Application for Fuel Oil Flexibility Bellingham Cogeneration Facility

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Submitted to:

Massachusetts Department of Environmental Protection
Central Region
627 Main Street
Worcester, MA 01608

U.S. Environmental Protection Agency
Region 1
One Winter Street
Boston, MA 02108

Prepared for:

Bellingham Cogeneration Facility
PO Box 1213
92B Depot Street
Bellingham, MA 02019

Prepared by:

Epsilon Associates, Inc.
3 Clock Tower Place, Suite 250
Maynard, MA 01754

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1.0 INTRODUCTION

This section provides a facility description, project overview and history, affected permits and regulatory review.

1.1 Facility Description

The Northeast Energy Associates, LP ("NEA") Bellingham Cogeneration Facility ("the Facility") is a dual fuel-fired plant rated at a combined 304 MW located at 92 Depot Street in Bellingham, MA. The Facility consists of two combustion turbines (Siemens Westinghouse W501D5) equipped with steam injection for control of NOx emissions, two unfired heat recovery steam generators (HRSGs) and one steam turbine. The Facility is currently permitted to operate on natural gas with distillate fuel oil (0.2%,wt sulfur) backup. Each turbine may operate up to 720 hours (30 days) or any combination of hours between turbines such that the Facility does not exceed a total of 1440 hours on oil per year. The PSD Permit limits oil-firing to periods of natural gas curtailment.

1.2 Project Overview

The purpose of this application is to obtain increased fuel oil-firing capabilities. This project initiated from a recent dialogue between the Northeast Energy and Commerce Association (NECA), the New England Independent System Operator (NE-ISO) and the Massachusetts Department of Environmental Protection (MADEP) to evaluate methods to avoid potential natural gas shortages during winter months. These shortages would be the result of increased natural gas demand from heating and power generation. While such shortages did not materialize this past winter due to unseasonably warm temperatures, NE-ISO and the Massachusetts Division of Energy Resources (MA DOER) (see the last paragraph in the letter provided in Attachment A,) continue to be concerned with this issue for next winter and beyond.

The Bellingham Cogeneration Facility was specifically mentioned as one of the facilities that would be counted upon due to its backup oil-firing capability. However, it is the position of the regulators that the PSD Permit language is currently preventing the Facility from burning oil on a discretionary basis. As a result, it is not economically feasible for the Facility to reserve fuel oil in advance of the winter months due to the uncertainty of whether the oil will be able to be burned (i.e. if and how long natural gas will be unavailable). It is also not cost effective to purchase oil when there are projected shortages of or interruption to natural gas supplies, and often an adequate supply of fuel oil and/or delivery trucks will not be available on such short notice to customers that do not have an existing contract.

In order to increase fuel oil-firing capability, the Facility requests the following:

a. Modify the PSD fuel oil-firing permit condition to allow the Facility to operate on oil without a natural gas curtailment stipulation. Although the Plan Approval, NOx RACT ECP and Operating Permit do not stipulate a natural gas curtailment, we request that the permit language be made consistent in order to avoid any ambiguities.

b. Increase the allowable hours on oil per year from 720 hours per combustion turbine to 1440 hours per combustion turbine (2880 hours between both combustion turbines).

As a result of these changes, the Facility will avoid significant emission increase thresholds and attain BACT emission levels by accepting the following restrictions:

a. Switch from 0.2%,wt sulfur fuel oil to 0.0015%,wt Ultra Low Sulfur Distillate (ULSD) pursuant to the phase-in approach presented in Section 4.4, and

b. Decrease facility-wide ton per year (tpy) emission limits for NOx, CO, VOC, PM and SO_2.

1.3 Project History

The Facility submitted a letter, dated 12/2/2005, to the U.S. Environmental Protection Agency (EPA) and the MADEP requesting clarification on inconsistent permit language pertaining to fuel oil operations, as summarized in Table 1-1. The Operating Permit only includes a limit to the number of hours the turbines may burn oil while the PSD Permit, Plan Approval and NOx RACT ECP contain additional oil-firing restrictions. It was the Facility's contention that the Operating Permit and corresponding Permit Shield superseded the underlying permits with respect to restrictions on fuel oil operations.

The EPA Region 1 office responded in a letter dated 1/9/06 stating that the Operating Permit Shield did not apply in this case and that the Facility is held to the PSD permit language that limits fuel oil usage to periods when natural gas in unavailable due to curtailment. EPA also provided a follow-up letter, dated 1/30/06, that clarified how an ISO request to not burn gas may constitute a "curtailment" making natural gas "unavailable". As described in the previous section, these determinations do not provide the Facility with the needed flexibility to reserve fuel oil for the winter heating months.

At the request of the MADEP, FPL Energy met at the Central Regional Office on February 2, 2006 to review the specific permit conditions and identify other site-specific factors that are limiting fuel oil availability at the Facility. This meeting was a follow-up to one held on December 12, 2005 at the DEP Boston office where the other "oil-capable" generation facilities in Massachusetts were invited.

Table 1-1: Differences with Fuel Oil Permit Restrictions

Permit	Fuel Oil Restriction*
PSD Approval (2/1/1989)	"...only use distillate fuel oil in the facility when natural gas is unavailable due to curtailment..."
Plan Approval (6/11/1992)	"...operate on gas as much as possible..."
NOx RACT ECP (11/3/1994)	"...operate on gas as much as possible..."
Operating Permit (7/10/2002)	No restriction

*The permits limit each turbine to 720 hours (30 days) on oil or any combination of hours on oil between the turbines such that the facility does not exceed a total of 1440 hours per year.

1.4 Affected Permits

The following permits must be modified in order to incorporate the proposed permit amendments outlined in Section 1.2:

1. PSD Approval (40 CFR 52.21), 2/1/1989
2. Plan Approval (310 CMR 7.02), 6/11/1992
3. NOx RACT ECP (310 CMR 7.19), 11/3/1994

In order to assist permit expedition, electronic versions of these permits are provided in Word format with this application, see Attachment C. When these approvals are issued, an Operating Permit Minor Modification application (Form BWP AQ 10) will be submitted to the MADEP. It is our understanding that the Operating Permit approval becomes effective upon MADEP receiving a completed Form BWP AQ 10.

1.5 Regulatory Summary

MADEP and EPA have stated that the proposed request to increase fuel oil flexibility at the Bellingham Cogeneration Facility is a change in the method of operation according to: (1) Nonattainment New Source Review (NSR) under 310 CMR 7.0 Appendix A and (2) Federal Prevention of Significant Deterioration (PSD) rules (40 CFR 52.21). However, this change does not constitute a major modification, as described in Section 2.0, since the Facility will not cause a significant net emissions increase. Therefore, Lowest Achievable Emissions Rate (LAER) and emissions offsets do not apply.

MADEP and EPA Region 1 have requested that this application contain an overview of the proposed permit amendments, an emissions summary and a Best Available Control Technology (BACT) analysis for NOx, CO, VOC, PM-10 and SO_2. Since the Facility was originally modeled and permitted for five months of fuel oil operation, no additional air quality modeling is required. MADEP and EPA Region 1 also agreed that a multi-source increment analysis is not required.

2.0 EMISSIONS SUMMARY

The Facility proposes to lower facility-wide emission limits. The proposed emission limits will prevent the Facility from exceeding the significant increase thresholds when comparing the facility's past actual emissions to the future potential emissions following the modification.

2.1 Past Actual to Future Potential Emissions

The Facility proposes to limit facility-wide emissions to representative past actual emissions plus an incremental increase less than the significant increase threshold for each pollutant on a 12-month rolling total basis. The resulting limits will all be less than the Facility's current potential to emit. The past actual emissions presented in this Section are based on operations in calendar years 2001 and 2003. These years are most representative of the Facility's normal source operation.

2.1.1 Nitrogen Oxides (NOx)

Emissions of NOx from both combustion turbines are measured in a common stack by the Facility's Continuous Emission Monitoring System (CEMS). The turbines' NOx emissions are reported quarterly in Electronic Data Reports (EDRs) submitted to the EPA. The average gas-fired NOx emissions total for calendar years 2001 and 2003 was 959 tpy. The significant increase threshold for NOx is 25 tpy. Therefore, the Facility will limit future potential NOx emissions from its existing limit of 1,017 tpy to 983 tpy, as summarized in Table 2-1.

2.1.2 Carbon Monoxide (CO)

Emissions of CO from both combustion turbines are measured in a common stack by the Facility's CEMS. The average CO emissions total for calendar years 2001 and 2003, as recorded by the CEMS, was 132 tpy. The significant increase threshold for CO is 100 tpy. Therefore, the Facility will limit future potential CO emissions from its existing limit of 822 tpy to 231 tpy, as summarized in Table 2-1.

2.1.3 Volatile Organic Compounds (VOC)

Past actual VOC emissions were determined by multiplying the actual gas-fired heat input (MMBtu), measured by billing meters and daily heat content samples, by an emission factor of 0.002 lb/MMBtu, representing the maximum 3-run average from the initial compliance stack testing. The average gas-fired VOC emissions total for calendar years 2001and 2003 was 22 tpy. The significant increase threshold for VOC is 25 tpy. Therefore, the Facility will limit future potential VOC emissions from its existing limit of 57 tpy to 46 tpy, as summarized in Table 2-1.

2.1.4 *Sulfur Dioxide (SO_2)*

Past actual SO_2 emissions were determined by multiplying the actual gas-fired heat input (MMBtu) by the 40 CFR 75 pipeline natural gas (PNG) default emission factor of 0.0006 lb/MMBtu. Natural gas being delivered by pipeline to the Facility has been demonstrated to meet the Part 75 definition of PNG. The average gas-fired SO_2 emissions total for calendar years 2001 and 2003 was 7 tpy. The significant increase threshold for SO_2 is 40 tpy. Therefore, the Facility will limit future potential SO_2 emissions from its existing limit of 206 tpy to 46 tpy, as summarized in Table 2-1.

2.1.5 *Particulate Matter (PM-10)*

Past actual PM-10 emissions were determined by multiplying the actual gas-fired heat input (MMBtu), measured by billing meters and daily heat content samples, by an emission factor of 0.0034 lb/MMBtu, representing an average from the initial compliance stack testing. The average gas-fired PM-10 emissions total for calendar years 2001 and 2003 was 37 tpy. The significant increase threshold for PM-10 is 15 tpy. Therefore, the Facility will limit future potential PM-10 emissions from its existing limit of 105 tpy to 51 tpy, as summarized in Table 2-1.

Table 2-1: Proposed Facility-Wide Emission Limits

Pollutant	2001 Emissions tpy	2003 Emissions tpy	Average Emissions tpy	<Sig. Increase Threshold tpy	Proposed Emission Caps tpy	Current Emission Caps tpy
NO_x	962.6	955.7	959	24	983	1017
CO	133.4	130.6	132	99	231	822
SO_2	6.6	6.6	7	39	46	206
VOC	22.0	21.9	22	24	46	57
PM	36.9	36.7	37	14	51	105

2.2 Summary of Current and Proposed Long-term Emission Limits

The Facility is proposing to reduce the facility-wide potential emissions for each pollutant based on the analysis presented in Section 2.1. The Facility also has long-term emission limits by fuel type. As a result of the lower facility-wide emission limits, the annual gas-fired and oil-fired CO emission limits (tpy) must decrease. The annual oil-fired SO_2

emission limit (tpy) will also decrease significantly. The Facility will offset the SO_2 limit decrease by switching to ULSD.

In order to operate on oil for up to 1,440 hours (per turbine), the oil-fired NOx annual limit must increase based on the Facility's short-term permit limit of 42 ppm@15%O_2 and the maximum rated oil heat input of the combustion turbines (i.e. 2,472 MMBtu/hr total). However, as already indicated, the facility-wide NOx potential to emit will decrease.

Based on initial compliance stack test data and the use of ULSD, the Facility will be capable of burning 1440 hours on oil (per turbine) while staying under the proposed annual emission limits. PM-10 will restrict hours of operation on gas if the full complement of 1440 hours of oil is used. (based on oil fired PM-10 stack test data from June 1992 (average of 0.023 lb/MMBtu). NOx and CO are expected to be less restrictive and will depend on the number of startups/shutdowns and the actual steady state emission rate on ULSD; these emissions will be measured by the CEMS. VOC and SO_2 will not restrict annual operation. The Facility will prepare monthly recordkeeping to ensure that the 12-month rolling emission limits are not exceeded.

Table 2-2 summarizes the current and proposed annual emission limits.

Table 2-2: Current and Proposed Long-term Emission Limits (tpy)

Pollutant	Facility-wide		Gas-Fired		Oil-Fired	
	Current	Proposed	Current	Proposed	Current	Proposed
NOx	1017	983	884	884	133	291 [2]
CO	822	231	531.5	231 [1]	291	231 [1]
VOC	57	46	44	44	13	13
PM	105	51	48	48	57	51 [1]
SO_2	206	46	16	16	190	46 [1]

[1] Fuel-specific limit reduced so as not to exceed the proposed facility-wide permit limit.

[2] Potential to emit firing oil for 1440 hours. The equation is: 1.194E-7 (lb/dscf)/ppm x 9190 dscf/mmbtu x 42 ppm x 20.9 / (20.9 – 15) x 2472 mmbtu/hr x 1440 hours/year x ton/2000 lbs = 291 tons

3.0 BACT ANALYSIS

At the request of MADEP and EPA, the Facility performed a BACT analysis for NOx, CO, VOC, PM-10 and SO_2.

3.1 Initial BACT Determination

The first step in a "top-down" BACT analysis is to determine the most stringent control technology available for a similar or identical source or source category. Technically infeasible technologies are then eliminated and the remaining technologies are ranked by control efficiency. These technologies are evaluated based on economic, energy and environmental impacts. If an alternative, starting with the most stringent, is eliminated based on these criteria, the next most stringent technology is evaluated until BACT is selected.

A BACT analysis was performed during the initial permitting of the Facility in the late 1980's. Baseline emissions were based on five months of oil-firing (0.2%,wt sulfur) with the remainder of the year operating on natural gas. Table 3-1 summarizes the initial BACT determination.

Table 3-1: Initial BACT Determination

Pollutant	Units	Nat Gas	#2 Oil	Control Method
NOx	ppm	25	42	Steam injection
CO	lb/MMBtu	0.0516	0.3277	Combustion Controls and Low-emitting fuels
VOC	lb/MMBtu	0.0043	0.0151	Combustion Controls and Low-emitting fuels
PM	lb/MMBtu	0.0047	0.0647	Low-emitting fuels
SO_2	lb/MMBtu	0.0016	0.2136	Low-emitting fuels

The main differences between the initial BACT determination and the BACT analysis presented below are:

- Decrease in facility-wide potential emissions (tpy)
- Decrease in the allowable hours on oil (5 months to 2 months)
- Increased costs to retrofit add-on controls on existing units.

All three of these factors will increase the cost per ton of emissions removed. The BACT analysis presented below shows that the control methods identified in the initial permitting remain BACT, except for SO_2. ULSD may soon be commercially available and is expected to be a cost effective alternative to the current permit limit of 0.2%,wt sulfur fuel oil. ULSD is also expected to generate less NOx and particulate matter than the current fuel oil.

Therefore, the Facility has committed to burning ULSD in lieu of 0.2%,wt sulfur fuel oil in order to obtain increased fuel oil flexibility.

3.2 Oxides of Nitrogen

NOx is formed during the combustion process due to the reaction between nitrogen and oxygen in the combustion air at high temperatures ("thermal NOx") and the reaction of nitrogen bound in the fuel with oxygen ("fuel NO_x"). Steam injection is currently used to minimize NOx at the Facility to less than 25 ppm@15%O_2 on natural gas and 42 ppm@15%O_2 on fuel oil, the corresponding permit limits. An evaluation of BACT for NOx is presented below.

3.2.1 Selective Catalytic Reduction

SCR is an add-on pollution control technology that injects either anhydrous or aqueous ammonia into the flue gas over a vanadium pentoxide catalyst. The NOx within the flue gas combines with the ammonia to form water and nitrogen. The reaction has a relatively narrow flue gas temperature window; below approximately 650°F the reaction is too slow, while above about 850°F the catalytic efficiency declines. SCR is considered a technically feasible method of reducing NOx emissions from this type of emission source.

Baseline Emission Rates for Use in the BACT Analysis

Baseline emissions used to determine how many tons of NOx an SCR would control are based on the proposed long-term emission limit of 983 tpy, as presented in Section 2.2. NOx concentrations using an SCR would be controlled from 42 ppm to 6 ppm on oil and from 25 ppm to 2 ppm on natural gas. Assuming an average control efficiency of 90%, 887 tons of NOx would be controlled using an SCR.

Cost Effectiveness Evaluation

A budgetary quote to retrofit SCR systems on both units was obtained from the Original Equipment Manufacturer (OEM) of the HRSGs, Nooter Eriksen. Since the existing units were not designed with adequate space for SCR, the HRSG must be moved in order to install a spool for the catalyst and adequate distance between the catalyst and the ammonia injection grid (minimum 15 feet) for proper mixing.

The Nooter Eriksen quote includes engineering, installation and total equipment costs (e.g. catalyst, spool, ammonia storage and delivery). Due to the shift in HRSG locations, the current access road would have to be re-routed to the other side of the plant stack and connected to the turbine hall access doors via two long driveways. The total capital cost also includes indirect installation costs such as engineering costs incurred by NEA, startup and performance testing costs and the net monetary losses from being down during construction. The total installed capital cost was annualized over 10 years at 10% interest.

Annual operating costs include aqueous ammonia supply and vaporization. The SCR system will also require additional operating and maintenance labor. The minimum catalyst guarantee is three years, and so replacement costs were annualized over this period at 10% interest. An estimated catalyst pressure drop of three inches and a buildup of ammonium salts on the boiler tubes will decrease the power generated from each combustion turbine. A similar facility experiences an additional pressure drop from the buildup between four and eight inches of water column. This facility must routinely CO_2 blast and water wash the boiler tubes to remove the ammonium salts. The buildup will also decrease the heat transfer in the economizer and evaporator sections of the boiler which will decrease the power generated from the steam turbine, though this cost was not accounted for in the calculations.

The annualized costs to retrofit both units are summarized in Table 3-2. Supporting calculations are presented in Attachment B.

Table 3-2 SCR Cost Effectiveness for NOx

Control System Life (yrs)	10
Annualized Capital Cost ($/yr)	$2,483,035
Direct Annual Cost ($/yr)	$8,684,423
Indirect Annual Cost ($/yr)	$643,826
Total Annual Cost ($/yr)	$11,811,284
NOx removed (tpy)	887
Cost Effectiveness ($/ton)	**$13,310**

Due to the significant costs associated with retrofitting the existing combined cycle combustion turbines, it will not be cost effective (using DEP's criteria for cost effectiveness in $/ton of NOx removed) to install SCR.

Environmental Impact

The SCR will introduce the following negative environmental impacts:

- An ammonia slip of 2 ppm could equate to approximately 30 tons of ammonia emissions per year resulting in an overall cost-effectiveness of $13,786 per ton.
- Ammonium sulfate emissions would result in an increase in PM-10.
- The decrease in the facility's output efficiency will increase CO_2 emissions since the combustion turbines will have to burn more fuel to make up for the output reduction.
- The spent SCR catalyst must be disposed of as a hazardous waste, transferring air emissions into a solid waste problem.

3.2.2 Steam Injection

The units are equipped with steam injection. Steam injection acts as a heat sink in the turbine combustor, lowering flame temperatures and resultant NOx formation. The controlled emission rates using steam injection at the Facility are less than 25 ppm NOx firing natural gas and 42 ppm NOx when firing fuel oil. Steam injection is considered BACT for NOx.

3.3 Carbon Monoxide

CO emissions are formed during the incomplete combustion of any fuel in the combustion process. Combustion controls are currently used to minimize CO at the Facility to less than 0.0516 lb/MMBtu on natural gas and 0.3277 lb/MMBtu on fuel oil, the corresponding permit limits. An evaluation of BACT for CO is presented below.

3.3.1 Oxidation Catalyst

The top level of CO control that can be achieved is with an oxidation catalyst. The flue gas exhaust from a turbine passes through a honeycomb catalyst which oxidizes the CO to form carbon dioxide. This type of emission control technology is considered a technically feasible method of reducing CO emissions from this type of emission source.

Baseline Emission Rate for Use in the BACT Analysis

Baseline emissions used to determine how many tons of CO an oxidation catalyst would control are based on the proposed long-term emission limit of 231 tpy, as presented in Section 2.2. CO emissions using an oxidation catalyst would be controlled by 90%.

Cost Effectiveness Evaluation for Oxidation Catalyst

A budgetary quote to retrofit oxidation catalyst on both units was also obtained from Nooter Eriksen. Although the HRSG would have to be moved in order to install an SCR, if only an oxidation catalyst were installed, it could be installed within existing space, saving a significant amount of construction cost.

The Nooter Eriksen quote includes engineering, installation and total equipment costs (e.g. catalyst). The total installed capital cost was annualized over 10 years at 10% interest. The catalyst was assumed to be replaced every five years based on the expected guarantee provided by Nooter Eriksen. An estimated catalyst pressure drop of one inch will decrease the power generated from each combustion turbine.

The annualized costs to retrofit both units are summarized in Table 3-3. Supporting calculations are presented in Attachment B.

Table 3-3 Oxidation Catalyst Cost Effectiveness for CO – Both Units

Control System Life	10
Annualized Capital Cost ($/yr)	$1,055,553
Direct Annual Cost ($/yr)	$1,352,819
Indirect Annual Cost ($/yr)	$259,031
Total Annual Cost ($/yr)	$2,667,404
CO removed (tpy)	208
Overall Cost Effectiveness ($/ton)	**$12,830**

Due to the significant costs associated with retrofitting the existing combined cycle combustion turbines, it will not be cost effective (using DEP's criteria for cost effectiveness in $/ton of CO removed) to install oxidation catalyst.

3.3.2 Combustion Controls

The units are already using combustion controls (e.g., proper tuning and operating at design loads) as BACT for CO. These controls provide for the most efficient combustion as possible generating minimal additional CO emissions. Combustion controls are considered BACT for CO.

3.4 Volatile Organic Compounds

VOC emissions are formed during the incomplete combustion of any fuel in the combustion process. Combustion controls are currently used to minimize VOC at the Facility to 0.0043 lb/MMBtu on natural gas and 0.0151 lb/MMBtu on fuel oil, the corresponding permit limits. An evaluation of BACT for VOC is presented below.

3.4.1 Oxidation Catalyst

The top level of VOC control that can be achieved is with an oxidation catalyst. The flue gas exhaust from the turbine would pass through a honeycomb catalyst, as described in Section 3.3, where the VOC would react with oxygen to form carbon dioxide and water. This type of emission control technology is considered a technically feasible method of reducing VOC emissions from this type of emission source.

Baseline Emission Rate for Use in the BACT Analysis

Baseline emissions used to determine how many tons of VOC an oxidation catalyst would control are based on the proposed long-term emission limit of 46 tpy, as presented in Section 2.2. VOC emissions using an oxidation catalyst would be reduced by approximately 46%, or by 21 tpy.

Cost Effectiveness for an Oxidation Catalyst

This cost analysis uses identical cost assumptions as described in the CO BACT analysis. The total cost effectiveness of controlling CO and VOC was also evaluated. The annualized costs to retrofit both units are summarized in Table 3-3. Supporting calculations are presented in Attachment B.

Table 3-4 Oxidation Catalyst Cost Effectiveness for VOC

Control System Life	10
Annualized Capital Cost ($/yr)	$1,055,553
Direct Annual Cost ($/yr)	$1,352,819
Indirect Annual Cost ($/yr)	$259,031
Total Annual Cost ($/yr)	$2,667,404
VOC removed (tpy)	21
Cost Effectiveness ($/ton)	**$125,349**
VOC + CO removed (tpy)	229
Cost Effectiveness ($/ton), VOC+CO	**$11,639**

Due to the significant costs associated with retrofitting the existing combined cycle combustion turbines, it will not be cost effective (using DEP's criteria for cost effectiveness in $/ton of VOC removed) to install oxidation catalyst. It is even not cost effective ($/ton) when combining the tons of CO and VOC removed by an oxidation catalyst.

3.4.2 Combustion Controls

The units are already using combustion controls (e.g., proper tuning and operating at design loads) as BACT for VOC. These controls provide for the most efficient combustion as possible generating minimal additional VOC emissions. Combustion controls are considered BACT for VOC.

3.5 Particulate Matter

PM emissions are typically generated from high molecular weight hydrocarbons that are not fully combusted plus ash and sulfates. Natural gas and No. 2 fuel oil have relatively low PM emission rates. The natural gas emission rates are limited to 0.0047 lb/MMBtu and on oil to 0.0647 lb/MMBtu. PM emission rates from ULSD are expected to be even less than the current fuel oil. There are no technically feasible methods to further reduce PM emissions from the turbines. Therefore, the Facility proposes to fire natural gas and ULSD as BACT for PM.

3.6 Sulfur Dioxide

SO_2 is formed by the reaction of sulfur found in fuel with oxygen from the combustion air. The Facility is currently limited to SO_2 emission rates of 0.0016 lb/MMBtu when firing natural gas and 0.2136 lb/MMBtu when firing 0.2%,wt sulfur fuel oil. While the future cost of ULSD (15 ppmw) is unknown, it is assumed that it will be cost effective from a BACT standpoint ($/ton SO_2 removed). However, it should be noted that ULSD will cost the Facility a premium over the currently permitted 0.2%S,wt fuel oil.

There are no technically feasible methods (e.g., scrubbers) to further reduce SO_2 emissions for the turbines. Therefore, the Facility proposes to fire natural gas and ULSD as BACT, resulting in minimal SO_2 emissions.

3.7 BACT Overview

BACT is the most stringent technically feasible and cost effective technology to reduce emissions. The Facility proposes to switch from 0.2%,wt sulfur fuel oil to 0.0015%,wt sulfur ULSD subject to the phase-in proposed in Section 4.4.

The BACT emission limits for the turbines are summarized in Table 3-5.

Table 3-5 BACT Summary

Pollutant	Units	Nat Gas	ULSD	Control Method
NOx	ppmvd@15%O_2	25	42	Steam injection
CO	lb/MMBtu	0.0516	0.3277	Combustion Controls and Low-emitting fuels
VOC	lb/MMBtu	0.0043	0.0151	Combustion Controls and Low-emitting fuels
PM	lb/MMBtu	0.0047	0.0647	Low-emitting fuels
SO_2	lb/MMBtu	0.0016	0.0016	Low-emitting fuels

4.0 PERMIT MODIFICATIONS

This Section summarizes the existing fuel oil restrictions and the proposed permit amendments.

4.1 Existing Fuel Oil Restrictions

The following sections summarize the applicable existing permit conditions in the PSD Approval, the Plan Approval, the NOx RACT ECP and the Operating Permit.

4.1.1 PSD Approval

There is a condition in the PSD Approval that limits fuel oil to periods when natural gas is unavailable due to curtailment. This language does not exist in the other permits. The PSD Approval is also the only permit in which the 720 hours (each turbine) is based on a consecutive 8760 hour period instead of a calendar year basis.

Section B - Operating Conditions and Restrictions, Condition 2

> "NEA's use of distillate fuel oil in the facility shall be restricted to periods of natural gas interruption which makes it impossible to fire natural gas, but in no case shall oil be fired for more than 3650 hours during any consecutive 8760 hour period (equivalent to five months of operation per year) until such time as NEA's long-term firm gas transportation arrangements have been approved and implemented and gas is being transported to the facility on a firm basis. Thereafter, NEA shall **only use distillate fuel oil in the facility when natural gas is unavailable due to curtailment** or when NEA's supply of natural gas has been diverted to Bay State Gas Company pursuant to NEA's agreement with Bay State; but in no case shall oil be fired for more than 720 hours during any consecutive 8760 hour period (i.e. 30 days per year)."

4.1.2 Plan Approval and NOx RACT ECP

The Plan Approval and NOx RACT ECP were both issued subsequent to the PSD permit and each requires the turbines to operate on gas "as much as possible". There is no requirement for natural gas curtailment.

Plan Approval: Section X.I - Operating Conditions, Condition 3, which is the same as
NOx RACT ECP: Section IV - Operating Conditions and Restrictions, Condition 2

> "Turbine combustor #1 and #2 shall **operate on gas as much as possible**, however in no case shall either combustion unit exceed 720 hours (30 days) or any combination of hours on oil such that the facility does not exceed a total of 1440 hours during any calendar year."

4.1.3 Operating Permit

The Operating Permit was the most recent permit issued. There is no requirement for natural gas curtailment or to operate on gas as much as possible.

Section 4.A - Emission Limits and Restrictions, EU#1 & EU#2 Restrictions, Item 1

> "Turbine #1 and #2 may operate for 720 hours (30 days) on distillate fuel oil for each turbine combustor or any combination of hours on oil such that the facility does not exceed a total of 1440 hours during any calendar year."

4.2 Proposed Fuel Oil Restrictions

The Facility requests that the permit language be made consistent such that the Facility may burn fuel oil on a discretionary basis. The Facility proposes to switch from 0.2%,wt sulfur to ULSD and as a result, has increased flexibility within the emission caps such that it requests to burn oil up to 1440 hours per turbine or any combination of hours such that the Facility does not exceed a total of 2880 hours. We propose that the permit conditions identified in Section 4.1 be replaced with the following permit condition, or something with similar intent:

> "Turbines #1 and #2 may each operate for 1440 hours on Ultra Low Sulfur Distillate (ULSD) or any combination of hours on ULSD between the turbines such that the facility does not exceed a total of 2880 hours during any 12-month rolling period."

Any other references to natural gas curtailment or burning natural gas "as much as possible", either in the permit conditions or in the project description should be removed and/or made consistent with the requested permit language above.

4.3 Revised Emission Limits

The long-term emission limits should be modified according to the summary presented in Table 2-2. The short-term emission limits will remain the same, except that the maximum sulfur content in fuel oil should be changed from 0.2%,wt to 15 ppmw. This equates to an SO_2 emission rate of approximately 0.0016 lb/MMBtu[1] (4 lbs/hr plant total).

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[1] This lb/MMBtu (and lb/hr) emission rate is based on 15 ppmw sulfur, an assumed density of 7.3 lb/gal and an assumed heat content of 140,000 Btu/gal. Actual fuel data on ULSD was not available from local suppliers.

4.4 ULSD Phase-in

Since ULSD is not yet commercially available, the Facility requests a phase-in period be incorporated into the permits. In order to be oil-capable for the 2006/2007 heating season, the Facility needs to reserve an adequate supply of fuel oil and delivery contract(s) during this summer. Since ULSD will not be commercially available this summer, the Facility requests that the turbines may combust up to 0.05%,wt sulfur fuel oil through March 2007. There is approximately 73,455 gallons of fuel oil currently in the Facility's storage tank with a sulfur content of 0.03%,wt sulfur. The Facility will take fuel oil sulfur samples and monitor fuel usage to demonstrate that facility-wide SO_2 emissions remain below 45 tons per 12-month rolling period.

After March 2007, the Facility would commit to ULSD assuming it is commercially available by then (i.e., generally available from a number of different competitive suppliers located in Massachusetts or Rhode Island as determined by NEA through market solicitation); however, requests that any oil remaining in the Facility's on-site oil storage tank at that time may be subsequently combusted. If NEA determines that ULSD is not commercially available by March 2007, NEA will notify the agencies in writing of such determination and shall be permitted to continue the use of 0.05%,wt sulfur fuel oil until such time that NEA determines ULSD is commercially available.

Attachment A

DOER Letter Regarding Ongoing Natural Gas Reliability Concerns

COMMONWEALTH OF MASSACHUSETTS
OFFICE OF CONSUMER AFFAIRS
AND BUSINESS REGULATION
DIVISION OF ENERGY RESOURCES
100 CAMBRIDGE STREET, SUITE 1020
BOSTON, MA 02114
Internet: http://www.mass.gov/doer
E-mail: energy@state.ma.us

Mitt Romney
Governor

Kerry Healey
Lieutenant Governor

Janice S. Tatarka
Director, Office of Consumer Affairs
and Business Regulation

David L. O'Connor
Commissioner

TELEPHONE
(617) 727-4732

FACSIMILE
(617) 727-0030
(617) 727-0093

AC

RECEIVED
MAR 24 2006
MEPA

March 24, 2006

Secretary Stephen Pritchard
Executive Office of Environmental Affairs
100 Cambridge St., Suite 900
Boston, MA o2114-2524

Attn: Anne Canaday, MEPA Unit-EOEA 13734, Everett Power Project

Dear Secretary Pritchard:

It has come to my attention that the MEPA Unit is currently reviewing the Expanded Environmental Notification Form (EENF) submitted by TDK Properties, Inc. for the so-called Everett Power Project. Noting that the review process under the Massachusetts Environmental Policy Act is not, *per se,* a permitting process but rather is designed to make the public and permitting agencies aware of all relevant information about a proposed project, I wanted to bring to your attention the important role that power plants such as this one can play in meeting the electricity supply needs of consumers in the greater Boston area.

As you are well aware, meeting the electricity demands of consumers in a densely developed area is a continuous challenge, particularly during extremely hot periods in the summer and especially cold and dark periods in the winter when electricity consumption for space cooling, space heating and lighting reaches its highest levels. The first and most important way in which this demand can be met is through the use of various forms of energy conservation and reductions in demand. My agency has overseen and encouraged such programs for many years. They have increased the reliability of the electricity system and reduced the cost to consumers for what they must still consume. We continue to seek out new opportunities to expand these programs, in Boston and across the state.

However, even with highly effective conservation and demand reduction programs, the greater Boston area, at least for the foreseeable future, will depend on having reliable and efficient generation resources to meet its predicted peak demands for electricity. Unfortunately, it does not now have a sufficient supply of those resources. Actions that must be taken to make up for this deficiency impose additional costs on our consumers and very likely harm our air quality.

The most efficient way to maintain reliable electricity supplies in these areas is through the use of a limited but critical amount "quick start" power generating capacity. These plants can start up and be ready to send power into the transmission system in less than 30 minutes. This enables them to be available to run in the event that the system loses another major source of power, such as a large power plant or transmission. The need to for these contingency generators is present through all hours of the year, not just during high demand hours, though in those hours they are especially valuable.

ISO-New England, the federally-regulated operator of the regional electricity system has determined that the Boston area (known technically as the North Eastern Management Area, or NEMA) will efficiently meet its reliability requirements with approximately 750 MW's of this type of generating capacity. However, at the moment, this area has only about 200 MW's of such capacity. As a result, to compensate for this shortage, ISO-NE must take various actions to meet reliability requirements throughout the year.

These actions include the use of differently designed power plants that, because of the type of fuel they use or the way the use it, are not able to start up or be shut down quickly. These plants must be started up well in advance of when they are actually needed. Therefore, to have them available to run in the event of a loss of another large resource, these plants must be kept running at low output levels so as to be able tor respond quickly in the event they are actually needed. This is an inefficient and expensive way to run these plants. It also makes them unavailable to compete to provide power in the regular energy market. Both of these results impose additional and otherwise unnecessary costs on electricity consumers. It also results in the emission of otherwise unnecessary pollutants by these plants that could be avoided if they were not being used this way. When and if these plants are called upon to increase their output to maintain reliability, they are likely to be less efficient at doing so and may well produce more pollutants per unit of energy than specially designed "quick start" generating units.

From an energy standpoint, the Everett Power Plant appears to be well designed to help meet the "quick start" generating needs of consumers in NEMA. It would provide up to 200 MW's of additional "quick start" generating capacity within the NEMA region, a substantial contribution toward alleviating the 500 MW shortage there. The willingness of the developers to risk their capital to build and operate it indicates that it has passed financial muster with them and the lenders that will finance its construction. Of course, this project, like any others that might be proposed, must meet all of the requirements of law regarding environmental and other regulated impacts. Other agencies will make those determinations.

I should add that this is not the only peaking unit likely to be proposed for the NEMA. ISO-NE has recently taken steps to improve its "forward reserve" market which will increase the financial rewards for units that provide generating capacity in areas that have particularly high peak demand periods, like greater Boston. Other plants may be proposed. Yet, given the difficulty in finding sites for such plants in densely developed areas like greater Boston, and, given the difficulty of meeting all the environmental, zoning and other siting requirements for these sites, it is important that state and local regulators give careful consideration to each and every proposal. It would be unfortunate if such proposals were evaluated without due consideration for the important contributions they would make to the reliability, affordability and environmental impact of the electricity system that serves consumers in these areas.

Finally, I would note that the developers have requested expedited decision-making on this project, through the submission of an expanded environmental notification form and a request for issuance of a Single EIR. I am given to understand that such an expedited MEPA process would be necessary to enable the installation of the generating units in time to be available to contribute electricity during next winter's peak demand season. I can assure you that this would be a material benefit to the NEMA region. I and many others were concerned about the reliability of the electricity system entering this past winter due to an excess dependency in NEMA and elsewhere on natural gas. This year's unusually warm winter helped avoid serious threats to reliability, but we should not count on the weather to be so warm again next winter. Since these units would use ultra-low sulfur diesel fuel, rather than natural gas, they would be a welcome addition to the diversity of fuels used to generate electricity during peak periods next winter.

I hope this information is helpful as you and the MEPA Unit assemble all relevant information on this project.

Sincerely yours,

DOC

David O'Connor

cc: Ranch C. Kimball, Secretary of Economic Affairs
John Chapman, Assistant Secretary of Economic Affairs for Energy

Attachment B

Supporting BACT Calculations

Economic Comparison of Using SCR to Control NOx Emissions on Both Units			
Control NOx from 42 ppm to 6 ppm on oil and from 25 ppm to 2 ppm on gas			
Equipment Costs			
a.	SCR Systems (catalyst, tank, skids)	NE Estimate	$6,500,000
b.	SCR Spools	NE Estimate	$600,000
c.	Taxes	(EC*0.05)	$355,000
Total Equipment Cost (TEC)			$7,455,000
Direct Installation Costs			
a.	Shorten Ducting for new SCR Spools	NE Estimate	$200,000
b.	Install New Foundation and Move HRSGs	NE Estimate	$1,800,000
c.	Install SCR Spools	NE Estimate	$600,000
d.	Install SCR catalyst, truck unload, tank, skids	NE Estimate	$2,100,000
e.	Install New Access Roads to turbine hall	FPL Estimate	$300,000
Total Direct Installation Cost (TDIC)			$5,000,000
Indirect Installation Costs			
a.	FPL Engineering, Start Up, Performance Test, Contingencies	(0.25*TEC)	$1,863,750
b.	Generation Loss from Construction (4 months)	(Avg $/MW, net)	$914,594
Total Indirect Installation Cost (TIIC)			$2,778,344
Total Capital Cost (TCC), Installed		(TEC+TDIC+TIIC)	$15,233,344
Capital Recovery Factor (CR) (10 yrs, 10%, factor = 0.163) * TCC			**$2,483,035**
Annual Operating Costs			
Direct Operating Costs			
a.	Operating Labor (OL)	(1/2 hr/8 hr shift operating)($35/hr)	$19,163
b.	Supervisor	(OL*0.15)	$2,874
c.	Maintenance Labor (ML)	(1/2 hr/8 hr shift operating)($35/hr)	$19,163
d.	Maintenance Materials (MM)	(ML=MM)	$19,163
e.	Catalyst (Cost + Sales + tax freight, replaced 1/3 yrs, 10% int)	(75% equip cost + t&f)	$2,090,400
f.	SCR Supply (tons NH3, 19% soln @ $0.051/lb)	Borden & Remington estimate	$26,366
g.	SCR Ammonia Vaporization	(123 kW @ $0.20/kWhr) (scaled)	$450,215
h.	Pressure Drop (3" wc per NE)	W501D5 perf. data ($0.20/kWhr)	$1,646,880
i.	Clean boiler tubes semi-annually for ammonium salts	MPW Estimate	$1,081,400
j.	Boiler Pressure Drop (4-8" wc, avg 6" wc from ammonium salts)	W501D5 perf. data ($0.20/kWhr)	$3,328,800
Total Direct Operating Cost (TDOC)			**$8,684,423**
Indirect Operating Costs			
a.	Overhead	((OL+ML+MM)*0.6)	$34,493
b.	Property Tax	(TCC*0.01)	$152,333
c.	Insurance	(TCC*0.01)	$152,333
d.	Administration	(TCC*0.02)	$304,667
Total Indirect Operating Cost (TIOC)			**$643,826**
Direct Annual Costs			$8,684,423
Indirect Annual Costs			$3,126,861
Total Annual Cost (TAC)		**(CR+TDOC+TIOC)**	**$11,811,284**
Emissions Controlled			
Baseline NOx Emissions			986
Reduced NOx Emissions (1440 hrs oil, 7320 hrs nat gas)			**887**
Cost Effectiveness ($/ton NOx Reduced)			**$13,310**

Economic Comparison of Using Oxidation Catalyst to Control CO Emissions on Both Units			
Control CO fby 90%			
Equipment Costs			
a.	Supply and Install CO System	NE Estimate	$4,064,000
c.	Taxes	(EC*0.05)	$203,200
Total Equipment Cost (TEC)			$4,267,200
Direct Installation Costs			
a.	Includes: foundation, erection, piping, electrical, insulation	NE Estimate	$1,024,000
Total Direct Installation Cost (TDIC)			$1,024,000
Indirect Installation Costs			
a.	Start Up, Performance Test, Contingencies	(0.1*TEC)	$426,720
b.	Generation Loss from Construction (1 month)	(Avg $/MW, net)	$757,867
Total Indirect Installation Cost (TIIC)			$1,184,587
Total Capital Cost (TCC), Installed		(TEC+TDIC+TIIC)	$6,475,787
Capital Recovery Factor (CR) (10 yrs, 10%, factor = 0.163) * TCC			**$1,055,553**
Annual Operating Costs			
Direct Operating Costs			
a.	Catalyst (Cost + Sales + tax freight, replaced 1/5 yrs, 10% int)	(75% equip cost + t&f)	$858,317
b.	Pressure Drop (1" wc per NE)	(0.25% power drop/2" pressure drop)	$494,502
Total Direct Operating Cost (TDOC)			**$1,352,819**
Indirect Operating Costs			
a.	Property Tax	(TCC*0.01)	$64,758
b.	Insurance	(TCC*0.01)	$64,758
c.	Administration	(TCC*0.02)	$129,516
Total Indirect Operating Cost (TIOC)			**$259,031**
Direct Annual Costs			$1,352,819
Indirect Annual Costs			$1,314,585
Total Annual Cost (TAC)		**(CR+TDOC+TIOC)**	**$2,667,404**
Emissions Controlled			
Baseline CO Emissions			231
Reduced CO Emissions			**208**
Cost Effectiveness ($/ton CO Reduced)			**$12,830**

Economic Comparison of Using Oxidation Catalyst to Control CO Emissions on Both Units					
Control VOC from 11 ppm to 6 ppm on oil and from 3 ppm to 2 ppm on gas					
Equipment Costs					
a.	Supply and Install CO System			NE Estimate	$4,064,000
c.	Taxes			(EC*0.05)	$203,200
Total Equipment Cost (TEC)					$4,267,200
Direct Installation Costs					
a.	Includes: foundation, erection, piping, electrical, insulation			NE Estimate	$1,024,000
Total Direct Installation Cost (TDIC)					$1,024,000
Indirect Installation Costs					
a.	Start Up, Performance Test, Contingencies			(0.1*TEC)	$426,720
b.	Generation Loss from Construction (1 month)			(Avg $/MW, net)	$757,867
Total Indirect Installation Cost (TIIC)					$1,184,587
Total Capital Cost (TCC), Installed				(TEC+TDIC+TIIC)	$6,475,787
Capital Recovery Factor (CR) (10 yrs, 10%, factor = 0.163) * TCC					**$1,055,553**
Annual Operating Costs					
Direct Operating Costs					
a.	Catalyst (Cost + Sales + tax freight, replaced 1/5 yrs, 10% int)			(75% equip cost + t&f)	$858,317
b.	Pressure Drop (1" wc per NE)		(0.25% power drop/2" pressure drop)		$494,502
Total Direct Operating Cost (TDOC)					**$1,352,819**
Indirect Operating Costs					
a.	Property Tax			(TCC*0.01)	$64,758
b.	Insurance			(TCC*0.01)	$64,758
c.	Administration			(TCC*0.02)	$129,516
Total Indirect Operating Cost (TIOC)					**$259,031**
Direct Annual Costs					$1,352,819
Indirect Annual Costs					$1,314,585
Total Annual Cost (TAC)				**(CR+TDOC+TIOC)**	**$2,667,404**
Emissions Controlled					
Baseline VOC Emissions					46
Reduced VOC Emissions (1440 hrs oil)					**21**
Cost Effectiveness ($/ton VOC Reduced)					**$125,349**

Attachment C

Electronic Version of Permits

Epsilon ASSOCIATES INC.

February 15, 2007

Mr. Donald Dahl
US EPA, Region 1
One Congress Street
Boston, MA 02114-2023

Subject: Application for Fuel Oil Flexibility
Information Request Responses
Bellingham Cogeneration Facility

3 Clock Tower Place, Suite 250
Maynard, MA 01754
www.epsilonassociates.com
978 897 7100
FAX 978 897 0099

Dear Mr. Dahl:

This correspondence is in regards to the Bellingham Cogeneration Facility permit application dated May 31, 2006. We received your request for additional information in a letter dated January 26, 2007, also contained in Attachment 1. Provided below are our responses.

1. **Baseline Emission Calculations.** The facility has revised its baseline emission calculations by using a consecutive 24-month period representative of normal source operation. Instead of using calendar years 2001 and 2003, the revised baseline emission calculations use 2001 and 2002. Supporting data and calculations are presented in Attachment 2. Replacement pages to our application are provided in Attachment 3.

2. **PM-10 and VOC Compliance Monitoring.** The facility plans to monitor compliance with the proposed emission caps for PM-10 and VOC by multiplying default emission factors, in units of lb/MMBtu, by the measured heat input to the combustion turbines, in units of MMBtu. This is the same methodology used to calculate past actual emissions for purposes of establishing the proposed emission caps.

   The default emission factors (lb/MMBtu) used to determine past actual emissions were based on the results obtained from the initial compliance stack testing program. For PM-10, the test program followed USEPA Reference Method 5 (front half PM). Condensable PM was not tested. For VOC, the test program followed USEPA Reference Method 25A and reported results as total hydrocarbons (as carbon). The Facility will calculate future actual emissions using the same basis. That is, emission calculations will use front half (Method 5) stack test results for PM-10 and total hydrocarbon stack test results (Method 25A) for VOC.

   Furthermore, the Massachusetts Department of Environmental Protection (MassDEP) is requiring the facility to apply higher VOC emissions whenever CO is above its emission limit, which is measured by facility's Continuous Emissions Monitoring System (CEMS). This calculation will be as follows:

$VOC_{actual} = VOC_{limit} \times (CO_{actual} / CO_{limit})$. Bellingham will incorporate these requirements, Conditions IX.I and IX.J of the amended 310 CMR 7.02 Plan Approval, into its recordkeeping procedures.

Actual unit heat input (MMBtu/hr) is determined from measuring fuel flow to the combustion turbines and the fuel heat content. Fuel flow is measured using a natural gas billing meter and calibrated fuel oil meters. The heat content is obtained from the supplier for natural gas and from on-site tank sampling and/or by delivery for fuel oil.

3. **Emission Caps Averaging Time.** A 30-day rolling emissions cap is not feasible because the Bellingham Cogeneration Facility has substantial and unpredictable annual variation in production. The facility operates when dictated by market conditions, which can be quite variable from one year to the next.

If there are any questions, please contact me at 978-461-6234 or Pete Holzapfel, General Manager of the Bellingham Cogeneration Facility, at 508-966-4872. Thank you for your attention to this matter.

Sincerely,

Sean R. Gregory

Sean R. Gregory, P.E.
Epsilon Associates, Inc.

Cc: Thomas Cusson, MassDEP CERO
Bob Donaldson, MADEP Boston
Jim Colman, MADEP Boston
Timothy Oliver, FPL Energy
David Cleary, FPL Energy
Peter Holzapfel, FPL Energy
Sean Gregory, Epsilon Associates, Inc.
Bellingham Cogeneration Facility, file copy

Attachment 1

EPA Information Request Letter (dated 1/26/07)

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION 1
1 CONGRESS STREET, SUITE 1100
BOSTON, MASSACHUSETTS 02114-2023

January 26, 2007

Sean R. Gregory, PE
Senior Engineer
Epsilon Associates, Inc.
3 Clock Tower Place, Suite 250
Maynard, MA 01754

Dear Mr. Gregory:

Thank you for your application dated May 31, 2006, requesting revisions to the prevention of significant deterioration (PSD) permit issued to Northeast Energy Associates (NEA) on February 1, 1989 for the construction and operation of a cogeneration facility in Bellingham, Massachusetts. In brief, you are requesting two revisions to the PSD permit. First, you seek to remove the restriction in permit condition no. 5 of when oil can be used as a fuel. Second, you seek to increase the amount of hours oil can be fired from 720 hours facility-wide to 1440 hours for each of the two turbines.

To process your application, EPA is requesting the following additional information:

1. 40 CFR 52.21(b)(48) allows an existing emissions unit to use any consecutive 24 month period within 5 or 10 year period preceding actual construction (depending on whether the facility meets the definition of a steam electric generating unit at 40 CFR 52.21(b)(31)). According to the application, calendar years 2001 and 2003 were chosen for baseline emissions. However, these years are not consecutive. Please supply us with baseline emissions for a 24 consecutive month period. In addition, please demonstrate how these emissions were calculated, including any emission factors, fuel consumption, or stack test results that were used.

2. How does NEA plan to monitor compliance with the new emission caps for PM-10 and VOC?

3. Your application proposes to cap emissions on a 12 month rolling basis. Except under unusual circumstances, EPA policy[1] requires emission caps to be on a short-term basis, such as a rolling 30 day period. What is NEA's justification that a 30 day rolling average is not feasible for the emission caps?

If you have any questions please call me at (617) 918-1657.

Sincerely,

Donald F. Dahl

Donald Dahl
Environmental Engineer

Cc: Thomas P. Cusson, MA DEP

[1]See Memorandum "Guidance on Limiting Potential to Emit in New Source Permitting" dated June 13, 1989, from Terrell Hunt and John Seitz to Addressees.

Attachment 2

Baseline Emissions Data and Calculations

Source of Data for Baseline Emissions

Pollutant	How Determined	Source
NO_x	CEMS	CEMS
CO	CEMS	CEMS
SO_2	0.0006 lb/MMBtu	Pipeline natural gas default
VOC	0.002 lb/MMBtu	Initial compliance stack test results
PM	0.0034 lb/MMBtu	Initial compliance stack test results

Heat Input Data

Year	Natural Gas Heat Input	Source
2001	22,034,249 MMBtu	Billing meter and monthly natural gas heat content (gross caloric value, GCV)
2002	21,882,430 MMBtu	

Sample Calculation

$$0.0006 \frac{lbSO_2}{MMBtu} x 22{,}034{,}249 \frac{MMBtu}{year(2001)} x \frac{ton}{2000lb} = 6.6tons$$

CEMS Data

Year	Natural Gas Heat Input	NOx CEMS	CO CEMS
2001	22,034,249 MMBtu	962.6 tons	252.7 tons*
2002	21,882,430 MMBtu	945.8 tons	179.3 tons

*The 133.4 tons of CO reported in the initial application was in error.

Attachment 3

Replacement Pages for Application

2.0 EMISSIONS SUMMARY

The Facility proposes to lower facility-wide emission limits. The proposed emission limits will prevent the Facility from exceeding the significant increase thresholds when comparing the facility's past actual emissions to the future potential emissions following the modification.

2.1 Past Actual to Future Potential Emissions

The Facility proposes to limit facility-wide emissions to representative past actual emissions plus an incremental increase less than the significant increase threshold for each pollutant on a 12-month rolling total basis. The resulting limits will all be less than the Facility's current potential to emit. The past actual emissions presented in this Section are based on operations in calendar years 2001 and 2002. These years are most representative of the Facility's normal source operation.

2.1.1 Nitrogen Oxides (NOx)

Emissions of NOx from both combustion turbines are measured in a common stack by the Facility's Continuous Emission Monitoring System (CEMS). The turbines' NOx emissions are reported quarterly in Electronic Data Reports (EDRs) submitted to the EPA. The average gas-fired NOx emissions total for calendar years 2001 and 2002 was 954 tpy. The significant increase threshold for NOx is 25 tpy. Therefore, the Facility will limit future potential NOx emissions from its existing limit of 1,017 tpy to 978 tpy, as summarized in Table 2-1.

2.1.2 Carbon Monoxide (CO)

Emissions of CO from both combustion turbines are measured in a common stack by the Facility's CEMS. The average CO emissions total for calendar years 2001 and 2002, as recorded by the CEMS, was 216 tpy. The significant increase threshold for CO is 100 tpy. Therefore, the Facility will limit future potential CO emissions from its existing limit of 822 tpy to 315 tpy, as summarized in Table 2-1.

2.1.3 Volatile Organic Compounds (VOC)

Past actual VOC emissions were determined by multiplying the actual gas-fired heat input (MMBtu), measured by billing meters and daily heat content samples, by an emission factor of 0.002 lb/MMBtu, representing the maximum 3-run average from the initial compliance stack testing. The average gas-fired VOC emissions total for calendar years 2001and 2002 was 22 tpy. The significant increase threshold for VOC is 25 tpy. Therefore, the Facility will limit future potential VOC emissions from its existing limit of 57 tpy to 46 tpy, as summarized in Table 2-1.

2.1.4 Sulfur Dioxide (SO_2)

Past actual SO_2 emissions were determined by multiplying the actual gas-fired heat input (MMBtu) by the 40 CFR 75 pipeline natural gas (PNG) default emission factor of 0.0006 lb/MMBtu. Natural gas being delivered by pipeline to the Facility has been demonstrated to meet the Part 75 definition of PNG. The average gas-fired SO_2 emissions total for calendar years 2001 and 2002 was 7 tpy. The significant increase threshold for SO_2 is 40 tpy. Therefore, the Facility will limit future potential SO_2 emissions from its existing limit of 206 tpy to 46 tpy, as summarized in Table 2-1.

2.1.5 Particulate Matter (PM-10)

Past actual PM-10 emissions were determined by multiplying the actual gas-fired heat input (MMBtu), measured by billing meters and daily heat content samples, by an emission factor of 0.0034 lb/MMBtu, representing an average from the initial compliance stack testing. The average gas-fired PM-10 emissions total for calendar years 2001 and 2002 was 37 tpy. The significant increase threshold for PM-10 is 15 tpy. Therefore, the Facility will limit future potential PM-10 emissions from its existing limit of 105 tpy to 51 tpy, as summarized in Table 2-1.

Table 2-1: Proposed Facility-Wide Emission Limits

Pollutant	2001 Emissions tpy	2002 Emissions tpy	Average Emissions tpy	<Sig. Increase Threshold tpy	Proposed Emission Caps tpy	Current Emission Caps tpy
NO_x	962.6	945.8	954	24	978	1017
CO	252.7	179.3	216	99	315	822
SO_2	6.6	6.6	7	39	46	206
VOC	22.0	21.9	22	24	46	57
PM	36.9	36.7	37	14	51	105

2.2 Summary of Current and Proposed Long-term Emission Limits

The Facility is proposing to reduce the facility-wide potential emissions for each pollutant based on the analysis presented in Section 2.1. The Facility also has long-term emission limits by fuel type. As a result of the lower facility-wide emission limits, the annual gas-fired and oil-fired CO emission limits (tpy) must decrease. The annual oil-fired SO_2

emission limit (tpy) will also decrease significantly. The Facility will offset the SO_2 limit decrease by switching to ULSD.

In order to operate on oil for up to 1,440 hours (per turbine), the oil-fired NOx annual limit must increase based on the Facility's short-term permit limit of 42 ppm@15%O_2 and the maximum rated oil heat input of the combustion turbines (i.e. 2,472 MMBtu/hr total). However, as already indicated, the facility-wide NOx potential to emit will decrease.

Based on initial compliance stack test data and the use of ULSD, the Facility will be capable of burning 1440 hours on oil (per turbine) while staying under the proposed annual emission limits. PM-10 will restrict hours of operation on gas if the full complement of 1440 hours of oil is used. (based on oil fired PM-10 stack test data from June 1992 (average of 0.023 lb/MMBtu). NOx and CO are expected to be less restrictive and will depend on the number of startups/shutdowns and the actual steady state emission rate on ULSD; these emissions will be measured by the CEMS. VOC and SO_2 will not restrict annual operation. The Facility will prepare monthly recordkeeping to ensure that the 12-month rolling emission limits are not exceeded.

Table 2-2 summarizes the current and proposed annual emission limits.

Table 2-2: Current and Proposed Long-term Emission Limits (tpy)

Pollutant	Facility-wide		Gas-Fired		Oil-Fired	
	Current	Proposed	Current	Proposed	Current	Proposed
NOx	1017	978	884	884	133	291 [2]
CO	822	315	531.5	315 [1]	291	315 [1]
VOC	57	46	44	44	13	13
PM	105	51	48	48	57	51 [1]
SO_2	206	46	16	16	190	46 [1]

[1] Fuel-specific potentials reduced so as not to exceed the proposed facility-wide permit limit.

[2] Potential to emit firing oil for 1440 hours. The equation is: 1.194E-7 (lb/dscf)/ppm x 9190 dscf/mmbtu x 42 ppm x 20.9 / (20.9 – 15) x 2472 mmbtu/hr x 1440 hours/year x ton/2000 lbs = 291 tons

3.0 BACT ANALYSIS

At the request of MADEP and EPA, the Facility performed a BACT analysis for NOx, CO, VOC, PM-10 and SO_2.

3.1 Initial BACT Determination

The first step in a "top-down" BACT analysis is to determine the most stringent control technology available for a similar or identical source or source category. Technically infeasible technologies are then eliminated and the remaining technologies are ranked by control efficiency. These technologies are evaluated based on economic, energy and environmental impacts. If an alternative, starting with the most stringent, is eliminated based on these criteria, the next most stringent technology is evaluated until BACT is selected.

A BACT analysis was performed during the initial permitting of the Facility in the late 1980's. Baseline emissions were based on five months of oil-firing (0.2%,wt sulfur) with the remainder of the year operating on natural gas. Table 3-1 summarizes the initial BACT determination.

Table 3-1: Initial BACT Determination

Pollutant	Units	Nat Gas	#2 Oil	Control Method
NOx	ppm	25	42	Steam injection
CO	lb/MMBtu	0.0516	0.3277	Combustion Controls and Low-emitting fuels
VOC	lb/MMBtu	0.0043	0.0151	Combustion Controls and Low-emitting fuels
PM	lb/MMBtu	0.0047	0.0647	Low-emitting fuels
SO_2	lb/MMBtu	0.0016	0.2136	Low-emitting fuels

The main differences between the initial BACT determination and the BACT analysis presented below are:

- Decrease in facility-wide potential emissions (tpy)
- Decrease in the allowable hours on oil (5 months to 2 months)
- Increased costs to retrofit add-on controls on existing units.

All three of these factors will increase the cost per ton of emissions removed. The BACT analysis presented below shows that the control methods identified in the initial permitting remain BACT, except for SO_2. ULSD may soon be commercially available and is expected to be a cost effective alternative to the current permit limit of 0.2%,wt sulfur fuel oil. ULSD is also expected to generate less NOx and particulate matter than the current fuel oil.

Therefore, the Facility has committed to burning ULSD in lieu of 0.2%,wt sulfur fuel oil in order to obtain increased fuel oil flexibility.

3.2 Oxides of Nitrogen

NOx is formed during the combustion process due to the reaction between nitrogen and oxygen in the combustion air at high temperatures ("thermal NOx") and the reaction of nitrogen bound in the fuel with oxygen ("fuel NO_x"). Steam injection is currently used to minimize NOx at the Facility to less than 25 ppm@15%O_2 on natural gas and 42 ppm@15%O_2 on fuel oil, the corresponding permit limits. An evaluation of BACT for NOx is presented below.

3.2.1 Selective Catalytic Reduction

SCR is an add-on pollution control technology that injects either anhydrous or aqueous ammonia into the flue gas over a vanadium pentoxide catalyst. The NOx within the flue gas combines with the ammonia to form water and nitrogen. The reaction has a relatively narrow flue gas temperature window; below approximately 650°F the reaction is too slow, while above about 850°F the catalytic efficiency declines. SCR is considered a technically feasible method of reducing NOx emissions from this type of emission source.

Baseline Emission Rates for Use in the BACT Analysis

Baseline emission rates are determined from the maximum annual potential to emit. For Bellingham, the maximum annual potential to emit is 978 tpy, as presented in Section 2.2. The BACT analysis also considers a more likely operating scenario in which the units are cycled to operate only during the peak periods of load demand each day, plus a time allotment for startup and shutdown. Two cycling scenarios were considered. The first scenario is based on a projected annual capacity factor, the "projected" case. The second cycling scenario assumes the units will cycle 360 days per year, the "maximum" case. Baseline emissions for the cycling scenarios are calculated from the maximum potential emissions associated with the reduced operating hours. An average SCR control efficiency of 90% was applied to baseline emissions, excluding startup and shutdown periods when the SCR is not operational.

Cost Effectiveness Evaluation

A budgetary quote to retrofit SCR systems on both units was obtained from the Original Equipment Manufacturer (OEM) of the HRSGs, Nooter Eriksen. Since the existing units were not designed with adequate space for SCR, the HRSG must be moved in order to install a spool for the catalyst and adequate distance between the catalyst and the ammonia injection grid (minimum 15 feet) for proper mixing.

The Nooter Eriksen quote includes engineering, installation and total equipment costs (e.g. catalyst, spool, ammonia storage and delivery). Due to the shift in HRSG locations, the current access road would have to be re-routed to the other side of the plant stack and connected to the turbine hall access doors via two long driveways. The total capital cost also includes indirect installation costs such as engineering costs incurred by NEA, startup and performance testing costs and the net monetary losses from being down during construction. The total installed capital cost was annualized over 10 years at 10% interest.

Annual operating costs include aqueous ammonia supply and vaporization. The SCR system will also require additional operating and maintenance labor. The minimum catalyst guarantee is three years, and so replacement costs were annualized over this period at 10% interest. The catalyst life was extended to five years for the projected cycling operating scenario. An estimated catalyst pressure drop of three inches and a buildup of ammonium salts on the boiler tubes will decrease the power generated from each combustion turbine. A similar facility experiences an additional pressure drop from the buildup between four and eight inches of water column. This facility must routinely CO_2 blast and water wash the boiler tubes to remove the ammonium salts. The buildup will also decrease the heat transfer in the economizer and evaporator sections of the boiler which will decrease the power generated from the steam turbine, though this cost was not accounted for in the calculations.

The annualized costs to retrofit both units are summarized in Table 3-2. Supporting calculations are presented in Attachment B.

Table 3-2 SCR Cost Effectiveness for NOx

Operating Scenario	Cycling (projected)	Cycling (m[illegible]	Base-Loaded
Operating Hours per Year	3,138	6,840	8,640
Control System Life (yrs)	10	10	10
Annualized Capital Cost ($/yr)	$2,500,090	$2,500,090	$2,500,090
Direct Annual Cost ($/yr)	$4,771,078	$8,037,073	$9,340,557
Indirect Annual Cost ($/yr)	$625,876	$640,451	$647,539
Total Annual Cost ($/yr)	$7,897,044	$11,177,614	$12,488,185
NOx removed (tpy)	359	425	879
Cost Effectiveness ($/ton)	$22,008	$26,302	$14,208

(1) Cycling the units is anticipated to be the primary operating scenario.
(2) "Cycling (projected)" operating hours is based on a projected capacity factor.
(3) "Cycling (max.)" operating hours assumes the units cycle 360 days per year.
(4) The Facility does not expect to operate as a base-loaded facility, though retains the ability.
(5) "Base-loaded" operating hours assumes the units operate 360 days per year.

Due to the significant costs associated with retrofitting the existing combined cycle combustion turbines, it will not be cost effective (using DEP's criteria for cost effectiveness in $/ton of NOx removed) to install SCR.

Environmental Impact

The SCR will introduce the following negative environmental impacts:

- 2 ppm ammonia slip equates to a maximum of 30 tpy of ammonia emissions.
- Ammonium sulfate emissions would result in an increase in PM-10.
- The decrease in the facility's output efficiency will increase CO_2 emissions since the combustion turbines will have to burn more fuel to make up for the output reduction.
- The spent SCR catalyst must be disposed of as a hazardous waste, transferring air emissions into a solid waste problem.

3.2.2 Steam Injection

The units are equipped with steam injection. Steam injection acts as a heat sink in the turbine combustor, lowering flame temperatures and resultant NOx formation. The controlled emission rates using steam injection at the Facility are less than 25 ppm NOx firing natural gas and 42 ppm NOx when firing fuel oil. Steam injection is considered BACT for NOx.

3.3 Carbon Monoxide

CO emissions are formed during the incomplete combustion of any fuel in the combustion process. Combustion controls are currently used to minimize CO at the Facility to less than 0.0516 lb/MMBtu on natural gas and 0.3277 lb/MMBtu on fuel oil, the corresponding permit limits. An evaluation of BACT for CO is presented below.

3.3.1 Oxidation Catalyst

The top level of CO control that can be achieved is with an oxidation catalyst. The flue gas exhaust from a turbine passes through a honeycomb catalyst which oxidizes the CO to form carbon dioxide. This type of emission control technology is considered a technically feasible method of reducing CO emissions from this type of emission source.

Baseline Emission Rate for Use in the BACT Analysis

Baseline emissions used to determine how many tons of CO an oxidation catalyst would control are based on the proposed long-term emission limit of 315 tpy, as presented in Section 2.2. CO emissions using an oxidation catalyst would be controlled by 90%.

Cost Effectiveness Evaluation for Oxidation Catalyst

A budgetary quote to retrofit oxidation catalyst on both units was also obtained from Nooter Eriksen. Although the HRSG would have to be moved in order to install an SCR, if only an oxidation catalyst were installed, it could be installed within existing space, saving a significant amount of construction cost.

The Nooter Eriksen quote includes engineering, installation and total equipment costs (e.g. catalyst). The total installed capital cost was annualized over 10 years at 10% interest. The catalyst was assumed to be replaced every five years based on the expected guarantee provided by Nooter Eriksen. An estimated catalyst pressure drop of one inch will decrease the power generated from each combustion turbine.

The annualized costs to retrofit both units are summarized in Table 3-3. Supporting calculations are presented in Attachment B.

Table 3-3 Oxidation Catalyst Cost Effectiveness for CO – Both Units

Control System Life	10
Annualized Capital Cost ($/yr)	$1,055,553
Direct Annual Cost ($/yr)	$1,352,819
Indirect Annual Cost ($/yr)	$259,031
Total Annual Cost ($/yr)	$2,667,404
CO removed (tpy)	284
Overall Cost Effectiveness ($/ton)	$9,409

Due to the significant costs associated with retrofitting the existing combined cycle combustion turbines, it will not be cost effective (using DEP's criteria for cost effectiveness in $/ton of CO removed) to install oxidation catalyst.

3.3.2 Combustion Controls

The units are already using combustion controls (*e.g.,* proper tuning and operating at design loads) as BACT for CO. These controls provide for the most efficient combustion as possible generating minimal additional CO emissions. Combustion controls are considered BACT for CO.

3.4 Volatile Organic Compounds

VOC emissions are formed during the incomplete combustion of any fuel in the combustion process. Combustion controls are currently used to minimize VOC at the Facility to 0.0043 lb/MMBtu on natural gas and 0.0151 lb/MMBtu on fuel oil, the corresponding permit limits. An evaluation of BACT for VOC is presented below.

3.4.1 Oxidation Catalyst

The top level of VOC control that can be achieved is with an oxidation catalyst. The flue gas exhaust from the turbine would pass through a honeycomb catalyst, as described in Section 3.3, where the VOC would react with oxygen to form carbon dioxide and water. This type of emission control technology is considered a technically feasible method of reducing VOC emissions from this type of emission source.

Baseline Emission Rate for Use in the BACT Analysis

Baseline emissions used to determine how many tons of VOC an oxidation catalyst would control are based on the proposed long-term emission limit of 46 tpy, as presented in Section 2.2. VOC emissions using an oxidation catalyst would be reduced by approximately 46%, or by 21 tpy.

Cost Effectiveness for an Oxidation Catalyst

This cost analysis uses identical cost assumptions as described in the CO BACT analysis. The total cost effectiveness of controlling CO and VOC was also evaluated. The annualized costs to retrofit both units are summarized in Table 3-3. Supporting calculations are presented in Attachment B.

Table 3-4 Oxidation Catalyst Cost Effectiveness for VOC

Control System Life	10
Annualized Capital Cost ($/yr)	$1,055,553
Direct Annual Cost ($/yr)	$1,352,819
Indirect Annual Cost ($/yr)	$259,031
Total Annual Cost ($/yr)	$2,667,404
VOC removed (tpy)	21
Cost Effectiveness ($/ton)	$125,349
VOC + CO removed (tpy)	305
Cost Effectiveness ($/ton), VOC+CO	$8,752

Due to the significant costs associated with retrofitting the existing combined cycle combustion turbines, it will not be cost effective (using DEP's criteria for cost effectiveness in $/ton of VOC removed) to install oxidation catalyst. It is even not cost effective ($/ton) when combining the tons of CO and VOC removed by an oxidation catalyst.

3.4.2 Combustion Controls

The units are already using combustion controls (*e.g.*, proper tuning and operating at design loads) as BACT for VOC. These controls provide for the most efficient combustion as

Economic Comparison of Using SCR to Control NOx Emissions on Both Units				
Control NOx from 42 ppm to 6 ppm on oil and from 25 ppm to 2 ppm on gas				
Operating Scenario:		Cycling (projected)	Cycling (max.)	Base-Loaded
Operating Hours Per Year:		3,138	6,840	8,640
Notes:				
(1) Cycling the units is anticipated to be the primary operating scenario.				
(2) "Cycling (projected)" operating hours is based on a projected capacity factor.				
(3) "Cycling (max.)" operating hours assumes the units cycle 360 days per year.				
(4) The Facility does not expect to operate as a base-loaded facility, though retains the ability.				
(5) "Base-loaded" operating hours assumes the units operate 360 days per year.				
Equipment Costs				
a. SCR Systems (catalyst, tank, skids)	NE Estimate	$6,500,000	$6,500,000	$6,500,000
b. SCR Spools	NE Estimate	$600,000	$600,000	$600,000
c. Taxes	(EC*0.05)	$355,000	$355,000	$355,000
Total Equipment Cost (TEC)		$7,455,000	$7,455,000	$7,455,000
Direct Installation Costs				
a. Shorten Ducting for new SCR Spools	NE Estimate	$200,000	$200,000	$200,000
b. Install New Foundation and Move HRSGs	NE Estimate	$1,800,000	$1,800,000	$1,800,000
c. Install SCR Spools	NE Estimate	$600,000	$600,000	$600,000
d. Install SCR catalyst, truck unload, tank, skids	NE Estimate	$2,100,000	$2,100,000	$2,100,000
e. Install New Access Roads to turbine hall	FPL Estimate	$300,000	$300,000	$300,000
f. Install Ammonia CEMS	FPL Estimate	$100,000	$100,000	$100,000
Total Direct Installation Cost (TDIC)		$5,100,000	$5,100,000	$5,100,000
Indirect Installation Costs				
a. FPL Engineering, Start Up, Performance Test, Contingencies	(0.25*TEC)	$1,863,750	$1,863,750	$1,863,750
b. Generation Loss from Construction (4 months)	(Cap.Factor x Avg $/MW, net)	$919,222	$919,222	$919,222
Total Indirect Installation Cost (TIIC)		$2,782,972	$2,782,972	$2,782,972
Total Capital Cost (TCC), Installed	(TEC+TDIC+TIIC)	$15,337,972	$15,337,972	$15,337,972
Capital Recovery Factor (CR) (10 yrs, 10%, factor = 0.163) * TCC		$2,500,090	$2,500,090	$2,500,090
Annual Operating Costs (Cycling - 6,840 hours per year)				
Direct Operating Costs				
a. Operating Labor (OL)	(1/2 hr/8 hr shift operating)($35/hr)	$6,865	$14,963	$18,900
b. Supervisor	(OL*0.15)	$1,030	$2,244	$2,835
c. Maintenance Labor (ML)	(1/2 hr/8 hr shift operating)($35/hr)	$6,865	$14,963	$18,900
d. Maintenance Materials (MM)	(ML=MM)	$6,865	$14,963	$18,900
e. Catalyst (Cost + Sales + tax freight, replaced 1/3 yrs, 10% int)	(75% equip cost + t&f)	$1,445,600	$2,090,400	$2,090,400
f. SCR Supply (tons NH3, 19% soln @ $0.051/lb)	Borden & Remington estimate	$77,664	$143,723	$204,695
g. SCR Ammonia Vaporization	(123 kW @ $0.20/kWhr) (scaled)	$161,298	$351,538	$444,048
h. Pressure Drop (3" wc per NE)	W501D5 perf. data ($0.20/kWhr)	$590,026	$1,285,920	$1,624,320
i. Clean boiler tubes semi-annually for ammonium salts	MPW Estimate	$1,081,400	$1,081,400	$1,081,400
j. Boiler Pressure Drop (7" wc from ammonium salts)	W501D5 perf. data ($0.20/kWhr)	$1,393,465	[illegible]036,960	$3,836,160
Total Direct Operating Cost (TDOC)		$4,771,078	[illegible],037,073	$9,340,557
Indirect Operating Costs				
a. Overhead	((OL+ML+MM)*0.6)	$12,358	$26,933	$34,020
b. Property Tax	(TCC*0.01)	$153,380	$153,380	$153,380
c. Insurance	(TCC*0.01)	$153,380	$153,380	$153,380
d. Administration	(TCC*0.02)	$306,759	$306,759	$306,759
Total Indirect Operating Cost (TIOC)		$625,876	$640,451	$647,539
Direct Annual Costs		$4,771,078	$8,037,073	$9,340,557
Indirect Annual Costs		$3,125,966	$3,140,541	$3,147,628
Total Annual Cost (TAC)	(CR+TDOC+TIOC)	$7,897,044	$11,177,614	$12,488,185
Emissions Controlled				
Baseline NOx Emissions		631	978	978
Reduced NOx Emissions ((baseline - startup/shutdown) x 90% control efficiency)		359	425	879
Cost Effectiveness ($/ton NOx Reduced)		$22,008	$26,302	$14,208

Economic Comparison of Using Oxidation Catalyst to Control CO Emissions on Both Units				
Control CO by 90%				
Equipment Costs				
a. Supply and Install CO System			NE Estimate	$4,064,000
c. Taxes			(EC*0.05)	$203,200
Total Equipment Cost (TEC)				$4,267,200
Direct Installation Costs				
a. Includes: foundation, erection, piping, electrical, insulation			NE Estimate	$1,024,000
Total Direct Installation Cost (TDIC)				$1,024,000
Indirect Installation Costs				
a. Start Up, Performance Test, Contingencies			(0.1*TEC)	$426,720
b. Generation Loss from Construction (1 month)			(Avg $/MW, net)	$757,867
Total Indirect Installation Cost (TIIC)				$1,184,587
Total Capital Cost (TCC), Installed			(TEC+TDIC+TIIC)	$6,475,787
Capital Recovery Factor (CR) (10 yrs, 10%, factor = 0.163) * TCC				$1,055,553
Annual Operating Costs				
Direct Operating Costs				
a. Catalyst (Cost + Sales + tax freight, replaced 1/5 yrs, 10% int)			(75% equip cost + t&f)	$858,317
b. Pressure Drop (1" wc per NE)		(0.25% power drop/2" pressure drop)		$494,502
Total Direct Operating Cost (TDOC)				$1,352,819
Indirect Operating Costs				
a. Property Tax			(TCC*0.01)	$64,758
b. Insurance			(TCC*0.01)	$64,758
c. Administration			(TCC*0.02)	$129,516
Total Indirect Operating Cost (TIOC)				$259,031
Direct Annual Costs				$1,352,819
Indirect Annual Costs				$1,314,585
Total Annual Cost (TAC)			(CR+TDOC+TIOC)	$2,667,404
Emissions Controlled				
Baseline CO Emissions				315
Reduced CO Emissions				284
Cost Effectiveness ($/ton CO Reduced)				$9,409

Epsilon ASSOCIATES INC.

February 15, 2007

Mr. Donald Dahl
US EPA, Region 1
One Congress Street
Boston, MA 02114-2023

Subject: Application for Fuel Oil Flexibility
Information Request Responses
Bellingham Cogeneration Facility

PRINCIPALS

Theodore A Barten, PE

Margaret B Briggs

Michael E Guski, CCM

Samuel G Mygatt, LLB

Dale T Raczynski, PE

Cindy Schlessinger

Lester B Smith, Jr

Victoria H Fletcher, RLA

Robert D O'Neal, CCM

3 Clock Tower Place, Suite 250
Maynard, MA 01754
www.epsilonassociates.com

978 897 7100
FAX 978 897 0099

Dear Mr. Dahl:

This correspondence is in regards to the Bellingham Cogeneration Facility permit application dated May 31, 2006. We received your request for additional information in a letter dated January 26, 2007, also contained in Attachment 1. Provided below are our responses.

1. **Baseline Emission Calculations.** The facility has revised its baseline emission calculations by using a consecutive 24-month period representative of normal source operation. Instead of using calendar years 2001 and 2003, the revised baseline emission calculations use 2001 and 2002. Supporting data and calculations are presented in Attachment 2. Replacement pages to our application are provided in Attachment 3.

2. **PM-10 and VOC Compliance Monitoring.** The facility plans to monitor compliance with the proposed emission caps for PM-10 and VOC by multiplying default emission factors, in units of lb/MMBtu, by the measured heat input to the combustion turbines, in units of MMBtu. This is the same methodology used to calculate past actual emissions for purposes of establishing the proposed emission caps.

   The default emission factors (lb/MMBtu) used to determine past actual emissions were based on the results obtained from the initial compliance stack testing program. For PM-10, the test program followed USEPA Reference Method 5 (front half PM). Condensable PM was not tested. For VOC, the test program followed USEPA Reference Method 25A and reported results as total hydrocarbons (as carbon). The Facility will calculate future actual emissions using the same basis. That is, emission calculations will use front half (Method 5) stack test results for PM-10 and total hydrocarbon stack test results (Method 25A) for VOC.

   Furthermore, the Massachusetts Department of Environmental Protection (MassDEP) is requiring the facility to apply higher VOC emissions whenever CO is above its emission limit, which is measured by facility's Continuous Emissions Monitoring System (CEMS). This calculation will be as follows:

$VOC_{actual} = VOC_{limit} \times (CO_{actual} / CO_{limit})$. Bellingham will incorporate these requirements, Conditions IX.I and IX.J of the amended 310 CMR 7.02 Plan Approval, into its recordkeeping procedures.

Actual unit heat input (MMBtu/hr) is determined from measuring fuel flow to the combustion turbines and the fuel heat content. Fuel flow is measured using a natural gas billing meter and calibrated fuel oil meters. The heat content is obtained from the supplier for natural gas and from on-site tank sampling and/or by delivery for fuel oil.

3. **Emission Caps Averaging Time.** A 30-day rolling emissions cap is not feasible because the Bellingham Cogeneration Facility has substantial and unpredictable annual variation in production. The facility operates when dictated by market conditions, which can be quite variable from one year to the next.

If there are any questions, please contact me at 978-461-6234 or Pete Holzapfel, General Manager of the Bellingham Cogeneration Facility, at 508-966-4872. Thank you for your attention to this matter.

Sincerely,

Sean R. Gregory

Sean R. Gregory, P.E.
Epsilon Associates, Inc.

Cc: Thomas Cusson, MassDEP CERO
Bob Donaldson, MADEP Boston
Jim Colman, MADEP Boston
Timothy Oliver, FPL Energy
David Cleary, FPL Energy
Peter Holzapfel, FPL Energy
Sean Gregory, Epsilon Associates, Inc.
Bellingham Cogeneration Facility, file copy

Attachment 1

EPA Information Request Letter (dated 1/26/07)

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION 1
1 CONGRESS STREET, SUITE 1100
BOSTON, MASSACHUSETTS 02114-2023

January 26, 2007

Sean R. Gregory, PE
Senior Engineer
Epsilon Associates, Inc.
3 Clock Tower Place, Suite 250
Maynard, MA 01754

Dear Mr. Gregory:

Thank you for your application dated May 31, 2006, requesting revisions to the prevention of significant deterioration (PSD) permit issued to Northeast Energy Associates (NEA) on February 1, 1989 for the construction and operation of a cogeneration facility in Bellingham, Massachusetts. In brief, you are requesting two revisions to the PSD permit. First, you seek to remove the restriction in permit condition no. 5 of when oil can be used as a fuel. Second, you seek to increase the amount of hours oil can be fired from 720 hours facility-wide to 1440 hours for each of the two turbines.

To process your application, EPA is requesting the following additional information:

1. 40 CFR 52.21(b)(48) allows an existing emissions unit to use any consecutive 24 month period within 5 or 10 year period preceding actual construction (depending on whether the facility meets the definition of a steam electric generating unit at 40 CFR 52.21(b)(31)). According to the application, calendar years 2001 and 2003 were chosen for baseline emissions. However, these years are not consecutive. Please supply us with baseline emissions for a 24 consecutive month period. In addition, please demonstrate how these emissions were calculated, including any emission factors, fuel consumption, or stack test results that were used.

2. How does NEA plan to monitor compliance with the new emission caps for PM-10 and VOC?

3. Your application proposes to cap emissions on a 12 month rolling basis. Except under unusual circumstances, EPA policy[1] requires emission caps to be on a short-term basis, such as a rolling 30 day period. What is NEA's justification that a 30 day rolling average is not feasible for the emission caps?

If you have any questions please call me at (617) 918-1657.

Sincerely,

Donald F Dahl

Donald Dahl
Environmental Engineer

Cc: Thomas P. Cusson, MA DEP

[1]See Memorandum "Guidance on Limiting Potential to Emit in New Source Permitting" dated June 13, 1989, from Terrell Hunt and John Seitz to Addressees.

Attachment 2

Baseline Emissions Data and Calculations

Source of Data for Baseline Emissions

Pollutant	How Determined	Source
NO_x	CEMS	CEMS
CO	CEMS	CEMS
SO_2	0.0006 lb/MMBtu	Pipeline natural gas default
VOC	0.002 lb/MMBtu	Initial compliance stack test results
PM	0.0034 lb/MMBtu	Initial compliance stack test results

Heat Input Data

Year	Natural Gas Heat Input	Source
2001	22,034,249 MMBtu	Billing meter and monthly natural gas heat content (gross caloric value, GCV)
2002	21,882,430 MMBtu	

Sample Calculation

$$0.0006\frac{lbSO_2}{MMBtu}x22{,}034{,}249\frac{MMBtu}{year(2001)}x\frac{ton}{2000lb}=6.6tons$$

CEMS Data

Year	Natural Gas Heat Input	NOx CEMS	CO CEMS
2001	22,034,249 MMBtu	962.6 tons	252.7 tons*
2002	21,882,430 MMBtu	945.8 tons	179.3 tons

*The 133.4 tons of CO reported in the initial application was in error.

Attachment 3

Replacement Pages for Application

2.0 EMISSIONS SUMMARY

The Facility proposes to lower facility-wide emission limits. The proposed emission limits will prevent the Facility from exceeding the significant increase thresholds when comparing the facility's past actual emissions to the future potential emissions following the modification.

2.1 Past Actual to Future Potential Emissions

The Facility proposes to limit facility-wide emissions to representative past actual emissions plus an incremental increase less than the significant increase threshold for each pollutant on a 12-month rolling total basis. The resulting limits will all be less than the Facility's current potential to emit. The past actual emissions presented in this Section are based on operations in calendar years 2001 and 2002. These years are most representative of the Facility's normal source operation.

2.1.1 Nitrogen Oxides (NOx)

Emissions of NOx from both combustion turbines are measured in a common stack by the Facility's Continuous Emission Monitoring System (CEMS). The turbines' NOx emissions are reported quarterly in Electronic Data Reports (EDRs) submitted to the EPA. The average gas-fired NOx emissions total for calendar years 2001 and 2002 was 954 tpy. The significant increase threshold for NOx is 25 tpy. Therefore, the Facility will limit future potential NOx emissions from its existing limit of 1,017 tpy to 978 tpy, as summarized in Table 2-1.

2.1.2 Carbon Monoxide (CO)

Emissions of CO from both combustion turbines are measured in a common stack by the Facility's CEMS. The average CO emissions total for calendar years 2001 and 2002, as recorded by the CEMS, was 216 tpy. The significant increase threshold for CO is 100 tpy. Therefore, the Facility will limit future potential CO emissions from its existing limit of 822 tpy to 315 tpy, as summarized in Table 2-1.

2.1.3 Volatile Organic Compounds (VOC)

Past actual VOC emissions were determined by multiplying the actual gas-fired heat input (MMBtu), measured by billing meters and daily heat content samples, by an emission factor of 0.002 lb/MMBtu, representing the maximum 3-run average from the initial compliance stack testing. The average gas-fired VOC emissions total for calendar years 2001and 2002 was 22 tpy. The significant increase threshold for VOC is 25 tpy. Therefore, the Facility will limit future potential VOC emissions from its existing limit of 57 tpy to 46 tpy, as summarized in Table 2-1.

2.1.4 *Sulfur Dioxide (SO_2)*

Past actual SO_2 emissions were determined by multiplying the actual gas-fired heat input (MMBtu) by the 40 CFR 75 pipeline natural gas (PNG) default emission factor of 0.0006 lb/MMBtu. Natural gas being delivered by pipeline to the Facility has been demonstrated to meet the Part 75 definition of PNG. The average gas-fired SO_2 emissions total for calendar years 2001 and 2002 was 7 tpy. The significant increase threshold for SO_2 is 40 tpy. Therefore, the Facility will limit future potential SO_2 emissions from its existing limit of 206 tpy to 46 tpy, as summarized in Table 2-1.

2.1.5 *Particulate Matter (PM-10)*

Past actual PM-10 emissions were determined by multiplying the actual gas-fired heat input (MMBtu), measured by billing meters and daily heat content samples, by an emission factor of 0.0034 lb/MMBtu, representing an average from the initial compliance stack testing. The average gas-fired PM-10 emissions total for calendar years 2001 and 2002 was 37 tpy. The significant increase threshold for PM-10 is 15 tpy. Therefore, the Facility will limit future potential PM-10 emissions from its existing limit of 105 tpy to 51 tpy, as summarized in Table 2-1.

Table 2-1: Proposed Facility-Wide Emission Limits

Pollutant	2001 Emissions tpy	2002 Emissions tpy	Average Emissions tpy	<Sig. Increase Threshold tpy	Proposed Emission Caps tpy	Current Emission Caps tpy
NO_x	962.6	945.8	954	24	978	1017
CO	252.7	179.3	216	99	315	822
SO_2	6.6	6.6	7	39	46	206
VOC	22.0	21.9	22	24	46	57
PM	36.9	36.7	37	14	51	105

2.2 Summary of Current and Proposed Long-term Emission Limits

The Facility is proposing to reduce the facility-wide potential emissions for each pollutant based on the analysis presented in Section 2.1. The Facility also has long-term emission limits by fuel type. As a result of the lower facility-wide emission limits, the annual gas-fired and oil-fired CO emission limits (tpy) must decrease. The annual oil-fired SO_2

emission limit (tpy) will also decrease significantly. The Facility will offset the SO_2 limit decrease by switching to ULSD.

In order to operate on oil for up to 1,440 hours (per turbine), the oil-fired NOx annual limit must increase based on the Facility's short-term permit limit of 42 ppm@15%O_2 and the maximum rated oil heat input of the combustion turbines (i.e. 2,472 MMBtu/hr total). However, as already indicated, the facility-wide NOx potential to emit will decrease.

Based on initial compliance stack test data and the use of ULSD, the Facility will be capable of burning 1440 hours on oil (per turbine) while staying under the proposed annual emission limits. PM-10 will restrict hours of operation on gas if the full complement of 1440 hours of oil is used. (based on oil fired PM-10 stack test data from June 1992 (average of 0.023 lb/MMBtu). NOx and CO are expected to be less restrictive and will depend on the number of startups/shutdowns and the actual steady state emission rate on ULSD; these emissions will be measured by the CEMS. VOC and SO_2 will not restrict annual operation. The Facility will prepare monthly recordkeeping to ensure that the 12-month rolling emission limits are not exceeded.

Table 2-2 summarizes the current and proposed annual emission limits.

Table 2-2: Current and Proposed Long-term Emission Limits (tpy)

Pollutant	Facility-wide		Gas-Fired		Oil-Fired	
	Current	Proposed	Current	Proposed	Current	Proposed
NOx	1017	978	884	884	133	291 [2]
CO	822	315	531.5	315 [1]	291	315 [1]
VOC	57	46	44	44	13	13
PM	105	51	48	48	57	51 [1]
SO_2	206	46	16	16	190	46 [1]

[1] Fuel-specific potentials reduced so as not to exceed the proposed facility-wide permit limit.

[2] Potential to emit firing oil for 1440 hours. The equation is: 1.194E-7 (lb/dscf)/ppm x 9190 dscf/mmbtu x 42 ppm x 20.9 / (20.9 – 15) x 2472 mmbtu/hr x 1440 hours/year x ton/2000 lbs = 291 tons

3.0 BACT ANALYSIS

At the request of MADEP and EPA, the Facility performed a BACT analysis for NOx, CO, VOC, PM-10 and SO_2.

3.1 Initial BACT Determination

The first step in a "top-down" BACT analysis is to determine the most stringent control technology available for a similar or identical source or source category. Technically infeasible technologies are then eliminated and the remaining technologies are ranked by control efficiency. These technologies are evaluated based on economic, energy and environmental impacts. If an alternative, starting with the most stringent, is eliminated based on these criteria, the next most stringent technology is evaluated until BACT is selected.

A BACT analysis was performed during the initial permitting of the Facility in the late 1980's. Baseline emissions were based on five months of oil-firing (0.2%,wt sulfur) with the remainder of the year operating on natural gas. Table 3-1 summarizes the initial BACT determination.

Table 3-1: Initial BACT Determination

Pollutant	Units	Nat Gas	#2 Oil	Control Method
NOx	ppm	25	42	Steam injection
CO	lb/MMBtu	0.0516	0.3277	Combustion Controls and Low-emitting fuels
VOC	lb/MMBtu	0.0043	0.0151	Combustion Controls and Low-emitting fuels
PM	lb/MMBtu	0.0047	0.0647	Low-emitting fuels
SO_2	lb/MMBtu	0.0016	0.2136	Low-emitting fuels

The main differences between the initial BACT determination and the BACT analysis presented below are:

- Decrease in facility-wide potential emissions (tpy)
- Decrease in the allowable hours on oil (5 months to 2 months)
- Increased costs to retrofit add-on controls on existing units.

All three of these factors will increase the cost per ton of emissions removed. The BACT analysis presented below shows that the control methods identified in the initial permitting remain BACT, except for SO_2. ULSD may soon be commercially available and is expected to be a cost effective alternative to the current permit limit of 0.2%,wt sulfur fuel oil. ULSD is also expected to generate less NOx and particulate matter than the current fuel oil.

Therefore, the Facility has committed to burning ULSD in lieu of 0.2%,wt sulfur fuel oil in order to obtain increased fuel oil flexibility.

3.2 Oxides of Nitrogen

NOx is formed during the combustion process due to the reaction between nitrogen and oxygen in the combustion air at high temperatures ("thermal NOx") and the reaction of nitrogen bound in the fuel with oxygen ("fuel NO_x"). Steam injection is currently used to minimize NOx at the Facility to less than 25 ppm@15%O_2 on natural gas and 42 ppm@15%O_2 on fuel oil, the corresponding permit limits. An evaluation of BACT for NOx is presented below.

3.2.1 Selective Catalytic Reduction

SCR is an add-on pollution control technology that injects either anhydrous or aqueous ammonia into the flue gas over a vanadium pentoxide catalyst. The NOx within the flue gas combines with the ammonia to form water and nitrogen. The reaction has a relatively narrow flue gas temperature window; below approximately 650°F the reaction is too slow, while above about 850°F the catalytic efficiency declines. SCR is considered a technically feasible method of reducing NOx emissions from this type of emission source.

Baseline Emission Rates for Use in the BACT Analysis

Baseline emission rates are determined from the maximum annual potential to emit. For Bellingham, the maximum annual potential to emit is 978 tpy, as presented in Section 2.2. The BACT analysis also considers a more likely operating scenario in which the units are cycled to operate only during the peak periods of load demand each day, plus a time allotment for startup and shutdown. Two cycling scenarios were considered. The first scenario is based on a projected annual capacity factor, the "projected" case. The second cycling scenario assumes the units will cycle 360 days per year, the "maximum" case. Baseline emissions for the cycling scenarios are calculated from the maximum potential emissions associated with the reduced operating hours. An average SCR control efficiency of 90% was applied to baseline emissions, excluding startup and shutdown periods when the SCR is not operational.

Cost Effectiveness Evaluation

A budgetary quote to retrofit SCR systems on both units was obtained from the Original Equipment Manufacturer (OEM) of the HRSGs, Nooter Eriksen. Since the existing units were not designed with adequate space for SCR, the HRSG must be moved in order to install a spool for the catalyst and adequate distance between the catalyst and the ammonia injection grid (minimum 15 feet) for proper mixing.

The Nooter Eriksen quote includes engineering, installation and total equipment costs (e.g. catalyst, spool, ammonia storage and delivery). Due to the shift in HRSG locations, the current access road would have to be re-routed to the other side of the plant stack and connected to the turbine hall access doors via two long driveways. The total capital cost also includes indirect installation costs such as engineering costs incurred by NEA, startup and performance testing costs and the net monetary losses from being down during construction. The total installed capital cost was annualized over 10 years at 10% interest.

Annual operating costs include aqueous ammonia supply and vaporization. The SCR system will also require additional operating and maintenance labor. The minimum catalyst guarantee is three years, and so replacement costs were annualized over this period at 10% interest. The catalyst life was extended to five years for the projected cycling operating scenario. An estimated catalyst pressure drop of three inches and a buildup of ammonium salts on the boiler tubes will decrease the power generated from each combustion turbine. A similar facility experiences an additional pressure drop from the buildup between four and eight inches of water column. This facility must routinely CO_2 blast and water wash the boiler tubes to remove the ammonium salts. The buildup will also decrease the heat transfer in the economizer and evaporator sections of the boiler which will decrease the power generated from the steam turbine, though this cost was not accounted for in the calculations.

The annualized costs to retrofit both units are summarized in Table 3-2. Supporting calculations are presented in Attachment B.

Table 3-2 SCR Cost Effectiveness for NOx

Operating Scenario	Cycling (projected)	Cycling (max)	Base-Loaded
Operating Hours per Year	3,138	6,840	8,640
Control System Life (yrs)	10	10	10
Annualized Capital Cost ($/yr)	$2,500,090	$2,500,090	$2,500,090
Direct Annual Cost ($/yr)	$4,771,078	$8,037,073	$9,340,557
Indirect Annual Cost ($/yr)	$625,876	$640,451	$647,539
Total Annual Cost ($/yr)	$7,897,044	$11,177,614	$12,488,185
NOx removed (tpy)	359	425	879
Cost Effectiveness ($/ton)	$22,008	$26,302	$14,208

(1) Cycling the units is anticipated to be the primary operating scenario.
(2) "Cycling (projected)" operating hours is based on a projected capacity factor.
(3) "Cycling (max.)" operating hours assumes the units cycle 360 days per year.
(4) The Facility does not expect to operate as a base-loaded facility, though retains the ability.
(5) "Base-loaded" operating hours assumes the units operate 360 days per year.

Cost Effectiveness Evaluation for Oxidation Catalyst

A budgetary quote to retrofit oxidation catalyst on both units was also obtained from Nooter Eriksen. Although the HRSG would have to be moved in order to install an SCR, if only an oxidation catalyst were installed, it could be installed within existing space, saving a significant amount of construction cost.

The Nooter Eriksen quote includes engineering, installation and total equipment costs (e.g. catalyst). The total installed capital cost was annualized over 10 years at 10% interest. The catalyst was assumed to be replaced every five years based on the expected guarantee provided by Nooter Eriksen. An estimated catalyst pressure drop of one inch will decrease the power generated from each combustion turbine.

The annualized costs to retrofit both units are summarized in Table 3-3. Supporting calculations are presented in Attachment B.

Table 3-3 Oxidation Catalyst Cost Effectiveness for CO – Both Units

Control System Life	10
Annualized Capital Cost ($/yr)	$1,055,553
Direct Annual Cost ($/yr)	$1,352,819
Indirect Annual Cost ($/yr)	$259,031
Total Annual Cost ($/yr)	$2,667,404
CO removed (tpy)	284
Overall Cost Effectiveness ($/ton)	$9,409

Due to the significant costs associated with retrofitting the existing combined cycle combustion turbines, it will not be cost effective (using DEP's criteria for cost effectiveness in $/ton of CO removed) to install oxidation catalyst.

3.3.2 Combustion Controls

The units are already using combustion controls (*e.g.*, proper tuning and operating at design loads) as BACT for CO. These controls provide for the most efficient combustion as possible generating minimal additional CO emissions. Combustion controls are considered BACT for CO.

3.4 Volatile Organic Compounds

VOC emissions are formed during the incomplete combustion of any fuel in the combustion process. Combustion controls are currently used to minimize VOC at the Facility to 0.0043 lb/MMBtu on natural gas and 0.0151 lb/MMBtu on fuel oil, the corresponding permit limits. An evaluation of BACT for VOC is presented below.

3.4.1 Oxidation Catalyst

The top level of VOC control that can be achieved is with an oxidation catalyst. The flue gas exhaust from the turbine would pass through a honeycomb catalyst, as described in Section 3.3, where the VOC would react with oxygen to form carbon dioxide and water. This type of emission control technology is considered a technically feasible method of reducing VOC emissions from this type of emission source.

Baseline Emission Rate for Use in the BACT Analysis

Baseline emissions used to determine how many tons of VOC an oxidation catalyst would control are based on the proposed long-term emission limit of 46 tpy, as presented in Section 2.2. VOC emissions using an oxidation catalyst would be reduced by approximately 46%, or by 21 tpy.

Cost Effectiveness for an Oxidation Catalyst

This cost analysis uses identical cost assumptions as described in the CO BACT analysis. The total cost effectiveness of controlling CO and VOC was also evaluated. The annualized costs to retrofit both units are summarized in Table 3-3. Supporting calculations are presented in Attachment B.

Table 3-4 Oxidation Catalyst Cost Effectiveness for VOC

Control System Life	10
Annualized Capital Cost ($/yr)	$1,055,553
Direct Annual Cost ($/yr)	$1,352,819
Indirect Annual Cost ($/yr)	$259,031
Total Annual Cost ($/yr)	$2,667,404
VOC removed (tpy)	21
Cost Effectiveness ($/ton)	$125,349
VOC + CO removed (tpy)	305
Cost Effectiveness ($/ton), VOC+CO	$8,752

Due to the significant costs associated with retrofitting the existing combined cycle combustion turbines, it will not be cost effective (using DEP's criteria for cost effectiveness in $/ton of VOC removed) to install oxidation catalyst. It is even not cost effective ($/ton) when combining the tons of CO and VOC removed by an oxidation catalyst.

3.4.2 Combustion Controls

The units are already using combustion controls (*e.g.*, proper tuning and operating at design loads) as BACT for VOC. These controls provide for the most efficient combustion as

Economic Comparison of Using SCR to Control NOx Emissions on Both Units					
Control NOx from 42 ppm to 6 ppm on oil and from 25 ppm to 2 ppm on gas					
Operating Scenario:			Cycling (projected)	Cycling (max.)	Base-Loaded
Operating Hours Per Year			3,138	6,840	8,640
Notes:					
	(1) Cycling the units is anticipated to be the primary operating scenario.				
	(2) "Cycling (projected)" operating hours is based on a projected capacity factor.				
	(3) "Cycling (max.)" operating hours assumes the units cycle 360 days per year.				
	(4) The Facility does not expect to operate as a base-loaded facility, though retains the ability.				
	(5) "Base-loaded" operating hours assumes the units operate 360 days per year.				
Equipment Costs					
a.	SCR Systems (catalyst, tank, skids)	NE Estimate	$6,500,000	$6,500,000	$6,500,000
b.	SCR Spools	NE Estimate	$600,000	$600,000	$600,000
c.	Taxes	(EC*0.05)	$355,000	$355,000	$355,000
Total Equipment Cost (TEC)			$7,455,000	$7,455,000	$7,455,000
Direct Installation Costs					
a.	Shorten Ducting for new SCR Spools	NE Estimate	$200,000	$200,000	$200,000
b.	Install New Foundation and Move HRSGs	NE Estimate	$1,800,000	$1,800,000	$1,800,000
c.	Install SCR Spools	NE Estimate	$600,000	$600,000	$600,000
d.	Install SCR catalyst, truck unload, tank, skids	NE Estimate	$2,100,000	$2,100,000	$2,100,000
e.	Install New Access Roads to turbine hall	FPL Estimate	$300,000	$300,000	$300,000
f.	Install Ammonia CEMS	FPL Estimate	$100,000	$100,000	$100,000
Total Direct Installation Cost (TDIC)			$5,100,000	$5,100,000	$5,100,000
Indirect Installation Costs					
a.	FPL Engineering, Start Up, Performance Test, Contingencies	(0.25*TEC)	$1,863,750	$1,863,750	$1,863,750
b.	Generation Loss from Construction (4 months)	(Cap.Factor x Avg $/MW, net)	$919,222	$919,222	$919,222
Total Indirect Installation Cost (TIIC)			$2,782,972	$2,782,972	$2,782,972
Total Capital Cost (TCC), Installed		(TEC+TDIC+TIIC)	$15,337,972	$15,337,972	$15,337,972
Capital Recovery Factor (CR) (10 yrs, 10%, factor = 0.163) * TCC			$2,500,090	$2,500,090	$2,500,090
Annual Operating Costs (Cycling - 6,840 hours per year)					
Direct Operating Costs					
a.	Operating Labor (OL)	(1/2 hr/8 hr shift operating)($35/hr)	$6,865	$14,963	$18,900
b.	Supervisor	(OL*0.15)	$1,030	$2,244	$2,835
c.	Maintenance Labor (ML)	(1/2 hr/8 hr shift operating)($35/hr)	$6,865	$14,963	$18,900
d.	Maintenance Materials (MM)	(ML = MM)	$6,865	$14,963	$18,900
e.	Catalyst (Cost + Sales + tax freight, replaced 1/3 yrs, 10% int)	(75% equip cost + t&f)	$1,445,600	$2,090,400	$2,090,400
f.	SCR Supply (tons NH3, 19% soln @ $0.051/lb)	Borden & Remington estimate	$77,664	$143,723	$204,695
g.	SCR Ammonia Vaporization	(123 kW @ $0.20/kWhr) (scaled)	$161,298	$351,538	$444,048
h.	Pressure Drop (3" wc per NE)	W501D5 perf. data ($0.20/kWhr)	$590,026	$1,285,920	$1,624,320
i.	Clean boiler tubes semi-annually for ammonium salts	MPW Estimate	$1,081,400	$1,081,400	$1,081,400
j.	Boiler Pressure Drop (7" wc from ammonium salts)	W501D5 perf. data ($0.20/kWhr)	$1,393,465	$3,036,960	$3,836,160
Total Direct Operating Cost (TDOC)			$4,771,078	$8,037,073	$9,340,557
Indirect Operating Costs					
a.	Overhead	((OL+ML+MM)*0.6)	$12,358	$26,933	$34,020
b.	Property Tax	(TCC*0.01)	$153,380	$153,380	$153,380
c.	Insurance	(TCC*0.01)	$153,380	$153,380	$153,380
d.	Administration	(TCC*0.02)	$306,759	$306,759	$306,759
Total Indirect Operating Cost (TIOC)			$625,876	$640,451	$647,539
Direct Annual Costs			$4,771,078	$8,037,073	$9,340,557
Indirect Annual Costs			$3,125,966	$3,140,541	$3,147,628
Total Annual Cost (TAC)		(CR+TDOC+TIOC)	$7,897,044	$11,177,614	$12,488,185
Emissions Controlled					
Baseline NOx Emissions			631	978	978
Reduced NOx Emissions ((baseline - startup/shutdown) x 90% control efficiency)			359	425	879
Cost Effectiveness ($/ton NOx Reduced)			$22,008	$26,302	$14,208

Economic Comparison of Using Oxidation Catalyst to Control CO Emissions on Both Units				
Control CO by 90%				
Equipment Costs				
a. Supply and Install CO System			NE Estimate	$4,064,000
c. Taxes			(EC*0.05)	$203,200
Total Equipment Cost (TEC)				$4,267,200
Direct Installation Costs				
a. Includes: foundation, erection, piping, electrical, insulation			NE Estimate	$1,024,000
Total Direct Installation Cost (TDIC)				$1,024,000
Indirect Installation Costs				
a. Start Up, Performance Test, Contingencies			(0.1*TEC)	$426,720
b. Generation Loss from Construction (1 month)			(Avg $/MW, net)	$757,867
Total Indirect Installation Cost (TIIC)				$1,184,587
Total Capital Cost (TCC), Installed			(TEC+TDIC+TIIC)	$6,475,787
Capital Recovery Factor (CR) (10 yrs, 10%, factor = 0.163) * TCC				$1,055,553
Annual Operating Costs				
Direct Operating Costs				
a. Catalyst (Cost + Sales + tax freight, replaced 1/5 yrs, 10% int)			(75% equip cost + t&f)	$858,317
b. Pressure Drop (1" wc per NE)		(0.25% power drop/2" pressure drop)		$494,502
Total Direct Operating Cost (TDOC)				$1,352,819
Indirect Operating Costs				
a. Property Tax			(TCC*0.01)	$64,758
b. Insurance			(TCC*0.01)	$64,758
c. Administration			(TCC*0.02)	$129,516
Total Indirect Operating Cost (TIOC)				$259,031
Direct Annual Costs				$1,352,819
Indirect Annual Costs				$1,314,585
Total Annual Cost (TAC)			(CR+TDOC+TIOC)	$2,667,404
Emissions Controlled				
Baseline CO Emissions				315
Reduced CO Emissions				284
Cost Effectiveness ($/ton CO Reduced)				$9,409

Epsilon
ASSOCIATES INC.

March 19, 2007

Mr. Donald Dahl
US EPA, Region 1
One Congress Street
Boston, MA 02114-2023

Subject: Application for Fuel Oil Flexibility
PSD Applicability Procedures
Bellingham Cogeneration Facility

PRINCIPALS
Theodore A Barten, PE
Margaret B Briggs
Michael E Guski, CCM
Samuel G Mygatt, LLB
Dale T Raczynski, PE
Cindy Schlessinger
Lester B Smith, Jr
Victoria H Fletcher, RLA
Robert D O'Neal, CCM

3 Clock Tower Place, Suite 250
Maynard, MA 01754
www.epsilonassociates.com
978 897 7100
FAX 978 897 0099

Dear Mr. Dahl:

This correspondence is in regards to the Bellingham Cogeneration Facility permit application dated May 31, 2006 and our phone conversation on March 13, 2007. The purpose of this letter is to document that the intent of our application with respect to the PSD permit is to apply the actual-to-projected-actual applicability procedures of 40 CFR 52.21(a)(2)(iv)(c) to demonstrate that the change is not projected to result in a significant emissions increase of a regulated NSR pollutant.

We acknowledge that the facility will need to calculate and maintain a record of the annual emissions, in tons per year on a calendar year basis, in order to demonstrate that the project will not contribute to a significant emissions increase. It is our interpretation that since the project will neither increase the design capacity nor the potential to emit of the emission units, this recordkeeping, for purposes of 40 CFR 52.21(r)(6)(iii), applies only for a period of five years following approval of the amended PSD permit.

Please feel free to contact me at 978-461-6234 or Pete Holzapfel, General Manager of the Bellingham Cogeneration Facility, at 508-966-4872. Thank you for your attention to this matter.

Sincerely,

Sean R. Gregory, P.E.
Epsilon Associates, Inc.

Cc: Thomas Cusson, MassDEP CERO
Bob Donaldson, MADEP Boston
Jim Colman, MADEP Boston
Timothy Oliver, FPL Energy
David Cleary, FPL Energy
Peter Holzapfel, FPL Energy
Sean Gregory, Epsilon Associates, Inc.
Bellingham Cogeneration Facility, file copy