Northeast Gateway Energy Bridge™ Deepwater Port Project

Northeast Gateway Energy Bridge, L.L.C.

Application for Minor Source Air Permit Modification

Submitted by:

Northeast Gateway Energy Bridge, L.L.C.
1330 Lake Robbins Drive, Suite 270
The Woodlands, TX 77380

Prepared by:

Tetra Tech EC, Inc.
133 Federal Street, 6th Floor
Boston, MA 02110

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SECTION 1 INTRODUCTION

On May 14, 2007, the U.S. Environmental Protection Agency (EPA) Region 1, issued the Clean Air Act (CAA) Permit RG1-DPA-CAA-01 ("Permit") for the construction and operation of the Northeast Gateway Energy Bridge™ Deepwater Port (Northeast Gateway Port or simply Northeast Gateway) to deliver an incremental supply of natural gas into the New England region. The Northeast Gateway Port is designed to deliver the natural gas at an average annual baseload sendout rate of approximately 400 million cubic feet per day (MMcfd, or 11 million cubic meters) with a peak sendout rate of 800 MMcfd (22 million cubic meters). The facility obtained all necessary permits and approvals, including the Permit and has since been constructed. The Port itself consists of two Submerged Turret Loading™ (STL™) buoys located in federal waters (approximately 13 miles off the coast of Gloucester and 22 miles northeast of Boston), a flexible riser, and separate flow lines that are connected to shore by a subsea pipeline. These components make up the entirety of the Port and are not sources of air emissions. Purpose built LNG regasification vessels (LNGRVs) are used to transport LNG to the Port. In order to deliver natural gas into the downstream subsea pipeline and subsequently into the New England energy market, the LNG must be transferred as gaseous natural gas. High pressure vaporizer systems located on board the LNGRVs regasify the LNG. EPA has made the determination that the activity of delivering the natural gas into the pipeline is an industrial process and therefore emissions generated by the vessels are the only source of emissions at the Northeast Gateway Port. At the time of submittal of the original application, the only existing LNGRVs were owned and operated by Excelerate Energy. In May 2008, the first delivery of natural gas was made to the Port by Excelerate Energy's LNGRV *Excellence*. At the completion of this initial delivery, we performed a comprehensive review of operational activities with respect to the Permit requirements, and determined that some minor modifications would be needed, which are described below. This report and its appendices comprise an application to modify the Permit to address these issues and also accommodate Excelerate Energy's next generation LNGRVs.

1.1 Regulatory/Permit Background

This permit modification request should be evaluated in light of the unusual regulatory and permitting context concerning the Northeast Gateway Port. First, there is ambiguity under the federal Deepwater Port Act (DWPA or Act) as to whether vessels are part of the Port and thus subject to federal and state air permitting requirements. Without detailing all the relevant provisions of the DWPA or its legislative history, the basic point is that the Act expressly excludes "vessels" from the definition of "deepwater port." *See* 33 U.S.C. 81502(9). Moreover, the DWPA defines "vessel" broadly as "every description of watercraft or other artificial contrivance used as a means of transportation on or through water." *Id.* § 1502(19). We understand that EPA takes the position that while vessels are moored at the Port and regasifying LNG, they become, temporarily, a manmade floating structure that is part of the Port for purposes of the DWPA. *See, e.g.,* EPA's Statement of Basis for Proposed Clean Air Permit, Northeast Gateway Energy Bridge L.L.C. at 8-9 (2007). These same vessels are used at Excelerate Energy's Gulf Gateway Deepwater Port and subject to a CAA Permit issued for that facility by EPA Region 6 without emission controls, and the Best Available Control Technology (BACT) has been determined to be the burning of only natural gas while at the Port. The issuance of that permit demonstrated EPA's willingness to exercise regulatory flexibility when applying stationary source permitting requirements to vessels. Despite this jurisdictional ambiguity, Northeast Gateway will continue to cooperate with EPA to develop a workable air permit for the Port.

Second, the Permit includes LNGRV emissions while at Port that are associated with normal seagoing activities and not industrial activities associated with the Port so-called “hoteling” emissions. In evaluating the air emissions from the Gulf Gateway Deepwater Port, EPA Region 6 specified why these hoteling emissions should not be considered in the permit:

> *The ‘to and fro’ emissions and ‘hoteling’ emissions from the vessels are associated with the normal seagoing activities of the vessels and not with the industrial activities associated with the Port. We thus intend to consider only the emissions from the activities in support of the Port’s function – i.e., those related to processing and transferring gas at the Port, regardless of whether they occur on the metering platform or on marine vessels propelled by external combustion engines, as stationary sources of emissions of the Port for CAA Title I and Title V purposes.*[1]

Although Northeast Gateway is not seeking to expressly exempt the hoteling emissions from the modified permit, we do ask EPA to recognize that some of the monitoring required by the Permit might include hoteling emissions, thereby overstating the regulated emissions.

Third, the Permit was written to address emissions specifically from the first and second generations of LNGRVs owned by Northeast Gateway L.L.C. (*see, e.g.,* Permit, page 1). Excelerate Energy requested during early consultations with the EPA that emission limits be placed on the physical Port facility (a type of “bubble concept” over the Port), and not on the specifics of each transport vessel calling on the Port. EPA did not accept the Excelerate Energy proposal and consequently the Permit expressly requires a permit modification or new permit before any other LNGRV with a different equipment configuration before it may use the Port. (*Id* pp. 1-2).

And finally, while Northeast Gateway is not seeking authorization to have LNGRV vessels owned by others[2] to use the Port at this time, we anticipate doing so within the next 5 to 10 years. Thus, to the extent that the modified Permit focuses on general limitations that apply to a range of LNGRV technologies and minimizes the number of equipment specific limitations and requirements, it will enhance the adaptability of the permit to future LNGRVs. This, in turn, will help ensure that the Port is fully utilized in the future.

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[1] Charles J. Sheehan (EPA Region 6 Counsel), letter to Mr. Michael Cathey (El Paso Energy Bridge Gulf of Mexico, L.L.C.) and Diana Dutton (Akin, Gump, Strauss, Hauer & Feld. L.L.P.), October 28, 2003 (available online at http://www.epa.gov/region07/programs/artd/air/nsr/nsrmemos/20031028.pdf).

[2] At least three companies are building or planning LNGRV vessels with the capacity to use the NEG Port: Suez, LNG NA; Woodside Petroleum, Ltd; and Höegh, LNG.

1.2 Proposed Permit Modifications

The primary purpose of this application for a permit modification is to address two issues associated with equipment on newer vessels and one issue associated with the operation of all of the vessels, as described below. In addition, we are requesting that permit conditions that apply prior to regasification or prior to initial startup be corrected, as described in Section 1.2.4.

1.2.1 Activity Monitoring for Auxiliary Generators on Second- and Third-Generation Vessels

All but one of Excelerate Energy's existing LNGRVs has been retrofitted with the necessary emission control equipment required to call on the Northeast Gateway Port. For the purpose of discussion in this application, we will refer only to the retrofitted vessels. Each of these vessels is equipped with an auxiliary engine which can be used for regasification purposes: each first-generation vessel is equipped with a 3,840 kilowatt (kW) diesel auxiliary engine (referred to as GE1 in the Permit) and each second-generation (and third-generation) vessel is equipped with a 4,018 kW (nominal) dual-fueled diesel electric engine (GE2) driving a 3,800 kW (nominal) alternator. The current permit includes a requirement that in any rolling 12-month period, the usage of all auxiliary engines on all vessels during regasification at the Port cannot exceed 370 hours. Section VI.B of the permit also requires that on each second-generation vessel, the GE2 engine must have non-resettable totalizing flow meters to measure the volume of natural gas used, non-resettable fuel meters to measure the amount of diesel used, non-resettable elapsed operating hour meters to accurately indicate the elapsed operating time, and meters to measure and record the kilowatt-hours (kW-hr) produced. Because these vessels operate in various parts of the world market besides at Northeast Gateway Port and could have to use the auxiliary engines, the non-resettable totalizing flow meters would also collect those hours of operation. When the vessel returned to the Northeast Gateway Port, the total hours registered on the meters would not be accurate for compliance purposes. As one solution, the engine vendor has been able to provide fuel consumption rates as a function of kW-hr produced, the second-generation vessels are only equipped with non-resettable elapsed operating hour meters and kW-hr meters, and fuel usage is calculated based on vendor data, as will be described in more detail in Section 2 of this application. **Northeast Gateway is therefore proposing that this generator monitoring requirements in Section VI.B be changed to reflect this fact.**

1.2.2 Auxiliary Boilers on Third-Generation Vessels

The two second-generation vessels, *Explorer* and *Express*, are equipped with auxiliary boilers (Aux1) rated at 100 million British thermal units per hour (MMBtu/hr) (providing up to 30 metric tonnes/hour of steam). The auxiliary boilers are capable of firing oil or gas, but are restricted to firing only gas while at the Northeast Gateway Port, and also have emissions controlled with Selective Catalytic Reduction (SCR) systems that reduce nitrogen oxides(NO_x) emissions to no more than 15 parts per million, volumetric dry basis corrected to 3% oxygen (O_2) (15 ppmvd @ 3% O_2).

Excelerate Energy's new third-generation vessels are essentially identical to the second-generation vessels, except that they are equipped with auxiliary boilers rated at 157 MMBtu/hr (providing up to

50 metric tonnes/hr of steam). Like the auxiliary boilers on the second-generation vessels, the auxiliary boilers are capable of firing oil or gas but will be restricted to firing only gas while at the Northeast Gateway Port, and will also have emissions controlled with SCR systems that reduce NO_x emissions to no more than 15 ppmvd @ 3% O_2. **Northeast Gateway is therefore proposing that the permit be revised to include these 50 tonne/hr boilers (as emission units "Aux2"), as described in more detail in Section 3 of this application, and require any auxiliary boiler installed on future Excelerate Energy vessels to have its emissions controlled with an SCR system and reduce NO_x emissions to no more than 15 ppmvd @ 3% O_2.** Although maximum hourly emissions from the 50 tonne/hr boilers are higher than those of the 30 tonne/hr boilers, Northeast Gateway is not proposing to change its current 12-month rolling-average facilitywide emissions caps of 49 tons/year NO_x and 99 tons/year carbon monoxide (CO).

1.2.3 Oil Burning in Main Boilers for Purposes of Lighting Gas Burners

Each LNGRV is equipped with two main boilers that are used for purposes of vessel propulsion, regasification, and hoteling, and are designed to operate in a gas-only mode, oil-only mode, or in a combination mode. For purposes of operating at the Northeast Gateway Port, the current permit requires LNGRVs to regasify their cargos while operating in a gas-only mode. Each boiler on the LNGRV is equipped with three burners to heat the vessel boilers. When the vessel arrives at the Northeast Gateway Port, prior to retrieval of the STL buoys, they are typically operating only two of the three burners while in the vicinity of the Port. While operating in the gas-only mode, boiler loads fluctuate with steam demand and the on-board burner management system for the vessel decides whether and when the boilers fire on two burners or three. When the boiler is operating on two burners and the burner management system calls for the third burner to be lit, the boilers momentarily switch to a dual-fuel mode and a small quantity of oil is used to ignite the gas in the third burner. The use of oil to light the gas-fired burner is required by both U.S. Coast Guard (USCG) regulations (46 CFR 154) and the International Code for the Construction and Equipment of Ships Carrying Liquefied Gases in Bulk (IGC Code). One interim solution contemplated by Northeast Gateway to eliminate the need to light additional burners and having to use oil during the regasification process was to operate the vessel with all three burners lit for the duration of the regasification activities. However, in order to comply with the NPDES permit, the LNGRV is required to reduce the amount of water utilized on the vessel while in regasification mode. To do this, Excelerate Energy developed and installed a Heat Recovery System (HRS) which allows the vessel to reduce their daily water intake and discharge amounts by about 95% over other similar vessels. It is not technically feasible for LNGRVs keep all three burners continuously lit, especially while the HRS is in use to comply with the EPA's NPDES permit. During these short events, a very limited quantity of oil will need to be burned for purposes of lighting of the third burner, whereas the current permit only addresses emissions from burning gas. **Northeast Gateway is proposing that the permit be modified to allow for a limited amount of oil burning for purposes of lighting the gas burners, as is discussed in more detail in Section 4.**

1.2.4 Permit Conditions Prior to Regasification or Initial Startup

Several permit conditions were added to Northeast Gateway's permit shortly before signing that were not part of the permit application and are not technically feasible. They do not have any regulatory basis, and we are hereby asking that these conditions be removed.

The first conditions that we are asking to be removed are those in Condition VIII.D that are identified as applying when any EBRV or LNGRV is moored at the facility and not regasifying. On pages 7-8 of EPA's responses to comments on the draft permit for this facility, EPA stated that:

> NEG LLC has stated that there will be periods when its vessel[s] is moored at the port but not regasifying. All emissions during these periods are unrelated to the regasification process; therefore, EPA will revise the permit and exclude emissions during these periods from the permit conditions designed to limit NEG's potential emissions as a stationary source....[However,] NEG LLC has indicated that its hoteling emissions that are no longer capped by this permit will not need to be addressed in a conformity determination because those emissions are well under the de minimis levels below which general conformity requirements do not apply and any additional hoteling emissions allowed outside the limits of the permit's emissions cap will be very low, about 0.45 TPY of NOx. As a result, there is no need to revisit the conformity determination on which EPA is relying to issue this permit. This emissions estimate assumes that NEG LLC will be operating its SCR control equipment while the vessel is moored to NEG, even when not regasifying. To preserve the integrity of the conformity determination, EPA has added a condition to this permit to require operation of the SCR controls whenever a vessel is moored to NEG, whether or not it is engaged in regasification.[3]

As noted in the USCG/MARAD Final General Conformity Determination,[4] the conformity threshold for NO_x is 100 tons per year (TPY) and the facility's total operational emissions subject to General Conformity requirements are only 58.8 TPY; we are nowhere close to the threshold. Of that 58.8 TPY, boiler emissions from each EBRV trip were calculated by summing emissions associated with 5 hours of travel within the Safety Zone operating on oil only (at a rate of 75 MMBtu/hr = 500 gal/hr ≈ 1,900 kg/hr) and 3 hours of maneuvering within the Safety Zone operating on oil only (at a rate of 30 MMBtu/hr = 200 gal/hr ≈ 744 kg/hr), with no SCR in use: i.e., emission factors shown in the General Conformity Determination reflected uncontrolled oil combustion, with NO_x emissions of 55.8 lb/1,000 gal ≈ 0.37 lb/MMBtu). Although emissions during regasification were identified as being controlled by SCR, no assumptions were made regarding the use of SCR prior to regasification. Therefore, the requirements of Condition VIII.D.i. through viii. have no basis in the conformity determination.

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[3] EPA Region 1, "Northeast Gateway Energy Bridge, LLC – Draft Air Permit RG1-DPA-CAA-01, Response to Comments," 2007.

[4] USCG/MARAD, "Final General Conformity Determination – Northeast Gateway Deepwater Port," March 26, 2007.

In addition, it is not technically feasible for us to comply with these requirements. International and USCG safety requirements require that at all times prior to mooring we fire at least some oil in the burners (we actually operate in a cleaner, dual-fuel mode prior to mooring—i.e., combined firing of boil-off gas and oil, not just oil). After mooring, we switch to firing gas, but our SCR vendor requires that the SCR catalyst must be regenerated for approximately two hours prior to the injection of urea (and this regeneration cannot be initiated prior to gas-only operation). We therefore cannot comply with the permit requirements that are equivalent to requiring that the SCR system be up and running (i.e., with urea flow) prior to regasification.

Separately, there is a question of the significance of the definition of "initial startup." On page 15 of EPA's responses to comments on the draft permit for this facility, EPA wrote that:

> NEG LLC asked EPA to define the term "initial startup" in Section IV of the draft permit to clarify that the permit does not apply to an LNG vessel until the vessel has gone through one full regasification event at the port. NEG argues that each vessel requires one full regasification event at the port to check equipment and to ensure that all vessel operations are working according to specifications....EPA agrees with NEG LLC's request and will revise the term "initial startup." This period of operation is essentially similar to shake-down periods of operation typically provided in NSR permits for land-based facilities."[3]

However, since this time, EPA staff have incorrectly interpreted the permit language as also applying to activities prior to initial startup.[5] We are therefore asking that EPA clarify the permit language to reflect EPA's statements in their 2007 responses to comments on the permit. In particular, we are asking for clarification that compliance testing for stack emissions is not required prior to each vessel's <u>second</u> full regasification.

1.3 Structure of Application

Sections 2 through 4 of this application provide a more detailed description of the three primary permit modifications summarized above, including their impacts on air emissions and regulatory applicability, and related aspects of monitoring and recordkeeping. The requested changes to permit conditions prior to regasification and initial startup have no impact on permit-related air emissions, regulatory applicability, or monitoring and recordkeeping. Section 5 identifies the total port emissions and any new facilitywide regulatory applicability; Section 6 identifies the BACT for the larger auxiliary boilers and oil firing in the boilers; and Section 7 provides the revised air quality impact assessment. Appendix A contains permit application forms (Northeast Gateway has selected the Massachusetts Department of Environmental Protection (MassDEP) Plan Approval application forms); Appendix B contains vendor specification and design data; Appendix C provides emissions calculations; and Appendix D contains dispersion modeling input and output files.

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[5] T. Olivier (EPA Region 1 Senior Enforcement Counsel), electronic mail message to W.L. Lahey (Anderson & Kreiger LLP), October 7, 2008.

SECTION 2 DUAL-FUEL GENERATOR MONITORING CHANGES

2.1 Description

Generator activity is required to be tracked for purposes of calculating actual emissions and ensuring that the annual emissions from the Port do not exceed the annual caps identified in the Permit. *Excellence* and *Excelerate* were constructed prior to issuance of the Permit, and the diesel generator on each first-generation vessel is equipped with the monitoring equipment identified in Sections VI.B.3 and VI.B.4 of the Permit: i.e., a non-resettable fuel consumption meter, a non-resettable elapsed operating hour meter, and a meter to measure and record kW-hr. (With respect to the term “non-resettable,” Excelerate’s meters are electronically totalized. While it is technically possible for a technician to reset the meters, the crew does not have the ability to do this.)

Explorer was under construction at the time the Permit was finalized and was delivered in March 2008; its dual-fuel diesel electric generator is equipped with an elapsed operating hour meter and a kW-hr meter, but fuel usage (oil and gas) is calculated based on data provided by the generator vendor in conjunction with the kW-hr meter.

2.2 Emissions Impacts

There are no emissions impacts associated with calculating fuel usage based on the power meter.

2.3 Regulatory Applicability

Although EPA is required to have some type of emissions tracking mechanism to ensure that the facility stays below its annual emissions caps of 49 tons/year NO_x and 99 tons/yr CO, there are no applicable federal or Massachusetts regulations which specify that the generator fuel usage be monitored directly. Calculating fuel usage based on kW-hr does not trigger any additional regulatory applicability.

2.4 Monitoring

The kW-hr meters installed for the dual-fuel generator on second-generation vessels transmit data to each vessel’s Integrated Automation System. Total kW-hr is recorded for each clock-hour; for example, if an engine operates at 3,000 kW between 0530 and 0600, a total of 1,500 kW-hr is recorded for the 0500-0600 hour. A signal is passed from the engine to the Integrated Automation System to identify whether the dual-fueled engine is operating in dual-fuel mode (99% gas) or diesel-only mode. Northeast Gateway has committed to always using these engines in dual-fuel mode only while regasifying at the Port.

Information regarding the number of elapsed hours is also recorded hourly in the Integrated Automation System and will be used for tracking compliance with Permit Condition V.B.6, which limits maximum hourly operations for all auxiliary engines at the Port to 370 hours per rolling 12-month period.

Figure 2-1 shows an example of a daily recordkeeping spreadsheet showing this information. These spreadsheets will be transmitted to the Northeast Gateway Port operator located in Salem, Massachusetts at the conclusion of each delivery and kept on file at that location.

Proposal for data logging for Dual fuel Diesel Engine in accordance with EPA Authorities requirements (BOSTON NEG).

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(o)	(p)	(q)	(r)
Local time	Generator readings					Energy input				Emission rates		Emiission rates 1 h average		Emiission rates 3 h average		Emissions	
time (h)	Running time h	Mean Power output kW	Energy output kWh	Fuel consumption kg	Gas consumption kg	HCV pilot fuel BTU/lb	LCV gas used BTU/lb	HCV gas used BTU/lb	Energy input MMBTU	NOx g/kWh	CO g/kWh	NOx lb/MMBTU	CO lb/MMBTU	NOx lb/MMBTU	CO lb/MMBTU	NOx lb	CO lb
7	1	2800	2800	5.6	454	18503	21535	23867	24.1	1.6	2.1	0.410	0.538			9.9	13.0
8	1	2700	2700	5.4	440	18503	21535	23867	23.4	1.6	2.1	0.407	0.535			9.5	12.5
9	1	3800	3650	7.3	563	18503	21535	23867	29.9	1.6	2.1	0.430	0.565	0.416	0.546	12.9	16.9
10	1	1000	1000	2.0	186	18503	21535	23867	9.9	1.6	2.1	0.357	0.469	0.398	0.523	3.5	4.6
11	1	1500	1500	3.0	267	18503	21535	23867	14.2	1.6	2.1	0.373	0.490	0.387	0.508	5.3	7.0
12	0.5	1600	800	1.6	141	18503	21535	23867	7.5	1.6	2.1	0.376	0.494	0.367	0.482	2.8	3.7
13	1	1700	1700	3.4	298	18503	21535	23867	15.8	1.6	2.1	0.379	0.498	0.376	0.494	6.0	7.9
14	1	2800	2800	5.6	454	18503	21535	23867	24.1	1.6	2.1	0.410	0.538	0.391	0.513	9.9	13.0
15	1	2700	2700	5.4	440	18503	21535	23867	23.4	1.6	2.1	0.407	0.535	0.399	0.523	9.5	12.5
16	1	3000	3000	6.0	480	18503	21535	23867	25.6	1.6	2.1	0.415	0.544	0.411	0.539	10.6	13.9
17	1	1000	1000	2.0	186	18503	21535	23867	9.9	1.6	2.1	0.357	0.469	0.393	0.516	3.5	4.6
18	1	1500	1500	3.0	267	18503	21535	23867	14.2	1.6	2.1	0.373	0.490	0.382	0.501	5.3	7.0
19	1	1600	1600	3.2	283	18503	21535	23867	15.0	1.6	2.1	0.376	0.494	0.369	0.484	5.7	7.4
20	0.9	1700	1530	3.1	268	18503	21535	23867	14.3	1.6	2.1	0.379	0.498	0.376	0.493	5.4	7.1
21	1	2800	2800	5.6	454	18503	21535	23867	24.1	1.6	2.1	0.410	0.538	0.389	0.510	9.9	13.0
22	1	2700	2700	5.4	440	18503	21535	23867	23.4	1.6	2.1	0.407	0.535	0.399	0.524	9.5	12.5
23	1	3000	3000	6.0	480	18503	21535	23867	25.6	1.6	2.1	0.415	0.544	0.411	0.539	10.6	13.9
24	1	1000	1000	2.0	186	18503	21535	23867	9.9	1.6	2.1	0.357	0.469	0.393	0.516	3.5	4.6
1	1	1500	1500	3.0	267	18503	21535	23867	14.2	1.6	2.1	0.373	0.490	0.382	0.501	5.3	7.0
2	1	1600	1600	3.2	283	18503	21535	23867	15.0	1.6	2.1	0.376	0.494	0.369	0.484	5.7	7.4
3	1	1700	1700	3.4	298	18503	21535	23867	15.8	1.6	2.1	0.379	0.498	0.376	0.494	6.0	7.9
4	0.4	2800	1120	2.2	181	18503	21535	23867	9.7	1.6	2.1	0.410	0.538	0.383	0.503	4.0	5.2
5	1	2700	2700	5.4	440	18503	21535	23867	23.4	1.6	2.1	0.407	0.535	0.396	0.520	9.5	12.5
6	1	3000	3000	6.0	480	18503	21535	23867	25.6	1.6	2.1	0.415	0.544	0.411	0.539	10.6	13.9
														0.411	0.539		
														0.415	0.544		

Figure 2-1. Sample Daily Report format for dual-fueled diesel engines (GE2).

Running time is shown in column (a); mean power output is shown in column (b); and oil and gas consumption is shown in columns (d) and (e).

SECTION 3 AUXILIARY BOILER CHANGES

3.1 Vessel Descriptions

The Permit currently only incorporates LNGRVs that are controlled by Excelerate Energy. Excelerate Energy controls a fleet of four LNGRVs (plus four additional new vessels that are in various stages of construction and have not yet been delivered). The three “first-generation” LNGRVs are equipped with two main boilers (B1 and B2 in the Permit, rated at 224 MMBtu/hr each) and a diesel auxiliary generator (GE1 in the Permit) for which the maximum power cannot exceed 3,650 kW.[6] The two “second-generation” and three “third-generation” LNGRVs are equipped with two main boilers (rated at 224 MMBtu/hr each), an auxiliary boiler, and a lower-emitting dual-fueled auxiliary generator (GE2) for which the maximum power cannot exceed 3650 kW.[7] Two of the three “first-generation” LNGRVs, and all subsequent ‘generation’ vessels will be able to call on Northeast Gateway. Emissions from all main boilers and auxiliary boilers on these vessels are controlled with SCR systems that control NO_x emissions to 15 ppmvd @ 3% O_2 (as measured over 3-hour averaging periods). The other “first-generation” vessel will not call on Northeast Gateway. Further discussions in this application regarding activity at the Northeast Gateway Port will assume only those vessels equipped with SCR.

All second-generation LNGRVs are equipped with 100 MMBtu/hr Aalborg Industries Mission™ OM 35 auxiliary boilers (Aux1) rated for 30 metric tonnes per hour of steam, and equipped with Hamworthy DFL low-NO_x burners. While moored at the Port, the boilers are required to fire regasified LNG only (no oil). This describes the two second-generation LNGRVs accurately. However, the three third-generation LNGRVs have Aalborg Industries Mission™ OL 55 auxiliary boilers rated at approximately 157 MMBtu/hr, rated for 50 metric tonnes per hour of steam. (Vendor brochures are included in Appendix B.) These boilers are equipped with Hamworthy DF low-NO_x burners and the SCR systems for these boilers have been upsized so that the outlet guarantee is still 15 ppmvd NO_x @ 3% O_2 (3-hour average), and will still be restricted to firing regasified LNG only during regasification operations. **We are proposing that the newer auxiliary boilers be incorporated into the Permit and designated as Aux2. Fleet details are shown in Table 3-1 below.**

The purpose of the auxiliary boiler (and HRS) is to boost regasification rate; although when auxiliary engines are off, both the first-generation and second-generation LNGRVs are limited to 500 MMscf/day when in closed-loop mode (as is required at Northeast Gateway). For the limited number of hours that the auxiliary engines are on, the 100 MMBtu/hr auxiliary boilers can boost the regasification rate to approximately 600 MMscf/day, and the 157 MMBtu/hr auxiliary boilers can boost the regasification rate to approximately 690 MMscf/day.

[6] The diesel engine is rated for 3840 kW, but the generator is only rated for 3650 kW.
[7] The dual-fueled engine is rated for 3800 kW, but the generator is only rated for 3650 kW.

Table 3-1. Listing of LNGRVs Controlled by Excelerate Energy.

Vessel Name	Hull Number	Generation	Aux. Boiler Heat Input Rating	Delivery Date
Excelsior*	2208	First	(N/A)	(already delivered)
Excellence	2218	First	(N/A)	(already delivered)
Excelerate	2237	First	(N/A)	(already delivered)
Explorer	2254	Second	100 MMBtu/hr	(already delivered)
Express	2263	Second	100 MMBtu/hr	May 2009
Exquisite	2270	Third	157 MMBtu/hr	Sept. 2009
Expedient	2271	Third	157 MMBtu/hr	Nov. 2009
Exemplar	2272	Third	157 MMBtu/hr	June 2010

**Excelsior* is not equipped with the air emissions control equipment required by the Permit and therefore will not be delivering cargos at the Northeast Gateway Port.

3.2 Emissions Impacts

Northeast Gateway is still committed to keeping facilitywide rolling 12-month emissions of NOx and CO limited in the same manner as identified in the current permit, i.e., to 49 TPY and 99 TPY, respectively. Because the use of all boilers is limited by the NOx and CO caps, and all boilers have the same lb/MMBtu emission rates, the larger auxiliary boilers on the third-generation vessels will not increase the annual potential to emit for any pollutants. However, the maximum hourly emissions from the auxiliary boilers on the third-generation vessels will be higher than those from the auxiliary boilers on the second-generation vessels due to the higher heat input rate. Table 3-2 illustrates the maximum hourly emissions for the 30 tonne/hour boilers in the current permit and the new 50 tonne/hour boilers.

Table 3-2. Comparison of emissions between the 30 tonne/hour auxiliary boilers and 50 tonne/hour auxiliary boilers.

Pollutant	lb/MMBtu (HHV)	lb/hr	
		30 tonne/hr aux. boilers	50 tonne/hr aux. boilers
NO_x (downstream of SCR)	0.018	1.8	2.8
CO	0.044	4.4	6.9
SO_2	0.0006	0.06	0.092
VOC	0.005	0.5	0.85
PM_{10} (filterable)	0.0019	0.19	0.29
HAP	0.0019	0.19	0.29

3.3 Regulatory Applicability

The use of 50 tonne/hour auxiliary boilers instead of 30 tonne/hour auxiliary boilers does not trigger any new boiler-specific regulations, nor does it trigger any new facilitywide regulations (as will be discussed in more detail in Section 5). However, our understanding is that EPA Region 1 will continue to interpret

Massachusetts' stationary source permitting regulations (310 CMR 7.02) as being applicable, and that therefore BACT must again be demonstrated for these units. The proposed use of natural gas as the only fuel, low-NO_x burners, and SCR represents BACT, as is demonstrated in Section 6 of this application.

3.4 Monitoring

Monitoring for the 50 tonne/hour auxiliary boilers will be identical to the monitoring for the 30 tonne/hour auxiliary boilers already included in the permit.

SECTION 4 OIL FIRING IN MAIN BOILERS DURING LOAD CHANGES

4.1 Description

Each of the two main boilers on the LNGRVs is equipped with three burners, each capable of firing fuel oil, gas (typically boil-off gas or BOG, although regasified LNG can also be fired if BOG supply is limited), or both (dual-fuel mode).

Typically, the LNGRVs will approach and then moor at the Port with two burners lit in dual-fuel mode in each boiler and will shift to gas only mode once safely moored at the buoy, and at low regasification rates only two burners may be needed. However, when loads require that the third gas burner in each boiler be lit, the main boilers are required to temporarily go to dual-fuel mode; they cannot light the third gas burners in gas-only mode. The need to burn oil during gas burner lightings is a safety requirement, which is identified in both the International Maritime Organization's "International Code for the Construction and Equipment of Ships Carrying Liquefied Gases in Bulk" (IGC Code) and USCG regulations for ships carrying liquefied gases (46 CFR 154.705 and 154.1854).

The number of burner lightings and the amount of fuel oil needed per lighting varies. Onshore pipeline conditions can limit both the sendout rate and the sendout temperature, and boiler management is not an exact science. However, at a minimum, it is expected that for each regasification event, a minimum of two burner lighting events will be needed per boiler (the boilers operate in parallel). The first occurs after the start of regasification as the sendout rate is initially ramped up to operational levels; it is expected that the third burner in each boiler will need to be lit prior to activation of the HRS. After the HRS is activated, the load on the boilers drops, and the third burners must be extinguished (oil does not need to be fired when the third gas burners are extinguished). Steam cannot be dumped while the HRS is active. With HRS engaged, and as the sendout rate is increased further, the third burners need to be relit. In general, the facility expects to operate at relatively high sendout rates, so that there is no need to further extinguish and re-light the third gas burners. However, the sendout rate is limited by natural gas pipeline conditions onshore, and if the conditions require relatively low boiler loads (i.e., at about the point where only two burners can be used), there may be a need for additional extinguishing and re-lighting.

A typical re-lighting involves about 10 minutes of oil firing; however, sometimes burner lighting events can require longer periods of time or shorter periods of time. On a recent voyage, the crew of one of the LNGRVs practiced lighting the third burners in the boilers (including both typical re-lightings and extended-period re-lightings) and simultaneously tracked the oil usage with three different instruments. Results of that testing are illustrated in Figure 4-1. Northeast Gateway has obtained assurances from the vendor of the SCR equipment that the SCR system can continue to be run during these burner lighting events (given their relatively short durations) and that catalyst temperatures are still sufficiently high to avoid any additional oxidation of sulfur dioxide (SO_2) to sulfate particulates (which are detrimental from the perspective of both air emissions and operational fouling).

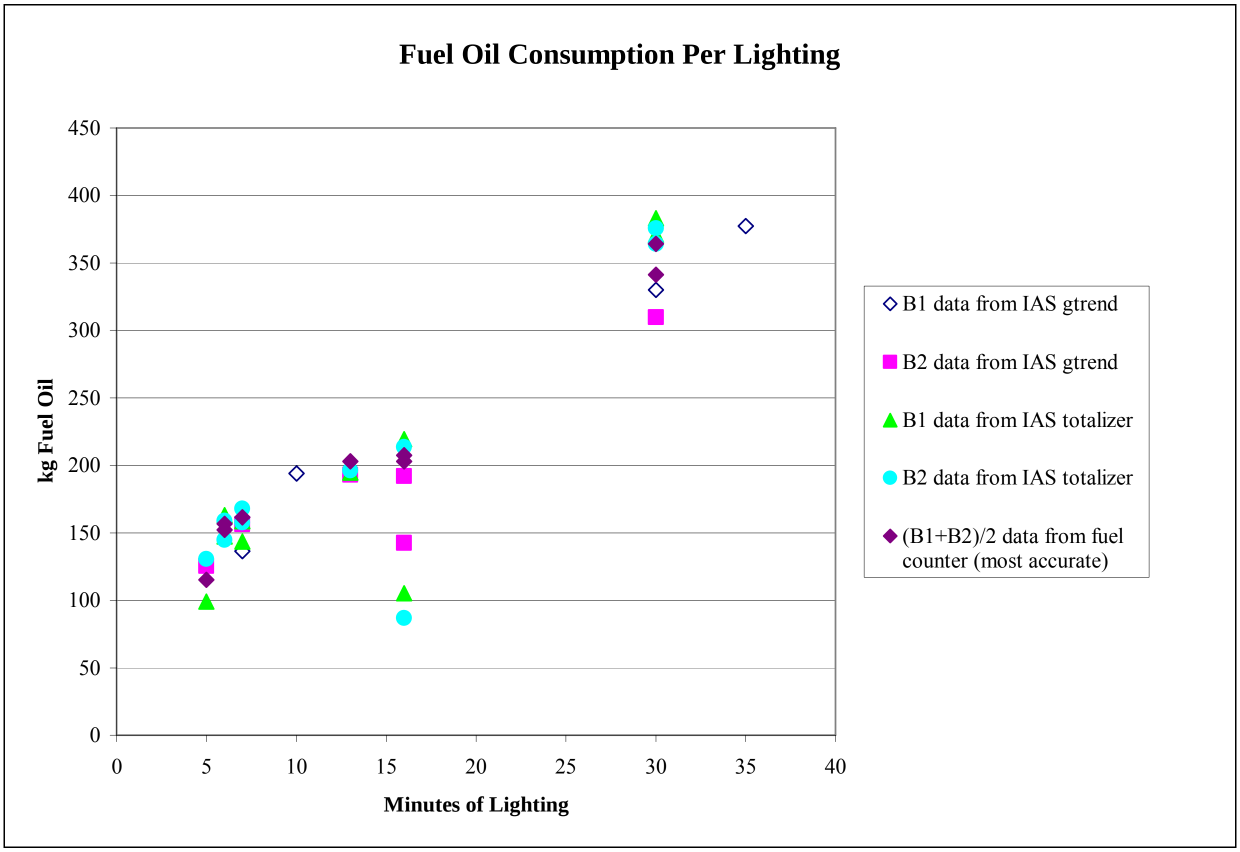


Figure 4-1. Fuel oil consumption during various relighting events, as a function of the time needed to light the third gas burners.

Because both the number of burner lightings per year and the duration of the lightings are uncertain, Northeast Gateway is proposing a conservative limitation on fuel oil usage for lighting events: 640,000 kg per year for the entire facility (total for all boilers on all vessels operating at both buoys). Fuel oil usage will however be restricted in the main boilers to being used only for burner lighting events. Demonstration of compliance with 3-hr and 24-hr National Ambient Air Quality Standards (NAAQS) requires that we also identify maximum oil usage over those time periods; therefore, we are restricting oil usage in each main boiler to 1,400 kg over any 3-hr period and 4,800 kg over any 24-hr period.

As will be explained in more detail in Section 6, BACT is achieved by using the lowest sulfur content in the residual oil, which is readily available. The vessels are fueled at various international locations, and currently the lowest possible sulfur content that can reliably be obtained is 1.5% (RMG 380LS grade). Northeast Gateway is committed to using such fuel oil for all burner lighting activities occurring while vessels are moored. Although lower sulfur content fuel oil is available in the United States, coming to the shore to fuel up or requiring a tanker to be dispatched from shore would likely create more air pollutant emissions (and emissions closer to shore) than the emissions reductions that could be achieved. Distillate fuel oil also cannot be used, as described in more detail in Section 6. Specifications for RMG 380LS, as well as analysis results for an actual sample, are tabulated in Table 4-1 below.

Table 4-1. RMG 380LS Specifications and Sample Analysis Results.

	Specification	Analysis Results for Actual Sample
Density at 15°C (kg/m^3)	≤ 991.0	962.7
API Grade	≥ 11.20	15.40
Viscosity at 50°C (cSt)	≤ 380.00	355.60
Viscosity at 100°C (cSt)	≤ 35.0	33.6
Upper Pour Point (°C)	≤ 30	0
Carbon Residue (wt. %)	≤ 18.00	7.44
Ash (wt. %)	≤ 0.150	0.010
Water (vol. %)	≤ 0.50	0.20
Sulfur (wt. %)	≤ 1.50	0.72
Sediment (wt. %)	≤ 0.10	0.01
Vanadium (ppmw)	≤ 300	14
Aluminum+Silicon (ppmw)	≤ 80	2
Flash Point (°C)	≥ 60	> 65

4.2 Emissions Changes

Testing conducted during the trial lightings shown in Figure 4-1 has indicated that the facility will still be able to comply with the existing 3-hour average emissions limits for NO_x and CO, due to the relatively small quantity of oil used (and the fact that gas-firing rates also decrease during oil burning). EPA emission factors for volatile organic compounds (VOCs) and hazardous air pollutants (HAPs) are actually lower for residual oil-fired boilers than for gas boilers, and therefore, these emissions will also not increase (although emissions of a few individual HAP, including metals, increase; details are provided in Appendix C). However, emissions of SO_2 and particulate matter (PM) will increase as a result of firing oil.

The maximum short-term and long-term emissions increases are shown in Table 4-2. These estimates are conservative because they assume that the increase in maximum emissions is equal to the emissions associated with oil firing, without taking credit for the fact that emissions associated with gas firing decrease when oil is being fired.

Table 4-2. Maximum Emissions Increases Resulting from Oil Firing.

	lb/hr per boiler (averaged over 3 hrs)	tons/yr per boiler	tons/yr facilitywide
SO_2	31.0	10.6	21.2
PM_{10} (filterable)	1.9	0.52	1.04
$PM_{2.5}$ (filterable)	1.5	0.38	0.76

4.3 Regulatory Implications

There are two Massachusetts regulations that pertain to the burning of a limited quantity of oil instead of just gas at fossil fuel utilization facilities: i.e., 310 CMR 7.04 requires the installation of smoke density meters on oil-fired equipment with heat input rates greater than 40 MMBtu/hr, and 310 CMR 7.05 limits the sulfur content of oils burned in various air pollution control districts. However, Massachusetts and EPA Region 1 have never interpreted these requirements as being applicable to international commercial marine vessels (such as those that currently burn higher-sulfur oils within state territorial boundaries and are not equipped with opacity meters), either while these vessels are in transit within state territorial boundaries or while they are docked and unloading or hoteling, and therefore, they should not apply to the LNGRVs associated with this project (which are also located outside the boundaries of the air pollution control districts).

The applicability of regulation 310 CMR 7.06(3), which applies specifically to smoke and opacity from marine vessels located in the Merrimack Valley Air Pollution Control District (APCD), Metropolitan Boston APCD, and Southern Massachusetts APCD, is unchanged by the use of oil in the boilers. The smoke requirement—which prohibits smoke with a shade, density or appearance equal to or greater than No. 1 of the Ringelmann Chart for a period in excess of six minutes during any one hour (never greater than No. 2 of the Ringelmann Chart)—is mirrored in Section V.A.10 of the existing permit.

Our understanding is that EPA Region 1 will continue to interpret Massachusetts' stationary source permitting regulations (310 CMR 7.02) as being applicable, and that therefore BACT must again be demonstrated for these units. The limiting of the use of oil to burner start-up only and the use of the fuel with the lowest sulfur content is representative of BACT, as described in more detail in Section 6.

The burning of small quantities of oil in the boilers for purposes of gas burner start-up does not trigger any other regulations that the gas-fired boilers are not already subject to.

4.4 Monitoring

As is currently the case, monitoring of NO_x and CO (and excess O_2) will still be conducted continuously during periods of oil firing, and emissions of other pollutants will be tracked using EPA emission factors. Emissions of VOC, SO_2, and PM will be tracked using EPA emission factors (for SO_2 and PM, these emission factors are based on the sulfur content of the fuel being fired, which will be analyzed).

Oil consumption will be tracked on an hourly basis using in-line fuel flowmeters. A VAF Instruments sliding vane positive displacement fuel flow meter measures fuel oil flow for both boilers together (the boilers operate in tandem) and transmits that signal to the Kyma ship performance system and then to the vessels' Integrated Automation System. Northeast Gateway plans to improve on these meters by installing two reliable non-resettable fuel oil counters per boiler, that measure total oil flow (upstream of the fuel oil header) and the amount of oil re-circulated back to the tanks (downstream of the fuel oil header, between the header and the recirculation valve). The total amount of oil burned is then calculated by taking the difference between these two readings.

SECTION 5 TOTAL PORT EMISSIONS AND REGULATORY IMPLICATIONS

As stated previously, total potential emissions of NO_x and CO from the Port will remain capped at 49 TPY and 99 TPY, respectively. For the other pollutants:

- Potential emissions of VOC will remain at 16.1 TPY (no change) and potential emissions of HAP will remain at 4.8 TPY (no change);
- SO_2 emissions increase from 4.9 TPY to 26.1 TPY, primarily as a result of the oil usage in the main boilers; and
- Particles with an aerodynamic diameter less than or equal to 10 microns (PM_{10}) emissions increase from 20.6 TPY to 21.6 TPY, and particles with an aerodynamic diameter less than or equal to 2.5 microns ($PM_{2.5}$) emissions increase from 20.6 TPY to 21.4 TPY, with most of these increases associated with the increased size of the auxiliary boilers rather than the oil usage in the main boilers.

These facilitywide emissions increases do not trigger any new regulatory requirements, with the exception of the permitting requirements identified in Sections 3 and 4.

SECTION 6 BEST AVAILABLE CONTROL TECHNOLOGY

The vessels calling on the Northeast Gateway Port were subjected to a BACT analysis during the development and construction of the Gulf Gateway Deepwater facility located within the purview of EPA Region 6. Due to the lack of any currently available control technology to satisfy stationary source requirements as applied to marine vessels of the type owned by Excelerate Energy, BACT was therefore determined to be the requirement for the vessels to burn only natural gas while regasifying LNG at the Gulf Gateway facility.

EPA Region 1 has previously interpreted Massachusetts' stationary source permitting regulations (310 CMR 7.02) as being applicable to the marine vessels calling on this Port. These regulations require that sources apply BACT, defined as:

> "*an emission limitation based on the maximum degree of reduction of any regulated air contaminant emitted from or which results from any regulated facility which the [Massachusetts Department of Environmental Protection], on a case-by-case basis taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such facility through application of production processes and available methods, systems and techniques...and may include a design feature, equipment specification, work practice, operating standard, or combination thereof*" [310 CMR 7.00]

BACT determinations have historically been conducted in accordance with federal guidance in the form of the 1990 draft Federal New Source Review Workshop Manual (NSR Manual).[8] The NSR manual identifies a five-step "top-down" procedure:

Step 1—Identify all control technologies, including demonstrated and transferable technologies

Step 2—Eliminate technically infeasible options

Step 3—Rank remaining control technologies by control effectiveness

Step 4—Evaluate most effective controls and document results

Step 5—Select BACT

When Northeast Gateway made their initial consultations with EPA Region 1 regarding the Northeast Gateway Port project, there had been no proven advancements in emissions control technology specifically designed for a marine application for steam boilers. Northeast Gateway had proposed improvements to general operations of the vessels to further reduce emissions of NOx and CO along with the restriction to burn only natural gas during regasification. Northeast Gateway was informed that another applicant proposing a similar project in the same vicinity had proposed installing Selective Catalytic Reduction on their vessels to further reduce NOx and CO, although there was no evidence that

[8] EPA, "New Source Review Workshop Manual," Draft, Research Triangle Park, NC: EPA Office of Air Quality Planning and Standards, October 1990.

these types of systems had actually ever been installed on LNG vessels. Nonetheless, Northeast Gateway proceeded with investigating this control technology and retrofitted two of its three existing vessels and designed it into all of its future vessels.

There are general considerations with respect to the applicability of BACT to the Northeast Gateway Port's marine vessels which are discussed in Section 6.1. Because BACT assessments are source-specific, the two types of emissions sources for this project—the auxiliary boilers described in Section 3 and the main boilers described in Section 4—are addressed separately in Sections 6.2 and 6.3. Conclusions of the control technology analyses are summarized in Section 6.4.

6.1 General Considerations for Northeast Gateway Port Marine Vessels

The Northeast Gateway Port has already done more to minimize air pollution impacts than any other comparable facility, but not all of these factors are easily considered within the BACT framework developed for stationary sources.

First, use of the STL™ buoy technology has made it possible to locate the Port 13 miles offshore, avoid visible impacts associated with a floating or fixed platform, and provide a port that is more likely to endure a storm than one involving a platform. "Cold ironing," which has been used to refer to the use of electricity or shoreside power instead of the vessel's power for unloading or regasifying LNG, is not possible at this facility (and separately, the USCG has stated that for LNG carriers, it is not acceptable to have the ship's propulsion system offline while docked).[9] Locating 13 miles offshore alleviates all of the air emissions impacts associated with alternative onshore facilities: i.e., those associated with tankers traveling and hoteling within 13 miles of shore, and those associated with associated activities of support vessels and vehicles associated with security close to shore.

Second, although the Permit refers to a relatively small number of emissions units—main boilers B1 and B2, an auxiliary boiler Aux1 (in some cases), and an auxiliary generator (GE1 or GE2)—it needs to be recognized that these units are located on <u>each vessel</u> visiting the Northeast Gateway Port and not on the Port itself. Because the Northeast Gateway Port has a limited capacity, the larger the number of vessels that may need to visit the Northeast Gateway Port, the smaller the emissions per vessel, the higher the costs of controls (since controls need to be installed on each vessel), and the worse the cost-effectiveness. In the case of the SCR systems that Northeast Gateway has committed to, the costs of having to substantially disassemble and reassemble the two first-generation vessels in a dry dock setting to install the systems and the costs of changing the designs on subsequent vessels have likely far exceeded the "economic feasibility" thresholds that MassDEP and EPA typically use for BACT analyses.

[9] See, for example, summary of 9/10/08 Interagency Conference Call between Kenneth Warn of FERC et al and John Becker of Medford et al, FERC Docket Number CP07-444-000, Accession Number 20080929-0017.

Third, when considering the feasibility of commitments, it is worth noting that stationary sources would typically have a “shakedown period” with equipment of up to 180 days with a fixed staff (with the capability of hiring experts in the field of control technology operation, emissions monitoring, etc.) before having to commit to the equipment being working in accordance with permit conditions. Currently, this is not possible for the LNGRVs. EPA’s current Permit restricts each LNGRV to only one “shakedown” visit (approximately 7 days, during which time the ship’s crew is also having to shakedown the actual regasification equipment to which the emissions control equipment is being applied) prior to compliance testing.

6.2 BACT for New Auxiliary Boilers

The new 157 MMBtu/hr auxiliary boilers are equipped with low-NO_x burners, and the third-generation vessels on which they are being installed are already being designed to accommodate SCR systems that reduce NO_x emissions to 15 ppmvd @ 3% O_2 when gas is fired. Northeast Gateway is committed to requiring that only gas be fired in these boilers during regasification activities at the Northeast Gateway Port (and these boilers are not subject to the same USCG/IGC oil-lighting requirements that the propulsion boilers are). Therefore, with respect to Step 1 of the BACT analysis (“identify all control technologies”), we will only identify those which would potentially be at least as stringent as what is being proposed.

For emissions of NO_x, the specification of 15 ppmvd @ 3% O_2 is already the most stringent that has ever been proposed for marine vessel boilers. In the case of the vessels controlled by Excelerate Energy, the SCR vendor (Argillon) has previous experience installing SCR on vessels, but installed a monitoring system with too high a range (500 ppmvd NO_x) for accurate measurement of concentrations this low (this system is being modified accordingly). No other technologies capable of this performance level have been installed on marine vessel boilers of this size or similar emission units.

By incorporating SCR into the design of the vessels, Excelerate has gone above and beyond what is typically required for BACT for NO_x. Prior to Northeast Gateway, this type of configuration has never been tried (let alone proven in practice) for marine applications, and therefore is beyond what should be considered BACT for this emissions source.

Natural gas is by nature a clean fuel, and the use of regasified LNG (which has even lower sulfur content, due to the fact that odorant has not yet been added for pipeline safety purposes) is already representative of BACT for SO_2 and PM emissions.

For land-based combustion units, oxidation catalysts have been used for control of emissions of CO, VOC, and HAP. However, there are several factors which influence the technical feasibility of CO catalysts in this application. First, the potential for high concentrations of methane in the exhaust—for example, from a tube leak—could present a safety risk across the CO catalyst. The Suez Distrigas expansion project in Everett did not use CO catalysts for this reason. Second, it is not clear whether the CO catalysts could be designed in a manner such that they would not be fouled by the firing of fuel oil (the SCR vendor has an SCR “sootblowing” system that keeps the SCR catalyst clean, but a similar system has not been designed for CO catalysts on marine vessels, nor does there appear to be sufficient space). Northeast Gateway believes that CO catalysts should therefore be considered technically infeasible.

As shown in Appendix B, the burner vendor (Hamworthy) for these boilers has stated that "carbon monoxide emissions for the boiler/burner combination operating at its design conditions (e.g., clean, etc.) will be extremely low and of the order of 10-20 ppm (13-27 mg/Nm^3 @ 3% O_2, 273K and 101 kPa)." This is identical to what was identified for the 30 tonne/hr boilers in the application May 2007 Permit, although BACT was conservatively determined to be 60 ppmvd @ 3% O_2 (0.044 lb/MMBtu) for that Permit (which is still substantially lower than the CO emission factor of 0.082 lb/MMBtu estimated for uncontrolled natural gas boilers by EPA's AP-42 publication). Nothing has changed appreciably in the field of CO control since the time of the May 2007 Permit, and therefore BACT for the new boilers is also 60 ppmvd @ 3% O2 (0.044 lb/MMBtu).

6.3 BACT for Oil-Firing in Main Boilers

BACT for the main boilers firing natural gas was already determined in the 2007 Permit and has been applied. As stated previously, oil firing will increase emissions of SO_2, PM, and some individual HAP (but not total HAP).

With respect to Step 1 of the BACT analysis procedure identified previously, "identify all alternatives," we have developed the following list:

1. Minimize the number of burner lighting events during regasification
2. Use less oil per burner lighting
3. Use oil with lower sulfur content

Step 2 of the BACT analysis procedure requires an analysis of technical feasibility. With respect to (1), Northeast Gateway is already committed to minimizing the number of burner lighting events during regasification. It is in our business interests to regasify the cargo as quickly as possible, which means using all three burners in both boilers if needed, when onshore pipeline conditions allow.

6.3.1 Technical Feasibility Assessment – Minimizing the Number of Lightings

With respect to minimizing the number of burner lightings, Northeast Gateway is already committed to minimizing the number of burner lighting events during regasification. The rate at which Northeast Gateway delivers its cargo is dependent upon the contractual terms under which the cargo was purchased, which means using all three burners in both boilers if needed, when onshore pipeline conditions allow. Typically, when the vessel is operating all three burners, excess steam generated during periods of low loads would normally be redirected into the vessel's condensers and cooled; however, this is not possible in the closed-loop mode with the HRS active because the system is designed in such a way that dump valves are to be kept closed to maintain adequate steam production since additional water intakes are secured. While utilizing the HRS, heat input to the main condenser would be too high and the main condenser could lose the vacuum if the steam pressure were to be dumped.

As described in Section 4, there is one lighting event (per boiler) that occurs prior to activation of the HRS. It is possible that the vessels could start out being moored with all three burners active and dump steam prior to activation of the HRS, but the water permit for the Northeast Gateway Port includes stringent limitations on the effluent temperature and flow conditions during the interval prior to the startup of the HRS. Northeast Gateway cannot confirm that it is possible to use three burners while maintaining compliance with the facility's water permit, and definitely cannot commit to doing this without additional operating experience at the Northeast Gateway Port. It is not technically feasible to further reduce the number of burner lighting events.

6.3.2 Technical Feasibility Assessment – Minimizing the Quantity of Oil Used Per Lighting

With respect to using less oil per burner lighting, it is in Northeast Gateway's interests to get the gas burners lit as efficiently as possible, with a minimum amount of oil. Each of the boiler's oil-fired burners can fire oil at rates between 99 kg/h/burner (minimum flow, dual-fuel mode) and 1,980 kg/h (burner capacity). The boiler manufacturer, Mitsubishi Heavy Industries (MHI), was asked to identify whether it was technically feasible to operate only the third oil burner to light the third gas burner, rather than having to turn on all three oil burners. MHI responded that they could not perform this action due to safety concerns; there are many factors which need to be addressed by the burner management system on LNG carriers, and for reasons of safety, these systems are not to be tampered with. This is therefore not a technically feasible option. It may, however, be technically feasible to install oil-fired pilots which would use less oil than the boiler's original oil burners and that are also capable of burning lighter distillate fuels. This option will be discussed in more detail in Section 6.3.4.

6.3.3 Technical Feasibility Assessment – Minimizing the Oil Sulfur Content

With respect to using oil with a lower sulfur content, the residual fuel with the lowest sulfur content that can be obtained reliably internationally is RMG 380 LS (low sulfur, residual marine gas with a maximum viscosity of 380 at 50 deg C), which has a maximum sulfur content of 1.5%. Northeast Gateway is committed to carrying RMG 380 LS onboard each vessel that regasifies at Northeast Gateway Port for purposes of burner lighting events. Although distillate fuels with lower sulfur contents are available, these cannot be used in the boiler's burners for purposes of lighting the gas burners because MHI has stated that it is technically infeasible. Lighter distillate oil (e.g., diesel fuel) can be used in oil-fired pilots; this is discussed in more detail in Section 6.3.4.

6.3.4 Evaluation of Installing Diesel Oil-Fired Pilot Burners

It is possible to light the gas burners using diesel oil-fired pilot burners. However, installing these diesel oil-fired pilot burners on existing vessels would have substantial economic and environmental costs. It is important to keep in mind that at Northeast Gateway, we have conservatively proposed a limit of

320 metric tonnes of heavy oil usage per year (actual oil usage is likely to be much less), which corresponds to 21 tons SO_2 per year for the low sulfur intermediate fuel oil with the maximum allowable sulfur content of 1.5%. Vessels would burn approximately 174 metric tons of heavy oil per day for deviating to a suitable location to carry out installation works. If only two days of travel were necessary to reach such a location, the amount of fuel oil would exceed the amount projected to be burned for the entire year. The quantity of emissions of SO_2 (and carbon dioxide [CO_2]) associated with such travel would far exceed the benefits of installing these burners. The economic costs of such a modification—i.e., those associated with the crews' time, taking the ship out of service for a month, lost revenues from LNG deliveries—would also be enormous.

The cost just for Mitsubishi to do the installation on a single burner per boiler on a single vessel has been quoted as being $26.4 million yen (roughly $250,000). It is expected that two out of three burners would need to be replaced by these diesel oil pilot burners for purposes of burner flexibility and/or redundancy for a conservative total price of about $435,000 per vessel. An additional $5,000 is needed for re-piping, and $2,000 is needed for re-inspection by the Class Society (Bureau Veritas). Costs for adding a fuel flow meter for the pilot and integrating fuel flow information into the Integrated Automation System software have not yet been estimated. Even considering only the $452,000 associated with the previously identified labor and installation, this translates into approximately $3.164 million for all seven vessels, which (applying a Capital Cost Recovery Factor of 0.096 based on 5% interest and 15 year equipment life) translates to approximately $304,000 per year. Emissions reductions are difficult to quantify, insofar as it is not clear exactly how much fuel the pilots would need to burn (they might not operate at their maximum capacity). However, even if it were assumed that essentially all of the 21 tons SO_2/yr were removed by use of the pilots, the costs associated with only the identified labor and installation are equivalent to approximately $14,500 per ton of SO_2 removed. As noted above, this cost effectiveness figure does not include all of the real costs of implementing the pilot burners.

6.4 Conclusion

BACT for the auxiliary boilers will involve the use of the regasified LNG as the only fuel, Hamworthy DF burners to minimize NO_x and CO, and the Argillon SCR system to reduce NO_x down to 15 ppmvd @ 3% O_2 or less.

BACT for oil firing in the main boilers will involve the minimizing the number of gas burner lighting events, minimizing the quantity of oil used per lighting, and utilizing RMG 380 LS fuel with a maximum sulfur content of 1.5% (wt.).

SECTION 7 AIR QUALITY IMPACT ASSESSMENT

7.1 Overview

A dispersion modeling analysis was conducted to evaluate potential air quality impacts resulting from the proposed project modification. The analysis was conducted in accordance with the methodology described in detail in the February 2006 Minor Source Air Permit Application for the Northeast Gateway Project (February 2006 Application), including the use of the Offshore and Coastal Dispersion (OCD) model. Specific conditions related to the modification that were evaluated with dispersion modeling include: 1) the emissions increases related to oil firing in the main boilers; and 2) the emissions increases related to the larger auxiliary boilers being installed on the third-generation vessels. The modeling procedures supporting this permit modification were discussed by telephone with EPA Region 1.[10]

7.2 Vessel Emissions

Emission and stack exhaust parameters are provided in Table 7-1(a-c) for each of the main boilers as well as the auxiliary generator and auxiliary boiler. Source data are provided for two different and very conservative operations scenarios for each of the two buoys.

- **Case 1:** First-Generation Vessels/Maximum Load Case—Both main boilers operated with maximum allowable oil firing, with the remaining operating time on natural gas at maximum load (224 MMBtu/hr); diesel-fired generator at maximum load (3,650 kW).
- **Case 2:** Third-Generation Vessels/Maximum Load Case—Both main boilers operated with maximum allowable oil firing, with the remaining operating time on natural gas at maximum load (224 MMBtu/hr); auxiliary boiler at maximum load (157 MMBtu/hr); dual-fuel generator at maximum load (3,650 kW).

As described in Section 5, annual emissions will increase for only SO_2 and PM_{10}/$PM_{2.5}$. Therefore, revised modeling was conducted for these pollutants only. While short-term emissions of CO and NO_X for the new larger auxiliary boiler may also increase, the modeling for these pollutants was not updated since NO_X is regulated with annual standard and original modeling for CO indicated that maximum predicted impacts were well below (approximately one order of magnitude less than) the significant impact levels (SILs), and the auxiliary boiler contributes just a fraction of the project CO emissions.[11]

As was assumed for the original modeling for the Northeast Gateway Port, short term modeling conservatively assumes that LNGRVs will be in operation at the same time at both locations (Buoy A and Buoy B). For annual emission impacts predictions, it is assumed that a vessel is always at Buoy B, since this location is the one nearest to the Massachusetts shoreline and thus providing worst case impacts. Additionally, the second vessel at Buoy A is assumed to be present for 10% of the time (876 hours). Similarly, generator operation is assumed to be limited to 336 hours per year at Buoy B and 34 hours per year at Buoy A.

[10] Telephone conversation between Brian Hennessey (EPA) and Ted Guertin (Tetra Tech EC) on September 23, 2008.
[11] As is described in Section 4, CO and NO_x emissions from the main boilers will not increase on either a short term or annual basis.

Table 7-1a. Emission Stack Parameters for the Northeast Gateway Energy Bridge Project

SOURCE	EAST (KM)	NORTH COORD (KM)	BUILDING HEIGHT (M)	STACK TOP HT (M)	STACK DIAM (M)	STACK ANGLE (DEG FROM VERT)	GRD-LVL ELEV. (M)	BLDG WIDTH (M)
SBBOILERB	366,941	4,695,344	33.2	37.4	1.4	45	0	33.25
PORTBOILERB	366,941	4,695,344	33.2	37.4	1.4	45	0	33.25
GENERATORB	366,941	4,695,344	33.2	37.4	0.7	45	0	33.25
SBBOILERA	368,973	4,694,752	33.2	37.4	1.4	45	0	33.25
PORTBOILA	368,973	4,694,752	33.2	37.4	1.4	45	0	33.25
GENERATORA	368,973	4,694,752	33.2	37.4	0.7	45	0	33.25
SBBOILERB2	366,941	4,695,344	33.2	37.4	1.4	45	0	33.25
PORTBOILERB2	366,941	4,695,344	33.2	37.4	1.4	45	0	33.25
AUXBOILB2 *	366,941	4,695,344	33.2	37.4	1.2	45	0	33.25
GENERATORB2	366,941	4,695,344	33.2	37.4	0.7	45	0	33.25
SBBOILERA2	368,973	4,694,752	33.2	37.4	1.4	45	0	33.25
PORTBOILA2	368,973	4,694,752	33.2	37.4	1.4	45	0	33.25
AUXBOILA2 *	368,973	4,694,752	33.2	37.4	1.2	45	0	33.25
GENERATORA2	368,973	4,694,752	33.2	37.4	0.7	45	0	33.25

* Stack diameter for the larger third generation vessel auxiliary boiler is 1.4 meters.

Table 7-1b. Emission Stack Parameters for the Northeast Gateway Energy Bridge Project

	STACK TEMPERATURE (K)		EXIT VELOCITY (M/S)	
SOURCE	**Case 1**	**Case 2**	**Case 1**	**Case 2**
SBBOILERB	436		12.3	
PORTBOILERB	436		12.3	
GENERATORB	583		31.3	
SBBOILERA	436		12.3	
PORTBOILA	436		12.3	
GENERATORA	583		31.3	
SBBOILERB2		436		12.3
PORTBOILERB2		436		12.3
AUXBOILB2		630		20.8
GENERATORB2		603		26.0
SBBOILERA2		436		12.3
PORTBOILA2		436		12.3
AUXBOILA2		630		20.8
GENERATORA2		603		26.0

Table 7-1c. Emission Stack Parameters for the Northeast Gateway Energy Bridge Project

SOURCE	SO_2 EMISSION RATE (G/S)						PM_{10} [(1)] EMISSION RATE (G/S)				$PM_{2.5}$ [(1)] EMISSION RATE (G/S)			
	Case 1			Case 2			Case 1		Case 2		Case 1		Case 2	
	3-HR	24-HR	Annual	3-HR	24-HR	Annual	24-HR	Annual	24-HR	Annual	24-HR	Annual	24-HR	Annual
SBBOILERB	3.91	1.68	0.32				0.13	0.070			0.11	0.060		
PORTBOILERB	3.91	1.68	0.32				0.13	0.070			0.11	0.060		
GENERATORB	2.49	2.49	0.105				0.43	0.018			0.43	0.018		
SBBOILERA[(2)]	3.91	1.68	0.032				0.13	0.007			0.11	0.006		
PORTBOILA[(2)]	3.91	1.68	0.032				0.13	0.007			0.11	0.006		
GENERATORA[(2)]	2.49	2.49	0.0105				0.43	0.0018			0.43	0.0018		
SBBOILERB2				3.91	1.68	0.32			0.13	0.070			0.11	0.070
PORTBOILERB2				3.91	1.68	0.32			0.13	0.070			0.11	0.070
AUXBOILB2				0.0116	0.0116	0.0116			0.037	0.037			0.037	0.037
GENERATORB2				0.126	0.126	0.0053			0.43	0.018			0.43	0.018
SBBOILERA2[(2)]				3.91	1.68	0.032			0.13	0.007			0.11	0.007
PORTBOILA2[(2)]				3.91	1.68	0.032			0.13	0.007			0.11	0.007
AUXBOILA2[(2)]				0.0116	0.0116	0.00116			0.037	0.0037			0.037	0.0037
GENERATORA2[(2)]				0.126	0.126	0.0005			0.43	0.0018			0.43	0.0018

Notes:
(1) PM_{10} and $PM_{2.5}$ emission rates based filterable particulate fraction only.
(2) Annual emissions for Buoy A reflect operation for 10% of the year.

7.3 Project Site Characteristics

A Good Engineering Practice stack height analysis was conducted and presented in the February 2006 Application (Section 6.3.1). The results of this analysis do not change. The meteorological data used for the analysis were also described in detail in the February 2006 Application (Section 6.3.2). However, to address the concerns EPA has regarding the representativeness of the mixing height determination for over water meteorological data set, a sensitivity analysis was conducted for a range of alternative fixed mixing height levels. In addition to the OCD modeling conducted with the meteorological data set described in the February 2006 Application, OCD modeling was also conducted with a range of fixed mixing height levels (38 meters (just above stack top height), 50 m, 100 m, 150 m, and 300 m). These fixed mixing height values were inserted in the over water meteorological databases for each of the 5 years modeled.

Background Air Quality

The measured ambient air quality data used to determine background air quality were updated for the most recent 3 years (2005 - 2007) of available data. Selected background concentrations are conservatively based on the maximum measured concentration (annual) or highest second highest concentrations (short-term averages) over those 3 years, for all pollutants except $PM_{2.5}$. To assess compliance with the $PM_{2.5}$ standard, the selected background concentrations are determined from measurements collected at the Lynn, Massachusetts, station (site#25-009-2006) and are based on the 3-year average of maximum concentrations for annual average background and 3-year average of the 98th percentile values for 24-hour average background. Use of these 3-year average values is consistent with the $PM_{2.5}$ standard. Table 7-2 provides a summary of 2005 - 2007 air quality data and the selected background concentrations for the pollutants being evaluated.

Table 7-2. Ambient Air Monitoring Data and Selected Background Concentrations

Pollutant	Monitor	Avg. Time	Units	NAAQS	2005 Conc	2006 Conc	2007 Conc	Background Concentration
PM_{10}	One City Square, Charlestown/Boston	24-Hr (HSH)	μg/m^3	150	40	46	38	46
	One City Square, Charlestown/Boston	Annual	μg/m^3	50	23.0	21.8	22.7	23.0
$PM_{2.5}$	390 Parkland, Lynn	24-Hr (98th Percentile)	μg/m^3	35	27.1	25.2	28.2	26.8 (3-year average)
	One City Square, Charlestown/Boston	Annual	μg/m^3	15	9.5	8.5	9.4	9.1 (3-year average)
SO_2	Long Island Boston Harbor	3-Hour (HSH)	ppm	0.5	0.031	0.013	0.021*	0.031 (88.7 μg/m^3)
	Long Island Boston Harbor	24-Hour (HSH)r	ppm	0.14	0.014	0.011	0.015*	0.015 (42.9 μg/m^3)
	Long Island Boston Harbor	Annual	ppm	0.030	0.0042	0.0032	0.0030	0.042 (12.0 μg/m^3)

* 3-hour and 24-hour average SO_2 concentrations for the Long Island monitoring station were not available in 2007 Air Quality Report. Therefore, concentrations are presented for 2004.

7.4 Air Quality Dispersion Modeling Analysis

The OCD model has been used to assess the air quality concentrations from the proposed modification to the Northeast Gateway Port. The analysis was conducted in accordance with the methodology present in the 2006 Permit Application, including the description of the modeling domain and modeled receptor locations.

OCD Model Results

Tables 7-3, 7-4, and 7-5 present the maximum predicted impact concentrations for SO_2, PM_{10} and $PM_{2.5,}$ respectively. These concentrations are compared to SILs and Class II PSD Increments. The tables show that maximum predicted impacts are greater than corresponding SILs for the short-term average concentrations (3-hour and 24-hour SO_2, 24-hour PM_{10}, and 24-hour $PM_{2.5}$). Maximum annual average concentrations are less than corresponding SILs. All pollutants and averaging periods are well below the corresponding PSD Increments. The worst case impacts occur at a distance of 500 meters from the project (just outside the safety zone) for all pollutants and averaging periods. Maximum predicted impact concentrations for all pollutants and averaging periods are less than corresponding SILs at the shoreline receptors. Maximum impacts were predicted under the assumed fixed 50 meter (short-term average concentrations) and 100 meter (annual average concentrations) mixing heights. However, these maximum concentrations predicted with fixed mixing height data were similar in magnitude to the concentrations predicted with the calculated mixing height meteorological data.

Since maximum predicted project impact concentrations for the short-term averages are greater than corresponding SILs, a cumulative modeling analysis with other emissions sources in the area was conducted for these pollutants and averaging periods.

Cumulative Source Modeling

As stated above, cumulative modeling was conducted for short-term SO_2, PM_{10}, and $PM_{2.5}$ concentrations. The EPA was contacted (Brian Hennessey, 9/23/08 telephone conversation) to determine whether cumulative modeling with other regional sources was necessary since the project is a minor source and is located in the Massachusetts Bay, 13 miles (21 kilometers) from the nearest land (Gloucester, Massachusetts). EPA indicted that cumulative modeling should be conducted with just the Neptune Deepwater Port emission sources. The Neptune Deepwater Port is also to be located in the Massachusetts Bay, approximately 8 kilometers from the Northeast Gateway project site. Emissions parameters for Neptune were determined from their May 2006 Minor Source Air Permit Application. The Neptune source parameters are presented in Table 7-6.

Cumulative modeling was conducted for each year in the 5-year meteorological data base and for both the OCD-calculated and worst case fixed mixing height scenarios. Table 7-7 presents the results of the cumulative modeling analysis. Maximum predicted cumulative impact concentrations (Northeast Gateway + Neptune) are summed with ambient background concentrations for comparison with the NAAQS. As shown on the table, total impact concentrations plus background are below the NAAQS for all pollutants and averaging periods. Therefore, compliance is demonstrated. All electronic OCD modeling files are provided on the CD provided in Appendix D.

Table 7-3. Maximum Predicted SO_2 Impacts

Year	Operating Scenario Case	Receptor	Deg	Dist. From Loc B Km	East Coord	North Coord	Averaging Period	Maximum Concentration ($\mu g/m^3$)	Significant Impact Level ($\mu g/m^3$)	Class II PSD Increment ($\mu g/m^3$)
2002	Case 1	#33	330	0.5	48.33	20.67	3- HOUR	272.6	25	512
2000	Case 1	#9	90	0.5	49.08	21.23	24- HOUR	50.2	5	91
2001	Case 1	#21	210	0.5	48.33	20.80	ANNUAL	0.48	1	20

Table 7-4. Maximum Predicted PM_{10} Impacts

Year	Operating Scenario Case	Receptor	Deg	Dist. From Loc B Km	East Coord	North Coord	Averaging Period	Maximum Concentration ($\mu g/m^3$)	Significant Impact Level ($\mu g/m^3$)	Class II PSD Increment ($\mu g/m^3$)
2000	Case 2	#9	90	0.5	49.08	21.23	24 HOUR	6.1	5	30
2001	Case 2	#21	210	0.5	48.33	20.80	ANNUAL	0.11	1	17

Table 7-5. Maximum Predicted $PM_{2.5}$ Impacts

Year	Operating Scenario Case	Receptor	Deg	Dist. From Loc B Km	East Coord	North Coord	Averaging Period	Maximum Concentration ($\mu g/m^3$)	Significant Impact Level ($\mu g/m^3$)	Class II PSD Increment ($\mu g/m^3$)
2000	Case 2	#9	90	0.5	49.08	21.23	24 HOUR	5.7	4	9
2001	Case 2	#21	210	0.5	48.33	20.80	ANNUAL	0.10	0.8	4

Note: Proposed rule for $PM_{2.5}$ Significant Impact Levels and PSD Increments has not been finalized. Values provided in table refer to the proposed rule's "Option 2" values as presented in the September 21, 2007 *Federal Register* [54112].

Table 7-6. Neptune LNG Source Parameters

Facility Name	Stack Id	Model Id	UTM-E (m)	UTM-N (m)	Distance from Project Site (kilometers)	SO_2 (g/s)	PM_{10} / $PM_{2.5}$ (g/s)	Stack Height (m)	T (K)	Dia. (m)	V (m/s)	Elv. (m)
NEPTUNE LNG	1	SRVBLR1	368,026	4,704,876	8.0	0.021	0.249	50.0	607.2	1.3	15.33	0
NEPTUNE LNG	2	POWERT1	368,026	4,704,876	8.0	0.009	0.432	50.0	675.6	1.2	28.07	0
NEPTUNE LNG	3	SRVBLR2	367,917	4,701,174	8.0	0.042	0.498	50.0	607.2	1.3	15.33	0
NEPTUNE LNG	4	POWER2	367,917	4,701,174	8.0	0.018	0.864	50.0	675.6	1.2	28.07	0

Note: As described in Neptune LNG's Minor Source Air Permit Application, the source parameters for the short term SO_2 and PM_{10}/$PM_{2.5}$ are based on one SRV operating at maximum sendout rate (90% load on two engines and two boilers) and the second SRV operating one engine and one boiler at 90% load. The maximum sendout SRV (2 boiler/2 engine) was located at the buoy closest to the Northeast Gateway project.

Table 7-7. Cumulative Modeling Impact Results

Pollutant / Averaging Period	Year	Operating Scenario Case	Receptor	Deg	Dist. From Loc B (km)	Maximum Predicted Concentration Northeast Gateway + Neptune (μg/m^3)	Background Concentration (μg/m^3)	Total Concentration (μg/m^3)	NAAQS (μg/m^3)
SO2 / 3-HR	2002	Case 1	#33	330	0.5	272.6	88.7	361.3	1300
SO2 / 24-HR	2000	Case 1	#9	90	0.5	50.2	42.9	93.1	365
PM10 / 24-HR	2000	Case 2	#9	90	0.5	6.1	46	52.1	150
PM2.5 / 24-HR	2000	Case 2	#9	90	0.5	5.7	26.8	32.5	35

APPENDIX A

Permit Application Forms

Massachusetts Department of Environmental Protection
Bureau of Waste Prevention – Air Quality
BWP AQ 02 Non-Major Comprehensive Plan Approval
BWP AQ 03 Major Comprehensive Plan Approval
Comprehensive Plan Approval Project Summary Application

Transmittal Number

Facility ID (if known)

A. Facility Data

INSTRUCTIONS

This form is to be completed when filing for a comprehensive Plan Approval (CPA). A CPA is required for projects exceeding the thresholds for that of a Limited Plan Approval (LPA) and in other cases as determined by the Department. When filing a CPA, one or more of the following forms is also required according to the type of project: BWP AQ CPA-1 to BWP AQ CPA-5 for equipment; BWP AQ SFP-1 to BWP AQ SFP-5 for VOC application and noise; BWP AQ SFC-1 to BWP AQ SFC-6 for pollution control equipment.

1. Northeast Gateway Energy Bridge Deepwater Port Project
Facility Name
Massachusettts Bay - Approximately 13 miles south of Gloucester, Massachusetts in federal waters
Location

2. Is the project for a new facility? ☐ Yes ☒ No

3. Previously approved? ☒ Yes ☐ No

If yes, list the previously issued air quality approval(s) for this process and associated emission limits in the table provided.

Application Number	Approval Date
RG1-DPA-CAA-01 (EPA Region 1)	May 14, 2007

4. Which permit category are you applying for? ☒ BPW AQ 02 ☐ BWP AQ O3

B. Applicability

1. POTENTIAL EMISSIONS are to be calculated from the maximum capacity of the equipment to emit pollutant under its physical and operational design. Any physical or operational limitation on the capacity of the equipment to emit a pollutant, including air pollution control equipment, restriction on hours of operation, or on the type or amount of material combusted, stored, or processed, shall be treated as part of its design only if the limitation is specifically stated in (a) plan approval(s) or if the facility proposes to incorporate such a restriction into this current plan approval. Fugitive emissions, to the extent quantifiable, are included in determining the potential emissions. Unless otherwise documented, potential emissions shall be based on 8,760 hours per year operation of source.

   Current Potential Emissions means the potential emissions for the entire facility as it currently exists. If this is for a new facility, then enter N/A in this column.

   Actual Baseline Emissions means the highest actual emissions for the facility in either of the previous two years. If this is for a new facility, then enter N/A in this column.

   Proposed Potential Emissions means the potential emissions for this proposed project alone.

Transmittal Number

Facility ID (if known)

B. Applicability (cont.)

Air Containment*	Current Potential Emissions (TPY)** (after control)	Actual Baseline Emissions (TPY)	Proposed Potential Emissions (TPY) (after control) (1)
Particulate	20.6	0	21.6
SO_x	4.9	0	26.1
NO_x	49.0	0	49.0
VOC	16.1	0	16.1
HOC			
Lead			
CO	99.0	0	99.0
HAP	4.8	0	4.8
Other			

(1) See Section 5 of application text.

*Complete only for air quality contaminants that will be affected by this project.
**TPY = tons per year

2. Is this project subject to:

- 310 CMR 7.00 Appendix A- Nonattainment Review? ☐ Yes ☒ No

  If yes, also complete section C- Nonattainment Review.

- Was netting used to avoid applicability? ☐ Yes ☒ No

  If yes, also complete Section III – Nonattainment Review

- Prevention of Significant Deterioration Permit (PSD) 40 CFR 52.21? ☐ Yes ☒ No
  Note: PSD applications are filed with the U.S. Environmental Protection Agency (EPA).
  If yes, also complete section D – PSD.

- Was netting used to prevent PSD? ☐ Yes ☒ No
  Note: PSD questions should be directed to EPA.
  If yes, also complete section D – PSD.

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

If yes, which subpart?

B. Applicability (cont.)

- National Emissions Standards for Hazardous Air Pollutants (NESHAPS) – 40 CFR 61:

☐ Yes ☒ No

If yes, which subpart?

- Maximum Achievable Control Technology (MACT), 40 CFR 63?

☐ Yes ☒ No

If yes, which subpart?

C. Nonattainment Review

This section must be completed only if the construction or modification occurring at the facility is subject to 310 CMR 7.00 Appendix A (Nonatttainment Review) ***or*** would be subject to Nonatttainment Review if netting did not occur.

Offsets and **Netting**

1. If the proposed project would be subject to 310 CMR 7.0 Appendix A - Nonattainment Review in the absence of netting, or if emission reduction credits are used as offsets as part of the application, what is being shutdown, curtailed or further controlled to obtain the emission reduction credit (netting is not allowed to avoid review under 310 CMR 7.02):

   Emission reduction credits must be part of an enforceable plan approval to be used for either “netting out” or “offsetting emission increases”.

2. For the source of emission credits, complete the following table:

Air Containment	Actual Baseline Emissions (TPY)	New Potential Emissions (TPY) (after control)	Emission Reduction Credit (TPY)

Transmittal Number

Facility ID (if known)

Actual Baseline Emissions means the average actual emissions for the source of emission credits in the previous two years.

New Potential Emissions means the potential emissions for the source of emission credits after project completion.

Emission Reduction Credit means the difference of Actual Baseline and New Potential Emissions.

C. Nonattainment Review (cont.)

3. If emission reduction credits come from a facility other than where the construction or modification occurs, provide the name and location of the facility:

D. Affirmative Demonstration of Compliance

The signature below provides the affirmative demonstration pursuant to 310 CMR 7.02 (3) that any facility (ies) in Massachusetts, owned or operated by the proponent for this project (or by an entity controlling, controlled by or under common control with such proponent) that is subject to 310 CMR 7.00, et seq., is in compliance with, or on a Department approved compliance schedule to meet, all provisions of 310 CMR 7.00, et seq., and any plan approval, order, notice of noncompliance or permit issued thereunder. This form must be signed by a responsible official working at the location of the proposed new or modified facility. Even if an agent has been designated to fill out this form, the responsible official must sign it. (Refer to the definition given in 310 CMR 7.00.)

Certification: I certify that I have examined the responses provided herein and that to the best of my knowledge they are true and complete.

Mark K. Lane
Print name

Signature of responsible official

Vice President-Operations
Position / title

Excelerate Energy, LLC.
Representing

October 30, 2008
Date

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

BWP AQ CPA-1 (for use with BWP AQ 02, 03)

Comprehensive Plan Approval Application for Fuel Utilization Facilities

Transmittal Number

Facility ID (if known)

A. Applicability

This form is to be used to apply for approval to construct, substantially reconstruct or alter a fuel utilization facility, such as but not limited to a boiler, oven, space heaters, fuel-burning engines, turbines, or other stationary fuel burning devices, subject to 310 CMR 7.02 (3).

Please refer to 310 CMR 7.02 (5)(a). Simple burner replacement on existing units having an energy input capacity less than 100,000,000 Btu per hour may submit form BWP-AQ CPA-2, Comprehensive Plan Application for Burner Replacement.

B. Materials that Constitute a Comprehensive Plan Approval Application

Proposed projects that are subject to the Comprehensive Plan Approval Application requirements for fuel utilization facilities must submit the following items to the appropriate Regional Office for review and approval.

☒ **Manufacturer's Specifications** and Brochures

The Following Item Must be Submitted in Duplicate and Must Bear the Seal And Signature of a Massachusetts Registered Professional Engineer

☒ **CPA forms** should reflect both existing units and the new or modified units at the facility.

☐ **Supplemental forms** for associated air pollution control equipment – If such equipment is present, the appropriate form must be included.

☐ **Standard Operating Procedure** – Clear, logical, sequential itemization of the manner in which the equipment is to be operated (normal and upset modes).

☐ **Standard Maintenance Procedure** – Must describe the scheduling of routine maintenance and equipment adjustments.

☐ **Plot Plan** – Scaled drawing indicating the outlines of the structures owned by the landlord of the building containing this project, as well as the locations of significant nearby structures and terrain features. Indicate the heights of the structures and the location and height of the stack(s) above ground level.

☐ **Topographic Map** – United States Geodetic Survey (USGS) map, or equivalent, showing the topographic contours for a distance of 1500 feet beyond the boundary lines in every direction.

☐ **Roof Plan** – Scaled drawing indicating the locations of the stack(s) and all fresh air intakes, windows, and doors. (This can be part of **Plot Plan**.)

☒ **Elevation Plan** – Scaled drawing locating the stack(s), fresh air intakes, windows, and doors.

☒ **Breech/Stack Plan** – Scaled drawing to show the location of sampling ports, barometric dampers, and opacity monitor(s).

☒ **Calculations** – Detailed calculation sheets showing the manner in which the pertinent quantitative data was determined.

☒ **Potential Emissions** – Detailed listing of proposed restrictions limiting potential emissions (see section E).

☐ **Miscellaneous** – The Department may require other materials if it considers them necessary to the plan's review. For example, modeling studies may be required, or monitoring data, or a noise survey. These special items are requested on the more complex or larger applications.

☒ **BACT Analysis**

C. Existing and Modified or New Combustion Unit(s) Data

Include all fuel utilization facilities at this address; attach another sheet when necessary. In this and subsequent sections, "Existing" refers to those combustion units that will remain in use at the facility, but will be unchanged by this project. - **FIRST GENERATION VESSELS**

	Unit 1[(1)]	Unit 2 [(1)]	Unit 3 [(2)]	
1. Is Unit Existing, to be Modified, or New?	Existing	Existing	Existing	
2. Description (boiler, oven, space heater, diesel, etc.)	Boiler	Boiler	Generator	
3. Manufacturer*	Mitsibishi Heavy Industries (MHI)	Mitsubishi Heavy Industries (MHI)	MAN/B&W	
4. Model number*	MB-4E-KS2	MB-4E-KS2	8L32/40	
5. Output rating (at 212° F) (indicate if Btu/hr or lbs. of steam/hr)			3650 kW	
6. Input rating (in Btu per hour)	224,000,000	224,000,000	27,000,000	
7. For boilers, indicate the steam usage breakdown				
a. % of steam for space heating use	0	0		
b. % of steam for air conditioning use	0	0		
c. % of steam for hot water or process use	100	100		
8. For boilers, indicate if WT, FT, CIS, HRT			N/A	
9. Boiler operating pressure [psigl]	932	932	N/A	
10. Thermal efficiency at 100% rating	88.1	88.1	N/A	
11. Maximum breaching temperature (°F)	336	336	590	
12. Furnace volume (if applicable)	1856	1856		
13. Grate area (if applicable)				
14. Indicate how combustion air is supplied to the boiler room				

*If undetermined at time of application, indicate probable unit "or equivalent". Specific make and model must be provided prior to final approval.

(1) Unit 1 and Unit 2 represent the first generation boilers, included on EBRVs – Excelsior, Excellence, and Excelerate (currently in service).

(2) Unit 3 represents first generation engines on first generation EBRVs

C. Existing and Modified or New Combustion Unit(s) Data

Include all fuel utilization facilities at this address; attach another sheet when necessary. In this and subsequent sections, "Existing" refers to those combustion units that will remain in use at the facility, but will be unchanged by this project. - **SECOND GENERATION VESSELS**

	Unit 4 (3)	Unit 5 (3)	Unit 6 (4)	Unit 7 (5)
1. Is Unit Existing, to be Modified, or New?	Existing	Existing	Exisiting	Existing
2. Description (boiler, oven, space heater, diesel, etc.)	Boiler	Boiler	Boiler	Generator
3. Manufacturer*	Mitsibishi Heavy Industries (MHI)	Mitsubishi Heavy Industries (MHI)	Aalborg Industries	Wartsila
4. Model number*	MB-4E-KS2	MB-4E-KS2	Mission OM35	32DF
5. Output rating (at 212° F) (indicate if Btu/hr or lbs. of steam/hr)				
6. Input rating (in Btu per hour)	224,000,000	224,000,000	100,000,000	26,700,000
7. For boilers, indicate the steam usage breakdown				
a. % of steam for space heating use	0	0	0	
b. % of steam for air conditioning use	0	0	0	
c. % of steam for hot water or process use	100	100	100	
8. For boilers, indicate if WT, FT, CIS, HRT				N/A
9. Boiler operating pressure [psigl]	932	932	Unk	N/A
10. Thermal efficiency at 100% rating	88.1	88.1	Unk	N/A
11. Maximum breaching temperature (°F)	336	336	789	626
12. Furnace volume (if applicable)	1856	1856	1227	N/A
13. Grate area (if applicable)	N/A	N/A	N/A	N/A
14. Indicate how combustion air is supplied to the boiler room				

*If undetermined at time of application, indicate probable unit "or equivalent". Specific make and model must be provided prior to final approval.

(3) Unit 4 and Unit 5 represent boilers on second generation EBRVs starting with the Explorer (2008).
(4) Unit 6 represents the auxiliary boiler on the second generation EBRVs
(5) Unit 7 represents engines on second generation EBRVs

C. Existing and Modified or New Combustion Unit(s) Data

Include all fuel utilization facilities at this address; attach another sheet when necessary. In this and subsequent sections, "Existing" refers to those combustion units that will remain in use at the facility, but will be unchanged by this project. - **THIRD GENERATION VESSELS**

	Unit 8[6]	Unit 9 [6]	Unit 10 [7]	Unit 11 [8]
1. Is Unit Existing, to be Modified, or New?	Future	Future	Future	Future
2. Description (boiler, oven, space heater, diesel, etc.)	Boiler	Boiler	Boiler	Generator
3. Manufacturer*	Mitsibishi Heavy Industries (MHI)	Mitsubishi Heavy Industries (MHI)	Aalborg Industries	Wartsila
4. Model number*	MB-4E-KS2	MB-4E-KS2	Mission OL55	32DF
5. Output rating (at 212° F) (indicate if Btu/hr or lbs. of steam/hr)				
6. Input rating (in Btu per hour)	224,000,000	224,000,000	157,000,000	26,700,000
7. For boilers, indicate the steam usage breakdown				
a. % of steam for space heating use	0	0	0	
b. % of steam for air conditioning use	0	0	0	
c. % of steam for hot water or process use	100	100	100	
8. For boilers, indicate if WT, FT, CIS, HRT				N/A
9. Boiler operating pressure [psigl]	932	932	142	N/A
10. Thermal efficiency at 100% rating	88.1	88.1	84.1	N/A
11. Maximum breaching temperature (°F)	336	336	675	626
12. Furnace volume (if applicable)	1856	1856	1872	N/A
13. Grate area (if applicable)	N/A	N/A	N/A	N/A
14. Indicate how combustion air is supplied to the boiler room				

*If undetermined at time of application, indicate probable unit "or equivalent". Specific make and model must be provided prior to final approval.

(6) Unit 8 and Unit 9 represent boilers on third generation EBRVs starting with the Exquisite (2009).
(7) Unit 10 represents the auxiliary boiler on the third generation EBRVs
(8) Unit 11 represents engines on third generation EBRVs

C. Existing and Modified or New Combustion Unit(s) Data (cont.)

15. Describe combustion unit cleaning method

	Unit 1	Unit 2	Unit 3	
a. Air blown (yes or no)				
b. Steam blown (yes or no)				
c. Brushed and vacuumed (yes or no)				
d. Other (describe)				
e. Frequency of cleaning				

D. Fuel Data - *FIRST GENERATION VESSELS*

1. Primary fuel

	Unit 1	Unit 2	Unit 3	
a. Type and grade	Nat gas	Nat gas	Diesel	
b. Sulfur content	0.0006 lbs/MMBtu	0.0006 lbs/MMBtu	0.5%	
c. Gross heating value (give units)	1000-1130 Btu/scf	1000-1130 Btu/scf	18,500 Btu/lb	
d. Ash content (% by dry weight)				
e. Proposed fuel supplier				

2. Standby or auxiliary fuel

	Unit 1	Unit 2	Unit 3	
a. Type and grade	RMG 380 LS	RMG 380 LS	N/A	
b. Sulfur content	1.5%	1.5%		
c. Gross heating value (give units)	18,610 Btu/lb (HHV)	18,610 Btu/lb (HHV)		
d. Ash content (% by dry weight)	0.15	0.15		
e. Proposed fuel supplier:				

	Unit 1	Unit 2	Unit 3	
3. Fuel additive				
a. Manufacturer				
b. Additive name				
c. Purpose of additive				

C. Existing and Modified or New Combustion Unit(s) Data (cont.)

15. Describe combustion unit cleaning method	Unit 4	Unit 5	Unit 6	Unit 7
a. Air blown (yes or no)				
b. Steam blown (yes or no)				
c. Brushed and vacuumed (yes or no)				
d. Other (describe)				
e. Frequency of cleaning				

D. Fuel Data - *SECOND GENERATION VESSELS*

1. Primary fuel	Unit 4	Unit 5	Unit 6	Unit 7
a. Type and grade	Nat gas	Nat gas	Nat gas	Dual Fuel – 99% Nat gas
b. Sulfur content	0.0006 lbs/MMBtu	0.0006 lbs/MMBtu	0.0006 lbs/MMBtu	0.0006 lbs/MMBtu
c. Gross heating value (give units)	1000-1130 Btu/scf	1000-1130 Btu/scf	1000-1130 Btu/scf	1000-1130 Btu/scf
d. Ash content (% by dry weight)				
e. Proposed fuel supplier				

2. Standby or auxiliary fuel	Unit 4	Unit 5	Unit 6	Unit 7
a. Type and grade	RMG 380 LS	RMG 380 LS	N/A	Diesel oil – 1%
b. Sulfur content	1.5%	1.5%		0.5%
c. Gross heating value (give units)	18,610 Btu/lb (HHV)	18,610 Btu/lb (HHV)		18,500 Btu/lb
d. Ash content (% by dry weight)	0.15	0.15		
e. Proposed fuel supplier:				

3. Fuel additive	Unit 4	Unit 5	Unit 6	Unit 7
3. Fuel additive				
a. Manufacturer				
b. Additive name				
c. Purpose of additive				

C. Existing and Modified or New Combustion Unit(s) Data (cont.)

15. Describe combustion unit cleaning method	Unit 8	Unit 9	Unit 10	Unit 11
a. Air blown (yes or no)				
b. Steam blown (yes or no)				
c. Brushed and vacuumed (yes or no)				
d. Other (describe)				
e. Frequency of cleaning				

D. Fuel Data - *THIRD GENERATION VESSELS*

1. Primary fuel	Unit 8	Unit 9	Unit 10	Unit 11
a. Type and grade	Nat gas	Nat gas	Nat gas	Dual Fuel – 99% Nat gas
b. Sulfur content	0.0006 lbs/MMBtu	0.0006 lbs/MMBtu	0.0006 lbs/MMBtu	0.0006 lbs/MMBtu
c. Gross heating value (give units)	1000-1130 Btu/scf	1000-1130 Btu/scf	1000-1130 Btu/scf	1000-1130 Btu/scf
d. Ash content (% by dry weight)				
e. Proposed fuel supplier				

2. Standby or auxiliary fuel	Unit 8	Unit 9	Unit 10	Unit 11
a. Type and grade	RMG 380 LS	RMG 380 LS	N/A	Diesel oil – 1%
b. Sulfur content	1.5%	1.5%		0.5%
c. Gross heating value (give units)	18,610 Btu/lb (HHV)	18,610 Btu/lb (HHV)		18,500 Btu/lb
d. Ash content (% by dry weight)	0.15	0.15		
e. Proposed fuel supplier:				

3. Fuel additive				
a. Manufacturer				
b. Additive name				
c. Purpose of additive				

E. Potential Emissions - *FIRST GENERATION VESSELS*

POTENTIAL EMISSIONS are used to determine applicability to air pollution control regulations and compliance fees. Unless otherwise restricted, potential emissions are calculated from the maximum operational capacity of the equipment as described in section C operated 8,760 hours per year. If you wish to limit potential emissions you must complete this section; this will be treated as part of the facility design and the limitation will be specifically stated in this Plan Approval.

1. In order to issue a permit limiting the facility's potential emissions, the Department must have a method to monitor compliance with the restriction. In other words, an enforceable permit condition must be available to the Department. The following questions require the facility to set a limit on the maximum amount of fuel combusted (per month and per year) and therefore, the maximum amount of emissions possible. This will become the means to monitor and enforce the restriction. Alternative methods of restricting potential emissions will be evaluated on a case-by-case basis and the applicant should contact the Department before proposing such alternatives. Any such alternative method must be consistent with the U.S. EPA's June 13, 1989 guidance entitled, "Guidance on Limiting Potential to Emit in New Source Permitting" (Copies of this guidance are available from DEP offices).

Proposed Fuel Restriction

Enter amount and units (gallons, cubic feet, etc.)

	Unit 1	Unit 2	Unit 3	Unit 4	Total
a. Maximum per month:	See Notes Below.				
primary fuel					
auxiliary	144,000 kg	144,000 kg			
b. Maximum per year:					
primary fuel					
auxiliary fuel	320,000 kg	320,000 kg			

2. Describe any other physical or operational limitation on the capacity of the equipment to emit a pollutant, including air pollution control equipment, restriction on hours of operation, etc., that will be used to restrict emissions:

The proposed restrictions above are combined limits for all vessels that operate at Northeast Gateway. The annual fuel restriction will be on a 12-month rolling basis. Other than these proposed fuel restrictions for auxiliary fuel listed above, the permitted equipment will continue to comply with the restrictions contained in the existing air permit.

Transmittal Number

Facility ID (if known)

E. Potential Emissions - *SECOND GENERATION VESSELS*

POTENTIAL EMISSIONS are used to determine applicability to air pollution control regulations and compliance fees. Unless otherwise restricted, potential emissions are calculated from the maximum operational capacity of the equipment as described in section C operated 8,760 hours per year. If you wish to limit potential emissions you must complete this section; this will be treated as part of the facility design and the limitation will be specifically stated in this Plan Approval.

1. In order to issue a permit limiting the facility's potential emissions, the Department must have a method to monitor compliance with the restriction. In other words, an enforceable permit condition must be available to the Department. The following questions require the facility to set a limit on the maximum amount of fuel combusted (per month and per year) and therefore, the maximum amount of emissions possible. This will become the means to monitor and enforce the restriction. Alternative methods of restricting potential emissions will be evaluated on a case-by-case basis and the applicant should contact the Department before proposing such alternatives. Any such alternative method must be consistent with the U.S. EPA's June 13, 1989 guidance entitled, "Guidance on Limiting Potential to Emit in New Source Permitting" (Copies of this guidance are available from DEP offices).

Proposed Fuel Restriction

Enter amount and units (gallons, cubic feet, etc.)

	Unit 4	Unit 5	Unit 6	Unit 7	Total
a. Maximum per month:	See Notes Below.				
primary fuel					
auxiliary	144,000 kg	144,000 kg			
b. Maximum per year:					
primary fuel					
auxiliary fuel	320,000 kg	320,000 kg			

2. Describe any other physical or operational limitation on the capacity of the equipment to emit a pollutant, including air pollution control equipment, restriction on hours of operation, etc., that will be used to restrict emissions:

The proposed restrictions above are combined limits for all vessels that operate at Northeast Gateway. The annual fuel restriction will be on a 12-month rolling basis. Other than these proposed fuel restrictions for auxiliary fuel listed above, the permitted equipment will continue to comply with the restrictions contained in the existing air permit.

Transmittal Number

Facility ID (if known)

E. Potential Emissions - *THIRD GENERATION VESSELS*

POTENTIAL EMISSIONS are used to determine applicability to air pollution control regulations and compliance fees. Unless otherwise restricted, potential emissions are calculated from the maximum operational capacity of the equipment as described in section C operated 8,760 hours per year. If you wish to limit potential emissions you must complete this section; this will be treated as part of the facility design and the limitation will be specifically stated in this Plan Approval.

1. In order to issue a permit limiting the facility's potential emissions, the Department must have a method to monitor compliance with the restriction. In other words, an enforceable permit condition must be available to the Department. The following questions require the facility to set a limit on the maximum amount of fuel combusted (per month and per year) and therefore, the maximum amount of emissions possible. This will become the means to monitor and enforce the restriction. Alternative methods of restricting potential emissions will be evaluated on a case-by-case basis and the applicant should contact the Department before proposing such alternatives. Any such alternative method must be consistent with the U.S. EPA's June 13, 1989 guidance entitled, "Guidance on Limiting Potential to Emit in New Source Permitting" (Copies of this guidance are available from DEP offices).

Proposed Fuel Restriction

Enter amount and units (gallons, cubic feet, etc.)

	Unit 8	Unit 9	Unit 10	Unit 11	Total
a. Maximum per month:	See Notes Below.				
primary fuel					
auxiliary	144,000 kg	144,000 kg			
b. Maximum per year:					
primary fuel					
auxiliary fuel	320,000 kg	320,000 kg			

2. Describe any other physical or operational limitation on the capacity of the equipment to emit a pollutant, including air pollution control equipment, restriction on hours of operation, etc., that will be used to restrict emissions:

The proposed restrictions above are combined limits for all vessels that operate at Northeast Gateway. The annual fuel restriction will be on a 12-month rolling basis. Other than these proposed fuel restrictions for auxiliary fuel listed above, the permitted equipment will continue to comply with the restrictions contained in the existing air permit.

F. Oil Viscosity Control Data - *FIRST GENERATION VESSELS*

1. For #4, #5, or #6 fuel oil, indicate below the method used to maintain proper atomizing viscosity [e.g., oil tank heater, oil line heater, pre-heater type, or other (such as room heat)]:

   Proper atomizing viscosity will be maintained using oil line heaters and a viscosity sensor.

2. Description of Oil Viscosity Controller (if applicable):

   a. Manufacturer

   b. Model number

   c. Recorder?

G. Burner Data - *FIRST GENERATION VESSELS*

For fuel dependant parameters, assume primary fuel is being used.

	Unit 1	Unit 2	Unit 3	
1. Burner manufacturer				
2. Burner model number				
3. Type of atomization (steam, air, press, mesh, rotary cup)				
4. Number of burners in each				
5. Max fuel firing rate (all burners firing) (Gal/hr, lbs./hr, cubic ft per hr, etc.)				
6. If oil, temperature and viscosity at max rating				
7. Normal fuel firing rate (indicate units)				
8. Max theoretical air requirement (scfm)				
9. Percent excess air at 100% rating				
10. Turndown ratio				

11. Burner modulation control (on/off, low/high fire, full automatic, manual)

12. Main burner flame ignition method (electric spark, auto gas pilot, hand held torch, other)

F. Oil Viscosity Control Data - *SECOND GENERATION VESSELS*

2. For #4, #5, or #6 fuel oil, indicate below the method used to maintain proper atomizing viscosity [e.g., oil tank heater, oil line heater, pre-heater type, or other (such as room heat)]:

   Proper atomizing viscosity will be maintained using oil line heaters and a viscosity sensor.

2. Description of Oil Viscosity Controller (if applicable):

   a. Manufacturer

   b. Model number

   c. Recorder?

G. Burner Data - *SECOND GENERATION VESSELS*

For fuel dependant parameters, assume primary fuel is being used.

	Unit 4	Unit 5	Unit 6	Unit 7
1. Burner manufacturer				
2. Burner model number				
3. Type of atomization (steam, air, press, mesh, rotary cup)				
4. Number of burners in each				
5. Max fuel firing rate (all burners firing) (Gal/hr, lbs./hr, cubic ft per hr, etc.)				
6. If oil, temperature and viscosity at max rating				
7. Normal fuel firing rate (indicate units)				
8. Max theoretical air requirement (scfm)				
9. Percent excess air at 100% rating				
10. Turndown ratio				

11. Burner modulation control (on/off, low/high fire, full automatic, manual)

12. Main burner flame ignition method (electric spark, auto gas pilot, hand held torch, other)

F. Oil Viscosity Control Data - *THIRD GENERATION VESSELS*

3. For #4, #5, or #6 fuel oil, indicate below the method used to maintain proper atomizing viscosity [e.g., oil tank heater, oil line heater, pre-heater type, or other (such as room heat)]:

   Proper atomizing viscosity will be maintained using oil line heaters and a viscosity sensor.

2. Description of Oil Viscosity Controller (if applicable):

   a. Manufacturer

   b. Model number

   c. Recorder?

G. Burner Data - *THIRD GENERATION VESSELS*

For fuel dependant parameters, assume primary fuel is being used.

	Unit 8	Unit 9	Unit 10	Unit 11
1. Burner manufacturer				
2. Burner model number				
3. Type of atomization (steam, air, press, mesh, rotary cup)				
4. Number of burners in each				
5. Max fuel firing rate (all burners firing) (Gal/hr, lbs./hr, cubic ft per hr, etc.)				
6. If oil, temperature and viscosity at max rating				
7. Normal fuel firing rate (indicate units)				
8. Max theoretical air requirement (scfm)				
9. Percent excess air at 100% rating				
10. Turndown ratio				

11. Burner modulation control (on/off, low/high fire, full automatic, manual)

12. Main burner flame ignition method (electric spark, auto gas pilot, hand held torch, other)

Transmittal Number

Facility ID (if known)

H. Combustion Unit Operating Schedule [1] - *FIRST GENERATION VESSELS*

				Unit 1	Unit 2	Unit 3
1.	Winter schedule	hrs/days	days/week	24 - 7	24 - 7	24 - 7
2.	Spring schedule	hrs/days	days/week	24 - 7	24 - 7	24 - 7
3.	Summer schedule	hrs/days	days/week	24 - 7	24 - 7	24 - 7
4.	Autumn schedule	hrs/days	days/week	24 - 7	24 - 7	24 - 7

(1) Units 1 and 2 represent the two boilers, unit 3 represents the auxiliary generator based on first generation EBRVs. Total annual operation will be limited as described in Section E of this application, i.e. the auxiliary generator could be operated for 24 hours/day for seven consecutive days during any season as needed, however, its total annual usage would be limited to 370 hours.

I. Noise Suppression Equipment - *FIRST GENERATION VESSELS*

The installation of some fuel burning units can cause a noise nuisance if precautions are not taken. This is especially true for diesel or turbine generators. Form BWP AQ SFP-3 must accompany the Plan Application for those units requiring noise suppression.

		Unit 1	Unit 2	Unit 3
1.	Manufacturer of silencer			
2.	Model Number			

J. Auxiliary Equipment - *FIRST GENERATION VESSELS*

		Unit 1	Unit 2	Unit 3
1.	Opacity Monitoring Equipment			
a.	Manufacturer			
b.	Model number			
c.	Lens cleaning method			
d.	Alarm type			
e.	Recorder manufacturer			
f.	Recorder model number			

The above device is required on all stacks serving equipment rated at an energy input capacity of 40,000,000 Btu per hour or greater which burn liquid or solid fuel. Other facilities, may also be required to install such equipment if the Department determines that it is necessary (310 CMR 7.04 (2)).

2. Boiler Draft

Transmittal Number

Facility ID (if known)

H. Combustion Unit Operating Schedule (2) *- SECOND GENERATION VESSELS*

			Unit 4	Unit 5	Unit 6	Unit 7
1. Winter schedule	hrs/days	days/week	24 - 7	24 - 7	24 - 7	24 - 7
2. Spring schedule	hrs/days	days/week	24 - 7	24 - 7	24 - 7	24 - 7
3. Summer schedule	hrs/days	days/week	24 - 7	24 - 7	24 - 7	24 - 7
4. Autumn schedule	hrs/days	days/week	24 - 7	24 - 7	24 - 7	24 - 7

(2) Units 4 and 5 represent the two boilers, unit 6 represents the auxiliary boiler on second generation EBRVs, and unit 7 represents the auxiliary generator based on second generation EBRVs. Total annual operation will be limited as described in Section E of this application, i.e. the auxiliary generator could be operated for 24 hours/day for seven consecutive days during any season as needed, however, its total annual usage would be limited to 370 hours.

I. Noise Suppression Equipment *- SECOND GENERATION VESSELS*

The installation of some fuel burning units can cause a noise nuisance if precautions are not taken. This is especially true for diesel or turbine generators. Form BWP AQ SFP-3 must accompany the Plan Application for those units requiring noise suppression.

	Unit 4	Unit 5	Unit 6	Unit 7
1. Manufacturer of silencer				
2. Model Number				

J. Auxiliary Equipment *- SECOND GENERATION VESSELS*

1. Opacity Monitoring Equipment	Unit 4	Unit 5	Unit 6	Unit 7
a. Manufacturer				
b. Model number				
c. Lens cleaning method				
d. Alarm type				
e. Recorder manufacturer				
f. Recorder model number				

The above device is required on all stacks serving equipment rated at an energy input capacity of 40,000,000 Btu per hour or greater which burn liquid or solid fuel. Other facilities, may also be required to install such equipment if the Department determines that it is necessary (310 CMR 7.04 (2)).

2. Boiler Draft

H. Combustion Unit Operating Schedule (3) - *THIRD GENERATION VESSELS*

				Unit 8	Unit 9	Unit 10	Unit 11
1.	Winter schedule	hrs/days	days/week	24 - 7	24 - 7	24 - 7	24 - 7
2.	Spring schedule	hrs/days	days/week	24 - 7	24 - 7	24 - 7	24 - 7
3.	Summer schedule	hrs/days	days/week	24 - 7	24 - 7	24 - 7	24 - 7
4.	Autumn schedule	hrs/days	days/week	24 - 7	24 - 7	24 - 7	24 - 7

(3) Units 8 and 9 represent the two boilers, unit 10 represents the auxiliary boiler on third generation EBRVs, and unit 11 represents the auxiliary generator based on third generation EBRVs. Total annual operation will be limited as described in Section E of this application, i.e. the auxiliary generator could be operated for 24 hours/day for seven consecutive days during any season as needed, however, its total annual usage would be limited to 370 hours.

I. Noise Suppression Equipment - *THIRD GENERATION VESSELS*

The installation of some fuel burning units can cause a noise nuisance if precautions are not taken. This is especially true for diesel or turbine generators. Form BWP AQ SFP-3 must accompany the Plan Application for those units requiring noise suppression.

		Unit 8	Unit 9	Unit 10	Unit 11
1.	Manufacturer of silencer				
2.	Model Number				

J. Auxiliary Equipment - *THIRD GENERATION VESSELS*

		Unit 8	Unit 9	Unit 10	Unit 11
1.	Opacity Monitoring Equipment				
a.	Manufacturer				
b.	Model number				
c.	Lens cleaning method				
d.	Alarm type				
e.	Recorder manufacturer				
f.	Recorder model number				

The above device is required on all stacks serving equipment rated at an energy input capacity of 40,000,000 Btu per hour or greater which burn liquid or solid fuel. Other facilities, may also be required to install such equipment if the Department determines that it is necessary (310 CMR 7.04 (2)).

2. Boiler Draft

a. Type (forced, included, or natural) ___ ___ ___ ___

b. Method used to control draft ___ ___ ___ ___

J. Auxiliary Equipment (cont.) - *FIRST GENERATION VESSELS*

3. **Air Pollution Control Equipment**

(Applicable supplemental forms must be submitted for these, see instructions)

a. Type (scrubber, ESP, cyclone, etc.)	SCR	SCR		
b. Manufacturer	Argillon	Argillon		
c. Model number	SINOx	SINOx		

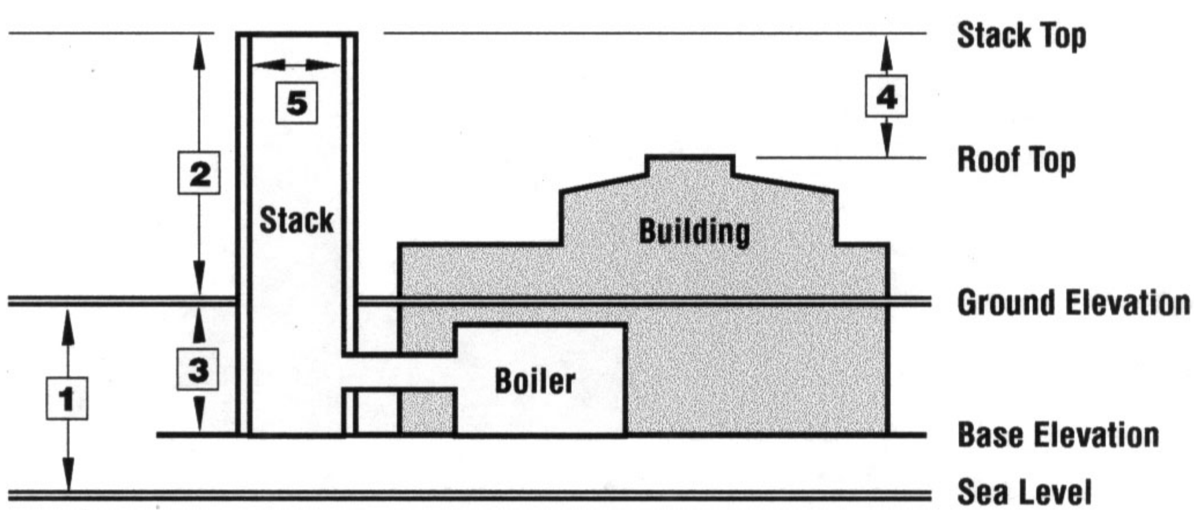
4. Does this application represent Best Available Control Technology (BACT) as required in Regulation 310 CMR 7.02(3)(j) 6?

a. ☒ Yes ☐ No

The use of SCR for NOx control from the proposed boilers to achieve a 90% reduction exceeds the emission control for all similar sized boilers whether land or vessel based. In addition, taking the air heaters out of service on the first generation boilers achieves an additional 20 - 30% NOx reduction. Second and third generation main boilers are expected to use Volcano type burners to further reduce NOx emissions.

b. Describe

K. Existing and New or Modified Stack Data



Questions for the above diagram

a.	Type (forced, included, or natural)				
b.	Method used to control draft				

J. Auxiliary Equipment (cont.) - *SECOND GENERATION VESSELS*

3. **Air Pollution Control Equipment**

(Applicable supplemental forms must be submitted for these, see instructions)

a.	Type (scrubber, ESP, cyclone, etc.)	SCR	SCR	SCR	
b.	Manufacturer	Argillon	Argillon	Argillon	
c.	Model number	SINOx	SINOx	SINOx	

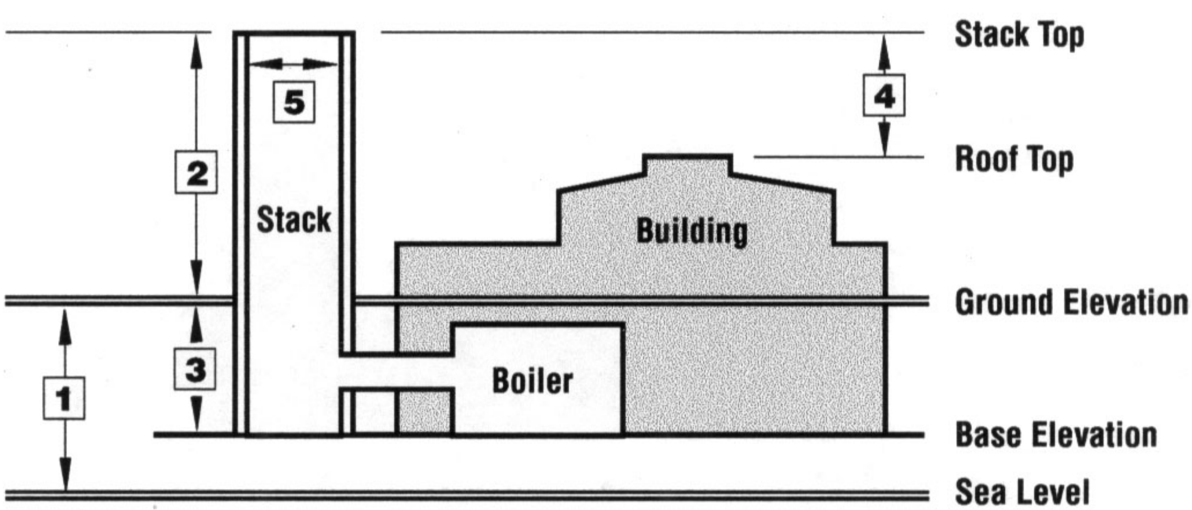
4. Does this application represent Best Available Control Technology (BACT) as required in Regulation 310 CMR 7.02(3)(j) 6?

a. ☒ Yes ☐ No

The use of SCR for NOx control from the proposed boilers to achieve a 90% reduction exceeds the emission control for all similar sized boilers whether land or vessel based. In addition, taking the air heaters out of service on the first generation boilers achieves an additional 20 - 30% NOx reduction. Second and third generation main boilers are expected to use Volcano type burners to further reduce NOx emissions.

b. Describe

K. Existing and New or Modified Stack Data



Questions for the above diagram

a. Type (forced, included, or natural) ________ ________ ________ ________

b. Method used to control draft ________ ________ ________ ________

J. Auxiliary Equipment (cont.) - *THIRD GENERATION VESSELS*

3. **Air Pollution Control Equipment**

(Applicable supplemental forms must be submitted for these, see instructions)

a. Type (scrubber, ESP, cyclone, etc.)	SCR	SCR	SCR	
b. Manufacturer	Argillon	Argillon	Argillon	
c. Model number	SINOx	SINOx	SINOx	

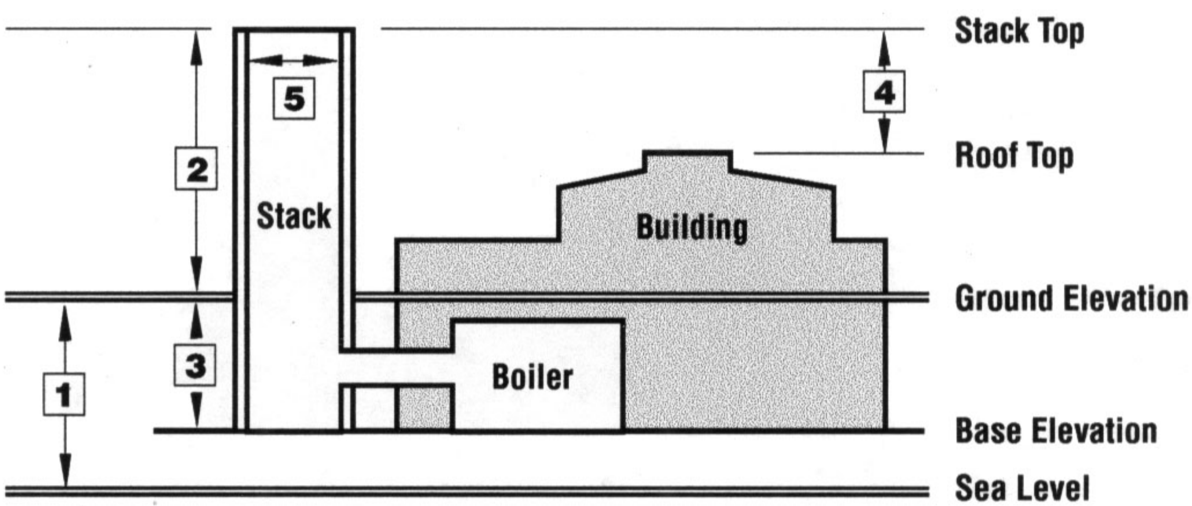
4. Does this application represent Best Available Control Technology (BACT) as required in Regulation 310 CMR 7.02(3)(j) 6?

a. ☒ Yes ☐ No

The use of SCR for NOx control from the proposed boilers to achieve a 90% reduction exceeds the emission control for all similar sized boilers whether land or vessel based. In addition, taking the air heaters out of service on the first generation boilers achieves an additional 20 - 30% NOx reduction. Second and third generation main boilers are expected to use Volcano type burners to further reduce NOx emissions.

b. Describe

K. Existing and New or Modified Stack Data



Questions for the above diagram

K. Existing and New or Modified Stack Data (cont.) *- FIRST GENERATION VESSELS*

	Stack 1	Stack 2	Stack3	
1. Ht. of ground above sea level (arrow 1)	0 ft	0 ft	0 ft	
2. Ht. of stack top above ground (arrow 2)	122.7 ft	122.7 ft	122.7 ft	
3. Ht. of ground above stack base (arrow 3)	0 ft	0 ft	0 ft	
4. Ht. of stack top above roof (arrow 4)	13.8 ft	13.8 ft	13.8 ft	
5. Stack exit size (inside) (arrow 5)	55.1 in	55.1 in	27.6 in	
6. Is stack existing, new, or modified?	existing	existing	existing	
7. Which combustion units on which stacks?	Unit 1	Unit 2	Unit 3	
8. Inside shell material	Steel	Steel	Steel	
9. Outside shell material	Steel	Steel	Steel	
10. Max gas exit velocity	69.6 fps	69.6 fps	102.6 fps	
11. Min gas exit velocity	28.2 fps	28.2 fps	≈ 50 fps	
12. Maximum stack gas exit temperature (^{0}F)	336	336	590	
13. Maximum stack gas volume (acfm)	69,200	69,200	14,138	
14. Type of rain protection	NA	NA	NA	

NOTE: The rain protection device should be of such a design as to allow the unimpeded escape of the stack gases. “Rain Hats” are prohibited.

L. Energy Conservation Devices *– FIRST GENERATION VESSELS*

	Unit 1	Unit 2	Unit 3
1. Feed water economizer (yes or no)	☒ Y ☐ N	☒ Y ☐ N	☐ Y ☐ N
2. Combustion air preheater (yes or no) (1)	☐ Y ☒ N	☐ Y ☒ N	☐ Y ☐ N
3. Blowdown heat recovery (yes or no)	☐ Y ☒ N	☐ Y ☒ N	☐ Y ☐ N
4. Oxygen trim control (yes or no)	☒ Y ☐ N	☒ Y ☐ N	☐ Y ☐ N
5. Other (describe)	☐ Y ☐ N	☐ Y ☐ N	☐ Y ☐ N

(1) The boilers are equipped with air preheaters; however, it has been determined that removing the air pre-heaters from service is an effective NOx control technology, and therefore, they will not will be used on these boilers..

K. Existing and New or Modified Stack Data (cont.) - *SECOND GENERATION VESSELS*

	Stack 4	Stack 5	Stack 6	Stack 7
1. Ht. of ground above sea level (arrow 1)	0 ft	0 ft	0 ft	0 ft
2. Ht. of stack top above ground (arrow 2)	122.7 ft	122.7 ft	122.7 ft	122.7 ft
3. Ht. of ground above stack base (arrow 3)	0 ft	0 ft	0 ft	0 ft
4. Ht. of stack top above roof (arrow 4)	13.8 ft	13.8 ft	13.8 ft	13.8 ft
5. Stack exit size (inside) (arrow 5)	55.1 in	55.1 in	42.7 in	27.6 in
6. Is stack existing, new, or modified?	existing	existing	existing	existing
7. Which combustion units on which stacks?	Unit 4	Unit 5	Unit 6	Unit 7
8. Inside shell material	Steel	Steel	Steel	Steel
9. Outside shell material	Steel	Steel	Steel	Steel
10. Max gas exit velocity	69.2 fps	69.2 fps	85.9 fps	85 fps
11. Min gas exit velocity	28.0 fps	28.0 fps	≈ 40 fps	≈ 45 fps
12. Maximum stack gas exit temperature (^{0}F)	336	336	789	626
13. Maximum stack gas volume (acfm)	68,700	68,700	51,300	11,754
14. Type of rain protection	NA	NA	NA	NA

NOTE: The rain protection device should be of such a design as to allow the unimpeded escape of the stack gases. "Rain Hats" are prohibited.

L. Energy Conservation Devices – *SECOND GENERATION VESSELS*

	Unit 4	Unit 5	Unit 6	Unit 7
1. Feed water economizer (yes or no)	☒ Y ☐ N	☒ Y ☐ N	☐ Y ☐ N	☐ Y ☐ N
2. Combustion air preheater (yes or no) (1)	☐ Y ☒ N	☐ Y ☒ N	☐ Y ☐ N	☐ Y ☐ N
3. Blowdown heat recovery (yes or no)	☐ Y ☒ N	☐ Y ☒ N	☐ Y ☐ N	☐ Y ☐ N
4. Oxygen trim control (yes or no)	☒ Y ☐ N	☒ Y ☐ N	☐ Y ☐ N	☐ Y ☐ N
5. Other (describe)	☐ Y ☐ N	☐ Y ☐ N	☐ Y ☐ N	☐ Y ☐ N

(1) The boilers are equipped with air preheaters; however, it has been determined that removing the air pre-heaters from service is an effective NOx control technology, and therefore, they will not will be used on these boilers..

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

BWP AQ CPA-1 (for use with BWP AQ 02, 03)

Comprehensive Plan Approval Application for Fuel Utilization Facilities

Transmittal Number

Facility ID (if known)

K. Existing and New or Modified Stack Data (cont.) - *THIRD GENERATION VESSELS*

	Stack 8	Stack 9	Stack 10	Stack 11
1. Ht. of ground above sea level (arrow 1)	0 ft	0 ft	0 ft	0 ft
2. Ht. of stack top above ground (arrow 2)	122.7 ft	122.7 ft	122.7 ft	122.7 ft
3. Ht. of ground above stack base (arrow 3)	0 ft	0 ft	0 ft	0 ft
4. Ht. of stack top above roof (arrow 4)	13.8 ft	13.8 ft	13.8 ft	13.8 ft
5. Stack exit size (inside) (arrow 5)	55.1 in	55.1 in	55.1 in	27.6 in
6. Is stack existing, new, or modified?	new	new	new	new
7. Which combustion units on which stacks?	Unit 8	Unit 9	Unit 10	Unit 11
8. Inside shell material	Steel	Steel	Steel	Steel
9. Outside shell material	Steel	Steel	Steel	Steel
10. Max gas exit velocity	69.2 fps	69.2 fps	68.2 fps	85 fps
11. Min gas exit velocity	28.0 fps	28.0 fps	13.5 fps	≈ 45 fps
12. Maximum stack gas exit temperature (^{0}F)	336	336	675	626
13. Maximum stack gas volume (acfm)	68,700	68,700	67,773	11,754
14. Type of rain protection	NA	NA	NA	NA

NOTE: The rain protection device should be of such a design as to allow the unimpeded escape of the stack gases. "Rain Hats" are prohibited.

L. Energy Conservation Devices – *THIRD GENERATION VESSELS*

	Unit 8	Unit 9	Unit 10	Unit 11
1. Feed water economizer (yes or no)	☒ Y ☐ N	☒ Y ☐ N	☐ Y ☐ N	☐ Y ☐ N
2. Combustion air preheater (yes or no) (1)	☐ Y ☒ N	☐ Y ☒ N	☐ Y ☐ N	☐ Y ☐ N
3. Blowdown heat recovery (yes or no)	☐ Y ☒ N	☐ Y ☒ N	☐ Y ☐ N	☐ Y ☐ N
4. Oxygen trim control (yes or no)	☒ Y ☐ N	☒ Y ☐ N	☐ Y ☐ N	☐ Y ☐ N
5. Other (describe)	☐ Y ☐ N	☐ Y ☐ N	☐ Y ☐ N	☐ Y ☐ N

(1) The boilers are equipped with air preheaters; however, it has been determined that removing the air pre-heaters from service is an effective NOx control technology, and therefore, they will not will be used on these boilers..

M. Miscellaneous

1.
Standard Industrial Classification (SIC) code(s) for this facility?
2.
Number of employees at this facility?
3. No
Is waste or recycled oil burned at this facility?
4. N/A
If numbers 4, 5, 6, fuel oil is used, identify who removes and disposes of the fuel oil sludge.

N. CPA Preparer

1. Chris Williams
Person who complied the plans applications materials
2. Tetra Tech EC, Inc.
Representing
3. 133 Federal Street, 6th Floor, Boston, MA 02110
Address
4. 617-457-8200
Telephone number
5. 10-23-08
Date completed

O. Certifications

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

Susan R. Leach
Print name

Susan R. Leach
Authorized signature

Lead Office Engineer
Position/title

Tetra Tech EC, Inc.
Representing

27 Oct. 2008
Date

41231
PE number

COMMONWEALTH OF MASSACHUSETTS
SUSAN R. LEACH, PE
CIVIL
No. 41231
REGISTERED
PROFESSIONAL ENGINEER

APPENDIX B

Vendor Specifications, Drawings, and Data

APPENDIX B1

First Generation Main Boiler Specifications

Performance Data

Main Boiler For **Daewoo H.2208/18**
Boiler Type **MB-4E-KS2**

Oil firing

Load			B.MAX	NOR	75% NOR	50% NOR	25% NOR
Evaporation	Total	kg/h	71,000	49,000	36,250	24,500	12,750
	SH Steam	kg/h	71,000	48,000	35,250	23,500	11,750
	DSH Steam	kg/h	0	1,000	1,000	1,000	1,000
Pressure	Drum	kg/cm^2g	69.4	65.3	63.6	62.4	61.8
	SH Outlet	kg/cm^2g	61.5	61.5	61.5	61.5	61.5
Water & Steam Temperature	Eco. Inlet	℃	139.8	139.8	139.8	139.8	139.8
	SH Inlet	℃	284.9	280.8	279.1	278.0	277.2
	SH Outlet	℃	515.0	515.0	515.0	496.9	456.5
	DSH Outlet	℃	284.9	288.4	288.4	288.4	288.4
Air Temperature	FDF Outlet	℃	38	38	38	38	38
	SAH Outlet	℃	120	120	120	120	120
Efficiency	(HHV Base)	%	88.4	88.5	88.3	87.7	84.9
Calorific Value	HHV	kcal/kg	10,280	10,280	10,280	10,280	10,280
	LHV	kcal/kg	9,713	9,713	9,713	9,713	9,713
Fuel Oil Consumption		kg/h	5166	3547	2624	1753	897
Excess Air Rate		%	10.0	10.0	12.2	18.5	54.3
O2 Rate		%	1.9	1.9	2.3	3.3	7.4
Combution Air Flow		kg/h	79119	54328	41002	28925	19266
Flue Gas Flow		kg/h	84285	57875	43626	30678	20163
Eco Outlet Gas Temp.		℃	175	167	162	158	154
Total Draft Loss		mmAq	543	256	145	72	31

Gas firing

Load			B.MAX	NOR	75% NOR	50% NOR	25% NOR
Evaporation	Total	kg/h	71,000	49,000	36,250	24,500	12,750
	SH Steam	kg/h	71,000	48,000	35,250	23,500	11,750
	DSH Steam	kg/h	0	1,000	1,000	1,000	1,000
Pressure	Drum	kg/cm^2g	69.4	65.3	63.6	62.4	61.8
	SH Outlet	kg/cm^2g	61.5	61.5	61.5	61.5	61.5
Water & Steam Temperature	Eco. Inlet	℃	139.8	139.8	139.8	139.8	139.8
	SH Inlet	℃	284.9	280.8	279.1	278.0	277.2
	SH Outlet	℃	515.0	515.0	515.0	515.0	493.2
	DSH Outlet	℃	284.9	288.4	288.4	288.4	288.4
Air Temperature	FDF Outlet	℃	38	38	38	38	38
	SAH Outlet	℃	120	120	120	120	120
Efficiency	(HHV Base)	%	83.8	84.0	83.9	83.3	80.7
Calorific Value	HHV	kcal/kg	13,270	13,270	13,270	13,270	13,270
	LHV	kcal/kg	11,964	11,964	11,964	11,964	11,964
Fuel Gas Consumption		kg/h	4243	2911	2153	1458	757
Excess Air Rate		%	10.0	10.0	12.2	18.5	54.3
O2 Rate		%	1.9	1.9	2.3	3.3	7.4
Combution Air Flow		kg/h	81368	55812	42101	30120	20357
Flue Gas Flow		kg/h	85612	58722	44254	31578	21114
Eco Outlet Gas Temp.		℃	180	169	164	158	154
Total Draft Loss		mmAq	560	264	150	76	34

APPENDIX B2

Second and Third Generation Main Boiler Specifications

Performance Data

Main Boiler For **Daewoo H.2254**
Boiler Type **MB-4E-KS2**

Oil firing

Load			B.MAX	NOR	75% NOR	50% NOR	25% NOR
Evaporation	Total	kg/h	71,000	49,000	36,250	24,500	12,750
	SH Steam	kg/h	71,000	48,000	35,250	23,500	11,750
	DSH Steam	kg/h	0	1,000	1,000	1,000	1,000
Pressure	Drum	kg/cm2g	69.4	65.3	63.6	62.4	61.8
	SH Outlet	kg/cm2g	61.5	61.5	61.5	61.5	61.5
Water & Steam Temperature	Eco. Inlet	℃	139.8	139.8	139.8	139.8	139.8
	SH Inlet	℃	284.9	280.8	279.1	278.0	277.2
	SH Outlet	℃	515.0	515.0	500.1	474.4	436.2
	DSH Outlet	℃	284.9	288.4	288.4	288.4	288.4
Air Temperature	FDF Outlet	℃	38	38	38	38	38
	SAH Outlet	℃	120	120	120	120	120
Efficiency	(HHV Base)	%	88.1	88.1	87.9	87.2	84.2
Calorific Value	HHV	kcal/kg	10280	10280	10280	10280	10280
	LHV	kcal/kg	9713	9713	9713	9713	9713
Fuel Oil Consumption		kg/h	5186	3563	2606	1731	889
Excess Air Rate		%	10.0	10.0	12.2	18.5	54.3
O2 Rate		%	1.9	1.9	2.3	3.3	7.4
Combustion Air Flow		kg/h	79,435	54,575	40,715	28,564	19,098
Flue Gas Flow		kg/h	84,621	58,138	43,322	30,295	19,987
ECO Inlet Gas Temp.		℃	394	355	333	313	295
ECO Outlet Gas Temp.		℃	184	177	173	170	166
CO2 Rate (Dry base)		%	14.4	14.4	14.0	13.3	10.1
O2 Rate (Dry base)		%	2.0	2.0	2.4	3.4	7.7
SO2 Rate (Dry base)		%	0.3	0.3	0.3	0.3	0.2
NOx emission (Ref O2=0%		ppm	515	379	362	462	461
CO emission (Ref O2=2%)		ppm	150	72	38	10	0
Particle (Ref O2=2%)		mg/Nm3	800	568	464	360	264
Total Draft Loss		mmAq	466	220	122	60	26

Gas firing

Load			B.MAX	NOR	75% NOR	50% NOR	25% NOR
Evaporation	Total	kg/h	68,500	49,000	36,250	24,500	12,750
	SH Steam	kg/h	68,500	48,000	35,250	23,500	11,750
	DSH Steam	kg/h	0	1,000	1,000	1,000	1,000
Pressure	Drum	kg/cm2g	69.4	65.5	63.7	62.5	61.8
	SH Outlet	kg/cm2g	61.5	61.5	61.5	61.5	61.5
Water & Steam Temperature	Eco. Inlet	℃	139.8	139.8	139.8	139.8	139.8
	SH Inlet	℃	284.9	281.1	279.3	278.0	277.3
	SH Outlet	℃	515.0	515.0	515.0	510.6	475.0
	DSH Outlet	℃	284.9	288.4	288.4	288.4	288.4
Air Temperature	FDF Outlet	℃	38	38	38	38	38
	SAH Outlet	℃	38	38	38	38	38
Efficiency	(HHV Base)	%	83.5	83.6	83.4	82.8	80.0
Calorific Value	HHV	kcal/kg	13270	13270	13270	13270	13270
	LHV	kcal/kg	11964	11964	11964	11964	11964
Fuel Gas Consumption		kg/h	4228	3008	2226	1506	782
Excess Air Rate		%	10.0	10.0	12.2	18.5	54.3
Combustion Air Flow		kg/h	81,069	57,673	43,543	31,107	21,044
Flue Gas Flow		kg/h	85,297	60,681	45,769	32,613	21,826
ECO Inlet Gas Temp.		℃	416	376	349	325	299
ECO Outlet Gas Temp.		℃	178	169	164	160	155
CO2 Rate (Dry base)		%	10.6	10.6	10.3	9.7	7.3
O2 Rate (Dry base)		%	2.1	2.1	2.5	3.6	7.9
NOx emission (Ref O2=0%		ppm	120	114	111	106	98
CO emission (Ref O2=2%)		ppm	<50	<50	<50	<50	<50
PM10 (Ref O2=2%)		ppm	<10	<10	<10	<10	<10
Total Draft Loss		mmAq	479	243	138	70	31

APPENDIX B3

Third Generation Auxiliary Boiler Emissions Data

HAMWORTHY
COMBUSTION

Proven Combustion Solutions

Incorporating:

PEABODY ENGINEERING
AIROIL - FLAREGAS
CHENTRONICS

BOILER EXHAUST NOX EMISSION GUARANTEE

AALBORG INDUSTRIES

DSME Exmar LNG RV's

50 T/H CAPACITY – MISSION OL 55

Hamworthy Combustion Reference:	**0MF13511 NOx Guarantee**
Client Reference Number:	
Date:	12th June 2007
Engineer:	Bob Seager
Direct Dial:	+44 (0)1202 662890
Facsimile:	+44 (0)1202 665333
E-mail:	bseager@hamworthy-combustion.com

Marine and Offshore

FUEL GAS FIRING COMBUSTION PERFORMANCE GUARANTEE

1.0 The following NOx emission performance guarantee is given strictly conditional upon compliance with the following factors:

a) The burners are in the 'as new' condition with gas nozzles having a flow tolerance not exceeding ± 2%.

b) The burners are correctly installed and operated as per Hamworthy instructions. All operating conditions including combustion air temperature, excess air levels, fuel condition, etc are as stated on the burner technical data sheet attached.

c) Where the air supply ductwork is not in Hamworthy scope of supply the circumferential air flow deviation in the burner must be within ± 10%

d) Performance guarantees are given against the following specification(s):-
(based on DSME Feed back dated 30/04/2007)

Fuel Gas Composition (volume base):

Nitrogen	0.13 %
Methane (CH_4)	93.93 %
Ethane (C_2H_6)	5.42 %
Propane (C_3H_8)	0.46 %
Butane (C_5H_{10})	0.05 %
Hydrocarbons (C_{4+})	0.01 %
Lower calorific value	37.6 MJ/Nm^3 ± 10%

e) It is important that the fuel(s) against which the emissions are to be measured is confirmed to be to specification before the trials commence, or at the latest concurrently with the trials. Any adverse deviations from the reference composition will annul the guarantee.

f) All measurements are taken in the 'steady state' condition.

2.0 All measurements must be carried out in strict accordance with procedures and instrument accuracy at least equal to appropriate British Standards.

3.0 The guaranteed NOx level is 128 ppm at 3% oxygen (dry)

1.0 Introduction

Hamworthy Combustion have been asked to provide data of the exhaust emissions from new auxiliary boilers to be installed on LNG carriers, when fitted with Hamworthy dual fuel register burners.

2.0 Fuels

The two main fuels to be considered are Marine Diesel Fuel Oil (ISO8217:DMA) and LNG fuel gas. The composition and physical properties of each fuel used for the basis of this data is:

2.1 Marine Diesel Fuel Oil

Density:	890 kg/Nm^3	
Viscosity:	1.5-6.0 cSt @ 40 ^{0}C	
Lower Calorific Value:	42.2 MJ/kg	
Elemental Analysis:	Carbon	86.1%
	Hydrogen	13.2%
	Sulphur	0.65 %
	Nitrogen	0.05%

2.2 Fuel Gas

Molecular Weight:	16.93	
Density:	0.757 kg/Nm^3	
Lower Calorific Value:	49.6 MJ/kg	
Composition (vol)	Methane	93.93 %
	Ethane	5.42 %
	Propane	0.46 %
	Butane	0.05 %
	Pentane	0.01 %
	Nitrogen	0.13 %
Elemental Analysis:	Carbon	75.41 %
	Hydrogen	24.38 %
	Nitrogen	0.22 %

3.0 Boilers

The boiler is considered at the normal load with the following operating basis:

Installation		
Boiler Type		Mission OL 55
Boiler Load	T/h	50
Combustion Air Temp.	^oC	38
Furnace Volume	m^3	53
Excess Air at MCR	%	15
Marine Diesel Fuel Oil Rate	Kg/h	3445
Fuel Gas Rate	Kg/h	3008
Excess Oxygen (Dry)	%	3.0

4.0 Exhaust Gas Composition

The exhaust composition main constituents are not a function of the boiler and burner design and operating conditions and hence do not change with boiler type. The exhaust gas compositions (wet basis) for the fuel oil and fuel gas are given below for duties of 25%, 50%, 75% and 100%.

4.1 Marine Diesel Fuel Oil

Boiler Load, %	25	50	75	100
Fuel Rate, kg/h	823	1653	2530	3445
Excess Air, %	38	21	17	15
Exhaust Gas Rate, kg/h	17291	30655	45451	60890
Exhaust Temp., Deg C	197	234	280	325
Exhaust Mol. Wt.	29.101	29.018	29.021	29.022
Exhaust Density, kg/Nm3	1.2943	1.2946	1.2947	1.2948
Exhaust Composition (Wet) by Volume, %:				
Carbon Dioxide, CO2	9.906	11.226	11.684	11.780
Water, H2O	9.112	10.326	10.748	10.836
Sulphur Dioxide, SO2	0.028	0.032	0.033	0.033
Oxygen, O2	5.506	3.448	2.735	2.585
Nitrogen, N2	74.563	74.089	73.924	73.890
Argon, Ar	0.884	0.879	0.877	0.876
Exhaust Composition (Wet) by Mass, %:				
Carbon Dioxide, CO2	15.025	17.022	17.715	17.860
Water, H2O	5.654	6.405	6.666	6.721
Sulphur Dioxide, SO2	0.062	0.070	0.073	0.074
Oxygen, O2	6.074	3.803	3.015	2.850
Nitrogen, N2	71.966	71.489	71.323	71.288
Argon, Ar	1.219	1.211	1.208	1.208

4.2 Fuel Gas

Boiler Load, %	25	50	75	100
Fuel Rate, kg/h	705	1421	2192	3008
Excess Air, %	29	18	17	15
Exhaust Gas Rate, kg/h	16257	30094	46047	62160
Exhaust Temp., Deg C	200	244	300	357
Exhaust Mol. Wt.	27.976	27.922	27.914	27.914
Exhaust Density, kg/Nm3	1.2482	1.2458	1.2454	1.2454
Exhaust Composition (Wet) by Volume, %:				
Carbon Dioxide, CO2	7.859	8.353	8.487	8.487
Water, H2O	15.246	16.204	16.462	16.462
Sulphur Dioxide, SO2	0.000	0.000	0.000	0.000
Oxygen, O2	3.871	2.797	2.508	2.508
Nitrogen, N2	72.169	71.795	71.694	71.694
Argon, Ar	0.856	0.851	0.850	0.850
Exhaust Composition (Wet) by Mass, %:				
Carbon Dioxide, CO2	12.547	13.267	13.377	13.377
Water, H2O	9.956	10.528	10.615	10.615
Sulphur Dioxide, SO2	0.000	0.000	0.000	0.000
Oxygen, O2	4.134	3.041	2.875	2.875
Nitrogen, N2	72.141	71.945	71.915	71.915
Argon, Ar	1.222	1.219	1.218	1.218

5.0 Nitrogen Oxides (NO_x)

For the Hamworthy DF burner type, the predicted emission from the boiler for fuel gas firing, and oil firing, are given in the tables below at boiler loads of 25%, 50%, 75%, and100%. Note NOx values are at 3% O_2 dry @ 273K and 101kPa.

FUEL GAS:

Boiler Load, %	25	50	75	100
Fuel Rate, kg/h	705	1421	2192	3008
Excess Air, %	29	18	17	15
NOx, ppm	102	93	103	118

MARINE DIESEL FUEL OIL:

Boiler Load, %	25	50	75	100
Fuel Rate, kg/h	823	1653	2530	3445
Excess Air, %	38	21	17	15
NOx, ppm	85	120	146	168

Note: The values are predictions only, and not guarantee values.

6.0 Carbon Monoxide (CO)

Carbon Monoxide emissions for the boiler/burner combination operating at its design conditions (e.g. clean, etc.) will be extremely low and of the order of 10 –20 ppm (13 – 27 mg/Nm^3 @ 3% O_2, 273K and 101 kPa)

Carbon Monoxide emissions increase in the event of incomplete combustion due to factors, such as:

1. In-sufficient air supply
2. Poor fuel oil atomisation
3. Dirty, blocked air swirlers
4. Dirty, blocked fuel nozzles
5. Flame impingement on boiler tube surfaces

Correct operation and maintenance procedures will ensure Carbon Monoxide emissions are limited to the typical values given above.

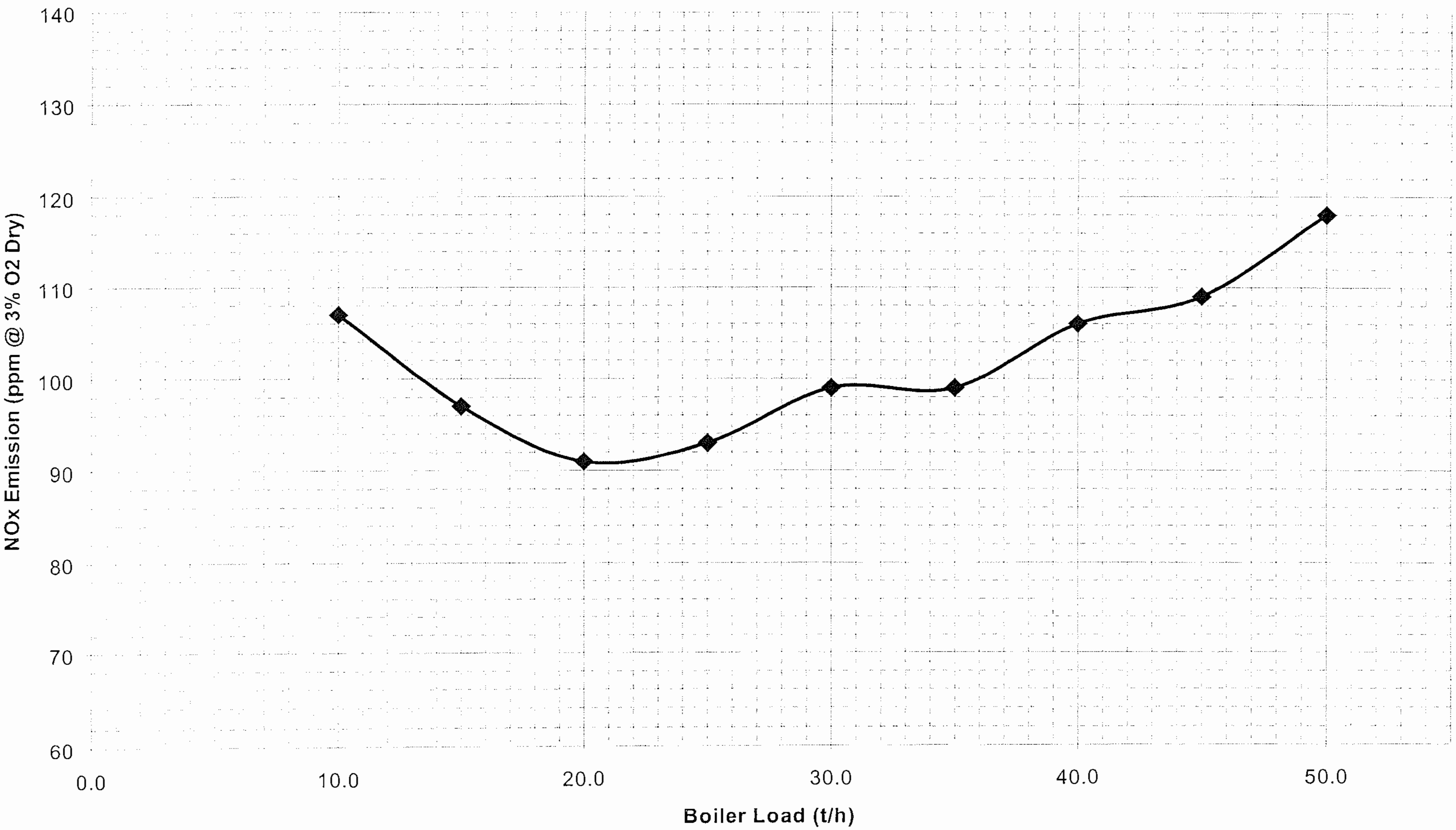
7.0 Unburnt Hydrocarbons (UHC)

For the Hamworthy DF type burner the predicted stack solids (PM) emissions for the boiler are virtually zero for the marine diesel oil and produced fuel gas as the fuels are so clean and pure.

HAMWORTHY
COMBUSTION

Application: Aalborg Mission OL 55 Boiler
1 x DF715 Register Burner
Natural Gas, Ambient Combustion Air

Predicted NOx Emission Concentration - Fuel Gas Firing



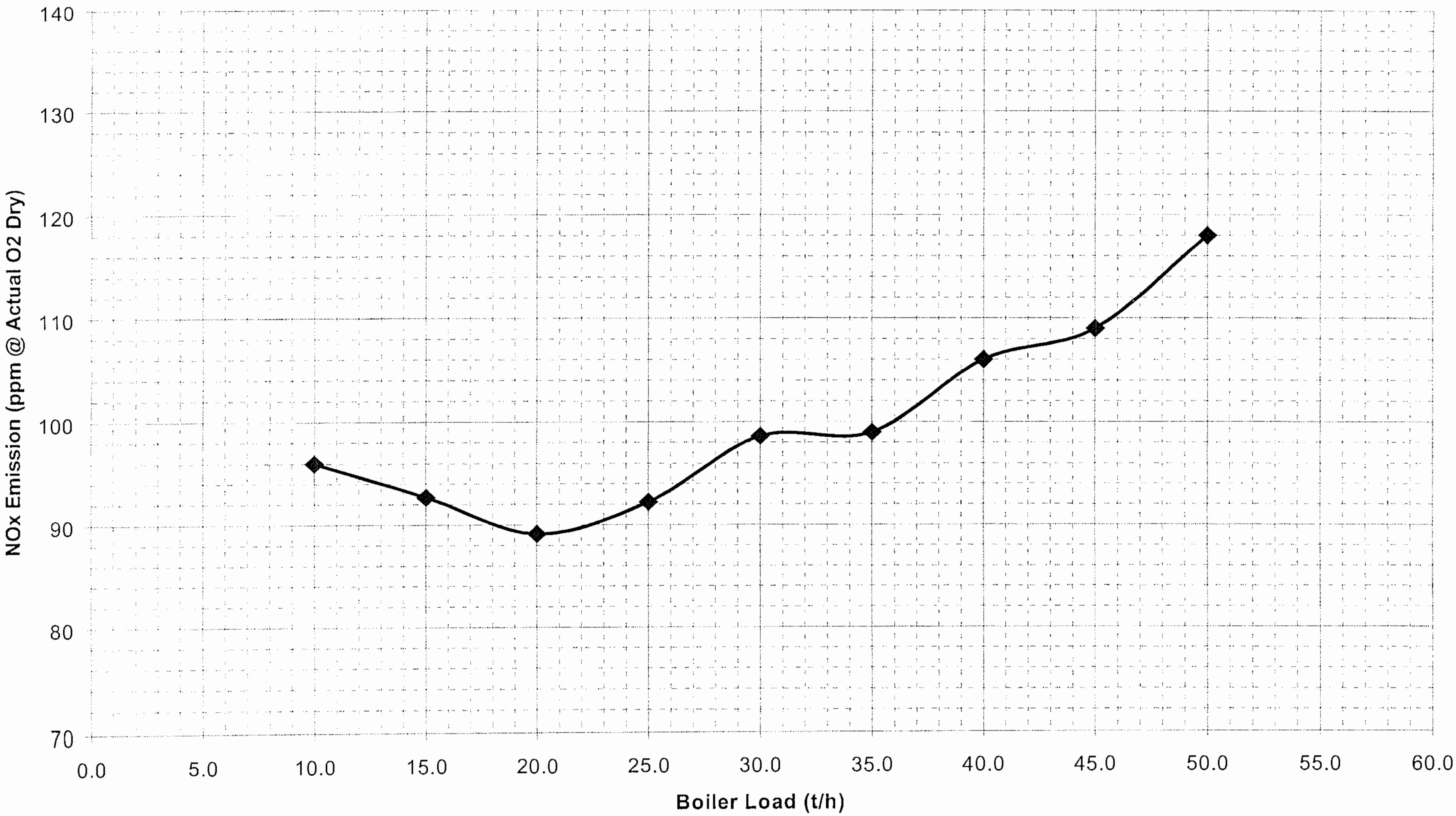
HC Ref.: MF900248
Project: DSME Hull No. 2270/71

12-Jun-07

HAMWORTHY
COMBUSTION

Application: Aalborg Mission OL 55 Boiler
1 x DF715 Register Burner
Natural Gas, Ambient Combustion Air

Predicted NOx Emission Concentration - Fuel Gas Firing



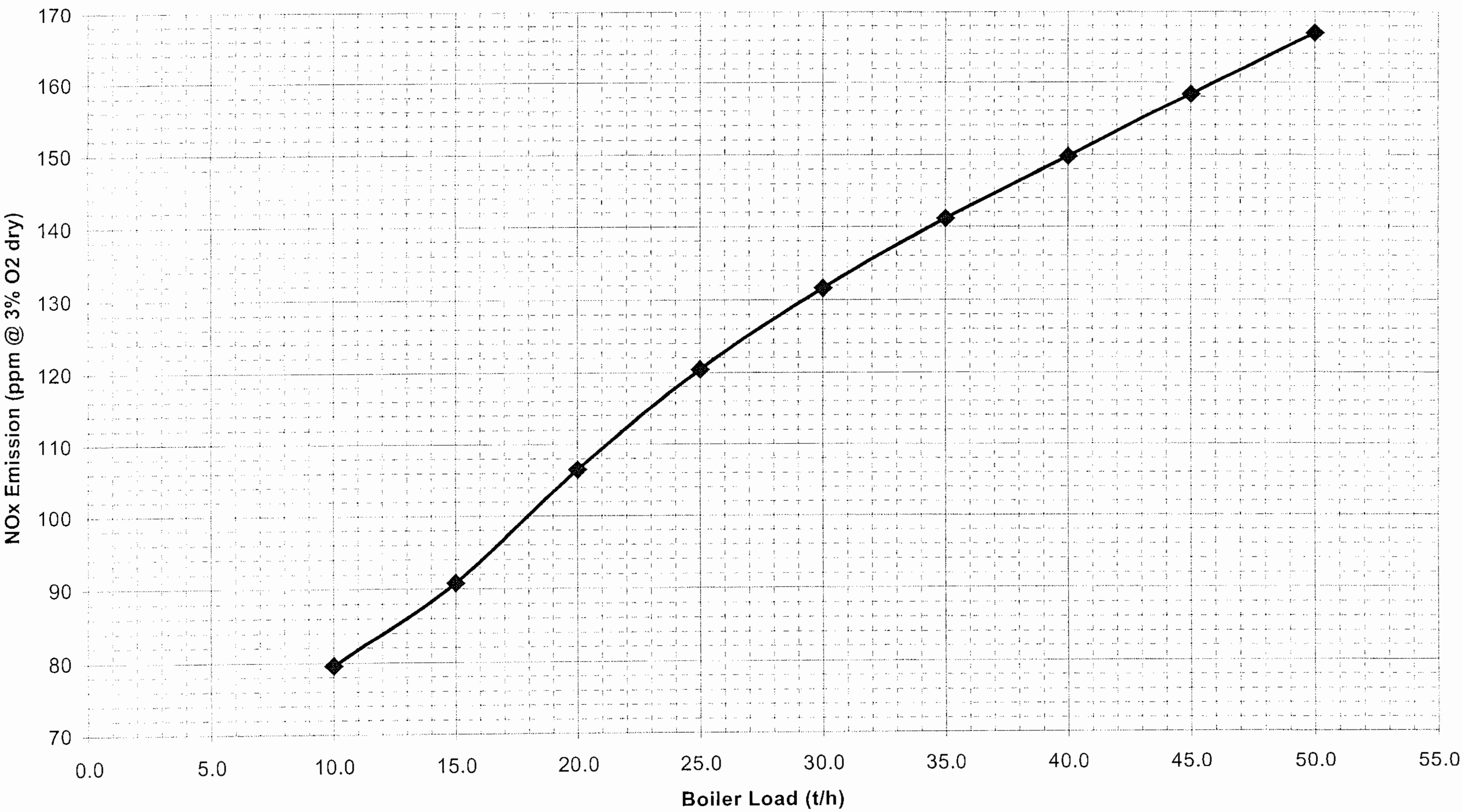
HC Ref.: MF900248
Project: DSME Hull No. 2270/71

12-Jun-07

HAMWORTHY
COMBUSTION

Application: Aalborg Mission OL 55 Boiler
1 x DF715 Register Burner
Marine Diesel Oil, Ambient Combustion Air

Predicted NOx Emission Concentration - Diesel Oil Firing



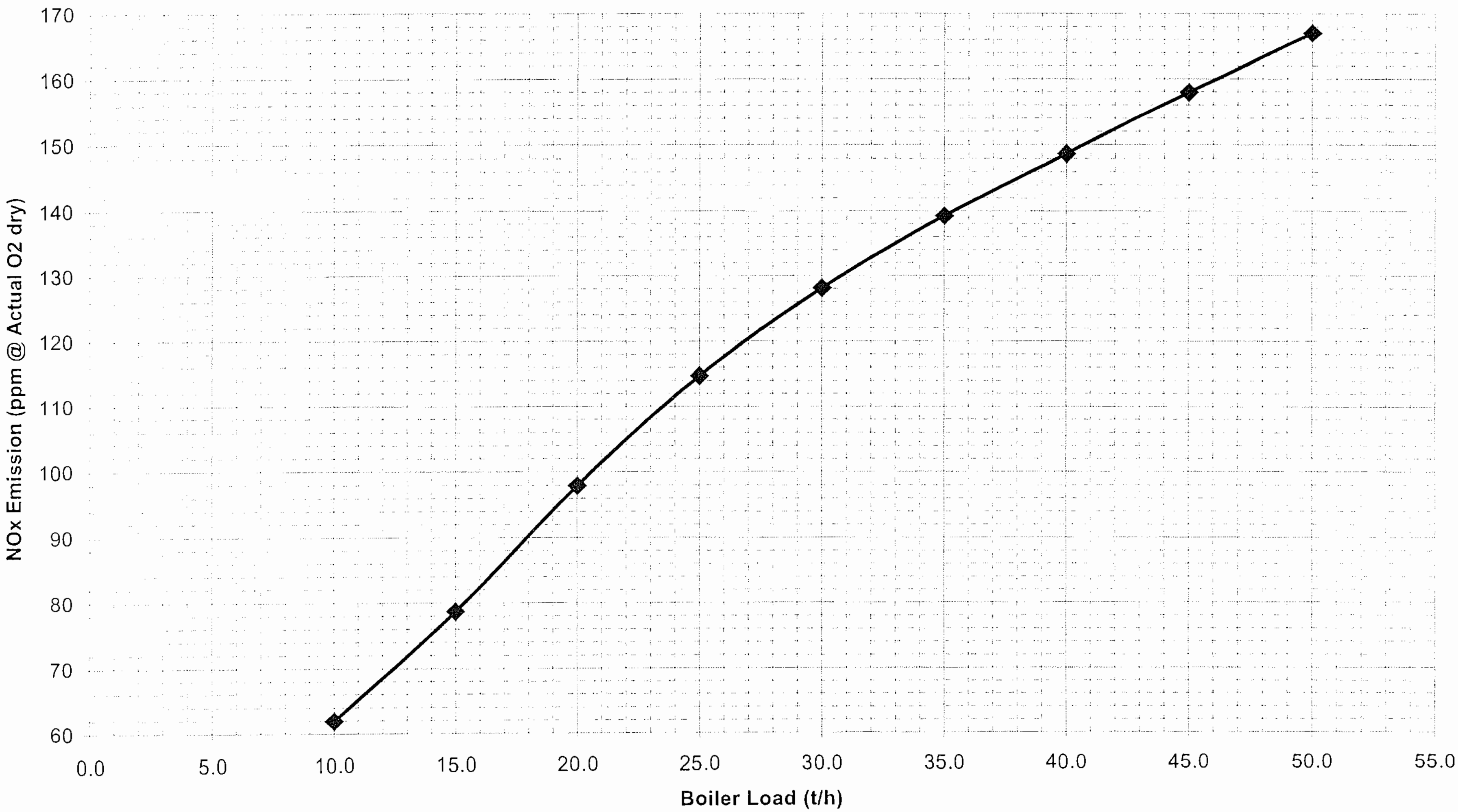
HC Ref.: MF900248
Project: DSME Hull No. 2270/71

12-Jun-07

HAMWORTHY
COMBUSTION

Application: Aalborg Mission OL 55 Boiler
1 x DF715 Register Burner
Marine Diesel Oil, Ambient Combustion Air

Predicted NOx Emission Concentration - Diesel Oil Firing



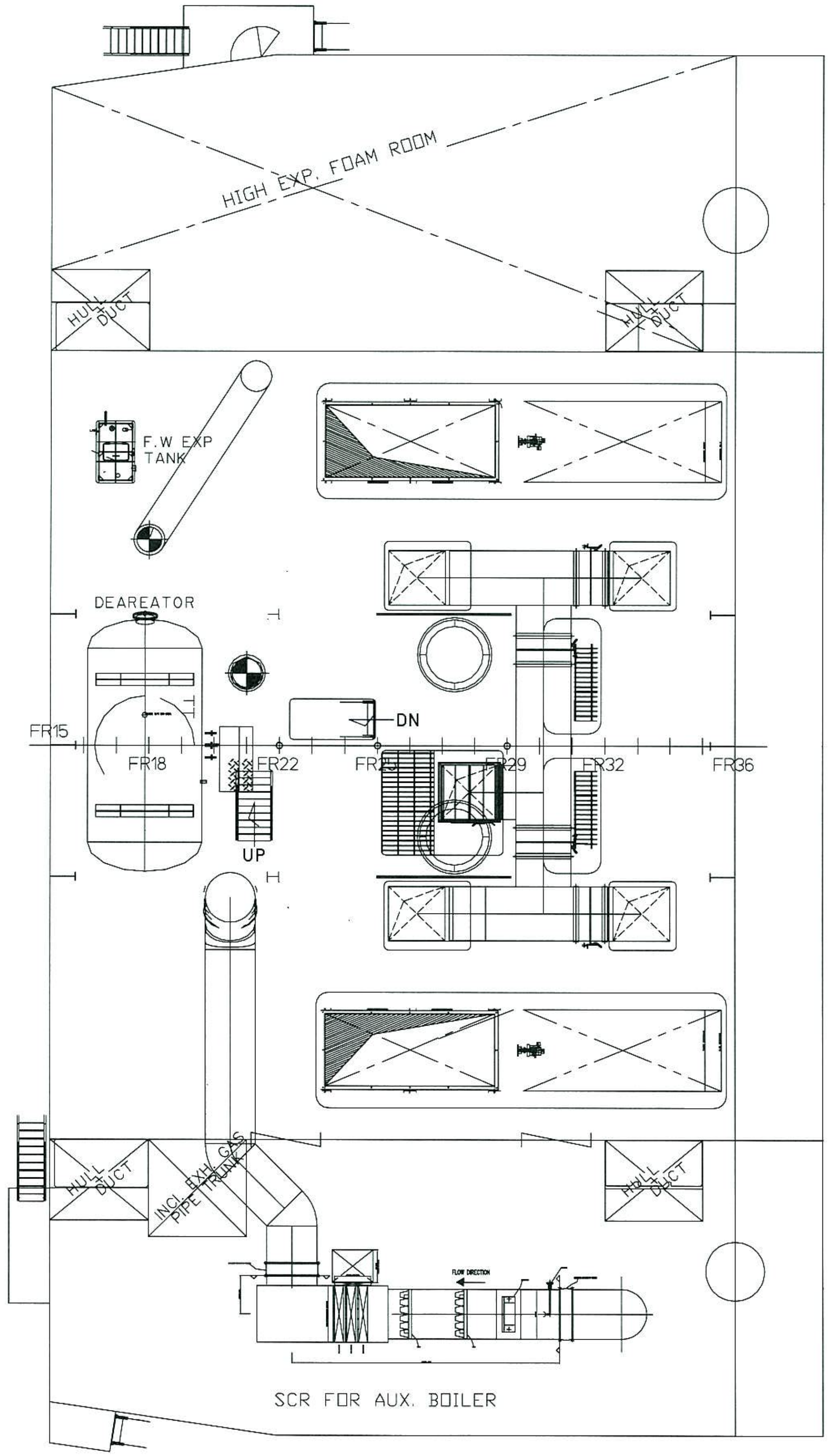
HC Ref.: MF900248
Project: DSME Hull No. 2270/71

12-Jun-07

APPENDIX B4

Diagram of Third Generation Auxiliary Boiler SCR

B – DECK PLAN



LNG CARRIER

ARRANGEMENT PROPOSAL 9 OF ARGILLON

10x11 REACTOR

STATUS : 2005-12-05

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APPENDIX C

Emissions Calculations

Appendix C - Calculations
Auxiliary Boiler (3rd Gen LNGRV)

Emissions and Modeling Parameters: 50 tonne/hr Auxiliary Boiler

Aalborg MIS OL-50000 boiler with Hamworthy DF 715 burners

Boiler Load		25%	50%	75%	100%
Fuel Consumption	kg/h	705	1,421	2,192	3,008
Heat Input Rate (HHV)	MMBtu/hr	37	74	115	157
O_2 Concentration	% (wet)	3.871	2.797	2.508	2.508
Outlet Gas Temp.	^oC	200	244	300	357
Exhaust Gas Rate	kg/h	16,257	30,094	46,047	62,160
Exhaust Mol. Wt.	g/mol	27.976	27.922	27.914	27.914
Exhaust flow	acfm	13,279	26,920	45,664	67,773
Exit velocity	m/s	4.1	8.3	14.0	20.8

All data except heat input rate, exhaust flow/velocity from vendor data sheet shown in Appendix B

Heat input rate calculated from vendor spec composition (see gas composition worksheet)

Exhaust flow calculated from ideal gas law, R = 0.002898 $(ft^3)(atm)/(mol)(K)$,

P = 1 atm; exit velocity assumes stack diam. of 1.40 m

NO_x (as NO_2)	lb/hr	0.66	1.34	2.07	2.8	based on SCR spec of 15 ppmvd @ 3% O_2
CO	lb/hr	1.6	3.3	5.0	6.9	based on 60 ppmvd @ 3% O_2 (conservative)
VOC	lb/hr	0.20	0.40	0.62	0.85	based on 5.5 lb/MMscf @ 1020 Btu/scf*
PM (filterable)	lb/hr	0.069	0.14	0.21	0.29	based on 1.9 lb/MMscf @ 1020 Btu/scf*
SO_2	lb/hr	0.022	0.044	0.067	0.092	based on 0.6 lb/MMscf @ 1020 Btu/scf*
HAP	lb/hr	0.069	0.14	0.21	0.29	based on 1.9 lb/MMscf @ 1020 Btu/scf*

*EPA AP-42 factors (see following page for calculation of total HAP factor)

Metric units (for modeling)

NO_x (as NO_2)	g/s	0.084	0.17	0.26	0.36
CO	g/s	0.20	0.41	0.63	0.87
PM (filterable)	g/s	0.009	0.017	0.027	0.037
SO_2	g/s	0.0027	0.0055	0.0085	0.0116

Appendix C - Calculations
Gas Parameters

	# of atoms							Composition (% by volume or mole)	
	H	C	S	N	O				
	1.0	12.0	32.1	14.1	16	Btu/scf (HHV)	Density (lb/scf)	100% methane	Hamworthy reference fuel
Nitrogen (N_2)	0	0	0	2	0	0	0.0748	0.00%	0.13%
Methane (CH_4)	4	1	0	0	0	1013	0.0424	100.00%	93.93%
Ethane (C_2H_6)	6	2	0	0	0	1792	0.0803	0.00%	5.42%
Propane (C_3H_8)	8	3	0	0	0	2592	0.1196	0.00%	0.46%
Isobutane (C_4H_{10})	10	4	0	0	0	3365	0.1582	0.00%	0.00%
n-butane (C_4H_{10})	10	4	0	0	0	3373	0.1582	0.00%	0.05%
Isopentane (C_5H_{12})	12	5	0	0	0	4007	0.1904		
n-Pentane (C_5H_{12})	12	5	0	0	0	4017	0.1904		0.01%
Heavies (C_6+)	14	6	0	0	0	4800	0.2274		
Total								100.00%	100.00%
Btu/scf (HHV) (60 ^oF)								1013	1063
Density (lb/scf) (60 ^oF)								0.0424	0.0448
GCV, Btu/lb								23,880	23,697
lb H/mol gas								4.03	4.16
lb C/mol gas								12.01	12.78
lb S/mol gas								0.00	0.00
lb N/mol gas								0.00	0.04
lb O/mol gas								0.00	0.00
%H (wt)		K_{hw}	5.57	K_{hd}	3.64			25.13%	24.50%
%C (wt)		K_c	1.53	K_c	1.53			74.87%	75.29%
%S (wt)		K_s	0.57	K_s	0.57			0.00%	0.00%
%N (wt)		K_n	0.14	K_n	0.14			0.00%	0.22%
%O (wt)		K_o	0.46	K_o	0.46			0.00%	0.00%
F_d, dscf/mmBtu								8,627	8,625
F_w, wscf/mmBtu								10,659	10,620

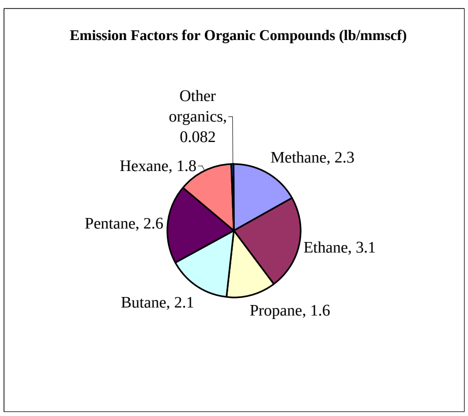
Appendix C - Calculations

HAP Emission Factor Calculation Sheet
Natural Gas Combustion (External)

Discussion: The emission factors for individual organic compounds and metals shown at the right are from the U.S. Environmental Protection Agency (EPA), "Compilation of Air Pollutant Emission Factors, Volume 1: Stationary Point and Area Sources" (AP-42), Section 1.4 for "Natural Gas Combustion" (external), rev. 7/98.

Emission factors prefaced with a "<" are based on method detection limits. Because emission factors for individual organics were developed independently of the emission factor for total organic compounds (TOC), the sum of the emission factors for individual organic pollutants (13.6 lb/mmscf) does not equal EPA's emission factor for TOC (11 lb/mmscf). Most metals are emitted as particulate matter; the total emission factor for metals (0.044 lb/mmscf) is much smaller than the emission factor for total particulate matter (7.6 lb/mmscf).

Most organics emitted from natural gas external combustion are not Hazardous Air Pollutants (HAP). Based on the available data, hexane is the most prevalent HAP; EPA based the emission factor for hexane (1.8 lb/mmscf) on the average of test results for a 28 mmBtu/hr boiler (emission factor 3.07 lb/mmscf) and test results for a 2.2 mmBtu/hr boiler (emission factor 0.59 lb/mmscf).



Pollutant	Emission Factor (lb/10^6 scf)[a]	Emission Factor (lb/10^6 Btu)[a]	Emission Factor Rating	Source (AP-42 Table)
Organic Compounds				
2-Methylnaphthalene[b]	2.4E-05	2.4E-08	D	1.4-3
3-Methylchloranthrene[b]	< 1.8E-06	< 1.8E-09	E	1.4-3
7,12-Dimethylbenz(a)anthracene[b]	< 1.6E-05	< 1.6E-08	E	1.4-3
Acenaphthene[b]	< 1.8E-06	< 1.8E-09	E	1.4-3
Acenaphthylene[b]	< 2.4E-06	< 2.4E-09	E	1.4-3
Anthracene[b]	< 1.8E-06	< 1.8E-09	E	1.4-3
Benz(a)anthracene[b]	< 1.8E-06	< 1.8E-09	E	1.4-3
Benzene[b]	2.1E-03	2.1E-06	B	1.4-3
Benzo(a)pyrene[b]	< 1.2E-06	< 1.2E-09	E	1.4-3
Benzo(b)fluoranthene[b]	< 1.8E-06	< 1.8E-09	E	1.4-3
Benzo(g,h,i)perylene[b]	< 1.2E-06	< 1.2E-09	E	1.4-3
Benzo(k)fluoranthene[b]	< 1.8E-06	< 1.8E-09	E	1.4-3
Butane	2.1E+00	0.00206	E	1.4-3
Chrysene[b]	< 1.8E-06	< 1.8E-09	E	1.4-3
Dibenzo(a,h)anthracene[b]	< 1.2E-06	< 1.2E-09	E	1.4-3
Dichlorobenzene[b]	1.2E-03	1.2E-06	E	1.4-3
Ethane	3.1E+00	0.00304	E	1.4-3
Fluoranthene[b]	3.0E-06	2.9E-09	E	1.4-3
Fluorene[b]	2.8E-06	2.7E-09	E	1.4-3
Formaldehyde[b]	7.5E-02	7.4E-05	B	1.4-3
Hexane[b]	1.8E+00	0.00176	E	1.4-3
Indeno(1,2,3-cd)pyrene[b]	< 1.8E-06	< 1.8E-09	E	1.4-3
Methane	2.3E+00	0.00225	B	1.4-2
Naphthalene[b]	6.1E-04	6E-07	E	1.4-3
Pentane	2.6E+00	0.00255	E	1.4-3
Phenanathrene[b]	1.7E-05	1.7E-08	D	1.4-3
Propane	1.6E+00	0.00157	E	1.4-3
Pyrene[b]	5.0E-06	4.9E-09	E	1.4-3
Toluene[b]	3.4E-03	3.3E-06	C	1.4-3
Metals				
Arsenic[b]	2.0E-04	2E-07	E	1.4-4
Barium	4.4E-03	4.3E-06	D	1.4-4
Beryllium[b]	< 1.2E-05	< 1.2E-08	E	1.4-4
Cadmium[b]	1.1E-03	1.1E-06	D	1.4-4
Chromium[b]	1.4E-03	1.4E-06	D	1.4-4
Cobalt[b]	8.4E-05	8.2E-08	D	1.4-4
Copper	8.5E-04	8.3E-07	C	1.4-4
Lead[b]	5.0E-04	4.9E-07	D	1.4-2
Manganese[b]	3.8E-04	3.7E-07	D	1.4-4
Mercury[b]	2.6E-04	2.5E-07	D	1.4-4
Molybdenum	1.1E-03	1.1E-06	D	1.4-4
Nickel[b]	2.1E-03	2.1E-06	C	1.4-4
Selenium[b]	< 2.4E-05	< 2.4E-08	E	1.4-4
Vanadium	2.3E-03	2.3E-06	D	1.4-4
Zinc	2.9E-02	2.8E-05	E	1.4-4
Total for substances identified as HAP	**< 1.9E+00**	**< 1.9E-03**		

[a] Factors are converted from lb/10^6 scf to lb/MMBtu (HHV) by dividing by 1,020 Btu/scf, as per EPA. Numbers preceded by "<" are based on method detection limits.
[b] Specifically listed as a "Hazardous Air Pollutant" (HAP) in the Clean Air Act, or a component of Polycyclic Organic Matter, which is also listed as a HAP.

Appendix C - Calculations
Main Boiler Emissions

Emissions for Main Boilers on Gas and Oil

Oil parameters:

Heat Content	40.8	MJ/kg (LHV)
	17,557	Btu/lb (LHV)
	18,610	Btu/lb (HHV)
Max. S content	1.50%	(wt.)

	Emission Factors		
	Gas (in current Permit)	Uncontrolled Fuel Oil (for burner lighting)*	
	lb/MMBtu (HHV)	lb/1000 gal	lb/MMBtu (HHV)
NO_x (as NO_2)	0.018	47	0.31
CO	0.044	5	0.033
VOC	0.005	0.28	0.002
PM_{10} (filterable)	0.0019	12.1	0.079
$PM_{2.5}$ (filterable)	0.0019	8.8	0.058
SO_2	0.0006	236	1.54
HAP	0.0019	0.19	0.0013

*EPA AP-42 factors (see Page C-5 for calculation of total HAP factor); assume density of 8.2 lb/gal

Short-Term Emissions	
Gas (in current Permit)	Proposed
4.0 lb/hr, 3-hr avg.	(no change)
9.8 lb/hr, 3-hr avg.	(no change)
1.2 lb/hr	(no change)
0.42 lb/hr*	1.9 lb/hr, 3-hr avg.**
(N/A)	1.5 lb/hr, 3-hr avg.**
0.13 lb/hr	31.0 lb/hr, 3-hr avg.**

*Limit of 0.0019 lb/MMBtu * 224 MMBtu/hr

**Based on assumption of 1,400 kg oil (max) per 3 hours; values conservatively calculated by adding emissions from oil firing to the current allowable emissions from gas firing, without making any correction for the small reduction in total gas firing as a result of firing oil)

NAAQS Modeling Emissions Rates (g/s), Per Main Boiler

Averaging Time	3 hr	8 hr	24 hr	Annual
Max. Fuel Oil (kg)	1,400		4,800	320,000
NO_x (as NO_2)				0.50
CO		1.23		
PM_{10} (filterable)			0.13	
$PM_{2.5}$ (filterable)			0.11	0.06
SO_2	3.91		1.68	0.32

Appendix C - Calculations
Main Boiler Emissions

HAP Emission Factor Calculation Sheet
Residual Oil Combustion (External)

Discussion: The emission factors for individual organic compounds and metals shown at the right are from the U.S. Environmental Protection Agency (EPA), "Compilation of Air Pollutant Emission Factors, Volume 1: Stationary Point and Area Sources" (AP-42), Section 1.3 for "Fuel Oil Combustion" (external), rev. 9/98.

Pollutant	Emission Factor (lb/1000 gal)[a]	Emission Factor (lb/MMBtu)[a]
Organic Compounds		
Benzene[b]	2.14E-04	1.40E-06
Ethylbenzene[b]	6.36E-05	4.17E-07
Formaldehyde[b]	3.30E-02	2.16E-04
Naphthalene[b]	1.13E-03	7.40E-06
1,1,1-Trichloroethane[b]	2.36E-04	1.55E-06
Toluene[b]	6.20E-03	4.06E-05
o-Xylene[b]	1.09E-04	7.14E-07
Acenaphthene[b]	2.11E-05	1.38E-07
Acenaphthylene[b]	2.53E-07	1.66E-09
Anthracene[b]	1.22E-06	7.99E-09
Benz(a)anthracene[b]	4.01E-06	2.63E-08
Benzo(b,k)fluoranthene[b]	1.48E-06	9.70E-09
Benzo(g,h,i)perylene[b]	2.26E-06	1.48E-08
Chrysene[b]	2.38E-06	1.56E-08
Dibenzo(a,h)anthracene[b]	1.67E-06	1.09E-08
Fluoranthene[b]	4.8E-06	3.2E-08
Fluorene[b]	4.5E-06	2.9E-08
Indeno(1,2,3-cd)pyrene[b]	2.1E-06	1.4E-08
Phenanathrene[b]	1.1E-05	6.9E-08
Pyrene[b]	4.3E-06	2.8E-08
OCDD[b]	3.1E-09	2.0E-11
Metals/Inorganics		
Antimony[b]	5.25E-03	3.44E-05
Arsenic[b]	1.32E-03	8.65E-06
Barium	2.57E-03	1.68E-05
Beryllium[b]	2.78E-05	1.82E-07
Cadmium[b]	3.98E-04	2.61E-06
Chloride	3.47E-01	2.27E-03
Chromium[b]	8.45E-04	5.54E-06
Cobalt[b]	6.02E-03	3.94E-05
Copper	1.76E-03	1.15E-05
Fluoride[b]	3.73E-02	2.44E-04
Lead[b]	1.51E-03	9.89E-06
Manganese[b]	3.00E-03	1.97E-05
Mercury[b]	1.13E-04	7.40E-07
Molybdenum	7.87E-04	5.16E-06
Nickel[b]	8.45E-02	5.54E-04
Phosphorus[b]	9.46E-03	6.20E-05
Selenium[b]	6.83E-04	4.48E-06
Vanadium	3.18E-02	2.08E-04
Zinc	2.91E-02	1.91E-04

Total for substances identified as HAP	1.9E-01	1.3E-03

[a] Conversion from lb/1000 gal to lb/MMBtu based on fuel heat content of 18,610 Btu/lb and density of 8.2 lb/gal

[b] Specifically listed as a "Hazardous Air Pollutant" (HAP) in the Clean Air Act, or a componen of Polycyclic Organic Matter, which is also listed as a HAP.

Appendix C - Calculations
Main Boiler Emissions

Potential to Emit (PTE)

	SO_2	PM_{10} (filterable)	$PM_{2.5}$ (filterable)	
Existing Facilitywide PTE:	4.9	20.6	20.6	tons/yr
Proposed PTE Increases:				
Emissions associated with oil firing (320,000 kg/yr limit)	21.2	1.04	0.76	tons/yr
New Facilitywide PTE:	26.1	21.6	21.4	tons/yr

APPENDIX D

Dispersion Modeling Files
(provided on CD in EPA copies)