VERMONT AGENCY OF NATURAL RESOURCES
Department of Environmental Conservation
Air Quality & Climate Division

TECHNICAL SUPPORT DOCUMENT

FOR

TITLE V PERMIT TO CONSTRUCT AND OPERATE

#AOP-21-048

Permit Date: August 30, 2022

Ryegate Associates – East Ryegate, VT

Owner/Operator:	**Stored Solar Services LLC dba Ryegate Associates** **1231 Main Road** **West Enfield, ME 04493**
Source:	**Ryegate Associates** **Wood-fired Electric Generating Station** **247 Weesner Drive** **East Ryegate, Vermont 05042**

Prepared By: Tony Mathis, Environmental Engineer
Air Quality & Climate Division

This Technical Support Document details the Agency of Natural Resources, Department of Environmental Conservation, Air Quality & Climate Division review for the Air Pollution Control Permit to Construct and Operate and Acid Rain Permit and is intended to provide additional technical information, discussion and clarification in support of the Permit. It is not intended to provide a comprehensive review of the Facility or permit process or duplicate the information contained in the Permit.

1.0 INTRODUCTION

Ryegate Associates, Incorporated (hereinafter "Permittee") owns and operates a 20 MW (net) wood fired electrical generating station (also referred to herein as "Facility"). The Permittee has applied to renew their Title V Operating Permit. In 2014, the Permittee installed an optional selective catalytic reduction (SCR) device to further reduce the NOx emissions from the Main Boiler. The SCR was added to allow this facility's electrical generation to qualify for out-of-state "Renewable Energy Credits" (RECs). Since the SCR was not required by the Agency and it would not result in any increases in air emissions, the Agency had previously determined that a construction permit was not needed to install and operate the SCR.

The electricity generated at the Ryegate Power Station is sold under the terms of a power purchase agreement (PPA) issued by the Public Service Board (PSB) on March 29, 2013. The electricity generated at the Ryegate Power Station is sold under the terms of a power purchase agreement (PPA) issued by the Public Service Board (PSB) on March 29, 2013. The original PPA was valid for a 10-year period from November 1, 2012 to November 1, 2022. On May 21, 2021, legislation was approved that granted a 2-year extension of this 10-year PPA. The new PPA expiration date is November 1, 2024In May 2022. Subsequently in May 2022, legislation (Act 155) was approved that granted an additional 10-year extension of the PPA, pending efficiency improvements at the Facility. The expiration date for the PPA under Act 155 is November 1, 2032.

Administrative Milestones:

Table 1-1: Administrative Summary

Administrative Item	Result or Date
Date Application Received:	03/03/2022
Date Administratively Complete:	03/03/2022
Date Technically Complete:	04/27/2022
Date Draft Decision:	05/05/2022
Date & Location Draft Decision/Comment Period Noticed:	05/05/2022 Environmental Notice Bulletin
Date & Location Public Meeting Noticed:	None requested
Date & Location of Public Meeting:	None requested
Deadline for Public Comments:	06/06/2022
Proposed Permit Submitted to EPA for Review:	06/14/2022
Date Final Decision:	08/302022
Classification of Source Under §5-401:	§5-401(3): Electric power generation facilities
Classification of Application:	Title V Subject Source
New Source Review Designation of Source:	Major Stationary Source
Facility SIC / NAICS Code(s):	4911 / 221117
Facility SIC / NAICS Code Description(s):	Electrical Services / Biomass Electric Power Generation

The allowable emissions for the Facility are summarized below:

Table 1-2: Estimated Air Contaminant Emissions (tons/year)[1]

$PM/PM_{10}/PM_{2.5}$	CO	NOx	SO2	VOC	Total HAPs [2]	CO_2e [3]
34	394	<100	25	39	<8/20 [2]	280,610

[1] $PM/PM_{10}/PM_{2.5}$ – total particulate matter, total particulate matter of 10 micrometers in size or smaller and total particulate matter of 2.5 micrometers in size or smaller, respectively. Unless otherwise specified, all PM is assumed to be $PM_{2.5}$; SO_2 - sulfur dioxide; NO_x - oxides of nitrogen measured as NO_2 equivalent; CO - carbon monoxide; VOCs - volatile organic compounds; HAPs - hazardous air pollutants as defined in §112 of the federal Clean Air Act.

[2] Emissions of individual HAPs each < 8 tpy and emissions of total HAPs combined <20 tpy. Actual total combined HAPs estimated at <12 tpy

[3] CO_2e 'at the stack' – includes emissions from biogenic sources. See section 3.3 for details. This is not a Facility limit.

2.0 FACILITY DESCRIPTION AND LOCATION

2.1 Facility Locations and Surrounding Area

The Permittee owns and operates a twenty (20) megawatt (net) wood-fired electrical generating station located just north of the village of East Ryegate at 247 Weesner Drive, East Ryegate, Vermont. The area surrounding the Facility property is rural and consists of primarily agricultural and residential uses. The Connecticut River borders the property to the East and U.S. Route 5 to the West. The geographical area is complex terrain in all directions surrounding the site. The facility is located approximately 145 kilometers from the Lye Brook Wilderness Area outside of Manchester, Vermont and approximately 61 kilometers from the Great Gulf and Dry River Wilderness Areas in New Hampshire.

2.2 Facility Description

Operations performed at the Facility are classified within the Standard Industrial Classification Code - 4911 (Electrical Services) or under the North American Industrial Classification System Code 221117 (Biomass Electric Power Generation). The Ryegate Power Station is listed as a stationary source of air contaminants under §5-401(3), Electrical power generation facilities, of the Vermont Air Pollution Control *Regulations* (*Regulations*).

The Facility is equipped a single, high-pressure, boiler designed to burn green wood fuel (Main Boiler). The Main Boiler is fired with whole tree wood chips delivered in standard chip vans. The wood fuel is primarily mixed hardwood and softwood, with some lesser amounts of sawdust, mill chips, and bark. The wood fuel chips are stored in two (2) silos and an uncovered outside storage pile before being mechanically conveyed to the Main Boiler. Wood fuel is fed at a rate of approximately thirty-five (35) tons per hour into the Main Boiler. The Facility is operated as a base load plant at or near 100% capacity at all times, excluding plant outages.

The Main Boiler is fitted with a liquefied petroleum gas (LPG) auxiliary burner having a maximum rated heat input of 50 million British thermal units per hour (MMBtu/hr). This burner is used primarily for plant start-up and for supplemental fuel. Steam produced by the Main Boiler is passed through a condensing turbine generator set with extraction steam utilized for feedwater heating. Condenser heat is removed via an open loop circulating water system to a cooling tower structure. The Facility has a 430 horsepower (HP) / 300 kilowatt (kW) LPG-fired engine generator set (Emergency Generator) for use during electric power outages, and an auxiliary LPG-fired boiler rated at five (5) MMBtu/hr (Auxiliary Boiler). The Auxiliary Boiler supplies hot water for space heating purposes during plant outages.

On August 4th, 1992, the Main Boiler was operated on liquefied petroleum gas (LPG) for a brief period to allow the Facility to produce electricity and to synchronize with the Green Mountain Power Corporation grid. The Main Boiler's initial startup on wood fuel occurred on September 7, 1992.

The regulated sources of air contaminant emissions at the Facility are listed in Table 2-1. Refer to Table 2-2 for information on air pollution control equipment used at the Facility.

<table>
<tr><th colspan="6">TABLE 2-1: Equipment and Stack Information</th></tr>
<tr><th>Description and Model Number</th><th>Rating</th><th>Fuel</th><th>Date Installed</th><th>Pollution Control Equipment</th><th>Stack Height (ft above grade)</th></tr>
<tr><td rowspan="2">Main Boiler:
Riley Stoker Corp.</td><td rowspan="2">300 MMBtu/hr</td><td rowspan="2">Wood</td><td>1992</td><td>Multicyclone, ESP, SNCR</td><td rowspan="2">212</td></tr>
<tr><td>2014</td><td>SCR</td></tr>
<tr><td>Main Boiler:
(Auxiliary Burner)
Coen Model 230/DAZ-22</td><td>50 MMBtu/hr</td><td>LPG</td><td>1992</td><td>Uncontrolled</td><td>212</td></tr>
<tr><td>Auxiliary Boiler
Manufacturer: Weil-McLain
Boiler Model # 1688R-W
Burner Model: WCR3-G-25B</td><td>5 MMBtu/hr</td><td>LPG</td><td>1992</td><td>Uncontrolled</td><td>60</td></tr>
<tr><td>Emergency Generator
Cummins Engine
Model #: GTA19
Serial Number: 25178626
Marathon Electric Generator Model #: 432RSL4015BP-310W</td><td>430 bhp
(280 kW)</td><td>LPG</td><td>1992</td><td>Uncontrolled</td><td>60</td></tr>
</table>

Table 2-2: Existing Air Pollution Control Equipment & Techniques	
Equipment	**Description**
Main Boiler – Mechanical Dust Collectors / Fly ash Reinjection System	Manufacturer: Zurn Mechanical Type of Unit: Cyclone Separator
Main Boiler – ESP	Manufacturer: PPC Industries Estimated Collection Efficiency: 99.5% Pressure Drop: 0.5 inch w.c. max Type of Unit: Plate and weighted wire Cleaning Method: Rapping Inlet Temperature: 300^0F Collecting surface area: 77,175 ft^2 Air Flow Rate: 115,000 acfm
Main Boiler - SNCR	Manufacturer: Nalco/Fuel Tech Estimated Collection Efficiency:30% Pressure Drop: N/A Dimensions: 12 injection nozzles – located approximately 30 feet above the furnace grate. Air Flow Rate: 335,000 lb/hr (flue gas) Other Pertinent Information: Injection of a 15/85 solution of urea and water.
Main Boiler - SCR	Manufacturer: CCA / Peerless Pressure Drop: N/A Dimensions: 6,500 square feet.

2.3 Description of Compliance Monitoring Devices

The Facility is equipped with continuous emission monitoring devices (CEMS) which measure the emission of NOx, CO, NH3 and either O_2 or CO_2 from the Main Boiler to the ambient air. In addition, the Facility also operates and maintains a continuous opacity monitoring system (COMS) which measures the opacity of the exhaust gas from the Main Boiler.

2.4 Proposed Modifications to Facility

The Permittee has not proposed any modifications to the Facility at this time.

In the previous permit, the Cummins diesel engine generator was permitted to operate up to 720 hours/yr. This diesel engine generator is now reduced to emergency-only operation, and, for 40 CFR Part 63 Subpart ZZZZ, is only required to meet the emergency engine requirements of this standard.

2.5 Identification of Sources with Insignificant or Negligible Emissions

Although not required for determining applicability with Subchapter X, quantifiable emissions from “insignificant activities” must be included for the purposes of establishing whether or not a source is subject to other air pollution control requirements, including, but not limited to: reasonably available control technology, major source status, and Title V operating permit applicability.

Additionally, guidance provided by the U.S. EPA (entitled “White Paper for Streamlined Development of Part 70 Permit Applications”) lists activities which are considered as “trivial” sources of air contaminants, and may be presumptively omitted from operating permit applications.

Table 2-3 lists activities at the Facility which were considered negligible or exempt sources of air contaminant emissions, and therefore were not considered as emission sources as part of the Permit to Operate renewal review.

<table>
<tr><th colspan="4">Table 2-3: Insignificant Fuel Combustion Equipment</th></tr>
<tr><th>Equipment</th><th>Size [1,2]</th><th>Fuel Type [3]</th><th>Date of Installation</th></tr>
<tr><td>Diesel Fire Pump
Cummins 6BTA 5.9 F!
Serial Number: 44698521</td><td>208 bhp</td><td>No. 2 Fuel Oil</td><td rowspan="3">1992</td></tr>
<tr><td>Fuel Yard Maintenance Building Heater</td><td>< 3 MMBtu/hr</td><td rowspan="3">LPG</td></tr>
<tr><td>Main Maintenance Building Heater</td><td>< 3 MMBtu/hr</td></tr>
<tr><td>LPG System Vaporizer
Make: Algas-SDi
Model Q1650V
Serial Number 08116660</td><td>< 3 MMBtu/hr</td><td>2009</td></tr>
</table>

[1] MMBtu/hr - Million British Thermal Units per hour maximum rated heat input.
[2] bhp – brake horsepower rated output as specified by the manufacturer. .
[3] LPG –Liquefied Petroleum Gas

Table 2-4: Other Insignificant Air Emission Sources	
Equipment	Comments
Central Vacuum System	Exhausts to building interior
Steam Turbine Vapor Extractor	110 acfm exhaust of steam vapor with negligible amounts of lubricating oil.

It should be noted that a process or equipment which is considered a “negligible activity” does not relieve the owner or operator from the responsibility of complying with any applicable requirements associated with said process or equipment.

3.0 QUANTIFICATION OF POLLUTANTS

The quantification of emissions from a stationary source is necessary in order to establish the regulatory review process necessary for the operating permit application and to determine applicability with various air pollution control requirements. These determinations are normally based upon allowable emissions. Allowable emission is defined as the emission rate calculated using the maximum rated capacity of the source and, if applicable, either: (a) the applicable emission standard contained in the *Regulations*, if any, or (b) the emission rate or design, operational or equipment standard specified in any order or agreement issued under the *Regulations* that is state and federally enforceable. An applicant may impose in its application an emission rate or design, or an operational or equipment limitation which may be incorporated in the Permit to restrict operation to a lower level. Such limitations may include fuel restrictions or production limits.

3.1 Estimating Potential Emissions of Criteria Pollutants from the Existing Stationary Source

<u>Main Boiler and Auxiliary Boiler:</u> For the Main Boiler, potential emissions of NO_X, PM, CO and VOCs were estimated based on emission limits specified in the Permit. Emissions of SO_2 were evaluated using the current AP-42 emission factors for combustion of wood fuel, found at *AP-42, Fifth Edition Volume 1, Chapter 1: External Combustion Sources, Section 1.6,* (AP-42) Table 1.6-2. Allowable SO_2 emissions were based on the previous permit for this Facility, as described below.

The potential emissions for HAPs are based on a combination of AP-42 emission factors and stack testing conducted at the Facility. Additional details of the stack regarding the selection of the various emission factors used to estimate HAP emissions are presented in section 3.2 of this document.

Previous permits for the Facility estimated the SO_2 emission rate from the combustion of wood based on AP-42 emission factors. The AP-42 emission factors for wood were updated in September 2003, and the updated factor for SO_2 represents a higher emission rate than the previous factor. The current AP-42 emission factor for bark and wet wood is 0.025 lb/MMBtu. The Facility performed stack testing for SO_2 on June 16, 2004, which reported SO_2 emissions of less than the detection limit of 0.0022 lb/MMBtu. The estimated hourly emission rate for SO_2 is greatest when firing wood fuel.

Based on this information, potential SO_2 emissions for the Main Boiler were based on firing wood fuel at a heat input of 300 MMBtu/hr for 8,760 hours/year, and an SO_2 emission factor of 0.025 lb/MMBtu of heat input. However, the allowable emissions for SO_2 were limited to 25 tons/year as based on this limitation being established in the previous permits. Based on previous stack testing for SO_2 on the Main Boiler, it is anticipated that the emissions from the Main Boiler will comply with this allowable emission limit that is less than the estimated potential emissions.

Table 3-1: Main Boiler – Estimated Potential Emissions

Wood: Boiler Rating: 300 MMBtu/hr, 35.3 ton/hr of wood with a Btu content of 4,250 Btu/lb
LPG: Supplemental Burner Rating: 50 MMBtu/hr, annual limit: 556,000 gallons [5]

Pollutant	Fuel(s)	Emission Factor			Estimated Emissions (tons / year)
		Factor	Units [1]	Reference	
SO_2	LPG	0.10S [2]	lb/1000gal	AP-42, Table 1.5-1 (7/98)	0.3
	Wood [3]	0.025	lb/MMBtu	AP-42 Table 1.6-2	32.9
NO_x	LPG / Wood	0.075 / 22.5	lb/MMBtu / lb/hr	Permit limit	98.6
PM	LPG / Wood	0.0070 / 5.0	gr/dscf [4] / lb/hr	Permit limit	21.9
CO	LPG / Wood	0.30 / 90.0	lb/MMBtu lb/hr	Permit limit	394
VOC	LPG / Wood	0.03 / 9.0	lb/MMBtu / lb/hr	Permit limit	39
HAPs	Wood	0.009	lb/MMBtu	AP-42, Table 1.6-3 and 1.6-4 (9/03) for all HAPs except: acrolein, benzene, formaldehyde and hydrogen chloride for which there was stack testing conducted at the Facility (6/17/2003 & 6/16/2004). Refer to Table 3-5 for further details.	11.8

[1] lb/MMBtu: pounds of pollutant emitted per million British thermal units of energy input to the boiler.
lb/1000 gal: pounds of pollutant emitted per 1000 gallons of fuel input to the boiler.
lb/hr: pounds of pollutant per hour

[2] S represents the sulfur content of LPG in grains of sulfur per 100 ft^3 of LPG. The Facility has a sulfur limit of 10 gr/100ft^3 so the emission factor is 0.1 * 10 = 1.0 lb sulfur/ 10^3 gallons of LPG.

[3] Stack testing of the Main Boiler on June 16, 2004 had no detections of SO_2 with a detection limit of 0.0022 lb/MMBtu

[4] grain/dscf: grains of particulate matter per dry cubic foot of exhaust gas at 12% CO_2 and at standard temperature (60°F) and pressure (1 atmosphere).

[5] 556,000 gallons is equivalent to 20,000,000 cubic feet. The prior permits limited LPG to 20,000,000 cubic feet.

Table 3-2: LPG Fired Auxiliary Boiler – Estimated Potential Emissions				
Total Fuel input: 5 MMBtu/hr * 720 hr/yr = 3,600 MMBtu/yr 3,600 MMBtu/yr * 1,000 gallon LPG/91.5 MMBtu/1,000 gallon = 39.3 x 10^3 gallons/yr LPG				
Pollutant	Emission Factor			Allowable Emissions (tons/year)
	Factor	Units [1]	Reference	
SO_2	0.1 S [2]	lb/1000 gal	AP-42, Liquefied Petroleum Gas Combustion, Table 1.5-1, 7/08	0.02
NO_x	13			0.26
PM	0.7			0.014
CO	7.5			0.15
VOC	0.8 [3]			0.016
HAPs	0.169 [4]		AP-42, Natural Gas Combustion, Table 1.4-3 and 1.4-4 (7/1998)	0.003

[1] lb/1,000 gallons: pounds of pollutant emitted per 1,000 gallons of LPG combusted.

[2] S represents the sulfur content of LPG in grains of sulfur per 100 ft^3 of LPG. The Facility has a sulfur limit of 10 gr/100ft^3 so the emission factor is 0.1 * 10 = 1.0 lb sulfur/ 10^3 gallons of LPG.

[3] VOC emission factor based on TOC emission factor (1.0 lb/1000 gallon) - CH_4 emission factor (0.2 lb/1000 gallon) for propane combustion from AP-42, Chapter 1, Section 1.5 Liquefied Petroleum Gas Combustion, Table 1.5-1.

[4] HAP emissions from propane combustion assumed to be the same as from natural gas combustion

Emergency Generator: Emissions for the 430 bhp Cummins GT19 engine powering the 300-kW emergency generator were based on the engine being operated for 200 hours per year. This engine was previously permitted to operate for 720 hours per year, but the operating hours for this engine have been restricted to emergency only to provide consistency with federal regulations and Agency policy.

Although the engine is allowed unrestricted hours of operation during actual emergencies, Agency policy for emissions estimation from emergency generators is to assume that emergency use would not exceed 100 hours per year. Engine readiness testing, operation for maintenance and similar activities are limited to 100 hours per year in the current permit.

Emission factors used to estimate emissions of SO_2, NOx, CO, PM, VOCs, and HAPs from this engine were the emission factors for uncertified engines as described in *AP-42, Chapter 3, Stationary Internal Combustions Sources, Section 3.2 –Natural Gas-fired Reciprocating Engines, (August 2000)*. The engine was assumed to be fueled with LPG containing a maximum of 10 gr/100 scf of sulfur with a heating value of 91,500 Btu per gallon. Fuel consumption for the engine was estimated at 40 gallons per hour.

Table 3-3: LPG-fueled Emergency Generator – Estimated Potential Emissions

Total fuel input: (40 gal/hr)*(200 hr/yr)*(91,500 btu/gal)*(1 MMBtu/10^6 Btu) = 732 MMBtu/yr
Emission estimate based on 200 hours/year of operation

Pollutant	Emission Factor			Allowable Emissions, (tons/yr)
	Factor	Units [1]	Reference	
SO_2	0.00059	lb/MMBtu	AP-42 Natural Gas-fired Reciprocating Engines, Table 3.2-2: 4-stroke lean-burn engines (07/2000)	0.0002
PM	$PM/PM_{10}/PM_{2.5}$: 0.000077 Condensable PM: 0.0099			0.004
NO_X	4.08			1.49
CO	0.317			0.12
VOC	0.118			0.04
HAP	0.071			0.036

[1] lb/MMBtu: pounds of pollutant emitted per million British Thermal Units of energy input to the engine.

<u>Cooling Tower:</u> Emissions of particulate matter from cooling tower drift were not estimated or included in previous permits, being identified as "negligible". These PM emissions were estimated using procedures described in *AP-42, Chapter 13, Miscellaneous Sources, Section 13.4 - Wet Cooling Towers (January 1995)*. Emissions from the cooling tower were based on information provided by the Permittee in the original application, including a cooling tower flowrate of 22,000 gallons per minute, a drift loss of 0.005%. The total dissolved solids contained in the circulating water in the cooling tower was assumed to be 5,000 ppm, based on the secondary maximum contaminant level (SMCL) for potable water of 500 ppm multiplied by a factor of 10. The estimated PM emissions from the cooling towers do not represent an emission increase for the Facility, but rather represent a quantification of emissions that have always been present at the Facility.

Table 3-4: Estimated Cooling Tower Drift Emissions

Pollutant	Cooling Tower Flow Rate (gallons/minute)	Circulating Water Lost as Drift %	Total Dissolved Solids Concentration of Cooling Water (parts per million)	Estimated PM Emissions (tons/yr)
PM	22,000	0.005	5,000	12.1

Emissions from the various sources at the Facility are summarized in Table 3-5 below:

Table 3-5: Summary of Estimated Air Contaminant Emissions by Source (tons/year)						
Source	$PM/PM_{10}/PM_{2.5}$	SO_2	NOx	CO	VOC	Total HAPs
Main Boiler	21.9	32.9	98.6	394.2	39.4	11.8
Auxiliary Boiler (LPG)	0.014	0.02	0.26	0.15	0.016	0.003-
Emergency Generator (LPG)	0.004	0.0002	1.49	0.12	0.04	0.093
Cooling Towers	12.1	---	---	---	---	0.036
Facility Estimated Potential Emissions	**34.02**	**32.92**	**100.35**	**394.47**	**39.47**	**11.93**
Facility Allowable Emissions	**34**	**25**	**100.4**	**394**	**39**	**<10/25**

As summarized in Table 3-5 above:

- The Facility has allowable emissions of all air contaminants in the aggregate of ten (10) or more tons per year: The Facility is therefore subject to Subchapter X of the *Regulations* and is designated as a Subchapter X Major Source.
- The Facility has allowable emissions of NOx and CO which classify the source as a federal “Major Source.”
- The Facility has allowable emissions of NOx and CO which classify the source as a "Title V Subject Source" and therefore is subject to the federal operating permit requirements of 40 *CFR.* Part 70 or 71.

3.2 Estimated Emissions of Hazardous Air Contaminants (HACs) and Hazardous Air Pollutants (HAPs) from the Existing Stationary Source.

The equipment at the Facility that was evaluated for emissions of HACs and HAPs includes the following:

- Main Boiler combustion emissions
- Main Boiler pollution control emissions.
- Auxiliary Boiler combustion emissions
- Emergency Generator combustion emissions
- Cooling Tower drift

Vermont Hazardous Air Contaminants (HACs):

Pursuant to §5-261(1)(b)(ii) of the *Regulations*, all fuel burning equipment which combusts virgin liquid or gaseous fuel and wood boilers constructed before January 1, 1993 are exempt from this section. Therefore, the Main Boiler combustion emissions, Auxiliary Boiler combustion emissions and the Emergency Generator combustion emissions are not subject to §5-261 of the *Regulations* at this time. However, combustion emissions from these sources are included in the discussion of Federal Hazardous Air Pollutants (HAPs) in this section.

Water circulated through the cooling towers contains various anti-microbial and anti-corrosion agents, which are emitted to the ambient air as the water droplets from the cooling tower evaporate. These emissions and known as “drift”, and HACs in Cooling Tower drift are subject to §5-261. The following table summarizes estimated potential HAC emissions from the Cooling Tower as a result of “drift”.

Table 3-6 Quantification of Cooling Tower HAC Emissions

Hazardous Air Contaminant	CAS#	Toxic Category	Emission Rate (lb/8-hrs)[1]	Action Level (lb/8-hrs)
Sodium Bromide	7647-15-6	2	0.0536	11.6
Chlorine	7782-50-5	3	0.00070	0.01
Methanol	67-56-1	2	0.0438	97

[1] For Category 3 HACs, emission rate is based on 2,000 hours/year of operation, or actual hours of operation. For category 1 and 2 HACs, the emission rate is based on 8,760 hours/year.

The estimated HAC emissions from the cooling towers do not exceed their respective Action Levels, and accordingly, cooling tower emissions were not evaluated further under§5-261 of the *Regulations*.

The SNCR / SCR systems have emissions of ammonia due to ammonia slip and these emissions are subject to §5-261 of the *Regulations*. The ammonia emissions from the SNCR system will be limited by the Permit to not exceed 20 parts per million by dry volume (ppmdv) of ammonia. Based on this permit limitation, the estimated maximum potential ammonia emissions due to the operation of the SNCR / SCR system may be estimated as follows:

Flue gas flow rate: 85,000 standard cubic feet per minute wet (scfmw)
Flue gas moisture content: 21%
Ammonia concentration: 20 ppmdv
Hours of operation: 8,760 hr/yr

(85,000 scfmw) * ((100%-21%)/100%) * (20 scf NH_3/1,000,000 scf exhaust) * (14.7 psia/((10.73 psia-scf/lbmole-^oR)*(528 ^oR)) * (17 lbs NH_3/lbmole NH_3) * 60 min/hr) * (8 hours) = **28.4 lb/8-hr of ammonia emissions.**

The Action Level for ammonia from Appendix C of the Regulations is 8.3 lbs/8-hr, so the estimated maximum potential ammonia emissions due to the operation of the SNCR / SCR system exceed the Action Level. Emissions during actual operation of the SNCR/SCR system are anticipated to be less than this estimate.

Review of HAC Emissions from Registration Data

Reported actual annual emissions of HACs from the Facility during 2017-2021 were reviewed to assess if any of the reported emissions exceeded their respective action level.

Table 3-7 Review of 2021-2017 HAC Emissions

HAC	CAS	Emissions by Year (lb/year)					Maximum Emission Rate (lb/h8-hr)	Action Level (lb/8-hr)
		2021	2020	2019	2018	2017		
Ammonia	7664-41-7	2197.6	4759.0	2639.7	2283.8	2388.6	4.3461	8.3
Chlorine	7782-50-5	0.739	0.73	0.591	0.741	0.74	0.0007	0.01
Morpholine	110-91-8	6.336	6.24	5.07	6.352	6.33	0.0058	8.3
Sodium Bromide	7647-15-6	56.601	45.26	45.26	56.74	56.5	0.0518	11.6

The reported HAC emissions during 2017-2021 did not exceed their respective action levels.

<u>Federal Hazardous Air Pollutants:</u>

The emissions of HAPs are quantified to determine if the Facility is a major source of HAPs and subject to any Federal NESHAPs standards (40 *CFR.* Part 63). HAP emissions from the Facility were estimated based on AP-42 emission factors for combustion of wood and LPG fuels, using emission factors available from *AP 42, Fifth Edition Compilation of Air Pollutant Emission Factors, Volume 1: Stationary*

Point and Area Sources (AP-42), and from limited emissions testing performed on the Main Boiler at the Facility. Emissions tests were conducted on May 18, 1993, June, 17, 2007, and June 16, 2004, and specific HAPs that were evaluated during these stack tests included the following:

- Acrolein
- Benzo(a)pyrene
- Benzene
- Formaldehyde
- Hydrogen chloride

The results of these stack tests were not conclusive due to detection limit issues for many of the above compounds.

Emissions of HAPs from the cooling tower were estimated as part of the HAC evaluation presented above. Estimation of speciated HAPs from operation of the Auxiliary Boiler and the Emergency Generator were not tabulated. Rather, the overall HAP emissions from these LPG-fired sources were estimated using emission factors from AP-42 and the permit limitations restricting operation of this equipment. The total potential to emit for HAPs from these three activities were estimated to be less than 0.2 tons per year.

Most of the Facility HAP emissions are from wood combustion in the Main Boiler. Table 3-8 presents a summary of the estimated HAP emissions from wood combustion in the Main Boiler at the Facility. These emission factors differ from those used in previous permits. The Agency has reviewed HAP emission factors for wood combustion based on site-specific testing, and emission factors from the National Counsel for Air and Stream Improvement (NCASI) and AP-42, and has developed this revised table of HAP emission factors.

This Facility has permit conditions that define the methods to be used for estimating HAP emissions on a 12-month rolling average basis. The Permit also limits HAP emissions from the Facility to less than 10 ton/year of any single HAP and less than 25 tons/year of all HAPS combined. With these limitations, the Facility is not subject to the federal Major Source HAP standards.

These permit conditions are based on the emission factors presented in Table 3-8, and with these limitations, the Facility is not subject to the federal Major Source HAP standards. This Permit also requires periodic emissions testing for certain HAPs that are anticipated to have the greatest emission factors. This testing will provide an ongoing review for the validity of the HAP emission estimates. Periodic testing will be required for the following HAPs :

- Formaldehyde 50-00-0
- Benzene 71-43-2
- Hydrogen Chloride 7647-01-0
- Methanol 67-56-1
- Chlorine 7782-50-5

- Styrene 100-42-5
- Dichloromethane (methylene chloride)

Emissions of the above-listed HAPs are anticipated to account for approximately 75% of the quantified HAP emissions from the Facility.

Table 3-8
Estimated Emission of Hazardous Air Pollutants
Main Boiler Wood Combustion

Pollutant	CAS #	Proposed Emission Factor (lb/MMBtu)	Reference	Estimated Annual Emissions [1] (lbs)
1,2,4-trichlorobenzene	120-82-1	2.90E-05	NCASI [7]	76.2
1,2-Dich[oroethane (ethylene dichloride)	107-06-2	2.90E-05	AP-42	76.2
1,2-Dichloropropane (propylene dichloride)	78-87-5	3.30E-05	AP-42	86.7
2,4,6-trichlorophenol	88-06-2	2.20E-07	NCASI	0.6
2,4-dinitrophenol	51-28-5	4.80E-07	NCASI	1.3
2,4-dinitrotoluene	121-14-2	9.40E-07	NCASI	2.5
4-nitrophenol	100-02-7	3.30E-07	NCASI	0.9
Acetaldehyde	75-07-0	1.90E-04	NCASI	499.3
Acetophenone	98-86-2	2.60E-07	NCASI	0.7
Acrolein [2]	107-02-8	2.40E-04	AP-42 (LO)	630.7
Antimony	---	7.90E-06	AP-42	20.8
Arsenic [3]	---	4.00E-06	AP-42 (LO)	10.5
Benzene [4]	71-43-2	8.5E-04	AP-42 (LO)	2,233.8
Beryllium	---	1.90E-06	NCASI	5.0
bis(2-ethylehexyl)phthalate	117-81-7	4.70E-08	AP-42	0.1
Bromomethane (methyl bromide)	74-83-9	1.50E-05	AP-42	39.4
Cadmium	---	4.10E-06	AP-42	10.8
Carbon disulfide	75-15-0	1.30E-04	NCASI	341.6
Carbon tetrachloride	56-23-5	8.90E-07	NCASI	2.3
Chlorine	7782-50-5	7.90E-04	AP-42	2,076.1
Chlorobenzene	108-90-7	3.30E-05	AP-42	86.7
Chloroform	67-66-3	3.10E-05	NCASI	81.5
Chloromethane (methyl chloride)	74-87-3	4.00E-05	NCASI	105.1
Chromium (total)	---	2.10E-05	AP-42	55.2
Cobalt	---	6.50E-06	AP-42	17.1
Cumene	98-82-8	1.80E-05	NCASI	47.3
Di-butyl phthalate	84-74-2	3.30E-05	NCASI	86.7
Dichloromethane (methylene chloride)	75-09-2	5.40E-04	NCASI	1,419.1
Ethyl benzene	100-41-4	3.10E-05	AP-42	81.5
Formaldehyde [5]	50-00-0	1.20E-03	AP-42 (LO)	3,153.6

Table 3-8
Estimated Emission of Hazardous Air Pollutants
Main Boiler Wood Combustion

Pollutant	CAS #	Proposed Emission Factor (lb/MMBtu)	Reference	Estimated Annual Emissions [1] (lbs)
Hexachlorobenzene	118-74-1	1.00E-06	NCASI	2.6
Hexane	110-54-3	2.90E-04	NCASI	762.1
Hydrogen Chloride	7647-01-0	8.34E-04	permit	2,191.8
lead compounds	---	4.80E-05	AP-42	126.1
Manganese [6]	---	8.60E-05	AP-42 (LO)	226.0
Mercury	---	3.50E-06	NCASI	9.2
Methanol	67-56-1	8.30E-04	NCASI	2,181.2
Methyl isobutyl ketone	108-10-1	2.30E-05	NCASI	60.4
Naphthalene	91-20-3	1.60E-04	NCASI	420.5
Nickel compounds	---	3.30E-05	AP-42	86.7
Pentachlorophenol	87-86-5	5.10E-08	AP-42	0.1
Phenol	108-95-2	5.10E-05	AP-42	134.0
Phosphorous	7723-14-0	2.70E-05	AP-42	71.0
Polycyclic organic matter (POM)	---	2.98E-05	AP-42	78.3
Propionaldehyde (propanol)	123-38-6	6.10E-05	NCASI	160.3
Selenium	---	3.00E-06	NCASI	7.9
Styrene	100-42-5	6.40E-04	NCASI	1,681.9
Tetrachloroethylene (perchloroethylene)	127-18-4	3.82E-05	AP-42	100.4
Toluene	108-88-3	2.90E-05	NCASI	76.2
Trichloroethylene	79-01-6	3.00E-05	AP-42	78.8
Vinyl chloride	75-01-4	1.80E-05	AP-42	47.3
Xylenes (includes o,m,p)	---	2.80E-05	NCASI	73.6
Total HAPs (tons)				**9.9**
Largest Emissions of a Single HAP (formaldehyde) (tons)				**1.6**

[1] Annual emission rate based on the Main Boiler firing wood at the maximum boiler heat input of 300 MMBtu/hr for 8,760 hours/year.
[2] Based on AP-42 factor less one outlier, with a resulting emission factor of 2.4E-04 lb/MMBtu
[3] Based on AP-42 factor less 13 outliers with a resulting emission factor of 4.0E-06 lb/MMBtu
[4] Based on AP-42 factor less one outlier with a resulting emission factor of 8.50E-04 lb/MMBtu
[5] Based on AP-42 factor less 7 outliers> 0.005 VOC limit, with a resulting emission factor of 1.2E-3 lb/MMBtu
[6] Based on AP-42 less 17 outliers with a resulting emission factor of 8.6E-05 lb/MMBtu
[7] National Council for Air and Stream Improvement (NCASI) “Compilation of ‘Air Toxic’ and Total Hydrocarbon Emissions Data for Sources at Kraft, Sulfite and Non-Chemical Pulp Mills – An Update” Technical Bulletin No. 858 =- February 2003

3.3 – Estimating Potential Green House Gas Emissions

Facility:	Ryegate	Permit #:	AOP-21-048			
Source ID	**Source Description**	**Fuel Combusted**	**Potential or Allowable Quantity Combusted**	**Units**	**Estimated wood usage (raw tons)**	**Estimated %MC for raw wood fuel**
	Main Boiler	Wood and Wood Waste	5,788	tons	9647	46.0%
	Main & Aux. Boilers	Propane	0	gallons	0	0.0%
	Emergency generator	Propane	0	gallons	0	0.0%

Table 2. Total Company-Wide Stationary Source Fuel Combustion

Fuel Type	Quantity Combusted	Units
Distillate Fuel Oil #2	0	gallons
Propane	0	gallons
Wood and Wood Waste	5,788	tons

For wood - the calculations are based on tons of wood at 10% MC

Table 3. Total Company-wide CO_2, CH_4 and N_2O Emissions from Stationary Source Fuel Combustion

Fuel Type	CO_2 (kg)	CO_2 (lb)	CH_4 (kg)	CH_4 (lb)	N_2O (kg)	N_2O (lb)
Propane	0	0	0.0	0.0	0.0	0.0
Total Fossil Fuel Emissions	0	0	0.0	0.0	0.0	0.0
Wood and Wood Waste	8,350,658	18,410,028	2,849	6,281	374	824
Total Non-Fossil Fuel Emissions	8,350,658	18,410,028	2,849	6,281	374	824
Total Emissions for all Fuels	8,350,658	18,410,028	2,849	6,281	374	824

Global Warming Potential	CO_2	CH_4	N_2O		**CO_2e**	
	1.0	21.0	310.0		**metric ton**	**short ton**
Total CO_2 Emissions - Equivalent (Fossil CO2e + Biogenic CH4 & N2O)					**176**	**194**
All CO2e emissions at stack (Fossil CO2e + Biogenic CO2e) - for APCD Permit info					**8,526**	**9,399**

4.0 DISCUSSION OF SELECT APPLICABLE AND NON-APPLICABLE REQUIREMENTS

The Agency will assess compliance with these regulations during any inspections of the Facility. The inspections will include confirmation of the proper operation and maintenance of equipment and air pollution control devices, visual observations of emission points, and review of any records required by the Permit.

4.1 Vermont Air Pollution Control Regulations and Statutes

§5-201 and §5-202 - Prohibition of Open Burning
This emission standard, which regulates the open burning of materials, applies to the entire Facility. Open burning of materials is prohibited except in conformance with the requirements of this section

Based on information provided by the Permittee, open burning is not typically conducted at the Facility. During future inspections of the Facility, the Agency will verify if there has been open burning activity at the Facility and if these activities are in compliance with this requirement.

§5-211(2) - Prohibition of Visible Air Contaminants - Installations constructed subsequent to April 30, 1970
This emission standard applies to the entire Facility. The Agency will assess compliance with these emission standards in the future during any inspections of the Facility. The inspections will include confirmation of the proper operation and maintenance of equipment and visual observations of emission points.

§5-221(1) - Prohibition of Potentially Polluting Materials in Fuel; Sulfur Limitation in Fuel
This prohibition applies to all stationary fuel burning equipment used on-site. Boilers at the Facility are fired with wood fuel and/or with liquefied petroleum gas (LPG). Diesel engines at the facility are fired with ultra-low sulfur diesel fuel that has a sulfur content of less than 0.0015% (15 parts per million) sulfur by weight.

The Applicant is anticipated to comply with this regulation based on the use of wood fuel, LPG, or ultra-low sulfur diesel fuels. The permit includes a sulfur testing protocol for wood fuel combusted at the Facility to verify that this fuel remains below 0.05% percent sulfur by weight. LPG and ULSD, by their official fuel specification definitions, comply with this requirement.

§5-231(3) - Prohibition of Particulate Matter; Combustion Contaminants
Based on the application submitted and information available to the Agency, this Facility currently has applicable fuel burning equipment subject to this regulation. The allowable particulate emissions from the subject equipment is summarized in Table 4-1.

(a)(i) 0.5 pounds per hour per million BTU's of *heat input* in combustion installations where the *heat input* is 10 million BTU's or less per hour.
(b)(iii) In excess of 0.10 gr/dscf corrected to12% CO_2 in any combustion installation that has a rated output of 1300 H.P. or greater which commences operation after December 5, 1977.

Table 4-1: Equipment Subject to §5-231(3)

Equipment ID	Rating	Emission Standard [1]	Emission Rate
Main Boiler	300 MMBtu/hr	0.10 gr/dscf @ 12% CO_2	---
Auxiliary Boiler	5 MMBtu/hr	0.5 lb/MMBtu	2.5 lb/hr
Emergency Generator	3.0 MMBtu/hr	0.5 lb/MMBtu	1.5 lb/hr

[1] The Main Boiler is held to a lower emission standard through MSER.

§5-231(4) - Prohibition of Particulate Matter; Fugitive Particulate Matter
This section requires the use of fugitive PM control equipment on all process operations and the application of reasonable precautions to prevent PM from becoming airborne during the handling, transportation, and storage of materials, or use of roads. This requirement applies to the entire Facility, and the Facility is anticipated to comply with the fugitive emission limitations of this section by compliance with the fugitive emissions conditions included in this permit.

§5-241(1) & (2) - Prohibition of Nuisance and Odor
This requirement applies to the entire Facility and prohibits the discharge of air contaminants that would be a nuisance to the public or the discharge of objectionable odors beyond the property-line of the Facility.

Based on the application submittal and information available to the Agency, the Facility currently is in compliance with this regulation. The Agency will verify compliance with this requirement in the future during any inspections of the Facility. Additionally, the Agency investigates complaints that it receives in order to determine whether or not there is a violation of this requirement.

§5-253.1 – 5-253.19 - Control of Volatile Organic Compounds
Based on the application submittal and information available to the Agency, this Facility currently has no applicable operations subject to these regulations.

§5-253.20 - Control of Volatile Organic Compounds
This subsection applies to any operation that emits VOCs and that is not subject to any other subsection of §5-253. A source is subject to this subsection if it has operations or processes not otherwise regulated under §5-253, that, as a group, have allowable emissions of 50 tons or more of VOCs per calendar year.

The VOC emissions from the Facility are permit-limited to 39 tons per year. Accordingly, this Facility is not currently subject to this regulation.

§5-261(2) - Control of Hazardous Air Contaminants - Hazardous Most Stringent Emission Rate.
See Section 7.0 below.

§5-271 – Control of Air Contaminants from Stationary Reciprocating Internal Combustion Engines
This emission standard applies to all stationary reciprocating internal combustion engines with a brake horsepower output rating of 450 hp or greater.

Based on the application submittal and information available to the Agency, the Facility is currently in compliance with this regulation, as the emergency generator is powered by a Cummins GTA19 rated at 430 bhp, and the emergency fire pump engine is a Cummins 6BTA 5.9 F1 rated at 208 bhp. Accordingly, the Facility has no stationary reciprocating engines with an output rating of 450 bhp or greater. However, a condition will be included as part of the permit to specifically identify this limitation. The Agency will verify compliance with this requirement in the future during any inspections of the Facility.

§5-402 – Written Reports When Required
This section gives the Agency authority to require the Facility to submit reports summarizing records required to be maintained by the Agency. The Agency will assess compliance with this regulation in the future during any inspections of the Facility.

§5-403 – Circumvention
This section prohibits the dilution or concealment of an air discharge in order to avoid air pollution control requirements. The Agency will assess compliance with this regulation in the future during any inspections of the Facility.

§5-404 – Methods for Sampling and Testing of Sources
This section allows the Agency to require testing of air emissions from the Facility and to specify the methods of testing. Based on the application submittal and information available to the Agency, the Facility currently is in compliance with this regulation. The Agency will assess compliance with this regulation in the future during any required testing or inspections of the Facility.

Subchapter VIII – Registration of Air Contaminant Source*.*
This Subchapter requires the owner or operator of a stationary source register with the Agency if the source produces five (5) tons per year or greater of actual emissions during the preceding calendar year. The owner or operator of a source is required to submit information regarding their operations and pay a fee based upon the quantity of emissions they produce and the fuels that they use at the source.

The Permittee is currently in compliance and has been registering its emissions with the Agency annually on those years when its total emissions exceed 5 tons per year.

4.2 Federal Air Pollution Control Regulations and the Clean Air Act

Section 111 of the Clean Air Act - New Source Performance Standards (NSPS). NSPSs are promulgated under Title 40, Part 60 of the Code of Federal Regulations (40 *CFR,* Part 60. The NSPSs that were reviewed for applicability and the applicable NSPSs are summarized in the following table.

Table 4-2 Applicable Requirements from Section 111 of the Clean Air Act New Source Performance Standards (NSPSs)
40 *CFR* Part 60, Subpart Db - Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units: §60.42b Standards for sulfur dioxide §60.43b Standards for particulate matter; §60.44b Standards for nitrogen oxides; §60.49b Reporting and recordkeeping requirements. The affected facility to which this Subpart applies is each steam generating unit for which construction, modification, or reconstruction is commenced after June 19, 1984 and that has a maximum design heat input capacity of greater than 29 megawatts (MW) (100 million BTU per hour). *The Main Boiler at the Facility is subject to the requirements of this regulation. The sulfur dioxide standards of this regulation (§60.42b) are not applicable, as the Facility does not combust coal or oil. The particulate matter standards of this regulation (§60.43b), are applicable, but the MSER for the Facility imposes a stricter PM standard. The NOx standards of this regulation (§60.44b) are not applicable, as the Main boiler does not fire natural gas, coal, distillate oil, or residual oil.*
40 *CFR* Part 60, Subpart Kb - Standards of Performance for Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction, or Modification Commenced after July 23, 1984. Applies to each storage vessel with a capacity greater than or equal to 75 m3 (19,804 gal) that is used to store volatile organic liquids (including petroleum). This subpart does not apply to the following: 1. Any storage vessel with a capacity less than 75 m^3 2. Any storage vessel storing a liquid with a vapor pressure less than 3.5 kPa 3. Any storage vessel with a capacity > 75 m^3 and <151 m^3 with a v.p. <15.0 kPa 4. Pressure vessels >29.7 psi and without emissions to the atmosphere. 5. Vessels permanently attached to mobile vehicles. 6. Vessels located at bulk gasoline plants. 7. Vessels located at gasoline service stations. For affected facilities, there are recordkeeping requirements and depending upon the material stored there may be standards for the tank's vent system. *The Facility has no storage tanks subject to this regulation.*

Section 112 of the Clean Air Act - National Emission Standards for Hazardous Air Pollutants (NESHAPs). NESHAPs are promulgated under 40 *CFR*. Part 61 and Part 63. Total HAP emissions are estimated to be less than 10 tons per year of combined HAPs, so the Facility would be classified as an area source of HAPs. The NESHAPs that were reviewed for applicability and the applicable NESHAPs are summarized in the following table.

Table 4-3 **Applicable Requirements from Section 112 of the Clean Air Act** **National Emission Standards for Hazardous Air Pollutants (NESHAPs)**
40 *CFR* Part 63, Subpart ZZZZ - National Emission Standards for Hazardous Air Pollutants for Reciprocating Internal Combustion Engines. Applies to new engines that commenced construction (installed) on or after June 12, 2006 at area sources of HAPs. Requires such engines to comply with NSPS Subpart IIII or JJJJ, as applicable. Also applies to existing engines that commenced construction (installed) prior to June 12, 2006 at area sources of HAPs. By May 3, 2013 requires non-emergency engines equal and greater than 300 bhp to meet CO emission standards, which may necessitate catalytic controls, and must install closed crankcase ventilation system or equivalent. Non-emergency engines <300 bhp must meet maintenance requirements including changing oil & filter and inspecting, and replacing if necessary, air filter, hoses and belts. Emergency units are subject to maintenance requirements and must install an elapsed hour meter and report electronically to EPA. Does not apply to existing emergency units at an area source residential/commercial/institutional facility unless they are enrolled in peak shaving or demand response (DR) programs. Emergency engines are unrestricted for actual emergency operation but restricted to 100 hours per year of testing and maintenance, of which 50 hours may be local DR (no qualifying programs currently known to exist) and 50 hours may be for non-compensated non-emergency operation. Most utility programs do not qualify as allowed emergency engine operation. 4Z ULSD requirements vary, however state regulations mandate ULSD across the board. For engines firing landfill or digester gas comprising 10% or more of the heat input, the engines are subject to management practices only (change oil & filter, inspect plugs, and inspect hoses and belts every 1440 hours or annually, whichever occurs first) as well as operating in accordance with manufacturer's recommendations and minimizing time at idle. *The Emergency Generator engine and Fire Pump engine at this Facility are subject to only the emergency engine requirements of this regulation, as they are restricted to emergency use only.*

Table 4-3 **Applicable Requirements from Section 112 of the Clean Air Act** **National Emission Standards for Hazardous Air Pollutants (NESHAPs)**
40 *CFR* Part 63, Subpart JJJJJJ - National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial and Institutional Boilers. Applies to new and existing fuel oil and solid fuel fired boilers located at area sources (major sources are subject to Subpart DDDDD). Natural gas or propane fired boilers are not subject. The natural gas and propane exemption allows use of backup fuel during periods of gas curtailment, gas supply emergencies, and for periodic testing not to exceed 48 hours combined during any calendar year. Oil fired hot water boilers less than 1.6 MMBTU/hr are not subject. The rule requires a tune-up for each boiler once every two years, except boilers with oxygen trim and oil boilers less than 5 MMBTU/hr may conduct tune-ups every five years. Existing facilities with any single boiler greater than 10 MMBTU/hr were required to conduct an site wide energy assessment audit to identify potential heat use efficiencies. New boilers greater than 10 MMBTU/hr are subject to PM emission limits. Boilers that commenced construction on or before June 4, 2010 are considered an existing source. New or reconstructed boilers that commenced construction or reconstruction on or before September 14, 2016, when demonstrating initial compliance with the PM emission limit must conduct a performance stack test in accordance with §63.11212 and Table 4 of this Subpart. These units must retest every three years if greater than 50% of the applicable PM standard, or every five years if less than 50% of the standard. An initial performance test must be conducted by September 14, 2021. New or reconstructed oil-fired boilers that commenced construction on or before September 14, 2016 that combust only oil that contains no more than 0.50 weight percent sulfur are not subject to the PM emission limit in Table 1 of this Subpart until September 14, 2019, provided that the Facility monitors and records on a monthly basis the type of fuel combusted. Boilers that combust only oil that contains no more than 0.0015 weight percent sulfur are not subject to the PM emission limit in Table 1. . *Subpart JJJJJJ is applicable to the Main Boiler at the Facility. Since the Main Boiler is considered an existing boiler under this regulation, it is subject to the work practice standards as well as notification, reporting and recordkeeping requirements established in this rule. The work practice standards include biennial tune-ups and a one-time energy assessment.* *Table 1 of Subpart JJJJJJ indicates that the boiler is not considered a new boiler under this subpart, nor is it an existing coal-fired boiler, and as such is not subject to any emission standards under Subpart JJJJJJ.* *The LPG-fired Auxiliary Boiler is not subject to Subpart JJJJJJ, as it is fired with gaseous fuel. Since the Facility is not a major source of HAPs, the Facility is not subject to Subpart DDDDD.*

Other Applicable Federal Air Quality Requirements. Other applicable Federal air quality requirements that are not promulgated under 40 *CFR*. Part 60, Part 61 and Part 63 are that were review for applicability are summarized in Table 4-4.

Table 4-4 Other Applicable Federal Air Quality Requirements
40 *CFR* Parts 72, 73, 75, 76, 77, 78, Acid Rain Program *The Facility was previously not subject to the requirements of the Acid Rain Program as a New Independent Power Production Facility under 40 CFR Part 72.6(b)(6).* *With the expiration of the contracts previously held by the Facility, the Facility is now subject to the requirements of the Acid Rain Program. However, the Facility complies with the new unit exemption requirements of 40 CFR §72.7(b)(1), as it has not been previously allocated any allowances under Subpart B of 40 CFR, Part 73, has a nameplate capacity less than or equal to 25 MWe, and combusts wood or LPG fuel, both of which have a sulfur content of less than 0.05%.* *To obtain this exemption, the Facility was required to submit a statement to the permitting authority by December 31 of the first year for which the unit is to be exempt under this section. This statement was to be signed by the designated or, if no designated representative has been authorized, a certifying official of each owner of the unit. The statement identified the unit, the nameplate capacity of each generator served by the unit and the fuels currently burned or expected to be burned by the unit and their sulfur content by weight, and stated that the owners and operators of the unit will comply with 40 CFR §72.7 (f). This statement was received by the Agency on December 17, 2012. The Permit for this Facility contains fuel sulfur monitoring provisions to ensure the wood fuel qualifies as a low sulfur fuel.* *A discussion of the development of the requirements for the Acid Rain Portion of this Permit is presented following this Table.*
Clean Air Act §§114(a)(3) Inspections, Monitoring and Entry; 502(b) Permit Programs; and 504(a)-(c) Permit Requirements and Conditions; 40 *CFR* Part 64 Compliance Assurance Monitoring (CAM); 40 *CFR* Part 70 §§70.6(a)(3)(i)(B) and 70.6(c)(1) State Operating Permit Programs - Permit content. Upon renewal of a Title V Permit to Operate, a facility must comply with enhanced monitoring and compliance assurance monitoring requirements if applicable. the CAM rule applies to each Pollutant Specific Emission Unit (PSEU) at a major source that is required to obtain a part 70 or part 71 permit if the unit satisfies all of the following criteria: 1) The unit is subject to an emission limitation or standard for the applicable regulated air pollutant other than an emissions limitation or standard that is exempt under §64.2(b)(1) [exempt limitations include emission limitations or standards proposed by the Administrator after November 15, 1990 pursuant to Section 111 or 112 of the Act], 2) The unit uses a control device to achieve compliance with any such limit or standard; and 3) The unit has pre-control device emissions of the applicable regulated pollutant that are equal to or greater than 100 percent of the amount, in tons per year, required for a source to be classified as a major source. *The Compliance Assurance Monitoring requirements apply to the particulate matter and nitrogen oxide emissions from the wood-fired Main Boiler at this Facility since (1) potential uncontrolled emissions of these pollutants from the wood-fired Main Boiler exceeds the major source threshold, (2) the wood-fired Main Boiler is subject to an emission standards for each of these pollutants, and (3) the wood-fired Main Boiler is equipped with an emission control device for each of these pollutants.* *Air contaminant emissions produced by the wood-fired boiler are controlled as follows: electrostatic precipitator, flue gas reinjection, selective non-catalytic reduction system (urea injection), selective catalytic reduction system (SCR) and combustion air control with oxygen trim and underfire/overfire air ratio.* *A discussion of the development of the requirements for CAM is presented following this Table.*

Table 4-4 **Other Applicable Federal Air Quality Requirements**
Clean Air Act §112r Prevention of Accidental Release; 40 *CFR* Part 68 Chemical Accident Prevention Programs. Facilities that have more than the threshold quantity of a regulated substance in a process are subject to these provisions including the requirements to conduct a hazard assessment, establish a prevention program and develop a risk management plan. *The Permittee has stated that the Facility does not store more than the threshold quantity of a regulated substance and thus is not subject to these requirements.*
40 *CFR* Part 98 Mandatory Greenhouse Gas Reporting. Requires reporting of GHG emissions annually to EPA for 1) facilities in source categories listed in §98.2(a)(1) including electric utility units subject to Acid Rain, MSW landfills that generate CH4 in amounts equivalent to 25,000 metric tons of CO2e or more per year and electrical transmission and distribution equipment at facilities where the total nameplate capacity of SF6 and PFC containing equipment exceeds 17,820 pounds, 2) facilities in source categories listed in §98.2(a)(2) including electronics manufacturing, iron and steel production and pulp and paper manufacturing that emit 25,000 metric tons of CO2e or more per year from such source categories as well as all stationary combustion, 3) facilities with stationary combustion sources that aggregate to 30 MMBtu/hr or more and which emit 25,000 metric tons of CO2e or more per year from all stationary combustion sources combined, and 4) fuel suppliers including all local natural gas distribution companies. *The U.S. EPA has retained the implementing authority for this regulation and is responsible for determining applicability. This regulation under Part 98 is not considered to be an applicable requirement per 40 CFR Part 70.2 and as noted in 74 FR 56260 (October 30, 2009). Part 98 is anticipated to apply to the Facility*. Emissions of CO_2 from biogenic sources are not included in the calculation of Facility CO_2 emissions. The emissions of CO_2 from non-biogenic sources, plus the CO_2 equivalent emissions of CH_4 and N_2O from the Facility do not exceed the 25,000-metric ton CO_2 equivalent emission threshold for reporting under 40 *CFR* Part 98.

Clean Air Act §§114(a)(3), 502(b), and 504(a)-(c); 40 CFR Part 70 §§70.6(a)(3)(i)(B) and 70.6(c)(1); and 40 CFR Part *64* - ***Compliance Assurance Monitoring.***

This permit continues the originally approved CAM plan for this Facility. The emissions of PM and NOx from the Main Boiler are subject to CAM because:

- the Facility has a Title V Operating Permit;
- the uncontrolled emission rate of these pollutants exceed their respective Title V major source thresholds (100 ton/yr);
- the emissions of PM (NSPS and MSER) and NOx (MSER) are subject to an applicable rule;
- the Main Boiler is equipped with emissions control devices for each of these pollutants.

CAM for NOx:

The use of a NOx Continuous Emissions Monitoring System (CEMS) satisfies the requirements of CAM for NOx monitoring.

CAM for PM:

This Facility does not have a direct measurement system for PM, so indirect (parametric) monitoring will be used to provide reasonable assurance that the control equipment is working properly.

For the control of PM emissions the Main Boiler is equipped with mechanical collectors (cyclones) followed by a five (5) field ESP. The ESP uses electric fields by applying a direct-current voltage across a pair of electrodes a discharge electrode and a collection electrode. PM suspended in the exhaust stream is electrically charged by passing through the electric field around each discharge electrode. The negatively charged particles then migrate toward the positively charged collection electrodes. The PM is separated from the gas stream by retention on the collection electrode. Particulate is removed from the collection plates by shaking and rapping the plants clean to collect the PM.

Generally, ESP performance improves as total power input increases. The voltage drops when a malfunction, such as grounded electrodes, occurs in the ESP. When the voltage drops, less particulate is charged and collected. Although this is the general rule, the voltage may remain high but the ESP may fail to perform its function if the collection plates are not cleaned, or rapped, appropriately. If the collection plates are not cleaned, the current drops. Therefore, it is important to monitor both voltage (kilovolts) and current (milliamps).

The Permittee has conducted two sets of stack testing to document the PM emission rate while the potential performance of the ESP is reduced either by taking collection fields off line or operating the ESP at reduced voltage and current in the individual fields.

On June 21, 1995 the Permittee carried out PM stack emission testing with reduced energy to the ESP to determine minimum operational schemes, while still meeting the PM emission limit. This testing was not observed by a representative of Agency. For this testing, if no power is supplied to a field, it is considered to be offline. If 50% of full power is supplied to a field, it is considered to be '½' of a field. The fields that were online were set for full power. During run 4, with only 2 fields in service ("3 fields offline"), the stack test indicated that the PM emission rate was less than the permit limit of 0.0007 gr/dscf @ 12% CO_2. Table 4-5 summarizes the results of this testing.

Table 4-5: PM Stack Testing – June 21, 1995				
Run #	Operating Scheme	Start time	Stop time	PM (gr/dscf @ 12% CO_2)
1	1.5 fields offline	8:30	10:35	0.0004
2	2 fields offline	11:30	13:30	0.0005
3	2.5 fields offline	14:10	16:10	0.0003
4	3 fields offline	18:35	20:35	0.0005

On July 25, 1995 the Permittee carried out additional PM stack emission testing with reduced energy: reduced kilovolt and milliamp to the individual fields. This testing coincided with the biennial PM compliance testing and was observed by a representative of the Agency. Prior to this testing, their normal operating mode for the ESP was to operate the secondary voltage and amperage near the maximum settings. The design maximum secondary voltage is 55 kV, and the design maximum secondary current is 650 mA.

Table 4-6: PM Stack Testing – July 25, 1995 ESP Secondary voltage and current operating ranges		
ESP Field	Field Secondary Voltage Range (kV) Min / Avg / Max	Field Secondary Current Range (mA) Min / Avg / Max
TR-1	38 / 42.5 / 47	117 / 246 / 455
TR-2	43 / 44.3 / 45	390 / 401.5 / 403
TR-3	25 / 25 / 25	39 / 39 / 39
TR-4	20 / 20.7 / 21	39 / 43 / 52
TR-5	18 / 18 / 18	39 / 40.5 / 52

During the 7/25/95 testing there were three runs (2 hour sampling times for each run) for typical boiler operation and the PM emission rates were determined to be: 0.0006, 0.0005, and 0.0002 gr/dscf @ 12% CO_2. There was a 4^{th} run that evaluated the PM emission rate for a 2 hour time period that included a soot blow cycle. For a soot blow event, which typically lasts 23 minutes, the Permittee increases the energy in the last 4 fields to near the maximum settings (the first field was already operating at its maximum setting). This energy increase was also carried out during the soot blow event that occurred during the 4^{th} run and the PM emission rate, for the entire 2 hour sample time, was 0.0002 gr/dscf @ 12% CO_2. The increased voltage and current settings for the soot blow sample run were not included in the values shown Table 4-6.

Based on the above testing, the Permittee has recommended the following operating ranges for the ESP's transformer-rectifier set for the Facility's PM CAM plan:

Table 4-7: Electrostatic Precipitator's Transformer-Rectifier Indicator Operating Range

ESP Field	Field Secondary Voltage Range (kV)	Field Secondary Current Range (mA)
TR-1	30 – 50	100 – 400
TR-2	30 – 50	300 – 500
TR-3	20 – 25	50 – 100
TR-4	20 – 25	50 – 100
TR-5	20 – 25	50 – 100

The Agency concurs with the Permittee's recommendation that, in addition to an inspection and maintenance program, the periodic monitoring of secondary voltage and secondary current as indicators represents an acceptable plan for providing a reasonable assurance that the Facility is meeting its PM emission limit.

Title IV of the Clean Air Act – Acid Rain Program 40 - CFR Parts 72 through 78

This permit will include conditions related to the applicable provisions of Title IV of the Clean Air Act (the Acid Rain Program). The Acid Rain Program set a goal of reducing annual nationwide SO_2 emissions by 10 million tons below 1980 emission levels through the use of a cap and trade program. It also establishes minimum NOx emission rates (not allowances in cap and trade). To achieve these reductions, the law required a two-phase implementation of the restrictions placed on electrical power generation facilities that combust coal, oil, and biomass.

- SO_2 Phase I began in 1995 and affected 263 units at 110 mostly coal-burning electric utility plants located in 21 Eastern and Midwestern states. An additional 182 units joined Phase I of the program as substitution or compensating units, bringing the total of Phase I affected units to 445. Emissions data indicate that 1995 SO_2 emissions at these units nationwide were reduced by almost 40 percent below their required level. Vermont had no Phase I plants.
- SO_2 Phase II, which began in the year 2000, further restricted the annual emissions limits imposed on these large, higher emitting plants and also set restrictions on smaller, cleaner plants fired by coal, oil, and gas, encompassing over 2,000 units in all. The SO_2 Phase II program affects existing utility units serving generators with an output capacity of greater than 25 megawatts and all new utility units. The Facility is subject to the limitations of the Phase II SO_2 program.
- NOx Phase I and Phase II - The Acid Rain Program also called for a 2-million-ton reduction in NOx emissions from coal fired units by the year 2000. Phase I applied in 1996 to certain coal-fired boiler types and Phase II applied in 2000 to additional boilers and also lowered the NOx emission rate of the boilers subject to the Phase I limitations. As the Facility is not a coal-fired unit, it is not subject to the NOx Phase I and Phase II limitations.

The Facility was previously not subject to the requirements of the Acid Rain Program as a New Independent Power Production Facility under 40 CFR Part 72.6(b)(6). With the expiration of the contracts previously held by the Facility, the Facility is now subject to the requirements of the Acid Rain Program. However, the Facility complies with the new unit exemption requirements of 40 *CFR* §72.7(b)(1), as it has not been previously allocated any allowances under Subpart B of 40 *CFR*, Part 73, has a nameplate capacity less than or equal to 25 MWe, and combusts wood or LPG fuel, both of which have a sulfur content of less than 0.05%.

To obtain this exemption, the Facility was required to submit a statement to the permitting authority by December 31 of the first year for which the unit is to be exempt under this section. This statement was to be signed by the designated or, if no designated representative has been authorized, a certifying official of each owner of the unit. The statement identified the unit, the nameplate capacity of each generator served by the unit and the fuels currently burned or expected to be burned by the unit and their sulfur content by weight, and stated that the owners and operators of the unit will comply with 40 *CFR* §72.7 (f). This statement was received by the Agency on December 17, 2012.

Accordingly, the Agency will incorporate the provisions and requirements of the exemption as described in 40 *CFR*, Part 72.7(a), (b)(1), (d), and (f) into this Permit.

A summary of the requirements of each of these subsections is as follows:

<u>40 *CFR*, Part 72.7(a) - Applicability</u>

This section applies to any new utility unit that has not previously lost an exemption under paragraph (f)(4) of this section and that, in each year starting with the first year for which the unit is to be exempt under this section:

(1) Serves during the entire year (except for any period before the unit commenced commercial operation) one or more generators with total nameplate capacity of 25 MWe or less;

(2) Burns fuel that does not include any coal or coal-derived fuel (except coal-derived gaseous fuel with a total sulfur content no greater than natural gas); and

(3) Burns gaseous fuel with an annual average sulfur content of 0.05 percent or less by weight (as determined under paragraph (d) of this section) and nongaseous fuel with an annual average sulfur content of 0.05 percent or less by weight (as determined under paragraph (d) of this section)

<u>40 *CFR*, Part 72.7(b)(1) - Applicable portions of Part 72 for Exempt Facilities</u>

Any new utility unit that meets the requirements of paragraph (a) of this section and that is not allocated any allowances under subpart B of part 73 of this chapter shall be exempt from the Acid Rain Program, except for the provisions of this section, §§72.2 through 72.6, and §§72.10 through 72.13.

40 *CFR*, Part 72.7(d) - Compliance

Compliance with the requirement that fuel burned during the year have an annual average sulfur content of 0.05 percent by weight or less shall be determined as follows using a method of determining sulfur content that provides information with reasonable precision, reliability, accessibility, and timeliness:

For nongaseous fuel burned during the year, the requirement is met if the annual average sulfur content is equal to or less than 0.05 percent by weight. The annual average sulfur content, as a percentage by weight, shall be calculated using the equation in paragraph (d)(2) of this section, as shown below:

$$\%S_{annual} = \frac{\sum_{n=1}^{last} \%S_n V_n d_n}{\sum_{n=1}^{last} V_n d_n}$$

In lieu of the factor, volume times density (V_n d_n), in the equation, the factor, mass (M_n), may be used, where M_n is: mass of the nongaseous fuel in a delivery during the year to the unit of which the nth sample is taken, in lb; or, for fuel delivered during the year to the unit continuously by pipeline, mass of the nongaseous fuel delivered starting from when the nth sample of such fuel is taken until the next sample of such fuel is taken, in lb.

40 *CFR*, Part 72.7(f) – Special Provisions

(1) The owners and operators and, to the extent applicable, the designated representative of a unit exempt under this section shall:

(i) Comply with the requirements of paragraph (a) of this section for all periods for which the unit is exempt under this section; and

(ii) Comply with the requirements of the Acid Rain Program concerning all periods for which the exemption is not in effect, even if such requirements arise, or must be complied with, after the exemption takes effect.

(2) For any period for which a unit is exempt under this section:

(i) For purposes of applying parts 70 and 71 of this chapter, the unit shall not be treated as an affected unit under the Acid Rain Program and shall continue to be subject to any other applicable requirements under parts 70 and 71of this chapter.

(ii) The unit shall not be eligible to be an opt-in source under part 74 of chapter.

(3) For a period of 5 years from the date the records are created, the owners and operators of a unit exempt under this section shall retain at the source that includes the unit records demonstrating that the requirements of paragraph (a) of this section are met. The 5-year period for keeping records may be extended for cause, at any time prior to the end of the period, in writing by the Administrator or the permitting authority.

(i) Such records shall include, for each delivery of fuel to the unit or for fuel delivered to the unit continuously by pipeline, the type of fuel, the sulfur content, and the sulfur content of each sample taken. *The Agency has determined that for purposes of compliance with this requirement, that monthly sampling of the wood fuel delivered to the Facility, and analysis of this fuel for sulfur content in accordance with the requirements of the Wood Fuel Sampling Plan as required by the Permit shall constitute compliance with the requirement of this part for sampling of "each delivery of fuel to the unit".*

(ii) The owners and operators bear the burden of proof that the requirements of paragraph (a) of this section are met.

(4) Loss of exemption. (i) On the earliest of the following dates, a unit exempt under paragraphs (b), (c), or (e) of this section shall lose its exemption and for purposes of applying parts 70 and 71 of this chapter, shall be treated as an affected unit under the Acid Rain Program:

(A) The date on which the unit first serves one or more generators with total nameplate capacity in excess of 25 MWe;

(B) The date on which the unit burns any coal or coal-derived fuel except for coal-derived gaseous fuel with a total sulfur content no greater than natural gas; or

(C) January 1 of the year following the year in which the annual average sulfur content for gaseous fuel burned at the unit exceeds 0.05 percent by weight (as determined under paragraph (d) of this section) or for nongaseous fuel burned at the unit exceeds 0.05 percent by weight (as determined under paragraph (d) of this section).

(ii) Notwithstanding §72.30(b) and (c), the designated representative for a unit that loses its exemption under this section shall submit a complete Acid Rain permit application on the later of January 1, 1998 or 60 days after the first date on which the unit is no longer exempt.

(iii) For the purpose of applying monitoring requirements under part 75 of this chapter, a unit that loses its exemption under this section shall be treated as a new unit that commenced commercial operation on the first date on which the unit is no longer exempt. [62 FR 55476, Oct. 24, 1997, as amended at 71 FR 25377, Apr. 28, 2006; 70 FR 25334, May 12, 2005]

5.0 CONTROL TECHNOLOGY REVIEW FOR MAJOR SOURCES AND MAJOR MODIFICATIONS

The Facility is not undergoing changes subject to new source review; therefore this section is not applicable.

6.0 AMBIENT AIR QUALITY IMPACT EVALUATION

Ambient air quality impact analyses were performed in 1987 as part of the original review for the Facility. The pollutants PM, SO_2, CO and NO_x were modeled and it was determined that the proposed impacts would not cause a violation of any National Ambient Air Quality Standard (NAAQS), exceed any PSD increment or significantly contribute to an existing violation of an NAAQS. Refer to permit AOP-01-017 and original technical support document for additional information. The results of this modeling are summarized in Table 6-1.

Table 6-1: Ambient Air Quality Impact Evaluations

Date of AQIE/ Permit #	Pollutant(s)	Summary of Results[1]
Interactive modeling performed on Main Boiler using ISCST as a screening tool and the EPA VALLEY model nomograph to calculate maximum 24-hour concentrations for PM and SO_2 taking into account complex terrain.		
October 1987 See original permit's technical support document.	PM	Emission Rate: 0.68 grams per second ISCST Results: 24-hr: 88/150, annual: 29/75 VALLEY Results: 24-hr: 94/150
	SO_2	Emission Rate: 3.51 grams per second ISCST Results: 3-hr: 575/1300, 24-hr 266/365, ann.: 73/80 VALLEY Results: 24-hr: 342/365
	CO	Emission Rate: 11.6 grams per second ISCST Results: 1-hr: 8924/40000, 8-hr: 4517/10000
	NO_x	Emission Rate: 10.4 grams per second ISCST Results: 1-hr: 234/320, annual: 43/100
A re-calculation of the ambient air quality impacts from the Facility was required because some emission rates and building dimensions changed from original application. In addition, the Agency adopted NO_x PSD increments since the original permit was issued.		
Technical Analysis for permit #AP-90-029a2 8/15/1991	PM	Emission Rate: 0.64 grams per second ISCST Results: 24-hr: 2.78/150, annual: 0.69/75
	CO	Emission Rate: 11.3 grams per second ISCST Results: 8-hr: 6760/10000
	NO_x	Emission Rate: 9.45 grams/second ISCST Results: annual: 83/100

[1] Results presented as "model output result/Ambient Air Quality Standard". Each value presented in micrograms per cubic meter and indicates the maximum short-term emission rate.

7.0 HAZARDOUS AIR CONTAMINANTS

Pursuant to §5-261 of the *Regulations*, any stationary source subject to the rule[1] with current or proposed actual emissions of a hazardous air contaminant (HAC) equal to or greater than the respective Action Level (found in Appendix C of the *Regulations*) shall be subject to the Regulation and shall achieve the Hazardous Most Stringent Emission Rate (HMSER) for the respective HAC. HMSER is defined as a rate of emissions which the Secretary, on a case-by-case basis, determines is achievable for a stationary source based on the lowest emission rate achieved in practice by such a category of source and considering economic impact and cost. HMSER may be achieved through application of pollution control equipment, production processes or techniques, equipment design, work practices, chemical substitution, or innovative pollution control techniques.

As noted in the exceptions to §5-261(1)(c)(ii), all fuel burning equipment which combusts virgin liquid or gaseous fuel and wood boilers constructed before January 1, 1993 are exempt from this section. Therefore, the Main Boiler, Auxiliary Boiler and the emergency engines at the Facility are not subject to §5-261 of the *Regulations* at this time.

Other processes at the Facility, including the cooling towers and the SNCR/SCR system have emissions of HACs. These emissions have been quantified and compared to their respective ALs in order to determine if review under §5-261 of the *Regulations* was warranted. Emissions of these HACs discussed in Section 3.2 of this document. Emissions of HACs from the cooling towers are not anticipated to exceed their respective ALs, and the emissions from the cooling towers will not be reviewed further under §5-261. However, the emission of ammonia from the SNCR/SCR system is estimated to exceed its AL, and accordingly, these ammonia emissions will be required to achieve HMSER.

7.1 HMSER Selection

Certain equipment at the Facility which is not directly related to combustion of wood in the boilers is subject to §5-261 of the *Regulations* and emissions of certain HACs from this equipment exceed the Action Levels for these HACs.

Specifically, the Agency has determined that the Facility emissions of ammonia (CAS 7664-41-7) from the SNCR/SCR system are in excess of the Action Level for ammonia. In Permit #AP-90-029a, issued July 11, 1990, HMSER for ammonia emissions was determined to be an ammonia emission limit of 40 parts per million on a dry volume basis (ppmdv) corrected to 12% CO_2 on a one-hour average when wood is contributing more than thirty (30) % of the instantaneous heat input to the Main Boiler.

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[1] APCR §5-261(1)(c)(ii) provides that solid fuel burning equipment (not including incinerators) installed or constructed prior to January 1, 1993, and all fuel burning equipment which combust virgin liquid or gaseous fuel shall not be subjects to the requirements of §5-261.

Based on reported emissions from this Facility and at other biomass-fired boilers in the region that utilize SCR systems, the Agency has revised the HMSER for ammonia emissions to be an ammonia emission limit of 20 parts per million on a dry volume basis (ppmdv) corrected to 12% CO_2 on a one-hour average when wood is contributing more than thirty (30) % of the instantaneous heat input to the Main Boiler. This HMSER evaluation shall be subject to re-evaluation five (5) years from the date of its determination and shall remain in effect until revised by the Agency, unless the source is modified or reconstructed during the five year period.

8.0 REASONABLY AVAILABLE CONTROL TECHNOLOGY

§5-1010 of the *Regulations* requires sources to install, maintain and use Reasonably Available Control Technology (RACT). RACT is defined in the *Regulations* as "devices, systems, process modifications or other apparatus or techniques designed to prevent or control emissions that are reasonably available, taking into account the social, environmental and economic impact of such controls, and alternative means of emission control". A RACT analysis typically reviews a range of emission reduction options, from the greatest reduction to the least (Top Down). RACT exists within a hierarchy of emission reduction acronyms. In descending order of emission reduction, these are: Lowest Achievable Emission Rate (LAER), MSER, BACT, NSPS, RACT.

There have been no previous RACT determinations for the Facility. However, the Permittee has voluntarily installed and currently is successfully operating a selective catalytic reduction (SCR) system to reduce the Facility's emissions of NOx.

Biomass fueled boilers are required to meet certain low NO_X emission limits for the Renewable Energy Credit (REC) markets in Massachusetts and Connecticut. A strong REC market impacts the economics of NO_X RACT. A compelling reason for an existing biomass fueled electric generating facility to install a NO_X reduction system is to qualify the electrical output of the facility for the REC market, thus allowing for REC sales in certain states. The NOx emission limit to qualify for these particular RECs is 0.075 lb/MMBtu based on a quarterly average.

The Permittee installed the additional SCR system at the Facility so they could qualify for the Class 1 Renewable Energy Credit market in Connecticut and Massachusetts. Accordingly, the Agency has determined that with successful installation and operation of the SCR system, and with qualifying for the Massachusetts and Connecticut REC markets, RACT for the main boiler at the Facility will now be the operation of the NO_X SCR system in addition to the operation of the SNCR system to achieve a NO_X emission limit of 0.075 lb/MMBtu based on a quarterly average.

If the Permittee elects to no longer participate in the REC market, they would be required to file a permit application, requesting reconsideration of this NO_X RACT determination. The Permittee would be required to demonstrate that the continued operation and maintenance cost, but not the initial capital costs are excessive for RACT.

This RACT determination shall be reviewed as part of the review of the next operating permit application for this Facility.