STATE OF MAINE
DEPARTMENT OF ENVIRONMENTAL PROTECTION

PAUL R. LEPAGE
GOVERNOR

PATRICIA W. AHO
COMMISSIONER

S. D. Warren Company	**Departmental**
Somerset County	**Findings of Fact and Order**
Skowhegan, Maine	**New Source Review**
A-19-77-6-A	**NSR # 6**

After review of the air emissions license minor modification 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	S. D. Warren Company (SDW)
LICENSE TYPE	06-096 CMR 115, Minor Modification
NAICS CODES	322121
NATURE OF BUSINESS	Pulp and Paper Mill
FACILITY LOCATION	1329 Waterville Road, U.S. Route 201 Skowhegan, Maine

B. Amendment Description

S.D. Warren Company (SDW) has submitted an amendment application to allow natural gas to be fired in No. 2 Power boiler which will include an upgrade to the boiler steam desuperheater system. The upgrade to the steam desuperheater system is needed to fire natural gas but as a result will also allow SDW to increase their biomass burn rate by up to 10,000 wet tons/year.

C. Emission Equipment

The following equipment is addressed in this air emission license:

Fuel Burning Equipment

Equipment	Maximum Capacity (MMBtu/hr)	Maximum Firing Rate	Fuel Type	Stack #
No. 2 Power Boiler	1300	1.275 million scf/hr	Natural Gas or a combination of gas with No. 6 fuel oil*, No. 2 fuel oil, used oil, biomass, TDF, waste paper, waste water treatment plant sludge, kraft condensates, LVHC gases, HVLC gases, solid oily waste, non-hazardous waste solvent rags	2
LNG fired vaporizer	8	7,843 scf/hr	Natural Gas	

* - the fuel oil, including used oil, shall not exceed a maximum sulfur content of 2.5% by weight.

D. Application Classification

The application for SDW does not violate any applicable federal or state requirements and does not reduce monitoring, reporting, testing or record keeping. This application does require a Best Available Control Technology (BACT) analysis performed per New Source Review.

Additionally, the modification of a major source is considered a major modification based on whether or not expected emissions increases exceed the "Significant Emission Increase Levels" as given in *Definitions Regulation*, 06-096 CMR 100 (as amended).

The emission increases are determined by subtracting the average actual emissions of the 24 months preceding the modification (or representative 24 months) from the projected future actual emissions. The total emission calculation table includes emission results from the replacement of oil with natural gas and the biomass burn rate increase by 10,000 wet tons/year resulting from the desuperheater upgrades required for natural gas conversion.

The results are as follows:

Pollutant	Average Past Actual Emissions 2010 & 2011 (ton/year)	Projected Future Actual Emissions (ton/year)	Net Change (ton/year)	Significance Level (ton/year)
PM	30.7	30.88	0.18	25
PM_{10}	30.7	30.88	0.18	15
SO_2	80.7	24.46	-56.24	40
NO_x	502.9	515.20	12.3	40
CO	598.7	607.40	8.7	100
VOC	5.5	6.70	1.0	40
CO_2e	580,781	559,390	-21,391	75,000

Note: The above numbers are for the No. 2 Power Boiler only. None of the other equipment at the facility is affected by this amendment.

The following assumptions were made in calculating these numbers:

1) natural gas replaces all actual No. 6 and No. 2 fuel oil burned resulting in an annual average natural gas usage of 555,608 MMBtu/yr i.e. ~63 MMBtu/hr average

2) natural gas and No. 6 oil current and projected future emissions were calculated using AP-42 emission factors

3) control efficiencies of 99% for PM and 90% for SO_2 were used with the natural gas and No. 6 oil current and projected future emissions

4) the calculations include an 8 MMBtu/hr LNG fired vaporizer

5) the facility's Continuous Emission Monitoring system results and state's emission factors were used in estimating the current and projected future biomass emissions.

The expected emissions changes are below the significant emission increase levels therefore, this amendment is determined to be a minor modification under *Minor and Major Source Air Emission License Regulations* 06-096 CMR 115 (as amended) since the changes being made are not addressed or prohibited in the Part 70 air emission license. An application to incorporate the requirements of this amendment 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. BACT is a top-down approach to selecting air emission controls considering economic, environmental, and energy impacts.

Project Description

Biomass is the primary fuel in the boiler and No. 6 oil is currently used as needed to meet steam demands, and to stabilize boiler operations in the event there is a reduction in or a loss of the biomass supply. S.D. Warren proposes to use natural gas during times when No. 6 fuel oil would be used. It is expected that natural gas will replace essentially all of the oil, however the boiler will retain the capacity to fire oil in addition to natural gas if needed. The mill proposes to fire natural gas in the No. 2 Power Boiler by installing up to eight gas burners in the 4 corners of the boiler above the existing No. 6 oil burners. A gas fuel train, flow meters, gas igniters and gas firing system controls will also be installed as part of the conversion project.

No. 2 Power Boiler was manufactured by Combustion Engineering and has a maximum heat input capacity of 1300 MMBtu/hr. The boiler is licensed to fire No. 6 oil, No. 2 oil, used oil, Tire Derived Fuel (TDF), biomass, bark, waste paper, wastewater treatment plant sludge, Low Volume, High Concentration (LVHC) gases, and High Volume Low Concentration (HVLC) gases. The No. 6 fuel oil, including used oil, is licensed for a maximum sulfur content of 2.5% by weight.

The No. 2 Power Boiler is equipped with the following air emissions control equipment: 225 Baron Industries cyclone separators and a Research Cottrell two-chamber, three field per chamber electrostatic precipitator (ESP) to control particulate matter emissions, a selective non-catalytic reduction system (SNCR) for control of nitrogen oxide emissions, an over-fired air system for control of carbon monoxide and volatile organics compound emissions and an AirPol spray tower wet scrubbing system utilizing either soda ash or caustic solution as the scrubbing liquid to control sulfur dioxide emissions.

Natural gas will be supplied to the mill by either a natural gas pipeline or by using a liquefied natural gas system.

Natural gas pipeline:

The mill anticipates that a natural gas pipeline may be constructed in the future to which the mill will have access. Should pipeline gas become available, the No. 2 Power Boiler gas burner system will have the capability to support full load firing capacity on natural gas without the use of auxiliary fuels.

The delivery of gas from a pipeline will require a gas pressure reduction station to reduce the pressure of the gas from the pipeline pressure to a pressure that will be used in the boiler. It is uncertain whether the pressure reduction station will be located on mill property.

Liquefied Natural Gas:

The installation of a liquefied natural gas unloading system on mill property to supply natural gas to the No. 2 Power Boiler is also being considered. If a liquefied natural gas system is installed, the proposed system will have an evaporative capacity of up to 400 MMBtu/hr. The liquefied natural gas unloading system will be comprised of storage tanks, a truck unloading station, a heated vaporizer and ambient vaporizers. The ambient vaporizers use ambient heat to evaporate the liquid gas. The heated vaporizer uses a gas burner which combusts approximately 2% of the liquid gas it is vaporizing. The heated vaporizer's maximum burn rate will be approximately 8 MMBtu/hr. By using liquefied natural gas, the mill expects to replace 95% of the oil currently burned. This is because the limited capacity of the heated evaporator (400 MMBtu/hr) will not meet the occasional higher firing demands.

Heat input from the natural gas vaporizer was included in the emission calculations. S.D. Warren does not propose to provide emissions control equipment on this vent, due to the small size of the vaporizer, the clean burning nature of the fuel, and the relative costs to provide any pollution control to this small unit.

Upgrade to the No. 2 Power Boiler's Steam Desuperheater System

A boiler model was run on the No. 2 Power Boiler to see how the burning of natural gas will affect the boiler. The model indicated that burning natural gas will result in higher upper furnace temperatures. This will result in additional attemperating water needed in the superheater section to desuperheat the steam. The attemperating water comes from steam that is currently condensed by boiler feed water in the sweet water condenser. Because feed water is used to condense more steam, the temperature difference of feed water increases. The hotter feed water entering the steam drum, reduces the temperature differential between the feed water entering the steam drum and the steam drum saturation temperature. A reduction in this temperature differential can negatively affect the water circulation through the boiler. Based on the modeling results, a desuperheater upgrade will be required to maintain this temperature differential as part of the natural gas conversion project.

Similarly, during the winter months, combustion of cooler and wetter biomass also tends to shift the heat released to the upper sections of the furnace. This also reduces the temperature differential between the steam drum and feed water entering the drum. Currently, when this differential reaches approximately 50°F, biomass firing rates are reduced. The upgrade to the steam desuperheating system will allow the boiler to maintain biomass firing rates when in the past biomass firing rates had to be reduced to maintain this temperature differential. The annual increase in biomass firing is estimated to be less than 10,000 wet tons/year.

B. Federal Regulations

1. New Source Performance Standards (NSPS) – Project Applicability:
   SDW proposes that the addition of natural gas in the boiler does not constitute a modification of the boiler as defined by the NSPS regulations.

   No. 2 Power Boiler was installed in 1989 and is subject to NSPS 40 CFR Part 60, Subpart Db and is therefore not subject to Subpart D.

   The Department has determined that adding natural gas firing capability to the No. 2 Power Boiler is not considered a modification for NSPS purposes based on the following: the conversion to natural gas will reduce NO_x, PM, and SO_2 emission rates and since the boiler already fires biomass at higher rates when the moisture content is lower, there will be no increase in short term emissions rates due to the desuperheater system upgrade. Therefore, this project in its entirety does not constitute a modification as defined by EPA's New Source Performance Standards found in 40 CFR Part 60, Subpart Db.

2. National Emission Standards for Hazardous Air Pollutants (NESHAP):
   The allowance to fire natural gas in No. 2 Power Boiler does not change the status of the boiler as an existing source for the purposes of the current applicable regulations under 40 CFR Part 63. The additional fuel is not considered a change which would make the unit either a new or reconstructed source.

C. Best Available Control Technology (BACT)

1. Particulate Matter

Available alternatives for control of particulate matter emissions from sources firing a wide range of fuels similar to No. 2 Power Boiler include wet scrubbers, fabric filters, cyclone separators, and ESP's. The most stringent emission levels have been achieved on this type of boiler equipped with cyclone separators in combination with ESP's or fabric filters. Fabric filters are not in common use on wood fired boiler because of concern for potential fire hazards. The cyclone separators and the ESP used on the No. 2 Power Boiler achieve an emission level of 0.03 lb/MMBtu, a level which has previously been determined to be BACT for this unit. Natural gas firing results in very low PM emissions and thus the use of this fuel in No. 2 Power Boiler as replacement for fuel oil firing will result in lower PM emissions from this boiler.

The Department finds that utilizing the current control devices and PM emission limits are BACT.

2. Sulfur Dioxide

The No. 2 Power Boiler is subject to NSPS Subpart Db which requires a 90% reduction in SO_2 emissions. S.D. Warren employs a spray tower wet scrubber for this purpose. The Department has previously determined that the unit's current emission limit of 0.27 lb/MMBtu achieved using the scrubber and a maximum oil sulfur content of 2.5% is BACT for this unit. As the sulfur content of natural gas is quite low, the use of this fuel in the boiler will result in lower SO_2 emissions than currently licensed.

The Department finds that the current SO_2 emission controls and emission limits on the No. 2 Power Boiler represents BACT.

3. Nitrogen Oxides

The No. 2 Power Boiler achieves a 0.2 lb/MMBtu emission limit for NO_x through the use of a Selective Non-Catalytic Reduction (SNCR) system. The combination of this control technology and emission limit has been determined to be BACT. NO_x emissions from natural gas firing are expected to be equivalent or less than emission from firing the current fuel mix. There are no alternatives available for combination fuel fired boilers that provides better control of NO_x emissions than SNCR.

The Department finds that the current NO_x emission controls on the unit are considered to be BACT. The NO_x emission limits on the No. 2 Power Boiler are equal to or less than the NO_x emission limits on the other combination boilers at pulp and paper mills in Maine.

4. Carbon Monoxide (CO) and Volatile Organic Compounds (VOC)

   BACT for firing natural gas in a power boiler is the use of good combustion control and overfire air. These two options are the only available alternatives for the control of CO and VOC emissions from combination boilers. CO emissions from natural gas firing are expected to be lower than the current fuel mix.

   The Department finds that good combustion control and use of overfire air are considered BACT for controlling CO and VOC.

5. Greenhouse gases

   Greenhouse gas (GHG) emissions result from the oxidation of organic compounds in the fuel to CO_2 and, to a lesser extent, methane and nitrous oxide. S.D. Warren found no listing in EPA's RACT/BACT/LAER Clearinghouse for controls or limits on combustion sources for GHGs. S.D. Warren also reviewed EPA's guidance document entitled "PSD and Title V Permitting Guidance for Greenhouse Gases" which states that "inherently lower emitting processes or practices should be evaluated as part of the BACT assessment for GHG". In this regard, the use of natural gas rather than fuel oil in the No. 2 Power Boiler will result in a reduction in annual GHG emissions from the unit due to the lower GHG emissions potential associated with natural gas. As there are no other alternative that have been demonstrated to provide a great degree of GHG emissions reduction, S.D. Warren concludes that the use of natural gas to replace fuel oil can be considered to be representative of BACT for GHG.

   The Department finds that employment of energy efficiency measures, such as adding the capability of firing natural gas, and maintaining good combustion practices represents BACT for GHG emissions from the No. 2 Power Boiler.

D. Incorporation into the Part 70 Air Emission License

The requirements in this 06-096 CMR 115 New Source Review amendment shall apply to SDW upon amendment 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, SDW must then apply for an amendment to the Part 70 license within one year of commencing the proposed operations as provided in 40 CFR Part 70.5.

E. Annual Emissions

No licensed emission increases are occurring as a result of this amendment.

III. AMBIENT AIR QUALITY ANALYSIS

S.D. Warren previously submitted an ambient air quality analysis 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 amendment.

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-19-77-6-A pursuant to the preconstruction licensing requirements of 06-096 CMR 115 and subject to the standard and special 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) No. 2 Power Boiler

A. Natural Gas may be fired in the No. 2 Power Boiler [06-096 CMR 115, BACT]

B. S.D. Warren shall maintain records of the amount of natural gas fired in No. 2 Power Boiler, on a monthly and 12 month total basis. [06-096 CMR 115, BACT]

C. S.D. Warren shall ensure that No. 2 Power Boiler is operated and maintained in a manner consistent with good combustion practices such that applicable emission limits are met. [06-096 CMR 115, BACT]

D. Emission limits established in Air Emission License A-19-70-A-I for the firing of multiple fuels in the No. 2 Power Boiler shall remain in effect when natural gas is being fired in the unit. [06-096 CMR 115, BACT]

(2) LNG Vaporizer

A. Fuel
The LNG fired vaporizer shall fire only natural gas. Total fuel use for the vaporizer shall be kept on a calendar year total basis.
[06-096 CMR 115, BACT]

B. Emissions shall not exceed the following:

Emission Unit	Pollutant	lb/MMBtu	Origin and Authority
LNG Vaporizer	PM	0.05	06-096 CMR 115, BACT

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

Emission Unit	PM (lb/hr)	PM_{10} (lb/hr)	SO_2 (lb/hr)	NO_x (lb/hr)	CO (lb/hr)	VOC (lb/hr)
LNG Vaporizer	0.4	0.4	0.005	0.78	0.66	0.04

D. Visible emissions from the LNG fired vaporizer shall not exceed an opacity of 10% opacity on a six (6) minute block average, except for no more than one (1) six (6) minute block average in a continuous 3-hour period.
[06-096 CMR 101]

(3) S.D. Warren shall submit an application to incorporate this amendment 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 1st DAY OF June, 2012.

DEPARTMENT OF ENVIRONMENTAL PROTECTION

BY: Melanie [illegible] for
PATRICIA ~~W. AHO~~, COMMISSIONER

PLEASE NOTE ATTACHED SHEET FOR GUIDANCE ON APPEAL PROCEDURES

Date of initial receipt of application: 3/30/2012
Date of application acceptance: 4/6/2012

Date filed with the Board of Environmental Protection:
This Order prepared by Lisa P. Higgins, Bureau of Air Quality.

Filed
JUN - 4 2012
State of Maine
Board of Environmental Protection