STATE OF MAINE
DEPARTMENT OF ENVIRONMENTAL PROTECTION
17 STATE HOUSE STATION AUGUSTA, MAINE 04333-0017

DEPARTMENT ORDER

Sappi North America, Inc. **Cumberland County** **Westbrook, Maine** **A-29-77-7-A**	**Departmental** **Findings of Fact and Order** **New Source Review** **NSR #7**

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	Sappi North America, Inc.
LICENSE TYPE	06-096 C.M.R. ch. 115, Minor Modification 06-096 C.M.R. ch. 115, Minor Revision
NAICS CODES	322220[1]
NATURE OF BUSINESS	Coated Paper Manufacturing
FACILITY LOCATION	89 Cumberland Street, Westbrook, Maine

B. NSR License Description

Sappi North America, Inc. (Sappi) was issued New Source Review (NSR) license A-29-77-5-A (NSR #5) on August 21, 2020, for their "2020 Restructuring Project." This project included the addition of two new natural gas-fired boilers (Boilers #22 and #23), the permanent shutdown of #9 Paper Machine, and expected reduction in utilization of Boilers #17, #18, and #21. NSR #5 was subsequently amended by NSR license A-29-77-6-A (NSR #6) on November 30, 2020, to include the installation of a small, natural gas-fired make-up air unit (MAU #1) as part of the 2020 Restructuring Project.

Pursuant to Condition (3) of NSR #5, Sappi has requested an NSR minor modification to allow Boilers #22 and #23 to operate concurrently with Boiler #21 and to demonstrate compliance with National Ambient Air Quality Standards (NAAQS) and increment standards through submission of an ambient air quality impact analysis.

[1] Due to changes made as part of the 2020 Restructuring Project, the facility's NAICS Code is being updated from 322121 (Paper Mill) to 322220 (Coated Paper Manufacturing).

In addition, Sappi has requested a minor revision to address the following changes:

1. Permanent shutdown of Boilers #17 and #18 and removal of obsolete requirements due to this change;
2. Clarification of Boiler #21's coal-firing capacity; and
3. Augmenting PM_{10} emission limits for Boiler #21 to include condensable particulate matter and establishing emission limits for $PM_{2.5}$ where none previously existed.

C. Emission Equipment

The following equipment is addressed in this NSR license:

Boilers

Equipment	Maximum Heat Input Capacity (MMBtu/hr)	Fuel	Manufacture Date	Install Date
Boiler #17	232.7 (199.0 limit)	distillate fuel, #6 fuel oil	1948	1948
Boiler #18	232.7 (199.0 limit)	distillate fuel, #6 fuel oil	1948	1948
Boiler #21	1,074[a] 397[b] 597[c]	biomass, CDD, sludge, coal, distillate fuel, #6 fuel oil	1981	1981
Boiler #22	99.9	natural gas	2019	2020
Boiler #23	42.0	natural gas	2017	2020

[a] When firing biomass and coal together.
[b] When firing only coal.
[c] When firing only #6 fuel oil.

D. Definitions

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

E. History and Project Description

Sappi operates a specialty paper coating facility with a power boiler complex for the production of steam and power. In addition to the boiler complex, the facility consists of three offline coaters[2], paper winding and shipping operations, a Technology Center, and a wastewater treatment plant.

[2] Sappi operates additional coaters that are considered insignificant activities.

Sappi is licensed to operate Boiler #21 to supply building heat, process steam, facility power, and power for sale to the grid. Boilers #17 and #18 were most recently operated as limited-use boilers historically used as back-up for Boiler #21, but are being permanently shut down and will be removed from Sappi's Part 70 License.

NSR #5 was issued on August 21, 2020, and included the installation of two new natural gas-fired boilers (Boilers #22 and #23) to supply process steam and building heat. At the time, Sappi was unsure whether Boilers #22 and #23 would be temporary or permanent installations. Therefore, the Department agreed to postpone requiring a new ambient air quality impact analysis until May 1, 2023, to allow time for Sappi to decide whether these boilers would be made permanent or replaced. This agreement was contingent on the facility's East-Side Boilers (Boilers #22 and #23) not operating concurrently with the West-Side Boilers (Boiler #21 and previously licensed Boilers #17 and #18) except for Transitional Periods, i.e., the time when Sappi is transitioning from one boiler group to the other.

Sappi submitted an updated ambient air quality impact analysis to the Department on April 28, 2023. In addition, Sappi submitted a modification request to relicense Boilers #22 and #23 such that they may operate concurrently with Boiler #21. Although Boilers #22 and #23 have been in operation for more than two years, they are conservatively being treated as new emission units for the purposes of this licensing action. Boiler #21 is not considered a modified or an affected emission unit. It will not experience any physical or operational changes, nor will it experience any increase in usage due to the changes proposed.

Sappi has also requested the permanent shutdown of Boilers #17 and #18. For simplicity, any reduction in actual emissions due to the shutdown of these units has been conservatively ignored.

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 Sappi does not violate any applicable federal or state requirements and does not reduce monitoring, reporting, testing, or recordkeeping requirements.

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) for existing affected emission units 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. The selected 24-month baseline period can differ on a pollutant-by-pollutant basis. However, there are no existing emission units which are considered "affected" by this project.

   As described above, Boiler #21 is not considered either a modified or an affected unit, and baseline emissions from Boilers #17 and #18 are conservatively being ignored.

   The only equipment addressed by this license are Boilers #22 and #23 which are being treated as new emission units. Baseline actual emissions for new equipment are considered to be zero for all pollutants; therefore, the selection of a baseline year is unnecessary.

2. Projected Actual Emissions

   New emission units must use potential to emit (PTE) emissions for projected actual emissions (PAE). Those emissions are presented in the following table.

Projected Actual Emissions (equal to PTE)

Equipment	PM (tpy)	PM_{10} (tpy)	$PM_{2.5}$ (tpy)	SO_2 (tpy)	NO_x (tpy)	CO (tpy)	VOC (tpy)
Boiler #22	2.2	2.2	2.2	0.4	15.8	16.6	1.8
Boiler #23	0.9	0.9	0.9	0.2	6.6	7.0	0.7
Total	**3.1**	**3.1**	**3.1**	**0.6**	**22.4**	**23.6**	**2.5**

3. Emissions Increases

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

Pollutant	Baseline Actual Emissions (ton/year)	Projected Actual Emissions (ton/year)	Emissions Increase (ton/year)	Significant Emissions Increase Levels (ton/year)
PM	0	3.1	+3.1	25
PM_{10}	0	3.1	+3.1	15
$PM_{2.5}$	0	3.1	+3.1	10
SO_2	0	0.6	+0.6	40
NO_x	0	22.4	+22.4	40
CO	0	23.6	+23.6	100
VOC	0	2.5	+2.5	40

4. 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 for an NSR pollutant to an existing major stationary source. Therefore, greenhouse gases are not considered subject to regulation in this license pursuant to 40 C.F.R. §§ 51.166(b)(48)(iii - iv).

Sappi has submitted an application to incorporate the requirements of this NSR license into the facility's Part 70 air emission license.

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. Boilers #22 and #23

Boilers #22 and #23 are package boilers with maximum heat inputs of 99.9 MMBtu/hr and 42.0 MMBtu/hr, respectively, firing natural gas. They were installed in 2020. However, they are being relicensed as if they were new emission units to remove the restriction on firing East-Side Boilers (Boilers #22 and #23) concurrently with West-Side Boilers (Boiler #21 and previously licensed Boilers #17 and #18).

Boilers #22 and #23 each exhaust through their own stack, and each stack shall be at least 70-feet above ground level.

1. Best Available Control Technology (BACT) Analysis

   Sappi submitted a BACT analysis for control of emissions from Boilers #22 and #23.

   a. Alternative Technologies

      Sappi considered several alternative technologies to provide facility heat and process steam as part of their BACT analysis, including the use of hydrogen fuel boilers, solar technologies, and industrial heat pumps.

      Hydrogen Fuel
      Alternative fuels, such as hydrogen, could be used to produce heat and steam at a significant reduction in pollutants which are products of combustion. However, there is no local infrastructure available to supply hydrogen fuel in the quantities needed. Therefore, the use of hydrogen fuel is not considered technologically feasible.

      Concentrating Solar / Solar Photovoltaics
      Concentrating solar technologies use mirrors to reflect and concentrate sunlight onto receivers that collect solar energy and convert it to heat. This technology is currently neither commercially proven nor suitable for continuous 24/7 manufacturing. Similarly, photovoltaics cannot provide 24/7 industrial steam for manufacturing. Neither of these technologies is determined to be technologically feasible.

      Industrial Heat Pumps
      Heat pumps are proven technology for heating and cooling of commercial facilities. However, heat pumps cannot provide the high-heat needs of the coaters and retrofitting the coaters to accommodate a heating system other than process steam

is outside the scope of this project. Therefore, the use of industrial heat pumps for this project is determined not to be technically feasible.

The Department finds that the use of these alternative technologies, instead of installation of Boilers #22 and #23, are not technically feasible and do not represent BACT for this project.

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

The principal components of the particulate matter emissions from Boilers #22 and #23 include filterable and condensable particulate matter (CPM) from incomplete combustion. Natural gas combustion typically has low emissions of filterable PM. Potential control technologies include baghouses, electrostatic precipitators (ESP), wet scrubbers, and multicyclones.

<u>Baghouses</u>
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. Baghouse systems are capable of PM filterable collection efficiencies greater than 98%. A baghouse is a technically feasible option for control of PM from Boilers #22 and #23.

<u>ESPs/WESPs</u>
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. ESP/WESP systems are capable of PM filterable collection efficiencies up to 98%. An ESP/WESP is a technically feasible option for control of PM from Boilers #22 and #23.

<u>Multicyclones</u>
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. Multicyclones have typical removal efficiencies of 40 – 90% for PM_{10} and 0 – 40% for $PM_{2.5}$. The use of multicyclones is considered a technically feasible option for the control of PM emissions from Boilers #22 and #23.

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. Wet scrubbers typically have removal efficiencies of 90 – 99% for emissions of PM_{10} and significantly lower efficiencies for $PM_{2.5}$ (as low as 50% for spray tower scrubbers). High-efficiency scrubbers such as venturi scrubbers can be used to achieve greater removal efficiencies for $PM_{2.5}$ of greater than 99% due to the high velocities and pressure drops at which they operate. A wet scrubber is a technically feasible option for control of PM emissions from Boilers #22 and #23.

BACT Determination for Particulate Matter

A search of the RBLC did not identify any particulate matter control technologies in use on natural gas-fired boilers similar to Boilers #22 and #23. Although each of the control options listed above is technically feasible, uncontrolled emissions of particulate matter from Boilers #22 and #23 combined are estimated to be no more than 3.1 tpy. Even assuming 100% control from the most cost-effective option (multicyclones), the cost of control would still exceed $100,000/ton. Therefore, additional controls for particulate matter from Boilers #22 and #23 are determined not to be economically feasible.

The Department finds the firing of natural gas and the following emission limits to represent BACT for particulate matter emissions from Boilers #22 and #23:

Units	**PM (lb/MMBtu)**	**PM_{10} (lb/MMBtu)**	**$PM_{2.5}$ (lb/MMBtu)**
Boiler #22	0.005	0.005	0.005
Boiler #23	0.005	0.005	0.005

Units	**PM (lb/hr)**	**PM_{10} (lb/hr)**	**$PM_{2.5}$ (lb/hr)**
Boiler #22	0.50	0.50	0.50
Boiler #23	0.21	0.21	0.21

These standards apply at all times. Upon request by the Department, compliance with the particulate matter limits shall be demonstrated through performance testing in accordance with 40 C.F.R. Part 60, Appendix A, Methods 5, 201, or 201A for filterable PM and Method 202 for CPM, or other methods as approved by the Department.

Visible emissions from Boilers #22 and #23 shall each not exceed 10% opacity on a six-minute block average basis. Compliance shall be demonstrated through performance testing in accordance with 40 C.F.R. Part 60, Appendix A, Method 9 upon request by the Department.

c. Sulfur Dioxide: SO_2

Emissions of SO_2 from Boilers #22 and #23 are attributable to the oxidation of sulfur compounds contained in the fuel. 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 natural gas.

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. Flue gas desulfurization by means of wet scrubbing can have control efficiencies upwards of 90%. However, operation of a scrubber is very energy intensive due to the pressure differential created. Although technically feasible, uncontrolled emissions of SO_2 from Boilers #22 and #23 are estimated to be less than 1.0 tpy. Therefore, operation of flue gas desulfurization for control of SO_2 from Boilers #22 and #23 is determined not to be economically feasible.

BACT Determination for SO_2
The Department finds the use of natural gas, which inherently has a low sulfur content, and the following emission limits to represent BACT for SO_2 emissions from Boilers #22 and #23.

Units	**SO_2 (lb/MMBtu)**	**SO_2 (lb/hr)**
Boiler #22	0.001	0.10
Boiler #23	0.001	0.04

These standards apply at all times. Compliance with the SO_2 limit shall be based on monthly recordkeeping of the amount of natural gas fired in Boilers #22 and #23 and the most recent tariff sheet showing the sulfur content of the natural gas fired.

d. 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. 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. Prompt NO_x forms from the oxidation of hydrocarbon radicals near the combustion flame; this produces an insignificant amount of NO_x.

Control of NO_x emissions can be accomplished through one of three methods: the use of add-on controls, such as selective catalytic reduction (SCR) and selective non-catalytic reduction (SNCR); the use of combustion control techniques, such as low excess air firing, low NO_x burners (LNBs), ultra-low NO_x burners (ULNBs), water/steam injection, and flue gas recirculation (FGR); and the combustion of clean fuel, such as natural gas.

<u>SCR</u>
SCR employs the reaction of NO_x with ammonia in the presence of a catalyst to produce nitrogen and water. 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, according to the following reactions:

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

SCR systems have typical control efficiencies between 70 – 90%. SCR is considered technically feasible for control of NO_x emissions from Boilers #22 and #23.

Capital costs for SCR systems are significantly higher than other types of NO_x control due to the large volume of catalyst that is required. Operation and maintenance costs are driven by reagent usage, catalyst replacement, and increased electrical power usage. Sappi estimated the cost of installing an SCR system at approximately $1.1 million with an additional $700,000 for additional infrastructure needed to accommodate the SCR system. When amortized over seven years, the cost of SCR for these units exceeds $10,000 per ton of NO_x removed. Therefore, operation of an SCR system for control of NO_x from Boilers #22 and #23 is determined not to be economically feasible.

<u>SNCR</u>
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 NO_x reduction efficiency decreases rapidly at temperatures outside this optimum temperature window which results in excessive unreacted ammonia slip and increased NO_x emissions.

The reagent solution (either ammonia or urea) is typically injected along the post-combustion section of the boiler. Injection sites must be optimized for reagent effectiveness and must balance residence time with flue gas stream temperature. The potential for unreacted ammonia slip emissions is greater with SNCR than with SCR and the overall NO_x reduction is less. SNCR systems have typical control efficiencies between 30 – 75%.

For boilers with a large turndown ratio, such as package boilers, it is nearly impossible to inject the reagent at a location where the temperature remains in the reaction window for all modes of operation. Additionally, to ensure proper mixing of the reagent with flue gas, a large amount of wall space is needed for installation of the injectors and a large furnace volume is needed to ensure adequate residence time for the reaction to occur. This is not possible for package boilers, such as Boilers #22 and #23, as they have a very small equipment footprint and lack the size/volume necessary to ensure an efficient reduction reaction. Therefore, operation of an SNCR system for control of NO_x from Boilers #22 and #23 is determined not to be technically feasible.

<u>LNBs/ULNBs</u>
LNBs reduce NO_x by accomplishing combustion in stages which delays the combustion process resulting in a cooler flame that suppresses thermal NO_x formation. While the technology varies between manufacturers, LNBs typically target emission levels around 30 ppmdv at 3% O_2. LNBs are a technically feasible option for control of NO_x from Boilers #22 and #23.

ULNBs typically employ rapid mixing of gaseous fuel with air near the burner exit. ULNBs typically target emission levels around 9 ppmdv at 3% O_2. Rapid mixing virtually eliminates prompt NO_x formation and promotes complete fuel combustion. However, the high amounts of excess air used in rapid mix burners reduces boiler efficiency. In addition, this type of burner configuration does not allow for high turndown ratios. Boilers #22 and #23 need to modulate frequently in response to changes in the mill steam demand. A high turndown ratio is required to operate this equipment as intended. Therefore, ULNBs are not a technically feasible option for control of NO_x from Boilers #22 and #23.

<u>FGR</u>
FGR is a system where a portion of the flue gas is recirculated back into the main combustion chamber; this helps to decrease the formation of thermal NO_x by lowering the peak flame temperature and reducing the oxygen concentration surrounding the flame zone. The recycled flue gas consists of combustion products which act as inert heat sinks during combustion of the fuel/air mixture. This reduces NO_x emissions by two mechanisms. Primarily, the recirculated gas acts as a diluent to reduce combustion temperatures, lowering peak flame temperatures, thus suppressing thermal NO_x formation. In addition, the recirculated flue gas lowers

the average oxygen concentration in the combustion zone, which lowers the amount of oxygen available to react with nitrogen to form NO_x. FGR systems are capable of control efficiencies up to 75%. FGR is considered technically feasible for control of NO_x emissions from Boilers #22 and #23.

Water/Steam Injections
Water/steam injection is the process of injecting water or steam into the combustion chamber to act as a thermal ballast in the combustion process. The ballast lowers the combustion temperature, minimizing thermal formation of NO_x. Water/steam injection can reduce NO_x emissions at a rate equivalent to flue gas recirculation and is technically feasible for the control of NO_x emissions from Boilers #22 and #23.

BACT Determination for NO_x
Sappi has proposed the installation and operation of LNBs and FGR to control NO_x from Boilers #22 and #23. The Department finds the use of LNBs and FGR for control of NO_x emissions and the following emission limits to represent BACT for NO_x emissions from Boilers #22 and #23.

Units	NO_x (lb/MMBtu)	NO_x (lb/hr)
Boiler #22	0.036	3.60
Boiler #23	0.036	1.51

This standards apply at all times. Upon request by the Department, compliance shall be demonstrated through performance testing in accordance with 40 C.F.R. Part 60, Appendix A, Method 7 or other method as approved by the Department.

Sappi shall operate the FGR during all times the boiler is operating except during periods of startup and shutdown (as those terms are defined in 40 C.F.R. Part 63, Subpart DDDDD).

e. 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 NO_x emissions may result in increased emissions of CO. Pollution control options to reduce CO and VOC emissions include add-on technologies such as catalytic oxidation and thermal oxidizers as well as combustion controls.

Catalytic Oxidation

Catalytic oxidation is a post combustion control technology that has been used extensively with gas turbines and internal combustion engines. Catalysts are typically based on a noble metal and operate by decreasing the temperature at which oxidation of CO and VOC will occur. The catalyst lowers the activation energy necessary for CO to react with available oxygen in the exhaust to produce CO_2. Despite the decreased oxidation temperature, process exhaust gas must typically be preheated prior to contact with the catalyst bed. An oxidation catalyst is located within the heat recovery section of the system, or in a downstream location where the exhaust gases are reheated to meet the proper temperature environment. The operating temperature window of an oxidation catalyst is between approximately 600 °F and 800 °F. Catalytic oxidation is considered technically feasible for control of CO and VOC emissions from Boilers #22 and #23.

A review of the RBLC did not find any boilers in similar configurations currently utilizing catalytic oxidation. Sappi estimated the cost of a catalytic oxidation system would be at least $450,000 with the cost of removal exceeding $10,000 per ton. Therefore, based on the combination of the cost per ton of pollutant controlled and the need to fire additional fuel to reheat the flue gas, the installation and operation of an oxidation catalyst for control of CO and VOC on Boilers #22 and #23 is determined to be economically infeasible and environmentally unjustified.

Oxygen Trim

Oxygen trim systems monitor the amount of oxygen in the exhaust gas and adjust the inlet flow of combustion air in order to achieve an optimum air-to-fuel ratio. By monitoring the oxygen level in the exhaust gas, fine adjustments can be applied to the combustion air ratio to compensate for combustion variables such as barometric pressure change, air humidity, and variances in fuel quality. If insufficient combustion air is available in the combustion chamber, incomplete combustion occurs, resulting in increased CO and VOC emissions. An oxygen trim system ensures adequate combustion air is present for complete combustion. Use of an oxygen trim system is considered technically feasible for control of CO and VOC emissions from Boilers #22 and #23.

BACT Determination for CO and VOC

The Department finds the use of an oxygen trim system and the following emission limits to represent BACT for CO and VOC emissions from Boilers #22 and #23.

Units	CO (lb/MMBtu)	VOC (lb/MMBtu)
Boiler #22	0.038	0.004
Boiler #23	0.038	0.004

Units	CO (lb/hr)	VOC (lb/hr)
Boiler #22	3.80	0.40
Boiler #23	1.60	0.17

These standards apply at all times. Upon request by the Department, compliance shall be demonstrated through performance testing in accordance with 40 C.F.R. Part 60, Appendix A, Method 10 or 19 (CO) and Method 25A (VOC) or other method as approved by the Department.

C. Boilers #17 and #18

Boilers #17 and #18 are 1940s vintage oil-fired boilers. These units have been permanently shut down and will no longer be used. Sappi has requested these emission units be removed from their license along with any conditions made obsolete by this action.

D. Boiler #21 Coal Firing

Boiler #21 has a maximum design heat input rating of 1,074 MMBtu/hr firing biomass fuel and coal, combined. Current licenses also state that it has a maximum design heat input capacity of 839 MMBtu/hr when firing only coal and 597 MMBtu/hr when firing only #6 fuel oil.

However, the listed coal capacity is predicated on the usage of stoker coal, i.e., larger pieces of coal that burn on the boiler's grate. The original boiler design specifications indicated that stoker coal could contribute up to 442 MMBtu/hr and pulverized coal could contribute up to 397 MMBtu/hr for a combined heat input of 839 MMBtu/hr.

After Boiler #21's initial installation, it was determined that the system could not reliably fire stoker coal and the mechanical equipment necessary to fire stoker coal was removed in the 1980s. Boiler #21 is not currently physically capable of firing any amount of stoker coal without significant capital expenditure and modifications to the boiler. Therefore, Sappi has requested that the license be updated to reflect that the maximum heat input when firing only coal is 397 MMBtu/hr. The maximum capacity of the boiler is unchanged since the unit is able to make up for the loss of stoker coal with increased biomass firing. This change has no impact on licensed emission limits or actual emissions of any pollutant.

E. Boiler #21 Particulate Matter Limits

Boiler #21 has a PM_{10} emission limit established through BACT of 0.08 lb/MMBtu that is based on filterable particulate matter only due to the emission limit being established prior to the definition of PM_{10} being revised to include condensable particulate matter (CPM). However, this limit is considered high enough that it can be considered inclusive of CPM and shall be going forward.

Additionally, Boiler #21 does not have established lb/hr emission limits for PM_{10} or $PM_{2.5}$. As part of this licensing action, Sappi has requested establishment of $PM_{2.5}$ emission limits where none had previously existed in support of the ambient air quality impact analysis.

The following tables outline the existing emission limits and the proposed new and revised emission limits, along with their associated compliance methods.

Table II-1: Existing PM_{10} and $PM_{2.5}$ Emission Limits

Emission Unit	Pollutant	Current Limit	Origin & Authority	Compliance Method
Boiler #21	PM_{10}	0.08 lb/MMBtu	06-096 C.M.R. ch. 115, BACT (A-29-71-C-A/R, 6/23/1988)	Method 5
	$PM_{2.5}$	–	–	–

Table II-2: Proposed New and Updated PM_{10} and $PM_{2.5}$ Emission Limits

Emission Unit	Pollutant	Proposed Limit	Origin & Authority	Compliance Method
Boiler #21	PM_{10}	0.08 lb/MMBtu	06-096 C.M.R. ch. 115, BACT	Method 5, 201, or 201A and Method 202
		75.0 lb/hr	06-096 C.M.R. ch. 115, § 7	
	$PM_{2.5}$	75.0 lb/hr	06-096 C.M.R. ch. 115, § 7	

The PM_{10} and $PM_{2.5}$ lb/hr emission limits assume 100% of filterable PM is also PM_{10} and $PM_{2.5}$. The filterable portion is based on an emission factor of 0.037 lb/MMBtu, which is equivalent to an applicable emission limit in 40 C.F.R. Part 63, Subpart DDDDD. The condensable portion is based on emission factors of 0.017 lb/MMBtu for biomass (AP-42 Table 1.6-1) and 0.06 lb/MMBtu for coal (AP-42 Table 1.1-5 assuming a sulfur content of 0.9%) and assuming maximum coal firing (397 MMBtu/hr) with the remainder of the maximum heat content firing biomass (677 MMBtu/hr).

The Department finds the proposed new and updated emission limits in Table II-2 either represent an administrative revision of BACT or are necessary to demonstrate compliance with ambient air quality standards (as indicated in Table II-2 above) for emissions of PM_{10} and $PM_{2.5}$.

Compliance shall be demonstrated pursuant to 40 C.F.R. Part 60, Appendix A, Method 5, 201, or 201A for filterable PM and Method 202 for CPM upon request by the Department.

F. 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. An application to incorporate the requirements of this NSR license into the Part 70 air emission license has been submitted to the Department.

G. 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:

- Operation of Boiler #21 at 100% for 8,760 hr/yr for PM, PM_{10}, $PM_{2.5}$, NO_x, CO, and VOC;
- An annual emission limit of 3,763.0 tpy for SO_2 for Boiler #21 as established in A-29-71-AG-M;
- Unlimited operation of Boilers #22 and #23;
- Unlimited operation of MAU #1;
- A 10% annual capacity factor for the Technology Center Boiler;
- Operating each generator for 100 hr/yr;
- Maximum operation (100% load for 8,760 hr/yr) of the fuel burning equipment associated with the coaters; and
- Maximum licensed VOC emissions for the coaters and Ultracast Roll Cleaning process.

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
Boiler #21	173.9	328.5	328.5	3,763.0	1,787.6	2,163.9	178.8
Boiler #22	2.2	2.2	2.2	0.4	15.8	16.6	1.8
Boiler #23	0.9	0.9	0.9	0.2	6.6	7.0	0.7
Technology Center Boiler	0.1	0.1	0.1	–	0.4	0.3	–
MAU #1	0.6	0.6	0.6	–	1.2	1.0	0.1
Engine #1	–	–	–	–	0.4	–	0.1
Engine #2	–	–	–	–	0.4	0.1	–
Engine #3	–	–	–	–	0.2	–	–
Engine #4	–	–	–	–	0.1	–	–
Engine #5	–	–	–	–	0.2	0.4	–
#35 Coater Dryer	1.5	1.5	1.5	–	3.0	2.5	0.2
#2 Coater 4th Zone Dryer	0.9	0.9	0.9	–	2.6	2.1	0.2
#20 Coater 7th Zone Dryer	0.9	0.9	0.9	–	1.7	1.4	0.1
#20 Coater Floatation Dryers	1.8	1.8	1.8	–	3.4	2.9	0.2
Catalytic Incinerator	4.0	4.0	4.0	–	4.4	7.8	–
#2 & #20 Coaters (combined, non-combustion)	–	–	–	–	–	–	139.7
Ultracast Roll Cleaning	–	–	–	–	–	–	2.0
Total TPY	**186.8**	**341.4**	**341.4**	**3,763.6**	**1,828.0**	**2,206.0**	**323.9**

III. AMBIENT AIR QUALITY ANALYSIS

A. Overview

A refined modeling analysis was performed to show that emissions from Sappi will not cause or contribute to violations of National Ambient Air Quality Standards (NAAQS) for SO_2, PM_{10}, $PM_{2.5}$, NO_2, or CO or to Class II increments for SO_2, PM_{10}, $PM_{2.5}$, or NO_2.

Based upon a direct comparison of their respective TPY baseline emissions and current TPY actual emissions, it has been determined that Sappi does not consume SO_2, PM_{10}, $PM_{2.5}$, or NO_2 increment; therefore, a Class II increment analyses was not required.

Since the project's emissions increases do not exceed significant emissions increase levels, it has been determined by the Department that the following additional impact analyses are not required to be evaluated or performed:

- General, Area, and Mobile Source Growth;
- Plants, Soils, and Animals;
- Visibility;
- Deposition; and
- Class I Air Quality Related Values (AQRVs).

B. Model Inputs

The AERMOD refined dispersion model was used to address NAAQS and increment impacts.

All modeling was performed in accordance with all applicable requirements of the Maine Department of Environmental Protection, Bureau of Air Quality and the United States Environmental Protection Agency (USEPA).

A valid 5-year hourly on-site meteorological database was used in the AERMOD refined modeling analysis. Wind data was collected at heights of 10 and 100 meters at the Sappi Westbrook meteorological monitoring site during the 5-year period January 1, 1989, through December 31, 1993. The following parameters and their associated heights were as follows:

TABLE III-1 : Meteorological Parameters and Collection Heights

Parameter	Sensor Height(s)
Scalar Wind Speed	10 meters, 100 meters
Scalar Wind Direction	10 meters, 100 meters
Standard Deviation of Wind Direction	10 meters, 100 meters
Standard Deviation of Vertical Wind Speed	7 meters
Temperature	7 meters, 100 meters

Each year of meteorological data met the 90% data recovery requirement, both singularly and jointly. Missing data from the primary site were substituted with representative data, interpolated, or coded as missing pursuant to USEPA guidance.

In addition, hourly Portland National Weather Service data, from the same time period were used to supplement the primary surface dataset for the required variables (cloud cover and ceiling height) that were not explicitly collected at the Sappi meteorological monitoring site. Concurrent upper-air data from the Portland National Weather Service site were also used in the analysis. Missing cloud cover and/or upper-air data values were interpolated or coded as missing pursuant to USEPA guidance.

All necessary representative micrometeorological surface variables for inclusion into AERMET (surface roughness, Bowen ratio, and albedo) were calculated using AERSURFACE utility program and from procedures recommended by USEPA.

Point-source parameters used in the modeling are listed in Table III-2.

TABLE III-2 : Point Source Stack Parameters

Stack	Stack Base Elevation (m)	Stack Height (m)	GEP Stack Height (m)	Stack Diameter (m)	UTM Easting NAD83 (m)	UTM Northing NAD83 (m)
CURRENT/PROPOSED						
Sappi						
• Boiler #21	13.11	109.70	115.24	3.20	390,910	4,837,849
• Boiler #22	16.15	21.33	33.83	1.31	391,476	4,837,820
• Boiler #23	16.15	21.33	35.10	0.77	391,468	4,837,804
Westbrook Energy Center						
• Combustion Turbine #1	28.96	50.29	79.24	5.49	388,966	4,834,733
• Combustion Turbine #2	28.96	50.29	79.24	5.49	388,955	4,834,765
ecomaine						
• Flue A	12.80	66.45	78.33	1.22	392,421	4,834,499
• Flue B	12.80	66.45	78.33	1.22	392,423	4,834,497

Emission parameters for NAAQS modeling are listed in Table III-3. Emission parameters are based on two maximum license allowed operating configurations.

For the purpose of determining maximum predicted impacts, the following assumptions were used:

- all NO_x emissions were conservatively assumed to convert to NO_2 (USEPA Tier I Method);
- PM_{10} and $PM_{2.5}$ emissions were conservatively assumed to be equal, as data to speciate was not available.

TABLE III-3 : Stack Emission Parameters

Stack	Averaging Periods	SO_2 (g/s)	PM_{10} (g/s)	$PM_{2.5}$ (g/s)	NO_x (g/s)	CO (g/s)	Stack Temp (K)	Stack Velocity (m/s)
Sappi – Scenario 1 – Max East/West								
• Boiler #21	All	129.91	9.46	9.46	94.73	62.25	464.82	24.52
• Boiler #22	All	0.013	0.063	0.063	0.45	0.48	411.48	9.67
• Boiler #23	All	0.005	0.026	0.026	0.19	0.20	431.48	11.58
Sappi – Scenario 2 – Max East								
• Boiler #21	All	60.03	4.85	4.85	35.02	23.01	449.82	6.80
• Boiler #22	All	0.013	0.063	0.063	0.45	0.48	411.48	9.67
• Boiler #23	All	0.005	0.026	0.026	0.19	0.20	431.48	11.58
Westbrook Energy Center								
• Combustion Turbine #1	All	1.51	2.77	2.77	2.27	-	351.00	21.02
• Combustion Turbine #2	All	1.51	2.77	2.77	2.27	-	351.00	21.02
ecomaine								
• Flue A		1.39	0.43	0.43	6.20	-	422.00	30.06
• Flue B	All	1.39	0.43	0.43	6.20	-	422.00	30.06

C. Single Source Modeling Impacts

AERMOD modeling was performed for 15 different Sappi operating scenarios that represented a range of maximum, typical, and minimum boiler loading and fuel-type combinations.

The AERMOD significant impact results for Sappi are shown in Table III-4. Maximum predicted impacts that exceed their respective significance level are indicated in boldface type.

For comparison to the Class II significance levels, the impacts for 1-hour SO_2, 1-hour NO_2, 24-hour $PM_{2.5}$, and annual $PM_{2.5}$ were conservatively based on the maximum High-1st-High predicted values, averaged over all five years of meteorological data. All other pollutants/averaging periods were conservatively based on their maximum High-1st-High predicted values.

No additional refined modeling was required for pollutants that did not exceed their respective significance levels.

TABLE III-4 : Maximum AERMOD Impacts from Sappi Alone

Pollutant	Averaging Period	Max Impact ($\mu g/m^3$)	Receptor UTM E (m)	Receptor UTM N (m)	Receptor Elevation (m)	Class II Significance Level ($\mu g/m^3$)
SO_2	1-hour	**210.11**	390,750	4,838,250	26.55	7.9
	3-hour	**190.46**	390,077	4,837,490	15.35	25
PM_{10}	24-hour	**6.15**	391,530	4,837,710	20.04	5
$PM_{2.5}$	24-hour	**4.81**	391,530	4,837,710	20.04	1.2
	Annual	**0.65**	391,530	4,837,716	19.94	0.2
NO_2	1-hour	**153.24**	390,750	4,838,250	26.55	7.5
	Annual	**5.73**	391,530	4,837,717	19.94	1
CO	1-hour	259.38	390,775	4,838,150	24.79	2,000
	8-hour	80.76	390,760	4,837,500	16.11	500

D. Secondary Formation of $PM_{2.5}$

A $PM_{2.5}$ compliance demonstration must account for both primary $PM_{2.5}$ from a source's direct PM emissions and secondarily formed $PM_{2.5}$ from a source's precursor emissions of NO_x and SO_2. The formation of secondary $PM_{2.5}$ is dependent on the concentrations of precursor and relative species, atmospheric conditions, and the interactions of precursors with other entities such as particles, rain, fog, or cloud droplets.

Since the contribution from secondary formation of $PM_{2.5}$ cannot be explicitly accounted for in AERMOD, the impacts of secondarily formed $PM_{2.5}$ from Sappi were determined using a Tier I analysis following methodologies prescribed in USEPA's *Guidance on the Development of Modeled Emission Rates for Precursors (MERPs) as a Tier 1 Demonstration Tool for Ozone and* $PM_{2.5}$ *under the PSD Permitting Program (April 2019).*

For a Tier I secondary formation assessment, a source uses technically credible empirical relationships between precursor emissions and secondary impacts, based upon USEPA modeling. Specifically, USEPA has performed single-source photochemical modeling to examine the range of modeled estimated impacts of secondary $PM_{2.5}$ formation for different theoretical source types (based on pollutant, stack height and location) for facilities in different geographical locations in the United States.

Sappi estimated the potential impact of its precursor emissions using Equation 2 from USEPA's MERPs guidance, in which a source's impacts are estimated as the product of the relevant hypothetical source air quality impacts relative to emissions, scaled either upwards or downwards to the emission rate of the project itself. Equation 2 is presented below:

$$\textit{Project Impact} = \begin{matrix}\textit{Project}\\ \textit{Emission Rate}\end{matrix} \; X \; \frac{\textit{Modeled impact from hypothetical modeling}}{\textit{Modeled emission rate from hypothetical modeling}}$$

This procedure was followed for both NO_x and SO_2 precursors and the individual contributions summed to achieve a final estimated potential secondary $PM_{2.5}$ concentration, as shown in Table III-5.

TABLE III-5 : Secondary $PM_{2.5}$ from NO_x & SO_2 Precursors

Pollutant	Potential Increase of Precursors (TPY)	Impact/Emissions Ratio ($\mu g/m^3$ / TPY)	Estimated Secondary $PM_{2.5}$ Impacts ($\mu g/m^3$)
NO_x	22.4	0.0001348	0.0030
SO_2	0.3	0.0014218	0.0004
Total Estimated Secondary $PM_{2.5}$ from NO_x and SO_2 precursors			**0.0034**

Using this methodology, the total estimated secondary $PM_{2.5}$ impact due to Sappi's NO_x and SO_2 precursor emissions were predicted to be extremely low (~0.003 $\mu g/m^3$) and are not expected to contribute significantly to the $PM_{2.5}$ NAAQS impacts.

E. Combined Source Modeling Impacts

As indicated in boldface type in Table III-4, other sources not explicitly included in the modeling analysis must be accounted for by using representative background concentrations for the area.

Background concentrations, listed in Table III-6, are derived from representative background data for use in the Southern Maine region.

TABLE III-6 : Background Concentrations

Pollutant	Averaging Period	Background Concentration ($\mu g/m^3$)	Site Name, Location
SO_2	1-hour	11	Deering Oaks, Portland
	3-hour	9	
PM_{10}	24-hour	68	Tukey's Bridge, Portland
$PM_{2.5}$	24-hour	17	Deering Oaks, Portland
	Annual	7	
NO_2	1-hour	39	Deering Oaks, Portland
	Annual	6	

The Department examined other nearby sources to determine if any impacts would be significant in or near Sappi's significant impact area. Due to the location of Sappi, the extent of Sappi's significant impact area for SO_2, PM_{10}, $PM_{2.5}$ and NO_2, and other nearby source's emissions of those same pollutants, the Department has determined that two additional sources would be explicitly included in the combined-source refined modeling: Westbrook Energy Center and ecomaine. Because Sappi's CO impacts were insignificant, no other nearby sources are required to be evaluated for potential inclusion into a combine-source analysis.

The maximum combined-source AERMOD modeled impacts for all sources combined, which were explicitly normalized to the form of their respective NAAQS, were added with conservative background concentrations to demonstrate compliance with NAAQS, as shown in Table III-7.

As calculated in Section D, the total estimated secondarily formed $PM_{2.5}$ due to Sappi's NO_x and SO_2 precursor emissions (~0.003 µg/m^3) was added to the maximum modeled impact to achieve a final value.

Because all pollutant/averaging period impacts using this method meet NAAQS, no further NAAQS modeling analyses need to be performed.

TABLE III-7 : Maximum Combined Source Impacts (µg/m³)

Pollutant	Averaging Period	Max Impact (µg/m^3)	Receptor UTM E (m)	Receptor UTM N (m)	Receptor Elevation (m)	Back-Ground (µg/m^3)	Total Impact (µg/m^3)	NAAQS (µg/m^3)
SO_2	1-hour	164.19	390,800	4,838,425	31.87	11	175.19	196
	3-hour	167.72	390,760	4,837,530	15.79	9	176.72	1,300
PM_{10}	24-hour	5.693*	391,530	4,837,710	20.04	68	73.693*	150
$PM_{2.5}$	24-hour	3.575*	391,530	4,837,717	19.94	17	20.575*	35
	Annual	0.696*	391,530	4,837,717	19.94	7	7.696*	12
NO_2	1-hour	111.93	390,825	4,838,425	29.68	39	150.93	188
	Annual	5.86	391,530	4,837,717	19.94	6	11.86	100

* Final predicted impacts for PM_{10} and $PM_{2.5}$ were adjusted by 0.003 µg/m^3 to account for secondary formation of particulates, as calculated in Section D.

F. Class II Increment

Based upon a direct comparison of their respective TPY baseline emissions and current TPY actual emissions, it has been determined that Sappi does not consume SO_2, PM_{10}, $PM_{2.5}$, or NO_2 increment; therefore, a Class II increment analyses was not required.

G. Summary

In summary, it has been demonstrated that Sappi, in conjunction with other sources, will not cause or contribute to a violation of any SO_2, PM_{10}, $PM_{2.5}$, NO_2, or CO NAAQS.

This determination is based on information provided by the applicant regarding the expected operation of the emission units. 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 Sappi 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.

The Department hereby grants New Source Review License Amendment A-29-77-7-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 NSR License A-29-77-5-A:

(1) **Boilers #22 and #23**

A. Boilers #22 and #23 shall fire only natural gas. [06-096 C.M.R. ch. 115, BACT]

B. Boilers #22 and #23 shall each exhaust through a stack that is at least 70-feet above ground level. [06-096 C.M.R. ch. 115, BACT]

C. Control Equipment

1. Sappi shall operate and maintain LNBs on Boilers #22 and #23 for control of NO_x during all times each boiler is operating. [06-096 C.M.R. ch. 115, BACT]

2. Sappi shall operate and maintain FGR on Boilers #22 and #23 for control of NO_x during all times each boiler is operating except during periods of startup and shutdown. [06-096 C.M.R. ch. 115, BACT]

3. Sappi shall operate and maintain an oxygen trim system on Boilers #22 and #23 for control of CO and VOC during all times the boiler is operating. [06-096 C.M.R. ch. 115, BACT]

D. Emission Limits and Standards

1. Emissions from Boilers #22 and #23 shall each not exceed the following limits. These limits apply at all times (including periods of startup, shutdown, and malfunction). Unless otherwise stated, limits are on a 1-hour block average basis. [06-096 C.M.R. ch. 115, BACT]

Emission Unit	PM (lb/MMBtu)	$PM_{10}/PM_{2.5}$ (lb/MMBtu)	SO_2 (lb/MMBtu)	NO_x (lb/MMBtu)	CO (lb/MMBtu)	VOC (lb/MMBtu)
Boiler #22	0.005	0.005	0.001	0.036	0.038	0.004
Boiler #23	0.005	0.005	0.001	0.036	0.038	0.004

Emission Unit	PM (lb/hr)	$PM_{10}/PM_{2.5}$ (lb/hr)	SO_2 (lb/hr)	NO_x (lb/hr)	CO (lb/hr)	VOC (lb/hr)
Boiler #22	0.50	0.50	0.10	3.60	3.80	0.40
Boiler #23	0.21	0.21	0.04	1.51	1.60	0.17

2. Visible emissions from Boilers #22 and #23 shall each not exceed 10% opacity on a six-minute block average basis. [06-096 C.M.R. ch. 101, § 3(A)(3) and 06-096 C.M.R. ch. 115, BACT]

E. Compliance Demonstration

1. Upon request by the Department, compliance with the particulate matter, NO_x, CO, and VOC emission limits shall be demonstrated through performance testing in accordance with the appropriate test method as approved by the Department. [06-096 C.M.R. ch. 115, BACT]

2. Compliance with the SO_2 limits is based on monthly recordkeeping of the amount of natural gas fired in Boilers #22 and #23 and the most recent tariff sheet showing the sulfur content of the natural gas fired. [06-096 C.M.R. ch. 115, BACT]

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

Boilers #17 and #18 are considered permanently shutdown and any previously issued NSR licenses or license conditions pertaining to these units are considered obsolete and deleted.

The following shall replace the PM_{10} emission limit contained in Condition (k)(5) of Air Emission License A-29-71-C-A/R:

(2) **Boiler #21**

Emissions shall not exceed the following [06-096 C.M.R. ch. 115, BACT]:

Pollutant	lb/MMBtu
PM_{10}	0.08

Compliance shall be demonstrated through performance testing in accordance with 40 C.F.R. Part 60, Appendix A, Method 5, 201, or 201A for filterable PM and Method 202 for CPM (or other methods approved by the Department) upon request by the Department.

The following are New Conditions:

(3) **Boiler #21**

Emissions shall not exceed the following [06-096 C.M.R. ch. 115, § 7]:

Pollutant	lb/hr
PM_{10}	75.0
$PM_{2.5}$	75.0

Compliance shall be demonstrated through performance testing in accordance with 40 C.F.R. Part 60, Appendix A, Method 5, 201, or 201A for filterable PM and Method 202 for CPM (or other methods approved by the Department) upon request by the Department.

(4) If the Department determines that any parameter value pertaining to construction and operation of the proposed 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, Sappi may be required to submit additional information. Upon written request from the Department, Sappi 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)]

DONE AND DATED IN AUGUSTA, MAINE THIS 7th DAY OF DECEMBER, 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: 4/28/2023
Date of application acceptance: 4/28/2023

Date filed with the Board of Environmental Protection:

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

FILED
DEC 07, 2023
State of Maine
Board of Environmental Protection