STATE OF MAINE
DEPARTMENT OF ENVIRONMENTAL PROTECTION

PAUL R. LEPAGE
GOVERNOR

PATRICIA W. AHO
COMMISSIONER

Huhtamaki, Inc.
Kennebec County
Waterville, Maine
A-416-77-2-A

Departmental
Findings of Fact and Order
New Source Review
NSR #2

FINDINGS OF FACT

After review of the air emissions license application, staff investigation reports, and other documents in the applicant's file in the Bureau of Air Quality, pursuant to 38 M.R.S.A., Section 344 and Section 590, the Department finds the following facts:

I. REGISTRATION

A. Introduction

FACILITY	Huhtamaki, Inc.
LICENSE TYPE	06-096 CMR 115, Minor Modification
NAICS CODES	322299
NATURE OF BUSINESS	Molded Pulp Products Manufacturing
FACILITY LOCATION	242 College Avenue, Waterville, Maine

Huhtamaki, Inc. – Waterville is a manufacturing facility that uses recycled newsprint, food board, milk carton stock, and other similar paper materials to produce molded pulp products. Cellulose fibers are mechanically cleaned, then vacuum drawn from liquid slurry onto pre-shaped wire dies, where they are formed, compressed, and dried into finished products. Finished products include, but are not limited to, paper plates, pizza trays, food trays, and other similar molded products. A small portion of the molded products are also laminated with a plastic film.

Huhtamaki has the potential to emit more than 100 tons per year (TPY) of sulfur dioxide (SO_2) and nitrogen oxides (NO_x); therefore, the source is a major source for criteria pollutants. Huhtamaki is not a major source of hazardous air pollutants (HAPs) because it does not have the potential to emit more than 10 TPY of a single HAP or more than 25 TPY of combined HAPs; therefore, the source is an area source for HAPs.

B. New Source Review License Description

Huhtamaki, Inc. (Huhtamaki) was issued Air Emission License A-416-70-A-I on January 14, 2002, permitting the operation of air emission sources associated with their molded pulp products facility. The license was subsequently amended on May 28, 2004 (A-416-70-B-A), and on November 5, 2004 (A-416-70-C-A). A New Source Review (NSR) license was issued to the facility on March 23, 2012 (A-416-77-1-A) to license the firing of either No. 6 fuel oil or natural gas as the primary fuel in Boiler #5.

This NSR license is to include the use of natural gas (NG) as an alternative fuel in Boilers #2 and #3, from either liquefied natural gas (LNG) stored on site or from a natural gas pipeline system currently planned but not yet available in the area.

C. Emission Equipment

The following equipment is addressed in this NSR air emission license:

Fuel Burning Equipment

Equipment	Max. Capacity (MMBtu/hr)	Maximum Firing Rate	Fuel Type, % sulfur	Year of Installation	Stack #
Boiler #2	29.3	32 Mscf/hr [+]	Natural gas	1959	1
		195.3 gal/hour	#6 fuel oil, [*] 1.7% S		
Boiler #3	29.3	32 Mscf/hr [+]	Natural gas	1950	
		195.3 gal/hour	#6 fuel oil, [*] 1.7% S		

[+] based on 1020 BTU/scf, including a 10% increase due to lower fuel use efficiency for natural gas compared to fuel oil.

[*] Propane & Diesel are used for start-up purposes. Additionally, Specification Waste Oil is mixed into the #6 fuel oil tank.

D. Application Classification

The application for modification of Boilers #2 and #3 to fire natural gas in addition to No. 6 fuel oil does not violate any applicable federal or state requirements and does not reduce monitoring, reporting, testing, or record keeping requirements.

This application is being processed under the New Source Review (NSR) licensing provisions contained in *Major and Minor Source Air Emission License Regulations*, 06-096 CMR 115 (as amended). The application includes a Best Available Control Technology (BACT) analysis performed per NSR requirements.

A modification is identified as major or minor by whether or not projected net emissions increases exceed the "Significant Emission Increase" levels as given in *Definitions Regulation*, 06-096 CMR 100 (as amended). Net emission increases are determined by subtracting the average actual emissions of the 24 months preceding the modification (or a 24-month period representative of normal operation) from the projected actual emissions.

In selecting a time period representative of normal operation, it is important to recognize that Boilers #2 and #3 are operated as backup boilers. As such, they have only operated when the primary boiler, Boiler #5, has been unable to meet the steam demands of the manufacturing facility. In the recent past, due to market and economic challenges, production has been lower than normal, and Boiler #5 alone has been sufficient to meet the steam demand. Upon review of historical data, fuel oil fired in Boilers #2 and #3 in the two year span of calendar years 2007 and 2008 reflects a higher production rate which is closer to historic mill operating levels and therefore considered more representative of the boilers' normal operation. Therefore, Huhtamaki has chosen to calculate baseline actual emissions from Boilers #2 and #3 data for the 2007 and 2008 calendar years. All baseline emissions were calculated based on EPA AP-42 emission factors and actual No. 6 fuel use records.

Projected actual emissions were conservatively calculated based on continuous firing of Boiler #2 and Boiler #3 and using a natural gas firing rate of equivalent heat input to the maximum No. 6 fuel oil firing rate plus an additional 10% to compensate for the lower fuel use efficiency of natural gas.

The results of the comparison of baseline actual emissions and projected actual emissions are as follows:

Pollutant	Average Past Actual Emissions 2007-2008 (tons/year)	Projected Actual Emissions (tons/year)	Net Change (tons/year)	Significance Level (tons/year)
PM	3.6	2.1	– 1.5	25
PM_{10}	3.2	2.1	– 1.1	15
SO_2	42.3	0.2	– 42.1	40
NO_x	10.8	43.6	+ 32.8	40
CO	1.0	23.3	+ 22.3	100
VOC	0.0	1.5	+ 1.5	40
CO_2e	5,097	33,056	+27,959	75,000

Note: The above numbers are for Boilers #2 and #3 only. No other equipment at the facility is affected by this NSR license.

This NSR license is determined to be a minor modification to the source under *Minor and Major Source Air Emission License Regulations* 06-096 CMR 115 (as amended) based on the following findings:

- The changes being made are not addressed or prohibited in the existing Part 70 air emission license.
- No net change in tons per year emissions of any pollutant will exceed the significance level, as demonstrated above.
- 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 the requested operation.

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 CMR 100 (as amended). 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 CMR 100 (as amended). BACT is a top-down approach to selecting air emission controls considering economic, environmental, and energy impacts.

B. Project Description

Huhtamaki operates Boilers #2 and #3 for steam and heat to support facility operations when Boiler #5 is offline or unable to meet production demands when operating alone. Both of these boilers are Babcock and Wilcox boilers, Boiler #2 installed in 1959 and Boiler #3 installed in 1950. Each of these two boilers has a capacity of 29.3 MMBtu/hour and fires No. 6 fuel oil, waste oil, propane, and diesel fuel at a maximum rate of 195.3 gallons/hour. Boilers #2 and #3 exhaust through a common stack, Stack #1, with an above ground level (AGL) height of 84 feet. With the modification addressed in this NSR license, these boilers will also be licensed to fire natural gas.

The conversion of Boiler #5 to fire natural gas, licensed in March of 2012 (A-416-77-1-A), included the installation of two 15,000 gallon LNG storage tanks. LNG is delivered by truck and transferred to the storage tanks, then vaporized as needed and conveyed via a fuel line to Boiler #5 for combustion. Natural gas fired in Boilers #2 and #3 will be supplied from the same LNG storage tanks. This project will include the installation of piping connecting Boiler #2 and Boiler

#3 to the existing pipeline supplied by the two LNG storage tanks. The facility plans to operate in this configuration until such time as a natural gas pipeline services the area. No additional air emissions will result from the additional piping installation or operation.

Boilers #2 and #3 are not subject to the New Source Performance Standards (NSPS) 40 CFR Part 60, Subpart Dc, *Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units*, for units greater than 10 MMBtu/hour but less than 100 MMBtu/hour for which construction, modification, or reconstruction is commenced after June 9, 1989. The project does not constitute a modification as defined in 40 CFR Part 60, Subpart B, §60.2 *Definitions* and §60.14 because there is no increase in pound per hour emissions of SO_2 or PM. The only pollutants with projected pound per hour emissions increases over previous license allowed levels are NO_x, CO, VOC, and greenhouse gases (GHG, expressed as carbon dioxide equivalents, CO_2e) which are not pollutants regulated by Subpart Dc.

C. BACT Determination

Under 06-096 CMR 115(4)(A)(4)(d), BACT is applied to all regulated pollutants, fugitive as well as stack emissions, from each emissions unit to be constructed, reconstructed, or modified by a project. The following is a summary of the BACT determination for Boilers #2 and #3, by pollutant.

1. Particulate Matter (PM and PM_{10})

   Units firing fuels with low ash content and high combustion efficiency exhibit low particulate matter emissions. The most stringent PM and PM_{10} control method demonstrated for boilers of this size and type is the use of low ash fuel such as natural gas. The Department finds good combustion controls with a limit of 7.6 lb/MMscf constitutes BACT for PM and PM_{10} emissions from Boilers #2 and #3 firing natural gas.

2. Sulfur Dioxide (SO_2)

   Sulfur dioxide is formed from the oxidation of sulfur in fuel. The options to control SO_2 emissions from fuel combustion include low sulfur fuel and add-on treatment of the combustion exhaust gases.

   Based on review of the RACT/BACT/LAER Clearinghouse (RBLC), EPA's AP-42 database, and other air emission licenses issued by the Department, add-on controls for SO_2 emissions from boilers of similar size firing natural gas were not identified. Due to the inherently low sulfur content of natural gas, additional SO_2 control from natural gas combustion is not economically feasible.

The Department finds good combustion controls with a limit of 0.6 lb/MMscf constitute BACT for SO_2 emissions from Boilers #2 and #3 firing natural gas.

3. Nitrogen Oxides (NO_x)

Formation of nitrogen oxides occurs by three different mechanisms. The formation of thermal NO_x arises from the thermal dissociation and subsequent reaction of nitrogen (N_2) and oxygen (O_2) in the combustion air. Prompt NO_x is formed through the early reactions of nitrogen molecules in the combustion air and hydrocarbon radicals in the fuel. The third type is fuel-bound NO_x.

Options for controlling NO_x emissions from the boiler include combustion control, selective catalytic reduction (SCR), selective non-catalytic reduction (SNCR), flue gas recirculation (FGR), and low-NO_x burners.

Additional control technology for the existing boilers is considered economically infeasible. Review of recent, similar projects did not identify any required add-on controls. Huhtamaki proposed as BACT burners furnished with low-NO_x gas spuds to inject the gas into fuel lean and fuel rich zones, improving combustion and minimizing NO_x emissions.

The Department finds the use of low-NO_x burners and good combustion controls with a limit of 157.5 lb/MMscf constitute BACT for NO_x emissions from Boilers #2 and #3.

4. Carbon Monoxide (CO)

The formation of CO occurs as a result of incomplete combustion of the fuel. Control of CO is accomplished by providing adequate fuel residence time and sufficiently high temperature in the combustion zone to ensure complete combustion. These control factors, however, also tend to result in higher emissions of NO_x. The firing of NG results in low emissions of CO under full load or ideal conditions, although operation at lower loads generally increases emissions because of inefficient combustion.

The CO emission controls that are technologically feasible include combustion control and use of an oxidation catalyst. CO catalytic oxidation reactors operate in a relatively narrow temperature range of 700°F to 1100°F. If boilers were operated in this range, CO emissions could be reduced by up to 90%. At lower temperatures, when CO is typically higher due to inefficient combustion, the CO conversion falls off rapidly; at higher temperatures, damage to the catalyst may occur.

Upon review of the RBLC and recent Maine air emission licenses, no boilers of similar size firing natural gas employing a CO control catalyst were found. Huhtamaki proposes the use of good combustion control as BACT for Boilers #2 and #3.

The Department finds that good combustion controls with a limit of 84 lb/MMscf constitutes BACT for CO emissions from Boilers #2 and #3.

5. Volatile Organic Compounds (VOC)

As with CO, low concentrations of VOCs are emitted from boilers firing natural gas as a result of incomplete combustion of fuel. An oxidation catalyst is an effective control for VOC emissions and can reduce VOC emissions by up to 90%. However, such measures are economically infeasible. Control of VOCs can be accomplished by providing adequate fuel residence time and high temperature in the combustion zone to ensure complete combustion. The facility proposes the use of good combustion control as BACT for Boilers #2 and #3.

The Department finds the use of good combustion controls with a limit of 5.5 lb/MMscf constitutes BACT for VOC emissions from Boilers #2 and #3.

6. Greenhouse Gases (GHG)

Greenhouse gases are considered regulated pollutants as of January 2, 2011, through 'Tailoring' revisions made to EPA's *Approval and Promulgation of Implementation Plans,* 40 CFR Part 52, Subpart A, §52.21 Prevention of Significant Deterioration of Air Quality rule. Greenhouse gases, as defined in 06-096 CMR 100 (as amended), are the aggregate group of the following gases: carbon dioxide, nitrous oxide, methane, hydrofluorocarbons, perfluorocarbons, and sulfur hexafluoride. For purposes of licensing, GHG are calculated and reported as carbon dioxide equivalents (CO_2e).

Emissions of GHG from boilers result from combustion of hydrocarbons in fossil fuels such as No. 6 fuel oil and natural gas. Information on control techniques and measures that are available to mitigate greenhouse gas emissions from boilers similar to Huhtamaki's Boilers #2 and #3 include new burners, operation and maintenance practices to maximize boiler efficiency, fuel switching, and carbon capture and storage. Carbon capture and storage is not a proven technology on a commercial basis and is not economically viable. Switching to natural gas from No. 6 fuel oil as a primary fuel potentially results in emitting 33% less CO_2 on a fuel-to-fuel basis.

Finally, review of the RBLC finds no further control devices or strategies for boilers similar to Boilers #2 and #3 firing natural gas to control CO_2e emissions. Huhtamaki proposes good operation and maintenance practices to maximize boiler efficiency and the firing of natural gas to control GHG emissions from its boilers.

Based on the above information, the Department finds that good operation and maintenance practices to maximize boiler efficiency is BACT for GHG emissions from Boilers #2 and #3 firing natural gas.

D. Emission Limits

Emission rates for Boilers #2 and #3 firing No. 6 fuel oil and specification waste oil are as previously licensed and have not been changed in this NSR license.

Emission rates for Boilers #2 and #3 firing natural gas are based on firing a combined total of 64,000 scf/hour of natural gas in these two boilers and the following factors:

PM/PM_{10} – 7.6 lb/MMscf: AP-42, Table 1.4-2 (date 7/98)
SO_2 – 0.6 lb/MMscf: AP-42, Table 1.4-2 (dated 7/98)
NO_X – 157.5 lb/MMscf: factor provided by burner vendor
CO – 84 lb/MMscf: AP-42, Table 1.4-1 (dated 7/98)
VOC – 5.5 lb/MMscf: AP-42, Table 1.4-2 (dated 7/98)
Opacity – 06-096 CMR 101

The BACT emission limits for Boilers #2 and #3 firing natural gas are the following:

Unit	PM, lb/hr	PM_{10}, lb/hr	SO_2, lb/hr	NO_x, lb/hr	CO, lb/hr	VOC, lb/hr
Boilers #2 and #3 – **combined emissions** (≤ 29.3 MMBtu/hour each) firing natural gas	0.48	0.48	0.04	10.08	5.38	0.35

Opacity - When operating either Boiler #2 or Boiler #3 and firing natural gas, visible emissions from Stack #1 shall not exceed 10% opacity on a six-minute block average basis, except for no more than one six-minute block average in a three-hour period. [06-096 CMR 101 (2)(B)(1)(c)]

When operating both Boiler #2 and Boiler #3 firing natural gas or any of these boilers firing fuel oil, visible emissions from Stack #1 shall not exceed 30% opacity on a six-minute block average basis, except for no more than three six-minute block averages in a three-hour block period. [06-096 CMR 101(2)(B)(5)(i)]

Huhtamaki shall be limited to a total of 553.6 MMscf/year of natural gas fired in Boilers #2 and #3.

Prior to January 1, 2018, the fuel oil fired in Boilers #2 and #3 shall be #6 fuel oil with a maximum sulfur content of 1.7% by weight. Per 38 MRSA §603-A(1) and (2), beginning January 1, 2018, the facility shall fire #6 fuel oil with a maximum sulfur content limit of 0.5% by weight.

E. Periodic Monitoring

Periodic monitoring for Boilers #2 and #3 shall include recordkeeping for each boiler to document both fuel oil use and natural gas use both on a monthly and 12-month rolling total basis.

F. 40 CFR Part 63 Subpart JJJJJJ

If Boilers #2 and #3 are operated as gas-fired boilers, they will not be subject to *National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers Area Sources* (40 CFR Part 63, Subpart JJJJJJ). [40 CFR § 63.11195 (e)] A gas-fired boiler is defined by this Subpart as follows:

> any boiler that burns gaseous fuels not combined with any solid fuels, burns liquid fuel only during periods of gas curtailment, gas supply emergencies, or periodic testing on liquid fuel. Periodic testing firing liquid fuel shall not exceed a combined total of 48 hours during any calendar year. [40 CFR § 63.11237]

Operation of Boilers #2 and #3 outside of these parameters may trigger applicability of 40 CFR Part 63, Subpart JJJJJJ. Records shall be maintained to document operation of Boilers #2 and #3 as gas-fired boilers, as defined, or as otherwise in compliance with the applicable provisions of Subpart JJJJJJ.

Operation of Boilers #2 and #3 such that they do not fit the definition of "gas-fired boiler" given above would cause Boilers #2 and #3 to be considered existing industrial boilers as defined in 40 CFR §63.11237 that are located at or are part of an area source of hazardous air pollutants (HAP), as defined in §63.2. As such, Boilers #2 and #3 may be subject to 40 CFR Part 63, Subpart JJJJJJ. However, this Subpart JJJJJJ is currently under reconsideration by the EPA, and the potential applicability of the Subpart to these units may change, contingent upon the final specifications and requirements of the proposed amendments.

G. Incorporation Into the Part 70 Air Emission License

The requirements in this 06-096 CMR 115 New Source Review license shall apply to the facility upon license issuance. Per *Part 70 Air Emission License Regulations*, 06-096 CMR 140 (as amended), Section 2(J)(2)(c), for a modification that has undergone NSR requirements or been processed through 06-096 CMR 115, the source must apply, within one year of commencing the proposed operations, for an amendment to the Part 70 license to include the NSR license requirements, as provided in 40 CFR Part 70.5.

H. Annual Emissions

1. Fuel Limits and Maximum Annual Emissions

Because emissions are dependent on the fuel being fired, and Huhtamaki wishes to retain licensed capability to fire No. 6 fuel oil and waste oil when natural gas is not available, the facility shall be restricted to the maximum annual emissions from the fuel which gives the highest tons per year quantity for each pollutant. The tons per year of pollutants from natural gas combustion were calculated based on 553.6 MMscf/year total of natural gas fired in Boilers #2 and #3. The tons per year limits of pollutants from No. 6 fuel oil combustion are as previously licensed.

Annual license allowed emissions change only for CO emissions as a result of this NSR license. The resulting annual emission limits for the facility based on a 12-month rolling total are as follows:

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

TPY:	PM	PM_{10}	SO_2	NO_x	CO	VOC
Boilers #2, and #3, combined	16.4	16.4	464.1	119.3	23.3	3.7
Boiler #5	46.7	46.7	415.1	93.3	20.5	1.5
Total	**63.1**	**63.1**	**879.2**	**212.6**	**43.8**	**5.2**

2. Greenhouse Gases

Based on the facility's fuel use limits, the worst case emission factors from AP-42, IPCC (Intergovernmental Panel on Climate Change), and *Mandatory Greenhouse Gas Reporting*, 40 CFR Part 98, and the global warming potentials contained in 40 CFR Part 98, Huhtamaki is below the major source threshold of 100,000 tons of CO_2e per year.

III. AMBIENT AIR QUALITY ANALYSIS

Huhtamaki previously submitted an ambient air quality analysis, as part of Air Emission License A-416-70-A-I issued January 14, 2002, demonstrating that emissions from the facility, in conjunction with all other sources, do not violate ambient air quality standards. An additional ambient air quality analysis is not required for this minor modification.

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 Air Emission License A-416-77-2-A pursuant to the preconstruction licensing requirements of 06-096 CMR 115 and subject to the specific conditions below.

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

SPECIFIC CONDITIONS

(1) **Boilers #2 and #3**

A. Huhtamaki is licensed to fire either No. 6 fuel oil or natural gas as the primary fuel in Boilers #2 and #3.

B. Records shall be maintained to document these boilers as natural gas fired boilers, as defined at 40 CFR § 63.11237, or the facility shall comply with the requirements of 40 CFR Part 63, Subpart JJJJJJ, as appropriate.

C. Fuel Sulfur Content
   1. Until December 31, 2012, the sulfur content of any #6 fuel oil fired shall not exceed 2.0% by weight. [06-096 CMR 106]
   2. Beginning January 1, 2018, any #6 fuel oil fired in Boilers #2 and #3 shall not exceed a maximum sulfur content limit of 0.5% by weight. [38 MRSA §603-A(1) and (2)]

D. Natural gas use in Boilers #2 and #3 shall not exceed 553.6 MMscf/year. Compliance shall be demonstrated by fuel records from the supplier showing the quantity and type of the fuel used. Records of annual fuel use shall be kept on a monthly and 12-month rolling total basis. [06-096 CMR 115, BPT]

E. Emissions from Boilers #2 and #3 shall not exceed the following when firing natural gas as the primary fuel in both boilers [06-096 CMR 115, BPT]:

Emission Unit	PM (lb/hr)	PM_{10} (lb/hr)	SO_2 (lb/hr)	NO_x (lb/hr)	CO (lb/hr)	VOC (lb/hr)
Boilers #2 and #3, combined	0.48	0.48	0.04	10.08	5.38	0.35

When operating either Boiler #2 or Boiler #3 and firing natural gas, visible emissions from Stack #1 shall not exceed 10% opacity on a six-minute block average basis, except for no more than one six-minute block average in a three-hour period. [06-096 CMR 101 (2)(B)(1)(c)]

When operating both Boiler #2 and Boiler #3 firing natural gas or any combination of boilers firing fuel oil, visible emissions from Stack #1 shall not exceed 30% opacity on a six-minute block average basis, except for three six-minute block averages in a three-hour block period. [06-096 CMR 101(2)(B)(5i)]

(2) **Incorporation into the Part 70 License**

Huhtamaki shall submit an application to incorporate this NSR license into the Part 70 air emission license no later than 12 months from commencement of the requested operation. [06-096 CMR 140, Section 2(J)(2)(c)]

DONE AND DATED IN AUGUSTA, MAINE THIS 19th DAY OF September , 2012.

DEPARTMENT OF ENVIRONMENTAL PROTECTION

BY: Melanie Loyzim for
PATRICIA W. AHO, COMMISSIONER

PLEASE NOTE ATTACHED SHEET FOR GUIDANCE ON APPEAL PROCEDURES

Date of initial receipt of application: August 13, 2012
Date of application acceptance: August 16, 2012

Date filed with the Board of Environmental Protection:

This Order prepared by Jane Gilbert, Bureau of Air Quality.

Filed
SEP 20 2012
State of Maine
Board of Environmental Protection