Rumford Power LLC **Oxford County** **Rumford, Maine** **A-724-77-2-A**	**Departmental** **Findings of Fact and Order** **New Source Review** **NSR #2**

FINDINGS OF FACT

After review of the air emission license amendment application, staff investigation reports, and other documents in the applicant's file in the Bureau of Air Quality, pursuant to 38 Maine Revised Statutes (M.R.S.) § 344 and § 590, the Maine Department of Environmental Protection (the Department) finds the following facts:

I. REGISTRATION

A. Introduction

FACILITY	Rumford Power LLC
LICENSE TYPE	06-096 C.M.R. ch. 115, Minor Modification
NAICS CODES	221112
NATURE OF BUSINESS	Electric Power Generation
FACILITY LOCATION	43 Industrial Park Road, Rumford, Maine

B. NSR License Description

Rumford Power LLC (RP) has requested a New Source Review (NSR) license amendment to implement changes referred to here as the "ULSD Project." RP is proposing to modify its Combustion Turbine to allow the turbine to fire distillate fuel in addition to the currently permitted fuel (natural gas).

C. Emission Equipment

The following existing equipment is modified by this project:

Equipment	Maximum Heat Input Capacity (MMBtu/hr)	Max. Firing Rate	Fuel Type	Output Capacity (MW)	Mfr. Date	Inst. Date
Combustion Turbine	1,975	1.94 Mcf/hr	Natural Gas	197	1998	1999
	2,111	15,134 gal/hr	Distillate Fuel			

The following new equipment is addressed in this NSR license:

Petroleum Storage Tanks

Equipment	Capacity (Gallons)	Products Stored	Roof Type
Tank #1*	2,000,000	Distillate Fuel	Fixed

*Tank #1 is considered an insignificant activity pursuant to 06-096 C.M.R. ch. 115, Appendix B, § B(1) and is mentioned for completeness purposes only.

D. Definitions

Distillate Fuel means the following:

- Fuel oil that complies with the specifications for fuel oil numbers 1 or 2, as defined by the American Society for Testing and Materials (ASTM) in ASTM D396;
- Diesel fuel oil numbers 1 or 2, as defined in ASTM D975;
- Kerosene, as defined in ASTM D3699;
- Biodiesel, as defined in ASTM D6751; or
- Biodiesel blends, as defined in ASTM D7467.

Records or *Logs* mean either hardcopy or electronic records.

Shutdown is defined as a period which begins when steady state operation stops and ends with cessation of Combustion Turbine firing. Shutdown shall be completed as soon as practicable, but in no case shall this period exceed 60 minutes.

Startup is defined as a period which begins when any fuel is fired in the Combustion Turbine after a shutdown and ends when the unit reaches steady state operation. Steady state operation is reached when the Combustion Turbine reaches 50% base load and the steam turbine is declared available for load changes. Aborted startups shall be included in this definition. Startup shall be completed as soon as practicable, but in no case shall this period exceed 300 minutes.

E. Project Description

The ULSD Project will allow RP to respond to additional dispatch scenarios due to the unpredictability of natural gas fuel costs and availability. Adding distillate fuel as an alternative fuel for limited use in the Combustion Turbine will allow RP to operate the unit when natural gas is curtailed, adding reliability to the grid. RP also wishes to have the option to fire distillate fuel when use of natural gas is not economically advantageous.

This project will require physical changes to the Combustion Turbine, addition of a water injection system for periods of distillate fuel firing, an upgraded selective catalytic reduction (SCR) system to reduce emissions of nitrogen oxides (NO_x), and the addition of a new carbon monoxide (CO) oxidation catalyst.

The maximum heat input of the Combustion Turbine when firing distillate fuel will be approximately 2,111 MMBtu/hr based on the estimated higher heating value of distillate fuel at temperatures below 15 °F of 0.1395 MMBtu/gallon. The Combustion Turbine will not have the capability to co-fire distillate fuel with natural gas, and RP is proposing to limit the firing of distillate fuel to 500 hours per year.

In support of the ULSD Project, RP proposes to install a 2.0 million gallon distillate fuel storage tank (Tank #1).

F. Application Classification

All rules, regulations, or statutes referenced in this air emission license refer to the amended version in effect as of the issued date of this license.

The application for RP does not violate any applicable federal or state requirements and does not reduce monitoring, reporting, testing, or recordkeeping requirements. However, this application does seek to modify a Best Available Control Technology (BACT) analysis performed per New Source Review.

The modification of a major source is considered a major or minor modification based on whether or not expected emissions increases exceed the "Significant Emission Increase" levels as given in *Definitions Regulation*, 06-096 Code of Maine Rules (C.M.R.) ch. 100. For a major stationary source, the expected emissions increase from each new, modified, or affected unit may be calculated as equal to the difference between the post-modification projected actual emissions and the baseline actual emissions for each NSR regulated pollutant.

1. Baseline Actual Emissions

Baseline actual emissions (BAE) are equal to the average annual emissions from any consecutive 24-month period within the ten years prior to submittal of a complete license application. RP has proposed using calendar years 2015 and 2016 as the 24-month baseline period from which to determine baseline actual emissions for all pollutants for emission units affected as part of this project.

BAE for the Combustion Turbine are consistent with emissions statements submitted to the Department in accordance with 06-096 C.M.R. ch. 137. Emissions of particulate matter were based on previous stack testing[1]. Emissions of PM_{10} and $PM_{2.5}$ were based

[1] A third-party auditing firm has reviewed the initial PM stack test report and determined that the correct emission rate should have been 0.48 lb/hr instead of the previously reported 0.21 lb/hr. This accounts for the difference in PM emissions between this license and A-724-77-1-A (issued 5/7/2020).

on filterable PM from previous stack testing plus condensable PM from AP-42, Table 3.1-2a. Emissions of SO_2 were based on the quantity of natural gas combusted and records of sulfur content from the supplier. Emissions of NO_x and CO were based on data from continuous emissions monitoring systems (CEMS). Emissions of VOC were based on standard emission factors.

The results of this baseline analysis are presented in the table below.

Baseline Actual Emissions (1/2015 – 12/2016 Average)

Equipment	PM (tpy)	PM_{10} (tpy)	$PM_{2.5}$ (tpy)	SO_2 (tpy)	NO_x (tpy)	CO (tpy)	VOC (tpy)
Combustion Turbine	0.47	6.62	6.62	0.79	27.50	64.20	0.92

2. Projected Actual Emissions

Projected actual emissions (PAE) are the maximum actual annual emissions anticipated to occur in any one of the five years (12-month periods) following the date existing units resume regular operation after the project or any one 12-month period in the ten years following if the project involves increasing the unit's design capacity or its potential to emit of a regulated pollutant.

In determining PAE from the Combustion Turbine, RP considered emissions resulting from both future periods of natural gas firing and emissions resulting from the firing of distillate fuel.

a. Natural Gas Firing

PAE from firing natural gas were calculated by first quantifying the average annual heat input to the Combustion Turbine during the baseline period (2015/2016). RP then conservatively increased that heat input by three percent to account for the Repair for Performance project addressed in Air Emission License A-724-77-1-A (5/7/2020) and also assumed the same frequency of startup and shutdown events as in the baseline period. RP then developed emission factors (lb/MMBtu) for each pollutant in each baseline year by taking actual annual emissions and dividing by the total heat input to the Combustion Turbine during each year. The highest emission factor for each pollutant for either year (2015 or 2016) was then applied to the projected actual heat input to the Combustion Turbine.

b. Distillate Fuel Firing

PAE from firing distillate fuel were calculated by taking the proposed emission limits from the Best Available Control Technology (BACT) analysis and converting them to lb/hr emission factors. The baseload emissions were determined by multiplying the lb/hr emission factor by the maximum proposed operation of 500 hours/year.

For periods of startup and shutdown, RP utilized estimated "lb/event" data, provided by engineering studies, to quantify any additional emissions associated with these events. RP estimates that there could be 25 startup/shutdown events, when firing distillate fuel, each year. There are no expected additional emissions of PM, PM_{10}, $PM_{2.5}$, or SO_2 over that of normal (baseload) operation.

Projected actual emissions from the affected equipment are shown below.

Projected Actual Emissions

Equipment	PM (tpy)	PM_{10} (tpy)	$PM_{2.5}$ (tpy)	SO_2 (tpy)	NO_x (tpy)	CO (tpy)	VOC (tpy)
Combustion Turbine *(natural gas)*	0.56	6.90	6.90	0.87	34.33	88.07	0.94
Combustion Turbine *(distillate fuel – baseload)*	8.97	8.97	8.97	0.79	10.26	6.25	1.08
Combustion Turbine *(distillate fuel – SU/SD)*	–	–	–	–	15.34	15.53	1.89
Total	**9.53**	**15.87**	**15.87**	**1.66**	**59.93**	**109.85**	**3.91**

3. Emission Adjustments

In determining projected actual emissions, RP excluded increases in emissions that the existing equipment could have accommodated during the baseline period and are unrelated to the current project. This is known as the Demand Growth Exclusion.

Operation of the Combustion Turbine is almost entirely market driven. Adding distillate fuel as an alternative fuel for limited use will allow RP to operate the Combustion Turbine should natural gas be curtailed or if use of natural gas is not economically advantageous. The addition of distillate fuel will have no impact on the future use of the Combustion Turbine when firing natural gas. Any future increase in the utilization of the Combustion Turbine when firing natural gas would be a reflection of a potential increase in demand and unrelated to the ULSD Project.

Therefore, RP proposes that excludable emissions be those emissions resulting from projected natural gas combustion that exceed baseline emissions. The Department agrees with this assessment.

Based on the analysis outlined above, the following emissions are excludable under the Demand Grown Exclusion:

Demand Growth Exclusion Emissions Adjustments

Equipment	PM (tpy)	PM_{10} (tpy)	$PM_{2.5}$ (tpy)	SO_2 (tpy)	NO_x (tpy)	CO (tpy)	VOC (tpy)
Combustion Turbine *(BAE)*	0.47	6.62	6.62	0.79	27.50	64.20	0.92
Combustion Turbine *(PAE for natural gas)*	0.56	6.90	6.90	0.87	34.33	88.07	0.94
Excludable Emissions	**0.10**	**0.28**	**0.28**	**0.08**	**6.83**	**23.87**	**0.02**

4. Emissions Increases

Emissions increases are calculated by subtracting BAE and excludable emissions from the PAE. The emission increase is then compared to the significant emissions increase levels.

Pollutant	Baseline Actual Emissions 2015 - 2016 (ton/year)	Projected Actual Emissions (ton/year)	Excludable Emissions (ton/year)	Emissions Increase (ton/year)	Significant Emissions Increase Levels (ton/year)
PM	0.47	9.53	0.10	8.97	25
PM_{10}	6.62	15.87	0.28	8.97	15
$PM_{2.5}$	6.62	15.87	0.28	8.97	10
SO_2	0.79	1.66	0.08	0.79	40
NO_x	27.50	59.93	6.83	25.60	40
CO	64.20	109.85	23.87	21.78	100
VOC	0.92	3.91	0.02	2.97	40

5. Classification

Since emissions increases do not exceed significant emissions increase levels, this NSR license is determined to be a minor modification under *Minor and Major Source Air Emission License Regulations,* 06-096 C.M.R. ch. 115.

This NSR license is not licensing a new major stationary source of an NSR pollutant that is not greenhouse gases (GHG) nor is it authorizing a major modification to an existing major stationary source for an NSR pollutant. Therefore, greenhouse gases are not considered subject to regulation in this license pursuant to 40 C.F.R. §§ 51.166(b)(48)(iii - iv).

An application to incorporate the requirements of this NSR license into the Part 70 air emission license shall be submitted no later than 12 months from commencement of operations after the work associated with the ULSD Project is completed.

II. BEST PRACTICAL TREATMENT (BPT)

A. Introduction

In order to receive a license, the applicant must control emissions from each unit to a level considered by the Department to represent Best Practical Treatment (BPT), as defined in *Definitions Regulation*, 06-096 C.M.R. ch. 100. Separate control requirement categories exist for new and existing equipment as well as for those sources located in designated non-attainment areas.

BPT for new sources and modifications requires a demonstration that emissions are receiving Best Available Control Technology (BACT), as defined in 06-096 C.M.R. ch. 100. BACT is a top-down approach to selecting air emission controls considering economic, environmental, and energy impacts.

B. Combustion Turbine

RP has proposed physical changes to the Combustion Turbine to accommodate the firing of distillate fuel in addition to the currently licensed natural gas. The maximum heat input of the Combustion Turbine when firing distillate fuel will be approximately 2,111 MMBtu/hr based on the estimated higher heating value of distillate fuel at temperatures below 15 °F of 0.1395 MMBtu/gallon. The Combustion Turbine will not have the capability to co-fire distillate fuel with natural gas, and RP is proposing to limit the firing of distillate fuel to 500 hours per year.

1. BACT Findings

   The ULSD Project involves physical changes to the Combustion Turbine that may result in increased emissions when firing distillate fuel. Therefore, the Combustion Turbine is a modified unit subject to BACT for distillate fuel firing.

   The physical changes are not expected to result in any increases in emissions when firing natural gas. Therefore, a revised BACT analysis is not required for the firing of natural gas, and the Combustion Turbine will continue to be subject to the previous BACT emission limits for natural gas firing.

   Following is a summary of the BACT determination for the Combustion Turbine firing distillate fuel by pollutant.

a. Particulate Matter: $PM/PM_{10}/PM_{2.5}$

Filterable and condensable particulate matter emissions from the Combustion Turbine may be formed from noncombustible constituents in the fuel or combustion air, from products of incomplete combustion, or from the formation of ammonium sulfate due to the conversion of SO_2 to SO_3, which is then available to react with ammonia in Selective Catalytic Reduction systems and form ammonium sulfate or ammonium bisulfate post-combustion.

(1) Identify Potential Control Options

Potential post-combustion control technologies for particulate matter considered include baghouses, electrostatic precipitators (ESP), wet scrubbers, and multicyclones. Additionally, RP considered the use of low ash/low sulfur fuels.

Baghouses
Baghouses consist of a number of fabric bags placed in parallel that collect particulate matter on the surface of the filter bags as the exhaust stream passes through the fabric membrane. The collected particulate is periodically dislodged from the bags' surface to collection hoppers via short blasts of high-pressure air, physical agitation of the bags, or by reversing the gas flow.

ESPs/WESPs
ESPs work by charging particles in the exhaust stream with a high voltage, oppositely charging a collection surface where the particles accumulate, removing the collected dust by a rapping process, and collecting the dust in hoppers. In wet ESPs (WESPs), the collectors are either intermittently or continuously washed by a spray of liquid, usually water. Instead of collection hoppers, a drainage system is used.

Multicyclones
Mechanical separators include cyclonic and inertial separators. In a multicyclone, centrifugal force separates larger PM from the gas stream. The exhaust gas enters a cylindrical chamber on a tangential path and is forced along the outside wall of the chamber at a high velocity, causing the PM to impact collectors on the outer wall of the unit and fall into a hopper for collection.

Wet Scrubbers
Wet scrubbers remove PM from gas streams primarily through impaction and, to a lesser extent, other mechanisms such as interception and diffusion. A scrubbing liquid (typically water) is sprayed countercurrent to the exhaust gas stream. Contact between the larger scrubbing liquid droplets and the suspended particulates removes the PM from the gas stream. Entrained liquid droplets then

pass through a mist eliminator (coalescing filter) which causes the droplets to become heavier and fall out of the exhaust stream.

Clean Fuels

Emissions of particulate matter can be minimized by firing low ash and low sulfur fuels such as natural gas and distillate fuel with a sulfur content of 0.0015% by weight (15 ppm) or less.

(2) Eliminate Infeasible Control Options

A search of EPA's RACT/BACT/LAER Clearinghouse (RBLC) did not identify any post-combustion control technologies for particulate matter in use on distillate fuel-fired turbines similar to the Combustion Turbine. Uncontrolled emissions of particulate matter from the Combustion Turbine are relatively small. In many cases, the low pollutant loading results in reduced control efficiency especially since most of the technologies listed above would have little to no effect on condensable particulate matter. Additionally, each of the technologies listed above would introduce an unacceptable amount of backpressure into the Combustion Turbine that would significantly reduce its efficiency. Therefore, the use of post-combustion control technologies for the control of particulate matter emissions from the Combustion Turbine is determined not to be technically feasible.

RP has proposed to fire natural gas as the Combustion Turbine's primary fuel and to limit firing of distillate fuel to 500 hours/year or less. The distillate fuel that is fired will have a sulfur content of 0.0015% by weight or less. This is determined to be the only control option that is technically feasible.

(3) Ranking of Control Options

The firing of clean fuels, such as natural gas and distillate fuel with a sulfur content of 0.0015% by weight (15 ppm) or less is determined to be the only control option that is technically feasible for control of particulate matter from the Combustion Turbine.

(4) Determination

The Department finds the firing of distillate fuel with a sulfur content not to exceed 0.0015% by weight, an annual operating limit for distillate fuel of 500 hours/year, and the following emission limits to represent BACT for particulate matter emissions from the Combustion Turbine when firing distillate fuel:

Units	$PM/PM_{10}/PM_{2.5}$
lb/MMBtu	0.017
lb/hr	35.89

These standards apply at all times. Compliance with the particulate matter limits shall be demonstrated through performance testing upon request by the Department.

Compliance with the annual operating limit for distillate fuel shall be demonstrated by records of all operating hours for the Combustion Turbine and the fuel type being fired during those hours. Time when the Combustion Turbine is starting up or shutting down while firing distillate fuel shall be included in this total.

Visible emissions from the Combustion Turbine shall not exceed 20% opacity on a six-minute block average basis. [06-096 C.M.R. ch. 101, §4(A)(4)]

By accepting an annual limit on distillate fuel firing of 500 hours per year, the Combustion Turbine remains below the annual capacity factor for non-gaseous fuels for which operation of a Continuous Opacity Monitoring System (COMS) would be required for all applicable requirements.

b. Sulfur Dioxide: SO_2

Emissions of SO_2 from the Combustion Turbine are attributable to the oxidation of sulfur compounds contained in the fuel.

(1) Identify Potential Control Options

Potential pollution control options to reduce SO_2 emissions include flue gas desulfurization by means of wet scrubbing and firing fuels with an inherently low sulfur content, such as distillate fuel with a sulfur content of 0.0015% or less.

Flue Gas Desulfurization
Flue gas desulfurization by means of wet scrubbing works by injecting a caustic solution into the scrubber unit to react with the SO_2 in the flue gas to form a precipitate and either carbon dioxide or water.

Clean Fuel
RP proposes to fire natural gas as the Combustion Turbine's primary fuel and to limit firing of distillate fuel to 500 hours/year or less. The distillate fuel that is fired will have a sulfur content of 0.0015% by weight or less.

(2) Eliminate Infeasible Control Options

A search of the RBLC did not identify any post-combustion SO_2 control technologies in use on distillate fuel-fired turbines similar to the Combustion Turbine.

Operation of a wet scrubber is very energy intensive due to the pressure differential created. Additionally, use of a wet scrubber would introduce an unacceptable amount of backpressure into the Combustion Turbine that would significantly reduce its efficiency. Therefore, the use of post-combustion control technologies for the control of SO_2 emissions from the Combustion Turbine is determined not to be technically feasible.

(3) Ranking of Control Options

The firing of clean fuels, such as natural gas and distillate fuel with a sulfur content of 0.0015% by weight (15 ppm) or less is determined to be the only control option that is technically feasible for control of SO_2 from the Combustion Turbine.

(4) Determination

The Department finds the firing of distillate fuel with a sulfur content not to exceed 0.0015% by weight, an annual operating limit for distillate fuel of 500 hours/year, and emission limits of 0.0015 lb/MMBtu and 3.17 lb/hr to represent BACT for SO_2 emissions from the Combustion Turbine when firing distillate fuel. This standard applies at all times.

Compliance with the SO_2 limits is based on recordkeeping documenting the amount and sulfur content of the distillate fuel fired.

Compliance with the annual operating limit for distillate fuel shall be demonstrated by records of all operating hours for the Combustion Turbine and the fuel type being fired during those hours. Time when the Combustion Turbine is starting up or shutting down while firing distillate fuel shall be included in this total.

c. Nitrogen Oxides: NO_x

NO_x from combustion is generated through one of three mechanisms: fuel NO_x, thermal NO_x, and prompt NO_x. Fuel NO_x is produced by the oxidation of nitrogen in the fuel source, with low nitrogen content fuels such as natural gas producing less NO_x than fuels with higher levels of fuel-bound nitrogen. Thermal NO_x forms in the high temperature area of the combustor and increases exponentially with increases in flame temperature and linearly with increases in residence time. Flame temperature is dependent upon the ratio of fuel burned in a flame to the amount of fuel needed to consume all the available oxygen, also known as the equivalence ratio. The lower this ratio is, the lower the flame temperature; thus, by maintaining a low fuel ratio (lean combustion), the potential for NO_x formation can be reduced. Prompt NO_x forms from the oxidation of hydrocarbon radicals near the combustion flame and produces an insignificant amount of NO_x in combustion turbines.

(1) Identify Potential Control Options

Potential control technologies for combustion turbines include add-on controls, such as selective catalytic reduction (SCR), selective non-catalytic reduction (SNCR), EMx^{TM}, and the use of combustion control techniques, such as water/steam injection.

SCR

SCR employs the reaction of NO_x with ammonia (NH_3) or urea in the presence of a catalyst to produce nitrogen and water, according to the following reactions:

$$4NO + 4NH_3 + O_2 \rightarrow 4N_2 + 6H_2O$$
$$2NO_2 + 4NH_3 + O_2 \rightarrow 3N_2 + 6H_2O$$

The reduction is considered "selective" because the catalyst selectively targets NO_x reduction in the presence of ammonia within a temperature range of approximately 480 ºF to 800 ºF.

SNCR

SNCR is a method of post combustion control that selectively reduces NO_x into nitrogen and water vapor by reacting the exhaust gas with a reagent such as ammonia or urea, similar to SCR. However, in SNCR, a catalyst is not used to lower the activation temperature of the NO_x reduction reaction. Therefore, SNCR is used when flue gas temperatures are between 1,600 ºF and 2,100 ºF.

The reagent solution (either ammonia or urea) is typically injected along the post-combustion section of the emissions unit. Injection sites must be optimized for reagent effectiveness and must balance residence time with flue gas stream temperature. The potential for unreacted ammonia emissions (ammonia slip) is greater with SNCR than with SCR, and the overall NO_x reduction is less.

The NO_x reduction efficiency decreases rapidly at temperatures outside the optimum temperature window which results in excessive unreacted ammonia slip and increased NO_x emissions. This temperature window is higher than the exhaust gas temperature from the Combustion Turbine and HRSG and would require additional burners to raise the exhaust to the required temperature range.

EMx™

EMx™ (formerly called SCONOX™) is a post-combustion catalytic NO_x reduction technology. EMx™ uses a precious metal catalyst and a NO_x absorption/regeneration process to convert CO and NO_x to CO_2, water, and elemental nitrogen. NO_x in the exhaust stream reacts with a potassium carbonate absorbent coating the surface of the oxidation catalyst in the EMx™ reactor forming potassium nitrites and nitrates that are deposited onto the catalyst surface. Each "can" within the reactor becomes saturated with potassium nitrites and nitrates over time and must be desorbed. Regeneration is accomplished by isolating the can and injecting hydrogen diluted with steam. The hydrogen is generated on-site with a small reformer that uses natural gas and steam as input streams. Hydrogen and carbon dioxide react with the potassium nitrites and nitrates to form elemental nitrogen and water and to regenerate the potassium carbonate for another absorption cycle.

Water/Steam Injections

Water/steam injection is the process of injecting water or steam into the combustion chamber to cool the combustion process and lower the peak flame temperature, thus reducing thermal NO_x. It is an effective control technique most often used in combination with SCR to achieve low emission rates.

(2) Eliminate Infeasible Control Options

EMx™ has not been demonstrated to reduce emissions of NO_x below those that can be achieved with SCR. Further, it is a complicated technology which has not been installed or demonstrated on a turbine greater than 45 MW. Therefore, EMx™ is not considered technically feasible for control of NO_x emissions from the Combustion Turbine.

SCR, SNCR, and water/steam injection are all considered technically feasible for control of NO_x from the Combustion Turbine.

(3) Ranking of Control Options

SNCR systems have typical control efficiencies between 30 – 70%. The NO_x reduction efficiency decreases rapidly at temperatures outside the optimum temperature window which results in excessive unreacted ammonia slip and increased NO_x emissions. This temperature window is higher than the exhaust gas temperature from the Combustion Turbine and HRSG and would require additional burners to raise the exhaust to the required temperature range. This would be less efficient and result in higher emissions of other combustion pollutants than use of the existing SCR system.

SCR systems have typical control efficiencies between 70 – 90%. Water/steam injection can reduce emissions of NO_x by up to 50% and is often used in combination with SCR.

A review of the RBLC identified several units that utilize SCR on combustion turbines firing distillate fuel. Almost all of them used a combination of SCR and water/steam injection. The emission limits for these units ranged from 4 - 8 ppm at 15% oxygen (O_2). The three emission units with the lowest NO_x emission limit of 4 ppm are all new construction (greenfield) units, and construction has subsequently been cancelled for two of these units.

RP has proposed to use both SCR and water injection for control of NO_x emissions from the Combustion Turbine when firing distillate fuel. RP has proposed emission limits of 5 ppmdv at 15% O_2 on a 24-hour block average basis when firing distillate fuel except for periods of startup and shutdown, as those terms are defined in this license. RP also proposes a limit of 5 ppmdv for emissions of ammonia (NH_3) when firing distillate fuel.

During periods of startup and shutdown, RP proposes an alternative emission limit of 300 ppmdv at 15% O_2 averaged over the duration of the startup or shutdown period. As noted in the Definitions section, a startup period cannot exceed 300 minutes and a shutdown period cannot exceed 60 minutes.

(4) Determination

The Department finds the use of SCR and water injection for control of NO_x emissions and the following emission limits to represent BACT for NO_x emissions from the Combustion Turbine when firing distillate fuel:

Units	NO_x	NH_3
ppmdv @ 15% O_2 (24-hour block average)	5.0	5.0
lb/hr (1-hour block average)	41.05	15.20

The NO_x standard applies at all times except for periods of startup and shutdown. The NH_3 standard applies at all times.

During periods of startup and shutdown when firing distillate fuel, emissions of NO_x from the Combustion Turbine shall not exceed 300 ppmdv at 15% O_2 averaged over the duration of the startup/shutdown period.

The applicable distillate fuel-fired NOx emission limit will apply during any operating period in which both gas and oil are fired e.g., during fuel transition.

Compliance with the NO_x ppmdv emission limit shall be demonstrated by operation of a NO_x CEMS. Compliance with the NH_3 ppmdv emission limit shall be demonstrated by operation of a NH_3 CEMS. Compliance with the lb/hr emission limits shall be demonstrated through performance testing upon request by the Department.

d. Carbon Monoxide and Volatile Organic Compounds: CO & VOC

CO and VOC emissions are attributable to the incomplete combustion of organic compounds in the fuel. Emissions result when there is insufficient residence time or when there is insufficient oxygen available near the hydrocarbon molecule during combustion to complete the final step in oxidation. Combustion modifications taken to reduce CO emissions may result in increased emissions of NO_x.

(1) Identify Potential Control Options

Pollution control options to reduce CO and VOC emissions include add-on technologies such as an oxidation catalyst as well as combustion controls.

<u>Oxidation Catalyst</u>
An oxidation catalyst is a post-combustion control technology that removes CO and VOC from the exhaust stream. In the presence of a catalyst, CO and VOC will react with oxygen present in the exhaust stream converting the compounds to carbon dioxide. No supplementary reactant is used in conjunction with an oxidation catalyst. Catalysts are typically based on a noble metal and operate by decreasing the temperature at which oxidation will occur. The catalyst lowers the activation energy necessary for CO and VOC to react with available oxygen.

(2) Eliminate Infeasible Control Options

The use of an oxidation catalyst is technically feasible for control of CO and VOC from the Combustion Turbine.

(3) Ranking of Control Options

RP has proposed the use of an oxidation catalyst for control of emissions of CO and VOC from the Combustion Turbine when firing distillate fuel. RP has proposed an emission limit for CO of 5 ppmdv at 15% O_2 on a 24-hour block average basis when firing distillate fuel except for periods of startup and shutdown, as those terms are defined in this license. RP also proposes a limit of 2 ppmdv for emissions of VOC when firing distillate fuel.

During periods of startup, RP proposes an alternative CO emission limit of 1,000 ppmdv at 15% O_2 averaged over the duration of the startup period. During periods of shutdown, RP proposes an alternative CO emission limit of 1,500 ppmdv at 15% O_2 averaged over the duration of the shutdown period. These alternative emission limits are the same as those previously approved for the firing of natural gas. As noted in the Definitions section, a startup period cannot exceed 300 minutes, and a shutdown period cannot exceed 60 minutes.

(4) Determination

The Department finds the use of an oxidation catalyst for control of emissions of CO and VOC and the following emission limits to represent BACT for emissions of CO and VOC from the Combustion Turbine when firing distillate fuel:

Units	CO	VOC
ppmdv @ 15% O_2	5.0 (24-hour block average)	2.0 (1-hour block average)
lb/hr	24.99 (1-hour block average)	4.33 (1-hour block average)

The CO standards apply at all times except for periods of startup and shutdown. The VOC standards apply at all times.

During periods of startup when firing distillate fuel, emissions of CO from the Combustion Turbine shall not exceed 1,000 ppmdv at 15% O_2 averaged over the duration of the startup period. During periods of shutdown when firing distillate fuel, emissions of CO from the Combustion Turbine shall not exceed 1,500 ppmdv at 15% O_2 averaged over the duration of the shutdown period.

The applicable distillate fuel-fired CO emission limit will apply during any operating period in which both gas and oil are fired e.g., during fuel transition.

Compliance with the CO ppmdv emission limit shall be demonstrated by operation of a CO CEMS. Compliance with the CO lb/hr emission limit and the VOC emission limits shall be demonstrated through performance testing upon request by the Department.

2. BACT Summary

Following is a summary of the BACT emission limits for the Combustion Turbine when firing distillate fuel:

Normal Operation:

Pollutant	lb/MMBtu	ppmdv @ 15% O_2	Averaging Period
$PM/PM_{10}/PM_{2.5}$	0.017	–	1-hour block
SO_2	0.0015	–	1-hour block
NO_x	–	5.0	24-hour block
CO	–	5.0	24-hour block
VOC	–	2.0	1-hour block
NH_3	–	5.0	24-hour block

Pollutant	lb/hr	Averaging Period
$PM/PM_{10}/PM_{2.5}$	35.89	1-hour block
SO_2	3.17	1-hour block
NO_x	41.05	1-hour block
CO	24.99	1-hour block
VOC	4.33	1-hour block
NH_3	15.20	1-hour block

Periods of Startup:

Pollutant	ppmdv @ 15% O_2	Averaging Period
NO_x	300	Duration of SU or SD Period
CO	1,000	Duration of SU or SD Period

Periods of Shutdown:

Pollutant	ppmdv @ 15% O_2	Averaging Period
NO_x	300	Duration of SU or SD Period
CO	1,500	Duration of SU or SD Period

Visible emissions from the Combustion Turbine shall not exceed 20% opacity on a six-minute block average basis. [06-096 C.M.R. ch. 101, §4(A)(4)]

3. New Source Performance Standards

   The ULSD Project is considered a "modification" of the Combustion Turbine pursuant to *Standards of Performance for New Stationary Sources*, 40 C.F.R. Part 60, Subpart A § 60.2.

   The Combustion Turbine is not subject to *Standards of Performance for Greenhouse Gas Emissions for Electric Generating Units*, 40 C.F.R. Part 60, Subpart TTTT. This regulation is applicable to new and reconstructed steam generating units (i.e., boilers/furnaces), integrated gasification combined cycle (IGCC) units (i.e., units that burn ≥ 50% solid-derived fuel), and combustion turbines. It is also applicable to modified steam generating units and IGCC units but <u>not</u> modified combustion turbines. RP's Combustion Turbine will be a modified unit which is not new or reconstructed.

   The Combustion Turbine is currently subject to *Standards of Performance for Stationary Combustion Turbines*, 40 C.F.R. Part 60, Subpart KKKK. Pursuant to 40 C.F.R. § 60.4305(b), stationary combustion turbines regulated under Subpart KKKK are exempt from the requirements of 40 C.F.R. Part 60, Subpart GG.

   Upon startup following the project, the Combustion Turbine will become subject to applicable requirements for NO_x and SO_2 when firing distillate fuel. These requirements shall be addressed in RP's Part 70 license at the time this NSR license is incorporated.

4. National Emission Standards for Hazardous Air Pollutants

   The Combustion Turbine is not subject to *National Emission Standards for Hazardous Air Pollutants for Stationary Combustion Turbines*, 40 C.F.R. Part 63, Subpart YYYY. This regulation applies to stationary combustion turbines located at a major source of hazardous air pollutants (HAP). RP is not licensed as a major source of HAP.

C. <u>Tank #1</u>

In support of the ULSD Project, RP proposes to install a 2.0 million gallon distillate fuel storage tank (Tank #1). Tank #1 is considered an insignificant activity pursuant to 06-096 C.M.R. ch. 115, Appendix B, § B(1) and is mentioned for completeness purposes only.

1. Chapter 111

   Tank #1 is not subject to *Petroleum Liquid Storage Vapor Control*, 06-096 C.M.R. ch. 111 because distillate fuel has a true vapor pressure less than 10.5 kilopascals (kPa). [06-096 C.M.R. ch. 111, § 1(B)]

2. Chapter 171

   Control of Petroleum Storage Facilities, 06-096 C.M.R. ch. 171 is not applicable to emission units at RP because RP is not a petroleum storage facility. [06-096 C.M.R. ch. 171, § 1(A)]

3. New Source Performance Standards

   Tank #1 is not subject to *Standards of Performance for Volatile Organic Liquid Storage Vessels (Including Petroleum Storage Vessels) for which Construction, Reconstruction, or Modification Commenced After July 23, 1984*, 40 C.F.R. Part 60, Subpart Kb, because the maximum vapor pressure of distillate fuel is less than 3.5 kilopascals.
   [40 C.F.R. § 60.110b(b)]

D. Incorporation Into the Part 70 Air Emission License

Pursuant to *Part 70 Air Emission License Regulations*, 06-096 C.M.R. ch. 140 § 1(C)(8), for a modification at the facility that has undergone NSR requirements or been processed through 06-096 C.M.R. ch. 115, the source must apply for an amendment to their Part 70 license within one year of commencing the proposed operations, as provided in 40 C.F.R. Part 70.5.

E. Annual Emissions

The table below provides an estimate of facility-wide annual emissions for the purposes of calculating the facility's annual air license fee and establishing the facility's potential to emit (PTE). Only licensed equipment is included, i.e., emissions from insignificant activities are excluded. Similarly, unquantifiable fugitive particulate matter emissions are not included except when required by state or federal regulations. Maximum potential emissions were calculated based on the following assumptions:

- Either operation of the Combustion Turbine for 8,760 hr/year firing natural gas or operation of the Combustion Turbine for 8,260 hr/year firing natural gas and 500 hr/year firing distillate fuel, whichever scenario is higher for the given pollutant;
- Operation of the Water Bath Heater for 8,760 hr/yr; and
- Operation of the Fire Pump for 100 hrs/yr.

This information does not represent a comprehensive list of license restrictions or permissions. That information is provided in the Order section of this license.

Total Licensed Annual Emissions for the Facility
Tons/year
(used to calculate the annual license fee)

	PM	PM_{10}	$PM_{2.5}$	SO_2	NO_x	CO	VOC	NH_3
Combustion Turbine	66.1	106.9	106.9	47.3	115.5	291.2	13.9	118.0
Water Bath Heater	2.4	2.4	2.4	0.1	1.9	1.6	0.1	–
Fire Pump	–	–	–	–	0.3	0.1	–	–
Total TPY	**68.5**	**109.3**	**109.3**	**47.4**	**117.7**	**292.9**	**14.0**	**118.0**

Pollutant	Tons/year
Single HAP	9.9
Total HAP	24.9

III. AMBIENT AIR QUALITY ANALYSIS

RP previously submitted an ambient air quality impact analysis outlined in air emission license A-724-71-A-N (dated 5/7/1998) demonstrating that emissions from the facility, in conjunction with all other sources, do not violate ambient air quality standards (AAQS). In accordance with EPA guidance[2] on the treatment of intermittent emissions, the Department has determined that an additional ambient air quality impact analysis is not required for this NSR license given the intermittent nature of the use of distillate fuel and this use being limited to 500 hours per year.

This determination is based on information provided by the applicant regarding the expected operation of the Combustion Turbine. If the Department determines that any parameter (e.g., stack size, configuration, flow rate, emission rates, nearby structures, etc.) deviates from what was included in the application, the Department may require RP to submit additional information and may require an ambient air quality impact analysis at that time.

ORDER

Based on the above Findings and subject to conditions listed below, the Department concludes that the emissions from this source:

- will receive Best Practical Treatment,
- will not violate applicable emission standards,
- will not violate applicable ambient air quality standards in conjunction with emissions from other sources.

[2] U.S. EPA, "*Memorandum: Additional Clarification Regarding Application of Appendix W Modeling Guidance for the 1-hour NO_2 National Ambient Air Quality Standard*." March 2011. Available online: https://www.epa.gov/sites/default/files/2015-07/documents/appwno2_2.pdf

The Department hereby grants New Source Review License Amendment A-724-77-2-A pursuant to the preconstruction licensing requirements of 06-096 C.M.R. ch. 115 and subject to the specific conditions below.

Severability. The invalidity or unenforceability of any provision of this License Amendment or part thereof shall not affect the remainder of the provision or any other provisions. This License Amendment shall be construed and enforced in all respects as if such invalid or unenforceable provision or part thereof had been omitted.

SPECIFIC CONDITIONS

The following shall replace Condition (1) of New Source Review License A-724-77-1-A:

(1) **Combustion Turbine**

A. Fuels

1. The Combustion Turbine shall fire only natural gas or distillate fuel. [06-096 C.M.R. ch. 115, BACT]

2. The firing of distillate fuel in the Combustion Turbine shall be limited to no more than 500 hours per year on a 12-month rolling total basis. Time when the Combustion Turbine is starting up or shutting down while firing distillate fuel shall be included in this total. Compliance shall be demonstrated by records of all operating hours for the Combustion Turbine and the fuel type being fired during those hours. [06-096 C.M.R. ch. 115, BACT]

3. RP shall not purchase or otherwise obtain for use in the Combustion Turbine distillate fuel with a maximum sulfur content that exceeds 0.0015% by weight (15 ppm). [06-096 C.M.R. ch. 115, BACT]

4. Compliance shall be demonstrated by fuel records showing the quantity, type, and the sulfur content of the fuel purchased for use in the Combustion Turbine. Records of fuel use shall be kept on a monthly basis. Fuel sulfur content compliance shall be demonstrated by tariff sheet, fuel delivery receipts from the supplier, a statement from the supplier that the fuel delivered meets Maine's fuel sulfur content standards, fuel supplier certification, certificate of analysis, or testing of fuel in the tank on-site, as applicable. [06-096 C.M.R. ch. 115, BACT]

B. Control Equipment

1. RP shall operate and maintain a selective catalytic reduction (SCR) system on the Combustion Turbine for control of NO_x during all times the Combustion Turbine is operating except for periods of startup and shutdown. [06-096 C.M.R. ch. 115, BACT]

2. RP shall operate and maintain dry low-NO_x (DLN) combustors on the Combustion Turbine for control of NO_x during all times the Combustion Turbine is operating and firing natural gas. [06-096 C.M.R. ch. 115, BACT (A-724-77-1-A, 5/7/2020)]

3. RP shall operate and maintain a water injection system on the Combustion Turbine for control of NO_x during all times the Combustion Turbine is operating and firing distillate fuel except for periods of startup and shutdown. [06-096 C.M.R. ch. 115, BACT]

4. RP shall operate and maintain an oxidation catalyst on the Combustion Turbine for control of CO and VOC during all times the Combustion Turbine is operating. [06-096 C.M.R. ch. 115, BACT]

5. The exhaust from the Combustion Turbine and HRSG shall be vented through a 150-foot above ground level stack. [06-096 C.M.R. ch. 115, BACT (A-724-77-1-A, 5/7/2020)]

C. Emission Limits and Standards

Emission limits are on a 1-hour block average basis unless otherwise stated.

1. Emissions from the Combustion Turbine shall not exceed the following limits. These limits apply at all times, except for periods of startup and shutdown. The distillate fuel emission limits apply during any operating period in which both distillate fuel and natural gas are fired.

Pollutant	ppmdv	Origin and Authority
NO_x (natural gas)	3.5 @ 15% O_2 (24-hr block avg)	06-096 C.M.R. ch. 115, BACT (A-724-77-1-A, 5/7/2020)
NO_x (distillate fuel)	5.0 @ 15% O_2 (24-hr block avg)	06-096 C.M.R. ch. 115, BACT
CO (natural gas)	15 @ 15% O_2 (24-hr block avg)	06-096 C.M.R. ch. 115, BACT (A-724-77-1-A, 5/7/2020)
CO (distillate fuel)	5.0 @ 15% O_2 (24-hr block avg)	06-096 C.M.R. ch. 115, BACT

2. Emissions from the Combustion Turbine shall not exceed the following limits. These limits apply at all times.

Pollutant	ppmdv	Origin and Authority
NH_3 (natural gas)	10 @ 15% O_2 (24-hr block avg)	06-096 C.M.R. ch. 115, BACT (A-724-77-1-A, 5/7/2020)
NH_3 (distillate fuel)	5.0 @ 15% O_2 (24-hr block avg)	06-96 M.R. ch. 115, BACT

3. Emissions from the Combustion Turbine shall not exceed the following limits. These limits apply at all times.

Pollutant	lb/MMBtu	Origin and Authority
PM (natural gas)	0.007	06-096 C.M.R. ch. 115, BACT (A-724-77-1-A, 5/7/2020)
PM (distillate fuel)	0.017	06-096 C.M.R. ch. 115, BACT
SO_2 (distillate fuel)	0.0015	06-096 C.M.R. ch. 115, BACT

4. Emissions from the Combustion Turbine shall not exceed the following limits when firing natural gas. These limits apply at all times unless otherwise noted.

Pollutant	lb/hr	Origin and Authority
PM	13.8	06-096 C.M.R. ch. 115, BACT (A-724-77-1-A, 5/7/2020)
PM_{10}	23.7	
$PM_{2.5}$	23.7	
SO_2	10.8	
NO_x (See Note 1)	25.5	
CO (See Note 1)	66.5	
VOC	3.1	
NH_3	27.0	

Note 1: Applies at all operating times except during periods of startup and shutdown.

5. Emissions from the Combustion Turbine shall not exceed the following limits when firing distillate fuel. These limits apply at all times unless otherwise noted.

Pollutant	lb/hr	Origin and Authority
PM	35.89	06-096 C.M.R. ch. 115, BACT
PM_{10}	35.89	
$PM_{2.5}$	35.89	
SO_2	3.17	
NO_x (See Note 1)	41.05	
CO (See Note 1)	24.99	
VOC	4.33	
NH_3	15.20	

Note 1: Applies at all operating times except during periods of startup and shutdown.

6. Visible emissions from the Combustion Turbine shall not exceed 20% opacity on a six-minute block average basis. [06-096 C.M.R. ch. 101, § 4(A)(4)]

D. Startup/Shutdown
[06-096 C.M.R. ch. 115, BACT]

1. RP shall minimize emissions from the Combustion Turbine to the maximum extent practicable during startup and shutdown and under maintenance or adjustment conditions by following proper operating procedures to minimize the emissions of air contaminants to the maximum extent practical.

2. Emissions from the Combustion Turbine during periods of startup shall not exceed the following. The distillate fuel emission limits apply during any operating period in which both distillate fuel and natural gas are fired.

Pollutant	Performance Standard	Averaging Period	Origin and Authority
NO_x (natural gas)	90 ppmdv @ 15% O_2	Duration of Startup	06-096 C.M.R. ch. 115, BACT (A-724-77-1-A, 5/7/2020)
NO_x (distillate fuel)	300 ppmdv @ 15% O_2	Duration of Startup	06-096 C.M.R. ch. 115, BACT
CO (natural gas)	1,000 ppmdv @ 15% O_2	Duration of Startup	06-096 C.M.R. ch. 115, BACT (A-724-77-1-A, 5/7/2020)
CO (distillate fuel)	1,000 ppmdv @ 15% O_2	Duration of Startup	06-096 C.M.R. ch. 115, BACT

3. *Startup* shall be defined as a period which begins when any fuel is fired in the Combustion Turbine after a shutdown and ends when the unit reaches steady state operation. Steady state operation is reached when the Combustion Turbine reaches 50% base load and the steam turbine is declared available for load changes. Aborted startups shall be included in this definition.

   Startup shall be completed as soon as practicable, but in no case shall this period exceed 300 minutes. RP shall maintain records of all startup times and durations. Records of startups lasting longer than 240 minutes shall include an explanation of the circumstances that led to the longer startup period.

4. Emissions from the Combustion Turbine during periods of shutdown shall not exceed the following:

Pollutant	Performance Standard	Averaging Period	Origin and Authority
NO_x (natural gas)	90 ppmdv @ 15% O_2	Duration of Shutdown	06-096 C.M.R. ch. 115, BACT (A-724-77-1-A, 5/7/2020)
NO_x (distillate fuel)	300 ppmdv @ 15% O_2	Duration of Shutdown	06-096 C.M.R. ch. 115, BACT
CO (natural gas)	1,500 ppmdv @ 15% O_2	Duration of Shutdown	06-096 C.M.R. ch. 115, BACT (A-724-77-1-A, 5/7/2020)
CO (distillate fuel)	1,500 ppmdv @ 15% O_2	Duration of Shutdown	06-096 C.M.R. ch. 115, BACT

5. *Shutdown* is defined as a period which begins when steady state operation stops and ends with cessation of Combustion Turbine firing. Shutdown shall be completed as soon as practicable, but in no case shall this period exceed 60 minutes. RP shall maintain records of all shutdown times and durations. Records of shutdowns lasting longer than 40 minutes shall include an explanation of the circumstances that led to the longer shutdown period.

E. Compliance Demonstration
[06-096 C.M.R. ch. 115, BACT]

1. Compliance with the SO_2 lb/hr limit is based on monthly recordkeeping of the hours of operation, the amount of natural gas or distillate fuel fired in the Combustion Turbine, and records of the fuel sulfur content (e.g., the most recent tariff sheet or fuel oil delivery records showing the sulfur content of the natural gas fired).

2. CEMS

   a. Compliance with the NO_x, CO, and NH_3 ppmdv emission limits shall be demonstrated through use of a Continuous Emission Monitoring System (CEMS) which meet the performance specifications of 40 C.F.R. Part 60, Appendix B and F, 40 C.F.R. Part 75, Appendix A and B, and 06-096 C.M.R. ch. 117 as applicable.

   b. A 24-hour block average basis shall be calculated as the arithmetic average of not more than 24 and not less than 8 one (1) hour block average periods. Only one 24-hour block average shall be calculated for each day, beginning at midnight. RP shall include all hours that the Combustion Turbine is operating during each day in each 24-hour block average with the exception of any hours which include periods of startup or shutdown. Any hour that includes any time considered part of a period of startup or shutdown shall not be included in the 24-hour block average.

3. Upon request by the Department, compliance with the visible emission limits shall be demonstrated through performance testing in accordance with 40 C.F.R. Part 60, Appendix A, Method 9.

4. Upon request by the Department, compliance with all other emission limits shall be demonstrated through performance testing in accordance with an appropriate test method as approved by the Department.

5. RP shall record data and maintain records for the following periodic monitoring values for the Combustion Turbine and its associated air pollution control equipment whenever the equipment is operating.

Parameter Monitored	Monitor Method	Monitoring Frequency	Record Frequency
Turbine natural gas firing rate	Flow meter	Continuously	Once per hour
Turbine distillate fuel firing rate	Flow meter	Continuously	Continuously
Electric load level	Electronic monitor	Continuously	Once per shift
Turbine air inlet temperature	Temperature probe	Continuously	Once per shift
Catalyst bed temperature	Temperature probe	Continuously	Once per shift

The following are New Conditions:

(2) **Future Project Emissions Reporting**

A. RP shall monitor, calculate, and maintain a record of the annual emissions, in tons per year on a calendar year basis, of PM_{10}, $PM_{2.5}$, and NO_x for the Combustion Turbine. RP must monitor, calculate, and maintain a record of the annual emissions for a period of 10 years following the resumption of regular operations after the change.
[40 C.F.R. § 52.21(r)(6)]

B. If the annual emissions, in tons per year, from the project exceed the baseline actual emissions, excluding any emission increase unrelated to the project and due to demand growth, for any of these pollutants by an amount equal to or greater than the significant emissions increase level for that pollutant, RP shall submit a report to the Department and EPA within 60 days after the end of the calendar year which contains the following:

1. The facility name, address, and phone number;
2. The annual emissions for the project; and
3. Any other information that the facility wishes to include in the report (e.g., an explanation as to why the emissions differ from the preconstruction projection.)

[40 C.F.R. § 52.21(r)(6)(v)]

(3) If the Department determines that any parameter value pertaining to construction and operation of the emissions units, including but not limited to stack size, configuration, flow rate, emission rates, nearby structures, etc., deviates from what was submitted in the application or ambient air quality impact analysis for this air emission license, RP may be required to submit additional information. Upon written request from the Department, RP shall provide information necessary to demonstrate AAQS will not be exceeded, potentially including submission of an ambient air quality impact analysis or an application to amend this air emission license to resolve any deficiencies and ensure compliance with AAQS. Submission of this information is due within 60 days of the Department's written request unless otherwise stated in the Department's letter. [06-096 C.M.R. ch. 115, § 2(O)]

(4) RP shall submit an application to incorporate this NSR license amendment into the facility's Part 70 air emission license no later than 12 months from commencement of the requested operation. [06-096 C.M.R. ch. 140 § 1(C)(8)]

DONE AND DATED IN AUGUSTA, MAINE THIS 14th DAY OF NOVEMBER, 2023.

DEPARTMENT OF ENVIRONMENTAL PROTECTION

BY:____ for _____
MELANIE LOYZIM, COMMISSIONER

PLEASE NOTE ATTACHED SHEET FOR GUIDANCE ON APPEAL PROCEDURES

Date of initial receipt of application: 8/23/2023
Date of application acceptance: 8/24/2023

Date filed with the Board of Environmental Protection:

This Order prepared by Lynn Muzzey, Bureau of Air Quality.

FILED

NOV 14, 2023

State of Maine
Board of Environmental Protection