahrenheit (ºF))	Moisture Content in the Inlet (Pounds Per Minute)
CTG 200 or 300 HRSG 200 or 300	~246,000 ACFM	~538 F	~58 Pounds Per Minute
Totals:			

2. Which metals/elements are present in gas stream?

☐ Potassium ☐ Arsenic ☐ Lead
☐ Zinc ☐ Sodium ☐ Phosphorus

3. Are there any other catalyst binding agents present in the gas stream?

☐ Yes – Describe Below ☒ No

TRACE CATALYST BINDING AGENTS IN NATURAL GAS AND ULSD.

4. Complete the table below to provide the maximum oxides of nitrogen (NOx) emissions:

Table 2

Emission Unit No(s). Being Controlled	Inlet NOx (Pounds Per Hour)	Inlet NOx (Parts Per Million by Volume, Dry Basis)
CTG 200 or 300	23.6 LBS/HOUR	~25 PPM @ 15% O2
HRSG 200 or 300	18.5 LBS/HOUR	~0.14 LBS/MMBTU

Continue to Next Page ►

B. Specifications

1. Manufacturer of Selective Catalytic Reduction (SCR) system: Haldor Topsoe Inc
   Company
2. Model Number (or Equivalent): DNX GT 201 Catalyst
   Number
3. Location of SCR unit relative to other pieces of equipment: ☐ High Dust ☒ Low Dust ☐ Tail End
4. Information about the catalyst used:
   a. Description of catalyst: Corrugated Monolith Structure
      Description
   b. Operating temperature range of catalyst: from 500 Degrees Fahrenheit (ºF) to 575 Degrees Fahrenheit (ºF)
   c. Pressure drop across the catalyst: ~3.0
      Inches of Water

5a. Number of catalyst layers the system can accommodate: 1
Number

5b. Number of catalyst layers that will be installed: 1
Number

6. Does the SCR system employ a guard bed for catalyst protection? ☐ Yes ☒ No*

   *If No, explain:

   NATURAL GAS AND ULSD FIRED

7. Expected catalyst life: 10 years
   Years
8. Operating hours per layer of catalyst: 87,600
   Hours
9. Can the catalyst be reactivated? ☐ Yes * ☐ No

   *If Yes, describe how:

   TBD

10. Catalyst cleaning method: ☐ Compressed Air Soot Blower ☐ Steam Soot Blower ☐ Sonic Horns ☒ Other – Describe: PERIODIC OFFLINE CLEANING
11. Describe SCR system dust management technologies and strategies being used, if any (e.g. ash screens):

    NONE NEEDED, NATURAL GAS AND ULSD FIRED.

B. Specifications (continued)

12. Are you proposing a by-pass stack? ☐ Yes * ☒ No

*If Yes, describe:

C. Description of Reducing Agent

1. Type and form of reducing agent proposed: ☐ Gaseous ☐ Liquid ☐ Anhydrous Ammonia ☐ Aqueous Ammonia ☐ Urea ☒ Other – Describe: AMMONIA GENERATED FROM UREA ONSITE.

2. If liquid, provide weight percent in solution: UREA SOLUTION 40% IN WATER
Weight Percent

3. Method of reducing agent injection: ☐ Direct Injection ☒ Injection Grid

4. Describe in detail how the concentration and usage rate of the reducing agent were determined. Continue on a separate attachment, if necessary.
CONCENTRATION BASED ON EXISTING UREA TO AMMONIA CONVERSION SYSTEM.

UREA USAGE RATE BASED ON MASS BALANCE

5. Describe the process controls for proper mixing of the reducing agent in the gas stream. Continue on a separate attachment, if necessary.
SPRAY INJECTORS WILL BE USED TO MIX UREA WITH HEATED AIR. UREA WILL DECOMPOSE, GENERATING AMMONIA. AMMONIA INJECTION GRID WILL BE INSTALLED UPSTREAM OF SCR CATALYST, MIXING AMMONIA WITH EXHAUST GAS.

6. Describe storage of the reagent, including details about any storage containment (e.g. dimension of berms, evaporative mitigation). Continue on a separate attachment, if necessary.
STORAGE OF UREA IN CONTAINED TANK AT AMBIENT CONDITIONS. AMMONIA GENERATED AS NEEDED.

7. Is the reagent subject to 42 U.S.C. 7401, Section 112(r)? ☐ Yes * ☒ No

*If Yes, attach a copy of the Risk Management Plan to this form.

8. You MUST attach to this form a copy of an analysis of possible impacts to off-property locations from a catastrophic release of the reducing agent, in comparison with American Industrial Hygiene Association Emergncy Response Planning Guidelines.

Not applicable.

D. Emissions Data

1. Complete the table below to provide maximum oxides of nitrogen (NOx) and ammonia (NH_3) slip concentrations and emission rates:

Table 3		
Air Contaminant	**Outlet** (Pounds Per Hour)	**Outlet**[1] (Parts Per Million By Volume, Dry Basis)
NOx	3.0 lb/hr (FIRING NG) 8.8 lb/hr (FIRING ULSD)	2.0 (Firing NG) 9.0 (Firing ULSD)
NH_3	0.9 lb/hr	2.0

[1]Boilers at 3% oxygen; combustion turbines at 15% oxygen; engines at 15% oxygen.

2. Explain how the above NOx and NH_3 emissions data were obtained. Attach appropriate calculations and documentation.

SEE BACT ANALYSIS IN APPLICATION TEXT, AND APPENDIX C FOR CALCULATIONS.

E. Drawing of Selective Catalytic Reduction System

You must attach to this form a schematic drawing of the proposed Selective Catalytic Reduction system. At a minimum, it must show the location(s) of the catalyst bed(s), bypass damper(s) if applicable, bypass stack if applicable, and normal stack. Sampling ports for emissions testing must also be shown.
[BMcD]

Note: You must notify the BWP Compliance & Enforcement Chief in the appropriate MassDEP regional office by telephone as soon as possible, within but no later than one (1) business day after you discover any upset or malfunction to facility equipment that results in excess emissions to the air and/or a condition of air pollution. You must submit written notice within seven (7) days thereafter.

F. Monitoring, Record Keeping & Failure Notification

1. Provide the manufacturer, make and model number of the proposed continuous emissions and opacity monitoring systems:

TBD

2. Identify the air contaminants that will be continuously monitored and recorded (e.g. NOx, NH_3, opacity)

NOX, NH3

3. Describe any proposed process monitors (e.g. ammonia injection, fuel combustion) and frequency of data recording:

FUEL COMBUSTION, UREA FLOWRATE, NOx CONCENTRATION, INLET SCR CATALYST TEMP, AND SCR CATLYST PRESSURE DROP. FREQUENCY OF DATA RECORDING TBD

F. Monitoring, Record Keeping & Failure Notification (continued)

4. Are there any alarms associated with the monitoring equipment? ☒ Yes – Complete Table 4 ☐ No – Explain Below

Table 4			
Operating Parameter Monitored	**Describe Alarm Trigger**	**Monitoring Device or Alarm Type**	**Does the Alarm Initiate an Automated Response?**
NOX	CEMS approaching Permit Limit	☐ Visual ☐ Auditory ☒ Automatic (Remote Monitoring) ☐ Other – Describe:	☐ Yes ☒ No If Yes, Describe:
NH3	CEMS approaching Permit Limit	☐ Visual ☐ Auditory ☒ Automatic (Remote Monitoring) ☐ Other – Describe:	☐ Yes ☒ No If Yes, Describe:
		☐ Visual ☐ Auditory ☐ Automatic (Remote Monitoring) ☐ Other – Describe:	☐ Yes ☐ No If Yes, Describe:

5. Describe the operating conditions that are monitored to determine the reducing agent injection rate:

   NOx EMISSION RATE AND FUEL FIRING RATE

6. How often will the catalyst be tested and by what test method (e.g. core sample)?

   TESTING IS RECOMMENDED TO BE PERFORMED ANNUALLY. THE TEST ELEMENTS FROM THE SCR CAN BE REMOVED AND SENT TO THE CATALYST VENDOR OR A THIRD PARTY.

7. List and explain all of the operating and safety controls associated with the SCR system. Continue on a separate attachment, if necessary.

   OPERATING TEMPERATURE & PRESSURE SENSORS, FUEL AND UREA FLOW MONITORS, STACK NOx AND NH3 CEMS.

8. List the SCR system emergency procedures to be used during system upsets. Continue on a separate attachment, if necessary.

   MANUAL ADJUSTMENT OF UREA FLOW, AND LOAD REDUCTION IF NEEDED.

F. Monitoring, Record Keeping & Failure Notification (continued)

9. Explain the typical fluctuations in SCR system operation, such as changes in effluent temperatures, flow rates, pollutant concentrations, etc., which may affect operation of the unit. Also explain the means by which control efficiency will be maintained throughout these fluctuations. Continue on a separate attachment, if necessary.

Typical fluctuations include startup, shutdown, and load changes. Control efficiency is maintained through a control system that continuously monitors urea flow, NH3 slip, NOx emissions, and system temperatures and measures at different points. Controls are automated with manual operator override available.

10. Describe the record keeping procedures to be used in identifying the cause, duration and resolution of each system failure/emission(s) exceedance. Continue on a separate attachment, if necessary.

Operations and maintenance logs will be used to track system upsets, and operations & emissions data will be maintained electronically. Emissions exceedances will be reported per the operating permit requirements. This report will include the deviation, including those attributable to upset conditions, the probable cause of the deviation, and the corrective actions or preventative measures taken.

11. How will the SCR system be designed so as to allow for emissions testing using MassDEP-sanctioned test methods?

The exhaust system will have sufficient straight runs to allow installation of CEMS and stack test ports per USEPA Method 1. I

G. Standard Operating & Maintenance Procedures

Attach to this form the standard operating and maintenance procedures for the proposed Selective Catalytic Reduction system, as well as a list of the spare parts inventory that you will maintain on site, as recommended by the equipment vendor. **TO BE PROVIDED AT A LATER DATE.**

Continue to Next Page ►

Massachusetts Department of Environmental Protection
Bureau of Waste Prevention – Air Quality

BWP AQ Selective Catalytic Reduction

Submit with Form CPA-FUEL and/or CPA-PROCESS whenever construction, substantial reconstruction or alteration of a Selection Catalytic Reduction system is proposed unless exempt per 310 CMR 7.02(2)(b).

X262144
Transmittal Number

1191844
Facility ID (if known)

H. Professional Engineer's Stamp

The seal or stamp and signature of a Massachusetts Registered Professional Engineer (P.E.) must be entered below. Both the seal or stamp impression and the P.E. signature must be original. This is to certify that the information contained in this Form has been checked for accuracy, and that the design represents good air pollution control engineering practice.

AJ Jablonowski
P.E. Name (Type or Print)

P.E. Signature

PRINCIPAL
Position/Title

EPSILON ASSOCIATES
Company

12/16/2016
Date (MM/DD/YYYY)

39123
P.E. Number

COMMONWEALTH OF MASSACHUSETTS
ANDREW JABLONOWSKI
CHEMICAL
No. 39123
REGISTERED
PROFESSIONAL ENGINEER

...amp Here.

I. Certification by Responsible Official

The signature below provides the affirmative demonstration pursuant to 310 CMR 7.02(5)(c)8 that any facility(ies) in Massachusetts, owned or operated by the proponent for this project (or by an entity controlling, controlled by or under common control with such proponent) that is subject to 310 CMR 7.00, et seq., is in compliance with, or on a MassDEP approved compliance schedule to meet, all provisions of 310 CMR 7.00, et seq., and any plan approval, order, notice of noncompliance or permit issued thereunder. This Form must be signed by a Responsible Official working at the location of the proposed new or modified facility. Even if an agent has been designated to fill out this Form, the Responsible Official must sign it. (Refer to the definition given in 310 CMR 7.00.)

I certify that I have personally examined the foregoing and am familiar with the information contained in this document and all attachments and that, based on my inquiry of those individuals immediately responsible for obtaining the information, I believe that the information is true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including possible fines and imprisonment.

Louis DiBerardinis
Responsible Official Name (Type or Print)

Louis DiBerardinis
Responsible Official Signature

Director, EHS Office
Responsible Official Title

Massachusetts Institute of Technology
Responsible Official Company/Organization Name

12/20/2016
Date (MM/DD/YYYY)

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Appendix B

Supplemental Information

Appendix B – Part 1

Turbine Information

- Solar Titan 250 Brochure
- Solar Titan 250 Case Study
- Solar Titan 250 Generator Set Information
- Solar Titan 250 SoLoNOx Information
- Haldor Topsoe SCR Catalyst Information

Solar Turbines
A Caterpillar Company

POWERING THE GLOBAL ENERGY DEMAND

TITAN 250
Gas Turbine System
For Power Generation Applications

Maximize Life-Cycle Benefits

Industrial Combined Heat and Power
Energy Star Award

Built on six decades of field-proven technology and experience, the *Titan* 250 will maximize the life-cycle benefits of your application. It can operate on a wide range of gaseous and liquid fuels and delivers 22 MW (21 745 kWe) of power and 77,000 pounds of steam per hour in a highly compact package.

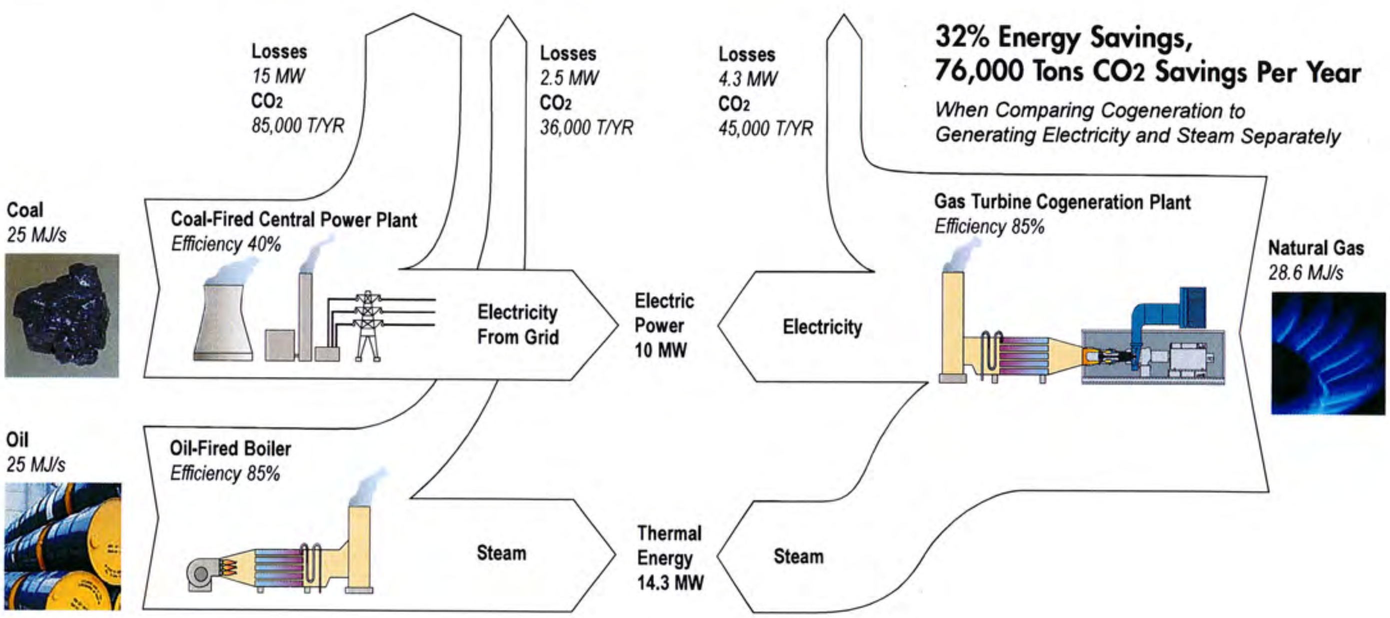
The *Titan* 250 was designed to give customers many years of productivity with low life-cycle cost. This means a gas turbine with high availability, reliability and durability that delivers best-in-class 39% efficiency, saving on fuel and reducing emissions. No other gas turbine system gives you better power density and efficiency with lower emissions while costing you less per kilowatt-hour. The *Titan* 250 provides all of these benefits and more throughout the entire life cycle of the package, adding more dollars to your bottom line.

University Combined Heat and Power
Energy Star Award

Hospital Combined Heat and Power
LEED Platinum Award

32% Energy Savings, 76,000 Tons CO_2 Savings Per Year

When Comparing Cogeneration to Generating Electricity and Steam Separately



Sustainable Solutions that Fit Your Application

Solar maintains a clear focus on providing customer satisfaction by designing products that lead their categories in critical performance and environmentally sustainable operation. *Solar*® gas turbines meet customer needs in ways that limit the impact on the environment, protect people who operate the equipment, and respect people who live nearby.

These products, including the *Titan* 250, provide sustainable solutions through the application of advanced technologies that enable high operating efficiency and low greenhouse gas emissions. Solar's industry-exclusive *SoLoNOx*™ dry low-emissions combustion technology has been proven to lower emissions and ensure compliance with stringent exhaust emission regulations worldwide. *SoLoNOx* technology cuts NOx emissions up to 90% and CO emissions are reduced as much as 30% over conventional combustion systems.

Municipal Power
Energy Star Award

Solar gas turbines incorporating *SoLoNOx* combustion systems, have logged more than 86 million operating hours, saving 2.1 million tons of NOx emissions, improving air quality for millions of people around the world. And many of our gas turbines have helped our customers win Energy Star, LEED and other awards recognizing efficiency and sustainability.

The *Titan* 250 gas turbine generator set can be applied in a variety of applications, including combined heat and power, peaking power/load management, district heating and cooling, and base load power. It will meet your requirements in a wide variety of industries and facilities, including hospitals, universities, rural electric cooperatives, municipal utilities, food processing, pulp and paper mills, manufacturing facilities, mining and refineries.

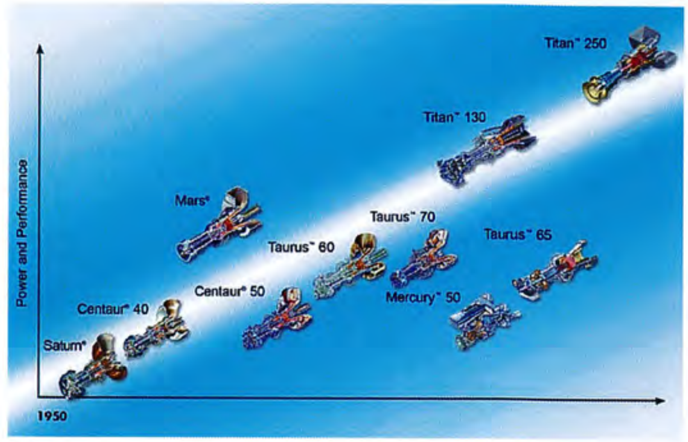
For combined heat and power applications, the *Titan* 250 generator set can be coupled with heat recovery equipment to optimize your application by capturing otherwise wasted thermal energy from the exhaust to produce steam for space, water or process heating, maximizing energy efficiency and increasing sustainability.

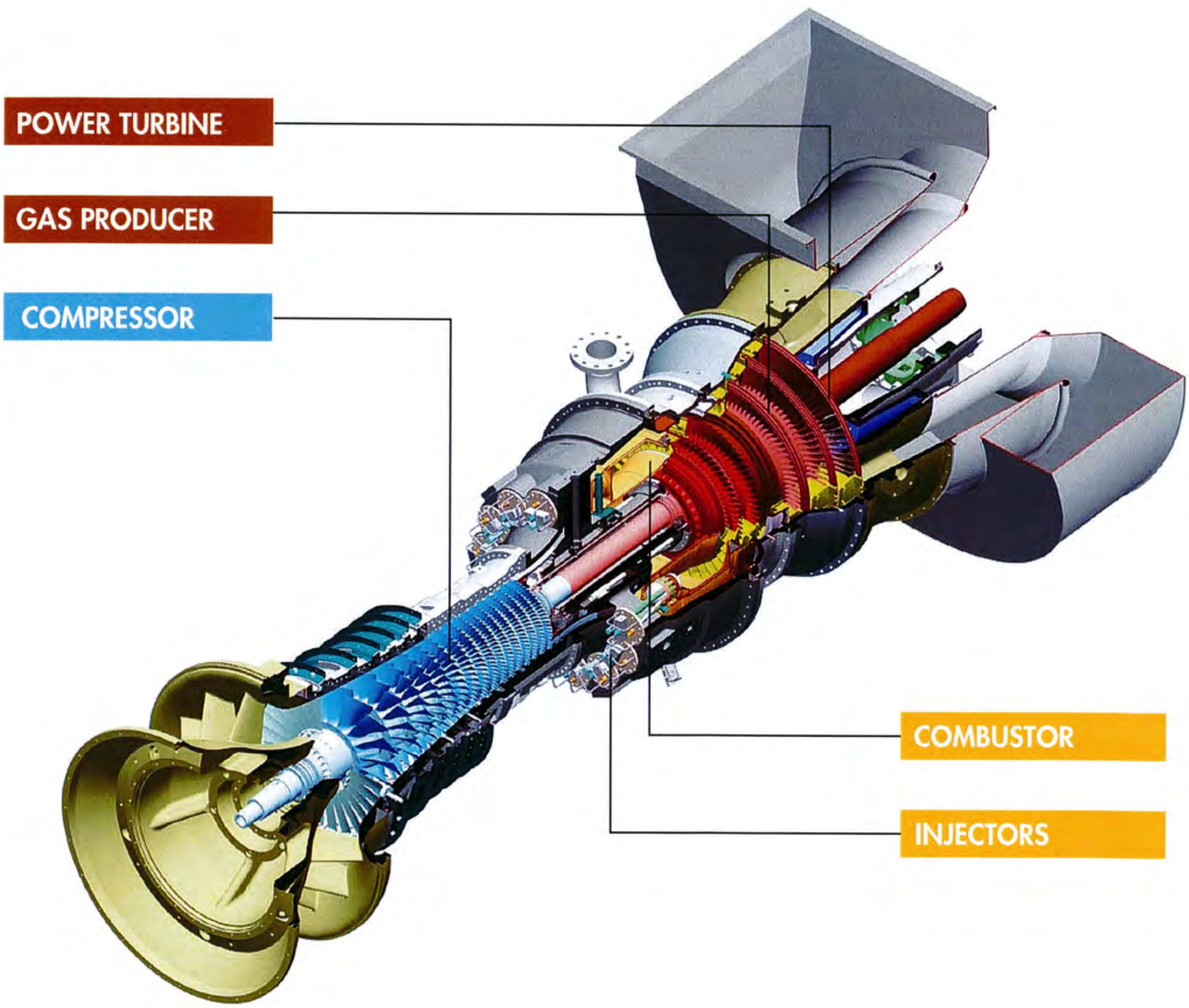
Because the *Titan* 250 is extremely reliable and efficient, utilities can benefit by using it to provide power to isolated communities, commercial centers and industries. Utilities will also benefit their communities by using the *Titan* 250 in peaking applications to reduce the incremental cost of additional generation.

Leveraging Proven Technology

The *Titan* 250 is a familiar machine, yet still a gas turbine like no other – taking the best from Solar's proven products. Each advancement builds on experience gained from our latest and most proven designs, while adding thoroughly tested technologies in critical areas of compressor aerodynamics, combustion, advanced materials, cooling performance and package design.

Configured for power generation, the *Titan* 250 comes fully integrated and self-contained with lube oil, fuel and *Turbotronic*™ control systems on board. Modular inlet, exhaust and ancillary systems can be adjusted to suit your application in enclosed or unenclosed packages.





Engineered for Excellence

Titan 250 gas turbines deliver best-in-class performance while saving on fuel and reducing emissions. Above all, the *Titan* 250 is engineered for durability, reliability and availability. Using smart diagnostics, remote monitoring and onsite maintenance capabilities, the *Titan* 250 takes advantage of advanced features to keep your operation online and producing for many years to come.

Look at the technologies behind the *Titan* 250 and you'll recognize key contributions from our most widely accepted products:

Compressor Section Technology

A 16-stage compressor produces a 24:1 pressure ratio. Coated components provide corrosion resistant surfaces for durability. The four-piece, split-case design allows for easy field maintenance. Variable guide vanes and stators permit smooth, reliable starting and stopping.

Combustion Section Technology

The 14 dry, lean-premixed *SoLoNOx* injectors deliver less fuel than conventional designs resulting in lower emissions.

The combustion liner is an Augmented Backside Cooled (ABC) configuration providing maximum cooling ensuring long-term durability.

Hot Section Technology

The two-stage gas producer features internally air-cooled first and second stage nozzle vanes as well as internally cooled first stage rotor blades. The design provides cylindrical blade tips and a rub-tolerant coating for improved tip control increasing efficiency.

The power turbine is a three-stage configuration utilizing shrouded blades to maximize efficiency and flatten the power curve.

And the *Titan* 250 gas turbine was designed with the same rigorous approach that has always served our customers well — extending these proven technologies to new products and advancing the state of the art.

The latest proven engineering methods give the *Titan* 250 its performance edge. Tools like computational fluid dynamics (CFD) and computer-aided thermal and mechanical analysis ensure achievement of design and performance objectives. A comprehensive reliability analysis gives you refinements in design and processes that further enhance availability:

- Adding redundancy
- Improving controls and optimizing shutdown logic
- Enhancing component reliability and durability
- Minimizing service events and their duration
- Expanding machine health monitoring and predictive maintenance

This design methodology ensures that customers receive robust equipment ready for long, reliable service across the entire life cycle of their project.

Higher Availability

Tougher projects and challenging markets demand maximum equipment availability. The *Titan* 250 promises more productive hours with less repair and fewer and shorter planned service intervals. It continues a design tradition of modular components for the ultimate in operational flexibility and service simplicity.

Monitoring and Diagnostics: Cornerstones of Productivity

Titan 250 packages provide remote monitoring and predictive diagnostics enabled by Solar's *InSight System*™, the industry's most advanced equipment health management system. This system provides a clear vision, focus and understanding of your equipment and is designed to save you time and money.

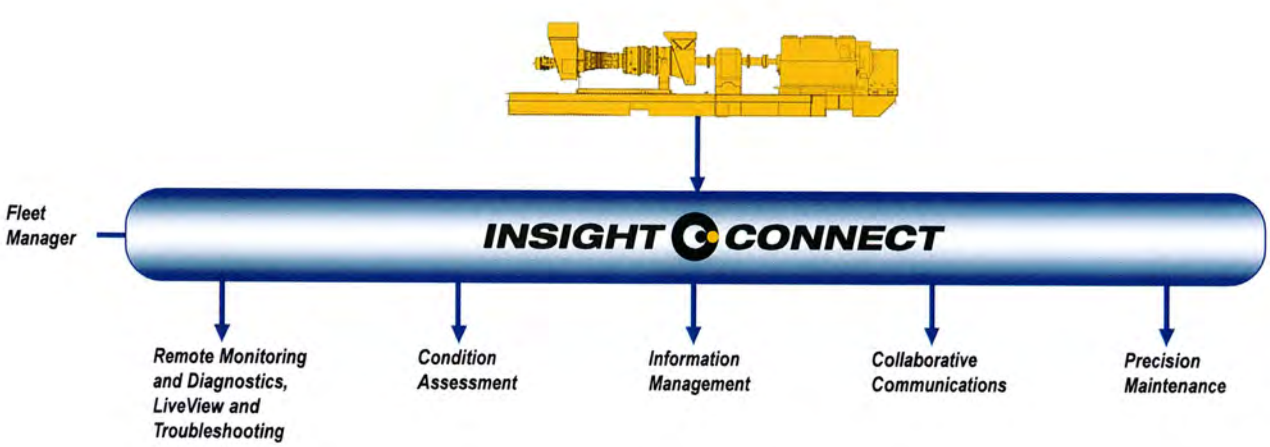
With *InSight System*, problems once found only by a technician's visit can be detected online from anywhere — even half a world away — so you can avoid unscheduled downtime.

Capabilities include:

- Advanced diagnostics
- Condition monitoring
- Remote troubleshooting
- E-mail alert notifications
- Predictive recommendations
- Equipment operation summary reports

Features delivered by *InSight System* rely on a dedicated connectivity solution, *InSight Connect*™, allowing reliable access to critical operational information. This secured web connection provides a standardized method for the acquisition and transmission of information while minimizing the impact to an existing customer network.

InSight System monitors your operation 24 hours a day. If trouble is detected at any time it helps you determine the prognosis, forecast the outcome, and decide whether to repair now or wait for the next scheduled service. With built-in predictive capability, some events that previously would have shut the package down now trigger fall-back to a safe operating mode and alert service personnel of the machine's status. The system also gathers and analyzes information — performance maps, historical displays, reports on availability and life-cycle cost — to help you make operational decisions that maximize your investment.



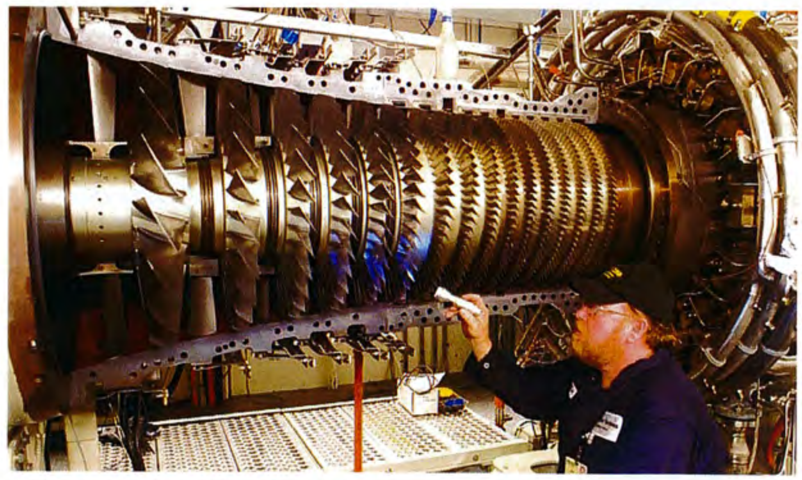
Designed for Productivity

The *Titan* 250 gas turbine system has been designed to give customers many years of productivity with the highest life-cycle value at the lowest life-cycle cost. This means equipment with the highest availability, reliability and durability, and machines that are easy to maintain and service.

Our complete approach to machinery management includes digital monitoring and control systems that help further minimize emissions, support predictive maintenance, increase availability, enable unattended operation, and reduce life-cycle costs.

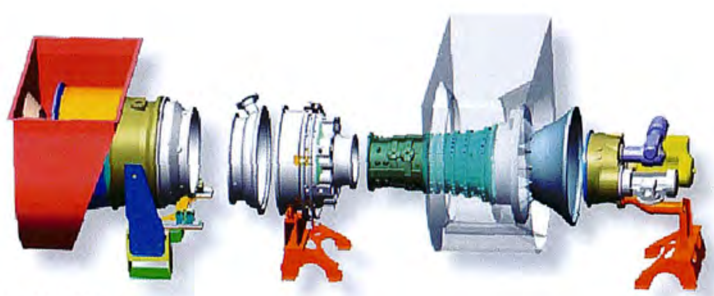
All regularly serviced components are placed near the sides of the package for ease of access and fast service. With our lateral and axial engine repair and maintenance system, you have the option of doing in situ condition-based repair, modular component exchange, or a complete exchange of major engine components.

Easy Access to Major Components



Onsite Inspection Capability

Lateral Rail System



Axial Rail System

The rail-mounted service system supports the turbine from below and allows easy access to inspect, repair or replace hot section components, bearings, blades and seals. Technicians can also remove and replace the gas producer independently of the power turbine, avoiding realignment of the power turbine and driven equipment. The rails can also be used to roll the entire turbine out for factory overhaul or exchange, minimizing downtime.

Contact Us and Put the Titan 250 to Work

Let us show you the true power and value of *Titan* 250 turbomachinery package. We stand on our experience gained from more than 13,600 turbine packages in 96 countries with over 1.5 billion hours of operation. In addition to expert application advice, you'll get in-depth technical assistance through our global customer support system.

We're ready to serve you from locations all over the world:

- 13 repair and overhaul centers
- 19 parts facilities
- 43 service locations

For more information, contact one of our representatives. To see a complete listing of our worldwide locations, visit our website or contact us at one of the phone numbers listed below.

Worldwide Headquarters

Solar Turbines Incorporated
P.O. Box 85376
San Diego, California 92186-5376
Telephone: +1 (619) 544-5352
email: powergen@solarturbines.com

www.solarturbines.com

Turbomach S.A
Via Campagna 15
6596 Riazzino, Switzerland
Telephone: +41 91 851 15 11
email: contact@turbomach.com

www.turbomach.com

B250PG/210/5M

50 MWe
COMBINED HEAT AND POWER INDEPENDENT POWER PRODUCER

OWNER
Manisa OIZ

LOCATION
Turkey

PRODUCT
Two Titan 250 Generator Sets

CUSTOMER VALUE
High Efficient and Flexible Energy Supply

Our customer, Manisa OIZ, one of the biggest industrial parks in Turkey, needed to fulfill the rapidly growing demand of electricity, as well as provide steam and hot water to their industrial tenants. We extended the capacity of their power plant with two of our latest Titan™ 250 gas turbines, which are the best in class for efficiency and match the customer's variable demand for electricity, steam and hot water.

Solar Turbines
A Caterpillar Company

50 MWe COMBINED CYCLE POWER PLANT

PLANT DATA
Two Titan 250 Gas Turbine Generator Sets (44 MWe)
Two Heat Recovery Steam Generators
Two Steam Turbine Generators
50 MWe - 250 Mwth Heat Supply
Fuel: Natural Gas

OUR PRODUCTS AND SERVICES
Gas Turbine Packages Supply and Auxiliaries
Design
Construction
Commissioning and Installation
Maintenance

RELIABLE

HIGHLY EFFICIENT

FLEXIBLE SOLUTION

The new combined cycle power plant is fully capable of supporting a highly unpredictable electricity demand and the variable needs of steam and hot water. The organization can rely on this stand-alone power plant in order to support the more than 180 industries that are connected for electricity and heat supply. Moreover, the efficiency of the plant and the low emissions of the Titan 250 ensure the customer's full compliance to the industrial emissions regulations of the country.

Solar Turbines Incorporated
Tel: +01 619-544-5352
Mail: powergen@solarturbines.com Web: www.solarturbines.com

dschp-moiz/116/EO

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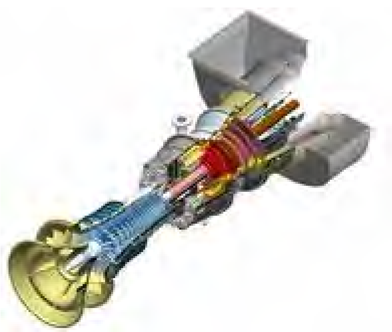
GAS TURBINE PACKAGES

TITAN 250

PACKAGE AND PERFORMANCE DATA-TITAN 250 GAS TURBINE GENERATOR SET - POWER GENERATION ›

OTHER MEDIA ›



Titan 250 PG - Generator Set

ISO PERFORMANCE/SPECIFICATIONS | BROCHURES | CASE STUDIES

TITAN 250 PG - GENERATOR SET

The Titan™ 250 is our most powerful package and is based on proven technologies from other Solar Turbines models. It produces 50 percent more power in the same footprint as the Titan 130. It provides 40 percent shaft efficiency with emissions reduced up to 30 percent.

ISO PERFORMANCE/SPECIFICATIONS UNITS: US METRIC

Power	21 745 kWe
Heat Rate	8775 Btu/kW-hr
Exhaust Flow	541,590 lb/hr

Exhaust Temperature	865ºF
Steam Production	77.6 - 298 klb/hr
Axial Exhaust	—
Radial Exhaust	—
SoLoNOx	Yes
Ultra Lean Premix	—

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PRODUCTS AND SOLUTIONS | SERVICES | ABOUT US | CAREERS

GAS TURBINE PACKAGES

TITAN 250

Back

PACKAGE AND PERFORMANCE DATA-TITAN 250 GAS TURBINE GENERATOR SET - POWER GENERATION

OTHER MEDIA

CASE STUDIES | CE/SPECIFICATIONS

TITAN 250 PG - GENERATOR SET

The Titan™ 250 is our most powerful package and is based on proven technologies from other Solar Turbines models. It produces 50 percent more power in the same footprint as the Titan 130. It provides 40 percent shaft efficiency with emissions reduced up to 30 percent.

ISO PERFORMANCE/SPECIFICATIONS

UNITS: US METRIC

Power	21 745 kWe 21 745 kWe

Heat Rate	8775 Btu/kW-hr 9260 kJ/kW-hr
Exhaust Flow	541,590 lb/hr 245 660 kg/hr
Exhaust Temperature	865ºF 465ºC
Steam Production	77.6 - 298 klb/hr 35.2 - 135.1 tonnes/hr
Axial Exhaust	— —
Radial Exhaust	— —
SoLoNOx	Yes Yes
Ultra Lean Premix	— —

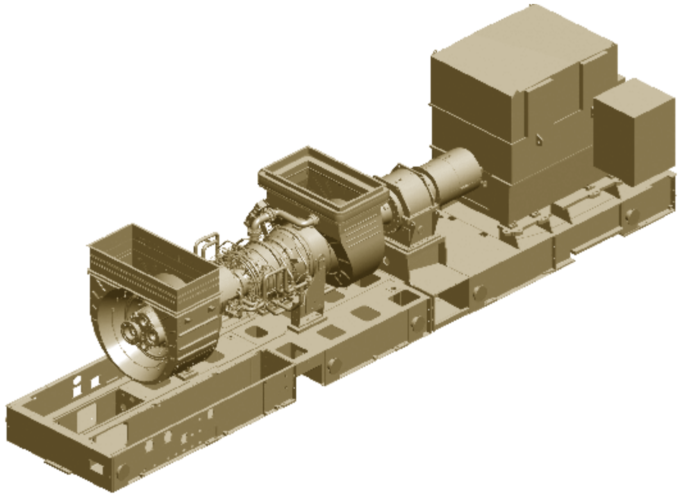
YouTube

Twitter

Solar® Turbines
A Caterpillar Company

TITAN 250
Gas Turbine Generator Set

Power Generation



General Specifications

Titan™ 250 Gas Turbine

- Industrial, Two-Shaft
- 16 Stage Axial Compressor
  - Variable Inlet Guide Vanes
  - Pressure Ratio: 24:1
  - Inlet Airflow: 67.3 kg/sec (148 lb/sec)
  - Vertically Split Case
- Combustion Chamber Annular-Type
  - 14 Lean-Premixed, Dry Low Emissions Injectors
  - Torch Ignitor System
- Gas Generator Turbine
  - 2-Stage Reaction
  - Max. Speed: 10,500 rpm
- Power Turbine
  - 3-Stage Reaction
  - Max. Speed: 7000 rpm
- Bearings
  - 5 Radial Journal, Tilt-Pad
  - 2 Active Thrust, Tilt-Pad
  - 2 Inactive Thrust, Fixed Tapered Land
- Coatings
  - Compressor: Inorganic Aluminum
  - Turbine and Nozzle Blades: Precious Metal Diffusion Aluminide
- Vibration Transducer Type
  - Proximity Probes , 2 per Radial Bearing/2 per Thrust Bearing

Main Reduction Drive

- Epicyclic Type
  - 1500 rpm (50 Hz) or 1800 rpm (60 Hz)
  - Accessory Power Take-Off

Generator

- Salient Pole, 3 Phase, 6 Wire, Wye Connected, Synchronous, with Permanent Magnet Generator Exciter
- Available Construction Types:
  - Duct In/Duct Out
  - Totally Enclosed Air-to-Air Cooled
  - Totally Enclosed Water-to-Air Cooled
- Sleeve Bearings
- Oil Jacking System
- NEMA Class F Insulation
- Class B Temperature Rise
- Voltages: 1100 to 13,800 VAC
- Frequency: 50 or 60 Hz

Package

- Mechanical Construction
  - Steel Base Frame with Drip Pans
  - 316L Stainless Steel Piping ≤8" dia.
  - Compression-Type Tube Fittings
- Electrical System
  - NEC, Class 1, Group D, Div 2
  - CENELEC/ATEX Zone 2
  - Cable Tray Wiring
  - 120 VDC Battery/Charger System
- Direct-Drive AC Start System
- Fuel System
  - Dry Low Emission (*SoLoNOx*)
  - Conventional
- Fuel Types
  - Natural Gas or Dual (Gas/Distillate)
- Integrated Lube Oil System
  - Turbine-Driven Main Pump
  - AC Motor-Driven Pre/Post Pump
  - DC (120 V) Motor-Driven Backup Pump
  - Oil Cooler and Oil Heater*
  - Tank Vent Separator and Flame Trap
  - Lube Oil Filter
- Turbine Compressor Cleaning System
  - On-Crank/On-Line
  - Portable Cleaning Tank*
- Air Inlet and Exhaust System
  - Carbon Steel
  - Stainless Steel
  - Coastal Type Filters
- Enclosure
  - Driver Only
  - Fire Detection and Suppression
- *Turbotronic*™ 4 Control System
  - Onskid Control System
    - Digital Onskid Display Panel
  - 24 VDC Control Power (120 VDC Input)
  - Serial Link Supervisory Interface
  - Field Programmable
  - Vibration Monitoring
  - Temperature Monitoring
  - Generator Control
    - Selectable Control Modes
    - Solid-State Voltage Regulation
    - Automatic Synchronization
    - Metering Panel with Manual Synchronization*
    - KW Control*
  - Heat Recovery Application Interface
  - Multiple Operator Display Screens
  - Data Collection and Playback
  - Turbine Performance Map*
  - *InSight System*™ Equipment Health Management*
  - Printer/Logger*
- Documentation
  - Electrical Drawings
  - Mechanical Drawings
  - Quality Control Data Book
  - Inspection and Test Plan
  - Test Reports
  - O&M Manuals
- Factory Testing of Turbine
- Factory Testing of Package
  - Non-Dynamic
  - Dynamic

* Option

Solar Turbines
A Caterpillar Company

TITAN 250
Gas Turbine Generator Set

Power Generation

Performance

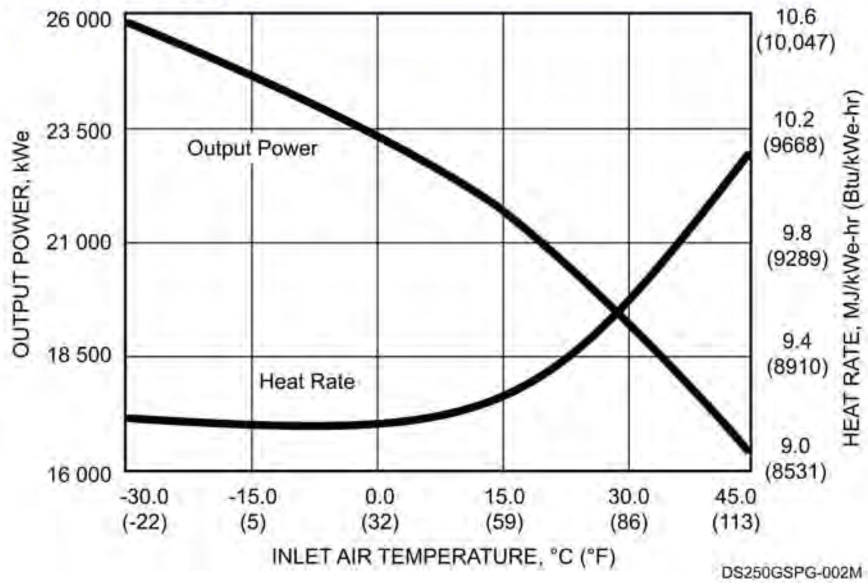
Output Power	21 745 kWe
Heat Rate	9260 kJ/kWe-hr (8775 Btu/kWe-hr)
Exhaust Flow	245 660 kg/hr (541,590 lb/hr)
Exhaust Temp.	465°C (865°F)

Application Performance

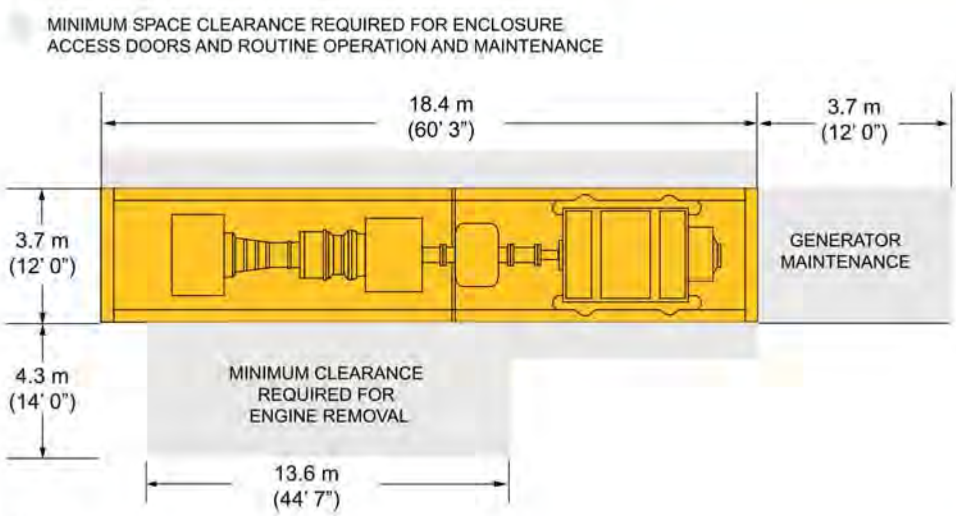
Steam (Unfired)	35.2 tonnes/hr (77,600 lb/hr)
Steam (Fired) 1536°C (2800°F)	184.8 tonnes/hr (407,490 lb/hr)
Chilling (Absorp.)	30 340 kW (8620 refrigeration tons)

Nominal rating – per ISO
At 15°C (59°F), sea level
No inlet/exhaust losses
Relative humidity 60%
Natural gas fuel with
LHV = 31.5 to 43.3 MJ/Nm³ (940 Btu/scf)
No accessory losses
Engine efficiency: 38.9%
(measured at generator terminals)

Available Power



Enclosure Access and Maintenance Space



Package Height: 4.1 m (13' 5")
Package Weight: 125 000 kg (276,000 lb)

Solar Turbines Incorporated
P.O. Box 85376
San Diego, CA 92186-5376

DS250PG/0113/EO

FOR MORE INFORMATION

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Solar Turbines
A Caterpillar Company

Solar Turbines Incorporated

9330 Sky Park Court
San Diego, CA 92123
Tel: (858) 694-1616

Submitted Electronically

September 20, 2016

Dave Brown
Program Manager Utilities – Department of Facilities
Massachusetts Institute of Technology
browndj@MIT.edu

RE: Titan™ 250 *SoLoNOx*™ Installation

Dear Mr. Brown:

The Titan 250 *SoLoNOx* planned for the MIT installation represents "best in class efficiency" and is equipped with state-of-the-art low emissions technology.

The Titan 250 leads the industry when it comes to power, efficiency, emissions and envelope. Since its introduction in 2004, the Titan 250 has benefited from Solar's long standing tradition of continuous improvement. The Titan 250 incorporates high efficiency airfoil designs, optimized cooling strategies, the latest ultra low emissions technologies

Solar's *SoLoNOx* technology employs lean-premixed combustion to reduce NOx emissions. Lean-premixed combustion reduces the conversion of atmospheric nitrogen to NOx by reducing the combustion flame temperatures as NOx formation rates are strongly dependent on flame temperature. Further reductions in emission are achieved by premixing the fuel and combustor airflow upstream of the combustor primary zone. The pre-mixing prevents stoichiometric burning locally with the flame, thus ensuring the entire flame is at fuel lean condition resulting in low emissions.

Please refer to the attached brochure for additional information on the Titan 250 and let me know if any additional detail on the features of the Titan 250 is needed to support the air permitting process.

Please contact me at 858.694.6609 if you have any questions or need any additional information.

Sincerely,
Solar Turbines Incorporated
Leslie Witherspoon
Manager Environmental Programs
witherspoon_leslie_h@solarturbines.com

cc: Bernie Pfeiffer, Solar

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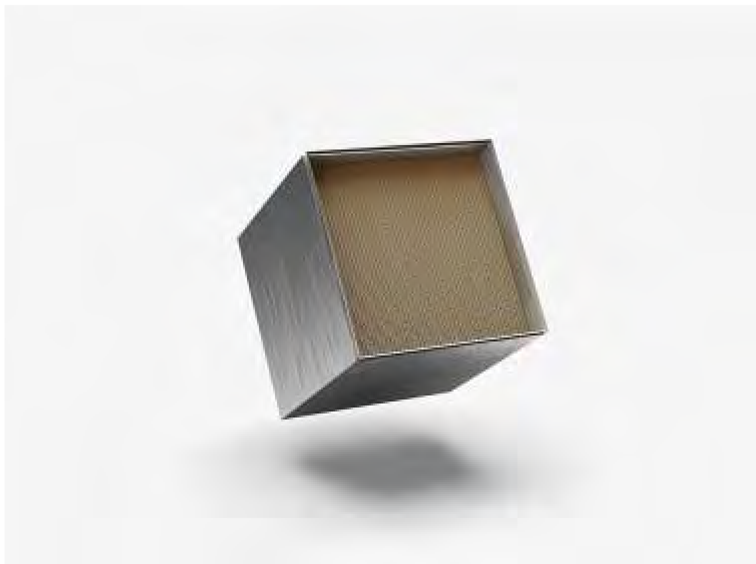
DNX® GT



DNX® GT series – Raising performance

The DNX® GT-series is Haldor Topsoe's recently developed line of catalysts tailored for gas turbine service. The GT-series comprises a range of GT catalysts for SCR NOx reduction and GTC catalysts for CO oxidation. Topsoe's DNX® GT-series offers:

- lower pressure drop
- improved activity
- enhanced operation in all temperature ranges
- fast emission compliance

Features

To enhance power production by minimizing the pressure drop and the required space for catalyst in the heat recovery steam generator (HRSG), Topsoe has developed a dedicated series of gas-turbine catalysts for SCR and for CO oxidation.

SCR catalysts

The GT catalysts feature an enhanced SCR activity which has been achieved through reformulating and changing the monolith structure of the original DNX®catalyst. Thereby an increased specific surface area and a higher catalyst wall utilization have been achieved which together with a larger open area provide an attractive combination of increased activity and lower pressure drop.

CO oxidation catalysts

catalyst and are available as a high-temperature version that can be positioned upstream the ammonia injection grid (AIG) and a version optimized for positioning downstream the SCR catalyst where the dual functionality leads to reduced SCR catalyst volume and in turn even lower pressure drop.

Benefits

The 20% boost in volume activity for the GT catalysts yield a corresponding reduction in required catalyst volume. Together with a 10% lower specific pressure drop, the GT catalysts offer a saving in overall pressure loss across the SCR catalyst in the order of 30% compared to the previous DNX® versions.
The dual function of the GTC catalysts makes it possible to locate the CO-oxidation catalyst downstream of the SCR in the HRSG. The SCR can then be designed with excess ammonia slip which is subsequently eliminated across the GTC catalyst with the remaining part of the NOx in the flue gas. This combined GT-GTC solution offers more than 40% reduction in SCR catalyst volume and more than 25% reduction in total pressure drop.
The low volume of high-void catalysts has a low thermal mass that offers unlimited heating rate and consequently a minimum time until emission compliance.

Property	Value
Range	180 - 500°C 356 - 932°F
Composition	$V_2O_5/WO_3/TiO_2$
Shape	Corrugated monolith

Used in industries

Ammonia
Automotive
Bio fuels
Cement
Chemicals
Coke & coal
Energy & power
Fertilizer
Hydrogen
Methanol
Mining & smelting
Oil & gas
Paper & printing
Petrochemicals
Polymers & plastics
Refining

Shale oil
Ships & marine
Steel
Sulfuric acid
Syngas
Waste disposal

Used in processes
NOx & CO removal

FIND US

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Kgs. Lyngby
Denmark

+45 45 27 20 00

topsoe@topsoe.dk

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PLEASE CONTACT ME

Nature of your enquiry*
- Please Select -

First name * **Last name ***

What do you want to talk about? *

Yes, please send me regular e-mail updates about Haldor Topsoe news, insights, products, events and services

SUBMIT

LATEST TWEETS

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Appendix B – Part 2

Engine Information

- CAT Engine Technical Data
- Loads Served by Engine

STANDBY 2000 ekW 2500 kVA

60 Hz 1800 rpm 480 Volts

TECHNICAL DATA

Open Generator Set - - 1800 rpm/60 Hz/480 Volts	DM8263	
EPA Certified for Stationary Emergency Application (EPA Tier 2 emissions levels)		
Generator Set Package Performance		
Genset Power rating @ 0.8 pf	2500 kVA	
Genset Power rating with fan	2000 ekW	
Fuel Consumption		
100% load with fan	522.5 L/hr	138.0 Gal/hr
75% load with fan	406.8 L/hr	107.5 Gal/hr
50% load with fan	293.6 L/hr	77.6 Gal/hr
Cooling System[1]		
Air flow restriction (system)	0.12 kPa	0.48 in. water
Air flow (max @ rated speed for radiator arrangement)	2480 m^3/min	87580 cfm
Engine Coolant capacity with radiator/exp. tank	475.0 L	125.5 gal
Engine coolant capacity	233.0 L	61.6 gal
Radiator coolant capacity	242.0 L	63.9 gal
Inlet Air		
Combustion air inlet flow rate	185.5 m^3/min	6550.9 cfm
Exhaust System		
Exhaust stack gas temperature	400.1 ° C	752.2 ° F
Exhaust gas flow rate	433.1 m^3/min	15294.8 cfm
Exhaust flange size (internal diameter)	203.2 mm	8.0 in
Exhaust system backpressure (maximum allowable)	6.7 kPa	26.9 in. water
Heat Rejection		
Heat rejection to coolant (total)	759 kW	43164 Btu/min
Heat rejection to exhaust (total)	1788 kW	101683 Btu/min
Heat rejection to aftercooler	672 kW	38217 Btu/min
Heat rejection to atmosphere from engine	133 kW	7564 Btu/min
Heat rejection to atmosphere from generator	85.5 kW	4862.4 Btu/min
Alternator[2]		
Motor starting capability @ 30% voltage dip	4999 skVA	
Frame	826	
Temperature Rise	105 ° C	189 ° F
Lube System		
Sump refill with filter	466.0 L	123.1 gal
Emissions (Nominal)[3]		
NOx g/hp-hr	5.45 g/hp-hr	
CO g/hp-hr	.3 g/hp-hr	
HC g/hp-hr	.11 g/hp-hr	
PM g/hp-hr	.025 g/hp-hr	

[1] For ambient and altitude capabilities consult your Cat dealer. Air flow restriction (system) is added to existing restriction from factory.

[2] Generator temperature rise is based on a 40 degree C ambient per NEMA MG1-32. UL 2200 Listed packages may have oversized generators with a different temperature rise and motor starting characteristics.

[3] Emissions data measurement procedures are consistent with those described in EPA CFR 40 Part 89, Subpart D & E and ISO8178-1 for measuring HC, CO, PM, NOx. Data shown is based on steady state operating conditions of 77ºF, 28.42 in HG and number 2 diesel fuel with 35º API and LHV of 18,390 btu/lb. The nominal emissions data shown is subject to instrumentation, measurement, facility and engine to engine variations. Emissions data is based on 100% load and thus cannot be used to compare to EPA regulations which use values based on a weighted cycle.

PERFORMANCE DATA[DM8263]

Performance Number: DM8263 **Change Level: 03**

SALES MODEL:	3516C	**COMBUSTION:**	DI
ENGINE POWER (BHP):	2,937	**ENGINE SPEED (RPM):**	1,800
GEN POWER WITH FAN (EKW):	2,000.0	**HERTZ:**	60
COMPRESSION RATIO:	14.7	**FAN POWER (HP):**	114.0
APPLICATION:	PACKAGED GENSET	**ASPIRATION:**	TA
RATING LEVEL:	STANDBY	**AFTERCOOLER TYPE:**	ATAAC
PUMP QUANTITY:	2	**AFTERCOOLER CIRCUIT TYPE:**	JW+OC, ATAAC
FUEL TYPE:	DIESEL	**INLET MANIFOLD AIR TEMP (F):**	122
MANIFOLD TYPE:	DRY	**JACKET WATER TEMP (F):**	210.2
GOVERNOR TYPE:	ADEM3	**TURBO CONFIGURATION:**	PARALLEL
ELECTRONICS TYPE:	ADEM3	**TURBO QUANTITY:**	4
CAMSHAFT TYPE:	STANDARD	**TURBOCHARGER MODEL:**	GTA5518BN-56T-1.12
IGNITION TYPE:	CI	**CERTIFICATION YEAR:**	2006
INJECTOR TYPE:	EUI	**CRANKCASE BLOWBY RATE (FT3/HR):**	2,937.9
FUEL INJECTOR:	2664387	**FUEL RATE (RATED RPM) NO LOAD (GAL/HR):**	13.7
REF EXH STACK DIAMETER (IN):	12	**PISTON SPD @ RATED ENG SPD (FT/MIN):**	2,244.1
MAX OPERATING ALTITUDE (FT):	3,117		

General Performance Data

GENSET POWER WITH FAN	PERCENT LOAD	ENGINE POWER	BRAKE MEAN EFF PRES (BMEP)	BRAKE SPEC FUEL CONSUMPTN (BSFC)	VOL FUEL CONSUMPTN (VFC)	INLET MFLD PRES	INLET MFLD TEMP	EXH MFLD TEMP	EXH MFLD PRES	ENGINE OUTLET TEMP
EKW	%	BHP	PSI	LB/BHP-HR	GAL/HR	IN-HG	DEG F	DEG F	IN-HG	DEG F
2,000.0	100	2,937	307	0.329	138.0	78.3	121.2	1,118.5	71.5	752.1
1,800.0	90	2,641	276	0.331	124.9	73.1	119.6	1,067.5	65.7	716.0
1,600.0	80	2,353	246	0.337	113.1	68.0	118.2	1,027.0	60.0	693.3
1,500.0	75	2,212	231	0.340	107.5	65.2	117.5	1,008.1	57.2	684.6
1,400.0	70	2,071	216	0.344	101.8	62.3	116.8	989.4	54.4	676.9
1,200.0	60	1,795	188	0.352	90.1	55.5	115.4	952.0	48.0	662.8
1,000.0	50	1,521	159	0.357	77.5	46.5	113.7	913.4	40.1	654.0
800.0	40	1,250	131	0.357	63.8	34.8	111.8	863.8	30.3	655.0
600.0	30	977	102	0.365	50.9	24.2	110.6	803.8	22.0	650.0
500.0	25	839	88	0.374	44.8	19.7	110.2	767.0	18.7	641.7
400.0	20	699	73	0.388	38.8	15.7	109.8	724.6	15.7	629.0
200.0	10	411	43	0.450	26.4	9.0	109.1	596.9	10.9	552.8

GENSET POWER WITH FAN	PERCENT LOAD	ENGINE POWER	COMPRESSOR OUTLET PRES	COMPRESSOR OUTLET TEMP	WET INLET AIR VOL FLOW RATE	ENGINE OUTLET WET EXH GAS VOL FLOW RATE	WET INLET AIR MASS FLOW RATE	WET EXH GAS MASS FLOW RATE	WET EXH VOL FLOW RATE (32 DEG F AND 29.98 IN HG)	DRY EXH VOL FLOW RATE (32 DEG F AND 29.98 IN HG)
EKW	%	BHP	IN-HG	DEG F	CFM	CFM	LB/HR	LB/HR	FT3/MIN	FT3/MIN
2,000.0	100	2,937	83	454.3	6,548.9	15,292.8	28,512.8	29,478.4	6,205.0	5,738.7
1,800.0	90	2,641	77	428.8	6,318.7	14,243.0	27,390.5	28,264.7	5,956.5	5,533.7
1,600.0	80	2,353	72	404.5	6,073.3	13,331.0	26,220.6	27,012.9	5,685.0	5,301.6
1,500.0	75	2,212	69	392.7	5,932.2	12,897.9	25,568.0	26,319.7	5,542.0	5,176.6
1,400.0	70	2,071	66	380.9	5,777.2	12,448.0	24,862.1	25,573.8	5,384.8	5,037.5
1,200.0	60	1,795	59	353.9	5,397.2	11,422.5	23,141.0	23,771.1	5,003.4	4,694.0
1,000.0	50	1,521	50	318.8	4,857.3	10,138.7	20,731.5	21,274.5	4,476.2	4,208.4
800.0	40	1,250	38	271.1	4,090.0	8,488.8	17,357.1	17,803.6	3,744.5	3,524.2
600.0	30	977	27	225.0	3,394.1	6,989.6	14,328.5	14,684.4	3,097.0	2,920.6
500.0	25	839	22	204.1	3,103.5	6,328.1	13,075.2	13,388.4	2,825.1	2,668.8
400.0	20	699	18	184.1	2,840.4	5,696.0	11,947.2	12,218.4	2,572.5	2,435.7
200.0	10	411	11	148.5	2,409.4	4,478.2	10,105.7	10,290.7	2,174.6	2,076.8

PERFORMANCE DATA[DM8263]

Heat Rejection Data

GENSET POWER WITH FAN	PERCENT LOAD	ENGINE POWER	REJECTION TO JACKET WATER	REJECTION TO ATMOSPHERE	REJECTION TO EXH	EXHUAST RECOVERY TO 350F	FROM OIL COOLER	FROM AFTERCOOLER	WORK ENERGY	LOW HEAT VALUE ENERGY	HIGH HEAT VALUE ENERGY
EKW	%	BHP	BTU/MIN	BTU/MIN	BTU/MIN	BTU/MIN	BTU/MIN	BTU/MIN	BTU/MIN	BTU/MIN	BTU/MIN
2,000.0	100	2,937	43,150	7,564	101,696	49,615	15,778	38,240	124,558	296,234	315,563
1,800.0	90	2,641	40,179	7,175	92,069	43,106	14,280	34,105	111,977	268,102	285,596
1,600.0	80	2,353	37,427	6,907	84,225	38,510	12,931	30,201	99,774	242,774	258,615
1,500.0	75	2,212	36,092	6,791	80,632	36,523	12,286	28,303	93,784	230,664	245,715
1,400.0	70	2,071	34,737	6,671	77,064	34,629	11,640	26,432	87,835	218,548	232,809
1,200.0	60	1,795	31,877	6,341	69,432	30,722	10,302	22,179	76,103	193,426	206,048
1,000.0	50	1,521	28,631	6,026	60,835	26,675	8,865	17,129	64,508	166,434	177,294
800.0	40	1,250	24,910	5,810	50,784	22,387	7,288	11,280	53,005	136,837	145,766
600.0	30	977	21,252	5,496	41,420	18,139	5,820	6,677	41,431	109,268	116,397
500.0	25	839	19,405	5,303	37,082	16,055	5,124	4,986	35,574	96,210	102,488
400.0	20	699	17,492	5,098	32,738	13,986	4,431	3,593	29,634	83,193	88,622
200.0	10	411	13,286	4,670	23,481	8,473	3,022	1,516	17,448	56,745	60,447

PERFORMANCE DATA[DM8263]

Emissions Data

RATED SPEED POTENTIAL SITE VARIATION: 1800 RPM

GENSET POWER WITH FAN		EKW	2,000.0	1,500.0	1,000.0	500.0	200.0
ENGINE POWER		**BHP**	**2,937**	**2,212**	**1,521**	**839**	**411**
PERCENT LOAD		**%**	**100**	**75**	**50**	**25**	**10**
TOTAL NOX (AS NO2)		G/HR	19,098	10,213	5,798	4,218	2,932
TOTAL CO		G/HR	1,564	847	905	1,772	1,794
TOTAL HC		G/HR	423	513	512	409	443
PART MATTER		G/HR	103.2	99.5	123.9	256.7	203.1
TOTAL NOX (AS NO2)	(CORR 5% O2)	MG/NM3	3,299.4	2,320.1	1,852.8	2,379.4	2,855.8
TOTAL CO	(CORR 5% O2)	MG/NM3	257.0	181.1	277.5	896.4	1,715.8
TOTAL HC	(CORR 5% O2)	MG/NM3	60.1	93.7	132.1	194.2	379.5
PART MATTER	(CORR 5% O2)	MG/NM3	14.4	18.5	35.1	120.0	161.3
TOTAL NOX (AS NO2)	(CORR 5% O2)	PPM	1,607	1,130	902	1,159	1,391
TOTAL CO	(CORR 5% O2)	PPM	206	145	222	717	1,373
TOTAL HC	(CORR 5% O2)	PPM	112	175	247	363	708
TOTAL NOX (AS NO2)		G/HP-HR	6.54	4.64	3.82	5.04	7.13
TOTAL CO		G/HP-HR	0.54	0.38	0.60	2.12	4.36
TOTAL HC		G/HP-HR	0.15	0.23	0.34	0.49	1.08
PART MATTER		G/HP-HR	0.04	0.05	0.08	0.31	0.49
TOTAL NOX (AS NO2)		LB/HR	42.10	22.52	12.78	9.30	6.46
TOTAL CO		LB/HR	3.45	1.87	2.00	3.91	3.95
TOTAL HC		LB/HR	0.93	1.13	1.13	0.90	0.98
PART MATTER		LB/HR	0.23	0.22	0.27	0.57	0.45

RATED SPEED NOMINAL DATA: 1800 RPM

GENSET POWER WITH FAN		EKW	2,000.0	1,500.0	1,000.0	500.0	200.0
ENGINE POWER		**BHP**	**2,937**	**2,212**	**1,521**	**839**	**411**
PERCENT LOAD		**%**	**100**	**75**	**50**	**25**	**10**
TOTAL NOX (AS NO2)		G/HR	15,915	8,511	4,832	3,515	2,443
TOTAL CO		G/HR	869	471	503	984	997
TOTAL HC		G/HR	318	385	385	308	333
TOTAL CO2		KG/HR	1,383	1,068	762	430	250
PART MATTER		G/HR	73.7	71.1	88.5	183.4	145.1
TOTAL NOX (AS NO2)	(CORR 5% O2)	MG/NM3	2,749.5	1,933.4	1,544.0	1,982.8	2,379.8
TOTAL CO	(CORR 5% O2)	MG/NM3	142.8	100.6	154.2	498.0	953.2
TOTAL HC	(CORR 5% O2)	MG/NM3	45.2	70.4	99.3	146.0	285.3
PART MATTER	(CORR 5% O2)	MG/NM3	10.3	13.2	25.1	85.7	115.2
TOTAL NOX (AS NO2)	(CORR 5% O2)	PPM	1,339	942	752	966	1,159
TOTAL CO	(CORR 5% O2)	PPM	114	80	123	398	763
TOTAL HC	(CORR 5% O2)	PPM	84	131	185	273	533
TOTAL NOX (AS NO2)		G/HP-HR	5.45	3.87	3.19	4.20	5.94
TOTAL CO		G/HP-HR	0.30	0.21	0.33	1.18	2.42
TOTAL HC		G/HP-HR	0.11	0.18	0.25	0.37	0.81
PART MATTER		G/HP-HR	0.03	0.03	0.06	0.22	0.35
TOTAL NOX (AS NO2)		LB/HR	35.09	18.76	10.65	7.75	5.39
TOTAL CO		LB/HR	1.92	1.04	1.11	2.17	2.20
TOTAL HC		LB/HR	0.70	0.85	0.85	0.68	0.73
TOTAL CO2		LB/HR	3,049	2,356	1,681	947	551
PART MATTER		LB/HR	0.16	0.16	0.20	0.40	0.32
OXYGEN IN EXH		%	10.8	12.3	13.3	14.2	15.8
DRY SMOKE OPACITY		%	0.3	0.5	1.2	3.7	3.0
BOSCH SMOKE NUMBER			0.15	0.21	0.43	1.25	1.12

MIT CUP Second Century Upgrade Project
Black Start Load List

Equip Tag No.	Location	Description	Electrical								
			Stand-by Equip.	Power HP	Power kW	Volts	Hz	VFD	FULL LOAD AMPS (NORMAL OPS)	CONNECTED kVA (NORMAL OPS)	BLACK START / EMERG kVA
CTG-200			StandBy	HP	kW	Volts	Hz	VFD			
BC-201	B42C-LV-03	Battery Charger	N	-	5.5	120	60	N			
D-201	B42C-LV-03	Generator Ventilation Air Damper	N	-	0.1	120	60	N			
FN-201	B42C-LV-03	CTG Supply Ventilation Air Fan	N	75	56.0	480	60	N	96	79.8	79.8
FN-202	B42C-LV-03	CTG Supply Ventilation Air Fan	Y	75	56.0	480	60	N	0	0.0	
FN-203	B42C-LV-03	CTG Exhaust Ventilation Air Fan	N	75	56.0	480	60	N	96	79.8	79.8
FN-204	B42C-LV-03	CTG Exhaust Ventilation Air Fan	Y	75	56.0	480	60	N	0	0.0	
GTSM-201	B42C-LV-03	Engine Starter Motor	N	200	149.2	480	60	Y	240	199.5	199.5
EC-201	B42C-LV-03	Engine On-line Water Wash Vessel	N	10	8.4	480	60	N	14	11.6	
WIP-201	B42C-LV-03	Water injection pump #1	N	5	4.2	480	60	N	7.6	6.3	6.3
-	B42C-LV-03	Starter Motor Space Heater	N	-	0.2	120	60	N			
LOP-201	B42C-LV-03	Backup Lube Oil pump	N	2.5	2.1	120	DC	N			
-	B42C-LV-03	Lube Oil heater	N	-	20.0	480	60	N	28.9	24.0	24.0
PLP-201	B42C-LV-03	Pre/Post Lube Oil pump	N	7.5	6.3	480	60	N	11	9.1	9.1
-	B42C-LV-03	Generator Space Heater	N	-	3.0	120	60	N			
JOP-201	B42C-LV-03	Jacking Oil pump	N	5	4.2	480	60	N	7.6	6.3	6.3
LFP-201	B42C-LV-03	Liquid Fuel Booster Pump 1	N	20	16.8	480	60	N	27	22.4	
-	B42C-LV-03	Enclosure Lights	N	-	1.0	120	60	N			
CTG-300			StandBy	HP	kW	Volts	Hz	VFD			
BC-301	B42C-LV-03	Battery Charger	N	-	5.5	120	60	N			
D-301	B42C-LV-03	Generator Venilation Air Damper/Actuator	N	-	0.1	120	60	N			
FN-301	B42C-LV-03	CTG Supply Ventilation Air Fan	N	75	56.0	480	60	N	96	79.8	
FN-302	B42C-LV-03	CTG Supply Ventilation Air Fan	Y	75	56.0	480	60	N	0	0.0	
FN-303	B42C-LV-03	CTG Exhaust Ventilation Air Fan	N	75	56.0	480	60	N	96	79.8	
FN-304	B42C-LV-03	CTG Exhaust Ventilation Air Fan	Y	75	56.0	480	60	N	0	0.0	
GTSM-301	B42C-LV-03	Engine Starter Motor	N	200	149.2	480	60	Y	0	0.0	
EC-301	B42C-LV-03	Engine On-line Water Wash Vessel	N	10	8.4	480	60	N	14	11.6	
WIP-301	B42C-LV-03	Water injection pump #1	N	5	4.2	480	60	N	7.6	6.3	
-	B42C-LV-03	Starter Motor Space Heater	N	-	0.2	120	60	N			
LOP-301	B42C-LV-03	Backup Lube Oil pump	N	2.5	2.1	120	DC	N			
-	B42C-LV-03	Lube Oil heater	N	-	20.0	480	60	N	28.9	24.0	
PLP-301	B42C-LV-03	Pre/Post Lube Oil pump	N	7.5	6.3	480	60	N	11	9.1	
-	B42C-LV-03	Generator Space Heater	N	-	3.0	120	60	N			
JOP-301	B42C-LV-03	Jacking Oil pump	N	5	4.2	480	60	N	7.6	6.3	
LFP-301	B42C-LV-03	Liquid Fuel Booster Pump 1	N	20	16.8	480	60	N	27	22.4	
-	B42C-LV-03	Enclosure Lights	N	-	1.0	-	-	N			
HRSG-200			StandBy	HP	kW	Volts	Hz	VFD			
PAF-201	B42C-LV-03	Purge Air Fan	N	20	16.8	480	60	N	27	22.4	22.4
CEMS-201	TBD	CEMS	N	-	x	120	60	N			
ED-203	B42C-LV-03	Flue Gas Exhaust Damper/Actuator	N	-	2.0	480	60	N	2.9	2.4	2.4
-	TBD	Control panel lighting	N	-	x	120	60	N			
HRSG-200 Fuel System			StandBy	HP	kW	Volts	Hz	VFD			
SAB-201	B42C-LV-03	Scanner Air Blower	N	3	2.5	480	60	N	4.8	4.0	
SAB-202	B42C-LV-03	Scanner Air Blower	Y	3	2.5	480	60	N	0	0.0	
HRSG-300			StandBy	HP	kW	Volts	Hz	VFD			
PAF-301	B42C-LV-03	Purge Air Fan	N	20	16.8	480	60	N	27	22.4	
CEMS-301	TBD	CEMS	N	-		-	-	N			
ED-303	B42C-LV-03	Flue Gas Exhaust Damper/Actuator	N	-	2.0	480	60	N	2.9	2.4	
-	TBD	Control panel lighting	N	-	x	120	60	N			
HRSG-300 Fuel System			StandBy	HP	kW	Volts	Hz	VFD			
SAB-301	B42C-LV-03	Scanner Air Blower	N	3	2.5	480	60	N	4.8	4.0	
SAB-302	B42C-LV-03	Scanner Air Blower	Y	3	2.5	480	60	N	0	0.0	
Steam System			StandBy	HP	kW	Volts	Hz	VFD			
Condensate System			StandBy	HP	kW	Volts	Hz	VFD			
Boiler Feedwater - Sheet 1			StandBy	HP	kW	Volts	Hz	VFD			
Treated Water			StandBy	HP	kW	Volts	Hz	VFD			
RO-100	B42C-LV-03	RO EDI Package 1	N	-	1.0	120	60	N			
ROP-101	B42C-LV-03	RO Booster Pump 1	N	2	1.7	480	60	N	3.4	2.8	
Urea			StandBy	HP	kW	Volts	Hz	VFD			
Steam Turbine			StandBy	HP	kW	Volts	Hz	VFD			
Process Cooling Water			StandBy	HP	kW	Volts	Hz	VFD			
PCP-001	B42C-LV-05	Process Cooling Water Pump	N	75	56.0	480	60	N	96	79.8	79.8
PCP-002	B42C-LV-05	Process Cooling Water Pump	N	75	56.0	480	60	N	96	79.8	
PCP-003	B42C-LV-05	Process Cooling Water Pump	Y	75	56.0	480	60	N	96	79.8	
Compressed Air			StandBy	HP	kW	Volts	Hz	VFD			
AC-105	B42C-LV-05	Air Compressor 1 - electric driven	N	250	186.5	480	60	Y	302	251.1	251.1
IAD-105	B42C-LV-05	Dessicant Air Dryer Package	N	-	6.0	460	60	N	8.7	7.2	
Chemical Feed			StandBy	HP	kW	Volts	Hz	VFD			
Blowdown & Steam Drips Sheet 1			StandBy	HP	kW	Volts	Hz	VFD			

MIT CUP Second Century Upgrade Project
Black Start Load List

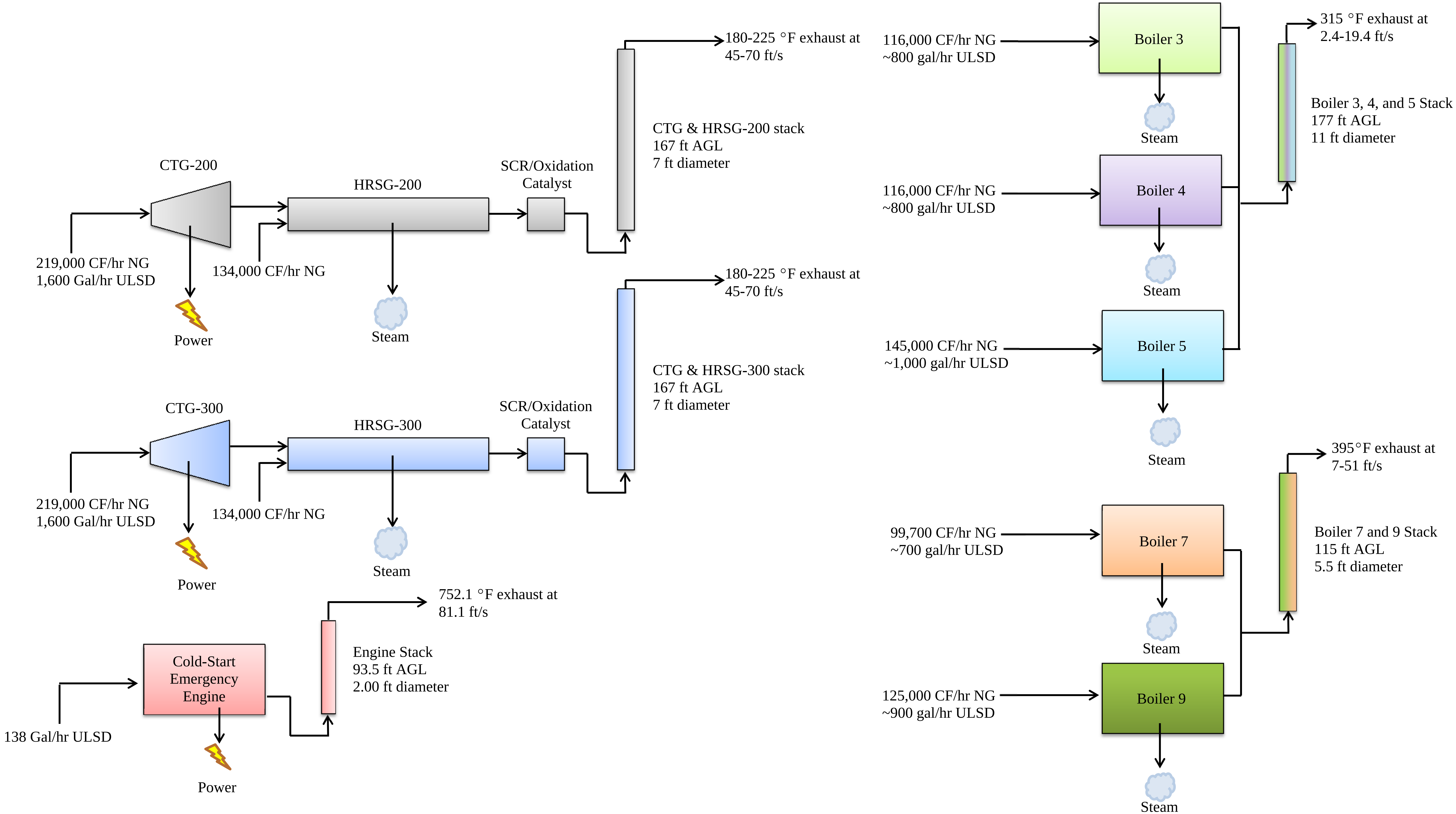
Equip Tag No.	Location	Description	Electrical								
			Stand-by Equip.	Power HP	Power kW	Volts	Hz	VFD	FULL LOAD AMPS (NORMAL OPS)	CONNECTED kVA (NORMAL OPS)	BLACK START / EMERG kVA
CRP-101	B42C-LV-03	Flashed Condensate Pump 1	N	10	8.4	480	60	N	14	11.6	11.6
CRP-102	B42C-LV-03	Flashed Condensate Pump 2	Y	10	8.4	480	60	N	0	0.0	
Fuel Gas			StandBy	HP	kW	Volts	Hz	VFD			
FGC-101	Roof	Fuel Gas Compressor - One Stage Two Turbines	N	350	261.1	480	60	Y	414	344.2	344.2
Water Sampling			StandBy	HP	kW	Volts	Hz	VFD			
Chilled Water			StandBy	HP	kW	Volts	Hz	VFD			
Glycol System			StandBy	HP	kW	Volts	Hz	VFD			
Hot Water System			StandBy	HP	kW	Volts	Hz	VFD			
HWP-101	TBD	HW Pump 1	N	15	12.6	480	60	Y	21	17.5	21
HWP-102	TBD	HW Pump 2	Y	15	12.6	480	60	Y	21	17.5	
STAND BY/BLACK START			StandBy	HP	kW	Volts	Hz	VFD			
DEG-	B42C-TBD	Starting motor	-	20	16.8	480	60	-	27	22.4	22.4
DEG-	B42C-TBD	Radiator fan no. 1	-	2	1.7	480	60	-	3.4	2.8	2.8
DEG-	B42C-TBD	Radiator fan no. 2	-	2	1.7	480	60	-	3.4	2.8	2.8
DEG-	B42C-TBD	Radiator fan no. 3	-	2	1.7	480	60	-	3.4	2.8	2.8
DEG-	B42C-TBD	Radiator fan no. 4	-	2	1.7	480	60	-	3.4	2.8	2.8
DEG-	B42C-TBD	Enclosure misc. power (lighting, heat etc.)	-	-	15.0	480	60	-	21.7	18.0	18.0
DEG-201	B42C-TBD	Enclosure control panel	-	-	0.5	120	60	-			
DEG-	B42C-TBD	Enclosure fire protection panel	-	-	0.5	120	60	-			
DEG-	B42C-TBD	Block heater (jacket water) and circ pump	-	-	12.0	480	60	-	17.3	14.4	14.4
DFOP-201	B42C-TBD	Fuel Oil Pump	-	0.75	0.6	-	-	-	1.6	1.3	1.3
DFOP-202	B42C-TBD	Fuel Oil Pump	-	0.75	0.6	-	-	-	1.6	1.3	1.3
DFOP-203	B42C-TBD	Fuel Oil Return Pump	-	0.5	0.4	-	-	-	1.1	0.9	0.9
DFOP-204	B42C-TBD	Fuel Oil Return Pump	-	0.5	0.4	-	-	-	1.1	0.9	0.9
Fuel Oil			StandBy	HP	kW	Volts	Hz	VFD			
FOS-100	B42C-LV-02	Fuel Oil Pump Skid - 1	N	-	0.5	120	60	-			
FOSP-101	B42C-LV-02	Fuel Oil Supply Pump 1	N	10	8.4	480	60	-	14	11.6	
FOSP-102	B42C-LV-02	Fuel Oil Supply Pump 2	Y	10	8.4	480	60	-	0	0.0	
FOT-100	B42- TBD	Fuel Oil Pump Skid - Transfer	N	-	0.5	120	60	-			
FOTP-101	B42- TBD	Fuel Oil Transfer Pump 1	N	20	16.8	480	60	-	27	22.4	
FOTP-102	B42- TBD	Fuel Oil Transfer Pump 2	Y	20	16.8	480	60	-	0	0.0	
Control System			StandBy	HP	kW	Volts	Hz	VFD			
HVAC			StandBy	HP	kW	Volts	Hz	VFD			
ERU-1		Offices Elev 18'-4" Mech Room (SF & EF)	N	2	1.6785	480	60	Y	6.8	5.7	
AHU-4		Control Room Area	N	7.5	6.294375	480	60	Y	11	9.1	9.1
AHU-5		Control Room Area	Y	7.5	6.294375	480	60	Y	0	0.0	
BCU-5		Substation & MCC Room #1	N	10	8.3925	480	60	Y	14	11.6	11.6
BCU-6		Substation & MCC Room #2	N	10	8.3925	480	60	Y	14	11.6	11.6
BCU-3		Cogen Electrical Room #1	N	0.5	0.419625	480	60	N	1.1	0.9	0.9
BCU-4		Cogen Electrical Room #2	N	0.5	0.419625	480	60	N	1.1	0.9	0.9
BCU-7		13GAC Bus Electrical Switchgear Room	N	1	0.83925	480	60	N	2.1	1.7	1.7
BCU-8		13GBD Bus Electrical Switchgear Room	N	1	0.83925	480	60	N	2.1	1.7	1.7
BCU-9		13C Bus Electrical Switchgear Room	N	1	0.83925	480	60	N	2.1	1.7	1.7
BCU-10		13D Bus Electrical Switchgear Room	N	1	0.83925	480	60	N	2.1	1.7	1.7
BCU-11		Rack Room 365	N	1	0.83925	480	60	N	2.1	1.7	1.7
BCU-12		Rack Room 365	Y	1	0.83925	480	60	N	2.1	1.7	
BCU-13		Main Reception 106	N	1	0.83925	480	60	N	2.1	1.7	
BCU-14		Multipurpose Room 110	N	1	0.83925	480	60	N	2.1	1.7	
BCU-15		Office Suite 120	N	0.5	0.419625	480	60	N	1.1	0.9	
BCU-16		Office 131, 133, 135	N	0.5	0.419625	480	60	N	1.1	0.9	
BCU-17		Print/File Room 136	N	0.5	0.419625	480	60	N	1.1	0.9	
BCU-18		Electrical Workshop 139	N	1	0.83925	480	60	N	2.1	1.7	
BCU-19		Corridor A 100C	N	1	0.83925	480	60	N	2.1	1.7	
UH-9		42C Receiving/Unloading Area (Steam UH)	N	0.33	0.276953	120	60	N			
UH-10		42C Receiving/Unloading Area (Steam UH)	N	0.33	0.276953	120	60	N			
SF-5		Fuel Oil Tank Room	N	5	4.19625	480	60	Y	7.6	6.3	6.3
SF-6		Receiving/Unloading Area	N	0.75	0.629438	480	60	Y	1.6	1.3	
SF-7		Cogen Plant Room	N	25	20.98125	480	60	Y	34	28.3	28.3
SF-8		Cogen Plant Room	N	25	20.98125	480	60	Y	34	28.3	28.3
SF-9		Cogen Plant Room	N	25	20.98125	480	60	Y	34	28.3	28.3
SF-10		Cogen Plant Room	N	25	20.98125	480	60	Y	34	28.3	28.3
SF-11		Cogen Plant Room	N	25	20.98125	480	60	Y	34	28.3	28.3
SF-12		Cogen Plant Room	N	25	20.98125	480	60	Y	34	28.3	28.3
SF-13B		Battery Room #2	N	0.5	0.419625	480	60	N	1.1	0.9	0.9
SF-14		Electrical Switchgear Rooms	N	1.5	1.258875	480	60	Y	3	2.5	2.5
RF-1		AHU-4 & AHU-5	N	3	2.51775	480	60	Y	4.8	4.0	4.0
EF-3		Fuel Oil Tank Room	N	5	4.19625	480	60	Y	7.6	6.3	6.3
EF-4		Receiving/Unloading Area	N	0.75	0.629438	480	60	Y	1.6	1.3	
EF-5B		Battery Room #2	N	0.5	0.419625	480	60	N	1.1	0.9	0.9

MIT CUP Second Century Upgrade Project
Black Start Load List

Equip Tag No.	Location	Description	**Electrical**								
			Stand-by Equip.	Power HP	Power kW	Volts	Hz	VFD	FULL LOAD AMPS (NORMAL OPS)	CONNECTED kVA (NORMAL OPS)	BLACK START / EMERG kVA
EF-6		Electrical Switchgear Rooms	N	1.5	1.258875	480	60	Y	3	2.5	2.5
EF-13		Cogen Plant Exhaust	N	15	12.58875	480	60	Y	21	17.5	17.5
EF-14		Cogen Plant Exhaust	N	15	12.58875	480	60	Y	21	17.5	17.5
EF-15		Cogen Plant Exhaust	N	15	12.58875	480	60	Y	21	17.5	17.5
EF-8		Cogen Plant Exhaust	N	15	12.58875	480	60	Y	21	17.5	17.5
EF-9		Cogen Plant Exhaust	N	15	12.58875	480	60	Y	21	17.5	17.5
EF-10		Cogen Plant Exhaust	N	15	12.58875	480	60	Y	21	17.5	17.5
EF-11		Cogen Plant Exhaust	N	15	12.58875	480	60	Y	21	17.5	17.5
EF-12		Cogen Plant Exhaust	N	15	12.58875	480	60	Y	21	17.5	17.5
TF-1		Toilet Exhaust elev 18'-4"	N	0.18	0.151065	115	60	N			
PFP			StandBy	HP	kW	Volts	Hz	VFD			
Fire Protection											
Plumbing											
Electrical Equip											
		General Bldg Lighting	N	--	150.0	277	60		348	167.0	167
									3762.8	3006.0	1750.9
									AMPS	**kVA**	**kVA**
										480V SUB(s)	DIESEL GEN

Appendix B – Part 3

Process Flow Diagram


CTG-200
219,000 CF/hr NG
1,600 Gal/hr ULSD
134,000 CF/hr NG
HRSG-200
SCR/Oxidation Catalyst
Power
Steam
180-225 °F exhaust at 45-70 ft/s
CTG & HRSG-200 stack
167 ft AGL
7 ft diameter
CTG-300
219,000 CF/hr NG
1,600 Gal/hr ULSD
134,000 CF/hr NG
HRSG-300
SCR/Oxidation Catalyst
Power
Steam
180-225 °F exhaust at 45-70 ft/s
CTG & HRSG-300 stack
167 ft AGL
7 ft diameter
Cold-Start Emergency Engine
138 Gal/hr ULSD
Power
752.1 °F exhaust at 81.1 ft/s
Engine Stack
93.5 ft AGL
2.00 ft diameter
116,000 CF/hr NG
~800 gal/hr ULSD
Boiler 3
Steam
116,000 CF/hr NG
~800 gal/hr ULSD
Boiler 4
Steam
145,000 CF/hr NG
~1,000 gal/hr ULSD
Boiler 5
Steam
315 °F exhaust at 2.4-19.4 ft/s
Boiler 3, 4, and 5 Stack
177 ft AGL
11 ft diameter
99,700 CF/hr NG
~700 gal/hr ULSD
Boiler 7
Steam
125,000 CF/hr NG
~900 gal/hr ULSD
Boiler 9
Steam
395°F exhaust at 7-51 ft/s
Boiler 7 and 9 Stack
115 ft AGL
5.5 ft diameter

Appendix B – Part 4

RBLC Lookup Printouts

- Signal Hills Wichita Falls Power LP
- Maui Electric Company Maalaea Generating Station
- Lenzing Fibers, Inc.
- CARB lookup for Los Angeles County Sanitation District

Pollutant Information

Click on the Process Information button to see more information about the process associated with this pollutant.
Or click on the Process List button to return to the list of processes.

FINAL

RBLC ID: TX-0498
Corporate/Company: SIGNAL HILLS
Facility Name: SIGNAL HILLS WICHITA FALLS POWER LP
Process: TURBINES (3)

Pollutant: Particulate Matter (PM) **CAS Number:** PM

Pollutant Group(s): Particulate Matter (PM), **Substance Registry System:** Particulate Matter (PM)

Pollution Prevention/**A**dd-on Control Equipment/**B**oth/**N**o Controls Feasible: N
P2/Add-on Description:

Test Method: Unspecified EPA/OAR Methods All Other Methods

Percent Efficiency:	0
Compliance Verified:	Unknown
EMISSION LIMITS:	
Case-by-Case Basis:	BACT-PSD
Other Applicable Requirements:	
Other Factors Influence Decision:	Unknown
Emission Limit 1:	1.0400 LB/H
Emission Limit 2:	4.5700 T/YR
Standard Emission Limit:	0
COST DATA:	
Cost Verified?	No
Dollar Year Used in Cost Estimates:	
Cost Effectiveness:	0 $/ton
Incremental Cost Effectiveness:	0 $/ton
Pollutant Notes:	

This document will now print as it appears on screen when you use the File » Print command.
Use View » Refresh to return to original state.

Pollutant Information

Click on the Process Information button to see more information about the process associated with this pollutant.
Or click on the Process List button to return to the list of processes.

RBLC Home | New Search | Search Results | Facility Information | Process List | Process Information | Pollutant Information

Help

FINAL

RBLC ID: HI-0021
Corporate/Company: MAUI ELECTRIC COMPANY, LTD.
Facility Name: MAALAEA GENERATING STATION
Process: COMBUSTION TURBINE, COMBINED CYCLE (2)

Pollutant: Particulate Matter (PM) **CAS Number:** PM

Pollutant Group(s): Particulate Matter (PM), **Substance Registry System:** Particulate Matter (PM)

Pollution Prevention/**A**dd-on Control Equipment/**B**oth/**N**o Controls Feasible: P

P2/Add-on Description: GOOD COMBUSTION DESIGN AND OPERATION.

Test Method: Unspecified EPA/OAR Methods All Other Methods

Percent Efficiency:	0
Compliance Verified:	Unknown
EMISSION LIMITS:	
Case-by-Case Basis:	BACT-PSD
Other Applicable Requirements:	
Other Factors Influence Decision:	Unknown
Emission Limit 1:	0.0450 GR/DSCF @ 12% CO2 3 HR AVERAGE
Emission Limit 2:	19.7000 LB/H 3 HR AVERAGE
Standard Emission Limit:	0
COST DATA:	
Cost Verified?	No
Dollar Year Used in Cost Estimates:	2005
Cost Effectiveness:	0 $/ton
Incremental Cost Effectiveness:	0 $/ton
Pollutant Notes:	

Pollutant Information

Click on the Process Information button to see more information about the process associated with this pollutant.
Or click on the Process List button to return to the list of processes.

FINAL

RBLC ID: AL-0282
Corporate/Company: LENZING FIBERS, INC.
Facility Name: LENZING FIBERS, INC.
Process: Gas Turbine with HRSG

Pollutant: Particulate matter, filterable (FPM)
CAS Number: PM

Pollutant Group(s): Particulate Matter (PM),
Substance Registry System: Particulate matter, filterable (FPM)

Pollution Prevention/**A**dd-on Control Equipment/**B**oth/**N**o Controls Feasible: P
P2/Add-on Description: Good combustion practices.

Test Method: EPA/OAR Mthd 5 (EPA/OAR Methods | All Other Methods)

Percent Efficiency:	0
Compliance Verified:	Unknown
EMISSION LIMITS:	
Case-by-Case Basis:	BACT-PSD
Other Applicable Requirements:	OPERATING PERMIT
Other Factors Influence Decision:	Unknown
Emission Limit 1:	0.0075 LB/MMBTU
Emission Limit 2:	0
Standard Emission Limit:	0
COST DATA:	
Cost Verified?	No
Dollar Year Used in Cost Estimates:	
Cost Effectiveness:	0 $/ton
Incremental Cost Effectiveness:	0 $/ton
Pollutant Notes:	

California Environmental Protection Agency
Air Resources Board

BACT Determination Detail

Category

Source Category:	Gas Turbine: Combined Cycle < 50 MW
SIC Code	4952
NAICS Code	22132

Emission Unit Information

Manufacturer:	Solar
Type:	Combined Cycle
Model:	MARS 90 13000
Equipment Description:	
Capacity / Dimentions	9.9 MW
Fuel Type	Landfill Gas
Multiple Fuel Types	
Operating Schedule (hours/day)/(days/week)/(weeks/year)e	Continuous (24/7/52)
Function of Equipment	

Bact Information

NOx Limit	25
NOx Limit Units	ppmvd@15%O2
NOx Average Time	
NOx Control Method	Add-on
NOx Control Method Desc	water injection
NOx Percent Control Efficiency	
NOx Cost Effectiveness (%/ton)	
NOx Incremental Cost Effectiveness (%/ton)	
NOx Cost Verified (Y/N)	
NOx Dollar Year	

CO Limit	60
CO Limit Units	ppmvd@15%O2
CO Average Time	
CO Control Method	
CO Control Method Desc	
CO Percent Control Efficiency	
CO Cost Effectiveness (%/ton)	
CO Incremental Cost Effectiveness (%/ton)	

CO Cost Verified (Y/N)	
CO Dollar Year	

VOC Limit	4.5
VOC Limit Units	lb/hr as ROG
VOC Average Time	
VOC Control Method	
VOC Control Method Desc	
VOC Percent Control Efficiency	
VOC Cost Effectiveness (%/ton)	
VOC Incremental Cost Effectiveness (%/ton)	
VOC Cost Verified (Y/N)	
VOC Dollar Year	
PM Limit	5.7
PM Limit Units	lb/hr
PM Average Time	
PM Control Method	
PM Control Method Desc	
PM Percent Control Efficiency	
PM Cost Effectiveness (%/ton)	
PM Incremental Cost Effectiveness (%/ton)	

PM Cost Verified (Y/N)	
PM Dollar Year	

SOx Limit	**1.3**
SOx Limit Units	**lb/hr**
SOx Average Time	
SOx Control Method	
SOx Control Method Desc	
SOx Percent Control Efficiency	
SOx Cost Effectiveness (%/ton)	
SOx Incremental Cost Effectiveness (%/ton)	
SOx Cost Verified (Y/N)	
SOx Dollar Year	

Project / Permit Information

Application/Permit No.:	358625
Application Completeness Date:	
New Construction/Modification:	Modification
ATC Date:	07-25-2000
PTO Date:	
Startup Date:	03-31-2002
Technology Status:	BACT Determination

Source Test Available:	Yes
Source Test Results:	

Facility / District Information

Facility Name:	Los Angeles County Sanitation District
Facility Zip Code:	
Facility County:	Los Angeles
District Name:	South Coast AQMD
District Contact:	Martin Kay
Contact Phone No.:	909-396-3115
Contact E-Mail:	mkay@aqmd.gov

Notes

Notes:

Report Error In Determination

Appendix B – Part 5

NOx Tracking Sheet

Massachusetts Institute of Technology's 5 Year Rolling NO_x Emissions Increases/Decreases Summary[(1)] 2015-2019 Last Updated 20/25/16							
Emission Unit[(2)]	**Year Installed**	**Rated Heat Input (mmBtu/hr)**	**Current Allowable Operation per Rolling Twelve Month Calendar Period (Hours)**	**NO_x Emission Factor**		**NO_x PTE per Rolling Twelve Month Calendar Period (tons)[(3)]**	**Actual NO_x Emissions per Rolling Twelve Month Calendar Period (tons)[(3)]**
NGH-E52	2015	1.50	8760	100	lb/10^6 SCF	N/A	0.066
NGH-NW35	2015	2.10	8760	0.0	lb/MMBTU	N/A	0.000
NGH-NW23	2015	2.00	8760	0.02	lb/MMBTU	N/A	0.000
NGH-W8	2015	0.40	8760	100	lb/10^6 SCF	N/A	0.018
NGH-W86	2016	16.40	8760	100.000	lb/10^6 SCF	N/A	0.718
DG-31	2016	7.41	300	2.245	lb/MMBTU	N/A	0.250
DG-W84/W85	2016	5.12	300	1.948	lb/10^6 SCF	N/A	0.150
NGH-WW15	2016	0.25	8760	100.00	lb/10^6 SCF	N/A	0.011
NGH-W97	2016	1.00	8760	0.02	lb/MMBTU	N/A	0.011
NGH-NW30	2016	3.00	8760	0.02	lb/MMBTU	N/A	0.032
NGH-N51/N52	2017	1.00	8760	0.02	lb/MMBTU	0.105	N/A
DG-12	2018	14.64	300	1.36	lb/MMBTU	2.976	N/A
DG-E53	2018	3.10	300	1.95	lb/MMBTU	0.906	N/A
DG-42-2	2019	19.18	300	1.36	lb/MMBTU	3.898	N/A
CT-42-200	2019	353 (219 + 134)	8760	N/A	lb/10^6 SCF	5.275	N/A
CT-42-300	2019	353 (219 + 134)	8760	N/A	lb/10^6 SCF	5.275	N/A
DG-NW14	2019	5.1	300	1.95	lb/MMBTU	1.496	N/A
DG-300bed dorm	2019	5.1	300	1.95	lb/MMBTU	1.496	N/A
					2015-2019 Total NO_x Tons Added	**21.428**	**1.254**
Emission Unit	**Year Removed**	not applicable					**NO_x emission reduction**
						2015-2019 Total NO_x Tons Removed	**0.000**
						5 YEAR NET NO_x EMISSIONS, CALENDAR YEARS 2015-2019 INCLUSIVE:	**22.682**

(1) Any net NO_x emissions increase occurring over a period of five consecutive calendar years that equates to 25 or more tons of NO_x shall become subject to the requirements of 310 CMR 7.00: Appendix A.

(3) The actual NO_x emissions equate to the average of the two most recent complete calendar years of representative actual NO_x emissions data when available. NO_x potential emissions are used if two complete calendar years of representative actual NO_x emissions data are not available.

*Note that these values are based on future fuel usage estimates

Massachusetts Institute of Technology's 5 Year Rolling NO_x Emissions Increases/Decreases Summary[1] 2016-2020 Last Updated 10/26/16							
Emission Unit[2]	Year Installed	Rated Heat Input (mmBtu/hr)	Current Allowable Operation per Rolling Twelve Month Calendar Period (Hours)	NO_x Emission Factor		NO_x PTE per Rolling Twelve Month Calendar Period (tons)[3]	Actual NO_x Emissions per Rolling Twelve Month Calendar Period (tons)[3]
NGH-W86	2016	16.40	8760	100	lb/10^6 SCF	N/A	0.718
DG-31	2016	7.41	300	2.2	lb/MMBTU	N/A	0.250
DG-W84/W85	2016	5.12	300	1.95	lb/10^6 SCF	N/A	0.150
NGH-WW15	2016	0.25	8760	100	lb/10^6 SCF	N/A	0.011
NGH-W97	2016	1.00	8760	0.024	lb/MMBTU	N/A	0.011
NGH-NW30	2016	3.00	8760	0.024	lb/MMBTU	N/A	0.032
NGH-N51/N52	2017	1.00	8760	0.024	lb/MMBTU	0.105	N/A
DG-12	2018	14.64	300	1.36	lb/MMBTU	2.976	N/A
DG-E53	2018	3.10	300	1.95	lb/MMBTU	0.906	N/A
DG-42-2	2019	19.18	300	1.36	lb/MMBTU	3.898	N/A
CT-42-200	2019	353 (219 + 134)	8760	N/A	lb/10^6 SCF	5.275	N/A
CT-42-300	2019	353 (219 + 134)	8760	N/A	lb/10^6 SCF	5.275	N/A
DG-NW14	2019	5.12	300	1.95	lb/MMBTU	1.496	N/A
DG-300bed dorm	2019	5.12	300	1.95	lb/MMBTU	1.496	N/A
CT-42-200	2020	353 (219 + 134)	8760	N/A	lb/10^6 SCF	5.275	N/A
CT-42-300	2020	353 (219 + 134)	8760	N/A	lb/10^6 SCF	5.275	N/A
DG-(new 600 bed)	2020	7.5	300	1.95	lb/MMBTU	2.192	N/A
DG-26	2020	6.0	300	1.95	lb/MMBTU	1.753	N/A
DG-(site 4)-1	2020	5.0	300	1.95	lb/MMBTU	1.461	N/A
DG-(site 4)-2	2020	5.0	300	1.95	lb/MMBTU	1.461	N/A
DG-(site 4)-3	2020	5.0	300	1.95	lb/MMBTU	1.461	N/A
DG-(site 4)-4	2020	5.0	300	1.95	lb/MMBTU	1.461	N/A
DG-54	2020	5.0	300	1.95	lb/MMBTU	1.461	N/A
DG-W51	2020	3.5	300	1.95	lb/MMBTU	1.023	N/A
DG-W15	2020	3.0	300	1.95	lb/MMBTU	0.877	N/A
DG-MET	2020	2.5	300	1.95	lb/MMBTU	0.731	N/A
DG-Music	2020	2.5	300	1.95	lb/MMBTU	0.731	N/A
DG-W71	2020	2.0	300	1.95	lb/MMBTU	0.584	N/A
DG-E2	2020	1.0	300	1.95	lb/MMBTU	0.292	N/A
					2016-2020 Total NO_x Tons Added	**47.466**	**1.170**
Emission Unit	**Year Removed**	not applicable					**NO_x emission reduction**
CT-42-1	2020						(42.000)
						2015-2019 Total NO_x Tons Removed	**(42.000)**
						5 YEAR NET NO_x EMISSIONS, CALENDAR YEARS 2016-2020 INCLUSIVE:	**6.636**

(1) Any net NO_x emissions increase occurring over a period of five consecutive calendar years that equates to 25 or more tons of NO_x shall become subject to the requirements of 310 CMR 7.00: Appendix A.

(3) The actual NO_x emissions equate to the average of the two most recent complete calendar years of representative actual NO_x emissions data when available. NO_x potential emissions are used if two complete calendar years of representative actual NO_x emissions data are not available.

*Note that these values are based on future fuel usage estimates

Appendix C

Supporting Calculations

Table C-1: MIT turbine & duct burner model cases per turbine

Operating Scenario I - Single New Turbine and Single Old Turbine

Relevant Sample Caclulations (located at end of Appendix C): C-1, C-2, C-3, C-4, & C-5

Epsilon 8/2016 with RGV input data from Solar and Deltak 02/2016

Epsilon Case No.	1	2	3	4	5	6	7	8	9	10	11	12	13	14
Ambient Temp (F)	50	0	60	0	60	0	60	0	60	0	60	0	60	0
% Load	100	100	75	75	50	50	40	40	100	100	75	75	65	65
Turbine Fuel	NG	NG	NG	NG	NG	NG	NG	NG	ULSD	ULSD	ULSD	ULSD	ULSD	ULSD
Duct Burner Fuel	NG	NG	NG	NG	OFF	OFF	OFF	OFF	NG	NG	NG	NG	OFF	OFF
Turbine Fuel Input (MMBtu/hr, LHV)	197.79	202.01	155.95	161.61	121.83	125.39	108.81	110.85	198.91	215.10	162.68	171.97	148.43	156.35
Duct Burner Fuel Input (MMBtu/hr, LHV)	112.4	120.5	106	135.2	0	0	0	0	113.9	122.3	107.3	136.6	0.0	0.0
Turbine Fuel Input (MMBtu/hr, HHV)	219.01	223.69	172.68	178.95	134.90	138.84	120.49	122.74	212.04	229.30	173.42	183.32	158.23	166.67
Duct Burner Fuel Input (MMBtu/hr, HHV)	124.46	133.43	117.37	149.71	0.00	0.00	0.00	0.00	126.12	135.42	118.81	151.26	0.00	0.00
CTG Exhaust Temp. (F)	858	761	836	697	824	684	820	681	848	748	822	687	818	679
Stack Exit Temp. (F)	180	180	180	180	180	180	180	180	225	225	225	225	225	225
CTG outlet Flow Rate (ft3/min)	307,178	308,161	263,390	267,889	224,135	225,408	209,832	210,552	310,536	321,675	271,978	279,660	253,558	259,813
Stack Flow Rate (ft3/min)	149,161	161,526	130,069	148,184	111,718	126,102	104,916	118,101	162,628	182,407	145,324	167,016	135,906	156,253
Turbines operating	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Stack Emissions - Turbine Contribution														
CO	2 ppm	2 ppm	5 ppm	5 ppm	5 ppm	5 ppm	5 ppm	5 ppm	7 ppm	7 ppm	7 ppm	7 ppm	7 ppm	7 ppm
NOx	2 ppm	2 ppm	3.2 ppm	3.2 ppm	3.2 ppm	3.2 ppm	3.2 ppm	3.2 ppm	9 ppm	9 ppm	9 ppm	9 ppm	9 ppm	9 ppm
PM	0.02 lb/MMBtu	0.02 lb/MMBtu	0.02 lb/MMBtu	0.02 lb/MMBtu	0.02 lb/MMBtu	0.02 lb/MMBtu	0.02 lb/MMBtu	0.02 lb/MMBtu	0.04 lb/MMBtu	0.04 lb/MMBtu	0.04 lb/MMBtu	0.04 lb/MMBtu	0.04 lb/MMBtu	0.04 lb/MMBtu
SO2	1 grain/ 100 SCF	1 grain/ 100 SCF	1 grain/ 100 SCF	1 grain/ 100 SCF	1 grain/ 100 SCF	1 grain/ 100 SCF	1 grain/ 100 SCF	1 grain/ 100 SCF	15 ppmw	15 ppmw	15 ppmw	15 ppmw	15 ppmw	15 ppmw
Stack Emissions - Duct Burner Contribution														
CO	0.011 lb/MMBtu	0.011 lb/MMBtu	0.011 lb/MMBtu	0.011 lb/MMBtu	0.011 lb/MMBtu	0.011 lb/MMBtu	0.011 lb/MMBtu	0.011 lb/MMBtu	0.011 lb/MMBtu	0.011 lb/MMBtu	0.011 lb/MMBtu	0.011 lb/MMBtu	0.011 lb/MMBtu	0.011 lb/MMBtu
NOx	0.011 lb/MMBtu	0.011 lb/MMBtu	0.011 lb/MMBtu	0.011 lb/MMBtu	0.011 lb/MMBtu	0.011 lb/MMBtu	0.011 lb/MMBtu	0.011 lb/MMBtu	0.011 lb/MMBtu	0.011 lb/MMBtu	0.011 lb/MMBtu	0.011 lb/MMBtu	0.011 lb/MMBtu	0.011 lb/MMBtu
PM	0.02 lb/MMBtu	0.02 lb/MMBtu	0.02 lb/MMBtu	0.02 lb/MMBtu	0.02 lb/MMBtu	0.02 lb/MMBtu	0.02 lb/MMBtu	0.02 lb/MMBtu	0.02 lb/MMBtu	0.02 lb/MMBtu	0.02 lb/MMBtu	0.02 lb/MMBtu	0.02 lb/MMBtu	0.02 lb/MMBtu
SO2	1 grain/ 100 SCF	1 grain/ 100 SCF	1 grain/ 100 SCF	1 grain/ 100 SCF	1 grain/ 100 SCF	1 grain/ 100 SCF	1 grain/ 100 SCF	1 grain/ 100 SCF	15 ppmw	15 ppmw	15 ppmw	15 ppmw	15 ppmw	15 ppmw
Stack Emissions - Turbine Contribution														
CO (lb/hr)	0.98	1.00	1.94	2.01	1.51	1.56	1.35	1.38	3.51	3.80	2.87	3.04	2.62	2.76
Nox (lb/hr)	1.61	1.65	2.04	2.11	1.59	1.64	1.42	1.45	7.42	8.02	6.07	6.41	5.54	5.83
PM (lb/hr)	4.38	4.47	3.45	3.58	2.70	2.78	2.41	2.45	8.48	9.17	6.94	7.33	6.33	6.67
SO2 (lb/hr)	6.26E-01	6.39E-01	4.93E-01	5.11E-01	3.85E-01	3.97E-01	3.44E-01	3.51E-01	3.30E-01	3.56E-01	2.70E-01	2.85E-01	2.46E-01	2.59E-01
Stack Emissions - Duct Burner Contribution														
CO (lb/hr)	1.37	1.47	1.29	1.65	0.00	0.00	0.00	0.00	1.39	1.49	1.31	1.66	0.00	0.00
Nox (lb/hr)	1.37	1.47	1.29	1.65	0.00	0.00	0.00	0.00	1.39	1.49	1.31	1.66	0.00	0.00
PM (lb/hr)	2.49	2.67	2.35	2.99	0.00	0.00	0.00	0.00	2.52	2.71	2.38	3.03	0.00	0.00
SO2 (lb/hr)	0.36	0.38	0.34	0.43	0.00	0.00	0.00	0.00	1.96E-01	2.11E-01	1.85E-01	2.35E-01	0.00E+00	0.00E+00
Stack Emissions - Total														
CO (lb/hr)	2.35	2.47	3.23	3.65	1.51	1.56	1.35	1.38	4.90	5.29	4.18	4.70	2.62	2.76
Nox (lb/hr)	2.98	3.12	3.33	3.76	1.59	1.64	1.42	1.45	8.81	9.51	7.37	8.08	5.54	5.83
PM (lb/hr)	6.87	7.14	5.80	6.57	2.70	2.78	2.41	2.45	11.00	11.88	9.31	10.36	6.33	6.67
SO2 (lb/hr)	0.98	1.02	0.83	0.94	0.39	0.40	0.34	0.35	0.53	0.57	0.45	0.52	0.25	0.26
Stack Characteristics														
Effective Stack Diameter (ft)	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0
Area (ft2)	38.5	38.5	38.5	38.5	38.5	38.5	38.5	38.5	38.5	38.5	38.5	38.5	38.5	38.5
Exit Velocity (ft/sec)	64.6	70.0	56.3	64.2	48.4	54.6	45.4	51.1	70.4	79.0	62.9	72.3	58.9	67.7
Exit Velocity (m/sec)	19.7	21.3	17.2	19.6	14.7	16.6	13.8	15.6	21.5	24.1	19.2	22.0	17.9	20.6

Table C-2: MIT turbine & duct burner model cases per turbine

Operating Scenario II - Both New Turbines

Relevant Sample Caclulations (located at end of Appendix C): C-1, C-2, C-3, C-4, C-5, & C-6

Epsilon 8/2016 with RGV input data from Solar and Deltak 02/2016

Epsilon Case Number	2.a	2.b	2.c	2.d	2.e	2.f	2.g	2.h	2.i	2.j	2.k	2.l	2.m	2.n
Ambient Temp (F)	50	0	60	0	60	0	60	0	60	0	60	0	60	0
% Load	100	100	75	75	50	50	40	40	100	100	75	75	65	65
Turbine Fuel	NG	NG	NG	NG	NG	NG	NG	NG	ULSD	ULSD	ULSD	ULSD	ULSD	ULSD
Duct Burner Fuel	NG	NG	NG	NG	OFF	OFF	OFF	OFF	NG	NG	NG	NG	OFF	OFF
Turbine Fuel Input (MMBtu/hr, LHV)	197.79	202.01	155.95	161.61	121.83	125.39	108.81	110.85	198.91	215.1	162.68	171.97	148.43	156.35
Duct Burner Fuel Input (MMBtu/hr, LHV)	112.4	120.5	106	135.2	0	0	0	0	113.9	122.3	107.3	136.6	0	0
Turbine Fuel Input (MMBtu/hr, HHV)	219.0	223.7	172.7	179.0	134.9	138.8	120.5	122.7	212.0	229.3	173.4	183.3	158.2	166.7
Duct Burner Fuel Input (MMBtu/hr, HHV)	124.5	133.4	117.4	149.7	0.0	0.0	0.0	0.0	126.1	135.4	118.8	151.3	0.0	0.0
Stack Exit Temp. (F)	180.0	180.0	180.0	180.0	180.0	180.0	180.0	180.0	225.0	225.0	225.0	225.0	225.0	225.0
Stack Flow Rate (ft3/min) (both turbines)	298,321.6	323,051.7	219,591.2	228,912.3	193,872.0	201,542.0	223,436.8	252,204.8	189,949.0	209,832.0	236,202.1	269,110.2	284,584.4	325,255.6
Turbines operating	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0
Stack Emissions - Turbine Contribution (per Turbine)														
CO	2 ppm	2 ppm	5 ppm	5 ppm	5 ppm	5 ppm	5 ppm	5 ppm	7 ppm	7 ppm	7 ppm	7 ppm	7 ppm	7 ppm
NOx	2 ppm	2 ppm	3.2 ppm	3.2 ppm	3.2 ppm	3.2 ppm	3.2 ppm	3.2 ppm	9 ppm	9 ppm	9 ppm	9 ppm	9 ppm	9 ppm
PM	0.02 lb/MMBtu	0.02 lb/MMBtu	0.02 lb/MMBtu	0.02 lb/MMBtu	0.02 lb/MMBtu	0.02 lb/MMBtu	0.02 lb/MMBtu	0.02 lb/MMBtu	0.04 lb/MMBtu	0.04 lb/MMBtu	0.04 lb/MMBtu	0.04 lb/MMBtu	0.04 lb/MMBtu	0.04 lb/MMBtu
SO2	1 grain/ 100 SCF	1 grain/ 100 SCF	1 grain/ 100 SCF	1 grain/ 100 SCF	1 grain/ 100 SCF	1 grain/ 100 SCF	1 grain/ 100 SCF	1 grain/ 100 SCF	15 ppmw	15 ppmw	15 ppmw	15 ppmw	15 ppmw	15 ppmw
Stack Emissions - Duct Burner Contribution (per duct Burner)														
CO	0.011 lb/MMBtu	0.011 lb/MMBtu	0.011 lb/MMBtu	0.011 lb/MMBtu	0.011 lb/MMBtu	0.011 lb/MMBtu	0.011 lb/MMBtu	0.011 lb/MMBtu	0.011 lb/MMBtu	0.011 lb/MMBtu	0.011 lb/MMBtu	0.011 lb/MMBtu	0.011 lb/MMBtu	0.011 lb/MMBtu
NOx	0.011 lb/MMBtu	0.011 lb/MMBtu	0.011 lb/MMBtu	0.011 lb/MMBtu	0.011 lb/MMBtu	0.011 lb/MMBtu	0.011 lb/MMBtu	0.011 lb/MMBtu	0.011 lb/MMBtu	0.011 lb/MMBtu	0.011 lb/MMBtu	0.011 lb/MMBtu	0.011 lb/MMBtu	0.011 lb/MMBtu
PM	0.02 lb/MMBtu	0.02 lb/MMBtu	0.02 lb/MMBtu	0.02 lb/MMBtu	0.02 lb/MMBtu	0.02 lb/MMBtu	0.02 lb/MMBtu	0.02 lb/MMBtu	0.02 lb/MMBtu	0.02 lb/MMBtu	0.02 lb/MMBtu	0.02 lb/MMBtu	0.02 lb/MMBtu	0.02 lb/MMBtu
SO2	1 grain/ 100 SCF	1 grain/ 100 SCF	1 grain/ 100 SCF	1 grain/ 100 SCF	1 grain/ 100 SCF	1 grain/ 100 SCF	1 grain/ 100 SCF	1 grain/ 100 SCF	15 ppmw	15 ppmw	15 ppmw	15 ppmw	15 ppmw	15 ppmw
Stack Emissions - Turbine Contribution (per Turbine)														
CO (lb/hr)	0.98	1.003	1.94	2.0	1.5	1.6	1.4	1.4	3.5	3.8	2.9	3.0	2.6	2.8
Nox (lb/hr)	1.61	1.65	2.04	2.1	1.6	1.6	1.4	1.4	7.4	8.0	6.1	6.4	5.5	5.8
PM (lb/hr)	4.4	4.5	3.5	3.6	2.7	2.8	2.4	2.5	8.5	9.2	6.9	7.3	6.3	6.7
SO2 (lb/hr)	0.6	0.6	0.5	0.5	0.4	0.4	0.3	0.4	0.3	0.4	0.3	0.3	0.2	0.3
Stack Emissions - Duct Burner Contribution (per Turbine)														
CO (lb/hr)	1.4	1.5	1.3	1.6	0.0	0.0	0.0	0.0	1.4	1.5	1.3	1.7	0.0	0.0
Nox (lb/hr)	1.4	1.5	1.3	1.6	0.0	0.0	0.0	0.0	1.4	1.5	1.3	1.7	0.0	0.0
PM (lb/hr)	2.5	2.7	2.3	3.0	0.0	0.0	0.0	0.0	2.5	2.7	2.4	3.0	0.0	0.0
SO2 (lb/hr)	0.4	0.4	0.3	0.4	0.0	0.0	0.0	0.0	0.2	0.2	0.2	0.2	0.0	0.0
Stack Emissions - Total (from both Turbines)														
CO (lb/hr)	4.70	4.94	6.45	7.31	3.03	3.11	2.70	2.75	9.80	10.57	8.36	9.40	5.24	5.52
Nox (lb/hr)	5.97	6.23	6.65	7.51	3.18	3.27	2.84	2.89	17.61	19.02	14.75	16.15	11.07	11.66
PM (lb/hr)	13.74	14.28	11.60	13.15	5.40	5.55	4.82	4.91	22.01	23.76	18.63	20.72	12.66	13.33
SO2 (lb/hr)	1.96	2.04	1.66	1.88	0.77	0.79	0.69	0.70	1.05	1.13	0.91	1.04	0.49	0.52
Stack Characteristics														
Effective Stack Diameter (ft)	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9
Area (ft2)	77.0	77.0	77.0	77.0	77.0	77.0	77.0	77.0	77.0	77.0	77.0	77.0	77.0	77.0
Exit Velocity (ft/sec)	64.6	70.0	47.5	49.6	42.0	43.6	48.4	54.6	41.1	45.4	51.1	58.3	61.6	70.4
Exit Velocity (m/sec)	19.7	21.3	14.5	15.1	12.8	13.3	14.8	16.6	12.5	13.9	15.6	17.8	18.8	21.5

Table C-3: Annual Average MIT turbine & duct burner model cases

Relevant Sample Caclulations (located at end of Appendix C): C-4, C-5, C-6, & C-7

Epsilon 8/2016

New Case Number	Op. Scen. I Annual	Op. Scen. II Annual
General Information		
Old Case Number	7A	7A
Ambient Temp (F)	60	60
% Load	75	75
Turbine Fuel	NG	NG
Duct Burner Fuel	NG	NG
HRSG EXHAUST		
Stack Exit Temp. (F)	180	180
Stack Flow Rate (ft3/min)	130,069	219,591
Turbines operating	1	2
Max hours operating ULSD	168	168
Stack Emissions - Total		
CO (lb/hr)[1]	1.58	3.17
Nox (lb/hr)[2]	3.45	6.89
PM (lb/hr)[3]	6.97	13.93
SO2 (lb/hr)[4]	0.98	1.96
Stack Characteristics		
Effective Stack Diameter (ft)	7.0	9.9
Area (ft2)	38.5	77.0
Exit Velocity (ft/sec)	56.3	47.5
Exit Velocity (m/sec)	17.2	14.5

Notes:

[1] Based on 168 hours ULSD at 100% load with a 0°F ambient temperature and remaining hours on natural gas at 50% load with a 60°F ambient temperature

[2] Based on 168 hours ULSD at 100% load with a 0°F ambient temperature and remaining hours on natural gas at 75% load with a 60°F ambient temperature

[3] Based on 168 hours ULSD at 100% load with a 0°F ambient temperature and remaining hours on natural gas at 100% load with a 50°F ambient temperature

[4] Based on 8,760 hours on natural gas at 100% load with a 50°F ambient temperature

Table C-4: Short Term Emissions from Other Combustion Sources

Relevant Sample Caclulations (located at end of Appendix C): C-4, C-8

Epsilon 8/2016

Emissions Unit	Boiler 3, 4, 5		Boilers 7&9		Turbine #1	Generator	Cold Start Engine
Case	Full Load	Minimum Load	Full Load (Boiler 7&9)	Full Load (Boiler 9 Only)	Full Load	Full Load	Full Load
Exit Temperature (F)	315	270	393	315	270	963	752.1
Exit Velocity (m/s)	5.91	0.73	17.68	8.06	35.79	61.94	24.72
Exhaust Flow (ACFM)	110,532	13,653	82,665	37,686	199,149	17,191	15,287
Stack Height (Ft)	177	177	115	115	120	63.75	96.5
Stack Diameter (ft)	11	11	5.5	5.5	6	1.34	2.00
Short-Term Emission Rate							
CO (lb/hr)	15.10	1.86	7.7	4.17	6.95	2.2	2.20
NOx (lb/hr)	113.28	13.95	16.59	11.92	46.6	1.175	1.20
PM10 (lb/hr)	20.77	2.56	6.59	3.58	13.94	0.76	0.400
PM2.5 (lb/hr)	20.77	2.56	6.59	3.58	13.94	0.76	0.400
SO2 (lb/hr)	0.57	0.07	0.33	0.18	0.470	0.032	0.029
Short-Term Emission Rate							
CO (lb/MMBtu)							
NOx (lb/MMBtu)							
PM10 (lb/MMBtu)	See Below						
PM2.5 (lb/MMBtu)							
SO2 (lb/MMBtu)							

Table C-4a: Boilers 3, 4, and 5 Heat Inputs

MMBtu/hr	Full Load[1]	Minimum[2]
Boiler 3	116.2	
Boiler 4	116.2	
Boiler 5	145.2	
Total	377.6	46.5

[1] Based on permitted maximum heat rating for Boilers 3, 4, and 5

[2] Based on only Boiler 3 or 4 operating at 40% load

Table C-4b: Boilers 3, 4, and 5 Emission Factors

Op Permit (lb/MMBtu)	Boiler 3 - Oil	Boiler 4 - Oil	Boiler 5 - Oil
CO	0.04	0.04	0.04
NOx	0.3	0.3	0.3
PM10	0.055	0.055	0.055
PM2.5	0.055	0.055	0.055

Table C-5: 2 MW Cold-Start Engine Emission Calculations & Model Inputs [1]

Relevant Sample Caclulations (located at end of Appendix C): C-9, C-10, & C-11

Epsilon 8/2016

752.1	F engine outlet temperature
752.1	F stack temperature (assumed no temperature loss)

6,205	ft3/min wet exhaust volume at 32F
15,287	ft3/min wet exhaust volume at stack temperature, converted from above

24	inches stack diameter from prior design
81.10	feet/second exhaust velocity

35.09	pounds/hour NOx (max across loads, nominal data)
2.2	pounds/hour CO (max across loads, nominal data)
0.4	pounds/hour PM (max across loads, nominal data)

138	gal/hour ULSD use
7	lb/gal ULSD density, estimated
966	lb/hr ULSD use
0.0015%	weight percent sulfur in ULSD
2	pounds SO2/pound sulfur
0.029	pounds/hour SO2 (max across loads)

1.13	pounds/hour UHC (max across loads)
100%	UHC is VOC (conservative)
1.13	pounds/hour VOC (max across loads, nominal data)

0.139	MMBtu/gal estimated heat content of ULSD
19.182	MMBtu/hr
166	lb CO2/MMBtu emission rate for liquid fuel
3,184	lb/hr CO2

[1] Based on sample information for a CAT DM8263 at 100% load

Table C-6: Annual Emissions from Other Combustion Sources

Relevant Sample Caclulations (located at end of Appendix C): C-8, C-9, C-11, & C-12

Epsilon 8/2016

Emissions Unit	Boiler 3, 4, 5		Boilers 7&9		Turbine #1	Generator	Cold Start Engine
Case	Full Load	Minimum Load	Full Load (Boiler 7&9)	Full Load (Boiler 9 Only)	Full Load	Full Load	Full Load
Exit Temperature (F)	315	270	393	315	270	963	752.1
Exit Velocity (m/s)	5.91	0.73	17.68	8.06	35.79	61.94	24.72
Exhaust Flow (ACFM)	110,532	13,653	82,665	37,686	199,149	17,191	15,287
Stack Height (Ft)	177	177	115	115	120	63.75	96.5
Stack Diameter (ft)	11	11	5.5	5.5	6	1.34	2.33
Emission Rate							
CO (lb/hr)	13.29	1.63	1.12	0.62	6.95	0.0753	0.075
NOx (lb/hr)	76.24	9.39	1.29	0.77	24.83	1.1750	1.20
PM10 (lb/hr)	11.51	1.42	1.01	0.56	4.98	0.0260	0.014
PM2.5 (lb/hr)	11.51	1.42	1.01	0.56	4.98	0.0260	0.014
SO2 (lb/hr)	0.57	0.07	0.33	0.18	0.47	0.0011	0.001
Emission Factors							
CO (lb/MMBtu)	See Below		0.011	0.035			
NOx (lb/MMBtu)			0.011	0.1			
PM10 (lb/MMBtu)			0.01	0.03			
PM2.5 (lb/MMBtu)			0.01	0.03			
SO2 (lb/MMBtu)			0.0014	0.0015			

Table C-6a: Boilers 3, 4, and 5 Heat Inputs

MMBtu/hr	Full Load[1]	Minimum[2]
Boiler 3	116.2	46.5
Boiler 4	116.2	
Boiler 5	145.2	
Total	377.6	46.5

[1] Based on permitted maximum heat rating for Boilers 3, 4, and 5

[2] Based on only Boiler 3 or 4 operating at 40% load

Table C-6b: Boilers 3, 4, and 5 Emission Factors

Op Permit (lb/MMBtu)	Boiler 3 - Gas	Boiler 4 - Gas	Boiler 5 - Gas
CO	0.035	0.035	0.035
NOx	0.2	0.2	0.2
PM10	0.03	0.03	0.03
PM2.5	0.03	0.03	0.03
SO2	0.0015	0.0015	0.0015

Table C-6c: Boiler Emission Rate Calculations

	B7 - gas	B9 - gas	B7 & 9 - gas	Boiler 3,4,5 NG	Boiler 3,4,5 ULSD+NG	Boiler 3,4,5 NG	Boiler 3,4,5 ULSD+NG
MMBtu/hr	99.70	125.80	225.50	MAX LOAD		MIN LOAD	
Hours Max	3,600	3,600					
CO lb/MMBtu	0.0110	0.0110					
NOx lb/MMBtu	0.0110	0.0110					
PM10 lb/MMBtu	0.0100	0.0100					
PM2.5 lb/MMBtu	0.0100	0.0100					
SO2 lb/MMBtu	0.0014	0.0014					
CO lb/hr	0.45	0.57	1.02	13.250	**13.286**	1.627	**1.631**
NOx lb/hr	0.45	0.57	1.02	75.520	**76.244**	9.296	**9.385**
PM10 lb/hr	0.41	0.52	0.93	11.328	**11.509**	1.394	**1.417**
PM2.5 lb/hr	0.41	0.52	0.93	11.328	**11.509**	1.394	**1.417**
SO2 lb/hr	0.06	0.07	0.13	**0.566**	**0.566**	**0.070**	**0.070**

Table C-6d: Boiler and Turbine Emission Rate Calculations

	B7 NG+ULSD	B9 NG+ULSD	B7 & 9 NG+ULSD	Turbine 1 - NG	Turbine 1 - NG + ULSD
MMBtu/hr	99.70	125.80	225.50	293.70	293.70
Hours Max	3,600	3,600		8,760	8,760
Hours ULSD	168	168		168	168
CO lb/hr	0.50	**0.62**	**1.12**	6.95	6.95
NOx lb/hr	0.52	**0.77**	**1.29**	24.40	24.83
PM10 lb/hr	0.45	**0.56**	**1.01**	4.80	4.98
PM2.5 lb/hr	0.45	**0.56**	**1.01**	4.80	4.98
SO2 lb/hr	0.06	0.07	0.13		

Table C-7: MIT PSD Increment Calculations

Epsilon 8/2016

INCREMENT EXPANDING																			
Source	Max 24-hr Fuel Use (Gallons)	Date	Max 24-hr Gas Use (SCF)	Date	MMBtu/hr	lb/MMBtu (Gas)	lb/MMBtu (Oil)	Short-Term Gas	Short-term Oil	Short-Term PM25 Lb/hr	2013 NG Usage	2014 NG Gas Usage	2013 FO Usage	2014 FO Fuel Usage	Avg NG Use	Avg. FO Use	Total MMBtu NG	Total MMBtu Oil	Annual PM25 Lb/hr
Boiler 3	13,213.65	12/31/2013	1,754,043	12/8/2014	116.2	0.0076	0.055	0.555	4.300	4.3	1.31E+08	9.81E+07	831,357	512,566	1.15E+08	6.72E+05	1.15E+05	9.54E+04	0.7
Boiler 4	19,948.17	2/6/2015	1,742,543	12/25/2013	116.2	0.0076	0.055	0.552	6.491	6.5	1.46E+08	9.23E+07	751,592	816,364	1.19E+08	7.84E+05	1.19E+05	1.11E+05	0.8
Boiler 5	17,284.04	2/6/2015	1,894,732	12/8/2014	145.2	0.0076	0.055	0.600	5.625	5.6	1.09E+08	1.25E+08	687,890	1,279,725	1.17E+08	9.84E+05	1.17E+05	1.40E+05	1.0
Existing CT	43,976.00	1/24/2014	6,192,320	12/13/2013	229.0	0.007	0.040	1.806	10.114	10.1	1.55E+09	1.63E+09	783,368	600,400	1.59E+09	6.92E+05	1.59E+06	9.82E+04	1.7
Existing DB	-	-	1,190,100	4/2/2013	64.7	0.005	0.055	0.248	-	0.2	2.52E+08	2.34E+08	-	-	2.43E+08		2.43E+05		0.14
Boiler 7	9,162.62	2/24/2015	1,202,035	2/16/2015	99.7	0.010	0.030	0.501	1.581	1.6	7.70E+05	1.20E+07	342.6	21759.0	6.39E+06	1.11E+04	6.39E+03	1.57E+03	0.013
Boiler 9	10,209.70	2/24/2015	1,580,329	3/23/2015	100.0	0.010	0.030	0.658	1.761	1.8	6.84E+06	1.74E+07	4765.20	53813.50	1.21E+07	2.93E+04	1.21E+04	4.16E+03	0.028
Cooling Tower 1 per cell (2)										0.026									0.026
Cooling Tower 2 per cell (2)										0.026									0.026
Cooling Tower 3 per cell (2)										0.047									0.047
Cooling Tower 4 per cell (2)										0.041									0.041
Cooling Tower 5										0.017									0.017
Cooling Tower 6										0.017									0.017

Table C-8: MIT PSD Increment Calculations

Epsilon 8/2016

Source	Hrs/Yr Gas	Hrs/Yr Oil	NG Limit (lb/MMBtu)	Oil Limit (lb/MMBtu)	MMBtu/hr Gas	MMBtu/hr Oil	Short Term (lb/hr)	Annual (lb/hr)
Boiler 3		168	0.0076	0.055	116.2	116.2	0.56	0.30
Boiler 4		168	0.0076	0.055	116.2	116.2	0.55	0.32
Boiler 5		168	0.0076	0.055	145.2	145.2	0.60	0.38
Boiler 7	3432	168	0.01	0.03	99.7	99.7	0.50	0.4
Boiler 9	3432	168	0.01	0.03	125.8	119.2	0.66	0.6
CT1	8592	168	0.02	0.04	Based on the Results of the Load Analysis			
CT2	8592	168	0.02	0.04				
DB1	8760	0	0.02					
DB2	8760	0	0.02					
New Engine							0.400	0.014
Cooling Tower 11 per cell							0.035	0.035
Cooling Tower 12 per cell							0.035	0.035
Cooling Tower 13 per cell							0.035	0.035

Table C-9: MIT CHP Evaluation - Emissions Estimates for VOC, NH3, and CO2

Relevant Sample Caclulations (located at end of Appendix C): C-1

Epsilon 8/2016

	Nat. Gas	ULSD
CT Heat Input (MMBtu/hr LHV)	197.8	198.9
HHV/LHV conversion	1.109	1.066
CT Heat Input (MMBtu/hr HHV)	219	212
Duct Burner Heat Input (MMBtu/hr LHV)	121	121
Duct Burner Heat Input (MMBtu/hr HHV)	134	134
EPA F-Factor for natural gas, dscf/MMBtu	8,710	9,190

Turbine Emissions			
VOC ppmvd @15% O2 (as methane)	1.70	7.00	MassDEP Top-Case BACT Guidance
VOC ppmvd @ 0% O2	6	25	
VOC (as CH4) ideal gas conv., ppm to lb/scf	4.160E-08	4.160E-08	
VOC lb/MMBtu (HHV)(as methane)	0.0022	0.0095	
VOC lb/hr	0.48	2.01	
NH3 ppmvd @15% O2	2.00	2.00	MassDEP Top-Case BACT Guidance
NH3 ppmvd @ 0% O2	7	7	
NH3 ideal gas conv., ppm to lb/scf	4.41E-08	4.41E-08	
NH3/MMBtu (HHV)	0.0027	0.0029	
NH3 lb/hr	0.60	0.61	
CO2e, lb/MMBtu	119	166	Consistency with recent applications
CO2e, lb/hr	26,103	35,198	

Duct Burner Emissions			
VOC lb/MMBtu (HHV)(as methane)	0.03		MassDEP Top-Case BACT Guidance
VOC lb/hr (as methane)	4.03		
NH3 lb/MMBtu (HHV)	0.0027		same as turbine
NH3 lb/hr	0.37		
CO2e, lb/MMBtu	119		Consistency with recent applications
CO2e, lb/hr	15,968		

Table C-10: Potential to Emit Calculations (Tons per year)

Relevant Sample Caclulations (located at end of Appendix C): C-1, C-2, C-3, C-10, C-13, & C-14

Epsilon 11/2016

Cold Start Engine		
300	hours/year	
	Engine Emissions (lb/hr)	Ton/year
CO	2.2	0.33
NOx	35.09	5.26
PM10/PM2.5	0.4	0.060
SO2	0.029	0.0043
VOC	1.13	0.17
CO2e	3,184	478

Turbines				
219.00	MMBtu/hr HHV firing gas (from 50°F Case)			
212.00	MMBtu/hr HHV firing ULSD (from 60°F Case)			
124.98	MMBtu/hr HHV duct burner firing gas			
2	turbines			
8,760	hours/year Maximum			
168	hours/year ULSD			
4,380	hours/year duct burner (full load equivalent - estimate for calculating annual proposed emission limits)			
	Turbine lb/MMBtu gas (per turbine)	Turbine lb/MMBtu ULSD (per turbine)	DB lb/MMBtu (per unit)	Ton/year
CO	0.0045	0.017	0.011	15.1
NOx	0.0074	0.035	0.011	21.1
PM10/PM2.5	0.02	0.040	0.020	50.0
SO2	0.0029	0.0016	0.0029	7.0
VOC	0.0022	0.0095	0.03	20.9
CO2e	119	166	119	294,970
NH3	0.0027	0.0029	0.0027	6.7

Project Potential Emissions, tons/year			
	Turbines	Cold Start Engine	Total
CO	15.1	0.33	**15.4**
NOx	21.1	5.3	**26.4**
PM10/PM2.5	50.0	0.06	**50.1**
H2SO4[1]	5.4	N/A	**5.4**
SO2	7.0	0.004	**7.0**
VOC	20.9	0.17	**21.0**
CO2e	294,970	478	**295,448**
NH3	6.7	0	**6.7**

1 Sulfuric acid mist emissions are a function of sulfur in the natural gas and ULSD, and oxidation in the catalysts, neither of which can be controlled by MIT. Again, limits for a project of this type would typically never be considered beyond documenting that the PSD modification threshold (7 ton/year) is not exceeded. For purposes of this calculation, potential SO2 emissions (7.0 tons/year for the project) and a conservative assumption of 50% conversion of sulfur dioxide to sulfuric acid mist yields potential emissions of 5.4 tons per year (7.0 tons X 50% conversion X 98/64 (molecular weight ratio of H2SO4 to SO2)). This calculation double-counts the sulfur in the system (assuming it is all emitted as SO2, and also assuming half of it is emitted as H2SO4)

Table C-11: Cold Start Engine Diesel Particulate Filter Unit BACT Cost Analysis

Engine Rating (kW)	2000
PM Emission Flow Rate (lb/hr)	0.4
PM Emission Flow Rate (tpy)	0.06

Fixed Costs		
Description	Cost	Comment
Primary Control Device & Auxiliary Equipment 450 kW EDR	$ 44,000.00	Quote from Rypos for 450 kW Emergency Diesel Generator from Exelon West Medway Application No.: CE-15-016
Equipment Cost Scaling Factor	2.45	Scaling Factor from Equation in Plant Design and Economics for Chemical Engineers, 3rd ed., p. 166. based on engine capacity
Primary Control Device & Auxiliary Equipment 2MW Cold-Start Engine	$ 107,682.01	product of scaling factor and Rypos Quote for 450 kW Emergency Diesel Generator
Instrumentation/Controls		included in primary control device estimate
Construction	$ 16,959.92	15% factor on TEC
Installation	$ 33,919.83	30% factor on TEC (includes foundation, erection and handling, electrical, piping, insulation, and painting)
Sales Tax	$ 5,384.10	5% factor on TEC (includes freight as well)
Freight Charges		included in tax
Testing and startup	$ 3,391.98	3% factor on TEC
Supervision	$ 11,306.61	10% factor on TEC
Total Equipment Cost (TEC)	$ 113,066.11	sum of Primary control device and auxiliary equipment cost, instrumentation, taxes, and freight
Total Capital Investment (TCI)	$ 178,644.46	

Annual Cost Factors		
Description	Value	Comment
Operating Factor (hr/yr)	300	based on emergency unit operations
Operating labor rate ($/hr):	$ 25.60	
Operating labor factor (hr/sh):	0.25	
Annual interest rate (fraction): [i]	0.1	based on MassDEP Guidance on AQ BACT form
Control system life (years): [n]	10	based on MassDEP Guidance on AQ BACT form
Capital recovery factor:	0.1627	$(i*(1+i)^n) / ((1+i)^n-1)$
Taxes, insurance, admin. factor:	0.04	per Table 2.10 of EPA Air Pollution Control Cost Manual (http://www.epa.gov/ttncatc1/dir1/c_allchs.pdf)
Pressure drop (in. w.c.):		
Electricity cost ($/kWh)		

Annual Costs		
Description	Value	Comment
Operating labor	$ 240.00	300 hr/yr divided by 8 hr/shift times 0.25 hours per shift times 25.60 $/hr
maintenance labor	$ 240.00	300 hr/yr divided by 8 hr/shift times 0.25 hours per shift times 25.60 $/hr
Subtotal raw labor	$ 480.00	
Labor overhead	$ 288.00	60% of operating and maintenance labor
Labor with overhead	$ 768.00	
Maintenance materials	$ 240.00	same as operating and maintenance labor
Property Taxes	$ 1,786.44	1% of TCI per Table 2.10 of EPA Air Pollution Control Cost Manual
Insurance	$ 1,786.44	1% of TCI per Table 2.10 of EPA Air Pollution Control Cost Manual
Fees	$ 3,572.89	2% of TCI per Table 2.10 of EPA Air Pollution Control Cost Manual
Total Annual Operating Costs	$ 8,153.78	
Electricity (kWh)		assume 0 to be conservative
Total Annual Energy Costs	$ -	kWh * $/kWh
Total Annual Cost	$ 8,153.78	
Capital Recovery	$ 29,073.56	capital recovery factor times TCI

Removal Cost Effectiveness		
Cost for Cost Effectiveness	$ 37,227.34	capital recovery plus total annual cost
Uncontrolled Emissions (tpy)	0.0600	PM Flow
Removal %	85%	
Removed Emissions (tpy)	0.051	Removal % times uncontrolled emissions
Cost Effectiveness ($/ton removed)	$ 729,947.87	

Table C-12: CTG ULSD Usage

212	average MMBtu/hr per turbine on ULSD
0.14	MMBtu/gal for ULSD
1,600.00	gal/hr ULSD usage of turbine (rounded up to 2 significant figures)
168	hr per 12 mo rolling period
268,800	**gal per 12 mo rolling per turbine period**
2	turbines
537,600	**gal per 12 mo rolling total**

Table C-13: MIT-CUP Emission Caps Recordkeeping Past Actual

Epsilon 9/2016

Unit	Beginning & Ending Dates		Fuel Data, annual average		Heat Input, annual average		Emissions (tpy)
			Natural Gas (10^6cf)	#6 Fuel Oil (gal)	Natural Gas (MMBtu)	#6 Fuel Oil (MMBtu)	PM
Boiler 3	1/1/2013	12/1/2014	114.8	671,962	114,777	100,794	3.21
Boiler 4	1/1/2013	12/1/2014	119.3	783,978	119,335	117,597	3.69
Boiler 5	1/1/2013	12/1/2014	117.2	983,808	117,224	147,571	4.51
Total	**1/1/2013**	**12/1/2014**	**351.3**	**2,439,747**	**351,335**	**365,962**	**11.4**

Table C-13a: MIT-CUP Projected Actual

Unit	Heat Input (MMBtu/hr)	Hours of ULSD firing	Fuel Data for Boilers 3,4,5, annual average		Heat Input for Boilers 3,4,5, annual average		Boilers (tpy)
			Natural Gas (10^6cf)	Fuel Oil (gal)	Natural Gas (MMBtu)	Fuel Oil (MMBtu)	PM
Boiler 3	116.2	48	210	39,840	209,993.42	5,578	1.0
Boiler 4	116.2	48	231	39,840	231,353.91	5,578	1.0
Boiler 5	145.2	48	258	49,783	257,825.16	6,970	1.2
Total	**377.6**	**48**	**699**	**129,463**	**699,172.49**	**18,125**	**3.2**

Table C-13b: Emission Factors Used In Emission Caps Calculations (from Permits/AP-42/Proposed)

Pollutant	Boilers 3, 4 and 5			
	Natural Gas		#6 Fuel Oil	
	Emission Factor	Units	Emission Factor	Units
PM	7.6	lb/10^6cf	7.82	lb/1000 gal
	0.0076	lb/MMBtu	0.055	lb/MMBtu

Table C-13c: Boiler 3,4,& 5 Fuel Usage

	2013 Natural Gas (MMSCF)	2013 Fuel Oil (gal)	2014 Natural Gas (MMSCF)	2014 Fuel Oil (gal)
Boiler 3	131.46	831,357	98.09	512,566
Boiler 4	146.34	751,592	92.33	816,364
Boiler 5	109.30	687,890	125.15	1,279,725
Total	387.10	2,270,839	315.57	2,608,655

Table C-14: MIT - GE LM2500 vs Solar Titan 250 GHG Emissions Analysis

Epsilon 11/2016

CTG Model	Total Generated Electric	Current Marginal Emission Factor for the ISO -NE Grid	GHG displaced from Grid Electricity
	MWh/yr	*lb/MWh*	*tons/yr*
Solar Titan 250	273,964	941	128,900
GE LM2500	234,421	941	110,295

CTG Model	Steam Generated by CTG & HRSG	CHP Fuel Specific Emission Factor	Average Thermal Efficiency of Facility Conventional Thermal Systems	GHG Displaced From Conventional Useful Heat System
	MMBtu/yr	*lb/MMBtu*	*%*	*tons/yr*
Solar Titan 250	1,446,663	117	80%	105,787
GE LM2500	1,463,185	117	80%	106,995

CTG Model	Total CTG Gas Usage	Total HRSG Gas Usage	CHP Fuel Specific Emission Factor	Site (CHP) Gross GHG Emissions
	MMBtu/yr	*MMBtu/yr*	*lb/MMBtu*	*tons/yr*
Solar Titan 250	2,537,725	324,375	117	167,433
GE LM2500	2,353,174	337,896	117	157,428

CTG Model	GHG displaced from Grid Electricity	GHG Displaced From Conventional Useful Heat System	Total GHG Displaced	Site (CHP) Gross GHG Emissions	Net GHG Reduction	
	tons/yr	*tons/yr*	*tons/yr*	*tons/yr*	*tons/yr*	%
Solar Titan 250	128,900	105,787	234,687	167,433	67,254	29%
GE LM2500	110,295	106,995	217,290	157,428	59,863	28%

[1] All MMBtu/yr and MWh/yr values based on Projected 2023 MIT loads as modeled

[2] The 117 lb/MMBtu factor is used instead of the actual 119 lb/MMBtu factor for consistency with the MEPA GHG analysis

Table C-15: MIT - Cooling Tower PM Emission Rate for PSD Applicability

Epsilon 12/2016

Unit	Drift Eliminator	Non-Chromium Inhibitor	Recirculation Rate	TDS Concentration	Drift Flowrate	Drift Rate	Solids in Drift	Max Operating Time	Annual Potential Emissions
			gallons/minute	PPM	%	gallons/minute	lb/hr	hr/yr	tons/yr
Cooling Tower 11	Yes	Yes	13,500	2,064	0.0005%	0.0675	0.0698	8,760	0.306
Cooling Tower 12	Yes	Yes	13,500	2,064	0.0005%	0.0675	0.0698	8,760	0.306
Cooling Tower 13	Yes	Yes	13,500	2,064	0.0005%	0.0675	0.0698	8,760	0.306
Total	–	–	–	–	–	–	–	–	0.92

NOTE: As an unrelated project, MIT has recently installed three new cooling towers (towers 11, 12, and 13). The cooling tower replacements do not rely on the proposed project and vice-versa; the replacement cooling towers are not required for the proposed project to operate, and the proposed project does not need to be constructed for MIT to gain full use of the replacement cooling towers. Replacement of the cooling towers did not trigger Massachusetts plan approval thresholds (potential emissions less than one ton per year). The projects were funded and constructed separately. Based on a pre-application meeting with MassDEP on July 29, 2014, the changes to the cooling towers are addressed in the air quality dispersion modeling analysis for this project. These calculations provide the basis for the model inputs, and provide for conservative inclusion in the PSD applicability review.

Emissions are calculated consistent with EPA AP-42 Section 13.4.2, which states "a *conservatively high* PM-10 emission factor can be obtained by (a) multiplying the total liquid drift factor by the total dissolved solids (TDS) fraction in the circulating water and (b) assuming that, once the water evaporates, all remaining solid particles are within the PM-10 size range." (emphasis in original)

Sample Calculations

Sample Calculation C-1: ppm to lb/hr from the turbine using CO from Epsilon Case 1			
Value	**Name**	**Units**	**Notes**
2.00	Starting ppmdv @ 15% O_2	ppmdv @ 15% O_2	Starting point
20.90	Percent Oxygen in atmospheric air	%	Standard value
15.00	Percent Oxygen basis for ppmdv	%	Given
8,710	F_d Factor for natural gas	dscf/MMBTU	From EPA Method 19 Table 19-1 (40 CFR 60)
1.194E-07	Conversion factor (lb/scf per 1 ppm for NO_2 reference)	(lb/dscf)/ppm	From EPA Method 20 (40 CFR 60)
28.00	Molecular Weight (MW) of CO	lb/lbmol	Standard value
46.00	Molecular Weight (MW) of NO_2 (reference compound)	lb/lbmol	Standard value
219.00	Heat input of turbine (natural gas)	MMBTU/hr	Design value of turbine for this operating case
1.04E-03	Conversion factor (lb/MMBTU per 1 ppm) for NOx	(lb/MMBTU)/ppm	Multiply conversion factor (lb/scf per 1 ppm) by F_d factor
6.33E-04	Conversion factor (lb/MMBTU per 1 ppm) for CO	(lb/MMBTU)/ppm	Multiply conversion factor (lb/MMBTU per 1 ppm) for NO_2 by ratio of MW
0.0013	lb/MMBTU at 15% O_2	lb/MMBTU	Multiply ppmdv @ 15% O_2 by conversion factor (lb/MMBTU per 1 ppm) for CO
3.54	Correction factor for 15% O_2 to atmospheric 20.9% O_2	--	20.9% / (20.9%-15%) correction factor from EPA Method 20 EQ 20-6 (40 CFR 60)
0.0045	lb/MMBTU CO	lb/MMBTU	Multiply correction factor for 15% O_2 by lb/MMBTU at 15% O_2
0.98	**CO emissions from a single CTG**	**lb/hr**	**Multiply the lb/MMBTU CO by the heat input of turbine (natural gas) value**

General Formula Top To Bottom: $2.00\ ppmvd\ @\ 15\%\ O_2 * \left(\left(8{,}710\frac{dscf}{MMBTU}\right) * \left(1.194 * 10^{-7}\frac{\frac{lb}{MMBTU}}{ppm}\right)\right) * \frac{20.9\ \%\ O_2\ air}{20.9\ \%\ O_2\ air - 15\%\ O_2\ reference} * \frac{28\frac{lb\ CO}{lbmol\ CO}}{46\frac{lb\ NO_2}{lbmol\ NO_2}} * 219\frac{MMBTU}{hr} = \mathbf{0.98}\frac{\mathbf{lb}}{\mathbf{hr}}$

Sample Calculation C-2: Grains per 100 standard cubic foot (SCF) of Sulfur to lb/hr SO2 from Epsilon Case 1			
Value	**Name**	**Units**	**Notes**
219.00	Heat Input of turbine (natural gas)	MMBTU/hr	Design value of turbine for this operating case
1.00	Sulfur content of fuel	gr/100scf	Design value of turbine for this operating case
0.01	Sulfur content of fuel	gr/scf	Divide grains of Sulfur per 100 SCF of natural gas by 100 SCF
7,000.00	Conversion factor (grains to pounds)	gr/lb	Standard conversion value
0.001	Conversion factor (SCF to BTU NG)	SCF/BTU	Standard conversion value
1,000,000	Conversion factor (BTU to MMBTU)	BTU/MMBTU	Standard conversion value
64.00	Molecular Weight of Sulfur Dioxide (SO2)	lb/lbmol	Standard value
32.00	Molecular Weight of atomic Sulfur	lb/lbmol	Standard value
2.00	Ratio of molecular weight of SO_2 to Sulfur	--	Divide MW of Sulfur Dioxide by MW of Sulfur
1.43E-06	Sulfur content of fuel	lb/SCF	Divide sulfur content of fuel (gr/scf) by conversion factor (grains to pounds)
1,000.00	Conversion factor (SCF to MMBTU)	SCF/MMBTU	Mutliply conversion factor (SCF to BTU NG) by conversion factor (BTU to MMBTU)
0.0014	Emission factor of Atomic Sulfur	lb/MMBTU	Multiply conversion factor (SCF to MMBTU) by Sulfur content of fuel (lb/SCF)
0.0029	Emission factor of Sulfur Dioxide	lb/MMBTU	Multiply emission factor of atomic Sulfur by ratio of molecular weight of SO_2 to S
6.26E-01	**SO_2 emissions from a single CTG**	**lb/hr**	**Multiply the lb/MMBTU SO_2 by the heat input of turbine (natural gas) value**

General Formula Top To Bottom: $\frac{1\ grain}{100\ scf} * \frac{1\ lb}{7{,}000\ grains} * \frac{1\ SCF\ Natural\ Gas}{1{,}000\ BTU} * \frac{1{,}000{,}000\ BTU}{1\ MMBTU} * \frac{64\frac{lb}{lbmol}SO_2}{32\frac{lb}{lbmol}S} * 219\frac{MMBTU}{hr} = \mathbf{0.626}\frac{\mathbf{lb}}{\mathbf{hr}}\mathbf{SO_2}$

Sample Calculations

Sample Calculation C-3: lb/MMBTU to lb/hr for Particulate Matter from Epsilon Case 1			
Value	**Name**	**Units**	**Notes**
0.02	Emission factor for Pariculate Matter (PM)	lb/MMBTU	Design value of turbine for this operating case
219.00	Heat input of turbine (natural gas)	MMBTU/hr	Design value of turbine for this operating case
4.38	**PM emissions from a single CTG**	**lb/hr**	**Multiply the lb/MMBTU PM by the heat input of turbine (natural gas) value**
General Formula Top To Bottom:	$0.02\frac{lb}{MMBTU} * 219\frac{MMBTU}{hr} = \mathbf{4.38\frac{lb}{hr}PM}$		

Sample Calculation C-4: Stack Area Calculation from Epsilon Case 1			
Value	**Name**	**Units**	**Notes**
7.00	Stack diameter	feet	Design value
3.14	Pi (π)	--	Standard value
3.50	Stack radius	feet	Diameter of stack divided by 2
38.48	**Area of Stack Exit**	**ft^2**	**Pi multiplied by the square of the stack radius**
General Formula Top To Bottom:	$\pi * \left(\frac{7\,ft}{2}\right)^2 = \mathbf{38.5\,ft^2}$		

Sample Calculation C-5: Stack Exit Velocity from Epsilon Case 1			
Value	**Name**	**Units**	**Notes**
149,161	Stack volumetric exhaust flow	ft^3/min	Design value based on outlet flow from combustion units and temperature of stack exhaust
38.48	Area of stack exit	ft^2	From Sample Calculation C-4
60.00	Conversion factor (minutes to seconds)	seconds/minute	Standard conversion factor
3,875.87	Stack exit velocity	ft/min	Stack volumetric exhaust flow divided by area of stack exit
64.60	Stack exit velocity	ft/sec	Stack exit velocity (ft/min) divided by conversion factor (minutes to seconds)
3.28	Conversion factor (feet to meters)	ft/m	Standard conversion factor
19.7	**Stack exit velocity (metric)**	**m/sec**	**Stack exit velocity (ft/s) divided by conversion factor (feet to meters)**
General Formula Top To Bottom:	$149{,}161\frac{ft^3}{minute} * \frac{1}{38.48\,ft^2} * \frac{1\ minute}{60\ seconds} * \frac{1\ meter}{3.28\ feet} = \mathbf{19.7\frac{meters}{second}}$		

Sample Calculation C-6: Effective Stack Diameter Calculation from Operating Scenario II			
Value	**Name**	**Units**	**Notes**
7.00	Diameter of single unit stack	feet	Design value
2.00	Number of unit stacks	--	Design value
3.14	Pi (π)	--	Standard value
3.50	Radius of a single unit stack	feet	Diameter of single unit stack divided by 2
38.48	Area of single stack	ft^2	Calculation shown in Sample Calculation C-4
77.0	Effective stack area	ft^2	Area of a single stack multipled by number of unit stacks
4.95	Effective stack radius	feet	Divide effective stack area by Pi and then take the square root of that value
9.9	**Effective stack diameter**	**feet**	**Multiply the effective stack radius by 2**
General Formula Top To Bottom:	$2 * \sqrt{\frac{\left(\left(\frac{7\,ft}{2}\right)^2 * \pi\right) * 2}{\pi}} = 9.9\ ft\ effective\ diameter$		

Sample Calculations

Sample Calculation C-7: Annual Average lb/hr PM from Table C-3			
Value	**Name**	**Units**	**Notes**
8,760	Total hours in a year	hr/yr	Standard value
168	Hours of ULSD firing	hr/yr	Project design value
8,592	Hours of natural gas firing	hr/yr	Obtained by subtracting hours of ULSD firing from 8,760 hours per year
11.88	ULSD emission rate of PM (from Epsilon Case 10)	lb/hr	Based on 100% load firing ULSD with a 0 °F ambient temperature
6.87	Natural gas emission rate of PM (from Epsilon Case 1)	lb/hr	Based on 100% load firing natural gas with a 50 °F ambient temperature
0.019	Fraction of hours firing USLD	--	Obtained by dividing hours of ULSD firing by total hours in a year
0.981	Fraction of hours firing natural gas	--	Obtained by dividing hours of natural gas firing by total hours in a year
0.23	Weighted contribution of ULSD firing to annual average	lb/hr	Obtained by multiplying the ULSD lb/hr emission rate by the fraction of hours firing ULSD
6.74	Weighted contribution of NG firing to annual average	lb/hr	Obtained by multiplying the NG lb/hr emission rate by the fraction of hours firing NG
6.97	**Annual average PM emissions from single unit**	**lb/hr**	**Obtained by adding the weighted emission contributions of USLD and NG firing**

General Formula Top To Bottom: $\frac{11.88\frac{lb}{hr} * 168\frac{hours\ of\ ULSD\ firing}{year}}{8{,}760\ hours\ per\ year} + \frac{6.87\frac{lb}{hr} * \left((8{,}760 - 168)\frac{hours\ of\ NG\ firing}{year}\right)}{8{,}760\ hours\ per\ year} = \mathbf{6.97}\frac{\mathbf{lb}}{\mathbf{hr}}\mathbf{PM}$

Sample Calculation C-8: Boiler Exhaust Flow for Boiler 3, 4, and 5 Firing Full Load from Table C-4			
Value	**Name**	**Units**	**Notes**
5.91	Exit velocity	m/s	Known value
11	Stack diameter	ft	Known value
3.14	Pi (π)	--	Standard value
3.28	Conversion factor (feet to meters)	ft/m	Standard conversion factor
60.00	Conversion factor (minutes to seconds)	seconds/minute	Standard conversion factor
5.50	Stack radius	ft	Stack diameter divided by 2
95.0	Stack area	ft^2	Pi multiplied by the square of the radius
1,163.09	Stack velocity	ft/min	Exit velocity multiplied by the conversion factors for meters to feet and seconds to minutes
110,532	**Exhaust flow**	**ACFM**	**Multiply the stack velocity by stack area to obtain volumetric flow**

General Formula Top To Bottom: $5.91\frac{m}{s} * 3.28\frac{ft}{m} * 60\frac{seconds}{minute} * \left(\pi * \left(\frac{11\ ft}{2}\right)^2\right) = 110{,}532\ ACFM$

Sample Calculation C-9: Converted Exhaust Volume from Cold-Start Engine			
Value	**Name**	**Units**	**Notes**
6,205	Exhaust parameter	ft^3/min	Spec. sheet - wet exhaust volume at 32F
32	Reference temperature of exhaust parameter	°F	Reference value
752.1	Exhaust temperature	°F	Stack temperature
492.0	Spec sheet value absolute temperature	°R	Spec sheet value temperature converted to Rankine (add 460)
1,212.1	Exhaust absolute temperature	°R	Stack temperature converted to Rankine (add 460)
2.46	Absolute temperature ratio (exhaust/spec sheet)	--	Exhaust absolute temperature divided by spec sheet value absolute temperature
15,287	**Wet stack exhaust volume**	**ft^3/min**	**Multiply exhaust parameter by temperature ratio**

General Formula Top To Bottom: $6{,}205\frac{ft^3}{minute} * \frac{(32 + 460)°R}{(752.1 + 460)°R} = \mathbf{15{,}287}\frac{\mathbf{ft^3}}{\mathbf{minute}}$

Sample Calculations

Sample Calculation C-10: ULSD Sulfur Content to lb/hr SO_2 (cold start engine)			
Value	**Name**	**Units**	**Notes**
138	Volumetric fuel usage of engine	gal/hr	Design value
7	Density of ULSD (estimated)	lb/gal	Standard value
0.0015%	Sulfur content of ULSD	wt%	Standard value
64.0	Molecular Weight (MW) of Sulfur Dioxide (SO_2)	lb/lbmol	Standard value
32.0	Molecular Weight (MW) of atmoic Sulfur	lb/lbmol	Standard value
966.0	Mass fuel usage of engine	lb/hr	Multiply volumetric fuel usage of engine by density of ULSD
2.0	Ratio of SO_2 to Sulfur	lb SO_2/lb S	Divide MW of Sulfur Dioxide by MW of Sulfur
0.014	Mass flow of Sulfur	lb S/hr	Multiply % sulfur in fuel by mass fuel usage of engine
0.029	**Mass flow of Sulfur Dioxide in exhaust**	**lb/hr SO2**	**Multiply mass flow of Sulfur by ratio of SO_2 to Sulfur (assumes 100% conversion)**
General Formula Top To Bottom: $138\frac{gal\ ULSD}{hr} * 7\frac{lb\ ULSD}{gal\ ULSD} * \frac{0.000015\ lb\ S}{lb\ ULSD} * \frac{64\ lb\ SO_2}{32\ lb\ S} = \mathbf{0.029\frac{lb}{hr}SO_2}$			

Sample Calculation C-11: Annual Exhaust Emissions from Cold Start Engine (using CO as example)			
Value	**Name**	**Units**	**Notes**
2.2	Nominal short term emissions from engine	lb/hr	Nominal data
300	Hours of engine operation	hr/yr	Design limit / regulatory limit
8,760	Hours per calendar year	hr/yr	Standard value
0.0342	Operational ratio	--	Hours of engine operation divided by total hours per calendar year
0.075	**Annual exhaust emissions from engine**	**lb/hr**	**Operational ratio of engine multiplied by short term emissions from engine**
General Formula Top To Bottom: $2.2\frac{lb\ CO}{hr} * \frac{300\ hours\ of\ engine\ operation\ per\ year}{8{,}760\ hours\ per\ calendar\ year} = \mathbf{0.075\frac{lb}{hr}CO\ annual}$			

Sample Calculations

Sample Calculation C-12: Annual Exhaust Emissions from Boilers 7 & 9 (using NOx as example)			
Value	**Name**	**Units**	**Notes**
99.7	Heat input of Boiler 7 on natural gas	MMBTU/hr	Design value
125.8	Heat input of Boiler 9 on natural gas	MMBTU/hr	Design value
0.011	NOx emission factor for Boiler 7 firing natural gas	lb/MMBTU	Design value
0.011	NOx emission factor for Boiler 9 firing natural gas	lb/MMBTU	Design value
3,600	Total Hours of operation	hr/yr	Permit value
168	Hours of operation on ULSD	hr/yr	Permit value
3,432	Hours of operation on natural gas	hr/yr	Subtract hours of operation ULSD from total hours of operation
8,760	Conversion factor from hours to year	hr/yr	Standard conversion factor
1.10	Short term hourly emissions of NOx from Boiler 7 firing natural gas	lb/hr	Multiply heat input for Boiler 7 by NOx emission factor for Boiler 7 firing natural gas
1.38	Short term hourly emissions of NOx from Boiler 9 firing natural gas	lb/hr	Multiply heat input for Boiler 9 by NOx emission factor for Boiler 9 firing natural gas
4.67	Short term hourly emissions of NOx from Boiler 7 firing ULSD	lb/hr	From short term limitations page of excel (Table C-4)
11.92	Short term hourly emissions of NOx from Boiler 9 firing ULSD	lb/hr	From short term limitations page of excel (Table C-4) (subtract Boiler 9 value from Boiler 7&9 value)
3,763.9	Annual emissions of NOx from Boiler 7 firing natural gas	lb/yr	Multiply short term hourly NOx emissions from Boiler 7 on natural gas by hours of operation on natural gas
4,749.2	Annual emissions of NOx from Boiler 9 firing natural gas	lb/yr	Multiply short term hourly NOx emissions from Boiler 9 on natural gas by hours of operation on natural gas
784.6	Annual emissions of NOx from Boiler 7 firing ULSD	lb/yr	Multiply short term hourly NOx emissions from Boiler 7 on ULSD by hours of operation on ULSD
2,002.6	Annual emissions of NOx from Boiler 9 firing ULSD	lb/yr	Multiply short term hourly NOx emissions from Boiler 9 on ULSD by hours of operation on ULSD
4,548.4	Annual NOx emissions from Boiler 7	lb/yr	Add annual NOx emissions from natural gas firing and annual NOx emissions from ULSD firing for Boiler 7
6,751.8	Annual NOx emissions from Boiler 9	lb/yr	Add annual NOx emissions from natural gas firing and annual NOx emissions from ULSD firing for Boiler 9
0.52	Annual average hourly NOx emissions from Boiler 7	lb/hr	Divide annual NOx emissions from Boiler 7 by total hours per year (8,760)
0.77	Annual average hourly NOx emissions from Boiler 9	lb/hr	Divide annual NOx emissions from Boiler 9 by total hours per year (8,760)
1.29	**Total annual average hourly NOx emissions from Boilers 7 & 9**	**lb/hr**	**Add annual average hourly NOx emissions from Boiler 7 and Boiler 9**

General Formula Top To Bottom:

$$\frac{\left(\left(99.7\frac{MMBTU}{hr}\right)*\left(0.011\frac{lb}{MMBTU}\right)*\frac{(3{,}600-168)hr}{yr}\right)+\left(\left(4.67\frac{lb}{hr}\right)*168\frac{hr}{yr}\right)}{8{,}760\frac{hr}{yr}}+\frac{\left(\left(125.8\frac{MMBTU}{hr}\right)*\left(0.011\frac{lb}{MMBTU}\right)*\frac{(3{,}600-168)hr}{yr}\right)+\left(\left(11.92\frac{lb}{hr}\right)*168\frac{hr}{yr}\right)}{8{,}760\frac{hr}{yr}}=\mathbf{1.29\frac{lb}{hr}\ NOx}$$

Sample Calculation C-13: Ton per Year Emissions from Cold-Start Engine (Using CO as an Example)			
Value	**Name**	**Units**	**Notes**
2.2	Nominal short term emissions from engine	lb/hr	Nominal data
300	Hours of engine operation	hr/yr	Design limit / regulatory limit
2,000	Conversion factor (pound to ton)	lb/ton	Standard conversion factor
660	Annual CO emissions from engine (Pounds)	lb/yr	Multiply short term emissions limit by hours of engine operation per year
0.330	**Annual CO emissions from engine (Tons)**	**tons/yr**	**Divide annual CO emissions from engine (pounds) by the pound to ton factor**

General Formula Top To Bottom:

$$2.2\frac{lb\ CO}{hr}*300\frac{hr}{yr}*\frac{1\ ton}{2{,}000\ lb}=\mathbf{0.33\frac{ton}{yr}}$$

Sample Calculations

Sample Calculation C-14: Ton per Year Emissions from Turbines (Using NOx as an Example)			
Value	**Name**	**Units**	**Notes**
219.00	Turbine heat input (natural gas)	MMBTU/hr	Design value
212.00	Turbine heat input (ULSD)	MMBTU/hr	Design value
124.98	Duct Burner heat input (natural gas)	MMBTU/hr	Design value
2.00	Number of Turbine/Duct Burner units	--	Design value
2,000.00	Conversion factor from lb to ton	lb/ton	Standard conversion factor
8,760.00	Total hours per year of turbine operation	hr/yr	Design value
168.00	Hours per year of turbine operation on ULSD	hr/yr	Design value
4,380.00	Hours/year duct burner (estimate for calculating annual proposed emission limits)	hr/yr	Design value
8,592.00	Hours per year of turbine operation on natural gas	hr/yr	Hours per year operation on ULSD subtracted from total hours per year of turbine operation
2.00	Volumetric emissions of NOx from CTG on natural gas	ppmdv @ 15% O_2	Design value
9.00	Volumetric emissions of NOx from CTG on ULSD	ppmdv @ 15% O_2	Design value
0.0074	NOx emissions factor from CTG on natural gas	lb/MMBTU	Converted from volumetric emissions using methods from Sample Calculation C-1
0.035	NOx emissions factor from CTG on ULSD	lb/MMBTU	Converted from volumetric emissions using methods from Sample Calculation C-1
0.011	NOx emissions factor from Duct Burner on natural gas	lb/MMBTU	Design value
1.61	NOx short term emission rate from CTG firing natural gas	lb/hr	Multiply NOx emissions factor from CTG on NG by Turbine heat input (firing NG)
7.42	NOx short term emission rate from CTG firing ULSD	lb/hr	Multiply NOx emissions factor from CTG on ULSD by Turbine heat input (firing ULSD)
1.37	NOx short term emission rate from Duct Burner firing natural gas	lb/hr	Multiply NOx emissions factor from DB on NG by DB heat input (firing NG)
13,863.9	Annual NOx emissions contribution from CTG on NG	lb/yr	Multiply NOx emission rate from CTG firing NG (lb/hr) by hr/yr operation of CTG on NG
1,246.0	Annual NOx emissions contribution from CTG on ULSD	lb/yr	Multiply NOx emission rate from CTG firing ULSD (lb/hr) by hr/yr operation of CTG on ULSD
6,021.5	Annual NOx emissions contribution from DB on NG	lb/yr	Multiply NOx emission rate from DB firing NG (lb/hr) by hr/yr operation of DB on NG
21,131.4	Annual NOx emissions contribution from single unit	lb/yr	Add up annual emissions from CTG firing NG, CTG firing ULSD, and DB firing NG
42,262.8	Annual NOx emissions contribution from both units	lb/yr	Multiply annual NOx emissions contribution from single unit by number of units
21.1	**Total annual NOx emissions from Turbines and Duct Burners**	**ton/yr**	**Divide annual NOx emissions contribution from both units by the conversion factor from pounds to tons**

General Formula Top To Bottom:

$$\frac{\left(219\frac{MMBTU}{hr}*0.0074\frac{lb}{MMBTU}*\frac{(8{,}760-168)hr}{yr}\right)}{2000\frac{lb}{ton}}+\frac{\left(212\frac{MMBTU}{hr}*0.035\frac{lb}{MMBTU}*\frac{168\ hr}{yr}\right)}{2000\frac{lb}{ton}}+\frac{\left(124.98\frac{MMBTU}{hr}*0.011\frac{lb}{MMBTU}*\frac{4{,}380\ hr}{yr}\right)}{2000\frac{lb}{ton}}=\mathbf{21.1\frac{ton}{yr}NOx}$$

Appendix D

Air Quality Dispersion Modeling Analysis

New Nominal 44 MW Cogeneration Project

Massachusetts Institute of Technology

Submitted to:

Massachusetts Department of Environmental Protection
Bureau of Waste Prevention
One Winter Street
Boston, Massachusetts 02108

Prepared for:

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December, 2016

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D-1 INTRODUCTION

D-1.1 Project Overview – Combustion Turbine Expansion

The Massachusetts Institute of Technology (MIT) is located on 168 acres along the Cambridge side of the Charles River Basin. As part of its mission, MIT is determined to support its research and other world-changing activities with efficient, reliable power and utilities. MIT is committed to achieving this while reducing its greenhouse gas (GHG) emissions at least 32% by 2030. To this end, MIT is proposing to upgrade its on-campus power plant- a key step in developing an energy strategy that makes climate change mitigation a top priority.

The MIT Central Utilities Plant (CUP) currently provides electricity, heat, and chilled water to more than 100 MIT buildings through, a combined heat and power (CHP) process known as cogeneration-a highly efficient method of generating electrical and thermal power simultaneously. The heat and electrical power it generates is used to maintain critical research facilities, laboratories, classrooms and dormitories.

A cogeneration system has significant efficiency and environmental advantages, as described by the Massachusetts Department of Environmental Protection (MassDEP)[1]:

> *"In a combined heat and power (CHP) system, the engine or combustion turbine is connected to an electrical generator for electrical power production. The hot exhaust gasses from the engine or combustion turbine are directed through a heat recovery system, such as a boiler, to recover thermal energy for use in heating, cooling, or other uses. This approach eliminates the need for a second combustion unit and therefore eliminates the emissions such a combustion unit would produce. CHP systems make more efficient use of fuel, such as natural gas or fuel oil, than two, separate stand alone, combustion units, one for electricity and one for thermal energy such as steam thus reducing the net emissions of greenhouse gas and other air contaminants."*

Since 1995, the CUP has consisted of a Siemens (ABB) GT10A Combustion Turbine Generator (CTG), a heat recovery steam generator (HRSG), an electric generator rated at approximately 21 Megawatt (MW), and ancillary equipment, all located in Building 42. The CUP also houses five boilers, designated as Boilers Nos. 3, 4, 5, 7 and 9, an emergency generator, and a number of cooling towers. Currently, the cogeneration system meets about 60% of campus electricity needs, and the steam generated from waste heat is used for campus heating and cooling (through steam-driven chillers).

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1 Proposed Amendments to 310 CMR 7.00, March 2008

MIT's proposed project would enable its power plant to meet nearly 100% of anticipated campus electric and thermal needs using cogeneration, enhancing on-campus power reliability in the event of a utility outage while also reducing MIT's GHG emissions by approximately 10%. The project involves retiring the plant's existing CTG (now reaching the end of its useful life) and installing two nominal 22 MW CTGs and two dedicated HRSGs designed with natural gas-fired duct burners. In addition, as part of the this project, MIT will eliminate the burning of No. 6 fuel oil in existing boilers, significantly lowering nitrogen oxides (NO_x) and regulated pollutant emissions.

Each of the new CTGs will fire natural gas purchased and delivered to the CUP under a firm gas contract. In the event that the natural gas supply is interrupted by the supplier or is otherwise unavailable to be combusted in the equipment, each CTG will be able to operate using ultra-low sulfur diesel (ULSD) as a backup fuel. Each CTG will exhaust to a HRSG. This system will be cleaner and more efficient overall when compared with the existing system. For example, the system's state-of-the-art emissions controls will include selective catalytic reduction (SCR) for NO_x control and an oxidation catalyst for the control of carbon monoxide (CO) and volatile organics (VOC). These controls are expected to reduce NO_x by 90% as compared to the existing CTG, which is not equipped with this technology.

D-1.2 Project Overview – Other Proposed Changes

In addition to installing two new CTGs, MIT proposes the following other changes:

- Addition of a 2 MW ULSD-fired cold-start engine unit to provide emergency power to start the CTGs when grid electricity is unavailable.

- As mentioned above, existing Boilers Nos. 3, 4, and 5 will cease burning No. 6 fuel oil and will only burn natural gas, with ULSD as a backup fuel for up to the equivalent heat input of 48 hours per year for testing and up to the equivalent heat input of 168 hours per year including testing and periods when natural gas is unavailable.

- This fuel changeover will occur within 12 months of the startup of the new CTGs. This will allow for adequate time to finish construction and remove the existing No. 6 fuel oil tanks. The boilers will not fire No. 6 fuel oil after initial startup (first fire) of the new CTGs.

- Existing Boilers Nos. 7 and 9 will fire natural gas only, with ULSD as a backup fuel for up to the equivalent heat input of 48 hours per year for testing and up to the equivalent heat input of 168 hours per year including testing and periods when natural gas is unavailable. This represents a substantial reduction in the ULSD operating time limitation from the current operating permit limit of 720 hours per year.[2]

D-1.3 Project Benefits

This project has been proposed and designed to improve conditions and provide benefits to MIT and the surrounding community. The intent of the project is to increase the resiliency of the campus, safeguarding crucial research and public safety by enabling MIT to function during
a power-loss event; to equip the MIT community with an efficient, reliable power source capable of supporting their groundbreaking work and experimentation; and to continue conserving energy and reducing MIT's impact on the environment.

The upgraded plant will provide a reliable source of energy that is more efficient than conventional energy sources and that will lower both GHG and pollutant emissions, as mentioned above. In addition, the upgraded plant will improve campus resiliency by placing critical equipment above the flood level, safeguarding the system to ensure that it can provide energy to MIT's campus during a flooding event.

By providing the MIT campus with a reliable power source and improving its self-sufficiency, the project will reduce the burden on the community in a power-loss situation. As a further benefit, MIT is providing Eversource Energy (formerly NSTAR) with a location inside the plant for a new regulator station that gives Eversource access to high-pressure gas. With this access, Eversource can continue providing service to this area of Cambridge even as it develops and expands. By allowing and hosting new Eversource equipment, the proposed project will also provide the City of Cambridge with a back-up gas supply for existing natural gas users, a significant public benefit.

The project is also expected to improve the surrounding community by enhancing the Albany Street streetscape, installing new lighting on public walkways, and installing new public seating.

A further benefit is the collection of rainwater on the roof of the expanded plant's new addition. This rainwater will be discharged to an existing holding basin (approximately 145,000 gallon capacity) located on the roof of Building N16. This water will be used in

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2 The original December 2015 application requested an increase in the allowable natural gas-fired operating hours for Boilers Nos. 7 and 9. MIT has withdrawn this request because further analysis of projected operations shows that the steam load will be more efficiently met using the new CHP units, however, the modeling still conservatively includes this request in the modeling.

the facility's cooling towers and will not flow into the City of Cambridge storm water system. The reuse of storm water will reduce local flooding risks and the facility's burden on the City's water and storm water systems.

D-1.4 Outline of CPA Air Quality Modeling Report

This report describes the air quality modeling analysis performed as part of the MassDEP plan approval program. The air quality analyses described in this report demonstrate that the proposed project will not violate the National Ambient Air Quality Standards (NAAQS), Massachusetts Ambient Air Quality Standards (MAAQS), PSD increments, and other applicable federal and state regulations.

The remainder of this report is organized in five sections. Section D-2 describes the federal and state air quality regulations applicable to the modeling analysis and presents the applicable air quality standards. Section D-3 provides a detailed description of the proposed Project including the design configuration, source data and the urban/rural determination for modeling, background air quality data, and the Good Engineering Practice (GEP) stack height analysis. Section D-4 describes the air quality modeling methodology and the modeling results are presented in Section D-5. Finally, Section D-6 lists the reference documents used in compiling this modeling report.

D-2 REGULATORY REQUIREMENTS

Under federal and state air laws, the MassDEP and the EPA have promulgated air quality regulations that establish ambient air quality standards and emission limits. These standards and limits impose design constraints on new facilities and provide the basis for an evaluation of the potential impacts of proposed projects on ambient air quality. This section briefly describes these regulations and their relevance to the proposed expansion of the CUP. As discussed below, regulations and guidance apply to the project as a whole or to individual components of the project (the CTGs/HRSGs, the cold-start engine, the boilers).

Prevention of Significant Deterioration review is a federally mandated program for review of new major sources of criteria pollutants or major modifications to existing sources. In Massachusetts, as of April 2011, MassDEP has "full responsibility for implementing and enforcing the federal PSD regulations."

The project as a whole triggers PSD Major Modification thresholds as follows:

- MIT is an existing major stationary source of air emissions per the federal PSD program at 40 CFR 52.21 (b)(1)(i), with potential emissions of one or more PSD pollutants above 100 tons/year for a facility with combinations of fossil-fuel boilers totaling more than 250 MMBtu/hr heat input.
- The project per 40 CFR 52.21 (b)(52) is the installation of the CTGs and associated HRSGs, the cold-start engine, and the change from No. 6 oil firing to ULSD firing in Boilers Nos. 3, 4, and 5. The restriction of ULSD operations in Boilers Nos. 7 and 9 is not a physical change or change in the method of operation.
- Per 40 CFR 52.21(a)(2)(iv), a project is a major modification for a regulated New Source Review (NSR) pollutant if it causes two types of emissions increases - a significant emissions increase, and a significant net emissions increase.
- The project will create a significant emissions increase per 40 CFR 52.21(b)(23)(i) for CO_2e, PM_{10} and $PM_{2.5}$. The emissions from the project are compared to PSD thresholds in Table A-1.
- The project will also create a significant net increase for CO_2e, PM_{10} and $PM_{2.5}$, as there are no contemporaneous emissions decreases that are enforceable as a practical matter per 40 CFR 52.21(b)(3)(vi).

Therefore, the project will be a major modification of an existing major source, subject to the requirement to obtain a PSD permit.

D-2.1 Applicable Air Quality Standards, Significant Emission Rates, Significant Impact Levels, and PSD Increments

Table D-1 shows the estimated future potential emissions from the project and the significant emission rates that trigger the applicable requirements. Potential emission rates are estimated based on performance data from the Solar Titan 250 provided by Vanderweil and proposed Best Available Control Technology (BACT) emission limits. These annual potential to emit estimates are based on the maximum permitted emission rate assuming two units with 168 hrs/yr burning ultra-low sulfur diesel (ULSD) and use of natural gas for the CTGs and duct burners on the HRSGs as necessary to meet the annual potential emission limits.

Table D-1 Project Future Potential Emissions vs. Significant Emission Rates

Pollutant	Estimated Potential Emission Rates (tpy)	Significant Emission Rate (tpy)	Significant? PSD Review Applies
NO_x	26.4	40	No
CO	15.4	100	No
PM_{10}	50.1	15	Yes
$PM_{2.5}$	50.1	10	Yes
SO_2	7.0	40	No
VOC	21.0	40	No
CO_2E	295,450	75,000	Yes

The project is subject to the PSD program for Particulate Matter and Greenhouse Gases (CO_{2e}), and must apply for and obtain a PSD Permit that meets regulatory requirements including:

- 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 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.

All of MA is designated as moderate non-attainment for the 1997 8-hr ozone standard and attainment for all other criteria pollutants. The project does not trigger Non-attainment New Source Review (NNSR) because potential NOx emissions are below the 310 CMR 7.00: Appendix A major source modification threshold of 25 tpy due to the non-attainment status for ozone. MIT is not currently a major source of VOC.

The facility cannot cause or contribute to the violation of any National or Massachusetts State Ambient Air Quality Standard (NAAQS or MAAQS) or consume more than the available PSD increment for pollutants subject to the PSD requirement. Air quality dispersion modeling is used to demonstrate compliance with these thresholds.

PSD increment is tracked on a county wide basis in Massachusetts. The PSD regulations define "minor source baseline date" at 40 CFR 52.21(b)(14)(ii) as "the earliest date after the trigger date on which… a major modification subject to 40 CFR 52.21… submits a complete application". Therefore, if the minor source baseline date has not been established for the baseline area (Middlesex County), this application will establish the baseline date when it is determined to be complete. EPA has established increment standards for PM_{10} and $PM_{2.5}$. Based on consultation with MassDEP the PM_{10} minor source baseline date was triggered on September 10th, 2001 by a PSD application from Kendall Station.

Table D-2 shows the NAAQS, significant impact levels (SILs), and PSD increments applicable at this time. The SILs are numerical values that represent thresholds of insignificant, i.e., de minimis, modeled source impacts. As shown in Table D-2, the SILs are small fractions of the health protective NAAQS. For new sources that exceed these levels, the air quality impact analysis is required to include the new source, existing interactive sources and measured background levels. If the maximum predicted impacts of a pollutant due to a proposed emission increase from the existing facility are below the applicable SILs, the predicted emissions from the proposed modification are considered to be in compliance with the NAAQS and PSD increments for that pollutant.

Table D-2 National and Massachusetts Ambient Air Quality Standards, SILs, & PSD Increments

Pollutant	Averaging Period	NAAQS/MAAQS ($\mu g/m^3$)		Significant Impact Level ($\mu g/m^3$)	PSD Increments ($\mu g/m^3$)	
		Primary	Secondary		Class I	Class II
NO_2	Annual (1)	100	Same	1	2.5	25
	1-hour (2)	188	None	7.5	None	None
SO_2	Annual (1)	80	None	1	2	20
	24-hour (3)	365	None	5	5	91
	3-hour (3)	None	1300	25	25	512
	1-hour (4)	196	None	7.8	None	None
$PM_{2.5}$	Annual (1)	12	15	0.3	1	4
	24-hour (5)	35	Same	1.2	2	9
PM_{10}	24-hour (7)	150	Same	5	8	30
CO	8-hour (3)	10,000	Same	500	None	None
	1-hour (3)	40,000	Same	2,000	None	None
Ozone	8-hour (8)	147	Same	N/A	None	None
Pb	3-month (1)	1.5	Same	N/A	None	None

(1) Not to be exceeded
(2) 98th percentile of 1-hour daily maximum concentrations, averaged over 3 years
(3) Not to be exceeded more than once per year.
(4) 99th percentile of 1-hour daily maximum concentrations, averaged over 3 years
(5) 98th percentile, averaged over 3 years
(6) Not to be exceeded more than once per year on average over 3 years
(7) Annual fourth-highest daily maximum 8-hr concentration, averaged over 3 years

Note that in January 2013, the Circuit Court decision[3] vacating the $PM_{2.5}$ significant monitoring concentration does not preclude the use of the SILs for $PM_{2.5}$ entirely, but requires monitoring data be presented. If the monitoring data shows that the difference between the $PM_{2.5}$ NAAQS and the $PM_{2.5}$ monitored background concentration in the area is greater than the EPA $PM_{2.5}$ SIL value, then EPA believes it would be sufficient to conclude that a proposed source with a $PM_{2.5}$ impact below the $PM_{2.5}$ SIL value will not cause or contribute to a violation of the $PM_{2.5}$ NAAQS and to forego a more comprehensive modeling analysis for $PM_{2.5}$.

For the source impact analysis for the $PM_{2.5}$ NAAQS, the analysis should address impacts of direct $PM_{2.5}$ emissions and/or $PM_{2.5}$ precursor emissions based upon the total amount of these emissions as compared to the respective significant emission rates (SERs).

For the project, it is deemed that it is not necessary to address the secondary formation of $PM_{2.5}$ in the NAAQS analysis. Based on Table III-1 in the EPA $PM_{2.5}$ guidance (May, 2014), the project falls into Case 2 which does not include a secondary impacts approach, Case 2 is defined as the situation where the direct $PM_{2.5}$ emissions are greater than 10 tpy and the precursor emissions of NO_x and SO_2 are individually less than 40 tpy.

3 http://www.epa.gov/nsr/documents/20130304qa.pdf.

D-3 PROJECT DESCRIPTION

D-3.1 Description of Project Site

MIT is a world-class educational institution which admitted its first students in 1865. Teaching and research—with relevance to the practical world as a guiding principle—continue to be its primary purpose. MIT is independent, coeducational, and privately endowed. Its five schools and one college encompass numerous academic departments, divisions, and degree-granting programs, as well as interdisciplinary centers, laboratories, and programs whose work cuts across traditional departmental boundaries.

As an academic and research facility, MIT has steam and electricity reliability needs that exceed those of typical industrial facilities. The MIT CUP has been sized to provide nearly 100% of the Institute's thermal and electrical power needs during most operating and weather conditions. The thermal and electrical energy generated is used to maintain critical research facilities, laboratories, classrooms and dormitories in the event of a power outage, gas curtailment, or other emergency.

The Central Utility Plant (CUP) is housed in Building 42 (N16, N16A, N16C and 43 on MIT campus maps) which is located between Vassar Street and Albany Street in Cambridge, MA. The new CTGs would be housed in an addition to Building 42 to be built on the site of an existing parking lot along Albany Street between the cooling towers and an existing parking garage. The addition would be approximately 184′ x 118′ by 63′ above ground level (AGL) with two approximately 167′ high AGL flues centrally co-located in a common stack structure. There will be a flue for each CTG vented through its respective Heat Recovery Steam Generator (HRSG). The cold start emergency engine stack will be roof-mounted and will have its own exhaust vent above its housing (93.5′ high AGL). An aerial locus of the area around the new project is shown in Figure D-1. The proposed new cogeneration addition and the proposed site for the new CTG stacks and new 2 MW cold start emergency engine stack are shown.

Table D-3 describes the key equipment at the CUP and lists the equipment designation abbreviations used in the operating permit (Application MBR-95-OPP-026).

Table D-3 Key Existing Equipment at the MIT Plant

Turbine No. 1	ABB GT10 (GT-42-1A) and Heat Recovery Steam Generator No. 1 (HRSG-42-1B) (collectively the Cogeneration Unit)
Boiler No. 3	Wickes 2 drum type R dual fuel (BLR-42-3)
Boiler No. 4	Wickes 2 drum type R dual fuel (BLR-42-4)
Boiler No. 5	Riley type VP dual fuel (BLR-42-5)
Generator No. 01	Emergency Diesel Generator Caterpillar No. 3516B 2MW (DG-42-6)
Boiler No. 7	Indeck Dual Fuel firing natural gas with ULSD backup (BLR-42-7)
Boiler No. 9	Rentech Boiler rated at 125 MMBtu/hr firing natural gas with Ultra Low Sulfur Diesel (ULSD) backup (BLR-42-9)
Cooling Towers	Wet mechanical towers Nos. 7,8,9,10, 11, 12, 13.

D-3.2 Project Description

The proposed project consists of two nominal 22 MW Solar Titan 250 CTGs fired primarily on natural gas. Backup ULSD will be used for up to the equivalent heat input of 48 hours per year for testing and up to the equivalent heat input of 168 hours per year including testing and periods when natural gas is interrupted by the supplier or is otherwise unavailable to be combusted in the equipment. Each CTG will exhaust to its own HRSG with a nominal 134 MMBtu/hr (HHV) gas-fired HRSG. The HRSG will include SCR for NO_x control and an oxidation catalyst for CO and VOC control. The two new CTGs with HRSGs will be located in an addition to Building 42 to be built on the site of an existing parking lot along Albany Street between the cooling towers and an existing parking garage. There will be two 167′ AGL high flues centrally co-located in a common stack structure. There will be a flue for each CTG vented through its respective HRSG system. The cold start engine flue will be located atop its housing (93.5′ AGL).

Pending approvals, MIT intends to begin installing the new CTGs in 2019 and complete installation and shakeout in late 2019 or early 2020. The existing Siemens CTG will be fully retired following completion of installation and shakeout for both of the new units in 2020. At no time will the existing Siemens CTG be operating at the same time as the new Solar Titan 250 CTGs.

In addition to the two new CTGs, MIT plans to add a 2 MW ULSD-fired cold-start engine unit to be used to start the CTGs in emergency conditions.

As a result of this project, existing Boiler Nos. 3, 4, and 5 will cease burning No. 6 fuel oil and will burn only natural gas, with ULSD as a backup fuel for up to the equivalent heat input of 48 hours per year for testing and up to the equivalent heat input of 168 hours per year including testing and periods when natural gas is unavailable.

Also, existing Boilers Nos. 7 and 9 will fire natural gas only, with ULSD as a backup fuel for up to the equivalent heat input of 48 hours per year for testing and up to the equivalent heat input of 168 hours per year including testing and periods when natural gas is unavailable. This is a substantial reduction in ULSD operating time from the current operating permit limit of 720 hours per year.

As an unrelated project, MIT has recently replaced cooling towers 3 and 4 with three new cooling towers (towers 11, 12, and 13). Cooling towers 1, 2, 5, and 6 are retired. Towers 7, 8, 9, and 10 will remain. The cooling tower replacements do not rely on the proposed project and vice-versa; the replacement cooling towers are not required for the proposed project to operate, and the proposed project does not need to be constructed for MIT to gain full use of the replacement cooling towers. Replacement of the cooling towers did not trigger Massachusetts plan approval thresholds (potential emissions less than one ton per year). The projects were funded and constructed separately. Based on a pre-application meeting with MassDEP on July 29, 2014, the changes to the cooling towers are addressed in this air quality dispersion modeling.

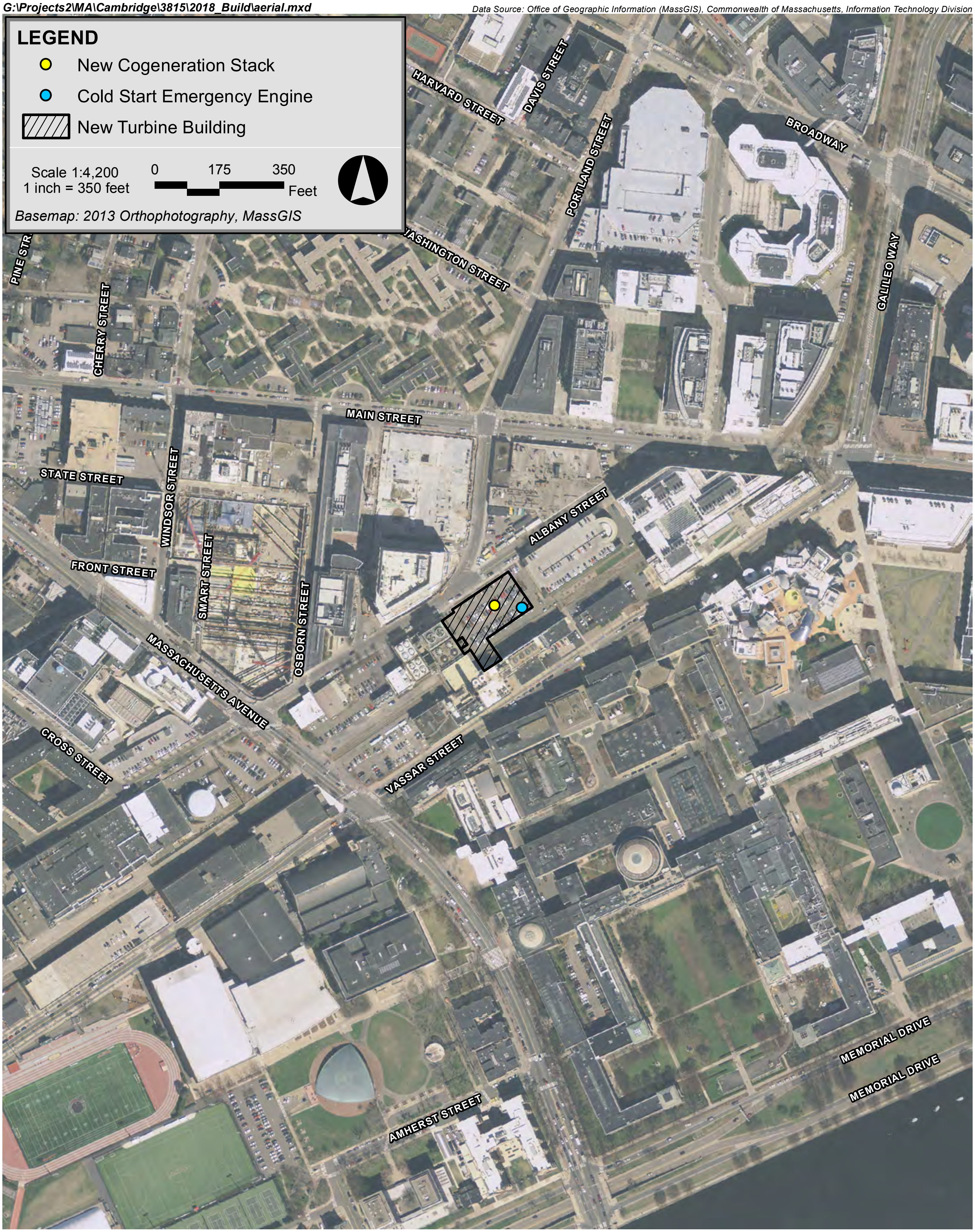
The project layout is shown in Figure D-2. MIT will be retiring some of the existing wet mechanical cooling towers and adding three new ones. Tower #1, 2, 3, 4, 5, 6 will be taken out of service while Towers #11, 12, and 13 will be added. Towers #7, 8, 9 and 10 will remain. Figure D-3 shows the locations of the existing cooling towers, and the cooling tower configuration once the project is built is shown in Figure D-4.

D-3.3 Source Data

In addition to modeling the impacts from the new units, the project includes modeling of the existing units at the MIT CUP to determine full facility impacts. Some modifications are proposed for the operations of the existing units while operating coincident with the new CTGs, including new restrictions are proposed on oil firing for existing Boilers Nos. 3, 4 & 5, 7 & 9. A range of potential operating loads (40%, 50%, 65%, 75%, and 100%) were modeled for the new units using a range of ambient temperatures (0°, 50°, & 60° F). The parameters for each operating case are listed in Attachment A. The new CTGs may burn natural gas with a backup fuel of ULSD. Both options over a range of loads and ambient temperatures were modeled to determine the case resulting in the highest air quality impact of each pollutant. The HRSG with duct burners will fire gas only but can be used during gas or oil firing of the CTGs. The worst case scenario is then modeled with the existing facility to demonstrate compliance with the NAAQS. The cooling tower emissions are below the MassDEP threshold for inclusion in air quality modeling, however because this is a PSD project for $PM_{2.5}$, the cooling towers are included in the modeling analysis at the request of MassDEP.

Two operational configurations shown in Table D-4 have been modeled, i.e. one new CTG operating through the HRSG, and 2 new CTGs operating through their HRSG's. For the one CTG case, both CTG 1 and CTG 2 stacks were modeled in the load analysis and the worst case location was carried throughout the modeling. When modeling the case of the two new CTGs operating through their HRSG's their plumes have been merged using an effective diameter to represent the area of the two individual flues.

Data Source: Office of Geographic Information (MassGIS), Commonwealth of Massachusetts, Information Technology Division



MIT Cogeneration Project **Cambridge, Massachusetts**

Figure D-1

Aerial Locus Map

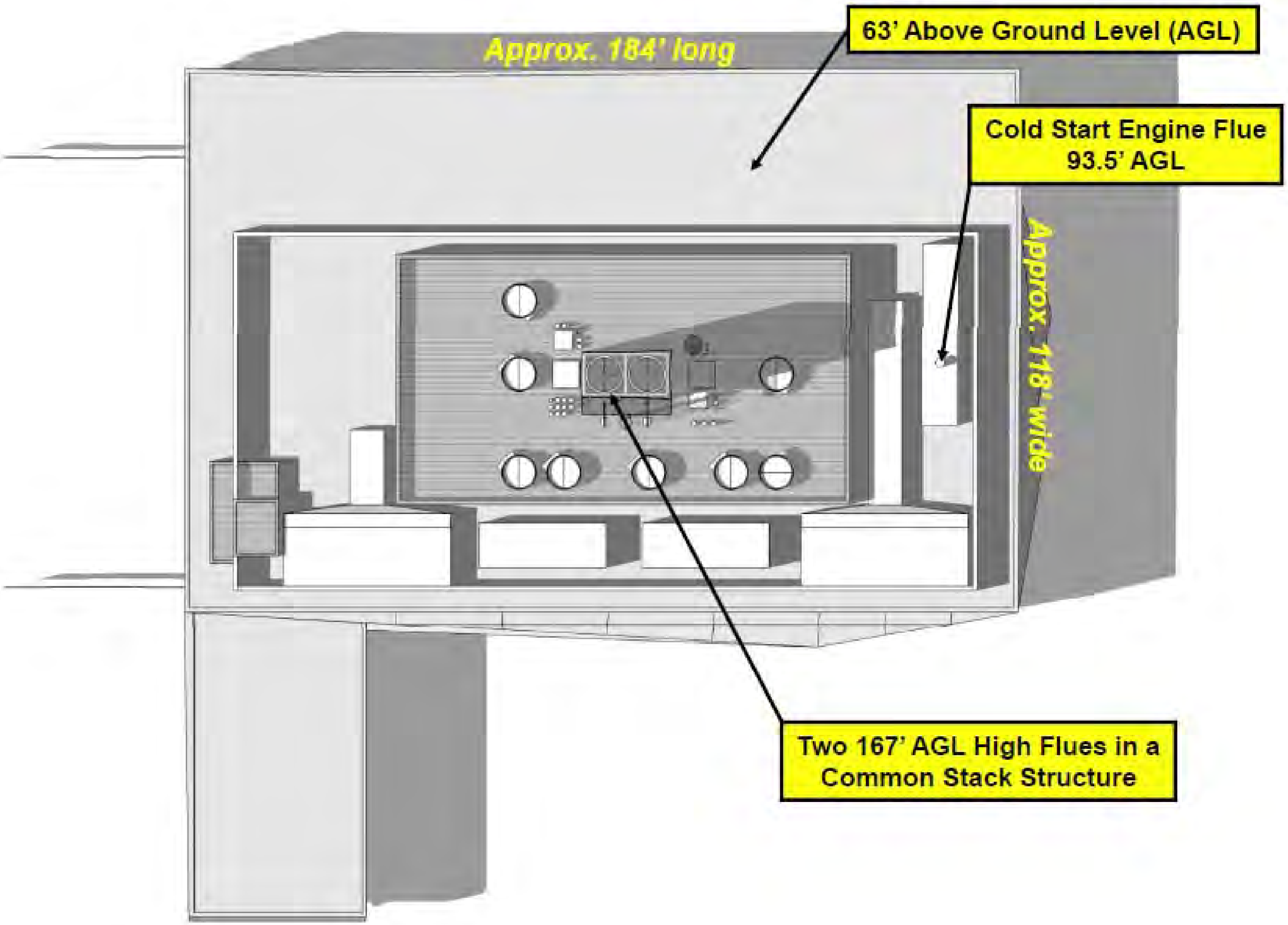


Figure D-2
Project Layout/Site Plan

Figure D-3

Existing Cooling Tower Locations

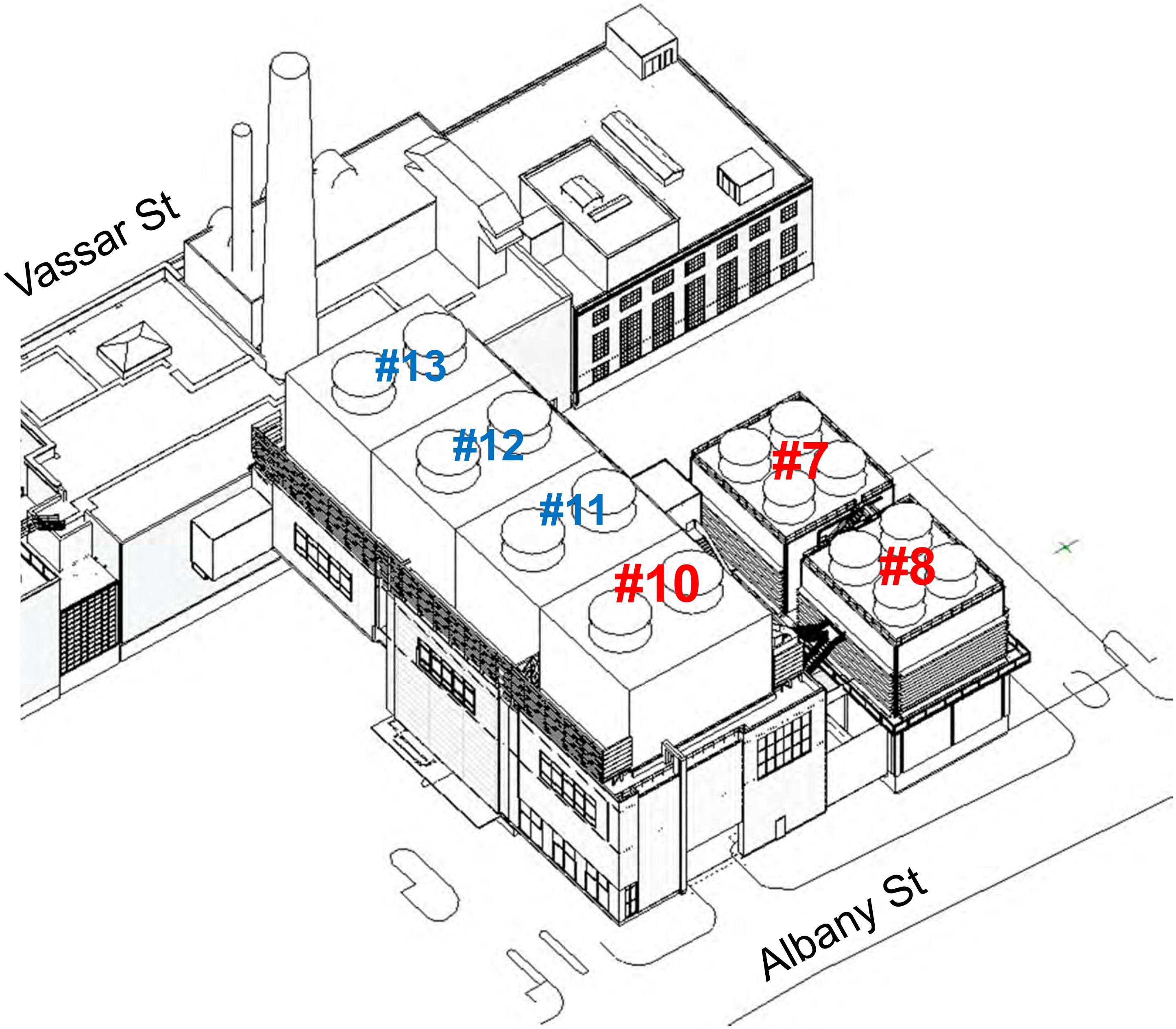


Figure D-4

Final Build Cooling Tower Locations (existing-red, new-blue)

Table D-4 Operational Scenarios

Scenario	New CTG Configuration	2MW Cold Start Emergency Engine	Additional MIT Sources Operating
1	1 CTG with HRSG	included	Turbine No.1; Boilers No.3,4,5; Boilers No.7,9; Generator No.01 Cooling TowersNo. 7,8,9,10,11,12,13
2	2 CTGs with HRSG	included	Boilers No.3,4,5; Boilers No. 7,9; Generator No. 01 Cooling Towers No. 7,8,9,10,11,12,13

Table D-5 summarizes the physical stack parameters for the new stacks and cooling towers. Note that the cooling towers have multiple cells, denoted with a letter in the naming convention. The UTM coordinates are located in zone 19.

Table D-5 Physical Stack Characteristics for the New Sources

Stack	UTM E (m)	UTM N (m)	Base Elevation (m)	Stack Height (m)	Stack Diameter (m)
CTG/HRSG 1	327593.31	4692056.99	5.5	50.9	2.1
CTG/HRSG 2	327595.85	4692058.57	5.5	50.9	2.1
Merged CTG Stack	327594.54	4692057.79	5.5	50.9	3.0
2 MW Cold Start Emergency Engine	327612.55	4692070.18	5.5	28.5	0.61
Cooling Tower 11A	327552.38	4692017.83	2.73	29.7	6.8
Cooling Tower 11B	327545.00	4692012.54	2.73	29.7	6.8
Cooling Tower 12A	327558.64	4692008.53	2.73	29.7	6.8
Cooling Tower 12B	327550.46	4692003.71	2.73	29.7	6.8
Cooling Tower 13A	327563.45	4692001.47	2.73	29.7	6.8
Cooling Tower 13B	327555.91	4691996.01	2.73	29.7	6.8

Oil is intended to be used only in the case of gas interruption (curtailment, gas supply emergency, or any required testing), however it is still included in the modeling. The source parameters and emission rates are shown in Tables D-6, and D-7 for the worst case load conditions for each pollutant and averaging time. The source parameters and emission rates for the 2 MW cold start emergency engine and cooling towers #11-13 are provided in Table D-8.

Table D-6 New CTG Source Characteristics and Emission Rates for 1 CTG with HRSG (Operational Scenario 1)

Pollutant	Avg. Period	Exit Velocity. (m/s)	Exit Temp (K)	Emission Rate (g/s)	Fuel	Load Condition
SO_2	1-Hour	19.7	355.4	0.12	NG	Case 1: 50° F, Turbine A 100% Load, Duct Burner On
	3-Hour	19.7	355.4	0.12	NG	Case 1: 50° F, Turbine A 100% Load, Duct Burner On
	24-Hour	19.7	355.4	0.12	NG	Case 1: 50° F, Turbine #A 100% Load, Duct Burner On
	Annual	17.2	355.4	0.12[1]	NG	I. Annual, Duct Burners On, Turbine A
NO_x	1-Hour	21.5	380.4	1.11	ULSD	Case 9: 60° F, Turbine B, 100% Load, Duct Burner On
	Annual	17.2	355.4	0.35[1]	NG	I. Annual, Duct Burners On, Turbine A
PM_{10}	24-Hour	21.5	380.4	1.39	ULSD	Case 9: 60°F, Turbine A, 100% Load, Duct Burner On
$PM_{2.5}$	24-Hour	21.5	380.4	1.39	ULSD	Case 9: 60°F, Turbine A, 100% Load, Duct Burner On
	Annual	17.2	355.4	0.88[1]	NG	I. Annual, Duct Burners On, Turbine A
CO	1-Hour	21.5	380.4	0.62	ULSD	Case 9: 60° F, 100% Load, Duct Burners On, Turbine A
	8-Hour	21.5	380.4	0.62	ULSD	Case 9: 60° F, Turbine B, 100% Load, Duct Burner On

[1] Emission rate reflects the potential emission limit specified in the air plan approval application.

Table D-7 New CTG Source Characteristics and Emission Rates for 2 CTGs with HRSGs (Operational Scenario 2)

Pollutant	Avg. Period	Exit Velocity. (m/s)	Exit Temp (K)	Emission Rate[1] (g/s)	Fuel	Load Condition[2]
SO_2	1-Hour	19.7	355.4	0.25	NG	Case 2a: 50°F, 100% Load, NG, Duct Burner On
	3-Hour	19.7	355.4	0.25	NG	Case 2a: 50°F, 100% Load, NG, Duct Burner On
	24-Hour	17.2	355.4	0.21	NG	Case 2c: 60°F, 75% Load, NG, Duct Burner On
	Annual	17.2	355.4	0.25[3]	NG	II. Annual
NO_x	1-Hour	24.1	380.4	2.40	ULSD	Case 2.j: 0°F, 100% Load, ULSD, Duct Burner On
	Annual	17.2	355.4	0.70[3]	NG	II. Annual
PM_{10}	24-Hour	19.2	380.4	2.35	ULSD	Case 2.k: 60°F, 75% Load, ULSD, Duct Burner On
$PM_{2.5}$	24-Hour	24.1	380.4	2.99	ULSD	Case 2.j: 0°F, 100% Load, ULSD, Duct Burner On
	Annual	17.2	355.4	1.76[3]	NG	II. Annual

Table D-7 New CTG Source Characteristics and Emission Rates for 2 CTGs with HRSGs (Operational Scenario 2) (Continued)

Pollutant	Avg. Period	Exit Velocity. (m/s)	Exit Temp (K)	Emission Rate[1] (g/s)	Fuel	Load Condition[2]
CO	1-Hour	19.2	380.4	1.05	ULSD	Case 2.k: 60°F, 75% Load, ULSD, Duct Burner On
	8-Hour	21.5	380.4	1.24	ULSD	Case 2.i: 60°F, 100% Load, ULSD, Duct Burner On

[1] Emission rate is the total for both CTGs.
[2] Condition is modeled as a merged flue for CTG 1 and 2.
[3] Emission rate reflects the potential emission limit specified in the air plan approval application.

Table D-8 New 2 MW Cold Start Emergency Engine and Cooling Tower Source Characteristics and Emission Rates

Source	Exit Temp (K)	Exit Velocity (m/s)	Short Term/ Annual	PM_{10}/ $PM_{2.5}$ (g/s)	SO_2 (g/s)	NO_x (g/s)	CO (g/s)
2 MW Cold Start Emergency Engine	673.2	24.7	Short-Term	1.6E-2[1]	3.7E-3	1.5E-1[2]	2.8E-1
			Annual[2]	1.7E-3	1.3E-4	1.5E-1	-
Cooling Towers #11, 12, 13 per cell (6)	298.7	8.0	N/A	4.4E-3	N/A	N/A	N/A

[1]Emission rate is scaled to reflect that MIT will not operate this engine any more than 8 hours in a given day

[2]Emission rate is scaled by 300/8760 per EPA Guidance (http://www.epa.gov/nsr/documents/20100629no2guidance.pdf) to reflect the intermittent operation of the emergency engine.

MIT Existing Facility Sources

As part of the permitting effort, MassDEP has the option to require demonstration that the full MIT facility will comply with the NAAQS. Boiler No. 9 was recently permitted (2011) and full facility compliance was achieved then. However, since then, there have been new nearby structures either built or proposed to be built. This modeling analysis takes those new structures into account and the operational changes to the existing sources described previously. . This modeling analysis also relies upon the load analysis conducted during the Boiler No. 9 permitting effort (Table D-10 reproduces the results of this load analysis). During the interim period where the existing CTG is still operating in conjunction with one new CTG/HRSG, Boilers No. 7 & 9 will not concurrently burn ULSD, after the existing CTG is retired this restriction will be lifted and in the event of an emergency both Boilers 7 & 9 would be capable of burning ULSD. The source parameters and emission rates used for this analysis are presented in Tables D-9, D-10 and D-11.

Emissions from Boilers No. 3, 4 and 5 are vented out the brick stack on the roof of the CUP. The existing CTG No. 1 stack and the emergency generator stack are also located on the roof of the existing CUP. Existing Boilers No.7 and #9 are located adjacent to Building N16A at 60 Albany Street, across the railroad tracks from the main CUP building. Exhaust from both Boiler No. 7 and Boiler No. 9 are combined and vent through a common stack.

Table D-9 Physical Stack Characteristics for the MIT Existing Sources

Stack	UTM E (m)	UTM N (m)	Base Elevation (m)	Stack Height (m)	Stack Diameter (m)
Boilers 7 & 9 Stack	327510.2	4692006.1	2.73	35.1	1.7
Boilers 3,4,5	327570.3	4691983.3	2.74	54.0	3.4
Turbine #1	327575.2	4691973.9	2.74	36.6	1.8
Generator #01	327595.7	4691984.2	2.74	19.4	0.4
Cooling Tower 1A	327604.2	4692009.7	2.73	18.1	4.4
Cooling Tower 1B	327609.4	4692013.3	2.73	18.1	4.4
Cooling Tower 2A	327614.7	4692016.6	2.73	18.1	4.4
Cooling Tower 2B	327619.5	4692020.0	2.73	18.1	4.4
Cooling Tower 3A	327545.7	4692010.4	2.73	20.6	6.2
Cooling Tower 3B	327541.6	4692016.3	2.73	20.6	6.2
Cooling Tower 4A	327553.7	4692015.4	2.73	20.6	6.2
Cooling Tower 4B	327549.8	4692021.9	2.73	20.6	6.2
Cooling Tower 5	327571.0	4691990.9	2.73	17.4	2.5
Cooling Tower 6	327576.8	4691994.7	2.73	17.4	2.5
Cooling Tower 7A	327522.7	4691998.6	2.73	20.6	4.9
Cooling Tower 7B	327528.5	4692002.2	2.73	20.6	4.9
Cooling Tower 7C	327518.9	4692004.9	2.73	20.6	4.9
Cooling Tower 7D	327523.9	4692008.3	2.73	20.6	4.9
Cooling Tower 8A	327513.3	4692013.3	2.73	20.6	5.0
Cooling Tower 8B	327518.5	4692016.4	2.73	20.6	5.0
Cooling Tower 8C	327514.5	4692022.9	2.73	20.6	5.0
Cooling Tower 8D	327509.3	4692019.3	2.73	20.6	5.0
Cooling Tower 9A	327501.1	4691981.7	2.73	10.0	4.0
Cooling Tower 9B	327497.6	4691980.0	2.73	10.0	4.0
Cooling Tower 9C	327493.8	4691976.7	2.73	10.0	4.0
Cooling Tower 9D	327490.2	4691975.0	2.73	10.0	4.0
Cooling Tower 10A	327542.2	4692034.4	2.73	30.2	8.0
Cooling Tower 10B	327534.2	4692027.3	2.73	30.2	8.0

Table D-10 Worst-case Operating Conditions for Existing MIT Stacks by Pollutant and Averaging Period[1]

Pollutant	Averaging Period	Boiler No. 7/9 Stack	Boilers #3,4,5	CTG
PM_{10}	Short-term	Boiler No. 9 alone full load	Full load	Full load
	Annual	Boiler No. 9 alone full load	Minimum Load	Full load
$PM_{2.5}$	Short-term	Boilers No. 7 and #9[2]	Full load	Full load
	Annual	Boiler No. 9 alone full load	Minimum Load	Full load
NO_2	Short-term	Boiler No. 9 alone full load	Full load	Full load
	Annual	Boiler No. 9 alone full load	Full load	Full load
SO_2	Short-term	Boiler No. 7 and 9[2]	Full load	Full load
	Annual	Boiler No. 9 alone full load	Minimum Load	Full load
CO	Short-term	Boiler No. 7 and #9[2]	Full load	Full load

[1]Reproduced from Table F-5 of the Boiler 9 Modeling Report, dated February 2011.

[2]For Operational Scenario 1, Boilers No. 7 & 9 will not concurrently burn ULSD therefore, the worst case scenario is Boiler No. 9 alone on full load burning ULSD.

Table D-11 Existing MIT Source Characteristics and Emission Rates

Stack	Operating Condition	Short-Term/ Annual	Exit Temp (K)	Exit Velocity (m/s)	PM_{10} (g/s)	$PM_{2.5}$ (g/s)	SO_2 (g/s)	NO_x (g/s)	CO (g/s)
Boilers No. 7 & 9	Boilers No. 7 & 9 (full load)	Short-Term	473.7	17.68	0.83	0.83	4.16E-2	2.09	0.97
		Annual			-	0.29	4.16E-2	0.35	-
	Boiler No. 9 only (full load)	Short-Term	430.4	8.06	0.45	0.45	2.27E-2	1.50	0.53
		Annual			-	0.164	2.27E-2	0.20	-
Boilers No. 3,4,5	Full Load	Short-Term	430.4	5.91	2.62	2.62	7.18E-2	14.27	1.90
		Annual			-	1.45	7.18E-2	9.61	-
	Minimum Load	Short-Term	405.4	0.73	0.32	0.32	8.82E-3	1.76	0.23
		Annual			-	0.179	8.82E-3	1.18	-
Turbine #1	Full Load	Short-Term	405.4	35.79	1.756	1.756	5.92E-2	5.87	0.88
		Annual			-	0.63	5.92E-2	3.13	-
Generator	Full Load	Short-Term	790.3	61.94	9.58E-2	9.58E-2	4.03E-3	0.15[1]	0.28
		Annual			-	3.28E-3	1.39E-4	0.15	N/A
Cooling Tower 1 per cell (2)	N/A	N/A	298.7	8.0	3.33E-3	3.33E-3	N/A	N/A	N/A
Cooling Tower 2 per cell (2)	N/A	N/A	298.7	8.0	3.33E-3	3.33E-3	N/A	N/A	N/A
Cooling Tower 3 per cell (2)	N/A	N/A	298.7	8.0	5.86E-3	5.86E-3	N/A	N/A	N/A
Cooling Tower 4 per cell (2)	N/A	N/A	298.7	8.0	5.18E-3	5.18E-3	N/A	N/A	N/A
Cooling Tower 5	N/A	N/A	298.7	8.0	2.15E-3	2.15E-3	N/A	N/A	N/A
Cooling Tower 6	N/A	N/A	298.7	8.0	2.15E-3	2.15E-3	N/A	N/A	N/A
Cooling Tower 7 per cell (4)	N/A	N/A	298.7	8.0	4.91E-3	4.91E-3	N/A	N/A	N/A
Cooling Tower 8 per cell (4)	N/A	N/A	298.7	8.0	4.91E-3	4.91E-3	N/A	N/A	N/A
Cooling Tower 9 per cell (4)	N/A	N/A	298.7	8.0	2.65E-3	2.65E-3	N/A	N/A	N/A
Cooling Tower 10 per cell (2)	N/A		298.7	8.0	4.40E-3	4.40E-3	N/A	N/A	N/A

[1] This emission rate is scaled by the permitted hours of operation per EPA Guidance. (http://www.epa.gov/nsr/documents/20100629no2guidance.pdf)

D-3.4 Urban/Rural Analysis

The USGS topographic quadrangle maps in the vicinity of the project were used to determine whether the land-use pattern in the environs of MIT is urban or rural for modeling purposes. The EPA recommended procedure in *The Guideline on Air Quality Models* (EPA, 2005) was followed to determine urban/rural classification using the Auer (1977) land use technique. The land use within the total area circumscribed by a 3 kilometer radius circle around the MIT CUP has been classified using the meteorological land use typing scheme shown in Table D-12. If the land use types I1, I2, C1, R2 and R3 account for 50 percent or more of the area, then urban dispersion coefficients should be used. Figure D-5 shows the 3 kilometer radius around the project site. Observation of USGS topographic map shows that the area within a 3 k radius of the MIT CUP is a predominantly urban setting. Therefore urban dispersion coefficients were used in the AERMOD modeling.

Table D-12 Identification and Classification of Land Use

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

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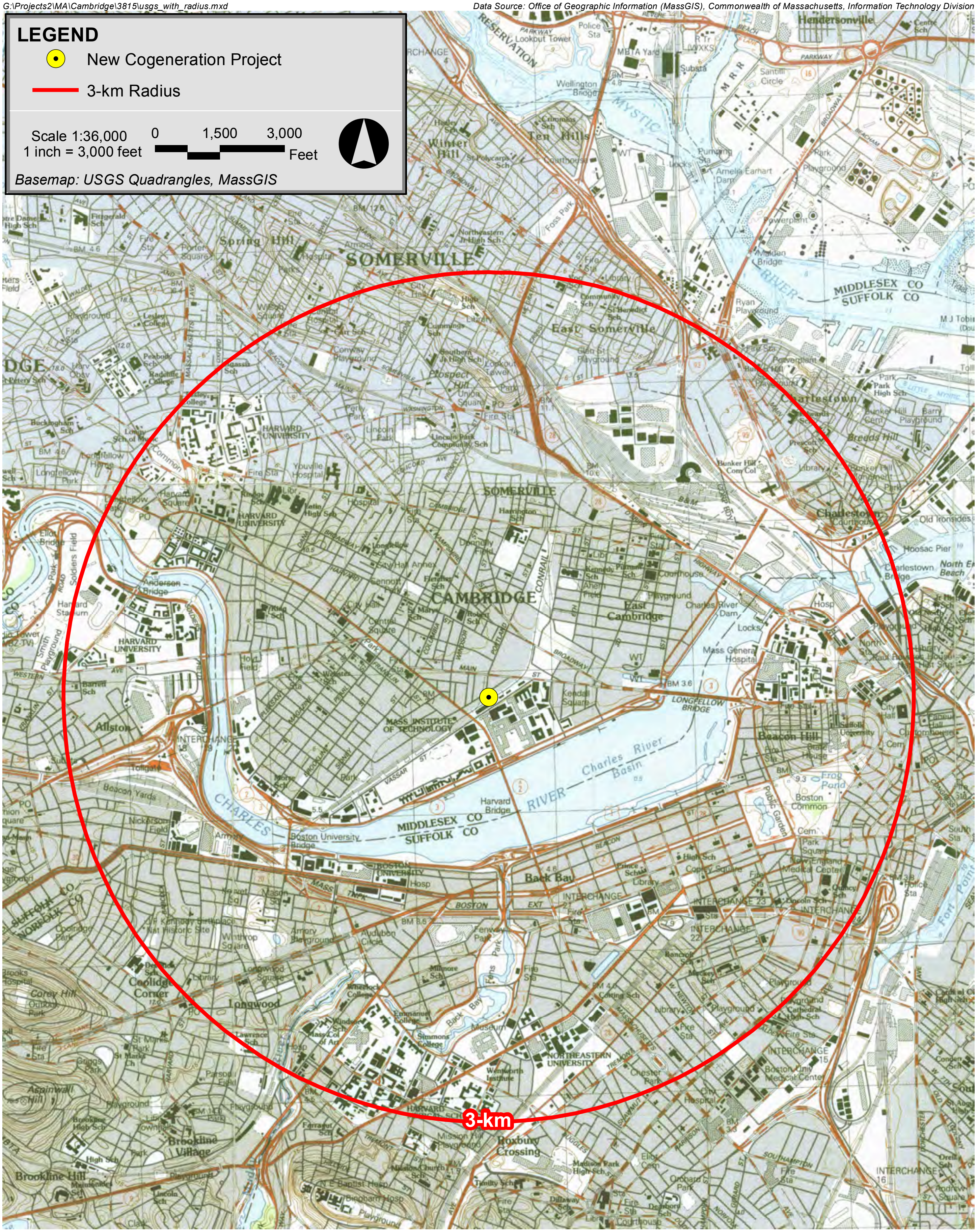
Data Source: Office of Geographic Information (MassGIS), Commonwealth of Massachusetts, Information Technology Division



MIT Cogeneration Project Cambridge, Massachusetts

Epsilon ASSOCIATES INC.

Figure D-5

USGS Topographic Map with 3-km Radius

D-3.5 Background Air Quality Data

Modeled concentrations due to emissions from the project are added to ambient background concentrations to obtain total concentrations. These total concentrations were compared to the NAAQS and MAAQS. To estimate background pollutant levels representative of the area, the most recent air quality monitor data reports published by MassDEP were obtained for 2012 through 2014. Data is also available via the EPA website (http://www.epa.gov/airquality/airdata) and was used for the 3-hour and 24-hour SO_2 averages since these are no longer included in the published monitor reports. Background concentrations were determined from the most representative available monitoring stations to the MIT CUP. The most representative monitoring site is also the closest monitoring site, located at Kenmore Square in Boston, MA, approximately 0.9 miles from the MIT CUP. The urban environment surrounding the monitor in Boston is similar to the urban environment in Cambridge near the MIT CUP. All pollutants are monitored at Kenmore Square, i.e., SO_2, CO, NO_2, PM_{10}, and $PM_{2.5}$. A summary of the background air quality concentrations based on the 2012-2014 data are presented in Table D-13. For the short-term averaging periods, the form of the standard value is used, and the highest monitored value is used for annual averages.

Table D-13 Observed Ambient Air Quality Concentrations and Selected Background Levels

Pollutant	Averaging Period	2012	2013	2014	Background Level	NAAQS
SO_2 ($\mu g/m^3$)	1-Hour	13.2	31.4	25.4	23.3	196
	3-Hour[a]	27.8*	36.4*	24.6*	36.4	1,300
	24-Hour[b]	14.1	15.7*	13.1*	15.7	365
	Annual	4.9	2.6	2.5	4.9	80
CO ($\mu g/m^3$)	1-Hour	1,489.8	1,489.8	1,962.4	1,962.4	40,000
	8-Hour	1,031.4	1,031.4	1,260.2	1,260.2	10,000
NO_2 ($\mu g/m^3$)	Annual	33.5	33.5	32.3	33.1	100
PM_{10} ($\mu g/m^3$)	24-Hour	28.0	50.0	53.0	53.0	150
$PM_{2.5}$ ($\mu g/m^3$)	Annual	9.0	8.0	6.0	7.7	12

Notes: (conversion factors of 1 ppm = 2,620 $\mu g/m^3$ SO_2; = 1,146 $\mu g/m^3$ CO; and 1,882 $\mu g/m^3$ NO_2 used).

* data obtained from EPA at http://www.epa.gov/airquality/airdata;

[a] Background level for 3-hr SO_2 is the highest-second-high SO_2 value (obtained from EPA website).

[b] Background level for 24-hr SO_2 and PM_{10} is based on the highest-second-high value.

[c] Background level for Annual $PM_{2.5}$ is the average concentration of three years.

For this analysis some level of temporal pairing of modeled and monitoring data was used. 24-hour $PM_{2.5}$ and 1-hour NO_2 are not represented in Table D-13 because background values of $PM_{2.5}$ and NO_2 were used in a post-processing step within AERMOD. For comparison with the 1-hr NO_2 standard, the 3-year (2012-2014) average of the 98th percentile background concentration by season and hour-of-day was used. For $PM_{2.5}$ the 3-year (2012-2014) average 98th percentile seasonal concentration was utilized consistent with the Tier 2 approach detailed in the EPA, Guidance for $PM_{2.5}$ Permit Modeling Memorandum was utilized (EPA, May 2014, EPA-454/B-14-001).

For 1-hr NO_2, the seasonal diurnal variation of measured data was taken into account (SEASHR option in AERMOD) using the 3-year (2011-2013) average of the 98th percentile background concentration by season and hour-of-day (per EPA 1-hr NO_2 memo, June 28, 2010).

MIT utilized 3-years (2012 – 2014) of $PM_{2.5}$ 24-hr monitoring concentrations from the Kenmore monitoring site (AQS 25-025-0002) for utilization in AERMOD modeling run. These monitored concentrations are on a once every three day cycle, therefore consistent with EPA guidance, the concentrations for each year were ranked and the top two concentrations removed from further consideration. The remaining concentrations were then separated into seasons by year, and the maximum value for each season was then averaged over the 3-year period.

D-3.5.1 Justification to use SILs

If the monitoring data shows that the difference between the NAAQS and the monitored background concentration in the area is greater than the EPA SIL value for that pollutant and averaging period, then EPA believes it would be sufficient to conclude that a proposed source with an impact below 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. Table D-14 presents the difference between the NAAQS and the monitored background concentration, compared to the SILs. As shown in Table D-14, all averaging periods for each pollutant has a delta between the monitored value and the NAAQS which is greater than the respective SIL, therefore use of the SILs as de minimis levels for all pollutants is appropriate.

Table D-14 Comparison of the Difference between the Monitored Air Quality Concentrations and the NAAQS to the Significant Impact Levels

Pollutant	Averaging Period	Background Level ($\mu g/m^3$)	NAAQS ($\mu g/m^3$)	Delta (NAAQS-Bkgrnd) ($\mu g/m^3$)	Significant Impact Level ($\mu g/m^3$)
SO_2	1-Hour	23.3	196	172.7	7.8
	3-Hour	36.4	1,300	1263.6	25
	24-Hour	15.7	365	349.3	5
	Annual	4.9	80	75.1	1
CO	1-Hour	1962.4	40,000	38,037.6	2,000
	8-Hour	1260.2	10,000	8,739.8	500
NO_2	1-Hour	90.9	188	97.1	7.5
	Annual	33.1	100	66.9	1
PM_{10}	24-Hour	53.0	150	97.0	5
$PM_{2.5}$	24-Hour	18.2	35	16.8	1.2
	Annual	7.7	12	4.3	0.3

D-3.6 Good Engineering Practice Stack Height Determination

The GEP stack height evaluation of the facility has been conducted in accordance with the EPA revised Guidelines for Determination of Good Engineering Practice Stack Height (EPA, 1985). The formula, as defined by the EPA guidelines, for the GEP stack height is:

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

where H_{GEP} = GEP stack height,

Hb = Height of adjacent or nearby structures,

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

Nearby = Within 5L of the stack from downwind (trailing edge) of the building.

A GEP analysis was conducted to determine the GEP formula stack height for each stack to account for potential downwash from nearby structures. The latest version of the EPA Building Profile Input Program (BPIP-Prime) was run for all stacks and buildings in the vicinity of the project to create the building parameter inputs to AERMOD. The new and proposed construction on Albany Street and Main Street (Novartis buildings) are included. A GEP height of 124 meters was calculated for each stack with the 50.8 meter tier of the new 610/650 Main Street building as the controlling structure for determining the GEP height. Figure D-6 shows the structure footprints and stack locations input into BPIP-Prime (heights are depicted in the figure). Each of the stacks modeled are below their GEP height and therefore exhaust emissions will experience the aerodynamic effects of downwash. Wind direction specific building parameters generated by BPIP-Prime were input into AERMOD to account for potential downwash from nearby structures in the dispersion calculations.

Data Source: Office of Geographic Information (MassGIS), Commonwealth of Massachusetts, Information Technology Division

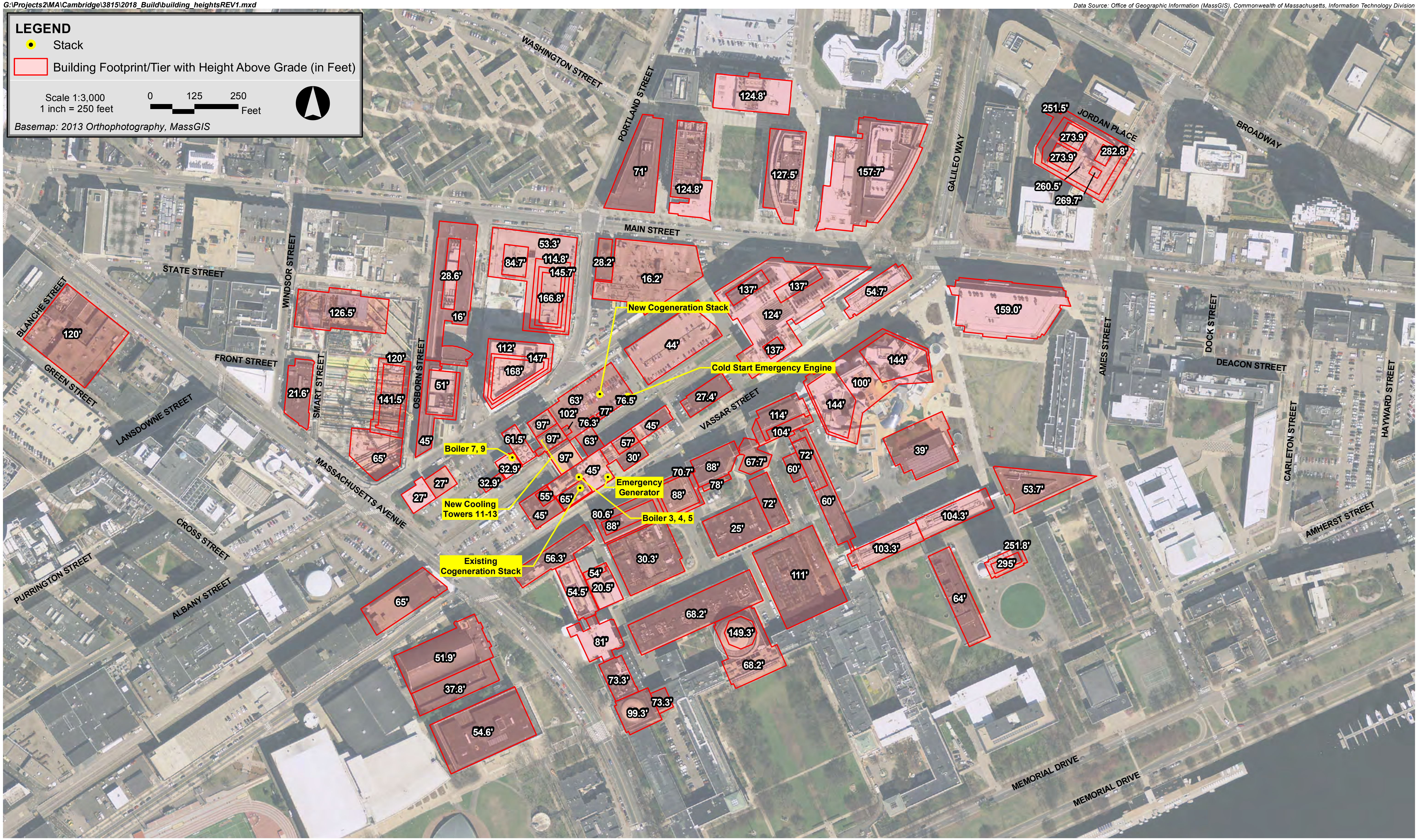


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Figure D-6

Building Footprints/Tiers and Heights Used in BPIP-Prime (Based on Anticipated Build-out by 2018)

D-4 AIR QUALITY IMPACT ANALYSES

The project conducted comprehensive air quality modeling analyses to demonstrate that the proposed project's air quality impacts would be in compliance with all state and Federal requirements. The ambient pollutant concentrations associated with the Project are addressed in the detailed air quality analysis discussed in this section. The following analyses were included:

- Load Analysis for new CTGs
- Modeling of criteria pollutants for comparison with the SILs
- Modeling of criteria pollutants for comparison with the NAAQS, including interactive source modeling for some pollutants.
- Modeling of non-criteria pollutants for comparison with the Massachusetts TELs and AALs
- Modeling for comparison with the PSD Increments for PSD pollutants
- VISCREEN modeling

Impacts of criteria emissions were modeled for comparison to ambient air quality standards. The modeling approach followed the guidance in the U.S. EPA Guideline on Air Quality Models (EPA, 2005) and the Massachusetts Modeling Guidance (MassDEP, 2011) to ensure that the ambient concentrations are protective of all applicable air quality standards.

In the New Source Review (NSR) Workshop Manual (EPA, 1990) the dispersion modeling analysis is separated into two distinct phases: 1) the preliminary analysis, and 2) a full impact analysis. In the preliminary analysis only the significant increase in potential emissions of a pollutant from a proposed new source or the significant net emissions increase of a pollutant from a proposed modification are modeled. The results of this analysis are used to determine:

- the worst-case stack parameters; and
- which criteria pollutants require a full impact analysis;
- the receptor locations to be used in the interactive modeling analysis (if necessary).

The EPA does not require a full impact analysis for a particular pollutant if the results of the preliminary analysis indicate the emissions from the proposed source or modification will not increase ambient concentrations by more than pollutant specific SILs (see Table D-2).

Per MassDEP Modeling Guidance for Significant Stationary Sources of Air Pollution (MassDEP, 2011), if impacts are below SILs, a compliance demonstration may still be required to ensure that the combined emissions from the existing facility and the proposed modification will not cause or contribute to a NAAQS violation for that pollutant.

D-4.1 Modeling Methodology

The project consists of the addition of two new CTGs and a 2MW cold start emergency engine at a new building along Albany Street, adjacent to the cooling towers. . AERMOD modeling for the each potential fuel burned at various ambient temperatures and load cases was performed for the new CTGs to determine the worst-case impact for each of the potential Operational Scenarios listed in Table D-4. Results from this analysis are presented in Section D-5.1.

The worst-case operating conditions for the new CTGs were then modeled with the 2 MW cold start emergency engine and the cooling towers to assess the criteria pollutant concentrations which are compared to the SILs presented earlier in Table D-2. Results from this analysis are presented in Section D-5.2.

If the maximum predicted impacts of a pollutant due to the emission increase from the existing facility are below the applicable SILs, the predicted emissions from the proposed modifications are considered to be in compliance with the NAAQS for that pollutant. However a compliance demonstration was conducted to ensure that the combined emissions from the existing facility and the proposed modification will not cause or contribute to a NAAQS violation for that pollutant (MassDEP, 2011). The appropriate modeled concentrations were combined with appropriate ambient background concentrations prior to comparison with the NAAQS.

If the maximum predicted impacts of a pollutant due to the emission increase from the existing facility are at or above the applicable SILs, and there are nearby sources of that pollutant that could significantly interact with emissions from the facility's proposed modification, the predicted air quality impacts from the existing facility as modified along with the predicted impacts from nearby significant sources should be added to the representative background and compared to the NAAQS for that pollutant (MassDEP, 2011).

EPA (2013) has recently adopted guidance regarding secondary $PM_{2.5}$ formation in modeling analyses.

- Case 1: If $PM_{2.5}$ emissions < 10 tpy and NOx & SO_2 emissions < 40 tpy, then no $PM_{2.5}$ compliance demonstration is required.

- Case 2: If $PM_{2.5}$ emissions > 10 tpy and NOx & SO_2 emissions < 40 tpy, then $PM_{2.5}$ compliance demonstration is required for direct $PM_{2.5}$ emission based on dispersion modeling, but no analysis of precursor emissions from the project source is necessary.

- Case 3: If $PM_{2.5}$ emissions > 10 tpy and NOx &/or SO_2 emissions > 40 tpy, then $PM_{2.5}$ compliance demonstration is required for direct $PM_{2.5}$ emission based on dispersion modeling, AND the applicant must account for impact of precursor emissions from the project source.

- Case 4: If $PM_{2.5}$ emissions < 10 tpy and NOx &/or SO_2 emissions > 40 tpy, then $PM_{2.5}$ compliance demonstration not required for direct $PM_{2.5}$ emissions, BUT the applicant must account for impact of precursor emissions from the project source.

Since this project falls into Case 2 ($PM_{2.5}$ =50.1 tpy, NOx=26.4 tpy and SO2=7.0 tpy), only direct emissions of $PM_{2.5}$ were modeled, and no analysis of precursor emissions is necessary.

In January 2013, EPA vacated the PSD rules for using the SIL for $PM_{2.5}$. As a result, EPA has allowed a modified SIL comparison to be acceptable for $PM_{2.5}$. One can justify the use of the SIL if the difference between the NAAQS and the measured background in the area is greater than the applicable SIL value (refer to discussion in Section D-3.5-1).

In addition to modeling for the criteria pollutants, an air toxic assessment was conducted with the AERMOD model. The predicted impacts of the emitted non-criteria pollutants are compared to the Massachusetts' annual average Allowable Ambient Limit values (AALs) and the 24-hour average Threshold Effects Exposure Limit values (TELs).

Since the project is PSD for particulate matter, additional air quality analyses are necessary. PSD Increment modeling is required for particulate matter (PM_{10} and $PM_{2.5}$). The determined worst-case operating condition for the new CTGs is used in the AERMOD increment modeling for Operational Scenario 2 (final building configuration for the new CTGs). The PM increment-consuming sources (.i.e., new CTGs, 2 MW cold start emergency engine, increase in gas-fired operating hours for Boilers 7 and 9 to allow year-round operation and new cooling towers) are modeled at their maximum allowable emissions rates, while the increment expanding sources at MIT (i.e., retiring existing CTG, switch from No. 6 oil to natural gas on Boilers No. 3, 4, & 5, and switch from No. 2 oil to primarily natural gas on Boilers No. 7 & 9, and retiring cooling towers) are modeled at their maximum actual emission rates (using a negative emission rate in AERMOD). Since the initial application was filed with MassDEP MIT has withdrawn the request to increase gas-fired operating hours for Boilers No. 7&9. However, these boilers have conservatively been left in the modeling analysis.

A visibility analysis was conducted using the U.S. EPA VISCREEN model for the Lye Brook Wilderness Area in southern Vermont. PSD regulations require analysis of air quality impacts on sensitive vegetation types, with significant commercial or recreational value, or sensitive types of soil.

D-4.2 Air Quality Model Selection and Options

The U.S. EPA approved air quality model used for this analysis is AERMOD (v15181). Modeling was performed to identify maximum impact conditions and comparison of receptor concentrations to applicable levels and thresholds. The modeling of the maximum impact condition for each pollutant and averaging period was based on expected operating parameters and emission rates for both fuel options presented in Tables D-5 through D-11.

The AERMOD model is a steady state plume model using Gaussian distributions that calculates concentrations at each receptor for every hour in the year. The model is designed for rural or urban applications and can be used with a rectangular or polar system of receptors that are allowed to vary with terrain. AERMOD is designed to operate with two preprocessor codes: AERMET processes meteorological data for input to AERMOD, and AERMAP processes terrain elevation data and generates receptor information for input to AERMOD. The AERMOD model was selected for the air quality modeling analysis because of several model features that properly simulate the proposed facility environs, including the following:

- Concentration averaging time ranging from one hour to one year;
- Ability to model multiple sources; and
- Estimating cavity impacts; and
- Use of actual representative hourly average meteorological data; and
- Ability to calculate simple, complex, and intermediate terrain concentrations.

The AERMOD model has incorporated the latest EPA building downwash algorithm, the Plume Rise Model Enhancements (PRIME), for the improved treatment of building downwash. PRIME can also account for the stack placement relative to the building thereby allowing for the ability to estimate impacts in the cavity region near the stack.

The AERMODView graphical user interface (GUI) provided by Lakes Environmental, Inc. (Lakes) was used to set up the model inputs for this project. Additionally, Lakes provides a multi-processor version of the AERMOD executable which allows for significantly faster processing while producing identical output to the standard EPA version. For this project, the multi-processor version of the most recent version of AERMOD was used.

A complete technical description of the AERMOD model may be found in the User's Guide for AERMOD (EPA, 2004).

Modeling for MIT was performed with all regulatory options in AERMOD set except for the assumption of 100% conversion of nitrogen oxides (NO_X) to nitrogen dioxide (NO_2).

The chemical conversion of NO_X into NO_2 is an important factor when assessing short-term NO_2 concentrations. It is determined that for short-term NO_2 impacts, the Plume Volume Molar Ratio Method (PVMRM) is the most appropriate method to be used. The PVMRM determines the conversion rate for NO_X to NO_2 based on a calculation of the NO_X moles emitted into the plume, and the amount of ozone moles contained within the volume of the plume between the source and receptor.

The PVMRM method is available as a non-regulatory-default options within the EPA-preferred AERMOD dispersion model. As a result of the non-regulatory-default status, pursuant to Sections 3.1.2.c, 3.2.2.a, and A.1.a(2) of 40 CFR Part 51, Appendix W, application of AERMOD with any non-default option is no longer considered a "preferred model" and, therefore, requires justification and approval by the Regional Office on a case-by-case basis. Use as an alternative modeling technique under Appendix W was justified in accordance with the five requirements of Section 3.2.2, paragraph (e) to MassDEP.

The following addresses each of the five requirements noted in Section 3.2.2(e) in order to justify the use of PVMRM for the purpose of determining compliance with the Federal 1-hour NO_2 standard.

3.2.2 (e)(i). The model has received a scientific peer review;

- The chemistry for the PVMRM model has received scientific peer review as noted in "Sensitivity Analysis of PVMRM and OLM in AERMOD" (MACTEC, 2004) and "Evaluation of Bias in AERMOD-PVMRM"(MACTEC, 2005). Both documents indicate that the model appears to perform as expected. The EPA suggests that the PVMRM produces a more realistic conversion of NO_X to NO_2 than other available methods.

3.2.2 (e)(ii). The model can be demonstrated to be applicable to the problem on a theoretical basis;

- The PVMRM model has been reviewed and the chemistry has been widely accepted by EPA as being appropriate for addressing the formation of NO_2 and the calculation of NO_2 concentration at receptors downwind. Additionally, the ""Sensitivity Analysis of PVMRM and OLM in AERMOD" report would indicate OLM/PVMRM provides a better estimation of the NO_2 impacts compared to other screening options.

3.2.2 (e)(iii). The data bases which are necessary to perform the analysis are available and adequate;

- Five years (2010-2014) of both hourly processed meteorological data (Boston, MA/Gray, ME) and concurrent hourly ozone monitoring data are available for this modeling application. Hourly ozone concentrations from the Harrison Ave. monitoring station (2.3 miles south-southeast of the MIT CUP) were input to AERMOD for each year modeled (2010-2014). The Lynn and Milton monitoring stations were used to replace hours with missing ozone data (10 miles to the northeast and 10.4 miles to the south-southwest, respectively). These data sets are adequate for use with AERMOD-PVMRM.

3.2.2 (e)(iv). Appropriate performance evaluations of the model have shown that the model is not biased toward underestimates;

- As noted the "Evaluation of Bias in AERMOD-PVMRM" report, PVMRM has been judged to provide an unbiased estimate.

3.2.2 (e)(v). A protocol on methods and procedures to be followed has been established.

- The methods and procedures for conducting an assessment for determining compliance with the federal 1-hour NAAQS are contained within. Specific PVMRM inputs are discussed here. The default value of 0.9 is used for the ambient equilibrium ratio in PVMRM. The in-stack ratio of NO_2/NOx is set to the default value of 0.5 for all sources except for the following: (a) 0.2 for the new diesel fired 2 MW cold start emergency IC engine and the existing diesel fired emergency generator based on past use for emergency generator engines and CAPCOA guidance[4]; (b) For oil fired operation of the existing No. 6 oil fired Boilers No. 3,4 & 5 0.10 for the in-stack ratio is used based on past use in other recent modeling such as Mystic 7 for the PSD modifications for Mystic 8 and 9 startup emissions. The value is also supported by other sources The Ambient Ratio Method (ARM) scaling factor of 0.75 is applied to the annual NO_2 predicted concentration. This is a U.S. EPA default approach based on the assumption that 75% of the NOx will convert to NO_2 on an annual basis.

For 24-hr $PM_{2.5}$ NAAQS modeling, the EPA Tier II methodology was employed. As part of the Tier II methodology it is necessary to demonstrate that there is a lack of a temporal correlation between modeled and monitored $PM_{2.5}$ concentrations. The worst-case 24-hr $PM_{2.5}$ load condition is when the new CTG(s) are burning ULSD. As mentioned previously, the b ULSD will be used for up to the equivalent heat input of 168 hours per year including

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[4] See Appendix C for default of 0.2 for diesel fired IC engines: http://www.valleyair.org/busind/pto/Tox_Resources/CAPCOANO2GuidanceDocument10-27-11.pdf

test and periods when natural gas is unavailable. Therefore, it is extremely unlikely that the maximum 24-hour modeled concentration on ULSD would coincide with the maximum 24-hr monitored $PM_{2.5}$ concentration and therefore utilization of the EPA Tier II methodology is justified.

D-4.3 Meteorological Data for Modeling

The meteorological data required to run AERMOD includes five years of representative surface and upper air observations. Hourly surface data from the National Weather Service (NWS) station at Boston Logan Airport with twice-daily upper air soundings from Gray, ME were used. These stations are the closest to and most representative of the Cambridge area. Logan Airport is approximately 4 miles to the east of MIT. The meteorological data for the period 2010-2014 were processed using AERMET (15181), AERMINUTE and AERSURFACE programs. The profile base elevation for this station is 6 meters.

The methodology used in the meteorological data processing with AERMET (15181) is based on U.S. EPA guidance, as set out in the March 2013 EPA memo "Use of ASOS Meteorological Data in AERMOD Dispersion Modeling", 40 CFR Part 51 Appendix W, the AERSURFACE user's guide, and other U.S. EPA publications, and is described below:

- Land use data is determined using the latest version (13016) of the AERSURFACE utility.
- For AERSURFACE, 12 directional sectors and seasonal variation in land use parameters are used. A 1 km radius around the measurement site is used to determine surface roughness lengths.
- Per the AERSURFACE User's Guide, surface moisture characterization is determined by comparing annual precipitation totals to the 30-year climatological norm for the area: a year is classified as "dry" if annual precipitation was less than the 30^{th} percentile value in the 30-year distribution, "wet" if greater than the 70^{th} percentile, and "average" if between the 30^{th} and 70^{th} percentiles. Based on the Boston precipitation data 2010 and 2011 were classified as 'wet', and 2012and 2013 were classified as "dry" and 2014 was classified as "average".
- AERMINUTE (version 14337) is used to incorporate 1-minute wind observations. A 0.5 m/s wind speed threshold is used for both AERMINUTE wind data.
- The MODIFY keyword, which performs automated QA/QC and data improvement algorithms on raw upper air data and is an established component of AERMET, is used.

- In order to make a determination as to whether Boston experiences continuous snow cover during the winter months, the 30-year climatological (1981-2010) monthly normal snow depth data was used. During this period Boston experienced at least an inch of snow on the ground less than 50% of the time. Therefore, the continuous snow cover option was not utilized in AERSURFACE as the site does not experience continuous snow cover during the winter months.

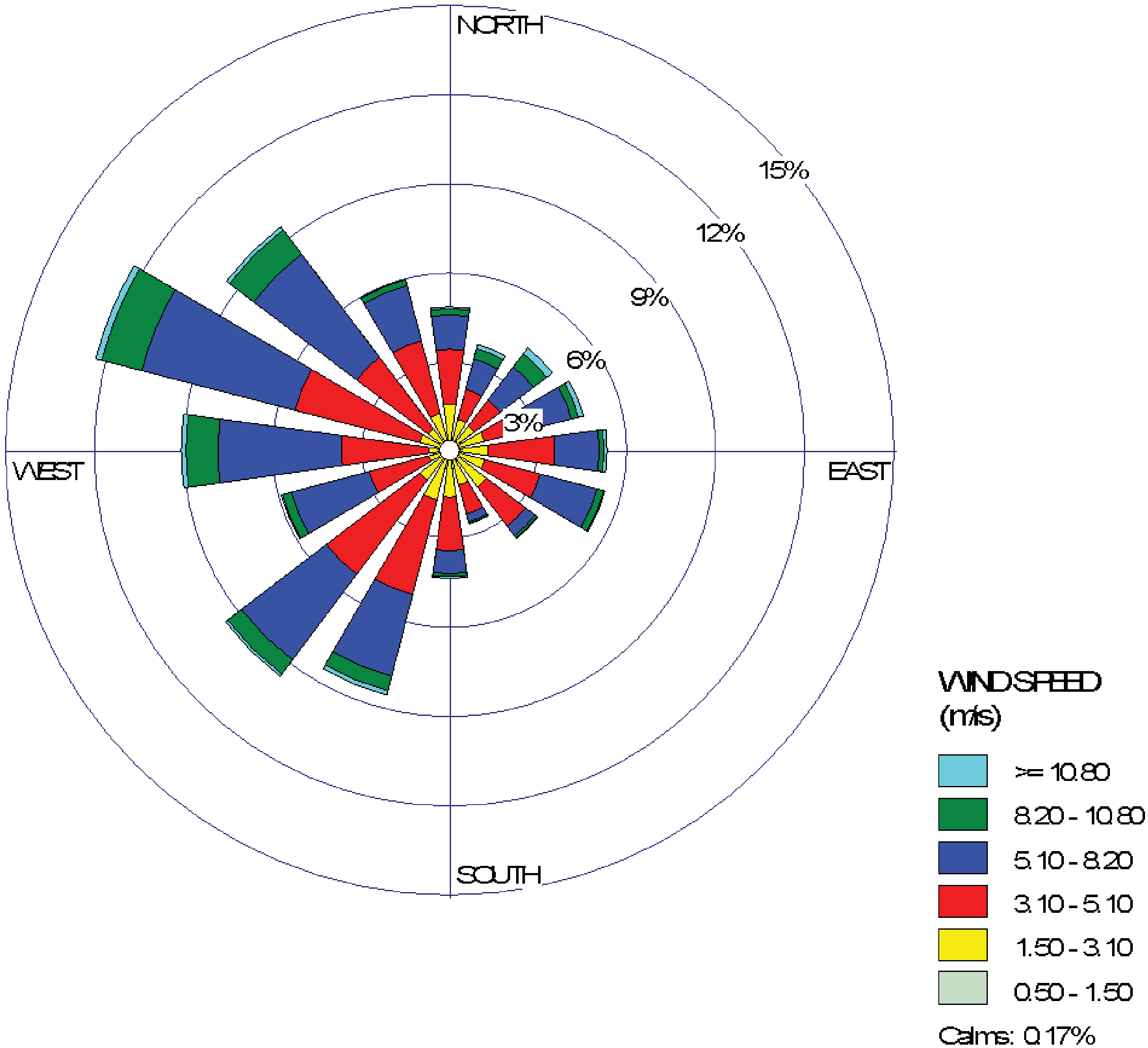
- AERMOD-ready meteorological data is assessed for completeness using the U.S. EPA's PSD meteorological data standard – data must be 90% complete on a quarterly basis, with four consecutive quarters meeting that standard being necessary for one year of meteorological data to be considered valid.

A composite wind rose for the five years of meteorological data to be used in the modeling analysis is presented in Figure D-7. The winds are predominantly from the western sector (SSW through NW).

D-4.4 Receptor Grid

The same nested Cartesian grid of receptors that was used in previous modeling (MIT Boiler No. 9, 2011) was used in this study. The grid was generated with spacing of 20 meters in a 40 meter by 40 meter bounding box centered on the main CUP stack, 50 meter spacing out to 200 meters, 100 meter spacing out to 2 km, 500 meter spacing out to 5 km, and 1,000 meter spacing out to 10 km. The nested grid of receptors was converted to discrete receptors and those falling on MIT buildings were removed from the analysis, allowing for ground level concentrations to be predicted.

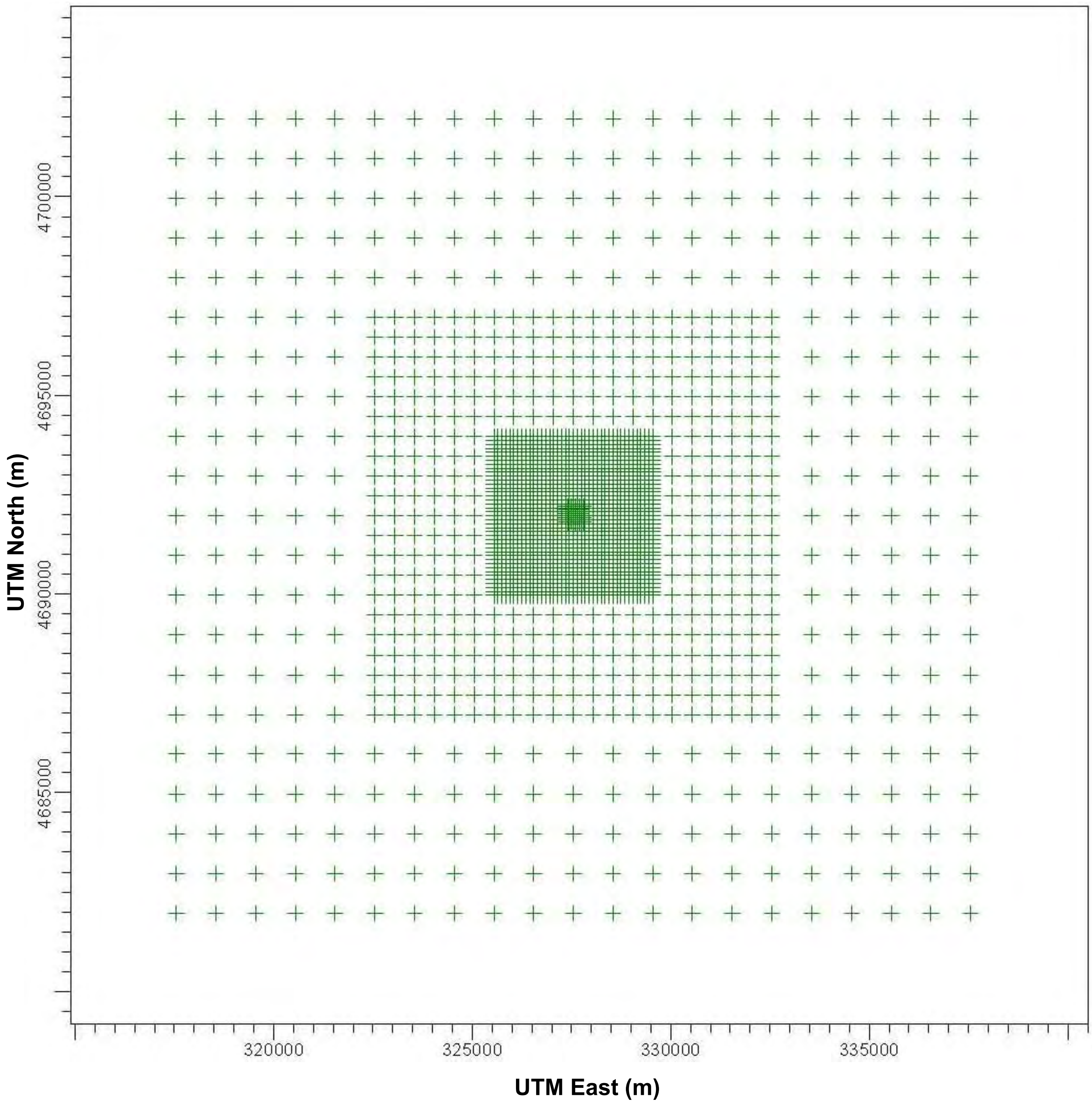
Terrain around the immediate site is relatively flat. The terrain elevation for each receptor was obtained electronically from USGS digital terrain data. The National Elevation Dataset (NED), with a resolution of 1/3 arc-second (approximately 10 meters) was processed using the AERMAP (11103) program. Figure D-8 shows the nested receptor grid. A total of 2,415 receptors were modeled in AERMOD. Elevations and hill heights for each receptor as well as the base elevations of the existing MIT sources modeled and buildings entered in BPIP-Prime were determined through the AERMAP processing.



WIND DIRECTION
(blowing from)

Figure D-7

5-year (2009-2013) Wind Rose of Measurements from the Boston Logan International Airport NWS Station



MIT Receptor Spacing:
50 m out to 200 m
100 m out to 2 km
500 m out to 5 km
1000 m out to 10 km

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Figure D-8

Nested Receptor Grid used in AERMOD Modeling

D-5 AIR QUALITY IMPACT RESULTS

D-5.1 CTG Load Analysis

A range of potential operating loads (40%, 50%, , 65%, 75%, and 100%) were modeled for the new CTGs using three ambient temperatures (0, 50, and 60 °F) with the duct burners on and off. 40% load is the minimum load on natural gas where emissions are guaranteed from the CTG manufacturer (50% load is the minimum load on ULSD), and 100% load represents maximum load. The ambient temperatures utilized represent the worst case heat input (0ºF) and an average heat input ambient temperature (50 ºF and 60 ºF). The CTGs may burn natural gas with a backup fuel of ULSD. The HRSGs will only operate on natural gas. Twenty-eight options over a range of loads and ambient temperatures as shown in Attachment A were modeled to determine the case resulting in the highest air quality impact of each pollutant for each averaging period for each of the two Operational scenarios.

The results of the load analysis are relied on for the remainder of the modeling. The cases resulting in the highest air quality impacts are listed in the Section D-3.3, the source data section, in Tables D-6 and D-7.

D-5.2 Significant Impact Level Analysis

The predicted air quality levels of the criteria pollutants were assessed through the initial modeling analysis of the project sources, including the new CTGs, 2 MW cold start emergency engine and the cooling towers (PM only). Each of the Operating Scenarios was modeled for comparison with the SILs. Table D-15 presents the criteria pollutant concentrations compared to the SILs for each operating scenario. Maximum concentrations of SO_2 and CO are below the SILs for all averaging periods for all operational scenarios. Maximum concentrations of NO_2, $PM_{2.5}$, and PM_{10} are above SILs for various averaging times (shown in bold). Therefore, cumulative impact modeling was required to be performed for these operational scenarios for the pollutants/averaging period combinations with impacts above the SILs.

Table D-15 Proposed Project AERMOD Modeled Results for Operational Scenarios 1 and 2 Compared to Significant Impact Levels (SILs)

Poll.	Avg. Time	Form	Max. Modeled Conc. ($\mu g/m^3$)	SIL ($\mu g/m^3$)	% of SIL	Period	Receptor Location (m) (UTME, UTMN, Elev.)
Operational Scenario 1 (1 new CTG/HRSG)							
SO_2	1-hr (1)	H	1.81	7.8	23%	2010-2014	327500.08, 4692112.84, 2.73
	3-hr	H	1.55	25	6%	10/1/13 hr 15	327450.08, 4692162.84, 2.73
	24 -hr	H	1.19	5	24%	1/29/10 hr 24	327650.08, 4692062.84, 2.74
	Annual	H	0.15	1	15%	2010	327550.08, 4692062.84, 2.73
PM_{10}	24-hr	H	**12.5**	5	250%	1/29/10 hr 24	327650.08, 4692062.84, 2.74
$PM_{2.5}$	24-hr (2)	H	**9.84**	1.2	820%	2010-2014	327550.08, 4692062.84, 2.73
	Ann. (2)	H	**0.91**	0.3	303%	2010-2014	327550.08, 4692112.84, 2.73
NO_2	1-hr (1)(3)	H	**14.5**	7.5	193%	2010-2014	327400.08, 4692162.84, 2.73
	Annual	H	**1.66**[3]	1	166%	2010	327550.08, 4692062.84, 2.73
CO	1-hr	H	8.76	2000	0%	5/7/13 hr 10	327500.08, 4692112.84, 2.73
	8-hr	H	5.75	500	1%	1/29/10 hr 16	327650.08, 4692062.84, 2.74
Operational Scenario 2 (2 new turbines/HRSGs)							
SO_2	1-hr (1)	H	2.4	7.8	31%	2010-2014	327500.08, 4692112.84, 2.73
	3-hr	H	2.0	25	8%	5/21/14 hr 12	327500.08, 4692112.84, 2.73
	24-hr	H	1.62	5	32%	1/29/10 hr 24	327650.08, 4692062.84, 2.74
	Annual	H	0.15	1	15%	2011	327850.08, 4692362.84, 2.74
PM_{10}	24-hr	H	**14.2**	5	284%	1/29/10 hr 24	327650.08, 4692062.84, 2.74
$PM_{2.5}$	24-hr (2)	H	**10.1**	1.2	844%	2010-2014	327850.08, 4692362.84, 2.74
	Ann. (2)	H	**0.98**	0.3	327%	2010-2014	327850.08, 4692362.84, 2.74
NO_2	1-hr (1)(3)	H	**15.6**	7.5	208%	2010-2014	327500.08, 4692112.84, 2.73
	Annual	H	**1.57**[3]	1	157%	2010	327550.08, 4692062.84, 2.73
CO	1-hr	H	10.2	2000	1%	8/9/12 hr 11	327400.08, 4692162.84, 2.73
	8-hr	H	7.9	500	2%	12/27.10 hr 24	327550.08, 4692062.84, 2.73

[1] High 1st High maximum daily 1-hr concentrations averaged over 5 years.
[2] High 1st High maximum concentrations averaged over 5 years.
[3] Annual NO_2 uses ARM for NOx to NO_2 conversion of 0.75 per EPA Guidance.
http://www.epa.gov/scram001/guidance/clarification/Additional_Clarifications_AppendixW_Hourly-NO2-NAAQS_FINAL_03-01-2011.pdf

D-5.3 National Ambient Air Quality Analysis

Since the proposed project is a modification to an existing facility, a compliance demonstration was conducted to ensure that the combined emissions from the existing facility and the proposed modification will not cause or contribute to a NAAQS violation for that pollutant (MassDEP, 2011). For the pollutants and averaging periods which had project impacts below the SILs (Table D-15) the appropriate modeled concentrations were combined with appropriate ambient background concentrations prior to comparison with the NAAQS. These results are presented in Section D-5.3.1. For those pollutants and averaging periods with project impacts above the SILs, cumulative source modeling was conducted and is described in Section D-5.3.2.

Post-processing of 1-hour NO_2

As AERMOD is run for the 1-hour NO_2 impacts (using the PVMRM option), the seasonal/diurnal values of NO_2 monitored background were input directly to the model. The appropriate background value was added to the modeled impact depending on the season and hour of day. Then the daily maximum of the total (modeled + background) hourly impacts was determined for each day. Following EPA's guidance (EPA, 2011) the design value is the 98th percentile highest of the annual distribution of the daily maximum 1-hour total impact at each receptor for the multiyear average (5 years). This analysis was performed for each receptor, and the results were compared to the 1-hour NO_2 standard.

Post-processing of 24-hour $PM_{2.5}$

As AERMOD is run for the 24-hour $PM_{2.5}$ impacts, the daily values of $PM_{2.5}$ monitored background were input directly to the model (as seasonal values). The appropriate background value was added to the modeled impact depending on the season. Then the 98th percentile daily total impact (modeled + background) at each receptor for the multiyear average (5 years) was determined and the results compared to the 24-hour $PM_{2.5}$ standard.

D-5.3.1 MIT Sources

AERMOD modeling was performed for the pollutants and averaging periods which had project impacts below the SILs (Table D-16). The project sources were modeled with the existing MIT sources; then the appropriate modeled concentrations were combined with appropriate ambient background concentrations prior to comparison with the NAAQS. For Operational Scenario 1 when only one new CTG is in operation, the existing CTG is still operating. For Scenario 2, the flues for the two new CTGs are merged and modeled with an effective diameter of 9.9 ft. MIT plans an in-service date of the two new units in 2019 and 2020. The existing ABB (Siemens) CTG will be fully retired following completion of installation and shakeout for both of the new units two new . Table D-16 presents the criteria pollutant concentrations compared to the NAAQS for each operating scenario. The total concentration (modeled plus background) are below the NAAQS for all pollutants.

Table D-16 AERMOD Model Results for the Full MIT Facility for Operational Scenarios 1 and 2 Compared to the NAAQS

Poll.	Avg. Period	Form	AERMOD Modeled Conc. ($\mu g/m^3$)	Background Conc. ($\mu g/m^3$)	Total Conc. ($\mu g/m^3$)	NAAQS ($\mu g/m^3$)	% of NAAQS	Period	Receptor Location (m) (UTME, UTMN, Elev.)
Operational Scenario 1 (1 new CTG/HRSG)									
SO_2	1-hr[(1)]	H4H	3.0	23.3	26.3	196	13%	2010-2014	327500.08, 4692212.84, 2.73
	3-hr.	H2H	2.8	36.4	39.2	1300	2%	3/12/13 hr 12	327500.08, 4692212.84, 2.73
	24-hr.	H2H	1.7	15.7	17.4	365	5%	3/12/13 hr 24	327500.08, 4692162.84, 2.73
	Annual	H	0.26	4.9	5.2	80	6%	2010	327550.08, 4692062.84, 2.73
PM_{10}	24-hr	H6H	31.6	53	84.6	150	56%	12/13/10 hr 24	327500.08, 4692212.84, 2.73
$PM_{2.5}$	24-hr[(2)]	H8H	16.6	16.5	33.1	35	94%	2010-2014	327550.08, 4692162.84, 2.73
	Annual[(3)]	H	2.1	7.7	9.8	12	82%	2010-2014	327550.08, 4692112.84 2.73
NO_2	1-hr[(2)]	H8H	71.1	78.2	149.3	188	79%	2010-2014	327550.08, 4692212.84, 2.73
	Annual	H	4.5[(4)]	46.2	50.7	100	51%	2010	327550.08, 4692112.84, 2.73
CO	1-hr.	H2H	67.1	1962.4	2029.5	40000	5%	7/26/11 hr 13	327500.08, 4692212.84, 2.73
	8-hr	H2H	44.2	1260.2	1304.4	10000	13%	5/16/14 hr 16	327500.08, 4692162.84, 2.73
Operational Scenario 2 (2 new turbines/HRSGs)									
SO_2	1-hr[(1)]	H4H	3.0	23.3	26.3	196	13%	2010-2014	327450.08, 4692162.84, 2.73
	3-hr	H2H	2.7	36.4	39.1	1300	3%	5/16/14 hr 12	327500.08, 4692212.84, 2.73
	24-hr	H2H	1.67	15.7	17.4	365	5%	12/30/12 hr24	327550.08, 4692062.84, 2.73
	Annual	H	0.22	4.9	5.12	80	6%	2010	32755.08, 4692062.84, 2.73
PM_{10}	24-hr	H6H	23.6	53	76.62	150	51%	5/23/11 hr 24	327500.08, 4692162.84, 2.73
$PM_{2.5}$	24-hr[(2)]	H8H	16.9	16.7	33.6	35	96%	2010-2014	327550.08, 4692062.84, 2.73
	Annual[(3)]	H	1.9	7.7	9.56	12	80%	2010-2014	327550.08, 4692112.84, 2.73
NO_2	1-hr[(2)]	H8H	92.7	73.7	166.4	188	89%	2010-2014	327550.08, 4692212.84, 2.73
	Annual	H	4.05[(4)]	46.2	50.25	100	50%	2010	327550.08, 4692112.84, 2.73
CO	1-hr.	H2H	57.0	1962.4	2019.4	40000	5%	7/10/10 hr 11	327500.08, 4692212.84, 2.73
	8-hr	H2H	38.5	1260.2	1298.7	10000	13%	5/16/14 hr 16	327500.08, 4692162.84, 2.73

[1] High 4th High (99th%) maximum daily 1-hr concentration averaged over 5 years.
[2] High 8th High over 5 years.
[3] Annual $PM_{2.5}$ is averaged over 5 years.
[4] Annual NO_2 uses ARM for NOx to NO_2 conversion of 0.75 per EPA Guidance. http://www.epa.gov/scram001/guidance/clarification/Additional_Clarifications_AppendixW_Hourly-NO2-NAAQS_FINAL_03-01-2011.pdf

D-5.3.2 Cumulative Impact Modeling

The results of the SILs analysis are used as the basis for the cumulative impact modeling. The project's impacts are above the 24-hr and annual $PM_{2.5}$, 24-hr PM_{10} and 1-hr NO_2 SILs at some receptor locations. Cumulative impact modeling is required at these receptors to verify that the project is not contributing significantly to a violation of the NAAQS.

Non-MIT facilities required for inclusion in the cumulative modeling are those emission sources within 10 km of the MIT CUP that emit significant $PM_{2.5}$, PM_{10} or NO_2 emission rates (>10 tpy $PM_{2.5}$, >15 tpy PM_{10} or >40 tpy NO_2 based on reported actual emissions). Four nearby facilities have been identified as satisfying the criteria for $PM_{2.5}$ and PM_{10}. Two additional sources were identified as satisfying the criteria for NO_2. The following facilities were identified as interactive sources for modeling purposes:

1. Veolia Kendall Station (~1.2 km to the east-northeast of MIT CUP)
2. Harvard Blackstone (~1.8 km to the west-northwest of MIT CUP)
3. MATEP (~3.0 km to the southwest of MIT CUP)
4. Boston Generating Mystic Station (~3.8 km to the north-northeast of MIT CUP)
5. (NO_2 Only) Logan Airport (~5.9 km to the east-northeast of the MIT CUP)
6. (NO_2 Only) Kneeland Street (~3.2 km to the east-southeast of the MIT CUP)

Epsilon has worked with MassDEP to define the source parameters and emissions rates for the sources at the facilities proposed for the cumulative impact modeling. Title V operating permits for the facilities were reviewed. The emission rates used in the cumulative modeling represents the maximum permitted emission rates for each facility. The cumulative source parameters proposed in the modeling protocol have been revised prior to the modeling commencing. The parameters have been updated to better align the stack coordinates with the MIT modeling domain and to better reflect the operations at these facilities. In particular, the following changes were incorporated:

- A review of the most recent operating permit for Kendall Station resulted in the following updates:

    1. Revised the exit velocity for Kendall Station Babcock Wilson #1-2, based on Unit #1 being taken out of service.

    2. Revised the stack diameter for the Combined Cycle CTG

    3. Determine the NOx emission rate for Kendall Station sources.

    4. Emission rates were adjusted because Kendall Station no longer burns No. 6 fuel oil.

- ♦ A review of the most recent operating permit for Mystic Station was used to determine the NOx emission rate for Mystic Station sources.

- ♦ Georeferenced MrSID basemaps were imported into AERMODview based on the NAD83 Datum, and the interactive source coordinates presented in the protocol were evaluated for accuracy. All stack and building UTM coordinates were adjusted to accurately reflect their locations with respect to the MIT modeling domain datum.

The table of source parameters and emission rates used in the cumulative modeling for the interactive sources is presented in Attachment B.

The latest version of the EPA Building Profile Input Program (BPIP-Prime) was run for all stacks and buildings in the vicinity of each facility to create the building parameter inputs to AERMOD. The cumulative AERMOD modeling accounts for potential downwash for each stack at each facility.

Cumulative AERMOD modeling was conducted for each of the project Operating Scenarios with predicted impacts above the SILs. The cumulative modeling included the project sources, existing MIT sources and the interactive sources listed in Attachment B. The cumulative impacts of all modeled sources plus the monitored background concentration are then compared to the NAAQS. The results of the cumulative source air quality modeling are presented in Table D-17.

The cumulative AERMOD modeling demonstrates that the project sources in any of the Operating Scenarios will not cause or contribute to a violation of the NAAQS.

Table D-17 AERMOD Model Results for the Full MIT Facility with Interactive Sources for Operational Scenarios 1 & 2 Compared to the NAAQS

Poll.	Avg. Period	Form	Total Conc. ($\mu g/m^3$)	AERMOD Predicted Contribution ($\mu g/m^3$)							Bkgrnd Conc. ($\mu g/m^3$)	NAAQS (μg/m3)	% of NAAQS	Period	Receptor Location (m)
				MIT	Kendall Station	Harvard Blackstone	MATEP	Mystic Station	Kneeland St.	Logan Airport					(UTME, UTMN, Elev.)
Operational Scenario 1 (1 new CTG/HRSG)															
PM_{10}	24-hr	H6H	84.7	31.6	0.002	0.04	0.021	0.0047	N/A	N/A	53	150	56.5%	12/13/10 hr 24	327500.08, 4692212.84, 2.73
$PM_{2.5}$	24-hr	H8H	33.4	16.3	0.01	0.34	0.00	0.02	N/A	N/A	16.7	35	95.4%	2010-2014	324550.08, 4692062.84, 2.73
	Annual	H	11.2	2.6	0.18	0.51	0.05	0.21	N/A	N/A	7.7	12	93.6%	2010-2014	327550.08, 4692112.84, 2.73
NO_2	1-hr[(1)]	H8H	155.2	82.5	0.01	0.01	0.02	0.02	0.011	0.042	72.6	188	82.5%	2010-2014	327500.08, 4692212.84, 2.73
	Annual[(2)]	H	54.8	4.5	1.03	1.01	0.78	0.61	0.47	0.25	46.2	100	54.8%	2010	327550.08, 4692112.84, 2.73
Operational Scenario 2 (2 new turbines/HRSGs)															
PM_{10}	24-hr	H6H	76.7	23.6	0.0032	0.0092	0.01452	0.0099	N/A	N/A	53	150	51%	5/23/11 hr 24	327500.08, 4692162.84, 2.73
$PM_{2.5}$	24-hr	H8H	34.4	18.1	0.014	0.40	0.010	0.014	N/A	N/A	15.9	35	98%	2010-2014	327550.08, 4692062.84, 2.73
	Annual	H	11.0	2.34	0.18	0.51	0.05	0.21	N/A	N/a	7.7	12	92%	2010-2014	327550.088, 4692062.84, 2.73
NO_2	1-hr[(1)]	H8H	139.7	54.3	0.129	0.106	0.058	0.033	0.043	0.038	85.0	188	74%	2010-2014	327550.08, 4692062.84, 2.73
	Annual[(2)]	H	54.4	4.1	1.0	1.0	0.8	0.6	0.5	0.3	46.2	100	46.2%	2010	327550.08, 4692112.84, 2.73

[1] High 8th High (98th%) maximum daily 1-hr concentration averaged over 5 years with seasonal/diurnal background; PVMRM used for conversion of NOx to NO_2.

[2] Annual NO_2 uses ARM for NO_x to NO_2 conversion of 0.75 per EPA Guidance. http://www.epa.gov/scram001/guidance/clarification/Additional_Clarifications_AppendixW_Hourly-NO2-NAAQS_FINAL_03-01-2011.pdf

D-5.4 Non-Criteria Pollutant Modeling

An air quality impact assessment of the non-criteria pollutants emitted from the project (turbines and 2 MW cold start emergency engine) was conducted. Applicable EPA AP-42 and California Air Toxics Emission Factor (CATEF) emission factors were used to derive the emission rates. The highest 24-hr and annual normalized AERMOD predicted concentrations were used, and then scaled by the pollutant emission rate to obtain the predicted concentration of each pollutant. For the TEL modeling, Case 2.G (NG) and Case 2.M (ULSD) were used and the worst-case impact was reported in Table D-18. Calculations are shown in Attachment D. The results in Table D-18 present the worst-case predicted non-criteria pollutant air quality impacts for those pollutants for which MassDEP has an annual Allowable Ambient Limit (AAL) or a 24-hour Threshold Effects Exposure Limit (TEL). The results show that air quality impacts from the non-criteria emissions are well below the threshold levels of the corresponding MassDEP AALs and TELs.

Table D-18 Non-Criteria Pollutant Modeled Concentrations from the Project for Comparison to Massachusetts' AALs and TELs

	Annual Concentrations (µg/m³)			*24-Hour Concentrations (µg/m³)*		
Pollutant	Total Impact	AAL	% of AAL	Total Impact	TEL	% of TEL
1,3-Butadiene	2.18E-5	0.003	0.7%	4.29E-3	1.2	0.4%
Acetaldehyde	1.09E-3	0.4	0.3%	1.20E-2	30	0.0%
Acrolein	1.76E-4	0.07	0.3%	2.12E-3	0.07	3.0%
Benzene	1.05E-3	0.1	1.1%	8.21E-2	0.6	13.7%
Dichlorbenzene	2.50E-5	81.74	0.0%	3.51E-4	81.74	0.0%
Ethylbenzene	8.70E-4	300	0.0%	8.56E-3	300	0.0%
Formaldehyde	1.17E-2	0.08	14.6%	2.16E-1	2	10.8%
Hexane	3.74E-2	47.62	0.1%	5.26E-1	95.24	0.6%
Naphthalene	1.80E-4	14.25	0.0%	1.65E-2	14.25	0.1%
Propylene Oxide	7.89E-4	0.3	0.3%	7.75E-3	6	0.1%
Toluene	3.67E-3	20	0.0%	5.03E-2	80	0.1%
Xylenes	1.78E-3	11.8	0.0%	2.71E-2	11.8	0.2%
Arsenic	5.51E-6	0.003	1.8%	5.84E-5	0.003	18.9%
Beryllium	4.64E-7	4.00E-04	0.1%	3.51E-6	1.00E-03	8.6%
Cadmium	2.31E-5	2.00E-04	11.5%	3.21E-4	2.00E-03	46.4%
Chromium	3.09E-5	0.68	0.0%	4.09E-4	1.36	0.2%
Lead	7.64E-6	0.07	0.0%	3.76E-3	0.14	2.7%
Mercury	5.54E-4	0.07	0.8%	3.80E-4	0.14	0.3%
Nickel	4.45E-5	0.18	0.0%	1.70E-3	0.27	0.6%
Selenium	3.69E-6	0.54	0.0%	6.71E-3	0.54	1.2%

D-5.5 PSD Increment Modeling

A PSD increment is the maximum allowable increase in concentration that is allowed to occur above a baseline concentration for a pollutant. The baseline concentration is defined for each pollutant (and relevant averaging period) 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. Modeling to show that allowable increments are not exceeded must include existing sources that are both within the baseline area and were constructed after the PSD baseline date and can include increment expanding sources (those that have added controls or stopped operating) after the PSD baseline date. 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.

The project is a major modification of an existing major source, subject to the requirement to obtain a PSD permit. PSD Increment modeling is required for PM_{10} and $PM_{2.5}$. Epsilon has conferred with MassDEP Boston BWP Air Planning and Evaluation Branch to determine if the $PM_{2.5}$ minor source baseline date has been established for the baseline area (county). It is believed that this application will establish the baseline date for $PM_{2.5}$ when it is determined to be complete. MassDEP confirmed that the baseline has been set for PM_{10} in Middlesex County. Increment-consuming sources (.i.e., new CTGs, 2 MW cold start emergency engine and cooling towers) will be modeled at their maximum allowable emissions rates, while the increment expanding sources at MIT (i.e., retiring existing CTG, switch from No.6 oil to No. 2 Fuel Oil on Boilers No. 3, 4, & 5, and reduction of ULSD firing to 168 hours/yrs in Boilers No. 7 & 9, and retiring cooling towers) will be modeled at their maximum actual emission rates (using a negative emission rate in AERMOD). The previously determined worst-case operating condition for the new turbines was used in the PSD increment modeling. However, for PM_{10} the baseline has been established and the following sources will be included as increment consuming: GenOn Kendall Station, Harvard Blackstone, MATEP, and Mystic Generating Station.

The actual emissions are determined for the existing sources at MIT in accordance with the October 1990 draft guidance in the New Source Review Workshop Manual, Prevention of Significant Deterioration and Nonattainment Area Permitting, which states the following:

> *For any increment-consuming (or increment-expanding) emissions unit, the actual emissions limit, operating level, and operating factor may all be determined from source records and other information (e.g., State emissions files), when available, reflecting actual source operation. For the annual averaging period, the change in the actual emissions rate should be calculated as the difference between:*

- the current average actual emissions rate, and

- the average actual emissions rate as of the minor source baseline date (or major source baseline date for major stationary sources).

In each case, the average rate is calculated as the average over previous 2-year period (unless the permitting agency determines that a different time period is more representative of normal source operation).

For each short-term averaging period (24 hours and less), the change in the actual emissions rate for the particular averaging period is calculated as the difference between:

- the current maximum actual emissions rate, and

- the maximum actual emissions rate as of the minor source baseline date (or major source baseline date for applicable major stationary sources undergoing construction before the minor source baseline date).

In each case, the maximum rate is the highest occurrence for that averaging period during the previous 2 years of operation.

Following this guidance the source operation records were reviewed for the 2-year period of April 1st, 2013 – March 31st 2015 for Boilers No. 3, 4, 5, 7 & 9, and the existing combustion CTG and HRSG. The maximum gas and oil usage were determined for a 24-hour period and the actual emission rate calculated based on the Lb/MMBtu permit limits in the current Title V operating permit for MIT. Emission statement data was reviewed for cooling towers 1, 2, 3, 4, 5, and 6.

The current actual emissions rates (annual emissions after the change) for MIT are as follows:

- For the new CTGs, the proposed permit limits for natural gas firing times, 8,592 hours/year plus the proposed permit limits for ULSD firing for 168 hours/year.

- For the new HRSGs, the proposed permit limits times 8.760 hours/year (natural gas only). This assumption of 8,760 hours per year of operation is a conservative approximation due to the fact that the duct burners are proposed with a limit equivalent to 4,380 hours of full load operation of both duct burners.

- For the new cold start emergency engine, the proposed permit limit times an annual operating restriction of 300 hours/year (ULSD)

- For Boilers No. 7 & 9, the proposed permit limits for natural gas firing times 8,592 hours/year plus the proposed permit limits for ULSD firing for 168 hours/year. This reflects the requested increase in allowable operating hours. Since the filing of the initial application, MIT has withdrawn the requested increase in allowable operating hours for Boilers 7 & 9, however these are conservatively included in the modeling.

- For Boilers No. 3, 4, & 5, the average of the actual total heat input (gas & oil) for the 2-year period of April 1st, 2013 – March 31st, 2015 times the natural gas per pound MMBtu permit limits in the current operating permit for MIT. Added to this are the permit limits for ULSD firing for 168 hours/year. Boilers No. 3, 4, & 5 will cease burning No. 6 oil prior to the new CTGs beginning normal operation (after installation and shakeout of the new units has concluded).

- For the cooling towers, the annual emission rate.

The PSD Increment modeling rates are summarized in Table D-19. Calculations are provided in Attachment C.

Table D-19 PM Emission Rates used in PSD Increment Modeling

Increment Consuming Sources		
	$PM_{10}/PM_{2.5}$ Emission Rate short term (g/s)	$PM_{2.5}$ Emission Rate annual (g/s)
New CTG 1 w/HRSG	PM_{10}: 1.17; $PM_{2.5}$: 1.49	0.88
New CTG 2 w/HRSG	PM_{10}: 1.17; $PM_{2.5}$: 1.49	0.88
Total	**PM_{10}: 2.35; $PM_{2.5}$: 2.99**	**1.76**
Boiler No. 3	0.071 (NG)	0.037 (NG/ULSD)
Boiler No. 4	0.069 (NG)	0.040 (NG/ULSD)
Boiler No. 5	0.076 (NG)	0.048 (NG/ULSD)
Total	0.215	0.126
Boiler No. 7[1]	0.063 (NG)	-
Boiler No. 9[1]	0.083 (NG)	0.164 (NG/ULSD)
Total	0.146	0.164
Cooling Towers #11, 12, 13 per cell (6)	0.0044	0.0044
Total	0.026	0.026
Cold Start Emergency Engine	0.0168	0.014
Increment Expanding Sources		
Existing CTG	1.27	0.21
HRSG	0.032	0.018
Total	1.31	0.24

Table D-19 PM Emission Rates used in PSD Increment Modeling (Continued)

Increment Consuming Sources		
	$PM_{10}/PM_{2.5}$ Emission Rate short term (g/s)	$PM_{2.5}$ Emission Rate annual (g/s)
Boiler No. 3 (No. 6)	0.54	0.088
Boiler No. 4 (No. 6)	0.82	0.100
Boiler No. 5 (No. 6)	0.71	0.126
Total	2.066	0.315
Boiler No. 7	0.20	-
Boiler No. 9	0.23	3.53E-3
Total	0.42	3.53E-3
Cooling Tower 1 per cell (2)	3.33E-3	3.33E-3
Cooling Tower 2 per cell (2)	3.33E-3	3.33E-3
Cooling Tower 3 per cell (2)	5.86E-3	5.86E-3
Cooling Tower 4 per cell (2)	5.18E-3	5.18E-3
Cooling Tower 5	2.15E-3	2.15E-3
Cooling Tower 6	2.15E-3	2.15E-3
Total	0.034	0.034

[1] Plans to increase Boiler No. 7 &9 operation have been withdrawn from the permit application. Emission rates are presented here as they are included in the PSD Increment modeling

As mentioned previously, the PM_{10} baseline has been previously triggered and it becomes necessary to perform modeling of the proposed changes for MIT in conjunction with changes in the PM_{10} baseline area as increment consuming. Emissions were modeled at the potential to emit as a conservative measure even though MIT had the option of modeling these sources at their actual emission rates. The following sources were included for the PM_{10} PSD increment modeling only and are summarized in Attachment B:

- Kendall Station: Babcock & Wilson #1-2, Babcock & Wilson #3, Turbopower CTG#1, and the Combined Cycle CTG
- Harvard Blackstone: The new combined heat and power system, and Boiler 13
- MATEP: Stack (Two identical flues)
- Mystic Station: CTG/HRSG #81, CTG/HRSG #82, CTG/HRSG #93, and CTG/HRSG #94

The PM-10 Emission Rates for the interactive sources used in the PSD Increment Modeling are summarized in Table D-20.

Table D-20 PM Emission Rates used in PSD Increment Modeling

PM_{10} PSD Increment Consuming Sources	
Kendall Station	PM_{10} Emission Rate grams/sec
Babcock & Wilson #1-2	0.81
Babcock & Wilson #3	1.22
Turbopower CTG #1	0.47
Combined Cycle CTG	6.3
Harvard Blackstone	
Boiler 6 & Boiler 13	3.53
New CHP	0.47
MATEP	
Stack (Two identical flues)	4.29
Mystic Station	
CTG/HRSG #81	4.1
CTG/HRSG #82	4.1
CTG/HRSG #93	4.1
CTG/HRSG #94	4.1

All sources are input in the AERMOD model with increment consuming sources using positive emissions rates and increment expanding sources with negative emission rates.

The PSD increment comparison was run for Operational Scenario 2 only as this is the final build scenario for this project. All impacts are matched in space and time and the resultant impact is compared to the PSD increment. The maximum resultant impact is used for annual averages and the highest second-high resultant impact is used for the 24-hr averages. The results of the PSD increment analysis are presented in Table D-21. The analysis shows that applicable PSD increments are not exceeded at any receptor for any MIT CoGen operating scenario.

Table D-21 AERMOD Model Results for Operational Scenario 2 compared to PSD Increments

Poll.	Avg. Period	Form	Resultant Modeled Conc. ($\mu g/m^3$)	Increment (μg/m3)	% of Increment	Period	Receptor Location (m) (UTME, UTMN, Elev.)
Operational Scenario 2 (2 new CTGs/HRSGs)							
PM_{10}	24-hr	H2H	8.85	30	29.5	5/9/10 Hr: 24	327650.08, 4692062.84, 2.74
$PM_{2.5}$	24-hr	H2H	8.25	9	91.7	11/14/11 Hr: 24	327850.08, 4692362.84, 2.74
	Annual	H	1.41	4	35.3	2010	327550.08, 4692062.84, 2.73

D-5.6 Class I Visibility Analysis

Section 169A of the Clean Air Act states "Congress hereby declares as a national goal the prevention of any future, and the remedying of any existing, impairment of visibility in mandatory Class I Federal areas which impairment results from man made air pollution." Under the regulations promulgated for visibility protection (40 CFR 51.301)) visibility impairment is defined as "...any humanly perceptible change in visibility (visual range, contrast, coloration) from that which would have existed under natural conditions." As part of this air quality analysis, a visibility impact analysis was performed.

The Lye Brook Wilderness Area in southern Vermont is the closest Class I area to the MIT CUP. Lye Brook is located approximately 175.5 km to the northwest of MIT. As part of the Regional Haze Regulations, EPA has devised a screening criterion for sources located more than 50 km from the Class I area. A source is considered to have negligible impacts when the combined annual emissions of SO_2, NOx, PM_{10}, and H_2SO_4 (in tons) divided by the distance (in km) from the Class I area is 10 or less. In this case, this ratio is about 0.52 (92.1 tons/175.5 km). Therefore, the proposed modifications to the source are expected to have negligible visibility impacts with respect to the Lye Brook Wilderness Area, and would not require any further Class I visibility impact analyses.

To confirm this result, a visibility analysis of the proposed project was conducted using the EPA VISCREEN program (Version 1.01 dated 88341). The VISCREEN model (EPA, 1992) provides the capability of assessing plume contrast (Cp) and plume perceptibility (Delta E) against two backgrounds: sky and terrain.

Visibility impacts are a function of particulate and NO_2 emissions. Particles are capable of either scattering or absorbing light while NO_2 absorbs light. It should be noted that NO_2 absorbs light greater in the blue end of the spectrum. These constituents can either increase or decrease the light intensity (or contrast) of the plume against its background. VISCREEN plume contrast calculations are performed at three wavelengths within the visible spectrum (blue, green, and red). Plume perceptibility as determined by VISCREEN is determined from plume contrast at all visible wavelengths and "is a function of changes in both brightness and color" (EPA, 1992).

The VISCREEN model provides three levels of analysis; Level 1, Level 2, and Level 3. The first two Levels are screening approaches. If the Project fails a Level-1 screening analysis, then more refined modeling must be conducted.

The perceptibility of a distinct plume depends on the plume contrast at all visible wavelengths. Perceptibility is a function of changes in both brightness and color. The color difference parameter, ΔE, was developed to specify the perceived magnitude of changes in color and brightness and is used as the primary basis for assessing perceptibility of plume visual impacts in the screening analysis. Plume contrast results from an increase or decrease in light transmitted from the viewing background through the plume to the

observer. This increase or decrease in light intensity is caused by plume constituents that scatter and/or absorb light. The first criterion is a ΔE value of 2.0; the second is a contrast value of 0.05 (EPA 1992).

A Level 1 VISCREEN analysis was performed on the nearest Class I area; Lye Brook Wilderness Area. Level 1 Screening in the VISCREEN model is designed to provide a conservative estimate of visual impacts from the plume. This conservatism is achieved by assuming worst-case meteorological conditions: extremely stable (F) atmospheric conditions, coupled with a very low wind speed (1 meter per second [m/s]) persisting for 12 hours, with a wind that would transport the plume directly adjacent to the observer. The observer is located at the closest location of the Class I area to the proposed source per VISCREEN guidance (EPA 1992), in this case, it is the east area of the Lye Brook Wilderness Area.

To be conservative, the proposed worst case new CTG emissions for each pollutant were used: PM (2 CTGs at 100% load, 0°F, ULSD) and NO_x (2 CTGs at 100% load, 0°F, ULSD). In addition to the CTGs emissions, the total emission rate includes the 2 MW cold start emergency engine (for PM and NO_x) and the cooling towers (for PM only). The total PM emission rate (3.03 g/s) and total NO_x emission rate (2.55 g/s) were input into the VISCREEN model. The minimum (175.5 km) and maximum (183.3 km) distances from the source to the Lye Brook Wilderness Area were input. A default background visual range of 194.8 km was used (U.S. Department of Interior, 2010). Table D-22 presents results of the VISCREEN modeling analysis completed for the MIT Cogen project.

The VISCREEN modeling demonstrates that the addition of the new CTGs, 2 MW cold start emergency engine and the cooling towers associated with the MIT Cogen project will comply with the criteria established in the Workbook for Plume Visual Impact Screening and Analysis (Revised) (EPA 1992) for maximum visual impacts inside the Lye Brook Wilderness Area.

Table D-22 Class I Visibility Modeling Results -Maximum Visual Impacts Inside the Class I Area

					Delta-E		Absolute Contrast	
Background	Theta (°)	Azimuth (°)	Distance (km)	Alpha (°)	Screening Criteria	Plume	Screening Criteria	Plume
SKY	10	84	175.5	84	2.00	0.203	0.05	0.003
SKY	140	84	175.5	84	2.00	0.039	0.05	-0.001
TERRAIN	10	84	175.5	84	2.00	0.167	0.05	0.002
TERRAIN	140	84	175.5	84	2.00	0.021	0.05	0.000

D-5.7 Effects on Soils and Vegetation Analyses

PSD regulations require analysis of air quality impacts on sensitive vegetation types, with significant commercial or recreational value, or sensitive types of soil. Evaluation of impacts on sensitive vegetation is 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). These procedures specify that predicted impact concentrations used for comparison account for project impacts and ambient background concentrations.

Most of the designated vegetation screening levels are equivalent to or exceed NAAQS and/or PSD increments, so that satisfaction of NAAQS and PSD increments assures compliance with sensitive vegetation screening levels. Since there are no specific PM_{10} or $PM_{2.5}$ screening level sensitive concentrations, no formal comparison was performed.

D-5.8 Growth

The peak construction work force is estimated to be 300 persons. MIT would not expect to add staff for plant operations.

It is expected that a significant construction force is available and is supported by the fact that within the Cambridge/Boston area, 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 building period.

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

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

D-5.9 Environmental Justice

Section 5.2 of the PSD application includes documentation to enable MassDEP to fulfill its obligation under the provisions of the April 11, 2011 PSD Delegation Agreement between MassDEP and EPA to "identify and address, as appropriate, disproportionately high and adverse human health or environmental effects of federal programs, policies, and activities on minority and low-income populations as set forth in Federal Actions to Address Environmental Justice in Minority Populations and Low-Income Populations." The Executive Office of Energy and Environmental Affairs (EEA) has established environmental justice neighborhoods which identify areas with minority populations and low-income populations.

D-6 REFERENCES

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MassDEP, 2011. Modeling Guidance for Significant Stationary Sources of Air Pollution. MassDEP Bureau of Waste Prevention, Boston, MA.

ATTACHMENT A

Source Parameters for New Turbine Load Cases

Table A-1 MIT turbine & duct burner model cases Operational Scenario 1

Case	1	2	3	4	5	6	7	8	9	10	11	12	13	14
Ambient Temp (F)	50	0	60	0	60	0	60	0	60	0	60	0	60	0
% Load	100	100	75	75	50	50	40	40	100	100	75	75	65	65
Turbine Fuel	NG	NG	NG	NG	NG	NG	NG	NG	ULSD	ULSD	ULSD	ULSD	ULSD	ULSD
Duct Burner Fuel	NG	NG	NG	NG	OFF	OFF	OFF	OFF	NG	NG	NG	NG	OFF	OFF
Turbine Fuel Input (MMBtu/hr, LHV)	197.8	202.0	156.0	161.6	121.8	125.4	108.8	110.9	198.9	215.1	162.7	172.0	148.4	156.4
Duct Burner Fuel Input (MMBtu/hr, LHV)	112.4	120.5	106.0	135.2	0.0	0.0	0.0	0.0	113.9	122.3	107.3	136.6	0.0	0.0
Turbine Fuel Input (MMBtu/hr, HHV)	219.0	223.7	172.7	179.0	134.9	138.8	120.5	122.7	212.0	229.3	173.4	183.3	158.2	166.7
Duct Burner Fuel Input (MMBtu/hr, HHV)	124.5	133.4	117.4	149.7	0.0	0.0	0.0	0.0	126.1	135.4	118.8	151.3	0.0	0.0
Stack Exit Temp. (F)	180	180	180	180	180	180	180	180	225	225	225	225	225	225
Stack Flow Rate (ft3/min)	149,161	161,526	130,069	148,184	111,718	126,102	104,916	118,101	162,628	182,407	145,324	167,016	135,906	156,253
Stack Exit Velocity (ft/s)	64.6	70.0	56.3	64.2	48.4	54.6	45.4	51.1	70.4	79.0	62.9	72.3	58.9	67.7
Emission Rates Turbine Only - Lb/Hr														
CO	0.98	1.00	0.77	0.80	0.61	0.62	0.54	0.55	3.51	3.80	2.87	3.04	2.62	2.76
NOx	1.6.1	1.65	1.27	1.32	0.99	1.02	0.89	0.90	7.42	8.02	6.07	6.41	5.54	5.83
PM10	4.38	4.47	3.45	3.58	2.70	2.78	2.41	2.45	8.48	9.17	6.94	7.33	6.33	6.67
PM2.5	4.38	4.47	3.45	3.58	2.70	2.78	2.41	2.45	8.48	9.17	6.94	7.33	6.33	6.67
SO2	6.26E-01	6.39E-01	4.93E-01	5.11E-01	3.85E-01	3.97E-01	3.44E-01	3.51E-01	3.30E-01	3.56E-01	2.70E-01	2.85E-01	2.46E-01	2.59E-01
Duct Burner - Lb/Hr														
CO	1.37	1.47	1.29	1.65	0.00	0.00	0.00	0.00	1.39	1.49	1.31	1.66	0.00	0.00
NOx	1.37	1.47	1.29	1.65	0.00	0.00	0.00	0.00	1.39	1.49	1.31	1.66	0.00	0.00
PM10	2.49	2.67	2.35	2.99	0.00	0.00	0.00	0.00	2.52	2.71	2.38	3.03	0.00	0.00
PM2.5	2.49	2.67	2.35	2.99	0.00	0.00	0.00	0.00	2.52	2.71	2.38	3.03	0.00	0.00
SO2	0.36	0.38	0.34	0.43	0.00	0.00	0.00	0.00	1.96E-01	2.11E-01	1.85E-01	2.35E-01	0.00	0.00
Total Emissions (Lb/Hour)														
CO	2.35	2.47	2.07	2.45	0.61	0.62	0.54	0.55	4.90	5.29	4.18	4.70	2.62	2.76
NOx	2.98	3.12	2.56	2.97	0.99	1.02	0.89	0.90	8.81	9.51	7.39	8.08	5.54	5.83
PM10	6.87	7.14	5.80	6.57	2.70	2.78	2.41	2.45	11.00	11.88	9.31	10.36	6.33	6.67
PM2.5	6.87	7.14	5.80	6.57	2.70	2.78	2.41	2.45	11.00	11.88	9.31	10.36	6.33	6.67
SO2	0.98	1.02	0.83	0.94	0.39	0.40	0.34	0.35	0.53	0.57	0.45	0.52	0.25	0.26
Total Emissions (g/s)														

Table A-1 MIT turbine & duct burner model cases Operational Scenario 1 (Continued)

Case	1	2	3	4	5	6	7	8	9	10	11	12	13	14
Ambient Temp (F)	50	0	60	0	60	0	60	0	60	0	60	0	60	0
% Load	100	100	75	75	50	50	40	40	100	100	75	75	65	65
CO	2.96E-01	3.11E-01	2.60E-01	3.09E-01	7.62E-02	7.85E-02	6.81E-02	6.94E-02	6.17E-01	6.66E-01	5.27E-01	5.92E-01	3.30E-01	3.48E-01
NO_x	3.76E-01	3.93E-01	3.23E-01	3.74E-01	1.25E-01	1.29E-01	1.12E-01	1.14E-01	1.11E+00	1.20E+00	9.29E-01	1.02E+00	6.97E-01	7.35E-01
PM_{10}	8.66E-01	9.00E-01	7.31E-01	8.28E-01	3.40E-01	3.50E-01	3.04E-01	3.09E-01	1.39E+00	1.50E+00	1.17E+00	1.31E+00	7.97E-01	8.40E-01
$PM_{2.5}$	8.66E-01	9.00E-01	7.31E-01	8.28E-01	3.40E-01	3.50E-01	3.04E-01	3.09E-01	1.39E+00	1.50E+00	1.17E+00	1.31E+00	7.97E-01	8.40E-01
SO_2	1.24E-01	1.29E-01	1.04E-01	1.18E-01	4.86E-02	5.00E-02	4.34E-02	4.42E-02	6.62E-02	7.14E-02	5.72E-02	6.55E-02	3.10E-02	3.26E-02
AERMOD v15181 X/Q Results														
1-hr High (X/Q) – Turb A	14.80589	14.26168	16.91790	15.4386	19.26435	17.03463	19.7981	17.43657	13.48548	11.89839	14.1816	13.34004	14.47937	13.70682
1-hr High (X/Q) – Turb B	14.76463	14.36589	16.90669	15.39615	17.88489	17.02772	19.41775	17.42937	13.61429	11.74507	14.21208	12.7863	14.58358	13.83042
1-hr High (X/Q) (5yr avg) – Turb A	14.32482	13.41704	16.05536	14.52615	17.11077	16.22722	17.77736	16.94331	11.86595	10.82114	12.89571	11.69795	13.58435	12.30807
1-hr High (X/Q) (5yr avg) – Turb B	14.32277	13.46236	16.03341	14.5269	17.12706	16.18954	17.69684	16.96733	11.96095	10.87161	12.97315	11.6426	13.60659	12.37432
3-hr High (X/Q) – Turb A	12.20667	9.97716	13.30463	12.24265	14.35766	13.42433	14.72136	14.13607	9.54864	9.22638	9.71421	9.29791	10.19639	9.80283
3-hr High (X/Q) – Turb B	12.18797	10.05973	13.22806	12.23881	14.19277	13.34357	14.59661	14.02637	9.83097	9.38635	9.75977	9.71037	10.19908	9.92015
8-hr High (X/Q) – Turb A	9.52044	8.89699	10.44165	9.56632	11.48121	10.64029	11.97477	11.10741	8.71531	8.02003	9.43259	8.54896	9.86259	8.94033
8-hr High (X/Q) – Turb B	9.39475	8.9013	10.43664	9.5486	11.49481	10.63015	11.94852	11.12409	8.71836	8.00604	9.42072	8.55263	9.86018	8.94189
24-hr High (X/Q) – Turb A	9.29971	8.74454	10.12015	9.33882	10.97504	10.30647	11.31536	10.68336	8.54524	7.77871	9.25009	8.38393	9.65012	8.78836
24-hr High (X/Q) – Turb B	9.26518	8.67077	10.14546	9.30208	11.00514	10.33432	11.35853	10.7047	8.47298	7.60733	9.23381	8.30549	9.66147	8.79115
24-hr High (X/Q) (5yr avg) – Turb A	7.47788	6.74535	8.51876	7.52494	9.70717	8.77411	10.17981	9.3124	6.57972	5.58007	7.48573	6.30563	7.95874	6.88942
24-hr High (X/Q) (5yr avg) – Turb B	7.34906	6.56117	8.43485	7.40539	9.62438	8.68979	10.11866	9.1919	6.40604	5.39525	7.4087	6.16153	7.88954	6.68898
Maximum Predicted Concentration ($\mu g/m^3$)														
1-hr NO_x	5.38	5.29	5.19	5.43	2.14	2.09	1.99	1.93	<u>13.27</u>	13.03	12.05	11.90	9.49	9.09
1-hr CO	4.39	4.47	4.40	4.76	1.47	1.34	1.35	1.21	<u>8.40</u>	7.93	7.48	7.90	4.82	4.81
8-hr CO	2.82	2.77	2.72	2.95	0.88	0.83	0.82	0.77	<u>5.38</u>	5.34	4.97	5.06	3.26	3.11
24-hr $PM_{2.5}$	6.47	6.07	6.23	6.23	3.30	3.07	3.09	2.88	<u>9.12</u>	8.35	8.78	8.23	6.35	5.79
24-hr PM_{10}	8.05	7.87	7.42	7.73	3.74	3.62	3.45	3.31	<u>11.85</u>	11.64	10.85	10.94	7.70	7.38
SO_2 1-hr	<u>1.77</u>	1.73	1.68	1.72	0.83	0.81	0.77	0.75	0.79	0.78	0.74	0.77	0.42	0.40
SO_2 3-hr	<u>1.51</u>	1.29	1.39	1.45	0.70	0.67	0.64	0.62	0.65	0.67	0.56	0.64	0.32	0.32
SO_2 24-hr	<u>1.15</u>	1.12	1.06	1.10	0.53	0.52	0.49	0.47	0.57	0.56	0.53	0.55	0.30	0.29

Table A-2 MIT turbine & duct burner model cases - Operational Scenario 2

Case	2.a	2.b	2.c	2.d	2.e	2.f	2.g	2.h	2.i	2.j	2.k	2.l	2.m	2.n
Ambient Temp (F)	50	0	60	0	60	0	60	0	60	0	60	0	60	0
% Load	100	100	75	75	50	50	40	40	100	100	75	75	65	65
Turbine Fuel	NG	NG	NG	NG	NG	NG	NG	NG	ULSD	ULSD	ULSD	ULSD	ULSD	ULSD
Duct Burner Fuel	NG	NG	NG	NG	OFF	OFF	OFF	OFF	NG	NG	NG	NG	OFF	OFF
Turbine Fuel Input (MMBtu/hr, LHV)	197.8	202.0	156.0	161.6	121.8	125.4	108.8	110.9	198.9	215.1	162.7	172.0	148.4	156.4
Duct Burner Fuel Input (MMBtu/hr, LHV)	112.4	120.5	106.0	135.2	0.0	0.0	0.0	0.0	113.9	122.3	107.3	136.6	0.0	0.0
Turbine Fuel Input (MMBtu/hr, HHV)	219.0	223.7	172.7	179.0	134.9	138.8	120.5	122.7	212.0	229.3	173.4	183.3	158.2	166.7
Duct Burner Fuel Input (MMBtu/hr, HHV)	124.5	133.4	117.4	149.7	0.0	0.0	0.0	0.0	126.1	135.4	118.8	151.3	0.0	0.0
Stack Exit Temp. (F)	180	180	180	180	180	180	180	180	225	225	225	225	225	225
Stack Flow Rate (ft3/min)	298,322	323,052	260,138	296,368	223,437	252,205	209,832	236,202	325,256	364,814	290,647	334,032	271,811	312,506
Stack Exit Velocity (ft/s)	64.6	70.0	56.3	64.2	48.4	54.6	45.4	51.1	70.4	79.0	62.9	72.3	58.9	67.7
Emission Rates Turbine Only - Lb/Hr (per Turbine)														
CO	0.98	1.00	0.77	0.80	0.61	0.62	0.54	0.55	3.51	3.80	2.87	3.04	2.62	2.76
NOx	1.61	1.65	1.27	1.32	0.99	1.02	0.89	0.90	7.42	8.02	6.07	6.41	5.54	5.83
PM10	4.38	4.47	3.45	3.58	2.70	2.78	2.41	2.45	8.48	9.17	6.94	7.33	6.33	6.67
PM2.5	4.38	4.47	3.45	3.58	2.70	2.78	2.41	2.45	8.48	9.17	6.94	7.33	6.33	6.67
SO2	6.26E-01	6.39E-01	4.93E-01	5.11E-01	3.85E-01	3.97E-01	3.44E-01	3.51E-01	3.30E-01	3.56E-01	2.70E-01	2.85E-01	2.46E-01	2.59E-01
Duct Burner - Lb/Hr (per Turbine)														
CO	1.37	1.47	1.29	1.65	0.00	0.00	0.00	0.00	1.39	1.49	1.31	1.66	0.00	0.00
NOx	1.37	1.47	1.29	1.65	0.00	0.00	0.00	0.00	1.39	1.49	1.31	1.66	0.00	0.00
PM10	2.49	2.67	2.35	2.99	0.00	0.00	0.00	0.00	2.52	2.71	2.38	3.03	0.00	0.00
PM2.5	2.49	2.67	2.35	2.99	0.00	0.00	0.00	0.00	2.52	2.71	2.38	3.03	0.00	0.00
SO2	0.36	0.38	0.34	0.43	0.00	0.00	0.00	0.00	1.96E-01	2.11E-01	1.85E-01	2.35E-01	0.00	0.00
Total Emissions (Lb/Hour) (from both Turbines)														
CO	4.70	4.94	4.13	4.90	1.21	1.25	1.08	1.10	9.80	10.57	8.36	9.40	5.24	5.52
NOx	5.97	6.23	5.13	5.93	1.99	2.05	1.78	1.81	17.61	19.02	14.75	16.15	11.07	11.66
PM10	13.74	14.28	11.60	13.15	5.40	5.55	4.82	4.91	22.01	23.76	18.63	20.72	12.66	13.33
PM2.5	13.74	14.28	11.60	13.15	5.40	5.55	4.82	4.91	22.01	23.76	18.63	20.72	12.66	13.33
SO2	1.96	2.04	1.66	1.88	0.77	0.79	0.69	0.70	1.05	1.13	0.91	1.04	0.49	0.52
Total Emissions (g/s) (from both Turbines)														

Table A-2 MIT turbine & duct burner model cases - Operational Scenario 2 (Continued)

Case	2.a	2.b	2.c	2.d	2.e	2.f	2.g	2.h	2.i	2.j	2.k	2.l	2.m	2.n
Ambient Temp (F)	50	0	60	0	60	0	60	0	60	0	60	0	60	0
% Load	100	100	75	75	50	50	40	40	100	100	75	75	65	65
CO	0.59	0.62	0.52	0.62	0.15	0.16	0.14	0.14	1.23	1.33	1.05	1.18	0.66	0.70
NO_x	0.75	0.79	0.65	0.75	0.25	0.26	0.22	0.23	2.22	2.40	1.86	2.04	1.39	1.47
PM_{10}	1.73	1.80	1.46	1.66	0.68	0.70	0.61	0.62	2.77	2.99	2.35	2.61	1.59	1.68
$PM_{2.5}$	1.73	1.80	1.46	1.66	0.68	0.70	0.61	0.62	2.77	2.99	2.35	2.61	1.59	1.68
SO_2	0.25	0.26	0.21	0.24	0.10	0.10	0.09	0.09	0.13	0.14	0.11	0.13	0.06	0.07
AERMOD v15181 X/Q Results														
1-hr High (X/Q)	10.11897	9.58449	11.44127	10.15156	13.55113	11.67837	13.85879	12.27893	7.81289	7.21865	9.31578	7.7349	9.8519	8.24553
1-hr High (X/Q) (5yr avg)	9.31179	8.67557	10.7114	9.26412	11.88303	10.81749	12.58373	11.36498	7.24067	6.7303	8.46173	7.19321	8.92558	7.83671
3-hr High (X/Q)	7.7157	6.63013	8.8744	7.73794	9.57956	9.2029	9.71489	9.44918	6.53703	5.96576	7.19648	6.40502	7.62541	6.70952
8-hr High (X/Q)	6.67928	6.30643	7.73077	6.71847	8.73611	7.92483	9.15477	8.3247	6.2328	5.08673	6.95852	5.95062	7.30458	6.36353
24-hr High (X/Q)	5.63293	4.52955	7.39274	5.72659	8.42715	7.6349	8.86685	8.09395	6.2328	5.08673	6.95852	5.95062	7.30458	6.36353
24-hr High (X/Q) (5yr avg)	4.04493	3.71782	5.28415	4.10114	0.59437	0.55819	0.61301	0.57828	3.49691	3.29464	4.1029	3.45017	4.67377	3.56039
Maximum Predicted Concentration ($\mu g/m^3$)														
1-hr NO_x	7.00	6.81	6.92	6.92	2.98	2.79	2.82	2.59	16.07	16.13	15.72	14.64	12.45	11.51
1-hr CO	6.00	5.97	5.96	6.27	2.07	1.83	1.89	1.70	9.65	9.62	9.81	9.16	6.51	5.74
8-hr CO	3.96	3.93	4.02	4.15	1.33	1.24	1.25	1.15	7.69	6.78	7.33	7.05	4.82	4.43
24-hr $PM_{2.5}$	7.00	6.69	7.72	6.79	4.45	3.87	4.29	3.76	9.70	9.86	9.63	9.01	7.45	5.98
24-hr PM_{10}	9.75	8.15	10.81	9.49	5.73	5.34	5.38	5.01	12.31	11.31	13.61	10.38	10.68	8.11
SO_2 1-hr	2.30	2.23	2.24	2.19	1.15	1.08	1.09	1.00	0.96	0.96	0.97	0.94	0.55	0.51
SO_2 3-hr	1.91	1.70	1.85	1.83	0.93	0.92	0.84	0.84	0.87	0.85	0.82	0.84	0.47	0.44
SO_2 24-hr	1.39	1.16	1.54	1.36	0.82	0.76	0.77	0.72	0.59	0.54	0.66	0.52	0.42	0.32

ATTACHMENT B

Source Parameters for Cumulative Impact Modeling

Table B-1 Source Parameters and Emission Rates for Cumulative Modeling Analysis* UTM Coordinates are NAD83, Zone 19N

Facility/Sources	UTM* East	UTM* North	Stack Dimensions		Exit Velocity	Exit Temp	PM2.5	PM10	NOx
	(m)	(m)	Height (m)	Diam(m)	(m/s)	(K)	(g/s)	(g/s)	(g/s)
Kendall Station									
BABCOCK & WILSON #2	328780.78	4692241.85	53.3	3.05	6.25	427.6	0.81	0.81	9.6
BABCOCK & WILSON #3	328760.64	4692244.83	53.3	2.92	9.45	460.9	1.22	1.22	14.4
TURBOPOWER CTG#1	328659.1	4692298.2	9.9	4.08	39.62	838.7	0.47	0.47	14.9
COMBINED CYCLE TURBINE	328722.3	4692228.1	76.2	5.11	28.96	394.3	6.3	6.3	6.9
Harvard Blackstone									
Turbine – ULSD; No Duct Fire (CHP) -ST	325795.4	4692345.7	33.5	1.25	19.21	444.3	0.47	0.47	0.54
Turbine – ULSD; No Duct Fire (CHP) –AN	325795.4	4692345.7	33.5	1.25	19.07	432.6	0.38	0.38	0.22
STACK 2 (Boilers 11 and 12)	325832.9	4692316.6	48.8	3.04	12.5	435.9	8.65	8.65	20.2
STACK2 (Boilers 6 and 13)	325806.8	4692328.7	45.7	3.66	10.36	469.3	3.53	3.53	10.2
MATEP									
STACK (TWO IDENTICAL FLUES)	326436.2	4689289.8	96	4.23	11.31	433.3	4.29	4.29	107.6
*Boston Generating Mystic Station***									
HIGH PRESSURE BLR #7 (DUAL FUEL)	329748.6	4695288.9	152.4	3.66	25.91	443.9	34.7	34.7	173.6
CTG/HRSG #81	329943.6	4695254.2	93	6.25	22.04	365	4.1	4.1	2.7
CTG/HRSG #82	329944.8	4695263.2	93	6.25	22.04	365	4.1	4.1	2.7
CTG/HRSG #93	329957.3	4695325.4	93	6.25	22.04	365	4.1	4.1	2.7
CTG/HRSG #94	329958.9	4695333.6	93	6.25	22.04	365	4.1	4.1	2.7
ROLLS ROYCE CTG	329630	4695256.4	9.1	3.66	12.8	810.9	2.8	2.8	9
Veolia Kneeland Street									
Stack 1	330471.67	4690635.24	81.4	3.51	15.24	505.4	N/A	N/A	35.3
Stack 2	330484.79	4690631.42	81.4	3.96	15.24	505.4	N/A	N/A	38.8
Logan Airport									
Keeler Boiler 1	333535.8	4692680.3	17.4	1.08	10.67	435.9	N/A	N/A	7.3
Keeler Boiler 2	333533.14	4692676.97	17.4	1.08	10.67	435.9	N/A	N/A	6.7
Keeler Boiler 3	333531.47	4692674.47	17.4	1.08	10.67	435.9	N/A	N/A	4.99

ATTACHMENT C

Calculations of Actual Emission Rates for PSD Increment Modeling

Table C-1 PM Short-term Emission Calculations based on Actual Operations

	Oil Historical Usage					NG Historical Usage				
Source	Max Oil Usage in a 24-hour period (gallons)	24-hour Period	Total MMBtu on Oil	EF OIl (Lb/MMBtu)	Actual Emission Oil Rate (lb/hr)	Max Gas Usage in a 24-hour period (scf)	24-hour Period	Total MMBTU on Gas	EF Gas (Lb/MMBtu)	Actual Emission Gas Rate (lb/hr)
Boiler No. 3	13,214	12/31/2013	1876	0.055	4.3	1,754,043	12/8/2014	1754	0.0076	0.56
Boiler No.4	19,948	2/6/2015	2833	0.055	6.5	1,742,543	12/25/2013	1743	0.0076	0.55
Boiler No.5	17,284	2/6/2015	2454	0.055	5.6	1,894,732	12/8/2014	1895	0.0076	0.6
Existing CTG	43,976	1/24/2014	6245	0.04	10.1	6,192,320	12/13/2013	6192	0.007	1.81
Existing DB	N/A	N/A	N/A	N/A	N/A	1,190,100	4/2/2013	1190	0.005	0.25
Boiler No. 7	9,163	2/24/2015	1301	0.03	1.6	1,202,035	2/16/2015	1202	0.01	0.5
Boiler No. 9	10,210	2/24/2015	1450	0.03	1.8	1,580,329	3/23/2015	1580	0.01	0.66

Period of Available Data for All Emission Units 4/1/13 – 3/31/15

Table C-2 PM Annual Emission Calculations based on Actual Operations

	Oil Historical Usage				NG Historical Usage				
Source	Average Oil Usage over 2 Year period (gallons)	Total MMBtu Oil	EF OIl (Lb/MMBtu)	Annual PM Oil Emissions Lb/Yr	Average Gas Usage Over a 2 Year period (scf)	Total MMBTU on Gas	EF Gas (Lb/MMBtu)	Actual PM Gas Emissions (lb/yr)	Expanding Emission Rate Total Lb/hr
Boiler No. 3	6.72E+05	9.54E+04	0.055	5,248	1.15E+08	1.15E+05	0.0076	872	0.7
Boiler No. 4	7.84E+05	1.11E+05	0.055	6,123	1.19E+08	1.19E+05	0.0076	907	0.8
Boiler No. 5	9.84E+05	1.40E+05	0.055	7,684	1.17E+08	1.17E+05	0.0076	891	1
Existing CTG	6.92E+05	9.82E+04	0.04	3,930	1.59E+09	1.59E+06	0.007	11,141	1.7
Existing HRSG	N/A	N/A	N/A	N/A	2.43E+08	2.43E+05	0.005	1,214	0.14
Boiler No. 7	1.11E+04	1.57E+03	0.03	47	6.39E+06	6.39E+03	0.01	64	0.013
Boiler No. 9	2.93E+04	4.16E+03	0.03	125	1.21E+07	1.21E+04	0.01	121	0.028

Period of Available Data for All Emission Units 4/1/13 – 3/31/15

Table C-3 PM Annual Emission Consuming Calculations based on Actual Operations for Boilers 3, 4, & 5

Annual PSD Increment Consuming Emission Calculation										
Source	Total MMBtu/hr Oil	Total MMBtu/hr Gas	Total MMBtu/hr	NG Emission Limit (lb/MMBtu)	NG Emissions (lb/yr)	Hrs/Yr Oil	MMBTU/hr Oil	Oil Emission Limit (lb/MMBtu)	Oil Emissions (lb/yr)	Consuming Emission Rate Total Lb/hr
Boiler No. 3	9.54E+04	1.15E+05	2.10E+05	0.0076	1,597.50	168	116.2	0.055	1,073.70	0.3
Boiler No. 4	1.11E+05	1.19E+05	2.31E+05	0.0076	1,753.00	168	116.2	0.055	1,073.70	0.32
Boiler No. 5	1.40E+05	1.17E+05	2.57E+05	0.0076	1,952.60	168	145.2	0.055	1,341.60	0.38

Period of Available Data for All Emission Units 4/1/13 – 3/31/15

Table C-4 PM Annual Emission Consuming Calculations based on Actual Operations for Boilers 7 & 9

Annual PSD Increment Consuming Emission Calculation									
Source	NG Hrs/Yr	MMBtu/hr Gas	NG Limit (Lb/MMBtu)	NG Emissions (Lb/yr)	Oil Hrs/yr	MMBtu/hr Oil	Oil Limit (Lb/MMBtu)	Oil Emissions (lb/yr)	Consuming Emission Rate Total Lb/hr
Boiler No. 7	8592[1]	99.7	0.01	8,566.20	168	99.7	0.03	502.5	1
Boiler No. 9	8592[1]	125.8	0.01	10,808.70	168	119.2	0.03	600.8	1.3

[1] Since the initial application, MIT has withdrawn the request for increasing the hours of operation on these units.

Appendix E

Acentech Noise Report

Massachusetts Department of Environmental Protection

Bureau of Waste Prevention – Air Quality

BWP AQ Sound

Submit alone and/or with Form CPA-FUEL and/or CPA-PPROCESS whenever the construction or alteration of stationary equipment (e.g. electrical generating equipment, motors, fans, process handling equipment or similar sources of sound) has the potential to cause noise, or in response to a MassDEP enforcement action citing noise as a condition of air pollution.

X262114
Transmittal Number

1191844
Facility ID (if known)

Important: When filling out forms on the computer, use only the tab key to move your cursor - do not use the return key.

tab

return

Introduction

When proposing sound suppression/mitigation measures, similar to the traditional "top-down" BACT process, the "top case" sound suppression/mitigation measures which deliver the lowest sound level increase above background are required to be implemented, unless these measures can be eliminated based upon technological or economic infeasibility. An applicant cannot "model out" of the use of the "top case" sound suppression/ mitigation measures by simply demonstrating that predicted sound levels at the property line when employing a less stringent sound suppression/mitigation strategy will result in a sound level increase of less than or equal to the 10 dBA (decibel, A –Weighted) above background sound level increase criteria contained in the MassDEP Noise Policy. A 10 dBA increase is the maximum increase allowed by MassDEP; it is not the sound level increase upon which the design of sound suppression/mitigation strategies and techniques should be based. Also, take into consideration that the city or town that the project is located in may have a noise ordinance (or similar) that may be more stringent than the criteria in the MassDEP Noise Policy

A. Sound Emission Sources & Abatement Equipment/Mitigation Measures

1. Provide a description of the source(s) of sound emissions and associated sound abatement equipment and/or mitigation measures. Also include details of sound emission mitigation measures to be taken during construction activities.

Two GE LM2500 combustion turbine generator (CTG) or similar and HRSG packages within new building. CTGs will have air inlet and exhaust mufflers and building ventilation systems will have attenuators. Fuel gas compressor and black start diesel generator will be in enclosures on the roof. New cooling towers with reduced-noise fans and variable frequency drives and louver barrier walls to be installed on roof of adjacent building. Sections B & C and letter report include details on planned project. Construction noise mitigation measures include: mufflers in suitable condition will be installed on all engine-driven equipment and noisier construction activities will be scheduled for regular daytime hours.

B. Manufacturer’s Sound Emission Profiles & Sound Abatement Equipment

Please attach to this form the manufacturer's sound generation data for the equipment being proposed for installation, or the existing equipment as applicable. This data must specify the sound pressure levels for a complete 360° circumference of the equipment and at given distance from the equipment. Also attach information provided by the sound abatement manufacturer detailing the expected sound suppression to be provided by the proposed sound suppression equipment.

C. Plot Plan

Provide a plot plan and aerial photo(s) (e.g. GIS) that defines: the specific location of the proposed or existing source(s) of sound emissions; the distances from the source(s) to the property lines; the location, distances and use of all inhabited buildings (residences, commercial, industrial, etc) beyond the property lines; identify any areas of possible future construction beyond the property line; and sound monitoring locations used to assess noise impact on the surrounding community. All information provided in the sound survey shall contain sufficient data and detail to adequately assess any sound impacts to the surrounding community, including elevated receptors as applicable, not necessarily receptors immediately outside the facility's property line.

Continue to Next Page ►

D. Community Sound Level Criteria

Approval of the proposed new equipment or proposed corrective measures will **not** be granted if the installation:

1. Increases off-site broadband sound levels by more than 10 dBA.above “ambient” sound levels. Ambient is defined as the lowest one-hour background A-weighted sound pressure level that is exceeded 90 percent of the time measured during equipment operating hours. Ambient may also be established by other means with the consent of MassDEP.

2. Produces off-site a "pure tone" condition. “Pure tone” is defined as when any octave band center frequency sound pressure level exceeds the two adjacent frequency sound pressure levels by 3 decibels or more.

3. Creates a potential condition of air pollution as defined in 310 CMR 7.01 and the MassDEP Noise Policy.

Note: These criteria are measured both at the property line and at the nearest inhabited building.

For equipment that operates, or will be operated intermittently, the ambient or background noise measurements shall be performed during the hours that the equipment will operate and at the quietest times of the day. The quietest time of the day is usually between 1:00 a.m. and 4:00 a.m. on weekend nights. The nighttime sound measurements must be conducted at a time that represents the lowest ambient sound level expected during all seasons of the year.

For equipment that operates, or will operate, continuously and is a significant source of sound, such as a proposed power plant, background shall be established via a minimum of seven consecutive days of continuous monitoring at multiple locations with the dBA L 90 data and pure tone data reduced to one-hour averages.

In any case, consult with the appropriate MassDEP Regional Office before commencing noise monitoring in order to establish a sound monitoring protocol that will be acceptable to MassDEP.

E. Full Octave Band Analysis

The following community sound profiles will require the use of sound pressure level measuring equipment in the neighborhood of the installation. An ANSI S1.4 Type 1 sound monitor or equivalent shall be use for all sound measurements. A detailed description of sound monitor calibration methodology shall be included with any sound survey.

1. Lowest **ambient** sound pressure levels during operating hours of the equipment.

   a. At property line:

A-Weighted	31.5	63.0	125	250	500	1K	2K	4K	8K	16K
PL-1 (61)	63	64	63	60	57	56	51	48	42	<42
PL-2 (59)	65	65	65	60	56	53	47	39	29	<29
PL-3 (63)	69	69	68	64	59	56	54	46	34	<34

E. Full Octave Band Analysis (continued)

b. At the nearest inhabited building and if applicable at buildings at higher elevation:

A- Weighted	31.5	63.0	125	250	500	1K	2K	4K	8K	16K
R-1 (58)	62	62	64	59	56	53	45	38	26	<26
R-2 (57)	67	66	62	57	54	52	46	39	28	<28
R-3 (56)	66	66	61	57	54	51	47	37	31	<31

Note: You are required to complete sound profiles 2a and 2b only if you are submitting this form in response to a MassDEP enforcement action citing a noise nuisance condition. If this is an application for new equipment, Skip to 3.

2. Neighborhood sound pressure levels with source operating without sound abatement equipment.

a. At property line:

A- Weighted	31.5	63.0	125	250	500	1K	2K	4K	8K	16K

b. At the nearest inhabited building and if applicable at buildings at higher elevation:

A- Weighted	31.5	63.0	125	250	500	1K	2K	4K	8K	16K

Continue to Next Page ►

Massachusetts Department of Environmental Protection
Bureau of Waste Prevention – Air Quality

BWP AQ Sound

Submit alone and/or with Form CPA-FUEL and/or CPA-PPROCESS whenever the construction or alteration of stationary equipment (e.g. electrical generating equipment, motors, fans, process handling equipment or similar sources of sound) has the potential to cause noise, or in response to a MassDEP enforcement action citing noise as a condition of air pollution.

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Transmittal Number

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Facility ID (if known)

E. Full Octave Band Analysis (continued)

3. **Expected** neighborhood sound pressure levels after installation of sound abatement equipment.

a. At property line:

A- Weighted	31.5	63.0	125	250	500	1K	2K	4K	8K	16K
PL-1 (64)	76	75	71	66	61	58	53	50	45	<45
PL-2 (59)	66	65	65	60	56	53	47	39	29	<29
PL-3 (63)	69	69	68	64	59	56	54	46	34	<34

b. At nearest inhabited building and if applicable at buildings at higher elevations:

A- Weighted	31.5	63.0	125	250	500	1K	2K	4K	8K	16K
R-1 (58)	63	63	64	59	56	53	45	38	28	<28
R-2 (57)	67	66	62	57	54	52	46	39	28	<28
R-3 (56)	66	66	61	58	54	51	47	37	31	<31

Note: MassDEP may request that actual measurements be taken after the installation of the noise abatement equipment to verify compliance at all off-site locations.

F. Professional Engineers Stamp

The seal or stamp and signature of a Massachusetts Registered Professional Engineer (P.E.) must be entered below. Both the seal or stamp impression and the P.E. signature must be original. This is to certify that the information contained in this Form has been checked for accuracy, and that the design represents good air pollution control engineering practice.

James D. Barnes
P.E. Name (Type or Print)

P.E. Signature

Supervisory Noise Consultant
Position/Title

Acentech Incorporated
Company

10/5/2015
Date (MM/DD/YYYY)

29612
P.E. Number

Place P.E. Seal or Stamp Here.

COMMONWEALTH OF MASSACHUSETTS
JAMES D. BARNES
No. 29612
MECHANICAL
REGISTERED
PROFESSIONAL ENGINEER

Massachusetts Department of Environmental Protection
Bureau of Waste Prevention – Air Quality
BWP AQ Sound

Submit alone and/or with Form CPA-FUEL and/or CPA-PPROCESS whenever the construction or alteration of stationary equipment (e.g. electrical generating equipment, motors, fans, process handling equipment or similar sources of sound) has the potential to cause noise, or in response to a MassDEP enforcement action citing noise as a condition of air pollution.

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Transmittal Number

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G. Certification by Responsible Official

The signature below provides the affirmative demonstration pursuant to 310 CMR 7.02(5)(c)8 that any facility(ies) in Massachusetts, owned or operated by the proponent for this project (or by an entity controlling, controlled by or under common control with such proponent) that is subject to 310 CMR 7.00, et seq., is in compliance with, or on a MassDEP approved compliance schedule to meet, all provisions of 310 CMR 7.00, et seq., and any plan approval, order, notice of noncompliance or permit issued thereunder. This Form must be signed by a Responsible Official working at the location of the proposed new or modified facility. Even if an agent has been designated to fill out this Form, the Responsible Official must sign it. (Refer to the definition given in 310 CMR 7.00.)

I certify that I have personally examined the foregoing and am familiar with the information contained in this document and all attachments and that, based on my inquiry of those individuals immediately responsible for obtaining the information, I believe that the information is true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including possible fines and imprisonment.

William VanSchalkwyk
Responsible Official Name (Type or Print)

William VanSchalkwyk
Responsible Official Signature

Managing Director, EHS Programs
Responsible Official Title

MIT
Responsible Official Company/Organization Name

12/14/2015
Date (MM/DD/YYYY)

Description of Sound Emission Profile and Sound Abatement Equipment
[Section B of MassDEP Form BWP AQ Sound (Noise Form)]

OPERATION SOUND AND MITIGATION MEASURES

The sound emissions from the entire CHP addition, which includes the combustion turbine generator packages, heat recovery steam generators, fuel gas compressors, chillers, new cooling towers, cold start generator, support equipment, and new building, will be specified, designed, and operated to address compliance with the MassDEP Noise Criteria and the City of Cambridge Noise Standards. Abatement methods to be employed to control the sound of the CHP addition will include the following:

- Combustion turbine generator sets will be installed in sound-attenuated enclosures.
- Majority of cogeneration equipment will be installed in an acoustically-designed building with appropriate treatments for building ventilation systems and access openings.
- Mufflers will be installed as necessary on the gas turbine air intake, gas exhaust, and turbine enclosure ventilation systems.
- Mufflers will be installed as needed on non-emergency steam vents.
- Reduced-noise lube oil cooler model will be used or sound barrier walls will be installed for the standard model as needed.
- The fuel gas compressor and drive motor will be installed in a sound-attenuated enclosure located on the roof with treated ventilation air paths.
- The cold start diesel generator will be installed in a sound-attenuated enclosure located on the roof with treated ventilation air paths.
- New mechanical draft wet cooling towers will include reduced-noise fans with variable frequency drives and louvered barrier walls as required to meet sound ordinance.

The major CHP equipment will be located within the southern section of the building toward the existing railroad tracks and other support systems and administrative spaces will be located on the northern section of the building toward Albany Street. As noted above, the CTG will be enclosed and located within the new building and the fuel gas compressor and cold start diesel generator will be installed in sound-attenuated enclosures located on the roof with treated ventilation air paths. The average sound levels around the enclosed CTG and the balance of the CHP area are estimated to be 85 dBA or less. The building walls and roof will have a minimum surface weight of 8 psf or a composite structure that can provide a minimum Sound Transmission Class (STC) rating of STC 30. The equipment and building air ventilation paths will include treatments (e.g., mufflers, lined ducts, acoustic louvers, and local barriers) with suitable sound attenuation; and the major ventilation openings will be on the south wall of the building facing the railroad tracks and shielded from direct line-of-sight to the community. The personnel doors and overhead doors that directly access the main CHP room from outdoors will be specified with an appropriate STC rating. The overall design and construction of the building shell will aim to achieve 55 to 60 dBA directly outside the building walls facing the community.

Figure A.
Drawing Showing Current MIT Central Utilities Plant (CUP) and Planned Combined Heat and Power (CHP) Addition.
[Section C of MassDEP Form BWP AQ Sound (Noise Form)]

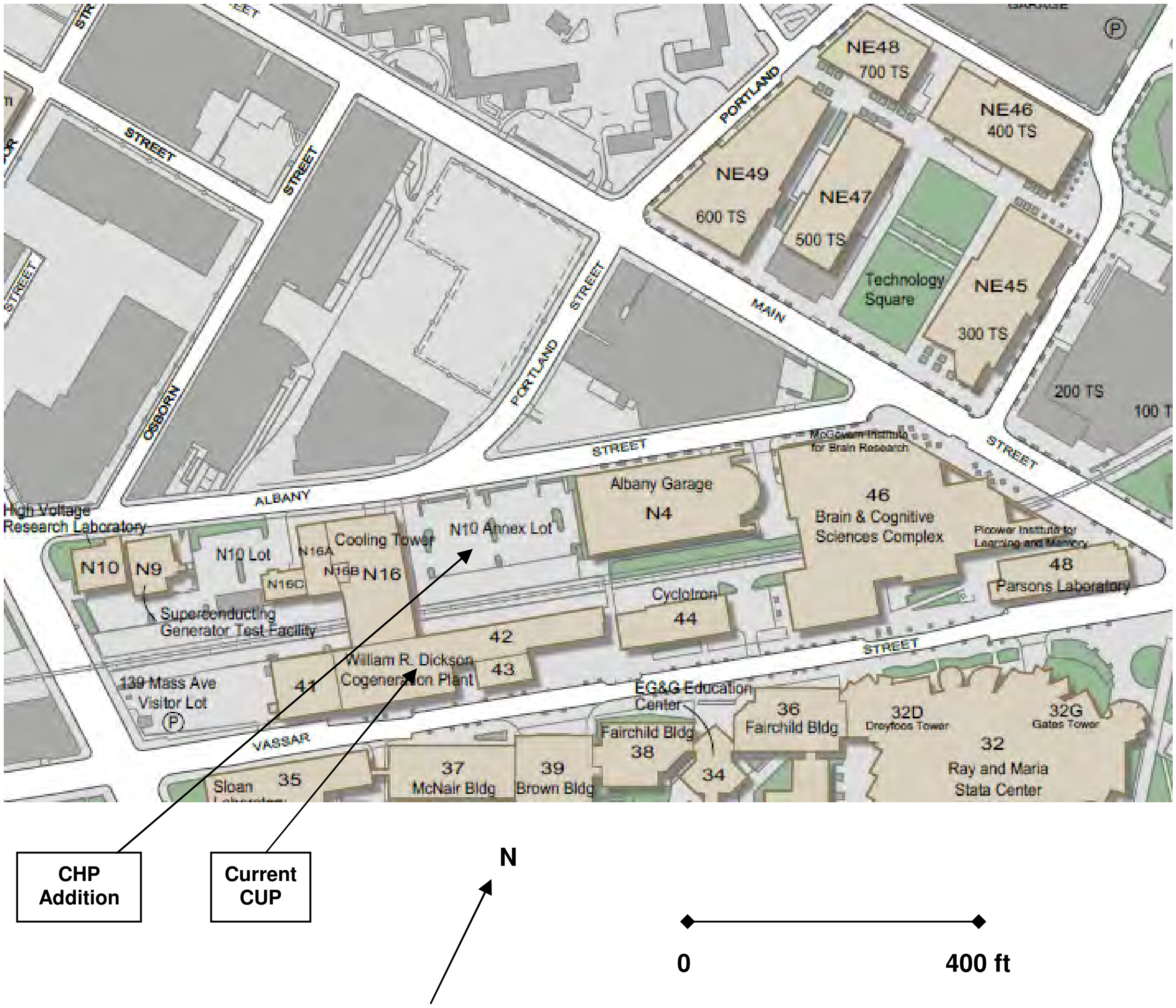

Figure B.
Aerial Photograph Showing Planned Location for MIT CHP Addition and Distances to Property Line (PL) and Residential (R) Locations for August 2014 Ambient Sound Survey and Analysis.
[Section C of MassDEP Form BWP AQ Sound (Noise Form)]

Six short-term measurement locations and one long-term measurement location (marked by *); ambient sound measured at long-term Location R-1A is representative of sound at Location R-1.

Location	Approximate Distance from Project Center (ft)
PL-1 (North)	70
PL-2 (Northeast)	650
PL-3 (Southwest)	650
R-1 (Newtowne Ct. Apts.)	580
R-2 (MIT Housing)	1200
R-3 (MIT Housing)	1100

N

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Acentech

5 October 2015

Massachusetts Institute of Technology
77 Massachusetts Ave, NE49-2021Q
Cambridge, MA 02139

Subject: Community Sound Study
Planned MIT Second Century Plant Upgrade
Cambridge, MA
Acentech Project No. 624469

Attention: John Engle
Director, Utility Projects

Dear Mr. Engle:

INTRODUCTION

Massachusetts Institute of Technology (MIT) proposes to upgrade their existing Central Utilities Plant (CUP) on Vassar Street at the Cambridge, MA campus to house additional CHP (Combined Heat and Power) equipment. The new equipment is designed to produce up to 44 MW of electrical power and 320,000 pph of thermal energy, using heat recovery steam generators, for distribution to the Institute's campus. The CHP addition will span the railroad tracks and be adjacent to the east side of Building N16. The additional building space will be developed in the area currently designated as the N10 Annex parking lot. The project will include the installation of two General Electric LM2500 combustion turbine generators (CTG) or similar equipment and heat recovery steam generator (HRSG) packages, two chillers, a cold start diesel generator, coolers, pumps, mechanical draft wet cooling towers, and other support equipment. Since the available gas pressure could fall below the minimum required pressure, one new high pressure fuel gas compressor will also be installed. Figure 1 shows the CHP project location on an aerial photograph and Figure 2 displays 3-D sketches of the existing project site and the site with the proposed CHP addition. Major equipment items for the new plant include:

- Two (2) CTGs with water-cooled generators
- Two (2) HRSGs with duct burners and SCR and CO catalysts
- Two (2) lube oil coolers and pumps
- Inlet filter housings with heating & cooling
- One (1) fuel gas compressor skid
- Liquid fuel storage and delivery systems
- 2 MW reciprocating internal combustion engine (RICE) cold start diesel generator
- 1000 CFM water-cooled air compressor
- Two (2) 2500 ton electric chillers
- Removal of seven (7) mechanical draft cooling tower units
- Addition of three (3) mechanical draft cooling tower units

The current 20 MW ABB GT-10 CTG and HRSG system, which was installed in 1994 at the existing CUP, will be retired following commissioning of the new cogeneration plant. In addition, several existing cooling tower units will be retired following the addition of new rooftop units.

The CHP Project team met with representatives of the Massachusetts Department of Environmental Protection (MassDEP) on 7/29/2014 and discussed several issues, including the sound study being conducted to support the project's Air Permit Application. It was agreed that the Project team would submit an ambient survey plan for MassDEP's review and comment, meet with MassDEP representatives and tour the project site and nearby community, assess compliance of the MIT's fleet of emergency generators and engine-driven water pumps, and where indicated, recommend noise mitigation for the existing emergency units.

To date, Acentech Incorporated has reviewed project information, met with MassDEP at the project site and reviewed our study plan, performed an ambient sound survey of the area, and developed estimates of the property line and off-site sound levels associated with the proposed new CHP plant. In addition, the study team has conducted a sound survey of all of the MIT emergency generators and diesel engine-driven water pumps, assessed compliance with the MassDEP noise criteria, and developed noise control recommendations. The pertinent findings of our study for the CHP plant are summarized in this letter report. The results of our study for the existing emergency power and diesel engine-driven water pump units are presented in a separate report.

EXISTING ACOUSTIC ENVIRONMENT

Acentech conducted an ambient sound survey to characterize the existing land uses, sound sources, and background acoustic environment in the area. The program included long-term continuous measurements collected over weekday and weekend periods with an automatic monitor and shorter-term samples obtained on two nights with a portable precision sound level meter.

Figure 3 is an aerial photograph that shows the area around the proposed new CHP Plant and identifies representative residential (R) and property line (PL) sound measurement locations. We collected ambient sound data during a nominal 14-day period between 5 and 20 August 2014. The long-term data show the repetitive day and night variations in the background sound levels in the area and the short-term data characterize the background acoustic environment during typically quieter nighttime periods.

The overall A-weighted sound levels and spectra were measured continuously with an automatic monitor at the following location as shown on Figures 3 and 4:

- R-1A -- N of project site across Main Street from the nearest residences

In addition, we performed short-term sampling of the overall A-weighted sound levels and spectral data and observed sound sources during the nighttime hours at the six locations on Figure 3:

- PL-1 -- N of project site across Albany Street
- PL-2 -- NE of project site at Albany Street and Main Street
- PL-3 -- SW of project site at Albany Street and Massachusetts Avenue
- R-1 -- N of project site at nearest residences on Main Street (Newtowne Court Apartments)
- R-2 -- W of project site at MIT housing on Massachusetts Avenue (MIT housing)
- R-3 -- SW of project site at MIT housing at Albany Street and Cross Street (MIT housing)

We collected short-term ambient sound measurements and observations at the above six locations on

Friday and Saturday nights (8-9 August and 9-10 August 2014).

As Figure 3 and the above list indicate, residential areas are located to the north, west, and southwest of the project site, while the nearest property lines are directly across Albany Street to the north of the site and farther away on Albany Street to the northeast and southwest of the site. We expect that a new multi-story building that is currently under construction on the MIT-owned property between the project site and Location R-1 will provide significant shielding of project sound that may propagate toward the community near Location R-1.

Table 1 lists the instruments that we employed for the ambient measurements. Each instrument was laboratory-calibrated within the past year, and field-calibrated with an acoustic calibrator before and after the measurements. The microphone for each instrument was fitted with a windscreen and mounted at a nominal height of five feet above the ground. For this survey we programmed the continuous monitor at Location R-1A to collect overall A-weighted sound levels and spectral data (1/3-octave band sound pressure levels) and to store the statistical values (Lmax, Lmin, L1, L10, L50, L90, and Leq) at ten-minute intervals. Similar statistical spectral data, plus octave band data, were collected for a one-hour period with a portable meter at each of the six property line and residential locations. Weather conditions during the overall survey from 5 to 20 August 2014 were seasonal with typical temperatures of 75 to 85ºF during the day and 60 to 65ºF during the night, calm to moderate winds, and one stormy period on 13 August 2014. The sound data and observations collected during our survey characterize the typical existing acoustic environment in the area.

Long-Term Data
Figure 5 illustrates the changes in ambient sound levels measured at the long-term monitor Location R-1A over the day and night periods, and specifically, present the Leq, L1, and L90 A-weighted sound levels for each 10-minute interval. The energy-average Leq sound levels include both the steady background sounds (e.g., distant traffic and building ventilation equipment) plus the short-term intrusive sounds (e.g., horn blast or local car passby). The L1 sound levels represent the nominal maximum sounds, such as local traffic sounds, that occurred for at least 1% of each interval (i.e., six seconds of each 10-minute interval). The L90 sound levels characterize the lowest background, or residual sound level exceeded for 90% of the time of each interval (i.e., nine minutes of each 10-minute interval). The L90 sound level occurs when short-term intrusive sound sources, such as local traffic passbys or aircraft flyovers, are absent and the sound level returns to a lower residual value. This figure reveals that the nighttime sound levels were generally lower than the daytime levels. The sound levels at these locations were typically due to sounds of building ventilation equipment in the area and distant and local road traffic. The data on Figure 5 indicate that the measured L90 sound levels ranged down to about 59 to 61 dBA at Location R-1A during the nighttime periods. In addition, this figure notes that local construction activity began during the second week, which increased the daytime sound levels measured at this location.

Short-Term Data
Table 2 summarizes the residual (L90) sound levels that were measured with a portable meter over a nighttime hour at each location. As previously noted, the L90 data are the levels exceeded for 90% of the sampling periods (i.e., 54 minutes of each hour) and represent the background, or residual, sound levels. The data in Table 2 indicate existing residual sound levels that ranged from 59 to 63 dBA at the property line Locations PL-1 to PL-3 and from 56 to 58 dBA at the residential Locations R-1 to R-3. The primary sound sources observed at these locations included: building ventilation equipment, local and distant road traffic, and MIT building and cooling tower equipment. Our observations did not indicate any unusual

activities in the area during the survey.

PROJECT SOUND CRITERIA

During the permitting phase it is necessary to determine the degree of sound reduction required for the proposed project. This is based upon estimates of the sound that will propagate from the facility and the sound level criteria appropriate for the offsite neighborhood. The sound criteria for this project will address the following factors:

- Ambient or background sound levels during the quieter times
- Type of neighborhood – residential, business, or industrial
- Character of sound generated by the proposed facility – sound pressure level and spectrum
- State and Local noise requirements

Depending on the major equipment and noise control selected for a project, a typical cogeneration facility can emit tonal and/or broadband sounds, low frequency sound, and steady and/or intermittent sounds that are noticeable in the community. The City of Cambridge and the MassDEP have noise requirements that protect residents from excessive sound.

City of Cambridge Noise Requirements

We understand that the requirements in Title 8, Chapter 8.16, NOISE CONTROL of the City of Cambridge Code of Ordinances apply to the project. The following table lists the local noise standards for different receptor land uses. These standards are enforced only for the source sound levels as a project owner has no control over the ambient sound levels. Since the cogeneration facility will operate continuously, its design should address the more stringent nighttime noise standards for the nearest residential receptors (50 dBA) and commercial receptors (65 dBA) in the surrounding area.

CITY OF CAMBRIDGE ZONING DISTRICT NOISE STANDARDS (ref: Table 8.16.060E)
Maximum Allowable Octave Band Sound Pressure Levels (dB)

Octave Band Center Frequency (Hz)	Residential Area		Residential in Industrial		Commercial Area	Industry Area
	Daytime	Other Times	Daytime	Other Times	Anytime	Anytime
31.5	76	68	79	72	79	83
63	75	67	78	71	78	82
125	69	61	73	65	73	77
250	62	52	68	57	68	73
500	56	46	62	51	62	67
1,000	50	40	56	45	56	61
2,000	45	33	51	39	51	57
4,000	40	28	47	34	47	53
8,000	38	26	44	32	44	50

Single Number (dBA)

Equivalent (dBA)	60	50	65	55	65	70

Although the CHP Project does not include an emergency generator, we understand based on discussions with the City of Cambridge that an emergency generator in a commercial area with no residences nearby does not need to meet the City's noise requirements. And if there is a nearby residence, the emergency generator is exempt from the ordinance as long as it is tested during daytime hours.

Commonwealth of Massachusetts
The Commonwealth of Massachusetts has enacted regulations for the control of air pollution (310 CMR 7.10). To enforce these regulations, MassDEP has issued guidelines that encourage the use of reasonable noise control measures and limit the level of industrial noise in residential areas as follows: a) not to increase the residual ambient sound level by more than 10 dBA and b) not to produce a pure tone condition where the sound pressure level in one octave band exceeds the levels in the two adjacent octave bands by 3 dB or more.

MassDEP has also clarified the application of its noise guidelines in an update on its website (ref: http://www.mass.gov/dep/air/laws/noisepol.htm). The website information includes a section - "Where Are MassDEP's Noise Criteria Applied?" - that states:

> "The MassDEP noise pollution policy describes criteria that MassDEP uses to evaluate noise impacts at both the property line and the nearest occupied residence or other sensitive receptor. When noise is found to be a nuisance or a threat to health, MassDEP requires the source to mitigate its noise. Noise levels that exceed the criteria at the source's property line by themselves do not necessarily result in a violation or a condition of air pollution under MassDEP regulations (see 310 CMR 7.10 U). The agency also considers the effect of noise on the nearest occupied residence and/or building housing sensitive receptors:
>
> - In responding to complaints, MassDEP measures noise levels at the complainant's location and at other nearby locations that may be affected (e.g., residences and/or buildings with other sensitive receptors). If the noise level at a sensitive receptor's location is more than 10 dBA above ambient, MassDEP requires the noise source to mitigate its impact.
> - A new noise source will be required to mitigate its sound emissions if they are projected to cause the broadband sound level at a residence or building housing sensitive receptors to exceed ambient background by more than 10 dBA.
> - A new noise source that would be located in an area that is not likely to be developed for residential use in the future (e.g., due to abutting wetlands or similarly undevelopable areas), or in a commercial or industrial area with no sensitive receptors may not be required to mitigate its noise impact on those areas, even if projected to cause noise levels at the facility's property line to exceed ambient background by more than 10 dBA. However, a new noise source that would be located in an area in which housing or buildings containing other sensitive receptors could be developed in the future may be required to mitigate its noise impact in these areas.
>
> This policy has been designed to protect affected residents and other sensitive occupants of nearby property, but not necessarily uninhabited areas in and around the source's property. Sources of noise may need to implement mitigation if residences or buildings occupied by sensitive receptors are developed where they may be affected by the source's noise."

OVERALL PROJECT SOUND CRITERIA

We recommend that the CHP Project be designed to meet the following sound criteria, which address the City of Cambridge Noise Standards, the MassDEP Noise Guidelines, and potential contributions from other MIT sources:

- 62 dBA - maximum sound level of CHP addition at property lines of nearest non-MIT properties (criteria aims to comply with associated nighttime residential octave band sound pressure levels in the Cambridge Noise Standards or be similar to existing ambient sound spectra, and as stated above, to allow for sounds from non-CHP sources at MIT);

- 47 dBA - maximum sound level of new CHP addition at the community residences (and aim to comply with associated nighttime residential octave band sound pressure levels in the Cambridge Noise Standards or be similar to existing ambient sound spectra);

- No significant tonal sounds at community residences; and

- 55 dBA - maximum sound levels at the community residences during transient startup and shutdown activities.

OPERATION SOUND AND MITIGATION MEASURES

Abatement methods to be employed to control the sound of the cogeneration project will include the following:

- Combustion turbine generator sets will be installed in sound-attenuated enclosures.

- Majority of cogeneration equipment will be installed in an acoustically-designed building with appropriate treatments for building ventilation systems and access openings.

- Mufflers will be installed as necessary on the gas turbine air intake, gas exhaust, and turbine enclosure ventilation systems.

- Mufflers will be installed as needed on non-emergency steam vents.

- Reduced-noise lube oil cooler model will be used or sound barrier walls will be installed for the standard model as needed.

- The fuel gas compressor and drive motor will be installed in a sound-attenuated enclosure located on the roof with treated ventilation air paths.

- The cold start diesel generator will be installed in a sound-attenuated enclosure located on the roof with treated ventilation air paths.

- New mechanical draft wet cooling towers will include reduced-noise fans with variable frequency drives and louvered barrier walls as required to meet sound ordinance.

The sound emissions from the entire CHP Project, which includes the combustion turbine generator packages, heat recovery steam generators, fuel gas compressors, chillers, new cooling towers, cold start generator, support equipment, and cogeneration building, will be specified and designed to address compliance with the MassDEP noise guidelines and City of Cambridge Noise Standards. Table 3 presents the sound estimates for the CHP addition at the nearest property line and residential locations. As noted below the table, the estimates at the nearest location (PL-1) are based on sound levels measured on the existing new cooling tower, information provided on the CHP equipment and building layout, recommended noise specification values, and the expected building design to meet the overall project sound criteria. The estimates at the other five more distant property line and community residential locations are based on the PL-1 levels with attenuation to account for distance (i.e., hemi-spherical spreading), but with no additional attenuation associated with other factors, such as shielding by intervening buildings, air absorption, or anomalous excess attenuation.

Table 4 presents similar information as Table 3, but the estimated total sound levels include the contributions of both the CHP addition sound and the ambient sound that we measured during the night at each location. The estimates, which are based on current project information, indicate the project design criteria are in compliance with the applicable MassDEP and City of Cambridge noise requirements. The project sound estimates will be updated during the detailed design and procurement process to check and verify compliance of the acoustical design with the noise requirements.

****

I trust that this letter provides a useful summary of our study. Should you have any questions regarding our analysis or this report, please call me at 617-499-8018.

Sincerely,

James D. Barnes, P.E.
Acentech Incorporated

Figures 1 – 5
Tables 1 – 4

xc: M. Thornton/Vanderweil
S. Dwyer/Vanderweil

J: 624469-RGV-MIT-newCHP-100515c.doc

Figure 1.
Aerial Photograph Showing Planned Location for CHP Addition to Existing MIT CUP.

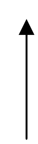
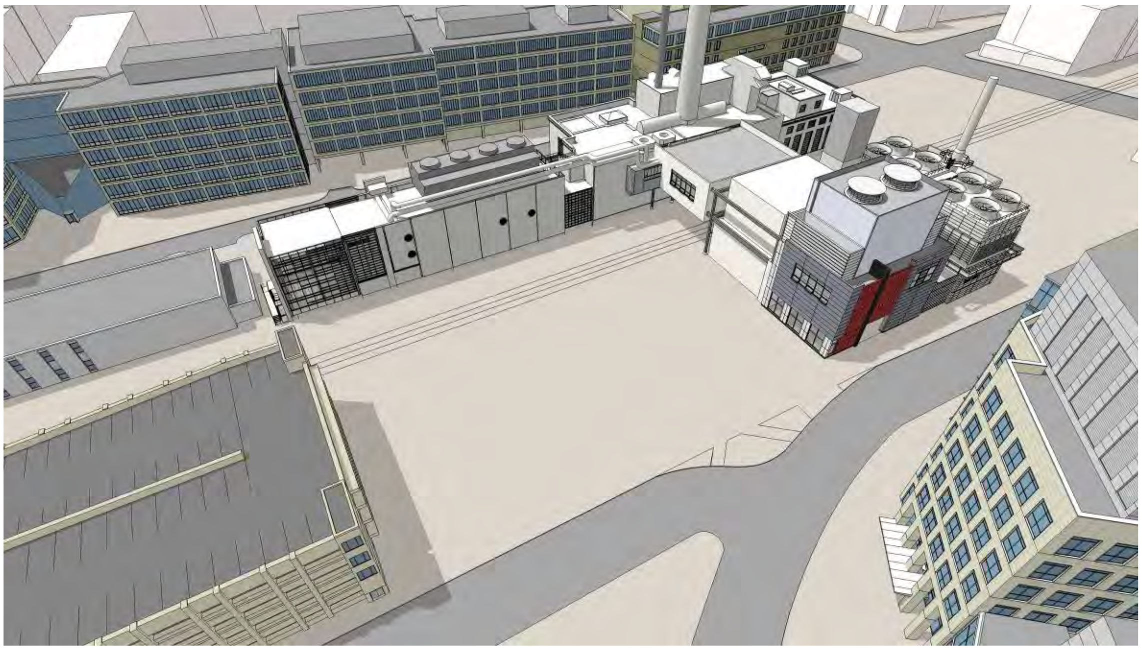


Figure 2.
3-D Sketches of Existing CUP and Proposed New CHP Addition.



Looking S at Existing CUP and Site of Proposed CHP Addition

Looking S at Existing CUP and Proposed CHP Addition

Figure 3.
Aerial Photograph Showing Planned Location for MIT CHP Addition and Distances to Property Line (PL) and Residential (R) Locations for August 2014 Ambient Sound Survey and Analysis.

Six short-term measurement locations and one long-term measurement location (marked by *); ambient sound measured at long-term Location R-1A is representative of sound at Location R-1.

Location	Approximate Distance from Project Center (ft)
PL-1 (North)	70
PL-2 (Northeast)	650
PL-3 (Southwest)	650
R-1 (Newtowne Ct. Apts.)	580
R-2 (MIT Housing)	1200
R-3 (MIT Housing)	1100

N

Figure 4.
Photograph Looking South from Long-Term Sound Monitoring Location R-1A toward CHP Addition Project Site.

Note: Non-residential MIT building now under construction in gravel area in foreground.

Figure 5.
Nominal Maximum (L1), Energy Average (Leq), and Residual (L90) Sound Levels Measured for 10-Minute Periods at Long-Term Monitoring Location R-1A (5 to 20 August 2014).

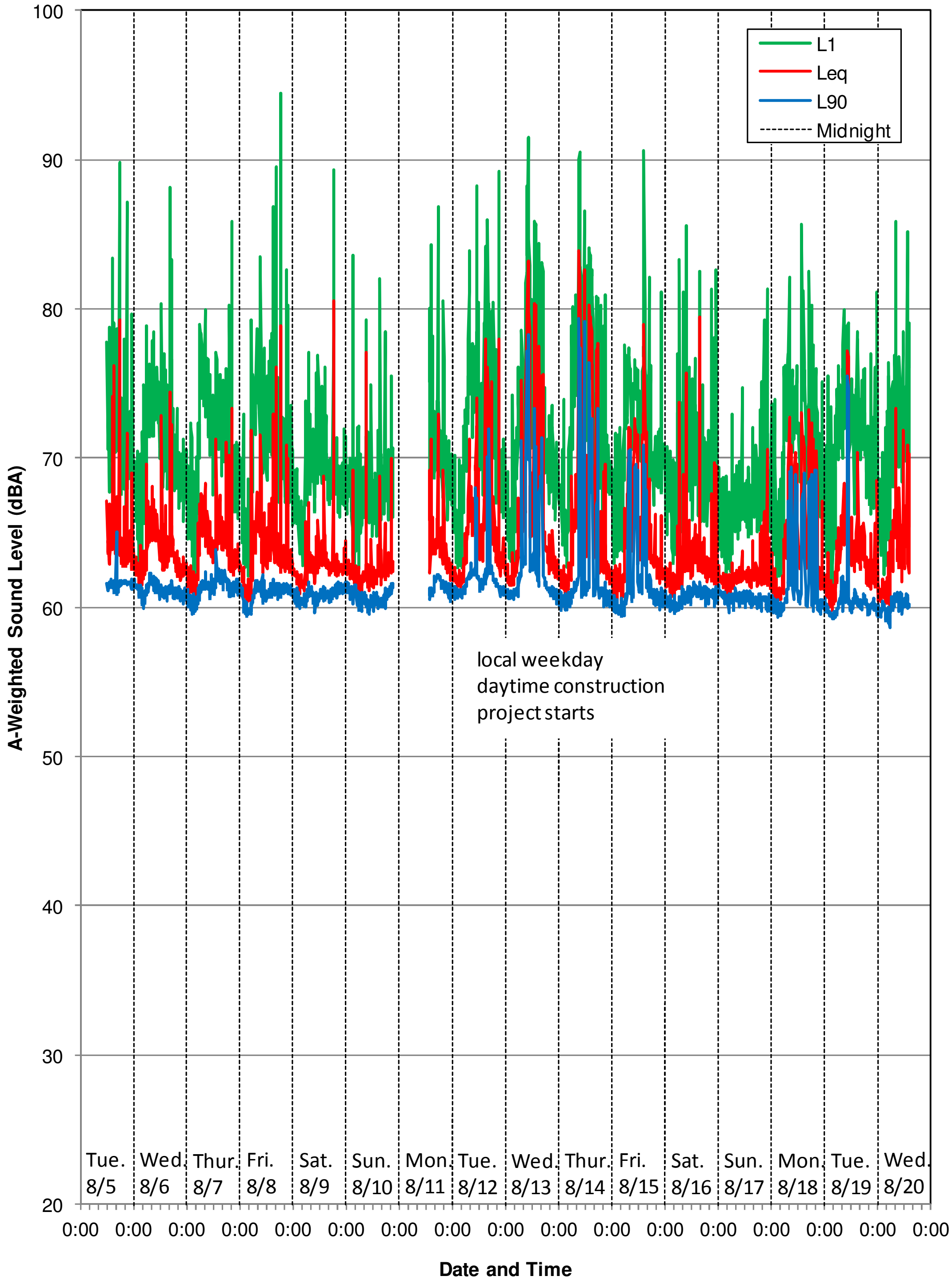


**Table 1.
Type of Acoustic Instrumentation Used for Ambient Sound Measurements during
5 to 20 August 2014.**

Instrument Type	Manufacturer	Model
Precision Sound Level Meter and Octave Band Analyzer	Rion	NA-28
Preamplifier	Rion	NH-23
1/2" Microphone	Rion	UC-59
Acoustic Calibrator	Rion	NC-74
Precision Sound Level Meter and Octave Band Analyzer	Rion	NL-52
Preamplifier	Rion	NH-25
1/2" Microphone	Rion	UC-59
Acoustic Calibrator	Rion	NC-74

Table 2.
Summary of Residual (One-Hour L_{90}) Sound Spectra Measured by Portable Meter at Property Line (PL) and Residential (R) Locations on Two Nights of August 2014 Ambient Sound Survey.

		Octave Band Center Frequency (Hz)									
Date	**Location**	**31.5**	**63**	**125**	**250**	**500**	**1000**	**2000**	**4000**	**8000**	**dBA**
8/8-9/2014	Location PL-1	63	64	63	60	57	56	51	48	42	61
11p-2:30a	Location PL-2	65	65	65	60	56	53	47	39	29	59
	Location R-1	62	62	64	59	56	53	45	38	26	58
8/9-10/2014	Location PL-3	69	69	68	64	59	56	54	46	34	63
11p-2:30a	Location R-2	67	66	62	57	54	52	46	39	28	57
	Location R-3	66	66	61	57	54	51	47	37	31	56
	Max Night	69	69	68	64	59	56	54	48	42	63
	Min Night	62	62	61	57	54	51	45	37	26	56

Measurement period at each location was one hour long.

Table 3.
Estimates of Project-Only Sound Pressure Levels and Overall A-Weighted Sound Levels at Residential Receptor (R) and Property Line (PL) Locations.

	Octave Band Center Frequency (Hz)									
Location	**31.5**	**63**	**125**	**250**	**500**	**1000**	**2000**	**4000**	**8000**	**dBA**
Location PL-1	76	75	70	65	59	53	48	44	41	62
Location PL-2	57	56	51	46	40	34	29	25	22	43
Location PL-3	57	56	51	46	40	34	29	25	22	43
Location R-1	58	57	52	47	41	35	30	26	23	44
Location R-2	51	50	45	40	34	28	23	19	16	37
Location R-3	52	51	46	41	35	29	24	20	17	38

Table 4.
Estimates of Total (Project + Ambient) Sound Pressure Levels and Overall A-Weighted Sound Levels at Residential Receptor (R) and Property Line (PL) Locations.

	Octave Band Center Frequency (Hz)									
Location	**31.5**	**63**	**125**	**250**	**500**	**1000**	**2000**	**4000**	**8000**	**dBA**
Location PL-1	76	75	71	66	61	58	53	50	45	64
Location PL-2	66	65	65	60	56	53	47	39	29	59
Location PL-3	69	69	68	64	59	56	54	46	34	63
Location R-1	63	63	64	59	56	53	45	38	28	58
Location R-2	67	66	62	57	54	52	46	39	28	57
Location R-3	66	66	61	58	54	51	47	37	31	56

Calculated values rounded-off to whole dB for display.

Estimates at the nearest location (PL-1) are based on sound levels measured on the existing new cooling tower, information provided on the CHP equipment and building layout, the recommended noise specification values, and the expected building design. The estimates at the other five more distant property line and community residential locations are based on the PL-1 levels with attenuation to account for distance only (i.e., hemi-spherical spreading), but with no additional attenuation to account for other factors, such as shielding by intervening buildings, air absorption, or anomalous excess attenuation.