Supplement to the Prevention of Significant Deterioration (PSD) Permit Application

Proposed Central Heating Plant University of Massachusetts Amherst, Massachusetts

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1.0 INTRODUCTION

The University of Massachusetts Building Authority (the Authority) proposes to construct and operate a new Central Heating Plant (CHP) at the University's campus in Amherst, Massachusetts. The proposed CHP will consist of a combustion turbine nominally rated at 10 megawatts, a heat recovery steam generator (HRSG) with a duct burner rated at 77.4 million Btu per hour, and four conventional package boilers each rated at 131,250 pounds per hour of steam. Because of limitations on the availability of natural gas, the combustion turbine and package boilers will be designed to burn either natural gas or transportation grade fuel oil; the duct burner will be fired exclusively with natural gas. Upon startup of the CHP, the Authority will decommission the seven boilers fired with coal, fuel oil and/or natural gas at its existing steam plant, as well as the coal handling and storage facilities elsewhere on campus. The location of the new CHP is shown in the site locus map in Figure 1-1.

In accordance with the requirements of 310 CMR 7.02, the Authority filed an application for a major comprehensive plan approval for the proposed CHP with the Massachusetts Department of Environmental Protection (MADEP) in November 2002 and subsequently filed a revised application in September 2003. The plan approval application demonstrated that that the proposed plant will meet all applicable MADEP requirements, including the application of Best Available Control Technology (BACT) and compliance with the National Ambient Air Quality Standards (NAAQS). Based on a review of the plan approval application, the MADEP issued the final approval for the proposed CHP in February 2004. The final approval establishes emission limitations for, amongst other criteria pollutants, filterable particulate with a mean diameter of less than 10 microns (PM_{10}), as well as associated testing, monitoring, recordkeeping and reporting requirements.

Because the proposed CHP is classified as a "major modification" for PM_{10}, it is also subject to the requirements of the Prevention of Significant Deterioration (PSD) regulations for PM_{10} only as set forth in 40 CFR Part 52.21. Accordingly, the Authority filed an application for a PSD permit for the proposed plant with the responsible permitting authority, the U.S. Environmental Protection Agency (U.S. EPA), Region 1, in January 2004. Based on a review of the PSD permit application, the U.S. EPA Region 1 requested that the Authority address total PM_{10}, including filterable and condensable particulate, in the control technology evaluation and air quality impact assessment. Accordingly, the Authority is submitting this supplement to the PSD permit application to demonstrate that the proposed plant will incorporate control devices and techniques representative of BACT for total PM_{10} and that the plant's impact will comply with applicable NAAQS and PSD allowable increments for that pollutant.

Figure 1-1

2. PROJECT DESCRIPTION

This section provides a description of the proposed project, addressing the combustion installations and associated air pollution control systems. It also provides performance and emissions data for the combustion turbine, HRSG, package boilers, and ancillary facilities.

2.1 Project Overview

The proposed CHP will include a cogeneration unit consisting of a combustion turbine and HRSG, steam generation units consisting of ~~three~~ four conventional package boilers, and ancillary equipment including an emergency generator and diesel fire pump. The CHP will be designed to satisfy the campus' base electrical load and steam supply requirements through the year 2025. The proposed combustion installations, therefore, must be capable of responding immediately and of sustaining continuous operation to meet the frequent and highly variable electrical and steam demands on campus. Because of limitations on the availability of natural gas, the combustion turbine and package boilers will be designed to burn either natural gas or transportation grade fuel oil; the duct burner will be fired exclusively with natural gas. The existing steam plant, consisting of seven boilers fired with coal, natural gas, and/or fuel oil, as well as the coal handling and coal storage facilities, will be decommissioned upon startup of the CHP. The CHP will be located at the site of existing athletic fields just west of the Mullins Center on Campus Center Way. A site layout for the CHP, showing the location of major structures and equipment, is presented in Figure 2-1.

2.2 Project Components

The proposed CHP will consist of a combustion turbine nominally rated at 10 megawatts (MW), a heat recovery steam generator (HRSG) with a duct burner rated at 77.4 million Btu per hour (MMBtu/hr), four conventional package boilers each rated at 131,250 pounds per hour (lb/hr) of superheated steam, an emergency generator rated at 7.7 MMBtu/hr, and a diesel fire pump rated at 1.2 MMBtu/hr. Design and performance data for each of these components are provided in the following sections.

2.2.1 Cogeneration Plant

The proposed combustion turbine generator will be a Solar Mars 100 series machine with a nominal rating of 10 MW. This machine is the most widely used combustion turbine in this size range in the United States. The combustion turbine will have a maximum heat input rate of approximately 121.9 MMBtu/hr firing natural gas and 115.5 MMBtu/hr firing fuel oil at ISO conditions (59ºF, 60 percent relative humidity, and sea level). The combustion turbine exhaust will be discharged to an HRSG

Figure 2-1

equipped with a duct burner rated at 77.4 MMBtu/hr. The combustion turbine will have the capability of firing either natural gas or transportation grade fuel oil; the duct burner will be fired exclusively with natural gas. The exhaust gases from the combustion turbine and HRSG will be discharged to the atmosphere via a dedicated flue within a 125-foot stack. In the event that the HRSG has to be brought off line, the combustion turbine exhaust will be discharged via an emergency flue within the same 125-foot stack. Performance data for the proposed combustion turbine/HRSG under the alternative fuel firing configurations and meteorological conditions are provided in Table 2-1.

The combustion turbine will utilize a dry low-NO_x (DLN) combustor to control the formation of nitrogen oxides (NO_x). To further reduce NO_x emissions, the combustion turbine will be equipped with a selective catalytic reduction (SCR) system. ~~The SCR system~~The SCR system will be designed to reduce NO_x emissions to 2.5 ppmvd or less firing natural gas and 6.0 ppmvd or less firing fuel oil, both corrected to

15 percent oxygen (O_2). The SCR system will also be designed to limit NH_3 emissions to 2.0 ppmvd or less corrected to 15 percent O_2. To control carbon monoxide (CO) emissions, the combustion turbine will also be equipped with an oxidation catalyst system. The oxidation catalyst system will be designed to reduce the outlet CO concentrations to 2.0 ppmvd or less ~~when~~ firing natural gas and 5.0 ppmvd or less ~~when~~ firing fuel oil, both corrected to 15 percent O_2.

The total PM_{10} emissions from the combustion turbine/HRSG include both "filterable" and "condensable" particulate matter. Filterable particulate is that portion of the total particulate that exists in the stack in either solid or liquid state and is measured on the filter or "front-half" of the U.S. EPA Method 5 sampling train. Condensable particulate, on the other hand, is that portion of the total particulate that exists as a gas in the stack, subsequently condensing in cooler ambient air to form particulate matter. As a gas in the stack, condensable particulate passes through the Method 5 filter and is subsequently measured by analyzing the impingers or "back half" of the sampling train.

The filterable PM_{10} emissions from combustion turbines result from the carryover of noncombustible trace constituents in the fuel, the introduction of particles with the combustion air, or the formation of particles consisting of unburned carbon. Filterable particulate emissions are extremely low when firing natural gas and only marginally higher when firing transportation fuel oil due to the fuel's low ash content. Condensable particulate, on the other hand, primarily result from the formation of ammonium salts downstream of the combustion turbine in the HRSG. The ammonia introduced in the SCR systems reacts with SO_2 and NO_x in the combustion gases to form ammonium sulfates and nitrates. Furthermore, the CO catalyst promotes the oxidation of these constituents in the combustion gases contributing to the formation of ammonium salts.

Table 2-1: Performance Data for the Proposed Combustion Turbine/HRSG

Load	**100%**											
Fuel Type	**Natural Gas**						**Fuel Oil**					
Ambient Temperature (°F)	0	0	60	60	100	100	0	0	60	60	100	100
Relative Humidity (%)	60	60	60	60	60	60	60	60	60	60	60	60
Duct Burner (Off/On)	No	Yes	No	Yes	No	Yes	No	Yes	No	Yes	No	Yes
Output (kW)	11,835	11,835	10,250	10,250	8,575	8,676	11,711	11,711	9,582	9,582	7,715	7,715
Gas Consumption (lb/hr)[a]	6,314	9,869	5,600	9,155	4,936	8,550	0	3,~~550~~555	0	3,555	0	3,555
Oil Consumption (lb/hr)	0	0	0	0	0	0	6,731	6,731	5,690	5,690	4,931	4,931
Heat Input (MMBtu/hr)	137.45	214.85	121.90	199.30	107.46	186.12	136.56	213.96	115.45	192.85	100.04	177.44
Exhaust Flow (lb/hr)	404,640	408,195	325,636	329,191	287,875	291,430	395,372	398,927	318,558	322,113	276,321	279,876
Stack Exit Temp (°F)	325	325	325	325	325	325	325	325	325	325	325	325
Stack Exit Flow (acfm)	133,853	135,122	109,347	110,347	102,278	102,360	129,709	130,382	105,854	106,332	96,733	96,422
PM_{10} (lb/MMBtu)	0.030	0.030	0.030	0.030	0.030	0.030	0.050	0.050	0.050	0.050	0.050	0.050
PM_{10} (lb/hr)	4.12	6.45	3.66	5.98	3.22	5.58	9.15	14.34	5.77	9.64	5.00	8.87

[a] The duct burner is fired exclusively with natural gas at a maximum firing rate of 3,555 lb/hr.

Federal and state permitting authorities have only recently required the application of SCR and oxidation catalyst systems to industrial or institutional cogeneration units around the country. Consequently, there is extremely limited data available on total PM_{10} emissions, and in particular condensable PM_{10} emissions, from dual-fuel cogeneration units equipped with both SCR and CO catalyst. Given the limited availability of emissions data, the total PM_{10} emissions from the proposed combustion turbine/HRSG are based on the emission guarantees provided by the equipment vendors of 0.030 lb/MMBtu when firing natural gas and 0.050 lb/MMBtu when firing distillate fuel oil. The total PM_{10} emissions from the combustion turbine/HRSG at maximum load under the alternative firing configurations are provided in Table 2-1.

2.2.2 Package Boilers

The ~~three~~ four package boilers will each have a maximum continuous rating of ~~175,000~~131,250 lb/hr of superheated steam at 460°F and 175 pounds per square inch gauge. Based on this steaming rate, the boilers will each have a maximum heat input rate of approximately ~~226.8~~170.1 MMBtu/hr firing natural gas and ~~216.2~~162.2 MMBtu/hr firing fuel oil. Again, because of the limited availability of natural gas, the boilers will be designed to burn either natural gas or transportation grade fuel oil. The exhaust gases from each of the boilers will be discharged via a dedicated flue~~s~~ encased within a common 125-foot stack. Performance data for each of the proposed package boilers under the alternative fuel firing configurations are provided in Table 2-2.

Table 2-2: Performance Data for the Proposed Package Boilers (Per Unit)

Load	**100%**	
Fuel Type	**Natural Gas**	**Fuel Oil**
Ambient Temperature (°F)	80	80
Steam Flow Rate (lb/hr)	~~175,000~~131,250	~~175,000~~131,250
Steam Temperature (°F)	460	460
Steam Pressure (psig)	175	175
Fuel Consumption (lb/hr)	~~10,404~~7,803	~~11,110~~8,332
Heat Input (MMBtu/hr)	~~226.80~~170.1	~~216.20~~162.2
Exhaust Temp. (°F)	334	332
Exhaust Flow (acfm)	~~68,976~~51,732	~~62,961~~47,018
PM_{10} (lb/MBtu)	0.020	0.050
PM_{10} (lb/hr)	3.40	8.11

The package boilers will utilize low-NO_x burners (LNB) to control the production of NO_x. To further reduce NO_x emissions, each of the boilers will ~~also~~ be equipped with an SCR system designed to limit the outlet NO_x concentrations to 5.0 ppmvd or less firing natural gas and 9.0 ppmvd or less firing fuel oil, both corrected to 3 percent O_2. The SCR system will also be designed to limit NH_3 emissions to 2.0 ppmvd or less corrected to 3 percent O_2. To control CO emissions, each of the boilers will also be equipped with an oxidation catalyst system designed to limit the outlet CO concentrations to 20 ppmvd or less ~~when~~ firing natural gas and 25 ppmvd or less ~~when~~ firing fuel oil, both corrected to 3 percent O_2.

Similar to the combustion turbine/HRSG, the total PM_{10} emissions from the four boilers also include filterable and condensable particulate matter as measured using the U.S. EPA Method 5 sampling train. Again the filterable particulate from boilers result from the carryover of noncombustible trace constituents in both the fuel and combustion air, while condensable particulate primarily results from the formation of ammonia salts in the boilers. Similar to the cogeneration unit, the ammonia introduced in the SCR system reacts with SO_2 and NO_x in the combustion gases to form ammonium sulfates and nitrates. The CO catalyst further promotes the oxidation of SO_2 and NO_x, enhancing the formation of the ammonium salts.

The MADEP has only recently required the application of SCR and CO catalyst systems to industrial or institutional boilers in the Commonwealth. Consequently, there are no data available on the total PM_{10} emissions from dual-fuel boilers equipped with both SCR and CO catalyst. Accordingly, the total PM_{10} emissions from the proposed boilers are based on emission guarantees provided by equipment vendors of 0.020 lb/MMBtu firing natural gas and 0.050 lb/MMBtu firing distillate fuel oil. The total PM_{10} emissions at maximum load under the alternative fuel firing configurations are provided in Table 2-2.

2.2.3 Emergency Generator and Diesel Fire Pump

An emergency generator will be provided to supply electrical power in the event of a power outage at the CHP. The prime mover for the generator will be a reciprocating engine fired with either natural gas or diesel fuel oil. The emergency generator will have a maximum heat input of 7.7 MMBtu/hr and a maximum power output of 750 kilowatts (kW). To allow for routine testing and maintenance and the possible loss of power at the plant, it has been assumed that the emergency generator will operate no more than 300 hours during any consecutive 12-month period. An emergency fire pump will also be provided to ensure sufficient water pressure in case of a fire at the plant. The emergency fire pump will be driven by a diesel engine having a maximum heat input of 1.2 MMBtu/hr. It has also been assumed that the emergency fire pump will operate no more than 300 hours during any consecutive 12-month period. Performance and emissions data for the emergency generator and diesel fire pump are summarized in Table 2-3.

Table 2-3 Performance Data for the Emergency Generator and Diesel Fire Pump[a]

Unit	Emergency Generator		Fire Pump Engine
Fuel Type	Natural Gas	Diesel Fuel Oil	Diesel Fuel Oil
Heat Input (MMBtu/hr)	7.70	7.70	1.20
Exhaust Temp. (°F)	0.29	0.29	0.95
Exhaust Flow (acfm)	2.26	2.26	1.14
PM_{10} (lb/MMBtu)	0.10	0.10	0.31
PM_{10} (lb/hr)	0.77	0.77	0.37

[a] Based on manufacturer's data or emission factors cited in U.S. EPA Document No. AP-42.

3.0 CONTROL TECHNOLOGY EVALUATION

This section demonstrates that the proposed control devices and techniques for PM_{10} emissions from the combustion turbine/HRSG and package boilers satisfy the BACT requirements of the PSD regulations under 40 CFR 52.21. This evaluation includes a review of previous BACT determinations made by Federal and state agencies for similar types of combustion installations around the country. It also includes an evaluation of the technical and economic feasibility of alternative technologies available for the control of PM_{10} emissions from such installations.

3.1 Technical Approach

Major new sources and major modifications to existing major sources are required to apply BACT pursuant to the PSD regulations in 40 CFR 52.21(j)(2). According to the PSD regulations, BACT means *"an emissions limitation based on the maximum degree of reduction for each air pollutant subject to regulation which would be emitted from any proposed major stationary source or major modification which the Administrator, on a case by case basis, taking into account energy, environmental and economic impacts, and other costs determines is achievable through application of production processes or available methods, systems and techniques for control of each air pollutant."*

Consistent with U.S. EPA guidance, a "top-down" approach was used in the determination of BACT for the combustion turbine/HRSG and package boilers. Using this top-down approach, alternative control technologies were identified for PM_{10} emitted from the combustion turbine and package boilers. Those alternatives found to be technically unfeasible were eliminated from further consideration, while the remaining technologies were ranked by their performance levels. The technically feasible alternatives were then evaluated on the bases of the associated economic, energy, and environmental impacts. If an alternative technology, starting with the most stringent, was eliminated based on any of these criteria, the next most stringent technology was evaluated until the identification of BACT.

In determining BACT, the evaluation may consider the combination of: (1) change in the raw material; (2) process modifications; and (3) add-on controls. Of these options, only add-on controls are available to further control PM_{10} emissions from cogeneration and boiler units fired with either natural gas or transportation grade fuel oil. The BACT evaluation, therefore, addresses only add-on controls for the control of PM_{10} emissions from both the combustion turbine/HRSG and package boilers at the proposed CHP.

3.2 BACT Determinations

Consistent with U.S. EPA guidance, we first reviewed available databases to identify previous BACT determinations made by Federal and state agencies for similar types of combustion installations around the country. These databases include:

- Emission limits established in recently issued pre-construction permits for similar combustion installations around the country as compiled by the U.S. EPA in its "RACT/BACT/LAER Clearinghouse" (RBLC).
- Emission limits established in recently issued pre-construction permits for similar combustion installations in California as compiled by the California Air Resources Board in its "BACT Clearinghouse."

It should be noted that the MADEP has made numerous BACT determinations for PM_{10} emissions from similar types of combustion installations in the Commonwealth. The MADEP, however, has historically regulated filterable particulate emissions only, rather than total particulate emissions (i.e., both filterable and condensable particulates). These BACT determination, therefore, do not establish a precedence for the total PM_{10} emission limits that will ultimately be established by the U.S. EPA Region 1 in its BACT determination for the proposed CHP.

Table 3-1 provides a summary of recent BACT determinations made by Federal and state agencies for either simple-cycle or combined-cycle combustion turbines fired with natural gas and/or distillate fuel oil. As shown in this table, only three of the combustion turbines listed in the databases are fired with both natural gas and distillate fuel oil. Of these, only one combustion turbine is equipped with SCR, but not a CO catalyst. The PM_{10} emission limits for this unit are 0.017 lb/MMBtu when firing natural gas and 0.0357 when firing distillate fuel oil. If this unit were equipped with a CO catalyst, the PM_{10} emission limits would be expected to be higher due to the increased formation of ammonium salts with CO catalysts. This review, therefore, generally supports the proposed PM_{10} emission limits of 0.030 lb/MMBtu when firing natural gas and 0.050 when firing fuel oil. The detailed RBLC and CARB BACT Clearinghouse databases for combustion turbines are provided in Appendix A.

Table 3-2 provides a summary of recent BACT determinations made by Federal and state agencies for industrial boilers fired with natural gas and/or distillate fuel oil. As shown in this table, only one natural gas-fired boiler is equipped with an SCR and CO catalyst system (i.e., the Liberty Generating Company). The PM_{10} emission limit for this auxiliary boiler is 0.008 lb/MMBtu when firing natural gas. The owner, however, was not required to conduct performance tests on the boiler to demonstrate compliance with the PM_{10} emission limit, but rather only to monitor the composition of the fuels fired in unit. Therefore, it is not possible to ascertain whether the actual

PM_{10} emissions from this gas-fired boiler ultimately complied with the specified PM_{10} emission limit. The remaining BACT determinations generally support the proposed PM_{10} emission limits of 0.020 lb/MMBtu when firing natural gas and 0.050 when firing fuel oil. The detailed RBLC and CARB BACT Clearinghouse data for industrial boilers are provided in Appendix A.

3.3 BACT Evaluation

The emissions of PM_{10} from the combustion turbine/HRSG and package boilers result from inert material contained in the fuels, particles introduced with the combustion air, particles consisting of unburned carbon, and ammonia salts formed by the reaction of ammonia with SO_2 and NO_x. The bulk of the total PM_{10} is attributable to the ammonium salts formed downstream of the SCR and oxidation catalyst systems. Regardless of the formation mechanism, all of the particulate emitted from combustion turbine/HRSG and package boilers are expected to be less than 1.0 microns in diameter.

3.3.1 Regulatory Precedence

In the preamble to the New Source Performance Standard (NSPS) for Stationary Gas Turbines (40 CFR 60 Subpart GG), the U.S. EPA recognized that “particulate emissions from stationary gas turbines are minimal.” Furthermore, the U.S. EPA found that particulate control devices are not typically installed on combustion turbines and that the cost of installing a particulate control device is prohibitive. The U.S. EPA, therefore, decided not to promulgate performance standards for particulate matter from stationary gas turbines. Similarly, the U.S. EPA concluded that particulate control devices were neither practical nor cost-effective for boilers fired with natural gas or distillate fuel oil in the establishing the NSPS for Industrial/Commercial/Institutional Steam Generating Units (40 CFR 60 Subpart Db). The U.S. EPA, therefore, did not promulgate performance standards for particulate matter from such boilers fired with either natural gas or distillate fuel oil.

2.2.2 Alternative Control Technologies

The most stringent particulate control method demonstrated on combustion turbines and institutional boilers is the use of fuels with low ash contents (such as natural gas or low sulfur transportation diesel). In the RBLC and CARB BACT Clearinghouse, the predominant control methods listed for combustion turbines or industrial boilers are the use of proper combustion controls and the firing of low-ash fuels. There were no listings for combustion turbines or boilers firing these fuels that were equipped with add-on controls, such as electrostatic precipitators or baghouses. These add-on control devices are not considered practical or cost-effective due to the low grain loading in the combustion gases (ranging from less than 0.01 to 0.05 lb/MMBtu), the extremely small size of the filterable particulate (almost entirely less than

1.0 micron), and the high proportion of condensable particulate (typically 60 to 80 percent of total particulate).

2.2.3 Conclusions

The proposed control techniques for PM_{10} emissions from the combustion turbine/HRSG and package boilers are the use of proper combustion controls and firing of clean fuels. Specifically, PM_{10} emissions will be controlled by means of the following devices and techniques:

- the use of clean fuels will minimize particulate attributable to the carryover of inert material in the fuel;
- the installation of high-performance combustors or burners will minimize the formation of unburned carbon in the combustion unit;
- the installation of high-efficiency filters will remove particles from the combustion air before being introduced into the combustion unit; and
- the maintenance of low ammonia slip (less than 2 ppm) will minimize the formation of ammonium salts downstream of the SCR and oxidation catalyst systems .

Based on our review of previous control technology determinations and evaluation of alternative control devices and techniques, the proposed control measures are considered representative of BACT for total PM_{10} emissions from the combustion turbine/HRSG and package boilers to be installed at the CHP. The proposed PM_{10} emission limits for the combustion turbine/HRSG and package boilers are summarized in Table 3-3.

Table 3-33:Proposed PM_{10} Emission Limits

Installation	PM_{10} Limits Natural Gas Firing (lb/MMBtu)	PM_{10} Limits Fuel Oil Firing (lb/MMBtu)
Combustion Turbine/HRSG	0.030	0.050
Package Boilers	0.020	0.050

4.0 AIR QUALITY IMPACT ASSESSMENT

This section describes the dispersion modeling procedures that were used in the air quality impact assessment, including the models employed, the model input options, and the supporting meteorological, terrain, air quality and point source data. The dispersion modeling analysis was conducted in accordance with procedures documented in the air quality modeling protocol submitted to the U.S. EPA, Region 1, on May 10, 2004 and subsequently amended on July 23, 2004 (see Appendix B). The amended protocol was approved by the U.S. EPA, Region 1 on July 23, 2004.

4.1 Technical Approach

The objective of the air quality modeling analysis is to demonstrate that the PM_{10} emissions from the proposed project will comply with the applicable NAAQS and PSD allowable increments. Currently, the Town of Amherst is located in a region classified as an attainment area for PM_{10}. To identify those new sources with the potential to violate or contribute to a violation of ambient air quality standards, the U.S. EPA has adopted significant impact levels (SILs) for criteria pollutants, including PM_{10}. If the impacts of a new source are found to be below the SILs, no further analysis is required to assess compliance with ambient air quality criteria. If the impacts are found to exceed the SILs, on the other hand, a more detailed dispersion modeling analysis is required to assess compliance with ambient air quality standards. This analysis must consider the impacts associated not only with the new source, but also with existing sources in the region.

4.1.1 Source Parameters

As previously stated, the cogeneration unit and four boilers will have the capability of firing both natural gas and transportation grade fuel oil. Because particulate emissions are greater when firing fuel oil than when firing natural gas, the modeling analysis considered only the fuel oil firing configuration for the combustion installations. Table 4-1 provides the stack parameters for the combustion turbine firing oil and the HRSG duct burner firing natural gas under various operating loads and meteorological conditions. The stack parameters for the four package boilers firing oil under the various operating loads are then provided in Table 4-2. Note that, because the emergency generator or diesel fire pump would operate only if the combustion turbine were out of service, these two sources were not included in the air quality modeling analysis.

Table 4-1: Stack Parameters for Combustion Turbine

Fuel Type	Fuel Oil								
Load Condition	**100%**			**75%**			**50%**		
Ambient Temperature (ºF)	0	60	100	0	60	100	0	60	100
Stack Height (m)	38.10	38.10	38.10	38.10	38.10	38.10	38.10	38.10	38.10
Stack Diameter (m)	1.98	1.98	1.98	1.98	1.98	1.98	1.98	1.98	1.98
Exit Velocity (m/s)	19.96	16.28	14.76	17.00	14.72	13.28	14.44	13.01	12.57
Exit Temperature (ºK)	436.1	436.1	436.1	436.1	436.1	436.1	436.1	436.1	436.1
PM_{10} Emissions (g/s)	1.348	1.215	1.118	1.190	1.075	1.005	0.959	0.978	0.926

Note: Stack Coordinates are 702,740 m Easting and 4,695,730 m Northing

Table 4-2: Stack Parameters for Package Boilers

Fuel Type	**Fuel Oil**		
Load Condition	**100%**	**75%**	**50%**
Ambient Temperature (ºF)	80	80	80
Stack Height (m)	38.10	38.10	38.10
Stack Diameter (m)	2.29	2.29	2.29
Exit Velocity (m/s)	21.64	16.23	10.82
Exit Temperature (ºK)	440.0	440.0	440.0
PM_{10} Emissions (g/s)	4.087	3.065	2.043

Note: Stack Coordinates are 702,740 m Easting and 4,695,730 m Northing.

4.1.2 GEP Stack Height

The Good Engineering Practice (GEP) Guidelines provide a method for determining the GEP formula stack height based on the dimensions of the "nearby" structures. A structure is considered nearby if it is within "five times the lesser of the height or the width dimension of the structure." For the proposed CHP, the only building having a potential effect on the stack emissions from the combustion installations is the Turbine and Boiler Building at the CHP. The Turbine and Boiler Building then will be the controlling structure in determining the GEP formula stack height.

According to the GEP Guidelines, the GEP formula stack height equals the controlling structure's height plus 1.5 times the lesser of the structure's height or projected width. Based on the building's height of 40 feet, the GEP formula height is 100 feet above grade. The University proposes to construct two 125-foot stacks, one serving the combustion turbine/HRSG and the other serving the ~~three~~ four package boilers. Note that the stack top elevation will be below the *de minimis* GEP stack height of 213 feet permitted under the GEP Guidelines.

4.1.3 Model Selection

The AERMOD model, version 02222, was used in this application. The U.S. EPA published a notice of its intention to promulgate AERMOD (v02222) as a Guideline Model on September 8, 2003 (Federal Register, Vol. 68, pp. 52934-52935). The AERMOD model can be used on a case-by-case basis with the approval of the U.S. EPA Regional Office. Because there is complex terrain nearby (receptors with elevations above stack top), the modeling analysis must consider the simultaneous contributions of multiple sources at elevated receptors. Using AERMOD eliminates the need for a separate screening model, like the single-source VALLEY model or CTSCREEN, to assess the potential impacts in complex terrain. AERMOD is also more scientifically advanced than ISC3 in simple terrain.

4.1.4 Meteorological Data

Dispersion models use meteorological data, including wind speed and wind direction, to simulate the transport and dispersion of air contaminants in the atmosphere. According to the U.S. EPA Guideline on Air Quality Models, modeling analyses should use either one-year of onsite observations or five years of nearby, representative observations compiled by the National Weather Service.

Because there are no onsite meteorological measurements available at the project site, representative observations from the nearest NWS station were used in the modeling analysis. The nearest first-order weather station is located at Westover Air Force Base (AFB) in Chicopee Falls, Massachusetts (FAA Identifier CEF, WBAN No. 14703). This station is located approximately 13 miles south of the site. The most recent data record from Westover AFB has many missing hours; whereas, a nearly complete five-year data record is available for 1991 through 1995. These data, therefore, were used in the air quality modeling analysis. The nearest upper air soundings collected during the same period are available from Albany, New York (FAA Identifier ALB, WBAN No. 14735). These soundings were used in conjunction with the surface observations from Westover AFB to develop the mixing heights used in the modeling analysis.

The AERMET (version 02222) was used to process the surface and upper air data to produce the necessary input file to AERMOD. AERMET requires roughness length, albedo, and daytime Bowen ratio. As agreed to in discussions with Brian Hennessey of U.S. EPA Region I, two different land use assumptions were made because of the uncertainty of whether the land use parameters (roughness length, albedo and Bowen ratio) should be representative of the site of the source or the site of the meteorological data. Two sets of AERMET and AERMOD runs were made for the five-year period of meteorological data; one for each land use classification.
Figures 4-1 and 4-2 present aerial photographs of the proposed source in Amherst, Massachusetts and the meteorological tower at Westover AFB in Chicopee, Massachusetts, respectively. The land use at the source location was divided into two sectors with wind directions 0 through 180 degrees classified as “Urban” and 180

through 360 degrees classified as “Cultivated land.” Land use at Westover AFB was also divided into two sectors with: wind directions 210 through 325 degrees classified as “Urban” and 325 through 210 degrees classified as “Grassland.” The seasonal values for the roughness length, albedo and Bowen ratio in Tables 4-1 to 4-3 of the *AERMET User’s Guide* were used in the modeling analysis, except that for both sites a roughness length of 0.50 m was used instead of the value of 1.0 m in Table 4-3. The structures at both locations are smaller and farther apart than those

Figure 4-1

Figure 4-2

associated with a roughness length of 1.0 meter. The maximum predicted PM_{10} impacts determined by the modeling analyses above were used to demonstrate compliance with the NAAQS and PSD allowable increments.

4.1.5 Model Receptors

The two stacks (one for the combustion turbine and one for the package boilers) are adjacent to each other. A polar grid to 20 kilometers was defined to determine the Significant Impact Area. Modeling receptors were located every 10 degrees at the following distances from the midpoint between the two stacks:

- 100-meter intervals from 100 to 2,000 meters;
- 250-meter intervals from 2,000 to 5,000 meters;
- 1000-meter intervals from 5,000 to 10,000 meters; and
- 2500-meter intervals from 10,000 to 20,000 meters.

In addition, 21 receptors were placed at sensitive locations in the immediate vicinity of the site. This resulted in a total of 1,533 receptors. AERMAP (v03107) was used to process the receptor elevations and associated hill heights. Twenty-four DEM quadrants (7.5 minute per quadrant) using a resolution of 30 meters were obtained from the USGS and were used in the AERMAP model. For the final PSD application, a denser grid of receptors was located near the location of the maximum predicted concentrations.

4.1.6 Background Air Quality

The CHP will be located in Hampshire County, which is currently designated as an attainment area for PM_{10}. If the projected impacts of PM_{10} from the proposed CHP are greater than the SILs, background contributions of PM_{10} from major sources affecting the Significant Impact Area, along with the contribution of other smaller sources estimated from monitored background, must be added to the projected impacts of the proposed plant in determining compliance with the standards.

The major sources within 25 km of the proposed site were identified by John Kirzec of the MADEP, Western Region. These sources include the following combustion installations: Smith College, Mount Tom, Solutia, MMWEC, and MASSPOWER. These sources were included in the assessment of compliance with the NAAQS. Of these sources, only MMWEC and MASSPOWER were subject to the PSD regulations for PM_{10} and, hence, were included in the assessment of PSD allowable increment consumption.

Because the MADEP has historically regulated only filterable particulate from combustion installations in the Commonwealth, the allowable PM_{10} emissions provided by the MADEP may not be representative of total particulate (*i.e.*, both filterable and condensable particulate) emissions typical of such installations. To determine whether the allowable PM_{10} emissions include both filterable and condensable particulates, the allowable PM_{10} emissions were compared with the emissions factors for total particulate for similar types of combustion installations cited in *Compilation of Air Pollutant Emission Factors*, U.S. EPA Document No. AP-42, Fifth Edition (as revised). The AP-42 document does provide emission factors for filterable and condensable particulate from coal- and oil-fired boilers comparable to those units at the Mt. Tom, Solutia and Smith College facilities. The AP-42 document, however, provides emission factors for filterable and condensable particulate only for combustion turbines using water injection for NO_x control; no such emission factors are provided for combustion turbines equipped with SCR, such as the units at the MMWEC and MASSPOWER facilities. Note that, in the comparison, the filterable PM_{10} emissions were assumed to be the lesser of the allowable PM_{10} emissions specified by the MADEP or the PM_{10} emission factor cited in AP-42. The results of this comparison are summarized in Table 4-3.

Table 4-3: Comparison of Allowable PM_{10} Emissions and Total PM_{10} Emission Factors

Source	Fuel Type	Heat Input (MMBtu/hr)	PM_{10} Limit (lb/MMBtu)	AP-42 Emission Factor (lb/MMBtu) Filterable[a]	Condensable	Total
Mt. Tom[b]	Coal	1,480	0.080	0.012	0.120	0.132
Solutia[c]	Coal	249.0	0.027	0.006	0.045	0.051
Smith College	2.2%S # 6 Oil	151.2	0.120	0.120(0.156)	0.010	0.130
	2.2%S # 6 Oil	138.0	0.100	0.100(0.156)	0.010	0.110
MMWEC	0.3%S #2 Oil	2,856	0.040	0.0072.	0.0043	0.0115[d]
	0.3%S #2 Oil	1,904	0.040	0.0072.	0.0043	0.0115[d]
MASSPOWER	0.2%S #2 Oil	1,250	0.049	0.0072.	0.0043	0.0115[d]
	0.2%S #2 Oil	1,250	0.049	0.0072.	0.0043	0.0115[d]

[a] Filterable PM_{10} is based on the lesser of the allowable PM_{10} emissions specified by the MADEP or the PM_{10} emission factor cited in AP-42 (on parentheses).

[b] Filterable PM_{10} emissions are based on an emission factor of 2.3A(100-η/100), where A is the ash content (%) and η is the ESP efficiency (%). The ash content is assumed to be 10%, and the ESP efficiency, 99.0%. Condensable PM_{10} is based on an emission factor of 0.1S-0.03, where S is the sulfur content (%). The sulfur content is assumed to be 0.75%.

[c] Filterable PM_{10} emissions are based on an emission factor of 2.3A(100-η/100), where A is the ash content (%) and η is the baghouse efficiency (%). The ash content is assumed to be 10%, and the baghouse efficiency, 99.5%. Condensable PM_{10} is based on an emission factor of 0.1S-0.03, where S is the sulfur content (%). The sulfur content is assumed to be 0.38%.

[d] Filterable and condensable PM_{10} emissions are based on the emission factors for combustion turbines fired with No. 2 distillate fuel oil using water injection for NO_x control.

As shown in Table 4-3, it appears that the allowable PM_{10} emissions specified by the MADEP are not necessarily representative of total particulate emissions from the coal- and oil-fired boilers at the Mt. Tom, Solutia and Smith College facilities. On the other hand, the allowable PM_{10} emissions for the combustion turbines specifically include an allowance for condensable particulate and, therefore, are considered representative of total PM_{10} emissions from both the MMWEC and MASSPOWER facilities. In the air quality analysis, the allowable PM_{10} emissions were used to demonstrate compliance with the NAAQS and PSD allowable increments. As a sensitivity, the adjusted PM_{10} emissions were used in the air quality modeling analysis to determine their effects on the compliance assessment. Table 4-4 summarizes the stack parameters for the existing PM_{10} sources, including the allowable and adjusted PM_{10} emissions.

To estimate the contribution of other minor sources in the region, ambient PM_{10} background concentrations were conservatively based on the highest short-term and annual average concentrations measured at Springfield monitoring stations over the last three years. The Howard Street (AIRS #25-013-0011) station operated during 2000-2002, the East Columbus Avenue (AIRS #25-013-2007) station operated in 2000 and the Main Street (AIRS #25-013-2009) station operated in 2002. Table 4-5 summarizes the background concentrations for PM_{10}. It should be noted that the minor source baseline has not been triggered in either the Towns of Amherst or Hadley, Massachusetts.

4.2 Air Quality Modeling Results

The nine combustion-turbine operating cases and three package-boiler operating cases were run separately for the two AERMET datasets for the five-year period, 1991 through 1995. For both meteorological datasets, the maximum 24-hour PM_{10} concentration for the combustion turbine was associated with the 100-percent load condition at an ambient temperature of 0˚F and, for the boilers, the 100-percent load condition. Furthermore, the meteorological dataset assuming land use characteristics in the vicinity of Westover AFB was always associated with the largest predicted concentrations. Therefore, the combustion turbine and boilers, under the worst-case operating conditions, were then modeled concurrently using the meteorological data assuming Westover AFB land use characteristics for the five-year period, 1991 through 1995.

4.2.1 Proposed Source Impacts

The results of the air quality modeling analysis are presented in Table 4-6. As shown in this table, only the maximum 24-hour PM_{10} concentration is greater than the corresponding SIL. Consequently, a more detailed dispersion modeling analysis is required to assess compliance with NAAQS and PSD allowable increments within those areas where the impacts are above the SILs. This analysis must consider the

Table 4-4 Existing PM_{10} Sources in the Region

Source	Heat Input (MMBtu/hr)	UTM Coordinates (m) Easting	Northing	Stack Height (m)	Stack Diameter (m)	Temperature (˚K)	Exit Velocity (m/s)	Allowable PM_{10} Emissions (g/s)	Adjusted PM_{10} Emissions[a] (g/s)
Smith College	289.2	694493.4	4686997	48.77	1.32	422.2	25.65	4.02	4.39
Mt. Tom	1,480	697447.1	4683556.5	112.77	3.05	422.2	28.12	14.92	24.62
MMWEC	952	704221.1	4669917	45.72	4.72	394.4	6.17	14.39	14.39
	952	704221.1	4669917	36.57	4.34	672.2	12.43	9.60	9.60
Solutia	249	704662.5	4670028.5	59.74	2.13	422.2	9.66	0.85	1.60
MASSPOWER	1,250	705502.9	4674506.5	64.92	4.80	394.4	15.68	15.44	15.44

[a] Adjusted PM_{10} emissions are based on the allowable PM_{10} emission specified by the MADEP adjusted to account for condensable PM_{10} using the emission factors cited in AP-42 or emission guarantees provided by equipment vendors.

Table 4-5: Background Concentrations of PM_{10} (2000-2002)[a]

		Measured Concentration (µg/m³)			Background
Pollutant	**Averaging Period**	**2000**	**2001**	**2002**	**Concentration (µg/m³)[a]**
PM_{10}	24-hour	79	63	56	79
	Annual	28	25	21	28

[a] The background concentrations are based on the highest short-term and annual average concentrations measured at Monitoring Station AIRS#25-013-2007 in Springfield from 2000 through 2002.

Table 4-6: Maximum Predicted AERMOD Concentrations Compared with the SILs

Pollutant	**Averaging Period**	**Maximum Concentration (µg/m³)**	**Direction and Distance**	**SILs (µg/m³)**
PM_{10}	24-hour	15.22	360 deg., 8,000 m	5
	Annual	0.97	360 deg., 8,000 m	1

impacts associated not only with the new source, but also with existing sources in the region. The maximum 24-hour PM_{10} concentrations are shown in isopleths in Figure 4-3. As shown in this figure, the predicted PM_{10} concentrations exceed the SILs in two small areas within a few kilometers of the site and in two hilly areas much farther downwind, one area located approximately 5.0 to 12.5 km north of the site and the other approximately 10 km south of the site. Any receptor where the predicted 24-hour PM_{10} concentrations were greater than 4 µg/m³ (which is 20 percent below the 5 µg/m³ SIL) was used for in the NAAQS and PSD increment compliance analyses.

4.2.2 NAAQS Compliance Analysis

The AERMOD model was used to predict the maximum 24-hour and annual average PM_{10} concentrations attributable to the proposed CHP, other existing sources, and background concentrations over the five-year period of 1991 through 1995. The highest, second-highest 24-hour and highest annual average concentrations associated with PM_{10} emissions from the proposed plant and background sources are compared with applicable NAAQS in Table 4-7. This comparison considers the predicted PM_{10} concentrations associated with both the allowable PM_{10} emissions and adjusted PM_{10} emissions from the existing sources in the area. As shown in Table 4-7, the predicted PM_{10} concentrations are well below the corresponding NAAQS, regardless of whether allowable PM_{10} or adjusted PM_{10} emissions are assumed for the existing sources. It should be noted that this analysis did not take into consideration the reduction in background levels that would be expected with

Figure 4-3

Table 4-7: Maximum Predicted AERMOD Concentrations Compared with the NAAQS

		Highest, Second-High Concentration (μg/m³)				
Pollutant	**Averaging Period**	**Proposed Plant**	**Major Sources**	**Background**	**Total**	NAAQS (μg/m³)
PM_{10}-Allowable[a]	24-hour	0.02	25.04	79.00	104.06	150
	Annual	0.21	2.61	28.00	30.82	50
PM_{10}-Adjusted[b]	24-hour	0.02	25.38	79.00	104.40	150
	Annual	0.21	2.67	28.00	30.88	50

[a] Allowable PM_{10} emissions are based on the PM_{10} emission limits specified for existing sources by the MADEP.

[b] Adjusted PM_{10} emissions are based on the greater of the PM_{10} emission limits specified for existing sources by the MADEP or the emission factors cited for such sources in AP-42.

the retirement of the boilers at the existing steam plant, as well as the coal handling and storage facilities elsewhere on campus.

4.2.3 PSD Increment Consumption Analysis

The AERMOD model was then used to predict the maximum 24-hour and annual average PM_{10} concentrations attributable to the proposed CHP and other PSD sources over the five-year period of 1991 through 1995. The highest, second-high 24-hour and highest annual average concentrations associated with the proposed plant and other PSD sources are compared with the applicable Class II allowable increments in Table 4-8. Because the allowable PM_{10} emissions from the existing PSD sources are considered representative of total PM_{10} emissions, the predicted PM_{10} concentrations are also considered representative of total PM_{10} concentrations. As shown in Table 4-8, the predicted PM_{10} concentrations are below the corresponding PSD allowable increments. Again, this analysis did not take into consideration the reduction in background levels that would be expected with the retirement of the existing boilers and coal handling facilities.

Table 4-8: Maximum Predicted AERMOD Concentrations Compared with the PSD Allowable Increments

		Highest, Second-High Concentration (μg/m³)			
Pollutant	**Averaging Period**	**Proposed Plant**	**Other PSD Sources**	**Total**	Increment (μg/m³)
PM_{10}	24-hour	0.02	24.59	24.61	30
	Annual	0.21	2.47	2.68	17

4.2.4 Conclusions

In conclusion, the modeling analysis indicates that the proposed CHP will neither cause nor contribute to a violation of the NAAQS for PM_{10}. By definition, therefore, the proposed plant will not have an adverse effect on public health or welfare in the area. Furthermore, the plant's impact will not exceed the PSD allowable increment for PM_{10} and thus will not have a significant effect on existing air quality.

4.3 Class I Area Analysis

The proposed CHP is considered a major modification for PM_{10} and thus is subject to the PSD review only for that pollutant. The PSD regulations include the requirement to assess the plant's potential impacts on air quality and visibility in Class I Areas. In this instance, the closest Class I Area is the Lye Brook Wilderness Area in Vermont, which is approximately 86 kilometers north-northwest of the Amherst Campus.

The potential emissions of the proposed units were compared with the actual emissions from existing units in determining the applicability of the PSD regulations. Based upon this comparison, the replacement of the existing steam plant with the CHP would result in a significant net increase of PM_{10}. On the other hand, the project would result in dramatic reductions in the potential emissions of both SO_2 and NO_x. It should be noted that, because the existing and proposed units are intended to provide steam for electrical generation and space heating on campus, the replacement of the existing plant with the CHP in actuality could result in a reduction in the actual emissions of all pollutants including PM_{10}, SO_2, and NO_x.

The major concern at Class I areas is the degradation of visibility resulting from long-range transport of pollution from distant major sources. Visibility is degraded by visible light scattered into and out of the line of sight and by light absorbed along the line of sight. Light extinction is the sum of light scattering and absorption and is usually quantified using the light extinction coefficient (b_{ext}). For the far field, like the impacts of the CHP at Lye Brook, the light absorption is due to elemental carbon or soot. The light scattering is due to the fine particulate smaller than 2.5 microns (fine primary particulate emitted directly from the plant and secondary particulate formed from SO_2 and NO_x) and from coarse particulate larger than 2.5 microns, but less than 10 microns, emitted directly from the plant.

Particle scattering coefficients for the components of atmospheric particulate are provided in the *Federal Land Managers' Air Quality Related Values Workgroup Phase I Report*, December 2000. These coefficients are multiplied by the mass concentration of each particulate species. For the fine particulate, ammonium sulfate and ammonium nitrate have a dry scattering coefficient of 3, organic aerosols a coefficient of 4, and soil (or fine primary plant particulate) a coefficient of unity. Sulfates and nitrates are further multiplied by a relative humidity factor that is equal to or greater than one and can be as large as 18. All coarse particulate have a coefficient of 0.6. This means that reducing concentrations of sulfates and nitrates would be far more efficient in improving visibility than reducing concentrations of primary particulate. Therefore, even if the project were to cause a slight increase in particulate emissions, the reduction in SO_2 and NO_x emissions (and the preferential scattering of light by sulfates and nitrates) would result in an improvement in visibility in the Lye Brook Wilderness Area.

Based upon these considerations, the University of Massachusetts Building Authority requested assistance from the U.S. Forest Service (USFS) in establishing the need to assess the impacts of the proposed project on air quality and visibility in the Lye Brook Wilderness Area. In the USFS's response of June 12, 2002, the agency determined that *"there will be no adverse impacts, and possibly a net benefit, to the Lye Brook Wilderness connected to the proposed modifications to the University of Massachusetts Central Heating Plant."* Accordingly, the USFS stated that no air quality or visibility analysis would be required for the Lye Brook Wilderness Area. Relevant correspondence between the USFS and the University of Massachusetts Building Authority is provided in Appendix C.

4.4 Additional Impact Analyses

The PSD regulations require that additional impact analyses be conducted to consider the project's effects on soils and vegetation and the potential impact of secondary growth. Because the project is classified as a major modification for PM_{10}, these analyses address project's effects on soils and vegetation and the potential impact of secondary growth for PM_{10} only

4.4.1 Secondary Growth

The proposed CHP is intended to produce steam used for electrical generation and space heating, which is currently produced by the existing steam plant. The project, therefore, is not expected to induce secondary growth beyond what is currently anticipated at the campus. Furthermore, the construction and work force for the project is not expected to be sufficiently large. Thus, no secondary growth related to the work force is expected during either construction or operation of the plant.

4.4.2 Soils and Vegetation

The PSD regulations require analysis of air quality impacts on sensitive vegetation types, with significant commercial or recreational value, or sensitive types of soil. This analysis was performed by comparing the predicted impacts with screening levels presented in the U.S. EPA document, "*A Screening Procedure for the Impacts of Air Pollution Sources on Plants, Soils and Animals."* It should be noted that the screening levels represent the minimum concentrations in either plant tissue or soils at which adverse growth effects or tissue injury were reported in the literature. Accordingly, the screening levels typically represent the lowest concentrations having an adverse effect on the most sensitive vegetation. If the impacts of the proposed plant are shown to be below these screening levels, therefore, it should not have an adverse impact on the vegetation grown in the region, including produce and tobacco.

The designated vegetation screening levels for criteria pollutants are equivalent to or exceed NAAQS and/or PSD increments. Therefore, compliance with the NAAQS and PSD increments would ensure compliance with sensitive vegetation screening levels. In particular, the U.S. EPA found that the information used in developing the NAAQS for total suspended particulate (TSP) would suffice for the evaluation of impacts on sensitive vegetation and soils. However, the U.S. EPA also found that trace metals in TSP might have greater impacts on vegetation and soils than the total amount of particulate matter. Therefore, this evaluation focuses on the deposition of trace metals potentially emitted from the proposed plant on soils and the subsequent uptake by plants. Note that no credit was taken for the reduction in particulate and trace metal emissions resulting from the decommissioning of the existing steam plant.

The deposition of trace metals on soils was evaluated using the screening techniques presented in U.S. EPA's document, "*A Screening Procedure for the Impacts of Air Pollution Sources on Plants, Soils, and Animals.*" This evaluation provides screening level estimates of deposited trace element concentrations based on a three-centimeter soil depth, an assumed 30-year life for the facility, and maximum annual concentrations of trace elements. The soil concentrations are calculated as follows:

$$DC = 21.5 * (N/d) * X_g$$

where: DC is the soil concentration (parts per million wet),
N is the expected lifetime of the source (assume 30 years),
d is the depth of the soil through which the deposited material is found (assume 3 centimeters), and
X_g is the maximum annual concentration of the trace elements attributable to the project ($\mu g/m^3$).

Using this procedure, the calculated soil concentrations were compared to acceptable soil screening levels provided by U.S. EPA. Soil concentrations are also used to calculate plant tissue concentrations assuming default plant to soil ratios provided by the screening methodology. Plant tissue concentrations were then compared to acceptable tissue screening concentrations and dietary screening concentrations for animals.

The screening analysis is documented in Section 6.0 of the report entitled "*Major Comprehensive Plan Approval Application: Proposed Central Heating Plant, University of Massachusetts, Amherst, Massachusetts,"* September 2003. The screening analysis results demonstrated that the proposed plant will not have an adverse impact on vegetation or soils in the region. In particular, because the screening levels are based upon the lowest concentrations having an adverse effect on the most sensitive vegetation, the plant will not adversely affect agricultural crops in the area, including produce and tobacco.

APPENDIX A

BACT CLEARINGHOUSE DATA

U.S. Environmental Protection Agency

Combustion Turbines

Boilers

California Air Resources Board

Combustion Turbines

Boilers

APPENDIX B

AIR QUALITY MODELING PROTOCOL

APPENDIX C

CLASS I AREA CORRESPONDENCE