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United States Environmental Protection Agency New England
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Preliminary Determination

University of Massachusetts Building Authority
One Beacon Street, 26th Floor
Boston, MA 02108

University of Massachusetts-Amherst Campus
Central Heating Plant

Draft PSD Permit Number 046-026-MA07

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I. General Information

Name of Source :	University of Massachusetts Central Heating Plant
Location:	University of Massachusetts Amherst Campus Amherst, Massachusetts
Applicant's Name and Address:	University of Massachusetts Building Authority One Beacon Street, 26th Floor Boston, MA 02108
Application Prepared By:	Earth Tech, Inc. 196 Baker Avenue Concord, MA 01742
PSD Permit Number:	draft 046-026-MA07
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II. INTRODUCTION

On August 2004, the University of Massachusetts Building Authority (the Authority) filed an application with the Environmental Protection Agency (EPA) Region I office for a Prevention of Significant Deterioration (PSD) permit under 40 CFR § 52.21. The Authority proposes to construct and operate a new central heating plant (CHP) at the University's Amherst Massachusetts campus. After reviewing the August 2004 "Supplement to the Prevention of Significant Deterioration (PSD) Permit Application," EPA Region I has prepared the following preliminary determination and draft PSD permit for the proposed CHP project.

EPA's permit decisions are based on the information and analysis provided by the applicant and its own technical expertise. The preliminary determination documents the information and analysis EPA used to support the PSD permit decisions. It includes a description of the proposed facility, the applicable PSD requirements, and an analysis showing how the applicant complied with the requirements.

EPA Region I has concluded that the Authority's application is complete and provides the necessary information to demonstrate that the proposed project meets the federal PSD regulations. As such, EPA is making the 2004 permit application part of the official record for this preliminary

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determination and PSD permit. In addition, since the application adequately demonstrated compliance with the federal PSD program regulations, the preliminary determination relies heavily on the language found in the application.

Please note that this project is also subject to the Massachusetts Department of Environmental Protection's (DEP) Plan Approval requirements under state regulations at 310 CMR 7.00. The DEP has issued the Authority a Plan Approval that regulates all pollutants emitted by the proposed facility, including the PM_{10} emissions regulated under this permit. EPA has worked closely with the DEP to ensure this PSD permit does not conflict with the DEP's Plan Approval requirements. The Authority must comply with both the federal PSD permit and the Massachusetts Plan Approval.

III. DESCRIPTION OF THE PROPOSED FACILITY

The Authority proposes to construct and operate a new Central Heating Plant (CHP) at the University's campus in Amherst, Massachusetts. The proposed CHP consists 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. The turbine and four boilers are equipped with selective catalytic reduction systems and oxidation catalysts. 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 and certification 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.

IV. PSD PROGRAM APPLICABILITY

Western Massachusetts is currently classified a serious nonattainment area for ground level ozone and attainment for all other criteria pollutants. Under these classifications, the Massachusetts Department of Environmental Protection administers the nonattainment NSR program to regulate emissions of Volatile Organic Compounds (VOC) and Nitrogen Oxides (NOx). EPA Region I administers the PSD program, which applies to emissions of all other regulated criteria pollutants.

EPA calculated the net emission increase to determine if the proposed CHP project is subject to the PSD program. If the resulting net emission difference is greater than the significance levels set out by the PSD program, the project is subject to the PSD program. Since no other creditable emission increase or decrease has occurred at the university within the last five years, the net emissions

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increase for this project equals the potential emissions increase from the proposed CHP project minus the actual emissions associated with the shut down of the existing boilers. The actual emissions from the existing boilers are based upon the average emissions over calendar years 2001 and 2002. To determine potential emissions from the proposed source, it was assumed that:

- the combustion turbine and package boilers are operated at maximum load firing transportation grade fuel oil for 8760 hours per year;
- the duct burner is operated at maximum load firing natural gas for 8760 hours per year; and
- the emergency generator and fire pump engine are operated at maximum load firing diesel fuel oil for 300 hours per year.

The following table shows the net change in emissions for each criteria pollutant

	Proposed CHP Potential Emissions (tpy)				**Existing Plant Actual Emissions (tpy)**	**Net Change in Emissions (tpy)**	**Major Source Threshold (tpy)**
Pollutant	**Combustion Turbine /HRSG**	**Package Boilers**	**Generator & Fire Pump**	**Total**			
PM_{10}	42	114	<<1	156	4	+152	15
SO_2	26	146	<<1	172	389	-217	40
NO_X	19	31	8	58	174	-116	25
CO	10	53	<<1	63	44	+19	100
VOC	3	14	<<1	17	23	-6	25

Using this information, the CHP project will result in a significant emissions increase of PM_{10} and is subject to PSD review for this pollutant only.

V. APPLICABLE PSD REQUIREMENTS

The PSD program requires the applicant to demonstrate that the combustion turbine and package boilers will incorporate air pollution control technologies representative of BACT, and that the resulting emissions will not cause or contribute to a violation of applicable ambient air quality standards or PSD allowable increments. The applicant is also required to assess the project's impacts on soils, visibility and secondary growth. The applicable federal PSD program regulations are listed below:

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- 40 CFR 52.21(j) Control Technology Review (Best Available Control Technology)
- 40 CFR 52.21(k) Source Impact Analysis (Air Quality Impact Assessment)
- 40 CFR 52.21(l) Air Quality Models
- 40 CFR 52.21(m) Air Quality Analysis
- 40 CFR 52.21(n) Source information
- 40 CFR 52.21(o) Additional Impact Analysis (Additional Impact Analysis)
- 40 CFR 52.21(p) Federal Class I Area Impacts (Air Quality Impact Assessment)

VI. PM_{10} EMISSIONS CHARACTERIZATION

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 micron in diameter.

VII. FEDERAL STANDARDS

1. New Source Performance Standards (NSPS)

A. Turbines

The New Source Performance Standard (NSPS) for Stationary Gas Turbines at 40 CFR 60 Subpart GG does not include a particulate standard for stationary gas turbines. In the preamble to this rule, the U.S. EPA recognized that "particulate emissions from stationary gas turbines are minimal." In addition, 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.

B. Boilers

The NSPS for Industrial/Commercial/Institutional Steam Generating Units at 40 CFR 60 Subpart Db did not include a particulate standard for industrial boilers fired with either natural gas or distillate fuel oil. In the preamble, EPA concluded that particulate control devices were neither practical nor cost-effective for boilers fired with natural gas or distillate fuel oil.

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2. Maximum Achievable Control Technologies (MACT)

A. Combustion Turbine

On January 14, 2003, EPA proposed the National Emission Standard for Hazardous Air Pollutant (NESHAP) for Stationary Combustion Turbines at 40 CFR 63, Subpart YYYY. The proposed standard did not include a particulate standard.

B. Boilers

On September 13, 2004, EPA issued the NESHAP for Industrial, Commercial, and Institutional Boilers and Process Heaters at 40 Part 63, Subpart DDDDD. The standard includes a particulate matter emission rate of 0.03 lbs/MMbtu that applies to industrial boilers burning liquid fuels such as distillate fuel oil. The NESHAP does not include a particulate standard for an industrial boiler burning natural gas.

VIII. BEST AVAILABLE CONTROL TECHNOLOGY (BACT) (40 CFR § 52.21(j))

Major new sources and major modifications to existing major sources are required to apply BACT pursuant to the PSD regulations at 40 CFR § 52.21(j)(2) and (3). BACT is defined as *"an emissions limitation... based on the maximum degree of reduction for each pollutant subject to regulation under [the Clean Air] Act which would be emitted from any proposed major stationary source or major modification which the Administrator, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such source or modification through application of production processes or available methods, systems and techniques... for control of such pollutant."* 40 CFR § 52.21(b)(12); Clean Air Act (CAA) §169(3). In addition, BACT can be no less stringent than any applicable NSPS or MACT standard. *Id.*

1. Top-down Analysis: Boilers and Turbine

To determine BACT for the combustion turbine/HRSG and package boilers, EPA used the "top-down" approach outlined in the draft 1990 New Source Review Workshop manual. The top-down approach includes the following five steps:

Step 1: Identify all control technologies
Step 2: Eliminate technically infeasible control options
Step 3: Rank remaining control technologies by control effectiveness
Step 4: Evaluate most effective controls and document results
Step 5: Select BACT

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Following the top-down approach, alternative control technologies are identified for PM_{10} emitted from the combustion turbine and package boilers. Those alternatives found to be technically unfeasible are eliminated from further consideration, while the remaining technologies are ranked by their performance levels. The technically feasible alternatives are then evaluated on the bases of the associated economic, energy, and environmental impacts. If an alternative technology, starting with the most stringent, is eliminated based on any of these criteria, the next most stringent technology is evaluated until a control option is identified as BACT.

A. Step 1-Identify All Control Technologies:

In the first step, EPA identified all available control options. Available control options are those air pollution technologies or techniques with a practical potential for application to the emission unit and regulated pollutant under evaluation. Potential control options may include a combination of: (1) raw material changes; (2) process modifications; and (3) add-on controls. EPA reviewed the RACT/BACT/LAER and the California BACT Clearinghouse databases supplied by the applicant. These databases included BACT determinations made by Federal and state agencies for similar types of combustion installations around the country. In addition, EPA contacted other state agencies and other sources of information such as control technology reference books.

From the review, EPA identified the following control options:

1. The use of clean fuels such as low sulfur fuel oils and natural gas that minimize particulate attributable to the carryover of inert material in the fuel;

2. The use of low polluting processes such as
   - high-performance combustors or burners to minimize the formation of unburned carbon in the combustion unit,
   - high-efficiency filters to remove particles from the combustion air before being introduced into the combustion unit, and
   - the maintenance of low ammonia slip to minimize the formation of ammonium salts downstream of the SCR and oxidation catalyst systems.

3 The use of particulate flue gas controls such as cyclones, fabric filters (Bag houses) and electrostatic precipitators (ESP).

B. Step 2-Eliminate Technically Infeasible Controls:

EPA evaluated the technical feasibility of the controls options identified in step 1 and concluded that flue gas controls are not technically feasible. EPA's conclusions were based on the information

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in the application and its own technical expertise that showed these controls would have little or no effect on these emission units. The Authority's application indicated that flue gas controls are typically used to control flue gas with relatively high grain loading. The CHP project's flue gas concentrations are very low (ranging from less than 0.01 to 0.05 lbs/MMBtu), making these controls impractical. The Authority also noted that condensible particulate matter constitutes the highest proportion of the project's projected total particulate matter emissions (typically 60 to 80 percent). Flue gas controls are designed to control filterable PM emissions and would have little or no effect on the control of condensible particulate matter. EPA does not know of any similar-type emission units burning low sulfur distillate oil/natural gas that are installed with these types of add-on controls.

C. Step 3-Rank Remaining Controls According to Their Effectiveness

EPA would typically rank and list all remaining control options in order of overall control efficiency. However, in this case, the remaining technically feasible controls can be applied together. Therefore, 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 using the following devices and techniques:

1. Clean fuels to minimize particulate attributable to the carryover of inert material in the fuel;
2. High-performance combustors or burners to minimize the formation of unburned carbon in the combustion unit;
3. High-efficiency filters to remove particles from the combustion air before being introduced into the combustion unit; and
4. the maintenance of low ammonia slip to minimize the formation of ammonium salts downstream of the SCR and oxidation catalyst systems.

D. Step 4-Evaluate Most Effective Controls and Document Results:

EPA documents the associated energy, environmental and economics impacts of each listed option. If the most effective control option is found to be inappropriate due to these impacts, EPA documents the reasons and considers the next option. No direct impact from the listed devices and techniques were identified.

E. Step 5-Select BACT:

Because there are no other impacts, EPA finds that the Authority's proposed list of devices and techniques is BACT for this project. EPA considered the information in the application and from other state agencies in reaching its proposed BACT emission limit.

<u>BACT Limits for the turbine</u>

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Table 3-1 of the August 2004 application 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 an oxidation catalyst. The PM_{10} emission limits for this unit are 0.017 lbs/MMBtu when firing natural gas and 0.0357 lbs/MMBtu when firing distillate fuel oil. If this unit were equipped with an oxidation catalyst, the PM_{10} emission limits would be expected to be higher due to the increased formation of ammonium salts from the oxidation catalyst.

Based on this information, the Authority proposed a PM_{10} emission limit of 0.030 lbs/MMBtu when firing natural gas and 0.050 lbs/MMBtu when firing fuel oil. However, in September, the Connecticut Department of Environmental Protection issued a permit to the University of Connecticut (UConn) for the installation of three gas turbines controlled with SCR and oxidation catalysts. The vendor for these turbines recommended a PM_{10} emission limit of 0.037 lbs/MMbtu. While the model of UConn turbines is different from the model of the turbine proposed by the Authority, EPA believes Connecticut's lower emission limit for the UConn turbine project supports a BACT emission limit of 0.040 lbs/MMbtu for the CHP turbine when firing fuel oil. The detailed RBLC and CARB BACT Clearinghouse databases for combustion turbines are provided in Appendix A of the August 2004 application.

BACT limit for the boilers

Table 3-2 of the August 2004 application 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 a SCR and oxidation catalyst system (i.e., the Liberty Generating Company). The PM_{10} emission limit for this auxiliary boiler is 0.008 lbs/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 the 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. Based on this information, the Authority proposed a PM_{10} emission limit for the industrial boilers of 0.020 lbs/MMBtu when firing natural gas and 0.050 lbs/MMBtu when firing fuel oil. The detailed RBLC and CARB BACT Clearinghouse data for industrial boilers are provided in Appendix A of the August 2004 application.

After the application was submitted to the Region I office, EPA issued a final MACT rule that applies to industrial, commercial and institutional boilers and process heaters. 69 FR 55218 (Sept. 13, 2004). The MACT rule is designed to control hazardous air pollutants (HAPs), including metallic HAP emissions, from these types of sources. Because of the wide variety of metallic HAPs

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present in industrial boiler emissions and the widely varying quantity and quality of emissions information, the MACT rule uses PM_{10} as a surrogate for non-mercury metallic HAPs. For industrial boilers that burn liquid fuels other than residual oil, the rule applies a 0.03 lbs/MMbtu PM_{10} emission limit. *See* 69 FR at 55223, 55224. EPA established the surrogate PM emission limit in this rule from filterable PM emissions test data. Condensible PM emissions were not considered. The MACT rule requires new units burning liquid fuels other than residual oil only to submit a "Notification of Compliance Status" that indicates the use of such liquid fuel, and does not require any initial or annual compliance tests. The rule does not include any compliance methods for measuring condensible PM emissions.

The definition of BACT in section 169(3) of the CAA provides that "[i]n no event shall application of [BACT] result in emissions of any pollutants which will exceed the emissions allowed by any applicable standard established pursuant to [section 111 or section 112 of the CAA]." *See also* 40 CFR § 52.21(b)(12). Since MACT standards are promulgated under section 112 of the Act, BACT for the proposed boilers must be as stringent as the MACT standard for boilers burning distillate fuel oil. However, as noted above, the MACT PM_{10} limit is based on filterable emissions only. Under EPA's PSD program, PSD permits must include emission limits that protect national ambient air quality standards, in addition to MACT standards. 40 CFR § 52.21(j), (k). As such, PSD permits must regulate total PM_{10} emissions, including filterable and condensible PM, and must include compliance testing to measure both filterable and condensible PM emissions.

To ensure that BACT does not exceed any applicable standard established under section 112 and protects NAAQS, Region I is proposing two BACT emission limits, with separate compliance testing requirements, for the boilers while firing distillate fuel oil:

- 0.030 lbs/MMbtu based on a method 201 test; and
- 0.040 lbs/MMbtu based on a method 201 and 202 test.

It should be noted that the DEP has made numerous BACT determinations for PM_{10} emissions from similar types of combustion installations in the Commonwealth. The DEP, however, has historically regulated filterable particulate emissions only, rather than total particulate emissions (i.e., both filterable and condensable PM). These BACT determinations, therefore, do not establish a precedent for total PM_{10} emission limits.

2. BACT Conclusions:

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A. Turbine and Boilers

Based on EPA's 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 the following table.

Proposed PM_{10} Emission Limits

Installation	PM_{10} Limits Natural Gas Firing (lbs/MMBtu)	PM_{10} Limits Fuel Oil Firing (lbs/MMBtu)
Combustion Turbine/HRSG	0.030	0.040
Package Boilers	0.020	0.040
		0.030 Filterable PM only method 201

B. Emergency Generator and Diesel Fire Pump

For the emergency generator and diesel fire pump, the Authority is limiting hourly operations to 300 hours per year for each unit. In addition, the emergency generator and fire pump will burn only ultra-low sulfur diesel fuel. The operational limitation and fuel oil restriction will limit total PM_{10} emissions for each unit to under 1 tpy. Given the economic impact of the costs of controlling such a small emission source, which is also intermittent, EPA concluded that additional controls are not necessary. Therefore, EPA is proposing the operational limitation and fuel oil restriction as BACT without additional analysis.

IX. AIR QUALITY IMPACT ASSESSMENT (40 CFR § 52.21(k) - (p))

Section 52.21(k) of 40 CFR Part 52 requires the applicant to demonstrate that the allowable emissions from the CHP project will not cause or contribute to a violation of the applicable National Ambient Air Quality Standard or PSD increment. In addition, the applicant must demonstrate that the CHP emissions will not adversely affect air quality related values in any Class I area (national parks and wilderness areas). 40 CFR § 52.21(p).

This section summarizes the Authority's air quality modeling analysis used to show compliance with

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the PSD program requirements. The summary includes a review of the modeling procedures used in the air quality impact assessment, the models employed, the model input options, and the supporting meteorological, terrain, air quality and point source data. The full dispersion modeling analysis is documented in the air quality modeling protocol submitted to the U.S. EPA, Region 1, in the August 2004 PSD application.

In sum, U.S. EPA, Region 1 has reviewed and approved the Authority's dispersion modeling demonstration. The Authority has demonstrated that the PM_{10} emission increase from the CHP project will remain well below the applicable NAAQS and increment levels. EPA notes that the Authority's modeling analysis used the higher emission rates proposed in its application and not the lower emission rates proposed by EPA in this PSD permit. As such, the Authority's analysis overestimated the impacts from the CHP project.

1. Technical Approach (40 CFR § 52.21(k), (m))

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.

2. Source Parameters

As previously stated, the cogeneration unit and four boilers will be capable 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. The attached analysis provides the stack parameters for the four package boilers firing oil under the various operating loads. Note that, because the emergency generator or diesel fire pump will operate only when the combustion turbine is out of service, the air quality modeling analysis did not include these two sources.

3. GEP Stack Height (40 CFR § 52.21(k), (m), (n))

EPA's 1985 Guideline for Determination of Good Engineering Practice (GEP) Stack Height

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provides 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 Authority proposes to construct two 125-foot stacks, one serving the combustion turbine/HRSG and the other serving the four package boilers. EPA notes that the stack top elevation will be below the *de minimis* GEP stack height of 213 feet permitted under the GEP Guidelines.

4. Model Selection (40 CFR § 52.21(l))

The Authority used the AERMOD model, version 02222 to conduct its air quality impacts analysis. EPA published a notice of its intent to promulgate AERMOD (v02222) as a Guideline Model on September 8, 2003 (Federal Register, Vol. 68, pp. 52934-52935). 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. Use of the AERMOD model 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. EPA Region 1 therefore approved the substitution of the AERMOD model for guideline models in this case.

5. Meteorological Data (40 CFR § 52.21(m), (n), Part 51 Appendix W)

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. 40 CFR Part 51, Appendix W, Section 9.3.1.2.a.

Because there are no onsite meteorological measurements available at the project site, the modeling analysis was based upon representative observations from the nearest NWS station. 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. A nearly complete five-year data record is, however, available for the period from 1991 through

1995. Therefore, the air quality modeling analysis is based upon this data. The nearest upper air soundings collected during the same period are available from Albsany, New York (FAA Identifier ALbs, WBAN No. 14735). The Authority's modeling analysis used these soundings in conjunction with the surface observations from Westover AFB to develop the mixing heights.

The Authority's analysis used AERMET (version 02222) to process the surface and upper air data to produce the necessary input file to AERMOD. AERMET requires roughness length, albsedo, and daytime Bowen ratio. The Authority made two different land use assumptions because of the uncertainty of whether the land use parameters (roughness length, albsedo and Bowen ratio) should be representative of the site of the source or the site of the meteorological data. The Authority ran two sets of AERMET and AERMOD runs for the five-year period of meteorological data, one for each land use classification. The Authority used the maximum predicted PM_{10} impacts determined by the modeling analysis to demonstrate compliance with the NAAQS and PSD allowable increments.

6. 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. The Authority used AERMAP (v03107) 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.

7. Background Air Quality (40 CFR § 52.21(m))

The CHP project 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, the Authority must add the background contributions of PM_{10} from major sources affecting the Significant Impact Area and the contribution of other smaller sources estimated from monitored background to the projected impacts of the proposed plant to determine compliance with the

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standards.

The Western Region MADEP identified major sources within 25 km of the proposed site. 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.

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.

8. Air Quality Modeling Results

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

9. Proposed Source Impacts (40 CFR § 52.21(k), (m))

Table V-1 presents the results of the air quality modeling analysis. As shown in this table, only the maximum 24-hour PM_{10} concentration is greater than the corresponding SIL. Consequently, the PSD rules require a more detailed dispersion modeling analysis to assess compliance with NAAQS and PSD allowable increments within those areas where the impacts are above the SILs. This analysis must consider the impacts associated not only with the new source, but also with existing sources in the region. 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. The NAAQS

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and PSD increment compliance analyses used any receptor where the predicted 24-hour PM_{10} concentrations were greater than 4 μg/m^3 (which is 20 percent below the 5 μg/m^3 SIL).

Table V-1

Maximum Predicted AERMOD Concentrations Compared with the SILs

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

10. NAAQS Compliance Analysis (40 CFR § 52.21(k)(1))

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 V-2. 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 V-2, 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 expected to occur with the retirement of the seven boilers at the existing steam plant, as well as the coal handling and storage facilities elsewhere on campus.

Table V-2
Maximum Predicted AERMOD Concentrations Compared with the NAAQS

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		Projected Concentrations (ug/m^3)				
Pollutant	Averaging Period	Proposed Plant	Major Sources	Background	Total	NAAQS (ug/m^3)
[a] PM_{10} Allowable	24-Hour Annual	0.02 0.21	25.04 2.61	79.00 28.00	104.06 30.82	150 50
[b] PM_{10} Adjusted	24-Hour Annual	0.02 0.21	25.38 2.67	79.00 28.00	104.40 30.88	150 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.

11. PSD Increment Consumption Analysis (40 CFR § 52.21(k)(2))

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 V-3. 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 V-3, 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 V-3
Maximum Predicted AERMOD Concentrations Compared with the PSD Allowable Increments

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Pollutant	Averaging Period	Proposed Plant	Other PSD Sources	Total	Increment (ug/m^3)
PM_{10}	24-hour	0.02	24.59	24.61	30
	Annual	0.21	2.47	2.68	17

12. 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.

13. Class I Area Analysis (40 CFR § 52.21(p))

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, EPA concluded that the replacement of the existing steam plant with the CHP could potentially result in a significant net increase of PM_{10}. On the other hand, the project will result in dramatic reductions in the potential emissions of both SO_2 and NOx. 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 would, under normal operations, 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.

X: ADDITIONAL IMPACT ANALYSES (40 CFR § 52.21(o))

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 the project's effects on soils and vegetation and the potential impact of secondary growth for PM_{10} only.

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.

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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. Therefore, if the impacts of the proposed plant are shown to be below these screening levels, the project is not likely to 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, EPA concluded that the plant will not adversely affect agricultural crops in the area, including produce and tobacco.

XI. ENDANGERED SPECIES ACT

Section 7 of the Endangered Species Act (ESA) requires that all federal actions such as federal PSD permits protect endangered species consistent with the ESA. To comply with the ESA, Region I consulted with Vernon Lang of the United States Fish and Wildlife Department-New England Field Office to determine if the CHP project posed any risk to endangered species in the Amherst Region of Massachusetts. After reviewing the specific impacts from the project, Mr. Lang concluded that the project did not pose a threat to any endangered or proposed endangered species or their habitat in the area, and that no further ESA impact analysis was required.

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