October 28, 2014

Mr. Patrick Bird
U.S. EPA Region 1
5 Post Office Square, OEP05-2
Boston, MA 02109-3912

Subject: **Comments on CAA Air Permit Modification**
Northeast Gateway Energy Bridge, LLC, Permit Number RG1-DPA-CAA-01

Dear Mr. Bird:

Tetra Tech offers the following final information as you prepare the modified Clean Air Act (CAA) permit for Northeast Gateway Energy Bridge, LLC, Permit Number RG1-DPA-CAA-01. These comments are in response to questions you offered in our August 19, 2014 meeting with you, as well as our own observations made during our review of the existing permit and potentially applicable regulations.

Since we offer comments on several different topics related to the contents of the permit, the following bullet list offers a summary of the topics covered, for your convenience:

- Opinion on Applicability of Non-Road Engine Rules
- Request to Adopt Fuel Oil Sulfur Limit of 0.1 Percent in Main Boilers
- Correction of Boiler PM10 Emission Limits
- Tables of Revised Potential Emissions
- Opinion on Applicability of Other Requirements in 40 CFR 60 Subpart Db
- Opinion on Ability to Comply with 40 CFR 60 Appendix B and Appendix F
- Opinion on Ability to Comply with 40 CFR 75 Appendix D Fuel Meter Specifications
- Request for Uniform Incident Reporting Timelines

Opinion on Applicability of Non-Road Engine Rules

We are formally requesting that the engines GE1 and GE2 be considered exempt from New Source Performance Standards (NSPS) under 40 CFR 60, and NESHAP standards under 40 CFR 63, in accordance with the reasoning offered by Steven Riva of EPA Region 2 in his April 11, 2013 letter to Excelerate Energy, which states that these engines meet the definition of nonroad engines at 40 CFR 1068.30(1)(i) because they will be used on a piece of equipment that is self-propelled. (Steven Riva's letter to Excelerate Energy is included as Attachment A to this

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comment letter.) As noted in Steven Riva's letter, if GE1 and GE2 are classified as nonroad engines, certain rules in 40 CFR Parts 89, 94, 1039, 1042, 1043, 1045, 1048, 1054, 1065, and 1068 may apply.

The only nonroad rule that applies to GE1 and GE2 is 40 CFR 1043 (Control of NOx, SOx, and PM Emissions from Marine Engines and Vessels Subject to the MARPOL Protocol). This rule will apply to GE1 and GE2 when an EBRV operates in U.S. navigable waters or the Exclusive Economic Zone of the United States (U.S. EEZ). 40 CFR 1043 requires engines constructed on or after January 1, 2000 to be covered by a valid EIAPP certificate. (All EBRV engines should already have such a certificate on file.)

Under 40 CFR 1043, the EBRV engines are subject to the Annex VI NOx emission standards in Table 1 to 1043.60 (12.1 g/kWh for 720 rpm engines built between 2004 and 2010), and the Annex VI fuel sulfur limits in Table 2 of 1043.60 (1.00 percent by weight through calendar year 2015, and 0.10 percent by weight from 2016 onward).

A brief explanation of why the other nonroad rules cited in Steven Riva's letter do not apply to GE1 and GE2 is enclosed as Attachment B to this letter. (A table listing the construction dates for each EBRV engine, as well as their displacement per cylinder, is also included as Attachment C to this letter.)

Request to Adopt Fuel Oil Sulfur Limit of 0.1 Percent in Main Boilers

The EPA Region 2 letter contained in Attachment A for Excelerate Energy's Aguirre Offshore GasPort Project in Puerto Rico, which includes a permanently moored EBRV (called an FSRU), concludes that the Industrial-Commercial-Institutional Steam Generating Unit NSPS (40 CFR 60 Subpart Db) would apply to the boilers on the FSRU. Based on EPA's interpretation in that letter, we believe that this NSPS could also be determined to apply to the main boilers B1 and B2, and auxiliary boilers Aux1 and Aux2 at NEG, unless further restrictions are imposed in the permit limiting the time that vessels could be moored at the Port. In this NSPS, boilers with the capability of burning oil, as is the case for the main boilers B1 and B2, are subject to additional monitoring requirements if they burn oil with a sulfur content in excess of 0.3 percent by weight, or an equivalent SO2 emission rate in excess of 0.32 lb/MMBtu. These requirements include the installation and operation of an SO2 CEMS and a continuous opacity monitoring system, neither of which is currently installed on the EBRV fleet.

This prompted Excelerate Energy to reevaluate the availability and feasibility of using very low sulfur oil for the pilot lighting at NEG. Based on this reevaluation, Excelerate Energy has determined that use of such low-sulfur distillate oil for main boiler burner lightings is now feasible, although it was not considered feasible when the issue was last considered in 2012. The EBRV main boilers will be fitted with a new model of fuel pump (and associated fuel oil cooler) that will allow the boilers to burn low sulfur marine gas oil (LSMGO) when needed for burner lightings while moored at NEG, and still retain the ability to burn HFO when not moored at NEG. LSMGO is a distillate grade of fuel that is available with a sulfur content of 0.1 percent by weight or less, which will not trigger the additional monitoring requirements of Subpart Db.

The requested quantity of fuel oil burning in the main boilers B1 and B2 will remain the same (640,000 kg/year for the entire facility), but the maximum allowable sulfur content is requested to be 0.1 percent by weight, instead of the 1.0 percent previously requested. Compliance with the fuel oil quantity limits and fuel oil sulfur limits will be demonstrated by recording quantities of fuel use in the main boilers while moored at NEG, and by maintaining copies of the fuel supplier certificates for each delivery of LSMGO taken onboard the EBRVs.

To reflect the switch from residual fuel oil to a low sulfur distillate grade, potential emissions from burner lighting have been revised, as emission rates for SO2 and particulate matter will be reduced.

Correction of Boiler PM10 Emission Limits

It should also be noted that the PM10 limits in the existing permit contain an inconsistency for the main and auxiliary boilers (B1, B2, and Aux1). The original air permit application filed with EPA in 2006 requested a PM emission limit of 1.7 lb/hr for each main boiler, and of 0.7 lb/hr for the auxiliary boiler Aux1. These lb/hr rates were based on the AP-42 emission factor of 7.6 lb/MMscf for condensable plus filterable particulates (equivalent to 0.0075 lb/MMBtu), in Table 1.4-2 of AP-42 (7/98 Edition).

However, the existing permit, as issued in 2007, contains PM limits of 1.7 lb/hr for each main boiler and 0.7 lb/hr for the auxiliary boiler Aux1 (as originally requested), but also limits PM from the boilers to only 0.0019 lb/MMBtu, which corresponds to the AP-42 emission factor for filterable particulates only. Since we are confident that gas-fired emissions from these boilers will be able to comply with lower lb/hr PM limits, we are proposing to reduce the lb/hr PM emission limits for the currently permitted boilers (B1, B2, and Aux1), so that they correspond to the lower 0.0019 lb/MMBtu value. (PM emissions from the proposed new auxiliary boiler Aux2 were already based on 0.0019 lb/MMBtu, and do not need revision.)

Tables of Revised Potential Emissions

Revised potential emissions from the main boilers, auxiliary boilers, and the entire facility are presented below, to reflect the changes discussed above. See Attachment D to this letter for detailed emission calculations.

Revised Main Boiler Short-Term Emission Rates

	Gas-only		**Burner lighting (gas plus LSMGO)**	
	lb/MMBtu	lb/hr	lb/MMBtu	lb/hr
NOx	0.018	4.0	0.018	4.0
CO	0.044	9.8	0.044	9.8
VOC	0.005	1.2	0.005	1.2
SO2	0.0006	0.13	None proposed	1.91
PM10	0.0019	~~1.7~~ 0.42	None proposed	0.54

Revised Auxiliary Boiler Aux1 Short-Term Emission Rates

Pollutant	lb/MMBtu	lb/hr
NOx	0.018	1.8
CO	0.044	4.4
VOC	0.005	0.5
SO2	0.0006	0.06
PM10	0.0019	~~0.7~~ 0.19

Auxiliary Boiler Aux2 Short-Term Emission Rates (no change)

Pollutant	lb/MMBtu	lb/hr
NOx	0.018	2.8
CO	0.044	6.9
VOC	0.005	0.85
SO2	0.0006	0.092
PM10	0.0019	0.29

Revised Facility-Wide Potential Annual Emissions (tons per year)

Pollutant	Existing permit	April 2012 letter	October 2014 letter
NOx	49	43.8	43.8
CO	99	99.0	99.0
VOC	16.1	16.0	16.0
SO2	4.9	16.1	3.4
PM10	20.6	20.9	5.5
PM2.5	N/A	20.2	5.4

Opinion on Applicability of Other Requirements in 40 CFR 60 Subpart Db

We believe the following sections of 40 CFR 60 Subpart Db either do or do not apply to the main and auxiliary boilers, B1, B2, Aux1, and Aux2, as described below. For the purpose of interpreting applicability, the following facts are considered:

- All of the main and auxiliary boilers (B1, B2, Aux1, and Aux2), are considered to be constructed, reconstructed, or modified after February 28, 2005. (For reference, the table in Attachment C to this letter includes the construction dates for each EBRV.)
- The main boilers B1 and B2 are limited to the use of natural gas or "very low sulfur oil," which is defined in 60.41b to have a sulfur content of no more than 0.30 percent by weight, or an uncontrolled SO2 emission rate of no more than 0.32 lb/MMBtu for units constructed, reconstructed, or modified after February 28, 2005.
- The auxiliary boilers Aux1 and Aux2 are limited to the use of natural gas.

- The main boilers B1 and B2, as well as the auxiliary boiler Aux1, are high heat release rate boilers as defined in 60.41b.
- The auxiliary boiler Aux2 has an unknown furnace volume, and is assumed to be a low heat release rate boiler as defined in 60.41b, for the purpose of determining the applicable NOx emission limit in 60.44b.

§60.42b Standard for sulfur dioxide (SO2).

The SO2 standards in 60.42b do not apply to any of the boilers, because units firing only gaseous fuel or very low sulfur oil are exempted under 60.42b(k)(2).

§60.43b Standard for particulate matter (PM).

Under 60.43b(f), the main boilers are subject to the opacity standard of no greater than 20 percent opacity (6-minute average), except for one 6-minute period per hour of not more than 27 percent opacity. In accordance with 60.43b(g), this opacity standard will apply to the main boilers at all times, except during periods of startup, shutdown, or malfunction.

Under 60.43b(d)(7), Method 9 of 40 CFR 60 Appendix A is to be used for determining the opacity of stack emissions from the main boilers.

- ***We propose the use of Method 22 in lieu of Method 9 for opacity observations. Subpart Db allows the use of Method 22 as an alternative to Method 9 in certain circumstances, as described under 60.48b(a)(2), and provides a schedule in paragraphs 60.48b(a)(2)(i) and (ii), in which an observer watches the stack once per day for 10 minutes and records the duration of visible emissions (except for water vapor). If visible emissions occur for 30 seconds or less in a 10-minute observation, compliance is demonstrated.***

The other PM standards in 60.43b do not apply to the main boilers, because units limited to very low sulfur oil and not using add-on PM controls are exempted under 60.43b(h)(5).

The auxiliary boilers are exempt from all PM and opacity standards in 60.43b because they only fire natural gas.

§60.44b Standard for nitrogen oxides (NOx).

Under 60.44b(a), the main boilers are subject to a NOx standard of 0.20 lb/MMBtu for high heat release rate boilers burning natural gas or distillate oil. (LSMGO is a distillate grade of oil.)

Under 60.44b(a), the auxiliary boiler Aux1 is subject to a NOx standard of 0.20 lb/MMBtu for high heat release rate boilers burning natural gas.

Under 60.44b(a), the auxiliary boiler Aux2 is subject to a NOx standard of 0.10 lb/MMBtu for low heat release rate boilers burning natural gas.

Under 60.44b(i), compliance with the NOx standard is based on a 30-day rolling average.

- ***We request that the 30-day averaging period be waived, since a given boiler may not accumulate 30 operating days within a reasonable amount of time. We propose an alternative compliance period, based on the average for all operating hours that occur in each calendar month, which would allow compliance to be determined without the need to wait for 30 operating days to occur.***

§60.45b Compliance and performance test methods and procedures for sulfur dioxide.

No stack testing for SO2 is required under 60.45b for any of the boilers, because the main and auxiliary boilers are exempt from the SO2 standards of 60.42b.

§60.46b Compliance and performance test methods and procedures for particulate matter and nitrogen oxides.

No stack testing for PM is required under 60.46b, because the main and auxiliary boilers are exempt from the PM standards of 60.43b.

Under 60.46b(e), the NOx performance test required under 60.8 shall be conducted for 30 boiler operating days, using the NOx CEMS.

- ***We request that the 30 operating day performance test be waived, and that compliance instead be demonstrated using the average for all operating hours that accumulate within 30 calendar days of initiating the performance test.***

§60.47b Emission monitoring for sulfur dioxide.

The SO2 monitoring requirements in 60.47b do not apply to any of the boilers, because they are exempt from the SO2 emission standards under 60.42b.

§60.48b Emission monitoring for particulate matter and nitrogen oxides.

We propose that the main boilers be exempted from the requirement to install a continuous opacity monitoring system (COMS) under 60.48b(a). An exemption from the COMS requirement is allowed under 60.48b(j)(7), as follows: "The affected facility burns only gaseous fuels or fuel oils that contain less than or equal to 0.30 weight percent sulfur and operates according to a written site-specific monitoring plan approved by the permitting authority. This monitoring plan must include procedures and criteria for establishing and monitoring specific parameters for the affected facility indicative of compliance with the opacity standard."

Under 60.48b(a), the main boilers require a Method 9 observation within 180 days of initial startup, and subsequently on the following schedule:

- If no opacity was observed in the previous test, retest within 12 calendar months of the previous test, or within 45 days of combusting LSMGO again, whichever is later;
- If opacity was observed in the previous test, but no 6-minute average was greater than 5 percent, retest within 6 calendar months of the previous test, or within 45 days of combusting LSMGO again, whichever is later;
- If opacity was greater than 5 percent in the previous test, but no 6-minute average was greater than 10 percent, retest within 3 calendar months of the previous test, or within 45 days of combusting LSMGO again, whichever is later;
- If any 6-minute average was greater than 10 percent in the previous test, retest within 45 days.
- ***We propose the use of Method 22 in lieu of Method 9 for opacity observations. Subpart Db allows the use of Method 22 as an alternative to Method 9 in certain circumstances, as described under 60.48b(a)(2), and provides a schedule in paragraphs 60.48b(a)(2)(i) and (ii), in which an observer watches the stack once per day for 10 minutes and records the duration of visible emissions (except for water vapor). If visible emissions occur for 30 seconds or less in a 10-minute observation, compliance is demonstrated.***

Under 60.48b(b)(1), all boilers are subject to the requirement to install and maintain a NOx CEMS that measures NOx and O2, and records the measurements.

Under 60.48b(c), all boilers are subject to the requirement to operate the CEMS for all periods of operation except for CEMS breakdowns and repairs, and continue recording data during CEMS calibration checks.

- ***We request that for each boiler, "all periods of operation" be interpreted as meaning ONLY those periods when the EBRV is moored at NEG, and the affected boiler is operating.***

Under 60.48b(d), calculate NOx averages in lb/MMBtu, and in accordance with 60.13(h), a 1-hour average is only valid if at least one data point is recorded in each 15-minute quadrant of an hour that the unit operates.

Under 60.48b(e), follow the procedures under 60.13 for operating the CEMS, except that as allowed under 60.48b(e)(2)(ii), NOx span values will be determined in accordance with section 2.1.2 in 40 CFR 75 Appendix A. The NOx analyzers will be configured with dual span values of 25 ppm and 500 ppm.

Under 60.48b(f), when NOx emission data are not obtained because of CEMS breakdowns, repairs, calibration checks and zero and span adjustments, backup analyzers or other methods must be used to obtain NOx data for at least 75 percent of the operating hours, in 22 out of 30 operating days.

- ***We request a modification of these criteria, to simply require valid NOx data for 75 percent of the operating hours that occur in each calendar month.***

Under 60.48b(g)(1), the boilers will comply with the provisions of paragraphs (b), (c), (d), (e)(2), (e)(3), and (f) of 60.48b.

§60.49b Reporting and recordkeeping requirements.

We believe the following recordkeeping and reporting requirements apply under 60.49b:

- Under 60.49b(a), submit notification of the date of initial startup.
- Under 60.49b(b), submit results of the initial performance test for NOx and opacity.
- Under 60.49b(d)(1), record the amount of each fuel combusted during each day, and once per month, recalculate the annual capacity factor for each fuel type on a 12-month rolling basis.
- Under 60.49b(f), maintain records of opacity for the main boilers, including:
  - Records of the proposed Method 22 observations;
  - Records collected under the approved site-specific monitoring plan allowed under 60.48b(j)(7).
- Under 60.49b(g), maintain records of NOx emissions, and NOx CEMS QA tests, including periods of missing or invalid data.
  - ***We request that all requirements under 60.49b(g) that refer to 30-day NOx averages, or to boiler operating days in the context of calculating 30-day averages, be waived, and that NOx averages instead be calculated based on a calendar-month average basis.***
  - The other records specified under 60.49b(g) will be stored by the DAHS server.
- Under 60.49b(h), submit excess emission reports for opacity (main boilers only), and for NOx (all boilers).
  - ***We request that references in 60.49b(h) to 30-day NOx averages, be waived, and that the reporting requirement instead be applied if a calendar-month average exceeds the applicable Subpart Db NOx standard.***
- Under 60.49b(i), submit reports containing the information recorded under 60.49b(g).
- Under 60.49b(o), all records required under 60.49b shall be maintained for at least two years.
- Under 60.49b(r)(1), maintain fuel receipts from the fuel supplier (for LSMGO), and from the LNG terminal (for LNG cargo supplying boiler fuel gas), indicating the oil sulfur content, and indicating either the LNG methane content, or LNG heating value.
- Under 60.49b(w), the reporting period for reports under Subpart Db is each 6 month period, and reports shall be postmarked by the 30th day following the end of the reporting period.

Opinion on Ability to Comply with 40 CFR 60 Appendix B and Appendix F

The existing CEMS meets the design specifications in section 6 of Appendix B, Performance Specification 2, with minor possible exceptions. (For example, the CO analyzer span may not fall within the range recommended in 6.1.1.1, since a single analyzer is configured to be shared between the main and auxiliary boilers. However, the dual CO spans of 0-100 ppm and 0-500 ppm should cover most operating conditions.)

The existing CEMS meets the recommendations for measurement location in section 8.1 of Appendix B, Performance Specification 2, with minor possible exceptions. (Each EBRV has slightly different lengths of exhaust stack between the nearest upstream and downstream disturbances, but to the extent possible, sample probes have been located at least two stack diameters downstream, and 0.5 stack diameters upstream, of the nearest disturbances.)

The existing CEMS should be capable of meeting the specifications for calibration drift (CD) and relative accuracy (RA) in section 13 of Performance Specification 2 (for NOx), section 13 of Performance Specification 3 (for O2), and section 13 of Performance Specification 4A (for CO).

Regarding the durations and frequencies of QA testing specified in Appendix B and Appendix F to 40 CFR 60, Northeast Gateway requires a customized schedule due to the intermittent presence of ships at the port.

- As stated in the existing air permit, all CEMS requirements, including the requirement to perform QA tests, do not apply when an EBRV is not moored at the NEG port.
- ***However, the ability to perform periodic QA testing while not moored at NEG would provide flexibility. We propose that QA tests performed while not moored at NEG may be considered valid for satisfying the corresponding permit requirement, if they are conducted in accordance with a test protocol and schedule approved by EPA.***
- Performance Specification 2 in Appendix B includes a requirement to conduct a calibration drift (CD) test on either 7 consecutive calendar days, or 7 consecutive unit operating days. This is problematic because it is possible that an EBRV could moor at the port, leave again in less than seven days, and not return again for a very extended period of time. ***We propose modifying the 7-day drift test in PS2 such that the requirement is satisfied if CD tests are performed on 7 consecutive operating days, or on each consecutive operating day that occurs within 30 calendar days of beginning the 7-day test, whichever comes first.***
- Performance Specification 2 includes a relative accuracy test audit (RATA) procedure consisting of 9 runs, each 21 minutes long. ***The draft QA plan submitted to EPA in 2009 proposed instead to conduct a relative accuracy audit (RAA), using three 60-minute runs, instead of nine 21-minute runs. (This allowed use of the emission performance test runs for both the RAA and the initial performance test.) The 2009 QA plan proposed that RAAs would be conducted during initial performance testing, and at least once every 5 years thereafter. Given the possibility of a ship not returning to NEG within 5 years, we propose revising the RAA frequency to be once every 5 years, or upon the next visit of an EBRV to NEG after the previous RAA, whichever is later.***
- Procedure 1 in Appendix F specifies that a CD check must be done at least once daily. ***As stated in the existing air permit, all CEMS requirements apply only while an EBRV is moored to the port.***
- Procedure 1 in Appendix F defines the “out-of-control period” as beginning with the completion of the fifth consecutive daily CD check that exceeds twice the drift specification (2.5 percent of span), or with the completion of the last daily CD check PRIOR to a CD check that exceeds four times the drift specification. ***We propose waiving this retrospective invalidation for CD checks exceeding four times***

the specification, due to the potential for that previous CD check having occurred during a previous EBRV visit months or years prior. Invalidation will instead apply only to data AFTER a CD check that exceeds four times the drift specification.

- Procedure 1 in Appendix F specifies the following frequencies for other audit activities:
  - RATA once every four calendar quarters, unless the unit does not operate in that fourth quarter, in which the RATA will be performed in the quarter the unit recommences operation;
  - Cylinder gas audit (CGA) in at least 3 out of 4 calendar quarters, whether or not the unit operates;
  - RAA may be done in 3 out of 4 calendar quarters (RAA can only be done when the unit is operating).
  - ***We propose that RATAs not be performed, but that RAAs be performed in place of a RATA, at the aforementioned schedule of once during initial performance testing, and once every 5 years thereafter, or upon the next visit of an EBRV to NEG after the previous RAA, whichever is later.***
  - ***We propose that CGAs be performed once per calendar quarter, or upon the next visit of an EBRV to NEG after the previous CGA, if more than one calendar quarter has passed since that EBRV's last visit to NEG.***

Opinion on Ability to Comply with 40 CFR 75 Appendix D Fuel Meter Specifications

As mentioned in our email to you on September 4, 2014, the requirements of 40 CFR 75 do not apply to any of the equipment at Northeast Gateway. The fuel meters installed on the vessels were not purchased or installed with the requirements of 40 CFR 75 in mind, and the fuel meter specifications under 40 CFR 75 Appendix D should be applied to any equipment at Northeast Gateway.

Request for Uniform Incident Reporting Timelines

Several conditions in the existing NEG air permit establish deadlines for timely reporting to EPA that seem arbitrary and inconsistent, or that place an undue burden on the permittee without any apparent environmental benefit:

- In section VII.C.1 of the existing permit, "breakdown conditions" must currently be reported to EPA by fax or email within four hours of detection, and in section VII.C.2, a written report must be submitted within one week after a breakdown condition has been corrected. We believe the four-hour requirement places an undue burden on operators for two reasons: 1) when a breakdown condition occurs, the first priorities of the operators are to ensure the safety of personnel and equipment, and then to attempt to correct the breakdown, all of which can easily take more than four hours; and, 2) if a breakdown condition occurs outside of business hours, such as on a Friday evening, it may be over two calendar days before EPA even becomes aware a notification was sent, in which case providing notice within 4 hours does not appear to produce any environmental benefit.

- In section VII.B of the existing permit, emission exceedances must be reported to EPA in writing within 96 hours of each occurrence. We believe that requiring written reports of emission exceedances to be submitted on a different schedule from written reports of breakdown conditions may result in confusion for the permittee, and may result in the need to submit multiple reports for cases when the same incident triggers both reporting requirements, when a single report could otherwise suffice.
- ***We propose a consistent set of timelines for reporting of breakdown conditions and emission exceedances, based on those commonly used by MassDEP in its state-issued permits. Under these proposed timelines, the permittee shall notify EPA by fax, email, or telephone no later than three (3) days after the occurrence of a breakdown condition or emission limit exceedance. The permittee shall submit a written report no later than seven (7) days after the occurrence of a breakdown condition or emission limit exceedance.***

We thank you for your consideration of these requests as you prepare a draft of the revised NEG air permit. Please feel free to contact me at (617) 443-7568, or at Chris.L.Williams@tetratech.com, with any questions.

Sincerely,

Chris Williams
Environmental Engineer

Cc: Mike Trammel, Excelerate Energy
Buck Booth, Excelerate Energy

Attachments

Attachment A

Letter from Steven Riva, EPA Region 2, to Mike Trammel of Excelerate Energy, Regarding NSPS-NESHAP Applicability to the Proposed Aguirre GasPort

April 11, 2013

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APR 11 2013

Mr. Mike Trammel
Director, Environmental Affairs
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Re: NSPS-NESHAP Applicability to the Proposed Aguirre GasPort Emission Units

Dear Mr. Trammel:

This is in response to your August 27, 2012 letter to the Region 2 Office of the U.S. Environmental Protection Agency (EPA). We apologize for the delay in preparing this response. In this letter you asked for EPA's concurrence on your interpretation of the non-applicability of the New Source Performance Standards (NSPS) and National Emission Standard for Hazardous Air Pollutants (NESHAP) or Maximum Achievable Control Technology (MACT) standards to emission units at the proposed Aguirre GasPort (GasPort), in particular, marine equipment/boilers/engines that will be used on the liquefied natural gas carriers (LNGCs). The GasPort will be located approximately 3 miles offshore of the Puerto Rico Electric Power Authority (PREPA) Aguirre Plant. Excelerate Energy, L.P. (Excelerate) has indicated that it needs EPA to confirm its interpretation before it selects a specific design of the LNGC as its Floating Storage and Regasification Unit (FSRU) since the wrong interpretation can lead to costly fuel changes or equipment retrofits to comply with the NSPS and MACT.

Excelerate plans to utilize one of its existing LNGCs currently in service as the FSRU for the project. The FSRU will be ready to receive and store liquefied natural gas (LNG) from other LNGCs at the rate of approximately one every 8 days. The FSRU will be permanently moored at the GasPort year-round performing regasification services except when there is a need to take the FSRU to safer waters due to an approaching hurricane and for a normal dry-dock time (typically once every 5 years) to ensure the FSRU's sea worthiness. During the scheduled dry-dock periods, Excelerate will provide a similar FSRU, as a temporary substitute at the GasPort. All of the LNGCs being considered for FSRU service are relatively new, state-of-the-art vessels delivered between 2005 and 2010 and currently permitted for use at the Northeast Gateway LNG and Neptune LNG terminals located offshore from Massachusetts. Each Excelerate LNGC under consideration is propelled by a pair of 224 MMBtu/hr dual-fueled main boilers (equipped with NOx-reducing selective catalytic reduction or SCR systems). These boilers make steam for the steam generators to produce electricity needed to power the ship's electric propellers or to power the LNG pumps, run the re-gasification process and other units on the FSRU while the ship is not travelling. Other equipment includes a gas-fired auxiliary boiler (100-157 MMBtu/hr) also equipped with an SCR system, a dual-fueled engine with a 4.0 MW generator, and various smaller combustion sources including an emergency generator (approx. 600 kW) which is used in case of power loss but is otherwise only tested for approximately 30 minutes per week, a shipboard incinerator (approximately 3 MMBtu/hr, used for routine disposal of trash and sludge for approximately 1 hour per day), an inert gas generator (approximately 45 MMBtu/hr external combustion unit); and lifeboat and rescue boat engines (which need to be tested weekly for approximately 30 minutes each). In addition, the proposed GasPort will be located within the Puerto Rico territorial sea and, therefore, is not subject to the Deepwater Port Act or the Outer Continental Shelf (OCS) regulations.

EPA is providing general guidance today on the potential applicability of the NSPS and NESHAP on the ancillary equipment on the FSRU for this particular project. Specific questions on the requirements and applicability of a particular NSPS/NESHAP can be discussed separately on a case-by-case basis as the need arises.

Please note that since the FSRU utilizes boilers as the main propulsion devices instead of reciprocating internal combustion engines (RICE), the FSRU does not meet the exemption provided by Section 302(z) of the Clean Air Act which excludes reciprocating internal combustion engines used as nonroad engines or for transportation purposes from being listed as stationary sources. Accordingly, the FSRU, once permanently moored to the GasPort and unlikely to be moved (except under special circumstances) will be considered a stationary source for Clean Air Act purposes. Since the NSPS and NESHAP apply to stationary sources, these rules will apply to the ancillary equipment on the FSRU. However, there are a few caveats that you should be aware with respect to non-RICE and RICE equipment on the FSRU:

1) Once the LNGC marine vessel that will be converted to an FSRU is moored to the GasPort, this marine vessel will become a stationary source and all the air pollution emitting equipment on board will become stationary sources with the exception of reciprocating internal combustion engines. As such, all non-RICE ancillary equipment located on the FSRU must meet the applicable NSPS based on the commenced construction date, i.e., manufactured date on the name plate of the individual equipment. The fact that this equipment was originally designed to be operated on a marine vessel when the equipment was constructed is immaterial for purposes of NSPS applicability. The fact that the equipment will be used at a stationary source combined with the individual manufactured date of the equipment (commenced construction date) is what triggers the NSPS on the existing equipment. For example, 40 CFR Subpart Db, Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units, applies to an affected unit that commenced construction, was modified, or was reconstructed after June 19, 1984. Since the LNGCs were delivered between 2005 and 2010, EPA assumes that the boilers were manufactured after the 1984 applicability date and, therefore, NSPS Subpart Db applies to the boilers, and so on.

2) All the affected equipment on the FSRU with the exception of reciprocating internal combustion engines will need to comply with any applicable NESHAP. Whether the existing source NESHAP or new source NESHAP will apply to the affected equipment depends on the manufactured date, ordered date, or onsite construction date of the individual equipment and how "commence construction" is defined in the applicable NESHAP.

3) All reciprocating internal combustion engines on the FSRU will not be considered stationary sources for the purposes of NSPS and NESHAP even if they have been or are subsequently modified, reconstructed, or replaced since these engines will be used on a piece of equipment that is self-propelled, (i.e., as long as the FSRU is self-propelled) (see paragraph (1)(i) in the nonroad engine definition at 40 CFR §1068.30). Such engines are defined as nonroad engines and the NSPS and NESHAP do not apply to nonroad engines. However, such engines must

comply with the nonroad engine rules in 40 CFR Parts 89, 94, 1039, 1042, 1043, 1045, 1048, 1054, 1065, and 1068, if applicable.

If you have any questions, please contact Mr. Frank Jon, of my staff, at (212) 637-4085.

Sincerely,

Steven C. Riva, Chief
Permitting Section
Air Programs Branch
Clean Air and Sustainability Division

cc: Keith H. Kennedy, Tetra Tech EC, Inc.

Attachment B

NEG Applicability of Non-Road Engine Rules

Summary of NEG Review of Potential Applicability of Non-Road Engine Rules

- 40 CFR 89 (CONTROL OF EMISSIONS FROM NEW AND IN-USE NONROAD COMPRESSION-IGNITION ENGINES) does not apply because 89.1(b)(4)(ii) excludes marine engines that have an exemption under 40 CFR 94 (other than those exemptions specified in 40 CFR 94.907 or 94.912). The EBRV engines are exempted under 40 CFR 94.1(b)(2), which excludes marine engines on foreign vessels from the requirements of 40 CFR 94. All of the Excelerate EBRVs are foreign vessels.
- 40 CFR 94 (CONTROL OF EMISSIONS FROM MARINE COMPRESSION-IGNITION ENGINES) does not apply because marine engines on foreign vessel are exempted under 94.1(b)(2).
- 40 CFR 1039 (CONTROL OF EMISSIONS FROM NEW AND IN-USE NONROAD COMPRESSION-IGNITION ENGINES) does not apply because 1039.5(b)(1)(v) exempts marine engines on foreign vessels. All of the Excelerate EBRVs are foreign vessels.
- 40 CFR 1042 (CONTROL OF EMISSIONS FROM NEW AND IN-USE MARINE COMPRESSION-IGNITION ENGINES AND VESSELS) does not apply because 1042.5(a) exempts engines installed on foreign vessels. All of the Excelerate EBRVs are foreign vessels.
- 40 CFR 1043 (CONTROL OF NOX, SOX, AND PM EMISSIONS FROM MARINE ENGINES AND VESSELS SUBJECT TO THE MARPOL PROTOCOL) applies to all of the EBRV engines when they operate in U.S. navigable waters or the Exclusive Economic Zone of the United States (U.S. EEZ). 40 CFR 1043 requires engines constructed on or after January 1, 2000 to be covered by a valid EIAPP certificate. (All EBRV engines should already have such a certificate on file.) The EBRV engines are subject to the Annex VI NOx emission standards in Table 1 to 1043.60 (12.1 g/kWh for 720 rpm engines built between 2004 and 2010), and the Annex VI fuel sulfur limits in Table 2 of 1043.60 (1.00 percent by weight through calendar year 2015, and 0.10 percent by weight from 2016 onward).
- 40 CFR 1045 (CONTROL OF EMISSIONS FROM SPARK-IGNITION PROPULSION MARINE ENGINES AND VESSELS) does not apply because it only covers propulsion marine engines. Auxiliary engines, which are defined to be non-propulsion engines, are exempted under 1045.5(a). All of the EBRV engines are non-propulsion engines.
- 40 CFR 1048 (CONTROL OF EMISSIONS FROM NEW, LARGE NONROAD SPARK-IGNITION ENGINES) does not apply because our interpretation is that neither GE1 nor GE2 are considered "new, spark-ignition nonroad engines" larger than 19 kW, despite the fact that these engines meet the size threshold, and do not qualify for the propulsion marine engines exemption in 40 CFR 1048. According to the definition of "spark-ignition" in 40 CFR 1048.801, a "spark plug or other sparking device" must be present. The MAN B&W 8L32/40 engines on first-generation EBRVs (i.e., GE1) are compression-ignition and have no sparking device. While the Wartsila 12V32DF engines on second- and third-generation EBRVs (i.e., GE2) do not have actual spark plugs, they inject a small amount of oil as a pilot fuel during gas-only combustion. The applicability of Part 1048 depends on whether "other sparking device" is interpreted to include oil pilot fuel. While other parts of the CFR, such as 40 CFR 60 Subpart JJJJ, have explicitly defined gas-fired engines with an oil pilot as spark-ignition engines, part 1048 does not. Therefore, these engines do not meet the definition of spark-ignition in 40 CFR 1048.

- 40 CFR 1054 (CONTROL OF EMISSIONS FROM NEW, SMALL NONROAD SPARK-IGNITION ENGINES AND EQUIPMENT) does not apply to the EBRV engines, because it only covers “new, spark-ignition” non-road engines with a power rating of 19 kW or less. All of the EBRV engines have a higher power rating than this.
- 40 CFR 1065 (ENGINE-TESTING PROCEDURES) specifies test procedures for engines subject to other parts. This part only applies to the extent that it is cross-referenced by another applicable regulation listed above (other than 40 CFR 1043, which is not one of the applicable parts listed in 1068.1).
- 40 CFR 1068 (GENERAL COMPLIANCE PROVISIONS FOR HIGHWAY, STATIONARY, AND NONROAD PROGRAMS) only applies to the extent that it is cross-referenced by another applicable regulation listed above (other than 40 CFR 1043, which is not one of the applicable parts listed in 1068.1).

Attachment C

EBRV Boiler and Engine Serial Numbers and Construction Dates

Northeast Gateway: EBRV Boiler and Engine Serial Numbers and Construction Dates

EBRV	Boiler #1	Boiler #2	Aux Boiler	Generator Engine
H.2218 Excellence Build Year: 2005 NEG Initial Startup: Jan-8-2010	Make: Mitsubishi Model: MB-4E-KS2 SN: 4419	Make: Mitsubishi Model: MB-4E-KS2 SN: 4420	N/A	Make: MAN B&W Model: 8L32/40 (Disp: 32.2 L/cylinder) SN: SB8L32-2671 Date:
H.2237 Excelerate Build Year: 2006 NEG Initial Startup: Feb-17-2010	Make: Mitsubishi Model: MB-4E-KS2 SN: 4781	Make: Mitsubishi Model: MB-4E-KS2 SN: 4782	N/A	Make: MAN B&W Model: 8L32/40 (Disp: 32.2 L/cylinder) SN: SB8L32-4425 Date: June 2005
H.2254 Explorer Build Year: 2008 NEG Initial Startup: Jan-28-2010	Make: Mitsubishi Model: MB-4E-KS2 SN: 4973	Make: Mitsubishi Model: MB-4E-KS2 SN: 4974	Make: Aalborg Model: Mission OM 35 SN: 739464	Make: Wartsila Model: 12V32DF (Disp: 28.1 L/cylinder) SN: PAAE043524 Date of engine build: December 2006
H.2263 Express Build Year: 2009 NEG Initial Startup: Feb-4-2010	Make: Mitsubishi Model: MB-4E-KS2 SN: 5009	Make: Mitsubishi Model: MB-4E-KS2 SN: 5010	Make: Aalborg Model: Mission OM 35 SN: 739873	Make: Wartsila Model: 12V32DF (Disp: 28.1 L/cylinder) SN: PAAE047940 Date of engine build: December 2007
H.2270 Exquisite Build Year: 2009	Make: Mitsubishi Model: MB-4E-KS2 SN: 5137	Make: Mitsubishi Model: MB-4E-KS2 SN: 5138	Make: Aalborg Model: Mission OL 55 SN: 1955738472	Make: Wartsila Model: 12V32DF (Disp: 28.1 L/cylinder) SN: PAAE066559 Date of engine build: April 2008
H.2271 Expedient Build Year: 2010	Make: Mitsubishi Model: MB-4E-KS2 SN: 5139	Make: Mitsubishi Model: MB-4E-KS2 SN: 5140	Make: Aalborg Model: Mission OL 55 SN: 1955838473	Make: Wartsila Model: 12V32DF (Disp: 28.1 L/cylinder) SN: PAAE066560 Date of engine build: May 2008
H.2272 Exemplar Build Year: 2010	Make: Mitsubishi Model: MB-4E-KS2 SN:	Make: Mitsubishi Model: MB-4E-KS2 SN:	Make: Aalborg Model: Mission OL 55 SN:	Make: Wartsila Model: 12V32DF (Disp: 28.1 L/cylinder) SN: PAAE083673 Date of engine build: February 2009

Attachment D

Revised Emission Calculations

Facility-Wide Potential Emissions (October 2014 update)
Northeast Gateway Energy Bridge LP

Pollutant	Short-term emission rates, lb/hr							
	B1	B2	B1 burner lighting	B2 burner lighting	Aux1	Aux2	GE1	GE2
NO_x	4.0	4.0	4.0	4.0	1.8	2.8	97.4	10.5
CO	9.8	9.8	9.8	9.8	4.4	6.9	26.9	26.6
VOC	1.2	1.2	1.2	1.2	0.5	0.85	10.2	6.5
PM_{10}	0.42	0.42	0.54	0.54	0.19	0.29	3.4	3.4
$PM_{2.5}$	0.42	0.42	0.45	0.45	0.19	0.29	0.0	0.0
SO_2	0.13	0.13	1.91	1.91	0.06	0.09	19.8	1.0

Pollutant	1st Generation EBRV Hours of Operation and Annual Emissions, tons per year								Total tons	Emission Cap
	B1	B2	B1 burner lighting	B2 burner lighting	Aux1	Aux2	GE1	GE2		
NO_x	19.5	19.5	0	0	--	--	4.9	--	43.8	49.0
CO	47.4	47.4	0	0	--	--	1.3	--	96.2	99.0
VOC	5.8	5.8	0	0	--	--	0.5	--	12.1	
PM_{10}	1.9	1.9	0.050	0.050	--	--	0.2	--	4.1	
$PM_{2.5}$	2.0	2.0	0.013	0.013	--	--	0.2	--	4.2	
SO_2	0.5	0.5	0.71	0.71	--	--	1.0	--	3.4	
Annual hours of operation (NOx and CO)	9636	9636	see note	see note	--	--	100	--		
Annual hours of operation (other pollutants)	9636	9636	see note	see note	--	--	100	--		

Note: Potential burner lighting emissions are based on total oil consumption, not hours of oil use.

Pollutant	2nd Generation EBRV Hours of Operation and Annual Emissions, tons per year								Total tons	Emission Cap
	B1	B2	B1 burner lighting	B2 burner lighting	Aux1	Aux2	GE1	GE2		
NO_x	16.4	16.4	0	0	7.3	--	--	0.5	40.6	49.0
CO	39.9	39.9	0	0	17.9	--	--	1.3	99.0	99.0
VOC	5.8	5.8	0	0	2.6	--	--	0.3	14.5	
PM_{10}	1.9	1.9	0.050	0.050	0.9	--	--	0.2	5.0	
$PM_{2.5}$	2.0	2.0	0.013	0.013	0.9	--	--	0.0	4.9	
SO_2	0.5	0.5	0.71	0.71	0.3	--	--	0.1	2.7	
Annual hours of operation (NOx and CO)	8100	8100	see note	see note	8100	--	--	100		
Annual hours of operation (other pollutants)	9636	9636	see note	see note	9636	--	--	100		

Note: Potential burner lighting emissions are based on total oil consumption, not hours of oil use.

Pollutant	3rd Generation EBRV Hours of Operation and Annual Emissions, tons per year								Total tons	Emission Cap
	B1	B2	B1 burner lighting	B2 burner lighting	Aux1	Aux2	GE1	GE2		
NO_x	14.8	14.8	0	0	--	10.4	--	0.5	40.6	49.0
CO	36.2	36.2	0	0	--	25.3	--	1.3	99.0	99.0
VOC	5.8	5.8	0	0	--	4.1	--	0.3	16.0	
PM_{10}	1.9	1.9	0.050	0.050	--	1.4	--	0.2	5.5	
$PM_{2.5}$	2.0	2.0	0.013	0.013	--	1.4	--	0.0	5.4	
SO_2	0.5	0.5	0.71	0.71	--	0.4	--	0.1	2.9	
Annual hours of operation (NOx and CO)	7345	7345	see note	see note	--	7345	--	100		
Annual hours of operation (other pollutants)	9636	9636	see note	see note	--	9636	--	100		

Note: Potential burner lighting emissions are based on total oil consumption, not hours of oil use.

Pollutant	Facility-Wide Worst Case Potential Emissions, tons per year
NO_x	43.8
CO	99.0
VOC	16.0
PM_{10}	5.5
$PM_{2.5}$	5.4
SO_2	3.4

Emissions for Main Boilers on Natural Gas (B1 and B2) (October 2014 update)

Mitsubishi Heavy Industries MB-4E-KS2 Boilers

HHV	13270	kcal/kg
	3.97	Btu/kcal
Fw	10600	wscf/mmBtu
Fd	8650	dscf/mmBtu

1st Generation Main Boiler

Load		B.MAX	NOR	75% NOR	50% NOR	25% NOR		Base	40% MAX
								Interpolated Data	
Fuel Gas Consumptior	kg/h	4243	2911	2153	1458	757	Based on manufacturer performance data		
O2 Concentration	% (wet)	1.9	1.9	2.3	3.3	7.4	Based on manufacturer performance data		
Eco Outlet Gas Temp	^{o}C	180	169	164	158	154	Based on manufacturer performance data	176	160
Heat Input (HHV)	MMBtu/hr	224	153	113	77	40	calculated	197	89
Volumetric flow	acfm	69,200	46,300	34,600	24,500	16,600	calculated	60,100	28,100

NO_x (as NO_2)	lb/hr	4.0	based on SCR spec of 15 ppmvd @ 3% O_2	3.6	1.6
CO	lb/hr	9.8	based on 60 ppmvd @ 3% O_2 (conservative)	8.7	3.9
VOC	lb/hr	1.2	based on AP-42 factor (0.0054 lb/MMBtu)	1.1	0.5
PM	lb/hr	0.42	based on AP-42 factor (0.0019 lb/MMBtu)	0.4	0.2
SO_2	lb/hr	0.13	based on AP-42 factor (0.0006 lb/MMBtu)	0.12	0.05
HAP	lb/hr	0.4	based on AP-42 factors (see following page)	0.4	0.2

2nd and 3rd Generation Main Boiler

Load		B.MAX	NOR	75% NOR	50% NOR	25% NOR		Base	40% MAX
								Interpolated Data	
Fuel Gas Consumptior	kg/h	4228	3008	2226	1506	782	Based on manufacturer performance data		
O_2 Concentration	% (dry)	2.1	2.1	2.5	3.6	7.9	Based on manufacturer performance data		
O_2 Concentration	% (wet)	1.9	1.9	2.3	3.3	7.4	Based on manufacturer performance data		
Eco Outlet Gas Temp	^{o}C	178	169	164	160	155	Based on manufacturer performance data	175	161
Heat Input (HHV)	MMBtu/hr	223	158	117	79	41	calculated	197	89
Volumetric flow	acfm	68,700	47,900	35,800	25,400	17,200	calculated	60,000	28,300

NO_x (as NO_2)	lb/hr	4.0	based on SCR spec of 15 ppmvd @ 15% O_2	3.6	1.6
CO	lb/hr	9.8	based on 60 ppmvd @ 3% O_2 (conservative)	8.7	3.9
VOC	lb/hr	1.2	based on AP-42 factor (0.0054 lb/MMBtu)	1.1	0.5
PM	lb/hr	0.41	based on AP-42 factor (0.0019 lb/MMBtu)	0.4	0.2
SO_2	lb/hr	0.13	based on AP-42 factor (0.0006 lb/MMBtu)	0.12	0.05
HAP	lb/hr	0.41	based on AP-42 factors (see HAP for boilers sheet)	0.37	0.17

Emissions for Main Boiler Burner Lightings on LSMGO (October 2014 update)
Mitsubishi Heavy Industries MB-4E-KS2 Boilers

Oil parameters for Low Sulfur Marine Gas Oil (LSMGO)

Heat Content (1)	MMBtu/1000 gal (HHV)	140
Density (1)	lb/gal	7.05
Max. S content	(wt.)	0.1%
Max. oil use per 3 hrs	kg (per boiler)	1,200
Max. oil use per 24 hrs	kg (per boiler)	4,800
Max. oil use per year	kg (per boiler)	320,000
Max. oil use per year	kg (facility-wide)	640,000

	Emission Factors		
	Gas-Only (same as current permit) (2)	Uncontrolled Fuel Oil (for burner lighting)	
	lb/MMBtu (HHV)	lb/1000 gal	lb/MMBtu (HHV)
NO_x (as NO_2) (3)	0.018	24	0.17
CO (3)	0.044	5	0.036
VOC (4)	0.005	0.20	0.001
PM_{10} (filterable) (5)	0.0019	1.00	0.0071
$PM_{2.5}$ (filterable) (5)	0.0019	0.25	0.0018
SO_2 (3)	0.0006	14.2	0.10
HAP (6,7,8)	0.0019	N/A	3.38E-04

Notes on emission factors:

1) Gas-only emission factors are based on existing permit limits. (Existing limit does not contain limits for PM2.5 or HAP.)
2) Distillate oil heat content and density based on AP-42 Chapter 1.3.
3) Uncontrolled distillate emission factors for NOx, CO, and SO2 are from AP-42 Table 1.3-1.
6) Uncontrolled distillate emission factor for VOC is from AP-42 Table 1.3-3.
5) Uncontrolled distillate emission factors for PM10 and PM2.5 are from AP-42 Table 1.3-6.
6) Gas-only HAP emission rate based on AP-42 Table 1.4-3 for organic compounds, and Table 1.4-4 for metals.
7) Distillate HAP emission rate based on AP-42 Table 1.3-9 for organic compounds, and Table 1.3-10 for metals.
8) HAP emission rates are presented only for comparision purposes. No HAP limits are proposed to be stated in the permit.

Proposed Short-Term Emissions	
Gas-Only (same as current permit)	Burner Lighting (gas plus LSMGO)
lb/hr	lb/hr
4.0 lb/hr, 3-hr avg.	(no increase) (3)
9.8 lb/hr, 3-hr avg.	(no increase) (3)
1.2 lb/hr	(no increase) (3)
0.42 lb/hr (1)	0.54 lb/hr, 3-hr avg. (4)
(N/A) (2)	0.45 lb/hr, 3-hr avg. (4)
0.13 lb/hr	1.91 lb/hr, 3-hr avg. (4)

Notes on short-term emissions:

1) Gas-only PM10 emission rate of 0.42 lb/hr is based on existing permit limit of 0.0019 lb/MMBtu multiplied by max. heat input rate of 224 MMBtu/hr. (The existing permit mistakenly contains a maximum gas-only PM10 limit of 1.7 lb/hr.)
2) Existing permit does notcontain a separate limit for PM2.5. PM2.5 emissions are calculated only for the purpose of dipsersion modeling, and are not proposed to be included as stated limits in the permit.
3) Burner lighting emission rates for NOx, CO, and VOC are assumed to be less than or equal to the maximum rates for gas-only firing, as SCR will continue to operate during burner lightings.
4) Burner lighting emission rates for PM10, PM2.5, and SO2 are based on a maximum total oil consumption of 1,200 kg within a 3-hour period hours, and conservatively add the oil-firing emissions to the maximum hourly totals for gas-only firing, without taking credit for the reduced gas heat input during burner lightings.

Emissions for 2nd Generation Auxiliary Boiler (Aux1) (October 2014 Update)

Aalborg Mission OM-35 Boiler with Hamworthy Low-Nox Burner

HHV	13270	kcal/kg
	3.97	Btu/kcal
Fw	10600	wscf/mmBtu

Auxiliary Boiler

Load		100%	
Fuel Gas Consumptior	kg/h	1903	Based on manufacturer performance data
O2 Concentration	% (wet)	3.25	Based on manufacturer performance data
Outlet Gas Temp	^{o}C	421	(received from vendor in email)
Heat Input (HHV)	MMBtu/hr	100	calculated
Volumetric flow	acfm	51,300	calculated

NO_x (as NO_2)	lb/hr	1.8	based on SCR spec of 15 ppmvd @ 15% O_2
CO	lb/hr	4.4	based on 60 ppmvd @ 3% O_2 (conservative)
VOC	lb/hr	0.5	based on AP-42 factor (0.0054 lb/MMBtu)
PM	lb/hr	0.19	based on AP-42 factor (0.0019 lb/MMBtu)
SO_2	lb/hr	0.06	based on AP-42 factor (0.0006 lb/MMBtu)
HAP	lb/hr	0.19	based on AP-42 factors (1.9 lb/MMscf @ 1020 Btu/scf - see earlier page)

HAP Emission Factor Calculation Sheet
Distillate 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. 05/2010.

Pollutant	Emission Factor (lb/1000 gal)[a]	(lb/MMBtu)[a]	Source (AP-42 Table)
Organic Compounds			
Benzene[b]	2.14E-04	1.53E-06	1.3-9
Ethylbenzene[b]	6.36E-05	4.54E-07	1.3-9
Formaldehyde[b]	3.30E-02	2.36E-04	1.3-9
Naphthalene[b]	1.13E-03	8.07E-06	1.3-9
1,1,1-Trichloroethane[b]	2.36E-04	1.69E-06	1.3-9
Toluene[b]	6.20E-03	4.43E-05	1.3-9
o-Xylene[b]	1.09E-04	7.79E-07	1.3-9
Acenaphthene[b]	2.11E-05	1.51E-07	1.3-9
Acenaphthylene[b]	2.53E-07	1.81E-09	1.3-9
Anthracene[b]	1.22E-06	8.71E-09	1.3-9
Benz(a)anthracene[b]	4.01E-06	2.86E-08	1.3-9
Benzo(b,k)fluoranthene[b]	1.48E-06	1.06E-08	1.3-9
Benzo(g,h,i)perylene[b]	2.26E-06	1.61E-08	1.3-9
Chrysene[b]	2.38E-06	1.70E-08	1.3-9
Dibenzo(a,h)anthracene[b]	1.67E-06	1.19E-08	1.3-9
Fluoranthene[b]	4.84E-06	3.46E-08	1.3-9
Fluorene[b]	4.47E-06	3.19E-08	1.3-9
Indeno(1,2,3-cd)pyrene[b]	2.14E-06	1.53E-08	1.3-9
Phenanathrene[b]	1.05E-05	7.50E-08	1.3-9
Pyrene[b]	4.250E-06	3.04E-08	1.3-9
OCDD[b]	3.10E-09	2.21E-11	1.3-9
Metals/Inorganics	(lb/10^12 Btu)	(lb/MMBtu)[a]	
Arsenic[b]	4	4.00E-06	1.3-10
Beryllium[b]	3	3.00E-06	1.3-10
Cadmium[b]	3	3.00E-06	1.3-10
Chromium[b]	3	3.00E-06	1.3-10
Copper	6	6.00E-06	1.3-10
Lead[b]	9	9.00E-06	1.3-10
Manganese[b]	6	6.00E-06	1.3-10
Mercury[b]	3	3.00E-06	1.3-10
Nickel[b]	3	3.00E-06	1.3-10
Selenium[b]	15	1.50E-05	1.3-10
Zinc	4	4.00E-06	1.3-10

Total for substances identified as HAP	3.4E-04

[a] Conversion from lb/1000 gal to lb/MMBtu based on fuel heat content of 140 MMBtu/1000 gal

[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.