DEVICE DESCRIPTIONS:

Table 1 – Significant Activity Identification		
Device/Emission Unit ID	**Manufacturer, Model #, Serial #, Date of Installation**	**Maximum Permitted Operating Limitations**
Boiler #1 (Wood-fired/Natural gas for startups) (EU01)	Riley Power Vibrating, Water-cooled Grate, Stoker Type Boiler Model # TBD Serial # TBD Proposed to be installed in 2009	1. 305 MMBtu/hr gross heat input rate while firing wood chips[1]; 2. 90 MMBtu/hr gross heat input rate from natural gas on boiler startups, at a maximum of 88,235 scf/hr[2]; and 3. Maximum of 190,000 lb/hr steam production at 850 psig and 900 degrees F on a 30 day rolling average.
Boiler #2 (Natural gas fired only) (EU02)	Superior Boiler Works Model # 9000 Serial # TBD Low NOx Burner Flue Gas Recirculation Proposed to be installed in 2009	1. 76.8 MMBtu/hr gross heat input rate while firing Natural gas; 2. 0.07539 MMcf/hr natural gas maximum fuel feed rate[3]; 3. Maximum operation of 700 hours per consecutive 12 month period; and 4. Maximum 60,000 lb/hr steam production.
Boiler #3 (Natural gas fired only) (EU03)	Superior Boiler Works Model # 9000 Serial # TBD Low NOx Burner Flue Gas Recirculation Proposed to be installed in 2009	1. 76.8 MMBtu/hr gross heat input rate while firing Natural gas; 2. 0.07539 MMcf/hr natural gas maximum fuel feed rate[4]; 3. Maximum operation of 700 hours per consecutive 12 month period; and 4. Maximum 60,000 lb/hr steam production.
Black Start Emergency Generator #1 (EG1) (EU04)	Cummins Model VT A 1710GS2 Serial # TBD Previously installed prior to 2006 (from the Pleasant St. facility) Proposed to be installed in 2009 at South Main Street facility	1. 5.6 MMBtu/hr while firing diesel fuel; 2. Maximum diesel firing rate of 40.9 gal/hr[5]; 3. Maximum generator output rating of 600 kilowatts, 831 Brake Horsepower; 4. Maximum of 500 hours of operation per consecutive 12 month period; and 5. Maximum TPE of NOx emissions from all EG combined shall be less than or equal to 25.0 tons per consecutive 12 month period.

[1] 305 MMBtu/hr gross heat input rate is based on an assumed higher heating value for wood chips as fired at 45% moisture equal to 4,675 Btu/lb and a maximum firing rate of 65,241 lb/hr wood chips as fired at 45% moisture.
[2] 90 MMBtu/hr gross heat input rate from natural gas is based on an assumed heating value of 1,020 Btu/scf of natural gas and a maximum of 88,235 scf/hr of natural gas firing.
[3] Based on an assumed heating value of 1,020 Btu/scf for natural gas.
[4] Based on an assumed heating value of 1,020 Btu/scf for natural gas.
[5] Based on an assumed lower heating value 5% less than the higher heating value and a parasitic load of 4% = 136,510 Btu/gal diesel fuel.

Table 1 – Significant Activity Identification		
Device/Emission Unit ID	**Manufacturer, Model #, Serial #, Date of Installation**	**Maximum Permitted Operating Limitations**
Black Start Emergency Generator #2 (EG2) (EU05)	Cummins Model TBD Serial # Unknown Proposed to be installed in 2009	1. 11.6 MMBtu/hr while firing diesel fuel; 2. Maximum diesel firing rate of 85.2 gal/hr[6]; 3. Maximum generator output rating of 1,250 kilowatts, 1,730 Brake Horsepower; 4. Maximum of 500 hours of operation per consecutive 12 month period; and 5. Maximum TPE of NOx emissions from all EG combined shall be less than or equal to 25.0 tons per consecutive 12 month period.
Spray Cooling Pond (EU06)	Proposed to be installed in 2009	Not applicable

CONTROL DEVICE DESCRIPTIONS:

Table 2: Pollution Control Equipment/Method Identification		
Emission Unit Controlled	**Description of Equipment/Method for Each Emission Unit**	**Primary Pollutants Controlled**
Boiler #1	Multi-clone	Particulate Matter (PM)
Boiler #1	Dry Electrostatic Precipitator (ESP)	PM
Boiler #1	Cold-side Selective Catalytic Reduction (C-SCR) System (approximately 450 degrees F, 2 catalyst beds, with 2 spare catalyst beds, located after the ESP) with ammonia injection	NO_x
Boiler #1	CO Catalyst System (Optional bed in SCR system)	CO
Wood Storage/Transfer	Best Management Practices – Conveyor systems totally enclosed and silos equipped with vent filters	PM
Ammonia Storage/Transfer	Best Management Practices and control of ammonia slip stream emissions from the boiler to less than 20 ppmvd at 6% oxygen.	Ammonia (NH_3)

STACK INFORMATION:

Table 3: Stack Criteria					
Emission Unit Number	**Emission Unit Description**	**Minimum Stack Height Above Ground Level (Feet)**	**Maximum Inside Stack Diameter (Feet)**	**Exhaust Air Flow (ACFM)**	**Exhaust Air Temperature (Degrees F)**
EU01	Boiler #1	130	6.0	83,190	140
EU02	Boiler #2	Combined Stack 110	Combined Stack 4.0	35,000	400
EU03	Boiler #3			35,000	400
EU04	EG1			4,790	935
EU05	EG2			9,980	782

6 Based on an assumed lower heating value 5% less than the higher heating value and a parasitic load of 4% = 136,510 Btu/gal diesel fuel.

EMISSIONS INFORMATION:

Table 4: Emission Limits[7] for Boiler #1

Pollutant	Emission Limit	Fuel Type	Source of Emission Limit	Proposed Emission Limits for Boiler #1 (lb/hr)	Proposed Emission Limits for Boiler #1 (ton/yr)
PM[8]	0.03 lb/MMBtu	Any Fuels	Subpart Db Emission Limit	9.15	40.08
SO_2	0.025 lb/MMBtu	Any Fuels	EPA AP-42 Emissions Data	7.625	33.40
NO_x	0.065 lb/MMBtu	Wood-only Firing	LAER Emission Limit	19.825	86.83
CO	0.18 lb/MMBtu	Any fuels	Vendor Guarantee – Good Combustion Control and/or Addition of CO Catalyst System	54.90	240.46
VOC	0.009 lb/MMBtu	Any fuels	Vendor Guarantee	2.745	12.02
HCl	0.000834 lb/MMBtu	Any fuels	NH DES Stack Test Data from Wood-fired Boilers	0.254	1.11
Ammonia	20 ppm @6% O_2	Any fuels	NH DES Ammonia Slip Emission Limit	3.07	13.44

<u>Ammonia Calculation:</u>
83,190 ACFM X ((460+68)/(460+140)) = 73,207 SCFM
73,207 SCFM X ((100-20.7)/100) = 58,053 DSCFM at 6% O2 at 68 degrees F
(20 FT^3 NH_3/1,000,000 FT^3 Stack Flow Dry) X (1 lb mole NH_3/385.3 FT^3 NH_3) X (17 lb NH3/lb mole NH3) X 58,053 DSCFM X 60 min/hr = 3.07 lb/hr NH_3

---

[7] These are the most stringent limits that apply for each pollutant. Additional emission limitations apply and will be contained in the Temporary Permit.

[8] Note that the MADOER requires a 0.012 lb PM/MMBtu in order to qualify for generating REC's and the State of New Hampshire will require 0.02 lb PM/MMBtu to qualify for generating REC's. The 0.03 lb/MMBtu total suspended particulate matter limit in 40 CFR 60.43b(h)(1) is the federally enforceable particulate matter standard that applies to the boiler for compliance demonstration purposes in this permit. This PM emission limit does not include condensible particulate matter. However, DES is requiring condensible particulate matter testing in the performance testing of Boiler #1.

Table 5 – Boiler 2 Emissions based on 700 hours maximum operation per year, firing Natural Gas				
Pollutant	**Emission Factor (lb/MMcf)**	**Max firing rate (MMcf/hr)**	**Emissions (lb/hr)**	**Emissions (tons/yr)**
PM_{10} (C+F)	7.6	0.07539	0.573	0.20
SO_2	0.6	0.07539	0.045	0.02
CO	84	0.07539	6.333	2.22
NOx	(0.049 lb/MMBtu)	(76.8 MMBtu/hr)	3.763	1.32
VOC	5.5	0.07539	0.415	0.15

Table 6 – Boiler 3 Emissions based on 700 hours maximum operation per year, firing Natural Gas				
Pollutant	**Emission Factor (lb/MMcf)**	**Max firing rate (MMcf/hr)**	**Emissions (lb/hr)**	**Emissions (tons/yr)**
PM_{10} (C+F)	7.6	0.07539	0.573	0.20
SO_2	0.6	0.07539	0.045	0.02
CO	84	0.07539	6.333	2.22
NOx	(0.049 lb/MMBtu)	(76.8 MMBtu/hr)	3.763	1.32
VOC	5.5	0.07539	0.415	0.15

Tables 5 and 6 Note: All emissions factors for the Boilers burning Natural Gas are from AP-42 Section 1.4, Natural Gas Combustion (07/1998), Tables 1.4-1 and 1.4-2, with the exception of NOx, which is the proposed LAER limit.

Table 7 – Emergency Generator 1 Emissions based on 500 hours maximum operation per year, firing Diesel Fuel				
Pollutant	**Emission Factor (lb/MMBtu)**	**Max firing rate (MMBtu/hr)**	**Emissions (lb/hr)**	**Emissions (tons/yr)**
PM_{10} (C+F)	0.0573	5.6	0.32	0.08
SO_2	0.404	5.6	2.26	0.57
CO	0.85	5.6	4.76	1.19
NOx	1.98	5.6	11.09	2.77
VOC	0.0846	5.6	0.474	0.12

Table 7 Notes: All emission factors for Emergency Generator 1 are from AP-42 Section 3.4, Large Stationary Diesel and All Stationary Dual-fuel Engines (10/96), Tables 3.4-1 and 3.4-2, with the exception of NOx, which is the proposed LAER limit of 1.98 lb/MMBtu determined by DES.

Table 8 – Emergency Generator 2 Emissions based on 500 hours maximum operation per year, firing Diesel Fuel				
Pollutant	**Emission Factor (lb/MMBtu)**	**Max firing rate (MMBtu/hr)**	**Emissions (lb/hr)**	**Emissions (tons/yr)**
PM_{10} (C+F)	0.015	11.6	0.174	0.04
SO_2	0.047	11.6	0.545	0.14
CO	0.144	11.6	1.670	0.42
NOx	1.272	11.6	14.755	3.69
VOC	0.015	11.6	0.174	0.04

Table 8 Notes: All emissions factors are Tier 2 emissions factors from 40 CFR 60 Subpart IIII. Note that the Tier 2 NOx emissions factor is less than the LAER limit of 1.98 lb/MMBtu determined by DES.

<u>Cooling Pond Emissions Calculations</u>

Assuming cooling water spray pond treatment and design similar to Bridgewater Power Company.

Use of AP-42 factor for natural draft tower factor most representative for a spray pond.

No blowdown.

Total dissolved solids (TDS) concentration = 3,600 ppm wet basis

Circulating flow rate = 17,000 gpm

17,000 gal/min circulation rate X 1,440 min/day = 24,480,000 gal/day

17,000 gal/min X 60 min/hr = 1,020,000 gal/hr circulation rate

DR = Drift Rate = drift rate for the pond expressed in gal drift/gal circulation

Drew Principles of Industrial Wastewater Treatment book page 166 contains the equation:

B + W = (E)/(C-1) to figure out drift losses

E = Evaporation rate as a % of feed rate = (Temperature drop across the system ((deg F)/1,000)

For Concord Steam Corporation E is calculated below:

Btu removed = 100,000,000 Btu/hr (based on 33% to condenser)

Evaporative cooling = 100,000 lb/hr water

100,000 lb/hr/8.34 lb/gal = 11,990 gal/hr water evaporated

11,990 gal/hr/60 min/hr = 200 gal/min water evaporated

200 gal/min evaporated/17,000 gal/min circulation rate = 1.18% evaporated (E)

B = Water loss by bleed-off, as a percentage of circulation rate, and assumed to be zero for Concord Steam Corporation.

W = Wind and drift water losses, as a percentage of circulation rate.

C = Cycles of concentration, which is the ratio between the total dissolved solids (TDS) in the cooling pond water and the TDS in the system's makeup supply. Determining optimum cycles of concentration for a cooling pond system is determined by its design, water characteristics, operating parameters, and treatment program. Assuming for Concord Steam Corporation this will vary from 12 cycles in the winter to about 20 cycles in the summer. Now we can calculate drift losses or W for varying cycles of circulation.

Back to the original equation above and assuming no bleed-off, we have:

(E/(C-1))/100 = W

For 12 cycles of concentration in the winter season:

(1.18/(12-1))/100 = 0.0010727% wind and drift losses = 0.000010727 gal drift/gal circulation

For 20 cycles of concentration in the summer season:

(1.18/(20-1))/100 = 0.0006211% wind and drift losses = 0.000006211 gal drift/gal circulation

Let's assume for an annual average use of 16 cycles of concentration:

(1.18/(16-1))/100 = 0.0007866% wind and drift losses = <u>0.000007866 gal drift/gal circulation</u>

In summary, for Concord Steam Corporation, wind and drift losses in gal/day are:
24,480,000 gal/day circulation X 0.0007866% = 193 gal/day

<u>Total Dissolved Solids Loss in Wind and Drift losses from the Cooling Pond</u>
For determining worst case TDS emissions, use 3,600 ppmw.
TDS loss in lb/min = (TDS ppmw/1,000,000) X (drift loss (gal/gal)) X (circ. rate (gal/min)) X (8.34 lb/gal)
TDS loss in lb/min = (3,600/1,000,000)*(0.000007866)*(17,000)*(8.34) = 0.00401 lb/min
0.00401 lb/min X 60 min/hr = 0.24 lb/hr
0.24 lb/hr X 24 hr/day = 5.76 lb/day TDS losses
5.76 lb/day X 365 days/yr = 2102 lb/yr TDS losses
2102 lb/yr/2,000 lb/ton = 1.05 tons/yr TDS losses

FACILITY WIDE EMISSIONS SUMMARY:

Table 9 – Facility Wide Maximum Permitted Emission Limits (tons/yr)							
Pollutant	**Boiler 1**	**Boiler 2**	**Boiler 3**	**EG1**	**EG2**	**Pond**	**Total**
PM (C+F)	40.08[9]	0.20	0.20	0.08	0.04	1.05	41.65
SO_2	33.40	0.02	0.02	0.57	0.14	NA	<100
CO	240.46	2.22	2.22	1.19	0.42	NA	<250
NOx	86.83	1.32	1.32	2.77	3.69	NA	95.93
VOC	12.02	0.15	0.15	0.12	0.04	NA	<50
HCl	1.11	NA	NA	NA	NA	NA	1.11
Ammonia	13.44	NA	NA	NA	NA	NA	13.44

Cooling Pond Water Treatment Chemical RTAP Calculations for Compliance with Env-A 1400
Concord Steam Corporation will be using about 7 different biocides, corrosion inhibitors, and anti-scalants in its circulating water cooling pond to treat the water for reuse as feedwater in the Boiler. Below are Tables 10 and 11 showing the maximum daily chemical usage for the spray cooling pond and comparison of total emissions of RTAPs with the deminimus values contained in Env-A 1450.

Table 10 – Spray Cooling Pond Water Treatment Chemical RTAP Feed Rates						
Product	**Ingredients (wt. %)**	**Max Daily Feed Rate (gal/day)**	**Density (lb/gal)**	**Max Daily Feed Rate (lb/day)**	**Max Ingredient Feed Rate (lb/day)**	**RTAP Yes or No**
Bleach	NaOCL - 15.0% NaOH – 0.2 to 2.0% NaCL – 12.0%	55	10.24	563.2	84.5 11.3 405.5	No Yes No
Sulfuric Acid	H_2SO_4 – 70.0%	4	15.28	61.12	42.8	Yes
WPD	Sodium Tolytriazole – 45 to 55%	1.5	9.9	14.85	8.2	No

9 This does not include condensible particulate matter. Boiler 1 will be tested for condensible particulate matter during the performance testing required by the Temporary Permit.

Table 10 – Spray Cooling Pond Water Treatment Chemical RTAP Feed Rates						
Product	**Ingredients (wt. %)**	**Max Daily Feed Rate (gal/day)**	**Density (lb/gal)**	**Max Daily Feed Rate (lb/day)**	**Max Ingredient Feed Rate (lb/day)**	**RTAP Yes or No**
Drewsperse	Propylene Glycol – 10 to 25% Polyethylene Glycol 1 to 10%	1.5	8.41	12.61	3.1 1.3	Yes Yes
Adjunct	NaOH – 100%	0.25	12.67	3.17	3.2	Yes
Amercor	Morpholine - 10 to 20% Cyclohexamine – 10 to 20%	0.25	8.24	2.06	0.41 0.41	Yes Yes
Amersite	Sodium Erythorbate – 8 to 18%	1	8.82	8.82	1.6	No

The next step is to determine wind and drift losses of the RTAPs from the Cooling Pond.

<u>Sodium Hydroxide Drift Losses</u>

NaOH feed rate = 563.2 + 3.167 lb/day
% by weight NaOH = 2% and 10%
NaOH concentration in ppmw = Daily consumption/Daily Circulation Rate
= ((563.2*0.02)+(3.167*1))/(24,480,000 gal/day*8.34 lb/gal) = 14.5/204,163,200
= 7.10E-08
= 0.071 ppmw
Daily Drift = Drift factor as a fraction* Daily circulation rate in gal/day
= 0.000007866 X 24,480,000 gal/day
= 193 gal/day
NaOH in Daily Drift Losses = 193 gal/day*8.34 lb/gal*0.071 ppmw/1,000,000 = <u>1.14E-04 lb/day</u>
1.14E-04 lb/day X 365 day/yr = <u>0.04 lb/yr</u>

<u>Sulfuric Acid Drift Losses</u>

H_2SO_4 feed rate = 61.12 lb/day
% by weight H_2SO_4 = 70.0%
H_2SO_4 concentration in ppmw = Daily consumption/Daily circulation rate
= (61.12 lb/day*0.70)/(24,480,000 gal/day*8.34 lb/gal)
= 2.10E-07
= 0.210 ppmw
Daily Drift = Drift factor as a fraction* Daily circulation rate in gal/day
= 0.000007866 X 24,480,000 gal/day
= 193 gal/day
H2SO4 in Daily Drift Losses = 193 gal/day*8.34 lb/gal*0.210 ppmw/1,000,000 = <u>3.38E-04 lb/day</u>
3.38E-04 lb/day X 365 day/yr = <u>0.12 lb/yr</u>

<u>Propylene Glycol Drift Losses</u>

Propylene Glycol feed rate = 3.1 lb/day
% by weight Propylene Glycol = 25%
Propylene Glycol concentration in ppmw = Daily consumption/Daily circulation rate

= (3.1 lb/day*0.25)/(24,480,000 gal/day*8.34 lb/gal)
= 3.8E-09
= 0.0038 ppmw
Daily Drift = Drift factor as a fraction* Daily circulation rate in gal/day
= 0.000007866 X 24,480,000 gal/day
= 193 gal/day
Propylene Glycol in Daily Drift Losses = 193 gal/day*8.34 lb/gal*0.0038 ppmw/1,000,000 = <u>6.12E-06 lb/day</u>
6.12E-06 lb/day X 365 day/yr = <u>0.0022 lb/yr</u>

<u>Polyethylene Glycol Drift Losses</u>
PEG feed rate = 1.3 lb/day
% by weight PEG = 10%
PEG concentration in ppmw = Daily consumption/Daily Circulation Rate
= (1.3*0.10)/(24,480,000 gal/day*8.34 lb/gal) = 0.13/204,163,200
= 6.37E-10
= 0.000637 ppmw
Daily Drift = Drift factor as a fraction* Daily circulation rate in gal/day
= 0.000007866 X 24,480,000 gal/day
= 193 gal/day
PEG in Daily Drift Losses = 193 gal/day*8.34 lb/gal*0.000637 ppmw/1,000,000 = <u>1.03E-06 lb/day</u>
1.03E-06 lb/day X 365 day/yr = <u>0.00037 lb/yr</u>

<u>Morpholine Drift Losses</u>
Morpholine feed rate = 0.41 lb/day
% by weight Morpholine = 20%
Morpholine concentration in ppmw = Daily consumption/Daily Circulation Rate
= (0.41*0.20)/(24,480,000 gal/day*8.34 lb/gal) = 0.082/204,163,200
= 4.02E-10
= 0.000402 ppmw
Daily Drift = Drift factor as a fraction* Daily circulation rate in gal/day
= 0.000007866 X 24,480,000 gal/day
= 193 gal/day
Morpholine in Daily Drift Losses = 193 gal/day*8.34 lb/gal*0.000402 ppmw/1,000,000 = <u>6.47E-07 lb/day</u>
6.47E-07 lb/day X 365 day/yr = <u>0.00024 lb/yr</u>

<u>Cyclohexamine Drift Losses</u>
Cyclohexamine feed rate = 0.41 lb/day
% by weight Cyclohexamine = 20%
Cyclohexamine concentration in ppmw = Daily consumption/Daily Circulation Rate
= (0.41*0.20)/(24,480,000 gal/day*8.34 lb/gal) = 0.082/204,163,200
= 4.02E-10
= 0.000402 ppmw
Daily Drift = Drift factor as a fraction* Daily circulation rate in gal/day
= 0.000007866 X 24,480,000 gal/day
= 193 gal/day
Cyclohexamine in Daily Drift Losses = 193 gal/day*8.34 lb/gal*0.000402 ppmw/1,000,000 = <u>6.47E-07 lb/day</u>
6.47E-07 lb/day X 365 day/yr = <u>0.00024 lb/yr</u>

Table 11 – Cooling Pond Water Treatment Chemical Wind/Drift Losses (Emissions)						
Chemical	**CAS #**	**Max Usage (lb/day)**	**Wind/drift Losses (lb/day)**	**Deminimus (lb/day)**	**Wind/drift Losses (lb/yr)**	**Deminimus (lb/yr)**
Sodium Hydroxide	1310-73-2	14.5	1.14E-04	0.26	0.04	96
Sulfuric Acid	7664-93-9	42.8	3.38E-04	0.028	0.12	10
Propylene Glycol	107-98-2	3.1	6.12E-06	16	0.0022	5,741
Polyethylene Glycol	25322-68-3	1.3	1.03E-06	1.6	0.00037	597
Morpholine	110-91-8	0.4	6.47E-07	2.8	0.00024	1,025
Cyclohexylamine	108-91-8	0.4	6.47E-07	1.2	0.00024	420

Based upon wind/drift losses calculated above and summarized in Table 11, all of the RTAPs contained in the Cooling Pond Water Treatment Chemicals proposed are emitted at rates less than the deminimus values in lb/day and lb/yr. Therefore, the RTAP emissions from Cooling Pond Water Treatment chemicals are in compliance with Env-A 1400, *Regulated Toxic Air Pollutants*.

Boiler Ammonia Slip Emissions Compliance with Env-A 1400

Concord Steam Corporation has proposed meeting a 20 ppmdv at **6**% oxygen ammonia slip emissions limit from the C-SCR system and out the Boiler stack. In order to demonstrate compliance with Env-A 1400 for ammonia, the adjusted in-stack concentration method in Env-A 1405.04 may be used to demonstrate compliance for the proposed emission limit of 20 ppmdv at 6% oxygen.

As previously shown above, ammonia emissions are 3.07 lb/hr.

Using the maximum stack flow of 58,053 Dry Standard Cubic Feet Per Minute equals 3.07 lb/hr NH_3.

X = emission rate of ammonia in lb/hr = 3.07 lb/hr

Y = grams per second of ammonia = X/7.94 = 3.07/7.94 = 0.3866 grams/sec NH_3

Z = micrograms/second of ammonia = Y X 1,000,000 = 0.3866 X 1,000,000 = 386,600 ug/sec NH_3

A = stack volume flow in actual cubic feet/minute

A = 83,190 ACFM

B = stack volume flow in actual cubic meters/second = A/2,119 = 83,190/2,119

B = 39.26 actual cubic meters/second

In-stack concentration (micrograms/cubic meter) = Z/B

In-stack concentration = 386,600/39.26 = 9,847 ug/cubic meter

Adjusted in-stack concentration = In-stack concentration/400 = 9,847/400

Adjusted in-stack concentration = 24.62 ug/cubic meter

The 24-hr ambient air limit for NH_3 = 100 ug/cubic meter

The annual ambient air limit for NH_3 = 100 ug/cubic meter

Therefore, 20 ppmvd NH_3 at 6% oxygen is below the 24-hour and annual ambient air limits for NH_3 contained in Env-A 1400, and the Boiler will be in compliance with the state air toxics program for its ammonia slip emissions.

<u>Determination of Most Stringent Emission Limits for Boiler #1</u>

<u>Nitrogen Oxides (NO_x):</u>

Env-A 1211.01(m) – <u>Applicability of NO_x RACT</u>

1. NO_x RACT does not apply to emission units which have installed BACT or LAER controls for NO_x emissions control, in that these NO_x emissions limits are more stringent than NO_x RACT.

40 CFR 60 Subpart Db – New Source Performance Standards (NSPS) for Industrial-Commercial-Institutional Steam Generating Units for Which Construction, Modification, or Reconstruction is Commenced After June 19, 1984

1. NOx emissions are limited to 0.10 or 0.20 lb/MMBtu on natural gas only, depending on if it is a low or high heat release rate type of boiler (this is a high heat release rate boiler); and
2. NOx emissions are limited to 2.1 lb/megawatt-hour gross energy output.
3. Pursuant to 40 CFR 60.44b(h), these emission standards apply at all times except during periods of startup, shutdown and malfunction.
4. Pursuant to 40 CFR 60.44b(i), compliance with the standards in (1) and (2) above are determined on a 30-day rolling average basis.

LAER-based NOx Emissions Limit

The applicant has proposed a LAER limit of 0.065 lb/MMBtu. There has been a recent biomass boiler permit for Russell Biomass, LLC that had a public hearing on June 25, 2008. The Massachusetts Department of Environmental Protection (MASS DEP) included in its conditional approval, a NOx limit of 0.060 lb/MMBtu, with no averaging period for the proposed wood-fired boiler, which was to be either a 740 MMBtu/hr bubbling fluidized bed (BFB) design or a 740 MMBtu/hr water-cooled, vibrating grate, advanced stoker-fired boiler. If Russell Biomass went with the BFB design, it was going to have a baghouse after the boiler followed by a selective catalytic reduction (SCR) system for NOx control. If Russell Biomass went with the stoker type boiler, boiler gases were to go through a multi-cyclone followed by a cold-side electrostatic precipitator (ESP). Following the ESP would be a two layer, regenerative selective catalytic reduction (RSCR) system with reheat. DES has been in conversation with the MASS DEP and understands that this project is not likely to be built. In addition, the 0.060 lb/MMBtu NOx LAER emission limit did not have any averaging period. DES knows from experience with its wood-fired power plants with add-on NOx control systems that the 0.060 lb/MMBtu emission limit would be difficult to meet, particularly if it had to be met during periods of startup, shutdown, and malfunction. DES has concluded that a NOx emission limit of 0.065 lb/MMBtu (30-day rolling average) for wood only firing and wood and natural gas firing are LAER emission rates, and these are at least as stringent as any other state or federal requirement.

Conclusion: The following NOx limits will be included in the Temporary Permit:

1. 0.065 lb/MMBtu (30-day rolling average) for wood only firing or wood and natural gas firing;

STACK TESTING REQUIREMENTS:

Pollutant	Applicable Testing Requirement	Testing Time Frame and Frequency
PM	NSPS Subpart Db (Boiler 1)	Boiler 1: Initial performance test within 60 days after achieving the maximum production rate, but no later than 180 days after initial startup. Establish operating parameter ranges corresponding to compliance with the particulate matter emissions limits. Compliance is based on the average of the three one-hour test runs.

Pollutant	Applicable Testing Requirement	Testing Time Frame and Frequency
Opacity	NSPS Subpart Db (Boiler 1)	Boiler 1: Initial performance test within 60 days after achieving the maximum production rate, but no later than 180 days after initial startup. Establish site-specific monitoring plan that includes procedures and criteria for establishing and monitoring specific parameters for Boiler 1 indicative of compliance with the 20% opacity standard and one 6-minute period per hour to not exceed the 27% opacity standard. Compliance is based on use of EPA Method 9 found in Appendix A of 40 CFR 60.
NOx	Env-A 803.02	Boiler 1: Initial performance test within 60 days after achieving the maximum production rate, but no later than 180 days after initial startup. Sources using NOx CEM only require initial stack test and satisfactory completion of CEM specification testing.
	LAER	Boiler 1: Initial performance test within 60 days after achieving the maximum production rate, but no later than 180 days after initial startup. Establish operating parameter ranges corresponding to compliance with the nitrogen oxide emissions limits for the various fuel mixtures. Compliance is based on the 24-hour calendar day average during testing.
NOx	Env-A 803.02	Boilers 2 and 3: Initial performance test within 60 days after achieving the maximum production rate, but no later than 180 days after initial startup. Subsequent NOx RACT testing is required once every three years after the initial performance test. Compliance is based on the average of three one-hour test runs.

Pollutant	Applicable Testing Requirement	Testing Time Frame and Frequency
CO	PSD Avoidance	Boiler 1: Initial performance test within 60 days after achieving the maximum production rate, but no later than 180 days after initial startup. Establish proper boiler operating parameter ranges for optimum boiler performance and CO emission control. Compliance is based on the average of three one-hour test runs. Sources using CO CEM only require initial stack test and satisfactory completion of CEM specification testing. Boilers 2 & 3: Initial performance test within 60 days after achieving the maximum production rate, but no later than 180 days after initial startup. Compliance is based on the average of three one-hour test runs. Subsequent tests once every three years after the initial compliance test to verify compliance with facility wide emissions cap for CO.
Ammonia	Env-A 1400	Boiler 1: Initial performance test within 60 days after achieving the maximum production rate, but no later than 180 days after initial startup. Subsequent testing once every 3 years. Compliance is based on the average of three one-hour test runs.
HCl	Env-A 1400	Boiler 1: Initial performance test within 60 days after achieving the maximum production rate, but no later than 180 days after initial startup. Compliance is based on the average of three one-hour test runs.

1. Continuous compliance with NOx, CO, and opacity limits for Boiler 1 shall be verified through a COMS and CEMS.

MONITORING REQUIREMENTS

The facility shall meet the following monitoring requirements for Boiler 1:

1. Continuous Emissions Monitoring for NOx, CO, and CO_2 or O_2
    a. Measure CO_2 or O_2 at each location where NOx or CO are measured.
    b. Obtain 1-hr averages of NOx, CO (all in units of lb/MMBtu and lb/hr), and CO_2 or O_2 and calculate 24-hr calendar day averages for NOx and CO in units of lb/MMBtu and lbs pollutant emitted per 24-hr calendar day. Calculate and record successive 30-day rolling averages of NOx and CO emissions in lb/MMBtu. Calculate and record daily emissions of NOx and CO in lb/day, monthly emissions of NOx and CO in tons/month, consecutive 12 month total emissions of NOx and CO in tons/consecutive 12 month period, and each successive monthly consecutive 12-month total emissions of NOx and CO in tons/consecutive 12-month period.
    c. Collect minimum amount of data specified in Env-A 808.10.
    d. Conduct initial, daily, quarterly and annual evaluations of the CEM systems in accordance with Env-A 808.
    e. Each CEM system shall meet the minimum specifications in Env-A 808.03.
    f. Submittal of CEM Monitoring Plan at least 90 days prior to installation in accordance with Env-A 808.04.
2. Continuous Opacity Monitoring
    a. Measure opacity in the discharge stack from Boiler 1 after all pollution control equipment.
    b. Collect minimum amount of data specified in Env-A 808.10.
    c. Conduct initial, daily, quarterly and annual evaluations of the CEM systems in accordance with Env-A 808.
    d. Each CEM system for opacity shall meet the minimum specifications in Env-A 808.03(b).
    e. Submittal of CEM Monitoring Plan at least 90 days prior to installation in accordance with Env-A 808.04.
3. Stack Volumetric Flow Monitoring
    a. Each stack volumetric flow monitoring system shall meet the minimum specifications specified in Env-A 808.03(d) or (e).
    b. Submittal of CEM Monitoring Plan at least 90 days prior to installation in accordance with Env-A 808.04.

RECORDKEEPING REQUIREMENTS

1. Continuous, daily, and monthly ammonia usage for the SCR system on Boiler 1.
2. Daily and monthly fuel usage for each fuel type and sulfur content (wood and natural gas) for Boiler 1.
3. Hours of operation of Boiler 1.
4. NSPS Startup, Shutdown, and Malfunction Records of 40 CFR 60.7(b) for Boiler 1.
5. Comply with the recordkeeping requirements of 40 CFR 60.49b(d), 60.49b(f), and 60.49b(h).
6. Env-A 808.06(a)-(c) Monitoring QA/QC Plan recordkeeping requirements.
7. Comply with the recordkeeping requirements of Env-A 902.01(c) (Regulated Toxic Air Pollutant Records), Env-A 903.02 (General Recordkeeping Requirements for Process Operations), Env-A 903.03(a)(4) (Natural Gas Utilization Records), Env-A 903.03 (General Recordkeeping Requirements for Combustion Devices), Env-A 904.02 (General VOC Recordkeeping Requirements), Env-A 905.02 (General NOx Recordkeeping Requirements), and Env-A 905.03 (Recordkeeping Requirements for Add-on NOx Controls).

8. 5 year record retention requirement of Env-A 902.01(a), which is more stringent than 40 CFR 60.7(f) and 40 CFR 60.49b(o).

REPORTING REQUIREMENTS

1. Comply with the reporting requirements of 40 CFR 60.49b(a)(1) and (3) (Initial Notifications), 40 CFR 60.49b(b) (Performance Test Results for Particulate Matter and performance evaluation of the opacity monitor, if one is in operation), 40 CFR 60.49b(h)(1) (Opacity excess emissions reports), 40 CFR 60.49b(v) (Use of electronic reports), and 40 CFR 60.49b(w) (The reporting period is every 6 month period.).
2. Comply with the NSPS excess emissions reporting requirements of 40 CFR 60.7(c) and (d).
3. Comply with the Performance Testing Reporting Requirements in Env-A 802.11.
4. Comply with the reporting requirements of Env-A 808.05 (CEMS and COMS Performance Specification Testing Reports), Env-A 808.07(c) and (e) (General Audit Notification Requirements), Env-A 808.07 (Quarterly Audit Reports), Env-A 808.04 and 808.06 (Monitoring and QA/QC Plan Submittals), 808.11 and 808.12 and 808.13(a)(5) through (9) (Quarterly Emission Reports).
5. Comply with the reporting requirements of Env-A 907.01 (General Reporting), Env-A 908.03 (VOC Reporting Requirements), Env-A 909.03 (NOx Reporting Requirements), Env-A 910.01 (Raw Material Usage for Air Pollution Control Equipment Reporting), and Env-A 911 (Permit Deviation Reporting).

MODELING:

All required ambient air quality impact analyses have been conducted for this project. Air quality impacts from this project will comply with all applicable state and federal air quality standards. Please refer to the Air Quality Impact Analysis section of the Statement of Basis for further details.

REVIEW OF APPLICABLE STATE REGULATIONS:

- Env-A 101.661 Emergency Generator Definition – Applicable to Emergency Generators 1 and 2
- Env-A 403.01 Acid Deposition Control Program – This is not applicable to this facility.
- Env-A 607.01(a) a device using natural gas or No. 2 fuel oil greater than 10 MMBtu/hr (Boilers 1, 2, and 3) requires a Temporary Permit
- Env-A 607.01(c) a device using wood with a heat input rate greater than 2 MMBtu/hr (Boiler 1) requires a Temporary Permit
- Env-A 607.01(d)(1)-(3) One or more internal combustion engines, excluding any unit with a design rating less than or equal to 150,000 Btu's per hour of gross heat input, at a source which either: (1) Combusts liquid fuel oil for which the combined total design gross heat input for all such engines is greater than or equal to 1,500,000 Btu's per hour; (2) Combusts natural gas or liquefied propane gas for which the combined total design gross heat input of all such engines is greater than or equal to 10,000,000 Btu's per hour; or (3) Has the potential to emit any single regulated air pollutant in an amount greater than 25 tons per year (Emergency Generators 1 and 2) require a Temporary Permit
- Env-A 607.01(g) a device with total actual volatile organic compound (VOC) emissions greater than or equal to 10 tons per year (Boiler 1) requires a permit

- Env-A 607.01(n) a device choosing to limit its potential to emit by accepting enforceable permit conditions that restrict its hours of operation, type or amount of material combusted, stored, or processed, or level of production (Boilers 2 and 3 and Emergency Generators 1 and 2) requires a Temporary Permit

- Env-A 607.01(q) a device subject to the new source performance standards contained in 40 CFR 60 (Boilers 1, 2, and 3 and Emergency Generator 2) requires a Temporary Permit

- Env-A 607.01(t) a device subject to rules governing non-attainment areas as contained in Env-A 618 (Boiler 1) requires a Temporary Permit

- Env-A 607.01(v) a device where a permit is required under the rules governing regulated toxic air pollutants pursuant to Env-A 1400 (Boiler 1) requires a Temporary Permit

- Env-A 618 Non-Attainment New Source Review Program – Applicable to facility (Boilers 1, 2, and 3, and Emergency Generators 1 and 2) in that NOx emissions are greater than the 50 ton per year major source threshold in the 4-county non-attainment area for ozone. A NOx emission limit must be established for each of these devices that is the Lowest Achievable Emission Rate and the facility must obtain NOx emissions offsets. Please refer to the Excel spreadsheet entitled "NOx Emissions Offsets Required" for detailed calculations of the NOx emissions offsets required. Based upon the consecutive 24 month period from January 1, 2006 through December 31, 2007 for purposes of establishing the baseline NOx emissions reductions credits, CSC is required to obtain 37 tons of ozone season NOx emissions offsets and 28 tons of non-ozone season NOx emissions offsets for the proposed facility at Langdon Street in Concord, New Hampshire.

- Env-A 619 Prevention of Significant Deterioration (PSD) of Air Quality Permit Requirements - Not applicable in that the facility has accepted a CO emission limit of 0.18 lb/MMBtu for Boiler 1 and a facility wide CO emissions cap of <250 tons/yr, which is below the 250 tons/yr threshold for PSD avoidance.

- Env-A 703 Permit Review Fees – In accordance with Env-A 702.01(c), the applicant shall pay the permit review fee pursuant to Env-A 703.03 since it is subject to fees in Env-A 703 for Non-Attainment New Source Review.

- Env-A 704 Testing and Monitoring Fees for Temporary Permits – Applicable for the testing to be conducted on Boilers 1, 2, and 3.

- Env-A 802 Compliance Stack Testing for Stationary Sources – Applicable for all testing to be conducted on Boilers 1, 2, and 3.

- Env-A 803.02 Compliance Stack Testing for NOx – Applicable to Boilers 1, 2, and 3.

- Env-A 806.02 Test Methods for Liquid Fuels – Applicable Facility Wide

- Env-A 806.03 Test Methods for Gaseous Fuels – Applicable Facility Wide

- Env-A 806.05 Recordkeeping Requirements – Retention of fuel oil delivery slips containing sulfur content by weight – Applicable to Emergency Generators 1 and 2.

- Env-A 807.02 Testing for Opacity from Stationary Sources – Applicable to Boilers 1, 2, and 3.

- Env-A 808 Continuous Emissions Monitoring – Applicable to the NOx, CO, CO2 or O2, stack volumetric flow meter, and opacity monitors required for Boiler 1 and the opacity monitors for Boilers 2 and 3.
- Env-A 902.01(a) Record Retention and Availability – Keep records on file for a minimum of 5 years, applicable facility wide.
- Env-A 903.02 General Recordkeeping Requirements for Process Operations – Applicable to the Boiler 1 Spray Cooling Pond.
- Env-A 903.03 General Recordkeeping Requirements for Combustion Devices – Applicable to Boilers 1, 2, and 3, and Emergency Generators 1 and 2.
- Env-A 903.04 General Recordkeeping Requirements for Continuous Emissions Monitoring Systems – Applicable to the NOx, CO, CO2 or O2, Opacity CEMs, and Stack Volumetric Flow meter on Boiler 1 and the Opacity CEMs on Boilers 2 and 3 – Keep records in accordance with Env-A 800 and all applicable federal regulations for continuous monitoring systems.
- Env-A 904.02 General VOC Recordkeeping – Applicable facility wide.
- Env-A 905.02 General NOx Recordkeeping – Applicable facility wide.
- Env-A 905.03 Recordkeeping for Sources or Devices with Add-on NOx Air Pollution Control – Applicable to Boiler 1.
- Env-A 907.01 General Reporting Requirements – Applicable facility wide – Annual emissions report.
- Env-A 908.03 VOC Reporting Requirements – Applicable facility wide.
- Env-A 909.03 NOx Reporting Requirements – Applicable facility wide.
- Env-A 910 Additional Reporting Requirements – As specified in the Temporary Permit.
- Env-A 911 Recordkeeping and Reporting Requirements for Permit Deviations – Applicable facility wide; since the source is considered a major source, they will need to apply for a Title V Operating permit 90 days prior to the expiration of the Temporary Permit.
- Env-A 1211 NOx RACT – Not applicable to Boilers 1, 2, and 3 and the Emergency Generators 1 and 2, as they are subject to more stringent LAER NOx emission limits than NOx RACT limits.
- 40 CFR 60.4207(a) (Subpart IIII) – Sulfur Content of Diesel Fuel - Beginning June 1, 2007, diesel fuel sulfur content limit of 500 ppm sulfur = 0.05% sulfur, by weight. – Applicable to Emergency Generator 2.
- 40 CFR 60.4207(b) (Subpart IIII) – Sulfur Content of Diesel Fuel – Beginning June 1, 2010, diesel fuel sulfur content limit of 15 ppm sulfur = 0.0015% sulfur, by weight. – Applicable to Emergency Generator 2.
- 40 CFR 60.4209(e) (Subpart IIII) – Install and operate a non-resettable hour meter to determine hours of operation of the device - Applicable to Emergency Generator 2.
- 40 CFR 60.4211(e) (Subpart IIII) – 100 hour restriction on maintenance and readiness testing and less

than 500 hours of operation per consecutive 12 month period for Emergency Generators – Applicable to Emergency Generator 2

- Env-A 1400 Regulated Toxic Air Pollutants – Applicable for ammonia (from SCR) on Boiler 1 and water treatment chemicals used in the cooling pond.
- Env-A 1605.01 (and 40 CFR 52) Sulfur Content Limitations for Gaseous Fuels – Natural gas shall contain no more than 15 grains of sulfur per 100 cubic feet of gas at standard temperature and pressure – Applicable facility wide.
- Env-A 1606 Sulfur Content Limitations for Solid Fuels – Does not apply to wood fuel.
- Env-A 2002.02 Visible Emission Standards for Fuel Burning Devices Installed After May 13, 1970 – 20% opacity limit – Applicable to all combustion devices at the facility.
- Env-A 2002.04(a) Activities Exempt from Visible Emission Standards – Applicable to Boilers 1, 2, and 3.
- Env-A 2002.04(d)-(f) Activities Exempt from Visible Emission Standards – Applicable to Boilers 1, 2, and 3.
- Env-A 2002.05 Opacity Standards for Fuel Burning Devices Subject to 40 CFR 60 – Applicable to Boilers 1, 2, and 3.
- Env-A 2002.08 Particulate Emission Standards for Fuel Burning Devices Installed on or After January 1, 1985 – Applicable to Boilers 1, 2, and 3, and Emergency Generators 1 and 2.
- Env-A 2100 – Particulate Matter and Visible Emission Standards – The requirements of Env-A 2100 are applicable to the wood chip handling system (the facility will comply by using conveyors and transfer points that will be totally enclosed) and ammonia system at CSC. It is not applicable to the wood storage piles.
- Env-A 2900 Multi-pollutant Annual Budget and Trading Program – Not Applicable.
- Env-A 3000 Emission Reduction Credits Trading Program – Either this or Env-A 3100 apply to the facility in order to acquire offsets of NOx emissions from Boiler 1.
- Env-A 3100 Discrete Emission Reduction Trading Program – Either this or Env-A 3000 apply to the facility in order to acquire offsets of NOx emissions from Boiler 1.
- Env-A 3200 NOx Budget Trading Program – Not Applicable
- Env-A 3700 NOx Emission Reduction Fund – Not Applicable
- Env-A 3800 – Voluntary Greenhouse Emission Reduction Registry – Not Applicable

REVIEW OF FEDERAL REGULATIONS FOR BOILERS 1, 2, and 3 (Applicable regulations are highlighted):

- 40 CFR 51.165 - Non-Attainment New Source Review (NSR) – Applicable to facility in that NOx emissions are greater than the 50 ton per year major source threshold in the 4-county non-attainment area for ozone. A NOx emission limit must be established that is the Lowest Achievable Emission Rate and the facility must obtain NOx emissions offsets.
- 40 CFR 52.21 – Prevention of Significant Deterioration (PSD) Program – Not applicable in that the facility has accepted a very stringent CO emission limit of 0.15 lb/MMBtu for Boiler 1 and a facility wide CO emissions cap of 203.15 tons/yr, which is below the 250 tons/yr threshold for PSD avoidance.
- 40 CFR 60 Subpart A – General Provisions – Boiler 1 is subject to Subpart Db and Boilers 2 and 3 are subject to Subpart Dc, making Subpart A applicable to each of the three Boilers.
- 40 CFR 60 Subpart D – NSPS for Fossil-Fuel-Fired Steam Generators for Which Construction, Modification, or Reconstruction is Commenced After August 17, 1971 – NA – Boiler #1 is not a fossil fuel fired steam generating unit greater than 250 MMBtu/hr or a wood-residue fired steam generating unit greater than 250 MMBtu/hr.
- 40 CFR 60 Subpart Da – NSPS for Electric Utility Steam Generating Units for Which Construction, Modification, or Reconstruction is Commenced After September 18, 1978 – Boiler #1 is not subject to this Subpart, as it is not by definition an electric utility steam generating unit.
- 40 CFR 60 Subpart Db – NSPS for Industrial-Commercial-Institutional Steam Generating Units for Which Construction, Modification, or Reconstruction is Commenced After June 19, 1984 – Subpart Db is applicable to Boiler 1, since Boiler 1 is a steam generating unit greater than 100 MMBtu/hr that is commencing construction after June 19, 1984.
- 40 CFR 60 Subpart Dc – NSPS for Small Industrial-Commercial-Institutional Steam Generating Units for Which Construction, Modification, or Reconstruction is Commenced After June 9, 1989– Applicable to Boilers 2 and 3, since they each have heat input ratings of 76.8 MMBtu/hr respectively, which falls in the middle of the 10 to 100 MMBtu/hr size category regulated by this Subpart.
- 40 CFR 60 Subpart IIII – NSPS for Stationary Compression Ignition Internal Combustion Engines for Which Construction, Modification, or Reconstruction is Commenced With Model Year 2007 or later for engines that are not fire pumps – Applicable to Emergency Generator 2.
- 40 CFR 63 Subpart DDDDD – MACT for Industrial, Commercial and Institutional Boilers and Process Heaters – Not applicable to Boiler 1 – Provided the facility stays less than 10 tons per year of any single HAP and below 25 tons per year for all HAP combined.
- 40 CFR Part 68 – Chemical Accident Prevention – This will not apply to Boiler 1 as CSC will use aqueous ammonia at less than 20% by weight.
- 40 CFR 72 – Permits Regulation (Acid Rain permits) – Boiler 1 is not an applicable unit under 40 CFR 72.
- 40 CFR 73 – Sulfur Dioxide Allowance System – Not Applicable.
- 40 CFR 74 – Sulfur Dioxide Opt-Ins – Not Applicable.
- 40 CFR 75 – Continuous Emission Monitoring – Not Applicable.
- 40 CFR 76 – Acid Rain Nitrogen Oxides Emission Reduction Program — Not Applicable.
- 40 CFR 77 – Excess Emissions – Not Applicable.
- 40 CFR 96 – NOx Budget Trading Program for SIPs – Not Applicable (New Hampshire is not part of the program.)
- 40 CFR 97 – Federal NOx Budget Trading Program – Not Applicable.

SUMMARY AND CONCLUSIONS:

In summary, the operations as applied for will be capable of meeting all regulations and standards for air quality. Therefore, a Temporary Permit shall be proposed for issuance.