Engineering Summary – UNH Cogeneration Project Fall 2003, Durham, NH

Application #: FY04-0148
AFS #: 3301700009
County: Strafford
Engineer: Laughton
Date: Late Fall 2003

The University of New Hampshire – Durham campus (UNH) is proposing to construct and operate an electrical cogeneration facility on its property located in Durham, NH. All power produced by the cogeneration plant would be used at the UNH campus and would also allow the option to provide power to the electric grid for use outside the UNH campus. EMCOR Energy & Technologies (EE&T) has been selected to design, engineer, provide, construct, commission, and operate the cogeneration plant, a new satellite chilled water plant (for Kingsbury Loop), and the existing campus heating plant. UNH will retain ownership of all of the permitted devices, while EE&T will be the operator of such equipment.

New equipment to be installed includes a 7.9 MW #2 fuel oil or natural gas fired combustion turbine with a heat recovery steam generator equipped with a duct burner firing natural gas only, an emergency black start emergency generator, a new 50,000 gallon No. 2 fuel oil storage tank, a cooling tower, and an absorption chiller plant for inlet air cooling to the combustion turbine.

Combustion Turbine Information
For firing natural gas:
Max heat input is 106.0 mmBtu/hr at 0 degrees F and the chiller OFF.
Max heat input is 92.5 mmBtu/hr at 100 degrees F with the chiller ON.
For firing No. 2 fuel oil:
Max heat input is 104.8 mmBtu/hr at 0 degrees F and the chiller OFF.
Max heat input is 89.6 mmBtu/hr at 100 degrees F with the chiller ON.
Equipped with So Low NOx burner design
Base load at 45.1 degrees F is 98 mmBtu/hr when firing natural gas and 95 mmBtu/hr when firing No. 2 fuel oil

Duct Burner Information
Max firing rate is 56.7 to 66.3 mmBtu/hr depending on final supplier selection.
Only operates when combustion turbine is on line. Not fresh air fired.

Black Start Emergency Generator Information
600 kW, 887 Hp Output, 6.84 mmBtu/hr, firing No. 2 fuel oil
Emergency startup power to the combustion turbine when natural gas is curtailed or problems with the electric natural gas compressor.

Absorption Chiller
For inlet air pre-cooling to the combustion turbine when the ambient air is greater than 70 degrees F. Driven by low pressure steam from the combustion turbine. 250 ton capacity. No air emissions from this source.

Cooling Tower
Two-cell Marley or BAC wet evaporative mechanical cooling tower. Supplies condensing water to absorption chiller. Only run when absorption chiller on line or existing steam turbine in use, during milder part of year when steam from the HRSG is not completely used for campus loads. Each cell has its own fan. Cooling Tower is drained in the winter.

No. 2 Fuel Oil Storage Tank
50,000 gallon above ground tank with a secondary containment tank for No. 2 fuel oil for the combustion turbine.

Natural Gas Compressor
Needed to boost natural gas pressure to 300 psi at the inlet to the combustion turbine. Compressor will be electrically powered and hence, no air emissions.

Existing Facility (Title V Operating Permit TV-OP-010 issued June 3, 1999)
Significant activities identified in the current Title V Operating Permit include 6 boilers and 7 emergency generators (202 to 890 Hp).
Five of the boilers are at the central heating plant and the Boiler #6 is at the New England Center.

EU1 & 2 = Boilers 1 & 2 are rated at 47.3 mmBtu/hr firing either No. 6 fuel oil at 1.5% S or natural gas.
EU3 & 4 = Boilers 3 & 4 are rated at 47.3 mmBtu/hr firing only No. 6 fuel oil at 1.5% S.
EU5 = Boiler 5 is rated at 16.7 mmBtu/hr firing No. 6 fuel oil at 1.5% S or natural gas.
EU6 = Boiler 6 at the New England Center is rated at 12.55 mmBtu/hr firing No. 2 fuel oil, liquid propane, and natural gas
Common stack for Boilers 1 through 4 and separate stacks for Boilers 5 and 6.
Boilers 1 through 4 have a total combined fuel oil limit of 3,326,400 gallons per year.
Boiler 5 has a fuel limit of 299,712 gallons per year.

EU7 = Heating Plant EG is 202 Hp diesel or #2 FO at less than 0.4% S
EU8 = Morse Hall EG is 353 Hp diesel or #2 FO at less than 0.4% S
EU9 = New England Center EG is 377 Hp diesel or #2 FO at less than 0.4% S
EU10 = Water Treatment Plant EG is 335 Hp diesel or #2 FO at less than 0.4% S
EU11 = Gables Hall EG is 377 Hp diesel or #2 FO at less than 0.4% S
EU12 = New Ice Arena EG is 377 Hp diesel or #2 FO at less than 0.4% S
EU13 = Biosciences Building EG is 890 Hp diesel or #2 FO at less than 0.4% S or propane or natural gas fired.

Boiler 1 B&W Model FF2972 47.3 mmBtu/hr installed in 1963 One end only firing
Boiler 2 B&W Model FF2972 47.3 mmBtu/hr installed in 1963 One end only firing
Boiler 3 B&W Model FF2713 47.3 mmBtu/hr installed in 1958 One end only firing
Boiler 4 Riley ? Model 47.3 mmBtu/hr installed in 1948 One end only firing
Boiler 5 Cleaver Brooks ? Model 16.7 mmBtu/hr installed in 1986 One end only firing
Boiler 6 at NEC Cleaver Brooks CB-662-300 12.55 mmBtu/hr installed in 1965 One end only firing

EU7 Caterpillar Model 3306 202 Hp 15 gal/hr, 2.03 mmBtu/hr
EU8 Caterpillar Model 3406 353 Hp 19 gal/hr, 2.57 mmBtu/hr

EU9 Caterpillar Model 3306B 377 Hp 34 gal/hr, 3.23 mmBtu/hr
EU10 Kohler Model 250R071 335 Hp 20 gal/hr, 2.7 mmBtu/hr
EU11 Caterpillar Model 3268A 377 Hp 34 gal/hr, 3.23 mmBtu/hr
EU12 Caterpillar Model 3306 377 Hp 34 gal/hr, 3.23 mmBtu/hr
EU13 Caterpillar Model 3412 890 Hp 80 gal/hr, 7.63 mmBtu/hr
Note that the Title V Permit application had no dates of installation listed on the ARD-2 forms for each of these 7 emergency generators.

Emissions Information/Permitting Strategy

The UNH campus located in Durham is in Strafford County, which is in an area designated as non-attainment for the federal ozone ambient air quality standard. This project is potentially subject to the Non-Attainment New Source Review (NNSR) requirements of the New Hampshire Code of Administrative Rules, Chapter Env-A 618 – *Additional Requirements in Non-Attainment Areas and the NH Portion of the Northeast Ozone Transport Region* for emissions of ozone precursor pollutants (NOx and VOC). By definition of "significant" in reference to a net emissions increase or potential to emit of NOx or VOC in the 4-county ozone classified non-attainment region, when the increase in net emissions from the source over any period of 5 consecutive calendar years; which includes the most recent calendar year in which the increase occurred is 25 tons per year. Since the potential increase in annual emissions of NOx and VOC from the project combined with actual annual average contemporaneous emissions increases of NOx and VOC over the previous 5 years are above the 25 ton per year thresholds, the facility has opted to net out of NNSR program requirements by taking federally enforceable facility wide caps for all criteria pollutants. Baseline annual actual emissions tons per year (tpy) for the existing 6 boilers plus existing 7 emergency generators were added with the deminimus values for the criteria pollutants and then the contemporaneous annual actual emissions of criteria pollutants for the 12 new boilers/heaters and 5 new emergency generators were subtracted for the new facility wide caps, which include the new cogeneration project equipment to be added. By netting out of NNSR, the facility will not have to install Lowest Achievable Emission Rate (LAER) emission control equipment on the new combustion turbine or heat recovery steam generator or black start emergency generator. In order to avoid the Prevention of Significant Deterioration (PSD) program requirements, the facility has opted to have federally enforceable facility wide caps for all criteria pollutants, as explained above, as it must net out for NOx, SO2, and PM10 emissions.

In reviewing applications for applicability of NNSR and PSD program requirements, DES looks at the most recent consecutive 24 month period within the last 5 years. UNH has chosen from June 1, 2001 to May 31, 2003 as the baseline period. DES considered all of the significant activities listed in the facility's Title V Operating permit TV-OP-010 issued on June 3, 1999 as what constitutes the existing baseline equipment. Since the Title V Operating Permit was issued, the facility installed 5 emergency generators and 12 small boilers/heaters on campus. NOx, SO2, and PM10 emissions of the cogeneration plant project alone are above PSD significance levels.

DES also must consider contemporaneous actual annual average emissions from the 5 new emergency generators and 12 new boilers/heaters and determine that they were below 25 tpy of NOx, 40 tpy of SO2, and 15 tpy for PM10 emissions, otherwise the cogeneration plant project could not net out of PSD review. Below is a summary table of contemporaneous emissions increases of criteria pollutants for the 5 new emergency generators and 12 new boilers/heaters. DES used actual fuel use for the three larger boilers (ETB1, ETB2, and ETB3) and actual hours

of operation for the 5 new emergency generators and used the PTE of the 9 smaller boilers/heaters in determining the increase in contemporaneous actual annual average emissions. See the Tables below for contemporaneous emissions increases and determining the new federally enforceable facility wide emissions caps (An Xcel spreadsheet is attached for additional clarification including emissions factors, fuel type, heat input rates, and hours of operation):

Contemporaneous Average Annual Actual Emissions Increases in most recent 24 consecutive months (June 1, 2001 through May 31, 2003)

Emission Unit	NOx	SO2	CO	VOC	PM10
EG1	0.02	0.0000	0.0018	0.0007	0.0000
EG2	0.11	0.0000	0.0071	0.0026	0.0000
EG3	0.16	0.0000	0.0174	0.0065	0.0000
EG4	0.04	0.0029	0.0095	0.0035	0.0031
EG5	0.00	0.0000	0.0003	0.0001	0.0000
Craft Cottage	0.0876	0.0005	0.0718	0.0047	0.0065
Schofield House	0.0876	0.0005	0.0718	0.0047	0.0065
Verret House	0.0876	0.0005	0.0718	0.0047	0.0065
Stoke	0.0876	0.0005	0.0718	0.0047	0.0065
Lockinvar1	0.0876	0.0005	0.0718	0.0047	0.0065
Lockinvar2	0.0876	0.0005	0.0718	0.0047	0.0065
Phillbrook1	0.0876	0.0005	0.0718	0.0047	0.0065
Phillbrook2	0.0876	0.0005	0.0718	0.0047	0.0065
Barton/Cote	0.0876	0.0005	0.0718	0.0047	0.0065
ETB1	0.15709	0.4461	0.0393	0.0027	0.0259
ETB2	0.15709	0.4461	0.0393	0.0027	0.0259
ETB3	0.15709	0.4461	0.0393	0.0027	0.0259
Total Increase	1.60	1.35	0.80	0.06	0.14

Establishing the new facility wide caps to net out of NSR and PSD program requirements (Baseline Emissions for June 1, 2001 through May 31, 2003 Total Actual Emissions in Tons for the 24 Consecutive Month Period for the Existing Equipment Covered by the Title V Operating Permit, adding the deminimus allowed and subtracting contemporaneous increases)

Emissions Unit	NOx	SO2	CO	VOC	PM10
Blrs 1-5 (oil)	102.1	437.2	9.3	1.4	31.6
Blrs 1-5 (gas)	3.8	0.023	3.2	0.21	0.29
Boiler 6	2.2	0.013	1.8	0.12	0.16
Ht Plt EG	0.08	0.0053	0.017	0.0065	0.0056
Morse EG	0.25	0.016	0.053	0.02	0.017
NECtr EG	0.07	0.0046	0.015	0.0057	0.0049
WWTP EG	0.08	0.0053	0.017	0.0065	0.0056
Gables EG	0.2	0.000035	0.025	0.0048	0.00058
New Ice EG	0.14	0.0092	0.03	0.011	0.01
Bio Science EG	0.15	0.01	0.032	0.012	0.01
2 yr Sum Total	109.07	437.28	14.489	1.7965	32.10
Annual Ave.	54.54	218.64	7.24	0.90	16.05
Demin. Allowed	24.9	39.9	99.9	24.9	14.9
Base + Demin. =	79.44	258.54	107.14	25.80	30.95
Minus Cont Incr	1.60	1.35	0.14	0.80	0.06
= New Caps	**77.83**	**257.20**	**107.00**	**25.00**	**30.89**

Note that pollutant emissions in rows 1 through 11 above are for the two year period from June 1, 2001 to May 31, 2003.

Rule Applicability

Env-A 603.01 – Permits Required

(a) – Devices listed in 607.01 require permits

Env-A 607.01 – Temporary Permit Required

(a) – A device using natural gas, liquefied petroleum gas, #2 fuel oil, diesel fuel oil, with a design rating greater than or equal to 10 mmBtu/hr of gross heat input is required to obtain a permit, CT and duct burner are capable of 106 mmBtu/hr and 66 mmBtu/hr gross heat input respectively

(h) – An aboveground, vertical, VOC storage tank with a capacity greater than or equal to 40,000 gallons and containing VOCs with a true vapor pressure greater than or equal to 1.52 pounds per square inch absolute (psia) at 60 degrees F, the proposed No. 2 fuel oil storage tank capacity of up to 50,000 gallons and with a vapor pressure for No. 2 fuel oil of greater than 1.52 psia requires a permit

Env-A 700 – Emission-based Fees

704 – Emission-based fees

Env-A 800 – Testing and Monitoring Procedures

801.02(a) – Testing and Monitoring Procedures – Purpose and applicability
802.02(a)-(f) Stack testing requirements for the CT/HRSG
802.03(a) and (b) – Pretest notice at least 30 days prior to testing.
802.04 – Submittal of pre-test protocol at least 30 days in advance of testing.
802.05 – Pre-test meeting at least 15 days prior to testing.
802.06 – Repeating a compliance stack test
802.07 – Scheduling changes allowed.
802.08(a) and (b) – Calibration data for stack sampling equipment.
802.09 – Use of alternative methods during a test.
802.10 – Operating conditions during a stack emissions test.

Monitoring fuel usage to the CT, DB, and BSEG.
Monitoring hours of operation of the BSEG

Facility is required to test the CT while firing No. 2 fuel oil without the HRSG on line at 90 to 100 percent peak load for three runs. Note that this is a change from the former performance testing required at 30, 50, 75, and 100 percent load or at four points in the normal operating range as EPA has recently promulgated changes to Subpart GG, which appeared in the Federal Register on April 14, 2003, pages 17990 to 18005. Since the facility will be using a NOx CEM, then it will have continuous indication if the CT is meeting its NOx emissions limitation of 25 ppmvd while firing natural gas or 65 ppmvd while firing No. 2 fuel oil. The Facility will repeat this test procedure with the CT while firing natural gas without the HRSG on line. In addition, the facility will test the CT and duct burner combined with the CT firing No. 2 fuel oil at 90 to 100 percent peak load and the duct burner at 100 percent load on natural gas for three runs. Finally, the facility will

test the CT and duct burner combined with the CT firing natural gas at 90 to 100 percent peak load and the duct burner at 100 percent load on natural gas for three runs. The facility shall test for NOx, CO, %O2 or CO2, SO2, PM10, and H2 SO4 mist on the CT and duct burner tests.

802.11(a) and (c) Submission of stack test results to DES within 60 days of completion of stack test and it specifies what to submit to DES.
803.02(a) – Facility is required to conduct an initial compliance stack test in accordance with Env-A 802 to demonstrate compliance with the NOx RACT limits for the CT.
803.02(b) – Facility must conduct testing of the CT and duct burner within 60 days of achieving maximum production rate but no later than 180 days after initial startup.
803.02(d) – CT is required to have stack testing done once every three years for purposes of demonstrating compliance with NOx RACT limits.
803.02(e) and (f) – Test methods to be used during NOx compliance stack testing.

<u>Env-A 808 – Continuous Emission Monitoring (NOx CEM on the CT)</u>

808.01(a)-(i) - Definitions

(a) "Calendar hour" means any 60-minute period commencing on the hour;

(b) "Facility operating hour" means, for the purposes of calculating data availability pursuant to Env-A 808.10, 42 minutes of facility operation during a calendar hour;

(c) "Facility operation" means one of the following:
  (1) For a steam generating unit that is required by this part to have a continuous emission monitoring (CEM) system installed, a time period during which any fuel is being combusted in the device; or
  (2) For any other facility that is required by this part to have a CEM system installed, a time period during which any material is being processed which contributes to the emissions monitored by the CEM system;

(d) "Gaseous excess emission" means:
  (1) A CEM system measurement of any of the gases listed in Env-A 808.01(e), above the emission limit specified in any applicable state or federal standard, based on the averaging time specified in that standard;
  (2) A CEM system measurement of any of the gases listed in Env-A 808.01(e), above the emission limit specified in any facility permit issued by the division, based on the averaging time specified in the permit; or
  (3) If neither (1) or (2), above, is applicable, a CEM system measurement of any of the gases listed in Env-A 808.01(e), above any emission limit to which the facility is subject, averaged over a 24-hour period;

(e) "Gaseous measuring CEM system" means a CEM system that measures concentrations of ammonia (NH_3), carbon monoxide (CO), sulfur dioxide (SO_2), NO_x, total reduced sulfur (TRS), hydrogen chloride (HCl), diluent gas, such as oxygen (O_2) or carbon dioxide (CO_2), or VOC;

(f) "Opacity excess emission" means any consecutive 6-minute or 60-minute period, or aggregate 60-minute period of opacity measurement, averaged in accordance with Env-A 808.03 (b), which exceeds any standards for visible emissions specified in Env-A 1900 through Env-A 2900, excluding any exempted periods specified in Env-A 2000;

(g) "Out of control period" means:
  (1) For a CEM system measuring gaseous emissions:

a. The time period beginning with the completion of the daily calibration drift check where the calibration drift (CD), as calculated pursuant to 40 CFR 60.13(d)(1), has exceeded twice the allowable limit for 5 consecutive days and ending with the CD check following corrective action that results in the CD being within the allowable CD limit;

b. The time period beginning with the completion of a daily CD check preceding the daily CD check that results in the CD being greater than 4 times the allowable limit and ending with the CD check following corrective action that results in the CD being within the allowable CD limit; or

c. The The time period beginning with the completion of a relative accuracy test audit (RATA), cylinder gas audit (CGA), or relative accuracy audit (RAA) as defined in 40 CFR 60, Appendix F, where the CEM system fails the accuracy criteria established and ending with successful completion of the same audit where the CEM system meets the accuracy criteria established after corrective action has occurred; and

(h) "Time-shared system" means a gaseous CEM system that measures the pollutant concentration of more than one gas stream; and

(i) "Valid hour of CEM emission data: means one of the following:

(1) A minimum of 42 minutes of CEM readings taken in any calendar hour, during which time the CEM is not in an out of control period as defined in Env-A 808.01(g), and the facility on which the CEM is installed is in operation; or

(2) For time-shared systems, 75% collection of gaseous CEM concentration readings of the total sampling time available for each emission point being monitored for those periods of time the CEM is not in an out of control period as defined by Env-A 808.01(g), and the facility on which the CEM is installed is in operation.

808.02(a)(2) – Applicability – The owner or operator of a stationary source shall install, operate, maintain, and perform quality assurance testing of a CEM system meeting all of the requirements specified in this part for a stationary source if any of the following conditions exists: The owner or operator of a source chooses to limit its potential to emit by accepting federally enforceable permit conditions that restrict its hours of operation, the type or amount of material combusted, stored, or processed, or its level of production, and continuous emission monitoring is determined by the division to be necessary to ensure that these permit conditions are not violated.

808.03(a),(c),(d),(e) – Minimum Specifications for CEM Systems

(a) A CEM system for measuring gaseous emissions shall average and record the data for each calendar hour;

(c) All CEM systems, opacity and gaseous measuring included, shall:

(1) Include a means to display instantaneous values of percent opacity and gaseous emission concentrations; and

(2) Complete a minimum of one cycle of operation, which shall include measurement, analyzing, and data recording for each successive 5-minute period for systems measuring gaseous emissions and each 10-second

period for systems measuring opacity, unless a longer time period is approved in accordance with Env-A 809;

(d) A stack volumetric flow measuring device required to be installed after January 1, 1992, shall meet the following requirements:

(1) All differential pressure flow monitors shall have an automatic blow-back purge system installed, and in wet stack conditions, shall have the capability for drainage of the sensing lines; and

(2) The stack flow monitoring system shall have the capability for manual calibration of the transducer while the system in on-line and for a zero check; and

(e) Alternatives to in-stack flow monitoring devices for determination of stack volumetric flow rate may be used if the owner or operator provides the Division with technical justification that the alternative can meet the same requirements for data availability, data accuracy, and quality assurance as an in-stack device.

808.04(a)-(c) – CEM Monitoring Plan – At least 90 days prior to the installation of the CEM system, the owner or operator shall submit a CEM monitoring plan to the Division including all of the information in Env-A 808.04(c) for approval.

808.05(a),(c),(d),(e) – Performance Specification Testing – The owner or operator shall conduct performance specification testing of the NOx CEM system in accordance with the following: (a) For a CEM system monitoring opacity or gaseous emissions, the performance specification requirements of 40 CFR 60, Appendix B shall apply; (c) All performance specification testing shall be conducted within 180 days of the CEM equipment initial startup; (d) The Division shall be notified of the date or dates of the performance specification testing at least 30 days prior to the scheduled dates so that they may be present during the testing; and (e) A written report summarizing the results of the testing shall be submitted to the Division within 30 days of the completion of the test.

808.06(a) & (c) – Quality Assurance/Quality Control (QA/QC) Plan Requirements – The owner or operator is required to develop a QA/QC plan for the NOx CEM system. A copy must be filed with the Division within 30 days of completion of the performance specification testing of the NOx CEM. It must be reviewed at least once annually and updated. Within 30 days of completion of the QA/QC plan annual review, the owner or operator must certify in writing to the Division that the owner or operator will continue to implement the source's existing QA/QC plan or submit in writing any changes to the plan and the reason for each change. The QA/QC plan shall be considered an update to the CEM monitoring plan required by Env-A 808.04.

808.07(a)-(e) – General Audit Requirements for All CEM Systems: (a) Required quarterly audits shall be done anytime during each calendar quarter, bur successive quarterly audits shall occur no more than 4 months apart; (b) Within 30 days following the end of each quarter, the owner or operator of the source shall submit to the Division a written summary report of the results of all required audits that were performed in that quarter, with the report format for the NOx CEM system conforming to that presented in 40 CFR 60 Appendix F, Procedure 1, Section 7; (c) The owner or operator shall notify the Division at least 30 days prior to the performance of a RATA; (d) The Division shall require rescheduling of any RATA if the staff necessary to observe the audit are not

available; and (e) The owner or operator shall provide at least two weeks notice prior to any other planned audit or test procedure.

808.08(a),(d),(f) – Audit Requirements for Gaseous CEM Systems

(a) For a system monitoring gaseous emissions of SO_2, NO_x, CO, TRS, H_2S, VOC, O_2 or CO_2, the quality assurance requirements and procedures described in 40 CFR 60, Appendix F, shall apply, with the following additions and clarifications for Procedure 1 of Appendix F:

(1) The owner or operator shall inform the division of all out of control periods, as defined in Appendix F, section 4.3, and Env-A 808.01(g), in the emission reports required pursuant to Env-A 808.11;

(2) The owner or operator may perform a RAA, as defined in 40 CFR 60, Appendix F, in place of a CGA; and

(3) For CEM systems where CGA audits cannot be performed, the owner or operator shall perform RAA audits in place of the CGA;

(d) The owner or operator of a stationary source determining compliance with a mass flow emissions limit by using a stack flow volumetric monitor or a fuel flow meter with O_2/CO_2 measurements to calculate heat input or stack flow rate, shall conduct annually a minimum 9-run RATA with the relative accuracy calculated in the units of the mass emissions measurement as specified in 40 CFR 60, Appendices B and F.

(f) For a stationary source using a stack volumetric flow monitor for the mass flow emissions calculation, the owner or operator shall also perform one of the following audit options:

(1) An audit that shall consist of:

a. A 3-run RAA, which shall be conducted in 2 of the calendar quarters in which the RATA specified in (d) is not conducted:

1. To determine the percentage accuracy of the source's stack flowrate measurement method; and

2. To compare the source's method of determining stack flowrate against the compliance method of measuring the stack flowrate, as follows:

(i) A velocity traverse shall be conducted following Methods 1 and 2 of 40 CFR 60, Appendix A;

(ii) A calculation of average wet standard cubic feet per hour shall be measured for each run using a stack gas molecular weight and percent stack moisture from either the stack flow monitor or the most recent Methods 3 and 4 measurement made at the subject source;

(iii) A leak check shall be performed after completion of the velocity traverse in accordance with 40 CFR 60, Appendix A, Method 2, part 3.1;

(iv) The thermocouple used for measurement of stack gas temperature shall be calibrated annually;

(v) Steps (i) through (iii) shall be repeated 2 more times to result in 3 compliance measurements of the stack volumetric flowrate;

(vi) A percentage accuracy calculation shall be performed as follows:

i. "WSCFH, CEM" means the 3-run average of the wet standard cubic feet per hour flow rate as determined by the stack flow monitor method;

ii. "WSCFH, M2" means the 3-run average of the wet standard cubic feet per hour as measured by the Method 1 and Method 2 procedures;

iii. To calculate the percentage accuracy of the monitor, the owner or operator shall calculate the difference between WSCFH, CEM and WSCFH, M2, divide the difference by the value of WSCFH, M2, and then multiply the result by 100, as in the formula below:

% Accuracy = ((WSCFH,CEM - WSCFH,M2)/(WSCFH,M2)) x 100

(vii) The absolute value of percentage accuracy shall be less than or equal to 10.0% for the monitor to pass the audit; and

(viii) If the percentage accuracy exceeds 10.0%, the monitor shall be considered "out of control" until necessary repairs/adjustments are performed to the system and the monitor successfully passes the percentage accuracy requirements, as determined by a repeat audit; and

b. In the remaining quarter in which the RATA specified in (d) and the RAA are not performed, a calibration of the transmitter or transducer, as applicable, of the stack flowrate or fuel flow monitor following the manufacturer's recommended calibration procedure; or

(2) An audit, to be performed in each calendar quarter in which the RATA specified in (d) is not conducted, which shall consist of:

a. A flow monitor differential-pressure sensing lines' leak check for low and high-pressure sides;

b. A stack flow probe inspection, including removal and cleaning of the probe as necessary;

c. A differential pressure transmitter/transducer calibration following the manufacturer's recommended calibration procedure; and

d. A continuous flow-to-load-ratio or gross heat rate evaluation in accordance with 40 CFR 75, Appendix B.

808.10(a)-(g) – Data Availability Requirements – The owner or operator of a source with a CEM shall operate the NOx CEM at all times during operation of the CT, except for periods of CEM breakdown, repairs, calibration checks, preventative maintenance, and zero/span adjustments. The percentage CEM data availability for opacity and all gaseous concentration monitors shall be maintained at a minimum of 90% on a calendar quarter basis. The percentage CEM data availability for opacity and all gaseous concentration monitors shall be maintained at a minimum of 75% for any calendar month. The percentage CEM data availability is calculated as specified in Env-A 808.10(d). If the percentage data availability requirements can't be met for any calendar quarter, the owner or operator is required to follow the procedures in Env-A 808.10(e)(1) and (2). If the percentage data availability requirements can't be met for any 2 consecutive calendar quarters, the owner or operator is required to follow the procedures in Env-A 808.10(f)(1) and (2) for installing a replacement CEM or Env-A 808.10(g).

808.11 – Quarterly Emission Reports - Within 30 days of the end of each calendar quarter, an owner or operator of a source with a gaseous or opacity measuring CEM system shall submit an emission report to the division.

808.12(a)-(c) – Emissions Reports for Sources Subject to 40 CFR 60 – The owner or operator of a source subject to 40 CFR 60 which is required to install, calibrate, operate, and maintain a CEM system shall provide the following information in each quarterly emission report specified in Env-A 808.11:

(a) The information specified in 40 CFR 60.7(c) and any applicable subpart of 40 CFR 60;
(b) The daily averages of gaseous CEM measurements and calculated emission rates; and
(c) The information required in Env-A 808.13(a)(5) through (9).

808.14(a)-(e) Valid Averaging Periods. The number of hours of valid CEM data required for determining a valid averaging period for the different emission standard periods shall be:

(a) For a 3-hr standard emission standard period, 2 hours of valid data;
(b) For a 4-hr standard emission standard period, 3 hours of valid data;
(c) For an 8-hr standard emission standard period, 6 hours of valid data;
(d) For a 12-hr standard emission standard period, 9 hours of valid data; and
(e) For a 24-hr standard emission standard period, 18 hours of valid data.

<u>Env-A 900 – Recordkeeping and Reporting Requirements</u>

902 – Availability of Records

902.01(a) - records retention = 5 yrs;

902.01(d) - all data submitted to ARD (emissions data & applicable emissions limitations) shall be made available to the public;

903.03(a) – General recordkeeping requirements for Combustion Sources. Maintain monthly records in accordance with Env-A 912 of fuel characteristics and utilization.

903.04(a) – General recordkeeping requirements for sources with continuous emissions monitoring systems (NOx CEMS on CT)

904.02 – VOC Emissions Statement Recordkeeping Requirements

Yes, facility wide emissions of VOC are greater than 10 tons per year

905.02 – NOx Emissions Statement Recordkeeping Requirements

Yes, facility wide emissions of NOx are greater than 10 tons per year

906 – Additional Recordkeeping Requirements

Keep track of consecutive 12 month facility wide combined totals of NOx, SO2, PM10, CO, VOC, and H2SO4 mist emissions to demonstrate compliance with keeeping less than the facility wide caps established in the permit for the facility to net out of Non-attainment New Source Review and Prevention of Significant Deterioration program requirements.

907 – General Reporting Requirements;

907.01 (a) – submit annual emission report; due on or before April 15 of following year (907.01(c))

907.01(b) – emissions report shall include:

(1) - actual emissions and method used for calculations

(2) – all information for process devices in accordance with 903.02(a) & (b).

908 – VOC Emissions Statements Reporting Requirements, submit annually, prior to April 15th of the following calendar year.

909 – NOx Emissions Statements Reporting Requirements, submit annually, prior to April 15th of the following calendar year.

910 – Additional reporting requirements

Monthly summary of consecutive 12 month facility wide NOx, SO2, PM10, VOC, CO, and H2SO4 mist emissions totals. Submit annually by April 15th of the following calendar year.

911 – Permit Deviations - Recordkeeping/Reporting for Permit Deviations (follow permit deviation reporting and recordkeeping requirements contained in the facility's Title V Operating Permit.

<u>Env-A 1204 – VOC RACT Requirements</u>

Not applicable.

<u>Env-A 1211 – NOx RACT Requirements</u>

1211.02(o) – "Emergency generator" definition.

1211.06(d) – 25 ppmvd at 15% oxygen or 0.092 lb NOx/mmBtu NOx emission limit for the CT while firing natural gas.

1211.06(c)(1)b.2. – 65 ppmdv corrected to 15% oxygen or 0.253 lb NOx/mmBtu NOx emission limit for the CT while firing oil.

1211.11 – NO, the facility is taking a federally enforceable limitation on hours of operation of 275 hours per year for each emergency generator to keep the combined theoretical potential to emit NOx emissions less than 25 tons per consecutive 12 month period, which is more stringent than Env-A 1211.01(j)(1).

<u>Env-A 1400 – Regulated Toxic Air Pollutants</u>

NO – All fuel burning devices at the UNH facility are burning virgin petroleum products and therefore exempt from Env-A 1400 as provided for in Env-A 1402.01(b)(4)d.

<u>Env-A 1600 – Fuel Specifications</u>

1604.01(a) – The sulfur content of No. 2 fuel oil shall be less than 0.4% sulfur by weight.

1605.01(a) – The sulfur content of natural gas shall be less than 15 grains sulfur per 100 standard cubic feet. Pipeline quality natural gas meets this requirment.

<u>Env-A 2000 – Fuel Burning Devices</u>

2003.02 – Opacity less than 20% for the CT, HRSG, and BSEG.

2003.04(a,d,f) – Exceedances allowed for the CT and HRSG

2003.08(c)(1) – PM less than or equal to 0.30 lb/mmBtu for the CT and HRSG combined and the BSEG.

Env-A 3100 – Discrete Emissions Reductions Trading Program

3104.08 – Requirement for submitting a Notice of Intent to Use DERs

3104.09 – Requirement for submitting a Notice and Certification of Use for DERs

3103.08 – Requirement for submitting a Notice and Certification of Generation of DERs

UNH has opted to include use of DERs in case the Combustion Turbine while firing No. 2 fuel oil is above the NOx RACT limit of 65 ppmvd at 15% oxygen.

Env-A 3700 – NOx Emissions Reduction Fund for NOx-emitting Generation Sources

Applicable to the CT. Must do recordkeeping and reporting. In that the CT NOx emissions will likely be less than 7 lb/MW, due to the SoLow NOx burner, the facility will likely not have to pay any NOx emissions reduction fund fees.

40 CFR Part 60 (NSPS)

Subpart A and Subpart GG, Standards of Performance for Stationary Gas Turbines, apply to the combustion turbine.

Section 60.7(a)(1-3,5) – Notifications of commencing construction, anticipated date of initial startup, and actual initial startup, and date CMS performance commences on the CT.

Section 60.7(b) – Maintain records of occurrence and duration of startups, shutdowns, and malfunctions for the CT and any periods during which a continuous monitoring system or monitoring device is inoperative.

Section 60.7(c) – Quarterly excess emissions and monitoring systems performance reporting requirements for the CT.

Section 60.7(f) – Recordkeeping requirement of NOx monitoring data, fuel use, performance testing data, calibration checks of instrumentation for a period of two years. Note that this condition is superseded by the Title V Permit requirement that the facility keep records for a minimum of 5 years from the initial date of such record, which is more stringent than this requirement.

Custom fuel monitoring requirements for the CT. Refer to EPA letter dated July 16, 2001 to Ken Colburn with the EPA Region 1 approved custom fuel monitoring conditions for pipeline natural gas and fuel oil.

Section 60.8(a) – Performance test required of the CT within 60 days after achieving the maximum production rate, but not later than 180 days after initial startup.

Section 60.8(b) – Performance tests shall be conducted and data reduced in accordance with the test methods and procedures contained in each applicable subpart.

Section 60.8(c) – Representative conditions the performance test is to be conducted under.

Section 60.8(d) – Requires 30 day advance notice of the performance test.

Section 60.8(e) – Owner/operator responsibilities for providing safe access and sampling stations for the performance test.

Section 60.8(f) – Each performance test shall consist of three separate runs using the applicable test method.

Section 60.332(a)(1) – NOx emission limitation for the CT. Note that this equates to about 75 ppmdv, which is higher than the New Hampshire NOx RACT limits of 25 ppmdv at 15% O2 while firing natural gas and 65 ppmvd at 15% O2 while firing No. 2 fuel oil. DES will use the more stringent NOx RACT limits.

Section 60.333(a) – SO2 emissions shall be less than 0.015 percent by volume at 15% oxygen and on a dry basis.

Section 60.333(b) – Fuel sulfur content of fuel burned in the CT shall be less than 0.8 percent sulfur by weight.
Section 60.335(a),(c),(d) – Test methods and procedures to be used during the performance test and for NOx RACT testing purposes and sulfur and nitrogen content of fuels limitations.
Subpart A and Subpart Dc, Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units, apply to the duct burner for the Heat Recovery Steam Generator on the Combustion Turbine. Note that the duct burner for the HRSG will only be firing natural gas and Subpart Dc has emissions limitations for particulate matter and SO2 while firing oil, which are not applicable to the duct burner.
Section 60.48c(a)(1) – Notifications of commencing construction, anticipated startup, and actual startup for the duct burner on the HRSG.
Section 60.48c(g) – Record and maintain records of the amounts of fuel combusted by the duct burner each day.
Section 60.48c(i) – Maintain records required by Section 60.48c for a period of two years. Note that this condition is superseded by the Title V Permit requirement that the facility keep records for a minimum of 5 years from the initial date of such record, which is more stringent than this requirement.
Subpart Kb, Standards of Performance for Volatile Organic Liquid Storage Vessels (including petroleum liquid storage vessels), applies to the No. 2 fuel oil storage tank.
Section 60.116b(a) – Keep copies of records of volatile organic liquids stored for a period of two years. Keep records of the tank dimensions and capacity for the life of the tank.
Section 60.116b(b) – Keep records of the tank dimensions and capacity.
Section 60.116b(c) – Maintain a record of the volatile organic liquid (VOL) stored, the period of storage, and the maximum true vapor pressure of that VOL during the respective storage period.

<u>40 CFR Part 63 (MACT)</u>

NO, source is not a major source of HAPs.

<u>Federally Enforceable Operating Limitations</u>

Facility is opting out of NOx RACT requirements for emergency generators in Env-A 1211.11 by keeping the combined theoretical potential to emit NOx emissions below 25 tons per consecutive 12 month period **by taking a 275 hours per year** limitation for each emergency generator at the facility. Note that this is more stringent than Env-A 1211.01(j)(1), which calls for restricting hours of operation to less than 500 hours.

<u>Stack Information</u>

Stack Dimensions for the CT/HRSG – 6.5 feet diameter at the exit, 100 feet above ground level, base elevation is at 61 feet above mean sea level.

<u>Federally Enforceable Emissions Limitations</u>

Facility Wide caps on criteria pollutants plus H2SO4 emissions were discussed earlier. The tons per consecutive 12 month period limits for each pollutant are listed below:
NOx = 77.83 tons
SO2 = 257.20 tons
CO = 107.00 tons
VOC = 25.00 tons
PM10 = 30.89 tons
H2SO4 = 6.90 tons

Duct Burner Emissions Limitations[1]
NOx = 0.1176 lb/mmBtu
CO = 0.1023 lb/mmBtu
VOC = 0.0237 lb/mmBtu
SO2 = 0.0043 lb/mmBtu
PM10 = 0.0089 lb/mmBtu
H2SO4 Mist = NA

* Note that the duct burner can not run alone without the CT running. Hence, DES will have a combined emission limit in lb/mmBtu for the CT and duct burner in the permit, which will be calculated from summing the maximum gross heat input rate of the CT times its lb/mmBtu emission rate limit plus the duct burner maximum gross heat input rate times its lb/mmBtu emission rate limit and dividing it by the sum of the gross heat input rates of the CT plus duct burner.

Combustion Turbine Emissions Limitations[2]
NOx (gas) = 25 ppmvd at 15% oxygen or 0.092 lb/mmBtu
NOx (oil) = 65 ppmvd at 15% oxygen or 0.253 lb/mmBtu
CO (gas) = 0.1122 lb/mmBtu
CO (oil) = 0.1150 lb/mmBtu
VOC (gas) = 0.0321 lb/mmBtu
VOC (oil) = 0.033 lb/mmBtu
SO2 (gas) = 0.0043 lb/mmBtu
SO2 (oil) = 0.3903 lb/mmBtu
PM10 (gas) = 0.0319 lb/mmBtu or 2.12 lb/hr
PM10 (oil) = 0.0804 lb/mmBtu or 5.25 lb/hr
H2SO4 Mist (gas) = 0.0003 lb/mmBtu
H2SO4 Mist (oil) = 0.030 lb/mmBtu

Black Start Emergency Generator Emissions Limitations[3]
NOx = 6.74 grams/brake Hp-hr = 40.0 lb/hr OR 5.85 lb/mmBtu
CO = 0.57 grams/brake Hp-hr = 3.4 lb/hr OR 0.50 lb/mmBtu
PM10 = 0.092 grams/brake Hp-hr = 0.55 lb/hr OR 0.08 lb/mmBtu
Note that this is much less than the 0.30 lb total particulate matter/mmBtu emission limit applicable to the black start emergency generator contained in Env-A 2003.08(c)(1).
VOC = 0.105 grams/brake Hp-hr = 0.62 lb/hr OR 0.09 lb/mmBtu
Assumes that 50% of hydrocarbons emitted as VOC when firing diesel fuel.
SO2 = 0.40 lb/mmBtu OR 2.74 lb/hr

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[1] Emission estimates for NOx, CO, and VOC from the duct burner operating on natural gas are based upon worst-case vendor emissions data among the three vendors for the duct burner in Appendix B of the permit application. Duct burner SO2 emissions are based on mass balance assuming all sulfur in the gas converts to SO2. PM10 emission factors for the duct burner are from AP-42, Fifth Edition, Volume 1, Chapter 1.4 – Natural Gas External Combustion (July 1998). Lb/mmBtu values are based on the higher heating values of the fuel.
[2] Emission estimates for NOx, CO, and VOC from the CT operating on natural gas and No. 2 fuel oil are based upon worst-case vendor guarantees listed in Appendix B of the permit application. SO2 emission rates have been estimated based upon mass balance of fuel sulfur loading (1.5 grains per 100 SCF) for full load operations, assuming that 100% of the fuel sulfur is converted to SO2. Particulate emissions are based upon vendor guarantees. Note that PM/PM10 emissions (it is assumed that all particulate emissions are less than 10 microns size range) include condensible particulate matter.
[3] Based on Caterpillar 750 kW lowest emissions engine "not to exceed data".

SO2 emission rate based on AP-42 emission factors.
All lb/hr rates above are based on maximum heat input rate of 6.84 mmBtu/hr

No. 2 fuel oil Storage Tank VOC Emissions
Working and breathing losses of VOC emissions from the new No. 2 fuel oil tank were estimated to be 0.01 tons per year using the EPA Tanks Version 4.09b Program for a 50,000 gallon No. 2 fuel oil storage tank.

Cooling Tower PM10 Emissions
See Appendix B of permit application for emissions calculation.
PM10 emissions = 0.06 tons per year

Summary Table of Emissions Limitations

Device	NOx	SO2	PM10	CO	VOC	H2SO4 Mist
CT (gas)	25 ppmvd at 15% O2 or 0.092 lb/mmBtu	0.0043 lb/mmBtu	2.12 lb/hr[4] OR 0.0319 lb/mmBtu	0.1122 lb/mmBtu	0.0321 lb/mmBtu	0.0003 lb/mmBtu
CT (oil)	65 ppmvd at 15% O2 or 0.253 lb/mmBtu	0.3903 lb/mmBtu	5.25 lb/hr[5] OR 0.0804 lb/mmBtu	0.1150 lb/mmBtu	0.033 lb/mmBtu	0.030 lb/mmBtu
DB (gas)	0.1176 lb/mmBtu	0.0043 lb/mmBtu	0.0089 lb/mmBtu	0.1023 lb/mmBtu	0.0237 lb/mmBtu	NA
CT (gas) & DB (gas)[6]	0.1019 lb/mmBtu OR 17.55 lb/hr	0.0044 lb/mmBtu OR 0.75 lb/hr	0.0194[7] lb/mmBtu OR 2.6 lb/hr	0.1084 lb/mmBtu OR 18.67 lb/hr	0.0288 lb/mmBtu OR 4.97 lb/hr	0.000348[8] lb/mmBtu OR 0.03 lb/hr
CT (oil) & DB (gas)[9]	0.2005 lb/mmBtu OR 34.31 lb/hr	0.2408 lb/mmBtu OR 41.19 lb/hr	0.0433[10] lb/mmBtu OR 5.8 lb/hr	0.1101 lb/mmBtu OR 18.83 lb/hr	0.0293 lb/mmBtu OR 5.02 lb/hr	0.0187[11] lb/mmBtu OR 3.2 lb/hr
BSEG	6.74 gram/bHP-hr or 40.0 lb/hr	0.40 lb/mmBtu or 2.76 lb/hr	0.08 lb/mmBtu or 0.55 lb/hr	0.50 lb/mmBtu or 3.40 lb/hr	0.09 lb/mmBtu or 0.62 lb/hr	NA

[4] Maximum short term PM10 emissions of 2.12 lb/hr from the CT firing natural gas occur at 0 deg F at any load, per vendor guarantee. Note that the 0.0319 lb/mmBtu value is for operation of the CT at 62.1 mmBtu/hr at 45 deg F, the worst case short term emissions of PM10 from the CT in terms of lb/mmBtu.
[5] Maximum short term PM10 emissions of 5.25 lb/hr from the CT firing No. 2 fuel oil occur at 0 deg F at any load, per vendor guarantee. Note that the 0.0804 lb/mmBtu value is for operation of the CT at 60.9 mmBtu/hr at 45 deg F, the worst case short term emissions of PM10 from the CT in terms of lb/mmBtu.
[6] Maximum gross heat input rate for CT on gas is 106.0 mmBtu/hr and DB on gas is 66.3 mmBtu/hr.
[7] Maximum combined PM10 emissions of 2.6 lb/hr occur when the CT is firing natural gas at any load while at 0 deg F, per vendor guarantee. Maximum combined PM10 emissions in lb/mmBtu occur when the CT is at a lower load (67.8 mmBtu/hr) firing natural gas at 0 deg F, with the HRSG at its maximum heat input rate of 66.3 mmBtu/hr on natural gas.
[8] CT at 106 mmBtu/hr and HRSG at 66.3 mmBtu/hr with ambient air temperature of 0 deg G and Chiller Off.
[9] Maximum gross heat input rate for CT on No. 2 fuel oil is 104.8 mmBtu/hr and DB on gas is 66.3 mmBtu/hr.
[10] Maximum combined PM10 emissions of 5.8 lb/hr occur when the CT is firing No. 2 fuel oil at any load while at 0 deg F, per vendor guarantee. Maximum combined PM10 emissions in lb/mmBtu occur when the CT is at a lower load (67.6 mmBtu/hr) firing No. 2 fuel oil at 0 deg F, with the HRSG at its maximum heat input rate of 66.3 mmBtu/hr on natural gas.
[11] CT at 104.8 mmBtu/hr on natural gas, HRSG at 66.3 mmBtu/hr with ambient temperature of 0 deg F and Chiller Off.

Device	NOx	SO2	PM10	CO	VOC	H2SO4 Mist
No. 2 Fuel Oil Tank	NA	NA	NA	NA	0.01 tpy	NA
Cooling Tower	NA	NA	0.06 tpy	NA	NA	NA
Facility Wide Caps[12]	77.83	257.20	30.89	107.00	25.00	6.90

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[12] Facility wide caps include all emissions devices in Attachment A at the UNH facility and are expressed in tons per consecutive 12 month period.