



Mailed  
UPS Tracking Number  
1Z5R86A70193889029

December 19, 2007

Alan Newman  
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Air Quality Program  
P.O. Box 47600  
Olympia, WA 98504-7600

Subject: Regional Haze Best Available Retrofit Technology (BART) Technical Analysis

Dear Mr. Newman:

Phyllis Baas, Section Head of WA Ecology Air Program issued Administrative Order #5072 to Port Townsend Paper Corporation on August 24, 2007. This order was amended and reissued on October 2, 2007. The amended order requires our company to comply with WAC 173-400-151 and orders us "to develop and submit a BART technical analysis for your facility."

In response to that order, we submit our Best Available Retrofit Technology Applicability Analysis and Determination Report. We consider this the complete response needed to fulfill the requirement of the Amended Administrative Order #5072 and would appreciate notification that the order is now closed.

Thank you for your guidance through this process. Please direct any technical questions regarding the analysis to Nancy Rogerson (360-379-2231) or myself (360-379-2112).

Sincerely,

Eveleen Muehlethaler  
VP - Assistant Mill Manager  
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Enclosure

cc: Robert Carruthers, Industrial Section, Department of Ecology

**BEST AVAILABLE RETROFIT TECHNOLOGY APPLICABILITY ANALYSIS AND  
DETERMINATION REPORT  
PORT TOWNSEND PAPER CORPORATION ■ PORT TOWNSEND, WA**

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**APPENDIX A**

**APPENDIX B**

**APPENDIX C**

**APPENDIX D**

**APPENDIX E**

## 1. EXECUTIVE SUMMARY

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This BART Applicability and Determination Analysis Report summarizes PTPC's determination that the PTPC Mill is subject to BART and provides a BART determination analysis as required. The facility does not cause or contribute to visibility impairment at the following Class I areas: Alpine Lakes Wilderness Area, Glacier Peak Wilderness Area, Goat Rocks Wilderness Area, Mount Adams Wilderness Area, Mount Rainier National Park, North Cascades National Park, and Pasayten Wilderness Area or at the Columbia River Gorge National Scenic Area. PTPC's BART applicability analysis demonstrates that the BART-eligible units at the mill may cause or contribute to visibility impairment at the Olympic National Park Class I area. Therefore, a BART determination analysis is conducted for the mill.

The BART Determination, based on engineering analyses of the technical and economic feasibility of available control technology alternatives and net visibility improvement analyses conducted to quantify the visibility improvement attributable to each feasible control alternative, demonstrates that BART represents the following control strategies:

### **No.10 Power Boiler**

- NO<sub>x</sub>: continued use of inherent staged combustion practices
- PM<sub>10</sub>: continued use of existing multiclone and venturi scrubber
- SO<sub>2</sub>: continued use of existing wet scrubber, which controls the SO<sub>2</sub> captured in the alkaline fly ash

### **Recovery Furnace**

- NO<sub>x</sub>: continued use of existing staged combustion practices
- PM<sub>10</sub>: continued use of existing dry ESP
- SO<sub>2</sub>: good operating practices, including minimization of fuel oil firing

### **Smelt Dissolving Tank**

- NO<sub>x</sub>: not applicable because the Smelt Dissolving Tank is not a source of NO<sub>x</sub>
- PM<sub>10</sub>: continued use of existing venturi scrubber
- SO<sub>2</sub>: continued use of existing venturi scrubber

### **Lime Kiln**

- NO<sub>x</sub>: good operating practices
- PM<sub>10</sub>: continued use of existing venturi scrubber
- SO<sub>2</sub>: continued use of existing venturi scrubber

## 2. INTRODUCTION

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Port Townsend Paper Corporation (PTPC) operates a kraft pulp and paper mill (PTPC Mill) in Port Townsend, WA. The PTPC Mill is a major source of air emissions and operates under a Title V Air Operating Permit, WA 000092-2, issued by the Washington Department of Ecology (Ecology). The facility is considered eligible to be regulated under the Best Available Retrofit Technology (BART) provisions of the Regional Haze Rule.

PTPC's evaluation of BART-eligibility and the modeling methods used to determine applicability of BART as described in this report are consistent with the following guidance:

- U.S. EPA, "Regional Haze Regulations and Guideline for Best Available Retrofit Technology (BART) Determinations," *Federal Register* Volume 70, Number 128, July 6, 2005.
- U.S. EPA, *Interagency Workgroup on Air Quality Modeling (IWAQM) Phase 2 Summary Report* (EPA-454/R-98-019), December 1998.
- U.S. EPA, *Guideline on Air Quality Models*, 40 CFR Part 51, Appendix W (Revised, November 9, 2005).
- Washington State Department of Ecology (Ecology), Washington, Oregon, and Idaho: *Protocol for the Application of the CALPUFF Modeling System Pursuant to the Best Available Retrofit Technology (BART) Regulation (BART Modeling Protocol)*, October 11, 2006.
- Letter from Sarah Rees, Ecology, to Matt Cohen, Heller Ehrman, LLP on behalf of the Coalition of BART Sources, responding to Regional Haze Modeling Questions, January 4 and January 22, 2007.
- Meeting between Alan Newman, Ecology; Clint Bowman, Ecology; Alice McConaughy, PTPC; Aaron Day, Trinity Consultants; Ryan Gesser, Trinity Consultants; and Kirsten Rollay, Trinity Consultants, June 4, 2007.

### 2.1 OVERVIEW OF REGIONAL HAZE RULE AND BART REQUIREMENTS

The Regional Haze Rule requires that major sources of visibility-affecting pollutants belonging to one or more of 26 specific industrial source categories evaluate BART if the source was "in existence" (i.e., built or reconstructed) before August 7, 1977 and began operation after August 7, 1962. Such sources are termed "BART-eligible sources." Major sources of visibility-affecting pollutants have the potential to emit 250 tons per year (tpy) of one or more of oxides of nitrogen (NO<sub>x</sub>), sulfur dioxide (SO<sub>2</sub>), and particulate matter less than 10 micrometers in aerodynamic diameter (PM<sub>10</sub>). Hereafter, the "BART-eligible source" is taken to mean the collection of sources at a facility in existence during the relevant time period within one or more BART source categories that has potential emissions of one or more visibility-affecting pollutants in excess of 250 tpy. The BART-eligible source may include multiple emission units, but need not include the entire facility.

### 2.1.1 DETERMINATION OF BART-ELIGIBILITY

The U.S. EPA BART guidelines define the following three steps for determining which sources at a facility are BART-eligible:

1. Identify the emission units in the BART source categories.
2. Identify the start-up dates of those units.
3. Compare potential emissions to the 250 tpy cutoff.

Kraft pulp mills are one of the listed source categories, and include pulp and paper manufacturing operations that are considered to be part of major Standard Industrial Classification 26 – Paper and Allied Products. Industrial boilers greater than 250 million British thermal units per hour (MMBtu/hr) in heat input capacity are also considered a listed BART-eligible source category. The collection of emission units known as the “BART-eligible source” has potential emissions of greater than 250 tpy of NO<sub>x</sub>, SO<sub>2</sub>, and PM<sub>10</sub>, which are visibility-affecting pollutants. Specific information about these emission units is provided in Section 3 of this BART Report.

### 2.1.2 ASSESSMENT OF CONTRIBUTION TO VISIBILITY IMPAIRMENT AND BART APPLICABILITY

A common modeling protocol has been developed for BART-eligible sources in Idaho, Oregon, and Washington as a combined effort between Idaho Department of Environmental Quality (IDEQ), Oregon Department of Environmental Quality (ODEQ), and Washington Department of Ecology (Ecology). The three agencies also collaborated to develop a consistent three-year meteorological dataset for the three states and surrounding areas for use by state regulatory agencies and BART-eligible sources. The final *Modeling Protocol for Washington, Oregon, and Idaho: Protocol for the Application of the CALPUFF Modeling System Pursuant to the Best Available Retrofit Technology (BART) Regulation (BART Modeling Protocol)* issued on October 11, 2006, adopts the U.S. EPA’s BART Guidelines and prescribes modeling techniques and data resources to conduct BART applicability modeling as well as the BART determination modeling (if required for a particular facility).

As described in detail in Section 6, a refined modeling analysis is conducted for impacts at Olympic National Park. This refined analysis includes several adjustments to the methods provided in the *BART Modeling Protocol*. The specific changes are detailed in Sections 6.1 and 6.2. The refined modeling analysis more accurately represents the background ammonia concentration for the area including and between PTPC and Olympic National Park. As well, the revised equation for calculating light extinction coefficients is used. The results of the refined modeling analysis more accurately represent actual visibility impacts due to emissions from PTPC at Olympic National Park.<sup>1</sup> This refined analysis is also applied for the BART Determination analyses presented in Section 12.

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<sup>1</sup> The refined analysis, including the use of the 0.5 ppb ammonia background, of the ammonia limiting method, and of the new IMPROVE algorithm as described in this section, was discussed and agreed upon with Ecology during a

A BART-eligible source is determined to be subject to BART if the source causes or contributes to visibility impairment at a federally protected Class I area. Causation is defined as a single-source impact of 1.0 deciviews (dv) or more and contribution is defined as a single-source impact of 0.5 dv or more, each evaluated on a 24-hour average basis. The deciview is a metric used to represent normalized light extinction attributable to visibility-affecting pollutants. To determine whether a BART-eligible facility causes or contributes to visibility impairment, U.S. EPA guidance requires the use of an air quality model, specifically recommending the CALPUFF modeling system, to quantify the impacts attributable to a single BART-eligible source. Because contribution to visibility impairment is sufficient cause to require a BART determination, 0.5 dv is the critical threshold for assessment of BART applicability.

Regional haze is quantified using the light extinction coefficient ( $b_{ext}$ ), which is expressed in terms of the haze index expressed in dv. The haze index ( $HI$ ) is calculated as shown in the following equation.

$$HI = 10 \ln \left( \frac{b_{ext}}{10} \right)$$

The impact of a BART-eligible source is determined by comparing the  $HI$  attributable to a source relative to estimated natural background conditions. The background extinction coefficient  $b_{ext, background}$  is affected by various chemical species and the Rayleigh scattering phenomenon and can be calculated as shown in the following equation.

$$b_{ext, background} \text{ (Mm}^{-1}\text{)} = b_{SO_4} + b_{NO_3} + b_{OC} + b_{Soil} + b_{Coarse} + b_{ap} + b_{Ray}$$

where,

$b_{SO_4} = 3[(NH_4)_2SO_4]f(RH)$	$[(NH_4)_2SO_4]$ denotes the ammonium sulfate concentration
$b_{NO_3} = 3[NH_4NO_3]f(RH)$	$[NH_4NO_3]$ denotes the ammonium nitrate concentration
$b_{OC} = 4[OC]$	$[OC]$ denotes the concentration of organic carbon
$b_{Soil} = 1[Soil]$	$[Soil]$ denotes the concentration of fine soils
$b_{Coarse} = 0.6[Coarse Mass]$	$[Coarse Mass]$ denotes the concentration of coarse dusts
$b_{ap} = 10[EC]$	$[EC]$ denotes the concentration of elemental carbon
$b_{Ray} = \text{Rayleigh Scattering (10 Mm}^{-1}\text{ by default)}$	Rayleigh Scattering is scattering due to air molecules
$f(RH) = \text{Relative Humidity Function}$	
$[ ] = \text{Concentration in } \mu\text{g/m}^3$	

Values for the parameters listed above specific to the natural background conditions at the Class I areas considered in this analysis are provided on an annual average basis in the U.S. EPA's *Guidance for Estimating Natural Visibility Conditions under the Regional Haze*

*Rule.*<sup>2</sup> More detailed information about the natural background conditions particular to the Class I areas potentially affected by the PTPC Mill is provided in Section 4.5 of this report.

Particulate species that affect visibility include coarse particulate matter (PMC), fine particulate matter (PMF), and elemental carbon (EC). Precursors to secondary organic aerosols (SOA) and fine particulate matter such as SO<sub>2</sub> and NO<sub>x</sub> also contribute to visibility impairment. The extinction coefficient due to emissions of visibility-affecting pollutants from a single BART-eligible source  $b_{ext,source}$  is predicted using an air quality model. The extinction due to the BART-eligible source is calculated as shown in the following equation.

$$b_{ext,source} (Mm^{-1}) = b_{SO_4} + b_{NO_3} + b_{PMC} + b_{PMF} + b_{SOA} + b_{EC}$$

where,

$b_{SO_4} = 3[(NH_4)_2SO_4]f(RH)$	$[(NH_4)_2SO_4]$ denotes the ammonium sulfate concentration
$b_{NO_3} = 3[NH_4NO_3]f(RH)$	$[NH_4NO_3]$ denotes the ammonium nitrate concentration
$b_{SOA} = 4[SOA]$	$[SOA]$ denotes the concentration of secondary organic aerosols (OC)
$b_{PMF} = 1[PMF]$	$[PMF]$ denotes the concentration of fine PM (soil)
$b_{PMC} = 0.6[PMC]$	$[PMC]$ denotes the concentration of coarse PM
$b_{EC} = 10[EC]$	$[EC]$ denotes the concentration of elemental carbon
$f(RH)$ = Relative Humidity Function	
$[ ]$ = Concentration in $\mu g/m^3$	

As described in the IWAQM Phase 2 Report, the change in visibility for the BART applicability analysis is compared to background conditions. The metric used for this comparison is usually the change in deciview ( $\Delta dv$ ) from a “clean” background condition. The delta-deciview ( $\Delta dv$ ) value is calculated from the source’s contribution to extinction,  $b_{ext,source}$ , and the background extinction,  $b_{ext,background}$ , with the following equation.

$$\Delta dv = 10 \ln \left[ \frac{(b_{ext,background} + b_{ext,source})}{b_{ext,background}} \right]$$

### 2.1.3 POTENTIALLY AFFECTED CLASS I AREAS

Following methods described in the *BART Modeling Protocol*, PTPC has performed modeling to determine whether BART-eligible operations at the PTPC Mill contribute to visibility impairment at any Class I areas. The *BART Modeling Protocol* specifies that all Class I areas within 300 km of a BART-eligible source must be evaluated to determine whether the source contributes to visibility impairment. Table 2-1 summarizes the distances separating the PTPC Mill from potentially affected Class I areas in Washington, Oregon, Idaho, and adjacent states

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<sup>2</sup> U.S. EPA, *Guidance for Estimating Natural Visibility Conditions Under the Regional Haze Rule*, Table 2-1, Attachment A, September 2003, EPA-454/B-03-005.

within 300 km of the PTPC Mill. Consistent with the *BART Modeling Protocol*, only those Class I areas within 300 km are considered further for the BART Applicability Analysis.

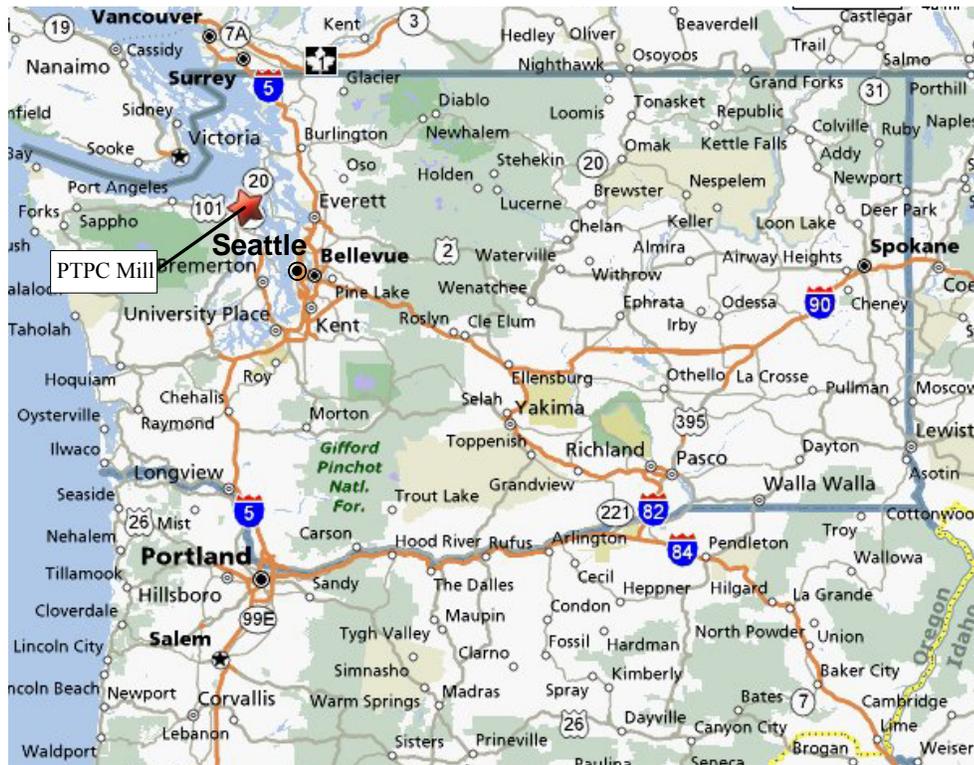
**TABLE 2-1. DISTANCES (KILOMETERS) SEPARATING CLASS I AREAS AND PTPC'S BART-ELIGIBLE SOURCES**

<b>Class I Area</b>	<b>Distance from PTPC (km)</b>
Alpine Lakes Wilderness Area	106
Glacier Peak Wilderness Area	101
Goat Rocks Wilderness Area	189
Mount Adams Wilderness Area	215
Mount Rainier National Park	141
North Cascades National Park	111
Olympic National Park	36
Pasayten Wilderness Area	156
Columbia River Gorge National Scenic Area <sup>a</sup>	270

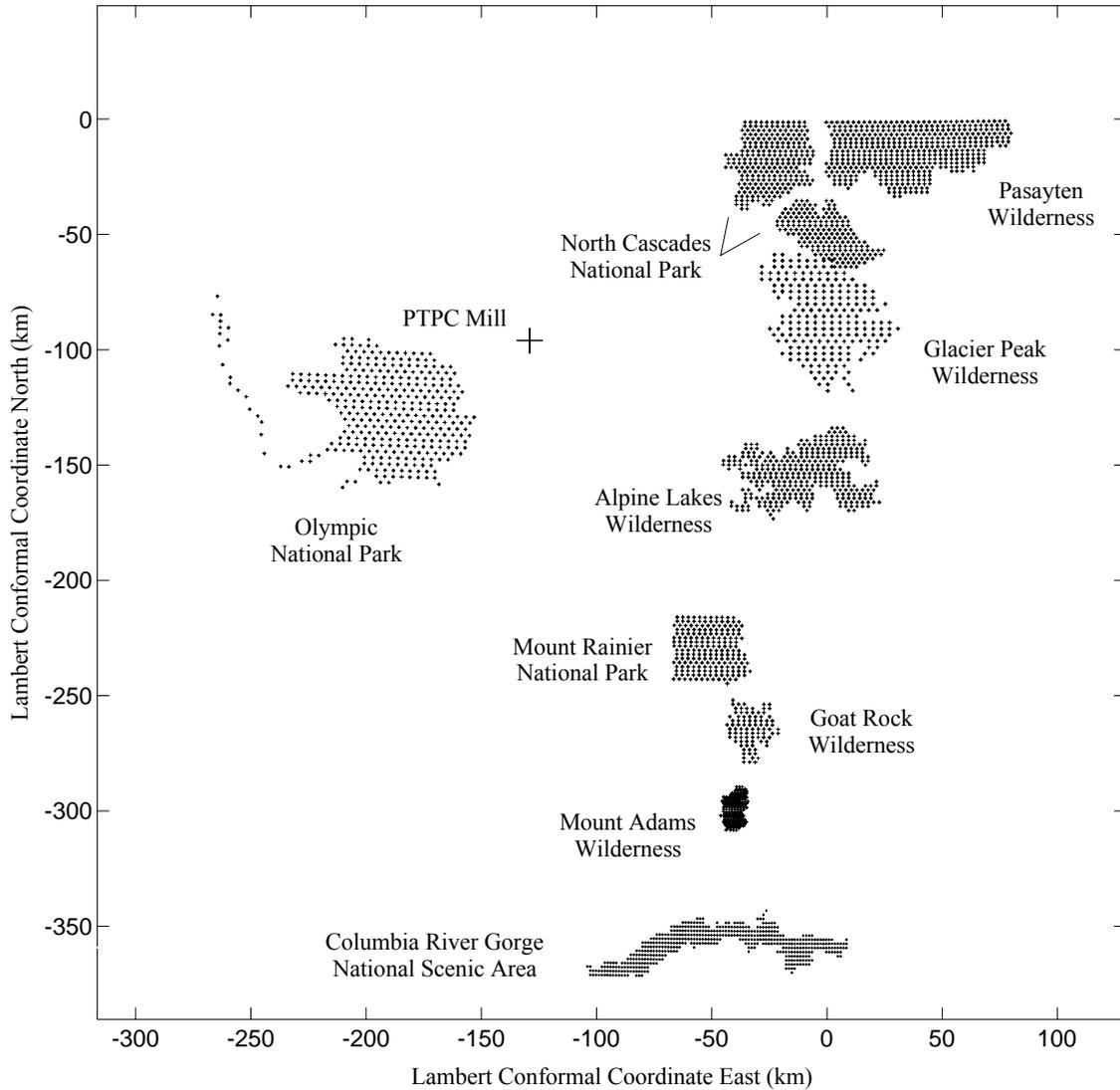
<sup>a</sup> The Columbia River Gorge National Scenic Area is not a federal Class I area; however, Region 10 has requested the inclusion of this area in the BART analyses for informational purposes.

Figure 2-1 illustrates the location of the PTPC Mill relative to the surrounding area and Figure 2-2 illustrates the location of the PTPC Mill relative to the Class I areas that are located within 300 km of the PTPC Mill.

FIGURE 2-1. LOCATION OF PORT TOWNSEND MILL



**FIGURE 2-2. LOCATION OF THE PTPC MILL AND CLASS I AND OTHER SENSITIVE AREAS WITHIN 300 KM**



#### 2.1.4 CALPUFF MODELING ANALYSES

As recommended by the U.S. EPA BART guidelines and the *BART Modeling Protocol*, the CALPUFF modeling system is used to compute the 24-hour average visibility impairment attributable to the PTPC Mill. For the BART applicability analysis, CALPUFF is also used to assess whether the 0.5 dv contribution threshold is exceeded, and if so, the frequency, duration, and magnitude of any exceedance events. For the BART determination analysis, CALPUFF is used to determine the amount of visibility improvement attributable to potential control technologies. CALPUFF is a refined air quality modeling system that is capable of simulating the dispersion, chemical transformation, and long-range transport of multiple visibility-affecting pollutant emissions from a single source and is therefore preferred for BART applicability and determination analyses. The CALPUFF modeling system is described in technical detail in the *BART Modeling Protocol*.

## **2.2 ORGANIZATION OF BART APPLICABILITY ANALYSIS AND DETERMINATION REPORT**

The remainder of this BART Applicability Analysis and Determination report is organized as follows.

- Section 3 describes the BART-eligible emission units at the PTPC Mill and the emission rates modeled in the BART Applicability Analysis.
- Section 4 describes the procedural and technical guidance for conducting Class I area analyses using the CALPUFF modeling system, including the data resources, technical modeling options, and quality assurance methods used in the CALMET, CALPUFF, and CALPOST analyses.
- Section 5 describes the results of the BART applicability modeling analysis .
- Section 6 presents the refined modeling analysis methodology and results for Olympic National Park and the conclusion that the PTPC Mill is subject to BART for impacts at Olympic National Park.
- Section 7 presents the BART determination methodology.
- Section 8 presents the BART-eligible emission units subject to MACT standards.
- Section 9 presents the identification of control technologies.
- Section 10 presents the elimination of technically infeasible control options.
- Section 11 presents the evaluation and documentation of the most effective control technologies.
- Section 12 presents the evaluation of net visibility improvement.
- Section 13 presents a summary of BART determinations.

Supplemental information is provided in several appendices to this report.

- Appendix A presents documentation for the emissions analysis used to conduct BART modeling.
- Appendix B presents the PM Emission Factor Documentation
- Appendix C presents the RBLC search results.
- Appendix D presents the BART feasibility cost calculations
- Electronic copies of model input and output files are provided on electronic media accompanying this BART Applicability Analysis Report, a file index for which is presented in Appendix E.

### 3. BART-ELIGIBLE SOURCE DESCRIPTION

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This section of the BART Applicability Analysis and Determination Report describes the emission units that comprise the BART-eligible source at the PTPC Mill. Emissions and exhaust characteristics of each emission unit are quantified to demonstrate how each unit is represented in the modeling analyses.

#### 3.1 BART-ELIGIBLE EMISSION UNITS

PTPC reviewed the criteria for BART-eligibility and determined that the four emission units described in Table 3-1 comprise the BART-eligible source at the PTPC Mill.

**TABLE 3-1. SUMMARY OF BART-ELIGIBLE EMISSION UNITS**

Emission Unit	Source Code/ Stack ID	BART Source Category <sup>a</sup>
Recovery Furnace	RecBlr	3, 22
Smelt Tank	SmltTank	3, 22
No. 10 Power Boiler <sup>b</sup>	10Blr	3
Lime Kiln	LimeKiln	3

<sup>a</sup> Category 3 denotes kraft pulp mills; category 22 denotes large fossil fuel boilers, which for the purposes of BART eligibility include boilers individually greater than 250 MMBtu/hr that burn any amount of fossil fuel.

<sup>b</sup> Ecology has not identified the No. 10 Power Boiler as a “BART-Eligible unit”; however, PTPC records show that the source commenced construction prior to August 7, 1977, and therefore meets the definition of “in existence”.

The PTPC Mill is BART-eligible because potential emissions exceed 250 tpy for at least one of NO<sub>x</sub>, SO<sub>2</sub>, and PM<sub>10</sub>, which are considered visibility-affecting pollutants. Note that volatile organic compounds (VOC) are not visibility-affecting pollutants for the purposes of BART applicability analyses. As acknowledged in Ecology’s letter to Matt Cohen and the BART Coalition Sources, VOC emissions should not be included in BART applicability modeling analyses, as CALPUFF is not an appropriate model for evaluating the impacts of VOC emissions on regional haze.<sup>3</sup>

The *BART Modeling Protocol* indicates that the U.S. EPA BART guidelines provide the option to address ammonia emissions from BART-eligible sources. The protocol indicates that Washington may consider ammonia and ammonia compounds as visibility impairing pollutants if it is determined that they are expected to contribute to visibility impairment. Idaho and Oregon have determined that there are no significant sources of ammonia or ammonia compounds that are BART-eligible. Ammonia emissions from PTPC are not expected to cause or contribute to visibility impairment.

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<sup>3</sup> Letter from Sarah Rees, Ecology, to Matt Cohen and the Coalition of BART Sources, responding to Regional Haze Modeling Questions, January 4 and January 22, 2007.

The following sections provide background information on operation, current emission limits, and emissions characteristics for each of the emission units evaluated to determine BART.

### **3.1.1 RECOVERY FURNACE**

PTPC operates a non-direct contact evaporator (NDCE) recovery furnace with an ESP. The recovery furnace fires predominantly black liquor solids (BLS) and some recycled fuel oil (RFO).

#### **3.1.1.1 RECOVERY FURNACE OPERATION**

Recovery furnaces operate by spraying spent chemical concentrated liquor from the digester, called black liquor, into the furnace where the organics in the black liquor solids, derived from pulping the wood, are combusted and the inorganic pulping chemicals are recovered and recycled. A chemical recovery furnace is not simply a “boiler” designed to burn fuel and produce steam; it is a complex device which serves as a chemical reactor, a chemical recovery unit, an internal high efficiency SO<sub>2</sub> scrubber, and an energy recovery center for recovery of stored solar energy in wood lignins.

The chemical recycling process in a recovery furnace is the heart of a pulp mill and is essential to making the kraft pulping process an environmental and economic success. Chemical recovery reclaims sufficient energy to produce a major portion of the Mill’s steam load and electrical power needs. More importantly, the process reduces the sodium sulfate in the black liquor to sodium sulfide, an active cooking chemical.

Sodium hydroxide, another active cooking chemical, is consumed and converted to sodium carbonate during the pulping process and passes through the chemical recovery furnace unchanged. These remaining sodium salts are recausticized in the lime cycle. The molten chemicals, called smelt, collect in the furnace bottom at about a 3:1 ratio of sodium carbonate to sodium sulfide. The smelt is continuously withdrawn from the furnace into a smelt dissolving tank. The flue gas is exhausted from the furnace into an ESP. Even though the black liquor is about ten percent sodium sulfur salts (sodium sulfide, sodium thiosulfate, and sodium sulfate), the soda fume in the recovery furnace is more than 98% efficient for *in situ* process scrubbing of SO<sub>2</sub> in the flue gas under normal operating conditions.

#### **3.1.1.2 CURRENT EMISSION LIMITS AND CONTROL**

Control technologies considered in the BART analysis must include those required for Best Available Control Technology (BACT), Lowest Achievable Emission Rate (LAER), and New Source Performance Standards (NSPS). The Recovery Furnace is currently subject to NESHAP Subpart MM, as well as other permit limits. The applicable PM, NO<sub>x</sub>, and SO<sub>2</sub> emission limits are shown in Table 3-2.

**TABLE 3-2. RECOVERY FURNACE CURRENT EMISSION LIMITS**

<b>Pollutant</b>	<b>Emission Limit</b>	<b>Regulatory Basis</b>
PM/PM <sub>10</sub> <sup>a</sup>	0.044 gr/dscf @ 8% O <sub>2</sub>	NESHAP Subpart MM 40 CFR 63.862(a)(1)(i)(A)
NO <sub>x</sub> <sup>b</sup>	NA	NA
SO <sub>2</sub> <sup>c</sup>	200 ppm @ 8% O <sub>2</sub>	Permit Limit PSD-I (Condition 2)

<sup>a</sup> PM limits of 0.08 gr/dscf and 0.10 gr/dscf both at 8 % O<sub>2</sub> also apply to the Recovery Furnace per Order DE 05AQIS-2892 and WAC 173-405-040(1)(a), respectively. Since the MACT limit of 0.044 gr/dscf at 8 % O<sub>2</sub> is also on the same basis, only the most stringent standard is presented in the table.

<sup>b</sup> There are no NO<sub>x</sub> limits that apply PTPC's Recovery Furnace

<sup>c</sup> A SO<sub>2</sub> limit of 500 ppm at 8 % O<sub>2</sub> also applies to the Recovery Furnace per WAC 173-405-040(11)(a). Since the 200 ppm at 8 % O<sub>2</sub> from the PSD-I Permit limit is on the same basis, the more stringent of the two limits is presented in the table.

An ESP is currently used to reduce PM/PM<sub>10</sub> to levels that comply with the NESHAP limits. No other control devices are used for the recovery furnace.

### 3.1.1.3 PM<sub>10</sub> EMISSIONS

The majority of PM<sub>10</sub> emissions from the recovery furnace are sodium salts with about 80% of the PM<sub>10</sub> being sodium sulfate and smaller amounts of potassium sulfate, sodium carbonate, and sodium chloride.<sup>4</sup> These salts primarily result from the carryover of solids and sublimation and condensation of inorganic chemicals.<sup>5</sup> Some PM<sub>10</sub> emissions can also be attributed to the combustion of fossil fuels. Filterable PM<sub>10</sub> emissions from fuel oil combustion depend not only on the completeness of combustion but also on the sulfur content of the oil. Fuel oil with lower sulfur content has lower viscosity due to desulfurization processes, resulting in better atomization and more complete combustion.<sup>6</sup>

### 3.1.1.4 NO<sub>x</sub> EMISSIONS

In the recovery furnace combustion process, NO<sub>x</sub> may form as fuel NO<sub>x</sub> and thermal NO<sub>x</sub>. Technical literature suggests that NO<sub>x</sub> formation from the chemical recovery process is primarily fuel NO<sub>x</sub> since recovery furnace temperatures are not high enough for significant thermal NO<sub>x</sub> formation.<sup>7</sup> NO<sub>x</sub> emissions from recovery furnaces are typically low due to the low nitrogen (N) concentration in the black liquor solids (approximately 0.1%), the low overall conversion of liquor N to NO<sub>x</sub> (10-25%), the insufficient temperatures for thermal NO<sub>x</sub> formation (highest recovery

<sup>4</sup> NCASI Technical Bulletin No. 725, *Particulate Matter Emissions From Kraft Mill Recovery Furnaces, Lime Kilns, and Smelt Dissolving Tanks*, November 1996.

<sup>5</sup> AP-42, Section 10.2, *Chemical Wood Pulping*, dated September 1990.

<sup>6</sup> AP-42, Section 1.3, *Fuel Oil Combustion*, dated September 1998.

<sup>7</sup> NCASI Special Report 99-01, *A Review of NO<sub>x</sub>/NO<sub>x</sub> Emission Control Strategies for Industrial Boilers, Kraft Recovery Furnaces, and Lime Kilns*, April 1999.

furnace temperatures are approximately 2,100 – 2,500 °F), and the existence of sodium fumes that can participate in “in-furnace” NO<sub>x</sub> reduction or removal.<sup>8</sup>

### **3.1.1.5 SO<sub>2</sub> EMISSIONS**

SO<sub>2</sub> emissions from the recovery furnace primarily result from the oxidation of total reduced sulfur (TRS). However, as previously noted, the chemical recovery process scrubs out most of the SO<sub>2</sub> emissions from the exhaust fume.

Additional SO<sub>2</sub> emissions result from the oxidation of sulfur in the fuel oil during the combustion process. Uncontrolled SO<sub>2</sub> emissions almost entirely depend upon the sulfur content of the fuel and are not dependent upon furnace properties such as size, burner design, or fuel grade. The majority of the fuel sulfur released is in the form of SO<sub>2</sub>.

## **3.1.2 SMELT DISSOLVING TANK**

PTPC operates a smelt dissolving tank with a wet scrubber to control PM.

### **3.1.2.1 SMELT DISSOLVING TANK OPERATION**

A smelt dissolving tank is another key element of the kraft pulping chemical recovery process. Smelt, the molten chemicals collected in a recovery furnace bottom, is continuously withdrawn from the furnace into a smelt dissolving tank. The smelt is then dissolved with weak wash in the smelt dissolving tank to produce green liquor, which is processed in the causticizing area to produce white liquor for use in the chip digestion process.

### **3.1.2.2 CURRENT EMISSION LIMITS AND CONTROL**

Control technologies considered in the BART analysis must include those required for BACT, LAER, and NSPS. The Smelt Dissolving Tank is currently subject to NESHAP Subpart MM, as well as other permit limits. The applicable PM, NO<sub>x</sub>, and SO<sub>2</sub> emission limits are shown in Table 3-3.

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<sup>8</sup> NCASI Special Report No. 03-06, *Effect of Kraft Recovery Furnace Operations on NO<sub>x</sub>NO<sub>x</sub> Emissions: Literature Review and Summary of Industry Experience*, October 2003.

**TABLE 3-3. SMELT DISSOLVING TANK CURRENT EMISSION LIMITS**

<b>Pollutant</b>	<b>Emission Limit</b>	<b>Regulatory Basis</b>
PM/PM <sub>10</sub> <sup>a</sup>	0.20 lb/ton BLS	NESHAP Subpart MM 40 CFR 63.862(a)(1)(i)(B)
NO <sub>x</sub> <sup>b</sup>	NA	NA
SO <sub>2</sub> <sup>c</sup>	NA	NA

<sup>a</sup> A PM limit of 0.3 lb/ton BLS also applies to the Smelt Dissolving Tank per WAC 173-405-040(2). Since the MACT limit of 0.20 lb/ton BLS is on the same basis, only the most stringent standard is presented in the table.

<sup>b</sup> There are no NO<sub>x</sub> limits that apply PTPC's Smelt Dissolving Tank

<sup>c</sup> There are no SO<sub>2</sub> limits that apply PTPC's Smelt Dissolving Tank

A scrubber is currently used to reduce PM/PM<sub>10</sub> emissions. No other control devices are used for the smelt dissolving tank.

### **3.1.2.3 PM<sub>10</sub> EMISSIONS**

PM emissions from smelt dissolving tanks are primarily composed of inorganic components such as sodium sulfate and sodium carbonate.

### **3.1.2.4 NO<sub>x</sub> EMISSIONS**

NO<sub>x</sub> emissions from smelt dissolving tanks are minimal since no combustion occurs in these emission units.

### **3.1.2.5 SO<sub>2</sub> EMISSIONS**

SO<sub>2</sub> emissions from the smelt dissolving tanks result from the oxidation of TRS in the smelt.

## **3.1.3 NO. 10 POWER BOILER**

PTPC operates the No. 10 Power Boiler with a 600 tube multiclone and wet venturi scrubber to control PM.

### **3.1.3.1 NO. 10 POWER BOILER OPERATION**

The No. 10 Power Boiler operates by combusting wood-waste, primary clarifier sludge, old corrugated container (OCC) rejects, and recycle fuel oil (RFO) to produce steam for use in the kraft pulping process. The boiler is a spreader stoker type boiler with horizontally opposed overfire air ports and tangential oil burners downstream of the grate. While it primarily fires wood waste on the grates, the RFO fired at the tangential burners contributes approximately 30 % of the heat input.

### **3.1.3.2 CURRENT EMISSION LIMITS AND CONTROL**

The No. 10 Power Boiler is currently subject to NSPS Subpart D and may be subject to NESHAP standards. NESHAP Subpart DDDDD (*NESHAP for Industrial, Commercial, and Institutional Boilers and Process Heaters*, also called "Boiler

MACT”) may apply to PTPC’s No. 10 Power Boiler. However, the Boiler MACT rule was vacated by the United States Court of Appeals decision on June 8, 2007. Therefore, the Boiler MACT standards are not addressed as current emission limits. The applicable PM, NO<sub>x</sub>, and SO<sub>2</sub> emission limits are shown in Table 3-4.

**TABLE 3-4. NO. 10 POWER BOILER CURRENT EMISSION LIMITS**

Pollutant	Emission Limit <sup>a</sup>	Regulatory Basis
PM	0.10 lb/MMBtu	NSPS Subpart D 40 CFR 60.42(a)(1)
NO <sub>x</sub>	0.30 lb/MMBtu	NSPS Subpart D 40 CFR 60.44(2)
SO <sub>2</sub>	0.80 lb/MMBtu	NSPS Subpart D 40 CFR 60.43(a)(1)

<sup>a</sup> NESHAP Subpart DDDDD, Boiler MACT, limits may have applied to the No. 10 Power Boiler. However the Boiler MACT rule was vacated by the United States Court of Appeals decision on June 8, 2007

PTPC currently uses a multiclone and a venturi scrubber to reduce PM/PM<sub>10</sub> emissions.

### 3.1.3.3 PM<sub>10</sub> EMISSIONS

PM<sub>10</sub> emissions from wood-fired boilers result from inorganic materials contained in the wood-waste and unburned carbon resulting from incomplete combustion.<sup>9</sup> The magnitude of the PM<sub>10</sub> emissions depends on the firing method, furnace type, load, and fuel type.

### 3.1.3.4 NO<sub>x</sub> EMISSIONS

NO<sub>x</sub> emissions from boilers are formed by two mechanisms, fuel NO<sub>x</sub> and thermal NO<sub>x</sub>, which are described in the following sections. Fuel NO<sub>x</sub> is the dominant mechanism for NO<sub>x</sub> formation during wood waste combustion.<sup>10</sup>

“Fuel NO<sub>x</sub>” forms when the nitrogen compounds bound with the fuel are converted into nitric oxide (NO) at temperatures above 1,600 °F. The amount of bound nitrogen that is converted to fuel NO<sub>x</sub> depends upon the fuel type and nitrogen content. Fuel NO<sub>x</sub> is dependent primarily on stoichiometric conditions and less on thermal conditions. Due to the rapid conversion, the primary mechanisms for reducing fuel NO<sub>x</sub> require creation of a “fuel-rich” zone and reducing available oxygen.<sup>11</sup>

<sup>9</sup> NCASI Technical Bulletin No. 884, *Compilation of Criteria Air Pollutant Emissions Data for Sources at Pulp and Paper Mills Including Boilers*, August 2004.

<sup>10</sup> NCASI Corporate Correspondent Memorandum No. 06-0142006, *Information on Retrofit Control Measures for Kraft Pulp Mill Sources and Boilers for NO<sub>x</sub>, SO<sub>2</sub> and PM Emissions*, June 2006.

<sup>11</sup> NCASI Special Report 99-01, *A Review of NO<sub>x</sub>/NO<sub>x</sub> Emission Control Strategies for Industrial Boilers, Kraft Recovery Furnaces, and Lime Kilns*, April 1999.

NO<sub>x</sub> formed in the high-temperature, post-flame region of the combustion equipment is “thermal NO<sub>x</sub>.” Thermal NO<sub>x</sub> is formed at high temperature by direct oxidation of atmospheric nitrogen and increases exponentially above 2,800 °F flame temperature. Thermal NO<sub>x</sub> formation increases with temperature, oxygen and nitrogen concentrations, and residence time. Temperature is the most important factor; thus, temperature reduction is a primary mechanism for reducing thermal NO<sub>x</sub> generation.<sup>12</sup> Spreader stoker boilers inherently burn at lower flame temperatures than traditional fossil fuel boilers, resulting in very low thermal NO<sub>x</sub> generation.

### **3.1.3.5 SO<sub>2</sub> EMISSIONS**

SO<sub>2</sub> emissions from combination wood residue and oil boilers are formed as the sulfur contained in the oil oxidizes during the combustion process. PTPC’s RFO contains 0.45 % to 0.75 % sulfur, approximately 30%<sup>13</sup> of which oxidizes and exits the stack as SO<sub>2</sub>. The remaining sulfur is captured by the alkaline wood ash and minimal amounts may exhaust as other sulfur compounds.<sup>14</sup>

## **3.1.4 LIME KILN**

PTPC operates a lime kiln with a wet scrubber to control PM.

### **3.1.4.1 LIME KILN OPERATION**

In PTPC’s lime kiln, calcium oxide (CaO) is regenerated from lime mud, which consists primarily of calcium carbonate (CaCO<sub>3</sub>). The heat required to convert the calcium carbonate to calcium oxide is provided by the combustion of fuel oil. Lime kilns are generally long rotating cylindrical units installed on a slope (one end of the lime kiln is at a higher elevation than the other). Lime mud enters the kiln at the “higher” end and makes its way down to the “lower” end of the kiln. The heat, provided by the fuel oil burner, is generated at the “lower” end of the kiln. This counter-current flow of lime mud and hot combustion gases provides an efficient environment for the conversion to CaO.

### **3.1.4.2 CURRENT EMISSION LIMITS AND CONTROL**

Control technologies considered in the BART analysis must include those required for BACT, LAER, and NSPS. The Lime Kiln is currently subject to NESHAP Subpart MM, as well as other permit limits. The applicable PM, NO<sub>x</sub>, and SO<sub>2</sub> emission limits are shown in Table 3-5.

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<sup>12</sup> Ibid.

<sup>13</sup> Average percentage of the sulfur burned that is emitted as SO<sub>2</sub>, calculated based on the correlation for sulfur capture in combination bark boilers developed by NCASI. NCASI Technical Bulletin No. 884, *Compilation of Criteria Air Pollutant Emissions Data for Sources at Pulp and Paper Mills Including Boilers*, August 2004, page 40 and 41.

<sup>14</sup> NCASI Technical Bulletin No. 884, *Compilation of Criteria Air Pollutant Emissions Data for Sources at Pulp and Paper Mills Including Boilers*, August 2004.

**TABLE 3-5. LIME KILN CURRENT EMISSION LIMITS**

<b>Pollutant</b>	<b>Emission Limit</b>	<b>Regulatory Basis</b>
PM/PM <sub>10</sub> <sup>a</sup>	0.064 gr/dscf @ 10% O <sub>2</sub>	NESHAP Subpart MM 40 CFR 63.862(a)(1)(i)(C)
NO <sub>x</sub> <sup>b</sup>	NA	NA
SO <sub>2</sub> <sup>c</sup>	500 ppm @ 10% O <sub>2</sub>	WAC 173-405-040(11)(a)

<sup>a</sup> A PM limit of 0.13 gr/dscf at 10% O<sub>2</sub> also applies to the Lime Kiln per WAC 173-405-040(3)(a). Since the MACT limit of 0.064 gr/dscf @ 10% O<sub>2</sub> is on the same basis, only the most stringent standard is presented in the table.

<sup>b</sup> There are no NO<sub>x</sub> limits that apply to PTPC's Lime Kiln

<sup>c</sup> A TRS limit of 8 ppm at 10 % O<sub>2</sub> also applies to the Lime Kiln per 40 CFR 60.283 (a)(5)

A scrubber is currently used to reduce PM/PM<sub>10</sub> emissions. No other control devices are used for the Lime Kiln.

### 3.1.4.3 PM<sub>10</sub> EMISSIONS

PM<sub>10</sub> emissions from lime kilns primarily result from combustion gasses picking up dust from lime mud and other particulate matter from alkali vaporization. Sodium sulfate and sodium carbonate primarily comprise the smaller PM with aerodynamic diameter less than 10 μm.

### 3.1.4.4 NO<sub>x</sub> EMISSIONS

NO<sub>x</sub> formation in PTPC's lime kiln occurs as both "thermal NO<sub>x</sub>" and "fuel NO<sub>x</sub>." The kiln reaches temperatures high enough for the direct oxidation of atmospheric nitrogen to NO<sub>x</sub>. Thermal NO<sub>x</sub> formation increases with temperature, oxygen and nitrogen concentrations, and residence time. Additionally, the nitrogen in the fuel oil fired by the lime kiln can convert to NO, forming "fuel NO<sub>x</sub>."

### 3.1.4.5 SO<sub>2</sub> EMISSIONS

SO<sub>2</sub> emissions from PTPC's lime kiln results from the oxidation of sulfur in the fuel oil and, to a lesser extent, sulfur in the lime mud. While the potential for SO<sub>2</sub> emissions from some lime kilns may be high based on the sulfur content of the fuel, most lime kilns emit very low levels of SO<sub>2</sub> due to the regenerated quicklime in the kiln acting as an inherent scrubbing agent. PTPC's scrubber following the kiln further augments this SO<sub>2</sub> removal process since the scrubbing solution becomes alkaline as it captures the lime dust.<sup>15</sup>

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<sup>15</sup> Ibid.

### 3.2 BART-ELIGIBLE SOURCE MODEL EMISSIONS INVENTORY

The BART applicability modeling analysis uses maximum actual 24-hour average emission rates of NO<sub>x</sub>, SO<sub>2</sub>, and PM<sub>10</sub>. The *BART Modeling Protocol* specifies the following hierarchy of information resources to establish the maximum actual 24-hour average emission rate for BART applicability modeling over the three year period from 2003 to 2005:

- 24-hour average actual emission rate from the highest emitting day within the period 2003 through 2005. Actual emissions may be calculated using emission factors specified in the Title V permits or representative stack tests.
- Allowable emissions (maximum 24-hour allowable).

PTPC uses a combination of measured process or firing rates, National Council for Air and Stream Improvement (NCASI) emission factors, and historical stack test data to determine the 24-hour average actual emission rates of each visibility-affecting pollutant from the highest emitting day. Table 3-6 summarizes these emission rates from each BART-eligible emissions unit considered in the applicability modeling analysis.<sup>16</sup> Detailed emissions calculations are provided in Appendix A.

**TABLE 3-6. SUMMARY OF MAXIMUM 24-HOUR AVERAGE ACTUAL EMISSION RATES**

Emission Unit	NO <sub>x</sub> (lb/hr)	SO <sub>2</sub> (lb/hr)	H <sub>2</sub> SO <sub>4</sub> (lb/hr)	Filterable PM <sub>10</sub> <sup>a</sup> (lb/hr)	Total PM <sub>10</sub> <sup>b</sup> (lb/hr)
Recovery Boiler	78.76	105.76	1.66	19.53	24.25
Smelt Dissolving Tank	1.05	0.26	0.11	9.55	9.94
No. 10 Power Boiler	82.61	71.39	8.09	31.59	56.62
Lime Kiln	9.98	1.61	0.78	6.35	7.69

<sup>a</sup> Filterable PM<sub>10</sub> represents the sum of the modeled filterable PM speciation groups of PMC, PMF, and EC.

<sup>b</sup> Total PM<sub>10</sub> (TPM<sub>10</sub>) represents the sum of the modeled filterable and condensable PM, including sulfuric acid (H<sub>2</sub>SO<sub>4</sub>).

Maximum emission rates for the Recovery Boiler are based upon the following:

- Maximum measured BLS firing rate from 2003 through 2005 (1,260 tons BLS per day) and NCASI NO<sub>x</sub> emission factor for a recovery furnace (1.5 lb NO<sub>x</sub> per ton BLS).
- Maximum measured BLS firing rate and average source test emission factor for SO<sub>2</sub> for each year (2003-2005).
- Maximum measured BLS firing rate and average source test emission factor for PM (TSP) for each year (2003-2005). The TSP emission factor is also the basis of the emissions speciation

<sup>16</sup> As discussed in Section 6.3, several improvements were made to the emission calculation method after the initial BART Applicability Analysis was conducted. All changes resulted in a decrease in modeled emission rates. The emission rates presented in this section reflect the refined calculations. However, the modeling results presented in Section 5 represent impacts based on the original (higher) emission rates. The refined modeling analysis and the BART Determination visibility analyses for Olympic National Park presented in Sections 6 and 12, respectively, are based on the refined emission rates as presented in this section.

used to calculate total PM<sub>10</sub> and total PM<sub>2.5</sub> emissions as described in the following sections of this analysis.

Maximum emission rates for the Smelt Dissolving Tank are based upon the following:

- NCASI emission factor of 0.02 lb NO<sub>x</sub>/ton BLS and maximum measured BLS firing rate (1,260 tons BLS per day) from 2003 to 2005.
- NCASI emission factor of 0.005 lb SO<sub>2</sub>/ton BLS and maximum measured BLS firing rate from 2003 to 2005.
- Maximum measured BLS firing rate and average source test emission factor for total PM (filterable plus condensable) for each year (2003-2005). The total PM emission factor is also the basis of the emissions speciation used to calculate total PM<sub>10</sub> and total PM<sub>2.5</sub> emissions as described in the following sections of this analysis.

Maximum emission rates for the No. 10 Power Boiler are based upon the following:

- Maximum measured firing rate (MMBtu per day) and Continuous Emission Monitor (CEM) data for 2003 through 2005 for NO<sub>x</sub> emissions.
- Maximum calculated SO<sub>2</sub> emission rate for 2003 through 2005 based on a NCASI correlation using the measured daily firing rate of each fuel.
- Maximum measured firing rate (MMBtu per day) and average source test emission factor for PM (TSP) for each year (2003-2005). The TSP emission factor is also the basis of the emissions speciation used to calculate total PM<sub>10</sub> and total PM<sub>2.5</sub> emissions as described in the following sections of this analysis.

Specifically with regard to the maximum actual SO<sub>2</sub> emission rate, PTPC estimates the SO<sub>2</sub> emissions from the specific fuel mix fired each day using a correlation for sulfur capture in combination bark boilers developed by NCASI. The majority of the sulfur contained in fuel oil normally oxidizes to form primarily SO<sub>2</sub>. However, in a boiler that combusts wood-residue as well as fuel oil, the alkaline fly ash absorbs the sulfur compounds, which is then captured by the wet scrubber. The correlation is presented below.<sup>17</sup>

$$Y = 0.45(X) - 0.55$$

where,

Y = lb sulfur emitted as SO<sub>2</sub> per dry ton of combined fuel

X = lb sulfur in combined fuel per ton of dry bark or wood residue

Maximum emission rates for the Lime Kiln are based upon the following:

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<sup>17</sup> NCASI Technical Bulletin No. 884, *Compilation of Criteria Air Pollutant Emissions Data for Sources at Pulp and Paper Mills Including Boilers*, August 2004, page 40 and 41.

- NCASI emission factor of 1.15 lb NO<sub>x</sub>/ton CaO and maximum CaO throughput rate from 2003 to 2005.<sup>18</sup>
- Maximum measured mud feed rate and average source test emission factor for SO<sub>2</sub> for each year (2003-2005).
- Maximum measured CaO throughput rate and average source test emission factor for total PM (filterable plus condensable) for each year (2003-2005). The TSP emission factor is also the basis of the emissions speciation used to calculate total PM<sub>10</sub> and total PM<sub>2.5</sub> emissions as described in the following sections of this analysis.

### 3.2.1 PM SPECIATION DESCRIPTION

Modeling of visibility impairment requires that the components of the exhaust stream be speciated because different types of particulate matter affect visibility to varying extents. The amount by which a mass of a certain species scatters or absorbs light is termed the *extinction efficiency* or *extinction coefficient* ( $b_{ext}$ ), and ranges from values of 0.6 m<sup>2</sup>/g for coarse particulate matter to 10 m<sup>2</sup>/g for elemental carbon. Fine particulate matter (1 m<sup>2</sup>/g) and organic aerosols (4 m<sup>2</sup>/g) scatter light with intermediate efficiencies, and ammonium sulfate and ammonium nitrate (that forms from precursor SO<sub>2</sub> and NO<sub>x</sub> emissions in the presence of ambient ammonia) are hygroscopic species that are particularly efficient at light scattering in the presence of ambient water vapor ( $3f(RH)$  m<sup>2</sup>/g, where  $f(RH)$  is a function of the relative humidity). The size distribution of particle species is also important, since smaller particles may be transported longer distances than larger particles and dispersed differently under prevailing ambient conditions. Figure 3-1 depicts the speciation of visibility-affecting pollutant emissions as represented in the *VISTAS BART Modeling Protocol*.<sup>19</sup>

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<sup>18</sup> CaO throughput converted from air dried tons pulp (ADTP) throughput rate using a NCASI provided conversion factor of 0.275 tons CaO per ADTP. Maximum measured throughput (2003-2005) is 958 ADTP per day or 208 tons CaO per day.

<sup>19</sup> Figure 4-3 of the VISTAS BART Modeling Protocol, downloaded from [http://www.vistas-sesarm.org/documents/BARTModelingProtocol\\_rev3.2\\_31Aug06.pdf](http://www.vistas-sesarm.org/documents/BARTModelingProtocol_rev3.2_31Aug06.pdf) on 03/20/07.

**FIGURE 3-1. PARTICULATE MATTER SPECIATION**

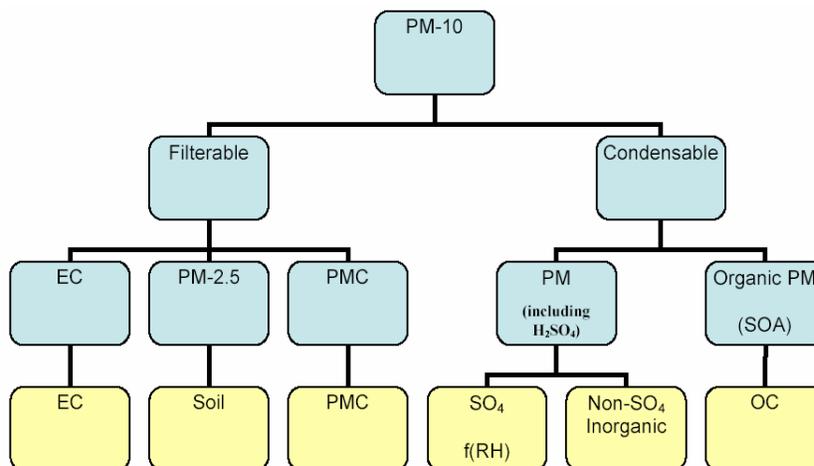


Figure 4-3 of the VISTAS BART Modeling Protocol, downloaded from [http://www.vistas-sesarm.org/documents/BARTModelingProtocol\\_rev3.2\\_31Aug06.pdf](http://www.vistas-sesarm.org/documents/BARTModelingProtocol_rev3.2_31Aug06.pdf) on 03/20/07.

PTPC developed the following emissions profiles based on engineering knowledge of kraft pulp mill operations and available reference data (e.g., NCASI, AP-42, etc.). However, it should be noted that the data quality on PM speciation is inadequate for setting regulatory emission limits and are provided here solely as the best estimated data for a scientific analysis of potential impacts on visibility impairment at Class I areas using CALPUFF modeling. The following analysis does not represent source test results for specific sources at the PTPC Mill.

PM emissions can be differentiated with respect to size, point of formation, and composition. Table 3-7 gives definitions for the nomenclature used herein.

**TABLE 3-7. NOMENCLATURE FOR EMISSIONS SPECIATION ANALYSIS**

Nomenclature	Description
TSP	Total suspended particulate, filterable PM with an aerodynamic diameter < 30 $\mu\text{m}$
PM <sub>10</sub>	Filterable particulate matter with an aerodynamic diameter < 10 $\mu\text{m}$
PM <sub>2.5</sub>	Filterable particulate matter with an aerodynamic diameter < 2.5 $\mu\text{m}$
PM <sub>2.5-10</sub>	Filterable particulate matter with an aerodynamic diameter > 2.5 and < 10 $\mu\text{m}$
CPM	Condensable particulate matter (organic and inorganic)
SOA	Secondary Organic Aerosols
PIC	Primary inorganic condensable particulate
TPM <sub>10</sub>	Filterable PM <sub>10</sub> + CPM
TPM <sub>2.5</sub>	Filterable PM <sub>2.5</sub> + CPM

These PM classifications are necessary in the Class I visibility analysis because each type of PM has a different effect on visibility as defined by the extinction efficiency. The emission rates of each of these particulate phases and size categories are modeled in

CALPUFF and grouped according to visibility-affecting characteristics as illustrated in Figure 3-1.

Elemental carbon (EC) typically results from unburned carbonaceous fuel and is distinguished from other PM types because of its light extinction characteristics. EC is assumed to have an aerodynamic diameter less than 2.5  $\mu\text{m}$ . Coarse PM (PMC) is typically filterable in nature and has an aerodynamic diameter between 2.5 and 10  $\mu\text{m}$ ; therefore,  $\text{PM}_{2.5-10}$  is composed of only PMC. Filterable PM with an aerodynamic diameter less than 2.5  $\mu\text{m}$  ( $\text{PM}_{2.5}$ ) is composed of EC and PMF. Condensable PM (CPM) is made up of both organic and inorganic species. The organic fraction of CPM is represented in CALPUFF as secondary organic aerosol (SOA) emissions by convention, which are also referred to as primary organic condensable (POC) emissions. Emissions of primary inorganic condensable particulate matter (PIC) may contain hygroscopic sulfates ( $\text{SO}_4$ ) and nitrates ( $\text{NO}_3$ ), as well as other salts (e.g., carbonates) that may be hygroscopic to a lesser degree, and hence are considered in a manner similar to PMF (i.e., as soil) in terms of light extinction.<sup>20</sup> Therefore, it is important to distinguish inorganic CPM since hygroscopic species (i.e., sulfate and nitrate) will have a greater extinction coefficient than non-hygroscopic (i.e., non-sulfate and non-nitrate) species. Even the distinction between primary sulfate and nitrate emissions is important since primary nitrate emissions will be affected by the partitioning of nitrate and nitric acid in the presence of ambient  $\text{NH}_3$ . PTPC distinguishes primary emissions of sulfates and nitrates, which are assigned to the appropriate modeled PM type (i.e.,  $\text{SO}_4$  and  $\text{NO}_3$ , respectively), from non-hygroscopic species (e.g., carbonates), which are assigned to the PIC modeled species.

Table 3-8 summarizes the grouping of PM species and extinction coefficient of each component. A discussion of the PM speciation methodologies for each of the BART-eligible sources at the PTPC Mill is presented in the following sections of this report.

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<sup>20</sup> The U.S. EPA's *Guidance for Tracking Progress under the Regional Haze Rule* identifies carbonates, magnesium oxides, and sodium oxides as components of the soil mass concentration when analyzed to assess natural background visibility (Malm 1994).

**TABLE 3-8. ASSIGNMENT OF EMITTED PM SPECIES TO MODELED PM CATEGORIES**

Modeled PM Category <sup>a</sup>	Components	Output Category <sup>b</sup>	Extinction Coefficient (m <sup>2</sup> /g)
PMC	Filterable coarse particles (PM <sub>2.5-10</sub> )	PMC	0.6
PMF	Filterable fine particles (PM <sub>2.5</sub> )	PMF	1
PIC	Non-hygroscopic, primary inorganic condensable (PIC) emissions	SOIL <sup>c</sup>	1
SO <sub>4</sub>	Primary inorganic condensable emissions of sulfates	SO <sub>4</sub>	3f(RH)
NO <sub>3</sub>	Primary inorganic condensable emissions of nitrates	SO <sub>4</sub>	3f(RH)
SOA <sup>d</sup>	Secondary organic aerosol emissions	SOA	4
EC	Uncombusted carbonaceous fuel	EC	10

<sup>a</sup> Modeled PM Category denotes the input of emissions data into CALPUFF.

<sup>b</sup> Output Category denotes the assignment of modeled emissions in POSTUTIL for the visibility calculations in CALPOST.

<sup>c</sup> Emissions of PIC are zero and therefore the SOIL output category is zero.

<sup>d</sup> Emissions of SOA are also referred to as primary organic condensable (POC) emissions.

PTPC has conservatively not further differentiated the modeled PM categories with respect to size. Therefore, PMF, PIC, SO<sub>4</sub>, NO<sub>3</sub>, SOA, and EC are assumed to have a mean diameter of 0.5 µm with a standard deviation of 1.5, and PMC particles are assumed to have a mean diameter of 5.00 µm with a standard deviation of 1.5.<sup>21</sup>

### 3.2.2 RECOVERY FURNACE PARTICULATE SPECIATION

PTPC operates a non-direct contact evaporator (NDCE) recovery furnace with an electrostatic precipitator (ESP). PM emissions from the recovery furnace are due to the combustion of fuel oil and/or black liquor solids (BLS), which are composed primarily of sodium sulfate and sodium carbonate. Because BLS firing is the normal operating scenario, PM emission speciation is based on this operating case. PTPC analyzed TSP stack test results from 2003 through 2005 to determine the maximum actual TSP emission rate to which the subsequent speciation analysis is applied.

To speciate the PM emissions from the recovery furnace, data from NCASI are used to determine PM size fractions and CPM emissions, which are included in

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<sup>21</sup> Modeling Protocol for Washington, Oregon, and Idaho: Protocol for the Application of the CALPUFF Modeling System Pursuant to the Best Available Retrofit Technology (BART) Regulation (BART Modeling Protocol), October 11, 2006.

Appendix B of this report for reference.<sup>22</sup> Table 3-9 summarizes the relevant data for this source.

**TABLE 3-9. RECOVERY FURNACE SPECIATION DATA**

Speciation Data	Value	Reference
Filterable PM <sub>10</sub> as a % of TSP	50.2%	NCASI Data NDCE Kraft Recovery Furnaces October 27, 2006
Filterable PM <sub>2.5</sub> as a % of TSP	37.2%	
PMC (PM <sub>2.5-10</sub> ) as a % of TSP	13.0%	
EC as % of Filterable PM <sub>2.5</sub>	0.025%	
Organic portion of CPM <sup>a</sup>	16.5%	
Non-sulfate inorganic portion of CPM <sup>a</sup>	48.3%	
Sulfate portion of CPM <sup>a</sup>	35.2%	

<sup>a</sup> The CPM emission rate is determined based on the NCASI emission factor of 0.09 lb CPM/ton BLS rather than a percentage of the total PM. NCASI concluded that there is no correlation between the CPM emission rate and the filterable PM emission rate for kraft recovery furnaces.

The emission rate to which these PM speciation percentages are applied is the recovery furnace's maximum TSP emission rate, which is based on the average TSP emission factor from PM emission tests and the maximum BLS firing rate for each year (2003-2005). The maximum TSP emission rate, 934 lb/day (38.9 lb/hr), occurs in 2005 using the TSP emission factor of 0.74 lb TSP per ton BLS and the maximum BLS firing rate of 1,260 tons BLS per day. The filterable PM<sub>10</sub> emission rate is 50.2% of this value, or 469 lb/day (19.5 lb/hr). The CPM emission rate associated with these filterable emission rates is 113 lb/day (4.73 lb/hr), based on NCASI's CPM mean emission factor of 0.09 lb/ton BLS. Note that filterable emission rates are expected to vary due to operating characteristics and filterable particle control efficiencies, whereas CPM emissions control is not expected to vary as much; NCASI evaluated available data and concluded that the CPM emission rate is not correlated with filterable PM emissions.<sup>23</sup> Therefore, using the maximum TSP emission rate and NCASI CPM emission factor guidance, the total PM<sub>10</sub> (TPM<sub>10</sub>) emission rate from the recovery furnace is estimated to be 582 lb/day (24.3 lb/hr).

Next, the organic CPM (SOA) emissions are determined by multiplying the calculated CPM emissions by the organic percentage of CPM, 16.5%. The organic CPM calculation for the recovery furnace is shown below.

$$\left(4.73 \frac{\text{lb CPM}}{\text{hr}}\right) \left(16.5\% \frac{\text{SOA}}{\text{CPM}}\right) = 0.78 \frac{\text{lb SOA}}{\text{hour}}$$

Sulfate and non-sulfate inorganic CPM emissions from each stack are calculated based on the remaining inorganic fraction of CPM emissions. As described in the NCASI guidance

<sup>22</sup> NCASI, *Particulate Emissions Data for Pulp and Paper Industry Specific Sources*, October 27, 2006.

<sup>23</sup> Electronic correspondence between Mr. Ashok Jain (NCASI) and Mr. Don Shepherd (National Park Service), October 3, 2006.

document, all non-sulfate inorganic CPM is conservatively assumed to be in the form of nitrate, which is also a hygroscopic species that has the same visibility impairment effect (i.e., extinction coefficient) as sulfate. This distinction and assumption is important because primary nitrate emissions can be modeled in the CALPUFF analyses in the same manner as primary sulfate emissions.

$$\left(4.73 \frac{\text{lb CPM}}{\text{hr}}\right) \left(35.2\% \frac{\text{sulfate inorganic CPM}}{\text{CPM}}\right) = 1.66 \frac{\text{lb inorganic CPM as sulfate}}{\text{hour}}$$

$$\left(4.73 \frac{\text{lb CPM}}{\text{hr}}\right) \left(48.3\% \frac{\text{non-sulfate inorganic CPM}}{\text{CPM}}\right) = 2.28 \frac{\text{lb inorganic CPM as nitrate}}{\text{hour}}$$

Filterable PM<sub>10</sub> emissions are divided among the two different size categories by multiplying TSP emissions by the percentage of filterable PM for each size category, yielding hourly emissions of PM<sub>2.5-10</sub> and PM<sub>2.5</sub>. NCASI estimates that 0.025% of PM<sub>2.5</sub> is EC, which is allocated among the PM<sub>2.5</sub> size category. Calculations for the recovery furnace are shown below.

$$\left(38.9 \frac{\text{lb TSP}}{\text{hr}}\right) \left(13.0\% \frac{\text{PM}_{2.5-10}}{\text{Filterable TSP}}\right) = 5.06 \frac{\text{lb PM}_{2.5-10}}{\text{hour}}$$

$$\left(5.06 \frac{\text{lb PM}_{2.5-10}}{\text{hour}}\right) \left(100\% \frac{\text{PMC}}{\text{PM}_{2.5-10}}\right) = 5.06 \frac{\text{lb PMC}}{\text{hour}}$$

$$\left(38.9 \frac{\text{lb TSP}}{\text{hr}}\right) \left(37.2\% \frac{\text{PM}_{2.5}}{\text{Filterable TSP}}\right) = 14.5 \frac{\text{lb PM}_{2.5}}{\text{hour}}$$

$$\left(14.470 \frac{\text{lb PM}_{2.5}}{\text{hr}}\right) \left(0.025\% \frac{\text{EC}}{\text{PM}_{2.5}}\right) = 0.0036 \frac{\text{lb EC}}{\text{hour}}$$

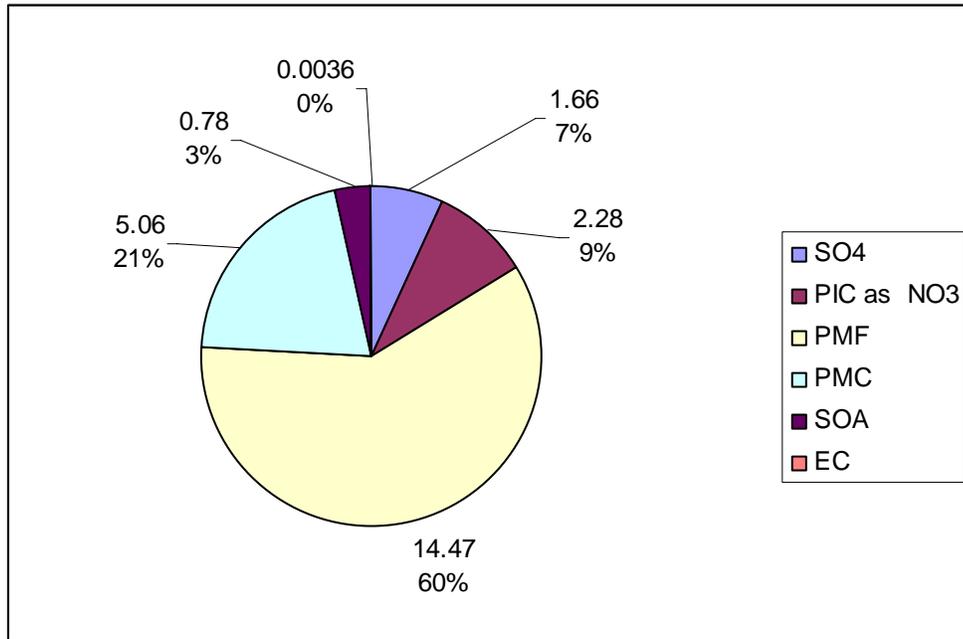
$$\left(14.470 \frac{\text{lb PM}_{2.5}}{\text{hr}}\right) \left(99.975\% \frac{\text{PMF}}{\text{PM}_{2.5}}\right) = 14.466 \frac{\text{lb PMF}}{\text{hour}}$$

Table 3-10 presents a summary of the speciated PM emissions for the recovery furnace. Figure 2-4 presents a graphical representation of the speciation of the total 24.25 lb/hr of TPM<sub>10</sub> from the recovery furnace.

**TABLE 3-10. RECOVERY FURNACE TPM<sub>10</sub> SPECIATION**

SO <sub>4</sub> (lb/hr)	PIC as NO <sub>3</sub> (lb/hr)	PMF (lb/hr)	PMC (lb/hr)	SOA (lb/hr)	EC (lb/hr)
1.66	2.28	14.47	5.06	0.78	0.0036

**FIGURE 3–2. RECOVERY FURNACE TPM<sub>10</sub> SPECIATION (LB/HR)**



### 3.2.3 SMELT DISSOLVING TANK PARTICULATE SPECIATION

PTPC operates a smelt dissolving tank (SDT) with a wet scrubber to control PM. PM emissions from a SDT are primarily composed of inorganic components such as sodium sulfate and sodium carbonate. PTPC analyzed the TSP stack test results from 2003 through 2005 to determine the maximum actual TSP emission rate from the smelt tank to which the subsequent speciation analysis is applied.

To speciate the PM emissions from the smelt tank, data from NCASI are used to determine PM size fractions and CPM emissions. The NCASI data is included in Appendix B of this report for reference.<sup>24</sup> The NCASI emission factors indicate that 4.0% of filterable PM<sub>2.5</sub> is Elemental Carbon (EC). Table 3-11 summarizes the relevant data for this source.

<sup>24</sup> NCASI, *Particulate Emissions Data for Pulp and Paper Industry Specific Sources*, October 27, 2006.

**TABLE 3-11. SMELT DISSOLVING TANK SPECIATION DATA**

Speciation Data	Value	Reference
Filterable PM <sub>10</sub> as a % of TSP	81.9%	NCASI Data Smelt Dissolving Tank with Scrubber October 27, 2006
Filterable PM <sub>2.5</sub> as a % of TSP	72.6%	
PMC (PM <sub>2.5-10</sub> ) as a % of TSP	9.3 %	
EC as % of Filterable PM <sub>2.5</sub>	4.0%	
Organic portion of CPM <sup>a</sup>	27.8%	
Sulfate inorganic portion of CPM <sup>a</sup>	27.3%	
Non-sulfate inorganic portion of CPM <sup>a</sup>	44.9%	

<sup>a</sup> The CPM emission rate is determined based on the NCASI emission factor of 0.0074 lb CPM/ton BLS rather than a percentage of the total PM. NCASI concluded that there is no correlation between the CPM emission rate and the filterable PM emission rate for smelt dissolving tanks.

The emission rate to which these PM speciation percentages are applied is the smelt dissolving tank’s maximum total PM (TPM) emission rate, which is based on the average TPM emission factor from TPM emission tests and the maximum BLS firing rate for each year (2003-2005).<sup>25</sup> The maximum TPM emission rate, 289 lb/day (12.05 lb/hr), occurs in 2005 using the TPM emission factor of 0.23 lb TPM per ton BLS and the maximum BLS firing rate of 1,260 tons BLS per day. The CPM emission rate associated with this filterable emission rate is 0.39 lb/hr, based on NCASI’s mean CPM emission factor of 0.0074 lb/ton BLS. Note that filterable emission rates are expected to vary due to operating characteristics and filterable particle control efficiencies, whereas CPM emissions control is not expected to vary as much. The total suspended particulate (TSP), or fine PM, emission rate is the TPM emission rate minus the CPM emission rate, or 11.66 lb TSP/hr. The filterable PM<sub>10</sub> emission rate is 81.9% of this value, or 9.55 lb/hr. Since 100% of the CPM emissions are assumed to be less than 2.5 μm in diameter, the total PM<sub>10</sub> (TPM<sub>10</sub>) emission rate is the sum of the filterable PM<sub>10</sub> and the CPM emissions. The total PM<sub>10</sub> (TPM<sub>10</sub>) emission rate from the SDT is therefore 9.94 lb/hr.

Next, the organic CPM (SOA) emissions are determined by multiplying the calculated CPM emission rate by the organic percentage of CPM, 27.8%. The organic CPM calculation for the SDT is shown below.

$$\left(0.39 \frac{\text{lb CPM}}{\text{hr}}\right) \left(27.8\% \frac{\text{SOA}}{\text{CPM}}\right) = 0.11 \frac{\text{lb SOA}}{\text{hour}}$$

Sulfate and non-sulfate inorganic CPM emissions from the SDT are calculated based on the remaining inorganic fraction of CPM emissions. As described in the NCASI guidance document, all non-sulfate inorganic CPM is conservatively assumed to be in the form of nitrate, which is also a hygroscopic species that has the same visibility impairment effect (i.e., extinction coefficient) as sulfate. This distinction and assumption is important

<sup>25</sup> The smelt dissolving tank and lime kiln at the PTPC Mill are tested for particulate emissions using Washington State Ecology Method 8, which measures a single value for both filterable and condensable particulate emissions.

because primary nitrate emissions can be modeled in the CALPUFF analyses in the same manner as primary sulfate emissions.

$$\left(0.39 \frac{\text{lb CPM}}{\text{hr}}\right) \left(27.8\% \frac{\text{sulfate inorganic CPM}}{\text{CPM}}\right) = 0.11 \frac{\text{lb inorganic CPM as sulfate}}{\text{hour}}$$

$$\left(0.39 \frac{\text{lb CPM}}{\text{hr}}\right) \left(44.9\% \frac{\text{non-sulfate inorganic CPM}}{\text{CPM}}\right) = 0.17 \frac{\text{lb inorganic CPM as nitrate}}{\text{hour}}$$

Filterable PM<sub>10</sub> emissions are divided among the two different size categories by multiplying TSP emissions by the percentage of filterable PM for each size category, yielding hourly emissions of PM<sub>2.5-10</sub> and PM<sub>2.5</sub>. NCASI estimates that 4.0 % of PM<sub>2.5</sub> is EC, which is allocated among the PM<sub>2.5</sub> size category. Calculations for the SDT are shown below.

$$\left(11.66 \frac{\text{lb TSP}}{\text{hr}}\right) \left(9.3\% \frac{\text{PM}_{2.5-10}}{\text{Filterable TSP}}\right) = 1.08 \frac{\text{lb PM}_{2.5-10}}{\text{hour}}$$

$$\left(1.08 \frac{\text{lb PM}_{2.5-10}}{\text{hour}}\right) \left(100\% \frac{\text{PMC}}{\text{PM}_{2.5-10}}\right) = 1.08 \frac{\text{lb PMC}}{\text{hour}}$$

$$\left(11.66 \frac{\text{lb TSP}}{\text{hr}}\right) \left(72.6\% \frac{\text{PM}_{2.5}}{\text{Filterable TSP}}\right) = 8.46 \frac{\text{lb PM}_{2.5}}{\text{hour}}$$

$$\left(8.46 \frac{\text{lb PM}_{2.5}}{\text{hr}}\right) \left(4.0\% \frac{\text{EC}}{\text{PM}_{2.5}}\right) = 0.34 \frac{\text{lb EC}}{\text{hour}}$$

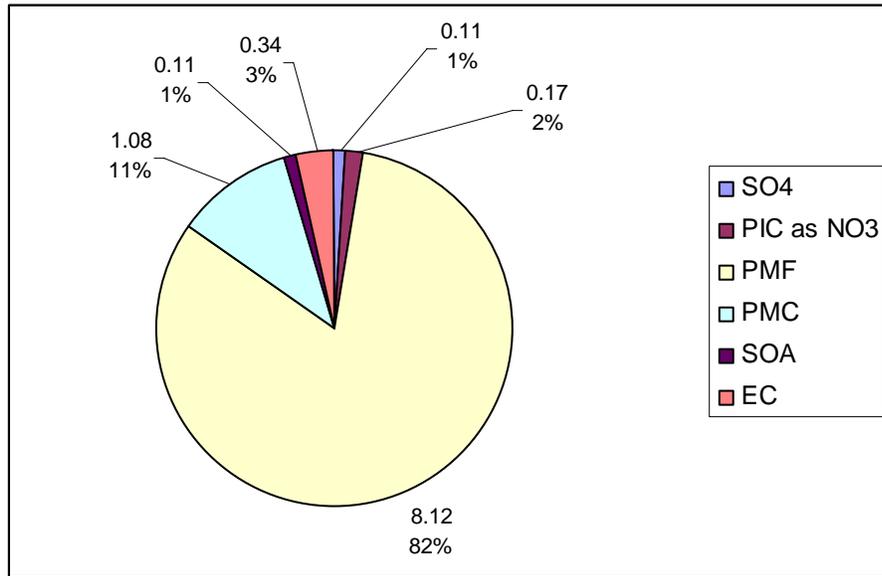
$$\left(8.46 \frac{\text{lb PM}_{2.5}}{\text{hr}}\right) \left(96.0\% \frac{\text{PMF}}{\text{PM}_{2.5}}\right) = 8.12 \frac{\text{lb PMF}}{\text{hour}}$$

Table 3-12 presents a summary of the speciated PM emissions for the smelt dissolving tank. Figure 3-3 presents a graphical representation of the speciation of the total 9.94 lb/hr of TPM<sub>10</sub>.

**TABLE 3-12. SMELT DISSOLVING TANK TPM<sub>10</sub> SPECIATION (LB/HR)**

SO <sub>4</sub> (lb/hr)	PIC as NO <sub>3</sub> (lb/hr)	PMF (lb/hr)	PMC (lb/hr)	SOA (lb/hr)	EC (lb/hr)
0.11	0.17	8.12	1.08	0.11	0.34

**FIGURE 3–3. SMELT DISSOLVING TANK PM SPECIATED EMISSIONS (LB/HR)**



### 3.2.4 PM SPECIATION FOR NO. 10 POWER BOILER

PTPC operates the No. 10 Power Boiler with a multiclone and venturi scrubber to control particulate emissions. The No. 10 Power Boiler combusts wood-waste, bark, primary clarifier sludge, old corrugated container (OCC) rejects, and recycle fuel oil (RFO). The No. 10 Power Boiler is specifically not permitted to burn salty hog fuel per Condition D(2)(c) of PTPC’s Air Operating Permit No. WA 000092-2. PTPC analyzed TSP stack test results from 2003 through 2005 to determine the maximum actual TSP emission rate to which the subsequent speciation analysis is applied.

To speciate the PM emissions from the boiler, data from AP-42 Table 1.6-5, *Cumulative Particle Size Distribution and Size-specific Emission Factors for Wood/Bark-Fired Boilers*,<sup>26</sup> and EPA speciation profiles<sup>27</sup> for both wood-fired boilers and oil-fired boilers are used to determine PM size fractions and CPM emissions. Table 3-13 summarizes the relevant data for this source.

<sup>26</sup> AP-42, Section 1.6, *Wood Residue Combustion in Boilers*, dated September 2003.

<sup>27</sup> U.S. EPA developed speciation profiles for generic sources, "pm25\_prof\_titles\_revised.xls" downloaded from <http://www.epa.gov/ttn/chief/emch/speciation/> on March 21, 2007.

**TABLE 3-13. NO. 10 POWER BOILER SPECIATION DATA**

Speciation Data	Value	Reference
PM <sub>10</sub> as a % of TSP	98%	AP-42 Section 1.6, Table 1.6-5 Wood-Fired Boiler with Scrubber Control <sup>a</sup>
PM <sub>2.5</sub> as a % of TSP	98%	
Organic PM (SOA) portion of TPM <sub>2.5</sub>	39%	EPA Speciation Profile for Wood Waste Boiler, Profile No. NWWAS
Sulfate (SO <sub>4</sub> ) portion of TPM <sub>2.5</sub>	8%	
Nitrate (NO <sub>3</sub> ) portion of TPM <sub>2.5</sub>	0%	
PMF portion of TPM <sub>2.5</sub> <sup>b</sup>	39%	
Elemental Carbon (EC) portion of TPM <sub>2.5</sub>	14%	
TPM <sub>2.5</sub> as a % of TSP <sup>c</sup>	185%	
Organic PM (SOA) portion of TPM <sub>2.5</sub>	3.84%	EPA Speciation Profile for Distillate Oil Fired Boiler, Profile No. 22003
Sulfate (SO <sub>4</sub> ) portion of TPM <sub>2.5</sub>	32.17%	
Nitrate (NO <sub>3</sub> ) portion of TPM <sub>2.5</sub>	0.24%	
PMF portion of TPM <sub>2.5</sub> <sup>b</sup>	56.05%	
Elemental Carbon (EC) portion of TPM <sub>2.5</sub>	7.70%	
TPM <sub>2.5</sub> as a % of TSP <sup>d</sup>	154%	

<sup>a</sup> The PM<sub>10</sub> and PM<sub>2.5</sub> size fractions as a percent of TSP are conservatively based on those for a wood-fired boiler with scrubber rather than a weighted average of wood-fired and oil-fired size fractions because the wood-fired boiler with scrubber size fractions result in higher total PM<sub>10</sub> (TPM<sub>10</sub>) emissions.

<sup>b</sup> PMF is equivalent to the “other” speciation category in the EPA speciation profiles, as it is the only remaining PM speciation category.

<sup>c</sup> Expressing TPM<sub>2.5</sub> as a % of TSP accounts for the emissions of condensable PM that are not measured in the front-half PM testing conducted at PTPC. For wood waste boilers, TPM<sub>2.5</sub> as a % of TSP is calculated based on the total percentage of filterable PM categories and the fraction of PM<sub>2.5</sub> of TSP as follows:

$$\left( \frac{98\%PM_{2.5}}{TSP} \right) \left( \frac{TPM_{2.5}}{(39\% + 14\%)FilterablePM_{2.5}} \right) = \frac{185\% TPM_{2.5}}{TSP}$$

<sup>d</sup> Expressing TPM<sub>2.5</sub> as a % of TSP accounts for the emissions of condensable PM that are not measured in the front-half PM testing conducted at PTPC. For distillate oil fired boilers, TPM<sub>2.5</sub> as a % of TSP for is calculated based on the total percentage of filterable PM categories and the fraction of PM<sub>2.5</sub> of TSP as follows:

$$\left( \frac{98\%PM_{2.5}}{TSP} \right) \left( \frac{TPM_{2.5}}{(56.05\% + 7.7\%)FilterablePM_{2.5}} \right) = \frac{154\% TPM_{2.5}}{TSP}$$

The emission rate to which these PM speciation percentages are applied is the No. 10 Power Boiler’s maximum TSP emission rate, based on the average TSP emission factor from PM emission tests and the maximum firing rate for each year (2003-2005). The maximum TSP emission rate, 774 lb/day (32.24 lb/hr), occurs in 2003 using the TSP emission factor of 0.093 lb TSP per MMBtu and the maximum firing rate of 8,323 MMBtu per day (347 MMBtu/hr).<sup>28</sup> The filterable PM<sub>10</sub> emission rate is 98% of this value, or 758 lb/day (31.59 lb/hr). Since the filterable PM<sub>2.5</sub> and PM<sub>10</sub> emission rates are both 98% of the TSP emission rate, there are no PM particles with diameters less than 10 μm and greater than 2.5 μm (PM<sub>2.5-10</sub>), the PM size range for course PM (PMC). Therefore, the emission rate of PMC from the No. 10 Power Boiler is zero.

PTPC created a speciation profile for the No. 10 Power Boiler using a weighted average of the two EPA speciation profiles presented in Table 3-13 based on the percentage of each

<sup>28</sup> The maximum measured firing rate of the No. 10 Power Boiler is based on steam production rather than measured hog fuel and fuel oil firing rates, as the measurement of the daily hog fuel feed rate may not accurately measure the hog fuel firing rate. The firing rate in MMBtu/day is calculated assuming the heat output is 1,000 Btu/lb steam, and assuming a boiler efficiency for wood of 65 % and for oil of 80 % and a fuel mix based on the measured oil firing rate.

type of fuel burned during PM source tests for each year (2003-2005). Individual speciation profiles are created for each year because the year with the highest TSP source test emission factor may not result in the worst-case total PM<sub>10</sub> emission rate if a higher percentage of fuel oil was burned (resulting in a higher CPM emission factor) in a different year. The ratio of fuel types and the TPM<sub>10</sub> emission factor for 2003 through 2005 are presented in Table 3-14. The following example equation shows the weighted average TPM<sub>10</sub> emission factor calculation for 2003 based on the percentage of each fuel burned.

$$\left(0.093 \frac{\text{lb TSP}}{\text{MMBtu}}\right) \times \left[ \left(70.3\% \frac{\text{wood burned}}{\text{total fuel burned}}\right) \left(185\% \frac{\text{lb TPM}_{10}}{\text{lb TSP from wood}}\right) + \left(29.7\% \frac{\text{oil burned}}{\text{total fuel burned}}\right) \left(154\% \frac{\text{lb TPM}_{10}}{\text{lb TSP from oil}}\right) \right] = 0.163 \frac{\text{lb TPM}_{10}}{\text{MMBtu}}$$

**TABLE 3-14. NO. 10 POWER BOILER FUEL USE DISTRIBUTIONS**

	2003	2004	2005
Percent Wood	70.3%	70.7%	72.7%
Percent Oil	29.7%	29.3%	27.3%
TPM <sub>10</sub> (lb/MMBtu)	0.163	0.147	0.145

As in the case of the TSP emission rate, the maximum total PM<sub>10</sub> (TPM<sub>10</sub>) emission rate of 1,359 lb/day (56.62 lb/hr) also occurs in 2003 using the TPM<sub>10</sub> emission factor of 0.163 lb TPM<sub>10</sub> per MMBtu and the maximum firing rate of 8,323 MMBtu per day. The 2003 data set represents the worst-case emissions for all PM speciation categories from the No. 10 Power Boiler. The speciation profile for 2003 is presented in Table 3-15 below.

**TABLE 3-15. NO. 10 POWER BOILER WEIGHTED AVERAGE SPECIATION PROFILE FOR 2003**

Speciation Category	Woodwaste Profile		Fuel Oil Profile		2003 Profile
	Percent of TPM <sub>10</sub>	Emission Factor (lb/MMBtu)	Percent of TPM <sub>10</sub>	Emission Factor (lb/MMBtu)	Emission Factor (lb/MMBtu)
TSP	54.08%	0.093	65.05%	0.093	0.093
CPM	47.00%	0.081	36.25%	0.052	0.072
Filterable PM <sub>10</sub>	53.00%	0.091	63.75%	0.091	0.091
Total PM <sub>10</sub>	100.00%	0.172	100.00%	0.143	0.163
Sulfate	8.00%	0.014	32.17%	0.046	0.023
Nitrate	0.00%	0.000	0.24%	0.000	0.000
SOA	39.00%	0.067	3.84%	0.005	0.049
PMF	39.00%	0.067	56.05%	0.080	0.071
PMC	0.00%	0.000	0.00%	0.000	0.000
EC	14.00%	0.024	7.70%	0.011	0.020

The sulfate (SO<sub>4</sub>), nitrate (NO<sub>3</sub>), SOA, PMF, PMC, and EC emission factors for the woodwaste and fuel oil profiles presented in the table are determined by multiplying the TPM<sub>10</sub> emission factor by the percentage that each category contributes to the total TPM<sub>10</sub>. A sample calculation for the sulfate emission factor for the woodwaste profile is shown below.

$$\left( 0.172 \frac{\text{lb TPM}_{10}}{\text{MMBtu}} \right) \left( 8\% \frac{\text{sulfate}}{\text{TPM}_{10}} \right) = 0.014 \frac{\text{lb sulfate}}{\text{MMBtu}}$$

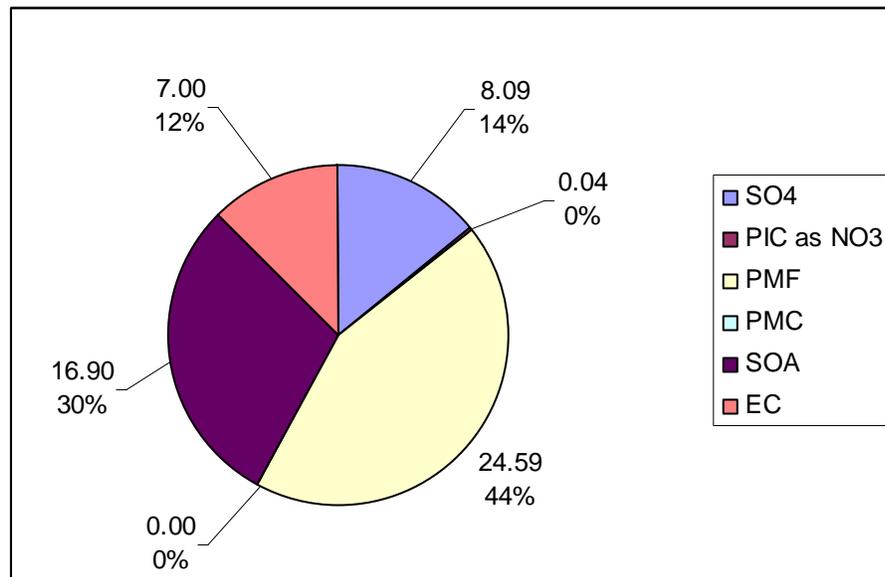
The weighted average 2003 emission factors for each particulate category are then determined based on the fuel mix burned during 2003 source tests of 70.3 % woodwaste and 29.7 % fuel oil. By multiplying the percentage of woodwaste burned by the emission factors for the woodwaste profile and the percentage of fuel oil burned by the emission factors for the fuel oil, then summing the products, the weighted average of the two speciation profiles is created.

Table 3-16 presents a summary of the speciated PM emission rates for the No. 10 Power Boiler. Figure 3-4 presents graphical representations of the speciated TPM<sub>10</sub> emissions of 56.62 lb/hr.

**TABLE 3-16. NO. 10 POWER BOILER TPM<sub>10</sub> SPECIATION**

	SO <sub>4</sub>	PIC as NO <sub>3</sub>	PMF	PMC	SOA	EC
<b>Emission Rate (lb/hr)</b>	8.09	0.04	24.59	0.00	16.9	7.00
<b>Percent of TPM<sub>10</sub></b>	14.29%	0.06%	43.44%	0.00%	29.85%	12.36%

**FIGURE 3-4. NO. 10 POWER BOILER TPM<sub>10</sub> SPECIATION (LB/HR)**



### 3.2.5 LIME KILN PARTICULATE SPECIATION

PTPC operates a lime kiln with a wet scrubber to control PM. PTPC analyzed the total particulate matter (TPM) stack test results from 2003 through 2005 to determine the maximum actual TPM emission rate from the lime kiln to which the subsequent speciation analysis is applied.

To speciate the PM emissions from the lime kiln, data from NCASI are used to determine PM size fractions and CPM emissions, which are included in Appendix B of this report for reference.<sup>29</sup> The NCASI emissions factors indicate that 4.0% of filterable PM<sub>2.5</sub> is elemental carbon (EC). Table 3-17 summarizes the relevant data for this source.

**TABLE 3-17. LIME KILN SPECIATION DATA**

Speciation Data	Value	Reference
Filterable PM <sub>10</sub> as a % of TSP	84.7%	NCASI Data Lime Kiln with Scrubber October 27, 2006
Filterable PM <sub>2.5</sub> as a % of TSP	76.8%	
PMC (PM <sub>2.5-10</sub> ) as a % of TSP	7.9 %	
EC as % of Filterable PM <sub>2.5</sub>	4.0%	
Organic portion of CPM <sup>a</sup>	8.3%	
Sulfate inorganic portion of CPM <sup>a</sup>	58.2%	
Non-sulfate inorganic portion of CPM <sup>a</sup>	33.5%	

<sup>a</sup> The CPM emission rate is determined based on the NCASI emission factor of 0.155 lb CPM/ton CaO rather than a percentage of the total PM. NCASI concluded that there is no correlation between the CPM emission rate and the filterable PM emission rate for lime kilns.

The emission rate to which these PM speciation percentages are applied is the lime kiln's maximum TPM emission rate, based on the average TPM emission factor from PM emission tests and the maximum lime (CaO) throughput rate for each year (2003-2005). The maximum TPM emission rate, 212 lb/day (8.84 lb/hr), occurs in 2003 using the TPM emission factor of 1.02 lb TPM per ton CaO and the maximum CaO throughput rate 208 tons CaO per day.<sup>30</sup> The CPM emission rate associated with this filterable emission rate is 1.35 lb/hr, based on NCASI's mean CPM emission factor of 0.155 lb/ton CaO. Note that filterable emission rates are expected to vary due to operating characteristics and filterable particle control efficiencies, whereas CPM emissions control is not expected to vary as much. The total suspended particulate (TSP), or filterable PM, emission rate is the TPM emission rate minus the CPM emission rate, or 7.50 lb TSP/hr. The filterable PM<sub>10</sub> emission rate is 84.7 % of this value, or 6.35 lb/hr. Since 100% of the CPM emissions are assumed to be less than 2.5 μm in diameter, the total PM<sub>10</sub> (TPM<sub>10</sub>) emission rate is the sum of the filterable PM<sub>10</sub> and the CPM emissions. The total PM<sub>10</sub> (TPM<sub>10</sub>) emission rate from the SDT is therefore 7.69 lb/hr.

<sup>29</sup> NCASI, *Particulate Emissions Data for Pulp and Paper Industry Specific Sources*, October 27, 2006.

<sup>30</sup> The maximum lime throughput rate is calculated based on the NCASI provided conversion factor of 0.275 ton CaO per air dried ton pulp (ADTP). NCASI Technical Bulletin No. 884, *Compilation of Criteria Air Pollutant Emissions Data for Sources at Pulp and Paper Mills Including Boilers*, August 2004.

Next, the organic CPM (SOA) emissions are determined by multiplying the calculated CPM emission rate by the organic percentage of CPM, 8.30 %. The organic CPM calculation for the lime kiln is shown below.

$$\left(1.35 \frac{\text{lb CPM}}{\text{hr}}\right) \left(8.30\% \frac{\text{SOA}}{\text{CPM}}\right) = 0.11 \frac{\text{lb SOA}}{\text{hour}}$$

Sulfate and non-sulfate inorganic CPM emissions from each stack are calculated based on the remaining inorganic fraction of CPM emissions. As described in the NCASI guidance document, all non-sulfate inorganic CPM is conservatively assumed to be in the form of nitrate, which is also a hygroscopic species that has the same visibility impairment effect (i.e., extinction coefficient) as sulfate. This distinction and assumption is important because primary nitrate emissions can be modeled in the CALPUFF analyses in the same manner as primary sulfate emissions.

$$\left(1.35 \frac{\text{lb CPM}}{\text{hr}}\right) \left(58.2\% \frac{\text{sulfate inorganic CPM}}{\text{CPM}}\right) = 0.78 \frac{\text{lb inorganic CPM as sulfate}}{\text{hour}}$$

$$\left(1.35 \frac{\text{lb CPM}}{\text{hr}}\right) \left(33.5\% \frac{\text{non - sulfate inorganic CPM}}{\text{CPM}}\right) = 0.45 \frac{\text{lb inorganic CPM as nitrate}}{\text{hour}}$$

Filterable PM<sub>10</sub> emissions are divided among the two different size categories by multiplying TSP emissions by the percentage of filterable PM for each size category, yielding hourly emissions of PM<sub>2.5-10</sub> and PM<sub>2.5</sub>. NCASI estimates that 4.0 % of PM<sub>2.5</sub> is EC, which is allocated among the PM<sub>2.5</sub> size category. Calculations for the lime kiln are shown below.

$$\left(7.50 \frac{\text{lb TSP}}{\text{hr}}\right) \left(7.9\% \frac{\text{PM}_{2.5-10}}{\text{Filterable TSP}}\right) = 0.59 \frac{\text{lb PM}_{2.5-10}}{\text{hour}}$$

$$\left(0.59 \frac{\text{lb PM}_{2.5-10}}{\text{hour}}\right) \left(100\% \frac{\text{PMC}}{\text{PM}_{2.5-10}}\right) = 0.59 \frac{\text{lb PMC}}{\text{hour}}$$

$$\left(7.50 \frac{\text{lb TSP}}{\text{hr}}\right) \left(76.8\% \frac{\text{PM}_{2.5}}{\text{Filterable TSP}}\right) = 5.76 \frac{\text{lb PM}_{2.5}}{\text{hour}}$$

$$\left(5.76 \frac{\text{lb PM}_{2.5}}{\text{hr}}\right) \left(4.0\% \frac{\text{EC}}{\text{PM}_{2.5}}\right) = 0.23 \frac{\text{lb EC}}{\text{hour}}$$

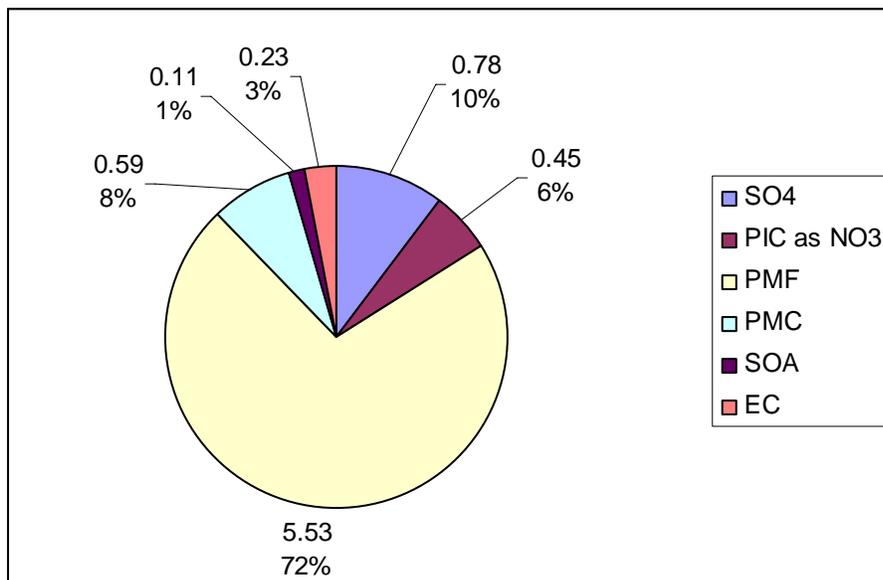
$$\left(5.76 \frac{\text{lb PM}_{2.5}}{\text{hr}}\right) \left(96.0\% \frac{\text{PMF}}{\text{PM}_{2.5}}\right) = 5.53 \frac{\text{lb PMF}}{\text{hour}}$$

Table 3-18 presents a summary of the speciated PM emissions for the Lime Kiln. Figure 3-5 presents a graphical representation of the speciation of the total 7.69 lb/hr of TPM<sub>10</sub>.

**TABLE 3-18. LIME KILN TPM<sub>10</sub> SPECIATION (LB/HR)**

SO <sub>4</sub> (lb/hr)	PIC as NO <sub>3</sub> (lb/hr)	PMF (lb/hr)	PMC (lb/hr)	SOA (lb/hr)	EC (lb/hr)
0.78	0.45	5.53	0.59	0.11	0.23

**FIGURE 3-5. LIME KILN PM SPECIATED EMISSIONS**



### 3.3 MODELED STACK PARAMETERS AND EMISSIONS

Actual stack parameters are input to the CALPUFF model to represent the point of visibility-affecting pollutant emissions. The location of each point source is represented consistently in the Lambert Conformal Coordinate system used for the meteorological data analyses provided by Ecology. Each exhaust discharges vertically without obstruction. Effects of building downwash are considered insignificant and are not modeled.<sup>31</sup> Table 3-19 summarizes the stack parameters and Table 3-20 summarizes all modeled emission rates for BART-eligible emission units at the PTPC Mill, including the speciated PM emission rates not specified in Table 3-6.<sup>32</sup>

<sup>31</sup> Given the distance from PTPC to the nearest Class I area (approximately 36 km), building downwash does not need to be considered. Phone conversation between Mr. Clint Bowman, Ecology, and Ms. Kirsten Rollay, Trinity, April 16, 2007.

<sup>32</sup> As discussed in Section 6.3, several changes to the emissions calculations (i.e., No. 10 Power Boiler, Lime Kiln, and Smelt Dissolving Tank PM emission factors, No. 10 Power Boiler worst-case firing rate) were made after the initial BART applicability analysis was conducted. All changes resulted in a decrease in modeled emission rates. The emission rates presented in this section reflect the refined calculations. However, the modeling results presented in Section 5 represent impacts based on the original (higher) emission rates. The refined modeling analysis and the BART Determination visibility analyses for Olympic National Park presented in Sections 6 and 12, respectively, are based on the refined emission rates as presented in this section. The original emission rates are provided as a footnote to Table 3-20.

The stack associated with the Recovery Furnace is taller than the nominal 65 meter (213.3 foot) GEP stack height. However, the building height of the dominant structure affecting emissions from the Recovery Furnace is 160 feet, resulting in a calculated GEP stack height of 400 feet. Because the actual stack height is less than this value, the actual stack height is used in the modeling analyses.

**TABLE 3-19. STACK PARAMETERS FOR BART-ELIGIBLE EMISSION UNITS**

Emission Unit	Modeling ID	Lambert Conformal Coordinate East (km)	Lambert Conformal Coordinate North (km)	Base Elevation (m)	Stack Height (ft)	Stack Diameter (ft)	Exit Gas Velocity (dscfm)	Exit Gas Temperature (F)
Recovery Furnace	RecBlr	-128.955	-96.024	5.49	251	7.00	179,861	343.00
Smelt Tank	SmltTank	-128.973	-95.974	5.49	171	5.90	9,056	168.50
No. 10 Power Boiler	10Blr	-128.997	-95.996	5.49	174	7.00	100,836	142.30
Lime Kiln	LimeKiln	-129.019	-95.981	5.49	120	6.00	17,257	155.90

**TABLE 3-20. MODELED EMISSION RATES FOR BART-ELIGIBLE UNITS**

Emission Unit	Modeling ID	SO <sub>2</sub> (g/s)	H <sub>2</sub> SO <sub>4</sub> (g/s)	NO <sub>x</sub> (g/s)	NO <sub>3</sub> (g/s)	PMF (g/s)	PMC (g/s)	SOA (g/s)	EC (g/s)
Recovery Boiler	RecBlr	1.33E+01	2.10E-01	9.92E+00	2.88E-01	1.82E+00	6.37E-01	9.82E-02	4.56E-04
Smelt Dissolving Tank <sup>a</sup>	SmltTank	3.31E-02	1.34E-02	1.32E-01	2.20E-02	1.02E+00	1.37E-01	1.36E-02	4.27E-02
No. 10 Power Boiler <sup>b</sup>	10Blr	9.00E+00	1.02E+00	1.04E+01	4.45E-03	3.10E+00	0.00E+00	2.13E+00	8.82E-01
Lime Kiln <sup>c</sup>	LimeKiln	2.03E-01	9.87E-02	1.26E+00	5.68E-02	6.96E-01	7.46E-02	1.41E-02	2.90E-02

<sup>a</sup> The filterable PM emission factors (PMF, PMC, and EC) for the Smelt Dissolving Tank were changed after the applicability analysis was conducted. The emission rates presented above reflect these updated calculations. However, the modeling results presented in Section 5 represent impacts based on the original (higher) emission rates. The original filterable PM emission rates for the Smelt Dissolving Tank are as follows: 1.06E-00 grams PMF per second, 1.41E-01 grams PMC per second, and 4.41E-02 grams EC per second.

<sup>b</sup> The emission calculations for the No. 10 Power Boiler were changed after the applicability analysis was conducted. The emission rates presented above reflect these updated calculations. However, the modeling results presented in Section 5 represent impacts based on the original (higher) emission rates. The original emission rates for the No. 10 Power Boiler are as follows: 1.16E+01 grams SO<sub>2</sub> per second, 1.38E+00 grams H<sub>2</sub>SO<sub>4</sub> per second, 1.07E+01 grams NO<sub>x</sub> per second, 6.04E-03 grams NO<sub>3</sub> per second, 4.20E+00 grams PMF per second, 0.00E+00 grams PMC per second, 2.89E+00 grams SOA per second, and 1.20E+00 grams EC per second.

<sup>c</sup> The filterable PM emission factors (PMF, PMC, and EC) for the Lime Kiln were changed after the applicability analysis was conducted. The emission rates presented above reflect these updated calculations. However, the modeling results presented in Section 5 represent impacts based on the original (higher) emission rates. The original filterable PM emission rates for the Lime Kiln are as follows: 8.21E-01 grams PMF per second, 8.80E-02 grams PMC per second, and 3.42E-02 grams EC per second.

## 4. AIR QUALITY MODELING ANALYSES FOR BART APPLICABILITY AND DETERMINATION

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This section of the report describes the modeling methods, data resources, and technical options used to conduct modeling analyses to assess visibility impacts. Air quality modeling for the BART applicability assessment and determination is conducted following the methods described in the *Washington, Oregon, and Idaho: Protocol for the Application of the CALPUFF Modeling System Pursuant to the Best Available Retrofit Technology (BART) Regulation (BART Modeling Protocol)*, dated October 11, 2006.

### 4.1 AIR QUALITY MODELING SYSTEM

CALPUFF is a multi-layer, multi-species, non-steady-state Lagrangian puff model, which can simulate the effects of time- and space-varying meteorological conditions on pollutant transport, transformation, and removal. The modeling system is designed to handle the complexities posed by the complex terrain, the large source-receptor distances, chemical transformation and deposition, and other issues related to Class I visibility impacts. A complete description of the model formulation and capabilities is provided in the *User's Guides* for the CALPUFF modeling system.

The CALPUFF modeling system has been adopted by the U.S. EPA as a recommended regulatory guideline model for source-receptor distances greater than 50 km, and for use on a case-by-case basis in complex flow situations for shorter distances. CALPUFF is recommended for Class I area impact assessments by the Interagency Workgroup on Air Quality Models (IWAQM). The U.S. EPA's BART guidance recommends CALPUFF as "the best modeling application available for predicting a single source's contribution to visibility impairment."

As a result of these recommendations, the *BART Modeling Protocol* is based on the use of CALPUFF and is used by PTPC for the source-specific analysis of visibility impacts attributable to the PTPC Mill. Specifically, CALMET Version 6.211/060414, CALPUFF Version 6.112/060412, POSTUTIL Version 1.52/060412, and CALPOST Version 6.131/060410 are designated as the recommended versions for modeling in the *BART Modeling Protocol* and are used in the CALPUFF BART Applicability Analysis and Determination Report for PTPC's Mill.

### 4.2 MODELING ANALYSIS TECHNIQUES

The *BART Modeling Protocol* specifies the methods for performing the modeling analysis for BART applicability and determination demonstrations. The following sections provide more specifics on PTPC's demonstration.

#### 4.2.1 VISIBILITY ASSESSMENT METRIC

The U.S. EPA BART guidelines prescribe that the 98<sup>th</sup> percentile, 24-hour average visibility impact computed in a modeling analysis that evaluates three years of meteorological data should be compared to the contribution threshold of 0.5 dv to assess BART applicability. The

*BART Modeling Protocol* and subsequent letter from Ecology to Matt Cohen on behalf of the Washington BART Coalition, clarify that Ecology conservatively considers the 98<sup>th</sup> percentile to be equivalent to the 8<sup>th</sup> highest result, on a 24-hour average for each modeled year and Class I area.<sup>33</sup> This same letter confirms Ecology's acceptance of the 0.5 dv threshold as a firm criterion in BART applicability analyses.

The default CALPOST processing of modeled visibility impacts outputs a summary table of results, ranking the highest 24-hour average impacts for the year at each Class I area, from which the 8<sup>th</sup> highest impact can be readily discerned. This interpretation of the visibility impact is a conservative estimate of the 98<sup>th</sup> percentile impact since the spatial and temporal variability of impacts at each receptor is ignored, recognizing that the receptor where the highest impact occurs can change from day to day.

#### **4.2.2 METEOROLOGICAL AND COMPUTATIONAL GRIDS**

The *BART Modeling Protocol* prescribes that BART applicability and determination analyses be conducted on a 4-km meteorological and computational grid. The resolution of the computational analysis dictates the extent to which geophysical (i.e., terrain and land use) and meteorological conditions are represented in the CALMET meteorological model, hence the advection, dispersion, and chemical transformation of visibility-affecting pollutants in the CALPUFF meteorological model. The meteorological modeling for the Idaho DEQ meteorological data set used 4-km grids to provide common data resources to eligible sources conducting BART analyses. This data set is used by PTPC to assess visibility impacts attributable to the mill.

#### **4.2.3 MODEL PROCESSING AND POSTPROCESSING METHODS**

The IWAQM *Phase 2 Report* prescribes recommended default model processing options to be used in CALPUFF analyses, which are in most cases considered regulatory default options under U.S. EPA's *Guideline on Air Quality Models*. IWAQM default model options are prescribed for use in modeling analyses where other defaults are not provided in the *BART Modeling Protocol*.

### **4.3 CALMET METEOROLOGICAL PROCESSING**

CALMET is the meteorological preprocessor that compiles three-dimensional meteorological fields from mesoscale model (MM) output, raw observations of surface and upper air conditions, precipitation measurements, and geophysical parameters into a single hourly, gridded data set for input to CALPUFF. The *CALMET User's Guide* provides a detailed description of the model's formulation and capabilities.

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<sup>33</sup> Letter from Sarah Rees, Ecology, to Matt Cohen and the Washington BART Coalition, January 4 and 22, 2007.

The federal *Guideline* for CALPUFF processing provides the following recommendations for the meteorological data period in Section 9.3.1.2:

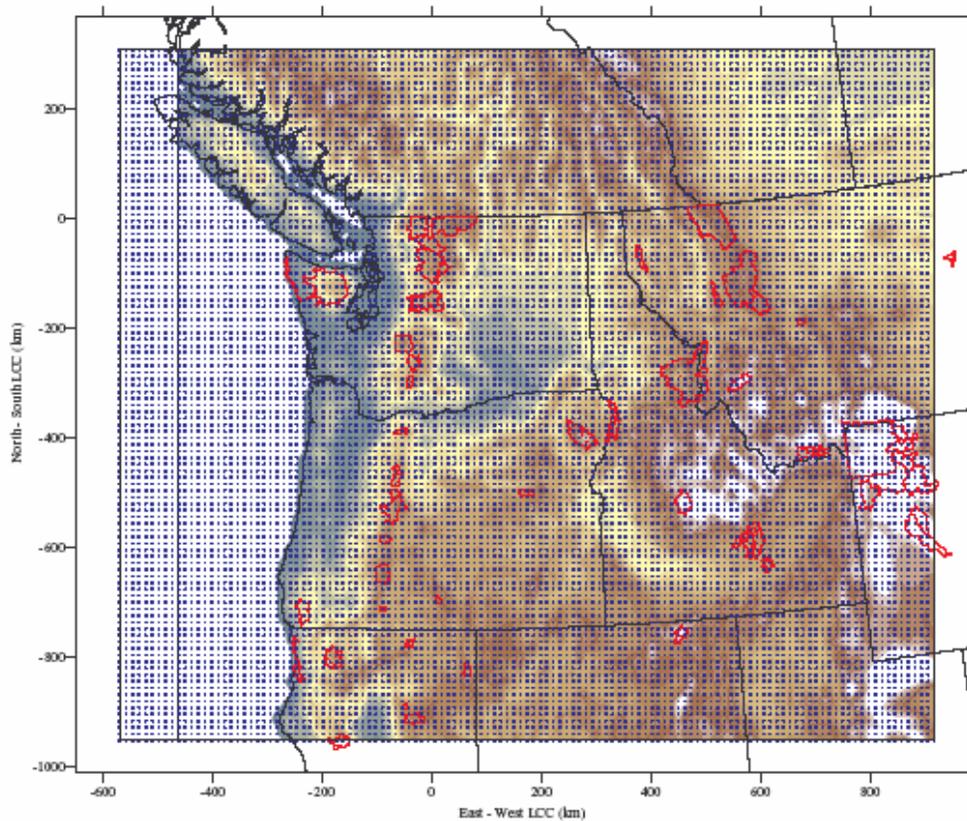
*Less than five, but at least three, years of meteorological data (need not be consecutive) may be used if mesoscale meteorological fields are available, as discussed in paragraph 9.3(c). These mesoscale meteorological fields should be used in conjunction with available standard [National Weather Service] NWS or comparable meteorological observations within and near the modeling domain.*

The *BART Modeling Protocol* prescribes the years 2003 through 2005 for BART Applicability Analyses. Washington, Oregon, and Idaho contracted the development of a consistent meteorological data set, which may be used for BART applicability and determination analyses. PTPC used the common CALMET data prepared for Washington, Oregon, and Idaho to conduct the BART analyses.

#### 4.3.1 CALMET METEOROLOGICAL DOMAIN

The CALMET modeling domain prepared for use by sources in Washington, Oregon, and Idaho is shown in Figure 4-1. The CALPUFF computational domains are selected as a subset of this domain as described in the following section of this report.

**FIGURE 4-1. CALMET MODELING DOMAIN  
(AS PROVIDED IN THE *BART MODELING PROTOCOL*)**



The regional domain is designed to allow any Class I areas within the area to be evaluated with a single meteorological database and consistent CALPUFF modeling options. The horizontal domain is comprised of grid cells, each containing a central grid point at which meteorological and computational parameters are calculated at each time step. A grid spacing interval of 4 km is used. The LCC projection system is used to describe the horizontal grid, with origin at 49 degrees North latitude and 121 degrees West longitude. Standard parallels for the projection are set at 30 degrees North and 60 degrees North.

Table 4-1 summarizes the vertical grid structure prescribed in the *BART Modeling Protocol*, which comprises ten vertical layers. The cell face height of each layer indicates its vertical extent. The vertical domain is composed of terrain-following grid cells, the number and size of which are chosen so as to constrain the boundary layer in which dispersion and chemical transformations take place. The highest cell face is selected to be 4,000 meters to constrain the default maximum mixing height of 3,000 meters.

**TABLE 4-1. VERTICAL GRID STRUCTURE**

<b>Vertical Grid Cell</b>	<b>Cell Face Height (meters)</b>
1	20
2	40
3	65
4	120
5	200
6	400
7	700
8	1,200
9	2,200
10	4,000

## **4.4 CALPUFF MODEL PROCESSING**

The CALPUFF analysis to assess the visibility impacts attributable to the PTPC Mill is conducted in accordance with the *BART Modeling Protocol* and the recommendations of *IWAQM Phase 2 Summary Report and Recommendations for Modeling Long Range Transport Impacts*, Appendix B of which provides recommended default CALPUFF parameters.

### **4.4.1 MODELED EMISSIONS AND CHEMICAL TRANSFORMATIONS**

Section 3 of this BART Report describes the BART-eligible emission units operated at the PTPC Mill and the visibility-affecting pollutants considered in the CALPUFF analysis. Emission rates are calculated following U.S. EPA and other regulatory guidance as discussed in Section 3 of this analysis for primary emissions of SO<sub>2</sub>, H<sub>2</sub>SO<sub>4</sub>, NO<sub>x</sub> and PM<sub>10</sub>. In addition to species emitted directly from the PTPC Mill, secondary formation of HNO<sub>3</sub>, NO<sub>3</sub>, and SO<sub>4</sub> is simulated using the MESOPUFF-II chemical transformation algorithms, which are considered the default for regulatory CALPUFF modeling. Background levels of ozone and

ammonia, which drive the simulated chemical transformation of emitted pollutants into visibility affecting species, are input to the model as described in subsequent sections of this report.

The BART analysis for the PTPC Mill is conducted by explicitly modeling in CALPUFF the actual emission rate from each point source of each particle species defined as described in Table 4-2. The nomenclature used in Table 4-2 is analogous to that used to describe the emissions from PTPC’s BART-eligible emission units in Section 3 of this report. Table 4-2 summarizes the relevant model input parameters for each modeled pollutant.

**TABLE 4-2. REPRESENTATION OF MODELED POLLUTANTS IN CALPUFF**

Modeled Species	Computed Deposition Mode	Geometric Mass Mean Diameter (micrometers)	Geometric Std. Deviation (micrometers) <sup>a</sup>	Precipitation Scavenging Coefficient	
				Liquid (s <sup>-1</sup> )	Frozen (s <sup>-1</sup> )
SO <sub>2</sub>	Gas	N/A	N/A	3.0E-05	0.00
SO <sub>4</sub>	Particle	0.5	1.5	1.0E-04	3.0E-05
NO <sub>x</sub>	Gas	N/A	N/A	N/A	N/A
HNO <sub>3</sub>	Gas	N/A	N/A	6.0E-05	0.00
NO <sub>3</sub>	Particle	0.5	1.5	1.0E-04	3.0E-05
PMC	Particle	5.0	1.5	1.0E-04	3.0E-05
PIC	Particle	0.5	1.5	1.0E-04	3.0E-05
PMF	Particle	0.5	1.5	1.0E-04	3.0E-05
SOA	Particle	0.5	1.5	1.0E-04	3.0E-05
EC	Particle	0.5	1.5	1.0E-04	3.0E-05

#### 4.4.2 CALPUFF DISPERSION ALGORITHMS

As specified in a March 16, 2006 U.S. EPA memorandum<sup>34</sup> and the *BART Modeling Protocol*, the use of Pasquill-Gifford (ISC-like) dispersion coefficients is enabled as the default option in the CALPUFF analysis.

#### 4.4.3 BUILDING DOWNWASH

The effects of building downwash are not considered in the CALPUFF analyses.<sup>35</sup>

#### 4.4.4 CALPUFF MODELING DOMAINS AND CLASS I AREA RECEPTORS

PTPC performed CALPUFF modeling on computational domains that are subsets of the Regional Domain specified in the *BART Modeling Protocol*. The size of the computational domain is selected to encompass the PTPC Mill and the Class I areas being analyzed, and to

<sup>34</sup> U.S. EPA Memorandum “Dispersion Coefficients for Regulatory Air Quality Modeling in CALPUFF” from Mr. Dennis Atkinson and Mr. Tyler Fox (Air Quality Modeling Group) to Ms. Kay Prince (Regulatory Planning Branch) dated March 16, 2006.

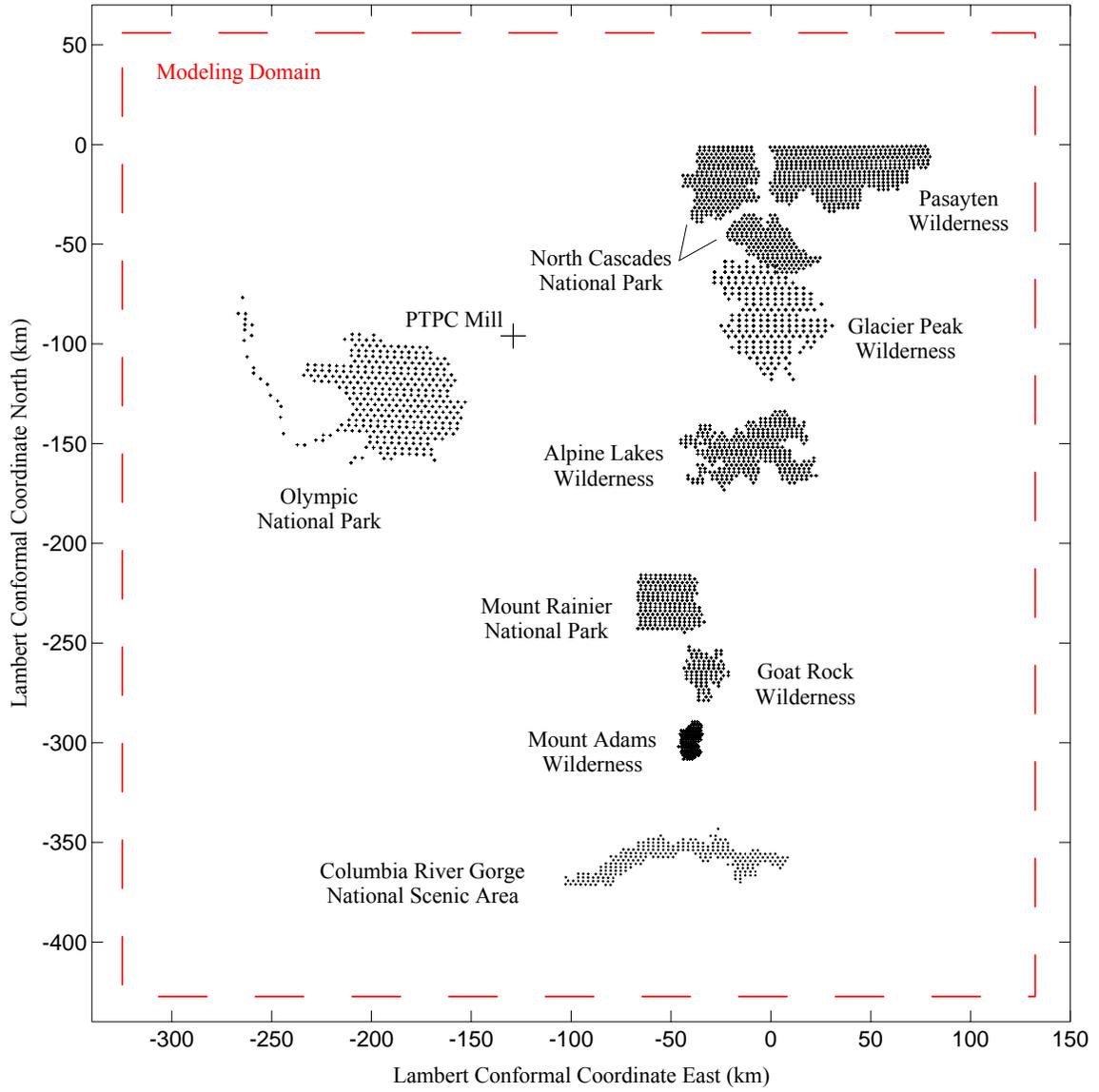
<sup>35</sup> Given the distance from PTPC to the nearest Class I area (approximately 36 km), building downwash does not need to be considered. Phone conversation between Mr. Clint Bowman, Ecology, and Ms. Kirsten Rollay, Trinity, April 16, 2007.

extend at least 50 km beyond in all directions. The size of the domain allows for the possible recirculation of puffs beyond the facility and areas being evaluated. Computational domains use the same vertical grid structure as described in the CALMET model formulation in Section 4.3.1 of this report. Figure 4-2 illustrates the computational domain used in PTPC's BART Applicability Analysis. In addition, the ground level receptors for the Class I areas within 300 km obtained from the National Park Service and for the Columbia River Gorge National Scenic Area obtained from Ecology are also depicted in Figure 4-2.<sup>36</sup> Terrain elevations and land use for the Regional domain are shown in Figure 4-3 and Figure 4-5. Terrain elevations and land use for the Computational domain are shown in Figure 4-4 and Figure 4-6.

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<sup>36</sup> Class I area receptors obtained from <http://www2.nature.nps.gov/air/maps/Receptors/index.htm>. Columbia River Gorge National Scenic Area receptors provided by Clint Bowman, Ecology, to Kirsten Rollay, Trinity, email, February 28, 2007.

**FIGURE 4-2. MODELING ANALYSIS COMPUTATIONAL DOMAIN**



**FIGURE 4-3. TERRAIN ELEVATIONS WITHIN THE REGIONAL DOMAIN**

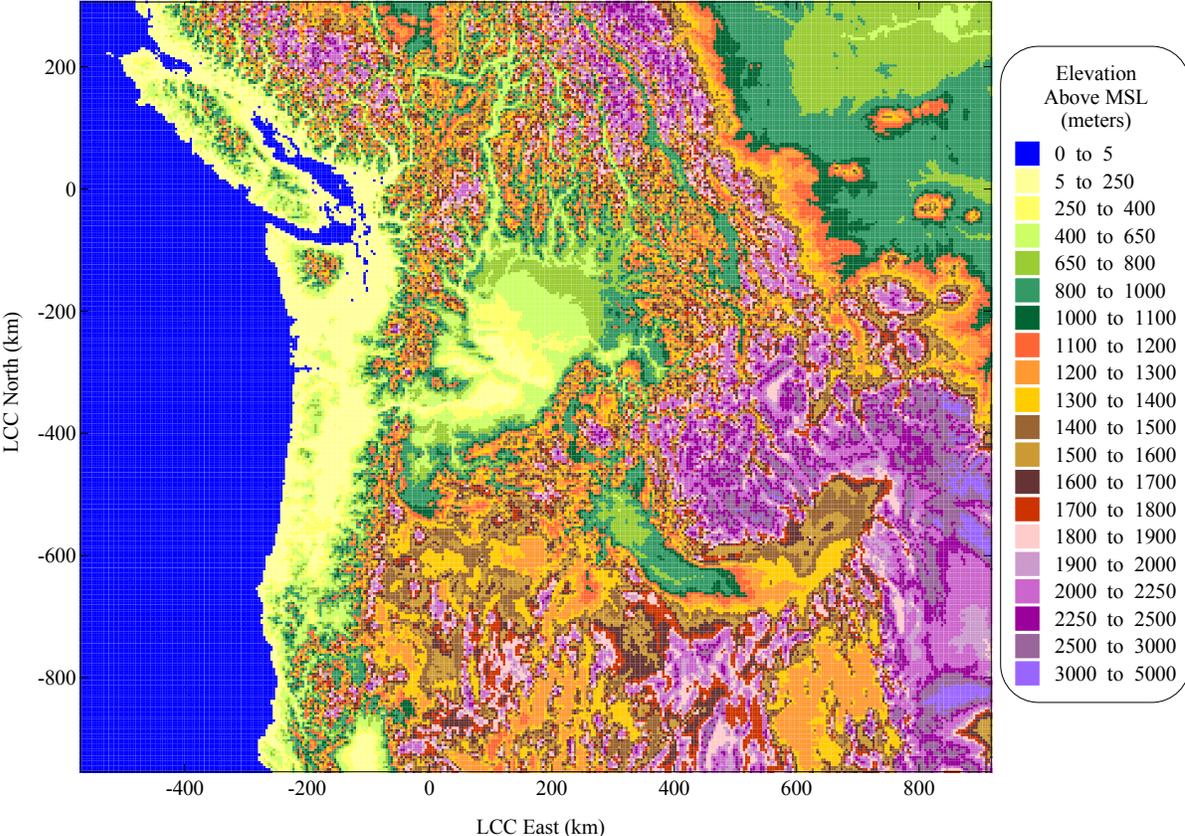
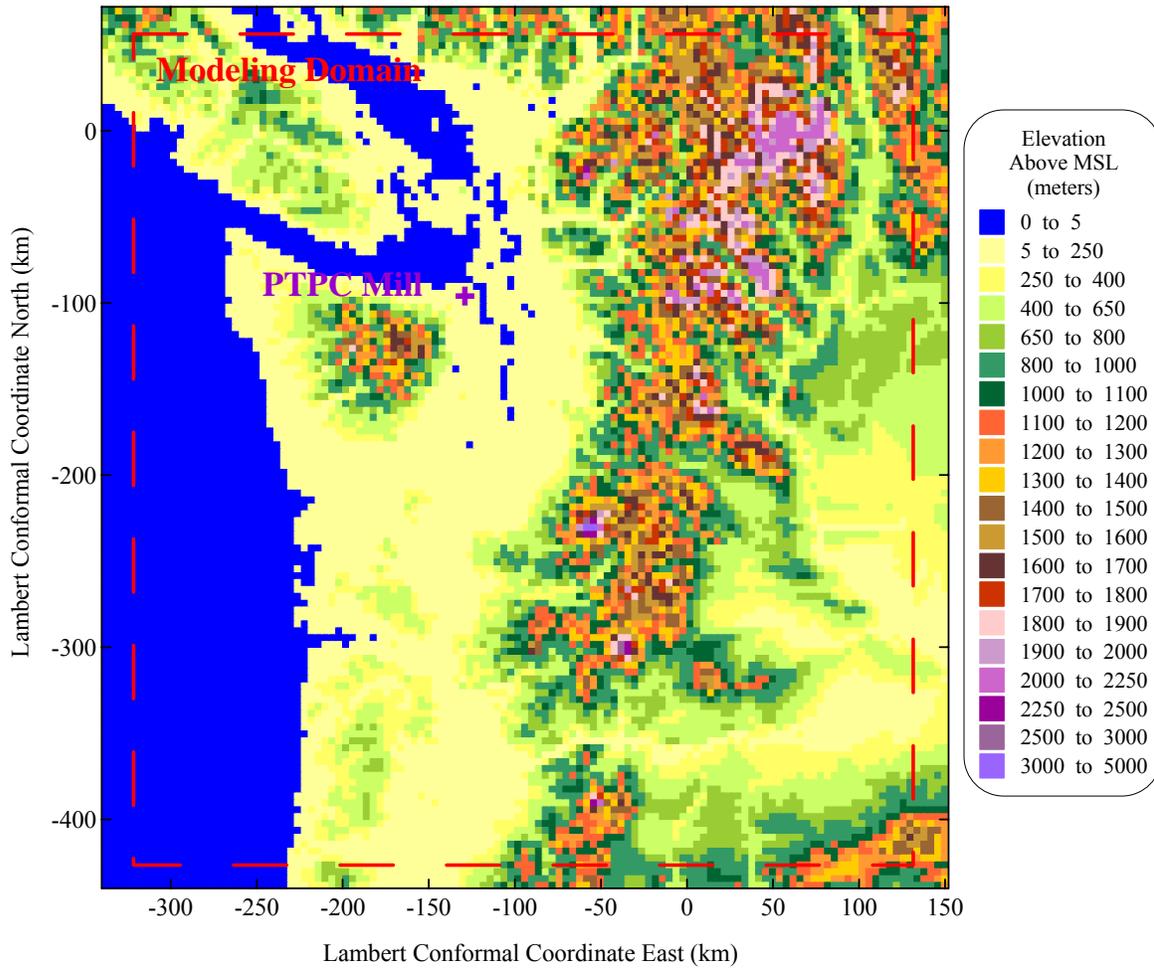
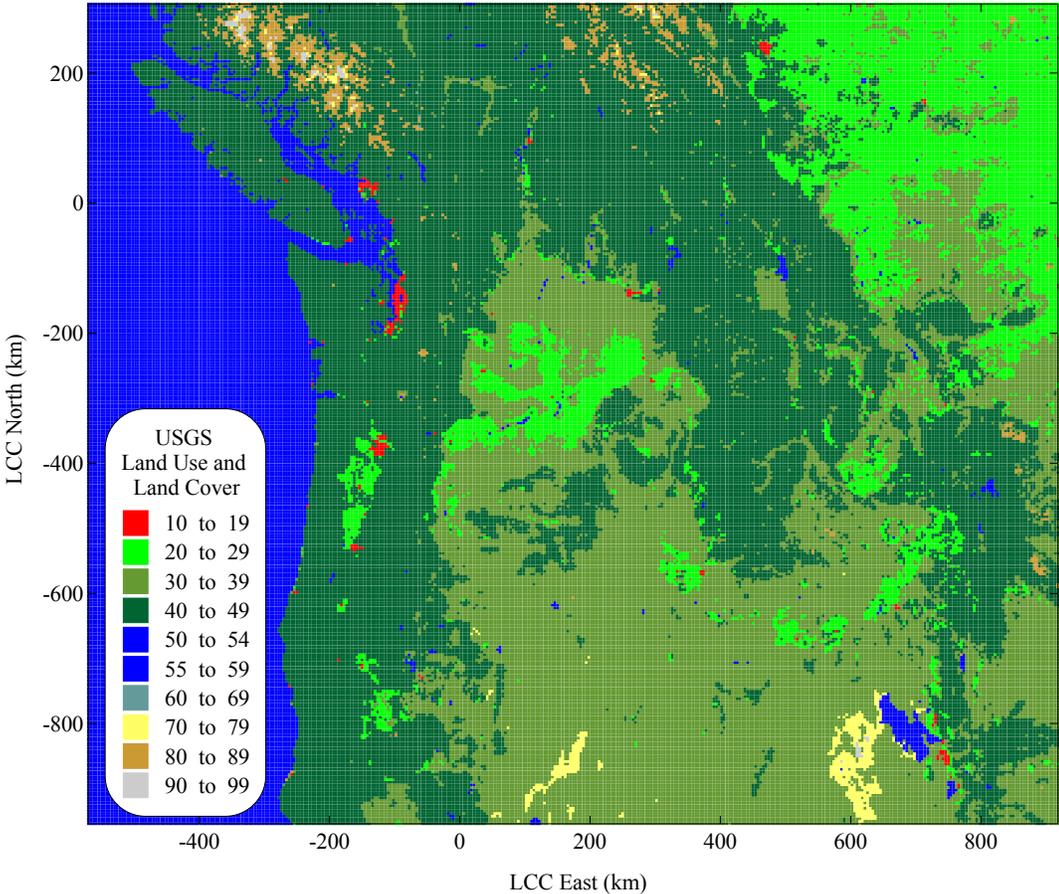


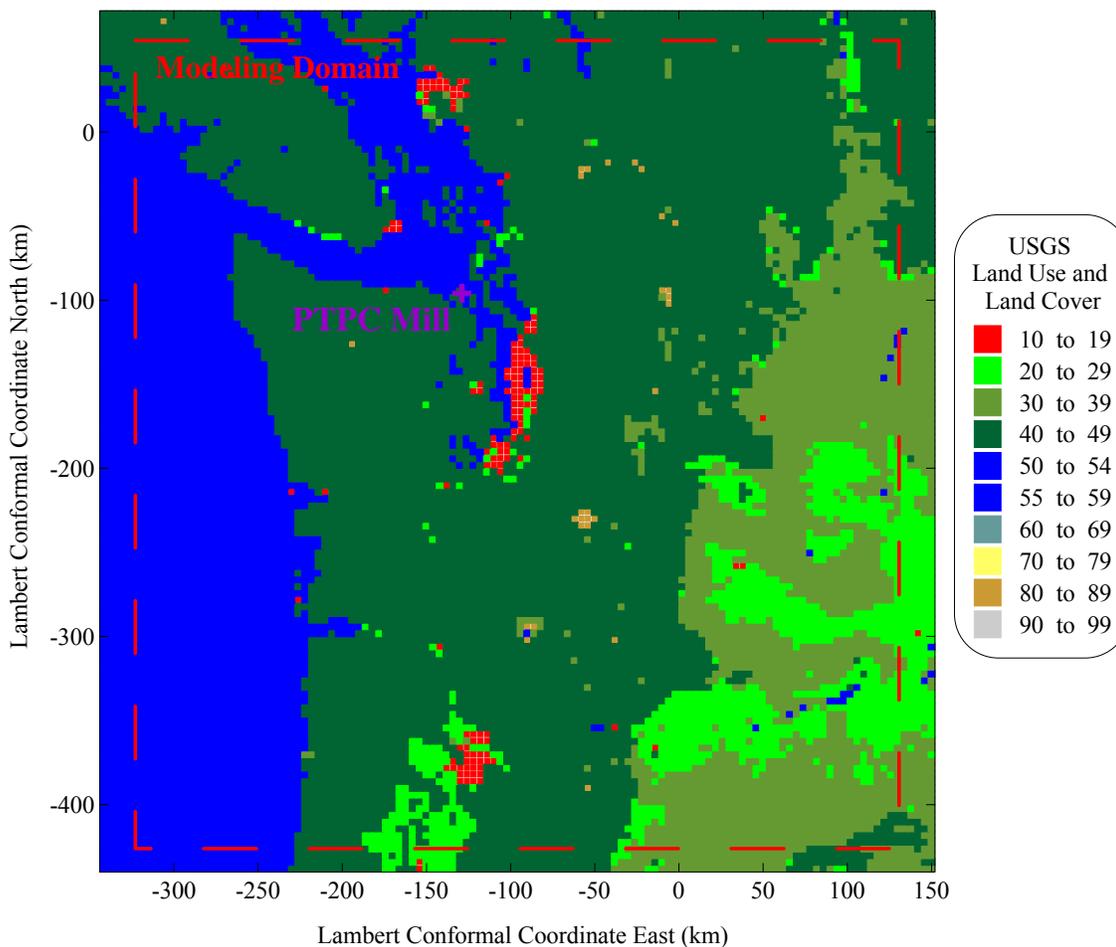
FIGURE 4-4. TERRAIN ELEVATIONS WITHIN THE COMPUTATIONAL DOMAIN



**FIGURE 4-5. LAND USE WITHIN THE REGIONAL DOMAIN**



**FIGURE 4-6. LAND USE WITHIN THE COMPUTATIONAL DOMAIN**



#### **4.4.5 BACKGROUND OZONE AND AMMONIA CONCENTRATIONS**

The CALPUFF model is capable of simulating linear chemical transformation effects by using pseudo-first-order chemical reaction mechanisms for the conversions of  $\text{SO}_2$  to  $\text{SO}_4$ , and  $\text{NO}_x$ , which consists of nitrogen oxide (NO) and nitrogen dioxide ( $\text{NO}_2$ ), to  $\text{NO}_3$  and  $\text{HNO}_3$ . In this study, chemical transformations involving five species ( $\text{SO}_2$ ,  $\text{SO}_4$ ,  $\text{NO}_x$ ,  $\text{HNO}_3$ , and  $\text{NO}_3$ ) are modeled using the MESOPUFF II chemical transformation scheme. Ambient concentrations of ammonia and ozone concentrations as represented in the model drive the MESOPUFF II chemical transformation simulation.

As recommended in the *BART Modeling Protocol*, a single value of 60 parts per billion (ppb) is used for all months for the background ozone concentration. In addition, the *BART Modeling Protocol* recommended constant ammonia background value of 17 ppb is used for all months.

#### **4.4.6 PUFF REPRESENTATION**

As recommended by the *BART Modeling Protocol*, the default integrated puff sampling methodology is enabled for the CALPUFF analysis. The default model option to disable puff splitting is used.

#### **4.4.7 ELECTRONIC FILES FOR CALPUFF ANALYSES**

Copies of all CALPUFF input and output files are included on the electronic media enclosed with this report.

### **4.5 CALPOST POSTPROCESSING AND NATURAL BACKGROUND CONDITIONS FOR LIGHT EXTINCTION AND HAZE INDEX CALCULATIONS**

Using the concentrations of visibility-affecting pollutants computed by CALPUFF, the CALPOST postprocessor is used to compute light extinction attributable to the PTPC Mill and the relevant metrics for the BART analysis. The computation of light extinction attributable to the natural background and source are generally described in Section 2.1.2 of this report.

#### **4.5.1 CLASS I AREA-SPECIFIC NATURAL BACKGROUND CONDITIONS**

The visibility goal of the Clean Air Act is both the remedying of existing visibility impairment and prevention of future visibility impairment. In its *BART Implementation Guidance*, U.S. EPA affirms that it interprets the goal to mean return atmospheric conditions to “natural visibility conditions.” For the purposes of BART analyses, the U.S. EPA has determined that it “did not intend to limit States to the use of the 20% best visibility days...States may use 20% best visibility days or annual average” to assess BART applicability.<sup>37</sup> However, in the January letter from Ecology to Matt Cohen, Ecology indicates that the preference for the appropriate approach is to use the 20% best visibility days to estimate the “natural” background.<sup>38</sup>

Therefore, natural background factors for each Class I area, as provided in Appendix B of the *BART Modeling Protocol*, are used in PTPC’s BART Applicability and Determination Analysis. For each Class I area within 300 km of the PTPC Mill and potentially affected by PTPC’s operations, Table 4-3 summarizes the default natural background conditions.

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<sup>37</sup> U.S. EPA Memorandum from Mr. Joseph Paisie to Ms. Kay Prince, as Attachment A to a proposed settlement agreement between the Utility Air Regulatory Group and U.S. EPA, published at 71 Federal Register No. 84, pp. 25,838-25,840, May 2, 2006.

<sup>38</sup> Letter from Sarah Rees, Ecology, to Matt Cohen and the Coalition of BART Sources, January 4 and January 22, 2007

**TABLE 4-3. NATURAL BACKGROUND CONCENTRATIONS FOR THE CLASS I AREAS**

Class I Area	BKSO4 µg/m <sup>3</sup>	BKNO3 µg/m <sup>3</sup>	BKPMC µg/m <sup>3</sup>	BKOC µg/m <sup>3</sup>	SOIL µg/m <sup>3</sup>	BKEC µg/m <sup>3</sup>
Alpine Lakes Wilderness Area	0.054	0.045	1.35	0.212	0.225	0.009
Glacier Peak Wilderness Area	0.054	0.045	1.34	0.210	0.223	0.009
Goat Rocks Wilderness Area	0.054	0.045	1.34	0.210	0.224	0.009
North Cascades National Park	0.053	0.044	1.33	0.209	0.222	0.009
Mount Adams Wilderness Area	0.053	0.044	1.33	0.209	0.222	0.009
Mount Rainier National Park	0.055	0.045	1.36	0.214	0.227	0.009
Olympic National Park	0.054	0.045	1.36	0.213	0.226	0.009
Pasayten Wilderness Area	0.053	0.044	1.33	0.208	0.222	0.009
Columbia River Gorge National Scenic Area	0.569	0.231	4.85	1.05	0.217	0.205

The effects of relative humidity to amplify the visibility impairment of hygroscopic sulfates and nitrates are characterized using CALPOST “Method 6,” which computes  $\Delta b_{ext}$  using a *monthly average* relative humidity adjustment particular to each Class I area applied to background and modeled sulfate and nitrate.

Table 4-4 summarizes the monthly average humidity values that are applied for the Class I areas considered in this analysis, as provided in Appendix B of the *BART Modeling Protocol*. Natural background conditions are calculated as described in Section 2.1.2 of this analysis.

**TABLE 4-4. MONTHLY AVERAGE  $f(RH)$  FOR SELECTED CLASS I AREAS**

Class I Area	January	February	March	April	May	June	July	August	September	October	November	December
Alpine Lakes Wilderness Area	4.25	3.79	3.47	3.90	2.93	3.22	2.92	3.12	3.25	3.91	4.47	4.51
Glacier Peak Wilderness Area	4.16	3.72	3.42	3.75	2.91	3.16	2.88	3.14	3.33	3.90	4.42	4.43
Goat Rocks Wilderness Area	4.25	3.75	3.36	4.24	2.83	3.38	3.03	3.19	3.07	3.77	4.42	4.55
North Cascades National Park	4.10	3.69	3.43	3.74	2.93	3.20	2.93	3.23	3.45	3.93	4.39	4.38
Mount Adams Wilderness Area	4.29	3.80	3.44	4.40	2.92	3.49	3.12	3.27	3.13	3.86	4.49	4.56
Mount Rainier National Park	4.42	3.96	3.64	4.65	3.06	3.69	3.30	3.50	3.40	4.11	4.66	4.66
Olympic National Park	4.51	4.08	3.82	4.08	3.17	3.46	3.12	3.48	3.71	4.38	4.83	4.75
Pasayten Wilderness Area	4.17	3.72	3.41	3.72	2.89	3.16	2.88	3.15	3.32	3.86	4.42	4.46
Columbia River Gorge National Scenic Area	5.03	5.03	2.59	2.59	2.59	2.11	2.11	2.11	3.51	3.51	3.51	5.03

## 4.5.2 VISIBILITY IMPACT CALCULATION

CALPOST is run separately for each Class I area to obtain the necessary visibility statistics for evaluating impacts relative to the BART visibility impairment thresholds. The inputs to CALPOST involve selection of the visibility method (i.e., Method 6) and entry of Class I area-specific data for computing background extinction and monthly relative humidity factors for hygroscopic aerosols as described in Section 4.5.1. CALPOST contains a receptor selection option that allow subsets of a receptor network modeling in CALPUFF to be selected for processing in a given CALPOST run. This selection specifies which receptors representing a single Class I area are selected for processing from a CALPUFF output file that may contain receptors from several Class I areas.

The visibility impacts are analyzed by tabulating the 98<sup>th</sup> percentile 24-hour average visibility impact for each year and Class I area. As described in Section 4.2.1, the default interpretation of the 98<sup>th</sup> percentile (8<sup>th</sup>-highest day regardless of variability at each receptor) is evaluated for each year.

## 4.5.3 QUALITY ASSURANCE OF POSTPROCESSING ANALYSES

The CALPOST inputs that are checked include the following:

- Visibility technique (Method 6)
- Monthly Class I-specific relative humidity factors for Method 6
- Background light extinction values calculated as appropriate using 20% best days natural background
- Inclusion of all appropriate species from modeled sources (e.g., sulfate, nitrate, organics, coarse and fine particulate matter, and elemental carbon).
- Extinction efficiencies for each species
- Appropriate Rayleigh scattering term ( $10 \text{ Mm}^{-1}$  for default modeling analyses)
- Screen to select appropriate Class I receptors for each CALPOST simulation.

## 5. BART APPLICABILITY ANALYSIS RESULTS

Table 5-1 summarizes the first through eighth highest modeled 24-hour average visibility impacts at each Class I area of interest attributable to the PTPC Mill.<sup>39</sup> Results are presented in terms of visibility impact in delta-deciview, ( $\Delta dv$ ) as defined in Section 2.1.2. The maximum 8<sup>th</sup> highest impact conservatively represents the 98<sup>th</sup> percentile visibility impact.

**TABLE 5-1. VISIBILITY ANALYSIS 24-HOUR AVERAGE VISIBILITY IMPACTS**

Class I Area	Ranked 2003 $\Delta dv$	Ranked 2004 $\Delta dv$	Ranked 2005 $\Delta dv$	Maximum 8 <sup>th</sup> High $\Delta dv$
Alpine Lakes Wilderness Area	0.389	0.623	1.152	0.313
	0.355	0.551	0.712	
	0.338	0.437	0.465	
	0.318	0.422	0.437	
	0.304	0.421	0.425	
	0.284	0.385	0.348	
	0.279	0.301	0.323	
	0.264	0.281	0.313	
Glacier Peak Wilderness Area	0.310	0.642	0.413	0.258
	0.266	0.401	0.345	
	0.264	0.309	0.340	
	0.256	0.307	0.295	
	0.254	0.291	0.274	
	0.251	0.258	0.268	
	0.230	0.251	0.267	
	0.226	0.238	0.258	
Goat Rocks Wilderness Area	0.228	0.305	0.200	0.137
	0.190	0.255	0.199	
	0.185	0.236	0.185	
	0.178	0.235	0.165	
	0.177	0.151	0.161	
	0.168	0.142	0.153	
	0.164	0.140	0.149	
	0.137	0.128	0.134	

<sup>39</sup> As discussed in Section 6.3, several changes to the emissions calculations (i.e., No. 10 Power Boiler, Lime Kiln, and Smelt Dissolving Tank PM emission factors, No. 10 Power Boiler worst-case firing rate) were made after the initial BART applicability analysis was conducted. All changes resulted in a decrease in modeled emission rates. The emission rates presented in Section 3 reflect the refined calculations. However, the modeling results in this section represent impacts based on the original (higher) emission rates. The refined modeling analysis and the BART Determination visibility analyses for Olympic National Park presented in Sections 6 and 12, respectively, are based on the refined emission rates as presented in Section 3. The original emission rates are provided as a footnote to Table 3-20.

**TABLE 5-1. VISIBILITY ANALYSIS 24-HOUR AVERAGE VISIBILITY IMPACTS (CONTINUED)**

<b>Class I Area</b>	<b>Ranked 2003 <math>\Delta</math>dv</b>	<b>Ranked 2004 <math>\Delta</math>dv</b>	<b>Ranked 2005 <math>\Delta</math>dv</b>	<b>Maximum 8<sup>th</sup>- High <math>\Delta</math>dv</b>
Mount Adams Wilderness Area	0.216 0.214 0.141 0.137 0.135 0.133 0.130 0.128	0.261 0.238 0.238 0.198 0.145 0.140 0.131 0.124	0.193 0.164 0.160 0.138 0.121 0.119 0.111 0.105	0.128
Mount Rainier National Park	0.426 0.414 0.374 0.341 0.335 0.305 0.277 0.272	0.451 0.369 0.365 0.347 0.298 0.295 0.232 0.231	0.618 0.549 0.320 0.317 0.275 0.238 0.224 0.211	0.272
North Cascades National Park	0.447 0.330 0.295 0.286 0.271 0.234 0.201 0.196	0.839 0.480 0.410 0.380 0.317 0.309 0.264 0.248	0.332 0.309 0.306 0.296 0.288 0.278 0.276 0.236	0.248
Olympic National Park	3.429 2.939 2.338 2.040 1.908 1.822 1.803 1.767	3.858 2.733 2.633 2.475 2.321 2.231 2.116 1.983	3.665 3.233 2.751 2.495 2.091 1.981 1.957 1.919	1.983
Pasayten Wilderness Area	0.199 0.191 0.163 0.135 0.123 0.123 0.122 0.120	0.385 0.378 0.307 0.197 0.186 0.173 0.168 0.147	0.222 0.202 0.201 0.177 0.172 0.140 0.135 0.123	0.147
Columbia River Gorge National Scenic Area	0.116 0.102 0.101 0.076 0.073 0.073 0.067 0.064	0.108 0.095 0.079 0.075 0.074 0.074 0.070 0.069	0.112 0.093 0.066 0.059 0.048 0.046 0.044 0.043	0.069

The results presented in Table 5-1 indicate that the 98<sup>th</sup> percentile visibility impact calculated does not exceed the 0.5 dv contribution threshold for eight of the nine areas modeled. The maximum 98<sup>th</sup> percentile visibility impact at Olympic National Park does exceed the 0.5 dv contribution threshold. The maximum number of days over 0.5 dv contribution for Olympic National Park for the years modeled occurs in 2003, in which 120 days have visibility impact above the 0.5 dv contribution threshold.

Following U.S. EPA's BART guidelines, these results indicate that the BART-eligible emission units at the PTPC Mill do not contribute to visibility impairment at the following Class I areas: Alpine Lakes Wilderness Area, Glacier Peak Wilderness Area, Goat Rocks Wilderness Area, Mount Adams Wilderness Area, Mount Rainier National Park, North Cascades National Park, and Pasayten Wilderness Area. In addition, the BART-eligible emission units at the PTPC Mill do not contribute to visibility impairment at the Columbia River Gorge National Scenic Area. Further analysis is required for the Olympic National Park.

## 6. REFINED MODELING ANALYSIS FOR OLYMPIC NATIONAL PARK

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A refined modeling analysis, as described below, is conducted for impacts at Olympic National Park. This refined analysis includes several adjustments to the methods provided in the BART Modeling Protocol. The specific changes are detailed in Sections 6.1 and 6.2. The refined modeling analysis more accurately represents the background ammonia concentration for the area including and between PTPC and Olympic National Park. As well, the revised equation for calculating light extinction coefficients is used. The results of the refined modeling analysis more accurately represent actual visibility impacts due to emissions from PTPC at Olympic National Park.<sup>40</sup>

### 6.1 AMMONIA BACKGROUND CONCENTRATION

The *BART Modeling Protocol* recommends using a constant ammonia background value of 17 ppb for all months. This background concentration is developed to account for ammonia-rich areas within the three-state region covered by the *BART Modeling Protocol*. The region covered between and including the PTPC Mill and Olympic National Park is primarily forest land. IWAQM provides a typical background ammonia concentration for forests of 0.5 ppb.<sup>41</sup> Therefore, PTPC conducted the refined CALPUFF analysis as described above, with a background ammonia concentration of 0.5 ppb.

In addition, the ammonia limiting method (ALM) re-partitions the distribution of HNO<sub>3</sub> and NO<sub>3</sub> concentrations at a Class I area as a function of the temperature, relative humidity, and free NH<sub>3</sub> during each hour. ALM re-partitioning using the NH<sub>3</sub> background level of 0.5 ppb is conducted in the refined analysis for Olympic National Park. POSTUTIL is run to apply the ALM to the Class I area.

### 6.2 LIGHT EXTINCTION COEFFICIENT

The extinction coefficient  $b_{\text{ext}}$  used in the light extinction algorithm (as described in Section 2.1.2 of this report) is affected by various chemical species and the Rayleigh scattering phenomenon. The original equation for the background extinction coefficient  $b_{\text{ext, background}}$  in the FLM's FLAG guidance is provided in Section 2.1.2 of this report.

More recently, the Interagency Monitoring of Protected Visual Environments (IMPROVE) workgroup has proposed a more robust equation for calculating light extinction, as described in detail in a report entitled "Revised IMPROVE Algorithm for Estimating Light Extinction from Particle

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<sup>40</sup> The refined analysis, including the use of the 0.5 ppb ammonia background, of the ammonia limiting method, and of the new IMPROVE algorithm as described in this section, was discussed and agreed upon with Ecology during a June 4, 2007 meeting at Ecology Headquarters, attended by Clint Bowman and Alan Newman, Ecology; Alice McConaughy, PTPC; and Aaron Day and Kirsten Rollay, Trinity Consultants.

<sup>41</sup> U.S. EPA, Interagency Workgroup on Air Quality Modeling (IWAQM), Phase 2, December 1998.

Speciation Data.”<sup>42</sup> The updated algorithm, which has been approved by the IMPROVE Steering Committee and is currently undergoing peer review, provides a more refined calculation by including visibility impairment due to the following processes:

- Visibility impairment due to different sizes of sulfates, nitrates, and organic carbon
- Visibility impairment due to sea salt particles
- Distinct water growth curves (i.e.,  $f(RH)$ ) for small sulfates and nitrates, large sulfates and nitrates, and sea salt
- Elevation-dependent (hence Class I area dependent) Rayleigh scattering coefficient
- Visibility impairment due to gaseous nitrogen dioxide ( $NO_2$ )

The revised IMPROVE light extinction algorithm takes the following form:

$$b_{ext} = 2.2 f_S(RH)[NH_4(SO_4)_2]_{Small} + 4.8 f_L(RH)[NH_4(SO_4)_2]_{Large} + 2.4 f_S(RH)[NH_4NO_3]_{Small} + 5.1 f_L(RH)[NH_4NO_3]_{Large} + 2.8[OC]_{Small} + 6.1[OC]_{Large} + 10[EC] + 1[PMF] + 0.6[PMC] + 1.4 f_{SS}(RH)[Sea Salt] + b_{Site-specific Rayleigh Scattering} + 0.33[NO_2]$$

Visibility impacts in Olympic National Park are calculated based on the new IMPROVE algorithm using the VISTAS IMPROVE spreadsheet tool.<sup>43</sup> The following specific inputs to the tool are used:

- Elevation-dependent Rayleigh scattering coefficient of  $11 \text{ Mm}^{-1}$  (Olympic National Park) from Table A2 of the IMPROVE’s “Revised IMPROVE Algorithm for Estimating Light Extinction from Particle Speciation Data” memo.<sup>44</sup>
- Sea Salt background concentration of  $0.14 \mu\text{g}/\text{m}^3$  or based on January 1, 2000 through June 1, 2006 data from the VIEWS web site (<http://vista.cira.colostate.edu/views/Web/Data/DataWizard.aspx>).
- Maximum 24-hour average daily  $NO_2$  concentration from 2003 to 2005 attributable to BART-eligible sources at the PTPC Mill as calculated by an additional CALPOST analysis

Although other anthropogenic (stationary and mobile) sources contribute to background levels of  $NO_2$  at Class I areas, for the purposes of this analysis, the  $NO_2$  concentration contributing to the light extinction is assumed to be attributable only to BART-eligible sources at the PTPC Mill. The 24-hour average  $NO_2$  concentration for each day is calculated by a separate CALPOST processing analysis, and converted from units of  $\mu\text{g}/\text{m}^3$  (default model output) to parts per billion as required by the tool. The maximum value is conservatively applied to each day of the visibility processing in the

<sup>42</sup> [http://vista.cira.colostate.edu/IMPROVE/Publications/GrayLit/gray\\_literature.htm](http://vista.cira.colostate.edu/IMPROVE/Publications/GrayLit/gray_literature.htm).

<sup>43</sup> The VISTAS IMPROVE spreadsheet tool was used with the revisions provided for use in calculating visibility impacts in Olympic National Park, <http://www.vistas-sesarm.org/BART/calpuff.asp>

<sup>44</sup> Accessed June 2007, [http://vista.cira.colostate.edu/improve/Publications/GrayLit/019\\_RevisedIMPROVEEq/RevisedIMPROVEAlgorithm3.doc](http://vista.cira.colostate.edu/improve/Publications/GrayLit/019_RevisedIMPROVEEq/RevisedIMPROVEAlgorithm3.doc)

new IMPROVE algorithm. The NO<sub>2</sub>/NO<sub>x</sub> ratio is conservatively entered as 1.0 in the CALPOST-IMPROVE tool.

The IMPROVE spreadsheet tool background calculations are adjusted to represent the 20% best days for Olympic National Park.<sup>45</sup> This included adjustment to the size breakdown defaults for source and natural background provided in the IMPROVE spreadsheet tool. The background values are provided in Appendix B of the *BART Modeling Protocol* and are provided in Table 6-1.

**TABLE 6-1. BACKGROUND EXTINCTION COEFFICIENTS FOR OLYMPIC NATIONAL PARK (20% BEST DAYS)**

<b>Background</b>	<b>Extinction Coefficient (µg/m<sup>3</sup>)</b>
Sulfates	0.054
Ammonium Nitrate	0.045
Organic Mass of Carbon	0.213
Elemental Carbon	0.009
Soil	0.23
Coarse Mass	1.36

### **6.3 BART ELIGIBLE SOURCE EMISSION RATES**

Several changes to the emissions calculations (i.e., No. 10 Power Boiler, Lime Kiln, and Smelt Dissolving Tank PM emission factors, No. 10 Power Boiler worst-case firing rate) were made after the initial BART applicability analysis (presented in Section 5) was conducted. The emission rates presented in Section 3 reflect the refined calculations. This refined modeling analysis and the BART Determination visibility analyses for Olympic National Park are based on the updated emission rates as presented in Section 3. The following list describes the changes to the emission calculations used for the refined modeling analysis.

- The measured firing rate for the No. 10 Power Boiler changed from being based on measured fuel use to measured steam production because the steam rate measurement is considered to be a consistent, regularly and directly monitored data source and is more suited to this modeling application. The fuel mix used for some calculations is based on the measured oil firing rate and the total firing rate, which is calculated based on steam production. This change affected emissions of all the pollutants from the No. 10 Power Boiler.
- The particulate emissions from the No. 10 Boiler changed from being calculated based on the grain loading presented in the particulate source tests to being based on the emission factor (in units of lb/MMBtu) presented in the particulate source tests. This change resulted in a decrease in the PM emissions from the No. 10 Power Boiler.

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<sup>45</sup> The IMPROVE spreadsheet tool was developed for use in the eastern states for average background values. The spreadsheet is amended to calculate background for western states, 20% best days.

- The particulate matter emission factors for the Smelt Dissolving Tank and Lime Kiln are also updated because the initial modeling run incorrectly assumed a source test method in which results represent only filterable particulate matter. The final modeling correctly identifies source test results as a measure of total particulate matter (filterable plus condensable).

## 6.4 VISIBILITY ANALYSIS RESULTS FOR OLYMPIC NATIONAL PARK

Table 6-2 provides the visibility analysis results of the refined analysis for Olympic National Park.

**TABLE 6-2. VISIBILITY ANALYSIS 24-HOUR AVERAGE VISIBILITY IMPACTS**

Class I Area	Ranked 2003 $\Delta dv$	Ranked 2004 $\Delta dv^a$	Ranked 2005 $\Delta dv$	Maximum 8 <sup>th</sup> -High $\Delta dv$
Olympic National Park	1.55	1.97	1.77	1.18
	1.49	1.82	1.76	
	1.42	1.79	1.55	
	1.23	1.39	1.21	
	1.05	1.33	1.20	
	1.04	1.24	1.05	
	1.04	1.21	1.00	
	1.01	1.18	0.99	

As shown, the 98<sup>th</sup> percentile visibility impact exceeds the 0.5 dv contribution threshold at Olympic National Park.

CALPUFF is typically used for long-range transport air dispersion modeling (i.e., greater than 50 km distance from the source). Therefore, PTPC also evaluated impacts at only the receptors that are greater than 50 km from the PTPC Mill. Of the 714 receptors covering Olympic National Park, 97 are within 50 km of the PTPC Mill. Table 6-3 provides the visibility analysis results from the refined analysis for Olympic National Park receptors beyond 50 km from the PTPC Mill.

**TABLE 6-3. VISIBILITY ANALYSIS 24-HOUR AVERAGE VISIBILITY IMPACTS BEYOND 50 KILOMETERS**

Class I Area	Ranked 2003 $\Delta dv$	Ranked 2004 $\Delta dv$	Ranked 2005 $\Delta dv$	Maximum 8 <sup>th</sup> -High $\Delta dv$
Olympic National Park (Only receptors greater than 50 km from the PTPC Mill)	1.40	1.59	1.37	0.99
	1.20	1.40	1.24	
	1.17	1.43	1.22	
	1.03	1.10	1.20	
	1.02	1.08	1.05	
	0.97	1.04	0.95	
	0.96	1.02	0.85	
	0.93	0.99	0.85	

As shown, the 98<sup>th</sup> percentile visibility impact at Olympic National Park receptors beyond 50 km from the facility is 0.99 dv contribution.

Following U.S. EPA's BART guidelines, these results indicate that a BART determination analysis is required to analyze the impact of PTPC's BART-eligible sources at Olympic National Park.

## 7. BART DETERMINATION METHODOLOGY

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In the July 8, 2005, final BART Regulations and Guidelines, the U.S. EPA established guidelines for performing a BART Determination.<sup>46</sup> As noted previously, the goal of this determination is to determine what BART is for each unit included in the BART-eligible source, that is, the emission limitation based on the degree of reduction achievable through the application of the best system of continuous emissions reduction. The emission limitations are established on a case-by-case basis and must take into account several factors:

- The availability and feasibility of retrofit control options
- Pollution control equipment currently utilized
- Costs of compliance for each control option
- Remaining useful life of the facility
- Energy and environmental impacts of the control options
- Visibility impacts analysis

To guide selection of appropriate BART limits, U.S. EPA noted that the BART Determination evaluation must include five specific steps:

1. Identify all available retrofit control options
2. Eliminate technically infeasible options
3. Evaluate control effectiveness of remaining control technologies
4. Evaluate impacts and document results
5. Evaluate net visibility improvement

Each of these steps is described in the following sections.

### 7.1 IDENTIFY ALL AVAILABLE RETROFIT CONTROL OPTIONS

The first step in the BART Determination is the identification of all retrofit control options, which:<sup>47</sup>

*...are those air pollution control technologies with a practical potential for application to the emissions unit and the regulated pollutant under evaluation...Technologies required as BACT or LAER are available for BART purposes and must be included as control alternatives... We do not expect the source owner to purchase or construct a process or control device that has not already been demonstrated in practice.*

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<sup>46</sup> 40 CFR Part 51, Appendix Y, Section IV.A

<sup>47</sup> 40 CFR Part 51, Appendix Y, Section IV.D.1

The guidelines also note that New Source Performance Standards (NSPS) level controls should be considered, as should pollution prevention options and usage (or improvement to existing units) of add-on controls. Section IV(C) of the BART guidelines describes a streamlined approach for evaluating BART for certain sources that are subject to MACT standards. U.S. EPA notes that “we believe that, in many cases, it will be unlikely that States will identify emission controls more stringent than the MACT standards without identifying control options that would cost many thousands of dollars per ton.” U.S. EPA subsequently provides guidance in Section IV(D)(9) that “if a source commits to a BART determination that consists of the most stringent controls available, then there is no need to complete” a comprehensive engineering analysis of BART. Certain BART-subject emission units at the PTPC Mill are subject to federally enforceable MACT emission limits under applicable NESHAP. As is subsequently described, the applicable MACT standards presumptively meet BART for affected emission units and pollutants. Additional engineering analyses are not conducted.

## **7.2 ELIMINATE TECHNICALLY INFEASIBLE OPTIONS**

The second step in performing the BART Determination is the elimination of technically infeasible control options. A control option is considered technically infeasible if technical difficulties (based on physical, chemical, or engineering principles) would not allow the option to be utilized successfully. Specifically, an option is considered technically feasible if it “has been installed and operated successfully for the type of source under review under similar conditions, or the technology could be applied to the source under review.”<sup>48</sup>

To demonstrate that an option is not technically feasible, the source must evaluate and document that either (1) the characteristics of the exhaust stream and/or the capabilities of the technology that would not allow the option to be used, or (2) the option is not commercially available.

## **7.3 EVALUATE CONTROL EFFECTIVENESS OF REMAINING CONTROL TECHNOLOGIES**

The third step in the BART Determination is the evaluation of control effectiveness of any control options considered technically feasible. The control effectiveness should include comparing options on the same basis (e.g., lb/MMBtu). Varying control effectiveness levels for the same control option can be considered (e.g., 50% control versus 75% control). The effectiveness evaluation should also consider ways to improve the control associated with any existing control options already employed, especially when existing control devices are not achieving as great of reduction as the same control device on a similar source.<sup>49</sup>

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<sup>48</sup> 40 CFR Part 51, Appendix Y, Section IV.D.2

<sup>49</sup> 40 CFR Part 51, Appendix Y, Section IV.D.3

## 7.4 EVALUATE IMPACTS AND DOCUMENT RESULTS

The fourth step in the BART Determination is to analyze the costs of compliance using the control option, the energy impacts of the control option, the non-air quality environmental impacts of the control option, and the remaining useful life of the equipment.

The first factor evaluated is the cost of compliance. Evaluation of this factor includes development of cost calculations necessary to determine the average cost effectiveness, which is defined as “the total annualized costs of control divided by the annual emissions reductions.”<sup>50</sup> The incremental cost effectiveness can also be evaluated in situations where a number of control options are being evaluated in order to compare those options to one another. Costs of compliance can be determined using U.S. EPA’s *OAQPS Control Cost Manual* as guidance.<sup>51</sup> Note that the emissions reductions included in the cost of compliance calculations should “represent a realistic depiction of anticipated annual emissions for the source...based upon actual emissions from a baseline period.”<sup>52</sup> Therefore, emission units with limited operation during the baseline period can consider similar limited operation (and limited emissions) in the cost effectiveness calculations.

The second factor evaluated is the energy impact. Energy impacts will result in additional costs or income to a source. Typically, these impacts are determined as part of the cost impact calculations, considering only the direct energy consumption.

The third factor evaluated is the non-air quality environmental impact. Environmental impacts include generation of additional solid or liquid waste and the disposal of such waste.

The fourth factor evaluated is the remaining useful life of the source. If the remaining useful life of the equipment is less than the time period recommended by U.S. EPA’s *OAQPS Control Cost Manual*, the shortened life should be utilized in the cost evaluations for the purposes of amortizing costs of the retrofit.

## 7.5 EVALUATE VISIBILITY IMPACTS

The fifth and final step in the BART Determination evaluation is to evaluate the visibility impacts, defined as the degree of visibility improvement for each BART-subject source, for the BART Determination. Visibility impacts should be evaluated using an appropriate dispersion model (e.g., CALPUFF) for each of the Class I areas for which the BART Applicability Analysis indicated the source caused or contributed to visibility impairment. When conducting the visibility impacts modeling, the source should:<sup>53</sup>

- *Run the model at pre-control and post-control emission rates according to the accepted protocol.*

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<sup>50</sup> 40 CFR Part 51, Appendix Y, Section IV.D.4.b

<sup>51</sup> U.S. EPA, *OAQPS Control Cost Manual, Sixth Edition*, January 2002. EPA-452/B-02-001.

<sup>52</sup> 40 CFR Part 51, Appendix Y, Section IV.D.4.d

<sup>53</sup> 40 CFR Part 51, Appendix Y, Section IV.D.5

- *Use the 24-hour average actual emission rate from the highest emitting day of the meteorological period modeled (for the pre-control scenario). Calculate the model results for each receptor as the change in deciviews compared against natural visibility condition. Post-control emission rates are calculated as a percentage of pre-control emission rates...*
- *Make the net visibility improvement determination...based on the modeled change in visibility impacts for the pre-control and post-control emission scenarios. ...consider the frequency, magnitude, and duration components of impairment. Suggestions for making the determination are:*
  - *Use of a comparison threshold... (e.g., the number of days or hours that the threshold was exceeded, a single threshold for determining whether a change in impacts is significant, or a threshold representing an x percent change in improvement).*
  - *Compare the 98<sup>th</sup> percent days for the pre- and post-control runs.*

Net visibility improvement associated with the addition of a specific control technology is evaluated to compare control options to one another and/or to the baseline visibility impacts.

## 8. BART-ELIGIBLE EMISSION UNITS SUBJECT TO MACT STANDARDS

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The Recovery Furnace, Smelt Dissolving Tank, and Lime Kiln are subject to MACT standards for PM as a surrogate for HAP. All three units are subject to 40 CFR Part 63 Subpart MM, *National Emission Standards for Hazardous Air Pollutants for Chemical Recovery Combustion Sources at Kraft, Soda, Sulfite, and Stand-Alone Semichemical Pulp Mills*. These MACT standards are considered to represent BART.<sup>54</sup> Table 8-1 presents the MACT limits for each emission unit subject to MACT standards.

**TABLE 8-1. BART-ELIGIBLE EMISSION UNITS FOR WHICH MACT REPRESENTS BART**

Emission Unit	Visibility-Impairing Pollutant Regulated by MACT Standard	MACT Limit	
		Value	Units
NDCE Recovery Furnace	PM	0.044	gr/dscf
Smelt Dissolving Tank	PM	0.200	lb/BLS
Lime Kiln	PM	0.064	gr/dsdf

The compliance date for 40 CFR Part 63 Subpart MM that applies to the three BART-eligible units listed above was March 13, 2004. No new technologies for controlling PM have subsequently become available after this recent date. Therefore, the MACT limits for PM from the Recovery Furnace, Smelt Dissolving Tank, and Lime Kiln listed in Table 8-1 are considered BART.

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<sup>54</sup> Per Section IV of EPA's "Guidelines for BART Determinations under the Regional Haze Rules" [40 CFR Part 51, Appendix Y], "Unless there are new technologies subsequent to the MACT standards which would lead to cost-effective increases in the level of control, [state agencies] may rely on the MACT standards for purposes of BART."

## 9. IDENTIFICATION OF CONTROL TECHNOLOGIES (STEP 1)

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Potentially applicable retrofit emission control technologies are identified by researching the U.S. EPA control technology database, technical literature, and by using process knowledge and engineering experience. The Reasonably Available Control Technology (RACT)/ Best Available Control Technology (BACT)/Lowest Achievable Emission Rate (LAER) Clearinghouse (RBLC), a database made available to the public through the U.S. EPA's Office of Air Quality Planning and Standards (OAQPS) Technology Transfer Network (TTN) lists technologies and corresponding emission limits that have been approved by regulatory agencies in permit actions. These technologies are grouped into categories by industry and can be referenced in determining what emissions levels are proposed for similar types of emissions units. Appendix C presents a summary of the RBLC search results for the PM, NO<sub>x</sub>, and SO<sub>2</sub> control technologies for each BART-eligible emission unit.

The following sections identify and describe various control options considered in the BART Determination analysis for PM<sub>10</sub>, NO<sub>x</sub>, and SO<sub>2</sub> emissions from the PTPC Mill.

### 9.1 PM<sub>10</sub> CONTROL TECHNOLOGIES

As described in Section 8, only the No. 10 power boiler is evaluated for control of PM<sub>10</sub>. The remaining units are subject to MACT limits for PM that are considered to represent BART. Taking into account the physical and operational characteristics of the No. 10 Power Boiler being evaluated to determine BART, the PM<sub>10</sub> control options are listed below and briefly described in the following paragraphs.

- Fabric Filters (Baghouse)
- Cyclone Separators
- Wet Scrubbers
- Electrostatic Precipitators (ESPs)
- Electrified Gravel Bed Filters (EGFs)
- Proper Operating Practices

#### 9.1.1 FABRIC FILTER (BAGHOUSE)

A baghouse consists of several fabric filters, typically configured in long, vertically suspended sock-like configurations. Dirty gas enters from one side, often from the outside of the bag, passing through the filter media and forming a particulate cake. The cake is removed by shaking or pulsing the fabric, which loosens the cake from the filter, allowing it to fall into a bin at the bottom of the baghouse. The air cleaning process stops once the pressure drop across the filter reaches an economically unacceptable level. Typically, the trade-off to frequent cleaning and maintaining lower pressure drops is the wear and tear on the bags from the cleaning process.

### **9.1.2 CYCLONE SEPARATOR**

Cyclone separators remove solids from the air stream by application of centrifugal force. Typically, the particle-laden gas enters the top of the cyclone tangentially to the barrel and spins inside the device. Due to the shape of the device, the gas turns and forms a vortex in the center of the device as the gas moves upward to the exit duct. The particles are removed by centrifugal force, which drives them to the wall of the collector where they fall to the bottom due to gravity. Cyclones are efficient in removing larger, denser particles but are not as effective for fine particle removal (less than 5  $\mu\text{m}$  diameter).

### **9.1.3 WET SCRUBBER**

Wet scrubbers intercept dust particles using droplets of liquid (usually water). The larger, particle-enclosing water droplets are separated from the remaining droplets by gravity. The solid particulates are then separated from the water.

### **9.1.4 ELECTROSTATIC PRECIPITATOR (ESP)**

An ESP removes particles from an air stream by electrically charging the particles, then passing them through a force field that causes them to migrate to an oppositely charged collector plate. The dust from the collector plates falls into a collection hopper at the bottom of the ESP. The collection efficiency of an ESP depends on particle diameter, electrical field strength, gas flow rate, and plate dimensions. ESPs can be designed for both dry and wet applications.

### **9.1.5 ELECTRIFIED GRAVEL BED FILTER (EGF)**

EGFs, also known as electrostatically augmented granular-bed moving filters, remove particles from an air stream by using electrostatic forces to attract pollutants to an electrically charged gravel bed. The gravel is removed from the filter bed and cleaned externally on a continuous basis. After the dust is removed from the gravel, the cleaned gravel is returned to the filter bed. EGFs are designed as an alternative to baghouse control technology for gas streams that may have a potential fire hazard associated with the use of fabric filters, or that have a high moisture content that would foul or corrode a fabric filter. EGFs are most commonly used to control dryers in the wood products industry, but have also been used to control PM from hogfuel boilers, curing ovens, and other emissions units with high temperature gas streams. As with ESPs, the control efficiency of an EGF depends on particle diameter, electrical field strength, gas flow rate, and the size of the filter bed. EGFs can achieve PM<sub>10</sub> control efficiencies up to 95 percent.<sup>55</sup>

### **9.1.6 PROPER OPERATING PRACTICES**

A properly operated emission unit will minimize the formation of PM<sub>10</sub> emissions. Proper design of combustion units (e.g., boiler and recovery furnaces) concerns features such as the fuel and combustion air delivery system and the shape and size of the combustion chamber.

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<sup>55</sup> PECHAN, "Update of Control Equipment Data to Support MPCA's Control Equipment Rule," Final Report No. 05.06.00X/9446.000, June 2005.

Good operating practices for combustion units typically consist of controlling parameters such as fuel feed rates and air/fuel ratios.

### 9.1.7 SUMMARY OF PM<sub>10</sub> CONTROL TECHNOLOGIES

Table 9-1 presents a summary of the potential PM<sub>10</sub> control technologies considered in the BART engineering analysis.

**TABLE 9-1. PM<sub>10</sub> CONTROL TECHNOLOGIES EVALUATED**

Control Technology	Available for Emission Unit (Yes/No) <sup>a</sup>			
	NDCE Recovery Furnace <sup>b</sup>	Smelt Dissolving Tank <sup>b</sup>	No. 10 Power Boiler	Lime Kiln <sup>b</sup>
Fabric Filters (Baghouse)	NA	NA	Yes	NA
Cyclone Separator	NA	NA	Yes	NA
Wet Scrubber	NA	NA	Yes	NA
ESP	NA	NA	Yes	NA
EGF	NA	NA	Yes	NA
Proper Operating Practices	NA	NA	Yes	NA

<sup>a</sup> Availability based on whether control technology can be considered for each.

<sup>b</sup> Availability of PM<sub>10</sub> control on all units except the No. 10 Power Boiler is not applicable because the remaining units comply with MACT standards for PM as described in Section 8.

## 9.2 NO<sub>x</sub> CONTROL TECHNOLOGIES

Potentially applicable NO<sub>x</sub> control technologies are identified based on the principles of control technology and engineering experience for general combustion units (e.g., industrial boilers). NO<sub>x</sub> control technologies are not evaluated for the Smelt Dissolving Tank since this unit is not a combustion device and is therefore not a source of NO<sub>x</sub> emissions.

Potential pollution prevention options include:

- Low Excess Air (LEA)
- Staged Combustion
- Flue Gas Recirculation (FGR)
- Low NO<sub>x</sub> Burners (LNB)
- Fuel Staging
- Water/Steam Injection
- Mid-Kiln Firing (MKF)
- Mixing Air Fan (Mid-Kiln Air Lances)
- Good Operating Practices and Proper Design

Potential pollution reduction options include:

- Selective Non-Catalytic Reduction (SNCR)

- Selective Catalytic Reduction (SCR)
- Oxidation/Reduction Scrubbing (Ozone Injection)

These control technologies are briefly discussed in the following paragraphs.

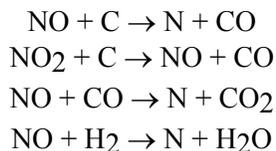
### 9.2.1 LOW EXCESS AIR (LEA)

Moderate NO<sub>x</sub> reductions can be achieved by lowering the amount of excess air (and thus, excess oxygen) available in the local flame zone. A NO<sub>x</sub> reduction of ten to twenty percent for every one percent reduction in the oxygen levels is theoretically feasible. Lower fuel NO<sub>x</sub> and lower thermal NO<sub>x</sub> are generated when combustion units operate with lower excess air.

### 9.2.2 STAGED COMBUSTION TECHNOLOGIES

Staged combustion technologies such as overfire air (OFA) reduce NO<sub>x</sub> emissions by creating a “fuel-rich” zone via air staging (diverting a portion of the total amount of air required through separate ports). Conditions in such a zone result in lower peak temperatures and thus, lower NO<sub>x</sub> emissions.

For typical staged combustion, there is a slight excess of air in the initial burn zone. The highest temperatures are reached here, generating thermal NO<sub>x</sub>. In the secondary burn zone, a secondary burner injects additional fuel into the marginally lean air, creating strongly rich air (i.e., more fuel is present than oxygen available to oxidize the fuel). In this reducing atmosphere, NO is reacted to N as the hydrocarbons and CO scavenge oxygen. For proper operation, the secondary burn zone must be between 1,800°F and 2,200°F. Following this section is the final burn zone, where secondary air (from the cooler) provides sufficient oxygen to oxidize the remaining combustibles. The following overall reactions occur.



### 9.2.3 FLUE GAS RECIRCULATION (FGR)

FGR reduces peak flame temperature, minimizing thermal NO<sub>x</sub>, by incorporating the recirculation of a portion of the flue gas back into the combustion zone as a replacement for combustion air. The recirculated combustion products provide inert gases that lower the adiabatic flame temperature and overall oxygen concentration in the combustion zone.<sup>56</sup> As a result, FGR limits NO<sub>x</sub> emissions by reduction of thermal NO<sub>x</sub> only, making it mostly effective for furnaces firing either natural gas or fuel oil.

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<sup>56</sup> Prasad, Arbind, “Air Pollution Control Technologies for Nitrogen Oxides,” *The National Environmental Journal*, May/June 1995.

## 9.2.4 LOW NO<sub>x</sub> BURNERS (LNB)

Traditional burner design introduces both the fuel and air into one combustion zone. To obtain optimal flames, large amounts of excess air must be combined with the fuel. This relatively “uncontrolled” combustion creates high flame temperatures and therefore higher NO<sub>x</sub> emissions.

To control the generation of thermal NO<sub>x</sub>, LNB technology stages combustion in the high temperature zone of the flame. The first stage is a fuel-rich, oxygen-lean atmosphere where little oxygen is available for NO<sub>x</sub> formation, which reduces peak flame temperatures by delaying the completion of the combustion process. Combustion is then completed downstream in the second stage where excess air is available but temperatures are lower than the hottest portion of the primary flame core.

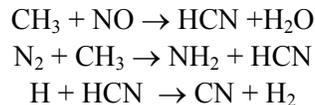
## 9.2.5 FUEL STAGING (REBURNING)

Also known as “reburning” or “off-stoichiometric combustion,” fuel staging is a technique where ten to twenty percent of the total fuel input is diverted to a second combustion zone downstream of the primary zone. The fuel in the secondary zone serves as a reducing agent: NO formed in the primary combustion zone is reduced to N<sub>2</sub>. This technique usually employs natural gas or distillate oil for the fuel in the secondary combustion zone.

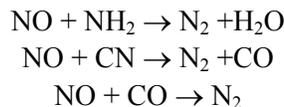
The kinetics involved in the reburn zone to reduce NO<sub>x</sub> are complex and not fully understood. The major chemical reactions are the following:<sup>57</sup>



The reaction process shown in the equation above is initiated by hydrocarbon formation in the reburn zone. Hydrocarbon radicals are released due to the pyrolysis of the fuel in an O<sub>2</sub> deficient, high-temperature environment. The hydrocarbon radicals then mix with the combustion gases from the main combustion zone and react with NO to form (CN) radicals and other stable products.



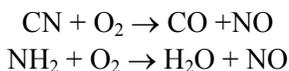
The CN radicals and other products can then react with NO to form N<sub>2</sub>, thus completing the major NO<sub>x</sub> reduction step.



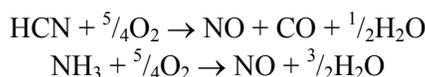
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<sup>57</sup>USEPA, Office of Air Quality Planning and Standards, “Alternative Control Technologies Document – NO<sub>x</sub> Emissions from Utility Boilers,” EPA-453/R-95-023, Pages 5-331 to 5-332.

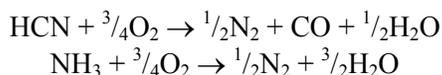
An O<sub>2</sub> deficient environment is important. If O<sub>2</sub> levels are high, the NO<sub>x</sub> reduction mechanism will not occur and other reactions will predominate.



To complete the combustion process, air must be introduced downstream of the reburn zone. Conversion of HCN and ammonia compounds in the burnout zone may regenerate some of the decomposed NO<sub>x</sub> by:



The NO<sub>x</sub> may continue to be reduced by the HCN and NH<sub>3</sub> compounds.



The major requirements for fuel staging are to reduce the fuel feed rate to the main combustion zone and to feed an equivalent amount of fuel to the reburn burners in the reburn zone.

## 9.2.6 WATER/STEAM INJECTION

Injection of water or steam into the main flame reduces the flame temperature and the generation of NO<sub>x</sub>. In some applications, NO<sub>x</sub> can be reduced by as much as 75 percent through water/steam injection.<sup>58</sup> If the temperature is reduced, thermal NO<sub>x</sub> will not be formed in as great a concentration.<sup>59</sup> However, if the flame temperature is sufficiently quenched, the generation of CO can increase and the process efficiency will decrease.

Water/steam injection is effective for reducing thermal NO<sub>x</sub> in natural gas fired Industrial/Commercial/Institutional (ICI) boilers and gas turbines. Because of low initial cost but higher variable costs, this technique is considered particularly effective for small, single-burner packaged boilers operated infrequently.<sup>24</sup> Water/steam injection reduces flame temperatures by absorbing the latent heat of vaporization which results in decreasing efficiency. It is mainly recommended as a temporary control measure to reduce NO<sub>x</sub> during peaking periods.<sup>60</sup>

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<sup>58</sup> USEPA, Office of Air Quality Planning and Standards. *Alternative Control Technologies Document – NO<sub>x</sub> Emissions from Industrial/Commercial/Institutional (ICI) Boilers*. EPA-453/R-032, Page 5-72.

<sup>59</sup> USEPA, Office of Air Quality Planning and Standards. *NO<sub>x</sub>, Why and How They are Controlled*. EPA-456/F-99-006R, November 1999, Page 16.

<sup>60</sup> R.K. Agrawal and S.C. Wood, *Innovative Solutions for Cost-effective NO<sub>x</sub> Control*, Pollution Engineering, June 2002.

### 9.2.7 MID-KILN FIRING (MKF)

In kilns, Mid Kiln Firing (MKF) is a form of staged fuel combustion. A specially designed fuel injection system introduces a second fuel source at a midpoint in the kiln. This system is typically used in cement kilns and allows the fuel to be burned at a material calcination temperature of 600°C to 900°C (1100°F to 1650°F).<sup>61</sup>

By adding fuel in the main flame at the mid-kiln, MKF changes the flame temperature and length. These changes may reduce thermal NO<sub>x</sub> formation by burning part of the fuel at a lower temperature and create reducing conditions at the fuel injection point which may destroy some of the NO<sub>x</sub> formed upstream in the kiln burning zone. The discontinuous MKF feed that results from introduction of staged fuels at the kiln midpoint (i.e., introduction of a solid fuel once every revolution) can result in increased CO emissions depending on the type of fuel used.

### 9.2.8 MIXING AIR FAN (MID-KILN AIR LANCES)

For lime kilns, this technology is a method of staging combustion air through the use of a fan that is mounted on the rotating kiln shell. This can reduce NO<sub>x</sub> formation by decreasing flame temperatures.

### 9.2.9 GOOD OPERATING PRACTICES AND PROPER DESIGN

The formation of NO<sub>x</sub> can be minimized by proper operation and design practices. Operators can control the combustion stoichiometry to minimize NO<sub>x</sub> formation while achieving efficient fuel combustion.

### 9.2.10 SELECTIVE NON-CATALYTIC REDUCTION (SNCR)

SNCR is an exhaust gas treatment process in which urea or ammonia is injected into the exhaust gas. High temperatures, normally between 1,600 and 1,900 °F, promote the reaction between urea or ammonia (NH<sub>3</sub>) and NO<sub>x</sub> to form N<sub>2</sub> and water.<sup>62</sup> The effectiveness of SNCR systems depends upon six main factors: (1) inlet NO<sub>x</sub> concentration, (2) temperature, (3) mixing, (4) residence time, (5) reagent-to-NO<sub>x</sub> ratio, and (6) fuel sulfur content. Lower NO<sub>x</sub> inlet concentrations result in a lower reduction of NO<sub>x</sub>. Temperature must fall within the appropriate range to avoid excess ammonia slip or oxidizing of NH<sub>3</sub> to NO<sub>x</sub>. Proper mixing of the reagent and the flue gas is necessary to ensure reduction of NO<sub>x</sub>. The residence time must be of an appropriate duration to allow completion of the reaction. If the reagent-to-NO<sub>x</sub> ratio is too high, excess NH<sub>3</sub> will become present in the exhaust. Finally, if the fuel has high sulfur content, NH<sub>3</sub> will react with sulfur trioxide to form ammonium sulfate salt compounds, which is a primary emission of a visibility-impairing pollutant.<sup>63</sup>

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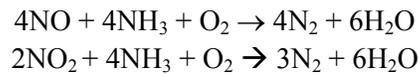
<sup>61</sup> Battye et al., EC/R Incorporated, "NO<sub>x</sub> Control Technology for the Cement Industry." Final report prepared for USEPA, September 19, 2000, Page 65.

<sup>62</sup> NCASI Special Report 03-04, *NO<sub>x</sub>/NO<sub>x</sub> Control in Forest Products Industry Boilers: A Review of Technologies, Costs, and Industry Experience*, August 2003.

<sup>63</sup> Ibid.

### 9.2.11 SELECTIVE CATALYTIC REDUCTION (SCR)

SCR is an exhaust gas treatment process in which NH<sub>3</sub> or urea is injected into the exhaust gas upstream of a catalyst bed for exhaust temperatures between 450 and 750 °F.<sup>64</sup> In the SCR process, the urea or NH<sub>3</sub> injected into the exhaust is stored in a liquid storage tank and vaporized before injection. The exhaust/ammonia mixture then passes over the catalyst. The function of the catalyst is to lower the activation energy of the NO decomposition reaction, therefore, lowering the temperature necessary to carry out the reaction. On the catalyst surface, NH<sub>3</sub> and nitric oxide (NO) or nitrogen dioxide (NO<sub>2</sub>) react to form diatomic nitrogen (N<sub>2</sub>) and water. The overall chemical reactions can be expressed as follows:



When operated within the optimum temperature range, the reaction can result in removal efficiencies between 70 and 90 percent.<sup>65</sup> The rate of NO<sub>x</sub> removal increases with temperature up to a maximum removal rate at a temperature between 700°F and 750°F. As the temperature increases above the optimum temperature, the NO<sub>x</sub> removal efficiency begins to decrease.<sup>66</sup>

The effectiveness of an SCR system depends upon the same factors as the SNCR system and the condition of the catalyst. The catalyst can degrade over time due to poisoning, fouling, thermal stress, and erosion by particulates, reducing the NO<sub>x</sub> removal efficiency of the SCR system.<sup>67</sup>

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<sup>64</sup> Ibid.

<sup>65</sup> Air Pollution Control Cost Manual, Section 4, Chapter 2, Selective Catalytic Reduction, NO<sub>x</sub> Controls, EPA/452/B-02-001, Page 2-9.

<sup>66</sup> Air Pollution Control Cost Manual, Section 4, Chapter 2, Selective Catalytic Reduction, NO<sub>x</sub> Controls, EPA/452/B-02-001, Page 2-10.

<sup>67</sup> NCASI Special Report 03-04, *NO<sub>x</sub>NO<sub>x</sub> Control in Forest Products Industry Boilers: A Review of Technologies, Costs, and Industry Experience*, August 2003.

### 9.2.12 OXIDATION/REDUCTION (O/R) SCRUBBING

Several proprietary Oxidation/Reduction (O/R) Scrubbing NO<sub>x</sub> removal processes are commercially available. It has been reported that O/R Scrubbing has a theoretical NO<sub>x</sub> removal efficiency of 95 percent.<sup>68</sup> The basic elements of the system are:

1. Cooling of the gas stream to its dew point temperature (150 to 250°F), which condenses a portion of the water vapor in the gas and generates condensate that requires disposal.
2. Low temperature oxidation of the NO<sub>x</sub>, CO, and SO<sub>2</sub> to higher oxides through controlled injection of ozone or sodium chlorite in a static mixer or reaction duct (the ozone/NO<sub>x</sub> ratios required to produce the desired NO<sub>x</sub> oxidation are reported to be less than stoichiometric amounts).
3. Absorption of higher vapor forms of nitrogen and sulfur oxides in a wet scrubber that produces nitric, sulfuric, and carbonic acid solution. These acids must be recovered and neutralized by the use of sodium hydroxide in the scrubber water (caustic scrubbing).
4. Once neutralized, the resultant scrubber water, containing nitric solution, can be discharged to a sanitary sewer system.

### 9.2.13 SUMMARY OF NO<sub>x</sub> CONTROL TECHNOLOGIES

Table 9-2 presents a summary of the potential NO<sub>x</sub> control technologies considered in the BART engineering analysis. Note that many of the technologies listed in this table are not feasible for all the PTPC Mill BART-eligible emission units, as discussed in greater detail in Section 10 of this report.

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<sup>68</sup> NCASI Special Report 03-04, *NO<sub>x</sub>NO<sub>x</sub> Control in Forest Products Industry Boilers: A Review of Technologies, Costs, and Industry Experience*, August 2003.

**TABLE 9-2. NO<sub>x</sub> CONTROL TECHNOLOGIES EVALUATED**

Control Technology	Available for Emission Unit (Yes/No) <sup>a</sup>			
	NDCE Recovery Furnace	Smelt Dissolving Tank <sup>b</sup>	No. 10 Power Boiler	Lime Kiln
Low Excess Air (LEA)	Yes	NA	Yes	No
Staged Combustion	No <sup>c</sup>	NA	No <sup>c</sup>	Yes
Flue Gas Recirculation (FGR)	Yes	NA	Yes	Yes
Low NO <sub>x</sub> Burners (LNB)	Yes	NA	Yes	Yes
Fuel Staging/Reburning	Yes	NA	Yes	Yes
Water/Steam Injection	No	NA	No	Yes
Mid-Kiln Firing	No	NA	No	Yes
Mixing Air Fan	No	NA	No	Yes
Good Operating Practices and Proper Design	Yes	NA	Yes	Yes
Selective Non-Catalytic Reduction (SNCR)	Yes	NA	Yes	Yes
Selective Catalytic Reduction (SCR)	Yes	NA	Yes	Yes
Oxidation/Reduction Scrubbing	Yes	NA	Yes	Yes

<sup>a</sup> Availability based on whether control technology can be considered for each emission unit, not on technical feasibility, which is addressed in Section 10.  
<sup>b</sup> NO<sub>x</sub> control technologies are not evaluated for the Smelt Dissolving Tank since this unit is not a combustion device and is therefore not a source of NO<sub>x</sub> emissions.  
<sup>c</sup> PTPC's Recovery Furnace and No. 10 Power Boiler inherently use staged combustion; therefore, adding this control technology is not available for these units.

### 9.3 SO<sub>2</sub> CONTROL TECHNOLOGIES

The following potential control options have been identified for SO<sub>2</sub> pollution prevention and reduction.

- Flue Gas Desulfurization (FGD) – Wet Injection with Wet Scrubber
- FGD – Semi-Dry Lime Slurry Injection with ESP or Baghouse
- FGD – Semi-Dry Lime Powder Injection with ESP or Baghouse
- FGD – Spray Drying with ESP or Baghouse
- Inherent Dry Scrubbing
- Fuel Selection
- Increased Oxygen Levels at the Burners
- Good Operating Practices

These control technologies are briefly discussed in the following paragraphs.

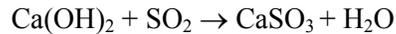
#### 9.3.1 FLUE GAS DESULFURIZATION (FGD) WITH WET SCRUBBER

In wet flue gas desulfurization (FDG), also known as dual-alkali (caustic) scrubbing, a solution of sodium hydroxide absorbs SO<sub>2</sub> from the flue gas. The SO<sub>2</sub> reacts with the sodium hydroxide and is removed in solution as a liquid waste. Additional sodium hydroxide solution is added to the recirculating scrubber solution to compensate for the quantity that

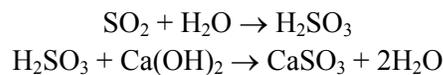
reacts with SO<sub>2</sub>. Typically, large quantities of liquid waste are disposed of using wastewater treatment holding ponds, or are fed back into processes where the sulfur can be recovered.<sup>69</sup>

### 9.3.2 FGD – SEMI-DRY LIME HYDRATE SLURRY INJECTION

For lime hydrate slurry injection, calcium hydroxide in the form of a lime slurry is injected into the gas stream. Calcium hydroxide and SO<sub>2</sub> will react to form calcium sulfite:



Also, SO<sub>2</sub> will react with water to form sulfurous acid, which can then react with calcium hydroxide to form calcium sulfite.



A fabric filter or ESP would need to be installed to remove the solid reaction products from the gas stream. After the calcium hydrate is injected into the gas stream, the slurry droplets will dry and the particulate matter will be removed from the stream by the fabric filter or ESP.

The removal of sulfur using a lime slurry is influenced by the following operating parameters:

1. Approach to the Saturation Temperature ( $\Delta T_{\text{sat}}$ ): The saturation temperature is the temperature at which liquid water evaporates at the same rate at which it condenses, or the aqueous liquid and gaseous phases are at equilibrium at a given pressure. Therefore, the operating temperature must be close to the saturation temperature ( $T_{\text{sat}}$ ) to allow for the particles to have some surface moisture for an adequate residence time. In addition, the  $\Delta T_{\text{sat}}$  must not be too small, i.e. the temperature can not be too close to the saturation temperature, or the particles will be too saturated, causing the particles to stick to the particulate control device and deteriorate the fabric filter.
2. Residence Time: A residence time of 2 to 3 seconds or more is necessary for the reactions to occur. Evaporation of a slurry droplet depends on the size and characteristics of the droplet.
3. Sorbent Properties: A greater surface area per unit weight of the lime hydrate (i.e., smaller particles) improves the potential for sulfur absorption.
4. Calcium to Sulfur Ratio: A greater calcium to sulfur ratio results in better removal efficiency.
5. Initial SO<sub>2</sub> Level: The removal efficiency will increase with higher initial SO<sub>2</sub> concentrations in the kiln exhaust gas.

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<sup>69</sup> Cooper, C. David and Alley, F.C. *Air Pollution Control – A Design Approach, 2<sup>nd</sup> Edition*. Waveland Press: Prospectus Height, Illinois, 1994.

### 9.3.3 FGD – DRY LIME HYDRATE POWDER INJECTION

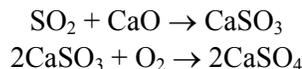
Lime hydrate powder injection controls SO<sub>2</sub> using the same methods as lime hydrate slurry injection and depends on most of the same parameters. As with the lime slurry, a fabric filter or ESP would need to be installed to remove the solid reaction products from the gas stream. The dry lime hydrate can be also be injected in either the feed chute or prior to the fabric filter or ESP. Dry lime hydrate powder decomposes to CaO at temperatures of 1076 °F and above.<sup>70</sup>

### 9.3.4 FGD – SPRAY DRYER WITH AN ESP

This technique requires installation of a spray dryer and an ESP. Dry lime is injected by a spray dryer into the flue gas in the form of fine droplets under well controlled conditions such that the droplets will absorb SO<sub>2</sub> from the flue gas and then become dry particles because of the evaporation of water. The dry particles are captured by the ESP downstream of the dryer. The captured particles are then removed from the system and disposed.<sup>71</sup>

### 9.3.5 INHERENT DRY SCRUBBING

In the case of lime kilns, the kiln inherently acts as a dry scrubber for SO<sub>2</sub> control. The lime dust generated in the kiln is a natural scrubbing medium, reacting with SO<sub>2</sub> according to the following reactions:



The amount of sulfur removed in a lime kiln varies with two primary parameters: size of the lime particles and the point in the lime kiln at which calcination begins. As the unit surface area increases (i.e., the particle size decreases), the SO<sub>2</sub> and the lime have greater contact which results in a higher SO<sub>2</sub> removal rate. The residence time of the SO<sub>2</sub> and lime at a high temperature also affects the amount of SO<sub>2</sub> removed.

### 9.3.6 LOW SULFUR FUEL SELECTION

SO<sub>2</sub> emissions are influenced by the sulfur content of the fuel as well as the sulfur content of the process material. For the recovery furnace, the black liquor solids are both the fuel and the material being processed. In the case of the smelt dissolving tank, there is no fuel burning, and in the case of the boiler, there is no process material. For the lime kiln, the fuel is the dominant source of sulfur rather than the lime feed. The sulfur emitted from an emission unit as SO<sub>2</sub> originates as sulfur in the raw materials processed or fuel combusted, unlike NO<sub>x</sub>, which may form from fuel nitrogen or chemical reactions with N<sub>2</sub> in the combustion air. Using fuel with lower sulfur content results in lower emissions of SO<sub>2</sub>.

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<sup>70</sup> Chemical Lime Company Material Safety Data Sheet, Calcium Hydroxide.

<sup>71</sup> Cooper, C. David and Alley, F.C. *Air Pollution Control – A Design Approach, 2<sup>nd</sup> Edition*. Waveland Press: Prospectus Height, Illinois, 1994.

### 9.3.7 INCREASED OXYGEN LEVELS AT THE BURNER

For lime kilns, an increase in oxygen levels in the kiln has been shown to decrease SO<sub>2</sub> emissions. The increase in oxygen drives the SO<sub>2</sub> to SO<sub>3</sub> allowing the SO<sub>3</sub> to react with lime to produce CaSO<sub>4</sub> as shown in the following reaction:



### 9.3.8 GOOD OPERATING PRACTICES

Good operating practices imply that the emission unit is operated within parameters that, without additional control technology, allow the equipment to operate as efficiently as possible.

### 9.3.9 SUMMARY OF SO<sub>2</sub> CONTROL TECHNOLOGIES

Table 9-3 presents a summary of the potential SO<sub>2</sub> control technologies considered in the BART engineering analysis. Note that many of the technologies listed in this table are not feasible for all the PTPC Mill BART-eligible emission units, as is discussed in greater detail in Section 10 of this report.

**TABLE 9-3. SO<sub>2</sub> CONTROL TECHNOLOGIES EVALUATED**

Control Technology	Available for Emission Unit (Yes/No) <sup>a</sup>			
	NDCE Recovery Furnace	Smelt Dissolving Tank	No. 10 Power Boiler	Lime Kiln
Flue Gas Desulfurization (FGD) with Wet Scrubber	Yes	Yes	Yes	Yes
FGD – Semi-Dry Lime Hydrate Slurry Injection with ESP or Baghouse	Yes	Yes	Yes	Yes
FGD – Semi-Dry Lime Hydrate Powder Injection with ESP or Baghouse	Yes	Yes	Yes	Yes
FGD – Spray Drying with ESP or Baghouse	Yes	Yes	Yes	Yes
Inherent Dry Scrubbing	No	No	No	Yes
Fuel Selection	Yes	No	Yes	Yes
Increased Oxygen Levels at the Burners	No	No	No	Yes
Good Operating Practices	Yes	Yes	Yes	Yes

<sup>a</sup> Availability based on whether control technology can be considered for each emission unit, not on technical feasibility, which is addressed in Section 10.

## **10. ELIMINATION OF TECHNICALLY INFEASIBLE CONTROL OPTIONS (STEP 2)**

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After the identification of control options, the next step in the BART Determination Analysis is to eliminate technically infeasible options. A control is eliminated from consideration if there are process-specific conditions that prohibit the implementation of control or if the highest control efficiency for that option would result in an emission level that is higher than any applicable regulatory limits. According to EPA's *Guidelines for BART Determinations under the Regional Haze Rules* [40 CFR Part 51, Appendix Y], technologies which have not yet been applied to (or permitted for) full scale operations need not be considered as available. Therefore, control options that have not been successfully demonstrated for a particular emission unit are considered technically infeasible and removed from further consideration as further discussed in the following sections. Appendix C presents a summary of the RBLC search results for the PM, NO<sub>x</sub>, and SO<sub>2</sub> control technologies for each BART-eligible emission unit.

### **10.1 PM<sub>10</sub> TECHNICALLY INFEASIBLE CONTROL OPTIONS**

The No. 10 Power Boiler is the only emission unit considered for application of BART control for PM<sub>10</sub>. The remaining BART-eligible emission units are subject to MACT standards for PM. As further described in Section 8, these MACT standards are considered to represent BART.

#### **10.1.1 PM<sub>10</sub> CONTROL FROM THE NO. 10 POWER BOILER**

The No. 10 Power Boiler is a spreader stoker type boiler with horizontally opposed overfire air ports and tangential oil burners downstream of the grate. The boiler combusts wood-waste, bark, primary clarifier sludge, old corrugated container (OCC) rejects, and oil. The boiler currently employs a 600 tube multiclone followed by a venturi scrubber for the control of particulate matter. The following sections describe several control options that are considered technically infeasible for application to the No. 10 Power Boiler.

##### **10.1.1.1 FABRIC FILTERS (BAGHOUSE)**

The use of fabric filters to control particulate matter emissions from wood-fired boilers results in a fire hazard due to the potential of burning cinders, temperature excursions, and/or operating upsets combined with fabric flammability causing the fabric filters to ignite. Because of this fire hazard, fabric filters are rarely used on wood-fired boilers. Fabric filters have been successfully used on some wood-fired boilers that burn wood-residue or bark stored in salt water because the salt reduces the fire hazard. However, PTPC's Title V Operating Permit specifically prohibits burning salty hog fuel in the No. 10 Power Boiler as part of the opacity limit. Therefore, the use of fabric filters to control particulate matter emissions from the No. 10 Power Boiler is considered technically infeasible due to fire hazard.

### **10.1.1.2 ELECTRIFIED GRAVEL BED FILTER (EGF)**

While electrified gravel bed filters (EGFs) have been implemented on some wood-fired boilers, their successful use has not been demonstrated. Difficulties arise in implementing this technology on wood-fired boilers when the gravel media becomes easily clogged, resulting in high backpressure and maintenance difficulties. Further, according to AP-42 Table 1.6-1, the PM and PM<sub>10</sub> emission factors from wood fired boilers controlled with an EGF system are higher than those controlled with a wet scrubber, indicating that an EGF system will not provide control improvement over the existing wet scrubber. Therefore, the installation of an EGF system for control of particulate matter from the No. 10 Power Boiler is not considered further.

## **10.2 NO<sub>x</sub> TECHNICALLY INFEASIBLE CONTROL OPTIONS**

Each of the following sections presents the control technologies for NO<sub>x</sub> and techniques identified as being technically infeasible for application to each emission unit. Reasons for eliminating each option are identified on a unit-by-unit basis.

### **10.2.1 NO<sub>x</sub> CONTROL FROM THE NO. 10 POWER BOILER**

The No. 10 Power Boiler is a load-following spreader stoker combination boiler with tangentially fired oil burners that combusts wood-waste, sludge, old corrugated container (OCC) rejects, and oil. The spreader stoker design inherently uses staged combustion. In PTPC's No. 10 Power Boiler, the fuel-rich combustion of the wood-waste on the grates results in incomplete combustion and lower flame temperatures. Downstream of the primary flame, the horizontally opposed overfire air ports supply excess air to complete the combustion. Further downstream, the tangential oil burners supply additional heat without increasing the primary flame temperature. This firing configuration results in low flame temperatures, and minimal thermal-NO<sub>x</sub> formation. As a result, the majority of the NO<sub>x</sub> from wood-fired boilers is fuel NO<sub>x</sub>.<sup>72</sup> The following sections describe several control options that are considered technically infeasible for application to the No. 10 Power Boiler.

#### **10.2.1.1 LOW EXCESS AIR (LEA)**

The LEA control option can produce limited NO<sub>x</sub> reductions. However, LEA results in the production of smoke, increased CO emissions, and other problems associated with the boiler operation, such as increased corrosion and fouling.<sup>73</sup> Due to fluctuations in the fuel properties, the low level of overall excess air will likely cause incomplete combustion, resulting in increased CO emissions. In addition, LEA is difficult to employ in spreader stoker boilers because high excess

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<sup>72</sup> NCASI Special Report 03-04, *NO<sub>x</sub>NO<sub>x</sub> Control in Forest Products Industry Boilers: A Review of Technologies, Costs, and Industry Experience*, August 2003.

<sup>73</sup> Ibid.

air levels are needed for proper fuel burning.<sup>74</sup> Finally, LEA is not anticipated to produce NO<sub>x</sub> reductions beyond those already achieved by the staged combustion inherently practiced in the boiler. Therefore, LEA is considered ineffective and technically infeasible and is not considered further.

#### **10.2.1.2 FLUE GAS RECIRCULATION (FGR)**

FGR reduces thermal NO<sub>x</sub> by routing a portion of the flue gas to the burner. The use of this technology would result in soot fouling. Further, FGR does not significantly reduce NO<sub>x</sub> emissions when firing a wood-waste spreader stoker boiler since the majority of NO<sub>x</sub> emissions arise from fuel nitrogen. Therefore, FGR (which controls thermal NO<sub>x</sub>) would not be anticipated to provide a significant reduction in the NO<sub>x</sub> emissions from the No. 10 Power Boiler. Applying FGR as a means of controlling NO<sub>x</sub> is considered ineffective for the No. 10 Power Boiler, and is not considered further.

#### **10.2.1.3 LOW NO<sub>x</sub> BURNERS (LNB)**

Low NO<sub>x</sub> burners are not expected to significantly reduce NO<sub>x</sub> emissions when firing a wood-waste spreader stoker boiler since the majority of NO<sub>x</sub> emissions arise from fuel nitrogen. Therefore, applying low NO<sub>x</sub> burners as a means of controlling NO<sub>x</sub> is considered ineffective for the No. 10 Power Boiler. Furthermore, a Combustion Engineering (CE) representative states that there is no commercially available low NO<sub>x</sub> oil burner that can be retrofitted into a tangential type burner like those used in PTPC's No. 10 Power Boiler. Therefore, the use of low NO<sub>x</sub> burners is considered technically infeasible and is not considered further.

#### **10.2.1.4 FUEL STAGING (REBURNING)**

Fuel staging requires the use of natural gas or distillate oil in a secondary combustion zone downstream of the primary zone. The No. 10 Power Boiler does not use these fuels. Further, fuel staging often employs FGR, which is considered infeasible for hogfuel boilers due to its inability to minimize fuel NO<sub>x</sub>, the primary component of NO<sub>x</sub> from wood-waste combustion.<sup>75</sup> For these reasons, this technology has not been successfully demonstrated. In addition, PTPC's No. 10 Power Boiler inherently uses a process similar to fuel staging by design. The tangential oil burners, which typically supply approximately 30 % of the heat to the boiler, are located downstream of the primary wood-fired flame. Since this technology has not been successfully demonstrated, it is considered technically infeasible and is not considered further.

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<sup>74</sup> Washington State Department of Ecology Publication No. 03-02-009, *Hog Fuel Boiler RACT Determination*, April 2003, downloaded June 25, 2007, <http://www.ecy.wa.gov/biblio/0302009.html>.

<sup>75</sup> NCASI Special Report 03-04, *NO<sub>x</sub>NO<sub>x</sub> Control in Forest Products Industry Boilers: A Review of Technologies, Costs, and Industry Experience*, August 2003.

### 10.2.1.5 SELECTIVE NON-CATALYTIC REDUCTION (SNCR)

SNCR technology has never been successfully demonstrated for wood-fired boilers with changing loads.<sup>76</sup> The No. 10 Power Boiler firing rate varies to meet the PTPC Mill's steam demand. Therefore, this technology is considered technically infeasible and is not considered further.

There are several reasons why SNCR technology has not been successfully implemented on load-following wood-fired boilers. The injection of the reagent must be applied in a narrow temperature window in order for the reduction reaction to successfully complete. In a load-following boiler, the region of the boiler where this temperature occurs varies depending on the firing rate, making it nearly impossible to control the SNCR reaction temperature. Another factor preventing proper implementation of SNCR technology in wood-fired boilers is inadequate reagent dispersion in the injection region, which can lead to significant amounts of unreacted ammonia exhausted to the atmosphere (i.e., large ammonia slip). At least one pulp mill wood-fired boiler had to abandon their SNCR system due to problems caused by poor dispersion of the reagent within the boiler.<sup>77</sup>

In addition, the ammonia injection, storage, and waste by-product collection system must be properly designed for spill containment and waste removal. Ammonia is listed as a hazardous substance (40 CFR 355, Appendix A) and as a toxic chemical (40 CFR 372.65). The Clean Air Act Amendments of 1990 also list ammonia as extremely hazardous, Section 112(r)(3). Therefore, use and/or emissions of ammonia could be subject to numerous other regulatory requirements.

### 10.2.1.6 SELECTIVE CATALYTIC REDUCTION (SCR)

SCR technology has never been successfully demonstrated for a spreader stoker boiler.<sup>78</sup> Therefore, this technology is considered technically infeasible and is not considered further.

There are several reasons why SCR technology has not been implemented on wood-fired boilers. Size constraints often make locating an SCR system near the boiler impossible. Further, most hogfuel boilers' temperature profiles are not appropriate for SCR, and the SCR system pressure drop requirements result in sizing concerns related to existing boiler fans. NCASI notes that the high PM concentrations upstream of the PM control equipment would impede catalyst effectiveness and could result in deactivation or poisoning of the catalyst, while

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<sup>76</sup> NCASI Corporate Correspondent Memorandum No. 06-0142006, *Information on Retrofit Control Measures for Kraft Pulp Mill Sources and Boilers for NO<sub>x</sub>, SO<sub>2</sub> and PM Emissions*, June 2006.

<sup>77</sup> Ibid.

<sup>78</sup> NCASI Corporate Correspondent Memorandum No. 06-0142006, *Information on Retrofit Control Measures for Kraft Pulp Mill Sources and Boilers for NO<sub>x</sub>, SO<sub>2</sub> and PM Emissions*, June 2006.

installation of SCR downstream of the PM control equipment would render the gas stream too cold for effective reaction with the catalyst to reduce NO<sub>x</sub>. The desired temperature range for SCR application is 450 to 750 °F, while the outlet temperature of the No. 10 Power Boiler's venturi scrubber is less than 150 °F. Reheating the flue gas would result in significant energy penalties. Furthermore, greater conversion of SO<sub>2</sub> to SO<sub>3</sub>, which readily converts to visibility-impairing H<sub>2</sub>SO<sub>4</sub>, is also expected to be produced by the catalyst.<sup>79</sup>

In addition, the handling and disposal of spent catalyst has been recognized as an environmental risk and a potential health hazard. Spent catalyst is expected to contain high levels of heavy metal oxides (particularly of vanadium and titanium) several of which are considered to be hazardous. For example, the U.S. EPA lists vanadium pentoxide as an extremely hazardous substance (40 CFR 355, Appendix A).

Additional concerns with an SCR system include the safety and environmental hazards involved with storage and use of large quantities of NH<sub>3</sub>. Because anhydrous NH<sub>3</sub> (used in SCR systems) is stored in pressurized vessels, leaks in NH<sub>3</sub> supply systems can result in toxic gas releases. Ammonia transportation, transfer operations, and use can be hazardous because of potential equipment failure and human error. Also, the U.S. EPA has listed NH<sub>3</sub> as a hazardous substance (40 CFR 355, Appendix A) and as a toxic chemical (40 CFR 372.65). The Clean Air Act Amendments of 1990 also list NH<sub>3</sub> as extremely hazardous (Section 112[r][3]). Therefore, use and/or emissions of ammonia could be subject to numerous other regulatory requirements.

### 10.2.1.7 OXIDATION/REDUCTION (O/R) SCRUBBING

This technology is designed to complement control systems that already include a caustic scrubber. PTPC's No. 10 Power Boiler is not equipped with a caustic scrubber. If a caustic scrubber were installed on the recovery furnace, other technical difficulties would arise. This technology is not considered readily available or proven for industrial boiler retrofit operations.<sup>80</sup> Further, it is not listed as a successfully demonstrated option in any RBLC determination. Even if such technology were to be considered proven and technically feasible for retrofit operations, it is unlikely to be cost feasible.<sup>81</sup> Therefore, this technology is eliminated from BART consideration.

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<sup>79</sup> NCASI Special Report 03-04, *NO<sub>x</sub>/NO<sub>x</sub> Control in Forest Products Industry Boilers: A Review of Technologies, Costs, and Industry Experience*, August 2003.

<sup>80</sup> This technology is not evaluated as a readily available BART option in the BART guidance documents for industrial boilers issued by the Midwest RPO (*Midwest RPO Candidate Control Measures for Industrial, Commercial, and Institutional Boilers*, March 2005) or MANE-VU (*Assessment of Control Technology Options for BART-Eligible Sources: Steam Electric Boilers, Industrial Boilers, Cement Plants, and Paper and Pulp Facilities*, March 2005).

<sup>81</sup> NCASI Special Report 03-04, *NO<sub>x</sub>/NO<sub>x</sub> Control in Forest Products Industry Boilers: A Review of Technologies, Costs, and Industry Experience*, August 2003.

## 10.2.2 NO<sub>x</sub> CONTROL FROM THE RECOVERY FURNACE

As described in Section 3, recovery furnaces operate by spraying spent chemical concentrated liquor from the digester, called black liquor, into the furnace where the organics in the black liquor solids, derived from pulping the wood, are combusted and the inorganic pulping chemicals are recovered and recycled. A chemical recovery furnace is not simply a “boiler” designed to burn fuel and produce steam; it is a complex device which serves as a chemical reactor, a chemical recovery unit, an internal high efficiency SO<sub>2</sub> scrubber, and an energy recovery center for recovery of stored solar energy in wood lignins.

As with all boilers, recovery furnaces have special safety systems to preclude fuel/air explosions and steam explosions if steam pressure ratings are exceeded. However, chemical recovery furnaces can experience other, unique types of explosions such as pyrolysis gas (CO, methane, hydrogen, and others) explosions and smelt/water explosions. If a recovery furnace experiences a “black out” where the flame extinguishes and the hot char bed continues to produce pyrolysis gases, then a spark or flame can reignite the gases and produce a fuel/air explosion. If a boiler tube develops a leak and water comes into contact with the molten salt at the bottom of the furnace, a very forceful explosion may take place. While such hazards are contained within the plant site and do not threaten the surrounding community, they pose a significant danger to employees and equipment. These special safety issues and the critical chemical reactions discussed previously are what makes a chemical recovery furnace unique and explains why some emission technologies that may work for ordinary boilers are technically infeasible and even dangerous for a chemical recovery furnace.

In a 2003 Special Report, NCASI specifically addressed options for reducing NO<sub>x</sub> emissions from recovery furnaces, indicating that no operating kraft recovery furnace currently utilizes post-combustion control and limited pollution prevention techniques for NO<sub>x</sub> are available.<sup>82</sup> A subsequent NCASI Corporate Correspondence Memorandum states:<sup>83</sup>

*[O]ptimization of the staged combustion principle within large, existing kraft recovery furnaces to achieve lower NO<sub>x</sub> emissions might be the only technologically feasible option at the present time for NO<sub>x</sub> reduction . . . Ultimately, the liquor nitrogen content, which is dependent on the types of wood pulped, is the dominant factor affecting the level of NO<sub>x</sub> emissions from black liquor combustion in a recovery furnace. Unfortunately, this factor is beyond the control of pulp mill operators.*

As described in the sections below, in the NCASI publications, and as presented in the RBLC search results, good combustion practices optimizing the staged combustion inherent in the design of the furnace is the only available technology for the control of NO<sub>x</sub> from a kraft recovery furnace.

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<sup>82</sup> NCASI Special Report No. 03-06, *Effect of Kraft Recovery Furnace Operations on NO<sub>x</sub>NO<sub>x</sub> Emissions: Literature Review and Summary of Industry Experience*, October 2003.

<sup>83</sup> NCASI Corporate Correspondent Memorandum No. 06-0142006, *Information on Retrofit Control Measures for Kraft Pulp Mill Sources and Boilers for NO<sub>x</sub>, SO<sub>2</sub> and PM Emissions*, June 2006.

### 10.2.2.1 LOW EXCESS AIR (LEA)

The LEA control option can produce limited NO<sub>x</sub> reductions. However, LEA results in the production of smoke, increased CO emissions, and other problems associated with the furnace operation, such as increased corrosion and fouling.<sup>84</sup> This technique also presents technical difficulties for kraft recovery furnaces since the black liquor properties and associated combustion gas compositions tend to fluctuate. As a result, the low level of overall excess air will likely cause incomplete combustion, resulting in increased CO emissions. Therefore, LEA is considered technically infeasible for control of NO<sub>x</sub> emissions from PTPC's recovery furnace.

### 10.2.2.2 FLUE GAS RECIRCULATION (FGR)

FGR does not significantly reduce NO<sub>x</sub> emissions when firing black liquor solids in a recovery furnace since the majority of NO<sub>x</sub> emissions arise from fuel nitrogen. Therefore, FGR (which controls thermal NO<sub>x</sub>) does not reduce the NO<sub>x</sub> emissions from black liquor solids combustion. Further, the corrosive conditions inherent in the firing of black liquor solids prevents the use of FGR as the fly ash in the flue gas stream would accumulate in the ductwork required for FGR and absorb moisture, resulting in duct pluggage and severe corrosion. Additionally, the reduced oxygen concentration formed in the furnace by FGR would result in an unacceptable increase in CO emissions. The increased flue gas volume would increase gas velocity in the superheaters and furnace bank, which can cause additional pluggage and lost capacity.

Applying FGR as a means of controlling NO<sub>x</sub> is considered technically infeasible and may inhibit the kraft recovery process.

### 10.2.2.3 LOW NO<sub>x</sub> BURNERS (LNB)

Although LNB have been extensively tested and used in utility furnaces and industrial furnaces, the transfer of this technology to the kraft recovery process has met with difficulties. Combustion properties are critical to the quality control and kraft recovery process in the recovery furnace. The fireside conditions in a kraft recovery furnace do not accommodate LNB; usage of LNB would prohibit use of multi-stage air feeds and multiple small fuel nozzles, compromising the burners' intended purpose of chemical recovery and impacting their ability to support liquor burning and hearth bed control. Further, the use of low NO<sub>x</sub> burners has not been successfully demonstrated for a kraft recovery furnace application.<sup>85</sup> Due to these technical complexities and lack of successful demonstration, the conversion of a

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<sup>84</sup> NCASI Special Report 03-04, *NO<sub>x</sub>NO<sub>x</sub> Control in Forest Products Industry Boilers: A Review of Technologies, Costs, and Industry Experience*, August 2003.

<sup>85</sup> NCASI Corporate Correspondent Memorandum No. 06-0142006, *Information on Retrofit Control Measures for Kraft Pulp Mill Sources and Boilers for NO<sub>x</sub>, SO<sub>2</sub> and PM Emissions*, June 2006.

standard recovery furnace burner using black liquor solids or fuel oil to low NO<sub>x</sub> design is not technically feasible and is not considered further.

#### **10.2.2.4 FUEL STAGING**

Fuel staging is not appropriate for use in a kraft recovery furnace. Usage of fuel staging is generally limited to natural gas or distillate oil combustion. Under normal operation, the furnace combusts mostly black liquor solids. The black liquor solids cannot be diverted to a second combustion zone without negatively impacting the delicate balance of the kraft recovery process. Therefore, this technology is considered technically infeasible and is not considered further.

#### **10.2.2.5 WATER/STEAM INJECTION**

Water/steam injection does not significantly reduce NO<sub>x</sub> emissions when firing black liquor solids in a recovery furnace since the majority of NO<sub>x</sub> emissions arise from fuel nitrogen. Therefore, water/steam injection (which controls thermal NO<sub>x</sub>) does not reduce the NO<sub>x</sub> emissions from black liquor solids combustion and this option is not considered further.

#### **10.2.2.6 SELECTIVE NON-CATALYTIC REDUCTION (SNCR)**

Based on trial testing of an SNCR in the early 1990s, several difficulties preclude use of an SNCR for control of NO<sub>x</sub> emissions from recovery furnaces. The recovery furnace's complex chemical reaction balance can be upset by the SNCR usage, potentially damaging the furnace and negatively impacting product quality. Due to the furnace load and exhaust gas temperature fluctuations as well as the control technology requiring optimum NH<sub>3</sub>/NO<sub>x</sub> molar ratio and correct reaction temperatures, combustion stability would be extremely difficult to monitor and maintain, likely resulting in the release of NH<sub>3</sub> into the atmosphere. Further, it is likely that formation of NH<sub>3</sub> salts would occur which could result in an increase of process downtime. In addition, the hazards involved with the storage of NH<sub>3</sub> and the increased emissions from NH<sub>3</sub> slip cause environmental and safety concerns. Finally, the recovery furnace may operate at temperatures above 2,000 °F; when temperatures exceed 2,000 °F, the NH<sub>3</sub> injected with the SNCR begins to oxidize, creating additional NO<sub>x</sub>.

While SNCR has been demonstrated during a short trial on a recovery furnace (which was decommissioned shortly after the trial concluded), long-term use of an SNCR system on a recovery furnace has never been evaluated. Theoretically, the ammonia from the SNCR would prevent the chlorine present in the black liquor from being purged through the stack as HCl. Without the purging, the chlorine would build up in the liquor, resulting in fouling and plugging of the furnace with high chloride deposits. The ammonia may also end up in the liquor cycle, resulting in ammonia emissions from the Smelt Dissolving Tank. Ammonia in the liquor

cycle would also eventually increase the nitrogen content of the black liquor, ultimately increasing the NO<sub>x</sub> emissions from the recovery furnace.<sup>86</sup>

SNCR for control of NO<sub>x</sub> emissions from a kraft recovery furnace has never been demonstrated on a long-term basis and is not listed on the RBLC for any recovery furnace.<sup>87</sup> Therefore, SNCR is considered a technically infeasible control technology for PTPC's recovery furnace.

### 10.2.2.7 SELECTIVE CATALYTIC REDUCTION (SCR)

Several technical and operational difficulties exist with SCR technology. The SCR process is temperature sensitive. Efficient operation requires constant exhaust temperatures within a defined range, usually  $\pm 50$  °F. Any load fluctuation resulting in exhaust gas temperature fluctuations reduces removal efficiency and upsets the NH<sub>3</sub>/NO<sub>x</sub> molar ratio needed for effective SCR control. A low temperature results in slow reaction rates which lead to low nitrogen oxides conversion and unreacted NH<sub>3</sub> passing through the reactor bed (ammonia slip). A high temperature results in shortened catalyst life and can lead to the oxidation of NH<sub>3</sub> and the formation of additional NO<sub>x</sub>.

Additional concerns with using a SCR system include the hazards involved with storing large quantities of NH<sub>3</sub> and with disposal of spent catalyst which has been contaminated by SO<sub>2</sub> and Cl<sub>2</sub>. The NH<sub>3</sub> also causes potential corrosion problems. Because anhydrous NH<sub>3</sub> used in SCR systems is stored in pressurized vessels, leaks in ammonia supply systems can result in toxic vapor releases. NH<sub>3</sub> transportation, transfer operations, and use can be hazardous because of potential equipment failure and human error.

Controlling the feed rate of the SCR reagent would also present unique technical considerations. The recovery furnace heat input and black liquor solids characteristics vary continuously. Reactant injection rates must be closely controlled to maintain a given level of NO<sub>x</sub> control while simultaneously avoiding excess ammonia slip. Such control requires precise knowledge of the furnace's NO<sub>x</sub> emission rate, which is directly related to the heat input rate.

The ammonia may also react with sulfur to form ammonium bisulfate, which has the potential to create a visible and/or detached plume. The lime may also react with the sulfur to form calcium sulfate. Ammonium bisulfate and calcium sulfate coatings, along with other dusts, will block the catalyst pores, thereby reducing the catalyst effectiveness.

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<sup>86</sup> NCASI Special Report 03-06, *Effect of Kraft Recovery Furnace Operations on NO<sub>x</sub>NO<sub>x</sub> Emissions: Literature Review and Summary of Industry Experience*, October 2003.

<sup>87</sup> NCASI Corporate Correspondent Memorandum No. 06-0142006, *Information on Retrofit Control Measures for Kraft Pulp Mill Sources and Boilers for NO<sub>x</sub>, SO<sub>2</sub> and PM Emissions*, June 2006.

In addition, the handling and disposal of spent catalyst has been recognized as an environmental risk and a potential health hazard. As described in Section 10.2.1.6, spent catalyst is expected to contain high levels of hazardous heavy metal oxides. Additional concerns with an SCR system include the safety and environmental hazards involved with storage and use of large quantities of NH<sub>3</sub>, as previously described in Section 10.2.1.6.

SCR technology for control of NO<sub>x</sub> emissions from a kraft recovery furnace has never been demonstrated even on a short-term basis and is not listed on the RBLC for any recovery furnace.<sup>88</sup> Based on this lack of demonstration and the technical concerns described, SCR is considered a technically infeasible control technology for PTPC's recovery furnace and is not considered further.

#### **10.2.2.8 OXIDATION/REDUCTION SCRUBBING**

This technology is designed to complement control systems that already include a caustic scrubber. PTPC's recovery furnace is not equipped with a caustic scrubber. If a caustic scrubber were installed on the recovery furnace, other technical difficulties would arise. The high moisture content of black liquor solids results in a high dew point temperature in the flue gas. The flue gas dew point temperature is expected to exceed 300 °F, the maximum temperature for effective oxidation/reduction scrubbing.

If the flue gas temperature is lowered to below 300 °F, condensation problems and associated high corrosion rates may result. Lowering the exhaust stream temperature prior to the scrubber to the required temperature of 300 °F requires bleed air or a water spray cooling tower, thus increasing the size of the induced draft (ID) fan and its power consumption. Cooling the gases to 300 °F, below the dew point temperature, would condense a portion of the water vapor and acid vapor. This condensate must be properly disposed since it cannot be used in other portions of the kraft recovery process. Further, the saturated flue gas from the scrubber requires heating before exiting through the flue stack to prevent in-stack condensation of acid gases and other adverse ambient impacts.

Finally, the ability of the O/R Scrubbing System to perform efficiently on a recovery furnace has not been demonstrated, particularly in the presence of CO<sub>2</sub> from combustion. Therefore, this technology is considered infeasible.

#### **10.2.3 NO<sub>x</sub> CONTROL FROM THE LIME KILN**

RBLC search results reveal that no add-on controls or combustion modifications have been required to meet RACT, BACT, or LAER. The database lists only requirements such as "good combustion" or "proper kiln design" as BACT for control of NO<sub>x</sub> from a lime kiln.

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<sup>88</sup> NCASI Corporate Correspondent Memorandum No. 06-0142006, *Information on Retrofit Control Measures for Kraft Pulp Mill Sources and Boilers for NO<sub>x</sub>, SO<sub>2</sub> and PM Emissions*, June 2006.

The following sections describe several control options that are considered technically infeasible for application to the Lime Kiln.

#### **10.2.3.1 STAGED COMBUSTION**

Staged combustion, also known as staged air combustion or non-selective non-catalytic reduction (NSNCR), is comprised of an initial burn zone (oxidizing), a secondary burn zone (reducing) and a final burn zone (oxidizing).

Although staged combustion can theoretically result in NO<sub>x</sub> reductions of 20 to 50 percent, the technology is not listed as a control for NO<sub>x</sub> in the RBLC database, and PTPC is aware of no lime kilns and only a few cement kilns using this technology. To date, PTPC is aware of only one full-scale industrial operation (a cement kiln in Brevik, Norway) using NSNCR that has reported on its experience. A recent paper reviews six years of operation of the Brevik plant. The Brevik plant included a low NO<sub>x</sub> burner in addition to NSNCR. While positive results were initially reported, the averaged results over the six years show little improvement as compared to prior operation with a conventional burner and no NSNCR. In addition, long-term testing showed increases in CO and SO<sub>2</sub> concentrations.<sup>89</sup>

Process differences between cement and lime production are the reason this technology has not been applied to the lime industry. A multi-stage preheater and cyclones, which a lime kiln does not have, are necessary for the staged combustion required for this control technology. Therefore, this technology is technically infeasible for lime kilns.

#### **10.2.3.2 MID-KILN FIRING (MKF)**

Although MKF can reduce NO<sub>x</sub> emissions in cement kilns, the longer, lower temperature flame and the addition of fuel to the lime would negatively affect the quality of the lime produced. Introduction of fuel at mid-kiln will increase carry-over of unburned carbon to the product. This unburned fuel will prevent the lime product from being used in many applications.<sup>90</sup> Further, MKF is not listed for control of NO<sub>x</sub> from a lime kiln in the RBLC. Therefore, this technology is considered technically infeasible for lime kilns.

#### **10.2.3.3 MIXING AIR FAN (MID-KILN AIR LANCES)**

This technology is a method of staging combustion air to reduce NO<sub>x</sub> formation through the use of a fan that is mounted on the rotating kiln shell. However, a mixing air fan can create an oxidizing environment in the kiln in a location that may increase the sulfur content of the product to an unacceptable concentration. In addition, there has been no application of a mixing air fan on a lime kiln in the

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<sup>89</sup> *NO<sub>x</sub> Emission Control Technologies for Cement and Lime Kilns*, (Draft, 1995). Radian Canada Inc.

<sup>90</sup> National Lime Association letter to Ms. Rosalina Rodriguez, North Carolina Department of Natural Resources, *Re: Comments on VISTA's Draft Regional Haze Modeling Protocol*, October 21, 2005.

United States. Because this technology is unproven, it is not considered further for NO<sub>x</sub> removal.

#### **10.2.3.4 FLUE GAS RECIRCULATION (FGR)**

FGR involves routing a portion of the flue gas to the combustion area for the purpose of reducing the maximum flame temperature (and thus lowering thermal NO<sub>x</sub>). However, achieving high flame temperatures is critical in the lime production process. The flame temperature achieved using FGR would be below the temperature necessary for proper lime formation. In addition, a long and lazy flame will be produced, which is not acceptable for ensuring lime quality. FGR would also require an excessive amount of ducting from the stack to the kiln inlet. Furthermore, FGR has never been demonstrated on a lime kiln and is not listed in the RBLC. For these reasons, FGR is considered technically infeasible for control of NO<sub>x</sub> from a lime kiln and is not considered further.

#### **10.2.3.5 LOW NO<sub>x</sub> BURNERS (LNB)**

Although NO<sub>x</sub> emissions are commonly controlled by low NO<sub>x</sub> burners in utility boilers, the transfer of low NO<sub>x</sub> burner technology from utility boilers to lime kilns is not technically feasible. Burner flame properties are critical to the quality control and calcining process to convert a high percentage of CaCO<sub>3</sub> mud to CaO reburn lime in the lime kiln. The burner flame shape and properties have a dramatic effect on calcining efficiency. Poor efficiency increases energy use and decreases the calcining capacity of the kiln. Due to these technical complexities, the conversion of a standard lime kiln burner to low NO<sub>x</sub> design is not technically feasible.

In addition, there is no commercially available low NO<sub>x</sub> burner on the market for implementation in a lime kiln. A 2006 NCASI Corporate Correspondent Memorandum states that “[t]he concept of ‘low NO<sub>x</sub> burner’ is considered a misnomer in the rotary kiln industry. . . In rotary kilns, it is not possible to stage the mixing in the same way [as low NO<sub>x</sub> burners in a boiler].”<sup>91</sup> Further, the RBLC does not indicate that this control technology has been considered for a lime kiln. Therefore, low NO<sub>x</sub> burners are not technically feasible and cannot be considered BACT for nitrogen oxides from a lime kiln.

#### **10.2.3.6 FUEL STAGING**

The major requirements for fuel staging are to have the fuel feed rate to the main combustion zone be reduced and have an equivalent amount of fuel being fed to the reburn burners in the reburn zone, located downstream of the main combustion zone. Reburning would require major changes for a lime kiln, which could impact the quality of the lime being produced. A lime kiln does not have an area that

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<sup>91</sup> NCASI Corporate Correspondent Memorandum No. 06-0142006, *Information on Retrofit Control Measures for Kraft Pulp Mill Sources and Boilers for NO<sub>x</sub>, SO<sub>2</sub> and PM Emissions*, June 2006.

could be used as a “reburn zone,” and additional heat is not needed for a lime kiln pre-heater. Due to these difficulties, this technology has not been previously applied to lime kilns. Therefore, fuel staging is not technically feasible and is not considered further.

### 10.2.3.7 WATER/STEAM INJECTION

Injection of water or steam into the main flame reduces the flame temperature and the generation of NO<sub>x</sub>. In some applications, NO<sub>x</sub> can be reduced by as much as 75 percent through water/steam injection.<sup>92</sup> If the temperature is reduced, thermal NO<sub>x</sub> will not be formed in as great a concentration.<sup>93</sup> However, if the flame temperature is sufficiently quenched, the generation of CO can increase and the process efficiency will decrease.

Water/steam injection is effective for reducing thermal NO<sub>x</sub> in natural gas fired Industrial/Commercial/Institutional (ICI) boilers and gas turbines. Because of low initial capital cost but higher variable operating costs, this technique is considered particularly effective for small, single-burner packaged boilers operated infrequently.<sup>24</sup> Water/steam injection reduces flame temperatures by absorbing the latent heat of vaporization which results in decreasing efficiency. It is mainly recommended as a temporary control measure to reduce NO<sub>x</sub> during peaking periods.<sup>94</sup>

In PTPC’s case, the technology would be applied to a lime kiln that is operated close to 8,760 hours per year and is primarily fueled by reprocessed fuel oil (RFO). Although, this technology is effective for natural gas fired boilers and turbines that are operated infrequently, it has not been utilized on a lime kiln that is operated year-round. Water/steam injection can decrease process efficiency and increase CO generation without a proven cost-effective reduction of NO<sub>x</sub> for an oil-fired system. Furthermore, the effectiveness of water/steam injection on NO<sub>x</sub> emissions from a lime kiln is unproven, and this technology is not listed in the RBLC. Therefore, this technology is considered technically infeasible and is not considered further.

### 10.2.3.8 SELECTIVE CATALYTIC REDUCTION (SCR)

Efficient operation of the SCR process requires fairly constant exhaust temperatures (usually ± 200°F).<sup>95</sup> Fluctuation in exhaust gas temperatures

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<sup>92</sup>USEPA, Office of Air Quality Planning and Standards. *Alternative Control Technologies Document – NO<sub>x</sub> Emissions from Industrial/Commercial/Institutional (ICI) Boilers*. EPA-453/R-032, Page 5-72.

<sup>93</sup>USEPA, Office of Air Quality Planning and Standards. *NO<sub>x</sub>, Why and How They are Controlled*. EPA-456/F-99-006R, November 1999, Page 16.

<sup>94</sup>R.K. Agrawal and S.C. Wood, *Innovative Solutions for Cost-effective NO<sub>x</sub> Control*, Pollution Engineering, June 2002.

<sup>95</sup>R.K. Agrawal and S.C. Wood, *Innovative Solutions for Cost-effective NO<sub>x</sub> Control*, Pollution Engineering, June 2002. Page 2-11.

reduces removal efficiency. If the temperature is too low, ammonia slip occurs. Ammonia slip is caused by low reaction rates and results in both higher NO<sub>x</sub> emissions and appreciable ammonia emissions. If the temperature is too high, oxidation of the NH<sub>3</sub> to NO can occur. Also, at higher removal efficiencies (beyond 80 percent), an excess of NH<sub>3</sub> is necessary, thereby resulting in some ammonia slip. Other emissions possibly affected by SCR include increased PM emissions (from ammonia salts in a detached plume) and increased SO<sub>3</sub> emissions (from oxidation of SO<sub>2</sub> on the catalyst).

To avoid fouling the catalyst bed with the PM in the exhaust stream, an SCR unit must be located downstream of the particulate matter control device (PMCD). However, due to the low exhaust gas temperature exiting the PTPC's wet scrubber PMCD (approximately 156°F), a heat exchanger system would be required to reheat the exhaust stream to the desired reaction temperature range of between 450°F to 750°F. The source of heat for the heat exchanger would be the combustion of fuel, with combustion products that would enter the process gas stream and generate additional NO<sub>x</sub>. Therefore, in addition to storage and handling equipment for the ammonia, the required equipment for the SCR system will include a catalytic reactor, heat exchanger and potentially additional NO<sub>x</sub> control equipment for the emissions associated with the heat exchanger fuel combustion.

In addition, the handling and disposal of spent catalyst has been recognized as an environmental risk and a potential health hazard. As described in Section 10.2.1.6, spent catalyst is expected to contain high levels of hazardous heavy metal oxides. Additional concerns with an SCR system include the safety and environmental hazards involved with storage and use of large quantities of NH<sub>3</sub>, as previously described in Section 10.2.1.6.

Finally, SCR is not listed in the RBLC database for control of NO<sub>x</sub> from a lime kiln. For all the reasons discussed above, SCR is removed from consideration based on technical infeasibility and environmental factors.

### **10.2.3.9 SELECTIVE NON-CATALYTIC REDUCTION (SNCR)**

Several difficulties preclude use of an SNCR for control of NO<sub>x</sub> emissions from lime kilns. If burner temperatures exceed 2,000 °F, the NH<sub>3</sub> injected with the SNCR will begin to oxidize, creating additional NO<sub>x</sub>. Another difficulty involves maintaining the correct NH<sub>3</sub>/NO<sub>x</sub> ratio during any load fluctuations. Any excess NH<sub>3</sub> would be released into the atmosphere, creating NH<sub>3</sub> slip. Not only does NH<sub>3</sub> slip result in emissions to the atmosphere, but leads to the formation of ammonium salts. These salts can result in a visible plume. In addition, the NH<sub>3</sub> injection, storage, and waste by-product collection system must be properly designed for spill containment and waste removal. Ammonia is listed as a hazardous substance (40 CFR 302.1), as an extremely hazardous substance (40 CFR 355, Appendix A), and

is regulated under the Chemical Release Provisions of the Clean Air Act Amendments of 1990 (Section 112(r)).

Use of this control technology in lime kilns would cause several concerns. Due to load and exhaust gas temperature fluctuations, optimum  $\text{NH}_3/\text{NO}_x$  molar ratio, as well as correct reaction temperatures, would be extremely difficult to monitor and maintain, and release of  $\text{NH}_3$  into the atmosphere can occur. Further, it is likely that formation of  $\text{NH}_3$  salts would occur, which could result in an increase of process downtime. In addition, the hazards involved with the storage of  $\text{NH}_3$  and the increased emissions from  $\text{NH}_3$  slip cause environmental and safety concerns.

The correct temperature window of 1,600 °F to 1,900 °F occurs inside the rotating body of the kiln. However, the location at which this temperature range occurs varies with time due to the rotating stone. In addition to the location variance, the temperature in this rotating zone also varies with time, which would likely result in poor reaction at incorrect temperatures. Further, locating injection nozzles in such an area is technically not feasible due to the inside of the kiln being approximately 75 percent full of stone. If a nozzle protruded from the wall of the stone chamber, the moving packed bed of rock would either knock it off or wear it off in a very short time. If the nozzle were inset into the wall of the chamber, the moving packed bed of stone would block the spray, and the ammonia or the urea mixture would simply coat a few of the stones, rather than mixing evenly throughout the gas stream. Similarly, if the ammonia or urea sprayed from the top of the chamber, it would have minimal residence time for distribution through the combustion gases before it would be blocked from distribution by the stone.

SNCR has never been demonstrated on a lime kiln and is not listed on the RBLC. Therefore, SNCR is considered a technically infeasible control technology for the lime kiln modification.

#### **10.2.3.10 OXIDATION/REDUCTION (O/R) SCRUBBING**

Several proprietary  $\text{NO}_x$  removal processes that use oxidation/reduction (O/R) scrubbing are commercially available such as Tri-Mer Corporation's TRI- $\text{NO}_x$ . These processes use an oxidizing agent, such as ozone or sodium chlorite, to oxidize NO to  $\text{NO}_2$  in a primary scrubbing stage. Then,  $\text{NO}_2$  is removed through caustic scrubbing in a secondary scrubbing stage. The flue gas from this second scrubber must be heated before exiting the flue stack to prevent in-stack condensation and adverse ambient impacts.

While O/R scrubbing has a high theoretical  $\text{NO}_x$  removal efficiency, Tri-Mer Corporation's TRI- $\text{NO}_x$  technology has never been installed for lime kilns or cement kilns.<sup>96</sup> Additionally, this technology is not listed in the RBLC database

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<sup>96</sup>Telephone conversation between Mr. Darryl Haley (Tri-Mer Corporation) and Mr. David Wilson (Trinity Consultants), October 18, 2001.

for lime kilns. Since O/R scrubbing has not been successfully demonstrated as a control technology for lime kilns, this technology is not considered further.

### **10.3 SO<sub>2</sub> TECHNICALLY INFEASIBLE CONTROL OPTIONS**

Each of the following sections presents the control technologies for SO<sub>2</sub> and techniques identified as being technically infeasible for application to each emission unit. Reasons for eliminating each option are identified on a unit-by-unit basis.

#### **10.3.1 SO<sub>2</sub> CONTROL FROM THE NO. 10 POWER BOILER**

The following sections describe SO<sub>2</sub> control options that are considered technically infeasible for application to the No. 10 Power Boiler.

##### **10.3.1.1 FGD – WET INJECTION WITH WET SCRUBBER**

Implementation of flue gas desulphurization (FGD) technology using wet injection with a wet scrubber on the No. 10 Power Boiler would involve adding an alkaline solution to the existing wet scrubber. However, the addition of this solution would further increase the pH of the scrubber effluent, which would in turn increase the pH of the ash clarifier into which the scrubber effluent empties. The ash clarifier's pH currently ranges from 11 to 12.2 and has a limit of 12.45 established to ensure that the contents of the ash clarifier are not classified as a dangerous waste under WAC 173-303-090. Increasing the pH of the ash clarifier beyond its current range would result in unsafe levels of alkalinity (solutions with a pH level of 12.5 or above are considered dangerous wastes per WAC 173-303-090).<sup>97</sup>

In addition to the technical difficulties, the implementation of wet FGD is unlikely to provide significant additional control of SO<sub>2</sub> due to the alkaline fly ash already naturally acting as a flue gas desulphurization alkaline reagent. As described in Section 3.2 for estimating SO<sub>2</sub> emissions from the power boiler, the alkaline fly ash absorbs the SO<sub>2</sub> in the flue gas in the same manner as a FGD alkaline reagent. Furthermore, the fly ash captured by the wet scrubber causes the scrubber water to become alkaline allowing for additional absorption of SO<sub>2</sub> in the scrubber water. Therefore, the addition of alkaline solution to the existing scrubber would be ineffective.

Another technical problem arises with converting the No. 10 Power Boiler's existing PM scrubber to a PM/SO<sub>2</sub> scrubber involving instrumentation. SO<sub>2</sub> scrubbers require a pH monitor in the scrubber to provide feedback control data for determining the quantity of alkaline solution to add to the scrubber water.

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<sup>97</sup> PTPC established a limit of 12.45 to ensure that the pH does not reach a level of 12.5 or greater. A solid waste exhibits the characteristic of corrosivity if a representative sample of the waste has a pH of greater than or equal to 12.5 (WAC 173-303-090(6)). Exhibiting the characteristic of corrosivity causes the waste to be dangerous waste (WAC 173-303-090(1)).

Controlling the quantity of alkaline solution based on the pH of the scrubber water is critical for effective SO<sub>2</sub> control. The pH probe must be placed in a flooded area for probe emersion within the scrubber to measure accurate readings. In the No. 10 Power Boiler's scrubber, any flooded area is quickly filled with captured fly ash plugging the probe's contact. In addition, the abrasive nature of the fly ash renders the pH probe life extremely short, resulting immediately in inaccurate or non-existent readings. Because of the varying quantity and alkalinity of the fly ash, the absence of accurate pH measurements in the scrubber could result in unsafe pH levels in the scrubber effluent. If only small amounts of alkaline solution are added to avoid this safety hazard, then the amount of control provided by the solution would become negligible. Therefore, the implementation of wet FGD technology for control of SO<sub>2</sub> from the No. 10 Power Boiler is considered technically infeasible and is not considered further.

#### **10.3.1.2 FGD – DRY OR SEMI-DRY**

Implementation of flue gas desulphurization (FGD) technology using dry or semi-dry sorbant injection is not possible in combination with a wet scrubber. The dry or semi-dry FGD technology requires either a baghouse or a dry ESP to filter the dry reaction products (as well as the PM resulting from combustion) from the exhaust stream. For the No. 10 Power Boiler, it is not feasible to replace the wet scrubber with a baghouse due to fire hazards. Replacing the wet scrubber with a dry ESP is also not feasible because of the load-varying operation of the boiler.<sup>98</sup> Therefore, control of SO<sub>2</sub> from the No. 10 Power Boiler using dry or semi-dry injection FGD technology is considered technically infeasible.

### **10.3.2 SO<sub>2</sub> CONTROL FROM THE RECOVERY FURNACE**

The following sections describe several SO<sub>2</sub> control options that are considered technically infeasible for application to the recovery furnace.

#### **10.3.2.1 FGD – WET INJECTION WITH WET SCRUBBER**

This technology has not been successfully demonstrated on recovery furnaces anywhere in the United States.<sup>99</sup> There are several reasons that a wet scrubber has not been applied for the control of SO<sub>2</sub> from a kraft recovery furnace. Recovery furnaces are by definition sulfur recovery units such that a well designed and properly operated recovery furnace emits little SO<sub>2</sub>. The pulp and paper industry works continuously to design increasingly complex and efficient black liquor combustion systems to achieve this result as well as to reduce odorous TRS emissions. The typical vendor guarantee for SO<sub>2</sub> for new recovery furnaces is equivalent to an expectation of zero steady state SO<sub>2</sub> emissions while still

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<sup>98</sup> Dry ESPs are not suited for use in processes which are highly variable because they are very sensitive to fluctuations in gas stream conditions. U.S. EPA, Air Pollution Control Technology Fact Sheet, EPA-452/F-03-028, OAQPS Control Cost Manual, 6<sup>th</sup> edition, EPA 452/B-02-001.

<sup>99</sup> NCASI, *Corporate Correspondence Memo CC-06-14: Information on Retrofit Control Measures for Kraft Pulp Mill Sources and Boilers for NO<sub>x</sub>, NO<sub>x</sub>, SO<sub>2</sub>, and PM Emissions*, June 4, 2006.

accounting for basically uncontrolled, highly sporadic, unpredictable, and short duration “spikes” in SO<sub>2</sub> emissions. These spikes can be theoretically traced back to dozens of potential culprits, the best characterized and understood of which is variations in black liquor sulfidity and solids content. Existing recovery furnaces such as PTPC’s also have much lower steady state SO<sub>2</sub> emissions than the SO<sub>2</sub> emission that occur during the short duration “spikes.” Thus, a scrubber would not actually remove much SO<sub>2</sub> and would be economically infeasible.

Based on the technical difficulties described and the lack of successful implementation, this technology is considered technically infeasible for control of SO<sub>2</sub> from PTPC’s recovery furnace and is not considered further.

### **10.3.2.2 FGD – SEMI-DRY OR DRY WITH ESP OR BAGHOUSE**

The spray dryer system operation is based on the feasibility of injecting a sorbent such as lime into the flue gas. For a kraft recovery furnace, such injection is not feasible. Dust from the recovery furnace flue gas is captured by the ESP and returned to the kraft recovery process. Introduction of lime into the flue gas will disrupt the recycle and chemical balance of the PTPC Mill. Therefore, this technology is considered technically infeasible and is eliminated from BART consideration.

### **10.3.2.3 LOW-SULFUR FUEL SELECTION**

Limiting the sulfur content of the fuel is technically infeasible for a kraft recovery furnace. The “fuel” in the case of PTPC’s recovery furnace is primarily the liquor processed by the recovery furnace. The sulfur content of the black liquor solids cannot be controlled by the mill. Furthermore, the majority of the sulfur in the dissolved solids leaves the furnace in the smelt product. Therefore, low-sulfur fuel selection is not considered further for the recovery furnace.

## **10.3.3 SO<sub>2</sub> CONTROL FROM THE SMELT DISSOLVING TANK**

The following describes the SO<sub>2</sub> control option that is considered technically infeasible for application to the Smelt Dissolving Tank.

### **10.3.3.1 FGD – SEMI-DRY OR DRY WITH ESP OR BAGHOUSE**

The spray dryer system operation is based on the feasibility of injecting lime into the flue gas and then using a dry ESP or baghouse downstream of the dryer to capture the dry particles. The Smelt Dissolving Tank’s exhaust stream has a high moisture content (typically 25 to 40 percent), making usage of a spray dryer/dry ESP system technically infeasible.<sup>100</sup>

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<sup>100</sup> NCASI, *Corporate Correspondence Memo CC-06-14: Information on Retrofit Control Measures for Kraft Pulp Mill Sources and Boilers for NO<sub>x</sub>, SO<sub>2</sub>, and PM Emissions*, June 4, 2006.

### 10.3.4 SO<sub>2</sub> CONTROL FROM THE LIME KILN

The following sections describe several SO<sub>2</sub> control options that are considered technically infeasible for application to the Lime Kiln.

#### 10.3.4.1 FGD – SEMI-DRY LIME HYDRATE SLURRY INJECTION

For lime hydrate slurry injection, calcium hydroxide in the form of a lime slurry is injected into the gas stream. A fabric filter or ESP would need to be installed on the kiln to remove the solid reaction products from the gas stream. After the calcium hydrate is injected into the gas stream, the slurry droplets will dry and the particulate matter will be removed from the stream by the fabric filter or ESP.

The only possible location to inject the lime hydrate is in the feed chute, which is between the kiln and the preheater chamber. The gas residence time in the feed chute is approximately 0.9 seconds, the saturation temperature is approximately 350°F, the actual temperature in the chute is approximately 2000°F, and the SO<sub>2</sub> concentration is relatively low. The injection of lime hydrate slurry at this location will not be effective because the  $\Delta T_{\text{sat}}$  temperature is too large (1650°F), the residence time is too short, and the SO<sub>2</sub> concentration is low. Another possible location for injection would be after the kiln and preheater but before the fabric filter or ESP. However, the kiln already has excess reactive lime available and providing additional lime will not have an appreciable contribution to reducing emissions. In addition, injection at this location is not effective due to the low temperature and low SO<sub>2</sub> concentration. Because lime hydrate slurry injection will not be effective under these conditions at either location, it is considered technically infeasible.

#### 10.3.4.2 FGD – DRY LIME HYDRATE POWDER INJECTION

For lime hydrate powder injection, calcium hydroxide in the form of a lime powder is injected into the gas stream. As with the lime slurry, a fabric filter or ESP would need to be installed on the kiln to remove the solid reaction products from the gas stream.

The dry lime hydrate can be also be injected in either the feed chute or prior to the fabric filter or ESP. Hydrated lime decomposes to CaO at a temperature of 1076°F.<sup>101</sup> Since the temperature in the feed chute is 1900-2000°F, the hydrated lime will decompose at this location. There is already an abundance of CaO dust at this point in the process, so any additional dry lime will not absorb additional SO<sub>2</sub>. Prior to the fabric filter or ESP, the temperature is less than 500 °F, which is too low for any substantial reaction between dry Ca(OH)<sub>2</sub> and SO<sub>2</sub> to occur. Dry lime hydrate injection will not be effective; therefore, it is not considered further.

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<sup>101</sup>Chemical Lime Company Material Safety Data Sheet, Calcium Hydroxide.

#### **10.3.4.3 FGD – LIME SPRAY DRYING**

Lime spray drying would spray lime in addition to that inherently present in the exhaust stream, so that the lime could absorb the SO<sub>2</sub> in the exhaust. There is already an abundance of lime product in the process. Additional dry lime will not absorb additional SO<sub>2</sub>. In general, injecting lime in the transfer chute to control SO<sub>2</sub> is redundant with control already achieved through inherent dry scrubbing of SO<sub>2</sub> and the lime product, and therefore, additional dry lime spray drying is not considered further.

#### **10.3.4.4 INCREASED OXYGEN LEVELS AT THE BURNER**

The required increase in O<sub>2</sub> levels for implementation of this technology results in additional sulfur being deposited in the lime product, which can potentially compromise product quality. Further, increased O<sub>2</sub> levels near the burner would lead to additional fuel and thermal NO<sub>x</sub> formation. Therefore, due to the environmental impacts associated with NO<sub>x</sub> emission increases and the potential impact on product quality, this technology will be removed from further consideration.

## 11. EVALUATION AND DOCUMENTATION OF MOST EFFECTIVE CONTROLS

(STEPS 3 & 4)

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Following a “top-down” approach, the highest ranked potentially applicable control option is evaluated first. If the evaluation concludes that this top option is technically and economically feasible, and the option does not have unacceptable energy demands or adverse environmental impacts, the option is considered in the visibility impacts assessment (Step 5) of the BART Determination process.

While the technical feasibility aspect of a BART evaluation is a fairly objective process, the same cannot be said for the economic feasibility. The definition of the limit of economic feasibility, the level at which the cost per ton of pollutant removed is considered an economic burden (infeasible) varies on a case-by-case basis as determined by the state regulatory agency.

Note that this BART cost feasibility analysis is based on conservative cost estimates (estimated costs are less than expected actual costs) and, unless noted otherwise, emissions reductions from the potential-to-emit. Actual emissions reductions realized would be lower since existing actual emissions, on an annual basis, are less than the potential emissions. Therefore, the resulting cost feasibility calculations (i.e., dollars per ton of pollutant removed) are also conservative in nature and are anticipated to be higher in practice.

### 11.1 ECONOMIC CALCULATIONS PROCESS

Economic analyses are performed to compare total costs (capital and annual) for potential control technologies. Capital costs include the initial cost of the components intrinsic to the complete control system. Annual operating costs include the financial requirements to operate the control system on an annual basis and include overhead, maintenance, outages, raw materials, and utilities.

The capital cost estimating technique used is based on a factored method for the indirect installation costs. That is, indirect installation costs are expressed as a function of known equipment costs.<sup>102</sup> This method is consistent with the latest U.S. EPA OAQPS guidance manual on estimating control technology costs.<sup>103</sup>

Total Purchased Equipment Cost represents the delivered cost of the control equipment, auxiliary equipment, and instrumentation. Auxiliary equipment consists of all the structural, mechanical, and electrical components required for the efficient operation of the device. Auxiliary equipment costs are estimated as a straight percentage of the equipment cost. Direct installation costs consist of the direct expenditures for materials and labor for site preparation, foundations, structural steel, erection,

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<sup>102</sup> This factored method may also be used to determine direct installation costs. However, for the control technology evaluated for installation on PTPC’s BART-eligible emissions units, PTPC has used engineering estimates establish the direct installation costs.

<sup>103</sup> U.S. EPA, OAQPS Control Cost Manual, 6<sup>th</sup> edition, EPA 452/B-02-001, July 2002.

pipng, electrical, painting and facilities. Indirect installation costs include engineering and supervision of contractors, construction and field expenses, construction fees, and contingencies. Other indirect costs include equipment startup, performance testing, working capital, and interest during construction.

Annual costs are comprised of direct and indirect operating costs. Direct annual costs include labor, maintenance, replacement parts, raw materials, utilities, and waste disposal. Indirect operating costs include plant overhead, taxes, insurance, general administration, and capital charges. With the exception of overhead, indirect operating costs are calculated as a percentage of the total capital costs. The indirect capital costs are based on the capital recovery factor (CFR) defined as:

$$CFR = \frac{i(1+i)^n}{(1+i)^n - 1}$$

where *i* is the annual interest rate and *n* is the equipment life in years. The equipment life is based on the normal life of the control equipment and varies on an equipment type basis. The same interest applies to all control equipment cost calculations. For this analysis, an interest rate of 7% is used based on information provided in the most recent OAQPS Control Cost Manual.

Detailed cost analyses calculations are presented in Appendix D.

## 11.2 RANKING AND EVALUATION OF PM<sub>10</sub> CONTROL TECHNOLOGIES

### 11.2.1 PM<sub>10</sub> CONTROL FROM THE NO. 10 POWER BOILER

#### 11.2.1.1 RANK OF REMAINING CONTROL TECHNOLOGIES

The feasible control technologies and their associated control efficiencies are presented in Table 11-1. The control efficiencies represent an incremental level of control above a base case.

**TABLE 11-1. REMAINING TECHNOLOGIES TO CONTROL PM FROM THE NO. 10 POWER BOILER**

Control Technology	Control <sup>a</sup>
Add Wet ESP with Existing System	0.01 gr/dscf
Existing Venturi Scrubber and Multiclone	Baseline

<sup>a</sup> The control level for the addition of a wet ESP is based on the guarantee provided by vendor (0.01 gr/dscf). This guarantee results in approximately 69 % control efficiency for reduction from potential emissions based on the current limit of 0.10 lb/MMBtu at maximum capacity (360 MMBtu/hr based on 250,000 pounds steam per hour) to the potential emissions based on the vendor guarantee at the design exhaust flow rate (200,000 acfm). Note that the control efficiency accounts for the additional control expected above the existing baseline operations.

### **11.2.1.2 EVALUATION OF MOST EFFECTIVE CONTROL**

The addition of a wet ESP to the existing scrubber would provide approximately 69% reduction of potential annual PM<sub>10</sub> emissions. However, the conservative cost per ton of PM<sub>10</sub> removed for the installation of a wet ESP to further control the No. 10 Power Boiler is \$11,294.<sup>104</sup> Therefore, PTPC concludes that the addition of a wet ESP for control of PM<sub>10</sub> is not economically feasible and a wet ESP is not considered further.<sup>105</sup>

## **11.3 RANKING AND EVALUATION OF NO<sub>x</sub> CONTROL TECHNOLOGIES**

### **11.3.1 NO<sub>x</sub> CONTROL FROM THE NO. 10 POWER BOILER**

Good operating practices are the only available NO<sub>x</sub> control technology for the No. 10 Power Boiler as further described in Section 13.2.1.

### **11.3.2 NO<sub>x</sub> CONTROL FROM THE RECOVERY FURNACE**

Good operating practices are the only available NO<sub>x</sub> control technology for the Recovery Furnace as further described in Section 13.2.2.

### **11.3.3 NO<sub>x</sub> CONTROL FROM THE SMELT DISSOLVING TANK**

BART is not evaluated for NO<sub>x</sub> from the Smelt Dissolving Tank since this unit is not a source of NO<sub>x</sub> emissions.

### **11.3.4 NO<sub>x</sub> CONTROL FROM THE LIME KILN**

Proper kiln design and operation is the only available NO<sub>x</sub> control technology for the Lime Kiln as further described in Section 13.2.4.

## **11.4 RANKING AND EVALUATION OF SO<sub>2</sub> CONTROL TECHNOLOGIES**

### **11.4.1 SO<sub>2</sub> CONTROL FROM THE NO. 10 POWER BOILER**

#### **11.4.1.1 RANK OF REMAINING CONTROL TECHNOLOGIES**

The feasible control technologies and their associated control efficiencies are presented in the following table.

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<sup>104</sup> A reduction in actual PM<sub>10</sub> emissions will result in an even greater cost since actual PM<sub>10</sub> emissions are below the current potential annual emissions.

<sup>105</sup> The efficiency and cost analysis for the installation of a wet ESP for control of PM<sub>10</sub> emissions from the No. 10 Power Boiler are based on incremental level of control above the base case. The scenario of replacing the wet scrubber with a wet ESP is not evaluated as the control level would be the same or decrease and the costs would increase (a new quench unit would need to be installed), resulting in a larger cost estimate in terms of dollars per ton of PM<sub>10</sub> removed.

**TABLE 11-2. REMAINING TECHNOLOGIES FOR CONTROL OF SO<sub>2</sub> FROM NO. 10 POWER BOILER**

<b>Control Technology</b>	<b>Control Efficiency</b>
Fuel Selection	34%
Existing Wet Venturi Scrubber	Baseline

#### **11.4.1.2 EVALUATION OF MOST EFFECTIVE CONTROL**

As discussed in Section 10.3.1, there are no available add-on control technologies that are technically feasible for the control of SO<sub>2</sub> from the No. 10 Power Boiler. However, using fuel oil containing lower sulfur would result in reduced SO<sub>2</sub> emissions. The cost of switching from the recycled fuel oil (RFO) currently fired in the No. 10 Power Boiler to 'High Spec' RFO with a guaranteed maximum sulfur content of 0.5 % is approximately \$15,702 per ton of SO<sub>2</sub> removed. This estimate conservatively calculates the current SO<sub>2</sub> emissions based on the guaranteed maximum sulfur content of 0.76 % in the RFO. The estimate also conservatively assumes that all sulfur in the fuel oil is emitted as SO<sub>2</sub>.<sup>106</sup> However, as discussed in Section 3.2, the alkaline fly ash created from wood-firing absorbs much of the sulfur compounds. This sulfur-containing ash is then removed from the exhaust stream in the multiclones and wet scrubber. Even ignoring this natural SO<sub>2</sub> scrubbing effect, this option is cost ineffective. Therefore, the option of reducing SO<sub>2</sub> emissions by using lower sulfur fuel oil in the No. 10 Power Boiler is not considered further.

#### **11.4.2 SO<sub>2</sub> CONTROL FROM THE RECOVERY FURNACE**

All control options other than good operating practices are eliminated as technically infeasible as further described in Section 13.3.2.

#### **11.4.3 SO<sub>2</sub> CONTROL FROM THE SMELT DISSOLVING TANK**

##### **11.4.3.1 RANK OF REMAINING CONTROL TECHNOLOGIES**

The feasible control technologies and their associated control efficiencies are presented in the following table.

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<sup>106</sup> For the cost analysis, SO<sub>2</sub> emissions are based on AP-42 Table 1.3-1 emission factor (157\*S% lb SO<sub>2</sub>/10<sup>3</sup> gallons), which assumes 100 % of the Sulfur in the oil is emitted as SO<sub>2</sub>.

**TABLE 11-3. REMAINING TECHNOLOGIES FOR CONTROL OF SO<sub>2</sub> FROM THE SDT**

<b>Control Technology</b>	<b>Control Efficiency</b>
Addition of alkaline solution to wet scrubber	90% <sup>a</sup>
Existing Wet Venturi Scrubber	Baseline

<sup>a</sup> For the purposes of the cost analysis, an additional 90 % control efficiency is conservatively assumed to be achievable by adding alkaline solution to the smelt dissolving tank scrubber water based on typical control for a wet FGD system. However, the control efficiency that can actually be achieved in practice is likely lower since the existing wet scrubber provides some SO<sub>2</sub> control.

**11.4.3.2 EVALUATION OF MOST EFFECTIVE CONTROL**

The addition of an alkaline solution to the existing wet scrubber may provide as much as 90 % reduction of potential annual SO<sub>2</sub> emissions. However, the cost for implementing this control technology is \$16,247 per ton of SO<sub>2</sub> removed when evaluating reduction in potential annual SO<sub>2</sub> emissions.<sup>107</sup> Therefore, the option of reducing SO<sub>2</sub> emissions by adding alkaline solution to the existing scrubber is considered economically infeasible and is not evaluated further.

**11.4.4 SO<sub>2</sub> CONTROL FROM THE LIME KILN**

**11.4.4.1 RANK OF REMAINING CONTROL TECHNOLOGIES**

The feasible control technologies and their associated control efficiencies are presented in the following table.

**TABLE 11-4. REMAINING TECHNOLOGIES FOR CONTROL OF SO<sub>2</sub> FROM LIME KILN**

<b>Control Technology</b>	<b>Control Efficiency<sup>a</sup></b>
Flue Gas Desulfurization (FGD) with Wet Scrubber	90%
Fuel Selection	34%
Existing Wet Venturi Scrubber	Baseline

<sup>a</sup> Incremental control efficiency over current wet scrubber system.

**11.4.4.2 EVALUATION OF MOST EFFECTIVE CONTROL**

For the purposes of this BART analysis, an additional 90 percent control efficiency is conservatively assumed to be achievable by adding alkaline solution to the lime kiln scrubber water based on typical control for a wet FGD system. However, the control efficiency that can actually be achieved in practice is likely much lower because of the inherent SO<sub>2</sub> scrubbing control already achieved with the existing system. According to NCASI, the regenerated quicklime in a kraft

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<sup>107</sup> A reduction in actual SO<sub>2</sub> emissions will result in an even greater cost since actual SO<sub>2</sub> emissions are below the current potential annual emissions.

lime kiln acts as an in-situ scrubbing agent.<sup>108</sup> In addition, the existing wet scrubber provides further SO<sub>2</sub> control since the scrubbing solution becomes alkaline from the captured lime dust.<sup>109</sup> However, given the relatively low cost of alkali addition to the scrubbing fluid, this option is evaluated to determine the visibility improvement that this option may provide.

As discussed in Section 11.4.1.2, using lower sulfur fuel oil is economically infeasible with a cost of \$15,702 per ton of SO<sub>2</sub> removed. Therefore, this option is not considered further for the control of SO<sub>2</sub> emissions from the Lime Kiln.

## **11.5 SUMMARY OF FEASIBLE BART OPTIONS**

BART control options that are found to be feasible based on the engineering analysis contained in this section are summarized in the following table. Each of these options must be evaluated to determine their impact on visibility, as Step 5 of the BART Determination process.

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<sup>108</sup> NCASI *Corporate Correspondence Memo CC 06-014: Information on Retrofit Control Measures for Kraft Pulp Mill Sources and Boilers for NO<sub>x</sub>, SO<sub>2</sub>, and PM*, June 9, 2006.

<sup>109</sup> *Ibid.*

**TABLE 11-5. SUMMARY OF FEASIBLE BART OPTIONS**

<b>Pollutant</b>	<b>Emission Unit</b>	<b>Control Option</b>	<b>Control Option Emissions Level or Control Efficiency</b>
PM <sub>10</sub>	No. 10 Power Boiler	Add ESP to Existing System <sup>a</sup>	0.01 gr/dscf (Vendor Guarantee) <sup>a</sup>
		Existing Venturi Scrubber	0.10 lb/MMBtu <sup>b</sup> (Current NSPS Subpart D Limit)
	Recovery Furnace	Existing ESP	0.044 gr/dscf <sup>b</sup> (Current MACT Subpart MM Limit)
	Smelt Dissolving Tank	Existing Venturi Scrubber	0.200 lb/BLS <sup>b</sup> (Current MACT Subpart MM Limit)
	Lime Kiln	Existing Venturi Scrubber	0.064 gr/dscf <sup>b</sup> (Current MACT Subpart MM Limit)
NO <sub>x</sub>	No. 10 Power Boiler	Existing Staged Combustion System	0.80 lb/MMBtu <sup>b</sup> (Current NSPS Subpart D Limit)
	Recovery Furnace	Existing Staged Combustion System	NA <sup>b, c</sup>
	Smelt Dissolving Tank	NA	NA <sup>b, c</sup>
	Lime Kiln	Good Operating Practices	NA <sup>b, c</sup>
SO <sub>2</sub>	No. 10 Power Boiler	Good Operating Practices	0.30 lb/MMBtu <sup>b</sup>
	Recovery Furnace	Good Operating Practices	200 PPM @ 8% O <sub>2</sub> <sup>b</sup> (Current PSD Limit)
	Smelt Dissolving Tank	Good Operating Practices	NA <sup>b, c</sup>
	Lime Kiln	Addition of Alkaline Solution to Scrubber	90 % Control
Existing Wet Scrubber		Continued use of wet scrubber with inherently alkaline scrubber solution 500 ppm @ 10 % O <sub>2</sub> <sup>b</sup> (Current WAC Limit)	

<sup>a</sup> The addition of a wet ESP to the existing wet scrubber on the No. 10 Power Boiler is determined to be cost ineffective. However, the visibility impact of implementing this control technology is evaluated for informational purposes to further support the ineffectiveness of implementing this control technology.

<sup>b</sup> For the purposes of presenting this BART emissions limit summary, for the baseline case (where no controls are applied), the existing emissions limits proposed as BART are listed in this table. However, the baseline emission rates used for the BART determination visibility modeling analysis are the maximum actual daily emission rates as presented and modeled for the BART applicability analysis rather than these maximum emissions limits.

<sup>c</sup> There are no current limits that apply to the emission unit for the specified pollutant.

## 12. EVALUATION OF NET VISIBILITY IMPROVEMENT (STEP 5)

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This section describes PTPC's modeling procedure and results for quantifying net visibility improvement at Olympic National Park. As presented in Section 5, the BART Applicability Analysis demonstrates that, with the exception of Olympic National Park, the BART-eligible emission units at the PTPC Mill do not contribute to visibility impairment at any other Class I areas or areas of interest<sup>110</sup> within 300 kilometers of the PTPC Mill. The net visibility improvement analysis presented in this section quantifies the net visibility improvement for all emissions reduction options that remain under consideration after the BART engineering analysis presented in Sections 9 through 11 of this report. The BART engineering analysis ruled out additional control options for all emissions units and pollutants except PM<sub>10</sub> emissions from the No. 10 Power Boiler and SO<sub>2</sub> emissions from the Lime Kiln) is there more than one competing control strategy. Table 11-5 summarizes the BART Determination options and concludes that for all other emission units and pollutants, existing emissions controls achieve the best available control.

### 12.1 BART DETERMINATION MODELING PROCEDURE

U.S. EPA BART guidance describes the following approach for conducting the net visibility analysis.<sup>111</sup> This approach is also summarized in the *BART Modeling Protocol* for Washington, Oregon, and Idaho.

- *Run the model at pre-control and post-control emission rates according to the accepted protocol.*
- *Use the 24-hour average actual emission rate from the highest emitting day of the meteorological period modeled (for the pre-control scenario). Calculate the model results for each receptor as the change in deciviews compared against natural visibility condition. Post-control emission rates are calculated as a percentage of pre-control emission rates...*
- *Make the net visibility improvement determination...based on the modeled change in visibility impacts for the pre-control and post-control emission scenarios. ...consider the frequency, magnitude, and duration components of impairment. Suggestions for making the determination are:*
  - *Use of a comparison threshold... (e.g., the number of days or hours that the threshold was exceeded, a single threshold for determining whether a change in impacts is significant, or a threshold representing an x percent change in improvement).*
  - *Compare the 98<sup>th</sup> percent days for the pre- and post-control runs.*

The visibility impacts attributable to PTPC Mill after applying the available control technologies (post-control) are modeled using the same CALPUFF modeling techniques and the same data resources, model processing options, and postprocessing techniques used for PTPC's refined BART

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<sup>110</sup> The Columbia River Gorge National Scenic Area is not a federal Class I area; however, Region 10 has requested the inclusion of this area in the BART analyses for informational purposes; therefore, it is included as an area of interest for the BART Applicability Analysis.

<sup>111</sup> 40 CFR Part 51, Appendix Y, Section IV.D.5

applicability analysis baseline scenario (pre-control), the results of which are presented in Section 6 of this report. These resources and methods are described in detail in Sections 4 and 6 of this report, and are summarized as follows:

- Use of 4-km CALMET meteorological fields prepared for Washington, Oregon, and Idaho to conduct the BART analyses
- Use of regulatory default model processing options in the CALPUFF Version 6.112/060412, POSTUTIL Version 1.52/060412, and CALPOST Version 6.131/060410 recommended for modeling in the *BART Modeling Protocol*
- Use of a single value of 60 parts per billion (ppb) is used for all months for the background ozone concentration as recommended in the *BART Modeling Protocol* and use of a spatially and temporally constant ammonia background level of 0.5 ppb<sup>112</sup>
- Postprocessing of visibility impacts through application of the ammonia limiting method and nitrate re-partitioning algorithms with a spatially and temporally constant ammonia background level of 0.5 ppb in POSTUTIL<sup>113</sup>
- Computation of natural background conditions and source-specific visibility impacts using the new IMPROVE equation for visibility impairment,<sup>114</sup> the 20% best visibility days to estimate the “natural” background conditions, and “Method 6” postprocessing using Class I-area specific monthly average relative humidity hygroscopic growth factors in CALPOST
- Calculation of the 98<sup>th</sup> percentile visibility impact in the VISTAS IMPROVE Spreadsheet as the highest, 8<sup>th</sup>-high 24-hour average visibility change in deciviews (dv) among three years of meteorological data modeled (which always provides a more conservative estimate of the 98<sup>th</sup> percentile than the 22<sup>nd</sup>-high impact over three years)
- Tabulation in CALPOST of the total number of days at each Class I area during which the computed 24-hour average visibility impact exceeds 0.5 dv and 1.0 dv<sup>115</sup>

Candidate emission control strategies are modeled and the results compared to the baseline scenario to quantify net visibility improvement at each Class I area using the following comparisons:<sup>116</sup>

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<sup>112</sup> The refined analysis, including the use of the 0.5 ppb ammonia background, of the ammonia limiting method, and of the new IMPROVE algorithm as described in Section 6, was discussed and agreed upon with Washington State Ecology during a June 4, 2007 meeting at Ecology Headquarters, attended by Clint Bowman and Alan Newman, Ecology, Alice McConaughy, PTPC, and Aaron Day and Kirsten Rollay, Trinity Consultants.

<sup>113</sup> Ibid.

<sup>114</sup> Ibid.

<sup>115</sup> The absolute improvement in the 98th percentile visibility impact is determined based on the applying the new IMPROVE algorithm. However, the new IMPROVE algorithm is applied only to the highest 22 days using the VISTAS IMPROVE spreadsheet as a post-processor applied to the results from the CALPOST output file. Therefore, the absolute improvement in the number of days during which a 24-hour average visibility impact attributable to the BART-subject source exceeds the 0.5 dv visibility impairment contribution threshold and the 1.0 dv visibility impairment causation threshold is based the CALPOST output file before the new IMPROVE algorithm is applied.

<sup>116</sup> Ibid.

- Absolute improvement in the 98<sup>th</sup> percentile visibility impact (if any) in deciviews (dv) compared to the baseline 98<sup>th</sup> percentile visibility impact, from which relative visibility improvement can be expressed in terms of economic efficiency (\$/dv) and emissions reductions (tons reduced/dv) to supplement the economic feasibility analyses (\$/ton) described in Section 11 of this report
- Absolute improvement in the number of days during which a 24-hour average visibility impact attributable to the BART-subject source exceeds the 0.5 dv visibility impairment contribution threshold
- Absolute improvement in the number of days during which a 24-hour average visibility impact attributable to the BART-subject source exceeds the 1.0 dv visibility impairment causation threshold

Table 12-1 summarizes the scenarios that are modeled to evaluate net visibility improvement. Note that per U.S. EPA guidance, each net visibility improvement analysis includes emissions from of all visibility-affecting pollutants (i.e., SO<sub>2</sub>, NO<sub>x</sub>, and PM<sub>10</sub>) from all BART-subject sources. This guidance states, “because of the complexity and nonlinear nature of atmospheric chemistry and chemical transformation among pollutants, EPA does not generally recommend that CALPUFF be used on a pollutant specific basis.”<sup>117</sup> Therefore, the modeling run for each BART control option scenario will include all pollutants from all BART-eligible sources, not only those pollutants that are affected by the control option applied for each scenario.

**TABLE 12-1. NET VISIBILITY IMPROVEMENT ANALYSIS CONTROL SCENARIOS**

<b>Modeling Scenario</b>	<b>Scenario Description</b>
BART100	Baseline Scenario as the refined applicability analysis presented in Section 6
BART101	Power Boiler No. 10 PM <sub>10</sub> reductions associated with the addition of a wet ESP (reduction of PM <sub>10</sub> emissions to 0.01 gr/dscf vendor guarantee)
BART102	Lime Kiln SO <sub>2</sub> emissions control for addition of alkaline solution to the existing wet scrubber (assumed 90% emissions reduction of SO <sub>2</sub> )

The results of these analyses for the two control scenarios BART101 and BART102 demonstrate the extent of net visibility improvement (if any), compared to the baseline case BART100 of each individual control option. A DVD enclosed with this report contains the modeling input and output files for these analyses.

## **12.2 NET VISIBILITY IMPROVEMENT ANALYSES**

This section describes the net visibility improvement associated with each control scenario compared to the baseline visibility impacts at Olympic National Park based on the refined modeling analysis presented in Section 6.

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<sup>117</sup> Undated U.S. EPA Memorandum from Mr. Joseph Paisie to Ms. Kay Prince.

### 12.2.1 NET VISIBILITY ANALYSES RESULTS

Table 12-2 summarizes the visibility impacts at Olympic National Park, the Class I area at which visibility is potentially affected by the PTPC Mill, for the baseline scenario and the two control option scenarios described in Section 12.1. The impacts are expressed in terms of the maximum 98th percentile (8th-highest), 24-hour average visibility impact among three years of meteorological data modeled and the number of days during which the PTPC Mill contributes or causes visibility impairment.

The baseline scenario (BART 100) impacts are used to assess the net visibility improvement of the emissions reductions and control technologies evaluated for BART.

**TABLE 12-2. BART DETERMINATION VISIBILITY IMPACTS**

<b>Modeling Scenario</b>	<b>98<sup>th</sup> Percentile <math>\Delta dv^a</math></b>	<b>Total Days &gt; 0.5 <math>\Delta dv^b</math></b>	<b>Total Days &gt; 1.0 <math>\Delta dv^b</math></b>
BART100	1.181	68	20
BART101	0.987	46	12
BART102	1.179	68	20

<sup>a</sup> The absolute improvement in the 98<sup>th</sup> percentile visibility impact is determined based on the applying the ammonia limiting method (ALM) and the new IMPROVE algorithm to both the baseline scenario and the two control scenarios.

<sup>b</sup> The absolute improvement in the number of days during which a 24-hour average visibility impact attributable to the BART-subject source exceeds the 0.5 dv visibility impairment contribution threshold and the 1.0 dv visibility impairment causation threshold is based on applying ALM only, because the new IMPROVE algorithm is applied to only the highest 22 days from the CALPOST output file using the VISTAS IMPROVE spreadsheet.

Table 12-3 summarizes the net visibility improvement of scenarios BART101 (control of PM<sub>10</sub> from the No. 10 Power Boiler) and BART102 (control of SO<sub>2</sub> from the Lime Kiln) compared to baseline scenario BART100.

**TABLE 12-3. NET VISIBILITY IMPROVEMENT**

<b>Modeling Scenario</b>	<b><math>\Delta 98^{\text{th}}</math> Percentile <math>\Delta dv</math></b>	<b><math>\Delta</math> Total Days &gt; 0.5 dv</b>	<b><math>\Delta</math> Total Days &gt; 1.0 dv</b>
BART101	-0.203	-22	-8
BART102	-0.002	0	0

### 12.2.2 INTERPRETATION AND SUMMARY OF NET VISIBILITY ANALYSES

As presented in Table 12-3, the visibility improvement resulting from 90 percent control of SO<sub>2</sub> from the Lime Kiln scrubber is 0.002 dv. This minimal improvement is not visually discernable; therefore, implementation of additional SO<sub>2</sub> control for PTPC's lime kiln is not justifiable. Similarly, the net visibility improvement of 0.203 dv resulting from the addition of a wet ESP to further control PM<sub>10</sub> emissions from the No. 10 Power Boiler is also not visually discernable.

As described in Section 11.2.1.2 of this report, the cost of installing a wet ESP as represented in BART101 is \$11,294 per additional ton of PM<sub>10</sub> reduced, which would achieve up to approximately 109 tpy of emissions reductions. This emission reduction translates to 0.203 dv of visibility improvement, meaning the effectiveness of BART101 could be expressed as 537 tons per dv, \$55,635 per ton per dv, or \$6,469,791 per dv. Although there is no bright line for cost-effectiveness and visibility improvement-effectiveness for control options, the investment in a wet ESP represented by BART101 is unwarranted since (1) the control option is not cost effective and (2) there is no perceptible improvement in visibility associated with the implementation of the control.<sup>118</sup>

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<sup>118</sup> The “Pre-Hearing Draft Regional Haze State Implementation Plan for South Carolina Class I Federal Areas” issued by DHEC establishes a threshold of \$2,000 per ton in determining reasonable costs for controls.

## 13. SUMMARY OF BART DETERMINATIONS

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This section presents a summary of the BART evaluation process and presents PTPC's BART Determinations, on a pollutant-by-pollutant basis, for each emission unit subject to BART at the PTPC Mill.

### 13.1 BART FOR PM<sub>10</sub>

The following sections summarize the BART determinations for control of PM<sub>10</sub> emissions from each BART-eligible source at the PTPC Mill. The Recovery Furnace, Smelt Dissolving Tank, and Lime Kiln are subject to NESHAP Subpart MM MACT limits. As such, these MACT standards are considered to represent BART as discussed in Section 8 of this report.<sup>119</sup>

#### 13.1.1 NO. 10 POWER BOILER

PTPC proposes continued use of the existing wet scrubber as BART for PM<sub>10</sub> emissions from the No. 10 Power Boiler. The analyses presented in this BART Applicability and Determination Report demonstrate the addition of a wet ESP to control PM<sub>10</sub> from the No. 10 Power Boiler is not economically feasible. Further, the net visibility improvement resulting from additional control of PM<sub>10</sub> with a wet ESP is not visually discernable, and therefore the implementation of this technology is not warranted.

#### 13.1.2 RECOVERY FURNACE

PTPC proposes to continue to use the existing ESP as BART. Actual emissions from use of the current ESP average less than 50% of the NESHAP Subpart MM limit of 0.044 gr/dscf at 8% O<sub>2</sub>.

#### 13.1.3 SMELT DISSOLVING TANKS

PTPC proposes to continue to use the existing scrubber in lieu of any additional add-on control or replacement of the existing scrubbers. PTPC will continue to operate the current scrubber to comply with the existing NESHAP Subpart MM limit of 0.20 lb PM<sub>10</sub> per ton BLS.

#### 13.1.4 LIME KILN

PTPC proposes to continue to use the existing wet scrubber as BART for PM<sub>10</sub> emissions from the Lime Kiln. PTPC will continue to operate the current scrubber to comply with the existing NESHAP Subpart MM limit of 0.064 gr/dscf at 10% O<sub>2</sub>.

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<sup>119</sup> Per Section IV of EPA's "Guidelines for BART Determinations under the Regional Haze Rules" [40 CFR Part 51, Appendix Y], "Unless there are new technologies subsequent to the MACT standards which would lead to cost-effective increases in the level of control, [state agencies] may rely on the MACT standards for purposes of BART."

## 13.2 BART FOR NO<sub>x</sub>

The following sections summarize the BART determinations for control of NO<sub>x</sub> emissions from each BART-eligible source at the PTPC Mill.

### 13.2.1 NO. 10 POWER BOILER

Good operating practices are the only available NO<sub>x</sub> control technology for the No. 10 Power Boiler. As discussed in Section 10.2.1, there are no technically feasible NO<sub>x</sub> control technologies available for retrofit installation on PTPC's wood-fired power boiler. However, as also discussed in Section 10.2.1, the spreader-stoker design of the No. 10 Power Boiler inherently uses staged combustion, resulting in lower flame temperatures and minimal thermal NO<sub>x</sub> formation. Therefore, PTPC proposes to continue good operation of the inherent staged combustion system as BART for NO<sub>x</sub> emissions from the No. 10 Power Boiler.

### 13.2.2 RECOVERY FURNACE

Recovery furnaces also inherently use staged combustion practices. The design of the kraft recovery furnace at the PTPC Mill uses multiple levels of air admission into the furnace to control the kraft recovery sodium sulfate reactions and to assure complete combustion of organic compounds. The process control system that regulates this staged combustion process helps minimize the formation of NO<sub>x</sub>.

In addition, there are no available control technologies for the control of NO<sub>x</sub> from PTPC's recovery furnace other than proper operation of the inherent staged combustion as discussed in Section 10.2.2. Use of this inherent staged combustion system maintains NO<sub>x</sub> emissions at levels similar to emission limits listed in the RBLC and is consistent with NCASI's recommended approach for BART for chemical recovery equipment.<sup>120</sup> Therefore, PTPC proposes to continue to properly operate the existing staged combustion system as BART for control of NO<sub>x</sub> emissions from the Recovery Furnace.

### 13.2.3 SMELT DISSOLVING TANK

BART was not evaluated for NO<sub>x</sub> from the Smelt Dissolving Tank since these units are not sources of NO<sub>x</sub> emissions.

### 13.2.4 LIME KILN

Proper kiln design and operation is the only available NO<sub>x</sub> control technology for the Lime Kiln. For purposes of product quality and process economics, PTPC operates its lime kiln using a minimum of excess air. This practice contributes to minimizing NO<sub>x</sub> emissions. Proper kiln design and operation is considered BACT by all recent determinations in the RBLC database. There is an absence of data that any NO<sub>x</sub> control technology has been

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<sup>120</sup> NCASI Corporate Correspondence Memo CC 06-014: *Information on Retrofit Control Measures for Kraft Pulp Mill Sources and Boilers for NO<sub>x</sub>, SO<sub>2</sub>, and PM*, June 9, 2006.

successfully demonstrated on a pulp and paper lime kiln. Therefore, proper kiln design and operation are proposed as BART for NO<sub>x</sub> emissions from PTPC's Lime Kiln.

### **13.3 BART FOR SO<sub>2</sub>**

The following sections summarize the BART determinations for control of SO<sub>2</sub> emissions from each BART-eligible source at the PTPC Mill.

#### **13.3.1 NO. 10 POWER BOILER**

All control options for control of SO<sub>2</sub> from the power boiler have been eliminated as technically or economically infeasible. SO<sub>2</sub> emissions from the boiler originate as sulfur in the fuel oil. PTPC works to operate the boiler to fire as little fuel oil as possible, since the cost of fuel oil is greater than the cost of wood residue. Therefore, PTPC proposes to continue to practice good operation of the boiler aimed at minimizing fuel oil firing as BART for SO<sub>2</sub> emissions from the No. 10 Power Boiler.

PTPC will take steps to ensure the optimal operation of the No. 10 Power Boiler by investing in a computerized control system designed to minimize excess air and increase combustion efficiency. The computerized system will increase combustion efficiency by promoting more complete combustion of the wood residue, which will result in a higher percentage of wood firing and a lower percentage of oil firing. Reduced oil firing will result in lower SO<sub>2</sub> emissions from the boiler.<sup>121</sup>

#### **13.3.2 RECOVERY FURNACE**

Good Operating Practices, as currently in place, are determined to be BART for the Recovery Furnace. Good operating practices entail minimizing fuel oil firing and maintaining the char bed resulting from black liquor solids combustion.

#### **13.3.3 SMELT DISSOLVING TANK**

For the Smelt Dissolving Tank, PTPC is proposing to continue to properly operate the Smelt Dissolving Tank wet scrubber as BART. Use of this scrubber achieves some SO<sub>2</sub> reduction and is consistent with NCASI's recommendation that existing scrubbers meet BART.<sup>122</sup>

#### **13.3.4 LIME KILN**

For PTPC's Lime Kiln, continued operation of the Lime Kiln wet scrubber is proposed as BART. As described in Section 11.4.4, the regenerated quicklime in the kiln acts as an in-situ scrubbing agent and the existing wet scrubber provides further SO<sub>2</sub> control since the

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<sup>121</sup> The reduction in fuel oil usage and SO<sub>2</sub> emissions from the installation of the computerized control system cannot be readily quantified as this system is designed for increased combustion efficiency. Therefore, the vendor is unwilling to provide any emissions guarantees.

<sup>122</sup> NCASI Corporate Correspondence Memo CC 06-014: *Information on Retrofit Control Measures for Kraft Pulp Mill Sources and Boilers for NO<sub>x</sub>, NO<sub>x</sub>, SO<sub>2</sub>, and PM*, June 9, 2006.

scrubbing solution becomes alkaline from the captured lime dust.<sup>123</sup> As demonstrated in Section 12.2, the only feasible control technology for reduction of SO<sub>2</sub> from the Lime Kiln, addition of alkaline solution to the existing scrubber, results in minimal visibility improvement that is not discernable. Therefore, as the only remaining control option, PTPC proposes continued operation of the existing wet scrubber as BART for control of SO<sub>2</sub> from the Lime Kiln.

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<sup>123</sup> NCASI Corporate Correspondence Memo CC 06-014: Information on Retrofit Control Measures for Kraft Pulp Mill Sources and Boilers for NO<sub>x</sub>, SO<sub>2</sub>, and PM, June 9, 2006.

**EMISSIONS CALCULATIONS**

**CALPUFF Source Parameters and Emission Rates**

	Location LCC East (km)	Location LCC North (km)	Height (m)	Base Elevation (m)	Diameter (m)	Gas Exit Velocity (m/s)	Stack Gas Exit Temp. (K)	SO2 (g/s)	SO4 (g/s)	NOX (g/s)	HNO3 (g/s)	NO3 (g/s)	PMF (g/s)	PMC (g/s)	SOA (g/s)	EC (g/s)
RecBir	-128.955	-96.024	76.50	5.49	2.13	35.97	445.93	1.33E+01	2.10E-01	9.92E+00	0.00E+00	2.88E-01	1.82E+00	6.37E-01	9.82E-02	4.56E-04
SmiTank	-128.973	-95.974	52.12	5.49	1.80	2.00	348.98	3.31E-02	1.34E-02	1.32E-01	0.00E+00	2.20E-02	1.02E+00	1.37E-01	1.36E-02	4.27E-02
10Bir	-128.997	-95.996	53.04	5.49	2.13	15.13	334.43	9.00E+00	1.02E+00	1.04E+01	0.00E+00	4.45E-03	3.10E+00	0.00E+00	2.13E+00	8.82E-01
LimeKiln	-129.019	-95.981	36.58	5.49	1.83	3.60	341.98	2.03E-01	9.87E-02	1.26E+00	0.00E+00	5.68E-02	6.96E-01	7.46E-02	1.41E-02	2.90E-02
Totals (g/s)								22.56	1.34	21.72	0.00	0.37				
Totals (lb/hr)								179.03	10.64	172.41	0.00	2.94				

## Recovery Furnace

Maximum 24-Hour Emissions (lb/D) using average factor for 2003-2005 and max throughput for each year.

	<u>2003</u>	<u>2004</u>	<u>2005</u>	<u>Max 2003-2005</u>
SO <sub>2</sub>	412	1,256	2,538	2,538
NOx	1,774	1,877	1,890	1,890

	<u>2003</u>	<u>2004</u>	<u>2005</u>
BLS Firing (T/D)	1,183	1,251	1,260

CALPUFF FACTORS	lb/T BLS		
	<u>2003</u>	<u>2004</u>	<u>2005</u>
Total PM	0.623	0.476	0.831
Filterable PM	0.533	0.386	0.741
Condensable PM	0.090	0.090	0.090
Filterable PM-10	0.267	0.194	0.372
Filterable PM-2.5	0.198	0.144	0.276
Condensable H <sub>2</sub> SO <sub>4</sub>	0.032	0.032	0.032
Condensable non-sulfate (NO <sub>3</sub> )	0.043	0.043	0.043
Condensable organic (SOA)	0.015	0.015	0.015
PMC800	0.027	0.019	0.037
PMC425	0.042	0.031	0.059
PMF187	0.047	0.034	0.066
PMF112	0.026	0.019	0.036
PMF081	0.038	0.027	0.052
PMF056	0.087	0.063	0.121
<b>PMC</b>	0.069	0.050	0.096
<b>SOIL/PMF</b>	0.198	0.144	0.276
EC187	0.00001	0.00001	0.00002
EC112	0.00001	0.00000	0.00001
EC081	0.00001	0.00001	0.00001
EC056	0.00002	0.00002	0.00003
<b>EC</b>	0.0000	0.0000	0.0001

CALPUFF EMISSIONS	max 24-hr lb/day			
	<u>2003</u>	<u>2004</u>	<u>2005</u>	<u>Max of 2003-2005</u>
Total PM	737	596	1047	1047
Filterable PM	630	483	934	934
Condensable PM	106	113	113	113
Filterable PM-10	316	243	469	469
Filterable PM-2.5	234	180	347	347
<b>Condensable H<sub>2</sub>SO<sub>4</sub></b>	37	40	<b>40</b>	<b>40</b>
<b>Condensable non-sulfate (NO<sub>3</sub>)</b>	51	54	<b>55</b>	<b>55</b>
<b>Condensable organic (SOA)</b>	18	19	<b>19</b>	<b>19</b>
PMC800	32	24	47	47
PMC425	50	39	74	74
PMF187	56	43	83	83
PMF112	31	24	46	46
PMF081	45	34	66	66
PMF056	103	79	153	153
<b>PMC</b>	82	63	<b>121</b>	<b>121</b>
<b>SOIL/PMF</b>	234	180	<b>347</b>	<b>347</b>
EC187	0.01	0.01	0.02	0.02
EC112	0.01	0.01	0.01	0.01
EC081	0.01	0.01	0.02	0.02
EC056	0.03	0.02	0.04	0.04
<b>EC</b>	0.06	0.04	<b>0.09</b>	<b>0.09</b>
			<b>max year</b>	

**2003 Recovery Furnace SO<sub>2</sub> Calculations**

ppm	Stack Test Data			BLS (T/hr)			SO2 lb/day	EF SO2 lb/BLS (T)
	dscf/min	MW <sub>SO2</sub>	Product	Stack Test	Max 24-hr	Ratio		
-	-	64.06	-		49			
-	-	64.06	-					
1.4	168,938	64.06	15,151,904	45		1.10	2.4	<b>0.05</b>
28.2	158,451	64.06	286,256,842	44		1.12	44.6	<b>1.01</b>
-	-	64.06	-					
-	-	64.06	-					
-	-	64.06	-					
-	-	64.06	-					
0.0	177,677	64.06	170,740	45		1.09	0.0	<b>0.001</b>
-	-	64.06	-					
8.8	171,616	64.06	96,365,800	46		1.08	15.0	<b>0.33</b>
-	-	64.06	-					
			286,256,842	4		1.12	<b>Max</b>	<b>1.01</b>
							<b>Ave</b>	<b>0.35</b>

**2004 Recovery Furnace SO<sub>2</sub> Calculations**

ppm	Stack Test Data			BLS (T/hr)			SO2 lb/day	EF SO2 lb/BLS (T)
	dscf/min	MW <sub>SO2</sub>	Product	Stack Test	Max 24-hr	Ratio		
-	-	64.06	-		52			
-	-	64.06	-					
94.3	161,743	64.06	977,124,454	44		1.19	152.3	<b>3.47</b>
-	-	64.06	-					
-	-	64.06	-					
9.6	180,880	64.06	110,895,822	45		1.15	17.3	<b>0.38</b>
-	-	64.06	-					
69.3	-	64.06	-				0.0	
1.2	179,557	64.06	14,187,161	44		1.17	2.2	<b>0.050</b>
-	-	64.06	-					
-	-	64.06	-					
3.1	175,297	64.06	34,813,595	50		1.04	5.4	<b>0.11</b>
			977,124,454	3		1.19	<b>Max</b>	<b>3.47</b>
							<b>Ave</b>	<b>1.00</b>

**2005 Recovery Furnace SO<sub>2</sub> Calculations**

Stack Test Data				BLS (T/hr)			SO <sub>2</sub> lb/day	EF
ppm	dscf/min	MW <sub>SO<sub>2</sub></sub>	Product	Stack Test	Max 24-hr	Ratio		SO <sub>2</sub> lb/BLS (T)
-	-	64.06	-		53			
-	-	64.06	-					
32.0	203,345	64.06	416,865,709	50		1.04	65.0	<b>1.29</b>
-	-	64.06	-					
-	-	64.06	-					
104.0	191,221	64.06	1,274,035,766	46		1.14	198.6	<b>4.32</b>
-	-	64.06	-					
-	-	64.06	-					
0.5	205,206	64.06	6,573,138	45		1.17	1.0	<b>0.023</b>
55.8	184,400	64.06	659,185,751	42		1.24	102.7	<b>2.42</b>
-	-	64.06	-					
-	-	64.06	-					
			1,274,035,766	6		1.14	<b>Max</b>	<b>4.32</b>
							<b>Ave</b>	<b>2.01</b>

## Smelt Dissolving Tank

Maximum 24-Hour Emissions (lb/D) using average factor for 2003-2005 and max throughput for each year.

	<u>2003</u>	<u>2004</u>	<u>2005</u>	<u>Max 2003-2005</u>
SO <sub>2</sub>	6	6	6	6
NO <sub>x</sub>	24	25	25	25

	<u>2003</u>	<u>2004</u>	<u>2005</u>
BLS Firing (T/D)	1,183	1,251	1,260

CALPUFF FACTORS	lb/T BLS		
	<u>2003</u>	<u>2004</u>	<u>2005</u>
Total PM	0.225	0.210	0.229
Filterable PM	0.218	0.202	0.222
Condensable PM	0.007	0.007	0.007
Filterable PM-10	0.178	0.166	0.182
Filterable PM-2.5	0.158	0.147	0.161
Condensable H <sub>2</sub> SO <sub>4</sub>	<b>0.002</b>	<b>0.002</b>	<b>0.002</b>
Condensable non-sulfate (NO <sub>3</sub> )	<b>0.003</b>	<b>0.003</b>	<b>0.003</b>
Condensable organic (SOA)	<b>0.002</b>	<b>0.002</b>	<b>0.002</b>
PM800	0.003	0.003	0.003
PM425	0.018	0.016	0.018
PM187	0.033	0.031	0.034
PM112	0.016	0.015	0.017
PM081	0.030	0.028	0.030
PM056	<b>0.072</b>	<b>0.067</b>	<b>0.074</b>
PMC	<b>0.020</b>	<b>0.019</b>	<b>0.021</b>
<b>SOIL/PMF</b>	<b>0.152</b>	<b>0.141</b>	<b>0.155</b>
EC187	0.001	0.001	0.001
EC112	0.001	0.001	0.001
EC081	0.001	0.001	0.001
EC056	0.003	0.003	0.003
EC	<b>0.006</b>	<b>0.006</b>	<b>0.006</b>

CALPUFF EMISSIONS	max 24-hr lb/day			
	<u>2003</u>	<u>2004</u>	<u>2005</u>	<u>Max of 2003-2005</u>
Total PM	266	263	289	289
Filterable PM	257	253	280	280
Condensable PM	9	9	9	9
Filterable PM-10	211	207	229	229
Filterable PM-2.5	187	184	203	203
Condensable H <sub>2</sub> SO <sub>4</sub>	2	3	3	<b>3</b>
Condensable non-sulfate (NO <sub>3</sub> )	4	4	4	<b>4</b>
Condensable organic (SOA)	2	3	3	<b>3</b>
PM800	3	3	3	3
PM425	21	20	23	23
PM187	39	39	43	43
PM112	19	19	21	21
PM081	35	35	38	38
PM056	85	84	93	93
PMC	24	24	26	<b>26</b>
<b>SOIL/PMF</b>	179	177	195	<b>195</b>
EC187	2	2	2	2
EC112	1	1	1	1
EC081	1	1	2	2
EC056	4	4	4	4
EC	7	7	8	<b>8</b>

max year

## #10 Power Boiler

Maximum 24-Hour Emissions (lb/D) using average factor for 2003-2005 and max throughput for each year.

	2003	2004	2005	Max 2003-2005
SO <sub>2</sub>	1,713	856	1,230	<b>1,713</b>
NO <sub>x</sub>	1,922	1,983	1,896	<b>1,983</b>
Total PM				<b>1,374</b>

Max 2003-2005 uses maximum emission factor or test scaled for maximum throughput

### 2003 #10 Power Boiler PM Speciation

	<u>EPA Speciation</u> <u>Guidance Profile</u> <u>NWWAS</u>	<u>EPA Speciation</u> <u>Guidance Profile</u> <u>22003</u>	<u>Wood Speciation &amp;</u> <u>Source Tests</u>	<u>Oil Speciation &amp;</u> <u>Source Tests</u>	<u>Weighted Average<sup>a</sup></u>
	Percent of PM 2.5	Percent of PM 2.5	lb/mmBtu	lb/mmBtu	(lb/mmBtu)
<b>CALPUFF FACTORS</b>					
Total PM			0.1737	0.1448	0.165
Filterable PM			0.093	0.093	0.093
Condensable PM	47.0%	36.3%	0.081	0.052	0.072
Filterable PM-10			0.091	0.091	0.091
Filterable PM-2.5	53.0%	63.8%	0.091	0.091	0.091
Total PM2.5	100.0%	100.0%	0.172	0.143	0.163
<b>Condensable H2SO4</b>	8.0%	32.2%	0.014	0.046	<b>0.023</b>
<b>Condensable non-sulfate (NO3)</b>	0.0%	0.2%	0.000	0.000	<b>0.000</b>
<b>Condensable organic (SOA)</b>	39.0%	3.8%	0.067	0.005	<b>0.049</b>
PMC800			0.000	0.000	0.000
PMC425			0.000	0.000	0.000
PMF187			0.001	0.002	0.001
PMF112			0.001	0.001	0.001
PMF081			0.000	0.000	0.000
PMF056			0.065	0.078	0.069
<b>PMF</b>	39.0%	56.1%	0.067	0.080	<b>0.071</b>
<b>PMC</b>			0.000	0.000	<b>0.000</b>
<b>EC</b>	14.0%	7.7%	0.024	0.011	<b>0.020</b>
	100.0%	100.0%			

Weighted average emission factor based on percentage of wood and fuel oil firing rates during source tests.

### 2004 #10 Power Boiler PM Speciation

	<u>EPA Speciation</u> <u>Guidance Profile</u> <u>NWWAS</u>	<u>EPA Speciation</u> <u>Guidance Profile</u> <u>22003</u>	<u>Wood Speciation &amp;</u> <u>Source Tests</u>	<u>Oil Speciation &amp;</u> <u>Source Tests</u>	<u>Weighted Average<sup>a</sup></u>
	Percent of PM 2.5	Percent of PM 2.5	lb/mmBtu	lb/mmBtu	(b/mmBtu)
<b>CALPUFF FACTORS</b>					
Total PM			0.156	0.1303	0.149
Filterable PM			0.084	0.084	0.084
Condensable PM	47.0%	36.3%	0.073	0.047	0.065
Filterable PM-10			0.082	0.082	0.082
Filterable PM-2.5	53.0%	63.8%	0.082	0.082	0.082
Total PM2.5	100.0%	100.0%	0.155	0.129	0.147
<b>Condensable H2SO4</b>	8.0%	32.2%	0.012	0.041	<b>0.021</b>
<b>Condensable non-sulfate (NO3)</b>	0.0%	0.2%	0.000	0.000	<b>0.000</b>
<b>Condensable organic (SOA)</b>	39.0%	3.8%	0.060	0.005	<b>0.044</b>
PMC800			0.000	0.000	0.000
PMC425			0.000	0.000	0.000
PMF187			0.001	0.001	0.001
PMF112			0.001	0.001	0.001
PMF081			0.000	0.000	0.000
PMF056			0.058	0.070	0.062
<b>PMF</b>	39.0%	56.1%	0.060	0.072	<b>0.064</b>
<b>PMC</b>			0.000	0.000	<b>0.000</b>
<b>EC</b>	14.0%	7.7%	0.022	0.010	<b>0.018</b>
	100.0%	100.0%			

Weighted average emission factor based on percentage of wood and fuel oil firing rates during source tests.

**2005 #10 Power Boiler PM Speciation**

	<u>EPA Speciation</u>	<u>EPA Speciation</u>	<u>Wood Speciation &amp;</u>	<u>Oil Speciation &amp;</u>	<u>Weighted Average<sup>a</sup></u>
	<u>Guidance Profile</u>	<u>Guidance Profile</u>	<u>Source Tests</u>	<u>Source Tests</u>	
	<u>NWWAS</u>	<u>22003</u>			
<i>CALPUFF FACTORS</i>	Percent of PM 2.5	Percent of PM 2.5	lb/mmBtu	lb/mmBtu	(b/mmBtu)
Total PM			0.154	0.1281	0.147
Filterable PM			0.082	0.082	0.082
Condensable PM	47.0%	36.3%	0.072	0.046	0.065
Filterable PM-10			0.081	0.081	0.081
Filterable PM-2.5	53.0%	63.8%	0.081	0.081	0.081
Total PM2.5	100.0%	100.0%	0.152	0.126	0.145
<b>Condensable H2SO4</b>	8.0%	32.2%	0.012	0.041	<b>0.020</b>
<b>Condensable non-sulfate (NO3)</b>	0.0%	0.2%	0.000	0.000	<b>0.000</b>
<b>Condensable organic (SOA)</b>	39.0%	3.8%	0.059	0.005	<b>0.044</b>
PMC800			0.000	0.000	0.000
PMC425			0.000	0.000	0.000
PMF187			0.001	0.001	0.001
PMF112			0.001	0.001	0.001
PMF081			0.000	0.000	0.000
PMF056			0.058	0.069	0.061
<b>PMF</b>	39.0%	56.1%	0.059	0.071	<b>0.062</b>
<b>PMC</b>			0.000	0.000	<b>0.000</b>
<b>EC</b>	14.0%	7.7%	0.0213	0.0097	0.018
	100.0%	100.0%			

Weighted average emission factor based on percentage of wood and fuel oil firing rates during source tests.

**#10 Power Boiler PM Speciation Summary**

<i>CALPUFF EMISSIONS</i>	max 24-hr lb/day			
	<u>2003</u>	<u>2004</u>	<u>2005</u>	<u>Max of 2003-2005</u>
Total PM	1374	1277	1294	1374
Filterable PM	774	718	725	774
Condensable PM	601	559	569	601
Filterable PM-10	758	704	711	758
Filterable PM-2.5	758	704	711	758
Total PM2.5	1359	1263	1280	1359
<b>Condensable H2SO4</b>	194	179	176	<b>194</b>
<b>Condensable non-sulfate (NO3)</b>	1	1	1	<b>1</b>
<b>Condensable organic (SOA)</b>	406	379	392	<b>406</b>
PMC800	-	-	-	-
PMC425	-	-	-	-
PMF187	12	11	11	12
PMF112	6	6	6	6
PMF081	-	-	-	-
PMF056	572	531	534	572
<b>PMF</b>	590	548	551	<b>590</b>
<b>PMC</b>	-	-	-	-
<b>EC</b>	168	156	160	<b>168</b>
EC187	-	-	-	3.4
EC112	-	-	-	1.7
EC081	-	-	-	0.0
EC056	-	-	-	162.8

## Lime Kiln

Maximum 24-Hour Emissions (lb/D) using average factor for 2003-2005 and max throughput for each year.				
	<u>2003</u>	<u>2004</u>	<u>2005</u>	<u>Max 2003-2005</u>
SO <sub>2</sub>	21	19	39	39
NOx	240	239	237	240

Max 2003-2005 uses maximum emission factor or test scaled for maximum throughput

	<u>2003</u>	<u>2004</u>	<u>2005</u>
Production (max ADTP/day)	758	756	750

CALPUFF FACTORS	lb/T CaO			Percent of total PM
	<u>2003</u>	<u>2004</u>	<u>2005</u>	
Total PM	1.018	0.842	0.810	100.0%
Filterable PM	0.863	0.687	0.655	84.8%
Condensable PM	0.155	0.155	0.155	15.2%
Filterable PM-10	0.731	0.582	0.555	71.8%
Filterable PM-2.5	0.663	0.528	0.503	65.1%
Condensable H <sub>2</sub> SO <sub>4</sub>	<b>0.090</b>	<b>0.090</b>	<b>0.090</b>	8.9%
Condensable non-sulfate (NO <sub>3</sub> )	<b>0.052</b>	<b>0.052</b>	<b>0.052</b>	5.1%
Condensable organic (SOA)	<b>0.013</b>	<b>0.013</b>	<b>0.013</b>	1.3%
PMC800	0.003	0.002	0.002	0.3%
PMC425	0.065	0.052	0.049	6.4%
PMF187	0.073	0.058	0.055	7.2%
PMF112	0.040	0.032	0.031	4.0%
PMF081	0.163	0.130	0.124	16.0%
PMF056	<b>0.360</b>	<b>0.287</b>	<b>0.273</b>	35.4%
PMC	<b>0.068</b>	<b>0.054</b>	<b>0.052</b>	6.7%
SOIL	<b>0.637</b>	<b>0.507</b>	<b>0.483</b>	62.5%
EC187	0.003	0.002	0.002	0.3%
EC112	0.002	0.001	0.001	0.2%
EC081	0.007	0.005	0.005	0.7%
EC056	0.015	0.012	0.011	1.5%
EC	<b>0.027</b>	<b>0.021</b>	<b>0.020</b>	2.6%

CALPUFF EMISSIONS	max 24-hr lb/day			Max of 2003-2005
	<u>2003</u>	<u>2004</u>	<u>2005</u>	
Total PM	212	175	167	212
Filterable PM	180	143	135	180
Condensable PM	32	32	32	32
Filterable PM-10	152	121	114	152
Filterable PM-2.5	138	110	104	138
<b>Condensable H<sub>2</sub>SO<sub>4</sub></b>	<b>19</b>	<b>19</b>	<b>19</b>	<b>19</b>
<b>Condensable non-sulfate (NO<sub>3</sub>)</b>	<b>11</b>	<b>11</b>	<b>11</b>	<b>11</b>
<b>Condensable organic (SOA)</b>	<b>3</b>	<b>3</b>	<b>3</b>	<b>3</b>
PMC800	1	0	0	1
PMC425	14	11	10	14
PMF187	15	12	11	15
PMF112	8	7	6	8
PMF081	34	27	26	34
PMF056	75	60	56	75
<b>PMC</b>	<b>14</b>	<b>11</b>	<b>11</b>	<b>14</b>
<b>SOIL/PMF</b>	<b>133</b>	<b>105</b>	<b>100</b>	<b>133</b>
EC187	1	1	0	1
EC112	0	0	0	0
EC081	1	1	1	1
EC056	3	2	2	3
EC	<b>5.53</b>	<b>4</b>	<b>4</b>	<b>5.53</b>
	<b>max year</b>			

Note: Conversion factor of 0.275 TCaO/ADTP used to calculate T CaO throughput per NCASI TB #884

**2003 SO<sub>2</sub> Lime Kiln Calculations**

Stack Test Data				Mud Feed (gpm)			SO2 lb/day	EF
ppm	dscf/min	MW <sub>SO2</sub>	Product	Stack Test	Max 24-hr	Ratio		SO2 lb/day/gpm
3.8	17,500	64.06	4,260,243	115	141	1.23	15.9	<b>0.139</b>
-	-	64.06	-					
-	-	64.06	-					
0.8	19,700	64.06	1,009,645	125		1.13	3.8	<b>0.030</b>
-	-	64.06	-					
-	-	64.06	-					
0.8	15,900	64.06	814,892	100		1.41	3.0	<b>0.030</b>
-	-	64.06	-					
-	-	64.06	-					
7.9	22,300	64.06	11,286,120	107		1.32	42.2	<b>0.395</b>
-	-	64.06	-					
-	-	64.06	-					
			11,286,120	10		1.32	<b>Max</b>	<b>0.395</b>
							<b>Ave</b>	<b>0.148</b>

**2004 SO<sub>2</sub> Lime Kiln Calculations**

Stack Test Data				Mud Feed (gpm)			SO2 lb/day	EF
ppm	dscf/min	MW <sub>SO2</sub>	Product	Stack Test	Max 24-hr	Ratio		SO2 lb/day/gpm
-	-	64.06	-		191			
-	-	64.06	-					
1.0	17,700	64.06	1,133,929	123		1.55	4.2	<b>0.034</b>
5.6	15,500	64.06	5,560,738	120		1.59	20.8	<b>0.173</b>
-	-	64.06	-					
-	-	64.06	-					
-	-	64.06	-					
-	-	64.06	-					
2.3	16,690	64.06	2,494,858	110		1.74	9.3	<b>0.085</b>
-	-	64.06	-					
-	16,300	64.06	-	125		1.53		
-	-	64.06	-					
			5,560,738	4		1.59	<b>Max</b>	<b>0.173</b>
							<b>Ave</b>	<b>0.10</b>

**2005 Lime Kiln SO<sub>2</sub> Calculations**

Stack Test Data				Mud Feed (gpm)			SO <sub>2</sub> lb/day	EF
ppm	dscf/min	MW <sub>SO<sub>2</sub></sub>	Product	Stack Test	Max 24-hr	Ratio		SO <sub>2</sub> lb/day/gpm
0.9	16,200	64.06	934,050	135	179	1.33	3.5	0.026
-	-	64.06	-					
-	-	64.06	-	135		1.33		
0.9	13,900	64.06	801,438				3.0	
-	-	64.06	-					
11.1	17,600	64.06	12,515,504	115		1.56	46.8	0.407
-	-	64.06	-					
-	-	64.06	-					
-	-	64.06	-					
-	-	64.06	-					
-	17,900	64.06	-	130		1.38		
			12,515,504	7		1.56		
							<b>Max</b>	<b>0.407</b>
							<b>Ave</b>	<b>0.22</b>



2003 PTPC PM Test Results for NDCE Kraft Recovery Furnace with ESP

PTPC Test Results										
	gr/dscf	dscf/min	min	BLS %	lb/hr fired	lb PM	T BLS	lb PM/T	BLS	
3/4/03	0.0231	168,938	120	71.3%	125,547	66.97	89.97	89.52	0.748	
4/14/03	0.0256	158,451	120	70.0%	125,774	69.60	88.60	88.04	0.791	
9/12/03	0.0097	177,677	120	72.0%	125,743	29.64	90.64	90.53	0.327	
11/25/03	0.0083	171,616	120	70.0%	130,847	24.31	91.59	91.59	0.265	

**NDCE Kraft Recovery Furnace with ESP**

PTPC Test Results		condensable		condensable split	
	total filterable	filterable	inorganic	organic	
	PM <sub>10</sub>	PM <sub>2.5</sub>	H <sub>2</sub> SO <sub>4</sub>	non-sulfate	
%	81.1%	37.2%	35.2%	48.3%	16.5%
(lb/ton BLS)	<b>0.48</b>	<b>0.194</b>	<b>0.032</b>	<b>0.043</b>	<b>0.015</b>

CONDENSABLE					
CALPUFF Code	Diameter (µm)	filterable (% of PM)	fine filterable <sup>2</sup>		non-sulfate inorganic condensable <sup>3</sup> (lb/ton BLS)
			inorganic - 99.975% of PM <sub>2.5</sub> filterable (lb/ton BLS)	elemental carbon - 0.025% of PM <sub>2.5</sub> filterable (lb/ton BLS)	
coarse (42.4%)	6.00 - 10.00 2.50-6.00	5.0% 8.0%	0.019 0.031		6.00 - 10.00 2.50-6.00
fine (57.6%)	1.25-2.50	8.8%	0.034	<b>0.00001</b>	
	1.00-1.25	4.9%	0.019	<b>0.00000</b>	
	0.625-1.00	7.1%	0.027	<b>0.00001</b>	<b>0.022</b>
	0.50-0.625	16.4%	0.063	<b>0.00002</b>	<b>0.022</b>
total		<b>50.2%</b>	<b>0.194</b>	<b>0.0000</b> EC	<b>0.015</b> SOA
Ext. coefficient			0.6	10	3*(RH) 4 3*(RH)

<sup>1</sup>Assumed nitrate comprises all of the non-sulfate inorganic CPM fractions. Sulfate and nitrate have the same extinction efficiency (3.0) and the same dependence on relative humidity, and thus in terms of modeling for visibility using the CALPUFF model, t

<sup>2</sup>the elemental carbon PM<sub>2.5</sub> emissions are assumed to be broken down into the particle size ranges 0 - 0.625 µm, 0.625 - 1.0 µm, 1.0 - 1.25 µm, and 1.25 - 2.5 µm in a fashion similar to the non-carbon PM<sub>2.5</sub> emissions

<sup>3</sup>the organic CPM, sulfate CPM and non-sulfate CPM emissions are assumed to be equally distributed in the particle size ranges of 0 to 0.625 µm and 0.625 to 1.0 µm

2004 PTPC PM Test Results for NDCE Kraft Recovery Furnace with ESP

PTPC Test Results										
	gr/dscf	dscf/min	min	BLS %	lb/hr fired	lb PM	T BLS	lb PM/T BLS		
3/12/04	0.0090	161,743	120	71.4%	122,762	25.05	87.65	0.286		
6/4/04	0.0174	180,880	120	67.0%	135,000	54.01	90.45	0.597		
9/9/04	0.0054	182,505	120	71.7%	123,927	17.04	88.86	0.192		
9/9/04	0.0101	178,591	120	72.2%	123,808	30.83	89.39	0.345		
9/9/04	0.0110	177,576	120	71.6%	123,739	33.52	88.60	0.378		
12/13/04	0.0174	175,297	120	71.6%	140,192	52.18	100.38	0.520		

**NDCE Kraft Recovery Furnace with ESP**

	total	filterable		condensable		condensable split	
		PM <sub>10</sub>	PM <sub>2.5</sub>	H <sub>2</sub> SO <sub>4</sub>	inorganic non-sulfate	organic	
%	89.2%	10.8%	37.2%	35.2%	48.3%	16.5%	
(lb/ton BLS)	<b>0.83</b>	<b>0.09</b>	<b>0.372</b>	<b>0.032</b>	<b>0.043</b>	<b>0.015</b>	

	FILTERABLE						CONDENSABLE				
	CALPUFF Code	Diameter (µm)	filterable (% of PM)	filterable (lb/ton BLS)	coarse filterable inorganic (lb/ton BLS)	fine filterable <sup>2</sup> inorganic - 99.975% of PM <sub>2.5</sub> filterable (lb/ton BLS)	elemental carbon - 0.025% of PM <sub>2.5</sub> filterable (lb/ton BLS)	H <sub>2</sub> SO <sub>4</sub> <sup>3</sup> (lb/ton BLS)	organic condensable <sup>3</sup> (lb/ton BLS)	non-sulfate inorganic condensable <sup>3</sup> (lb/ton BLS)	Diameter (µm)
coarse (42.4%)	PM800	6.00 - 10.00	5.0%	0.037	<b>0.037</b>						6.00 - 10.00
	PM425	2.50-6.00	8.0%	0.059	<b>0.059</b>						2.50-6.00
	PM187	1.25-2.50	8.8%	0.066		<b>0.066</b>	<b>0.00002</b>				1.25-2.50
fine (57.6%)	PM112	1.00-1.25	4.9%	0.036		<b>0.036</b>	<b>0.00001</b>	<b>0.016</b>	<b>0.007</b>	<b>0.022</b>	1.00-1.25
	PM081	0.625-1.00	7.1%	0.052		<b>0.052</b>	<b>0.00001</b>	<b>0.016</b>	<b>0.007</b>	<b>0.022</b>	0.625-1.00
	PM056	0.50-0.625	16.4%	0.121		<b>0.121</b>	<b>0.00003</b>				0.50-0.625
total			<b>50.2%</b>	<b>0.372</b>	<b>0.096</b>	<b>0.276</b>	<b>0.0001</b>	<b>0.032</b>	<b>0.015</b>	<b>0.043</b>	
Ext. coefficient				0.6	PMC	SOIL	EC	H <sub>2</sub> SO <sub>4</sub>	SOA	NO <sub>3</sub> <sup>1</sup>	
						1	10	3*(RH)	4	3*(RH)	

<sup>1</sup>Assumed nitrate comprises all of the non-sulfate inorganic CPM fractions. Sulfate and nitrate have the same extinction efficiency (3.0) and the same dependence on relative humidity, and thus in terms of modeling for visibility using the CALPUFF model, t

<sup>2</sup>the elemental carbon PM<sub>2.5</sub> emissions are assumed to be broken down into the particle size ranges 0 - 0.625 µm, 0.625 - 1.0 µm, 1.0 - 1.25 µm, and 1.25 - 2.5 µm in a fashion similar to the non-carbon PM<sub>2.5</sub> emissions

<sup>3</sup>the organic CPM, sulfate CPM and non-sulfate CPM emissions are assumed to be equally distributed in the particle size ranges of 0 to 0.625 µm and 0.625 to 1.0 µm

2005 PTPC PM Test Results for NDCE Kraft Recovery Furnace with ESP

	gr/dscf	dscf/min	min	BLS %	lb/hr fired	lb PM	T BLS	lb PM/T BLS
3/7/05	0.0279	203,345	120	70.5%	142,874	97.22	100.73	0.965
6/28/05	0.0224	191,221	120	68.5%	134,131	73.48	91.88	0.800
9/26/05	0.0107	205,206	120	71.3%	125,913	37.62	89.78	0.419
10/21/05	0.0209	184,400	120	68.3%	124,180	66.10	84.81	0.779

**Smelt Dissolving Tank With Venturi Scrubber**

	total	filterable		condensable		split	
		PM <sub>10</sub>	PM <sub>2.5</sub>	H <sub>2</sub> SO <sub>4</sub>	inorganic non-sulfate	organic	
%		81.9%	72.6%	27.3%	44.9%	27.8%	
(lb/ton BLS)	<b>0.23</b>	<b>0.178</b>	<b>0.158</b>	<b>0.002</b>	<b>0.003</b>	<b>0.002</b>	

		FILTERABLE					CONDENSABLE			
CALPUFF Code	Diameter (µm)	filterable (% of PM)	filterable (lb/ton BLS)	coarse filterable inorganic (lb/ton BLS)	fine filterable <sup>2</sup>		H <sub>2</sub> SO <sub>4</sub> <sup>3</sup> (lb/ton BLS)	organic condensable <sup>3</sup> (lb/ton BLS)	non-sulfate inorganic condensable <sup>3</sup> (lb/ton BLS)	Diameter (µm)
					inorganic - 96.0% of PM <sub>2.5</sub> filterable (lb/ton BLS)	elemental carbon - 4.0% of PM <sub>2.5</sub> filterable (lb/ton BLS)				
coarse (42.4%)	6.00 - 10.00	1.2%	0.003	<b>0.003</b>						6.00 - 10.00
	2.50-6.00	8.1%	0.018	<b>0.018</b>						2.50-6.00
	1.25-2.50	15.9%	0.035		<b>0.033</b>	<b>0.00138</b>				1.25-2.50
	1.00-1.25	7.9%	0.017		<b>0.016</b>	<b>0.00068</b>				1.00-1.25
fine (57.6%)	0.625-1.00	14.3%	0.031		<b>0.030</b>	<b>0.00124</b>	<b>0.001</b>	<b>0.001</b>	<b>0.002</b>	0.625-1.00
	0.50-0.625	34.6%	0.075		<b>0.072</b>	<b>0.00301</b>	<b>0.001</b>	<b>0.001</b>	<b>0.002</b>	0.50-0.625
total		<b>81.9%</b>	<b>0.178</b>	<b>0.020</b>	<b>0.152</b>	<b>0.0063</b>	<b>0.002</b>	<b>0.002</b>	<b>0.003</b>	
				<b>PMC</b>	<b>SOIL</b>	<b>EC</b>	<b>H<sub>2</sub>SO<sub>4</sub></b>	<b>SOA</b>	<b>NO<sub>3</sub><sup>1</sup></b>	
Ext. coefficient			0.6		1	10	3*(RH)	4	3*(RH)	

<sup>1</sup>Assumed nitrate comprises all of the non-sulfate inorganic CPM fractions. Sulfate and nitrate have the same extinction efficiency (3.0) and the same dependence on relative humidity, and thus in terms of modeling for visibility using the CALPUFF model, t

<sup>2</sup>the elemental carbon PM<sub>2.5</sub> emissions are assumed to be broken down into the particle size ranges 0 - 0.625 µm, 0.625 - 1.0 µm, 1.0 - 1.25 µm, and 1.25 - 2.5 µm in a fashion similar to the non-carbon PM<sub>2.5</sub> emissions

<sup>3</sup>the organic CPM, sulfate CPM and non-sulfate CPM emissions are assumed to be equally distributed in the particle size ranges of 0 to 0.625 µm and 0.625 to 1.0 µm

**Smelt Dissolving Tank With Venturi Scrubber**

	total	filterable condensable		filterable		condensable split		
		filterable (% of PM)	Diameter (µm)	PM <sub>10</sub>	PM <sub>2.5</sub>	H <sub>2</sub> SO <sub>4</sub>	inorganic non-sulfate	organic
coarse (42.4%)		1.2%	6.00 - 10.00	0.003	<b>0.003</b>	27.3%	44.9%	27.8%
		8.1%	2.50-6.00	0.016	<b>0.147</b>	<b>0.002</b>	<b>0.003</b>	<b>0.002</b>
fine (57.6%)		15.9%	1.25-2.50	0.032				
		7.9%	1.00-1.25	0.016				
		14.3%	0.625-1.00	0.029				
		34.6%	0.50-0.625	0.070				
total		<b>81.9%</b>		<b>0.166</b>				
Ext. coefficient					0.6	1	10	3*(RH)

FILTERABLE				CONDENSABLE						
CALPUFF Code	Diameter (µm)	filterable (% of PM)	filterable (lb/ton BLS)	coarse filterable inorganic (lb/ton BLS)	inorganic - 96.0% of PM <sub>2.5</sub> filterable (lb/ton BLS)	elemental carbon - 4.0% of PM <sub>2.5</sub> filterable (lb/ton BLS)	H <sub>2</sub> SO <sub>4</sub> <sup>3</sup> (lb/ton BLS)	organic condensable <sup>3</sup> (lb/ton BLS)	non-sulfate inorganic condensable <sup>3</sup> (lb/ton BLS)	Diameter (µm)
PM800	6.00 - 10.00	1.2%	0.003	<b>0.003</b>						6.00 - 10.00
PM425	2.50-6.00	8.1%	0.016	<b>0.016</b>						2.50-6.00
PM187	1.25-2.50	15.9%	0.032		<b>0.031</b>	<b>0.00129</b>				1.25-2.50
PM112	1.00-1.25	7.9%	0.016		<b>0.015</b>	<b>0.00064</b>				1.00-1.25
PM081	0.625-1.00	14.3%	0.029		<b>0.028</b>	<b>0.00116</b>	<b>0.001</b>	<b>0.001</b>	<b>0.002</b>	0.625-1.00
PM056	0.50-0.625	34.6%	0.070		<b>0.067</b>	<b>0.00280</b>	<b>0.001</b>	<b>0.001</b>	<b>0.002</b>	0.50-0.625
total		<b>81.9%</b>	<b>0.166</b>	<b>0.019</b>	<b>0.141</b>	<b>0.0059</b>	<b>0.002</b>	<b>0.002</b>	<b>0.003</b>	
Ext. coefficient				<b>PMC</b>	<b>SOIL</b>	<b>EC</b>	<b>H<sub>2</sub>SO<sub>4</sub></b>	<b>SOA</b>	<b>NO<sub>3</sub><sup>1</sup></b>	
				0.6	1	10	3*(RH)	4	3*(RH)	

<sup>1</sup>Assumed nitrate comprises all of the non-sulfate inorganic CPM fractions. Sulfate and nitrate have the same extinction efficiency (3.0) and the same dependence on relative humidity, and thus in terms of modeling for visibility using the CALPUFF model, t

<sup>2</sup>the elemental carbon PM<sub>2.5</sub> emissions are assumed to be broken down into the particle size ranges 0 - 0.625 µm, 0.625 - 1.0 µm, 1.0 - 1.25 µm, and 1.25 - 2.5 µm in a fashion similar to the non-carbon PM<sub>2.5</sub> emissions

<sup>3</sup>the organic CPM, sulfate CPM and non-sulfate CPM emissions are assumed to be equally distributed in the particle size ranges of 0 to 0.625 µm and 0.625 to 1.0 µm

**Smelt Dissolving Tank With Venturi Scrubber**

	total	filterable		condensable		filterable		condensable split	
		filterable	condensable	PM <sub>10</sub>	PM <sub>2.5</sub>	H <sub>2</sub> SO <sub>4</sub>	inorganic non-sulfate	organic	
%	96.8%	3.2%	3.2%	81.9%	72.6%	27.3%	44.9%	27.8%	
(lb/ton BLS)	<b>0.23</b>	<b>0.22</b>	<b>0.01</b>	<b>0.182</b>	<b>0.161</b>	<b>0.002</b>	<b>0.003</b>	<b>0.002</b>	

FILTERABLE						CONDENSABLE					
CALPUFF Code	Diameter (µm)	filterable (% of PM)	filterable (lb/ton BLS)	coarse filterable inorganic (lb/ton BLS)	fine filterable <sup>2</sup>	inorganic - 96.0% of PM <sub>2.5</sub> filterable (lb/ton BLS)	elemental carbon - 4.0% of PM <sub>2.5</sub> filterable (lb/ton BLS)	H <sub>2</sub> SO <sub>4</sub> <sup>3</sup> (lb/ton BLS)	organic condensable <sup>3</sup> (lb/ton BLS)	non-sulfate inorganic condensable <sup>3</sup> (lb/ton BLS)	Diameter (µm)
PM800	6.00 - 10.00	1.2%	0.003	<b>0.003</b>							6.00 - 10.00
PM425	2.50-6.00	8.1%	0.018	<b>0.018</b>							2.50-6.00
PM187	1.25-2.50	15.9%	0.035		<b>0.034</b>		<b>0.00141</b>				1.25-2.50
PM112	1.00-1.25	7.9%	0.017		<b>0.017</b>		<b>0.00070</b>				1.00-1.25
PM081	0.625-1.00	14.3%	0.032		<b>0.030</b>		<b>0.00127</b>	<b>0.001</b>	<b>0.001</b>	<b>0.002</b>	0.625-1.00
PM056	0.50-0.625	34.6%	0.077		<b>0.074</b>		<b>0.00307</b>	<b>0.001</b>	<b>0.001</b>	<b>0.002</b>	0.50-0.625
total		<b>81.9%</b>	<b>0.182</b>	<b>0.021</b>	<b>0.0064</b>	<b>0.155</b>	<b>EC</b>	<b>0.002</b>	<b>SOA</b>	<b>0.003</b>	
Ext. coefficient				0.6	10	1		3*†(RH)	4	3*†(RH)	

<sup>1</sup>Assumed nitrate comprises all of the non-sulfate inorganic CPM fractions. Sulfate and nitrate have the same extinction efficiency (3.0) and the same dependence on relative humidity, and thus in terms of modeling for visibility using the CALPUFF model, t

<sup>2</sup>the elemental carbon PM<sub>2.5</sub> emissions are assumed to be broken down into the particle size ranges 0 - 0.625 µm, 0.625 - 1.0 µm, 1.0 - 1.25 µm, and 1.25 - 2.5 µm in a fashion similar to the non-carbon PM<sub>2.5</sub> emissions

<sup>4</sup>the organic CPM, sulfate CPM and non-sulfate CPM emissions are assumed to be equally distributed in the particle size ranges of 0 to 0.625 µm and 0.625 to 1.0 µm

Lime Kiln With Wet Scrubber

	total	filterable	condensable	filterable		condensable split		
				PM <sub>10</sub>	PM <sub>2.5</sub>	H <sub>2</sub> SO <sub>4</sub>	inorganic non-sulfate	organic
%		84.8%	15.2%	84.7%	76.8%	58.2%	33.5%	8.3%
(lb/ton CaO)	<b>1.02</b>	<b>0.86</b>	<b>0.16</b>	<b>0.731</b>	<b>0.663</b>	<b>0.090</b>	<b>0.052</b>	<b>0.013</b>

FILTERABLE				CONDENSABLE				
CALPUFF Code	Diameter (µm)	filterable (% of PM)	filterable (lb/ton CaO)	fine filterable <sup>2</sup>		organic condensable <sup>3</sup> (lb/ton CaO)	non-sulfate inorganic condensable <sup>3</sup> (lb/ton CaO)	Diameter (µm)
				inorganic - 96.0% of PM <sub>2.5</sub> filterable (lb/ton CaO)	elemental carbon - 4.0% of PM <sub>2.5</sub> filterable (lb/ton CaO)			
coarse (42.4%)	6.00 - 10.00 2.50-6.00	0.3% 7.6%	0.003 0.065	coarse filterable inorganic (lb/ton CaO)				6.00 - 10.00 2.50-6.00
fine (57.6%)	1.25-2.50	8.8%	0.076		inorganic - 96.0% of PM <sub>2.5</sub> filterable (lb/ton CaO)			1.25-2.50
	1.00-1.25	4.9%	0.042					1.00-1.25
	0.625-1.00	19.7%	0.170					0.625-1.00
	0.50-0.625	43.4%	0.375					0.50-0.625
total		<b>84.7%</b>	<b>0.731</b>	<b>0.068</b> PMC	<b>0.637</b> SOIL	<b>0.0265</b> EC	<b>0.013</b> SOA	<b>0.052</b> NO <sub>3</sub> <sup>1</sup>
Ext. coefficient				0.6	1	10	4	3*(RH)

<sup>1</sup> Assumed nitrate comprises all of the non-sulfate inorganic CPM fractions. Sulfate and nitrate have the same extinction efficiency (3.0) and the same dependence on relative humidity, and thus in terms of modeling for visibility using the CALPUFF model, t

<sup>2</sup> the elemental carbon PM<sub>2.5</sub> emissions are assumed to be broken down into the particle size ranges 0 - 0.625 µm, 0.625 - 1.0 µm, 1.0 - 1.25 µm, and 1.25 - 2.5 µm in a fashion similar to the non-carbon PM<sub>2.5</sub> emissions

<sup>3</sup> the organic CPM, sulfate CPM and non-sulfate CPM emissions are assumed to be equally distributed in the particle size ranges of 0 to 0.625 µm and 0.625 to 1.0 µm

2003 PTPC PM Test Results for Lime Kiln with Wet Scrubber

PTPC Test Results									
	gr/dscf	dscf/min	min	lb PM	ADTP/D	T CaO	lb PM/T	CaO	
1/3/03	0.0311	17,500	1,440	112	615.8	169		0.661	
4/3/03	0.0592	19,700	1,440	240	664.1	183		1.314	
7/2/03	0.0334	15,900	1,440	109	646.2	178		0.614	
10/17/03	0.0389	22,300	842	104	255.7	70		1.484	

Lime Kiln With Wet Scrubber

	total	filterable	condensable	condensable split		
				filterable	inorganic	organic
		PM <sub>10</sub>	PM <sub>2.5</sub>	H <sub>2</sub> SO <sub>4</sub>	non-sulfate	organic
%		81.6%	18.4%	58.2%	33.5%	8.3%
(lb/ton CaO)	<b>0.84</b>	<b>0.69</b>	<b>0.16</b>	<b>0.090</b>	<b>0.052</b>	<b>0.013</b>

	FILTERABLE						CONDENSABLE					
	CALPUFF Code	Diameter (µm)	filterable (% of PM)	filterable (lb/ton CaO)	coarse filterable inorganic (lb/ton CaO)	inorganic - 96.0% of PM <sub>2.5</sub> filterable (lb/ton CaO)	fine filterable <sup>2</sup>	elemental carbon - 4.0% of PM <sub>2.5</sub> filterable (lb/ton CaO)	H <sub>2</sub> SO <sub>4</sub> <sup>3</sup> (lb/ton CaO)	organic condensable <sup>3</sup> (lb/ton CaO)	non-sulfate inorganic condensable <sup>3</sup> (lb/ton CaO)	Diameter (µm)
coarse (42.4%)	PM800	6.00 - 10.00	0.3%	0.002	<b>0.002</b>							6.00 - 10.00
	PM425	2.50-6.00	7.6%	0.052	<b>0.052</b>							2.50-6.00
fine (57.6%)	PM187	1.25-2.50	8.8%	0.060		<b>0.058</b>	<b>0.00242</b>					1.25-2.50
	PM112	1.00-1.25	4.9%	0.034		<b>0.032</b>	<b>0.00134</b>	<b>0.045</b>	<b>0.006</b>	<b>0.026</b>		1.00-1.25
	PM081	0.625-1.00	19.7%	0.135		<b>0.130</b>	<b>0.00541</b>	<b>0.045</b>	<b>0.006</b>	<b>0.026</b>		0.625-1.00
	PM056	0.50-0.625	43.4%	0.298		<b>0.287</b>	<b>0.01194</b>	<b>0.045</b>	<b>0.006</b>	<b>0.026</b>		0.50-0.625
total			<b>84.7%</b>	<b>0.582</b>	<b>0.054</b>	<b>0.507</b>	<b>0.0211</b>	<b>0.090</b>	<b>0.013</b>	<b>0.052</b>		
Ext. coefficient					0.6	1	10	3*(RH)	4	3*(RH)		

<sup>1</sup>Assumed nitrate comprises all of the non-sulfate inorganic CPM fractions. Sulfate and nitrate have the same extinction efficiency (3.0) and the same dependence on relative humidity, and thus in terms of modeling for visibility using the CALPUFF model, t

<sup>2</sup>the elemental carbon PM<sub>2.5</sub> emissions are assumed to be broken down into the particle size ranges 0 - 0.625 µm, 0.625 - 1.0 µm, 1.0 - 1.25 µm, and 1.25 - 2.5 µm in a fashion similar to the non-carbon PM<sub>2.5</sub> emissions

<sup>3</sup>the organic CPM, sulfate CPM and non-sulfate CPM emissions are assumed to be equally distributed in the particle size ranges of 0 to 0.625 µm and 0.625 to 1.0 µm

2004 PTPC PM Test Results for Lime Kiln with Wet Scrubber

PTPC Test Results									
	gr/dscf	dscf/min	min	lb PM	ADTP/D	T CaO	lb PM/T	CaO	
3/8/04	0.0301	17,700	1,440	109	615.8	169		0.646	
4/26/04	0.0480	15,500	1,298	138	615.8	169		0.815	
9/20/04	0.0705	16,581	1,276	213	615.8	169		1.259	
11/9/04	0.0328	16,300	1,440	110	615.8	169		0.649	

Lime Kiln With Wet Scrubber

	total	filterable condensable		condensable split	
		filterable	condensable	inorganic	organic
(lb/ton CaO)	0.81	PM <sub>10</sub>	H <sub>2</sub> SO <sub>4</sub>	PM <sub>2.5</sub>	0.013
%	80.9%	84.7%	58.2%	33.5%	8.3%
	0.65	0.555	0.090	0.052	0.013

CONDENSABLE								
CALPUFF Code	Diameter (µm)	filterable (% of PM)	fine filterable <sup>2</sup>		H <sub>2</sub> SO <sub>4</sub> <sup>3</sup> (lb/ton CaO)	organic condensable <sup>3</sup> (lb/ton CaO)	non-sulfate inorganic condensable <sup>3</sup> (lb/ton CaO)	Diameter (µm)
			inorganic - 96.0% of PM <sub>2.5</sub> filterable (lb/ton CaO)	elemental carbon - 4.0% of PM <sub>2.5</sub> filterable (lb/ton CaO)				
coarse (42.4%)	6.00 - 10.00	0.3%	0.002					6.00 - 10.00
	2.50-6.00	7.6%	0.049					2.50-6.00
	1.25-2.50	8.8%	0.058	0.055				1.25-2.50
	1.00-1.25	4.9%	0.032	0.031	0.045	0.006	0.026	1.00-1.25
	0.625-1.00	19.7%	0.129	0.124	0.045	0.006	0.026	0.625-1.00
	0.50-0.625	43.4%	0.285	0.273				0.50-0.625
total		84.7%	0.555	0.483	0.090	0.013	0.052	
				SOIL	H <sub>2</sub> SO <sub>4</sub>	SOA	NO <sub>3</sub> <sup>1</sup>	
Ext. coefficient			0.6	1	3*(RH)	4	3*(RH)	

<sup>1</sup> Assumed nitrate comprises all of the non-sulfate inorganic CPM fractions. Sulfate and nitrate have the same extinction efficiency (3.0) and the same dependence on relative humidity, and thus in terms of modeling for visibility using the CALPUFF model, t

<sup>2</sup> the elemental carbon PM<sub>2.5</sub> emissions are assumed to be broken down into the particle size ranges 0 - 0.625 µm, 0.625 - 1.0 µm, 1.0 - 1.25 µm, and 1.25 - 2.5 µm in a fashion similar to the non-carbon PM<sub>2.5</sub> emissions

<sup>3</sup> the organic CPM, sulfate CPM and non-sulfate CPM emissions are assumed to be equally distributed in the particle size ranges of 0 to 0.625 µm and 0.625 to 1.0 µm

2005 PTPC PM Test Results for Lime Kiln with Wet Scrubber

PTPC Test Results									
	gr/dscf	dscf/min	min	lb PM	ADTP/D	T CaO	lb PM/T	CaO	
1/27/05	0.0334	16,200	1,440	111	615.8	169	0.656		
5/24/05	0.0237	13,900	1,440	68	664.1	183	0.371		
7/14/05	0.0395	17,600	1,440	143	646.2	178	0.804		
12/8/05	0.0282	17,900	1,371	99	255.7	70	1.408		

**NCASI PM EMISSION FACTOR GUIDANCE**

# Particulate Emissions Data for Pulp and Paper Industry-Specific Sources

Revised October 27, 2006

*This document was originally distributed as an attachment to NCASI Corporate Correspondent Memorandum No. 06-021 on August 25, 2006. Since that time, NCASI has acquired data for the elemental carbon component of filterable particulate matter emitted by kraft recovery furnaces. This document has been revised to reflect these new data, and the changes are highlighted in yellow.*

This material has been prepared to assist mills which are using the CALPUFF model to assess the visibility impacts of their kraft pulp mill sources. It contains data on particulate emissions from the major sources at kraft pulp mills, including smelt dissolving tanks, lime kilns, and recovery furnaces. Boilers are not addressed since EPA AP-42 emission factors are considered the best source for these sources. The EPA AP-42 particulate emission factors for coal-fired, oil-fired, gas-fired and wood-fired boilers are also presented in NCASI Technical Bulletin No. 884 (NCASI 2004).

The CALPUFF model requires as input emission rates of filterable and condensable particles in different size distribution ranges. Over the years, NCASI has conducted studies at a number of kraft mill sources to characterize their PM and CPM (condensable particulate matter) emissions. These and other industry generated data have been compiled in NCASI Technical Bulletin No. 884 (NCASI 2004). The CALPUFF model, however, requires input of emission rates of particles in size ranges which are more detailed than what is generally measured. Consequently, in this document, the industry and NCASI data have been combined with the detailed size distribution data in AP-42 to provide data suitable for CALPUFF modeling for kraft recovery furnaces, lime kilns, and smelt dissolving tanks. The elemental carbon content data from EPA's CMAQ (Community Multi-Scale Air Quality) data base have also been included in this document.

In reviewing and using these data it should be noted that CPM emissions comprise an organic and an inorganic fraction. The inorganic fraction of CPM may consist of sulfates, nitrates, and soil (inert material presumably from passing of otherwise filterable PM material through the filter). It has been suggested that as a worst case visibility impact analysis, the non-sulfate fraction of inorganic CPM may be treated as nitrate, which has the same extinction coefficient of 3 as sulfate. However, there is little evidence that nitric acid or hygroscopic ammonium nitrate is present in CPM. Thus, caution should be exercised in assuming that all the non-sulfate inorganic CPM is nitrate.

To assist mills in using their own data for input into CALPUFF, NCASI has developed a companion spreadsheet, which has been posted on the NCASI website at <http://www.ncasi.org/support/downloads/Detail.aspx?id=37>. (A user name and password are required for access.) The spreadsheet allows facilities to input their site-specific PM and, if available, PM<sub>10</sub>, PM<sub>2.5</sub> and CPM data to the different size fractions for input into CALPUFF. *Note: This spreadsheet has been updated to reflect the new information on elemental carbon fo kraft recovery furnaces.*

## Smelt Dissolving Tanks

The emission data for smelt dissolving tanks were obtained from NCASI Technical Bulletin Nos. 884 (NCASI 2004) and 898 (NCASI 2005). These data are summarized in Table 1. All smelt dissolving tanks (SDTs) in this data set had wet particulate control devices, and thus "wet" stacks. Wet stacks are not amenable to be tested for PM<sub>10</sub>, PM<sub>2.5</sub> and condensible PM (CPM) by the traditional EPA Methods 201A (PM<sub>10</sub>), modified 201A (PM<sub>2.5</sub>), CTM 039 (PM<sub>10</sub>, PM<sub>2.5</sub>) and CTM 040 (PM<sub>10</sub>, PM<sub>2.5</sub>), which are designed for stacks following dry PM control devices. Thus far, the only PM<sub>10</sub>, PM<sub>2.5</sub> and CPM emission data for SDTs with wet stacks have been obtained by O'Connor and Geneste (2003) using a modified dilution tunnel method. O'Connor and Geneste quantified total PM<sub>10</sub> and PM<sub>2.5</sub> emissions from seven Canadian smelt dissolving tanks with wet stacks. They determined the filterable and condensible

fractions of total PM<sub>10</sub> and PM<sub>2.5</sub> emissions by heating the filters to 120°C and determining weight loss. The portion remaining after heating was assumed to be the filterable material and the portion lost was assumed to equal the condensible portion of the samples

Table 1 is a summary of the PM data for smelt dissolving tanks. The detailed data are presented in Table A1 of Appendix A. The filterable PM data in Table 1 were obtained from combining the data set of 36 sources listed in NCASI Technical Bulletin No. 884 (NCASI 2004), Table A15c, and the data set of 6 sources listed in NCASI Technical Bulletin No. 898 (NCASI 2005). The data for PM<sub>10</sub> and PM<sub>2.5</sub> emissions, which are presented as a percentage of the filterable PM, correspond to the eight Canadian SDTs reported by O'Connor and Geneste (2003) after subtracting 19% attributed to CPM (see NCASI Technical Bulletin No. 884, Table A15d).

The total CPM data in Table 1 were obtained from NCASI tests (3 units) and mill tests (3 units), both of which are summarized in NCASI Technical Bulletin No. 898 (NCASI 2005). Organic and inorganic (water soluble) CPM fractions were also determined in emissions from these six units. Sulfate CPM fractions were determined in three of the six units. Total CPM data for two other units were available in NCASI files. CPM emissions for eight Canadian mill SDTs were also estimated by O'Connor and Geneste (2003) using the modified dilution tunnel method. However, these emissions were found to be consistently much higher than the corresponding emissions from U.S. SDT vents by as much as one to two orders of magnitude. Use of foul or dirty condensates to make weak wash used as scrubbing solution on the SDTs which in turn may have contained elevated levels of organics and ammonia is suspected to be the cause of this large difference. Consequently, the Canadian data were not used for estimating averages of total SDT CPM emissions in Table 1.

**Table 1.** Smelt Tank Data Summary

Parameter	Measurement Method	No. of Sources	Range	Mean	Mean
			(lb/ton BLS)		Percent of PM or CPM
PM	EPA Method 5	42	0.03 - 0.64	0.148	
PM <sub>10</sub>	Dilution Tunnel	7			81.9 <sup>1</sup>
PM <sub>2.5</sub>	Dilution Tunnel	7			72.6 <sup>1</sup>
CPM – Total	EPA Method 202	8	0.002 - 0.015	0.0074	
CPM – Organic		6			27.8 <sup>2</sup>
CPM Inorganic - Sulfate (as H <sub>2</sub> SO <sub>4</sub> )		3			27.3 <sup>2</sup>
CPM Inorganic – non-sulfate <sup>3</sup>		6			44.9 <sup>2</sup>

<sup>1</sup>filterable PM<sub>10</sub> and PM<sub>2.5</sub> values expressed as percent of filterable PM values; <sup>2</sup>organic and inorganic (sulfate and non-sulfate) CPM values expressed as percent of total CPM values; <sup>3</sup>Nitrate may comprise some or all of the non-sulfate inorganic CPM fractions. As a conservative measure, the non-sulfate portion of inorganic CPM may be assumed to be sulfate. Sulfate and nitrate have the same extinction efficiency (3.0) and the same dependence on relative humidity, and thus in terms of modeling for visibility using the CALPUFF model, they will behave the same way. This assumption is conservative since in reality some of the nitrate may become nitric acid in the atmosphere, depending on temperature, relative humidity and availability of ammonia. However, as a first step, the assumption of all inorganic condensable PM as sulfate should be sufficient. Primary NO<sub>3</sub> should not be categorized as soil, because soil is non-hygroscopic with lower extinction efficiency (1.0). If the assumption of all inorganic CPM as sulfate proves to be too conservative, it may be possible to conduct tests with the model to explore whether the NO<sub>3</sub> can be properly entered as a primary (emitted) pollutant.

## Recovery Furnaces

The recovery furnace data were obtained from NCASI Technical Bulletins Nos. 852 (NCASI 2002) and 884 (NCASI 2004). These are summarized in Table 2. All of the recovery furnaces in this data set use electrostatic precipitators (ESP) for particulate matter emissions control. In NCASI Technical Bulletins No. 852 and 884, the total PM data for the data sets where PM<sub>10</sub> and PM<sub>2.5</sub> were also measured were obtained by using an in-stack filter. The total PM values in these tests, thus, are similar to what would be obtained if an EPA Method 17 train was used. However, in Subpart BB, kraft mills subject to NSPS are required to add 0.004 gr/dscf to the results of in-stack Method 17 when the latter is used as an alternative to EPA Method 5. Thus, in order to estimate PM<sub>10</sub> and PM<sub>2.5</sub> fractions of Method 5-derived PM values, 0.004 gr/dscf was added to the total PM values obtained with the EPA CTM-40 train. For example, if a run gave 0.020, 0.025 and 0.036 gr/dscf for PM<sub>2.5</sub>, PM<sub>10</sub> and total PM, respectively, the total PM value was adjusted upwards to 0.036 + 0.004 or 0.040 gr/dscf. The PM<sub>2.5</sub> would then be  $0.020/0.040 \times 100 = 50$  percent of PM Method 5 and PM<sub>10</sub> would be  $0.0250/0.040 \times 100 = 62$  percent of PM Method 5. If such adjustments to total PM values were not made, the values of PM<sub>2.5</sub> and PM<sub>10</sub> as percent of total PM would have been higher and these are shown in the table footnote.

The PM data for DCE recovery furnaces shown in Table 2 are from the 23 sources listed in NCASI Technical Bulletin No. 884 (NCASI 2004), Table A11c. Detailed data are presented in Table A2 of Appendix A. The PM<sub>10</sub> and PM<sub>2.5</sub> data for the DCE recovery furnaces are from the 4 DCE sources listed in Technical Bulletin No. 884 (NCASI 2004), Table A11d. Total CPM, organic CPM, inorganic CPM (water soluble) and sulfate CPM data were available from two sources listed in Technical Bulletins No. 852 (NCASI 2002). Data for total CPM, organic CPM, and inorganic CPM emissions from two DCE recovery furnaces and sulfate emissions from one DCE furnace generated in an ongoing unpublished NCASI study are also included in Table 2.

The PM data for the NDCE recovery furnaces shown in Table 2 are from the 20 sources listed in NCASI Technical Bulletin No. 884 (NCASI 2004), Table A12b. Detailed data are presented in Table A3 of Appendix A. The PM<sub>10</sub> and PM<sub>2.5</sub> data are from the 10 NDCE sources listed in Technical Bulletin No. 884 (NCASI 2004), Table A12c for which both PM<sub>10</sub> and PM<sub>2.5</sub> data were available. The NDCE furnace CPM data are from 6 sources listed in Technical Bulletin No. 884 (NCASI 2004). The organic CPM, inorganic CPM (water soluble) and sulfate CPM data are from two sources listed in Technical Bulletin No. 852 (NCASI 2002). Data for total CPM, organic CPM, and inorganic CPM emissions from one NDCE recovery furnace generated in an ongoing unpublished NCASI study are also included in Table 2.

**Table 2.** Recovery Furnace Data Summary

<b>Kraft DCE Recovery Furnace</b>					
Parameter	Measurement Method	No. of Sources	Range (lb/ton BLS)	Mean	Mean Percent of PM or CPM
PM	EPA Method 5	23	0.07 - 2.58	0.74	
PM <sub>10</sub>	EPA CTM-040	4			56.7 <sup>1</sup>
PM <sub>2.5</sub>	EPA CTM-040	4			40.2 <sup>1</sup>
CPM – Total	EPA Method 202	4	0.208 – 0.678	0.38	
CPM - Organic		4			7.4 <sup>2</sup>
CPM Inorganic - Sulfate (as H <sub>2</sub> SO <sub>4</sub> )		3			36.0 <sup>2</sup>
CPM Inorganic – non-sulfate <sup>3</sup>		3			56.6 <sup>2</sup>
<b>Kraft NDCE Recovery Furnace</b>					
Parameter	Measurement Method	No. of Sources	Range (lb/ton BLS)	Mean	Mean Percent of PM or CPM
PM	EPA Method 5	20	0.02 - 3.50	0.65	
PM <sub>10</sub>	EPA CTM-040	10			50.2 <sup>1</sup>
PM <sub>2.5</sub>	EPA CTM-040	10			37.2 <sup>1</sup>
CPM – Total	EPA Method 202	7	0.05 - 0.15	0.09	
CPM – Organic		3			16.5 <sup>2</sup>
CPM Inorganic - Sulfate (as H <sub>2</sub> SO <sub>4</sub> )		3			35.2 <sup>2</sup>
CPM Inorganic – non-sulfate <sup>3</sup>		1			48.3 <sup>2</sup>

<sup>1</sup>filterable PM<sub>10</sub> and PM<sub>2.5</sub> values expressed as percent of filterable PM values – note that PM<sub>10</sub> and PM<sub>2.5</sub> were calculated as percent of total PM by adding 0.004 gr/dscf to total PM values; average PM<sub>10</sub> and PM<sub>2.5</sub> values without such adjustment would be higher (75.0% and 52.9%, respectively, for DCE furnaces and 67.8% and 51.0%, respectively, for NDCE furnaces); <sup>2</sup>organic and inorganic (sulfate and non-sulfate) CPM values expressed as percent of total CPM values; <sup>3</sup>see footnote 3 in Table 1

## Lime Kilns

The lime kiln data were obtained from NCASI Technical Bulletins Nos. 852 (NCASI 2002), 884 (NCASI 2004), and 898 (NCASI 2005) and are summarized in Table 3. Detailed data are presented in Table A4 of Appendix A. The emissions data are separated by control device type. The majority of lime kilns in this data set used wet control devices for particulate control. Two of the lime kilns used an ESP for particulate control, followed by a wet scrubber for SO<sub>2</sub> control. The remainder used an ESP for particulate control. Once again, as for SDTs, wet stacks are not amenable to be tested for PM<sub>10</sub>, PM<sub>2.5</sub> and CPM by the traditional EPA Methods 201A (PM<sub>10</sub>), modified 201A (PM<sub>2.5</sub>), CTM 039 (PM<sub>10</sub>, PM<sub>2.5</sub>) and CTM 040 (PM<sub>10</sub>, PM<sub>2.5</sub>), which are designed for stacks following dry PM control devices. O'Connor and Geneste (2003) used a modified dilution tunnel method to quantify total PM<sub>10</sub> and PM<sub>2.5</sub> emissions from six Canadian kraft lime kilns with wet scrubbers.

The filterable PM data for lime kilns using wet control devices are from 31 sources listed in NCASI Technical Bulletin No. 884 (NCASI 2004), Table A13c. The data for PM<sub>10</sub> and PM<sub>2.5</sub> emissions for lime kilns using wet control devices are presented as a percentage fraction of the total PM corresponding to the six Canadian lime kilns tested by O'Connor and Geneste (2003) (see NCASI Technical Bulletin No. 884, Table A13d) for which both PM<sub>10</sub> and PM<sub>2.5</sub> data were obtained. In the O'Connor and Geneste (2003) study, lime kiln total PM<sub>10</sub> and PM<sub>2.5</sub> emissions were measured using a dilution tunnel followed by size-specific cyclones and quartz filters. To determine the filterable and condensible fractions of total PM<sub>10</sub> and PM<sub>2.5</sub> emissions, the filters were heated at 120°C to determine weight loss. The portion remaining after heating was assumed to be the filterable fraction and the portion lost was assumed to equal the condensible fraction of the samples.

The CPM data for lime kilns with wet scrubbers in Table 3 were obtained from NCASI tests (4 units) reported in NCASI Technical Bulletin No. 898 (NCASI 2005) and from the Canadian study (seven kilns) summarized in Technical Bulletin No. 884 (NCASI 2004). The organic CPM, inorganic CPM and sulfate CPM data are from two to three sources listed in Technical Bulletin No. 898 (NCASI 2005).

All of the PM and CPM data for lime kilns using an ESP followed by a wet control device are from two sources listed in NCASI Technical Bulletin No. 898 (NCASI 2005). Unfortunately, no PM<sub>10</sub> and PM<sub>2.5</sub> data are available for such sources. However, if one assumes that the wet scrubber played no role in removing or contributing to PM emissions from such sources, which is not an unreasonable assumption, one could use the results for lime kilns using ESPs to estimate the PM<sub>10</sub> and PM<sub>2.5</sub> fractions of PM. Total CPM emissions data for two kilns, and organic CPM, inorganic CPM and sulfate CPM emissions for one kiln are obtained from Technical Bulletin No. 898 (NCASI 2005).

The filterable PM data for lime kilns using an ESP alone are from the 7 sources listed in NCASI Technical Bulletin No. 884 (NCASI 2004), Table A13c. The PM<sub>10</sub> and PM<sub>2.5</sub> data are from the 6 sources listed in Technical Bulletin No. 884 (NCASI 2004), Table A13d. These data are also presented as a percentage fraction of the filterable PM corresponding to the six lime kilns tested. As discussed earlier for the recovery furnaces, the in-stack total PM data for kilns with ESPs were adjusted by 0.004 gr/dscf to obtain estimated total Method 5 PM values. These adjusted PM values were used to estimate PM<sub>2.5</sub> and PM<sub>10</sub> values at percents of EPA Method 5 values. Table 3 also shows the estimated percentages if the total PM value was not adjusted. The CPM data are from 4 sources that are summarized in NCASI Technical Bulletin No. 852 (NCASI 2002). The organic CPM, organic CPM (water soluble) and sulfate CPM data are from two to three sources listed in Technical Bulletins No. 852 (NCASI 2002).

**Table 3. Lime Kiln Data Summary**

<b>Lime Kilns with Wet Particulate Control Devices</b>					
Parameter	Measurement Method	No. of Sources	Range (lb/ton CaO)	Mean	Mean Percent of PM or CPM
PM	EPA Method 5	31	0.35 – 5.34	1.59	
PM <sub>10</sub>	Dilution Tunnel	6			84.7 <sup>1</sup>
PM <sub>2.5</sub>	Dilution Tunnel	6			76.8 <sup>1</sup>
CPM – Total	EPA Method 202	11	0.020 - 0.453	0.155	
CPM - Organic		3			8.3 <sup>2</sup>
CPM Inorganic - Sulfate (as H <sub>2</sub> SO <sub>4</sub> )		2			58.2 <sup>2</sup>
CPM Inorganic – non-sulfate <sup>4</sup>		3			33.5 <sup>2</sup>
<b>Lime Kilns with a Dry ESP for Particulate Control Followed by a Wet Scrubber</b>					
Parameter	Measurement Method	No. of Sources	Range (lb/ton CaO)	Mean	Mean Percent of PM or CPM
PM	EPA Method 5	2	0.043 - 0.053	0.048	
PM <sub>10</sub>					No Data <sup>3</sup>
PM <sub>2.5</sub>					No Data <sup>3</sup>
CPM – Total	EPA Method 202	2	0.070 - 0.161	0.116	
CPM - Organic		1			54.9 <sup>2</sup>
CPM Inorganic - Sulfate (as H <sub>2</sub> SO <sub>4</sub> )		1			45.1 <sup>2</sup>
CPM Inorganic – non-sulfate <sup>4</sup>		1			0.0 <sup>2</sup>
<b>Lime Kilns with a Dry ESP for Particulate Control</b>					
Parameter	Measurement Method	No. of Sources	Range (lb/ton CaO)	Mean	Mean Percent of PM
PM	EPA Method 5	7	0.024 - 0.525	0.175	
PM <sub>10</sub>	EPA CTM-040	6			30.2 <sup>1</sup>
PM <sub>2.5</sub>	EPA CTM-040	6			11.0 <sup>1</sup>
CPM – Total	EPA Method 202	4	0.057 - 0.198	0.152	
CPM - Organic		3			31.5 <sup>2</sup>
CPM Inorganic - Sulfate (as H <sub>2</sub> SO <sub>4</sub> )		2			20.8 <sup>2</sup>
CPM Inorganic – non-sulfate <sup>4</sup>		3			47.7 <sup>2</sup>

<sup>1</sup>filterable PM<sub>10</sub> and PM<sub>2.5</sub> values expressed as percent of filterable PM values – note that for lime kilns with ESPs, PM<sub>10</sub> and PM<sub>2.5</sub> were calculated as percent of total PM by adding 0.004 gr/dscf to total PM values; average PM<sub>10</sub> and PM<sub>2.5</sub> values without such adjustment would be higher (64.2% and 23.6%, respectively); <sup>2</sup>organic and inorganic (sulfate and non-sulfate) CPM values expressed as percent of total CPM values; <sup>3</sup>may be estimated using the fractions for lime kilns with dry ESPs in Table 3; <sup>4</sup>see footnote 3 in Table 1

### Estimating PM Emissions in Particle Size Ranges

Table 4 reproduces the representative particle size distributions for PM emissions from various kraft recovery sources (smelt tanks, lime kilns and recovery furnaces) as provided in Chapter 10.2 (Chemical Wood Pulping) of EPA's AP-42 document. Using these distributions and the mean emissions for PM<sub>10</sub> and PM<sub>2.5</sub> as percent of total PM shown in Table 1 (smelt dissolving tanks), Table 2 (kraft recovery furnaces) and Table 3 (lime kilns), further breakdowns of PM<sub>10</sub> and PM<sub>2.5</sub> emissions can be developed for the particle size ranges 0 to 0.625 μm, 0.625 to 1.0 μm, 1.0 to 1.25 μm, 1.25 to 2.5 μm, 2.5 to 6.0 μm, and 6.0 to 10.0 μm and these are also shown in Table 4. Note that if mill-specific measurements for PM<sub>10</sub> and/or PM<sub>2.5</sub> were used instead, this would result in slightly different estimates for the breakdowns (as explained later).

In addition to the various size contents of filterable PM, visibility impact modeling also requires information on the elemental carbon content of PM<sub>2.5</sub>. Recent NCASI data collected at a DCE furnace show that elemental carbon constituted only 0.025% of the filterable PM<sub>2.5</sub> emissions. In the absence of other information, it may be appropriate to also apply this elemental carbon content value to non-DCE furnaces. For lime kilns and smelt dissolving tanks, in EPA's CMAQ (Community Multi-scale Air Quality) database, the elemental carbon fraction of total PM<sub>2.5</sub> (filterable PM<sub>2.5</sub> + CPM) was reported as 0.0153, and the filterable, non-elemental carbon fraction of total PM<sub>2.5</sub> was reported as 0.3699. Thus, the elemental C fraction of filterable PM<sub>2.5</sub> for lime kilns and smelt dissolving tanks is 0.0397 (0.0153 / {0.0153 + 0.3699}), or about 4%.

**Table 4.** Breakdown of PM Emissions from Kraft Recovery Sources – from Chapter 10.2 of AP-42

PM size, μm	Smelt Tank <sup>1a</sup>	Smelt Tank <sup>1b</sup>	Lime Kiln <sup>2</sup>	Lime Kiln <sup>3</sup>	DCE Furnace <sup>4</sup>	NDCE Furnace <sup>4</sup>
	Cumulative Mass % ≤ stated size					
15	89.9	95.3	98.9	91.2	no data	78.8
10	89.5	95.3	98.3	88.5	no data	74.8
6	88.4	94.3	98.2	86.5	68.2	71.9
2.5	81.3	85.2	96.0	83.0	53.8	67.3
1.25	63.5	63.8	85.0	70.2	40.5	51.3
1	54.7	54.2	78.9	62.9	34.2	42.4
0.625	38.7	34.2	54.3	46.9	22.2	29.6
Total	100.0	100.0	100.0	100.0	100.0	100.0
PM <sub>6.0-10.0</sub> , as % of PM <sup>6</sup>	1.2%	0.9%	0.3%	7.0%	2.7% <sup>5</sup>	5.0%
PM <sub>2.5-6.0</sub> , as % of PM <sup>6</sup>	8.1%	8.4%	7.6%	12.2%	13.8%	8.0%
PM <sub>1.25-2.5</sub> , as % of PM <sup>6</sup>	15.9%	18.2%	8.8%	1.7%	9.9%	8.8%
PM <sub>1.0-1.25</sub> , as % of PM <sup>6</sup>	7.9%	8.2%	4.9%	1.0%	4.7%	4.9%
PM <sub>0.625-1.0</sub> , as % of PM <sup>6</sup>	14.3%	17.0%	19.7%	2.1%	9.0%	7.1%
PM <sub>0.625</sub> , as % of PM <sup>6</sup>	34.6%	29.1%	43.4%	6.2%	16.6%	16.4%

<sup>1a</sup>smelt dissolving tank vent with venturi scrubber; <sup>1b</sup>smelt dissolving tank vent with packed tower; <sup>2</sup>lime kiln with venturi scrubber; <sup>3</sup>lime kiln with ESP; <sup>4</sup>kraft recovery furnace with ESP; <sup>5</sup>cumulative mass % for PM<sub>10</sub> not available; assumed same ratio of PM<sub>10</sub> to PM<sub>6.0</sub> as for NDCE furnaces; <sup>6</sup>these PM distributions (expressed as percent of total PM) are estimated based on the mean PM<sub>10</sub> and PM<sub>2.5</sub> emissions shown in Tables 1, 2 and 3 (as % of total PM); note that they would be different if mill-specific PM<sub>10</sub> and PM<sub>2.5</sub> measurements were used instead – see section on Excel Spreadsheet for further explanation

**Sample Calculation** – The following calculations show how a mill which has Method 5 PM data may use the information contained in this document to estimate the emission rates needed for BART modeling.

**Known:** The total PM emissions from a DCE kraft recovery furnace are 1.0 lb/ton BLS.

*From Table 2, the filterable  $PM_{10}$  emissions from this furnace =  $0.567 \times 1.0 = 0.567$  lb/tbls*

*and the filterable  $PM_{2.5}$  emissions =  $0.402 \times 1.0 = 0.402$  lb/tbls*

*Thus, the  $PM_{coarse}$  emissions =  $PM_{10} - PM_{2.5} = 0.567 - 0.402 = 0.165$  lb/tbls*

*From Table 4,  $PM_{coarse}$  emissions that are  $PM_{2.5-6.0} = 0.138 \times 1.0 = 0.138$  lb/tbls,*

*and  $PM_{coarse}$  emissions that are  $PM_{6.0-10.0} = 0.027 \times 1.0 = 0.027$  lb/tbls*

*The filterable  $PM_{2.5}$  emissions comprise both elemental carbon and non-elemental carbon emissions. The elemental carbon  $PM_{2.5}$  emissions = 0.025% of total filterable  $PM_{2.5}$  emissions =  $0.00025 \times 0.402 = 0.0001$  lb/tbls*

*The non-elemental carbon filterable  $PM_{2.5}$  emissions = remaining 99.975% of filterable  $PM_{2.5}$  emissions =  $0.99975 \times 0.402 = 0.402$  lb/tbls*

*From Table 4, further contents of the non-carbon filterable  $PM_{2.5}$  emissions are estimated as follows:*

*$PM_{0.625}$  emissions =  $0.99975 \times 0.166 \times 1.0 = 0.166$  lb/tbls*

*$PM_{0.625-1.0}$  emissions =  $0.99975 \times 0.09 \times 1.0 = 0.09$  lb/tbls*

*$PM_{1.0-1.25}$  emissions =  $0.99975 \times 0.047 \times 1.0 = 0.047$  lb/tbls*

*$PM_{1.25-2.5}$  emissions =  $0.99975 \times 0.099 \times 1.0 = 0.099$  lb/tbls*

*and further contents of the elemental carbon  $PM_{2.5}$  emissions are estimated as follows (note- the non-carbon and elemental carbon filterable  $PM_{2.5}$  emissions are assumed to have similar breakdowns):*

*$PM_{0.625}$  emissions =  $0.00025 \times 0.166 \times 1.0 = 0.00004$  lb/tbls*

*$PM_{0.625-1.0}$  emissions =  $0.00025 \times 0.09 \times 1.0 = 0.00002$  lb/tbls*

*$PM_{1.0-1.25}$  emissions =  $0.00025 \times 0.047 \times 1.0 = 0.00001$  lb/tbls*

*$PM_{1.25-2.5}$  emissions =  $0.00025 \times 0.099 \times 1.0 = 0.00001$  lb/tbls*

*From Table 2, the total CPM emissions = 0.38 lb/tbls (note - CPM emissions are independent of PM emissions)*

*Also from Table 2, the organic CPM emissions =  $0.074 \times 0.38 = 0.028$  lb/tbls*

*the sulfate as  $H_2SO_4$  component of inorganic CPM emissions =  $0.36 \times 0.38 = 0.137$  lb/tbls*

*and the rest of the inorganic CPM (non-sulfate) emissions =  $0.38 - 0.028 - 0.137 = 0.215$  lb/tbls*

The calculated emission rates can be input into the CALPUFF model for determining visibility impacts.

### Excel Spreadsheet Example Calculations

NCASI has prepared an excel spreadsheet that carries out the above calculations for all six categories of unit operations shown in Table 4. For a mill that has only PM data for a given unit operation, the spreadsheet estimates all the distributions as shown above using the mean  $PM_{10}$ ,  $PM_{2.5}$ , and CPM values shown in Tables 1, 2 and 3 combined with the PM distributions shown in Table 4. The spreadsheet also

allows a mill to input its own PM<sub>10</sub> and PM<sub>2.5</sub> values, as also its own CPM, organic CPM and inorganic CPM as sulfate (H<sub>2</sub>SO<sub>4</sub>) values. The spreadsheet is available on the NCASI website at <http://www.ncasi.org/support/downloads/Detail.aspx?id=37>. (A user name and password are required for access).

## References

- National Council for Air and Stream Improvement, Inc. (NCASI). 2002. Performance of EPA stack sampling methods for PM<sub>10</sub>, PM<sub>2.5</sub> and condensible particulate matter on sources equipped with electrostatic precipitators. Technical Bulletin No. 852. Research Triangle Park, NC: National Council for Air and Stream Improvement, Inc.
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- . 2005. Condensible particulate matter emissions from sources equipped with wet scrubbers. Technical Bulletin No. 898. Research Triangle Park, NC: National Council for Air and Stream Improvement, Inc.
- . 2006. PM<sub>2.5</sub> and condensible particulate matter emissions from kraft recovery furnaces and power boilers. Technical Bulletin in preparation. Research Triangle Park, NC: National Council for Air and Stream Improvement, Inc.
- O'Connor, B., and Geneste, S. 2003. Development of PM<sub>10</sub> and PM<sub>2.5</sub> stack emission factors for kraft mill smelt dissolving tanks and lime kilns with wet scrubbers. In Proceedings of the PAPTAC Pacwest Conference, Harrison Hot Springs, British Columbia, Canada, May 7-10.

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**Appendix A**

The following tables provide detailed data for the PM emissions from smelt dissolving tanks, lime kilns and kraft recovery furnaces.

**Table A1. Smelt Dissolving Tank Particulate Matter Emissions**

Mill Code	Total In-Stack PM gr/dscf	PM <sub>10</sub>	PM <sub>2.5</sub>	Total CPM lb/t BLS	Organic CPM lb/t BLS % of total		Inorganic CPM			
							Total		SO <sub>4</sub> as H <sub>2</sub> SO <sub>4</sub>	
							lb/t BLS	% of total	lb/t BLS	% of total
		As % of PM								
SDTA	0.0529	99.4%	86.7%	0.0401 <sup>2</sup>						
SDTB	0.1632	96.6%	87.3%	0.1224 <sup>2</sup>						
SDTC	0.1077	68.3%	64.6%	0.0584 <sup>2</sup>						
SDTD	0.0540	62.0%	58.7%	0.0266 <sup>2</sup>						
SDTE	0.0760			0.0306 <sup>2</sup>						
SDTF	0.0160	91.0%	84.3%	0.0114 <sup>2</sup>						
SDTG1	0.4237	70.7%	54.0%	0.2153 <sup>2</sup>						
SDTG2	0.0758	85.2%	72.4%	0.0487 <sup>2</sup>						
Mill A	0.0500			0.0020	0.0005	25.6%	0.0015	74.4%	0.0015	74.9%
Mill B	0.0400			0.0070	0.0018	26.0%	0.0052	74.0%	0.0018	25.5%
Mill C	0.0200			0.0080	0.0018	22.4%	0.0062	77.6%	0.0014	17.0%
Mill F1	0.0200			0.0060	0.0004	6.3%	0.0056	93.7%		
Mill F2	0.0200			0.0060	0.0002	2.9%	0.0058	97.1%		
Mill G	0.0400			0.0150	0.0076	50.4%	0.0074	49.6%		
SDTAD	0.72 lb/hr			0.0140						
SDTAE	0.0387			0.0010						
Mean	0.0799	81.9%	72.6%	0.0074	0.0020	27.8% <sup>1</sup>	0.0053	72.2% <sup>1</sup>	0.0015	27.3% <sup>1</sup>
Number	7	7	7	8 <sup>2</sup>	6		6		3	

<sup>1</sup>The mean % for organic CPM is obtained by dividing the mean organic CPM in lb/t BLS by the mean of the corresponding set of total CPM in lb/t BLS - same for inorganic CPM (total and SO<sub>4</sub> as H<sub>2</sub>SO<sub>4</sub>).

<sup>2</sup>These Canadian mill CPM data were not developed using EPA Method 202; thus only the CPM data generated using M202 for the U.S. mill SDTs (Mills A, B, C, F1, F2, G, AD and AE) were included when estimating the mean. CPM emissions estimated using the modified dilution tunnel method in the Canadian SDT vents appear to be consistently higher than their U.S. counterparts by one to two orders of magnitude. Use of foul or dirty condensates in the Canadian mill SDT scrubbers with high levels of organics and ammonia is suspected.

*Note – italicized entries denote non-detects shown at 1/2 detection limit*

**Table A2.** DCE Kraft Recovery Furnace Particulate Matter Emissions

Mill Code	Total In-Stack PM gr/dscf	PM <sub>10</sub> <sup>1</sup>	PM <sub>2.5</sub> <sup>1</sup>	Total CPM lb/t BLS	Organic CPM		Inorganic CPM			
		As % of PM			lb/t BLS	% of total	Total		SO <sub>4</sub> as H <sub>2</sub> SO <sub>4</sub>	
		lb/t BLS	% of total				lb/t BLS	% of total	lb/t BLS	% of total
B2RF	0.0118	51.3%	34.8%	0.6778	0.0404	6.0%	0.6373	94.0%	0.2428	35.8%
G1RF	0.0034	35.1%	24.3%	0.2080	0.0347	16.7%	0.1733	83.3%	0.0865	41.6%
C1	0.0250	67.2%	46.6%							
C8	0.0800	73.3%	55.1%							
A3RF	0.0061			0.2800	0.0112	4.0%	0.2688	96.0%	0.0860	30.7%
B1RF	0.0254			0.3731	0.0277	7.4%	0.3454	92.6%		
Mean	0.0253	56.7%	40.2%	0.3847	0.0285	7.4% <sup>2</sup>	0.3562	92.6% <sup>2</sup>	0.1384	36.0% <sup>2</sup>
Number	4	4	4	4	4		4		3	

<sup>1</sup>PM<sub>10</sub> and PM<sub>2.5</sub> calculated as percent of total PM by adding 0.004 gr/dscf to total PM value; average PM<sub>10</sub> and PM<sub>2.5</sub> values without such adjustment would be higher (75.0% and 52.9%, respectively); <sup>2</sup>The mean % for organic CPM is obtained by dividing the mean organic CPM in lb/t BLS by the mean of the corresponding set of total CPM in lb/t BLS - same for inorganic CPM (total and SO<sub>4</sub> as H<sub>2</sub>SO<sub>4</sub>).

**Table A3.** NDCE Kraft Recovery Furnace Particulate Matter Emissions

Mill Code	Total In-Stack PM gr/dscf	PM <sub>10</sub> <sup>1</sup>	PM <sub>2.5</sub> <sup>1</sup>	Total CPM lb/t BLS	Organic CPM		Inorganic CPM			
		As % of PM			lb/t BLS	% of total	Total		SO <sub>4</sub> as H <sub>2</sub> SO <sub>4</sub>	
		lb/t BLS	% of total				lb/t BLS	% of total	lb/t BLS	% of total
B3RF	0.0053	28.0%	19.4%	0.0579	0.0062	10.7%	0.0517	89.3%		
E1RF	0.0076	36.2%	29.3%						0.0970	
F1RF	0.0072	37.5%	30.4%	0.0684	0.0189	27.6%	0.0495	72.4%	0.0241	35.2%
RFAB	0.0074			0.0880						
RFAE	0.0023			0.1340						
RFAF	0.0030									
RFAH	0.0130			0.0470						
C1	0.0160	64.1%	34.7%							
C4	0.0634	69.1%	49.3%							
C6a	0.0468	83.0%	53.0%							
C6b	0.0118	70.3%	52.3%							
C11	0.0106	69.6%	59.1%							
C12	0.0033	27.5%	25.1%	0.0780						
C21	0.0162	17.3%	19.7%							
A4RF	0.0203			0.1538	0.0212	13.8%	0.1326	86.2%		
Mean	0.0156	50.2%	37.2%	0.0896	0.0154	16.5% <sup>2</sup>	0.0779	83.5% <sup>2</sup>	0.0605	35.2% <sup>2</sup>
Number	10	10	10	7	3		3		1	

<sup>1</sup>PM<sub>10</sub> and PM<sub>2.5</sub> calculated as percent of total PM by adding 0.004 gr/dscf to total PM value; average PM<sub>10</sub> and PM<sub>2.5</sub> values without such adjustment would be higher (67.8% and 51.0%, respectively); <sup>2</sup>The mean % for organic CPM is obtained by dividing the mean organic CPM in lb/t BLS by the mean of the corresponding set of total CPM in lb/t BLS - same for inorganic CPM (total and SO<sub>4</sub> as H<sub>2</sub>SO<sub>4</sub>).

**RBLC SEARCH RESULTS**

**RBLC Search Results  
Port Townsend Paper Company  
Smelt Dissolving Tank**

RBLC ID	FACILITY NAME	CORPORATE OR COMPANY NAME	PERMIT DATE	PROCESS NAME	FUEL	THRUPUT	THRUPUT UNIT	PROCESS NOTES	POLLUTANT	CONTROL	CTRLDESC	EMISLIMIT1	EMISLIMITUNIT
LA-0155	ST. FRANCISVILLE MILL	CROWN PAPER COMPANY	4/29/2001	SMELT DISSOLVING TANK	68.75		T/H THROUGHPUT IS T/H OF BLS		Particulate Matter (PM)	N	NONE INDICATED UNDER THIS PERMIT	11.69	LB/H
SC-0083	WEYERHAEUSER COMPANY-MARLBORO PAPER MILL	WEYERHAEUSER COMPANY	12/10/2002	SMELT DISSOLVING TANK		4.4	MMLB/D	Throughput is MMLB BLS/DAY	Particulate Matter (PM)	B	SCRUBBER/RECOVERY FURNACE FIRING AND PULP PRODUCTION LIMITS (4.4 MM LB BLS/D AND 1410 ADTBP/D)	0.199	LB/T
AL-0116	GULF STATES PAPER CORPORATION	GULF STATES PAPER CORPORATION	12/10/1997	SMELT DISSOLVING TANK		3.94	MMLB/D BLS		Particulate Matter (PM)	A	WET SCRUBBER AND LOW SULFIDE WATER	0.12	LB/T BLS
SC-0083	WEYERHAEUSER COMPANY-MARLBORO PAPER MILL	WEYERHAEUSER COMPANY	12/10/2002	SMELT DISSOLVING TANK		4.4	MMLB/D	Throughput is MMLB BLS/DAY	Sulfur Dioxide (SO2)	P	RECOVERY FURNACE FIRING RATE AND PULP PRODUCTION LIMITS (4.4 MM LB BLS/D AND 1410 ADTBP/D)	0.05	LB/T
AL-0116	GULF STATES PAPER CORPORATION	GULF STATES PAPER CORPORATION	12/10/1997	SMELT DISSOLVING TANK		3.94	MMLB/D BLS		Sulfur Dioxide (SO2)	A	WET SCRUBBER AND LOW SULFIDE WATER	0.05	LB/T BLS
SC-0083	WEYERHAEUSER COMPANY-MARLBORO PAPER MILL	WEYERHAEUSER COMPANY	12/10/2002	SMELT DISSOLVING TANK		4.4	MMLB/D	Throughput is MMLB BLS/DAY	Sulfur, Total Reduced (TRS)	B	LOW SULFIDE WATER SCRUBBER/RECOVERY FURNACE FIRING RATE AND PULP PRODUCTION RATE (4.4 MM LB BLS/D AND 1410 ADTBP/D) AND PULP PRODUCTION LIMITS	0.03	LB/T
AL-0116	GULF STATES PAPER CORPORATION	GULF STATES PAPER CORPORATION	12/10/1997	SMELT DISSOLVING TANK		3.94	MMLB/D BLS		Sulfur, Total Reduced (TRS)	A	WET SCRUBBER AND LOW SULFIDE WATER	0.033	LB/T BLS
*WA-0303	LONGVIEW FIBRE PAPER AND PACKAGING, INC	LONGVIEW FIBRE PAPER AND PACKAGING, INC	11/1/2006	SMELT DISSOLVING TANK 15		1150	TBLS/D	THROUGHPUT IS AN OPERATIONAL LIMIT	Nitrogen Oxides (NOx)	N		7	T/YR
*WA-0303	LONGVIEW FIBRE PAPER AND PACKAGING, INC	LONGVIEW FIBRE PAPER AND PACKAGING, INC	11/1/2006	SMELT DISSOLVING TANK 15		1150	TBLS/D	THROUGHPUT IS AN OPERATIONAL LIMIT	Particulate Matter (PM)	N		26	T/YR
*WA-0303	LONGVIEW FIBRE PAPER AND PACKAGING, INC	LONGVIEW FIBRE PAPER AND PACKAGING, INC	11/1/2006	SMELT DISSOLVING TANK 15		1150	TBLS/D	THROUGHPUT IS AN OPERATIONAL LIMIT	Sulfur Dioxide (SO2)	N		12	T/YR
*WA-0303	LONGVIEW FIBRE PAPER AND PACKAGING, INC	LONGVIEW FIBRE PAPER AND PACKAGING, INC	11/1/2006	SMELT DISSOLVING TANK 15		1150	TBLS/D	THROUGHPUT IS AN OPERATIONAL LIMIT	Sulfur, Total Reduced (TRS)	N		67	T/YR
*WA-0303	LONGVIEW FIBRE PAPER AND PACKAGING, INC	LONGVIEW FIBRE PAPER AND PACKAGING, INC	11/1/2006	SMELT DISSOLVING TANK 18		1200	T BLS/D		Nitrogen Oxides (NOx)	N		7	T/YR
*WA-0303	LONGVIEW FIBRE PAPER AND PACKAGING, INC	LONGVIEW FIBRE PAPER AND PACKAGING, INC	11/1/2006	SMELT DISSOLVING TANK 18		1200	T BLS/D		Particulate Matter (PM)	N		26	T/YR
*WA-0303	LONGVIEW FIBRE PAPER AND PACKAGING, INC	LONGVIEW FIBRE PAPER AND PACKAGING, INC	11/1/2006	SMELT DISSOLVING TANK 18		1200	T BLS/D		Sulfur Dioxide (SO2)	N		4	T/YR
*WA-0303	LONGVIEW FIBRE PAPER AND PACKAGING, INC	LONGVIEW FIBRE PAPER AND PACKAGING, INC	11/1/2006	SMELT DISSOLVING TANK 18		1200	T BLS/D		Sulfur, Total Reduced (TRS)	N		67	T/YR
*WA-0303	LONGVIEW FIBRE PAPER AND PACKAGING, INC	LONGVIEW FIBRE PAPER AND PACKAGING, INC	11/1/2006	SMELT DISSOLVING TANK 19		2000	T BLS/D	THROUGHPUT IS AN OPERATING LIMIT	Nitrogen Oxides (NOx)	N		11	T/YR
*WA-0303	LONGVIEW FIBRE PAPER AND PACKAGING, INC	LONGVIEW FIBRE PAPER AND PACKAGING, INC	11/1/2006	SMELT DISSOLVING TANK 19		2000	T BLS/D	THROUGHPUT IS AN OPERATING LIMIT	Particulate Matter (PM)	N		44	T/YR
*WA-0303	LONGVIEW FIBRE PAPER AND PACKAGING, INC	LONGVIEW FIBRE PAPER AND PACKAGING, INC	11/1/2006	SMELT DISSOLVING TANK 19		2000	T BLS/D	THROUGHPUT IS AN OPERATING LIMIT	Sulfur Dioxide (SO2)	N		16	T/YR
*WA-0303	LONGVIEW FIBRE PAPER AND PACKAGING, INC	LONGVIEW FIBRE PAPER AND PACKAGING, INC	11/1/2006	SMELT DISSOLVING TANK 19		2000	T BLS/D	THROUGHPUT IS AN OPERATING LIMIT	Sulfur, Total Reduced (TRS)	N		114	T/YR
*WA-0303	LONGVIEW FIBRE PAPER AND PACKAGING, INC	LONGVIEW FIBRE PAPER AND PACKAGING, INC	11/1/2006	SMELT DISSOLVING TANK 22		1950	T BLS/D	THROUGHPUT IS THE OPERATING LIMIT	Nitrogen Oxides (NOx)	N		11	T/YR
*WA-0303	LONGVIEW FIBRE PAPER AND PACKAGING, INC	LONGVIEW FIBRE PAPER AND PACKAGING, INC	11/1/2006	SMELT DISSOLVING TANK 22		1950	T BLS/D	THROUGHPUT IS THE OPERATING LIMIT	Particulate Matter (PM)	N		44	T/YR
*WA-0303	LONGVIEW FIBRE PAPER AND PACKAGING, INC	LONGVIEW FIBRE PAPER AND PACKAGING, INC	11/1/2006	SMELT DISSOLVING TANK 22		1950	T BLS/D	THROUGHPUT IS THE OPERATING LIMIT	Sulfur Dioxide (SO2)	N		31	T/YR
*WA-0303	LONGVIEW FIBRE PAPER AND PACKAGING, INC	LONGVIEW FIBRE PAPER AND PACKAGING, INC	11/1/2006	SMELT DISSOLVING TANK 22		1950	T BLS/D	THROUGHPUT IS THE OPERATING LIMIT	Sulfur, Total Reduced (TRS)	N		0.0168	LB/T BLS
LA-0122	MANSFIELD MILL	INTERNATIONAL PAPER - MANSFIELD MILL	8/14/2001	SMELT DISSOLVING TANK NO.1 AND NO.2		71	TBLS/H	EMISSION POINTS 06-78, 07-78	Particulate Matter < 10 µ (PM10)	A	WET SCRUBBERS	14.2	LB/H
*MS-0075	MONTICELLO MILL	GEORGIA PACIFIC CORP.	7/9/2003	SMELT DISSOLVING TANKS (4)	NA	36.5	T BLS/H, each tank	DISSOLVES SMELT FROM THE RECOVERY BOILER TO FORM GREEN LIQUOR.	Particulate Matter (PM)	A	SCRUBBERS, 4 EACH	0.2	LB/T AIR-DRIED PULP
*MS-0075	MONTICELLO MILL	GEORGIA PACIFIC CORP.	7/9/2003	SMELT DISSOLVING TANKS (4)	NA	36.5	T BLS/H, each tank	DISSOLVES SMELT FROM THE RECOVERY BOILER TO FORM GREEN LIQUOR.	Particulate Matter < 10 µ (PM10)	A	SCRUBBERS, 4 EACH	5.8	LB/H
*MS-0075	MONTICELLO MILL	GEORGIA PACIFIC CORP.	7/9/2003	SMELT DISSOLVING TANKS (4)	NA	36.5	T BLS/H, each tank	DISSOLVES SMELT FROM THE RECOVERY BOILER TO FORM GREEN LIQUOR.	Sulfur Dioxide (SO2)	A	SCRUBBERS ON EACH TANK	6.5	LB/H
TX-0263	DONAHUE INDUSTRIES, INC. PAPER MILL	DONAHUE INDUSTRIES, INC.	10/17/2000	SMELT TANK				EMISSION RATES ARE BASED ON 8640 H/YR OF OPERATION	Particulate Matter < 10 µ (PM10)	N	NONE INDICATED	8.3	LB/H
TX-0263	DONAHUE INDUSTRIES, INC. PAPER MILL	DONAHUE INDUSTRIES, INC.	10/17/2000	SMELT TANK				EMISSION RATES ARE BASED ON 8640 H/YR OF OPERATION	Sulfur Dioxide (SO2)	N	NONE INDICATED	2.5	LB/H
TX-0263	DONAHUE INDUSTRIES, INC. PAPER MILL	DONAHUE INDUSTRIES, INC.	10/17/2000	SMELT TANK				EMISSION RATES ARE BASED ON 8640 H/YR OF OPERATION	Sulfur, Total Reduced (TRS)	N	NONE INDICATED	1.4	LB/H
LA-0174	PORT HUDSON OPERATIONS	GEORGIA-PACIFIC CORPORATION	1/25/2002	SMELT TANK NO. 1		3.32	MM LB BLS/D	EMISSION POINT NO. 7 IS SCRUBBER FOR THIS PROCESS.	Nitrogen Oxides (NOx)	P	GOOD EQUIPMENT DESIGN	10.44	LB/H
LA-0174	PORT HUDSON OPERATIONS	GEORGIA-PACIFIC CORPORATION	1/25/2002	SMELT TANK NO. 1		3.32	MM LB BLS/D	EMISSION POINT NO. 7 IS SCRUBBER FOR THIS PROCESS.	Particulate Matter (PM)	A	WET SCRUBBER	9.22	LB/H
LA-0174	PORT HUDSON OPERATIONS	GEORGIA-PACIFIC CORPORATION	1/25/2002	SMELT TANK NO. 1		3.32	MM LB BLS/D	EMISSION POINT NO. 7 IS SCRUBBER FOR THIS PROCESS.	Particulate Matter < 10 µ (PM10)	A	WET SCRUBBER	9.22	LB/H
LA-0174	PORT HUDSON OPERATIONS	GEORGIA-PACIFIC CORPORATION	1/25/2002	SMELT TANK NO. 1		3.32	MM LB BLS/D	EMISSION POINT NO. 7 IS SCRUBBER FOR THIS PROCESS.	Sulfur Dioxide (SO2)	A	WET SCRUBBER	9.22	LB/H
LA-0174	PORT HUDSON OPERATIONS	GEORGIA-PACIFIC CORPORATION	1/25/2002	SMELT TANK NO. 1		3.32	MM LB BLS/D	EMISSION POINT NO. 7 IS SCRUBBER FOR THIS PROCESS.	Sulfur, Total Reduced (TRS)	N		0.84	LB/H

**RBLC Search Results  
Port Townsend Paper Company  
Smelt Dissolving Tank**

RBLC ID	FACILITY NAME	CORPORATE OR COMPANY NAME	PERMIT DATE	PROCESS NAME	FUEL	THRUPUT	THRUPUT UNIT	PROCESS NOTES	POLLUTANT	CONTROL	CTRLDESC	EMISLIMIT1	EMISLIMIT1UNIT
LA-0174	PORT HUDSON OPERATIONS	GEORGIA-PACIFIC CORPORATION	1/25/2002	SMELT TANK NO. 2		2.25	MM LB BLS/D	EMISSION POINT NOS. 8 AND 9 ARE WET SCRUBBERS NUMBERED 2A AND 2B, RESPECTIVELY. EMISSION LIMITS ARE PER SCRUBBER.	Nitrogen Oxides (NOx)	P	GOOD EQUIPMENT DESIGN	7.06	LB/H
LA-0174	PORT HUDSON OPERATIONS	GEORGIA-PACIFIC CORPORATION	1/25/2002	SMELT TANK NO. 2		2.25	MM LB BLS/D	EMISSION POINT NOS. 8 AND 9 ARE WET SCRUBBERS NUMBERED 2A AND 2B, RESPECTIVELY. EMISSION LIMITS ARE PER SCRUBBER.	Particulate Matter (PM)	A	WET SCRUBBERS	6.24	LB/H
LA-0174	PORT HUDSON OPERATIONS	GEORGIA-PACIFIC CORPORATION	1/25/2002	SMELT TANK NO. 2		2.25	MM LB BLS/D	EMISSION POINT NOS. 8 AND 9 ARE WET SCRUBBERS NUMBERED 2A AND 2B, RESPECTIVELY. EMISSION LIMITS ARE PER SCRUBBER.	Particulate Matter < 10 µ (PM10)	A	WET SCRUBBERS	6.24	LB/H
LA-0174	PORT HUDSON OPERATIONS	GEORGIA-PACIFIC CORPORATION	1/25/2002	SMELT TANK NO. 2		2.25	MM LB BLS/D	EMISSION POINT NOS. 8 AND 9 ARE WET SCRUBBERS NUMBERED 2A AND 2B, RESPECTIVELY. EMISSION LIMITS ARE PER SCRUBBER.	Sulfur Dioxide (SO2)	A	WET SCRUBBERS	6.24	LB/H
LA-0174	PORT HUDSON OPERATIONS	GEORGIA-PACIFIC CORPORATION	1/25/2002	SMELT TANK NO. 2		2.25	MM LB BLS/D	EMISSION POINT NOS. 8 AND 9 ARE WET SCRUBBERS NUMBERED 2A AND 2B, RESPECTIVELY. EMISSION LIMITS ARE PER SCRUBBER.	Sulfur, Total Reduced (TRS)	A	WET SCRUBBER	0.63	LB/H
*LA-0201	RED RIVER MILL	WEYERHAEUSER CO	5/24/2006	SMELT TANK NO. 3		1168000	TONS BLS/YR	RECOVERY BOILER NO. 3 & SMELT TANK NO. 3 VENT THROUGH A COMMON STACK.	Nitrogen Oxides (NOx)	P	PROPER COMBUSTION CONTROL AND AIR COMBUSTION OPTIMIZATION		
*LA-0201	RED RIVER MILL	WEYERHAEUSER CO	5/24/2006	SMELT TANK NO. 3		1168000	TONS BLS/YR	RECOVERY BOILER NO. 3 & SMELT TANK NO. 3 VENT THROUGH A COMMON STACK.	Particulate Matter < 10 µ (PM10)	A	ELECTROSTATIC PRECIPITATOR		
*LA-0201	RED RIVER MILL	WEYERHAEUSER CO	5/24/2006	SMELT TANK NO. 3		1168000	TONS BLS/YR	RECOVERY BOILER NO. 3 & SMELT TANK NO. 3 VENT THROUGH A COMMON STACK.	Sulfur Dioxide (SO2)	P	PROPER BOILER DESIGN AND OPERATION		
*LA-0201	RED RIVER MILL	WEYERHAEUSER CO	5/24/2006	SMELT TANK NO. 3		1168000	TONS BLS/YR	RECOVERY BOILER NO. 3 & SMELT TANK NO. 3 VENT THROUGH A COMMON STACK.	Sulfur, Total Reduced (TRS)	P	PROPER BOILER DESIGN AND OPERATION		
WI-0141	MOSINEE PAPER CORPORATION	MOSINEE PAPER CORPORATION	12/18/2000	SMELT TANK, PROCESS #P30, STACK #S12		275	TADP/D	THROUGHPUT IS TONS AIR DRIED PULP PER DAY. THE SMELT DISSOLVING TANK (SDT) IS PART OF THE GREEN LIQUOR MAKE-UP SYSTEM WHICH PRODUCES GREEN LIQUOR USING RECOVERY CHEMICALS. ADDITIONAL POLLUTANT: ACROLEIN, NO CONTROLS, EMISSION LIMIT: 0.20 LB/H, REG BASIS: OTHER (STATE REG).	Nitrogen Oxides (NOx)	N		2.7	T/YR
WI-0141	MOSINEE PAPER CORPORATION	MOSINEE PAPER CORPORATION	12/18/2000	SMELT TANK, PROCESS #P30, STACK #S12		275	TADP/D	THROUGHPUT IS TONS AIR DRIED PULP PER DAY. THE SMELT DISSOLVING TANK (SDT) IS PART OF THE GREEN LIQUOR MAKE-UP SYSTEM WHICH PRODUCES GREEN LIQUOR USING RECOVERY CHEMICALS. ADDITIONAL POLLUTANT: ACROLEIN, NO CONTROLS, EMISSION LIMIT: 0.20 LB/H, REG BASIS: OTHER (STATE REG).	Particulate Matter (PM)	A	VENTURI SCRUBBER.	11.43	T/YR
WI-0141	MOSINEE PAPER CORPORATION	MOSINEE PAPER CORPORATION	12/18/2000	SMELT TANK, PROCESS #P30, STACK #S12		275	TADP/D	THROUGHPUT IS TONS AIR DRIED PULP PER DAY. THE SMELT DISSOLVING TANK (SDT) IS PART OF THE GREEN LIQUOR MAKE-UP SYSTEM WHICH PRODUCES GREEN LIQUOR USING RECOVERY CHEMICALS. ADDITIONAL POLLUTANT: ACROLEIN, NO CONTROLS, EMISSION LIMIT: 0.20 LB/H, REG BASIS: OTHER (STATE REG).	Sulfur Dioxide (SO2)	N		1.3	T/YR
WI-0141	MOSINEE PAPER CORPORATION	MOSINEE PAPER CORPORATION	12/18/2000	SMELT TANK, PROCESS #P30, STACK #S12		275	TADP/D	THROUGHPUT IS TONS AIR DRIED PULP PER DAY. THE SMELT DISSOLVING TANK (SDT) IS PART OF THE GREEN LIQUOR MAKE-UP SYSTEM WHICH PRODUCES GREEN LIQUOR USING RECOVERY CHEMICALS. ADDITIONAL POLLUTANT: ACROLEIN, NO CONTROLS, EMISSION LIMIT: 0.20 LB/H, REG BASIS: OTHER (STATE REG).	Sulfur, Total Reduced (TRS)	N		2	T/YR
NC-0092	RIEGELWOOD MILL	INTERNATIONAL PAPER COMPANY	5/10/2001	SMELT TANKS					Sulfur Dioxide (SO2)	A	FAN IMPINGEMENT-TYPE WET SCRUBBER	6.2	LB/H
AL-0101	INTERNATIONAL PAPER CO. RIVERDALE MILL	INTERNATIONAL PAPER CO. RIVERDALE MILI	4/15/1997	NO. 2 SMELT DISSOLVING TANK		0		REVISED TRS LIMIT	Sulfur, Total Reduced (TRS)	N	REVISED TRS LIMIT FROM 0.0168 TO 0.033 LB/TONS BLACK LIQUOR SOLIDS	0.033	LB/T BLS
*TX-0485	INLAND PAPERBOARD AND PACKAGING ORANGE MILL	INLAND PAPERBOARD AND PACKAGING INC	10/5/2004	NO. 1 AND NO. 2 DISSOLVING TANK				TOTAL REDUCED SULFUR: .6 LB/H 2.5 T/YR; EMISSIONS ARE FOR EACH TANK.	Particulate Matter < 10 µ (PM10)	N		6.9	LB/H
*TX-0485	INLAND PAPERBOARD AND PACKAGING ORANGE MILL	INLAND PAPERBOARD AND PACKAGING INC	10/5/2004	NO. 1 AND NO. 2 DISSOLVING TANK				TOTAL REDUCED SULFUR: .6 LB/H 2.5 T/YR; EMISSIONS ARE FOR EACH TANK.	Sulfur Dioxide (SO2)	N		2.1	LB/H
*TX-0515	INTERNATIONAL PAPER COMPANY PULP AND PAPER MILL	INTERNATIONAL PAPER COMPANY	1/11/2006	NO.1 SMELT TANK SCRUBBER					Nitrogen Oxides (NOx)	N		1.8	LB/HR
*TX-0515	INTERNATIONAL PAPER COMPANY PULP AND PAPER MILL	INTERNATIONAL PAPER COMPANY	1/11/2006	NO.1 SMELT TANK SCRUBBER					Particulate Matter < 10 µ (PM10)	N		10.9	LB/HR
*TX-0515	INTERNATIONAL PAPER COMPANY PULP AND PAPER MILL	INTERNATIONAL PAPER COMPANY	1/11/2006	NO.1 SMELT TANK SCRUBBER					Sulfur Dioxide (SO2)	N		3.28	LB/HR
*TX-0515	INTERNATIONAL PAPER COMPANY PULP AND PAPER MILL	INTERNATIONAL PAPER COMPANY	1/11/2006	NO.1 SMELT TANK SCRUBBER					Sulfur, Total Reduced (TRS)	N		1.8	LB/HR
*TX-0515	INTERNATIONAL PAPER COMPANY PULP AND PAPER MILL	INTERNATIONAL PAPER COMPANY	1/11/2006	NO.1 SMELT TANK SCRUBBER					Sulfuric Acid (mist, vapors, etc)	N		0.15	LB/HR
*TX-0515	INTERNATIONAL PAPER COMPANY PULP AND PAPER MILL	INTERNATIONAL PAPER COMPANY	1/11/2006	NO.2 SMELT TANK SCRUBBER					Nitrogen Oxides (NOx)	N		3.28	LB/HR
*TX-0515	INTERNATIONAL PAPER COMPANY PULP AND PAPER MILL	INTERNATIONAL PAPER COMPANY	1/11/2006	NO.2 SMELT TANK SCRUBBER					Particulate Matter < 10 µ (PM10)	N		19.85	LB/HR
*TX-0515	INTERNATIONAL PAPER COMPANY PULP AND PAPER MILL	INTERNATIONAL PAPER COMPANY	1/11/2006	NO.2 SMELT TANK SCRUBBER					Sulfur Dioxide (SO2)	N		6.78	LB/HR

**RBLC Search Results  
Port Townsend Paper Company  
Smelt Dissolving Tank**

RBLC ID	FACILITY NAME	CORPORATE OR COMPANY NAME	PERMIT DATE	PROCESS NAME	FUEL	THRUPUT	THRUPUT UNIT	PROCESS NOTES	POLLUTANT	CONTROL	CTRLDESC	EMISLIMIT1	EMISLIMITUNIT
*TX-0515	INTERNATIONAL PAPER COMPANY PULP AND PAPER MILL	INTERNATIONAL PAPER COMPANY	1/11/2006	NO.2 SMELT TANK SCRUBBER					Sulfur, Total Reduced (TRS)	N		3.28	LB/HR
*TX-0515	INTERNATIONAL PAPER COMPANY PULP AND PAPER MILL	INTERNATIONAL PAPER COMPANY	1/11/2006	NO.2 SMELT TANK SCRUBBER					Sulfuric Acid (mist, vapors, etc)	N		0.31	LB/HR
LA-0117	GAYLORD CONTAINER CORP - BOGALUSA MILL	GAYLORD CONTAINER CORP	3/18/1999	PULP MILL, SMELT DISSOLVING TANK #21	BLACK LIQUOR SOLIDS	68.75	T/H BLS	RETROACTIVE PSD.	Particulate Matter < 10 µ (PM10)	N		13.8	LB/H
*TX-0515	INTERNATIONAL PAPER COMPANY PULP AND PAPER MILL	INTERNATIONAL PAPER COMPANY	1/11/2006	BATCH DIGESTOR FUGITIVES					Sulfur, Total Reduced (TRS)	N		0.87	LB/HR
*TX-0485	INLAND PAPERBOARD AND PACKAGING ORANGE MILL	INLAND PAPERBOARD AND PACKAGING INC	10/5/2004	BLACK LIQUOR POND				TOTAL REDUCED SULFUR: 3.20 TPY					
TX-0263	DONAHUE INDUSTRIES, INC. PAPER MILL	DONAHUE INDUSTRIES, INC.	10/17/2000	BROWN KRAFT PULP STORAGE					Sulfur, Total Reduced (TRS)	N	NONE INDICATED	0.18	LB/H
TX-0263	DONAHUE INDUSTRIES, INC. PAPER MILL	DONAHUE INDUSTRIES, INC.	10/17/2000	BROWN STOCK WASHERS				FUGITIVE EMISSIONS ARE AN ESTIMATE. EMISSION RATES ARE BASED ON 8640 H/YR OF OPERATION	Sulfur, Total Reduced (TRS)	N	NONE INDICATED	9.82	LB/H
LA-0122	MANSFIELD MILL	INTERNATIONAL PAPER - MANSFIELD MILL	8/14/2001	CATIONIC STARCH SILO				EMISSION POINT 32-93	Particulate Matter < 10 µ (PM10)	A	BAG FILTERS DURING LOADING	1.8	LB/H
TX-0263	DONAHUE INDUSTRIES, INC. PAPER MILL	DONAHUE INDUSTRIES, INC.	10/17/2000	CAUSTICIZER TANKS				EMISSION RATES ARE BASED ON 8520 H/YR OF OPERATION	Particulate Matter < 10 µ (PM10)	N	NONE INDICATED	0.5	LB/H
TX-0263	DONAHUE INDUSTRIES, INC. PAPER MILL	DONAHUE INDUSTRIES, INC.	10/17/2000	HEAVY BLACK LIQUOR STORAGE					Sulfur, Total Reduced (TRS)	N	NONE INDICATED	0.18	LB/H
LA-0122	MANSFIELD MILL	INTERNATIONAL PAPER - MANSFIELD MILL	8/14/2001	HEAVY BLACK LIQUOR TANK				EMISSION POINT 28-93H	Sulfur, Total Reduced (TRS)	N	NO ADDITIONAL CONTROL REQUIRED	2.1	LB/H
LA-0122	MANSFIELD MILL	INTERNATIONAL PAPER - MANSFIELD MILL	8/14/2001	INTERMEDIATE BLACK LIQUOR TANK 1 & 2				EMISSION POINTS 28-93F, 28-93G	Sulfur, Total Reduced (TRS)	N	NO ADDITIONAL CONTROL REQUIRED	0.96	LB/H
*TX-0485	INLAND PAPERBOARD AND PACKAGING ORANGE MILL	INLAND PAPERBOARD AND PACKAGING INC	10/5/2004	NO.5 WHITE LIQUOR TANK VENT				TOTAL SULFUR REDUCTION: <.01 LB/HR .02 TPY					
LA-0122	MANSFIELD MILL	INTERNATIONAL PAPER - MANSFIELD MILL	8/14/2001	PRIMARY BLACK LIQUOR FILTER				EMISSION POINT 30-93B	Sulfur, Total Reduced (TRS)	N	NO ADDITIONAL CONTROL REQUIRED	2.1	LB/H
LA-0122	MANSFIELD MILL	INTERNATIONAL PAPER - MANSFIELD MILL	8/14/2001	PRIMARY HIGH DENSITY TANKS A, B & C				EMISSION POINTS 31-93I, 31-93J, 31-93K	Sulfur, Total Reduced (TRS)	N	NO ADDITIONAL CONTROL REQUIRED	0.82	LB/H
LA-0122	MANSFIELD MILL	INTERNATIONAL PAPER - MANSFIELD MILL	8/14/2001	PRIMARY WEAK BLACK LIQUOR, TANK EAST AND WEST				EMISSION POINTS 28-93A(E), 28-93B(W)	Sulfur, Total Reduced (TRS)	N	NO ADDITIONAL CONTROL REQUIRED	0.04	LB/H
LA-0117	GAYLORD CONTAINER CORP - BOGALUSA MILL	GAYLORD CONTAINER CORP	3/18/1999	PULP MILL, RECOVERY FURNACE, BLACK LIQUOR SOLID FU	BLS		908	MMBTU/H	Particulate Matter < 10 µ (PM10)	N		78.64	LB/H
LA-0117	GAYLORD CONTAINER CORP - BOGALUSA MILL	GAYLORD CONTAINER CORP	3/18/1999	PULP MILL, SMALL DIGESTER LINE			18.13	T/H (SEE NOTES)	Sulfur, Total Reduced (TRS)	N		3.93	LB/H
LA-0122	MANSFIELD MILL	INTERNATIONAL PAPER - MANSFIELD MILL	8/14/2001	RB1 & RB2 BLACK LIQUOR DUMP TANK				EMISSION POINTS 28-93R, 28-93S	Sulfur, Total Reduced (TRS)	N	NO ADDITIONAL CONTROL REQUIRED	0.01	LB/H
LA-0122	MANSFIELD MILL	INTERNATIONAL PAPER - MANSFIELD MILL	8/14/2001	SECONDARY BLACK LIQUOR FILTER				EMISSION POINT 30-93A	Sulfur, Total Reduced (TRS)	N	NO ADDITIONAL CONTROL REQUIRED	0.76	LB/H
LA-0122	MANSFIELD MILL	INTERNATIONAL PAPER - MANSFIELD MILL	8/14/2001	SECONDARY HIGH DENSITY TANK				EMISSION POINT 31-93L	Sulfur, Total Reduced (TRS)	N	NO ADDITIONAL CONTROL REQUIRED	0.59	LB/H
LA-0122	MANSFIELD MILL	INTERNATIONAL PAPER - MANSFIELD MILL	8/14/2001	SECONDARY WEAK BLACK LIQUOR TANK				EMISSION POINT 28-93C	Sulfur, Total Reduced (TRS)	N	NO ADDITIONAL CONTROL REQUIRED	0.19	LB/H
LA-0122	MANSFIELD MILL	INTERNATIONAL PAPER - MANSFIELD MILL	8/14/2001	SEMICHEMICAL HIGH DENSITY TANK				EMISSION POINT 31-93M	Sulfur, Total Reduced (TRS)	N	NO ADDITIONAL CONTROL REQUIRED	0.45	LB/H
LA-0122	MANSFIELD MILL	INTERNATIONAL PAPER - MANSFIELD MILL	8/14/2001	SEMICHEMICAL WEAK BLACK LIQUOR TANK				EMISSION POINT 28-93D	Sulfur, Total Reduced (TRS)	N	NO ADDITIONAL CONTROL REQUIRED	0.09	LB/H
LA-0122	MANSFIELD MILL	INTERNATIONAL PAPER - MANSFIELD MILL	8/14/2001	SPILL TANK NO.1 & NO.2				EMISSION POINTS 28-93P, 28-93Q	Sulfur, Total Reduced (TRS)	N	NO ADDITIONAL CONTROL REQUIRED	0.01	LB/H
LA-0122	MANSFIELD MILL	INTERNATIONAL PAPER - MANSFIELD MILL	8/14/2001	SWING WEAK BLACK LIQUOR TANK				EMISSION POINT 28-93E	Sulfur, Total Reduced (TRS)	N	NO ADDITIONAL CONTROL REQUIRED	0.19	LB/H
TX-0263	DONAHUE INDUSTRIES, INC. PAPER MILL	DONAHUE INDUSTRIES, INC.	10/17/2000	WEAK BLACK LIQUOR STORAGE					Sulfur, Total Reduced (TRS)	N	NONE INDICATED	0.06	LB/H
LA-0122	MANSFIELD MILL	INTERNATIONAL PAPER - MANSFIELD MILL	8/14/2001	WHITE LIQUOR CLARIFIER 1 & 2			87600	TCAO/YR EACH	Sulfur, Total Reduced (TRS)	N	NO ADDITIONAL CONTROL REQUIRED	0.03	LB/H
LA-0122	MANSFIELD MILL	INTERNATIONAL PAPER - MANSFIELD MILL	8/14/2001	WHITE LIQUOR TANK 1 THRU 3			58400	TCAO/YR EACH	Sulfur, Total Reduced (TRS)	N	NO ADDITIONAL CONTROL REQUIRED	0.02	LB/H

**RBLC Search Results**  
**Port Townsend Paper Company**  
**Lime Kiln**

RBLC ID	FACILITY NAME	CORPORATE OR COMPANY NAME	PERMIT DATE	PROCESS NAME	FUEL	THRUPUT	THRUPUT UNIT	PROCESS NOTES	POLLUTANT	CONTROL CTRLDESC	EMISLIMIT1	EMISLIMIT1UNIT
LA-0155	ST. FRANCISVILLE MILL	CROWN PAPER COMPANY	4/29/2001	DATED 4/5/89) REMAINS 2.0 LB/TON BLACK LIQUOR SOLIDS FIRED."	CAO	12.25	T/H		Particulate Matter (PM)	N	NONE INDICATED. STACK TESTS V	7.35 LB/H
MS-0077	MONTICELLO MILL	GEORGIA PACIFIC CORPORATION	3/4/2005	LIME KILN	NATURAL GAS	145.9	MMBTU/H	THE LIME KILN CALCINES LIME MUD INTO CALCIUM OXIDE USING NATURAL GAS AS FUEL. IT IS ALSO THE PRIMARY INCINERATOR FOR NCG.	Nitrogen Oxides (NOx)	P	GOOD COMBUSTION	95.6 LB/H
*TX-0485	INLAND PAPERBOARD AND PACKAGING ORANGE MILL	INLAND PAPERBOARD AND PACKAGING INC	10/5/2004	LIME KILN	NATURAL GAS			TOTAL REDUCED SULFURE: 6.41 LB/H 11.21 T/YR	Nitrogen Oxides (NOx)	N		42 LB/H
OR-0044	HALSEY PULP MILL	POPE & TALBOT, INC.	1/22/2004	LIME KILN	NATURAL GAS	78320	TONS CAO/YEAR	EXISTING LIME KILN INSTALLED IN 1969. A NEW BURNER IS BEING INSTALLED. NOX BACT LIMIT DETERMINED TO BE 112 PPM @ 10% O2 (3-HOUR AVERAGE) AND 241 TONS PER YEAR. BACT WAS DETERMINED TO BE GOOD COMBUSTION CONTROL.	Nitrogen Oxides (NOx)	P	GOOD COMBUSTION CONTROL	112 PPM@10% O2
*MS-0075	MONTICELLO MILL	GEORGIA PACIFIC CORP.	7/9/2003	LIME KILN	NATURAL GAS	200	MMBTU/H	KILN CONVERTS LIME MUD INTO CALCIUM OXIDE AND IS ALSO THE PRIMARY INCINERATOR FOR NCG FROM THROUGH OUT THE MILL.	Nitrogen Oxides (NOx)	P	GOOD COMBUSTION PRACTICES AND KILN DESIGN.	95.6 LB/H
LA-0122	MANSFIELD MILL	INTERNATIONAL PAPER - MANSFIELD MILL	8/14/2001	LIME KILN	NATURAL GAS	142	MMBTU/H	EMISSION POINT 03-78	Nitrogen Oxides (NOx)	P	GOOD PROCESS CONTROLS, WATER CONTENT OF LIME	103.7 LB/H
TX-0263	DONAHUE INDUSTRIES, INC. PAPER MILL	DONAHUE INDUSTRIES, INC.	10/17/2000	LIME KILN	NAT GAS, NO.2 OIL			EMISSION RATES ARE BASED ON 8520 H/YR OF OPERATION.	Nitrogen Oxides (NOx)	N		22.7 LB/H
NC-0092	RIEGELWOOD MILL	INTERNATIONAL PAPER COMPANY	5/10/2001	LIME KILN	NO.6 FUEL OIL	212	LB/MMBTU		Particulate Matter (PM)	A	ESP AND A FIXED THROAT SPRAY VENTURI-TYPE WET SCRUBBER	0.13 GR/DSCF @ 10% O2
MS-0077	MONTICELLO MILL	GEORGIA PACIFIC CORPORATION	3/4/2005	LIME KILN	NATURAL GAS	145.9	MMBTU/H	THE LIME KILN CALCINES LIME MUD INTO CALCIUM OXIDE USING NATURAL GAS AS FUEL. IT IS ALSO THE PRIMARY INCINERATOR FOR NCG.	Particulate Matter < 10 µ (PM10)	A	VENTURI SCRUBBER	29.9 LB/H
*TX-0485	INLAND PAPERBOARD AND PACKAGING ORANGE MILL	INLAND PAPERBOARD AND PACKAGING INC	10/5/2004	LIME KILN	NATURAL GAS			TOTAL REDUCED SULFURE: 6.41 LB/H 11.21 T/YR	Particulate Matter < 10 µ (PM10)	N		30 LB/H
*MS-0075	MONTICELLO MILL	GEORGIA PACIFIC CORP.	7/9/2003	LIME KILN	NATURAL GAS	200	MMBTU/H	KILN CONVERTS LIME MUD INTO CALCIUM OXIDE AND IS ALSO THE PRIMARY INCINERATOR FOR NCG FROM THROUGH OUT THE MILL.	Particulate Matter < 10 µ (PM10)	A	SCRUBBER	21.2 LB/H
LA-0122	MANSFIELD MILL	INTERNATIONAL PAPER - MANSFIELD MILL	8/14/2001	LIME KILN	NATURAL GAS	142	MMBTU/H	EMISSION POINT 03-78	Particulate Matter < 10 µ (PM10)	A	VENTURI SCRUBBER USING CAUSTIC SOLUTION	39.2 LB/H
TX-0263	DONAHUE INDUSTRIES, INC. PAPER MILL	DONAHUE INDUSTRIES, INC.	10/17/2000	LIME KILN	NAT GAS, NO.2 OIL			EMISSION RATES ARE BASED ON 8520 H/YR OF OPERATION.	Particulate Matter < 10 µ (PM10)	A	SCRUBBER	22.7 LB/H
MS-0077	MONTICELLO MILL	GEORGIA PACIFIC CORPORATION	3/4/2005	LIME KILN	NATURAL GAS	145.9	MMBTU/H	THE LIME KILN CALCINES LIME MUD INTO CALCIUM OXIDE USING NATURAL GAS AS FUEL. IT IS ALSO THE PRIMARY INCINERATOR FOR NCG.	Sulfur Dioxide (SO2)	A	WET (VENTURI) SCRUBBER WITH OPTIMAL MUD WASHING	23.4 LB/H
*TX-0485	INLAND PAPERBOARD AND PACKAGING ORANGE MILL	INLAND PAPERBOARD AND PACKAGING INC	10/5/2004	LIME KILN	NATURAL GAS			TOTAL REDUCED SULFURE: 6.41 LB/H 11.21 T/YR	Sulfur Dioxide (SO2)	N		57.95 LB/H
*MS-0075	MONTICELLO MILL	GEORGIA PACIFIC CORP.	7/9/2003	LIME KILN	NATURAL GAS	200	MMBTU/H	KILN CONVERTS LIME MUD INTO CALCIUM OXIDE AND IS ALSO THE PRIMARY INCINERATOR FOR NCG FROM THROUGH OUT THE MILL.	Sulfur Dioxide (SO2)	A	SCRUBBER	12.4 LB/H
LA-0122	MANSFIELD MILL	INTERNATIONAL PAPER - MANSFIELD MILL	8/14/2001	LIME KILN	NATURAL GAS	142	MMBTU/H	EMISSION POINT 03-78	Sulfur Dioxide (SO2)	A	CAO AND WET SCRUBBER USING CAUSTIC SOLUTION	8.4 LB/H
TX-0263	DONAHUE INDUSTRIES, INC. PAPER MILL	DONAHUE INDUSTRIES, INC.	10/17/2000	LIME KILN	NAT GAS, NO.2 OIL			EMISSION RATES ARE BASED ON 8520 H/YR OF OPERATION.	Sulfur Dioxide (SO2)	B	SCRUBBER AND SWEET NAT GAS WITH A SULFUR CONTENT LIMIT OF 0.3%	5.4 LB/H
MS-0077	MONTICELLO MILL	GEORGIA PACIFIC CORPORATION	3/4/2005	LIME KILN	NATURAL GAS	145.9	MMBTU/H	THE LIME KILN CALCINES LIME MUD INTO CALCIUM OXIDE USING NATURAL GAS AS FUEL. IT IS ALSO THE PRIMARY INCINERATOR FOR NCG.	Sulfur, Total Reduced (TRS)	A	WET (VENTURI) SCRUBBER WITH OPTIONAL MUD WASHING	20 PPMV @ 10% O2
LA-0122	MANSFIELD MILL	INTERNATIONAL PAPER - MANSFIELD MILL	8/14/2001	LIME KILN	NATURAL GAS	142	MMBTU/H	EMISSION POINT 03-78	Sulfur, Total Reduced (TRS)	P	VENTURI SCRUBBER USING FRESH WATER	6.5 PPM
NC-0092	RIEGELWOOD MILL	INTERNATIONAL PAPER COMPANY	5/10/2001	LIME KILN	NO.6 FUEL OIL	212	LB/MMBTU		Sulfur, Total Reduced (TRS)	A	ESP AND A FIXED THROAT SPRAY VENTURI-TYPE WET SCRUBBER	8 PPM @ 10% O2
TX-0263	DONAHUE INDUSTRIES, INC. PAPER MILL	DONAHUE INDUSTRIES, INC.	10/17/2000	LIME KILN	NAT GAS, NO.2 OIL			EMISSION RATES ARE BASED ON 8520 H/YR OF OPERATION.	Sulfur, Total Reduced (TRS)	A	SCRUBBER	0.9 LB/H
MS-0077	MONTICELLO MILL	GEORGIA PACIFIC CORPORATION	3/4/2005	LIME KILN	NATURAL GAS	145.9	MMBTU/H	THE LIME KILN CALCINES LIME MUD INTO CALCIUM OXIDE USING NATURAL GAS AS FUEL. IT IS ALSO THE PRIMARY INCINERATOR FOR NCG.	Sulfuric Acid (mist, vapors, etc)	N		2.5 LB/H
*MS-0075	MONTICELLO MILL	GEORGIA PACIFIC CORP.	7/9/2003	LIME KILN	NATURAL GAS	200	MMBTU/H	KILN CONVERTS LIME MUD INTO CALCIUM OXIDE AND IS ALSO THE PRIMARY INCINERATOR FOR NCG FROM THROUGH OUT THE MILL.	Sulfuric Acid (mist, vapors, etc)	A	CAUSTIC SCRUBBER	
*WA-0303	LONGVIEW FIBRE PAPER AND PACKAGING, INC	LONGVIEW FIBRE PAPER AND PACKAGING, INC	11/1/2006	LIME KILN 3		240	T CAO/D	THE EXHAUST STACKS SHALL BE MODIFIED OR REPLACED SO MODELED EXHAUST GAS DISPERSION IS EQUAL TO OR BETTER THAN THAT INDICATED FOR THE ORIGINALLY-PROPOSED DESIGN IN THE PERMIT APPLICATION.	Nitrogen Oxides (NOx)	N		340 PPM DV @ 10% O2
*WA-0303	LONGVIEW FIBRE PAPER AND PACKAGING, INC	LONGVIEW FIBRE PAPER AND PACKAGING, INC	11/1/2006	LIME KILN 3		240	T CAO/D	THE EXHAUST STACKS SHALL BE MODIFIED OR REPLACED SO MODELED EXHAUST GAS DISPERSION IS EQUAL TO OR BETTER THAN THAT INDICATED FOR THE ORIGINALLY-PROPOSED DESIGN IN THE PERMIT APPLICATION.	Particulate Matter (PM)	N		34 T/YR

**RBLC Search Results**  
**Port Townsend Paper Company**  
**Lime Kiln**

RBLC ID	FACILITY NAME	CORPORATE OR COMPANY NAME	PERMIT DATE	PROCESS NAME	FUEL	THRUPUT	THRUPUT UNIT	PROCESS NOTES	POLLUTANT	CONTROL CTRLDESC	EMISLIMIT1	EMISLIMIT1UNIT
*WA-0303	LONGVIEW FIBRE PAPER AND PACKAGING, INC	LONGVIEW FIBRE PAPER AND PACKAGING, INC	11/1/2006	LIME KILN 3		240	T CAO/D	THE EXHAUST STACKS SHALL BE MODIFIED OR REPLACED SO MODELED EXHAUST GAS DISPERSION IS EQUAL TO OR BETTER THAN THAT INDICATED FOR THE ORIGINALLY-PROPOSED DESIGN IN THE PERMIT APPLICATION.	Sulfur Dioxide (SO2)	N	20	PPMDV @ 10% O2
*WA-0303	LONGVIEW FIBRE PAPER AND PACKAGING, INC	LONGVIEW FIBRE PAPER AND PACKAGING, INC	11/1/2006	LIME KILN 3		240	T CAO/D	THE EXHAUST STACKS SHALL BE MODIFIED OR REPLACED SO MODELED EXHAUST GAS DISPERSION IS EQUAL TO OR BETTER THAN THAT INDICATED FOR THE ORIGINALLY-PROPOSED DESIGN IN THE PERMIT APPLICATION.	Sulfur, Total Reduced (TRS)	N	20	PPMDV @ 10% O2
*WA-0303	LONGVIEW FIBRE PAPER AND PACKAGING, INC	LONGVIEW FIBRE PAPER AND PACKAGING, INC	11/1/2006	LIME KILN 4		250	T CAO/D	THE EXHAUST STACKS SHALL BE MODIFIED OR REPLACED SO MODELED EXHAUST GAS DISPERSION IS EQUAL TO OR BETTER THAN THAT INDICATED FOR THE ORIGINALLY-PROPOSED DESIGN IN THE PERMIT APPLICATION.	Nitrogen Oxides (NOx)	N	340	PPMDV @ 10% O2
*WA-0303	LONGVIEW FIBRE PAPER AND PACKAGING, INC	LONGVIEW FIBRE PAPER AND PACKAGING, INC	11/1/2006	LIME KILN 4		250	T CAO/D	THE EXHAUST STACKS SHALL BE MODIFIED OR REPLACED SO MODELED EXHAUST GAS DISPERSION IS EQUAL TO OR BETTER THAN THAT INDICATED FOR THE ORIGINALLY-PROPOSED DESIGN IN THE PERMIT APPLICATION.	Particulate Matter (PM)	N	35.6	T/YR
*WA-0303	LONGVIEW FIBRE PAPER AND PACKAGING, INC	LONGVIEW FIBRE PAPER AND PACKAGING, INC	11/1/2006	LIME KILN 4		250	T CAO/D	THE EXHAUST STACKS SHALL BE MODIFIED OR REPLACED SO MODELED EXHAUST GAS DISPERSION IS EQUAL TO OR BETTER THAN THAT INDICATED FOR THE ORIGINALLY-PROPOSED DESIGN IN THE PERMIT APPLICATION.	Sulfur Dioxide (SO2)	N	20	PPMDV @ 10% O2
*WA-0303	LONGVIEW FIBRE PAPER AND PACKAGING, INC	LONGVIEW FIBRE PAPER AND PACKAGING, INC	11/1/2006	LIME KILN 4		250	T CAO/D	THE EXHAUST STACKS SHALL BE MODIFIED OR REPLACED SO MODELED EXHAUST GAS DISPERSION IS EQUAL TO OR BETTER THAN THAT INDICATED FOR THE ORIGINALLY-PROPOSED DESIGN IN THE PERMIT APPLICATION.	Sulfur, Total Reduced (TRS)	N	20	PPMDV @ 10% O2
*WA-0303	LONGVIEW FIBRE PAPER AND PACKAGING, INC	LONGVIEW FIBRE PAPER AND PACKAGING, INC	11/1/2006	LIME KILN 5		325	T CAO/D		Nitrogen Oxides (NOx)	N	275	PPMDV @ 10% O2
*WA-0303	LONGVIEW FIBRE PAPER AND PACKAGING, INC	LONGVIEW FIBRE PAPER AND PACKAGING, INC	11/1/2006	LIME KILN 5		325	T CAO/D		Particulate Matter (PM)	N	0.06	GR/DSCF @ 10% O2
*WA-0303	LONGVIEW FIBRE PAPER AND PACKAGING, INC	LONGVIEW FIBRE PAPER AND PACKAGING, INC	11/1/2006	LIME KILN 5		325	T CAO/D		Sulfur Dioxide (SO2)	N	20	PPMDV @ 10% O2
*WA-0303	LONGVIEW FIBRE PAPER AND PACKAGING, INC	LONGVIEW FIBRE PAPER AND PACKAGING, INC	11/1/2006	LIME KILN 5		325	T CAO/D		Sulfur, Total Reduced (TRS)	N	20	PPMDV @ 10% O2
LA-0122	MANSFIELD MILL	INTERNATIONAL PAPER - MANSFIELD MILL	8/14/2001	LIME KILN AUXILIARY ENGINE		370	HP	EMISSION POINT 35-96	Nitrogen Oxides (NOx)	P		4.2 LB/H
LA-0122	MANSFIELD MILL	INTERNATIONAL PAPER - MANSFIELD MILL	8/14/2001	LIME KILN AUXILIARY ENGINE		370	HP	EMISSION POINT 35-96	Particulate Matter < 10 µ (PM10)	P		0.26 LB/H
LA-0122	MANSFIELD MILL	INTERNATIONAL PAPER - MANSFIELD MILL	8/14/2001	LIME KILN AUXILIARY ENGINE		370	HP	EMISSION POINT 35-96	Sulfur Dioxide (SO2)	P		0.22 LB/H
LA-0174	PORT HUDSON OPERATIONS	GEORGIA-PACIFIC CORPORATION	1/25/2002	LIME KILN NO. 1		340	T/D	EMISSION POINT NO. 10. THROUGHPUT IS 340 TONS CALCIUM OXIDE PER DAY. TOTAL ANNUAL THROUGHPUT OF LIME KILNS (EMISSION POINT NOS. 10 AND 11) LIMITED TO LESS THAN 162,500 TONS OF LIME, ON A ROLLING 12-MONTH BASIS, TO MAINTAIN NOX INCREASE BELOW PSD SIGNIFICANCE LEVEL.	Nitrogen Oxides (NOx)	P	GOOD EQUIPMENT DESIGN AND PROPER COMBUSTION TECHNIQUES	48.78 LB/H
LA-0174	PORT HUDSON OPERATIONS	GEORGIA-PACIFIC CORPORATION	1/25/2002	LIME KILN NO. 1		340	T/D	EMISSION POINT NO. 10. THROUGHPUT IS 340 TONS CALCIUM OXIDE PER DAY. TOTAL ANNUAL THROUGHPUT OF LIME KILNS (EMISSION POINT NOS. 10 AND 11) LIMITED TO LESS THAN 162,500 TONS OF LIME, ON A ROLLING 12-MONTH BASIS, TO MAINTAIN NOX INCREASE BELOW PSD SIGNIFICANCE LEVEL.	Particulate Matter (PM)	A	WET SCRUBBERS	25.76 LB/H
LA-0174	PORT HUDSON OPERATIONS	GEORGIA-PACIFIC CORPORATION	1/25/2002	LIME KILN NO. 1		340	T/D	EMISSION POINT NO. 10. THROUGHPUT IS 340 TONS CALCIUM OXIDE PER DAY. TOTAL ANNUAL THROUGHPUT OF LIME KILNS (EMISSION POINT NOS. 10 AND 11) LIMITED TO LESS THAN 162,500 TONS OF LIME, ON A ROLLING 12-MONTH BASIS, TO MAINTAIN NOX INCREASE BELOW PSD SIGNIFICANCE LEVEL.	Particulate Matter < 10 µ (PM10)	A	WET SCRUBBERS	25.76 LB/H
LA-0174	PORT HUDSON OPERATIONS	GEORGIA-PACIFIC CORPORATION	1/25/2002	LIME KILN NO. 1		340	T/D	EMISSION POINT NO. 10. THROUGHPUT IS 340 TONS CALCIUM OXIDE PER DAY. TOTAL ANNUAL THROUGHPUT OF LIME KILNS (EMISSION POINT NOS. 10 AND 11) LIMITED TO LESS THAN 162,500 TONS OF LIME, ON A ROLLING 12-MONTH BASIS, TO MAINTAIN NOX INCREASE BELOW PSD SIGNIFICANCE LEVEL.	Sulfur Dioxide (SO2)	B	WET SCRUBBERS AND OPTIMAL MUD WASHING	3.26 LB/H
LA-0174	PORT HUDSON OPERATIONS	GEORGIA-PACIFIC CORPORATION	1/25/2002	LIME KILN NO. 1		340	T/D	EMISSION POINT NO. 10. THROUGHPUT IS 340 TONS CALCIUM OXIDE PER DAY. TOTAL ANNUAL THROUGHPUT OF LIME KILNS (EMISSION POINT NOS. 10 AND 11) LIMITED TO LESS THAN 162,500 TONS OF LIME, ON A ROLLING 12-MONTH BASIS, TO MAINTAIN NOX INCREASE BELOW PSD SIGNIFICANCE LEVEL.	Sulfur, Total Reduced (TRS)	N		3.5 LB/H

**RBLC Search Results**  
**Port Townsend Paper Company**  
**Lime Kiln**

RBLC ID	FACILITY NAME	CORPORATE OR COMPANY NAME	PERMIT DATE	PROCESS NAME	FUEL	THRUPUT	THRUPUT UNIT	PROCESS NOTES	POLLUTANT	CONTROL CTRLDESC	EMISLIMIT1	EMISLIMIT1UNIT
*LA-0201	RED RIVER MILL	WEYERHAEUSER CO	5/24/2006	LIME KILN NO. 2	NATURAL GAS	191625	TONS CaO/YR	MAXIMUM HEAT INPUTS PER FUEL: NATURAL GAS - 93 MM BTU/HR PETROLEUM COKE - 80 MM BTU/HR TURPENTINE - 5 MM BTU/HR EMISSION POINT NO. 11. THROUGHPUT IS 270 TONS CALCIUM OXIDE PER DAY. TOTAL ANNUAL THROUGHPUT OF LIME KILNS (EMISSION POINT NOS. 10 AND 11) LIMITED TO LESS THAN 162,500 TONS OF LIME, ON A ROLLING 12-MONTH BASIS, TO MAINTAIN NOX INCREASE BELOW PSD SIGNIFICANCE LEVEL.	Nitrogen Oxides (NOx)	P	PROPER KILN DESIGN AND OPTIMIZED COMBUSTION PRACTICES	190 PPM @ 10% O2
LA-0174	PORT HUDSON OPERATIONS	GEORGIA-PACIFIC CORPORATION	1/25/2002	LIME KILN NO. 2		270	T/D	EMISSION POINT NO. 11. THROUGHPUT IS 270 TONS CALCIUM OXIDE PER DAY. TOTAL ANNUAL THROUGHPUT OF LIME KILNS (EMISSION POINT NOS. 10 AND 11) LIMITED TO LESS THAN 162,500 TONS OF LIME, ON A ROLLING 12-MONTH BASIS, TO MAINTAIN NOX INCREASE BELOW PSD SIGNIFICANCE LEVEL.	Nitrogen Oxides (NOx)	P	GOOD EQUIPMENT DESIGN AND PROPER COMBUSTION TECHNIQUES	38.75 LB/H
LA-0174	PORT HUDSON OPERATIONS	GEORGIA-PACIFIC CORPORATION	1/25/2002	LIME KILN NO. 2		270	T/D	EMISSION POINT NO. 11. THROUGHPUT IS 270 TONS CALCIUM OXIDE PER DAY. TOTAL ANNUAL THROUGHPUT OF LIME KILNS (EMISSION POINT NOS. 10 AND 11) LIMITED TO LESS THAN 162,500 TONS OF LIME, ON A ROLLING 12-MONTH BASIS, TO MAINTAIN NOX INCREASE BELOW PSD SIGNIFICANCE LEVEL.	Particulate Matter (PM)	A	ELECTROSTATIC PRECIPITATOR	20.45 LB/H
*LA-0201	RED RIVER MILL	WEYERHAEUSER CO	5/24/2006	LIME KILN NO. 2	NATURAL GAS	191625	TONS CaO/YR	MAXIMUM HEAT INPUTS PER FUEL: NATURAL GAS - 93 MM BTU/HR PETROLEUM COKE - 80 MM BTU/HR TURPENTINE - 5 MM BTU/HR EMISSION POINT NO. 11. THROUGHPUT IS 270 TONS CALCIUM OXIDE PER DAY. TOTAL ANNUAL THROUGHPUT OF LIME KILNS (EMISSION POINT NOS. 10 AND 11) LIMITED TO LESS THAN 162,500 TONS OF LIME, ON A ROLLING 12-MONTH BASIS, TO MAINTAIN NOX INCREASE BELOW PSD SIGNIFICANCE LEVEL.	Particulate Matter < 10 µ (PM10)	A	ELECTROSTATIC PRECIPITATOR	0.01 GR/DSCF @ 10% O2
LA-0174	PORT HUDSON OPERATIONS	GEORGIA-PACIFIC CORPORATION	1/25/2002	LIME KILN NO. 2		270	T/D	EMISSION POINT NO. 11. THROUGHPUT IS 270 TONS CALCIUM OXIDE PER DAY. TOTAL ANNUAL THROUGHPUT OF LIME KILNS (EMISSION POINT NOS. 10 AND 11) LIMITED TO LESS THAN 162,500 TONS OF LIME, ON A ROLLING 12-MONTH BASIS, TO MAINTAIN NOX INCREASE BELOW PSD SIGNIFICANCE LEVEL.	Particulate Matter < 10 µ (PM10)	A	ELECTROSTATIC PRECIPITATOR	20.45 LB/H
*LA-0201	RED RIVER MILL	WEYERHAEUSER CO	5/24/2006	LIME KILN NO. 2	NATURAL GAS	191625	TONS CaO/YR	MAXIMUM HEAT INPUTS PER FUEL: NATURAL GAS - 93 MM BTU/HR PETROLEUM COKE - 80 MM BTU/HR TURPENTINE - 5 MM BTU/HR EMISSION POINT NO. 11. THROUGHPUT IS 270 TONS CALCIUM OXIDE PER DAY. TOTAL ANNUAL THROUGHPUT OF LIME KILNS (EMISSION POINT NOS. 10 AND 11) LIMITED TO LESS THAN 162,500 TONS OF LIME, ON A ROLLING 12-MONTH BASIS, TO MAINTAIN NOX INCREASE BELOW PSD SIGNIFICANCE LEVEL.	Sulfur Dioxide (SO2)	B	FLUE GAS DESULFURIZATION, PROPER KILN DESIGN AND OPERATION, AND OPTIMIZED MUD WASHING	70 PPM @ 10% O2
LA-0174	PORT HUDSON OPERATIONS	GEORGIA-PACIFIC CORPORATION	1/25/2002	LIME KILN NO. 2		270	T/D	EMISSION POINT NO. 11. THROUGHPUT IS 270 TONS CALCIUM OXIDE PER DAY. TOTAL ANNUAL THROUGHPUT OF LIME KILNS (EMISSION POINT NOS. 10 AND 11) LIMITED TO LESS THAN 162,500 TONS OF LIME, ON A ROLLING 12-MONTH BASIS, TO MAINTAIN NOX INCREASE BELOW PSD SIGNIFICANCE LEVEL.	Sulfur Dioxide (SO2)	B	WET SCRUBBERS AND OPTIMAL MUD WASHING	2.59 LB/H
*LA-0201	RED RIVER MILL	WEYERHAEUSER CO	5/24/2006	LIME KILN NO. 2	NATURAL GAS	191625	TONS CaO/YR	MAXIMUM HEAT INPUTS PER FUEL: NATURAL GAS - 93 MM BTU/HR PETROLEUM COKE - 80 MM BTU/HR TURPENTINE - 5 MM BTU/HR EMISSION POINT NO. 11. THROUGHPUT IS 270 TONS CALCIUM OXIDE PER DAY. TOTAL ANNUAL THROUGHPUT OF LIME KILNS (EMISSION POINT NOS. 10 AND 11) LIMITED TO LESS THAN 162,500 TONS OF LIME, ON A ROLLING 12-MONTH BASIS, TO MAINTAIN NOX INCREASE BELOW PSD SIGNIFICANCE LEVEL.	Sulfur, Total Reduced (TRS)	P	PROPER KILN DESIGN AND OPERATION WITH OPTIMIZED MUD WASHING	8 PPM @ 10% O2
LA-0174	PORT HUDSON OPERATIONS	GEORGIA-PACIFIC CORPORATION	1/25/2002	LIME KILN NO. 2		270	T/D	EMISSION POINT NO. 11. THROUGHPUT IS 270 TONS CALCIUM OXIDE PER DAY. TOTAL ANNUAL THROUGHPUT OF LIME KILNS (EMISSION POINT NOS. 10 AND 11) LIMITED TO LESS THAN 162,500 TONS OF LIME, ON A ROLLING 12-MONTH BASIS, TO MAINTAIN NOX INCREASE BELOW PSD SIGNIFICANCE LEVEL.	Sulfur, Total Reduced (TRS)	N		2.81 LB/H
*TX-0515	INTERNATIONAL PAPER COMPANY PULP AND PAPER MILL	INTERNATIONAL PAPER COMPANY	1/11/2006	LIME KILN NO2					Nitrogen Oxides (NOx)	N		38.91 LB/HR
*TX-0515	INTERNATIONAL PAPER COMPANY PULP AND PAPER MILL	INTERNATIONAL PAPER COMPANY	1/11/2006	LIME KILN NO2					Particulate Matter < 10 µ (PM10)	N		26.3 LB/HR
*TX-0515	INTERNATIONAL PAPER COMPANY PULP AND PAPER MILL	INTERNATIONAL PAPER COMPANY	1/11/2006	LIME KILN NO2					Sulfur Dioxide (SO2)	N		1.2 LB/HR
*TX-0515	INTERNATIONAL PAPER COMPANY PULP AND PAPER MILL	INTERNATIONAL PAPER COMPANY	1/11/2006	LIME KILN NO2					Sulfur, Total Reduced (TRS)	N		2.5 LB/HR
*TX-0515	INTERNATIONAL PAPER COMPANY PULP AND PAPER MILL	INTERNATIONAL PAPER COMPANY	1/11/2006	LIME KILN NO2					Sulfuric Acid (mist, vapors, etc)	N		0.25 LB/HR
SC-0084	BOWATER COATED PAPER DIVISION	BOWATER	10/31/2001	LIME KILN, NO. 2	NO. 6 FUEL OIL			PSD Limits for PM/PM10 and NOx. Synthetic Minor Limits for CO and SO2	Nitrogen Oxides (NOx)	N		152 PPMVD @ 10 % O2
SC-0084	BOWATER COATED PAPER DIVISION	BOWATER	10/31/2001	LIME KILN, NO. 2	NO. 6 FUEL OIL			PSD Limits for PM/PM10 and NOx. Synthetic Minor Limits for CO and SO2	Particulate Matter (PM)	A	ESP	0.03 GR/DSCF @ 10% O2
*WA-0303	LONGVIEW FIBRE PAPER AND PACKAGING, INC	LONGVIEW FIBRE PAPER AND PACKAGING, INC	11/1/2006	LIME KILNS 1 AND 2		140	T CAO/D EACH	THE EXHAUST STACKS SHALL BE MODIFIED OR REPLACED SO MODELED EXHAUST GAS DISPERSION IS EQUAL TO OR BETTER THAN THAT INDICATED FOR THE ORIGINALLY-PROPOSED DESIGN IN THE PERMIT APPLICATION.	Nitrogen Oxides (NOx)	N		340 PPMVD @ 10% O2
*WA-0303	LONGVIEW FIBRE PAPER AND PACKAGING, INC	LONGVIEW FIBRE PAPER AND PACKAGING, INC	11/1/2006	LIME KILNS 1 AND 2		140	T CAO/D EACH	THE EXHAUST STACKS SHALL BE MODIFIED OR REPLACED SO MODELED EXHAUST GAS DISPERSION IS EQUAL TO OR BETTER THAN THAT INDICATED FOR THE ORIGINALLY-PROPOSED DESIGN IN THE PERMIT APPLICATION.	Particulate Matter (PM)	N		20 T/YR

**RBLC Search Results**  
**Port Townsend Paper Company**  
**Lime Kiln**

RBLC ID	FACILITY NAME	CORPORATE OR COMPANY NAME	PERMIT DATE	PROCESS NAME	FUEL	THRUPUT	THRUPUT UNIT	PROCESS NOTES	POLLUTANT	CONTROL CTRLDESC	EMISLIMIT1	EMISLIMIT1UNIT
*WA-0303	LONGVIEW FIBRE PAPER AND PACKAGING, INC	LONGVIEW FIBRE PAPER AND PACKAGING, INC	11/1/2006	LIME KILNS 1 AND 2			140 T CAO/D EACH	THE EXHAUST STACKS SHALL BE MODIFIED OR REPLACED SO MODELED EXHAUST GAS DISPERSION IS EQUAL TO OR BETTER THAN THAT INDICATED FOR THE ORIGINALLY-PROPOSED DESIGN IN THE PERMIT APPLICATION.	Sulfur Dioxide (SO2)	N		20 PPMVD @ 10% O2
*WA-0303	LONGVIEW FIBRE PAPER AND PACKAGING, INC	LONGVIEW FIBRE PAPER AND PACKAGING, INC	11/1/2006	LIME KILNS 1 AND 2			140 T CAO/D EACH	THE EXHAUST STACKS SHALL BE MODIFIED OR REPLACED SO MODELED EXHAUST GAS DISPERSION IS EQUAL TO OR BETTER THAN THAT INDICATED FOR THE ORIGINALLY-PROPOSED DESIGN IN THE PERMIT APPLICATION.	Sulfur, Total Reduced (TRS)	N		20 PPMVD @ 10% O2
GA-0095	WEYERHAEUSER - FLINT RIVER OPERATIONS	WEYERHAEUSER - FLINT RIVER OPERATIONS	5/28/2003	ROTARY LIME KILN	NO. 6 FUEL OIL		370 T/D	THE COMPANY REPLACED THE CALCINER WITH A ROTARY LIME KILN.	Nitrogen Oxides (NOx)	N		175 PPM @ 10% O2
GA-0095	WEYERHAEUSER - FLINT RIVER OPERATIONS	WEYERHAEUSER - FLINT RIVER OPERATIONS	5/28/2003	ROTARY LIME KILN	NO. 6 FUEL OIL		370 T/D	THE COMPANY REPLACED THE CALCINER WITH A ROTARY LIME KILN.	Particulate Matter (PM)	A	ESP	0.01 GR/DSCF @ 10% O2
GA-0095	WEYERHAEUSER - FLINT RIVER OPERATIONS	WEYERHAEUSER - FLINT RIVER OPERATIONS	5/28/2003	ROTARY LIME KILN	NO. 6 FUEL OIL		370 T/D	THE COMPANY REPLACED THE CALCINER WITH A ROTARY LIME KILN.	Sulfur, Total Reduced (TRS)	P	LOW SULFUR FUEL	8 PPMVD @ 10% O2
LA-0155	ST. FRANCISVILLE MILL	CROWN PAPER COMPANY	4/29/2001	DATED 4/5/89) REMAINS 2.0 LB/TON BLACK LIQUOR SOLIDS FIRED."	30.239		84 T/YR		Particulate Matter (PM)	N	NONE INDICATED	0.62 LB/H
LA-0155	ST. FRANCISVILLE MILL	CROWN PAPER COMPANY	4/29/2001	DATED 4/5/89) REMAINS 2.0 LB/TON BLACK LIQUOR SOLIDS FIRED."	30.239		148 T/YR		Particulate Matter (PM)	N	NONE INDICATED	0.62 LB/H
TX-0263	DONAHUE INDUSTRIES, INC. PAPER MILL	DONAHUE INDUSTRIES, INC.	10/17/2000	LIME MUD CLARIFICATION AND STORAGE					Sulfur, Total Reduced (TRS)	N	NONE INDICATED	0.02 LB/H
LA-0122	MANSFIELD MILL	INTERNATIONAL PAPER - MANSFIELD MILL	8/14/2001	LIME MUD PRECOAT FILTER			175200 TCAO/YR	EMISSION POINT 29-93U	Sulfur, Total Reduced (TRS)	N	NO ADDITIONAL CONTROL REQUIRED	0.16 LB/H
LA-0122	MANSFIELD MILL	INTERNATIONAL PAPER - MANSFIELD MILL	8/14/2001	LIME MUD STORAGE TANK			175200 TCAO/YR	EMISSION POINT 29-93T	Sulfur, Total Reduced (TRS)	N	NO ADDITIONAL CONTROL REQUIRED	0.08 LB/H
LA-0122	MANSFIELD MILL	INTERNATIONAL PAPER - MANSFIELD MILL	8/14/2001	LIME MUD WASHER 1 & 2			87600 TCAO/YR EACH	EMISSION POINTS 29-93R, 29-93S	Sulfur, Total Reduced (TRS)	N	NO ADDITIONAL CONTROL REQUIRED	0.04 LB/H
*TX-0485	INLAND PAPERBOARD AND PACKAGING ORANGE MILL	INLAND PAPERBOARD AND PACKAGING INC	10/5/2004	LIME SILO					Particulate Matter < 10 µ (PM10)	P	BEST MANAGEMENT PRACTICES FOR PULP WASHING, AND THE REDUCTION OF VOC ADDITIVES TO THE PAPERMAKING SYSTEM	3.4 LB/H
*TX-0485	INLAND PAPERBOARD AND PACKAGING ORANGE MILL	INLAND PAPERBOARD AND PACKAGING INC	10/5/2004	LIME SILO					Particulate Matter < 10 µ (PM10)	N		0.01 LB/H
LA-0122	MANSFIELD MILL	INTERNATIONAL PAPER - MANSFIELD MILL	8/14/2001	LIME SLAKER			30 T/H CAO	EMISSION POINT 08-78	Particulate Matter < 10 µ (PM10)	A	WET SCRUBBER	2.1 LB/H
LA-0122	MANSFIELD MILL	INTERNATIONAL PAPER - MANSFIELD MILL	8/14/2001	LIME SLAKER			30 T/H CAO	EMISSION POINT 08-78	Sulfur, Total Reduced (TRS)	A	WET SCRUBBER	0.14 LB/H
*LA-0207	MANSFIELD MILL	INTERNATIONAL PAPER CO	7/22/2004	LIME SLAKER (EQT014)					Particulate Matter (PM)	A	WET SCRUBBER	2.1 LB/H
*LA-0207	MANSFIELD MILL	INTERNATIONAL PAPER CO	7/22/2004	LIME SLAKER (EQT014)					Sulfur, Total Reduced (TRS)	A	WET SCRUBBER	0.14 LB/H
MS-0077	MONTICELLO MILL	GEORGIA PACIFIC CORPORATION	3/4/2005	AIR HEATER, PETROLEUM COKE			5 MMBTU/H	THE HEATER BURNS NATURAL GAS. THE HEATED AIR IS ROUTED TO THE PET COKE GRINDING MILL FOR USE AS SWEEP AIR TO DRY THE PET COKE.	Nitrogen Oxides (NOx)	P	GOOD COMBUSTION PRACTICES	0.37 LB/H
MS-0077	MONTICELLO MILL	GEORGIA PACIFIC CORPORATION	3/4/2005	AIR HEATER, PETROLEUM COKE			5 MMBTU/H	THE HEATER BURNS NATURAL GAS. THE HEATED AIR IS ROUTED TO THE PET COKE GRINDING MILL FOR USE AS SWEEP AIR TO DRY THE PET COKE.	Particulate Matter < 10 µ (PM10)	B	BAGHOUSE AND GOOD COMBUSTION PRACTICES	
MS-0077	MONTICELLO MILL	GEORGIA PACIFIC CORPORATION	3/4/2005	AIR HEATER, PETROLEUM COKE			5 MMBTU/H	THE HEATER BURNS NATURAL GAS. THE HEATED AIR IS ROUTED TO THE PET COKE GRINDING MILL FOR USE AS SWEEP AIR TO DRY THE PET COKE.	Sulfur Dioxide (SO2)	P	GOOD COMBUSTION PRACTICES	
*LA-0207	MANSFIELD MILL	INTERNATIONAL PAPER CO	7/22/2004	DIGESTER SYSTEMS, PRIMARY, SECONDARY, & SEMI-CHEMICAL					Sulfur, Total Reduced (TRS)	A	THERMAL INCINERATION IN THE LIME KILN OR NCG INCINERATOR	
TX-0263	DONAHUE INDUSTRIES, INC. PAPER MILL	DONAHUE INDUSTRIES, INC.	10/17/2000	LIME BLOWER				EMISSION RATES ARE BASED ON 8520 H/YR OF OPERATION	Particulate Matter < 10 µ (PM10)	N	NONE INDICATED	0.4 LB/H

**RBLC Search Results**  
**Port Townsend Paper Company**  
**Recovery Furnace**

RBLCID	FACILITYNAME	CORPORATEORCOMPANYNAME	PERMITDATE	PROCESSNAME	FUEL	THRUPUT THRUPUTUNIT	PROCESSNOTES	POLLUTANT	CONTROL CTRLDESC	EMISLIMIT1	EMISLIMIT1UNIT
LA-0155	ST. FRANCISVILLE MILL	CROWN PAPER COMPANY	4/29/2001	RECOVERY FURNACE		68.75 T/H BLS	THROUGHPUT: 68.75 T/H BLS = 825 MMBTU/H. CONVERTED USING 6000 BTU/LB BLS	Particulate Matter (PM)	A ELECTROSTATIC PRECIPITATOR	31.25	LB/H
MS-0078	MONTICELLO MILL	GEORGIA PACIFIC CORPORATION	5/14/2004	BOILER, NO. 1 RECOVERY	BLS	861.4 MMBTU/H	RECOVERY BOILER BURNS BLACK LIQUOR FROM KRAFT PULPING TO MAKE SMELT AND STEAM FOR PROCESS HEAT AND ELECTRIC GENERATION	Nitrogen Oxides (NOx)	P STAGED AIR COMBUSTION	200.2	LB/H
MS-0078	MONTICELLO MILL	GEORGIA PACIFIC CORPORATION	5/14/2004	BOILER, NO. 1 RECOVERY	BLS	861.4 MMBTU/H	RECOVERY BOILER BURNS BLACK LIQUOR FROM KRAFT PULPING TO MAKE SMELT AND STEAM FOR PROCESS HEAT AND ELECTRIC GENERATION	Particulate Matter < 10 µ (PM10)	A TWO ELECTROSTATIC PRECIPITATORS	194.3	LB/H
MS-0078	MONTICELLO MILL	GEORGIA PACIFIC CORPORATION	5/14/2004	BOILER, NO. 1 RECOVERY	BLS	861.4 MMBTU/H	RECOVERY BOILER BURNS BLACK LIQUOR FROM KRAFT PULPING TO MAKE SMELT AND STEAM FOR PROCESS HEAT AND ELECTRIC GENERATION	Sulfur Dioxide (SO2)	P COMBUSTION CONTROL AND FURNACE DESIGN	408.33	LB/H
MS-0078	MONTICELLO MILL	GEORGIA PACIFIC CORPORATION	5/14/2004	BOILER, NO. 1 RECOVERY	BLS	861.4 MMBTU/H	RECOVERY BOILER BURNS BLACK LIQUOR FROM KRAFT PULPING TO MAKE SMELT AND STEAM FOR PROCESS HEAT AND ELECTRIC GENERATION	Sulfur, Total Reduced (TRS)	P COMBUSTION CONTROL	31.5	LB/H
MS-0078	MONTICELLO MILL	GEORGIA PACIFIC CORPORATION	5/14/2004	BOILER, NO. 1 RECOVERY	BLS	861.4 MMBTU/H	RECOVERY BOILER BURNS BLACK LIQUOR FROM KRAFT PULPING TO MAKE SMELT AND STEAM FOR PROCESS HEAT AND ELECTRIC GENERATION	Sulfuric Acid (mist, vapors, etc)	P COMBUSTION CONTROLS		
MS-0078	MONTICELLO MILL	GEORGIA PACIFIC CORPORATION	5/14/2004	BOILER, NO. 2 RECOVERY	BLS	861.4 mmbtu/h	RECOVERY BOILER BURNS BLACK LIQUOR FROM KRAFT PULPING TO MAKE SMELT AND STEAM FOR PROCESS HEAT AND ELECTRIC GENERATION	Nitrogen Oxides (NOx)	P STAGED AIR COMBUSTION	200.2	LB/H
MS-0078	MONTICELLO MILL	GEORGIA PACIFIC CORPORATION	5/14/2004	BOILER, NO. 2 RECOVERY	BLS	861.4 mmbtu/h	RECOVERY BOILER BURNS BLACK LIQUOR FROM KRAFT PULPING TO MAKE SMELT AND STEAM FOR PROCESS HEAT AND ELECTRIC GENERATION	Particulate Matter < 10 µ (PM10)	A TWO ESP	194.3	LB/H
MS-0078	MONTICELLO MILL	GEORGIA PACIFIC CORPORATION	5/14/2004	BOILER, NO. 2 RECOVERY	BLS	861.4 mmbtu/h	RECOVERY BOILER BURNS BLACK LIQUOR FROM KRAFT PULPING TO MAKE SMELT AND STEAM FOR PROCESS HEAT AND ELECTRIC GENERATION	Sulfur Dioxide (SO2)	P COMBUSTION CONTROL AND FURNACE DESIGN	408.33	LB/H
MS-0078	MONTICELLO MILL	GEORGIA PACIFIC CORPORATION	5/14/2004	BOILER, NO. 2 RECOVERY	BLS	861.4 mmbtu/h	RECOVERY BOILER BURNS BLACK LIQUOR FROM KRAFT PULPING TO MAKE SMELT AND STEAM FOR PROCESS HEAT AND ELECTRIC GENERATION	Sulfur, Total Reduced (TRS)	P COMBUSTION CONTROL	31.5	LB/H
MS-0078	MONTICELLO MILL	GEORGIA PACIFIC CORPORATION	5/14/2004	BOILER, NO. 2 RECOVERY	BLS	861.4 mmbtu/h	RECOVERY BOILER BURNS BLACK LIQUOR FROM KRAFT PULPING TO MAKE SMELT AND STEAM FOR PROCESS HEAT AND ELECTRIC GENERATION	Sulfuric Acid (mist, vapors, etc)	P COMBUSTION CONTROL		
AL-0116	GULF STATES PAPER CORPORATION	GULF STATES PAPER CORPORATION	12/10/1997	FURNACE, RECOVERY		3.94 MMLB/D BLS		Nitrogen Dioxide (NO2)	P PROPER DESIGN AND OPERATION	90	PPMDV @ 8% O2
AR-0027	POTLATCH CORPORATION - CYPRESS BEND MILL	POTLATCH CORPORATION - CYPRESS BEND MILL	3/13/2000	FURNACE, RECOVERY	BLACK LIQUID SOLIDS	2.57 MMLB BLS/D	MODIFICATION OF RECOVERY FURNACE	Nitrogen Oxides (NOx)	P PROPER DESIGN AND OPERATION	110	PPMDV
AL-0116	GULF STATES PAPER CORPORATION	GULF STATES PAPER CORPORATION	12/10/1997	FURNACE, RECOVERY		3.94 MMLB/D BLS		Particulate Matter (PM)	A ESP	0.021	GR/DSCF @ 8% O2
AL-0116	GULF STATES PAPER CORPORATION	GULF STATES PAPER CORPORATION	12/10/1997	FURNACE, RECOVERY		3.94 MMLB/D BLS		Sulfur Dioxide (SO2)	P PROPER DESIGN AND OPERATON	100	PPMDV @ 8% O2
AR-0027	POTLATCH CORPORATION - CYPRESS BEND MILL	POTLATCH CORPORATION - CYPRESS BEND MILL	3/13/2000	FURNACE, RECOVERY	BLACK LIQUID SOLIDS	2.57 MMLB BLS/D	MODIFICATION OF RECOVERY FURNACE	Sulfur, Total Reduced (TRS)	P PROPER DESIGN AND OPERATION	5	PPMDV
AL-0116	GULF STATES PAPER CORPORATION	GULF STATES PAPER CORPORATION	12/10/1997	FURNACE, RECOVERY		3.94 MMLB/D BLS		Sulfur, Total Reduced (TRS)	P PROPER DESIGN AND OPERATION	5	PPMDV @ 8% O2
AL-0116	GULF STATES PAPER CORPORATION	GULF STATES PAPER CORPORATION	12/10/1997	FURNACE, RECOVERY		3.94 MMLB/D BLS		Sulfuric Acid (mist, vapors, etc)	N	0.042	LB/T BLS
AL-0123	U S ALLIANCE	U S ALLIANCE	9/25/1998	FURNACE, RECOVERY, NO. 4	BLACK LIQUOR	0		Nitrogen Oxides (NOx)	N	338.5	LB/H
AL-0123	U S ALLIANCE	U S ALLIANCE	9/25/1998	FURNACE, RECOVERY, NO. 4	BLACK LIQUOR	0		Particulate Matter (PM)	N	0.015	GR/DSCF @ 8% O2
AL-0123	U S ALLIANCE	U S ALLIANCE	9/25/1998	FURNACE, RECOVERY, NO. 4	BLACK LIQUOR	0		Sulfur Dioxide (SO2)	N	1647.7	LB/H
AL-0123	U S ALLIANCE	U S ALLIANCE	9/25/1998	FURNACE, RECOVERY, NO. 4	BLACK LIQUOR	0		Sulfur, Total Reduced (TRS)	N	5	PPM @ 8% O2
WI-0208	DOMTAR NEKOOSA MILL	DOMTAR INDUSTRIES INC.	4/23/2004	KRAFT BLACK LIQUOR RECOVERY FURNACE, B14	TRONG BLACK LIQUOI	37.5 bl	BLRF FIRES T/H STRONG BLACK LIQUOR; NATURAL GAS SUPPLEMENTAL FUEL	Nitrogen Oxides (NOx)	P GOOD COMBUSTION CONTROL	90	PPMDV @ 8% O2
WI-0208	DOMTAR NEKOOSA MILL	DOMTAR INDUSTRIES INC.	4/23/2004	KRAFT BLACK LIQUOR RECOVERY FURNACE, B14	TRONG BLACK LIQUOI	37.5 bl	BLRF FIRES T/H STRONG BLACK LIQUOR; NATURAL GAS SUPPLEMENTAL FUEL	Particulate Matter (PM)	A EXISTING ESP	0.03	GR/DSCF @ 8% O2
WI-0208	DOMTAR NEKOOSA MILL	DOMTAR INDUSTRIES INC.	4/23/2004	KRAFT BLACK LIQUOR RECOVERY FURNACE, B14	TRONG BLACK LIQUOI	37.5 bl	BLRF FIRES T/H STRONG BLACK LIQUOR; NATURAL GAS SUPPLEMENTAL FUEL	Sulfur Dioxide (SO2)	P GOOD OPERATING PRACTICES	60	PPMDV @ 8% O2
WI-0208	DOMTAR NEKOOSA MILL	DOMTAR INDUSTRIES INC.	4/23/2004	KRAFT BLACK LIQUOR RECOVERY FURNACE, B14	TRONG BLACK LIQUOI	37.5 bl	BLRF FIRES T/H STRONG BLACK LIQUOR; NATURAL GAS SUPPLEMENTAL FUEL	Sulfur, Total Reduced (TRS)	P GOOD OPERATING PRACTICES	5	PPMDV @ 8% O2
*TX-0515	INTERNATIONAL PAPER COMPANY PULP AND PAPER MILL	INTERNATIONAL PAPER COMPANY	1/11/2006	NO 1 RECOVERY FURNACE NORTH/SOUTH STACK			EMISSIONS ARE FOR EACH STACK (2)	Nitrogen Oxides (NOx)	N	63.12	LB/HR
*TX-0515	INTERNATIONAL PAPER COMPANY PULP AND PAPER MILL	INTERNATIONAL PAPER COMPANY	1/11/2006	NO 1 RECOVERY FURNACE NORTH/SOUTH STACK			EMISSIONS ARE FOR EACH STACK (2)	Particulate Matter < 10 µ (PM10)	N	26.58	LB/HR
*TX-0515	INTERNATIONAL PAPER COMPANY PULP AND PAPER MILL	INTERNATIONAL PAPER COMPANY	1/11/2006	NO 1 RECOVERY FURNACE NORTH/SOUTH STACK			EMISSIONS ARE FOR EACH STACK (2)	Sulfur Dioxide (SO2)	N	210.94	LB/HR
*TX-0515	INTERNATIONAL PAPER COMPANY PULP AND PAPER MILL	INTERNATIONAL PAPER COMPANY	1/11/2006	NO 1 RECOVERY FURNACE NORTH/SOUTH STACK			EMISSIONS ARE FOR EACH STACK (2)	Sulfur, Total Reduced (TRS)	N	1.87	LB/HR
*TX-0515	INTERNATIONAL PAPER COMPANY PULP AND PAPER MILL	INTERNATIONAL PAPER COMPANY	1/11/2006	NO 1 RECOVERY FURNACE NORTH/SOUTH STACK			EMISSIONS ARE FOR EACH STACK (2)	Sulfuric Acid (mist, vapors, etc)	N	9.69	LB/HR
*TX-0515	INTERNATIONAL PAPER COMPANY PULP AND PAPER MILL	INTERNATIONAL PAPER COMPANY	1/11/2006	NO 1 RECOVERY FURNACE NORTH/SOUTH STACK-MSS			EMISSIONS ARE PER STACK (2)	Particulate Matter < 10 µ (PM10)	N	52	LB/HR
*TX-0515	INTERNATIONAL PAPER COMPANY PULP AND PAPER MILL	INTERNATIONAL PAPER COMPANY	1/11/2006	NO 2 RECOVERY FURNACE EAST/WEST STACK			EMISSIONS ARE PER STACK (2)	Nitrogen Oxides (NOx)	N	112.42	LB/HR
*TX-0515	INTERNATIONAL PAPER COMPANY PULP AND PAPER MILL	INTERNATIONAL PAPER COMPANY	1/11/2006	NO 2 RECOVERY FURNACE EAST/WEST STACK			EMISSIONS ARE PER STACK (2)	Particulate Matter < 10 µ (PM10)	N	42.59	LB/HR
*TX-0515	INTERNATIONAL PAPER COMPANY PULP AND PAPER MILL	INTERNATIONAL PAPER COMPANY	1/11/2006	NO 2 RECOVERY FURNACE EAST/WEST STACK			EMISSIONS ARE PER STACK (2)	Sulfur Dioxide (SO2)	N	375.71	LB/HR
*TX-0515	INTERNATIONAL PAPER COMPANY PULP AND PAPER MILL	INTERNATIONAL PAPER COMPANY	1/11/2006	NO 2 RECOVERY FURNACE EAST/WEST STACK			EMISSIONS ARE PER STACK (2)	Sulfur, Total Reduced (TRS)	N	3.33	LB/HR
*TX-0515	INTERNATIONAL PAPER COMPANY PULP AND PAPER MILL	INTERNATIONAL PAPER COMPANY	1/11/2006	NO 2 RECOVERY FURNACE EAST/WEST STACK			EMISSIONS ARE PER STACK (2)	Sulfuric Acid (mist, vapors, etc)	N	17.25	LB/HR
*TX-0515	INTERNATIONAL PAPER COMPANY PULP AND PAPER MILL	INTERNATIONAL PAPER COMPANY	1/11/2006	NO 2 RECOVERY FURNACE EAST/WEST STACK-MSS			EMISSIONS ARE PER STACK (2)	Particulate Matter < 10 µ (PM10)	N	79	LB/HR
SC-0083	WEYERHAEUSER COMPANY-MARLBORO PAPER MILL	WEYERHAEUSER COMPANY	12/10/2002	NO. 1 RECOVERY FURNACE	HEAVY BLACK LIQUOF	4.4 MMLB/D	Throughput is mmlb of BLS per day	Nitrogen Oxides (NOx)	P ADDITION OF 4TH LEVEL OF AIR TO RECOVERY FURNACE/GOOD COMBUSTION PRACTICE/RECOVERY FURNACE FIRING RATE AND PULP PRODUCTION LIMITS (4.4 MMLB BLS/D AND 1410 ADTBP/D)	100	PPM @ 8% O2

**RBLC Search Results  
Port Townsend Paper Company  
Recovery Furnace**

RBLCID	FACILITYNAME	CORPORATEORCOMPANYNAME	PERMITDATE	PROCESSNAME	FUEL	THRUPUT	THRUPUTUNIT	PROCESSNOTES	POLLUTANT	CONTROL	CTRLDESC	EMISLIMIT1	EMISLIMIT1UNIT
SC-0083	WEYERHAEUSER COMPANY-MARLBORO PAPER MILL	WEYERHAEUSER COMPANY	12/10/2002	NO. 1 RECOVERY FURNACE		4.4	MLLB/D	Throughput is mmlb of BLS per day	Particulate Matter (PM)	B	ELECTROSTATIC PRECIPITATOR/RECOVERY FURNACE FIRING RATE AND PULP PRODUCTION (4.4 MM LB BLS/D AND 1410 ADTBP/D) LIMITS	0.021	GR/DSCF@ 8% O2
AL-0201	INTERNATIONAL PAPER COMPANY-PRATTVILLE	INTERNATIONAL PAPER COMPANY	2/21/2001	NO. 1 RECOVERY FURNACE	HEAVY BLACK LIQUOF	2.85	MLLB/D	Existing Furnace to be modified with larger induced draft and automatic port rodders.	Sulfur / Sulfates	N		20	PPM
SC-0083	WEYERHAEUSER COMPANY-MARLBORO PAPER MILL	WEYERHAEUSER COMPANY	12/10/2002	NO. 1 RECOVERY FURNACE	HEAVY BLACK LIQUOF	4.4	MLLB/D	Throughput is mmlb of BLS per day	Sulfur Dioxide (SO2)	P	GOOD COMBUSTION/RECOVERY FURNACE FIRING RATE AND PULP PRODUCTION LIMITS (4.4 MM LB BLS/D AND 1410 ADTBP/D)	75	PPM @ 8% O2
SC-0083	WEYERHAEUSER COMPANY-MARLBORO PAPER MILL	WEYERHAEUSER COMPANY	12/10/2002	NO. 1 RECOVERY FURNACE	HEAVY BLACK LIQUOF	4.4	MLLB/D	Throughput is mmlb of BLS per day	Sulfur, Total Reduced (TRS)	P	LOW ODOR RECOVERY FURNACE/GOOD COMBUSTION PRACTICE/RECOVERY FURNACE FIRING RATE AND PULP PRODUCTION LIMITS (4.4 MM LB BLS/D AND 1410 ADTBP/D)	4	PPM @ 8% O2
AL-0148	IP PRATTVILLE	INTERNATIONAL PAPER COMPANY	4/14/2000	NO. 1 RECOVERY FURNACE	BLACK LIQUOR SOLIDS	2.85	MLLB/D	EXISTING FURNACE TO BE MODIFIED WITH LARGER INDUCED DRAFT AND AUTOMATIC PORT RODDERS	Sulfur, Total Reduced (TRS)	N		20	PPM
SC-0083	WEYERHAEUSER COMPANY-MARLBORO PAPER MILL	WEYERHAEUSER COMPANY	12/10/2002	NO. 1 RECOVERY FURNACE	HEAVY BLACK LIQUOF	4.4	MLLB/D	Throughput is mmlb of BLS per day	Sulfuric Acid (mist, vapors, etc)	P	RECOVERY FURNACE FIRING RATE AND PULP PRODUCTION LIMITS (4.4 MM LB BLS/D AND 1410 ADTBP/D)	2.21	LB/H
LA-0117	GAYLORD CONTAINER CORP - BOGALUSA MILL	GAYLORD CONTAINER CORP	3/18/1999	PULP MILL, RECOVERY FURNACE, BLACK LIQUOR SOLID FU	BLS	908	MMBTU/H	THE FURNACE WAS CONSTRUCTED IN 1989 UNDER A PSD PERMIT. EMISSIONS WERE UNDERESTIMATED. BLS=BLACK LIQUOR SOLIDS. FURNACE #21.	Particulate Matter < 10 µ (PM10)	N		78.64	LB/H
NC-0092	RIEGELWOOD MILL	INTERNATIONAL PAPER COMPANY	5/10/2001	RECOVERY BOILER	NO. 6 FUEL OIL	557	MMBTU/H	BOILER FIRES AN AVERAGE OF 5.59 MILLION POUNDS OF BLACK LIQUOR SOLIDS PER DAY.	Nitrogen Dioxide (NO2)	P	GOOD COMBUSTION PRACTICE	586.5	LB/H
TX-0263	DONAHUE INDUSTRIES, INC. PAPER MILL	DONAHUE INDUSTRIES, INC.	10/17/2000	RECOVERY BOILER				EMISSION RATES ARE BASED ON 8640 H/YR OF OPERATION	Nitrogen Oxides (NOx)	N	NONE INDICATED	55	LB/H
GA-0092	GEORGIA PACIFIC CORP. - CEDAR SPRING OPERATIONS	GEORGIA PACIFIC CORP.	7/25/2002	RECOVERY BOILER	BLS			No process modifications actually made (PSD triggered on maintenance project). No actual increases occurred. For SO2, NOx, CO, TS, H2S, and SAM, pollution prevention is staged combustion & good air pollution control practices.	Particulate Matter (PM)	A	ESP	49.7	LB/H
NC-0092	RIEGELWOOD MILL	INTERNATIONAL PAPER COMPANY	5/10/2001	RECOVERY BOILER	NO. 6 FUEL OIL	557	MMBTU/H	BOILER FIRES AN AVERAGE OF 5.59 MILLION POUNDS OF BLACK LIQUOR SOLIDS PER DAY.	Particulate Matter (PM)	A	ESP	0.044	GR/DSCF @ 8% O2
TX-0263	DONAHUE INDUSTRIES, INC. PAPER MILL	DONAHUE INDUSTRIES, INC.	10/17/2000	RECOVERY BOILER				EMISSION RATES ARE BASED ON 8640 H/YR OF OPERATION	Particulate Matter < 10 µ (PM10)	N	NONE INDICATED	50.5	LB/H
NC-0092	RIEGELWOOD MILL	INTERNATIONAL PAPER COMPANY	5/10/2001	RECOVERY BOILER	NO. 6 FUEL OIL	557	MMBTU/H	BOILER FIRES AN AVERAGE OF 5.59 MILLION POUNDS OF BLACK LIQUOR SOLIDS PER DAY.	Sulfur Dioxide (SO2)	P	GOOD COMBUSTION PRACTICE	979.2	LB/H
TX-0263	DONAHUE INDUSTRIES, INC. PAPER MILL	DONAHUE INDUSTRIES, INC.	10/17/2000	RECOVERY BOILER				EMISSION RATES ARE BASED ON 8640 H/YR OF OPERATION	Sulfur Dioxide (SO2)	N	NONE INDICATED	206	LB/H
TX-0263	DONAHUE INDUSTRIES, INC. PAPER MILL	DONAHUE INDUSTRIES, INC.	10/17/2000	RECOVERY BOILER				EMISSION RATES ARE BASED ON 8640 H/YR OF OPERATION	Sulfur, Total Reduced (TRS)	N	NONE INDICATED	2.7	LB/H
TX-0263	DONAHUE INDUSTRIES, INC. PAPER MILL	DONAHUE INDUSTRIES, INC.	10/17/2000	RECOVERY BOILER				EMISSION RATES ARE BASED ON 8640 H/YR OF OPERATION	Sulfuric Acid (mist, vapors, etc)	N	NONE INDICATED	4.6	LB/H
*MS-0075	MONTICELLO MILL	GEORGIA PACIFIC CORP.	7/9/2003	RECOVERY BOILER NO. 1	BLACK LIQUOR	861.4	MMBTU/H	BOILER BURNS CONCENTRATED BLACK LIQUOR TO RECOVER DIGESTING CHEMICAL.	Nitrogen Oxides (NOx)	N		200.2	LB/H
*MS-0075	MONTICELLO MILL	GEORGIA PACIFIC CORP.	7/9/2003	RECOVERY BOILER NO. 1	BLACK LIQUOR	861.4	MMBTU/H	BOILER BURNS CONCENTRATED BLACK LIQUOR TO RECOVER DIGESTING CHEMICAL.	Particulate Matter < 10 µ (PM10)	A	ESP	194.3	LB/H
*MS-0075	MONTICELLO MILL	GEORGIA PACIFIC CORP.	7/9/2003	RECOVERY BOILER NO. 1	BLACK LIQUOR	861.4	MMBTU/H	BOILER BURNS CONCENTRATED BLACK LIQUOR TO RECOVER DIGESTING CHEMICAL.	Sulfur Dioxide (SO2)	N		408.33	LB/H
*MS-0075	MONTICELLO MILL	GEORGIA PACIFIC CORP.	7/9/2003	RECOVERY BOILER NO. 2	BLACK LIQUOR	861.4	MMBTU/H		Nitrogen Oxides (NOx)	N		200.2	LB/H
*MS-0075	MONTICELLO MILL	GEORGIA PACIFIC CORP.	7/9/2003	RECOVERY BOILER NO. 2	BLACK LIQUOR	861.4	MMBTU/H		Particulate Matter (PM)	A	ESP	194.3	LB/H
*MS-0075	MONTICELLO MILL	GEORGIA PACIFIC CORP.	7/9/2003	RECOVERY BOILER NO. 2	BLACK LIQUOR	861.4	MMBTU/H		Sulfur Dioxide (SO2)	N		408.33	LB/H
*LA-0201	RED RIVER MILL	WEYERHAEUSER CO	5/24/2006	RECOVERY BOILER NO. 3	BLACK LIQUOR	6.4	MM LB/DAY	RECOVERY BOILER NO. 3 & SMELT TANK NO. 3 VENT THROUGH A COMMON STACK.	Nitrogen Oxides (NOx)	P	PROPER COMBUSTION CONTROL AND AIR COMBUSTION OPTIMIZATION	80	PPM @ 8% O2
*LA-0201	RED RIVER MILL	WEYERHAEUSER CO	5/24/2006	RECOVERY BOILER NO. 3	BLACK LIQUOR	6.4	MM LB/DAY	RECOVERY BOILER NO. 3 & SMELT TANK NO. 3 VENT THROUGH A COMMON STACK.	Particulate Matter < 10 µ (PM10)	A	ELECTROSTATIC PRECIPITATOR		
*LA-0201	RED RIVER MILL	WEYERHAEUSER CO	5/24/2006	RECOVERY BOILER NO. 3	BLACK LIQUOR	6.4	MM LB/DAY	RECOVERY BOILER NO. 3 & SMELT TANK NO. 3 VENT THROUGH A COMMON STACK.	Sulfur Dioxide (SO2)	P	PROPER BOILER DESIGN AND OPERATION		
*LA-0201	RED RIVER MILL	WEYERHAEUSER CO	5/24/2006	RECOVERY BOILER NO. 3	BLACK LIQUOR	6.4	MM LB/DAY	RECOVERY BOILER NO. 3 & SMELT TANK NO. 3 VENT THROUGH A COMMON STACK.	Sulfur, Total Reduced (TRS)	P	PROPER BOILER DESIGN AND OPERATION	3	PPM @ 8% O2
LA-0122	MANSFIELD MILL	INTERNATIONAL PAPER - MANSFIELD MILL	8/14/2001	RECOVERY BOILER NO.1 AND NO.2		71	TBLS/H	EMISSION POINTS 04-78, 05-78	Nitrogen Oxides (NOx)	P	GOOD PROCESS CONTROLS	147.8	LB/H
LA-0122	MANSFIELD MILL	INTERNATIONAL PAPER - MANSFIELD MILL	8/14/2001	RECOVERY BOILER NO.1 AND NO.2		71	TBLS/H	EMISSION POINTS 04-78, 05-78	Particulate Matter < 10 µ (PM10)	A	ESP	96.5	LB/H
LA-0122	MANSFIELD MILL	INTERNATIONAL PAPER - MANSFIELD MILL	8/14/2001	RECOVERY BOILER NO.1 AND NO.2		71	TBLS/H	EMISSION POINTS 04-78, 05-78	Sulfur Dioxide (SO2)	P	GOOD PROCESS CONTROLS	510	LB/H
LA-0122	MANSFIELD MILL	INTERNATIONAL PAPER - MANSFIELD MILL	8/14/2001	RECOVERY BOILER NO.1 AND NO.2		71	TBLS/H	EMISSION POINTS 04-78, 05-78	Sulfur, Total Reduced (TRS)	P	GOOD PROCESS CONTROLS	5	PPMV
WI-0141	MOSINEE PAPER CORPORATION	MOSINEE PAPER CORPORATION	12/18/2000	RECOVERY BOILER, PROCESS #B21, STACK #S11	BLACK LIQUOR	250	MMBTU/H	THE BLACK LIQUOR IS SPRAYED INTO THE RECOVERY FURNACE. THE ORGANIC MATERIALS IN THE BLACK LIQUOR ARE COMBUSTED AND THE SODIUM SUFATE IS REDUCED TO SODIUM SULFIDE.	Nitrogen Oxides (NOx)	P	THE PERMITTEE SHALL DEMONSTRATE GOOD COMBUSTION OPERATIONS BY MONITORING THE TEMPERATURE OF THE GAS STREAM AND THE IN-STU PERCENT OF OXYGEN OF THE FLUE GAS.	186.2	T/YR
WI-0141	MOSINEE PAPER CORPORATION	MOSINEE PAPER CORPORATION	12/18/2000	RECOVERY BOILER, PROCESS #B21, STACK #S11	BLACK LIQUOR	250	MMBTU/H	THE BLACK LIQUOR IS SPRAYED INTO THE RECOVERY FURNACE. THE ORGANIC MATERIALS IN THE BLACK LIQUOR ARE COMBUSTED AND THE SODIUM SUFATE IS REDUCED TO SODIUM SULFIDE.	Particulate Matter (PM)	A	ESP	79.76	T/YR

**RBLC Search Results**  
**Port Townsend Paper Company**  
**Recovery Furnace**

RBLCID	FACILITYNAME	CORPORATEORCOMPANYNAME	PERMITDATE	PROCESSNAME	FUEL	THRUPUT	THRUPUTUNIT	PROCESSNOTES	POLLUTANT	CONTROL CTRLDESC	EMISLIMIT1	EMISLIMIT1UNIT
WI-0141	MOSINEE PAPER CORPORATION	MOSINEE PAPER CORPORATION	12/18/2000	RECOVERY BOILER, PROCESS #B21, STACK #S11	BLACK LIQUOR	250	MMBTU/H	THE BLACK LIQUOR IS SPRAYED INTO THE RECOVERY FURNACE. THE ORGANIC MATERIALS IN THE BLACK LIQUOR ARE COMBUSTED AND THE SODIUM SUFATE IS REDUCED TO SODIUM SULFIDE.	Sulfur Dioxide (SO2)	N	209.8	T/YR
WI-0141	MOSINEE PAPER CORPORATION	MOSINEE PAPER CORPORATION	12/18/2000	RECOVERY BOILER, PROCESS #B21, STACK #S11	BLACK LIQUOR	250	MMBTU/H	THE BLACK LIQUOR IS SPRAYED INTO THE RECOVERY FURNACE. THE ORGANIC MATERIALS IN THE BLACK LIQUOR ARE COMBUSTED AND THE SODIUM SUFATE IS REDUCED TO SODIUM SULFIDE.	Sulfur, Total Reduced (TRS)	P	7.23	T/YR
WI-0141	MOSINEE PAPER CORPORATION	MOSINEE PAPER CORPORATION	12/18/2000	RECOVERY BOILER, PROCESS #B21, STACK #S11	BLACK LIQUOR	250	MMBTU/H	THE BLACK LIQUOR IS SPRAYED INTO THE RECOVERY FURNACE. THE ORGANIC MATERIALS IN THE BLACK LIQUOR ARE COMBUSTED AND THE SODIUM SUFATE IS REDUCED TO SODIUM SULFIDE.	Sulfuric Acid (mist, vapors, etc)	N	0.663	LB/H
*LA-0207	MANSFIELD MILL	INTERNATIONAL PAPER CO	7/22/2004	RECOVERY BOILERS NO. 1 & 2 (EQT036 & 037)		961.3	MMBTU/H	THROUGHPUT FOR EACH. MAXIMUM RATES: 84 TBLS/HR; 703,850 TBLS/YR	Nitrogen Oxides (NOx)	P	135	LB/H
*LA-0207	MANSFIELD MILL	INTERNATIONAL PAPER CO	7/22/2004	RECOVERY BOILERS NO. 1 & 2 (EQT036 & 037)		961.3	MMBTU/H	THROUGHPUT FOR EACH. MAXIMUM RATES: 84 TBLS/HR; 703,850 TBLS/YR	Particulate Matter (PM)	A	100.5	LB/H
*LA-0207	MANSFIELD MILL	INTERNATIONAL PAPER CO	7/22/2004	RECOVERY BOILERS NO. 1 & 2 (EQT036 & 037)		961.3	MMBTU/H	THROUGHPUT FOR EACH. MAXIMUM RATES: 84 TBLS/HR; 703,850 TBLS/YR	Sulfur Dioxide (SO2)	P	217.6	LB/H
*LA-0207	MANSFIELD MILL	INTERNATIONAL PAPER CO	7/22/2004	RECOVERY BOILERS NO. 1 & 2 (EQT036 & 037)		961.3	MMBTU/H	THROUGHPUT FOR EACH. MAXIMUM RATES: 84 TBLS/HR; 703,850 TBLS/YR	Sulfur, Total Reduced (TRS)	P	25.1	T/YR
*LA-0207	MANSFIELD MILL	INTERNATIONAL PAPER CO	7/22/2004	RECOVERY BOILERS NO. 1 & 2 (EQT036 & 037)		961.3	MMBTU/H	THROUGHPUT FOR EACH. MAXIMUM RATES: 84 TBLS/HR; 703,850 TBLS/YR	Sulfuric Acid (mist, vapors, etc)	P	6	LB/H
AL-0222	ROCK-TENN MILL COMPANY, LLC	ROCK-TENN MILL COMPANY, LLC	6/3/2004	RECOVERY FURNACE		4.32	mmlb/day	4.32 MMLBS/DAY OF BLACK LIQUOR SOLIDS	Nitrogen Oxides (NOx)	N	110	PPMV @ 8% O2
NC-0089	ROANOKE RAPIDS MILL	CHAMPION INTERNATIONAL CORPORATION	7/31/1998	RECOVERY FURNACE	BLACK LIQUOR SOLIDS	2.77	MM LB/D	FURNACE ALSO LIMITED TO BURNING 744,000 GAL/YR NO. 6 FUEL OIL.	Nitrogen Oxides (NOx)	P	110	PPM @ 8% O2
AL-0222	ROCK-TENN MILL COMPANY, LLC	ROCK-TENN MILL COMPANY, LLC	6/3/2004	RECOVERY FURNACE		4.32	mmlb/day	4.32 MMLBS/DAY OF BLACK LIQUOR SOLIDS Throughput is lb steam/h. Recovery furnace is designed to recover and regenerate spent cooking chemicals from wood pulping operations. The furnace is also the primary steam generating unit at the mill. Permitted modifications are: improved furnace ash chemistry; re-evaluate current sootblowing sequence; optimize recovery furnace scrubber to handle increased solids load; circulation study.	Particulate Matter (PM)	A	0.021	GR/DSCF @ 8% O2
KY-0085	MEADWESTVACO KENTUCKY, INC/WICKLIFFE	MEADWESTVACO KENTUCKY, INC	2/27/2002	RECOVERY FURNACE		473000	LB/H	FURNACE ALSO LIMITED TO BURNING 744,000 GAL/YR NO. 6 FUEL OIL.	Particulate Matter (PM)	A	1.35	LB/T ADP
NC-0089	ROANOKE RAPIDS MILL	CHAMPION INTERNATIONAL CORPORATION	7/31/1998	RECOVERY FURNACE	BLACK LIQUOR SOLIDS	2.77	MM LB/D	4.32 MMLBS/DAY OF BLACK LIQUOR SOLIDS Throughput is lb steam/h. Recovery furnace is designed to recover and regenerate spent cooking chemicals from wood pulping operations. The furnace is also the primary steam generating unit at the mill. Permitted modifications are: improved furnace ash chemistry; re-evaluate current sootblowing sequence; optimize recovery furnace scrubber to handle increased solids load; circulation study.	Particulate Matter < 10 µ (PM10)	A	0.021	GR/DSCF @ 8% O2
AL-0222	ROCK-TENN MILL COMPANY, LLC	ROCK-TENN MILL COMPANY, LLC	6/3/2004	RECOVERY FURNACE		4.32	mmlb/day	4.32 MMLBS/DAY OF BLACK LIQUOR SOLIDS Throughput is lb steam/h. Recovery furnace is designed to recover and regenerate spent cooking chemicals from wood pulping operations. The furnace is also the primary steam generating unit at the mill. Permitted modifications are: improved furnace ash chemistry; re-evaluate current sootblowing sequence; optimize recovery furnace scrubber to handle increased solids load; circulation study.	Sulfur Dioxide (SO2)	N	100	PPMV @ 8% O2
KY-0085	MEADWESTVACO KENTUCKY, INC/WICKLIFFE	MEADWESTVACO KENTUCKY, INC	2/27/2002	RECOVERY FURNACE		473000	LB/H	FURNACE ALSO LIMITED TO BURNING 744,000 GAL/YR NO. 6 FUEL OIL.	Sulfur Dioxide (SO2)	A	0.29	LB/T ADP
NC-0089	ROANOKE RAPIDS MILL	CHAMPION INTERNATIONAL CORPORATION	7/31/1998	RECOVERY FURNACE	BLACK LIQUOR SOLIDS	2.77	MM LB/D	4.32 MMLBS/DAY OF BLACK LIQUOR SOLIDS Throughput is lb steam/h. Recovery furnace is designed to recover and regenerate spent cooking chemicals from wood pulping operations. The furnace is also the primary steam generating unit at the mill. Permitted modifications are: improved furnace ash chemistry; re-evaluate current sootblowing sequence; optimize recovery furnace scrubber to handle increased solids load; circulation study.	Sulfur Dioxide (SO2)	P	75	PPM @ 8% O2
AL-0222	ROCK-TENN MILL COMPANY, LLC	ROCK-TENN MILL COMPANY, LLC	38141	RECOVERY FURNACE		4.32	mmlb/day	4.32 MMLBS/DAY OF BLACK LIQUOR SOLIDS Throughput is lb steam/h. Recovery furnace is designed to recover and regenerate spent cooking chemicals from wood pulping operations. The furnace is also the primary steam generating unit at the mill. Permitted modifications are: improved furnace ash chemistry; re-evaluate current sootblowing sequence; optimize recovery furnace scrubber to handle increased solids load; circulation study.	Sulfur, Total Reduced (TRS)	N	5	PPMV @ 8% O2
KY-0085	MEADWESTVACO KENTUCKY, INC/WICKLIFFE	MEADWESTVACO KENTUCKY, INC	37314	RECOVERY FURNACE		473000	LB/H	FURNACE ALSO LIMITED TO BURNING 744,000 GAL/YR NO. 6 FUEL OIL.	Sulfur, Total Reduced (TRS)	B	40	PPMV @ 8% O2
NC-0089	ROANOKE RAPIDS MILL	CHAMPION INTERNATIONAL CORPORATION	36007	RECOVERY FURNACE	BLACK LIQUOR SOLIDS	2.77	MM LB/D	4.32 MMLBS/DAY OF BLACK LIQUOR SOLIDS Throughput is lb steam/h. Recovery furnace is designed to recover and regenerate spent cooking chemicals from wood pulping operations. The furnace is also the primary steam generating unit at the mill. Permitted modifications are: improved furnace ash chemistry; re-evaluate current sootblowing sequence; optimize recovery furnace scrubber to handle increased solids load; circulation study.	Sulfur, Total Reduced (TRS)	P	5	PPM @ 8% O2
AL-0222	ROCK-TENN MILL COMPANY, LLC	ROCK-TENN MILL COMPANY, LLC	38141	RECOVERY FURNACE		4.32	mmlb/day	4.32 MMLBS/DAY OF BLACK LIQUOR SOLIDS Throughput is lb steam/h. Recovery furnace is designed to recover and regenerate spent cooking chemicals from wood pulping operations. The furnace is also the primary steam generating unit at the mill. Permitted modifications are: improved furnace ash chemistry; re-evaluate current sootblowing sequence; optimize recovery furnace scrubber to handle increased solids load; circulation study.	Sulfuric Acid (mist, vapors, etc)	N	3.78	LB/H
*WA-0303	LONGVIEW FIBRE PAPER AND PACKAGING, INC	LONGVIEW FIBRE PAPER AND PACKAGING, INC	39022	RECOVERY FURNACE 15		1150	TBLS/D	1150 TBLS/D IS AN OPERATING LIMIT.	Nitrogen Oxides (NOx)	N	95	PPMDV @ 8% O2
*WA-0303	LONGVIEW FIBRE PAPER AND PACKAGING, INC	LONGVIEW FIBRE PAPER AND PACKAGING, INC	39022	RECOVERY FURNACE 15		1150	TBLS/D	1150 TBLS/D IS AN OPERATING LIMIT.	Particulate Matter (PM)	N	NONE INDICATED	182.5 T/YR
*WA-0303	LONGVIEW FIBRE PAPER AND PACKAGING, INC	LONGVIEW FIBRE PAPER AND PACKAGING, INC	39022	RECOVERY FURNACE 15		1150	TBLS/D	1150 TBLS/D IS AN OPERATING LIMIT.	Sulfur Dioxide (SO2)	N	60	PPMDV @ 8% O2
*WA-0303	LONGVIEW FIBRE PAPER AND PACKAGING, INC	LONGVIEW FIBRE PAPER AND PACKAGING, INC	39022	RECOVERY FURNACE 15		1150	TBLS/D	1150 TBLS/D IS AN OPERATING LIMIT.	Sulfur, Total Reduced (TRS)	N	17.5	PPMDV @ 8% O2
*WA-0303	LONGVIEW FIBRE PAPER AND PACKAGING, INC	LONGVIEW FIBRE PAPER AND PACKAGING, INC	39022	RECOVERY FURNACE 18		1200	TBLS/D	1200 TBLS IS AN OPERATING LIMIT.	Nitrogen Oxides (NOx)	P	95	PPMDV @ 8% O2

**RBLC Search Results  
Port Townsend Paper Company  
Recovery Furnace**

RBLCID	FACILITYNAME	CORPORATEORCOMPANYNAME	PERMITDATE	PROCESSNAME	FUEL	THRUPUT	THRUPUTUNIT	PROCESSNOTES	POLLUTANT	CONTROL	CTRLDESC	EMISLIMIT1	EMISLIMIT1UNIT
*WA-0303	LONGVIEW FIBRE PAPER AND PACKAGING, INC	LONGVIEW FIBRE PAPER AND PACKAGING, INC	39022	RECOVERY FURNACE 18		1200	TBLS/D	1200 TBLS IS AN OPERATING LIMIT.	Particulate Matter (PM)	N	FACILITY WILL HAVE A FEDERAL LIMIT OF PM10 REPRESENTING A 20% REDUCTION FROM THE CURRENTLY ALLOWED EMISSION LIEVELS. WITH THIS NEW BASELINE FOR POTENTIAL PM10, BACT IS NO FURTHER CONTROL APPLICATION.	219	T/YR
*WA-0303	LONGVIEW FIBRE PAPER AND PACKAGING, INC	LONGVIEW FIBRE PAPER AND PACKAGING, INC	39022	RECOVERY FURNACE 18		1200	TBLS/D	1200 TBLS IS AN OPERATING LIMIT.	Sulfur Dioxide (SO2)	N	FACILITY WILL HAVE A FEDERAL LIMIT OF SO2 REPRESENTING A 53% REDUCTION FROM THE CURRENTLY ALLOWED EMISSION LEVELS. BACT IS NO FURTHER CONTROL APPLICATION.	60	PPMDV @ 8% O2
*WA-0303	LONGVIEW FIBRE PAPER AND PACKAGING, INC	LONGVIEW FIBRE PAPER AND PACKAGING, INC	39022	RECOVERY FURNACE 18		1200	TBLS/D	1200 TBLS IS AN OPERATING LIMIT.	Sulfur, Total Reduced (TRS)	N	NO FURTHER CONTROL APPLICATION IS EITHER FEASIBLE OR ECONOMICALLY JUSTIFIABLE.	17.5	PPMDV @ 8% O2
*WA-0303	LONGVIEW FIBRE PAPER AND PACKAGING, INC	LONGVIEW FIBRE PAPER AND PACKAGING, INC	39022	RECOVERY FURNACE 19		2000	T BLS/D		Nitrogen Oxides (NOx)	P	GOOD COMBUSTION PRACTICES.	95	PPMDV @ 8% O2
*WA-0303	LONGVIEW FIBRE PAPER AND PACKAGING, INC	LONGVIEW FIBRE PAPER AND PACKAGING, INC	39022	RECOVERY FURNACE 19		2000	T BLS/D		Particulate Matter (PM)	N	FACILITY WILL HAVE A LIMIT ON PM10 REPRESENTING A 20% REDUCTION FROM THE CURRENTLY ALLOWED EMISSION LEVELS. WITH THIS NEW BASELINE FOR POTENTIAL PM10, BACT IS NO FURTHER CONTROL.	292	T/YR
*WA-0303	LONGVIEW FIBRE PAPER AND PACKAGING, INC	LONGVIEW FIBRE PAPER AND PACKAGING, INC	39022	RECOVERY FURNACE 19		2000	T BLS/D		Sulfur Dioxide (SO2)	P	FACILITY WILL HAVE A LIMIT ON SO2 REPRESENTING A 53% REDUCTION FROM THE CURRENTLY ALLOWED EMISSION LEVELS. WITH THIS NEW BASELINE FOR POTENTIAL SO2, BACT IS NO FURTHER CONTROL.	60	PPMDV @ 8% O2
*WA-0303	LONGVIEW FIBRE PAPER AND PACKAGING, INC	LONGVIEW FIBRE PAPER AND PACKAGING, INC	39022	RECOVERY FURNACE 19		2000	T BLS/D		Sulfur, Total Reduced (TRS)	N	FURTHER CONTROL IS EITHER INFEASIBLE OR NOT ECONOMICALLY JUSTIFIABLE.	10	PPMDV @ 8% O2
*WA-0303	LONGVIEW FIBRE PAPER AND PACKAGING, INC	LONGVIEW FIBRE PAPER AND PACKAGING, INC	39022	RECOVERY FURNACE 22		1950	T BLS/D		Nitrogen Oxides (NOx)	N		95	PPMDV @ 8% O2
*WA-0303	LONGVIEW FIBRE PAPER AND PACKAGING, INC	LONGVIEW FIBRE PAPER AND PACKAGING, INC	39022	RECOVERY FURNACE 22		1950	T BLS/D		Particulate Matter (PM)	N		256	T/YR
*WA-0303	LONGVIEW FIBRE PAPER AND PACKAGING, INC	LONGVIEW FIBRE PAPER AND PACKAGING, INC	39022	RECOVERY FURNACE 22		1950	T BLS/D		Sulfur Dioxide (SO2)	N		120	PPMDV @ 8% O2
*WA-0303	LONGVIEW FIBRE PAPER AND PACKAGING, INC	LONGVIEW FIBRE PAPER AND PACKAGING, INC	39022	RECOVERY FURNACE 22		1950	T BLS/D		Sulfur, Total Reduced (TRS)	N		3	PPMDV @ 8% O2
LA-0174	PORT HUDSON OPERATIONS	GEORGIA-PACIFIC CORPORATION	37281	RECOVERY FURNACE NO. 1		2.81	MM LB/D	EMISSION POINT NO. 72. TOTAL ANNUAL FIRING RATE OF RECOVERY FURNACES (EMISSION POINT NOS. 72 AND 73) LIMITED TO LESS THAN 1,216,000 TONS OF BLS, ON A ROLLING 12-MONTH BASIS, TO MAINTAIN NOX INCREASE BELOW PSD SIGNIFICANCE LEVEL.	Nitrogen Oxides (NOx)	P	STAGED COMBUSTION, GOOD EQUIPMENT DESIGN AND PROPER COMBUSTION TECHNIQUES.	142.01	LB/H
LA-0174	PORT HUDSON OPERATIONS	GEORGIA-PACIFIC CORPORATION	37281	RECOVERY FURNACE NO. 1		2.81	MM LB/D	EMISSION POINT NO. 72. TOTAL ANNUAL FIRING RATE OF RECOVERY FURNACES (EMISSION POINT NOS. 72 AND 73) LIMITED TO LESS THAN 1,216,000 TONS OF BLS, ON A ROLLING 12-MONTH BASIS, TO MAINTAIN NOX INCREASE BELOW PSD SIGNIFICANCE LEVEL.	Particulate Matter (PM)	A	ELECTROSTATIC PRECIPITATOR	37.31	LB/H
LA-0174	PORT HUDSON OPERATIONS	GEORGIA-PACIFIC CORPORATION	37281	RECOVERY FURNACE NO. 1		2.81	MM LB/D	EMISSION POINT NO. 72. TOTAL ANNUAL FIRING RATE OF RECOVERY FURNACES (EMISSION POINT NOS. 72 AND 73) LIMITED TO LESS THAN 1,216,000 TONS OF BLS, ON A ROLLING 12-MONTH BASIS, TO MAINTAIN NOX INCREASE BELOW PSD SIGNIFICANCE LEVEL.	Particulate Matter < 10 µ (PM10)	A	ELECTROSTATIC PRECIPITATOR	37.31	LB/H
LA-0174	PORT HUDSON OPERATIONS	GEORGIA-PACIFIC CORPORATION	37281	RECOVERY FURNACE NO. 1		2.81	MM LB/D	EMISSION POINT NO. 72. TOTAL ANNUAL FIRING RATE OF RECOVERY FURNACES (EMISSION POINT NOS. 72 AND 73) LIMITED TO LESS THAN 1,216,000 TONS OF BLS, ON A ROLLING 12-MONTH BASIS, TO MAINTAIN NOX INCREASE BELOW PSD SIGNIFICANCE LEVEL.	Sulfur Dioxide (SO2)	N		105.91	LB/H
LA-0174	PORT HUDSON OPERATIONS	GEORGIA-PACIFIC CORPORATION	37281	RECOVERY FURNACE NO. 1		2.81	MM LB/D	EMISSION POINT NO. 72. TOTAL ANNUAL FIRING RATE OF RECOVERY FURNACES (EMISSION POINT NOS. 72 AND 73) LIMITED TO LESS THAN 1,216,000 TONS OF BLS, ON A ROLLING 12-MONTH BASIS, TO MAINTAIN NOX INCREASE BELOW PSD SIGNIFICANCE LEVEL.	Sulfur, Total Reduced (TRS)	P	UPGRADE BLOX SYSTEM	4.53	LB/H
LA-0174	PORT HUDSON OPERATIONS	GEORGIA-PACIFIC CORPORATION	37281	RECOVERY FURNACE NO. 2		3.96	MM LB/D	EMISSION POINT NO. 73. TOTAL ANNUAL FIRING RATE OF RECOVERY FURNACES (EMISSION POINT NOS. 72 AND 73) LIMITED TO LESS THAN 1,216,000 TONS OF BLS, ON A ROLLING 12-MONTH BASIS, TO MAINTAIN NOX INCREASE BELOW PSD SIGNIFICANCE LEVEL.	Nitrogen Oxides (NOx)	P	STAGED COMBUSTION, GOOD EQUIPMENT DESIGN AND PROPER COMBUSTION TECHNIQUES.	192.06	LB/H

**RBLC Search Results  
Port Townsend Paper Company  
Recovery Furnace**

RBLCID	FACILITYNAME	CORPORATEORCOMPANYNAME	PERMITDATE	PROCESSNAME	FUEL	THRUPUT	THRUPUTUNIT	PROCESSNOTES	POLLUTANT	CONTROL	CTRLDESC	EMISLIMIT1	EMISLIMIT1UNIT
LA-0174	PORT HUDSON OPERATIONS	GEORGIA-PACIFIC CORPORATION	37281	RECOVERY FURNACE NO. 2		3.96	MM LB/D	EMISSION POINT NO. 73. TOTAL ANNUAL FIRING RATE OF RECOVERY FURNACES (EMISSION POINT NOS. 72 AND 73) LIMITED TO LESS THAN 1,216,000 TONS OF BLS, ON A ROLLING 12-MONTH BASIS, TO MAINTAIN NOX INCREASE BELOW PSD SIGNIFICANCE LEVEL.	Particulate Matter (PM)	A	ELECTROSTATIC PRECIPITATOR	56	LB/H
LA-0174	PORT HUDSON OPERATIONS	GEORGIA-PACIFIC CORPORATION	37281	RECOVERY FURNACE NO. 2		3.96	MM LB/D	EMISSION POINT NO. 73. TOTAL ANNUAL FIRING RATE OF RECOVERY FURNACES (EMISSION POINT NOS. 72 AND 73) LIMITED TO LESS THAN 1,216,000 TONS OF BLS, ON A ROLLING 12-MONTH BASIS, TO MAINTAIN NOX INCREASE BELOW PSD SIGNIFICANCE LEVEL.	Particulate Matter < 10 µ (PM10)	A	ELECTROSTATIC PRECIPITATOR	56	LB/H
LA-0174	PORT HUDSON OPERATIONS	GEORGIA-PACIFIC CORPORATION	37281	RECOVERY FURNACE NO. 2		3.96	MM LB/D	EMISSION POINT NO. 73. TOTAL ANNUAL FIRING RATE OF RECOVERY FURNACES (EMISSION POINT NOS. 72 AND 73) LIMITED TO LESS THAN 1,216,000 TONS OF BLS, ON A ROLLING 12-MONTH BASIS, TO MAINTAIN NOX INCREASE BELOW PSD SIGNIFICANCE LEVEL.	Sulfur Dioxide (SO2)	N		143.23	LB/H
LA-0174	PORT HUDSON OPERATIONS	GEORGIA-PACIFIC CORPORATION	37281	RECOVERY FURNACE NO. 2		3.96	MM LB/D	EMISSION POINT NO. 73. TOTAL ANNUAL FIRING RATE OF RECOVERY FURNACES (EMISSION POINT NOS. 72 AND 73) LIMITED TO LESS THAN 1,216,000 TONS OF BLS, ON A ROLLING 12-MONTH BASIS, TO MAINTAIN NOX INCREASE BELOW PSD SIGNIFICANCE LEVEL.	Sulfur, Total Reduced (TRS)	P	UPGRADE BLOX SYSTEM	6.13	LB/H
GA-0114	INLAND PAPERBOARD AND PACKAGING, INC. - ROME LINERBOARD MILL	TEMPLE INLAND, INC.	38273	RECOVERY FURNACE, BLS FUEL	BLS	5.3	MMLB/D	THROUGHPUT IS MMLB OF BLS PER DAY. ADDITIONAL FUEL DISTILLATE OIL ONLY, MODIFICATION OF EXISTING FURNACE. UNIT CAPABLE OF FIRING FUEL OIL AT 850 MMBTU/HR. DISTILLATE FUEL FIRING IN SEPARATE PROCESS.	Particulate Matter < 10 µ (PM10)	A	ESP	0.021	GR/DSCF @ 8% O2
GA-0114	INLAND PAPERBOARD AND PACKAGING, INC. - ROME LINERBOARD MILL	TEMPLE INLAND, INC.	38273	RECOVERY FURNACE, BLS FUEL	BLS	5.3	MMLB/D	THROUGHPUT IS MMLB OF BLS PER DAY. ADDITIONAL FUEL DISTILLATE OIL ONLY, MODIFICATION OF EXISTING FURNACE. UNIT CAPABLE OF FIRING FUEL OIL AT 850 MMBTU/HR. DISTILLATE FUEL FIRING IN SEPARATE PROCESS.	Sulfur, Total Reduced (TRS)	P	SYSTEM DESIGN AND GOOD OPERATION PRACTICES	5	PPM @ 8% O2
SC-0084	BOWATER COATED PAPER DIVISION	BOWATER	37195	NO. 3 RECOVERY FURNACE	HEAVY BLACK LIQUOR			PSD Limits for PM/PM10 and NOx. Synthetic Minor Limits for CO and SO2	Nitrogen Oxides (NOx)	N	GOOD COMBUSTION CONTROL	80	PPMVD @ 8% O2
SC-0084	BOWATER COATED PAPER DIVISION	BOWATER	37195	NO. 3 RECOVERY FURNACE	HEAVY BLACK LIQUOR			PSD Limits for PM/PM10 and NOx. Synthetic Minor Limits for CO and SO2	Particulate Matter (PM)	A	ESP	0.036	GR/DSCF @ 8% O2
NC-0107	INTERNATIONAL PAPER - RIEGELWOOD MILL	INTERNATIONAL PAPER	38064	NO. 5 RECOVERY BOILER	BLACK LIQUOR SOLIDS	140	T/H		Nitrogen Oxides (NOx)	P	PROPER DESIGN AND GOOD COMBUSTION CONTROL	100	PPMV
NC-0108	INTERNATIONAL PAPER - ROANOKE RAPIDS MILL	INTERNATIONAL PAPER	38049	NO. 7 RECOVERY FURNACE	BLACK LIQUOR SOLIDS	3	MMLB/D		Nitrogen Oxides (NOx)	P	FURNACE DESIGN AND COMBUSTION OPTIMIZATION	100	PPM
NC-0108	INTERNATIONAL PAPER - ROANOKE RAPIDS MILL	INTERNATIONAL PAPER	38049	NO. 7 RECOVERY FURNACE	BLACK LIQUOR SOLIDS	3	MMLB/D		Particulate Matter < 10 µ (PM10)	A	EXISTING MULTIFIELD ELECTROSTATIC PRECIPITATOR	0.021	GR/DSCF
NC-0108	INTERNATIONAL PAPER - ROANOKE RAPIDS MILL	INTERNATIONAL PAPER	38049	NO. 7 RECOVERY FURNACE	BLACK LIQUOR SOLIDS	3	MMLB/D		Sulfur Dioxide (SO2)	P	FURNACE DESIGN AND COMBUSTION OPTIMIZATION	75	PPM
NC-0108	INTERNATIONAL PAPER - ROANOKE RAPIDS MILL	INTERNATIONAL PAPER	38049	NO. 7 RECOVERY FURNACE	BLACK LIQUOR SOLIDS	3	MMLB/D		Sulfur, Total Reduced (TRS)	P	FURNACE DESIGN AND COMBUSTION OPTIMIZATION	5	PPM
*TX-0485	INLAND PAPERBOARD AND PACKAGING ORANGE MILL	INLAND PAPERBOARD AND PACKAGING INC	38265	NO.1 AND NO. 2 RECOVERY FURNACE	NATURAL GAS			TOTAL REDUCED SULFUR (TSR): 24 LB/H 41 T/YR; EMISSIONS ARE FOR EACH SOURCE	Nitrogen Oxides (NOx)	N		90	LB/H
*TX-0485	INLAND PAPERBOARD AND PACKAGING ORANGE MILL	INLAND PAPERBOARD AND PACKAGING INC	38265	NO.1 AND NO. 2 RECOVERY FURNACE	NATURAL GAS			TOTAL REDUCED SULFUR (TSR): 24 LB/H 41 T/YR; EMISSIONS ARE FOR EACH SOURCE	Particulate Matter < 10 µ (PM10)	N		56	LB/HR
*TX-0485	INLAND PAPERBOARD AND PACKAGING ORANGE MILL	INLAND PAPERBOARD AND PACKAGING INC	38265	NO.1 AND NO. 2 RECOVERY FURNACE	NATURAL GAS			TOTAL REDUCED SULFUR (TSR): 24 LB/H 41 T/YR; EMISSIONS ARE FOR EACH SOURCE	Sulfur Dioxide (SO2)	N		915.7	LB/H
*TX-0485	INLAND PAPERBOARD AND PACKAGING ORANGE MILL	INLAND PAPERBOARD AND PACKAGING INC	38265	NO.1/NO.2 RECOVERY BOILER SALT CAKE MIX TANK					Particulate Matter < 10 µ (PM10)	N		0.03	LB/H
*TX-0485	INLAND PAPERBOARD AND PACKAGING ORANGE MILL	INLAND PAPERBOARD AND PACKAGING INC	38265	BARK BOILER				WOOD WASTES, WAXED CARDBOARD BOXES, BARK, NATURAL GAS, AND NON-CONDENSIBLE GASES ARE FUELS; TOTAL SULFUR REDUCTION: 2.31 LB/H 2.08 T/YR	Nitrogen Oxides (NOx)	P	INLAND PAPERBOARD PROPOSES TO USE BEST COMBUSTION PRACTICES AND INSTALL SNCR TECHNOLOGY (OR AN EQUIVANT CONTROL TECHNOLOGY) ON THE BARK BOILER TO CONTROL NOX. IT IS ESTIMATED THAT SNCR WILL REDUCE NOX BY 22%. THEREFORE, THE	104	LB/H
*TX-0485	INLAND PAPERBOARD AND PACKAGING ORANGE MILL	INLAND PAPERBOARD AND PACKAGING INC	38265	BARK BOILER				WOOD WASTES, WAXED CARDBOARD BOXES, BARK, NATURAL GAS, AND NON-CONDENSIBLE GASES ARE FUELS; TOTAL SULFUR REDUCTION: 2.31 LB/H 2.08 T/YR	Particulate Matter < 10 µ (PM10)	P	THE COMPANY PROPOSES TO UPGRADE THE EXISTING VENTURI SCRUBBER TO CONTROL PARTICULATE MATTER EMISSIONS TO 0.07 LB/MMBTU. THIS IS BELOW THE NSPS LEVEL OF 0.10 LB/MMBTU FOR BARK BOILERS. IT WAS SHOWN THAT REPLACING THE SCRUBBER	33	LB/H

**RBLC Search Results  
Port Townsend Paper Company  
Recovery Furnace**

RBLCID	FACILITYNAME	CORPORATEORCOMPANYNAME	PERMITDATE	PROCESSNAME	FUEL	THRUPUT	THRUPUTUNIT	PROCESSNOTES	POLLUTANT	CONTROL	CTRLDESC	EMISLIMIT1	EMISLIMITUNIT
*TX-0485	INLAND PAPERBOARD AND PACKAGING ORANGE MILL	INLAND PAPERBOARD AND PACKAGING INC	38265	BARK BOILER				WOOD WASTES, WAXED CARDBOARD BOXES, BARK, NATURAL GAS, AND NON-CONDENSIBLE GASES ARE FUELS; TOTAL SULFUR REDUCTION: 2.31 LB/H 2.08 T/YR	Sulfur Dioxide (SO2)	P	THE EMISSIONS OF SO2 WILL BE CONTROLLED BY A 91% REDUCTION THROUGH NATURAL ALKALINE SCRUBBER INSIDE THE BOILER AND BY ADDING CAUSTIC TO THE SCRUBBER SOLUTION. RESEARCH BY NCASI HAS SHOWN THAT CONTROL OF SO2 INSIDE THE BARK	48.5 LB/H	
AL-0123	U S ALLIANCE	U S ALLIANCE	36063	BOILER, AUX. POWER, NO.1	WAXED CARDBOARD BOXES, BARK NATURAL GAS		0		Nitrogen Oxides (NOx)	N		0.2 LB/MBTU	
KY-0085	MEADWESTVACO KENTUCKY, INC/WICKLIFFE	MEADWESTVACO KENTUCKY, INC	37314	BOILER, BARK			631 MMBTU/H	fuels include: bark/wood waste, waste treatment sludge, waste oil, and natural gas. Maximum hourly heat input shall not exceed: 463 mmbtu/h when firing 55% moisture content wood residue; 634 mmbtu/h when firing 30% moisture content wood residue; and 631 mmbtu/h when firing any optimum mixture of wood residue and natural gas. Boiler is incineration point for the NCG vent streams.	Nitrogen Oxides (NOx)	N		0.4 LB/MMBTU	
KY-0085	MEADWESTVACO KENTUCKY, INC/WICKLIFFE	MEADWESTVACO KENTUCKY, INC	37314	BOILER, BARK	BARK		631 MMBTU/H	fuels include: bark/wood waste, waste treatment sludge, waste oil, and natural gas. Maximum hourly heat input shall not exceed: 463 mmbtu/h when firing 55% moisture content wood residue; 634 mmbtu/h when firing 30% moisture content wood residue; and 631 mmbtu/h when firing any optimum mixture of wood residue and natural gas. Boiler is incineration point for the NCG vent streams.	Particulate Matter (PM)	A	ESP	0.1 LB/MMBTU	
KY-0085	MEADWESTVACO KENTUCKY, INC/WICKLIFFE	MEADWESTVACO KENTUCKY, INC	37314	BOILER, BARK	BARK		631 MMBTU/H	fuels include: bark/wood waste, waste treatment sludge, waste oil, and natural gas. Maximum hourly heat input shall not exceed: 463 mmbtu/h when firing 55% moisture content wood residue; 634 mmbtu/h when firing 30% moisture content wood residue; and 631 mmbtu/h when firing any optimum mixture of wood residue and natural gas. Boiler is incineration point for the NCG vent streams.	Sulfur Dioxide (SO2)	N		0.8 MMBTU/H	
GA-0114	INLAND PAPERBOARD AND PACKAGING, INC. - ROME LINERBOARD MILL	TEMPLE INLAND, INC.	38273	BOILER, COAL FIRED	COAL		565 MMBTU/H	MODIFICATION TO A 1962 BOILER	Particulate Matter < 10 µ (PM10)	A	ESP	0.05 LB/MMBTU	
AL-0123	U S ALLIANCE	U S ALLIANCE	36063	BOILER, MULTI-FUEL, NO. 1	WOOD WASTE		0		Nitrogen Oxides (NOx)	N		0.2 LB/MMBTU	
AL-0123	U S ALLIANCE	U S ALLIANCE	36063	BOILER, MULTI-FUEL, NO. 1	WOOD WASTE		0		Particulate Matter (PM)	N		0.1 LB/MMBTU	
AL-0123	U S ALLIANCE	U S ALLIANCE	36063	BOILER, MULTI-FUEL, NO. 1	WOOD WASTE		0		Sulfur Dioxide (SO2)	A		396 LB/H	
GA-0114	INLAND PAPERBOARD AND PACKAGING, INC. - ROME LINERBOARD MILL	TEMPLE INLAND, INC.	38273	BOILER, OIL-FIRED	NO. 2 FUEL OIL		192 MMBTU/H	NATURAL GAS BACKUP	Particulate Matter < 10 µ (PM10)	N		0.05 LB/MMBTU	
AL-0116	GULF STATES PAPER CORPORATION	GULF STATES PAPER CORPORATION	35774	BOILER, POWER	SEE NOTES		775 MMBTU/H	FUEL IS BARK AND CLARIFIER SLUDGE	Nitrogen Dioxide (NO2)	P	LOW NOX NATURAL GAS AND FUEL OIL BURNERS PROPER DESIGN AND OPERATION, WOOD ASH ALKALINITY ACTS AS THE SCRUBBING MEDIA. USE OF TRANSPORTATION GRADE FUEL OIL.	0.3 LB/MMBTU	
AL-0116	GULF STATES PAPER CORPORATION	GULF STATES PAPER CORPORATION	35774	BOILER, POWER	SEE NOTES		775 MMBTU/H	FUEL IS BARK AND CLARIFIER SLUDGE	Sulfur Dioxide (SO2)	P		355.7 LB/H	
NC-0092	RIEGELWOOD MILL	INTERNATIONAL PAPER COMPANY	37021	BOILER, POWER, COAL-FIRED	COAL		249 MMBTU/H	POWER BOILER CAN FIRE COAL, NO. 6 FUEL OIL, OR BARK/WOOD FIBER SLUDGE.	Nitrogen Oxides (NOx)	P	GOOD COMBUSTION PRACTICE	0.4 LB/MMBTU	
NC-0092	RIEGELWOOD MILL	INTERNATIONAL PAPER COMPANY	37021	BOILER, POWER, COAL-FIRED	COAL		249 MMBTU/H	POWER BOILER CAN FIRE COAL, NO. 6 FUEL OIL, OR BARK/WOOD FIBER SLUDGE.	Particulate Matter (PM)	A	MULTICLONE AND A VARIABLE THROAT VENTURI-TYPE WET SCRUBBER	0.16 LB/MMBTU	
NC-0092	RIEGELWOOD MILL	INTERNATIONAL PAPER COMPANY	37021	BOILER, POWER, COAL-FIRED	COAL		249 MMBTU/H	POWER BOILER CAN FIRE COAL, NO. 6 FUEL OIL, OR BARK/WOOD FIBER SLUDGE.	Sulfur Dioxide (SO2)	A	MULTICLONE AND A VARIABLE THROAT VENTURI-TYPE WET SCRUBBER	0.8 LB/MMBTU	
NC-0092	RIEGELWOOD MILL	INTERNATIONAL PAPER COMPANY	37021	BOILER, POWER, OIL-FIRED	NO. 6 FUEL OIL		249 MMBTU/H	POWER BOILER CAN FIRE COAL, NO. 6 FUEL OIL, OR BARK/WOOD FIBER SLUDGE.	Nitrogen Oxides (NOx)	P	GOOD COMBUSTION PRACTICE	0.367 LB/MMBTU	
NC-0092	RIEGELWOOD MILL	INTERNATIONAL PAPER COMPANY	37021	BOILER, POWER, OIL-FIRED	NO. 6 FUEL OIL		249 MMBTU/H	POWER BOILER CAN FIRE COAL, NO. 6 FUEL OIL, OR BARK/WOOD FIBER SLUDGE.	Particulate Matter (PM)	A	MULTICLONE AND A VARIABLE THROAT VENTURI-TYPE WET SCRUBBER	0.0562 LB/MMBTU	
NC-0092	RIEGELWOOD MILL	INTERNATIONAL PAPER COMPANY	37021	BOILER, POWER, OIL-FIRED	NO. 6 FUEL OIL		249 MMBTU/H	POWER BOILER CAN FIRE COAL, NO. 6 FUEL OIL, OR BARK/WOOD FIBER SLUDGE.	Sulfur Dioxide (SO2)	A	MULTICLONE AND VARIABLE THROAT VENTURI-TYPE WET SCRUBBER	0.8 LB/MMBTU	
NC-0092	RIEGELWOOD MILL	INTERNATIONAL PAPER COMPANY	37021	BOILER, POWER, WOODWASTE-FIRED	WOODWASTE		600 MMBTU/H	THROUGHPUT IS MAXIMUM PERMITTED HEAT INPUT RATE FOR BARK/WOOD FIBER SLUDGE/FOSSIL FUEL FIRING.	Nitrogen Oxides (NOx)	P	GOOD COMBUSTION PRACTICE	0.35 LB/MMBTU	
NC-0092	RIEGELWOOD MILL	INTERNATIONAL PAPER COMPANY	37021	BOILER, POWER, WOODWASTE-FIRED	WOODWASTE		600 MMBTU/H	THROUGHPUT IS MAXIMUM PERMITTED HEAT INPUT RATE FOR BARK/WOOD FIBER SLUDGE/FOSSIL FUEL FIRING.	Particulate Matter (PM)	A	MULTICLONE AND A VARIABLE THROAT VENTURI-TYPE WET SCRUBBER	0.25 LB/MMBTU	
NC-0092	RIEGELWOOD MILL	INTERNATIONAL PAPER COMPANY	37021	BOILER, POWER, WOODWASTE-FIRED	WOODWASTE		600 MMBTU/H	THROUGHPUT IS MAXIMUM PERMITTED HEAT INPUT RATE FOR BARK/WOOD FIBER SLUDGE/FOSSIL FUEL FIRING.	Sulfur Dioxide (SO2)	A	MULTICLONE AND A VARIABLE THROAT VENTURI-TYPE WET SCRUBBER	0.024 LB/MMBTU	
GA-0114	INLAND PAPERBOARD AND PACKAGING, INC. - ROME LINERBOARD MILL	TEMPLE INLAND, INC.	38273	BOILER, SOLID FUEL	BARK		856 MMBTU/H	BARK, WASTEWATER SLUDGE, TDF, FUEL OIL; MAY BE USED TO INCIENRATE NCG GASES; NEW BOILER	Particulate Matter < 10 µ (PM10)	A	ESP	0.025 LB/MMBTU	
GA-0114	INLAND PAPERBOARD AND PACKAGING, INC. - ROME LINERBOARD MILL	TEMPLE INLAND, INC.	38273	BOILER, SOLID FUEL	BARK		856 MMBTU/H	BARK, WASTEWATER SLUDGE, TDF, FUEL OIL; MAY BE USED TO INCIENRATE NCG GASES; NEW BOILER	Sulfur, Total Reduced (TRS)	N	BOILER IS CONTROL DEVICE -- DESTROYS HVLC NCGS IN WASTE FUEL	99 % REDUCTION	
LA-0122	MANSFIELD MILL	INTERNATIONAL PAPER - MANSFIELD MILL	37117	BOILOUT TANK				EMISSION POINT 28-930	Sulfur, Total Reduced (TRS)	N	NO ADDITIONAL CONTROL REQUIRED	0.01 LB/H	

**RBLC Search Results  
Port Townsend Paper Company  
Recovery Furnace**

RBLCID	FACILITYNAME	CORPORATEORCOMPANYNAME	PERMITDATE	PROCESSNAME	FUEL	THRUPUT	THRUPUTUNIT	PROCESSNOTES	POLLUTANT	CONTROL	CTRLDESC	EMISLIMIT1	EMISLIMIT1UNIT
*WA-0303	LONGVIEW FIBRE PAPER AND PACKAGING, INC	LONGVIEW FIBRE PAPER AND PACKAGING, INC	39022	COGEN 23		695	MMBTU/H	EITHER POWER BOILER 12, 13, 16, 17, OR 20 MUST BE OFF-LINE WHEN COGEN 23 IS OPERATING. 4 H OF OPERATIONAL OVERLAP IS ALLOWED FOR NORMAL STARTUP AND SHUTDOWN. COMPLIANCE SHALL BE DEMONSTRATED FROM RECORDING CHARTS AND OPERATORS' LOGS.	Nitrogen Oxides (NOx)	N		7	PPMDV @ 15% O2
					NATURAL GAS								
*WA-0303	LONGVIEW FIBRE PAPER AND PACKAGING, INC	LONGVIEW FIBRE PAPER AND PACKAGING, INC	39022	COGEN 23		695	MMBTU/H	EITHER POWER BOILER 12, 13, 16, 17, OR 20 MUST BE OFF-LINE WHEN COGEN 23 IS OPERATING. 4 H OF OPERATIONAL OVERLAP IS ALLOWED FOR NORMAL STARTUP AND SHUTDOWN. COMPLIANCE SHALL BE DEMONSTRATED FROM RECORDING CHARTS AND OPERATORS' LOGS.	Particulate Matter (PM)	P	USE ONLY PIPELINE QUALITY NATURAL GAS.	0.002	GR/DSCF @ 15% O2
					NATURAL GAS								
*WA-0303	LONGVIEW FIBRE PAPER AND PACKAGING, INC	LONGVIEW FIBRE PAPER AND PACKAGING, INC	39022	COGEN 23		695	MMBTU/H	EITHER POWER BOILER 12, 13, 16, 17, OR 20 MUST BE OFF-LINE WHEN COGEN 23 IS OPERATING. 4 H OF OPERATIONAL OVERLAP IS ALLOWED FOR NORMAL STARTUP AND SHUTDOWN. COMPLIANCE SHALL BE DEMONSTRATED FROM RECORDING CHARTS AND OPERATORS' LOGS.	Sulfur Dioxide (SO2)	P	ONLY PIPELINE QUALITY NATURAL GAS MAY BE USED AS FUEL	0.25	LB/MMBTU
					NATURAL GAS								
*MS-0075	MONTICELLO MILL	GEORGIA PACIFIC CORP.	37811	COMBINATION BOILER		917.4	MMBTU/H	FUELS ARE SCRAP WOOD, SLUDGE, TDF	Nitrogen Oxides (NOx)	B	LOW NOX BURNERS, STOKER CONTROLS, OVERFIRE AIR SYSTEM AND GOOD COMBUSTION PRACTICES.	284.4	LB/H
*MS-0075	MONTICELLO MILL	GEORGIA PACIFIC CORP.	37811	COMBINATION BOILER	SCRAP WOOD	917.4	MMBTU/H	FUELS ARE SCRAP WOOD, SLUDGE, TDF	Particulate Matter < 10 µ (PM10)	A	MULTICLONE AND ESP	91.7	LB/H
*MS-0075	MONTICELLO MILL	GEORGIA PACIFIC CORP.	37811	COMBINATION BOILER	SCRAP WOOD	917.4	MMBTU/H	FUELS ARE SCRAP WOOD, SLUDGE, TDF	Sulfur Dioxide (SO2)	P	SULFUR LIMIT ON FUELS BURNED. SEE NOTE	2335.5	LB/H
LA-0174	PORT HUDSON OPERATIONS	GEORGIA-PACIFIC CORPORATION	37281	COMBINATION BOILER NO. 1	WOOD WASTE / NAT GA	459.5	MMBTU/H	EMISSION POINT NO. 5. FUEL CAN BE EITHER WOOD WASTE OR NATURAL GAS.	Nitrogen Oxides (NOx)	P	LOW-NOX BURNERS	128.7	LB/H
LA-0174	PORT HUDSON OPERATIONS	GEORGIA-PACIFIC CORPORATION	37281	COMBINATION BOILER NO. 1	WOOD WASTE / NAT GA	459.5	MMBTU/H	EMISSION POINT NO. 5. FUEL CAN BE EITHER WOOD WASTE OR NATURAL GAS.	Particulate Matter (PM)	A	WET SCRUBBER(S)	32.42	LB/H
LA-0174	PORT HUDSON OPERATIONS	GEORGIA-PACIFIC CORPORATION	37281	COMBINATION BOILER NO. 1	WOOD WASTE / NAT GA	459.5	MMBTU/H	EMISSION POINT NO. 5. FUEL CAN BE EITHER WOOD WASTE OR NATURAL GAS.	Particulate Matter < 10 µ (PM10)	A	WET SCRUBBER(S)	32.42	LB/H
LA-0174	PORT HUDSON OPERATIONS	GEORGIA-PACIFIC CORPORATION	37281	COMBINATION BOILER NO. 1	WOOD WASTE / NAT GA	459.5	MMBTU/H	EMISSION POINT NO. 5. FUEL CAN BE EITHER WOOD WASTE OR NATURAL GAS.	Sulfur Dioxide (SO2)	B	ADD-ON: WET SCRUBBER. P2: FUEL CAN BE EITHER WOOD WASTE OR NATURAL GAS.	37.37	LB/H
LA-0174	PORT HUDSON OPERATIONS	GEORGIA-PACIFIC CORPORATION	37281	COMBINATION BOILER NO. 1	WOOD WASTE / NAT GA	459.5	MMBTU/H	EMISSION POINT NO. 5. FUEL CAN BE EITHER WOOD WASTE OR NATURAL GAS.	Sulfur, Total Reduced (TRS)	N		0.46	LB/H
*LA-0201	RED RIVER MILL	WEYERHAEUSER CO	38861	HOGGED FUEL BOILER NO. 2		940	MMBTU/hr	BOILER ALSO FIRES PAPER MILL SLUDGE (UP TO 40 MM BTU/HR), RECYCLED FIBER REJECTS (UP TO 40 MM BTU/HR), AND NATURAL GAS (STANDBY ONLY).	Nitrogen Oxides (NOx)	A	SNCR	0.15	LB/MMBTU
					HOGGED FUEL								
*LA-0201	RED RIVER MILL	WEYERHAEUSER CO	38861	HOGGED FUEL BOILER NO. 2		940	MMBTU/hr	BOILER ALSO FIRES PAPER MILL SLUDGE (UP TO 40 MM BTU/HR), RECYCLED FIBER REJECTS (UP TO 40 MM BTU/HR), AND NATURAL GAS (STANDBY ONLY).	Particulate Matter < 10 µ (PM10)	A	ELECTROSTATIC PRECIPITATOR	0.025	LB/MMBTU
					HOGGED FUEL								
*LA-0201	RED RIVER MILL	WEYERHAEUSER CO	38861	HOGGED FUEL BOILER NO. 2		940	MMBTU/hr	BOILER ALSO FIRES PAPER MILL SLUDGE (UP TO 40 MM BTU/HR), RECYCLED FIBER REJECTS (UP TO 40 MM BTU/HR), AND NATURAL GAS (STANDBY ONLY).	Sulfur Dioxide (SO2)	N		0.015	LB/MMBTU
					HOGGED FUEL								
*TX-0485	INLAND PAPERBOARD AND PACKAGING ORANGE MILL	INLAND PAPERBOARD AND PACKAGING INC	38265	NO. 1 PFI BOILER					Nitrogen Oxides (NOx)	N		49.83	LB/H
*TX-0485	INLAND PAPERBOARD AND PACKAGING ORANGE MILL	INLAND PAPERBOARD AND PACKAGING INC	38265	NO. 1 PFI BOILER					Particulate Matter < 10 µ (PM10)	N		3	LB/H
*TX-0485	INLAND PAPERBOARD AND PACKAGING ORANGE MILL	INLAND PAPERBOARD AND PACKAGING INC	38265	NO. 1 PFI BOILER					Sulfur Dioxide (SO2)	N		5	LB/H
*TX-0485	INLAND PAPERBOARD AND PACKAGING ORANGE MILL	INLAND PAPERBOARD AND PACKAGING INC	38265	NO. 2 PFI BOILER	SEE BARK BOILER				Nitrogen Oxides (NOx)	N		21	LB/H
*TX-0485	INLAND PAPERBOARD AND PACKAGING ORANGE MILL	INLAND PAPERBOARD AND PACKAGING INC	38265	NO. 2 PFI BOILER	SEE BARK BOILER				Particulate Matter < 10 µ (PM10)	N		3.13	LB/H
*TX-0485	INLAND PAPERBOARD AND PACKAGING ORANGE MILL	INLAND PAPERBOARD AND PACKAGING INC	38265	NO. 2 PFI BOILER	SEE BARK BOILER				Sulfur Dioxide (SO2)	N		0.25	LB/H
*TX-0485	INLAND PAPERBOARD AND PACKAGING ORANGE MILL	INLAND PAPERBOARD AND PACKAGING INC	38265	PACKAGE BOILER	SEE BARK BOILER				Nitrogen Oxides (NOx)	N		28.5	LB/H
*TX-0485	INLAND PAPERBOARD AND PACKAGING ORANGE MILL	INLAND PAPERBOARD AND PACKAGING INC	38265	PACKAGE BOILER	SEE BARK BOILER				Particulate Matter < 10 µ (PM10)	N		1.2	LB/H
*TX-0485	INLAND PAPERBOARD AND PACKAGING ORANGE MILL	INLAND PAPERBOARD AND PACKAGING INC	38265	PACKAGE BOILER	SEE BARK BOILER				Sulfur Dioxide (SO2)	N		0.14	LB/H
*TX-0515	INTERNATIONAL PAPER COMPANY PULP AND PAPER MILL	INTERNATIONAL PAPER COMPANY	38728	POWER BOILER					Nitrogen Oxides (NOx)	N		326.1	LB/HR
*TX-0515	INTERNATIONAL PAPER COMPANY PULP AND PAPER MILL	INTERNATIONAL PAPER COMPANY	38728	POWER BOILER					Particulate Matter < 10 µ (PM10)	A	CYCLONE	108.7	LB/HR
*TX-0515	INTERNATIONAL PAPER COMPANY PULP AND PAPER MILL	INTERNATIONAL PAPER COMPANY	38728	POWER BOILER					Sulfur Dioxide (SO2)	A	WET SCRUBBER	175.72	LB/HR
*TX-0515	INTERNATIONAL PAPER COMPANY PULP AND PAPER MILL	INTERNATIONAL PAPER COMPANY	38728	POWER BOILER					Sulfur, Total Reduced (TRS)	N		0.99	LB/HR
*TX-0515	INTERNATIONAL PAPER COMPANY PULP AND PAPER MILL	INTERNATIONAL PAPER COMPANY	38728	POWER BOILER					Sulfuric Acid (mist, vapors, etc)	N		14.65	LB/HR
*MS-0075	MONTICELLO MILL	GEORGIA PACIFIC CORP.	37811	POWER BOILER - NG	NATURAL GAS	766	MMBTU/H		Nitrogen Oxides (NOx)	N		418.4	LB/H
*MS-0075	MONTICELLO MILL	GEORGIA PACIFIC CORP.	37811	POWER BOILER - NG	NATURAL GAS	766	MMBTU/H		Particulate Matter < 10 µ (PM10)	N		3.8	LB/H
*MS-0075	MONTICELLO MILL	GEORGIA PACIFIC CORP.	37811	POWER BOILER - NG	NATURAL GAS	766	MMBTU/H		Sulfur Dioxide (SO2)	N		0.46	LB/H
LA-0122	MANSFIELD MILL	INTERNATIONAL PAPER - MANSFIELD MILL	37117	POWER BOILER #1 & #2, COAL		645	MMBTU/H	EMISSION POINTS 01-78, 02-78. SPECIFIC TYPE OF COAL IS NOT AVAILABLE-- SCC CODE WAS ASSIGNED ARBITRARILY FOR PURPOSES OF THIS DATABASE.	Nitrogen Oxides (NOx)	P	LOW NOX STAGED BURNERS, CMS FOR O2 NOX EMISSIONS	451.5	LB/H
					COAL								
LA-0122	MANSFIELD MILL	INTERNATIONAL PAPER - MANSFIELD MILL	37117	POWER BOILER #1 & #2, COAL		645	MMBTU/H	EMISSION POINTS 01-78, 02-78. SPECIFIC TYPE OF COAL IS NOT AVAILABLE-- SCC CODE WAS ASSIGNED ARBITRARILY FOR PURPOSES OF THIS DATABASE.	Particulate Matter < 10 µ (PM10)	A	SINGLE STAGE DUST COLLECTOR/ESP	64.5	LB/H
					COAL								
LA-0122	MANSFIELD MILL	INTERNATIONAL PAPER - MANSFIELD MILL	37117	POWER BOILER #1 & #2, COAL		645	MMBTU/H	EMISSION POINTS 01-78, 02-78. SPECIFIC TYPE OF COAL IS NOT AVAILABLE-- SCC CODE WAS ASSIGNED ARBITRARILY FOR PURPOSES OF THIS DATABASE.	Sulfur Dioxide (SO2)	P	SULFUR IN COAL NOT TO EXCEED 1.2% BY WEIGHT	774	LB/H
					COAL								

**RBLC Search Results  
Port Townsend Paper Company  
Recovery Furnace**

RBLCID	FACILITYNAME	CORPORATEORCOMPANYNAME	PERMITDATE	PROCESSNAME	FUEL	THRUPUT	THRUPUTUNIT	PROCESSNOTES	POLLUTANT	CONTROL CTRLDESC	EMISLIMIT1	EMISLIMIT1UNIT
LA-0122	MANSFIELD MILL	INTERNATIONAL PAPER - MANSFIELD MILL	37117	POWER BOILER #1 & #2, COMBINED FUEL	COMBINED FUEL	760	MMBTU/H	EMISSION POINTS 01-78, 02-78. ARBITRARILY ASSIGNED SCC CODE. THE BOILER BURNS COAL (UNSPECIFIED) NATURAL GAS, OIL, RECYCLED PLANT FIBER, AND WOOD WASTE.	Nitrogen Oxides (NOx)	P	LOW NOX STAGE BURNERS, CMS FOR O2 NOX EMISSIONS	
LA-0122	MANSFIELD MILL	INTERNATIONAL PAPER - MANSFIELD MILL	37117	POWER BOILER #1 & #2, COMBINED FUEL	COMBINED FUEL	760	MMBTU/H	EMISSION POINTS 01-78, 02-78. ARBITRARILY ASSIGNED SCC CODE. THE BOILER BURNS COAL (UNSPECIFIED) NATURAL GAS, OIL, RECYCLED PLANT FIBER, AND WOOD WASTE.	Particulate Matter < 10 µ (PM10)	A	SINGLE STAGE DUST COLLECTOR/ESP	76 LB/H
LA-0122	MANSFIELD MILL	INTERNATIONAL PAPER - MANSFIELD MILL	37117	POWER BOILER #1 & #2, COMBINED FUEL	COMBINED FUEL	760	MMBTU/H	EMISSION POINTS 01-78, 02-78. ARBITRARILY ASSIGNED SCC CODE. THE BOILER BURNS COAL (UNSPECIFIED) NATURAL GAS, OIL, RECYCLED PLANT FIBER, AND WOOD WASTE.	Sulfur Dioxide (SO2)	P	LIMIT SULFUR CONTENT OF FUEL	
LA-0122	MANSFIELD MILL	INTERNATIONAL PAPER - MANSFIELD MILL	37117	POWER BOILER #1 & #2, COMBINED FUEL	COMBINED FUEL	760	MMBTU/H	EMISSION POINTS 01-78, 02-78. ARBITRARILY ASSIGNED SCC CODE. THE BOILER BURNS COAL (UNSPECIFIED) NATURAL GAS, OIL, RECYCLED PLANT FIBER, AND WOOD WASTE.	Sulfur, Total Reduced (TRS)	P	GOOD PROCESS CONTROLS	0.22 LB/H
LA-0122	MANSFIELD MILL	INTERNATIONAL PAPER - MANSFIELD MILL	37117	POWER BOILER #1 & #2, OIL	FUEL OIL	645	MMBTU/H	EMISSION POINTS 01-78, 02-78	Nitrogen Oxides (NOx)	P	LOW NOX STAGE BURNERS, CMS FOR O2 NOX EMISSIONS	193.5 LB/H
LA-0122	MANSFIELD MILL	INTERNATIONAL PAPER - MANSFIELD MILL	37117	POWER BOILER #1 & #2, OIL	FUEL OIL	645	MMBTU/H	EMISSION POINTS 01-78, 02-78	Particulate Matter < 10 µ (PM10)	A	SINGLE STAGE DUST COLLECTOR/ESP	64.5 LB/H
LA-0122	MANSFIELD MILL	INTERNATIONAL PAPER - MANSFIELD MILL	37117	POWER BOILER #1 & #2, OIL	FUEL OIL	645	MMBTU/H	EMISSION POINTS 01-78, 02-78	Sulfur Dioxide (SO2)	P	SULFUR CONTENT OF FUEL SHALL NOT EXCEED 0.7% BY WEIGHT.	516 LB/H
TX-0263	DONAHUE INDUSTRIES, INC. PAPER MILL	DONAHUE INDUSTRIES, INC.	36816	POWER BOILER 11	FUEL TYPE AND THROUGHPUT UNKNOWN				Nitrogen Oxides (NOx)	N	NONE INDICATED	81 LB/H
TX-0263	DONAHUE INDUSTRIES, INC. PAPER MILL	DONAHUE INDUSTRIES, INC.	36816	POWER BOILER 11	FUEL TYPE AND THROUGHPUT UNKNOWN				Particulate Matter < 10 µ (PM10)	N	NONE INDICATED	63.9 LB/H
TX-0263	DONAHUE INDUSTRIES, INC. PAPER MILL	DONAHUE INDUSTRIES, INC.	36816	POWER BOILER 11	FUEL TYPE AND THROUGHPUT UNKNOWN				Sulfur Dioxide (SO2)	N	NONE INDICATED	5.4 LB/H
TX-0263	DONAHUE INDUSTRIES, INC. PAPER MILL	DONAHUE INDUSTRIES, INC.	36816	POWER BOILER 11	FUEL TYPE AND THROUGHPUT UNKNOWN				Sulfuric Acid (mist, vapors, etc)	N	NONE INDICATED	0.23 LB/H
*WA-0303	LONGVIEW FIBRE PAPER AND PACKAGING, INC	LONGVIEW FIBRE PAPER AND PACKAGING, INC	39022	POWER BOILER 16	FUEL OIL	525	MMBTU/H	OPERATING LIMIT IS 525 MMBTU/H FUEL APPLICATION. THE EXHAUST STACKS SHALL BE MODIFIED OR REPLACED SUCH THAT MODELED EXHAUST GAS DISPERSION IS EQUAL TO OR BETTER THAN THAT INDICATED FOR THE ORIGINALLY-PROPOSED DESIGN IN THE PERMIT APPLICATION. EITHER POWER BOILER 12, 13, 16, 17, OR 20 MUST BE OFF-LINE WHEN COGEN 23 IS OPERATING. 4 H OF OPERATIONAL OVERLAP IS ALLOWED FOR NORMAL STARTUP AND SHUTDOWN. COMPLIANCE SHALL BE DEMONSTRATED FROM RECORDING CHARTS AND OPERATORS' LOGS. ASSIGNED SCC CODE FOR WASTE OIL, AS CODE IS NOT AVAILABLE FOR FUEL OIL.	Nitrogen Oxides (NOx)	N		410 PPM DV @ 7% O2
*WA-0303	LONGVIEW FIBRE PAPER AND PACKAGING, INC	LONGVIEW FIBRE PAPER AND PACKAGING, INC	39022	POWER BOILER 16	FUEL OIL	525	MMBTU/H	OPERATING LIMIT IS 525 MMBTU/H FUEL APPLICATION. THE EXHAUST STACKS SHALL BE MODIFIED OR REPLACED SUCH THAT MODELED EXHAUST GAS DISPERSION IS EQUAL TO OR BETTER THAN THAT INDICATED FOR THE ORIGINALLY-PROPOSED DESIGN IN THE PERMIT APPLICATION. EITHER POWER BOILER 12, 13, 16, 17, OR 20 MUST BE OFF-LINE WHEN COGEN 23 IS OPERATING. 4 H OF OPERATIONAL OVERLAP IS ALLOWED FOR NORMAL STARTUP AND SHUTDOWN. COMPLIANCE SHALL BE DEMONSTRATED FROM RECORDING CHARTS AND OPERATORS' LOGS. ASSIGNED SCC CODE FOR WASTE OIL, AS CODE IS NOT AVAILABLE FOR FUEL OIL.	Particulate Matter (PM)	N		0.1 GR/DSCF @ 7% O2
*WA-0303	LONGVIEW FIBRE PAPER AND PACKAGING, INC	LONGVIEW FIBRE PAPER AND PACKAGING, INC	39022	POWER BOILER 16	FUEL OIL	525	MMBTU/H	OPERATING LIMIT IS 525 MMBTU/H FUEL APPLICATION. THE EXHAUST STACKS SHALL BE MODIFIED OR REPLACED SUCH THAT MODELED EXHAUST GAS DISPERSION IS EQUAL TO OR BETTER THAN THAT INDICATED FOR THE ORIGINALLY-PROPOSED DESIGN IN THE PERMIT APPLICATION. EITHER POWER BOILER 12, 13, 16, 17, OR 20 MUST BE OFF-LINE WHEN COGEN 23 IS OPERATING. 4 H OF OPERATIONAL OVERLAP IS ALLOWED FOR NORMAL STARTUP AND SHUTDOWN. COMPLIANCE SHALL BE DEMONSTRATED FROM RECORDING CHARTS AND OPERATORS' LOGS. ASSIGNED SCC CODE FOR WASTE OIL, AS CODE IS NOT AVAILABLE FOR FUEL OIL.	Sulfur Dioxide (SO2)	N		250 PPM DV @ 7% O2
*WA-0303	LONGVIEW FIBRE PAPER AND PACKAGING, INC	LONGVIEW FIBRE PAPER AND PACKAGING, INC	39022	POWER BOILER 17	FUEL OIL	591	MMBTU/H	OPERATING LIMIT IS 591 MMBTU/H. THE EXHAUST STACKS SHALL BE MODIFIED OR REPLACED SO MODELED EXHAUST GAS DISPERSION IS EQUAL TO OR BETTER THAN THAT INDICATED FOR THE ORIGINALLY-PROPOSED DESIGN IN THE PERMIT APPLICATION. EITHER POWER BOILER 12, 13, 16, 17, OR 20 MUST BE OFF-LINE WHEN COGEN 23 IS OPERATING. 4 H OF OPERATIONAL OVERLAP IS ALLOWED FOR NORMAL STARTUP AND SHUTDOWN. COMPLIANCE SHALL BE DEMONSTRATED FROM RECORDING CHARTS AND OPERATORS' LOGS. ASSIGNED SCC CODE FOR WASTE OIL AS FUEL OIL IS NOT AN OPTION.	Nitrogen Oxides (NOx)	N		410 PPM DV @ 7% O2

**RBLC Search Results  
Port Townsend Paper Company  
Recovery Furnace**

RBLCID	FACILITYNAME	CORPORATEORCOMPANYNAME	PERMITDATE	PROCESSNAME	FUEL	THRUPUT	THRUPUTUNIT	PROCESSNOTES	POLLUTANT	CONTROL	CTRLDESC	EMISLIMIT1	EMISLIMIT1UNIT
*WA-0303	LONGVIEW FIBRE PAPER AND PACKAGING, INC	LONGVIEW FIBRE PAPER AND PACKAGING, INC	39022	POWER BOILER 17	FUEL OIL	591	MMBTU/H	OPERATING LIMIT IS 591 MMBTU/H. THE EXHAUST STACKS SHALL BE MODIFIED OR REPLACED SO MODELED EXHAUST GAS DISPERSION IS EQUAL TO OR BETTER THAN THAT INDICATED FOR THE ORIGINALLY-PROPOSED DESIGN IN THE PERMIT APPLICATION. EITHER POWER BOILER 12, 13, 16, 17, OR 20 MUST BE OFF-LINE WHEN COGEN 23 IS OPERATING. 4 H OF OPERATIONAL OVERLAP IS ALLOWED FOR NORMAL STARTUP AND SHUTDOWN. COMPLIANCE SHALL BE DEMONSTRATED FROM RECORDING CHARTS AND OPERATORS' LOGS. ASSIGNED SCC CODE FOR WASTE OIL AS FUEL OIL IS NOT AN OPTION.	Particulate Matter (PM)	N		0.1 GR/DSCF @ 7% O2	
*WA-0303	LONGVIEW FIBRE PAPER AND PACKAGING, INC	LONGVIEW FIBRE PAPER AND PACKAGING, INC	39022	POWER BOILER 17	FUEL OIL	591	MMBTU/H	OPERATING LIMIT IS 591 MMBTU/H. THE EXHAUST STACKS SHALL BE MODIFIED OR REPLACED SO MODELED EXHAUST GAS DISPERSION IS EQUAL TO OR BETTER THAN THAT INDICATED FOR THE ORIGINALLY-PROPOSED DESIGN IN THE PERMIT APPLICATION. EITHER POWER BOILER 12, 13, 16, 17, OR 20 MUST BE OFF-LINE WHEN COGEN 23 IS OPERATING. 4 H OF OPERATIONAL OVERLAP IS ALLOWED FOR NORMAL STARTUP AND SHUTDOWN. COMPLIANCE SHALL BE DEMONSTRATED FROM RECORDING CHARTS AND OPERATORS' LOGS. ASSIGNED SCC CODE FOR WASTE OIL AS FUEL OIL IS NOT AN OPTION.	Sulfur Dioxide (SO2)	P	LOW SULFUR FUEL	250 PPMDV @ 7% O2	
*WA-0303	LONGVIEW FIBRE PAPER AND PACKAGING, INC	LONGVIEW FIBRE PAPER AND PACKAGING, INC	39022	POWER BOILER 20	FUEL OIL	900	MMBTU/H	OPERATING LIMIT IS 900 MMBTU/H. THE EXHAUST STACKS SHALL BE MODIFIED OR REPLACED SUCH THAT MODELED EXHAUST GAS DISPERSION IS EQUAL TO OR BETTER THAN THAT INDICATED FOR THE ORIGINALLY-PROPOSED DESIGN IN THE PERMIT APPLICATION. EITHER POWER BOILER 12, 13, 16, 17, OR 20 MUST BE OFF-LINE WHEN COGEN 23 IS OPERATING. 4 H OF OPERATIONAL OVERLAP IS ALLOWED FOR NORMAL STARTUP AND SHUTDOWN. COMPLIANCE SHALL BE DEMONSTRATED FROM RECORDING CHARTS AND OPERATORS' LOGS. SCC CODE CHOSEN FOR WASTE OIL AS FUEL OIL IS NOT AN AVAILABLE OPTON.	Nitrogen Oxides (NOx)	N		0.3 LB/MMBTU	
*WA-0303	LONGVIEW FIBRE PAPER AND PACKAGING, INC	LONGVIEW FIBRE PAPER AND PACKAGING, INC	39022	POWER BOILER 20	FUEL OIL	900	MMBTU/H	THROUGHPUT IS OPERATING LIMIT. THE EXHAUST STACKS SHALL BE MODIFIED OR REPLACED SUCH THAT MODELED EXHAUST GAS DISPERSION IS EQUAL TO OR BETTER THAN THAT INDICATED FOR THE ORIGINALLY-PROPOSED DESIGN IN THE PERMIT APPLICATION. EITHER POWER BOILER 12, 13, 16, 17, OR 20 MUST BE OFF-LINE WHEN COGEN 23 IS OPERATING. 4 H OF OPERATIONAL OVERLAP IS ALLOWED FOR NORMAL STARTUP AND SHUTDOWN. COMPLIANCE SHALL BE DEMONSTRATED FROM RECORDING CHARTS AND OPERATORS' LOGS. SCC CODE CHOSEN FOR WASTE OIL AS FUEL OIL IS NOT AN AVAILABLE OPTON.	Particulate Matter (PM)	N		0.048 GR/DSCF @ 7% O2	
*WA-0303	LONGVIEW FIBRE PAPER AND PACKAGING, INC	LONGVIEW FIBRE PAPER AND PACKAGING, INC	39022	POWER BOILER 20	FUEL OIL	900	MMBTU/H	THROUGHPUT IS OPERATING LIMIT. THE EXHAUST STACKS SHALL BE MODIFIED OR REPLACED SUCH THAT MODELED EXHAUST GAS DISPERSION IS EQUAL TO OR BETTER THAN THAT INDICATED FOR THE ORIGINALLY-PROPOSED DESIGN IN THE PERMIT APPLICATION. EITHER POWER BOILER 12, 13, 16, 17, OR 20 MUST BE OFF-LINE WHEN COGEN 23 IS OPERATING. 4 H OF OPERATIONAL OVERLAP IS ALLOWED FOR NORMAL STARTUP AND SHUTDOWN. COMPLIANCE SHALL BE DEMONSTRATED FROM RECORDING CHARTS AND OPERATORS' LOGS. SCC CODE CHOSEN FOR WASTE OIL AS FUEL OIL IS NOT AN AVAILABLE OPTON.	Sulfur Dioxide (SO2)	P	LOW-SULFUR FUEL	100 PPMDV @ 7% O2	
LA-0174	PORT HUDSON OPERATIONS	GEORGIA-PACIFIC CORPORATION	37281	POWER BOILER NO. 2	FUEL OIL	65.5	MMBTU/H	EMISSION POINT NO. 6.	Nitrogen Oxides (NOx)	P	LOW-NOX BURNERS	61.34 LB/H	
LA-0174	PORT HUDSON OPERATIONS	GEORGIA-PACIFIC CORPORATION	37281	POWER BOILER NO. 2	NAT GAS	65.5	MMBTU/H	EMISSION POINT NO. 6.	Particulate Matter (PM)	P	FIRED BY NATURAL GAS	3.33 LB/H	
LA-0174	PORT HUDSON OPERATIONS	GEORGIA-PACIFIC CORPORATION	37281	POWER BOILER NO. 2	NAT GAS	65.5	MMBTU/H	EMISSION POINT NO. 6.	Particulate Matter < 10 µ (PM10)	P	FIRED BY NATURAL GAS	3.33 LB/H	
LA-0174	PORT HUDSON OPERATIONS	GEORGIA-PACIFIC CORPORATION	37281	POWER BOILER NO. 2	NAT GAS	65.5	MMBTU/H	EMISSION POINT NO. 6.	Sulfur Dioxide (SO2)	P	FIRING NATURAL GAS	0.26 LB/H	
LA-0174	PORT HUDSON OPERATIONS	GEORGIA-PACIFIC CORPORATION	37281	POWER BOILER NO. 5	NATURAL GAS	987	MMBTU/H	EMISSION POINT NO. 27.	Nitrogen Oxides (NOx)	P	LOW-NOX BURNERS	127.19 LB/H	
LA-0174	PORT HUDSON OPERATIONS	GEORGIA-PACIFIC CORPORATION	37281	POWER BOILER NO. 5	NATURAL GAS	987	MMBTU/H	EMISSION POINT NO. 27.	Particulate Matter (PM)	P	FUELED BY NATURAL GAS	6.9 LB/H	
LA-0174	PORT HUDSON OPERATIONS	GEORGIA-PACIFIC CORPORATION	37281	POWER BOILER NO. 5	NATURAL GAS	987	MMBTU/H	EMISSION POINT NO. 27.	Particulate Matter < 10 µ (PM10)	P	FUELED BY NATURAL GAS	6.9 LB/H	
LA-0174	PORT HUDSON OPERATIONS	GEORGIA-PACIFIC CORPORATION	37281	POWER BOILER NO. 5	NATURAL GAS	987	MMBTU/H	EMISSION POINT NO. 27.	Sulfur Dioxide (SO2)	P	FUELED BY NATURAL GAS	5126 LB/H	
LA-0174	PORT HUDSON OPERATIONS	GEORGIA-PACIFIC CORPORATION	37281	POWER BOILER NO. 5	NATURAL GAS	987	MMBTU/H	EMISSION POINT NO. 27.	Sulfur, Total Reduced (TRS)	N		0.48 LB/H	
TX-0263	DONAHUE INDUSTRIES, INC. PAPER MILL	DONAHUE INDUSTRIES, INC.	36816	POWER BOILER NOS. 4, 5, 8, AND 9				ANNUAL EMISSIONS ONLY ARE LISTED FOR THESE GRANDFATHERED BOILERS FUEL TYPE AND THROUGHPUT UNKNOWN. ANNUAL LIMIT OF 4,803 MMSCF.	Nitrogen Oxides (NOx)	N	NONE INDICATED	672.6 T/YR	
TX-0263	DONAHUE INDUSTRIES, INC. PAPER MILL	DONAHUE INDUSTRIES, INC.	36816	POWER BOILER NOS. 4, 5, 8, AND 9				ANNUAL EMISSIONS ONLY ARE LISTED FOR THESE GRANDFATHERED BOILERS FUEL TYPE AND THROUGHPUT UNKNOWN. ANNUAL LIMIT OF 4,803 MMSCF.	Particulate Matter < 10 µ (PM10)	N	NONE INDICATED	18.3 T/YR	
TX-0263	DONAHUE INDUSTRIES, INC. PAPER MILL	DONAHUE INDUSTRIES, INC.	36816	POWER BOILER NOS. 4, 5, 8, AND 9				ANNUAL EMISSIONS ONLY ARE LISTED FOR THESE GRANDFATHERED BOILERS FUEL TYPE AND THROUGHPUT UNKNOWN. ANNUAL LIMIT OF 4,803 MMSCF.	Sulfur Dioxide (SO2)	N	NONE INDICATED	1.4 T/YR	

**RBLC Search Results  
Port Townsend Paper Company  
Recovery Furnace**

RBLCID	FACILITYNAME	CORPORATEORCOMPANYNAME	PERMITDATE	PROCESSNAME	FUEL	THRUPUT	THRUPUTUNIT	PROCESSNOTES	POLLUTANT	CONTROLCTRLDESC	EMISLIMIT1	EMISLIMIT1UNIT
*WA-0303	LONGVIEW FIBRE PAPER AND PACKAGING, INC	LONGVIEW FIBRE PAPER AND PACKAGING, INC	39022	POWER BOILERS 12 AND 13		444	MMBTU/H, EA	THE EXHAUST STACKS SHALL BE MODIFIED OR REPLACED SO MODELED EXHAUST GAS DISPERSION IS EQUAL TO OR BETTER THAN THAT INDICATED FOR THE ORIGINALLY-PROPOSED DESIGN IN THE PERMIT APPLICATION. EITHER POWER BOILER 12, 13, 16, 17, OR 20 MUST BE OFF-LINE WHEN COGEN 23 IS OPERATING. 4 H OF OEPARATIONAL OVERLAP IS ALLOWED FOR NORMAL STARTUP AND SHUTDOWN. COMPLIANCE SHALL BE DEMONSTRATED FROM RECORDING CHARTS AND OPERATORS' LOGS. ASSIGNED SCC CODE FOR WASTE OIL AS FUEL OIL IS NOT AN AVAILABLE CHOICE.	Nitrogen Oxides (NOx)	N	410	PPMDV @ 7% O2
*WA-0303	LONGVIEW FIBRE PAPER AND PACKAGING, INC	LONGVIEW FIBRE PAPER AND PACKAGING, INC	39022	POWER BOILERS 12 AND 13		444	MMBTU/H, EA	THE EXHAUST STACKS SHALL BE MODIFIED OR REPLACED SO MODELED EXHAUST GAS DISPERSION IS EQUAL TO OR BETTER THAN THAT INDICATED FOR THE ORIGINALLY-PROPOSED DESIGN IN THE PERMIT APPLICATION. EITHER POWER BOILER 12, 13, 16, 17, OR 20 MUST BE OFF-LINE WHEN COGEN 23 IS OPERATING. 4 H OF OEPARATIONAL OVERLAP IS ALLOWED FOR NORMAL STARTUP AND SHUTDOWN. COMPLIANCE SHALL BE DEMONSTRATED FROM RECORDING CHARTS AND OPERATORS' LOGS. ASSIGNED SCC CODE FOR WASTE OIL AS FUEL OIL IS NOT AN AVAILABLE CHOICE.	Particulate Matter (PM)	N	0.048	GR/DSCF @ 7% O2
*WA-0303	LONGVIEW FIBRE PAPER AND PACKAGING, INC	LONGVIEW FIBRE PAPER AND PACKAGING, INC	39022	POWER BOILERS 12 AND 13		444	MMBTU/H, EA	THE EXHAUST STACKS SHALL BE MODIFIED OR REPLACED SO MODELED EXHAUST GAS DISPERSION IS EQUAL TO OR BETTER THAN THAT INDICATED FOR THE ORIGINALLY-PROPOSED DESIGN IN THE PERMIT APPLICATION. EITHER POWER BOILER 12, 13, 16, 17, OR 20 MUST BE OFF-LINE WHEN COGEN 23 IS OPERATING. 4 H OF OEPARATIONAL OVERLAP IS ALLOWED FOR NORMAL STARTUP AND SHUTDOWN. COMPLIANCE SHALL BE DEMONSTRATED FROM RECORDING CHARTS AND OPERATORS' LOGS. ASSIGNED SCC CODE FOR WASTE OIL AS FUEL OIL IS NOT AN AVAILABLE CHOICE.	Sulfur Dioxide (SO2)	N	100	PPMDV @ 7% O2

**RBLC Search Results  
Port Townsend Paper Company  
Power Boiler**

RBLCID	FACILITYNAME	CORPORATEORCOMPANYNAME	PERMITDATE	PROCESSNAME	FUEL	THRUPUT	THRUPUTUNIT	PROCESSNOTES	POLLUTANT	CONTROL	CTRLDESC	EMISLIMIT1	EMISLIMITIUNIT
*MS-0075	MONTICELLO MILL	GEORGIA PACIFIC CORP.	7/9/2003	RECOVERY BOILER NO. 1	BARK	861.4	MMBTU/H	BOILER BURNS CONCENTRATED BLACK LIQUOR TO RECOVER DIGESTING CHEMICAL.	Nitrogen Oxides (NOx)	N		200.2	LB/H
*MS-0075	MONTICELLO MILL	GEORGIA PACIFIC CORP.	7/9/2003	RECOVERY BOILER NO. 2	BARK	861.4	MMBTU/H		Nitrogen Oxides (NOx)	N		200.2	LB/H
*MS-0075	MONTICELLO MILL	GEORGIA PACIFIC CORP.	7/9/2003	RECOVERY BOILER NO. 2	BARK	861.4	MMBTU/H		Particulate Matter (PM)	A	ESP	194.3	LB/H
*MS-0075	MONTICELLO MILL	GEORGIA PACIFIC CORP.	7/9/2003	RECOVERY BOILER NO. 1	BARK	861.4	MMBTU/H	BOILER BURNS CONCENTRATED BLACK LIQUOR TO RECOVER DIGESTING CHEMICAL.	Particulate Matter < 10 µ (PM10)	A	ESP	194.3	LB/H
*MS-0075	MONTICELLO MILL	GEORGIA PACIFIC CORP.	7/9/2003	RECOVERY BOILER NO. 1	BARK	861.4	MMBTU/H	BOILER BURNS CONCENTRATED BLACK LIQUOR TO RECOVER DIGESTING CHEMICAL.	Sulfur Dioxide (SO2)	N		408.33	LB/H
*MS-0075	MONTICELLO MILL	GEORGIA PACIFIC CORP.	7/9/2003	RECOVERY BOILER NO. 2	BARK	861.4	MMBTU/H		Sulfur Dioxide (SO2)	N		408.33	LB/H
GA-0114	INLAND PAPERBOARD AND PACKAGING, INC. - ROME LINERBOARD MILL	TEMPLE INLAND, INC.	10/13/2004	RECOVERY FURNACE, BLS FUEL	BARK	5.3	MLLB/D	THROUGHPUT IS MMLB OF BLS PER DAY. ADDITIONAL FUEL DISTILLATE OIL ONLY. MODIFICATION OF EXISTING FURNACE. UNIT CAPABLE OF FIRING FUEL OIL AT 850 MMBTU/HR. DISTILLATE FUEL FIRING IN SEPARATE PROCESS.	Particulate Matter < 10 µ (PM10)	A	ESP	0.021	GR/DSCF @ 8% O2
GA-0114	INLAND PAPERBOARD AND PACKAGING, INC. - ROME LINERBOARD MILL	TEMPLE INLAND, INC.	10/13/2004	RECOVERY FURNACE, BLS FUEL	BARK	5.3	MLLB/D	THROUGHPUT IS MMLB OF BLS PER DAY. ADDITIONAL FUEL DISTILLATE OIL ONLY. MODIFICATION OF EXISTING FURNACE. UNIT CAPABLE OF FIRING FUEL OIL AT 850 MMBTU/HR. DISTILLATE FUEL FIRING IN SEPARATE PROCESS.	Sulfur, Total Reduced (TRS)	P	SYSTEM DESIGN AND GOOD OPERATION PRACTICES	5	PPM @ 8% O2
LA-0122	MANSFIELD MILL	INTERNATIONAL PAPER - MANSFIELD MILL	8/14/2001	POWER BOILER #1 & #2, COMBINED FUEL	BARK & WASTE WOOD	760	MMBTU/H	EMISSION POINTS 01-78, 02-78. ARBITRARILY ASSIGNED SCC CODE. THE BOILER BURNS COAL (UNSPECIFIED) NATURAL GAS, OIL, RECYCLED PLANT FIBER, AND WOOD WASTE.	Nitrogen Oxides (NOx)	P	LOW NOX STAGE BURNERS, CMS FOR O2 NOX EMISSIONS		
LA-0122	MANSFIELD MILL	INTERNATIONAL PAPER - MANSFIELD MILL	8/14/2001	POWER BOILER #1 & #2, COMBINED FUEL	BARK & WASTE WOOD	760	MMBTU/H	EMISSION POINTS 01-78, 02-78. ARBITRARILY ASSIGNED SCC CODE. THE BOILER BURNS COAL (UNSPECIFIED) NATURAL GAS, OIL, RECYCLED PLANT FIBER, AND WOOD WASTE.	Particulate Matter < 10 µ (PM10)	A	SINGLE STAGE DUST COLLECTOR/ESP	76	LB/H
LA-0122	MANSFIELD MILL	INTERNATIONAL PAPER - MANSFIELD MILL	8/14/2001	POWER BOILER #1 & #2, COMBINED FUEL	BARK & WASTE WOOD	760	MMBTU/H	EMISSION POINTS 01-78, 02-78. ARBITRARILY ASSIGNED SCC CODE. THE BOILER BURNS COAL (UNSPECIFIED) NATURAL GAS, OIL, RECYCLED PLANT FIBER, AND WOOD WASTE.	Sulfur Dioxide (SO2)	P	LIMIT SULFUR CONTENT OF FUEL		
WI-0228	WPS - WESTON PLANT	WISCONSIN PUBLIC SERVICE	38279	B63, S63; B64, S64 - NATURAL GAS STATION HEATER 1 AND 2	HOG FUEL	0.75	MMBTU/H	EMISSION LIMITS ARE THOSE FOR EACH UNIT.	Particulate Matter (PM)	P	NATURAL GAS	0.01	LB/H
WV-0023	MAIDSVILLE	LONGVIEW POWER, LLC	38048	AUXILIARY BOILER	HOG FUEL	225	mmbtu/h	LIMITED TO NATURAL GAS USE AND 3,000 HOURS OF OPERATION PER YEAR	Particulate Matter (PM)	P	GOOD COMBUSTION PRACTICES AND THE USE OF CLEAN FUELS	0.0022	LB/MMBTU
GA-0116	TRI-GEN BIOPOWER	TRIGEN BIOPOWER	36123	BOILER, MULTI-FUEL	SCRAP WOOD	265.1	MMBTU/H	UNIT CAPABLE OF BURNING WOODWASTE, MILL SLUDGE, TDF, PULP MILL REJECTS (#2 FUEL OIL AS STARTUP FUEL). BUBBLING FLUIDIZED BED BOILER	Nitrogen Oxides (NOx)	P	COMBUSTION WITH INHERENT NOX FORMATION CONTROL FEATURES.	66.3	LB/H
ND-0022	NORTHERN SUN	ARCHER DANIELS MIDLAND COMPANY	38838	WOOD/HULL FIRED BOILER	SCRAP WOOD			THE BOILER IS ALLOWED TO COMBUST HULLS (SUNFLOWER OR SOYBEAN HULLS), BIOMASS FUELS, CREOSOTE-TREATED RAILROAD TIES AND CLEAN WOOD. BIOMASS FUELS CONSIST OF APPROXIMATELY 70-95% HULLS, 2.5%-30% WAX AND 6% VEGETABLE OIL.	Particulate Matter (PM)	A	ESP	0.08	LB/MM BTU
GA-0116	TRI-GEN BIOPOWER	TRIGEN BIOPOWER	36123	BOILER, MULTI-FUEL	SCRAP WOOD	265.1	MMBTU/H	UNIT CAPABLE OF BURNING WOODWASTE, MILL SLUDGE, TDF, PULP MILL REJECTS (#2 FUEL OIL AS STARTUP FUEL). BUBBLING FLUIDIZED BED BOILER	Particulate Matter (PM)	A	ESP AND WET SCRUBBER	0.1	LB/MMBTU
NH-0013	SCHILLER STATION	PUBLIC SERVICE OF NEW HAMPSHIRE	38285	BOILER, WOOD FIRED CFB, UNIT #5	SCRAP WOOD AND BARK	720	MMBTU/h	720 MMBTU/HR ON BIOMASS. WOOD FUEL: INCLUDES WHOLE TREE CHIPS, UNTREATED BYPRODUCTS OR RESIDUE FROM FOREST PRODUCTS MFG OPERATIONS, STUMP GRINDINGS, OR GROUND PALLETS. 635 MMBTU/HR ON COAL WITH MAXIMUM SULFUR CONTENT OF 1.5 LB/MMBTU SHORT TERM AND 1.0 LB/MMBTU (3 MONTH AVERAGE). COAL IS BACKUP FUEL, BUT COULD PLANT CAN FIRE COAL UP TO 8760 H/YR. ALL LIMITS EXCEPT SO2 ARE BASED ON WOOD FUEL USE.	Particulate Matter < 10 µ (PM10)	A	FABRIC FILTER	0.025	LB/MMBTU
GA-0116	TRI-GEN BIOPOWER	TRIGEN BIOPOWER	36123	BOILER, MULTI-FUEL	SCRAP WOOD AND BARK	265.1	MMBTU/H	UNIT CAPABLE OF BURNING WOODWASTE, MILL SLUDGE, TDF, PULP MILL REJECTS (#2 FUEL OIL AS STARTUP FUEL). BUBBLING FLUIDIZED BED BOILER	Particulate Matter < 10 µ (PM10)	A	ESP AND WET SCRUBBER	0.03	LB/MMBTU
*AL-0223	STEVENSON MILL	SMURFIT STONE CONTAINER CORP.	38912	NO. 2 WOOD-FIRED BOILER	SEE NOTES	620	mmbtu/h		Sulfur Dioxide (SO2)	N		93	LB/H
ND-0022	NORTHERN SUN	ARCHER DANIELS MIDLAND COMPANY	38838	WOOD/HULL FIRED BOILER	SEE NOTES			THE BOILER IS ALLOWED TO COMBUST HULLS (SUNFLOWER OR SOYBEAN HULLS), BIOMASS FUELS, CREOSOTE-TREATED RAILROAD TIES AND CLEAN WOOD. BIOMASS FUELS CONSIST OF APPROXIMATELY 70-95% HULLS, 2.5%-30% WAX AND 6% VEGETABLE OIL.	Sulfur Dioxide (SO2)	N		0.47	LB/MM BTU

**RBLC Search Results  
Port Townsend Paper Company  
Power Boiler**

RBLCID	FACILITYNAME	CORPORATEORCOMPANYNAME	PERMITDATE	PROCESSNAME	FUEL	THRUPUT	THRUPUTUNIT	PROCESSNOTES	POLLUTANT	CONTROL	CTRLDESC	EMISLIMIT1	EMISLIMIT1UNIT
NH-0013	SCHILLER STATION	PUBLIC SERVICE OF NEW HAMPSHIRE	38285	BOILER, WOOD FIRED CFB, UNIT #5	TDF	720	MMBTU/h	720 MMBTU/HR ON BIOMASS. WOOD FUEL: INCLUDES WHOLE TREE CHIPS, UNTREATED BYPRODUCTS OR RESIDUE FROM FOREST PRODUCTS MFG OPERATIONS, STUMP GRINDINGS, OR GROUND PALLETS. 635 MMBTU/HR ON COAL WITH MAXIMUM SULFUR CONTENT OF 1.5 LB/MMBTU SHORT TERM AND 1.0 LB/MMBTU (3 MONTH AVERAGE). COAL IS BACKUP FUEL, BUT COULD PLANT CAN FIRE COAL UP TO 8760 H/YR. ALL LIMITS EXCEPT SO2 ARE BASED ON WOOD FUEL USE.	Sulfur Oxides (SOx)	P	LIME INJECTION	0.02	LB/MMBTU
*AL-0223 WA-0298 WA-0298	STEVENSON MILL ABERDEEN DIVISION ABERDEEN DIVISION	SMURFTT STONE CONTAINER CORP. SIERRA PACIFIC INDUSTRIES SIERRA PACIFIC INDUSTRIES	38912 37546 37546	NO. 2 WOOD-FIRED BOILER HOG FUEL BOILER HOG FUEL BOILER	TDF WASTE WOOD WASTE WOOD	620 310 310	mmbtu/h MMBTU/H MMBTU/H	spreaders stoker boiler spreaders stoker boiler	Sulfuric Acid (mist, vapors, etc) Nitrogen Oxides (NOx) Particulate Matter (PM)	N B A	SNCR, BOILER DESIGN ESP	13.6 0.15 0.02	LB/H LB/MMBTU LB/MMBTU
VA-0268	THERMAL VENTURES	MARTINSVILLE THERMAL, LLC	37302	BOILER, STEAM	WOOD	120	MMBTU/H	Wood limit 70% Mixture. Wood/Bark excluding any wood which contains chemical treatments or has affixed thereto paint and/or finishing materials or paper or plastic laminates: Average annual heat content: 5,000 Btu/lb HHV	Nitrogen Dioxide (NO2)	P	GOOD COMBUSTION PRACTICES AND CONTINUOUS EMISSION MONITORING DEVICE.	0.4	LB/MMBTU
*OH-0307	SOUTH POINT BIOMASS GENERATION	BIOMASS ENERGY	38811	WOOD FIRED BOILERS (7)	WOOD	318	MMBTU/H	SEVEN WOOD FIRED BOILERS PURCHASED FROM THE ETHANOL INDUSTRY AND BEING RETROFITTED TO BURN WOOD, FOR ELECTRIC POWER.	Nitrogen Oxides (NOx)	A	SELECTIVE CATALYTIC REDUCTION	27.98	LB/H
MN-0046	DISTRICT ENERGY ST. PAUL, INC	DISTRICT ENERGY ST. PAUL INC	37210	BOILER	WOOD	550	MMBTU/H		Nitrogen Oxides (NOx)	A	SELECTIVE, NON-CATALYTIC REDUCTION, SNCR	0.15	LB/MMBTU, BIOMASS
ME-0026	WHEELABRATOR SHERMAN ENERGY COMPANY	WHEELABRATOR SHERMAN ENERGY COMPANY	36259	BOILER # 1	WOOD	315	MMBTU/H	FUEL IS WOOD WASTE, NO.2 FUEL. # 2 FUEL ONLY FOR START UP AND EMERGENCY BACKUP. THE PEANUT HULL UNLOADING SHALL PROCESS NO MORE THAN 20,000 TONS (50%MOISTURE) WOOD PER YEAR, CALCULATED MONTHLY AS THE SUM OF EACH CONSECUTIVE 12-MONTH PERIOD. COMPLIANCE FOR THE CONSECUTIVE 12-	Nitrogen Oxides (NOx)	P	GOOD COMBUSTION PRACTICES	0.25	LB/MMBTU
*VA-0298	INTERNATIONAL BIOFUELS, INC	INTERNATIONAL BIOFUELS, INC	38699	PEANUT HULL UNLOADING	WOOD	3	tons/hr	MONTH PERIOD DEMONSTRATED MONTHLY BY ADDING THE TOTAL FOR THE MOST RECENTLY COMPLETED CALENDAR MONTH TO THE INDIVIDUAL MONTHLY TOTALS FOR THE PRECEDING 11 MONTHS.	Particulate Matter (PM)	N		0.6	LB/H
*VA-0298	INTERNATIONAL BIOFUELS, INC	INTERNATIONAL BIOFUELS, INC	38699	PRIMARY GRIND HAMMERMILLS	WOOD	121	tons/hr	THE PRIMARY GRIND HAMMERMILLS SHALL PROCESS NO MORE THAN 949,168 TONS (50% MOISTURE) WOOD PER YEAR, CALCULATED MONTHLY AS THE SUM OF EACH CONSECUTIVE 12-MONTH PERIOD. COMPLIANCE FOR THE CONSECUTIVE 12-MONTH PERIOD SHALL BE DEMONSTRATED MONTHLY BY ADDING THE TOTAL FOR THE MOST RECENTLY COMPLETED CALENDAR MONTH TO THE INDIVIDUAL MONTHLY TOTALS FOR THE PRECEDING 11 MONTHS.	Particulate Matter (PM)	B	SETTING CHAMBERS AND CYCLONES AND CEM SYSTEM	14.5	LB/H
*VA-0298	INTERNATIONAL BIOFUELS, INC	INTERNATIONAL BIOFUELS, INC	38699	ROTARY AND FUEL DRYER PROCESSING	WOOD	65.6	tons/hr	THE ROTARY DRYERS SHALL PROCESS NO MORE THAN 347,698 DRY TONS WOOD PER YEAR FORM THE OUTLET OF THE DRYERS, CALCULATED MONTHLY AS THE SUM OF EACH CONSECUTIVE 12 MONTH PERIOD. THE ROTARY DRYERS SHALL DRY WOOD WITH AN OVERALL COMPOSITION OF LESS THAN 50% SOFT WOOD. COMPLIANCE FOR THE CONSECUTIVE 12 MONTH PERIOD SHALL BE DEMONSTRATED MONTHLY BY ADDING THE TOTAL FOR THE MOST RECENTLY COMPLETED CALENDAR MONTH TO THE INDIVIDUAL MONTHLY TOTALS FOR THE PRECEDING 11 MONTHS.	Particulate Matter (PM)	B	SETTING CHAMBERS AND CYCLONES CEM SYSTEM	13.1	LB/H
*VA-0298	INTERNATIONAL BIOFUELS, INC	INTERNATIONAL BIOFUELS, INC	38699	PELLET MILLS PROCESSING	WOOD	51	tons/yr	THE PELLET MILLS1 THROUGH 16 SHALL PROCESS NO MORE THAN 395,836 DRY TONS WOOD PER YEAR CALCULATED MONTHLY AS THE SUM OF EACH CONSECUTIVE 12 MONTH PERIOD. COMPLIANCE FOR THE CONSECUTIVE 12 MONTH PERIOD SHALL BE DEMONSTRATED MONTHLY BY ADDING THE TOTAL FOR THE MOST RECENTLY COMPLETED CALENDAR MONTH TO THE INDIVIDUAL MONTHLY TOTALS FOR THE PRECEDING 11 MONTHS.	Particulate Matter (PM)	B	CYCLONES	10.2	LB/H

**RBLC Search Results**  
**Port Townsend Paper Company**  
**Power Boiler**

RBLCID	FACILITYNAME	CORPORATEORCOMPANYNAME	PERMITDATE	PROCESSNAME	FUEL	THRUPUT	THRUPUTUNIT	PROCESSNOTES	POLLUTANT	CONTROL	CTRLDESC	EMISLIMIT1	EMISLIMIT1UNIT
VA-0268	THERMAL VENTURES	MARTINSVILLE THERMAL, LLC	37302	BOILER, STEAM	WOOD	120	MMBTU/H	Wood limit 70% Mixture. Wood/Bark excluding any wood which contains chemical treatments or has affixed thereto paint and/or finishing materials or paper or plastic laminates: Average annual heat content: 5,000 Btu/lb HHV	Particulate Matter (PM)	P	GOOD COMBUSTION PRACTICES AND CONTINUOUS EMISSION MONITORING DEVICE.	0.15	LB/MMBTU
MN-0046	DISTRICT ENERGY ST. PAUL, INC	DISTRICT ENERGY ST. PAUL INC	37210	BOILER	WOOD	550	MMBTU/H		Particulate Matter (PM)	A	CYCLONE, ESP	0.03	LB/MMBTU
ME-0026	WHEELABRATOR SHERMAN ENERGY COMPANY	WHEELABRATOR SHERMAN ENERGY COMPANY	36259	BOILER # 1	WOOD	315	MMBTU/H	FUEL IS WOOD WASTE, NO.2 FUEL. # 2 FUEL ONLY FOR START UP AND EMERGENCY BACKUP.	Particulate Matter (PM)	A	ESP, CYCLONE.	11.4	LB/H
*OH-0307	SOUTH POINT BIOMASS GENERATION	BIOMASS ENERGY	38811	WOOD FIRED BOILERS (7)	WOOD	318	MMBTU/H	SEVEN WOOD FIRED BOILERS PURCHASED FROM THE ETHANOL INDUSTRY AND BEING RETROFITTED TO BURN WOOD, FOR ELECTRIC POWER.	Particulate Matter < 10 µ (PM10)	A	PULSE JET BAGHOUSE	3.97	LB/H
*VA-0298	INTERNATIONAL BIOFUELS, INC	INTERNATIONAL BIOFUELS, INC	38699	PEANUT HULL UNLOADING	WOOD	3	tons/hr	THE PEANUT HULL UNLOADING SHALL PROCESS NO MORE THAN 20,000 TONS (50%MOISTURE) WOOD PER YEAR, CALCULATED MONTHLY AS THE SUM OF EACH CONSECUTIVE 12-MONTH PERIOD. COMPLIANCE FOR THE CONSECUTIVE 12-MONTH PERIOD DEMONSTRATED MONTHLY BY ADDING THE TOTAL FOR THE MOST RECENTLY COMPLETED CALENDAR MONTH TO THE INDIVIDUAL MONTHLY TOTALS FOR THE PRECEDING 11 MONTHS.	Particulate Matter < 10 µ (PM10)	N		0.6	LB/H
*VA-0298	INTERNATIONAL BIOFUELS, INC	INTERNATIONAL BIOFUELS, INC	38699	PRIMARY GRIND HAMMERMILLS	WOOD	121	tons/hr	THE PRIMARY GRIND HAMMERMILLS SHALL PROCESS NO MORE THAN 949,168 TONS (50% MOISTURE) WOOD PER YEAR, CALCULATED MONTHLY AS THE SUM OF EACH CONSECUTIVE 12-MONTH PERIOD. COMPLIANCE FOR THE CONSECUTIVE 12-MONTH PERIOD SHALL BE DEMONSTRATED MONTHLY BY ADDING THE TOTAL FOR THE MOST RECENTLY COMPLETED CALENDAR MONTH TO THE INDIVIDUAL MONTHLY TOTALS FOR THE PRECEDING 11 MONTHS.	Particulate Matter < 10 µ (PM10)	B	SETTING CHAMBERS AND CYCLONES CEM SYSTEM	14.5	LB/H
*VA-0298	INTERNATIONAL BIOFUELS, INC	INTERNATIONAL BIOFUELS, INC	38699	ROTARY AND FUEL DRYER PROCESSING	WOOD	65.6	tons/hr	THE ROTARY DRYERS SHALL PROCESS NO MORE THAN 347,698 DRY TONS WOOD PER YEAR FORM THE OUTLET OF THE DRYERS, CALCULATED MONTHLY AS THE SUM OF EACH CONSECUTIVE 12 MONTH PERIOD. THE ROTARY DRYERS SHALL DRY WOOD WITH AN OVERALL COMPOSITION OF LESS THAN 50% SOFT WOOD. COMPLIANCE FOR THE CONSECUTIVE 12 MONTH PERIOD SHALL BE DEMONSTRATED MONTHLY BY ADDING THE TOTAL FOR THE MOST RECENTLY COMPLETED CALENDAR MONTH TO THE INDIVIDUAL MONTHLY TOTALS FOR THE PRECEDING 11 MONTHS.	Particulate Matter < 10 µ (PM10)	B	SETTING CHAMBERS AND CYCLONES AND CEM SYSTEM	13.1	LB/H
*VA-0298	INTERNATIONAL BIOFUELS, INC	INTERNATIONAL BIOFUELS, INC	38699	PELLET MILLS PROCESSING	WOOD	51	tons/yr	THE PELLET MILLS1 THROUGH 16 SHALL PROCESS NO MORE THAN 395,836 DRY TONS WOOD PER YEAR CALCULATED MONTHLY AS THE SUM OF EACH CONSECUTIVE 12 MONTH PERIOD. COMPLIANCE FOR THE CONSECUTIVE 12 MONTH PERIOD SHALL BE DEMONSTRATED MONTHLY BY ADDING THE TOTAL FOR THE MOST RECENTLY COMPLETED CALENDAR MONTH TO THE INDIVIDUAL MONTHLY TOTALS FOR THE PRECEDING 11 MONTHS.	Particulate Matter < 10 µ (PM10)	B	CYCLONES	10.2	LB/H
VA-0268	THERMAL VENTURES	MARTINSVILLE THERMAL, LLC	37302	BOILER, STEAM	WOOD	120	MMBTU/H	Wood limit 70% Mixture. Wood/Bark excluding any wood which contains chemical treatments or has affixed thereto paint and/or finishing materials or paper or plastic laminates: Average annual heat content: 5,000 Btu/lb HHV	Particulate Matter < 10 µ (PM10)	P	GOOD COMBUSTION PRACTICES AND CONTINUOUS EMISSION MONITORING DEVICE.	0.14	LB/MMBTU
*OH-0307	SOUTH POINT BIOMASS GENERATION	BIOMASS ENERGY	38811	WOOD FIRED BOILERS (7)	WOOD	318	MMBTU/H	SEVEN WOOD FIRED BOILERS PURCHASED FROM THE ETHANOL INDUSTRY AND BEING RETROFITTED TO BURN WOOD, FOR ELECTRIC POWER.	Sulfur Dioxide (SO2)	A	SPRAY DRYER ADSORBER OR DRY SODIUM BICARBONATE INJECTION SYSTEM	22.13	LB/H
VA-0268	THERMAL VENTURES	MARTINSVILLE THERMAL, LLC	37302	BOILER, STEAM	WOOD	120	MMBTU/H	Wood limit 70% Mixture. Wood/Bark excluding any wood which contains chemical treatments or has affixed thereto paint and/or finishing materials or paper or plastic laminates: Average annual heat content: 5,000 Btu/lb HHV	Sulfur Dioxide (SO2)	P	GOOD COMBUSTION PRACTICES AND CONTINUOUS EMISSION MONITORING DEVICE.	0.47	LB/MMBTU

**RBLC Search Results  
Port Townsend Paper Company  
Power Boiler**

RBLCID	FACILITYNAME	CORPORATEORCOMPANYNAME	PERMITDATE	PROCESSNAME	FUEL	THRUPUT	THRUPUTUNIT	PROCESSNOTES	POLLUTANT	CONTROL	CTRLDESC	EMISLIMIT1	EMISLIMIT1UNIT
ME-0026	WHEELABRATOR SHERMAN ENERGY COMPANY	WHEELABRATOR SHERMAN ENERGY COMPANY	36259	BOILER # 1	WOOD	315	MMBTU/H	FUEL IS WOOD WASTE, NO.2 FUEL. # 2 FUEL ONLY FOR START UP AND EMERGENCY BACKUP.	Sulfur Dioxide (SO2)	P	FIRING OF WOOD ONLY, OIL ONLY DURING STARTUP, FLAME STABILIZATION, OR AS EMERG.BACKUP. OIL S < 0.5% BY WT.	38.9	LB/H
MI-0285	GRAYLING GENERATING STATION	GRAYLING GENERATING STATION	37152	BOILER, MIXED FUEL (WOOD & TIRES), SPREADER STROKE	WOOD AND TIRES	500	MMBTU/H	UP TO 45 TON/DAY OF TDF ALLOWED. AT FULL LOAD THIS IS 3.5% OF HEAT INPUT	Nitrogen Oxides (NOx)	A	SNCR, UREA, CEMS. NOX EMISSIONS NOT ADVERSELY EFFECTED BY TDF. NO CHANGE TO LIMIT	106	PPMVD @ 15% 02
MI-0285	GRAYLING GENERATING STATION	GRAYLING GENERATING STATION	37152	BOILER, MIXED FUEL (WOOD & TIRES), SPREADER STROKE	WOOD AND TIRES	500	MMBTU/H	UP TO 45 TON/DAY OF TDF ALLOWED. AT FULL LOAD THIS IS 3.5% OF HEAT INPUT	Particulate Matter (PM)	A	MULTICLONES AND ESP. INCREASE OVER ACTUAL PRIOR EMISSIONS IS 14.84 T/YR. PSD LEVEL OF SIGNIFICANCE IS 15 T/YR. EMISSION LIMIT BEING REDUCED FROM 15 LB/H. TDF DOUBLES PM10 EMISSIONS LIMIT ON AMOUNT OF TDF.	0.03	LB/MMBTU
MI-0285	GRAYLING GENERATING STATION	GRAYLING GENERATING STATION	37152	BOILER, MIXED FUEL (WOOD & TIRES), SPREADER STROKE	WOOD AND TIRES	500	MMBTU/H	UP TO 45 TON/DAY OF TDF ALLOWED. AT FULL LOAD THIS IS 3.5% OF HEAT INPUT	Sulfur Dioxide (SO2)	P	ALKALINE NATURE OF WOOD ASH REMOVES SOME OF TIRE SO2 TO AROUND 5% OF THEORETICAL EMISSIONS (AT THIS RATE OF TDF). 39 TON INCREASE OVER PRIOR ACTUAL.	10.9	PPMVD @ 15% 02
MI-0285	GRAYLING GENERATING STATION	GRAYLING GENERATING STATION	37152	BOILER, MIXED FUEL (WOOD & TIRES), SPREADER STROKE	WOOD AND TIRES	500	MMBTU/H	UP TO 45 TON/DAY OF TDF ALLOWED. AT FULL LOAD THIS IS 3.5% OF HEAT INPUT	Sulfuric Acid (mist, vapors, etc)	N	NOT DETECTED IN OCTOBER 1999 TESTS. PSD SIGNIFICANCE IS 7 T/YR . LIMIT IS 6.6 T/YR	0.003	LB/MMBTU
WA-0329	DARRINGTON ENERGY COGENERATION POWER PLANT	DARRINGTON ENERGY LLC	38394	WOOD WASTE-FIRED BOILER	WOOD WASTE	403	MMBTU/H		Nitrogen Oxides (NOx)	A	SNCR	0.12	LB/MMBTU
AR-0072	DEL TIN FIBER LLC	DEL-TIN FIBER LLC	37680	HEAT ENERGY SYSTEM	WOOD WASTE	291	MMBTU/H	The heat energy system is a Callidus Closed Loop Gasification System (CLGS) which gasifies biomass fuel, which is bark, sawdust, sander dust, chips, and other residual wood materials, in a rotary kiln to produce a combustible gas used as fuel in a secondary combustion chamber (SCC).	Nitrogen Oxides (NOx)	B	LOW NOX COMBUSTORS AND SNCR	87.2	LB/H
ME-0021	S.D. WARREN CO. - SKOWHEGAN, ME	S.D. WARREN CO. - SKOWHEGAN, ME	37222	BOILER, #2	WOOD WASTE	1300	MMBTU/H	BOILER FIRES BARK, WOOD/WOOD WASTE, DEWATERED MILL SLUDGE, NO. 2 FUEL OIL, NO. 6 FUEL OIL, TIRE DERIVED FUEL, WASTE PAPERS, RECLAIMED SPECIFICATION AND OFF SPEC WASTE OIL.	Nitrogen Oxides (NOx)	A	SCNR	260	LB/H
ME-0021	S.D. WARREN CO. - SKOWHEGAN, ME	S.D. WARREN CO. - SKOWHEGAN, ME	37222	BOILER, #2	WOOD WASTE	1300	MMBTU/H	BOILER FIRES BARK, WOOD/WOOD WASTE, DEWATERED MILL SLUDGE, NO. 2 FUEL OIL, NO. 6 FUEL OIL, TIRE DERIVED FUEL, WASTE PAPERS, RECLAIMED SPECIFICATION AND OFF SPEC WASTE OIL.	Particulate Matter (PM)	A	MECHANICAL DUST COLLECTOR, ESP.	171	T/YR
WA-0329	DARRINGTON ENERGY COGENERATION POWER PLANT	DARRINGTON ENERGY LLC	38394	WOOD WASTE-FIRED BOILER	WOOD WASTE	403	MMBTU/H		Particulate Matter < 10 µ (PM10)	A	DRY ESP	0.02	LB/MMBTU
AL-0198	SMURFIT-STONE-STEVENSON	SMURFIT-STONE-STEVENSON	37529	BOILER, NO.2 WOOD RESIDUE	WOOD WASTE	620	MMBTU/H		Sulfur Dioxide (SO2)	N		0.1	LB/MMBTU
ME-0021	S.D. WARREN CO. - SKOWHEGAN, ME	S.D. WARREN CO. - SKOWHEGAN, ME	37222	BOILER, #2	WOOD WASTE	1300	MMBTU/H	BOILER FIRES BARK, WOOD/WOOD WASTE, DEWATERED MILL SLUDGE, NO. 2 FUEL OIL, NO. 6 FUEL OIL, TIRE DERIVED FUEL, WASTE PAPERS, RECLAIMED SPECIFICATION AND OFF SPEC WASTE OIL.	Sulfur Dioxide (SO2)	A	SODIUM BASED WET SCRUBBER	351	LB/H
*VA-0298	INTERNATIONAL BIOFUELS, INC	INTERNATIONAL BIOFUELS, INC	38699	WOOD THERMAL OXIDERS FOR WOOD PELLENT PROCESS	WOOD/WOOD PASTE	43	mmbtu/hr	EMISSIONS ARE FOR ONE OF TWO UNITS. CONTROL EFFICIENCY % FOR SETTING CHAMBERS 20% EACH, CYCLONES 90% THERMAL OXIDIZERS 99% EACH	Nitrogen Oxides (NOx)	B	THERMAL OXIDIZERS AND CEM SYSTEM	18.9	LB/H
*VA-0298	INTERNATIONAL BIOFUELS, INC	INTERNATIONAL BIOFUELS, INC	38699	WOOD THERMAL OXIDERS FOR WOOD PELLENT PROCESS	WOOD/WOOD PASTE	43	mmbtu/hr	EMISSIONS ARE FOR ONE OF TWO UNITS. CONTROL EFFICIENCY % FOR SETTING CHAMBERS 20% EACH, CYCLONES 90% THERMAL OXIDIZERS 99% EACH	Particulate Matter (PM)	B	SETTING CHAMBER AND CYCLONE	3.9	LB/H
*VA-0298	INTERNATIONAL BIOFUELS, INC	INTERNATIONAL BIOFUELS, INC	38699	RAW MATERIAL UNLOADING	WOOD/WOOD PASTE	121	tons/hr	THE RAW MATERIALS UNLOADING SHALL PROCESS NO MORE THAN 949,168 TONS (50% MOISTURE) WOOD PER YEAR, CALCULATED MONTHLY AS THE SUM OF EACH CONSECUTIVE 12-MONTH PERIOD COMPLIANCE OF THE CONSECUTIVE 12-MONTH PERIOD SHALL BE DEMONSTRATED MONTHLY BY ADDING THE TOTAL FOR THE MOST RECENTLY COMPLETED CALENDAR MONTH TO THE INDIVIDUAL MONTHLY TOTALS FOR THE PRECEDING 11 MONTHS.	Particulate Matter (PM)	N		12.1	LB/H
*VA-0298	INTERNATIONAL BIOFUELS, INC	INTERNATIONAL BIOFUELS, INC	38699	WOOD THERMAL OXIDERS FOR WOOD PELLENT PROCESS	WOOD/WOOD PASTE	43	mmbtu/hr	EMISSIONS ARE FOR ONE OF TWO UNITS. CONTROL EFFICIENCY % FOR SETTING CHAMBERS 20% EACH, CYCLONES 90% THERMAL OXIDIZERS 99% EACH	Particulate Matter < 10 µ (PM10)	B	SETTING CHAMBER AND CYCLONES	3.4	LB/H
*VA-0298	INTERNATIONAL BIOFUELS, INC	INTERNATIONAL BIOFUELS, INC	38699	RAW MATERIAL UNLOADING	WOOD/WOOD PASTE	121	tons/hr	THE RAW MATERIALS UNLOADING SHALL PROCESS NO MORE THAN 949,168 TONS (50% MOISTURE) WOOD PER YEAR, CALCULATED MONTHLY AS THE SUM OF EACH CONSECUTIVE 12-MONTH PERIOD COMPLIANCE OF THE CONSECUTIVE 12-MONTH PERIOD SHALL BE DEMONSTRATED MONTHLY BY ADDING THE TOTAL FOR THE MOST RECENTLY COMPLETED CALENDAR MONTH TO THE INDIVIDUAL MONTHLY TOTALS FOR THE PRECEDING 11 MONTHS.	Particulate Matter < 10 µ (PM10)	N		12.1	LB/H

**RBLC Search Results  
Port Townsend Paper Company  
Power Boiler**

RBLCID	FACILITYNAME	CORPORATEORCOMPANYNAME	PERMITDATE	PROCESSNAME	FUEL	THRUPUT	THRUPUTUNIT	PROCESSNOTES	POLLUTANT	CONTROL	CTRLDESC	EMISLIMIT1	EMISLIMIT1UNIT
*VA-0298	INTERNATIONAL BIOFUELS, INC	INTERNATIONAL BIOFUELS, INC	38699	WOOD THERMAL OXIDERS FOR WOOD PELLENT PROCESS	WOOD/WOOD PASTE	43	mmbtu/hr	EMISSIONS ARE FOR ONE OF TWO UNITS. CONTROL EFFICIENCY % FOR SETTING CHAMBERS 20% EACH, CYCLONES 90% THERMAL OXIDIZERS 99% EACH	Sulfur Dioxide (SO2)	B	THERMAL OXIDIZERS AND CEM SYSTEM	2.2	LB/H
*VA-0298	INTERNATIONAL BIOFUELS, INC	INTERNATIONAL BIOFUELS, INC	38699	HEAT ENERGY SYSTEMS FOR PELLET PROCESSING	WOOD/WOOD PASTE	77	mmbtu/hr	2 HEAT ENERGY SYSTEMS. THE EMISSIONS ARE FOR 1 OF 2 SYSTEMS. CONTROL EFFICIENCY % FOR SETTING CHAMBERS 20% EACH, CYCLONES 90% THERMAL OXIDIZERS 99% EACH	Nitrogen Oxides (NOx)	B	THERMAL OXIDIZERS AND CEM SYSTEM	0.22	LB/MMBTU
*VA-0298	INTERNATIONAL BIOFUELS, INC	INTERNATIONAL BIOFUELS, INC	38699	HEAT ENERGY SYSTEMS FOR PELLET PROCESSING	WOOD/WOOD PASTE	77	mmbtu/hr	2 HEAT ENERGY SYSTEMS. THE EMISSIONS ARE FOR 1 OF 2 SYSTEMS. CONTROL EFFICIENCY % FOR SETTING CHAMBERS 20% EACH, CYCLONES 90% THERMAL OXIDIZERS 99% EACH	Particulate Matter (PM)	B	SETTING CHAMBERS AND CYCLONES	6.9	LBS/H
*VA-0298	INTERNATIONAL BIOFUELS, INC	INTERNATIONAL BIOFUELS, INC	38699	HEAT ENERGY SYSTEMS FOR PELLET PROCESSING	WOOD/WOOD PASTE	77	mmbtu/hr	2 HEAT ENERGY SYSTEMS. THE EMISSIONS ARE FOR 1 OF 2 SYSTEMS. CONTROL EFFICIENCY % FOR SETTING CHAMBERS 20% EACH, CYCLONES 90% THERMAL OXIDIZERS 99% EACH	Particulate Matter < 10 µ (PM10)	B	SETTING CHAMBERS AND CYCLONES	6.2	LB/H
*VA-0298	INTERNATIONAL BIOFUELS, INC	INTERNATIONAL BIOFUELS, INC	38699	HEAT ENERGY SYSTEMS FOR PELLET PROCESSING	WOOD/WOOD PASTE	77	mmbtu/hr	2 HEAT ENERGY SYSTEMS. THE EMISSIONS ARE FOR 1 OF 2 SYSTEMS. CONTROL EFFICIENCY % FOR SETTING CHAMBERS 20% EACH, CYCLONES 90% THERMAL OXIDIZERS 99% EACH	Sulfur Dioxide (SO2)	B	THERMAL OXIDERS AND CEM SYSTEM	3.9	LB/H
GA-0117	TRI-GEN BIOPOWER	TRI-GEN BIOPOWER	37035	BOILER, MULTIFUEL	WOODWASTE AND PAPERMILL SLUDGE	302.2	MMBTU/H	MULTIFUEL BOILER MODIFED TO INCREASE HEAT INPUT RATE FROM 265.1 MMBTU/HR TO 302.2 MMBTU/HR	Particulate Matter < 10 µ (PM10)	A	ESP AND WET SCRUBBER	8	LB/H
AL-0116	GULF STATES PAPER CORPORATION	GULF STATES PAPER CORPORATION	35774	FURNACE, RECOVERY		3.94	MMLB/D BLS		Nitrogen Dioxide (NO2)	P	PROPER DESIGN AND OPERATION	90	PPMDV @ 8% O2
AL-0116	GULF STATES PAPER CORPORATION	GULF STATES PAPER CORPORATION	35774	FURNACE, RECOVERY		3.94	MMLB/D BLS		Particulate Matter (PM)	A	ESP	0.021	GR/DSCF @ 8% O2
KY-0085	MEADWESTVACO KENTUCKY, INC/WICKLIFFE	MEADWESTVACO KENTUCKY, INC	37314	RECOVERY FURNACE		473000	LB/H	Throughput is lb steam/h. Recovery furnace is designed to recover and regenerate spent cooking chemicals from wood pulping operations. The furnace is also the primary steam generating unit at the mill. Permitted modifications are: improved furnace ash chemistry; re-evaluate current sootblowing sequence; optimize recovery furnace scrubber to handle increased solids load; circulation study.	Sulfur Dioxide (SO2)	A	WET SCRUBBER	0.29	LB/T ADP
AL-0116	GULF STATES PAPER CORPORATION	GULF STATES PAPER CORPORATION	35774	FURNACE, RECOVERY		3.94	MMLB/D BLS		Sulfur Dioxide (SO2)	P	PROPER DESIGN AND OPERATON	100	PPMDV @ 8% O2
KY-0085	MEADWESTVACO KENTUCKY, INC/WICKLIFFE	MEADWESTVACO KENTUCKY, INC	37314	RECOVERY FURNACE		473000	LB/H	Throughput is lb steam/h. Recovery furnace is designed to recover and regenerate spent cooking chemicals from wood pulping operations. The furnace is also the primary steam generating unit at the mill. Permitted modifications are: improved furnace ash chemistry; re-evaluate current sootblowing sequence; optimize recovery furnace scrubber to handle increased solids load; circulation study.	Sulfur, Total Reduced (TRS)	B	GOOD ENGINEERING PRACTICE, CEM MONITORING, WET SCRUBBER	40	PPMV @ 8% O2
LA-0122	MANSFIELD MILL	INTERNATIONAL PAPER - MANSFIELD MILL	37117	RECOVERY BOILER NO.1 AND NO.2		71	TBLS/H	EMISSION POINTS 04-78, 05-78	Sulfur, Total Reduced (TRS)	P	GOOD PROCESS CONTROLS	5	PPMV
AL-0116	GULF STATES PAPER CORPORATION	GULF STATES PAPER CORPORATION	35774	FURNACE, RECOVERY		3.94	MMLB/D BLS		Sulfur, Total Reduced (TRS)	P	PROPER DESIGN AND OPERATION	5	PPMDV @ 8% O2
OK-0103	WEYERHAEUSER -- VALLIANT	WEYERHAEUSER	38273	CFB BOILER				THROUGHPUT AS MMBTU/H IS CONFIDENTIAL. THE CFB BOILER WILL BURN A VARIETY OF FUELS IN VARYING COMBINATIONS AND AMOUNTS. FUELS WILL INCLUDE, BUT ARE NOT LIMITED TO COAL, WOOD AND BARK RESIDUALS, OCC REJECTS, WASTEWATER TREATMENT SLUDGE, OIL, NATURAL GAS, PETROLEUM COKE (PETCOKE), AND NCGS/SOGS. USED OILS FROM MILL EQUIPMENT MAY ALSO BE ADDED TO THE CFB BOILER FUEL MIXTURE. EXHAUST GASES WILL BE EMITTED TO THE ATMOSPHERE THROUGH A SHARED STACK WITH THE NEW RECOVERY FURNACE.	Sulfuric Acid (mist, vapors, etc)	A	CFB BOILER WITH LIMESTONE INJECTION	0.0012	LB/MMBTU
OK-0103	WEYERHAEUSER -- VALLIANT	WEYERHAEUSER	38273	CHEMICAL RECOVERY FURNANCE					Sulfuric Acid (mist, vapors, etc)	P	GOOD COMBUSTION PRACTICES	0.5	PPM @ 8% O2
AL-0116	GULF STATES PAPER CORPORATION	GULF STATES PAPER CORPORATION	35774	FURNACE, RECOVERY		3.94	MMLB/D BLS		Sulfuric Acid (mist, vapors, etc)	N		0.042	LB/T BLS

**BART FEASIBILITY COST CALCULATIONS**

**No. 10 Power Boiler  
Cost Analysis for the Control of PM<sub>10</sub> with Wet ESP Technology  
Capital Cost Summary (Average Cost Analysis)**

Cost	Variable	Basis	Value	Reference
<b>Direct Costs</b>				
<b>Purchased Equipment Cost</b>				
Basic Equipment	BE	BE	\$3,925,000 <sup>a</sup>	Vendor Estimate
Options				<sup>c</sup> Not estimated
Auxiliary Equipment				<sup>c</sup> Not estimated
Instrumentation		BE*0.10		<sup>a</sup> Included in Vendor Estimate
Sales Tax		BE*0.03	\$117,750 <sup>b</sup>	OAQPS Sixth Edition
Freight		BE*0.05		<sup>a</sup> Included in Vendor Estimate
Total Purchased Equipment Cost	PEC	SUM	\$4,042,750	Calculation
<b>Installation Costs</b>				
Foundations and Supports		PEC*0.04	-- <sup>c</sup>	Not estimated
Handling and Erection		PEC*0.50	-- <sup>c</sup>	Not estimated
Electrical		PEC*0.08	-- <sup>c</sup>	Not estimated
Piping		PEC*0.01	-- <sup>c</sup>	Not estimated
Insulation for ductwork		PEC*0.02	-- <sup>c</sup>	Not estimated
Painting		PEC*0.02	-- <sup>c</sup>	Not estimated
Total Direct Installation Costs	DIC	SUM	\$1,500,000	
Site Preparation	SP			<sup>c</sup> Not estimated
Buildings	B			<sup>c</sup> Not estimated
Total Direct Costs	TDC	PEC + DIC + SP + B	\$5,542,750	Calculation
<b>Indirect Costs</b>				
Engineering		PEC*0.20	\$808,550 <sup>b</sup>	OAQPS Sixth Edition
Construction and Field Expense		PEC*0.20	\$808,550 <sup>b</sup>	OAQPS Sixth Edition
Contractor Fees		PEC*0.10	\$404,275 <sup>b</sup>	OAQPS Sixth Edition
Start-up		PEC*0.01	-- <sup>c</sup>	Not estimated
Performance Test		PEC*0.01	\$40,428 <sup>b</sup>	OAQPS Sixth Edition
Model Study		PEC*0.02	\$80,855 <sup>b</sup>	OAQPS Sixth Edition
Contingencies		PEC*0.03	\$121,283 <sup>b</sup>	OAQPS Sixth Edition
Total Indirect Cost	TIC	SUM	\$2,263,940	Calculation
<b>Total Capital Investment (TCI)</b>	<b>TCI</b>	<b>TDC + TIC</b>	<b>\$7,806,690</b>	<b>Calculation</b>

<sup>a</sup> Data provided by Geoenergy, a division of A.H. Lundberg Associates, Inc., emailed by Nancy Rogerson, PTPC, to Anna Henson, Trinity Consultants, on October 19, 2007.

<sup>b</sup> Office of Air Quality Planning and Standards (OAQPS), EPA Air Pollution Control Cost Manual, Sixth Edition, Sec 6, Chpt 3, Table 3.16. EPA 452-B-02-001 (<http://www.epa.gov/ttn/catc/products.html#cccinfo>), Turner et. al., September 1999.

<sup>c</sup> Costs not included in estimate.

**No. 10 Power Boiler  
Cost Analysis for the Control of PM<sub>10</sub> with Wet ESP Technology  
Annual Cost Summary (Average Cost Analysis)**

Direct Operating Cost	Basis	Value	Reference
<b>Maintenance</b>			
Maintenance Cost	FCC*0.01	\$40,428 <sup>a</sup>	OAQPS Sixth Edition
ESP plate area	ft <sup>2</sup>	25,704	Engineering Estimate
Labor Cost	\$4,125 (if A<50,000)	\$7,327 <sup>a,c</sup>	OAQPS Sixth Edition
Total Maintenance Cost (\$/yr)	Maintenance + Labor	\$47,754 <sup>a</sup>	OAQPS Sixth Edition
<b>Operating Labor</b>			
Operator	0.5-2 hours per shift	\$10,283 <sup>a</sup>	OAQPS Sixth Edition
Supervisor	15% of operator	\$1,542 <sup>a</sup>	OAQPS Sixth Edition
Electricity	(consumption rate) x (hours/yr) x (unit cost)	\$52,980 <sup>a,d</sup>	OAQPS Sixth Edition
Fan		-- <sup>b</sup>	Not estimated
Pump		-- <sup>b</sup>	Not estimated
Fuel		-- <sup>b</sup>	Not estimated
Cooling Water		-- <sup>b</sup>	Not estimated
Dust Disposal	(\$20/ton)x(ton/year)	-- <sup>b</sup>	Not estimated
<b>Wastewater</b>			
Wastewater Treatment	(5gal/min-kacfm)x(\$1.3/kgal)x(114.6kacfm)	-- <sup>b</sup>	Not estimated
Wastewater Maintenance	maintenance personnel	-- <sup>b</sup>	Not estimated
Wastewater Disposal	(throughput/year) x (waste fraction)	-- <sup>b</sup>	Not estimated
Treated Water Disposal	(5gal/min-kacfm)x(\$1.46/kgal)x(110kacfm)	-- <sup>b</sup>	Not estimated
<b>Total Direct (\$/yr)</b>	<b>DAC</b>	<b>\$112,560</b>	
<b>Indirect</b>			
Overhead	60% of O&M Costs	\$67,536 <sup>a</sup>	OAQPS Sixth Edition
Administration, Property Tax, and Insurance	4% of TCI	\$312,268 <sup>a</sup>	OAQPS Sixth Edition
CRF	20 Years, 7% Interest	0.094 <sup>a</sup>	OAQPS Sixth Edition
Capital Recovery	CRF*TCI	\$736,896 <sup>a</sup>	Calculation
<b>Total Indirect (\$/yr)</b>	<b>IAC</b>	<b>\$1,116,700</b>	Calculation
Recovery Credit	Credit for process which can be reused or sold	\$0 <sup>e</sup>	Not estimated
<b>Total Annual Cost</b>	<b>TAC=DAC+IAC</b>	<b>\$1,229,260</b>	

<sup>a</sup> Office of Air Quality Planning and Standards (OAQPS), EPA Air Pollution Control Cost Manual, Sixth Edition, Sec 6, Chpt 3. EPA 452-B-02-001 (<http://www.epa.gov/ttn/catc/products.html#cccinfo>), Turner et. al., September 1999.

<sup>b</sup> Costs not included in estimate.

<sup>c</sup> The \$4,125 maintenance cost, provided by OAQPS in 1987 dollars, is converted to 2006 dollars used for this cost analysis.

<sup>d</sup> Assumes electrical cost for PTPC of \$0.036/kWh provided by Nancy Rogerson, PTPC, to Anna Henson, Trinity Consultants, 10/23/07 email.

<sup>e</sup> Recovery credit is not included in this estimate.

**No. 10 Power Boiler  
 Cost Analysis for the Control of PM<sub>10</sub> with Wet ESP Technology and Scrubber  
 Cost Effectiveness Summary (Average Cost Analysis)**

PM <sub>10</sub> emission rate (with scrubber) (lb/MMBtu)	0.10 <sup>a</sup>
PM <sub>10</sub> emission rate with scrubber (ton/yr)	157.6 <sup>b</sup>
PM <sub>10</sub> emission rate with ESP in addition to scrubber (gr/dscf)	0.010 <sup>a</sup>
PM <sub>10</sub> emission rate with ESP in addition to scrubber (ton/yr)	48.7 <sup>c</sup>
Additional PM <sub>10</sub> removed by ESP (ton/yr)	108.84
Total Annual Cost (TAC) of adding ESP to operations controlled by scrubber	\$1,229,260
Cost Effectiveness of adding ESP to operations controlled by scrubber (\$/additional ton PM <sub>10</sub> removed)	\$11,294

<sup>a</sup> For the purposes of this cost analysis, all PM is assumed to be PM<sub>10</sub>.

<sup>b</sup> Emissions from the scrubber in tons per year calculated based on continuous operation (8760 hours per year) and maximum fuel use based on the steam capacity and the boiler efficiency as shown below.

Steam Capacity (kb/hr)	250
Wood-fired Efficiency	65%
Oil-fired Efficiency	80%
Percent Wood Fired	70%
Percent Oil Fired	30%
Heat of Steam (Btu/lb)	1000
Maximum heat input capacity (MMBtu/hr)	360

<sup>c</sup> Emissions in tons per year calculated based on continuous operation (8760 hours per year) and the flow rates specified in the Geoenergy bid as listed below.

Design Flow Rate (ACFM)	200,000
Design Flow Rate (DSCFM)	129,755

## Cost Analysis for the Control of SO<sub>2</sub>: Low Sulfur Fuel Cost Effectiveness Summary

Maximum Sulfur in Baseline Fuel	0.76 (weight %)	<sup>a</sup>
SO <sub>2</sub> emitted	5.01 (lb / barrel)	<sup>b</sup>
Cost of Baseline Fuel	\$50.90 (\$ / barrel)	<sup>c</sup>
Maximum Sulfur in Low Sulfur Fuel	0.5 (weight %)	<sup>a</sup>
SO <sub>2</sub> emitted assuming 100 % S=SO <sub>2</sub>	3.30 (lb / barrel)	<sup>b</sup>
Cost of Low Sulfur Fuel	\$64.36 (\$ / barrel)	<sup>c</sup>
SO <sub>2</sub> removed by Low Sulfur Fuel	1.71 (lb / barrel)	
Cost of Switching to Low Sulfur Fuel	\$13.46 (\$ / barrel)	
Cost Effectiveness of Low Sulfur Fuel (\$/lb SO <sub>2</sub> removed)	\$7.85 (\$ / pound)	
Cost Effectiveness of Low Sulfur Fuel (\$/ton SO <sub>2</sub> removed)	\$15,702 (\$ / ton)	

<sup>a</sup> Percent weight of sulfur in fuel based on maximum guaranteed sulfur by vendor.

<sup>b</sup> SO<sub>2</sub> emissions based on AP-42 Table 1.3-1 emission factor (157\*S% lb SO<sub>2</sub>/10<sup>3</sup> gallons)

<sup>c</sup> Cost of fuel based on current prices paid by PTPC as of September, 2007.

**ELECTRONIC MEDIA FILE INDEX**

Electronic media enclosed with this report contain the input and output files from all CALPUFF, POSTUTIL, and CALPOST processing for the modeling analysis. The applicability analysis, refined applicability analysis for Olympic National Park, determination analysis for control of the No. 10 Power Boiler with an ESP, and the determination analysis for control of the Lime Kiln with alkaline solution added to the scrubber, are contained in separate folders. A consistent file naming convention is used throughout, with the following general structure.

### **BART Applicability Analysis Naming Convention** **CALPUFF Runstream Files**

yy = **03**, **04**, and **05** denotes data analysis years 2003, 2004, and 2005, respectively

CPUFyy.fff

*fff* = **inp** denotes input files

*fff* = **lst** denotes CALPUFF output summary files

*fff* = **con** denotes CALPUFF output concentration files

WFLUXyy.dat = denotes CALPUFF output wet deposition flux files

DFLUXyy.dat = denotes CALPUFF output dry deposition flux files

### **Screening Analyses POSTUTIL Processing Files**

yy = **03**, **04**, and **05** denotes data analysis years 2003, 2004, and 2005, respectively

PUSUMyy.inp = denotes input files

SUMyy.lst = denotes POSTUTIL output summary files

### **CALPOST Runstream Files**

aa VISyy.inp = denotes input files

yy = **03**, **04**, and **05** denotes data analysis years 2003, 2004, and 2005, respectively

aa denotes the Class I and other areas considered in the analysis:

Alpine Lakes	=	Alpine Lakes Wilderness Area
Glacier Peak	=	Glacier Peak Wilderness Area
Goat Rocks	=	Goat Rocks Wilderness Area
Mount Adams	=	Mount Adams Wilderness Area
Mount Rainier	=	Mount Rainier National Park
North Cascades	=	North Cascades National Park
Olympic	=	Olympic National Park
Pasayten	=	Pasayten Wilderness Area
Gorge	=	Columbia River Gorge National Scenic Area

aa yy VIS.lst = denotes CALPOST output summary files

yy = **03**, **04**, and **05** denotes data analysis years 2003, 2004, and 2005, respectively

*aa* denotes the Class I areas considered in the analysis:

Alpine Lakes	=	Alpine Lakes Wilderness Area
Glacier Peak	=	Glacier Peak Wilderness Area
Goat Rocks	=	Goat Rocks Wilderness Area
Mount Adams	=	Mount Adams Wilderness Area
Mount Rainier	=	Mount Rainier National Park
North Cascades	=	North Cascades National Park
Olympic	=	Olympic National Park
Pasayten	=	Pasayten Wilderness Area
Gorge	=	Columbia River Gorge National Scenic Area

### **BART Applicability Analysis Naming Convention**

For the Refined BART Applicability Analysis and BART Determination modeling files, which apply the ammonia limiting method (ALM) and the new IMPROVE equation, a similar naming convention is used with more detail added to denote additional post-processing files.

#### **CALPUFF Runstream Files**

*yy* = **03**, **04**, and **05** denotes data analysis years 2003, 2004, and 2005, respectively

CPUF $_{yy}$ .*fff*

*fff* = **inp** denotes input files

*fff* = **lst** denotes CALPUFF output summary files

*fff* = **con** denotes CALPUFF output concentration files

WFLUX $_{yy}$ .dat = denotes CALPUFF output wet deposition flux files

DFLUX $_{yy}$ .dat = denotes CALPUFF output dry deposition flux files

#### **Screening Analyses POSTUTIL Processing Files**

*yy* = **03**, **04**, and **05** denotes data analysis years 2003, 2004, and 2005, respectively

PU\_ALM\_ $_{yy}$ .inp = denotes input files using ALM

ALM\_ $_{yy}$ .lst = denotes POSTUTIL output summary files using ALM

## **CALPOST Runstream Files**

*yy* = **03**, **04**, and **05** denotes data analysis years 2003, 2004, and 2005, respectively  
*aa* denotes the Class I and other areas considered in the analysis. In the case of these analyses, Olympic National Park is the only Class I area analyzed, which is denoted as Olympic

*aa* ALM VIS<sub>yy</sub>.inp = denotes input files for visibility impacts at all receptors

*aa* 50 ALM VIS<sub>yy</sub>.inp = denotes input files for visibility impacts at receptors beyond 50 km from PTPC

*aa* ALM NOX<sub>yy</sub>.inp = denotes input files for NO<sub>x</sub> concentrations at all receptors

*aa* 50 ALM NOX<sub>yy</sub>.inp = denotes input files for NO<sub>x</sub> concentrations at receptors beyond 50 km from PTPC

*aa* ALM VIS<sub>yy</sub>.lst = denotes output files for visibility impacts at all receptors

*aa* 50 ALM VIS<sub>yy</sub>.lst = denotes output files for visibility impacts at receptors beyond 50 km from PTPC

*aa* ALM NOX<sub>yy</sub>.con = denotes output files for NO<sub>x</sub> concentrations at all receptors

*aa* 50 ALM NOX<sub>yy</sub>.lst = denotes output files for NO<sub>x</sub> concentrations at receptors beyond 50 km from PTPC

NewIMPROVEOlympicyyyy.xls = denotes the processing spreadsheet used to apply the IMPROVE equation

*yyyy* = denotes data analysis years 2003, 2004, and 2005, respectively