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PSD AMENDMENT FOR POWER BOILER NO. 7 NO_X LIMITS

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LIST OF ACRONYMS

BACT	Best Available Control Technology
CEMS	Continuous Emission Monitoring System
CFR	Code of Federal Regulations
CMAQ	Community Multi-scale Air Quality
CO	Carbon Monoxide
DLN	Dry Low NO_X
EPA	Environmental Protection Agency
Ecology	Washington Department of Ecology
FGR	Flue Gas Recirculation
HCl	hydrogen chloride
ha	hectare
hr	hour
Jansen	Jansen Technologies, Inc.
K	Kelvin
KC	Kimberly-Clark
km	kilometer
lb	pound
μg	microgram
MMBtu	Million British Thermal Units
NAAQS	National Ambient Air Quality Standards
NH_3	ammonia
NH_4Cl	ammonium chloride
NOC	Notice of Construction
NO_X	Nitrogen Oxides
NO_2	Nitrogen dioxide
NP	National Park
NSPS	New Source Performance Standard
OFA	Overfire Air

PM	Particulate Matter
PM_2	Particulate Matter less than 2.5 Microns
PM_{10}	Particulate Matter less than 10 Microns
ppb	parts per billion
ppm	parts per million
PSD	Prevention of Significant Deterioration
RBLC	RACT/BACT/LAER Clearinghouse
RSCR	Regenerative Selective Catalytic Reduction
SCR	Selective Catalytic Reduction
SDA	Spray Dryer Absorber
SIL	Significant Impact Level
SNCR	Selective Non-catalytic Reduction
Simpson	Simpson Tacoma Kraft Company, LLC
UTM	Universal Transverse Mercator
WAC	Washington Administrative Code
WSU	Washington State University
yr	year

1 INTRODUCTION

Simpson Tacoma Kraft Company, LLC (Simpson) has retained SLR International Corp to prepare and submit this request to amend Prevention of Significant Deterioration (PSD) Permit No. PSD-06-02 that the Washington Department of Ecology (Ecology) issued for its Steam Turbine Generator Project (hereafter referred to as the Cogen Project). Results from the December 23 and 24, 2009 compliance test, as required under the PSD-06-02 permit, and a review of NO_X emissions from the continuous emission monitoring system (CEMS) indicate that the Power Boiler No. 7 cannot achieve continuous compliance with the permitted NO_X emission limits. This amendment request seeks to revise these permitted NOx emission limits

This report also provides a history of projects relevant to NO_X emissions from Power Boiler No. 7 and related permitting activity, a summary of the Best Available Control Technology (BACT) analysis and PSD emission limits, efforts made by Simpson to be in a position to comply with the emission limits, new proposed BACT limits, and a discussion of the ambient air quality implications of the proposed changes.

2 POWER BOILER NO. 7 PROJECT SUMMARY

Simpson currently operates a Kraft pulp and paper mill at 801 Portland Avenue in Tacoma, Washington as authorized under the Air Operating Permit 000085-0. This permit was issued by the Ecology on July 27, 2005.

On April 21, 2006 Ecology issued Notice of Construction Order No. 3255-AQ06 to install an improved overfire air (OFA) system on Power Boiler No. 7. Simpson completed construction of the OFA project in October 2006. The improved OFA system was installed to allow Simpson to utilize more biomass and decrease the usage of fossil fuels in Power Boiler No. 7 while still meeting the existing emission limits. The OFA system improves the distribution of combustion air in the furnace, allowing Simpson to burn high moisture biomass without needing additional fossil fuel to increase the furnace temperature for complete combustion. Because the OFA project did not change the maximum capacity rating of the boiler it was not subject to New Source Review. After the OFA project was completed, the fossil fuel fraction required for efficient combustion using high moisture biomass, or at low operating rates, decreased as expected.

Simpson also received a PSD permit (PSD-06-02) from Ecology on May 22, 2007 to install a steam turbine electrical generator driven by steam produced from the existing Recovery Boiler No. 4 and Power Boiler No. 7. The Cogen Project allows the facility to cogenerate and distribute electric power to the grid. As part of this project, Power Boiler No. 7 was to be modified to increase its maximum continuous steaming capacity from 300,000 lb/hr to 340,000 lb/hr, produce higher pressure and temperature steam, and use biomass fuel to support the entire steam production. The proposed modifications for the boiler included adding tube area to the superheater section, installing larger forced-draft and induced-draft fan motors, improving the biomass fuel feed system, and improving the ash handling, electrostatic precipitator, and other ancillary systems.

Although not all of the modifications to Power Boiler No. 7 had been completed and with the boiler operating at a lower steaming rate than originally planned, Simpson was able to begin commercial operation of the steam turbine. The steam turbine began to export electrical power on a regular and scheduled basis on July 1, 2009.

For the Cogen Project, the PSD regulated pollutants were nitrogen oxide (NO_X), carbon monoxide (CO), and particulate matter less than 10-micron in diameter (PM_{10}). Therefore, case-by-case BACT analyses were performed for these pollutants as a part of the Cogen Project permitting process.

3 PSD EMISSION LIMITS

The emission limits approved in the Cogen Project PSD permit were based on past actual NO_X emissions and engineering estimates provided by Jansen Combustion Boiler Technologies, Inc. (Jansen), who designed the improved OFA system. Prior to the submittal of the Cogen Project PSD application the Power Boiler No. 7 NO_X emissions recorded by the CEMS were on the lower end of the historical range while CO emissions were on the higher end. During this time boiler firing rates were also relatively low. The Cogen Project's PSD application was submitted before the improved OFA system was installed and operational and the permit was issued before Simpson had enough operating experience with the improved OFA system to determine its effect on emissions. Jansen predicted that the OFA system would provide a 20 percent reduction in NO_X emissions. However, Jansen would not provide a guarantee for any of the emission estimates.

The BACT determination in the Cogen Project PSD permit for NO_X and CO was 0.20 lb/MMBtu and 0.35 lb/MMBtu, respectively, accomplished through proper combustion controls and OFA. The annual limits were calculated from the short-term BACT limits using a maximum firing rate of 595.4 MMBtu/hr and 8,760 hours of operation per year.

Environmental Protection Agency (EPA) guidance allows an agency to revise BACT limits if sufficient emission reductions cannot be reasonably achieved after the source makes efforts to comply with the permit limits and reduce emissions to a lower level. This requires reopening the BACT analysis and consideration of current BACT technology and requirements in the analysis.[1] These issues are addressed in the sections below.

Washington Administrative Code (WAC) 173-400-750 allows Ecology to revise PSD permit conditions if certain criteria are met. The criteria, and the reasons that the criteria are met in this case, are listed below:

(a) ***The change in conditions will not cause the source to exceed an emissions standard established by regulation***. NO_X is the only pollutant affected by the proposed revision. The only emission standard potentially applicable to NO_X emissions from the boiler are contained in New Source Performance Standard (NSPS) Subpart Db, Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units. The new proposed limit is consistent with the NSPS Subpart Db limit of 0.30 lb/MMBtu.

(b) ***No ambient air quality standard or PSD increment will be exceeded as a result of the change***. As discussed below, the predicted NO_X concentration from the facility is below the National Ambient Air Quality Standard and PSD Increment Standard.

(c) ***The change will not adversely impact the ability of Ecology or the authority to determine compliance with an emissions standard.*** Simpson will continue to operate the CEMS to monitor NO_X, CO, and oxygen to determine compliance with the emission standards.

(d) ***The revised PSD permit will continue to require BACT, as defined at the time of the original PSD permit, for each new or modified emission unit approved by the original PSD permit.*** The conclusions in the original BACT analysis have not changed, except that since the application was submitted, CEMS data have indicated that the boiler may not be able to meet the new NO_X emission limits on a continuous basis while maintaining compliance with CO emission limits. Further discussion of BACT is provided below.

(e) ***The revised PSD permit continues to meet the requirements of WAC 173-400-112(2), and 173-400-113, as applicable.*** As discussed in the following sections, the proposed amendment does not affect compliance with the requirements for new sources in nonattainment areas or new sources in attainment or unclassifiable areas.

[1] EPA's Memorandum, *Request for Determination on Best Available Control Technology (BACT) Issues – Ogden Martin Tulsa Municipal Waste Incinerator Facility*, November 19, 1987.

5 SIMPSON'S EFFORT TO REDUCE EMISSIONS

Typically in combustion processes, NO_X emissions are somewhat inversely related to CO emissions: NO_X emissions increase as CO emissions decrease. Optimization of combustion in the boiler involves balancing CO and NO_X emissions. CO emissions from the Power Boiler No. 7 have shown an overall decrease since the installation of the OFA system despite an increase in firing rate, as expected, with one exception. Higher observed CO emissions during the first quarter of 2009 have been attributed to an air heater leak, which was partially repaired.

As discussed in the PSD application for the Cogen Project, Simpson did not agree with Jansen's estimate that NO_X emissions would decrease by 20% after installation of the improved OFA system. As predicted by Simpson, NO_X emissions increased due to the higher combustion temperature and oxygen-to-fuel ratio resulting from the improved OFA system. Several other factors that may affect NO_X and CO emissions and could be contributing to the overall increase in NO_X emissions from the boiler include:

- Challenges related to the instrumentation, controls, and OFA design.
- Changes to fuel with higher fuel-bound NO_X levels.
- Higher moisture content in the biomass.
- Excess oxygen control.
- Higher furnace temperatures leading to an increase in thermal NO_X formation.
- Fuel distribution on the grate. A more even fuel distribution has been shown to reduce NO_X emissions.
- Tube leaks in the combustion air heater that reduce the amount of combustion air that can be delivered to the furnace and reduce the available amount of overfire air.

The following list summarizes Simpson's efforts to decrease and maintain NO_X emissions.

2006

- **April 21** – Notice of Construction (NOC) issued for OFA Project
- **September 5** – Submitted Cogen Project PSD/NOC application
- **September** – Installed new OFA System

2007

- **May 23** – PSD Permit issued for Cogen Project. Begin detailed design and construction for Cogen Project. Proposed design changes included increasing the maximum continuous steaming capacity of Power Boiler No. 7 to 340,000 lb/hr using biomass fuel alone compared to its original design of 300,000 lb/hr from mixed biomass and fossil fuel.

- **July** – Ordered new superheater and cold side economizer for the Cogen Project.

2008

- **May** – Contracted QBM Engineering to upgrade boiler instrumentation and control.
- **June** – Corrected over fire air flow and under grate air flow absolute air flow calculations.
- **July through August** – Replaced obsolete operator control screens with new HMI package. Engineered hardware, software and HMI screens for Burner Management System and air flow controls.
- **September** – Boiler down to install superheater, cold side economizer, interstage attemperator, and sweetwater condenser. Installed new biomass fuel feed chutes with offset back blast damper (chute plugging). Modified OFA system air heater. Unable to increase boiler production capacity due to discovery of tube thinning in generator bank.
- **October through December** – Commissioned variable speed Induced Draft Fan and Forced Draft Fan. Implemented redundant operator interface network. Continued to engineer hardware, software and HMI screens for Burner Management System and air flow controls.

2009

- **January through February** – Installed copper backbone and devices for Burner Management System and air flow controls. Started implementation of Fuel Flame Safety controls.
- **March** – Power Boiler No. 7 down to replace generator bank to increase steam capacity.
- **April** – Cogen boiler capacity upgrade work completed. Burner Management System controls completed. Implemented upgraded auxiliary fuel air curves for oil and gas. Automated OFA flow based on air master set point. Automated under grate air flow based on air master set point. Completed implementation of Fuel Flame Safety controls. Started implementation of Advanced Combustion Air Controls.
- **May** – Optimized and tuned new Burner Management System and air controls.
- **June** – Provided a real time boiler efficiency screen for Operators. Installed additional pressure transmitter to increase accuracy of OFA calculation. Began testing of the steam turbine. Power Boiler No. 7 at reduced rate due to capacity and plugging of biomass fuel delivery systems.
- **July** – The steam turbine is certified for commercial operation by the power customer and it began to export electrical power on a regular and scheduled basis. Implemented electronic cam on distributor air dampers to reduce tramp air. Implemented closed door interlock on biomass fuel delivery chutes to reduce tramp air. Increased hydraulic capacity on biomass fuel reclaimer. Installed automated moisture meter for biomass feeding the boiler. Installed variable speed drives on biomass feed systems. Modified biomass feed equipment to improve feed uniformity. Implemented advanced operator interface display for environmental parameters.

- **August** – Provided online boiler emission statistics on HMI screens – 1 hr, 12 hr, 24 hr, 7 day, and monthly CO and NO_X values. Provided online boiler air consumption summary table on HMI screens.
- **September** – Submitted test plan and notification of testing to Ecology for the initial compliance test as required by the PSD Permit. Confirmed OFA fan capacity is adequate because flow is being reduced by air heater leaks. Purchased new electronic scale package for biomass fuel supply and return belts.
- **October** – Repaired portion of failed Air Heater Tubes attributed to CO increases. Installed first variable speed mixing screw in the biomass bin (provides more even fuel distribution on the grate). Relocated 24" structural beam above feed screws to reduce tramp air by keeping the clean-out doors closed.
- **November** – Optimized under grate air damper automatic pressure control system. Detroit Stoker factory representative on site to evaluate Distributor Air Fan and Biomass Fuel Distribution Dampers.

2010

- **January** – Installed additional variable speed mixing screws in the biomass and improved reliability of the biomass reclaim system, improving distribution and uniformity of fuel to the grate, and consistency of the fuel delivery to the boiler. Developed and implemented advanced fuel algorithms for improved combustion control.
- **February** – Installed additional furnace oxygen measurement meters, to increase accuracy of furnace combustion measurements, improving combustion controls and further controlling emissions. Installed and began using new and more accurate biomass fuel measurements to fine tune boiler fuel combustion controls.
- **May** – Repair the air heater tubes. Install final (fourth) variable speed mixing screw in biomass fuel bins to improve feed uniformity and control.
- **June** – Installed the backpressure control valve at the outlet of the 425 pound steam extraction stage of the steam turbine. Without the backpressure valve, the turbine does not operate as it was designed.

Capital Expenditures and Contracts Issued

- 9/2007 – ACE Replace Power Boiler No. 7 NO_X/O_2 and CO emission analyzers
- 10/2007 – ACE Rockwell to PHD Tag Conversion
- 11/2007 – ACE Power Boiler No. 7 HMI Replacement
- 11/2007 – ACE Redundant Operator Interface Network
- 5/2008 – Contract QBM Engineering Process Engineer (PO0802952)
- 12/2008 – ACE Power Boiler No. 7 Burner Management Upgrade
- 2/2009 – ACE Power Boiler No. 7 Biomass Fuel Bin Modifications

- 4/2009 – ACE Power Boiler No. 7 Biomass Fuel Bin Modifications
- 8/2009 – ACE Power Boiler No. 7 Biomass Fuel Feed
- 8/2009 – ACE Power Boiler No. 7 Optimization O2, CO and NOX Control
- 9/2009 – Contract MoistTech to provide real time biomass fuel moisture meter (PO0905137)
- 9/2009 – Contract Jansen Engineering to test OFA fan (PO0905296)
- 9/2009 – Contract ABB to develop automated air and emissions controls (PO0905117)
- 10/2009 – Contract Weightech to provide upgrade biomass fuel scales (PO0905487)
- 10/2009 – ACE Power Boiler No. 7 Biomass Fuel Feed Supplemental
- 10/2009 – Contract Detroit Stoker to test Distributor Air fan (PO0905877)
- 10/2009 – Contract ABB to develop automated under grate air damper control (PO0905558)

As summarized above, Simpson has been implementing actions to minimize NOx emission and keep NO_X below the PSD BACT limits. However, it is clear that the boiler will not be able to demonstrate continuous compliance with the new 0.20 lb/MMBtu NO_X limit while maintaining CO emission below 0.35 lb/MMBtu.

Simpson is proposing to increase the Power Boiler No. 7's BACT limit for NO_X from 0.20 to 0.30 lb/MMBtu. This would also require a revision of the annual NO_X limit from 522 tons to 782 tons based on the revised BACT limit.

Because the source is subject to a NSPS, the minimum control efficiency to be considered BACT must result in an emission rate less than or equal to the NSPS emission limit. Thus, before a BACT analysis is performed, the applicable NSPS emission limits must be determined. Power Boiler No. 7 is subject to NSPS Subpart Db, Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units. 40 CFR 60.44b(d) limits NO_X emissions to 0.30 lb/million Btu on a 30-day rolling average.

As part of the original PSD Application, Simpson submitted a complete top-down BACT analysis for the Power Boiler No. 7. The "top down" method are outlined in the EPA's October 1990 Draft New Source Review Workshop Manual. The original BACT analysis is provided as Appendix A to this report. SLR reevaluated each step of the "top down" method and a summary of the analysis is provided below.

6.1 IDENTIFY ALL POTENTIAL CONTROL TECHNOLOGIES

Based on this research and other engineering experience, SLR concludes that the control technologies evaluated in the original Cogen Project PSD application and the discussions in the original BACT analysis are still valid. The following control technologies are still considered for this BACT analysis. No new technologies have been identified.

- EMx™
- Regenerative Selective Catalytic Reduction (RSCR)
- Selective Catalytic Reduction (SCR)
- Selective Non-catalytic Reduction (SNCR)
- Dry Low NO_X (DLN) burners
- Methane DeNOX
- Flue Gas Recirculation (FGR)
- Improved OFA system

6.2 ELIMINATE TECHNICALLY INFEASIBLE OPTIONS

Because the proposed design specifications and operation of boiler have not changed, the technological feasibility analysis performed in the original application is still applicable. A review of EPA's RACT/BACT/LAER Clearinghouse (RBLC) database indicates that EMx™ has not been applied to any wood-fired boiler. Furthermore, the exhaust from wood combustion can degrade the performance of the control system Therefore, EMx™ is still considered technologically infeasible and is rejected as a BACT control alternative.

The DLN burner and FGR are also still eliminated from consideration as BACT based on the ineffectiveness of these control alternatives with the current boiler design.

6.3 RANK REMAINING CONTROL TECHNOLOGIES

The remaining control technologies are ranked based on control effectiveness as shown in Table 6-1. The control effectiveness presented in the original application is still applicable in terms of control efficiency. The NO_X emission rate is higher than those originally presented because of the higher baseline of 0.30 lb/MMBtu that is achieved using the existing OFA system.

TABLE 6-1. CONTROL TECHNOLOGY AND CONTROL EFFECTIVENESS

Control Technology	NO_X Emission Rate (lb/MMBtu)
RSCR	0.075
SCR	0.10
Methane DeNOX	0.10
SNCR	0.10 – 0.12
OFA system (Baseline)	0.30

6.4 EVALUATE THE MOST EFFECTIVE CONTROLS

The fourth of the five steps in the top-down BACT analysis procedure is to evaluate the most effective control and document the results. This has been performed for each remaining control technology. A technology may be eliminated based on economic, energy, or environmental impacts.

6.4.1 ENVIRONMENTAL IMPACTS

Simpson continues to use biomass fuel that is transported on Puget Sound which has higher concentrations of sodium chloride relative to wood that does not contact salt water. As stated in the original application, fine particulate formation and a visible plume is a concern with any control systems using ammonia injection (SNCR, SCR, or RSCR). SNCR has been used on wood-fired boilers (as indicated in the RBLC database). However, the fuel mix, boiler design, and boiler operation (including ductwork, flue gas temperature profiles and desired residence times, flue gas chemistry, etc.) can affect the control efficiency and cause collateral environmental impacts. These environmental impacts result from emissions of unreacted ammonia (ammonia slip). The escaping ammonia can react with sulfur and chloride compounds in the flue gas to form fine particulate matter (ammonium chloride, sulfate, or nitrate particulates) which may lead to a visible plume or be absorbed into fly ash. Ammonia itself is also a toxic air pollutant subject to regulation under WAC 173-460 in Washington.

Detached ammonium chloride (NH_4Cl) plumes are a particular problem for boilers that burn salt-laden wood (wood ocean transported via log booms or wood from coastal forests)

because of the relatively high chloride content of the wood. The chloride content of salt-laden wood can be in the range of 0.8% whereas non-salted wood typically has chloride content less than 0.01%.[2]

An ammonium chloride plume can form when ammonia (NH_3) combines with hydrogen chloride (HCl) present in the exhaust gas under the following reaction:

$$NH_3 \text{ (gas)} + HCl \text{ (gas)} \Rightarrow NH_4Cl \text{ (solid)}$$

The amount formed depends on the concentrations of NH_4Cl in the exiting gas and how quickly the plume is diluted. Dilution reduces the temperature of the plume allowing the NH_4Cl to sublime. However, dilution could also reduce the concentration of NH_4Cl within the plume to the point that it is no longer visible. A critical point is reached when the plume is diluted enough to reach the point of solid formation at approximately 220 ºF, but concentrations of NH_4Cl are still high enough for a visible plume.

Excessive ammonia slip occurs when adequate dispersion of the SNCR reagent is not achieved in the boiler ductwork within the range of residence times available and temperatures needed for the NO_X reduction reactions to go to completion. Ammonia slip can vary from 10 to up to 50 parts per million (ppm) depending on the boiler design, boiler operation, fuel variability, and desired control efficiency. Ammonia slip tends to be higher for a SNCR retrofit because the boiler is not originally designed with ammonia injection as a retrofit option. Ammonia injection is effective over a relatively narrow temperature range, 1,600 – 2,000 °F. Power Boiler No. 7 is generally within this range, but, as with most Stoker-type biomass fired boilers, has considerable variation across the fire box.

Ammonia injection works best with constant boiler operating conditions. The fuel combusted in Power Boiler No. 7 is a mixture of biomass, wastewater sludge, and chip fines and is constantly varying in quality in terms of size (from sawdust up to 6 inch pieces), moisture content, and heat content (see Table 6-2 below).

TABLE 6-2. FUEL QUALITY

Parameter	Units	Minimum	Maximum	Mean	Standard Deviation
Heat Input	Btu/lb	6,620	10,600	8,199	513
Moisture	%	36	62.2	52.1	4.6

Therefore, although base-loaded, the furnace temperature changes considerably at the NH_3 injection point. Period 'cold spots' due to low heating value fuel lead to 'puffs' of NH_3 slippage. Furthermore, NO_X formation is in a constant state of flux because of the fuel variability making it difficult to determine the proper ammonia injection rate.

[2] "Emissions from Wood-Fired Combustion Equipment", British Columbia Ministry of Environment, June 30, 2008.

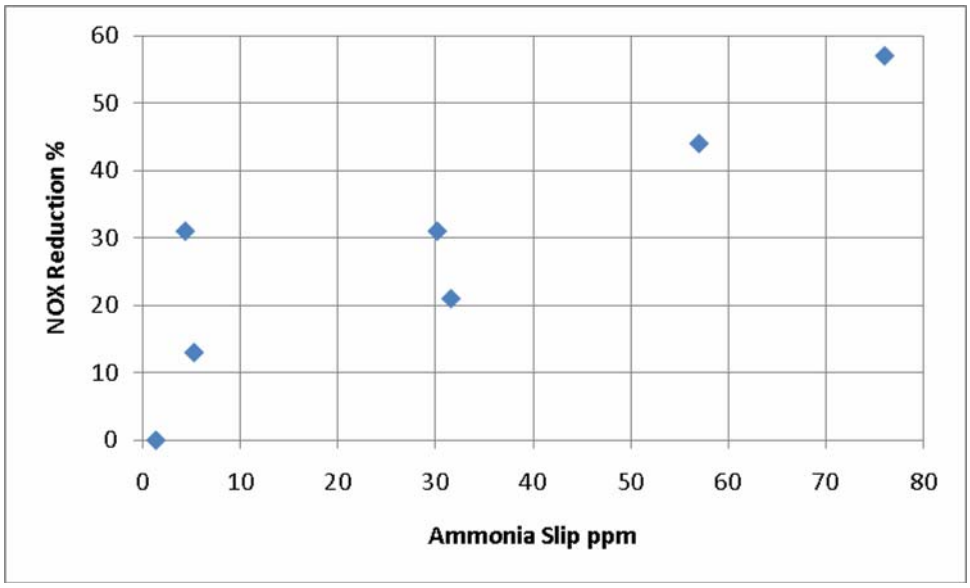
In order to achieve a high level of control efficiency, a high level of ammonia injection is required, increasing the potential for ammonia slip. For Power Boiler No. 7, Jansen Engineering provided an estimate of 20% control with an ammonia slip of 5 ppm and 45% control with an ammonia slip of 30 ppm for the 2006 Cogen Project PSD application. These estimates were not guaranteed by the control vendor. Updated numbers were provided by Fuel Tech, Inc. based on the higher NO_X baseline of 0.30 lb/MMBtu. Fuel Tech estimates the maximum control achievable while limiting ammonia slip to 5 ppm is 25%. The highest level of control the system could achieve is 64%, but the ammonia slip is 40 ppm at that level of control. Again, these are not firm guarantees.

However, experience at the Kimberly-Clark (KC) pulp mill in Everett, Washington shows ammonia slip may be much higher. Test data from KC's boiler showed ammonia slip much higher than anticipated was needed to approach the NO_X emissions design level (See Table 6-3 and Figure 6-1). The results from KC's boiler are relevant to Power Boiler No. 7 because they are of similar design (Stoker type boilers) and age. Ammonia injection and slip was considerably higher than expected when trying to approach the permitted NO_X reduction rate. The desired NO_X reduction rate was never achieved at full load due to the detached plume problem. Looking at the ammonia slip vs NO_X reduction on Figure 6-2 below, it is more reasonable to think the ammonia slip would be at least 10 ppm and could be as much as 30 ppm to achieve a NO_X reduction of 20%. At 45% control, ammonia slip may be at least 57 ppm.

TABLE 6-3. KIMBERLY-CLARK AMMONIA SLIP

Test Date	Test Condition	Ammonia Addition (lb/hr)	Ammonia Slip (ppm)	NO_X Concentration (ppm)	NO_X % Reduction
September 26-27, 1996	1	0	1.4	134	0
	2	194	4.4	88	31
	3	416	57	67	44
	4	647	76	57	57
November 18-19, 1996	1	203	5.3	100	13
	2	353	30.2	84	31
	3	404	31.6	101	21

FIGURE 6-1. KIMBERLY-CLARK NO_X REDUCTION VS. AMMONIA SLIP



The other main factor for ammonium chloride formation, HCl, is formed from chloride in the biomass. Chloride content in Simpson's biomass is higher than the national average because it contains wood from high alkali soils or coastal forests, and logs transported on salt water. In addition, to reduce fresh water usage Simpson uses direct cooling of effluent prior to the activated sludge treatment process. The cooling media is salt water pumped directly from Commencement Bay. This adds salt load that ends up in the secondary treatment sludge. This sludge is currently dewatered and burned in Power Boiler No. 7. Chloride in Simpson's biomass fuel (mixture) ranges from 35 to 5,630 ppm and has an average chloride content of 1,109 (or 0.11%). Most of the chloride in the fuel mixture comes from the salt-laden wood and sludge. Table 6-4 below shows the chloride concentration of fuel analysis conducted by Simpson, Kimberly-Clark, and Sierra Pacific.

TABLE 6-4. CHLORIDE CONCENTRATION IN FUEL MG/KG (PPM)

Source	Minimum	Maximum	Mean	Standard Deviation
NCASI Bark	<40	273	90	
NCASI Stemwood(1)	50	91	62.4	
Simpson Fuel Mixture(2)	35	5,630	1,109	780
Kimberly-Clark				
Woodwaste Fuel	500	700	570	113
Hog Fuel	680	2,000	1,229	1,200
Sludge	370	960	516	420
Multiclone	910	3,500	1,991	2,000
Sierra Pacific Fuel Mixture	1,540	2,930	2,417	

(1) Reference NCASI tech bulletin.
(2) From 75 samples tested between March 2005 and December 2006.

As shown in Table 6-4 above, local chloride concentrations are higher than the national average. Furthermore, Simpson's chloride content is similar to those obtained from other sources in Washington where ammonium chloride plume formation has been a problem. It is fair to assume almost all of the chloride in the fuel is converted to HCl based on source test data. Using the mean chloride concentration for Simpson's fuel mix and assuming all chloride forms HCl results in an HCl concentration 78 ppmv for Power Boiler No. 7. Results of 22 stack tests conducted between November 2001 and April 2005 using the normal fuel mix gave a range of 70 to 109 ppmv @ 7% oxygen with an average of 82 ppmv. Table 6-5 below compares Simpsons measured HCl with Kimberly Clark and Sierra Pacific.

TABLE 6-5. EXHAUST HCL CONCENTRATION PPMV @ 7% O2

Source	Minimum	Maximum	Mean
Simpson	70	109	82
Kimberly-Clark	Unknown	(0.124 lb/MMBtu)	73 (0.090 lb/MMBtu)
Sierra Pacific	Unknown	Unknown	72

Simpson's HCl outlet concentration is higher than those measured at the other two sources with ammonium chloride plume formation problems.

Data from the KC mill, control vendors, and boiler combustion engineers indicate a visible NH_4Cl plume can be expected when NH_3 concentrations reach about 5 ppm with high HCl concentrations (See Table 6-6). KC further tested the plume to verify that NH_4Cl particles were responsible for the opacity.

TABLE 6-6. KIMBERLY-CLARK OPACITY VS. AMMONIA SLIP

Test Condition	Ammonia Slip (ppm)	NO_X % Reduction	Method 9 Opacity (%)
1	1.4	0	12
2	4.4	31	9
3	57	44	36
4	76	57	58

Professor John Kramlich of the Mechanical Engineering Department at the University of Washington has studied the formation of NH_4Cl plumes. He has developed a method for estimating NH_4Cl concentrations in the exhaust gas using thermochemical equilibrium calculations based on the composition of the exhaust gas and plume entrainment. In addition, he has developed equations using the Lambert-Beer Law to estimate the opacity of the plume. Given the expected exhaust concentration of 82 ppm HCl and 5 ppm NH_3, the opacity is estimated at 10%. Note that this estimate only considers the visibility impairment caused by the NH_4Cl particles formed and does not include visibility degradation from other pollutants present in the exhaust gas stream. At the highest ammonia slip estimated by Fuel Tech for the best NO_X reduction rate, the opacity is estimated at 60.8%. The opacity limit for Power Boiler No. 7 is 10% under Condition E-2 of the Title V permit.

The biomass supplied to the mill comes from up to 20 different suppliers, most are sawmills or log chippers that remove the bark and grind it up to create the fuel. Simpson receives building and demolition waste in lesser quantities. Simpson also uses screenings of the wood chips supplied to the digester for pulp production, called fines. The final source of fuel to Power Boiler No. 7 is the waste treatment sludge, both primary and secondary, from the mill waste treatment system. The secondary sludge typically contains over 1,000 mg/kg of chloride and is roughly 50% of the chloride load going to Power Boiler No. 7. Fuel costs would increase if the fuel supplies with high chloride content were eliminated and replaced with low chloride content biomass. The cost to replace these suppliers is approximately $1.52 million/year. If the sludge is not burned in the power boiler, it would have to be landfilled. The cost to haul this sludge to landfill instead of burning it would be approximately $1 million/year. There would also be additional cost associated with replacing the sludge with biomass fuel of approximately $700,000/year. Therefore, the total cost of removing fuel with the highest chloride content is $3.22 million/year and SNCR control would no longer be cost effective.

Although NH_4Cl plume formation is the chief concern, there are other environmental impacts to consider from using any ammonia injection technology. There is the potential for increased formation of $PM_{2.5}$ occurring which could impact the $PM_{2.5}$ non-attainment area around Tacoma. For SCR or RSCR technology, the catalysts must also be replaced on a routine basis and may be classified as a hazardous waste in some cases.

For all these reasons, SNCR, SCR, and RSCR control technologies are still removed from consideration as BACT due to adverse environmental impacts.

6.4.2 COST EFFECTIVENESS

In the original BACT analysis, Methane DeNOX was determined to be cost ineffective. With an increase in the NO_X emission baseline, this control technology has been revisited to see if it is has become cost effective. Jansen estimated 50% removal efficiency for Methane DeNOX at the time of the original BACT analysis. Using the new proposed baseline of 0.30 lb/MMBtu, the updated cost effectiveness is $17,037 per ton of NO_X removed, which is still outside the envelope of acceptable costs.[3]

Improved OFA System is still the only control options feasible for the Power Boiler No. 7. There are no adverse environmental or energy impacts associated with the proposed control alternative.

6.5 SELECT BACT

Simpson proposes to apply improved OFA system to control NO_X emissions from the Power Boiler No. 7. Simpson proposes a NO_X BACT emission limit of 0.30 lb/MMBtu based on a 30-day rolling average. Compliance with the emission limit will be demonstrated by CEMS.

[3] We assume capital and operating costs have not decreased or increased significantly since 2006 for this type of control technology.

As part of the above BACT analysis, SLR searched the RBLC database for wood-fired utility and large industrial boiler/furnace greater than 250 MMBtu/hr. The search included all RBLC entries since January 1991.

The RBLC search results are provided in Appendix B. The RBLC search was also used to evaluate BACT limits of similar projects. Table 6-7 provides a summary of the search results for both NO_X and CO. Although Simpson is only proposing to revise the NO_X limit, information on CO is relevant and important because of the inverse relationship of these pollutants for combustion sources. CO emissions are the result of incomplete combustion. High flame temperatures and intimate air/fuel mixing are essential for low CO emissions. However, increasing flame temperature by modifying air/fuel mixing patterns in order to reduce CO emissions can result in an increase of NO_X emissions. Therefore, the CO emission limit should be considered when setting BACT for NO_X.

TABLE 6-7. NEW AND MODIFIED BOILER RBLC RESULTS

Permit Date	Facility Name	State	NO_X Emission Limit (lb/MMBtu)	CO Emission Limit (lb/MMBtu)	New/Modified
5/1/2006	Northern Sun	ND	0.2 30-Day Rolling Avg.	0.63	Modified
2/1/2006	Boise Cascade - Boise White Paper LLC	WA	0.3 30-Day Rolling Avg.	500 ppmvd (~0.51 lb/MMBtu) 12 Month Rolling Avg.	Modified
11/23/2004	Bogalusa Mill	LA	0.45	0.6 Annual Avg.	Modified
4/9/1999	Wheelabrator Sherman Energy Company	ME	0.25 30-Day Avg.	0.45	Modified
2/27/2002	Meadwestvaco Kentucky, Inc/Wickliffe	KY	0.4	N/A	New
12/10/1997	Gulf States Paper Corporation	AL	0.30	N/A	Modified
11/5/1996	Valliant	OK	0.30	N/A	New
4/17/1996	Willamette Industries - Marlboro Mill	SC	0.30	0.30	New
12/21/1994	International Paper Company	PA	0.54	0.70	New
12/19/1994	KES Chateaugay Project	NY	0.23	0.35	New
7/1/1993	Scott Paper Company	WA	150 ppm (~ 0.25 lb/MMBtu 30-day Avg.)	511 ppm (~ 0.50 lb/MMBtu Annual Avg.)	New
9/29/1992	Wheelabrator Ridge Energy, Inc.	FL	0.14	0.32	New
2/4/1991	Willamette Industries Inc	LA	0.30	0.30	New

N/A = Not Available

Because the Power Boiler No. 7 was retrofitted with the improved OFA system in 2006 rather than being originally designed for optimum combustion as with new units, the retrofitted unit cannot be expected to achieve the same NO_X emission rates as a new boiler. Therefore, it is more appropriate to compare emission limits for Power Boiler No. 7 to PSD projects related to the modification of existing wood-fired boilers (with a capacity rating

greater than 250 MMBtu/hr). RBLC data show that the NO_X BACT emission limits using proper combustion and/or OFA systems for modified wood-fired boiler projects range from 0.2 to 0.45 lb/MMBtu.

The BACT determinations performed on KES Chateaugay Project, Scott Paper Company, and Wheelabrator Ridge Energy were for new boilers. Moreover, the boiler permitted for KES Chateaugay Project is less than half the size of the Power Boiler No. 7. The CO BACT limit of 0.50 lb/MMBtu the Scott Paper Company's boiler is much higher than the current CO BACT limit of 0.35 lb/MMBtu for Power Boiler No. 7. The boiler at Wheelabrator Ridge Energy is permitted to fire 60% wood and 40% tire.

As shown in Table 2 above, the Northern Sun facility in North Dakota received a PSD permit for modification of its existing boiler with a NO_X BACT limit of 0.2 lb/MMBtu, based on a 30-day rolling average. However, the CO BACT limit is 0.63 lb/MMBtu which is almost twice the Power Boiler No. 7's CO BACT limit of 0.35 lb/MMBtu. The boiler is rated at approximately 280 MMBtu/hr with a nominal steam output of about 170,000 lb/hr, which is less than half the size of the Power Boiler No. 7. Moreover, the Northern Sun's boiler is fired with a mixture of sunflower hulls, wax residue, and up to 50% wood products. This is a significantly different fuel mixture than that used at Simpson.

Wheelabrator Sherman Energy Company in Maine received a PSD permit for modification of their existing boiler with a NO_X BACT limit of 0.25 lb/MMBtu, based on a 30-day rolling average and 0.30 lb/MMBtu on a 24-hr block. Startup, shutdown, and periodic maintenance were not included in determining compliance with the short term and/or rolling average emission rates. Furthermore, the CO BACT limit is 0.45 lb/MMBtu on a 30-day rolling average.

Proper combustion with the improved OFA system is still BACT for Power Boiler No. 7. However, we do not agree with the BACT limit proposed in the original Cogen Project PSD application (and established in the PSD permit) particularly in light of actual boiler performance since operation of the improved OFA system. We do not believe the BACT limits were set with an adequate margin of safety considering all operation loads and fuel sources. In addition, this limit was too stringent given the unusually low CO limits. The EPA Environmental Appeals Board has made it clear that permitting agencies have the discretion to set BACT limits that allow for continuous compliance and with a reasonable safety factor ("Permit agencies retain discretion to set BACT limits at levels that do not necessarily reflect the highest possible control efficiencies but, rather, will allow permittees to achieve compliance on a consistent basis;" "There is nothing inherently wrong with setting an emissions limitation that takes into account a reasonable safety factor.") [4]

NO_X emissions have ranged from 0.169 to 0.284 lb/MMBtu (30-day average) since Simpson installed the improved OFA system and 0.234 to 0.284 lb/MMBtu (30-day average) since startup of the steam turbine. The average NO_X rate of 0.259 lb/MMBtu adjusted for a 25% margin of safety calculates to 0.324 lb/MMBtu.

Simpson is therefore proposing to revise the NO_X BACT for Power Boiler No. 7 to 0.30 lb/MMBtu based on a rolling 30-day average. Compliance with the emission limit will still be demonstrated by CEMS. The proposed limit is within the BACT limit ranges identified in the RBLC search. Furthermore, the proposed limit is consistent with the NSPS limit for wood-fired boilers. The CO limit will remain 0.35 lb/MMBtu, which is still on the low end for boilers of this size.

Simpson is also requesting to adjust the annual NO_X emission limit from 522 tons to 782 tons in proportion to the revised BACT limit. The revised NO_X emission limits would not affect any other emission units in the facility.

[4] In Re Steel Dynamics, Inc., PSD Appeal Nos. 99-4 & 99-5, June 22, 2000; and In Re Knauf Fiber Glass, GMBH, PSD Appeal Nos. 99-8 through 99-72, March 14, 2000. Also cited in In Re Kendall New Century Development, PSD Appeal No. 03-01, April 29, 2003; and In Re Cardinal FG Company, PSD Appeal No. 04-04, March 22, 2005.

A new dispersion modeling analysis is necessary to ensure the new limits do not cause or contribute to a violation of the National Ambient Air Quality Standards (NAAQS) or PSD Increment standards. This dispersion modeling analysis was completed using the same modeling methodology outlined in the original Cogen Project PSD application, submitted on September 5, 2006. The analysis is provided as Appendix C to this report and the results are summarized in Table 8-1 below. The predicted ambient concentration from the proposed NO_X emissions are below the NAAQS and PSD Increments.

TABLE 8-1. CLASS II NO_2 AIR QUALITY ANALYSIS RESULTS

Analysis	Averaging Period	Maximum Predicted NO_2 Concentration(1) ($\mu g/m^3$)	Standard ($\mu g/m^3$)
NAAQS	Annual	71.3	100(2,3)
	1-hour	38.0	191(4)
PSD Increment	Annual	22.9	25(2)

(1) Assume a 75% conversion of NO_X to NO_2.
(2) Annual arithmetic mean.
(3) Includes a background concentration of 28 $\mu g/m^3$.
(4) 3-year average of the 98th percentile of the daily maximum 1-hour average.

The Class I area PSD Increment, visibility, and nitrogen deposition analyses are also reevaluated with the higher NO_X emissions. ENVIRON International Corporation completed the modeling study using CALPUFF following the protocol approved for a similar modeling analysis for the Simpson Lumber Company, LLC Shelton mill and subsequently approved for use in this amendment request application. As requested by the Federal Land Managers, the analysis includes an NO_2 concentration, nitrogen deposition, and visibility impairment evaluation for Alpine Lakes Wilderness Area (WA), Mount Rainier National Park (NP), and Olympic NP. The full analysis and results are presented in Appendix D and summarized in Table 8-2 below. The NO_X emissions are not expected to adversely impact Class I areas.

TABLE 8-2. CLASS I AREA ANALYSIS RESULTS

Class I Area	Annual Average NO_2 Concentration[1] ($\mu g/m^3$)		Annual Average Nitrogen Deposition (kg/ha/yr)	98th Percentile Predicted Extinction Change	
				Method 2 (%)	Method 8 (%)
Alpine Lakes WA	0.0097		0.0043	4.45[4]	4.31[4]
Mount Rainier NP	0.0100		0.0031	3.91	1.72
Olympic NP	0.0052		0.0017	4.37	4.82[4]
Class I Area Maximum	0.0100		0.0043	4.37	1.72
Standard	EPA SIL[2]	0.1	0.005	5	5
	FLM SIL[2]	0.03			
	Class I Increment[3]	2.5			

(1) NO_X was conservatively assumed to be 100 percent converted to NO_2.
(2) FLM = Federal Land Manager; EPA proposed and FLM recommended from the Federal Register, Vol. 61, No. 142, p. 38292, July 23, 1996.
(3) 40 CFR 52.21(c), adopted by reference in WAC 173-400-720(4)(a)(v).
(4) The maximum extinction change is presented.

Per 40 CFR 52.21(i)(5), an ozone analysis is required for any net emissions increase of 100 tons per year or more of NO_X subject to PSD permitting. Although Simpson is only requesting an increase in the NO_X emission limit, the net emission increase (as that term is defined under 40 CFR 52.21 - PSD regulations) of VOC and CO proposed in the 2006 PSD permit was also modeled in order to develop a more complete analysis of the effect on regional ozone formation as a result of the entire Cogen Project.

On behalf of Simpson, SLR employed a team led by Professor Brian Lamb of the Washington State University Laboratory for Atmospheric Research (WSU), to conduct a modeling study of the air quality effects of the proposed permit limit changes. The WSU team used the Community Multi-scale Air Quality (CMAQ) modeling system for the ozone analysis. The CMAQ model and the AIRPACT-3 air quality forecasting system are further described in the enclosed report (Appendix E). Effects on ambient ozone concentrations were simulated by applying CMAQ for two one-week scenarios that were selected in cooperation with Ecology.[5]

The analysis compares the predicted ozone concentration from baseline actual emissions (as that term is defined under 40 CFR 52.21(b)(48)) and proposed emission limits for NO_X, VOC, and CO. The results are summarized in Table 8-3 below.

[5] Email communication on December 16, 2009 Clint Bowman, Ecology, to Joseph K. Vaughan, Ph.D., WSU.

TABLE 8-3. OZONE AIR QUALITY ANALYSIS RESULTS

Scenario	Maximum Predicted Ozone Concentration (ppb)	Maximum Ozone Increase Over Base Case (ppb)
June 2008	90	0.087 (<0.1%)
August 2008	112	0.090 (<0.1%)

The ozone analysis demonstrates that the proposed emission limits are not expected to affect significantly 8-hour average ozone maximum values during conditions like those modeled. Therefore, the proposed increase in the NO_X emission limit is not expected to cause or contribute to a violation of the NAAQS for ozone.

9 AMENDMENT REQUEST

In accordance with WAC 173-400-750, Simpson is submitting this application for the following revisions to the PSD-06-02 permit.

Approval Condition 1.1 – Change "0.20 lb/MMBtu" to **"**0.30 lb/MMBtu".
Approval Condition 1.2 – Change "522 tons per year" to "782 tons per year".

Simpson is requesting an approval of these revisions from Ecology.

APPENDIX A

2006 PSD APPLICATION BACT ANALYSIS

PSD Amendment for Power Boiler No. 7
NO_2 Air Quality Analysis
Simpson Tacoma Kraft Company
801 Portland Avenue
Tacoma, WA 98421

August 2010
Project: 108.00217.00024

BEST AVAILABLE CONTROL TECHNOLOGY ANALYSIS

Steam Turbine Generator Project
Tacoma, Washington

1.0 INTRODUCTION

Simpson Tacoma Kraft Company LLC (Simpson) operates a pulp and paper mill located at 801 Portland Avenue in Tacoma. Simpson currently generates steam for general mill operations using #4 Recovery Boiler, #6 Power Boiler, and #7 Power Boiler. Simpson proposes to install a steam turbine generator driven by steam produced from #4 Recovery Boiler and #7 Power Boilers. This project will allow Simpson Tacoma Kraft to generate and distribute electrical power.

As part of this project Simpson will upgrade the #7 Power Boiler to increase its Maximum Continuous Rated (MCR) steaming capacity from 300,000 lbs/hour to 340,000 lbs/hour (610 MMBtu/hr). Because there will be an emission increase associated with use of this additional steam capacity, Simpson must conduct an analysis for pollutants emitted by #7 Power Boiler to ensure that the best available control technology (BACT) is being applied. The BACT analysis evaluates the energy, environmental, economic, and other costs associated with each technology, and weighs those costs against the reduced emissions the technology would provide.

Geomatrix queried EPA's Reasonably Available Control Technology (RACT)/BACT/Lowest Achievable Control Technology (LAER) Clearinghouse (RBLC) database for BACT determinations involving wood-fired boilers. The California Air Resources Board (CARB) BACT Clearinghouse was also searched for applicable permits, either pending or issued. This initial broad search was refined by eliminating sources that did not emit pollutants as a result of similar operation (e.g., co-firing other fuels such as coal or municipal waste with wood, black liquor with fuel oil, or refinery gas with natural gas). The sections that follow discuss the available control technologies and, ultimately, the selection of BACT for each pollutant.

All wood-fired boiler permits meeting the criteria outlined above were included in the review. Permitted emission limits were compared on a pound per MMBtu (lb/MMBtu) basis. An equivalent lb/MMBtu emission limit was calculated for sources that had permit limits expressed only as an emission rate over some short-term period (e.g., pounds per hour [lb/hr], pounds per day [lb/day]) by combining the emission rate with the maximum heat input.

2.0 BACT ANALYSIS OVERVIEW

This BACT analysis is consistent with general EPA guidance[1]. The EPA BACT guidance document details a "top-down" approach for selecting the appropriate control technology. The steps are as follows:

- Step 1. Identify all control technologies. Identify all available control techniques that could potentially be applied to control emissions of regulated pollutants from the power boiler.

- Step 2. Eliminate technically infeasible options. If any of the control techniques cannot be successfully used on #7 Power Boiler due to technical difficulties, document this finding. Such control techniques would not be considered further in the BACT analysis.

- Step 3. Rank remaining control technologies by control effectiveness. Assess the performance of each control technique and rank them beginning with the most effective control technique.

- Step 4. Evaluate most cost effective controls. Estimate emission reductions, annual costs, cost effectiveness, energy impacts, and other environmental impacts of the control techniques.

- Step 5. Select BACT. This will generally be the most effective option not rejected based on energy, environmental, and economic impacts.

2.1 TECHNICAL FEASIBILITY

EPA's new source review guidance suggests that "...control alternatives should include not only existing controls for the source category in question, but also (through technology transfer) controls applied to similar source categories and gas streams." EPA guidance also indicates that in order for such a technology transfer to be judged technically feasible, its application should be relatively seamless and free of technical speculation. For this BACT analysis, technical feasibility was determined using the following criteria:

- The control technology was previously applied to emission streams sufficiently similar to the one being proposed. Any differences between the proposed current and previous applications should not impact the performance of the control technology. The control technology and emission limit should not cause deterioration of the related process equipment, or irretrievably affect product quality.

[1] U.S. Environmental Protection Agency, *New Source Review Workshop Manual,* October, 1990.

- The emission limit associated with the control technology, including consideration for normal and reasonable variability in the control level, should be consistently achievable under normal and conscientious operating practices.

- The emission limits should not result in frequent violations despite a well-designed and installed, and conscientiously operated control system. Frequent violations increase costs to both the source and the regulatory agency (and consequently the public) as a result of investigation, litigation, and reconstruction, and do not benefit the environment.

2.2 ECONOMIC JUSTIFIABILITY

An economically justifiable control technology is neither the maximum amount a source is able to spend, nor the maximum amount any source in the same source category has spent in the past. For this BACT analysis, economic justifiability was determined based on cost effectiveness. If the cost per ton of pollutant reduced for a particular technically feasible control system is disproportionately high compared to the cost per ton in recent BACT determinations for other sources in the same source category, the control technology is deemed not cost-effective, and can be rejected as economically unjustifiable.

3.0 NO_X BACT ANALYSIS

NOx is generated when combustion temperatures are high enough for the nitrogen in the combustion air (often referred to as "thermal" NOx) or bound in the fuel ("prompt" NOx) to combine with oxygen to form NO. Depending upon conditions, some portion of the NO will react to form NO_2.

3.1 IDENTIFICATION OF POSSIBLE CONTROL ALTERNATIVES

There are a variety of options available for controlling NOx emissions from combustion sources. Some options involve combustion controls that reduce NOx formation, while others utilize add-on control devices to eliminate NOx after it is formed but before it is exhausted to the atmosphere.

Combustion controls reduce NOx emissions by controlling the combustion temperature and the availability of oxygen. Combustion air containing both nitrogen and oxygen can combine in a high temperature environment to form thermal NOx. The oxidation of nitrogen that is chemically bound in fuel sources can also form what is called fuel-bound NOx.

"Proper combustion" generally refers to control, generally computerized, of the fuel feed rate, the amount of combustion air in the furnace, and other parameters, to ensure that the boiler operates as designed. This type of control is common on boilers constructed in the last few decades. One step up from proper combustion is Flue Gas Recirculation (FGR). FGR displaces air in the combustion zone and reduces the overall excess air level.

In a Methane $DeNO_X$ reburn system a fuel (preferably natural gas) and a carrier fluid (any mixture of recirculated flue gases, steam, water, and industrial grade nitrogen) are injected into the combustion chamber. This creates an oxygen deficient secondary combustion zone for reducing NO_X and decomposing other nitrogen bearing compounds. In addition, an oxidizing tertiary combustion zone is created by injecting overfire air into the combustion chamber above the oxygen deficient secondary combustion zone for thorough mixing and final burnout of combustibles. The overfire air is an oxidizing fluid consisting of recirculated flue gases, steam, water, or industrial grade nitrogen.

Dry low-NOx (DLN) burners control thermal NOx formation by avoiding high temperature combustion zones and uneven oxygen distribution. This is accomplished by burner designs that

carefully control the mixing of fuel and combustion air. Generally, use of DLN burners requires a wall-fired furnace and pulverized biomass fuel that is burned in suspension with coal or natural gas.

Add-on controls such as selective catalytic reduction (SCR) and selective non-catalytic reduction (SNCR) systems are other technologies for controlling NOx emissions from combustion sources. In the SNCR process, a nitrogen compound reducing agent (generally ammonia in some form: urea, aqueous ammonia, or anhydrous ammonia) is mixed with the exhaust from the combustion device, generally in the furnace or at the furnace exit. The NOx reacts with the ammonia to form nitrogen and water.

The SCR process is similar to SNCR in that a reagent reacts with NOx, but a catalyst matrix, or "bed" is added downstream of the furnace to aid the reaction. The catalyst used in SCR systems allows the reduction reactions to occur at lower temperatures: 300 to 1,100 °F for SCR, depending upon the catalyst, as opposed to 1,550 to 2,100 °F for SNCR. Most SCR systems have been installed to reduce NOx emissions in exhaust streams with relatively little particulate matter (e.g., natural gas-fired boilers).

Exhaust streams with relatively high particulate loading, such as solid fuel-fired boilers, subject the catalyst to poisoning (by sulfur and alkaline compounds), erosion, and plugging. One solution to avoid these negative effects is to place the catalyst downstream of some particulate control equipment (e.g., a fabric filter or electrostatic precipitator). While this arrangement presents a cleaner exhaust stream to the catalyst, it also results in exhaust that may be too cool for the catalyst to effectively promote the desired reaction. Larger volume catalyst beds, specially designed low-temperature catalysts, and exhaust reheat using natural gas burners are schemes developed to compensate for a lower temperature exhaust. Systems called "regenerative" SCR (RSCR), that use heat-storing ceramic media derived from catalytic oxidation technology to reduce the amount of natural gas required to reheat the exhaust, have been developed recently to reduce costs.

EMx™ (formerly called SCONOx™) is similar to SCR, except that NOx in the exhaust stream reacts with potassium carbonate (K2CO3) to form potassium nitrate (KNO3). This compound is reacted with hydrogen to form gaseous nitrogen (N2), and regenerate the K2CO3. The lower exhaust temperature limit required for the reactions in the EMx™ to take place is less than that of SCR (300 °F as opposed to 450 °F). The EMx™ system is also said to provide reductions in CO and VOC emissions by oxidation.

3.2 CONTROL ALTERNATIVE REVIEW

The results of the RBLC and CARB database queries for NOx control technologies are presented in Table B-1, sorted by permit limit, each beginning with the NOx limit proposed by Simpson for the power boiler. Because of the number of entries in the database, the tables present only a representative range of recent permit limits.

The following technologies were found in the databases searched for controlling NOx from wood-fired boilers:

- SNCR
- RSCR
- SCR
- Proper combustion

3.2.1 Summary of Possible Control Alternatives

Based on literature and database searches the following alternatives are possible for controlling NOx emissions from a wood-fired boiler:

- Proper Combustion
- FGR
- Methane $DeNO_X$
- DLN
- SNCR
- SCR
- RSCR
- EMx^{TM}

3.2.2 Technical Feasibility of Control Alternatives

This section evaluates the technical feasibility of the control technologies presented in the previous section with respect to controlling NOx emissions from wood-fired boilers.

Jansen Combustion and Boiler Technology, Inc. (Jansen) designed an Over Fire Air (OFA) system that Simpson plans to install in September 2006. Because Jansen is already familiar with the combustion characteristics of #7 Power Boiler, Simpson retained Jansen to assist in evaluating NOx control options for this BACT analysis.

Proper Combustion

The #7 Power Boiler has been equipped with multi-level air addition and good combustion controls since its startup in 1991. This has performed well in terms of controlling NOx emissions. The #7 Power Boiler's NOx emissions averaged 0.205 lb/MMBtu from 1996 through 2005. In general, a wood-fired boiler using appropriate design and operated with modern computerized controls to ensure proper combustion can be expected to emit NOx at a rate of between 0.20 and 0.30 lb/MMBtu.

The improved OFA system that will become operational in fall 2006 represents state-of-the-art combustion control. This technology is well-proven for wood-fueled boilers.

FGR

FGR has proven to effectively reduce NO_X emissions on spreader stoker boilers. For application in #7 Power Boiler, a hot duty fan would need to be installed downstream of the multiclone to feed the combustion air system. The recirculated flue gas can be supplied to either the undergrate air, overfire air, or both. The NO_X reduction estimates provided by Jansen assume that FGR would be delivered to both the undergrate air and overfire air, but not to the (oil and natural gas) auxiliary burners.

Methane $DeNO_X$

Methane $DeNO_X$ is designed for wood-waste fired stoker type boilers. It has been applied to bark and sludge fired boilers in Minnesota and in Louisiana in 1995 and 1996. There have been very few industrial installations on wood fired boilers because of the high cost of the additional natural gas firing. Because of the limited number of installations, there is some uncertainty on the efficiency that could be achieved on Simpson's boiler.

DLN Burner

For a boiler the size of Simpson's power boiler, two or more DLN burners would be required. With such burners, the fuel would be burned in suspension using wall-mounted burners. This would be a significant departure from the power boiler's design, which has wood combustion occurring on a moving grate. These burners are generally intended to limit the amount of fuel-bound nitrogen that is converted to NOx during combustion, and are generally suited to smaller boilers that burn wood waste containing a high percentage of resins, such as the waste from medium density fiberboard (MDF), plywood, or veneer operations. These resins contain large amounts of fuel nitrogen, whereas the wood burned in Simpson's boiler has lower fuel nitrogen. In this case, the emission rate with DLN burners (0.35 lb/MMBtu) is higher than could be achieved by an uncontrolled mass burner-type boiler using a combustion grate (approximately 0.20 lb/MMBtu), so this technology will be eliminated from consideration as BACT.

SNCR

Ammonia injection nozzles are positioned in the combustion zone to use the relatively high temperatures there to promote the reaction of NOx and ammonia. The SNCR system can be located inside the furnace because SNCR systems do not rely on a catalyst which is subject to plugging from particulate matter in the flue gases. The relative simplicity and effectiveness of SNCR systems has resulted in SNCR becoming the most common add-on NOx control technology for wood-fired boilers that operate under steady load.

SCR

The RBLC and other research indicates that there is only one existing, permitted, or proposed wood-fired boiler in the United States that employs a traditional SCR system to control NOx emissions, other than recent RSCR installations (see below).

Catalysts used in SCR systems can be divided into three categories based on the temperature range in which they are designed to operate. High temperature catalysts operate in the 650 to 1,100 °F range, medium temperature in the 500 to 725 °F range, and low temperature in the 300 to 680 °F range.

Low-temperature catalysts, which operate at the expected boiler exhaust temperature, are typically used to reduce NOx emissions in relatively "clean" (i.e., low particulate and low

sulfur) exhaust from natural gas combustion sources. While wood is typically not considered a high-sulfur fuel, the waste water treatment sludge mixed with the wood fuel combusted in #7 Power Boiler contains sulfur and is emitted as SO2. Low temperature catalysts readily convert a portion of any SO2 in the exhaust to SO3, which then would react with the injected ammonia to produce ammonium sulfate and sulfite, which are highly corrosive salts. Ammonium sulfite is also been found to deactivate catalysts by crystallizing on the catalyst surfaces. Low-temperature SCR systems are considered technically infeasible for reducing NOx emissions from wood-fired boilers.

Medium- and high-temperature catalysts are less prone to complications from sulfur and particulate in the exhaust, but both would require exhaust reheat. Sauder Woodworking in Archibold, Ohio, which operates two 57 MMBtu/hr wood-fired boilers, is the lone instance of a "traditional" medium-temperature SCR system being applied to reduce NOx from wood-fired combustion sources. Therefore, medium- and high-temperature SCR systems are considered technically feasible, although only medium-temperature SCR systems will be considered, as it is unlikely that a given high-temperature SCR would cost less than a comparable medium-temperature system because of the need for more preheating of the flue gases before treatment.

The Sauder boilers have stoker-type furnaces that burn furniture manufacturing waste. Simpson's power boiler would require a "tail end" SCR system located downstream of a particulate control device to prevent catalyst erosion or poisoning. The exhaust gases exiting the particulate control device would need to be reheated, most likely by combusting natural gas, to the temperature required by the catalyst to promote NOx reduction.

RSCR

Regenerative SCR (RSCR) systems have been developed recently to make application of a medium-temperature SCR system more economical by using a regenerative ceramic bed to recover heat from the reheated flue gases to limit the use of the reheat fuel. Also, because reheat fuel is kept to a minimum, it facilitates positioning the NOx reduction system after a dust collection device, which serves to prolong the life of the catalyst.

A critical consideration that might render RSCR impractical for use with #7 Power Boiler may only be confirmed with testing. As discussed in greater detail under "Collateral Environmental Impacts," #7 Power Boilers flue gases contain unusually high concentrations of hydrochloric

acid. Acid gases can degrade the alumina catalyst supports that are normally used. This could significantly decrease catalyst life and increase cost.

EMx™

To date, EMx™ has been designed and used only on small- to medium-sized natural gas-fired stationary turbines and boilers for demonstration purposes. The technology has never been applied to a wood-fired boiler of any kind. Wood-fired combustion sources emit higher concentrations of particulate matter, organic compounds, and sulfur oxides compared to natural gas-fired sources. The organic compounds from wood combustion tend to have higher molecular weights and more complex structures, and the impact these would have on the EMx™ system is unknown.

The EMx™ system is sensitive to sulfur in the exhaust, which can degrade the performance of the system. While wood waste is not generally considered a high-sulfur fuel, #7 Power Boiler also burns sludge and oil. As indicated in Table 2-12 of the PSD application, average baseline and projected future emissions are approximately 85 lb/hr of SO2. Natural gas in California, where EMx™ has been applied, has a maximum sulfur limit of one grain per 100 standard cubic feet (gr/100 scf) of gas. On a heat input basis, this is equivalent to an SO2 emission rate of 0.85 lb/hr. Sensitivity to sulfur, combined with a lack of comparable existing applications suggests that EMx™ is technologically infeasible as a control technology for controlling NOx emissions from a wood-fired boiler.

The following is a list of the technically feasible NOx control technologies:

- Proper combustion
- FGR
- Methane $DeNO_x$
- SNCR
- Medium-temperature SCR
- RSCR

3.2.3 Effectiveness of Remaining Technologies

This section describes the remaining technologies in more detail and ranks them by effectiveness.

Proper Combustion

The #7 Power Boiler's annual average NOx emissions during the ten-year period 1996 through 2005 was 0.205 lb/MMBtu, with a low of 0.178 and a high of 0.258. This is a very good level of performance relative to boilers that rely on proper combustion for NOx control. In general, a wood-fired boiler, using appropriate design and operated with modern computerized controls to ensure proper combustion, emits NOx at a rate of between 0.20 and 0.30 lb/MMBtu. Almost all NOx that is emitted from wood fuel boilers is fuel NOx as opposed to thermal NOx because combustion temperatures are generally low.[2] This has two important implications. One is that technologies that attempt to reduce the formation of thermal NOx will have limited effect. The other is that there is potential for emissions to increase if boiler conditions change in favor of 1) producing higher combustion temperatures, thereby increasing thermal NOx, or 2) increasing the oxygen-to-fuel ratio in the combustion zone; thereby increasing fuel NOx.

Jansen predicts that a 20 percent reduction in NOx emissions may occur after OFA is installed in September 2006. Based on the 0.18 lb/MMBtu NOx emissions observed over the 2004 to 2005 period, this would reduce the emission factor to about 0.15 lb NOx/MMBtu.

Both the starting value of 0.18 and the 0.15 after OFA are not likely to be realistic, however. NOx emissions over the past two years have not been representative of operations historically. In other words, the 0.18 lb/MMBtu average is not a representative starting value. Over the last two years, NOx emissions have been at the low end of #7 Power Boiler's historical range and CO emissions have been at the high end of the historic range. High CO emissions are a symptom of lower-than-ideal combustion temperature or insufficient oxygen in the combustion zone. To some extent, NOx emissions are inversely related to CO emissions, so NOx can be expected to increase as CO decreases. The primary reason Simpson is installing OFA is to reduce CO emissions. It accomplishes that by improving air distribution inside the furnace so combustion is more complete. This will result in both higher combustion temperatures and higher oxygen-to-fuel ratio in the combustion zone. Consequently, there is good reason to believe that NOx emissions will likely increase back to earlier levels when CO decreases to or below its earlier levels. Finally, we note that Jansen will not guarantee NOx emission at 0.15 lb/MMBtu.

[2] NCASI Technical Bulletin 914, February 2006. "An Analysis of Factors Affecting L7ong Duration NOx Emissions from Hog Fuel Boilers."

In view of these factors, a NOx emission rate of 0.20 lb/MMBtu is a reasonable expectation for #7 Power Boiler with overfire air and proper combustion techniques. This represents a very good level of performance considering the 0.18 to 0.26 variability in annual emissions that has been observed in the past. A NOx emission rate of 0.20 lb/MMBtu is also at the low end for wood-fired boilers that rely on combustion control for NOx suppression. It also corresponds to the standard under the latest (2006) version of EPA's New Source Performance Standards for Industrial Boilers [40 CFR Part 60 Subpart Db] for co-firing wood with fossil fuels.

Accordingly, a baseline of 0.20 lb/MMBtu is used in evaluating the efficiency and cost-effectiveness of the other control alternatives.

FGR

Jansen estimates that FGR could be used to reduce the generating bank outlet oxygen level to about 1.9% and the corresponding stack oxygen level to 4.4%. Jansen estimates this would reduce NOx emissions by about 10% compared to the baseline (proper combustion with the overfire air system), or 0.18 lb/MMBtu. However, Simpson is not confident that a 10% NOx reduction could be achieved because FGR works by reducing generation of thermal NOx, while #7 Power Boiler's baseline NOx emission is mostly fuel-based. Because of the lower oxygen levels, it is anticipated that CO emissions would increase if FGR were implemented.

Methane $DeNO_X$

NO_X reductions of 30-40% are typical for Methane $DeNO_X$. In one case, NO_X reductions of 60% were achieved when injecting natural gas equivalent to 13% of the total heat input. Assuming a reduction of 50%, the Simpson boiler could achieve a NO_X emission factor of 0.10 lb/MMBtu.

SNCR

Properly designed SNCR systems are generally capable of reducing NOx emissions by 40 to 70 percent. Jansen estimated SNCR applied to the power boiler could achieve 0.11 to 0.16 lb/MMBtu depending on the level of urea injection (35 and 21 gallons per hour, respectively). The lower emission rate has greater ammonia slip and greater concern for visible plume issues (30 ppm for the 0.11 lb/MMBtu case versus 5 ppm for the 0.16 lb/MMBtu case).

The use of SNCR to control NOx from a wood-fired boiler at the Kimberly-Clark (KC) pulp mill in Everett, Washington provides relevant data to evaluate the potential effectiveness of SNCR (and other urea or ammonia based control technologies) on #7 Power Boiler. Simpson's and KC's wood-fueled boilers are of similar design and age. Simpson's boiler started operation in 1991 and KC's in 1995. Operating data from KC's boiler[3] showed ammonia slip much higher than anticipated was needed to approach the NOx emissions design level. They did not reach the design level because the plume opacity increased dramatically as the ammonia slip increased. Note that KC's baseline NOx emission is very similar to the 0.20 lb/MMBtu for Simpson's #7 Power Boiler. This is not surprising in view of similarity of the fuels and boiler designs.

It is possible that the effectiveness of ammonia in reducing NOx was hindered by its reaction with the abundant chloride in the flue gas. At any rate, KC's experience suggests that SNCR's effectiveness would likely be much lower than expected for controlling NOx emissions from #7 Power Boiler. At best, a removal efficiency of 25% might be achievable.

Medium-Temperature SCR

The Sauder Woodworking boilers, the lone applications of a medium-temperature SCR system to wood-fired boilers, have permit limits of 0.20 lb/MMBtu. Based on the performance of SCR systems applied to natural gas-fired combustion sources, it is conceivable that an SCR system could achieve an emission limit lower than 0.20 lb/MMBtu, but it has not been demonstrated in practice on a wood-fired boiler.

RSCR

There are two instances of RSCR systems have been retrofitted to control NOx from existing wood-fired boilers (Whitefield Power & Light in New Hampshire and Boralex Stratton in Maine). While these boilers have short-term permit limits of 0.24 and 0.33 lb/MMBtu, respectively, the RSCR manufacturer (Vogt Power International) indicates that the installed NOx control systems are actually capable of achieving an emission factor of 0.075 lb/MMBtu. Both facilities installed the RSCR to participate in Connecticut's Renewable Portfolio Standard Program, though only Whitefield Power & Light has a quarterly permit limit of 0.075 lb/MMBtu.

[3] D. Abrams, "Permitting, Startup, and Repermitting of the Wood Waste Cogeneration Boiler at Kimberly-Clark, Everett, Washington." 1998 TAPPI Environmental Conference Proceedings. Table IV.

Jansen estimates the Simpson boiler could achieve 0.038 lb/MMBtu with RSCR control with an ammonia slip of 10 ppm on an annual average basis. This is not an official vendor guarantee and Simpson is not confident that 0.038 lb/MMBtu can be achieved given that previous applications of RSCR have been permitted for emission limits based on nearly twice this emission factor. An emission rate of 0.075 lb/MMBtu could be used as a reasonable expectation for RSCR because it is the lowest emission rate that has actually been permitted.

But there are questions as to whether use of RSCR on wood-fired boilers has been sufficiently extensive to consider it reasonably proven for reducing NOx emissions from such boilers. RSCR systems have been applied as retrofit NOx controls on only two existing wood-fired boilers with stoker-type furnaces, and they only started operation in late 2004. Further, there were special circumstances in that both had additional incentives to apply advanced but unproven NOx control technology. Both facilities sought to qualify for tax credits and other preferences offered in the Northeast (which has ozone background concentrations that are significantly higher than they are in the Pacific Northwest). In particular, the Connecticut Renewable Energy Credit (CT REC) and the Massachusetts Renewable Energy Portfolio Standard (RPS) offer subsidies for electrical generation units that use eligible biomass fuels and meet ultra-low emissions criteria. The qualifying NOx emission rate is 0.075 lb/MMBtu, which can only be achieved by RSCR or SCR, making these two circumstances unique.

3.2.4 Ranking by Effectiveness

The remaining technologically feasible control technologies ranked in decreasing order of effectiveness are:

- RSCR (0.075 lb/MMBtu)
- SNCR (0.10 -0.12 lb/MMBtu)
- Methane $DeNO_X$, Medium-temperature SCR (0.10 lb/MMBtu)
- FGR (0.18 lb/MMBtu)
- Proper combustion (0.20 lb/MMBtu)

3.2.5 Evaluation of Cost Effectiveness

The baseline control technology considered for the cost analyses is proper combustion with overfire air. The projected emission rate after the OFA upgrade is 0.20 lb/MMBtu.

Technically feasible NOx controls that could be applied are: SNCR, Methane DeNOx, Medium-temperature SCR, and RSCR. Medium-temperature SCR applied after a particulate control device with exhaust reheat is considered to be less effective than RSCR at reducing NOx emissions, but only RSCR is included in the cost-effectiveness analysis because it was judged to have lower energy consumption and is likely to be more cost-effective than medium-temperature SCR in the long run.

This section compares the cost effectiveness of various NOx control alternatives. Direct and indirect costs were estimated using the EPA's "Air Pollution Cost Manual" (Sixth Edition, January 2002, EPA/452/B-02-001). Table B-2 contains a summary of the cost effectiveness of each control option.

An SNCR system could reduce NOx emissions to 0.16 or even 0.11 lb/MMBtu on an annual average basis. Based on information from Jansen, an SNCR system to provide a NOx emission factor of 0.16 lb/MMBtu, would require an installed cost of approximately $1.5 million. As shown in the cost calculations in Appendix A, the cost is equivalent to an incremental cost of about $4,708 per ton of NOx removed, which may be considered cost effective. Reducing NO_X even further (to 0.11 lb/MMBtu) using more urea is more cost effective ($2,876 per ton). However, ammonia slip would increase from 5 ppm to 30 ppm, increasing the probability that a visible plume could result.

Installation of an RSCR system, which is considered to be the most economical tail-end medium temperature SCR system that could be applied to the power boiler, would reduce NOx emissions to 0.075 lb/MMBtu. The incremental cost per annual ton of NOx removed over the baseline would be over $7,000, which is not as cost-effective as SNCR. The cost-effectiveness calculations are presented in Appendix A. Compared with SNCR, this control would cost from $8,000 to $18,000 per ton of additional NO_X removal, depending on the SNCR option.

The RSCR system is estimated to create 10 ppm of ammonia slip, which is twice the ammonia slip estimated for SNCR. Furthermore, RSCR would require 20 gallons per hour of fuel oil to reheat the exhaust gas and a 1,300 horsepower booster fan to overcome the pressure drop. One of the primary reasons for the overfire air project was to reduce fuel oil combustion in the power boiler. The additional fuel combustion would result in an additional 16 tpy of NO_X emissions and 6 to 7 tpy of SO_2 emissions. The 1,300 horsepower fan would require approximately 1,293 kilowatts of energy (assuming 75% efficiency), or2.4% of the proposed turbine's electric output.

Based on information from Jansen, a Methane DeNOx system to provide a NOx emission factor of 0.10 lb/MMBtu, would require an installed cost of approximately $1.5 million. The system requires a 300 horsepower fan for flue gas recirculation and 1,200 standard cubic feet per minute of natural gas. As shown in the cost calculations in Appendix A, the cost is about $25,000 per ton of NOx removed, which is outside the envelope of acceptable costs.

Of all the control technologies evaluated, SNCR is the most cost effective control for NO_X and has the least associated energy impact. SNCR, however, is highly likely to have an unacceptable collateral environmental impact.

Collateral Environmental Impacts

The nitrogen compound-based control technologies – SNCR, SCR, and RSCR – are each likely to have a significant collateral environmental impact if installed at the #7 Power Boiler: the release of unreacted nitrogen compounds would be likely to result in a visible plume from the boiler. SNCR, for instance, invariably involves emissions of unreacted ammonia, called ammonia slip. The escaping ammonia can react with sulfur and chloride compounds in the flue gas to form fine particulate matter and, potentially, a visible plume. These particles are formed at lower temperatures that exist downstream from the particulate control device and are not captured. The ammonia slip also represents the emission of a toxic air pollutant that would not be present if SNCR was not employed.

The experience of the Kimberly-Clark mill in Everett indicates that it would be very risky to apply SNCR to the #7 Power Boiler. When KC installed SNCR in the mid-1990's to control NOx emissions from its wood-fueled boiler, a persistent visible plume resulted from the stack. The community objected vigorously to the plume. According to KC's former environmental manager, the visible plume was produced by very fine ammonium chloride particles that were formed after the gases left the stack. During subsequent testing, KC found that a visible plume was produced at essentially all levels of ammonia addition.[4] As a result of this experience, the Department of Ecology allowed KC to discontinue using SNCR treatment.

KC's experience is particularly relevant to the use of SNCR and other nitrogen compound-based control technologies at Simpson, because Simpson and KC share many of the same salt laden wood fuel suppliers. Since both are situated on Puget Sound, where logs are commonly transported by floating them in salt water, the wood they tend to receive has much higher

[4] Phone conversation with Dick Abrams, former Kimberly-Clark environmental manager, Aug. 25, 2006.

concentrations of sodium chloride than is found in the absence of salt water contact. Data collected by the National Council for Air and Stream Improvement (NCASI)[5] indicates that the average chloride concentration in wood burned by Simpson's #7 Power Boiler has more than ten times the chloride content as the average fuel sampled around the country. Much of the chloride is emitted as hydrochloric acid (HCl) gas when the wood is combusted. When EPA's Industrial Boiler MACT rule was proposed, and eventually promulgated as 40 CFR Part 63 Subpart DDDDD, both mills discovered that they were among few in the country that had difficulty meeting the rule's HCl emissions standards. Consequently, both mills had to perform health-based compliance evaluations to demonstrate that their HCl emissions do not create a health risk. The fact that Simpson's and KC's wood boilers have both been shown to have unusually high HCl concentrations in their flue gases means that they are likely to have a similar likelihood of producing ammonium chloride fume when nitrogen compounds such as ammonia are added to the flue gas as part of using SNCR, SCR, or RSCR controls.

As noted above, Simpson's and KC's wood-fueled boilers are of similar design and age. Simpson's boiler started operation in 1991 and KC's in 1995. Similar boiler design is another reason to believe that injecting nitrogen compounds into the exhaust gases would produce a similar visible emission.

Simpson is very concerned about emitting visible emissions. The mill is located in a more populated area than any other pulp mill in the country and is plainly visible from downtown Tacoma. Simpson has invested more than $350 million in improvements since purchasing the mill in 1985. A significant portion of that cost and effort has gone into reducing nuisance emissions, including odor, noise, and visible emissions. Simpson believes the BACT determination must give considerable weight to the likelihood that SNCR, SCR, and RSCR technologies would likely have an unacceptable collateral environmental impact.

Because SNCR, SCR, and RSCR each entail introducing nitrogen compounds to combustion gases, they each pose a high risk of producing a visible plume when the exhaust leaves the stack. Based on this risk, as well as the limited applications of SCR and RSCR to wood-fueled boilers, this analysis concludes that the emission limits achievable by nitrogen compound-based control technologies (SNCR, SCR, and RSCR) are not BACT for controlling NOx from the #7 Power Boiler.

[5] Technical Bulletin 875, April 2004. "Nationwide Evaluation of Mercury and Chorine Levels in Bark and Stemwood."

3.3 SELECTION OF BACT FOR NOx

Simpson proposes that BACT for NOx emissions from #7 Power Boiler is 0.20 lb/MMBtu, based on using proper combustion controls and overfire air. The anticipated 0.20 lb/MMBtu emission rate expected after overfire air is implemented is low compared with other boilers that employ optimal combustion control and equals BACT limits at many facilities with SNCR.

As discussed above, technologies that employ ammonia injection (SNCR, SCR, and RSCR), although effective at reducing NOx emissions, are not acceptable because of the high risk of producing a persistent, visible plume of ammonium chloride particles from the stack.

4.0 PM10 BACT ANALYSIS

PM10 is produced by combustion processes as unburned solid carbon (soot), unburned vapors or gases that subsequently condense, and the non-combustible portion of the fuel (ash).

4.1 IDENTIFICATION OF POSSIBLE CONTROL ALTERNATIVES

The concept of applying combustion controls and appropriate furnace design, or "proper combustion," to minimize PM10, CO, and VOC emissions includes adequate fuel residence time, proper fuel-air mixing, and temperature control to ensure the maximum amount of fuel is combusted. Optimization of these factors for PM10, CO, and VOC control can result in an increase in the NOx emissions. Thus, boiler designers strive to balance the factors under their control to achieve the lowest possible emissions of all pollutants.

The two most popular add-on control technologies for control of PM10 emissions from a solid-fueled boiler are electrostatic precipitators (ESP) and fabric filters, or "baghouses." ESPs remove particles from an exhaust stream by imposing an electrical charge on the particles and then attracting them to an oppositely charged plate. The dust collected on the charged plates is periodically removed by vibrating or rapping of the plates.

Fabric filters use various types of materials (generally fabrics) to trap particles while the gas passes through the voids in the material. The dust that becomes caked on the fabric bags is removed periodically by shaking, blowing jets of air, or using sonic horns.

Wet scrubbers, such as venturi scrubbers are less common PM10 control devices because they typically have lower control efficiencies than either ESPs or fabric filters. They also complicate waste disposal by introducing liquids that create sludge when combined with the removed PM10. A venturi is a narrowed section of duct followed by an expanded section of duct, with scrubbing liquid injected at the constricted section. The liquid in atomized by the increased velocity exhaust flow, and the particles impact the droplets and are collected. Because the liquid must be atomized to ensure high collection efficiency, a high-energy exhaust flow is required.

4.2 CONTROL ALTERNATIVE REVIEW

The results of the database query for PM10 control technologies is presented in Table B-4, sorted by permit limit, beginning with the PM10 limit proposed by Simpson for the wood-fired

power boiler. Because of the number of entries in the database, the tables present only a representative range of recent permit limits.

4.2.1 Summary of Possible Control Alternatives

Based on literature and database searches the following control alternatives are possible for the boiler:

- Fabric filter
- ESP
- Venturi scrubber
- Limit sulfur in fuel
- Proper combustion

4.2.2 Technical Feasibility of Control Alternatives

Fabric filters, ESPs, venturi scrubbers, and proper combustion are all technically feasible for removing PM10 from the power boiler's exhaust stream. It is not technically feasible to remove the sulfur contained in wood before combusting it. Venturi scrubbers are generally employed to control PM10 from smaller boilers with lower exhaust flow, and typically have lower control efficiencies than ESPs or baghouses.

4.2.3 Effectiveness of Remaining Technologies

This section briefly describes the effectiveness of the remaining technologies and ranks them in order of effectiveness. In addition to the PM10 removal efficiency of each technology, the pressure drop associated with the technology is also presented. Higher pressure drops require more powerful fans, which increase both capital and operating costs.

Proper Combustion

Utilizing only proper combustion techniques, the power boiler would be expected to emit PM10 at a rate of 0.517 lb/MMBtu based on an AP-42 emission factor.

Venturi Scrubbers

Venturi scrubbers with pressure drops of between 5 and 10 inches of water typically remove less than 99 percent of PM10 from exhaust flows. Units with pressure drops of 20 inches of water or greater can remove greater than 99 percent of PM10.

Fabric Filters

Fabric filter systems typically operate with pressure drops between 2 and 12 inches of water. PM10 control efficiencies are capable of removing over 99 percent of PM10 from exhaust gases.

ESPs

ESPs, which typically experience pressure losses of around 0.5 inches of water, are capable of removing over 99 percent of PM10 from exhaust gases.

4.2.4 Ranking by Effectiveness

The remaining technologically feasible control technologies ranked in decreasing order of effectiveness are:

- ESP; Fabric filter (judged to be equally effective)
- Venturi Scrubber

4.2.5 Evaluation of Cost Effectiveness

No cost-effectiveness evaluation is presented because Simpson is proposing to use ESP technology to control PM10 emissions from the power boiler, which is considered the most effective control technology available.

4.3 SELECTION OF BACT FOR PM10

Simpson proposes that BACT for PM10 emissions from the power boiler is the use of an ESP. Simpson currently operates an ESP to control PM10 emissions from the power boiler with a permit limit of 0.01 grains per dry standard cubic foot at 7% excess oxygen, which is equivalent to approximately 0.020 lb/MMBtu (filterable component only). The existing ESP has been well proven in 15 years of service and continues to give comparable performance to the other units cited in Table B-4.

5.0 CO AND VOC BACT ANALYSIS

Carbon monoxide (CO) and volatile organic compounds (VOCs) are products of the incomplete combustion of carbonaceous fuels.

5.1 IDENTIFICATION OF POSSIBLE CONTROL ALTERNATIVES

Emissions of CO and VOCs can be limited through proper operation of a well-designed boiler. Good boiler design and operation includes maintaining adequate fuel residence times to ensure CO oxidation, proper fuel-air mixing, and temperature control. Optimizing these factors to limit CO and VOC production can result in an increase in combustion temperatures and thermal NOx emissions. A "balancing act" that minimizes production of all pollutants must be maintained during the design and operation of a boiler.

The other control alternatives employ add-on devices to oxidize CO and VOC to CO2 after they have exited the furnace.

Thermal oxidation (TO) systems oxidize CO and VOCs to CO2 and water (H2O) through combustion. The TO system consists of a burner and a chamber designed to maintain temperature and residence time adequate to completely oxidize the CO and VOCs in the exhaust gases. TOs generally operate at approximately 1,500 °F.

Catalytic oxidation (CatOx) systems use a matrix or "bed" coated with noble metals (e.g., platinum) to facilitate the conversion of CO and VOCs to a non-pollutant (CO2 and H2O). Catalytic oxidizers operate in a narrow temperature range of approximately 500 °F to 1,000 °F. At lower temperatures the CO conversion efficiency falls off rapidly.

Because higher temperatures are desirable for improved conversion of CO and VOCs by both TO and CatOx systems, the exhaust temperature must be increased, resulting in higher fuel use. In order to reduce burner plugging, catalyst masking, and pressure drop across the system, a particulate control system (e.g., an ESP or fabric filter) must be located upstream of the control system.

EMx™ (formerly SCONOx, described in the NOx BACT analysis) also utilizes a catalytic technique that oxidizes CO to CO2 in addition to controlling NOx emissions.

5.2 CONTROL ALTERNATIVE REVIEW

The results of the database queries for CO and VOC control technologies are presented in Tables B-5 and B-6, sorted by permit limit, beginning with the CO and VOC limits proposed by Simpson for the project. Because of the number of entries in the database, the tables present only a representative range of recent permit limits.

5.2.1 Summary of Possible Control Alternatives

Based on literature and database searches the following control alternatives are possible for the boiler:

- Proper boiler design and operation
- Thermal oxidation
- Catalytic oxidation
- EMx™

5.2.2 Technical Feasibility of Control Alternatives

Proper boiler design and operation is the most widespread technique used to limit CO and VOC emissions from wood-fired boilers.

No instances of a TO system being used to reduce either CO or VOC emissions from a wood-fired boiler could be found. However, because TO systems are not affected by particulate loading or temperature of the exhaust stream, they are considered technically feasible for reducing CO and VOC emissions from the power boiler.

Oxidation catalysis has been applied to reduce CO and, incidentally, VOC emission from wood-fired boilers. Bio Energy Corp. installed an oxidation catalyst system to control CO emissions from a 225 MMBtu/hr stoker-type boiler in West Hopkinton, NH. The unit is permitted to co-fire oil, and has an effective short-term CO permit limit of 1.0 lb/hr. The catalyst system experienced problems, including the need for premature catalyst replacement, and the unit has not operated since 2002.

In 2002, Ohio EPA issued a permit for a facility that would consist of retrofitting seven unused coal-fired stoker boilers to burn biomass. Oxidation catalysts were proposed to control CO emissions, and the permit limit was equivalent to 0.011 lb/MMBtu. The facility was never constructed, and Ohio EPA reissued the permit in 2004 with an hourly average CO permit limit

equivalent to 0.0086 lb/MMBtu. This emission rate was based on an uncontrolled emission rate of 0.2 lb/MMBtu and an oxidation catalyst control efficiency of 95.7 percent. The facility has still not begun construction, and Ohio EPA has recently reissued the permit again.

Vogt Power International is developing an oxidation catalyst system that is similar in design and function to the RSCR system described in the NOx BACT analysis. It has been installed (along with the RSCR system) at the Whitefield Power facility for evaluation, and is expected to achieve 50 percent control or better. While oxidation catalyst technology is clearly a mature technology, application to wood-fired boilers is still under development. Nevertheless, for purposes of this BACT analysis, application of oxidation catalyst systems for control of CO and VOC from the power boiler will be considered technically feasible.

As discussed in the NOx BACT analysis, EMx™ is extremely sensitive to presence of sulfur in the exhaust stream, and has never been demonstrated on a boiler of the same size as Simpson's power boiler. Therefore, EMx™ is not considered technically feasible for controlling CO emissions from the power boiler.

5.2.3 Effectiveness of Remaining Technologies

This section describes the remaining technologies in more detail and ranks them by effectiveness.

Combustion Controls

Combustion controls provide a wide range of control effectiveness, depending on the configuration of the system. Generally, emissions resulting from incomplete combustion (CO and VOC) are balanced with emissions related to high furnace temperatures (NOx) to achieve optimally low emissions of all pollutants. The OFA system that Simpson will install in #7 Power Boiler in September 2006 is designed to give optimal combustion of CO and VOC. The purpose of this upgrade is to reduce CO emissions while firing more wood fuel..

Catalytic Oxidation

Oxidation catalysts are generally capable of providing between 40 and 90 percent reduction in CO emissions. The most economical and effective application would likely involve a system located downstream of a particulate control device that reheated the exhaust gas to increase the

exhaust temperature so the catalyst temperature would be in the range needed to achieve a reasonable control efficiency.

Thermal Oxidation

A properly designed thermal oxidizer that achieves the necessary temperature, residence time, and turbulence can destroy up to 99 percent of the CO in an exhaust stream, and up to 99.99 percent of VOCs.

5.2.4 Ranking by Effectiveness

The remaining technologically feasible control technologies ranked in decreasing order of effectiveness are:

- Thermal oxidation
- Catalytic oxidation
- Proper combustion

5.2.5 Evaluation of Cost Effectiveness

While the capital cost of a thermal oxidation system is relatively small, the ongoing fuel costs to achieve the TO operating temperature of 1,500 °F would make the cost effectiveness of a TO system higher than the cost effectiveness of a CatOx system. Therefore, only the CatOx system is evaluated for cost effectiveness.

The cost effectiveness of installing an oxidation catalyst to achieve 50 percent control of CO emissions from a wood-fired boiler was calculated. There are two approaches to applying oxidation catalyst technology to a wood-fired boiler. The approach that has been demonstrated in practice (although the unit is no longer operating) is to reduce the efficiency of the boiler's waste heat recovery system in order to make the oxidation catalyst effective by increasing the exhaust gas temperature. Direct and indirect costs were estimated using the EPA's "Air Pollution Cost Manual" (Sixth Edition, January 2002, EPA/452/B-02-001). The cost of the oxidation catalyst itself (including an additional catalyst bed to allow semi-annual chemical cleaning), the additional ductwork, increasing the size of the particulate control device, and increased fuel use due to loss of efficiency equates to approximately $13,800 per ton of CO controlled, which is outside the envelope of acceptable costs. The cost-effectiveness calculations are presented in Appendix A.

5.3 SELECTION OF BACT FOR CO AND VOC

Based on the analysis presented in this section, Simpson proposes that BACT for CO emissions from the power boiler is proper combustion controls. The OFA system that Simpson will install in 7 Power Boiler in September 2006 represents the best available combustion control for an existing wood-fuel boiler. CO emissions would be limited to 0.35 lb/MMBtu.

For VOCs, BACT for the power boiler is proposed to be proper combustion. While emission limits are not proposed for VOCs, the emission factor used to calculate emission rates is 0.017 lb/MMBtu (NCASI Environmental Handbook, Chapter 10).

6.0 SO2 BACT ANALYSIS

Sulfur dioxide (SO2) emissions largely depend on the amount of sulfur present in the fuel. Sulfur contained in the fuel combines with oxygen at combustion temperatures to form SO2.

6.1 IDENTIFICATION OF POSSIBLE CONTROL ALTERNATIVES

There are three basic alternatives for reducing SO2 emissions from boilers: removal of sulfur from the fuel before it is combusted, injection of limestone (applies only to fluidized bed boilers), and removal of SO2 from the exhaust gas after combustion.

Sulfur is present in wood, but is chemically combined with the wood. Whereas techniques for removing sulfur-containing minerals (e.g., pyrites) combined with coal have been developed over the past few decades, the relatively small amount of sulfur present in wood and the nature of the sulfur present in the wood have made development of techniques to remove sulfur from wood a virtually nonexistent field.

Limestone injection systems introduce crushed limestone (or dolomite, depending upon availability) into a fluidized bed in the furnace along with the fuel where it absorbs the SO2 (and other acid gasses such as HCl and HF) as it is created. The reacted limestone is removed from the exhaust along with the ash.

Scrubbing, or flue gas desulfurization (FGD) systems remove SO2 from the exhaust gases after they leave the furnace using a slurry of lime or limestone (some systems use sodium or other sorbent materials) and water into a chamber which the gases pass through. The sorbent in the slurry comes in contact with the SO2 in the exhaust gas and reacts with it. Depending upon the design of the system, the reacted sorbent slurry can remain wet or be dried by the hot exhaust such that only dry reacted sorbent remains. In dry FGD systems, often called spray driers, the particulate control system (usually a fabric filter) must be sized to handle the additional load created by the SO2 control system. Both wet and dry FGD systems require waste handling operations to remove the reacted sorbent material.

6.2 CONTROL ALTERNATIVE REVIEW

The results of the database query for SO2 control technologies are presented in Table B-7, sorted by permit limit, beginning with the SO2 limit proposed by Simpson for the power boiler. Because of the number of entries in the database, the tables present only a representative range of recent permit limits.

6.2.1 Summary of Possible Control Alternatives

Based on literature and database searches the following control alternatives are possible for the boiler:

- Removal of sulfur from fuel
- Limestone injection
- Flue gas desulfurization

6.2.2 Technical Feasibility of Control Alternatives

There do not appear to be any technically feasible precombustion sulfur removal techniques associated with wood fuel. Thus, precombustion sulfur removal schemes are all removed from consideration as BACT for SO2.

Limestone injection is commonly incorporated into the design of wood-fired fluidized-bed boilers, but is not considered a technically feasible means of reducing SO2 emissions from stoker-type furnace designs.

FGD systems are more commonly applied to coal-fired boilers, and, while there are no apparent technical restrictions to application of FGD systems to wood-fired boilers, there are no instances of this technology being used to reduce SO2 emissions from a wood-fired boiler.

6.2.3 Effectiveness of Remaining Technologies

Wet scrubbers are the most effective, and can achieve greater than 90 percent reduction in SO2 emissions. Dry scrubbers and spray driers are capable of control efficiencies on the order of 85 to 90 percent.

6.2.4 Ranking by Effectiveness

The remaining technologically feasible control technologies ranked in decreasing order of effectiveness are:

- FGD
- No control

6.2.5 Cost Effectiveness Evaluation

Wet FGD systems, though more effective at removing SO2, are less desirable than spray driers because the wet reacted sorbent requires a more elaborate treatment and disposal system.

Spray driers, when used to control SO2 from fluidized-bed boilers, are most commonly applied in addition to, rather than instead of, the integral limestone injection system. The cost-effectiveness evaluation presented here assumes that a spray drier system is used to increase the overall SO2 reduction beyond the 30 percent control provided by limestone injection.

A spray dryer cost estimate provided by McBurney for a recent Sierra Pacific Industries (SPI) project in Skagit County, Washington was used as the basis for the cost effectiveness evaluation. The cost of applying a spray dryer to Simpson's power boiler, assuming 90 percent control of SO2, would be over $65,000 per ton of SO2 removed, which is outside the envelope of acceptable cost effectiveness. The cost-effectiveness calculations are presented in Appendix A.

6.3 Selection of BACT for SO2

Simpson proposes that no control is BACT for reducing SO2 emissions from a wood-fired boiler, and that no emission limit is warranted for wood combustion in #7 Power Boiler.

7.0 TOXIC AND HAZARDOUS AIR POLLUTANT BACT ANALYSIS

Specific toxic air pollutant (TAP) and hazardous air pollutant (HAP) analyses were not conducted for the power boiler. BACT determinations for PM10 and VOCs are generally considered adequate for most sources. The power boiler will limit PM10 emissions by use of an ESP, and VOC emissions through use of proper combustion designed to facilitate complete combustion of organic compounds.

TABLES

TABLE B-1

SNCR EFFIENCY AT KIMBERLY CLARK, EVERETT
Steam Turbine Generator Project
Tacoma, Washington

Condition	Ammonia	Ammonia Slip,	NOx, lb/MMBtu	Opacity by
Design		25	0.069	
Baseline	0	0	0.215	12%
2	194	4.4	0.14	9%
3	416	57	0.11	36%
4	647	76	0.09	58%

TABLE B-2

NOX CONTROL TECHNOLOGY SEARCH RESULTS

Steam Turbine Generator Project
Tacoma, Washington

Facility Name	Location	Date of Permit	Heat Input (MMBtu/hr)	Permit Limit (lb/MMBtu)	Control Technology	Basis
Simpson Tacoma Kraft	Tacoma, WA	Proposed	595	0.20	Overfire Air/Proper Combustion	BACT-OTHER
Whitefield Power & Light	Whitefield, NH	9/10/04	220	0.33/0.075[1]	RSCR	OTHER
Soledad Energy	Soledad, CA	9/30/88	210	0.094/0.085[2]	FBC, SNCR	BACT-OTHER
South Point Power	South Point, OH	3/29/04	318	0.088	SCR	OTHER
Seattle Steam	Seattle, WA	6/23/06	100	0.1	FBC, SNCR	BACT-OTHER
Multitrade LP	Hurt, VA	2/21/92	374	0.1[3]	SNCR	BACT-PSD
Sierra Pacific Industries	Fredonia, WA	12/14/05[6]	430	0.13/0.1[4]	SNCR	BACT-PSD
Sierra Pacific Industries	Aberdeen, WA	10/17/02	310	0.15/0.1[4]	SNCR	BACT-PSD
Hampton Lumber	Darrington, WA	6/1/05	245	0.15	SNCR	BACT-OTHER
Weyerhaeuser Co.	Bruce, MS	5/9/95	90	0.23	Proper combustion	BACT-PSD
Boralex Stratton	Stratton, ME	1/4/05	672	0.24/0.075[5]	RSCR	BACT-OTHER
Wheelabrator Energy	Sherman Station, ME	4/9/99	315	0.25	Proper combustion	BACT-PSD
Mead Containerboard	Stevenson, AL	1/15/97	620	0.25	Proper combustion	BACT-PSD
Georgia Pacific Corp.	Gloster, MS	4/11/95	244	0.3	None	BACT-PSD
Schiller Station	Portsmouth, NH	10/25/04	720	0.6	FBC, SNCR	BACT-OTHER

1 Daily average/Quarterly average.
2 Hourly average/Daily average.
3 Thirty-day rolling average.
4 Daily average/Annual average.
5 Daily average/Quarterly average (quarterly limit only for Connecticut's Renewable Portfolio Standard Program, not part of air permit)
6 Currently under construction.

TABLE B-3

NOX CONTROL TECHNOLOGY COST EFFECTIVENESS SUMMARY
Steam Turbine Generator Project
Tacoma, Washington

Control	Emission Factor (lb/MMBtu)	Emissions (tpy)	Annualized Cost	Cost Effectiveness ($/ton)	Incremental Cost Effectiveness	
					Compare with FGR	Compare with SNCR
Baseline	0.2	522	-	-	-	-
FGR	0.18	469	$322,623	$6,186	-	-
SNCR-1	0.16	417	$491,136	$4,708	$3,231	-
SNCR-2	0.11	287	$675,096	$2,876	$1,931	-
Methane DeNOx	0.10	261	$6,664,458	$25,555	$30,398	$39,453
RSCR-1	0.075	196	$2,301,492	$7,060	$7,227	$8,167

TABLE B-4

PM10 CONTROL TECHNOLOGY SEARCH RESULTS

Steam Turbine Generator Project
Tacoma, Washington

Facility Name	Location	Date of Permit	Heat Input (MMBtu/hr)	Permit Limit (lb/MMBtu)	Control Technology	Basis
Simpson Tacoma Kraft	Tacoma, WA	Proposed	595	0.02	ESP	BACT-OTHER
Kimberly-Clark Tissue Co.	Everett, WA	7/1/93	718	0.016[2]	Fabric Filter	BACT-OTHER
Soledad Energy	Soledad, CA	9/30/88	210	0.018	Multiclone, ESP	BACT-OTHER
Sierra Pacific Industries	Fredonia, WA	12/14/05[3]	430	0.02	ESP	BACT-PSD
Hampton Lumber	Darrington, WA	6/1/05	245	0.02	Multiclone, ESP	BACT-OTHER
Sierra Pacific Industries	Aberdeen, WA	10/17/02	315	0.02	Mulitclone, ESP	BACT-PSD
Decker Energy International	East Ryegate, VT	7/11/90	300	0.02[2]	Mech. Collector, ESP	BACT-PSD
Boralex Livermore Falls	Livermore Falls, ME	9/5/91	534	0.02	Multiclone, ESP	BACT-PSD
Multitrade of Pittsylvania	Hurt, VA	2/21/92	374	0.02	Multiclone, ESP	BACT-PSD
Schiller Station	Portsmouth, NH	10/25/04	720	0.025	Fabric Filter	BACT-OTHER
South Point Power	South Point, OH	3/29/04	318	0.028	Fabric Filter	BACT-PSD
Seattle Steam	Seattle, WA	6/23/06	100	0.03	Fabric Filter	BACT-OTHER
Boralex Stratton	Stratton, ME	1/4/05	672	0.03	ESP	BACT-OTHER
Mead Containerboard	Stevenson, AL	1/15/97	620	0.03	Multiclone, ESP	BACT-PSD
Wheelabrator Sherman Energy	Sherman Station, ME	4/9/99	630	0.036	Fabric Filter	BACT-PSD
Whitefield Power & Light	Whitefield, NH	9/10/04	220	0.1	Multiclone, ESP	OTHER
Gulf States Paper Corp.	Moundville, AL	10/14/98	98	0.1	Multiclone, ESP	BACT-PSD
Weyerhaeuser Co.	Millport, AL	10/28/94	91	0.15	Venturi Scrubber	BACT-PSD

1 Permit limit calculated based on heat input, actual limit is in gr/dscf, and permit requires filterable-only PM10 test method.

2 Currently under construction.

TABLE B-5

CO CONTROL TECHNOLOGY SEARCH RESULTS

Steam Turbine Generator Project
Tacoma, Washington

Facility Name	Location	Date of Permit	Heat Input (MMBtu/hr)	Permit Limit (lb/MMBtu)	Control Technology	Basis
Simpson Tacoma Kraft	Tacoma, WA	Proposed	595	0.35	Proper Combustion	BACT-OTHER
Schiller Station	Portsmouth, NH	10/25/04	720	0.1	FBC, PC	BACT-OTHER
Seattle Steam	Seattle, WA	6/23/06	100	0.1	FBC, PC	BACT-OTHER
South Point Power	South Point, OH	3/29/04	318	0.14	Oxy. Cat., PC	BACT-PSD
Soledad Energy	Soledad, CA	9/30/88	210	0.15/0.1[1]	FBC, PC	BACT-OTHER
Hampton Lumber	Darrington, WA	6/1/05	245	0.23	Proper Combustion	BACT-OTHER
Boralex Ashland	Ashland, ME	4/2/92	586	0.3	Proper Combustion	BACT-OTHER
Willamette Industries Inc	Campti, LA	2/4/91	940	0.3[1]	Proper Combustion	BACT-PSD
Decker Energy International	East Ryegate, VT	7/11/90	300	0.3	Proper Combustion	BACT-PSD
Sierra Pacific Industries	Fredonia, WA	12/14/05[2]	430	0.35	Proper Combustion	BACT-PSD
Sierra Pacific Industries	Aberdeen, WA	10/17/02	310	0.35	Proper Combustion	BACT-PSD
KES Chateaugay Project	Chateaugay, NY	12/19/94	275	0.35	Proper Combustion	BACT-OTHER
Multitrade of Pittsylvania	Hurt, VA	2/21/92	374	0.35	Proper Combustion	BACT-PSD
Mead Containerboard	Stevenson, AL	1/15/97	620	0.4	Proper Combustion	BACT-PSD
Weyerhaeuser Company	Bruce, MS	5/9/95	90	0.4	Proper Combustion	BACT-PSD
Gulf States Paper Corp	Moundville, AL	10/14/98	98	0.5	Proper Combustion	BACT-PSD
Boralex Stratton	Stratton, ME	1/4/05	672	0.6	Proper Combustion	BACT-OTHER
Bio Energy Corp.	West Hopkinton, NH	7/23/98	225	1.0	Oxy. Cat., PC	BACT-OTHER
Plum Creek Mfg-Columbia Falls	Columbia Falls, MT	7/26/95	292	1.6[a]	Proper Combustion	BACT-PSD

1 Permit limit calculated based on heat input; actual permit limit is in lb/hr.

2 Currently under construction.

TABLE B-6

VOC CONTROL TECHNOLOGY SEARCH RESULTS
Steam Turbine Generator Project
Seattle, Washington

Facility Name	Location	Date of Permit	Heat Input (MMBtu/hr)	Emission Rate (lb/MMBtu)	Control Technology	Basis
Simpson Tacoma Kraft	Tacoma, WA	Proposed	595	0.017[1]	Proper Combustion	BACT-OTHER
Schiller Station	Portsmouth, NH	10/25/04	720	0.005	FBC, PC	BACT-OTHER
Seattle Steam	Seattle, WA	6/23/06	100	0.005	FBC, PC	BACT-OTHER
South Point Power	South Point, OH	3/29/04	318	0.013	Oxy. Cat., PC	BACT-PSD
Sierra Pacific Industries	Fredonia, WA	12/14/05[2]	430	0.019	Proper Combustion	BACT-PSD
Boralex Livermore Falls	Livermore Falls, ME	9/5/91	534	0.02	Proper Combustion	BACT-PSD
Georgia Pacific Corp	Gloster, MS	4/11/95	244	0.02	None	BACT-PSD
Hampton Lumber	Darrington, WA	6/1/05	245	0.025	Proper Combustion	BACT-OTHER
Sierra Pacific Industries	Aberdeen, WA	10/17/02	310	0.025	Proper Combustion	BACT-PSD
Soledad Energy	Soledad, CA	9/30/88	210	0.027	FBC, PC	BACT-OTHER
Wheelabrator Sherman Energy Co.	Penobscott, ME	4/9/99	315	0.03	Proper Combustion	BACT-PSD
Gulf States Paper Corp	Demopolis, AL	12/10/97	775	0.03	Proper Combustion	BACT-PSD
Mead Containerboard	Stevenson, AL	1/15/97	620	0.03	Proper Combustion	BACT-PSD
Southern Soya Corp.	Estill, SC	10/2/95	58	0.05	Proper Combustion	LAER
Weyerhaeuser Co.	Millport, AL	10/28/94	91	0.05	None	BACT-PSD
Boralex Stratton	Stratton, ME	1/4/05	672	0.07	Proper Combustion	BACT-OTHER
Multitrade of Pittsylvania	Hurt, VA	2/21/92	374	0.07	Proper Combustion	BACT-PSD
Gulf States Paper Corp	Moundville, AL	10/14/98	98	0.1	None	BACT-PSD
Boralex	Chateaugay, NY	12/19/94	275	0.1	None	BACT-OTHER
Kimberly-Clark Tissue Co.	Everett, WA	7/1/93	718	0.5	Proper Combustion	BACT-OTHER

1 Anticipated emission rate, not a proposed permit limit.

2 Currently under construction.

TABLE B-7

SO2 CONTROL TECHNOLOGY SEARCH RESULTS
Steam Turbine Generator Project
Tacoma, Washington

Facility Name	Location	Date of Permit	Heat Input (MMBtu/hr)	Emission Rate (lb/MMBtu)	Control Technology	Basis
Simpson Tacoma Kraft	Tacoma, WA	Proposed	595	0.0045[1]	Proper Combustion	BACT-OTHER
Temple-Inland Forest Products	Diboll, TX	9/28/01	40	0.002	None	OTHER
WGP, Incorporated	Androscoggin, ME	5/20/93	89	0.008	Wood Combustion	BACT-PSD
Duke Solutions Evendale	Hamilton, OH	11/24/99	29	0.01	None	OTHER
J. M. Huber Corporation	Aroostock, ME	11/13/93	84	0.01	Wood Combustion	OTHER
Erath Veneer Corp.	Rocky Mount, VA	12/30/86	32	0.017	None	BACT-PSD
Georgia Pacific Corp.	Amite, MS	4/11/95	244	0.017	None	OTHER
Schiller Station	Rockingham, NH	10/25/04	720	0.02	FBC, LI	OTHER
Riegelwood Mill	Columbus, NC	5/10/01	600	0.024	None	BACT-PSD
Soledad Energy	Soledad, CA	9/30/88	216	0.027	FBC, LI	BACT-PSD
KES Chateaugay Project	Franklin, NY	12/19/94	275	0.03	None	OTHER
Seattle Steam	Seattle, WA	6/23/06	100	0.039[1]	FBC, LI	BACT-OTHER
South Point Power	Lawrence, OH	2/7/02	318	0.07	Sodium Bicarb. Inj.	OTHER
Apple Grove Pulp And Paper	Mason, WV	6/17/96	773	0.08	None	BACT-PSD
Smurfit-Stone-Stevenson	Jackson, AL	9/30/02	620	0.1	None	BACT-PSD
Willamette Industries	Marlboro, SC	4/17/96	470	0.1	None	OTHER
Wheelabrator Sherman Energy	Penobscot, ME	4/9/99	315	0.12	Wood Combustion	BACT-PSD
Thermal Ventures	Henry, VA	2/15/02	120	0.47	None	OTHER
Mead/Westvaco Kentucky	Ballard, KY	2/27/02	631	0.8	None	BACT-PSD

1 Anticipated emission rate, not a proposed permit limit.

APPENDIX A

TABLE A-1

Flue Gas Recirculation Cost Effectiveness

Steam Turbine Generator Project
Tacoma, Washington

CAPITAL COSTS			
Total Capital Costs [TCC] (TEC+TDC+TIC)		$1,200,000	Jansen
Total Annualized Capital Costs [TACC] (20 years @ 7% interest)		$113,272	*Calculation*
DIRECT AND INDIRECT ANNUALIZED COSTS			
DIRECT OPERATING COSTS (DOC)			
I. Labor for operations ($30/person-hour)(1 hr/shift)(3 shifts/day)(365 day/yr)		$0	Engineering Estimate
II. Supervisory Labor (0.15* operations labor)		$0	OAQPS
III. Maintenance Labor ($35/person-hour)(.5 hr/shift)(3 shifts/day)(365 day/yr)		$16,425	Engineering Estimate
IV. Replacement Parts (100% of maintance labor)		$16,425	OAQPS
V. Utility costs			Engineering Estimate
a. Fan elect. = ($0.05/kW-hr)(8760 hr/yr)(300hp)(0.7457kW/hp)/(0.75 efficiency)		$130,647	Jansen
INDIRECT OPERATING COSTS (IOC)			
VIII. Overhead (0.6*O&M costs(I-III of DOC)		$9,855	OAQPS
IX. Administration (0.02*TCC)		$24,000	OAQPS
X. Insurance (0.01*TCC)		$12,000	OAQPS
Total Direct and Indirect Annualized Costs [TDIAC] (DOC+IOC)		$209,352	*Calculation*
TOTAL ANNUALIZED COSTS [TAC] (TACC+TDIAC)		$322,623	*Calculation*
Baseline emissions (no controls, w OFA - 0.20 lb/MMBtu)	tons/year	522	Simpson
Emissions w/FGR (assuming 0.18 lb/MMBtu)	tons/year	469	Jansen
Reduction from baseline	Percent	10	*Calculation*
Total Emissions Reduction	tons/year	52.2	*Calculation*
Cost per ton Conrolled	*$/ton*	$ 6,186	*Calculation*

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TABLE A-2

SNCR Cost Effectiveness

Steam Turbine Generator Project
Tacoma, Washington

CAPITAL COSTS			
Total Capital Costs [TCC] (TEC+TDC+TIC)		$1,500,000	Jansen
Total Annualized Capital Costs [TACC] (20 years @ 7% interest)		$141,589	*Calculation*
DIRECT AND INDIRECT ANNUALIZED COSTS			
DIRECT OPERATING COSTS (DOC)			
I. Labor for operations ($30/person-hour)(0.25 hr/shift)(3 shifts/day)(365 day/yr)		$8,213	Engineering Estimate
II. Supervisory Labor (0.15* operations labor)		$1,232	OAQPS
III. Maintenance Labor ($35/person-hour)(0.25 hr/shift)(3 shifts/day)(365 day/yr)		$9,581	Engineering Estimate
IV. Replacement Parts			
a. Catalyst (none)		$0	
b. Other (100% of maintance labor)		$9,581	OAQPS
V. Utility costs (none)		$0	
VI. Ammonia costs (urea) =(35 gal/hr)*(24*365 hr/yr)*($1.50/gal)		$459,900	Jansen
INDIRECT OPERATING COSTS (IOC)			
VIII. Overhead (0.6*O&M costs(I-III of DOC)		$0	OAQPS
IX. Administration (0.02*TCC)		$30,000	OAQPS
X. Insurance (0.01*TCC)		$15,000	OAQPS
Total Direct and Indirect Annualized Costs [TDIAC] (DOC+IOC)		$533,507	*Calculation*
TOTAL ANNUALIZED COSTS OXIDATION CATALYST [TAC_{OC}] (TACC+TDIAC)		$675,096	*Calculation*
Baseline emissions (no controls, w OFA - 0.20 lb/MMBtu)	tons/year	522	*Calculation*
Emissions w/SNCR (0.11 lb/MMBtu)	tons/year	286.9	*Calculation*
Reduction from baseline	Percent	45.0	*Calculation*
Total Emissions Reduction	tons/year	234.7	*Calculation*
Cost per ton Controlled	***$/ton***	$ 2,876	*Calculation*

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TABLE A-3

SNCR Cost Effectiveness

Steam Turbine Generator Project
Tacoma, Washington

CAPITAL COSTS			
Total Capital Costs [TCC] (TEC+TDC+TIC)		$1,500,000	Jansen
Total Annualized Capital Costs [TACC] (20 years @ 7% interest)		$141,589	*Calculation*
DIRECT AND INDIRECT ANNUALIZED COSTS			
DIRECT OPERATING COSTS (DOC)			
I. Labor for operations ($30/person-hour)(0.25 hr/shift)(3 shifts/day)(365 day/yr)		$8,213	Engineering Estimate
II. Supervisory Labor (0.15* operations labor)		$1,232	OAQPS
III. Maintenance Labor ($35/person-hour)(0.25 hr/shift)(3 shifts/day)(365 day/yr)		$9,581	Engineering Estimate
IV. Replacement Parts			
a. Catalyst (none)		$0	
b. Other (100% of maintance labor)		$9,581	OAQPS
V. Utility costs (none)		$0	
VI. Ammonia costs (urea) =(21 gal/hr)*(24*365 hr/yr)*($1.50/gal)		$275,940	Jansen
INDIRECT OPERATING COSTS (IOC)			
VIII. Overhead (0.6*O&M costs(I-III of DOC)		$0	OAQPS
IX. Administration (0.02*TCC)		$30,000	OAQPS
X. Insurance (0.01*TCC)		$15,000	OAQPS
Total Direct and Indirect Annualized Costs [TDIAC] (DOC+IOC)		$349,547	*Calculation*
TOTAL ANNUALIZED COSTS OXIDATION CATALYST [TAC_{OC}] (TACC+TDIAC)		$491,136	*Calculation*
Baseline emissions (no controls, w OFA - 0.20 lb/MMBtu)	tons/year	522	*Calculation*
Emissions w/SNCR (0.16 lb/MMBtu)	tons/year	417.3	*Calculation*
Reduction from baseline	Percent	20.0	*Calculation*
Total Emissions Reduction	tons/year	104.3	*Calculation*
Cost per ton Controlled	*$/ton*	$ 4,708	*Calculation*

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TABLE A-4

RSCR Cost Effectiveness

Steam Turbine Generator Project
Tacoma, Washington

CAPITAL COSTS			
Total Capital Costs [TCC] (TEC+TDC+TIC)		$7,500,000	Jansen
Total Annualized Capital Costs [TACC] (20 years @ 7% interest)		$707,947	*Calculation*
DIRECT AND INDIRECT ANNUALIZED COSTS			
DIRECT OPERATING COSTS (DOC)			
I. Labor for operations ($30/person-hour)(1 hr/shift)(3 shifts/day)(365 day/yr)		$32,850	Engineering Estimate
II. Supervisory Labor (0.15* operations labor)		$4,928	OAQPS
III. Maintenance Labor ($35/person-hour)(0.5 hr/shift)(3 shifts/day)(365 day/yr)		$16,425	Engineering Estimate
IV. Replacement Parts			
a. Catalyst (1 set of beds every 3 yrs), $750,000 each set annualized at 7 % interest		$285,789	Jansen
b. Other (100% of maintance labor)		$16,425	OAQPS
V. Utility costs (Fan elect.) = ($0.05/kW-hr)(24*365 hr/yr)(1300hp)(0.7457KW/hp)/(0.75 efficiency)		$566,135	Engineering Estimate
VI. Ammonia costs (19% aqueous) =(14 gal/hr)*24*365*($0.80/gal)		$98,112	Jansen
VII. Oil = 20 gal/hr * $1.80/gal*24*365 days		$315,360	Jansen
INDIRECT OPERATING COSTS (IOC)			
VIII. Overhead (0.6*O&M costs(I-III of DOC)		$32,522	OAQPS
IX. Administration (0.02*TCC)		$150,000	OAQPS
X. Insurance (0.01*TCC)		$75,000	OAQPS
Total Direct and Indirect Annualized Costs [TDIAC] (DOC+IOC)		$1,593,545	*Calculation*
TOTAL ANNUALIZED COSTS OXIDATION CATALYST [TAC_{OC}] (TACC+TDIAC)		$2,301,492	*Calculation*
Baseline emissions (no controls, w OFA - 0.20 lb/MMBtu)	tons/year	522	Calculation
Emissions w/RSCR (0.075 lb/MMBtu)	tons/year	195.6	Calculation
Reduction from baseline	Percent	62.5	*Calculation*
Total Emissions Reduction	tons/year	326.0	*Calculation*
Cost per ton Conrolled	*$/ton*	$ 7,060	*Calculation*

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TABLE A-5

Methane De-NOx Cost Effectiveness

Steam Turbine Generator Project
Tacoma, Washington

CAPITAL COSTS			
Total Capital Costs [TCC] (TEC+TDC+TIC)		$1,500,000	Jansen
Total Annualized Capital Costs [TACC] (20 years @ 7% interest)		$141,589	*Calculation*
DIRECT AND INDIRECT ANNUALIZED COSTS			
DIRECT OPERATING COSTS (DOC)			
I. Labor for operations ($30/person-hour)(0.25 hr/shift)(3 shifts/day)(365 day/yr)		$8,213	Engineering Estimate
II. Supervisory Labor (0.15* operations labor)		$1,232	OAQPS
III. Maintenance Labor ($35/person-hour)(0.25 hr/shift)(3 shifts/day)(365 day/yr)		$9,581	Engineering Estimate
IV. Replacement Parts			
a. Catalyst (none)		$0	
b. Other (100% of maintance labor)		$9,581	OAQPS
V. Utility costs (Fan elect.) = ($0.05/kW-hr)(8760 hr/yr)(300hp)(0.7457KW/hp)/(0.75 efficiency)		$130,647	Jansen
VI. Ammonia costs (none)		$0	
VII. Fuel (1,200 scfm nat gas at $10/1000 cf)		$6,307,200	Jansen
INDIRECT OPERATING COSTS (IOC)			
VIII. Overhead (0.6*O&M costs(I-III of DOC)		$11,415	OAQPS
IX. Administration (0.02*TCC)		$30,000	OAQPS
X. Insurance (0.01*TCC)		$15,000	OAQPS
Total Direct and Indirect Annualized Costs [TDIAC] (DOC+IOC)		$6,522,869	*Calculation*
TOTAL ANNUALIZED COSTS OXIDATION CATALYST [TAC_{OC}] (TACC+TDIAC)		$6,664,458	*Calculation*
Baseline emissions (no controls, w OFA - 0.20 lb/MMBtu)	tons/year	522	Jansen
Emissions w/methane deNOx (0.10 lb/MMBtu)	tons/year	260.8	Jansen
Reduction from baseline	Percent	50.0	*Calculation*
Total Emissions Reduction	tons/year	260.8	*Calculation*
Cost per ton Controlled	*$/ton*	$ 25,555	*Calculation*

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TABLE A-6

Flue Gas Desulfurization Cost Effectiveness

Steam Turbine Generator Project
Tacoma, Washington

CAPITAL COSTS		
DIRECT COSTS	**COST**	
I. Purchased Equipment		
a. Primary Equipment	$1,850,900	wood-fired boiler only.
b. Instrumentation (0.1*a)	$185,090	
c. Sales tax (0.08*a)	$148,072	
d. Freight (0.05*a)	$92,545	
Total Purchases Equipment Cost [TEC]	$2,276,606	
II. Direct Installation Costs		
a. Foundations and Supports (0.08*TEC)	$182,129	
b. Handling and Erection (0.14*TEC)	$318,725	
c. Electrical (0.04*TEC)	$91,064	
d. Piping (0.02*TEC)	$45,532	
e. Insulation for Ductwork (0.01*TEC)	$22,766	OAQPS
f. Painting (0.01*TEC)	$22,766	OAQPS
Total Direct Costs [TDC](I+II)	$682,982	*Calculation*
INDIRECT COSTS		
III. Indirect Installation		
a. Engineering and Supervision (0.10*TEC)	$227,661	OAQPS
b. Construction and Field Expenses (0.05*TEC)	$113,830	OAQPS
c. Contractor Fee (0.10*TEC)	$227,661	OAQPS
d. Contingencies (0.03*TEC)	$68,298	OAQPS
IV. Other Indirect Costs		
a. Startup and Testing (0.03*TEC)	$68,298	OAQPS
b. Working Capital (30 days of direct operating costs [I-VII below/12])	$22,608	OAQPS
Total Indirect Costs [TIC](III+IV)	$728,356	*Calculation*
Total Capital Costs [TCC] (TEC+TDC+TIC)	$3,687,944	*Calculation*
Total Annualized Capital Costs [TACC] (20 years @ 7% interest)	$348,116	*Calculation*
DIRECT AND INDIRECT ANNUALIZED COSTS		
DIRECT OPERATING COSTS (DOC)		
I. Labor for operations ($30/person-hour)(1 hr/shift)(3 shifts/day)(365 day/yr)	$32,850	Engineering Estimate
II. Supervisory Labor (0.15* operations labor)	$4,928	
III. Maintenance Labor ($35/person-hour)(0.5 hr/shift)(3 shifts/day)(365 day/yr)	$16,425	
IV. Replacement Parts (100% of maintance labor)	$16,425	
V. Utility costs		
a. Fan elect. = ($0.05/kW-hr)(8760 hr/yr)(400hp)(0.7457kW/hp)/(0.75 efficiency)	$174,196	
b. Water = (65 gal/min)(60min/hr)(8760 hr/yr)(0.1337cf/gal)($0.001/cf)	$4,568	
c. Sewer = (25 gal/min)(60min/hr)(8760 hr/yr)(0.1337cf/gal)($0.001/cf)	$1,757	
VI. Limestone costs		
a. Limestone =(30 lb/hr)*(8760 hr/yr)*($60/ton)/(2000lb/ton)	$7,884	
b. Disposal =(40 lb/hr)*(8760 hr/yr)*($700/ton)/(2000lb/ton)	$12,264	
INDIRECT OPERATING COSTS (IOC)		
VIII. Overhead (0.6*O&M costs(I-III of DOC)	$32,522	
IX. Administration (0.02*TCC)	$73,759	
X. Insurance (0.01*TCC)	$36,879	
Total Direct and Indirect Annualized Costs [TDIAC] (DOC+IOC)	$414,455	
TOTAL ANNUALIZED COSTS [TAC] (TACC+TDIAC)	$762,571	

Baseline emissions (NCASI, no controls - 0.0045 lb/MMBtu)	tons/year	11.7	*Calculation*
Emissions w/SO2 scrubber (assuming 0.00045 lb/MMBtu)	tons/year	1.2	*McBurney (2005) & Calculation*
Reduction from baseline	Percent	90.0	*Calculation*
Total Emissions Reduction	tons/year	10.6	*Calculation*
Cost per ton Controlled	*$/ton*	$ 72,201	*Calculation*

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TABLE A-7

Oxidation Catalyst Cost Effectiveness

Steam Turbine Generator Project
Tacoma, Washington

CAPITAL COSTS			
DIRECT COSTS		**COST**	**Source**
I. Purchased Equipment			
a. Primary Equipment (catalyst bed and additional ductwork)		$2,293,150	Babcock Power & SPI (2005)
b. Instrumentation (0.1*a)		$229,315	OAQPS
c. Sales tax (0.08*a)		$183,452	OAQPS
d. Freight (0.05*a)		$114,657	OAQPS
Total Purchases Equipment Cost [TEC]		$2,820,574	Calculation
II. Direct Installation Costs			
a. Foundations and Supports (0.08*TEC)		$225,646	OAQPS
b. Handling and Erection (0.14*TEC)		$394,880	OAQPS
c. Electrical (0.04*TEC)		$112,823	OAQPS
d. Piping (0.02*TEC)		$56,411	OAQPS
e. Insulation for Ductwork (0.01*TEC)		$28,206	OAQPS
f. Painting (0.01*TEC)		$28,206	OAQPS
Total Direct Costs [TDC](I+II)		$846,172	Calculation
INDIRECT COSTS			
III. Indirect Installation			
a. Engineering and Supervision (0.10*TEC)		$282,057	OAQPS
b. Construction and Field Expenses (0.05*TEC)		$141,029	OAQPS
c. Contractor Fee (0.10*TEC)		$282,057	OAQPS
d. Contingencies (0.03*TEC)		$84,617	OAQPS
IV. Other Indirect Costs			
a. Startup and Testing (0.03*TEC)		$84,617	OAQPS
b. Working Capital (30 days of direct operating costs [I-VII below/12])		$472,282	OAQPS
Total Indirect Costs [TIC](III+IV)		$1,346,660	Calculation
Total Capital Costs [TCC] (TEC+TDC+TIC)		$5,013,407	Calculation
Total Annualized Capital Costs [TACC] (20 years @ 7% interest)		$473,230	Calculation
DIRECT ANNUALIZED COSTS			
DIRECT OPERATING COSTS (DOC)			
I. Labor for operations ($30/person-hour)(1 hr/shift)(3 shifts/day)(365 day/yr)		$32,850	Engineering Estimate
II. Supervisory Labor (0.15* operations labor)		$4,928	OAQPS
III. Maintenance Labor ($35/person-hour)(0.5 hr/shift)(3 shifts/day)(365 day/yr)		$16,425	Engineering Estimate
IV. Replacement Parts			
a. Catalyst (2 beds every 3 yrs), $1,000,000 annualized at 7 % interest		$381,052	Hipp (2003)
b. Other (100% of maintance labor)		$16,425	OAQPS
V. Utility costs(None)		$0	
VI. Fuel Penalty =($20/MMBtu)*(595 MMBtu/hr)*(8760 hr/yr)*(0.05)		$5,215,704	Hipp (2003)
INDIRECT OPERATING COSTS (IOC)			
VIII. Overhead (0.6*O&M costs(I-III of DOC)		$0	OAQPS
IX. Administration (0.02*TCC)		$100,268	OAQPS
X. Insurance (0.01*TCC)		$50,134	OAQPS
Total Direct Annualized Costs [TDAC] (DOC+IOC)		$5,817,785	Calculation
TOTAL ANNUALIZED COSTS OXIDATION CATALYST [TAC_{OC}] (TACC+TAC)		$6,291,015	Calculation
Baseline emissions (w/proper combustion - 0.35 lb/MMBtu)	tons/year	912.7	
Emissions w/catalyst (assuming 0.175 lb/MMBtu)	tons/year	456.4	*DCF (2003) & Calculation*
Reduction from baseline	Percent	50.0	*Calculation*
Total Emissions Reduction	tons/year	456.4	*Calculation*
Cost per ton Conrolled	*$/ton*	$ 13,785	*Calculation*

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APPENDIX B

EPA RACT/BACT/LAER CLEARINGHOUSE DATABASE SEARCH RESULTS

PSD Amendment for Power Boiler No. 7
NO_2 Air Quality Analysis
Simpson Tacoma Kraft Company
801 Portland Avenue
Tacoma, WA 98421

August 2010
Project: 108.00217.00024

Table 1. EPA's RACT/BACT/LAER Clearinghouse
Process Type: Utility & Large Industrial Size Boiler/Furnace (> 250 MMBtu/hr)
Fuel: Biomass (wood)
Pollutant: Nitrogen Oxide (NO_X)
Permit Dates Between January 1991 and October 2009

RBLCID	Permit Date	Permit Number	Facility Name	State	Process Name	Fuel	Throughput	Unit	Control Method	Emission Limit	Unit	Averaging Period	LAER/BACT?	Comments
NH-0016	9/25/2009	TP-0033	Clean Power Berlin LLC	NH	Boiler 1	Wood Chips	40.75	tons/hr	Selective Catalytic Reduction (SCR) With Staged Combustion	0.065	lb/MMBtu	30-Day Rolling Avg.	LAER	
NH-0015	2/27/2009	TP-0014	Concord Steam Corporation	NH	Boiler #1 (Riley Power Vibrating, Water-Cooled Grate, Stoker Type Boiler)	Biomass (wood chips)	32.62 (305 MMBtu/hr)	tons/hr	SCR	0.065	lb/MMBtu	30-Day Rolling Avg.	LAER	
MN-0074	8/23/2007	13900114	Koda Energy	MN	Biomass Boiler	Biomass	308.18	MMBtu/hr	Selective Non-Catalytic Reduction (SNCR), Low Nox Burner, Overfired Air (OFA)	0.25	lb/MMBtu	When Combusting Biomass	BACT	New
WA-0335	5/22/2007	PSD-06-02	Simpson Tacoma Kraft Company, LLC	WA	Power Boiler No. 7 (hog fuel boiler)	Wood Waste	595	MMBtu/hr	Proper Combustion Controls With Over-Fire Air (OFA)	0.2	lb/MMBtu	30-Day Rolling Avg.	BACT	Modification of Existing Boiler
ND-0022	5/1/2006	PTC06004	Northern Sun	ND	Wood/Hull Fired Existing Stroker Boiler	Biomass (wood/hull)	280	MMBtu/hr	Combustion Controls	0.2	lb/MMBtu	30-Day Rolling Avg.	BACT	Modification of Existing Boiler
OH-0307	4/4/2006	07-00534	South Point Biomass Generation	OH	Wood Fired Boilers (7)	Wood	318	MMBtu/hr	SCR	0.44	lb/MMBtu	Manufacturer's Factor	BACT	
WA-0337	2/1/2006	PSD-01-07 AMENDMENT 1	Boise Cascade - Boise White Paper LLC	WA	Utility-And Large Industrial-Size Boilers/Furnaces (>250 MMBtu/hr)	Wood/Bark	343	MMBtu/hr	OFA System, Electro-Static Precipitator (ESP)	0.3	lb/MMBtu	30-Day Rolling Avg.	BACT	Modification of Existing Boiler
WA-0327	1/25/2006	PSD 05-04	Sierra Pacific Industries - Skagit County Lumber Mill	WA	Wood-Fired Cogeneration Unit	Bark & Waste Wood	430	MMBtu/hr	SNCR	0.13	lb/MMBtu	Calendar Day	BACT	New
WA-0329	2/11/2005	PSD 03-04	Darrington Energy Cogeneration Power Plant	WA	Wood Waste-Fired Boiler	Wood Waste	403	MMBtu/hr	SNCR	0.12	lb/MMBtu	24-Hr	BACT	New
LA-0188	11/23/2004	PSD-LA-698	Bogalusa Mill	LA	No. 12 Hogged Fuel Boiler	Bark	787.5	MMBtu/hr	Existing Overfire Air System With Low NOx Burners In The Under Grate Air Heater System, Plus Good Combustion Practices	0.45	lb/MMBtu	Not Specified	BACT	Modification of Existing Boiler
NH-0013	10/25/2004	TP-B-0501	Schiller Station	NH	Boiler, Wood Fired Cfb, Unit #5	Biomass (wood)	720	MMBtu/hr	SNCR	0.075	lb/MMBtu	24 Hr Avg.	BACT	
										0.6	lb/MMBtu	30-Day Rolling Avg.	BACT/NSPS	
AR-0072	2/28/2003	1714-AOP-R3	Del Tin Fiber LLC	AR	Heat Energy System	Wood Waste	291	MMBtu/hr	Low NOx Combustors And SNCR	0.3	lb/MMBtu	Not Specified	BACT	
WA-0298	10/17/2002	PSD-02-02	Sierra Pacific - Aberdeen Division	WA	Hog Fuel Boiler (spreader stoker boiler)	Wood Waste	310	MMBtu/hr	SNCR, Boiler Design	0.15	lb/MMBtu	24 Hr Avg.	BACT	New
KY-0085	2/27/2002	VF-01-002	Meadwestvaco Kentucky, Inc/Wickliffe	KY	Boiler, Bark	Bark	631	MMBtu/hr	None	0.4	lb/MMBtu	Not Specified	BACT	

Table 1. EPA's RACT/BACT/LAER Clearinghouse
Process Type: Utility & Large Industrial Size Boiler/Furnace (> 250 MMBtu/hr)
Fuel: Biomass (wood)
Pollutant: Nitrogen Oxide (NO_X)
Permit Dates Between January 1991 and October 2009

RBLCID	Permit Date	Permit Number	Facility Name	State	Process Name	Fuel	Throughput	Unit	Control Method	Emission Limit	Unit	Averaging Period	LAER/BACT?	Comments
ME-0021	11/27/2001	A-19-71-K-A	S.D. Warren Co. - Skowhegan	ME	Boiler #2	Wood Waste	1300	MMBtu/hr	SNCR	0.2	lb/MMBtu	Not Specified	BACT	Modification of Existing Boiler
MN-0046	11/15/2001	12300063-001	District Energy St. Paul, Inc	MN	Boiler	Wood	550	MMBtu/hr	SNCR	0.15	lb/MMBtu	Not Specified	BACT	
ME-0026	4/9/1999	1-67-71-K-A/R	Wheelabrator Sherman Energy Company	ME	Boiler # 1	Wood	315	MMBtu/hr	Good Combustion Practices	0.25	lb/MMBtu	30-Day Avg.	BACT	Modification of Existing Boiler
AL-0116	12/10/1997	105-0001-X027	Gulf States Paper Corporation	AL	Boiler, Power	Bark/Clarifier Sludge	775	MMBtu/hr	Low Nox Natural Gas And Fuel Oil Burners	0.3	lb/MMBtu	Not Specified	Not Specified	Modified
OK-0038	11/5/1996	96-043-C PSD	Valliant	OK	Bark Boiler	wood/bark			OFA	0.3	lb/MMBtu	Not Specified	Not Specified	New
WV-0016	6/17/1996	R14-11	Apple Grove Pulp And Paper Company, Inc	WV	Wood Waste Boiler	Wood	772.6	MMBtu/hr	SNCR	0.1	lb/MMBtu	Not Specified	Not Specified	New
SC-0045	4/17/1996	1680-0043	Willamette Industries - Marlboro Mill	SC	Boiler Woodwaste/Bark/Natural Gas	Woodwaste	470	MMBtu/hr	Good Combustion Control	0.3	lb/MMBtu	Not Specified	Not Specified	New
FL-0094	1/31/1995	PSD-FL-208	U.S. Sugar Corp	FL	Bagasse Boiler	Bagasses	738	MMBtu/hr	Low NOx Burners	0.25	lb/MMBtu	Not Specified	Not Specified	New
PA-0145	12/21/1994	25-028	International Paper Company	PA	Boiler Firing Bark & Wood Waste	Bark And Wood Waste	326	MMBtu/hr	Not Specified	0.54	lb/MMBtu	Not Specified	Not Specified	Modified
NY-0055	12/19/1994	163400 0116	KES Chateaugay Project	NY	Riley Stoker Wood Boiler Ep #00001	Wood/Wood Waste	275	MMBtu/hr	No Controls	0.23	lb/MMBtu	Not Specified	RACT	New
FL-0069	9/27/1993	PSD-FL-196	Okeelanta Cogeneration	FL	Boiler, Spreader Stoker, Biomass, (3 Units)	Bagasses	760	MMBtu/hr	SNCR	0.15	lb/MMBtu	30-Day Rolling Avg.	Not Specified	New
FL-0070	9/27/1993	PSD-FL-197	Osceola Power Limited Partnership	FL	Boiler, Spreader Stoker, Biomass, 2	Bagasse	760	MMBtu/hr	SNCR	0.14	lb/MMBtu	30-Day Rolling Avg.	Not Specified	New
WA-0276	7/1/1993	DE98-AQI02(NEW)	Scott Paper Company	WA	Boiler, Woodwaste-Fired	Wood/Wood Waste	718	MMBtu/hr	Combustion Controls	0.25	lb/MMBtu	Not Specified	BACT	New
FL-0198	9/29/1992	PSD-FL-183	Wheelabrator Ridge Energy, Inc.	FL	Electric Generation, Boiler, Wood & Waste Fuel	Wood	630	MMBtu/hr	Good Combustion Practices	0.143	lb/MMBtu	Not Specified	BACT	New
CT-0147	5/13/1992	089-070-0042-01	Killingly Energy Limited Partnership	CT	Boiler, Wood Fired	Wood	517.3	MMBtu/hr	SNCR, Staged Combustion.	0.175	lb/MMBtu	Not Specified	BACT	New (never built)
ME-0024	4/2/1992	A-577-72-A-N	Beaver - Ashland Alternative Energy, Inc.	ME	Boiler, Wood Fired, #1	Wood	534	MMBtu/hr	SNCR	0.15	lb/MMBtu	Not Specified	Not Specified	New
ME-0013	9/5/1991	A-555-72-A-N	Beaver-Livermore Falls	ME	Boiler, Wood Waste	Wood/Wood Waste	533.64	MMBtu/hr	SNCR	0.15	lb/MMBtu	Not Specified	BACT	
CA-0424	7/10/1991		Thermo Electron'S Delano Energy Company Inc.	CA	Boiler, Fluidized Bed, Biomass Fired	Bagasses	315	MMBtu/hr	NH3 Injection/Thermal Denox	44	PPM @ 12% CO2	Not Specified	BACT	
MI-0180	5/31/1991	373-86A	Cogeneration Michigan Associates	MI	Boiler, Wood Fired	Wood/Wood Waste	523	MMBtu/hr	SNCR	0.15	lb/MMBtu	Not Specified	BACT	

Table 1. EPA's RACT/BACT/LAER Clearinghouse
Process Type: Utility & Large Industrial Size Boiler/Furnace (> 250 MMBtu/hr)
Fuel: Biomass (wood)
Pollutant: Nitrogen Oxide (NO_X)
Permit Dates Between January 1991 and October 2009

RBLCID	Permit Date	Permit Number	Facility Name	State	Process Name	Fuel	Throughput	Unit	Control Method	Emission Limit	Unit	Averaging Period	LAER/BACT?	Comments
VA-0174	4/8/1991	30871	Multitrade Of Pittsylvania County, L.P.	VA	Boiler, Wood/Coal Fired, 3	RDF	373.7	MMBtu/hr	SNCR	0.1	lb/MMBtu	30-Day Rolling Avg.	BACT	New
LA-0074	2/4/1991	PSD-LA-562	Willamette Industries Inc	LA	Boiler, Hogged Fuel	Wood/Wood Waste	940	MMBtu/hr	Design & Operation	0.3	lb/MMBtu	Not Specified	BACT	New

Table 2. EPA's RACT/BACT/LAER Clearinghouse
Process Type: Utility & Large Industrial Size Boiler/Furnace (> 250 MMBtu/hr)
Fuel: Biomass (wood)
Pollutant: Carbon Monoxide (CO)
Permit Dates Between January 1991 and October 2009

RBLCID	Permit Date	Permit Number	Facility Name	State	Process Name	Fuel	Throughput	Unit	Control Method	Emission Limit	Unit	Averaging Time	LAER/BACT?	Comments
MN-0074	8/23/2007	13900114	Koda Energy	MN	Biomass Boiler	Biomass	308.18	MMBtu/hr	Good Combustion Practice	0.43	lb/MMBtu	30-Day Rolling Avg.	BACT	New
WA-0335	5/22/2007	PSD-06-02	Simpson Tacoma Kraft Company, LLC	WA	Power Boiler No. 7 (hog fuel boiler)	Wood Waste	595	MMBtu/hr	Overfire Air (OFA) System	0.35	lb/MMBtu	30-Day Rolling Avg.	BACT	Modification of Existing Boiler
ND-0022	5/1/2006	PTC06004	Northern Sun	ND	Wood/Hull Fired Existing Stroker Boiler	Biomass (wood/hull)	280	MMBtu/hr	Good Combustion Practices	0.63	lb/MMBtu	Not Specified	BACT	
OH-0307	4/4/2006	07-00534	South Point Biomass Generation	OH	Wood Fired Boilers (7)	Wood	318	MMBtu/hr	Oxidation Catalyst	0.1	lb/MMBtu	Not Specified	BACT	
WA-0337	2/1/2006	PSD-01-07 AMENDMEN T 1	Boise Cascade - Boise White Paper LLC	WA	Utility-And Large Industrial-Size Boilers/Furnaces (>250 Million Btu/H)	Wood/Bark	343	MMBtu/hr	OFA, Electrostatic Precipitator (ESP)	500	ppmvd	12 Month Rolling Avg.	BACT	Modification of Existing Boiler
WA-0327	1/25/2006	PSD 05-04	Sierra Pacific Industries - Skagit County Lumber Mill	WA	Wood-Fired Cogeneration Unit	Bark & Waste Wood	430	MMBtu/hr	Good Combustion Practice	0.35	lb/MMBtu	Not Specified	BACT	New
WA-0329	2/11/2005	PSD 03-04	Darrington Energy Cogeneration Power Plant	WA	Wood Waste-Fired Boiler	Wood Waste	403	MMBtu/hr	Good Combustion Practices	0.35	lb/MMBtu	24-Hr	BACT	New
LA-0188	11/23/2004	PSD-LA-698	Bogalusa Mill	LA	No. 12 Hogged Fuel Boiler	Bark	787.5	MMBtu/hr	Existing OFA And Good Combustion Practices	0.6	lb/MMBtu	Annual Avg.	BACT	
NH-0013	10/25/2004	TP-B-0501	Schiller Station	NH	Boiler, Wood Fired CFB, Unit #5	Biomass (wood)	720	MMBtu/hr	Good Combustion Practices With the Fluidized Bed Design	0.1	lb/MMBtu	24 Hr/Above 50% Load	BACT	
GA-0114	10/13/2004	2631-115-0021-V-01-4	Inland Paperboard And Packaging, Inc. - Rome Linerboard Mill	GA	Boiler, Solid Fuel	Bark	856	MMBtu/hr	Staged Combustion And Good Combustion Practices	368	PPM @ 3% O2	Not Specified	BACT	
LA-0178	11/14/2003	PSD-LA-77(M-2)	Deridder Paper Mill	LA	Wood-Fired Boiler	Bark	454.29	MMBtu/hr	Good Equipment Design And Proper Combustion Techniques	0.33	lb/MMBtu	Annual Avg.	BACT	
AR-0072	2/28/2003	1714-AOP-R3	Del Tin Fiber LLC	AR	Heat Energy System	Wood Waste	291	MMBtu/hr	Good Combustion Practice	0.78	lb/MMBtu	Not Specified	BACT	
WA-0298	10/17/2002	PSD-02-02	Aberdeen Division	WA	Hog Fuel Boiler	Wood Waste	310	MMBtu/hr	Good Combustion	0.35	lb/MMBtu	Not Specified	BACT	
ME-0021	11/27/2001	A-19-71-K-A	S.D. Warren Co. - Skowhegan	ME	Boiler, #2	Wood Waste	1300	MMBtu/hr	Good Boiler Design And Combustion Practices.	0.4	lb/MMBtu	Not Specified	BACT	
MN-0046	11/15/2001	12300063-001	District Energy St. Paul, Inc	MN	Boiler	Wood	550	MMBtu/hr	Good Combustion	0.3	lb/MMBtu	Not Specified	BACT	
GA-0117	5/24/2001	2631-039-0025-P-01-1	Tri-Gen Biopower	GA	Boiler, Multifuel	Woodwaste And Papermill Sludge	302.2	MMBtu/hr	Good Design And Combustion Principles	0.3	lb/MMBtu	Not Specified	BACT	
ME-0026	4/9/1999	1-67-71-K-A/R	Wheelabrator Sherman Energy Company	ME	Boiler # 1	Wood	315	MMBtu/hr	Good Combustion Practices	0.45	lb/MMBtu	Not Specified	BACT	

Table 2. EPA's RACT/BACT/LAER Clearinghouse
Process Type: Utility & Large Industrial Size Boiler/Furnace (> 250 MMBtu/hr)
Fuel: Biomass (wood)
Pollutant: Carbon Monoxide (CO)
Permit Dates Between January 1991 and October 2009

RBLCID	Permit Date	Permit Number	Facility Name	State	Process Name	Fuel	Throughput	Unit	Control Method	Emission Limit	Unit	Averaging Time	LAER/BACT?	Comments
OK-0038	11/5/1996	96-043-C PSD	Valliant	OK	Bark Boiler	Wood/Bark	Not Specified	Not Specified	No Controls	6627	lb/hr	Not Specified	Not Specified	New
WV-0016	6/17/1996	R14-11	Apple Grove Pulp And Paper Company, Inc	WV	Wood Waste Boiler	Wood	772.6	MMBtu/hr	CO Oxidation Catalyst (No Sludge); No CO Control W/Sludge.	0.3	lb/MMBtu	Not Specified	Not Specified	New
SC-0045	4/17/1996	1680-0043	Willamette Industries - Marlboro Mill	SC	Boiler Woodwaste/Bark/Natural Gas	Woodwaste	470	MMBtu/hr	Good Combustion Control	0.3	lb/MMBtu	Not Specified	Not Specified	New
FL-0094	1/31/1995	PSD-FL-208	U.S. Sugar Corp	FL	Bagasse Boiler	Bagasses	738	MMBtu/hr	No Controls	0.7	lb/MMBtu	Not Specified	Not Specified	New
NY-0055	12/19/1994	163400 0116	KES Chateaugay Project	NY	Riley Stoker Wood Boiler Ep #00001	Wood/Wood Waste	275	MMBtu/hr	No Controls	0.35	lb/MMBtu	Not Specified	Not Specified	New
FL-0069	9/27/1993	PSD-FL-196	Okeelanta Cogeneration	FL	Boiler, Spreader Stoker, Biomass, (3 Units)	Bagasses	760	MMBtu/hr	Boiler Design And Good Combustion Practice	0.5	lb/MMBtu	30-day Rolling Avg.	Not Specified	New
WA-0276	7/1/1993	DE98-AQI02(NEW)	Scott Paper Company	WA	Boiler, Woodwaste-Fired	Wood/Wood Waste	718	MMBtu/hr	Combustion Control, Boiler Design	511	PPM @ 7% O2	Not Specified	BACT	New
FL-0198	9/29/1992	PSD-FL-183	Wheelabrator Ridge Energy, Inc.	FL	Electric Generation, Boiler, Wood & Waste Fuel	Wood	630	MMBtu/hr	Good Combustion Practices	0.32	lb/MMBtu	Not Specified	BACT	New
CT-0147	5/13/1992	089-070-0042-01	Killingly Energy Limited Partnership	CT	Boiler, Wood Fired	Wood	517.3	MMBtu/hr	No Controls	0.29	lb/MMBtu	Not Specified	BACT	New (never built)
ME-0024	4/2/1992	A-577-72-A-N	Beaver - Ashland Alternative Energy, Inc.	ME	Boiler, Wood Fired, #1	Wood	534	MMBtu/hr	Good Combustion Control	0.3	lb/MMBtu	Not Specified		New
ME-0013	9/5/1991	A-555-72-A-N	Beaver-Livermore Falls	ME	Boiler, Wood Waste	Wood/Wood Waste	533.64	MMBtu/hr	Good Combustion Control	0.3	lb/MMBtu	Not Specified	BACT	
CA-0424	7/10/1991		Thermo Electron's Delano Energy Company Inc.	CA	Boiler, Fluidized Bed, Biomass Fired	Bagasses	315	MMBtu/hr	Fluidized Bed	127	PPM @ 12% CO2	Not Specified	BACT	
MI-0180	5/31/1991	373-86A	Cogeneration Michigan Associates	MI	Boiler, Wood Fired	Wood/Wood Waste	523	MMBtu/hr	Combustion Controls	0.4	lb/MMBtu	Not Specified	BACT	
VA-0174	4/8/1991	30871	Multitrade Of Pittsylvania County, L.P.	VA	Boiler, Wood/Coal Fired, 3	RDF	373.7	MMBtu/hr	No Controls	0.35	lb/MMBtu	Not Specified	BACT	New
LA-0074	2/4/1991	PSD-LA-562	Willamette Industries Inc	LA	Boiler, Hogged Fuel	Wood/Wood Waste	940	MMBtu/hr	Design & Operation	0.3	lb/hr	Not Specified	BACT	New

APPENDIX C

CLASS II NO2 AIR QUALITY ANALYSIS REPORT

PSD Amendment for Power Boiler No. 7
NO_2 Air Quality Analysis
Simpson Tacoma Kraft Company
801 Portland Avenue
Tacoma, WA 98421

August 2010
Project: 108.00217.00024

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PSD AMENDMENT FOR POWER BOILER NO. 7 NO_2 AIR QUALITY ANALYSIS

SIMPSON TACOMA KRAFT COMPANY
801 PORTLAND AVENUE
TACOMA, WA 98421

Prepared for:

Simpson Tacoma Kraft
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August 2010
Project: 108.00217.00024

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LIST OF ACRONYMS

BACT	Best Available Control Technology
CFR	Code of Federal Regulations
CO	Carbon Monoxide
EPA	Environmental Protection Agency
hr	hour
K	Kelvin
km	kilometer
lb	pound
m	meter
μg	microgram
MMBtu	Million British Thermal Units
NAAQS	National Ambient Air Quality Standards
NO_X	Nitrogen Oxides
NO_2	Nitrogen dioxide
PM	Particulate Matter
PM_{10}	Particulate Matter less than 10 Microns
PSD	Prevention of Significant Deterioration
SIA	Source Impact Area
SIL	Significant Impact Level
sec	second
tpy	tons per year
UTM	Universal Transverse Mercator

1 INTRODUCTION

Simpson Tacoma Kraft (Simpson) currently operates a Kraft pulp and paper mill at 801 Portland Avenue in Tacoma, Washington This facility received a Prevention of Significant Deterioration (PSD) permit (PSD-06-02) from Ecology on May 22, 2007 to install a steam turbine electrical generator driven by steam produced from the existing Recovery Boiler No. 4 and Power Boiler No. 7 (referred to as the Cogen Project). This project allows the facility to cogenerate and distribute electric power to the grid. For this Cogen Project, the PSD regulated pollutants were nitrogen oxide (NO_X), carbon monoxide (CO), and particulate matter less than 10-micron in diameter (PM_{10}). Therefore, case-by-case Best Available Control Technology (BACT) analyses were performed for these pollutants as a part of the PSD permitting process.

In an amendment request, Simpson is proposing to increase the Power Boiler No. 7's BACT limit for NO_X from 0.20 to 0.30 lb/MMBtu. This would also require a revision of the annual NO_X limit from 522 tons to 782 tons based on the revised BACT limit. This report provides a new dispersion modeling analysis for NO_X that is necessary to ensure the new limits do not cause or contribute to a violation of the National Ambient Air Quality Standards (NAAQS) or PSD Increment standards.

2 MODELING METHODOLOGY AND SOURCES

This section discusses the dispersion modeling used to demonstrate compliance with the NAAQS and Class II PSD Increments for NO_X. This air quality analysis is organized into two major parts: Significance Impact Analysis and Full Impact Analysis. The techniques used are consistent with current EPA modeling guidelines.[1, 2] Model methodology and setup parameters used in this analysis follow the September 2006 PSD permit application submitted. Any differences are noted below.

2.1 SIGNIFICANCE ANALYSIS

To determine whether a pollutant must be considered in the full impact modeling analysis, the first step is to model the proposed emission changes (i.e., the net emissions increase) and compare the results to the applicable Significant Impact Levels (SILs) and monitoring *de minimis*. The dispersion modeling analysis is complete if maximum off-property concentration is below the SIL. If the modeled concentrations are equal to or above the SIL, a Full Impact Analysis is required to demonstrate compliance with the NAAQS and PSD Increments. If the predicted concentration exceeds the monitoring *de minimis* threshold for any pollutant, pre-construction monitoring is required.

2.1.1 SOURCE IMPACT AREA

The modeling results are used to determine the source impact area (SIA) of the proposed source. The SIA is distance from the proposed plant to the furthest receptor with a predicted concentration equal to or above the SIL. The SIA is defined for each pollutant and averaging period. In the event that there are no predicted significant impacts, the SIA is zero.

2.1.2 SOURCE EMISSIONS AND PARAMETERS

The Significance Analysis only includes the net emissions increase from the proposed change. NO_X emissions from Power Boiler #7 are the only emissions affected by the PSD amendment request. The net emissions increase is the proposed potential emissions minus the baseline emissions. The 2006 PSD application identified 2000 to 2001 as the baseline year and baseline emissions of 289 tons per year (tpy). Future potential emissions are estimated based on the BACT limit of 0.3 pounds per million British thermal units (lb/MMBtu) proposed in the PSD amendment and the potential heat input capacity of the boiler of 595.6 MMBtu per hour (MMBtu/hr). This calculates to 782 tpy for the proposed potential emissions. Therefore, the net emission increase is 782 minus 289 or 493 tpy.

The stack parameters for Power Boiler No. 7 are provided in Table 2-1 below. Emissions exhaust through two stacks with emissions split evenly between them.

---

[1] U.S. EPA, Office of Air Quality Planning and Standards, *New Source Review Workshop Manual, Draft* (Research Triangle Park, NC: October, 1990), p. C-24.

[2] Code of Federal Regulations, Title 40–Protection of Environment, Part 51, Appendix W, July 1, 1999.

TABLE 2-1. POWER BOILER NO. 7 STACK PARAMETERS

Source ID	Source Description	Release Height (m)	Exit Temp. (K)	Exit Velocity (m/sec)	Stack Diameter (m)
PB7a	Power Boiler No.7 Stack A	53.64	494.3	24.84	2.06
PB7b	Power Boiler No.7 Stack B	53.64	494.3	24.84	2.06

Source locations and elevations are shown in Table 2-2.

TABLE 2-2. POWER BOILER NO. 7 STACK LOCATION AND ELEVATION

Source ID	UTM-X(1) (m)	UTM-Y(1) (m)	Stack Elevation (m)
PB7a	543,414.0	5,234,724.0	1.45
PB7b	543,417.0	5,234,719.2	1.45

(1) UTM zone 10, NAD 27 horizontal datum.

2.2 FULL IMPACT ANALYSIS

If the proposed emissions increase is shown to have a significant impact (i.e., predicted ambient concentrations exceed the SILs), a Full Impact Analysis is conducted as discussed below. The Full Impact Analysis includes emissions from the proposed project along with nearby surrounding sources.

2.2.1 NATIONAL AMBIENT AIR QUALITY STANDARD ANALYSIS

The NAAQS are maximum concentration ceilings measured in terms of the total ground level, ambient concentration of a pollutant at a particular location open to the atmosphere. Emissions from nearby surrounding sources are modeled with potential emission from all NO_X sources at the Simpson Tacoma Kraft facility in the Full Impact Analysis. Ecology provided actual emissions from the 2006 and 2007 emissions inventory. However, maximum allowable emissions from each source should be used in the NAAQS Analysis. Maximum allowable emissions are estimated from the actual emission by taking the maximum of 2006 and 2007 emissions and multiplying by three.[3] A representative background concentration is added to the model results for comparison to the appropriate NAAQS as discussed in Section 2.2.5 below. The emission rates and stack parameters for the NO_X sources are discussed in Sections 2.2.3 and 2.2.4 below.

2.2.2 PSD INCREMENT ANALYSIS

The PSD Increment Standard is the maximum allowable increase in pollutant concentration over a baseline concentration. For the PSD Increment Analysis the change in actual concentration between the current and baseline period is calculated. The two-year average actual emissions from the 2006 and 2007 emissions inventory are modeled to determine the

[3] Approved by Washington Department of Ecology in an email dated November 30, 2009.

current concentration. The baseline concentration is defined as the ambient concentration that existed at the baseline date. The baseline date is February 8, 1988 for major sources and March 26, 1990 for minor sources. The actual emissions from the 1988 emissions inventory for major sources and 1990 emissions inventory for minor sources are modeled to determine the baseline concentration. The baseline concentration is subtracted from the current concentration to determine the change in concentration for comparison with the PSD Increment Standard. The emission rates and stack parameters for the NO_X sources are discussed in Sections 2.2.3 and 2.2.4 below.

2.2.3 SIMPSON TACOMA KRAFT SOURCES

The allowable, actual, and baseline emission rates for Simpson Tacoma Kraft sources are provided in Table 2-3 below. Allowable emissions are used for the NAAQS analysis and the two year average actual (2007 and 2008) and 1988 baseline emissions are used for the PSD Increment analysis. Baseline emissions are zero for any sources that did not exist in the baseline year. Allowable and 2-year average actual emissions are zero for any sources that have been removed since the baseline year.

TABLE 2-3. NO_X EMISSIONS FOR SIMPSON TACOMA KRAFT SOURCES

Source Description	Allowable (tpy)	2-year Average Actual (tpy)	1988 Baseline (tpy)
Power Boiler No. 7 Stack A	391	NA	NA
Power Boiler No. 7 Stack B	391	NA	NA
Recovery Boiler No. 4	515	292	273
Smelt Tank No. 4 East	6	5	NA
Smelt Tank No. 4 West	6	5	NA
Lime Kiln No. 1	76	38	6
Lime Kiln No. 2	4	2	5
Boiler No. 6	146	48	192
Recovery Boiler No. 3	NA	NA	14
Boiler No. 1 Stack	NA	NA	37
Boiler No. 2	NA	NA	127
Boiler No. 3-5	NA	NA	280

Typical dispersion modeling allows for emissions units to be represented as point, area, line, or volume sources. Because all of the emissions points associated with this modeling analysis are stacks, they are represented as point sources in the dispersion model. The stack parameters for each source are provided in Table 2-4.

TABLE 2-4. STACK PARAMETERS FOR SIMPSON TACOMA KRAFT SOURCES

Source ID	Source Description	Release Height (m)	Exit Temp. (K)	Exit Velocity (m/sec)	Stack Diameter (m)
Current Sources					
PB7a	Power Boiler No. 7 Stack A	53.64	494.3	24.84	2.06
PB7b	Power Boiler No. 7 Stack B	53.64	494.3	24.84	2.06
RB4	Recovery Boiler #4	83.82	470.9	10.75	4.27
SDT4E	Smelt Tank No. 4 East	63.40	335.4	16.42	1.22
SDT4W	Smelt Tank No. 4 West	63.40	335.4	16.42	1.22
LK1	Lime Kiln No. 1	37.49	342.0	14.80	1.22
LK2	Lime Kiln No. 2	37.80	322.6	3.64	1.22
PB6	Boiler No. 6	36.58	400.9	37.16	1.83
Baseline Sources					
BASERB3	Recovery Boiler No. 3	37.49	344.7	18.7	2.90
BASERB4	Recovery Boiler No. 4	83.82	439.1	11.5	4.27
BASELK1	Lime Kiln No. 1	37.49	346.3	15.0	1.37
BASELK2	Lime Kiln No. 2	37.80	339.7	6.8	1.22
BASEPB1	Boiler No. 1	32.00	406.3	9.4	1.37
BASEPB2	Boiler No. 2	48.16	344.1	7.4	2.29
BASEPB35	Boiler No. 3-5	48.16	341.3	14.3	2.59
BASEPB6	Boiler No. 6	36.58	435.2	12.2	1.98

Source locations and elevations are shown in Table 2-5.

TABLE 2-5. SIMPSON TACOMA KRAFT SOURCES' LOCATION AND ELEVATION

Source ID	UTM-X(1) (m)	UTM-Y(1) (m)	Stack Elevation (m)
PB7a	543,414.0	5,234,724.0	1.45
PB7b	543,417.0	5,234,719.2	1.45
RB4	543,358.9	5,234,820.5	1.45
SDT4E	543,408.0	5,234,786.4	1.45
SDT4W	543,390.0	5,234,776.0	1.45
LK1	543,490.2	5,234,670.8	1.45
LK2	543,513.9	5,234,648.9	1.45
PB6	543,426.1	5,234,705.1	1.45
BASERB3	543,396.5	5,234,761.5	1.45
BASEPB1	543,467.2	5,234,683.6	1.45
BASEPB2	543,439.0	5,234,724.1	1.45
BASEPB35	543,439.0	5,234,724.1	1.45

(1) UTM Zone 10, NAD 27 horizontal datum.

A plot showing the NO_X sources with the buildings and property fenceline is provided in Figure 1.

2.2.4 NEARBY SOURCES

A list of Washington sources was provided by the Washington Department of Ecology from their 2006 and 2007 emissions inventories. The sources are screened to determine which sources have the potential to significantly influence concentrations within the SIA using the following procedure:

1. Sources that are located greater than 57.8 km (SIA + 50 km) from the Simpson Tacoma Kraft facility are eliminated. If the latitude and longitude location for the nearby source is missing, the coordinates are estimated using the source's street address and Google Earth.
2. Estimate the significant impact distance of each nearby source. Model a generic stack that is representative of a combustion source in SCREEN3 with the following parameters:

   Height: 25 ft (7.6 m)
   Diameter: 2 ft (0.61 m)
   Velocity: 33 ft/s (10 m/s)
   Temperature: 350 ˚F (450 K)

   Calculate the annual emissions threshold that would cause a significant impact at various distances using the SCREEN3 results. The results from SCREEN3 and the calculations are shown in Table 2-6 below. Match the facility-wide emissions of the nearby source to the threshold in the table to estimate the significant impact distance of that source.

TABLE 2-6. ESTIMATED SIGNIFICANT IMPACT DISTANCE VERSUS NO_X EMISSION RATE

Significant Impact Distance (meters)	NO_X Emissions (tpy)	Significant Impact Distance (meters)	NO_X Emissions (tpy)	Significant Impact Distance (meters)	NO_X Emissions (tpy)
100	4.66	2,400	11.16	13,000	34.85
200	4.94	2,500	11.19	14,000	37.59
300	5.41	2,600	11.24	15,000	40.35
400	5.91	2,700	11.30	16,000	43.07
500	6.57	2,800	11.38	17,000	45.80
600	7.27	2,900	11.47	18,000	48.56
700	7.95	3,000	11.57	19,000	51.34
800	8.66	3,500	12.33	20,000	54.13
900	9.37	4,000	13.20	22,000	59.78
1,000	10.22	4,500	14.15	24,000	65.48
1,100	10.85	5,000	15.15	26,000	71.26
1,200	11.54	5,500	16.20	28,000	77.09
1,300	12.29	6,000	17.28	30,000	82.97
1,400	12.86	6,500	18.41	32,000	88.73
1,500	12.76	7,000	19.56	34,000	94.50
1,600	12.60	7,500	20.75	36,000	100.33
1,700	12.13	8,000	21.96	38,000	106.16
1,800	11.77	8,500	23.19	40,000	112.02
1,900	11.49	9,000	24.43	42,000	117.92
2,000	11.28	9,500	25.68	44,000	123.83
2,100	11.21	10,000	26.94	46,000	129.79
2,200	11.17	11,000	29.52	48,000	135.71
2,300	11.16	12,000	32.16	50,000	141.73

3. Eliminate sources that are not significant. If the significant impact distance of the nearby source intersects the SIA, the nearby source is included in the full impact analysis.

Actual NO_X emissions from the inventory are used for the PSD Increment analysis. As stated in Section 2.2.1 and approved by Washington Department of Ecology, actual NO_X emissions are multiplied by 3 to estimate maximum emissions for use in the NAAQS analysis. Baseline sources for the PSD Increment Analysis are screened in the same way, using actual emissions from 1990 for minor sources and 1988 for major sources.

The same generic stack parameters listed above will be used for any nearby sources with missing stack parameters in the inventory. Elevations for each source were obtained using AERMAP (version 09040) and terrain elevations from the National Elevation Dataset.

The screening calculations for the nearby sources are shown in Appendix B. The emission rates and stack parameters for each competing source included in the full impact analysis is

also provided in Appendix B. A plot showing the location of the nearby sources and surrounding terrain is provided in Figure 2.

2.2.5 BACKGROUND CONCENTRATION

An ambient background concentration is added to the concentration predicted by the dispersion model for comparison with the NAAQS. Nitrogen dioxide (NO_2) data is collected on Beacon Hill in Seattle, Washington. The measured concentration was 28 $\mu g/m^3$ on an annual average period in 2008.

2.3 NO_X TO NO_2

The Ambient Air Quality Objectives set a limit on the concentration of NO_2. The modeling analysis is based on emissions of total NO_X, which includes both NO and NO_2. NO_2 concentrations are conservatively calculated assuming 75% conversion of NO_X to NO_2.[4]

[4] 40 CFR 51, App. W, Section 5.2.4

Modeling results are shown in Table 3-1 and concentration contour plots are provided in Figure 3. Table 3-1 also lists SILs and monitoring *de minimus* levels for comparison with the predicted concentration. As shown, the predicted concentration exceeds the SIL for the annual averaging period. The predicted concentration is below the annual monitoring *de minimis* of 14 $\mu g/m^3$ and, therefore, the new proposed emission limits do not affect applicability of pre-construction monitoring requirements. A SIL and monitoring *de minimus* has not been promulgated for the 1-hour NO_X standard.

The concentration contour plot (Figures 3) shows the SIA and the location of the maximum predicted concentration occurring approximately 750 meters south of Power Boiler No. 7 within the extents of the fine receptor grid. The receptors showing exceedances of SILs extend up to 7.8 km to the south of the facility to the edge of the coarse receptor grid. The coarse grid was extended to the south by two kilometers to ensure the entire SIA was captured. No additional significant receptors are identified in the extended coarse grid.

Table 3-1. NO_2 Significant Impact Analysis Results

Averaging Period	Date	UTM East (km)	UTM North (km)	Maximum Concentration ($\mu g/m^3$)	SIA (km)	SIL ($\mu g/m^3$)	Monitoring *De Minimis* ($\mu g/m^3$)
Annual	2002	543.200	5,234.000	2.9(1)	7.8	1	14 (1)
1-Hour	--	--	--	38.0(2)	9.3	7.5(3)	--

(1) Annual arithmetic mean.
(2) 5-year average of the 98th percentile of the daily maximum 1-hour average.
(3) Proposed interim SIL.

All input and output files are provided on the CD in Appendix C.

As shown in Table 3-1 of Section 3, proposed project emissions are shown to have predicted ambient concentration that exceeds the annual SIL for NO_2. Therefore, a Full Impact Analysis is conducted for NO_2. NO_2 emissions from all Simpson Tacoma Kraft sources are modeled with nearby sources that are considered to influence NO_2 concentrations within the SIA.

4.1 NAAQS RESULTS

Results of the NAAQS analysis are provided in Table 4-1 below. As shown, the total predicted concentration from proposed and nearby sources plus the background concentration is below the NAAQS. The maximum predicted concentration occurs on the northeastern facility fenceline. The main sources contributing to the maximum concentration is Power Boiler No. 7. A concentration contour plot is provided in Figure 4.

TABLE 4-1. NAAQS ANALYSIS RESULTS

Averaging Period	Year of Maximum	UTM East (km)	UTM North (km)	Modeled Concentration ($\mu g/m^3$)	Background ($\mu g/m^3$)	Total Concentration ($\mu g/m^3$)	NAAQS ($\mu g/m^3$)
Annual	2002	543,422.8	5,234,842	43.3	28	71.3	100(1)
1-hour	--	--	--	38.0	110	148	191(2)

(1) Annual arithmetic mean.

(2) 3-year average of the 98th percentile of the daily maximum 1-hour average.

4.2 PSD INCREMENT RESULTS

Results of the PSD Increment analysis for NO_X are provided in Table 4-2 below. As shown, the total predicted concentration is below the PSD Increment standard. The maximum predicted concentration occurs on the northeastern facility fenceline. The main sources contributing to the maximum concentration is Power Boiler No. 7. A concentration contour plot is provided in Figure 5.

TABLE 4-2. PSD INCREMENT ANALYSIS RESULTS

Year of Maximum	UTM East (km)	UTM North (km)	Modeled Concentration ($\mu g/m^3$)	PSD Increment ($\mu g/m^3$)
2002	543,422.8	5,234,842	22.9	25(1)

(1) Annual arithmetic mean.

All input and output files are provided in Appendix C.

FIGURES

FIGURE 1. SIMPSON TACOMA KRAFT NO_X SOURCES

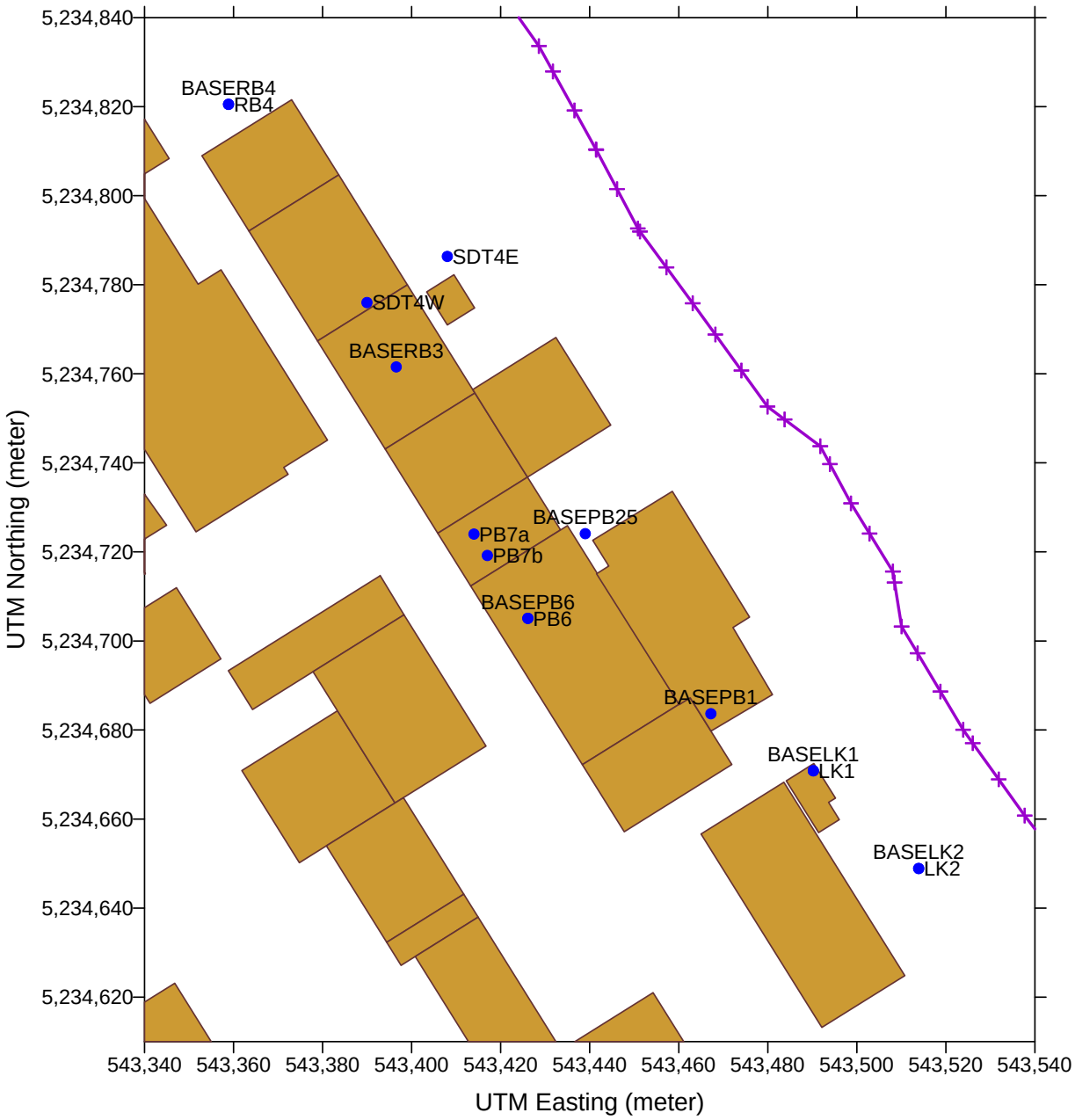
FIGURE 2. NEARBY NO_X SOURCES

FIGURE 3. SIGNIFICANCE ANALYSIS ANNUAL NO_2

FIGURE 4. SIGNIFICANCE ANALYSIS 1-HOUR NO_2

FIGURE 5. NAAQS ANALYSIS ANNUAL NO_2

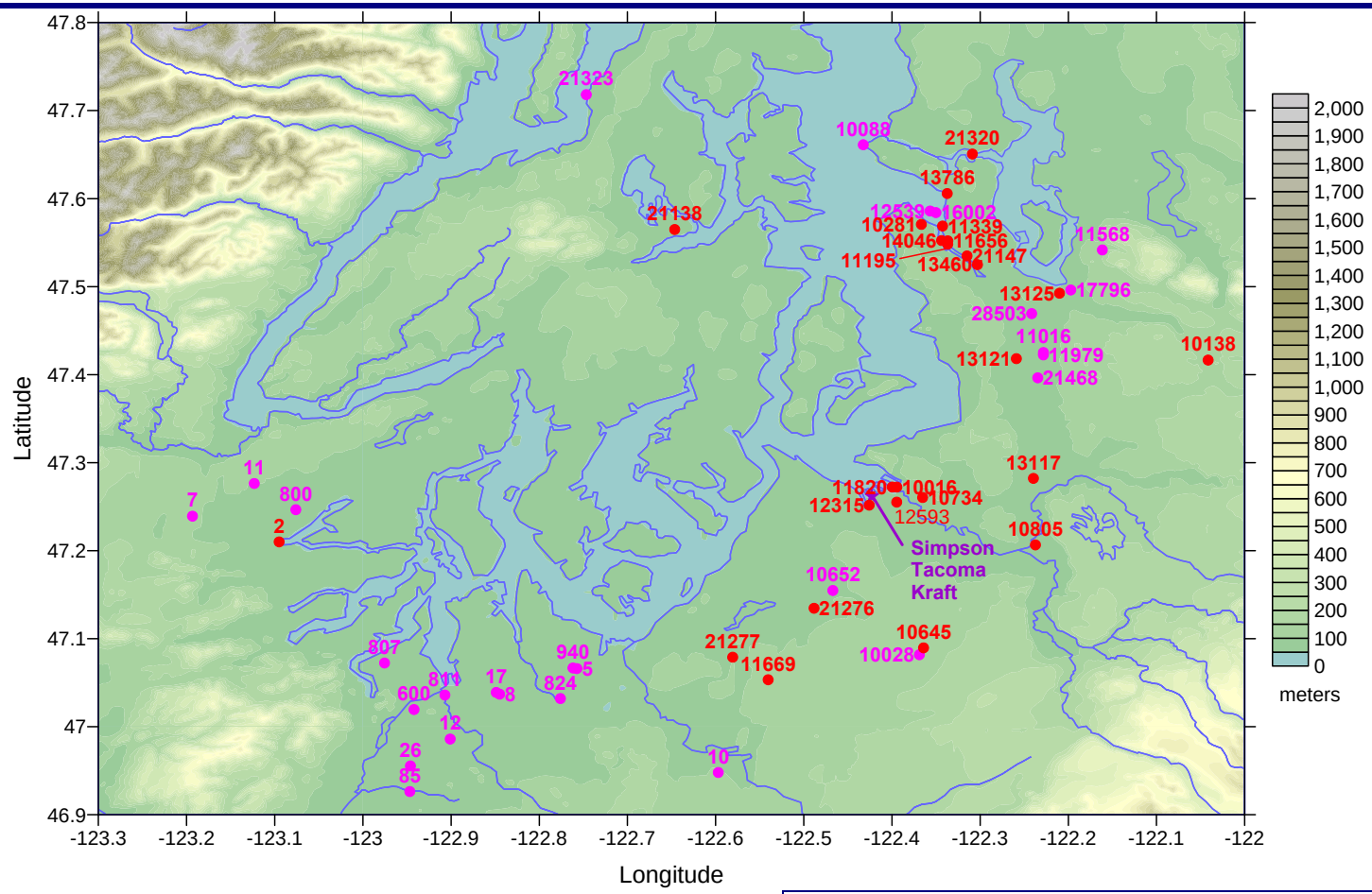
FIGURE 6. PSD INCREMENT ANALYSIS ANNUAL NO_2



UTM ZONE 10, NAD 27

SLR

Report PSD AMENDMENT AIR QUALITY ANALYSIS SIMPSON TACOMA KRAFT TACOMA, WA			
Drawing SIMPSON TACOMA KRAFT NOX SOURCES			
Date August 2010	Scale AS SHOWN		Fig. No.
File Name Simpson.srf	Project No. 108.00217.00024		1



UTM ZONE 10, NAD 27

Significant Nearby Source of NOX

Nearby Source of NOX

SLR

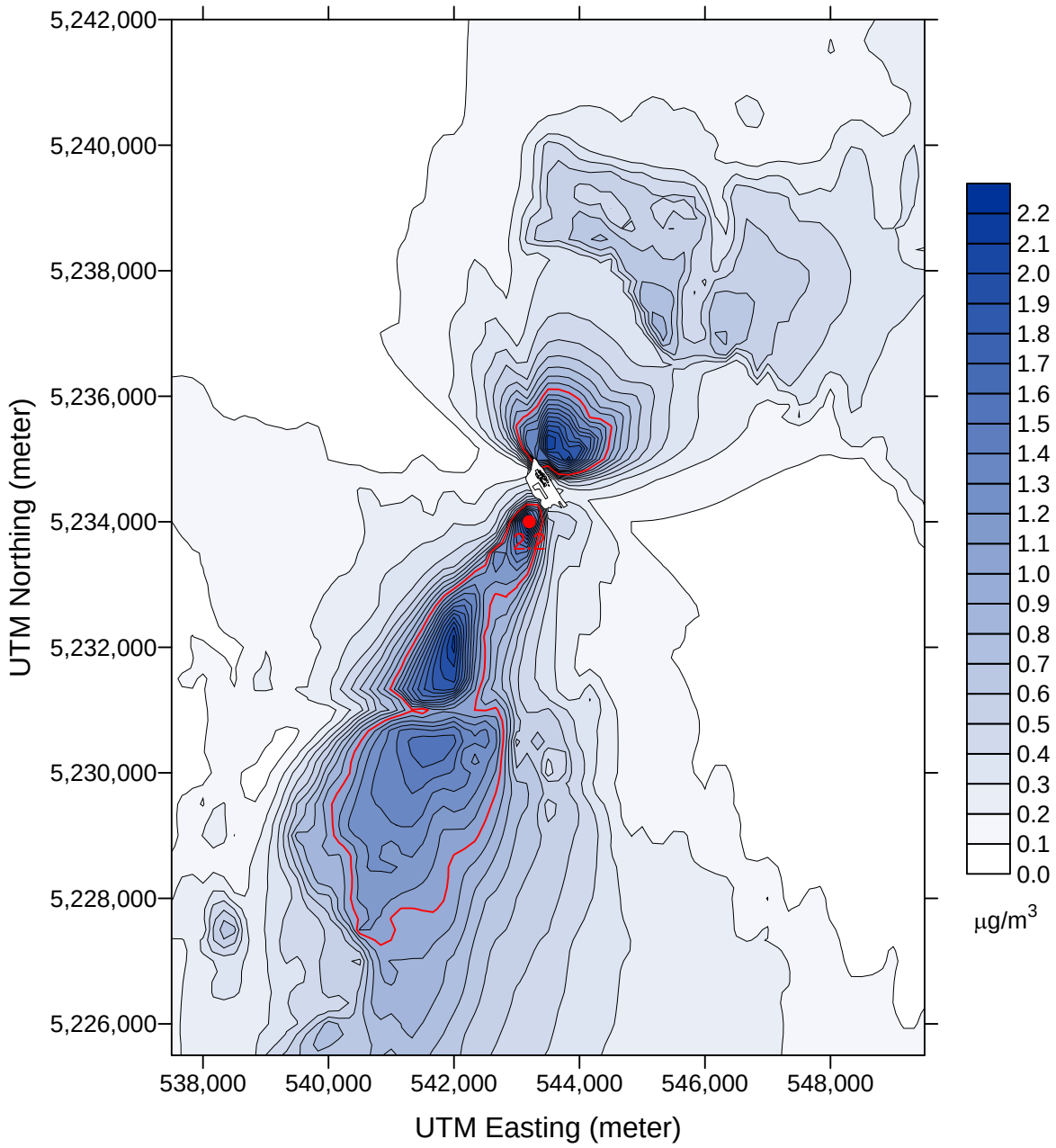
Report

PSD AMENDMENT NO_2 AIR QUALITY ANALYSIS
SIMPSON TACOMA KRAFT
TACOMA, WA

Drawing

NEARBY NOX SOURCES

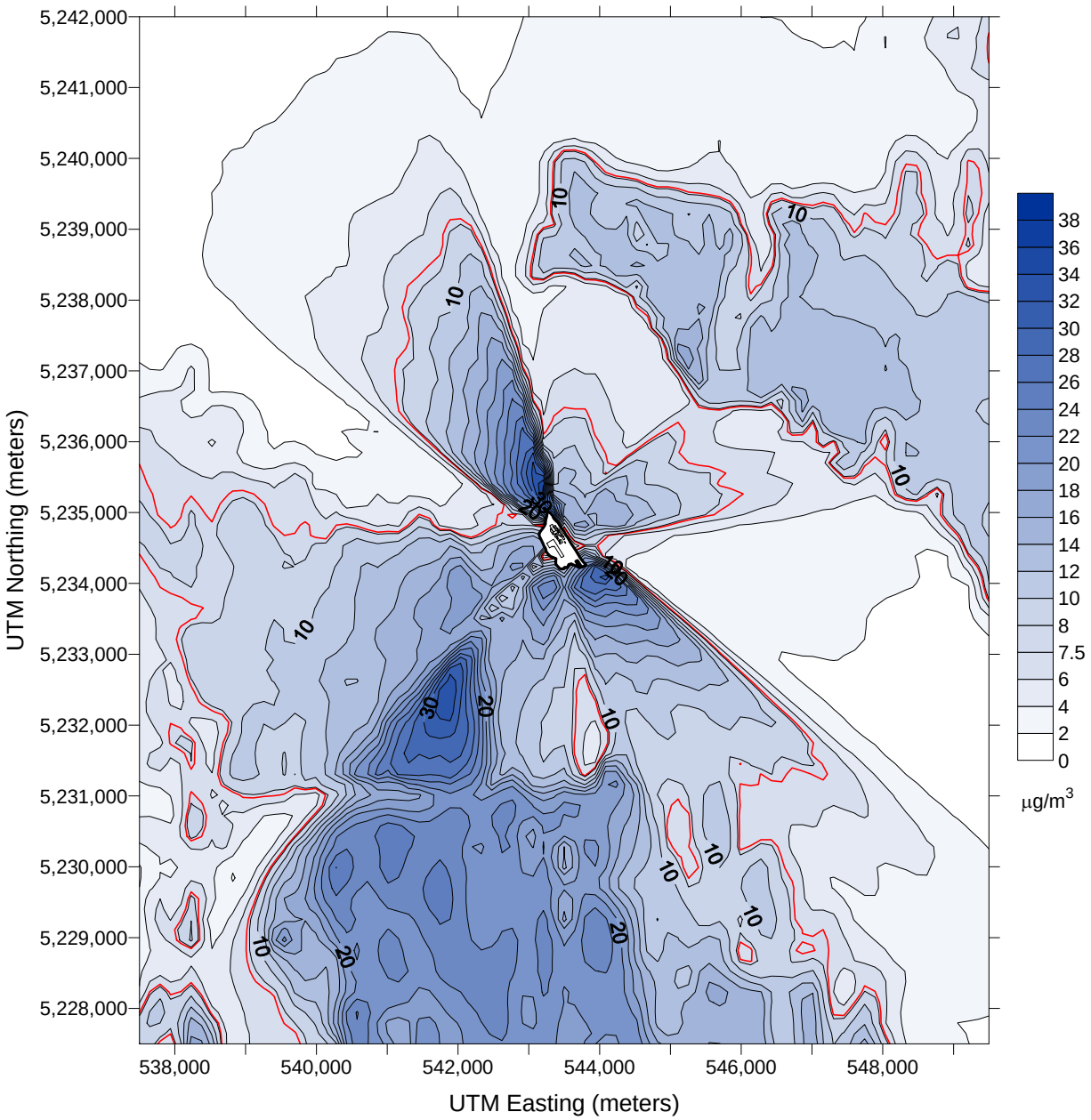
Date August 2010	Scale AS SHOWN	Fig. No.
File Name Nearby.srf	Project No. 108.00217.00024	2



UTM ZONE 10, NAD 27

SLR

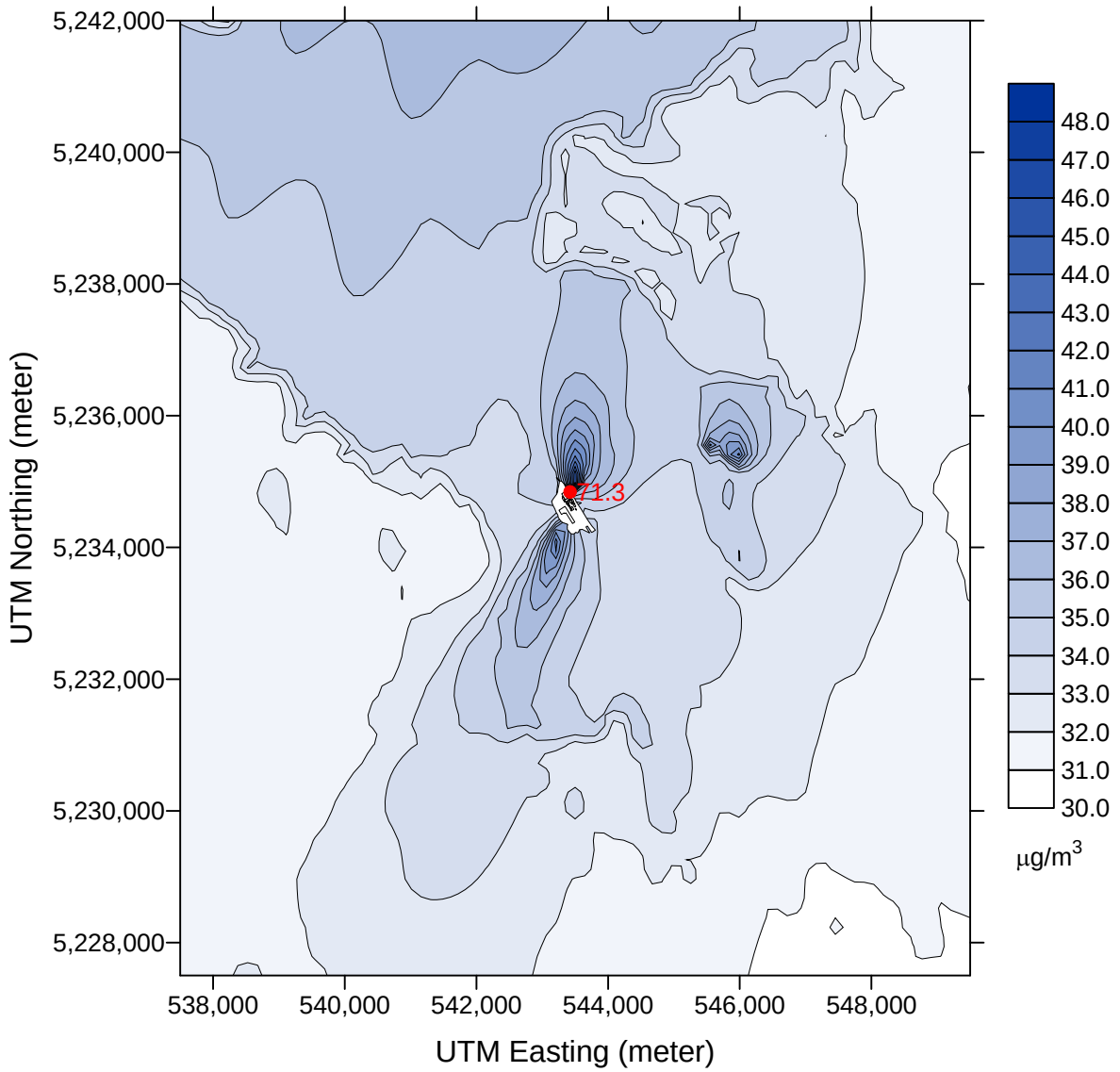
Report PSD AMENDMENT NO_2 AIR QUALITY ANALYSIS SIMPSON TACOMA KRAFT TACOMA, WA		
Drawing SIGNIFICANCE ANALYSIS ANNUAL NO2		
Date August 2010	Scale AS SHOWN	Fig. No.
File Name Significance.srf	Project No. 108.00217.00024	3



UTM ZONE 10, NAD 27

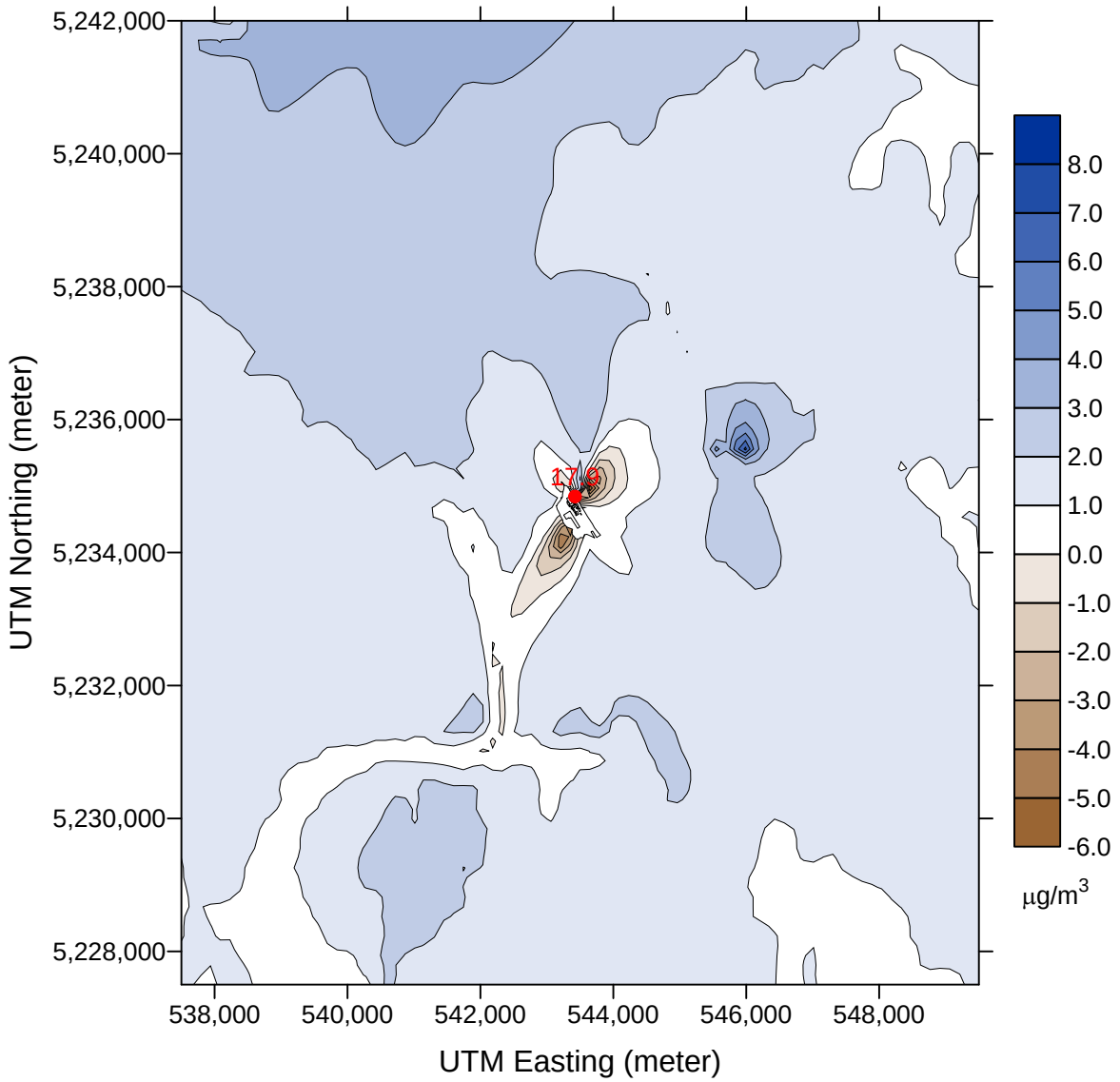
SLR

Report PSD AMENDMENT NO_2 AIR QUALITY ANALYSIS SIMPSON TACOMA KRAFT TACOMA, WA			
Drawing SIGNIFICANCE ANALYSIS 1-HOUR NO2			
Date August 2010	Scale AS SHOWN		Fig. No.
File Name Significance.srf	Project No. 108.00217.00024		4



UTM ZONE 10, NAD 27

Report PSD AMENDMENT NO_2 AIR QUALITY ANALYSIS SIMPSON TACOMA KRAFT TACOMA, WA		
Drawing NAAQS ANALYSIS ANNUAL NO2		
Date August 2010	Scale AS SHOWN	Fig. No.
File Name NAAQS.srf	Project No. 108.00217.00024	5



UTM ZONE 10, NAD 27

SLR

Report PSD AMENDMENT NO_2 AIR QUALITY ANALYSIS SIMPSON TACOMA KRAFT TACOMA, WA		
Drawing PSD INCREMENT ANALYSIS ANNUAL NO2		
Date August 2010	Scale AS SHOWN	Fig. No.
File Name PSD.srf	Project No. 108.00217.00024	6

APPENDIX A

DETAILED EMISSION CALCULATIONS

PSD Amendment for Power Boiler #7
NO_2 Air Quality Analysis
Simpson Tacoma Kraft Company
801 Portland Avenue
Tacoma, WA 98421

August 2010
Project: 108.00217.00024

Table 1. Potential NOx Emissions
Power Boiler No. 7 PSD Amendment NO2 Air Quality Analysis
Simpson Tacoma Kraft, Tacoma, WA

Emission Unit	Potential Rate	NOx Emission Factor			Potential NOx Emissions (tons/yr)	Reference
Recovery Boiler #4	675,250 ton BLS/yr	1.52E+00	lb/ton BLS	(1)	515	Title V Enforceable Limit
Smelt Tank #4 East & West	675,250 ton BLS/yr	3.30E-02	lb/ton BLS	(2)	11	Maximum Production & NCASI
Lime Kiln #1	89,409 ton CaO/yr	1.69E+00	lb/ton CaO	(3)	76	95% of Maximum Production & NCASI
Lime Kiln #2	4,706 ton CaO/yr	1.69E+00	lb/ton CaO	(3)	4	5% of Maximum Production & NCASI
Boiler #6	250 MMBtu/hr	4.70E+01	lb/1,000 gal	(4)	146	NOC Limit & AP-42
Power Boiler #7	595.4 MMBtu/hr	3.00E-01	lb/MMBtu	(5)	782	Proposed BACT Limit

Assumptions:

Total Kraft Mill Capacity (ADUT/day) =	1,146	(6)
Recovery Boiler #4 Capacity (ton BLS/day) =	1,850	(6)
Boiler #6 Capacity (lb steam/yr) =	210,000	(6)
Boiler #6 Steam Limit (lb steam/yr) =	782,000,000	(7)
Conversion Factor 1 (ADTP/ADUT) =	1	(6)
Conversion Factor 2 (lb CaO/ADTP) =	450	(6)
Conversion Factor 3 (lb BLS/ADTP) =	3,300	(6)
Heating Value (MMBtu/1,000 gal) =	150	(8)

Notes:

(1) Emission factors were obtained from NCASI's Handbook of Environmental Regulations and Control. Volume 1: Pulp and Paper Manufacturing, Chapter 6: Chemical Recovery Processes, Table 6.5.3.9-1 & Table 6.5.3.10-1, September 1, 2008.
(2) Emission factors were obtained from NCASI's Handbook of Environmental Regulations and Control. Volume 1: Pulp and Paper Manufacturing, Chapter 6: Chemical Recovery Processes, Table 6.5.4.3-1 & Table 6.5.4.4-1, September 1, 2008.
(3) Emission factors were obtained from NCASI's Handbook of Environmental Regulations and Control. Volume 1: Pulp and Paper Manufacturing, Chapter 6: Chemical Recovery Processes, Table 6.5.6-1, September 1, 2008. Mean value for Lime Kilns firing natural gas (worst-case between gas and oil).
(4) Emission factors were obtained from EPA's AP-42, Section 1.3, September 1998, Table 1.3-1, Criteria Pollutant Emission Factor for Fuel Oil Combustion. Boiler > 100 MMBtu/hr, No.6 Oil Fired, Normal Firing.
(5) Proposed BACT limit.
(6) Provided by Simpson Tacoma Kraft.
(7) NOC Order 4153-AQ07, Appendix A.
(8) Heating Value from AP-42.

Table 2. Actual NOx Emissions
Power Boiler No. 7 PSD Amendment NO2 Air Quality Analysis
Simpson Tacoma Kraft, Tacoma, WA

Emission Unit	2007 Actual NO_X Emissions (tons/yr)	2008 Actual NO_X Emissions (tons/yr)	2-Year Average Emissions (tons/yr)
Recovery Boiler #4	281	303	292
Smelt Tank #4 East & West	9	9	9
Lime Kiln #1	39	37	38
Lime Kiln #2	2	2	2
Boiler #6	46	50	48
Power Boiler #7	331	283	307

APPENDIX B

NEARBY SOURCES

PSD Amendment for Power Boiler #7
NO_2 Air Quality Analysis
Simpson Tacoma Kraft Company
801 Portland Avenue
Tacoma, WA 98421

August 2010
Project: 108.00217.00024

Table 1. 2006 Nearby Sources Screening
Power Boiler No. 7 PSD Amendment Request NO2 Air Quality Analysis
Simpson Tacoma Kraft, Tacoma, Washington

FIPS County Code	Source ID	Facility Name	UTM X	UTM Y	Distance to SIA (m)	Screening for PSD Increment Analysis			Screening for NAAQS Analysis		
						Total NO_X Emissions (tpy)	Significant Impact Distance (m)	Significant Source? (1) (Yes/No)	Total NO_X Emissions x 3 (tpy)	Significant Impact Distance (m)	Significant Source? (1) (Yes/No)
033	10088	King Co Ntrl Res Wastewater Treatment	542,700	5,278,600	36,092	126	46,000	**Yes**	378	>50,000	**Yes**
033	10138	King Co Solid Waste Op Sec Cedar Hills	572,400	5,251,700	25,802	64	24,000	No	192	>50,000	**Yes**
033	10281	Nucor Steel Seattle Inc	547,730	5,268,580	26,341	184	>50,000	**Yes**	552	>50,000	**Yes**
033	11016	Hexcel Corporation	558,300	5,252,500	15,396	2	100	No	6	500	No
033	11195	BPB Gypsum Inc, Washington	550,000	5,266,100	24,270	43	16,000	No	129	46,000	**Yes**
033	11339	Ash Grove Cement Co, E Marginal	549,540	5,268,390	26,429	1,329	>50,000	**Yes**	3,987	>50,000	**Yes**
033	11568	Mutual Materials Co, Newcastle	563,200	5,265,500	28,798	9	900	No	27	11,000	No
033	11656	Saint-Gobain Containers Inc	550,000	5,266,520	24,682	418	>50,000	**Yes**	1,254	>50,000	**Yes**
033	11979	Hytek Finishes Co	558,300	5,252,200	15,167	2	100	No	6	500	No
033	13117	Boeing Commercial Airplane Auburn	557,600	5,236,600	6,520	86	32,000	**Yes**	258	>50,000	**Yes**
033	13125	Boeing Commercial Airplane Renton	559,600	5,260,000	22,225	36	14,000	No	108	40,000	**Yes**
033	13460	Jorgensen Forge Corp	552,560	5,263,540	22,443	40	15,000	No	120	44,000	**Yes**
033	13786	Seattle Steam Co, Western	549,900	5,272,500	30,539	217	>50,000	**Yes**	651	>50,000	**Yes**
033	14046	Lafarge North America Inc	549,470	5,266,560	24,618	2,201	>50,000	**Yes**	6,603	>50,000	**Yes**
033	16002	Kinder Morgan Liquids Terminal, LLC	548,960	5,270,080	27,999	1	100	No	3	100	No
033	17796	Kenworth Truck Co - Renton	560,560	5,260,420	23,102	7	600	No	21	8,000	No
033	21147	Boeing Commercial Airplane NBF Plant 2	551,660	5,264,640	23,242	31	12,000	No	93	34,000	**Yes**
033	21320	Washington University of Power Plant & Hospital	552,000	5,277,500	35,840	51	19,000	No	153	>50,000	**Yes**
033	21408	Seattle-Tacoma International Airport	552,295	5,254,402	13,799	31	12,000	No	93	34,000	**Yes**
033	21468	Rexam Beverage Can Co	557,850	5,249,300	12,726	4	100	No	12	1,700	No
033	28503	King Co Ntrl Res Wastewater Treatment	557,250	5,257,400	18,775	2	100	No	6	500	No
035	21138	Naval Base Kitsap at Bremerton	526,694	5,267,803	29,275	68	26,000	No	204	>50,000	**Yes**
035	21323	US Naval Base Kitsap at Bangor	519,096	5,284,802	47,881	34	13,000	No	102	38,000	No
045	0002	Simpson Timber Co	492,901	5,228,307	43,129	65	24,000	No	195	>50,000	**Yes**
053	10016	Georgia-Pacific Gypsum LLC	545,895	5,235,402	0	67	26,000	**Yes**	201	>50,000	**Yes**
053	10028	Puget Sound Energy, Frederickson	548,000	5,214,250	13,192	11	2,300	No	33	13,000	No
053	10348	Microchip Technology Incorporated	554,800	5,222,400	8,989	1	100	No	3	100	No
053	10645	Frederickson Power LP	548,351	5,215,119	12,427	30	12,000	No	90	34,000	**Yes**
053	10652	Tucci & Sons Inc McChord	540,495	5,222,302	4,971	4	100	No	12	1,700	No
053	10734	Tucci & Sons Inc Taylor Way	548,119	5,234,103	0	2	100	**Yes**	6	500	**Yes**
053	11669	Rainier Veneer Inc	535,000	5,211,000	17,382	23	8,500	No	69	26,000	**Yes**
053	11820	Graymont Western US Inc	545,500	5,235,400	0	58	22,000	**Yes**	174	>50,000	**Yes**
053	12593	US Oil & Refining Co	545,900	5,233,500	0	125	46,000	**Yes**	375	>50,000	**Yes**
053	21277	US Army Fort Lewis DA Public Works	531,930	5,213,830	16,052	49	19,000	**Yes**	147	>50,000	**Yes**
067	0008	Crown Cork & Seal Co Inc	511,871	5,209,089	32,856	4	100	No	12	1,700	No
067	0010	Lasco Bathware	530,763	5,199,266	29,857	1	100	No	3	100	No
067	0012	Dart Container Corp Of Washington	507,624	5,203,415	39,763	3	100	No	9	900	No

FIPS County Code	Source ID	Facility Name	UTM X	UTM Y	Distance to SIA (m)	Screening for PSD Increment Analysis			Screening for NAAQS Analysis		
						Total NO_X Emissions (tpy)	Significant Impact Distance (m)	Significant Source? (1) (Yes/No)	Total NO_X Emissions x 3 (tpy)	Significant Impact Distance (m)	Significant Source? (1) (Yes/No)
067	0811	Central Steam Plant	507,161	5,208,971	36,680	5	300	No	15	5,000	No
067	0824	Weyerhaeuser - Lacey	517,039	5,208,546	29,371	20	7,500	No	60	24,000	No

Notes:

(1) The source is signficant if [Distance to SIA] is less than [Significant Impact Distance].

Table 2. 2007 Nearby Sources Screening
Power Boiler No. 7 PSD Amendment Request NO2 Air Quality Analysis
Simpson Tacoma Kraft, Tacoma, Washington

FIPS County Code	Source ID	Facility Name	UTM X	UTM Y	Distance to SIA (m)	Screening for PSD Increment Analysis			Screening for NAAQS Analysis		
						Total NO_X Emissions (tpy)	Significant Impact Distance (m)	Significant Source? (1) (Yes/No)	Total NO_X Emissions x 3 (tpy)	Significant Impact Distance (m)	Significant Source? (1) (Yes/No)
033	10088	King Co Ntrl Res Wastewater Treatment	542,700	5,278,600	36,092	33	13,000	No	99	36,000	No
033	10138	King Co Solid Waste Op Sec Cedar Hills	572,400	5,251,700	25,802	68	26,000	**Yes**	204	>50,000	**Yes**
033	10281	Nucor Steel Seattle Inc	547,730	5,268,580	26,341	178	>50,000	**Yes**	534	>50,000	**Yes**
033	11016	Hexcel Corporation	558,300	5,252,500	15,396	2	100	No	6	500	No
033	11195	CertainTeed Gypsum Manufacturing Inc	550,000	5,266,100	24,270	39	15,000	No	117	42,000	**Yes**
033	11339	Ash Grove Cement Co, E Marginal	549,540	5,268,390	26,429	1,205	>50,000	**Yes**	3,615	>50,000	**Yes**
033	11568	Mutual Materials Co, Newcastle	563,200	5,265,500	28,798	9	900	No	27	11,000	No
033	11656	Saint-Gobain Containers Inc	550,000	5,266,520	24,682	431	>50,000	**Yes**	1,293	>50,000	**Yes**
033	11979	Hytek Finishes Co	558,300	5,252,200	15,167	3	100	No	9	900	No
033	12539	Todd Pacific Shipyards Corp	548,460	5,270,280	28,123	1	100	No	3	100	No
033	13117	Boeing Commercial Airplane Auburn	557,600	5,236,600	6,520	76	28,000	**Yes**	228	>50,000	**Yes**
033	13121	Boeing Space Center	555,995	5,251,702	13,341	30	12,000	No	90	34,000	**Yes**
033	13125	Boeing Commercial Airplane Renton	559,600	5,260,000	22,225	31	12,000	No	93	34,000	**Yes**
033	13460	Jorgensen Forge Corp	552,560	5,263,540	22,443	44	17,000	No	132	48,000	**Yes**
033	13786	Seattle Steam Co, Western	549,900	5,272,500	30,539	215	>50,000	**Yes**	645	>50,000	**Yes**
033	14046	Lafarge North America Inc	549,470	5,266,560	24,618	2,805	>50,000	**Yes**	8,415	>50,000	**Yes**
033	16002	Kinder Morgan Liquids Terminal, LLC	548,960	5,270,080	27,999	1	100	No	3	100	No
033	17796	Kenworth Truck Co - Renton	560,560	5,260,420	23,102	5	300	No	15	5,000	No
033	21147	Boeing Commercial Airplane NBF Plant 2	551,660	5,264,640	23,242	28	11,000	No	84	32,000	**Yes**
033	21320	Washington University of Power Plant & Hospital	552,000	5,277,500	35,840	98	36,000	**Yes**	294	>50,000	**Yes**
033	21468	Rexam Beverage Can Co	557,850	5,249,300	12,726	4	100	No	12	1,700	No
033	28503	King Co Ntrl Res Wastewater Treatment	557,250	5,257,400	18,775	6	500	No	18	6,500	No
035	21138	Naval Base Kitsap at Bremerton	526,694	5,267,803	29,275	54	20,000	No	162	>50,000	**Yes**
035	21323	Naval Base Kitsap at Bangor	519,096	5,284,802	47,881	29	11,000	No	87	32,000	No
045	0002	Simpson Timber Co	492,901	5,228,307	43,129	60	24,000	No	180	>50,000	**Yes**
045	0007	Washington Corrections Center	485,467	5,231,568	50,243	2	100	No	6	500	No
045	0011	Ace Paving -Shelton	490,775	5,235,681	44,858	2	100	No	6	500	No
045	0800	Mason County Forest Products Llc	494,339	5,232,369	41,342	1	100	No	3	100	No
053	10016	Georgia-Pacific Gypsum LLC	545,895	5,235,402	0	70	26,000	**Yes**	210	>50,000	**Yes**
053	10028	Puget Sound Energy, Frederickson	548,000	5,214,250	13,192	10	1,000	No	30	12,000	No
053	10645	Frederickson Power LP	548,351	5,215,119	12,427	35	14,000	**Yes**	105	38,000	**Yes**
053	10652	Tucci & Sons Inc McChord	540,495	5,222,302	4,971	4	100	No	12	1,700	No
053	10734	Tucci & Sons Inc Taylor Way	548,119	5,234,103	0	1	100	**Yes**	3	100	**Yes**
053	10805	Sonoco Products Co Paper Div	557,855	5,228,202	8,056	9	900	No	27	11,000	**Yes**
053	11669	Rainier Veneer Inc	535,000	5,211,000	17,382	25	9,500	No	75	28,000	**Yes**
053	11820	Graymont Western US Inc	545,500	5,235,400	0	57	22,000	**Yes**	171	>50,000	**Yes**
053	12315	Simpson Lumber Company, LLC	543,545	5,233,102	0	1	100	**Yes**	3	100	**Yes**

FIPS County Code	Source ID	Facility Name	UTM X	UTM Y	Distance to SIA (m)	Screening for PSD Increment Analysis			Screening for NAAQS Analysis		
						Total NO_X Emissions (tpy)	Significant Impact Distance (m)	Significant Source? (1) (Yes/No)	Total NO_X Emissions x 3 (tpy)	Significant Impact Distance (m)	Significant Source? (1) (Yes/No)
053	12593	US Oil & Refining Co	545,900	5,233,500	0	129	46,000	**Yes**	387	>50,000	**Yes**
053	21276	US Air Force McChord Air Force Base	538,894	5,220,050	7,565	35	14,000	**Yes**	105	38,000	**Yes**
053	21277	US Army Fort Lewis DA Public Works	531,930	5,213,830	16,052	56	22,000	**Yes**	168	>50,000	**Yes**
067	0005	Lakeside Industries - Lacey	518,517	5,212,338	25,692	7	600	No	21	8,000	No
067	0008	Crown Cork & Seal Co Inc	511,871	5,209,089	32,856	4	100	No	12	1,700	No
067	0010	Lasco Bathware	530,763	5,199,266	29,857	3	100	No	9	900	No
067	0012	Dart Container Corp Of Washington	507,624	5,203,415	39,763	3	100	No	9	900	No
067	0017	Georgia Pacific Corrugated Llc	511,583	5,209,308	32,943	3	100	No	9	900	No
067	0026	Northwest Pipeline Gp	504,193	5,200,021	44,580	1	100	No	3	100	No
067	0085	Granite Northwest Inc	504,143	5,196,783	46,816	2	100	No	6	500	No
067	0600	Pepsi Northwest Beverages Llc	504,499	5,207,140	39,910	3	100	No	9	900	No
067	0807	Evergreen State College	501,957	5,213,009	39,010	6	500	No	18	6,500	No
067	0811	Central Steam Plant	507,161	5,208,971	36,680	6	500	No	18	6,500	No
067	0824	International Paper	517,115	5,208,546	29,317	21	8,000	No	63	24,000	No
067	0940	Thurston County Waste And Recovery Center - Landfill	518,182	5,212,407	25,895	14	4,500	No	42	16,000	No

Notes:
(1) The source is signficant if [Distance to SIA] is less than [Significant Impact Distance]

Table 3. Nearby Source Stack Parameters
Power Boiler No. 7 PSD Amendment Request NO2 Air Quality Analysis
Simpson Tacoma Kraft, Tacoma, Washington

Source Information					Stack Parameters							Notes
FIPS County Code	Source ID	Source Name	Emission Unit	Emission Unit ID	UTM-E (km)	UTM-N (km)	Base Elevation (m)	Stack Height (m)	Temp. (K)	Velocity (m/s)	Diameter (m)	Notes
033	10088	King Co Ntrl Res Wastewater Treatment	Internal Combustion--Elec Gener	1008811	542,700.1	5,278,600.2	3.12	7.62	449.8	69.5	0.41	
			Internal Combustion--Industrial	1008822	542,700.1	5,278,600.2	3.12	13.72	477.6	4.6	1.01	
			Internal Combustion Engines-Misc	1008831	542,700.1	5,278,600.2	3.12	9.14	1,074.8	1.1	1.22	
033	10138	King Co Solid Waste Op Sec Cedar Hills	Landfill Flare (5)	1013811	572,400.2	5,251,700.3	83.52	12.19	1,160.9	1.0	3.66	
033	10281	Nucor Steel Seattle Inc	Direct Arc Electric Arc Furnace	1028111	547,730.1	5,268,580.2	5.4	27.43	338.7	3.2	11.43	*
			Direct Arc Electric Arc Furnace	1028112	547,730.1	5,268,580.2	5.4	27.43	338.7	3.2	11.43	*
			Reheat Furnace	1028121	547,730.1	5,268,580.2	5.4	16.15	518.2	3.2	2.06	
033	11195	CertainTeed Gypsum Manufacturing Inc	In-Process Fuel Use	1119511	550,000.1	5,266,100.2	4.9	7.62	449.8	10.0	0.61	
033	11339	Ash Grove Cement Co, E Marginal	Clinker Handling And Storage	1133911	549,540.1	5,268,390.2	2.8	3.05	295.4	0.3	0.91	*
			Clinker Handling And Storage	1133912	549,540.1	5,268,390.2	2.8	3.05	295.4	0.3	0.91	*
033	11656	Saint-Gobain Containers Inc	Furnace #3	1165611	550,000.1	5,266,520.2	2.65	21.34	517.6	12.5	1.23	
			Furnace #4	1165621	550,000.1	5,266,520.2	2.65	17.37	477.6	13.2	1.02	
			Furnace #5	1165631	550,000.1	5,266,520.2	2.65	21.34	494.3	17.9	1.02	
			Furnace #2	1165641	550,000.1	5,266,520.2	2.65	21.34	577.6	12.4	0.74	
			Non-Furnace Natural Gas	1165671	550,000.1	5,266,520.2	2.65	7.62	449.8	10.0	0.61	*
			Other Diesel Combustion	1165681	550,000.1	5,266,520.2	2.65	7.62	449.8	10.0	0.61	*
033	13117	Boeing Commercial Airplane Auburn	Ext Comb Boilers-Commc'L/Instit	1311711	557,600.3	5,236,600.2	27.77	8.84	410.9	19.2	1.52	*
			Ext Comb Boilers-Commc'L/Instit	1311712	557,600.3	5,236,600.2	27.77	8.84	410.9	19.2	1.52	*
			Fabricated Metal Products	1311766	557,600.3	5,236,600.2	27.77	16.46	291.5	12.2	1.42	
			Internal Comb Engines-Comml/Inst	1311781	557,600.3	5,236,600.2	27.77	3.05	449.8	3.2	0.21	
033	13121	Boeing Space Center	Boilers	1312111	555,994.6	5,251,701.9	8.21	7.62	449.8	10.0	0.61	*
			Internal Comb Engines - Diesel	1312171	555,994.6	5,251,701.9	8.21	7.62	449.8	10.0	0.61	*
033	13125	Boeing Commercial Airplane Renton	External Comb Boilers-Industrial	1312513	559,600.2	5,260,000.2	9.65	14.02	430.4	3.1	1.52	*
			External Comb Boilers-Industrial	1312515	559,600.2	5,260,000.2	9.65	14.02	430.4	3.1	1.52	*
			Internal Combustion Emergency Generators	13125111	559,600.2	5,260,000.2	9.65	1.52	310.9	10.0	0.15	
033	13460	Jorgensen Forge Corp	Steel Casting with Baghouse	1346011	552,560.2	5,263,540.2	3.57	7.62	449.8	10.0	0.61	
			Natural Gas Combustion	1346021	552,560.2	5,263,540.2	3.57	9.14	313.7	97.4	1.83	
033	13786	Seattle Steam Co, Western	Riley	1378611	549,900.1	5,272,500.2	14.08	39.62	449.8	9.4	1.91	*
			Garrett & Shaffer	1378621	549,900.1	5,272,500.2	14.08	39.62	449.8	9.4	1.91	*
			Combustion Engineering - (D)	1378631	549,900.1	5,272,500.2	14.08	45.72	449.8	15.8	1.45	*
			Combustion Engineering - (D)	1378632	549,900.1	5,272,500.2	14.08	45.72	449.8	15.8	1.45	*
			Combustion Engineering - (D)	1378633	549,900.1	5,272,500.2	14.08	45.72	449.8	15.8	1.45	*
			Combustion Engineeering - (A)	1378641	549,900.1	5,272,500.2	14.08	45.72	449.8	9.4	1.91	
033	14046	Lafarge North America Inc	Cement Kiln	1404611	549,470.1	5,266,560.2	3.19	76.20	449.8	8.0	3.96	
			Slag Dryer	1404641	549,470.1	5,266,560.2	3.19	4.88	316.5	0.4	1.10	

Source Information					Stack Parameters							Notes
FIPS County Code	Source ID	Source Name	Emission Unit	Emission Unit ID	UTM-E (km)	UTM-N (km)	Base Elevation (m)	Stack Height (m)	Temp. (K)	Velocity (m/s)	Diameter (m)	Notes
033	21147	Boeing Commercial Airplane NBF Plant 2	External Comb Boilers - Indus	2114711	551,660.2	5,264,640.2	2.68	18.29	445.4	11.7	0.98	*
			Internal Combustion Emergency Generators	21147141	551,660.2	5,264,640.2	2.68	1.52	310.9	10.0	0.15	
			Internal Combustion Turbine	21147151	551,660.2	5,264,640.2	2.68	2.44	294.3	1.1	6.15	
			Ext Combustion Boilers-Indust	2114781	551,660.2	5,264,640.2	2.68	18.29	445.4	11.7	0.98	*
033	21320	Washington University of Power Plant & Hospital	External Combustion Stack	2132011	552,000.1	5,277,500.2	21.34	60.66	394.3	24.0	2.74	*
			External Combustion Stack	2132012	552,000.1	5,277,500.2	21.34	60.66	394.3	24.0	2.74	*
033	21408	Seattle-Tacoma International Airport	Fuel Oil Burned In Boilers	2140812	552,294.5	5,254,402.0	115.97	7.62	449.8	10.0	0.61	
035	21138	Naval Base Kitsap at Bremerton	External Combustion Boilers	2113811	526,693.6	5,267,802.8	29.68	91.74	435.9	9.5	1.74	*
			External Combustion Boilers	2113812	526,693.6	5,267,802.8	29.68	91.74	435.9	9.5	1.74	*
			External Combustion Boilers	2113813	526,693.6	5,267,802.8	29.68	91.74	435.9	9.5	1.74	*
			Internal Combustion Engines	2113821	526,693.6	5,267,802.8	29.68	7.62	602.6	10.0	0.61	*
			Internal Combustion Engines	2113822	526,693.6	5,267,802.8	29.68	7.62	602.6	10.0	0.61	*
045	0002	Simpson Timber Co	Boiler - Wood / Bark - EU1	000281	492,901.3	5,228,307.1	2.62	21.64	449.8	8.4	1.83	
053	10016	Georgia-Pacific Gypsum LLC	Dryer Stack 1	1001611a	545,926.0	5,235,233.0	2.75	10.67	466.5	10.3	0.91	Provided by Puget Sound Clean Air Agency.
			Dryer Stack 2	1001611b	545,908.0	5,235,237.0	2.7	10.67	510.9	10.6	0.91	
			Dryer Stack 3	1001611c	545,899.0	5,235,239.0	2.68	10.67	549.8	8.0	0.91	
			Dryer Stack 4a	1001611d	545,896.0	5,235,240.0	2.67	10.67	510.9	8.4	0.91	
			Dryer Stack 4b	1001611e	545,892.0	5,235,241.0	2.66	10.67	510.9	8.2	0.91	
			Dryer Stack 5a	1001611f	545,889.0	5,235,242.0	2.65	10.67	499.8	2.6	0.91	
			Dryer Stack 5b	1001611g	545,884.0	5,235,243.0	2.64	10.67	499.8	4.3	0.91	
			Dryer Stack 6	1001611h	545,862.0	5,235,248.0	2.57	10.67	422.0	9.8	0.91	
			Dryer Stack 7	1001611i	545,821.0	5,235,258.0	2.44	10.67	394.3	17.4	0.91	
			Imp Mill 1 Stack	1001611j	545,720.0	5,235,270.0	2.00	25.91	416.5	22.0	0.51	
			Imp Mill 2 Stack	1001611k	545,714.0	5,235,271.0	1.97	25.91	416.5	19.6	0.51	
			Imp Mill 3 Stack	1001611l	545,709.0	5,235,272.0	1.95	25.91	416.5	24.4	0.51	
			Imp Mill 4 Stack	1001611m	545,702.0	5,235,274.0	1.92	25.91	416.5	24.4	0.51	
			Imp Mill 5 Stack	1001611n	545,695.0	5,235,275.0	1.89	25.91	422.0	32.1	0.51	
			Imp Mill 6 Stack	1001611o	545,690.0	5,235,276.0	1.89	25.91	416.5	24.4	0.51	
			Imp Mill 7 Stack	1001611p	545,685.0	5,235,278.0	1.88	25.91	416.5	24.4	0.51	
			Imp Mill 8 Stack	1001611q	545,678.0	5,235,280.0	1.87	25.91	416.5	23.8	0.51	
			FGD Building NOC 8546	1001621	545,745.0	5,235,212.0	2.01	30.48	372.0	25.0	1.00	
053	10645	Frederickson Power LP	1-01-006-01External Combustion Boilers	1064511	548,350.9	5,215,119.2	126.31	32.00	355.4	16.5	5.49	
053	10734	Tucci & Sons Inc Taylor Way	Asphaltic Concrete	1073411	548,119.1	5,234,102.7	2.66	7.62	449.8	10.0	0.61	
053	10805	Sonoco Products Co Paper Div	Boilers	1080512	557,854.8	5,228,201.8	22.17	12.19	594.3	8.0	1.07	
053	11669	Rainier Veneer Inc	Wood Boiler Scrubber Stack	1166911	535,000.3	5,211,000.1	103.77	10.67	394.3	13.9	1.19	
053	11820	Graymont Western US Inc	Lime Manufacture	1182011	545,500.3	5,235,400.2	1.66	16.76	505.4	0.5	10.97	
053	12315	Simpson Lumber Company, LLC	Planermill/Sawmill baghouse stack	1231513	543,544.6	5,233,101.9	1.97	9.14	288.7	17.5	1.01	
053	12593	US Oil & Refining Co	Internal Combustion Engines	1259322	545,900.3	5,233,500.2	6.35	37.49	580.4	4.3	2.08	*
			Internal Combustion Engines	1259323	545,900.3	5,233,500.2	6.35	37.49	580.4	4.3	2.08	*

Source Information					Stack Parameters							Notes
FIPS County Code	Source ID	Source Name	Emission Unit	Emission Unit ID	UTM-E (km)	UTM-N (km)	Base Elevation (m)	Stack Height (m)	Temp. (K)	Velocity (m/s)	Diameter (m)	Notes
053	21276	US Air Force McChord Air Force Base	Boiler Fuel Combustion	2127611	538,893.6	5,220,049.7	92.65	7.62	449.8	10.0	0.61	*
			Boiler Fuel Combustion	2127612	538,893.6	5,220,049.7	92.65	7.62	449.8	10.0	0.61	*
			Boiler Fuel Combustion	2127613	538,893.6	5,220,049.7	92.65	7.62	449.8	10.0	0.61	*
053	21277	US Army Fort Lewis DA Public Works	Fuel Oil Burned In Boilers	2127715	531,930.3	5,213,830.1	94.34	7.62	449.8	10.0	0.61	*
			Landfill Gas Flares	21277111	531,930.3	5,213,830.1	94.34	7.62	449.8	10.0	0.61	*
			Natural Gas & Methane In Boilers	2127721	531,930.3	5,213,830.1	94.34	7.62	449.8	10.0	0.61	*
			Natural Gas & Methane In Boilers	2127722	531,930.3	5,213,830.1	94.34	7.62	449.8	10.0	0.61	*
			Natural Gas & Methane In Boilers	2127726	531,930.3	5,213,830.1	94.34	7.62	449.8	10.0	0.61	*
			Generators	2127731	531,930.3	5,213,830.1	94.34	7.62	449.8	10.0	0.61	*
053	0008	SIMPSON TACO. KRAFT	RECOVERY BOILER #3	BASERB3	543,396.5	5,234,761.5	1.45	37.49	344.8	18.7	2.90	
			RECOVERY BOILER # 4	BASERB4	543,358.9	5,234,820.5	1.45	83.82	439.3	11.5	4.27	
			LIME KILN #1	BASELK1	543,490.2	5,234,670.8	1.45	37.49	346.5	15.0	1.37	
			LIME KILN #2	BASELK2	543,513.9	5,234,648.9	1.45	37.80	339.8	6.8	1.22	
			BOILER #1 STACK	BASEPB1	543,467.2	5,234,683.6	1.45	32.00	406.5	9.4	1.37	
			BOILER #2/SCRUBBER MV168 STACK	BASEPB2	543,439.0	5,234,724.1	1.45	48.16	344.3	7.4	2.29	
			BOILER #3-5/SCRUBBER MV204 STACK	BASEPB35	543,439.0	5,234,724.1	1.45	48.16	341.5	14.3	2.59	
			BOILER #6 STACK	BASEPB6	543,426.1	5,234,705.1	1.45	36.58	435.4	12.2	1.98	
053	0019	KAISER ALUMINUM AND	BOILERS STACK	BASEKAL1	548,100.0	5,234,100.0	2.68	21.34	477.6	1.7	0.73	
			ROD MILL & CASTING & AL MELTING	BASEKAL2	547,800.0	5,234,100.0	4.12	16.15	338.7	36.4	1.22	
045	0002	SIMPSON TIMBER	BOILER HOGGED FUEL (WOOD/BARK)	BASESIM1	493,100.0	5,228,300.0	0.11	21.34	374.3	10.0	0.61	

* Units with the same stack parameters are modeled as one point source with emissions summed.

Table 4. Nearby Source Emissions
Power Boiler No. 7 PSD Amendment Request NO2 Air Quality Analysis
Simpson Tacoma Kraft, Tacoma, Washington

Source Information					Emissions					Notes
FIPS County Code	Source ID	Source Name	Emission Unit	Emission Unit ID	2006 (g/sec)	2007 (g/sec)	NAAQS 2-year Maximum x 3 (g/sec)	PSD Increments 2-year Average (g/sec)	Baseline (g/sec)	Notes
033	10088	King Co Ntrl Res Wastewater Treatment	Internal Combustion--Elec Gener	1008811	2.1863E+00	NA	6.5588E+00	2.1863E+00	NA	
			Internal Combustion--Industrial	1008822	1.2370E+00	NA	3.7109E+00	1.2370E+00	NA	
			Internal Combustion Engines-Misc	1008831	2.0137E-01	NA	6.0410E-01	2.0137E-01	NA	
033	10138	King Co Solid Waste Op Sec Cedar Hills	Landfill Flare (5)	1013811	1.8411E+00	1.9561E+00	5.8684E+00	1.8986E+00	NA	
033	10281	Nucor Steel Seattle Inc	Direct Arc Electric Arc Furnace	1028111	2.2150E+00	2.1863E+00	6.6451E+00	2.2006E+00	NA	*
			Direct Arc Electric Arc Furnace	1028112	3.1643E-01	3.1643E-01	9.4930E-01	3.1643E-01	NA	*
			Reheat Furnace	1028121	2.7616E+00	2.6178E+00	8.2848E+00	2.6897E+00	NA	
033	11195	CertainTeed Gypsum Manufacturing Inc	In-Process Fuel Use	1119511	1.2370E+00	1.1219E+00	3.7109E+00	NA	NA	
033	11339	Ash Grove Cement Co, E Marginal	Clinker Handling And Storage	1133911	3.5038E+01	3.1499E+01	1.0511E+02	3.3269E+01	NA	*
			Clinker Handling And Storage	1133912	3.1931E+00	3.1643E+00	9.5793E+00	3.1787E+00	NA	*
033	11656	Saint-Gobain Containers Inc	Furnace #3	1165611	8.0547E-01	8.3423E-01	2.5027E+00	8.1985E-01	NA	
			Furnace #4	1165621	9.7807E+00	9.1478E+00	2.9342E+01	9.4642E+00	NA	
			Furnace #5	1165631	6.6163E-01	1.7835E+00	5.3506E+00	1.2226E+00	NA	
			Furnace #2	1165641	5.4657E-01	5.1780E-01	1.6397E+00	5.3218E-01	NA	
			Non-Furnace Natural Gas	1165671	5.7533E-02	NA	1.7260E-01	5.7533E-02	NA	*
			Other Diesel Combustion	1165681	1.7260E-01	1.1507E-01	5.1780E-01	1.4383E-01	NA	*
033	13117	Boeing Commercial Airplane Auburn	Ext Comb Boilers-Commc'L/Instit	1311711	2.2438E+00	1.9274E+00	6.7314E+00	2.0856E+00	NA	*
			Ext Comb Boilers-Commc'L/Instit	1311712	8.6300E-02	1.4383E-01	4.3150E-01	1.1507E-01	NA	*
			Fabricated Metal Products	1311766	5.7533E-02	5.7533E-02	1.7260E-01	5.7533E-02	NA	
			Internal Comb Engines-Comml/Inst	1311781	8.6300E-02	5.7533E-02	2.5890E-01	7.1917E-02	NA	
033	13121	Boeing Space Center	Boilers	1312111	0.0000E+00	4.3150E-01	1.2945E+00	NA	NA	*
			Internal Comb Engines - Diesel	1312171	0.0000E+00	4.3150E-01	1.2945E+00	NA	NA	*
033	13125	Boeing Commercial Airplane Renton	External Comb Boilers-Industrial	1312513	1.1507E-01	8.6300E-02	3.4520E-01	NA	NA	*
			External Comb Boilers-Industrial	1312515	8.9177E-01	8.0547E-01	2.6753E+00	NA	NA	*
			Internal Combustion Emergency Generators	13125111	2.8767E-02	NA	8.6300E-02	NA	NA	
033	13460	Jorgensen Forge Corp	Steel Casting with Baghouse	1346011	5.7533E-02	8.6300E-02	2.5890E-01	NA	NA	
			Natural Gas Combustion	1346021	1.0931E+00	1.1794E+00	3.5383E+00	NA	NA	
033	13786	Seattle Steam Co, Western	Riley	1378611	1.1794E+00	1.2370E+00	3.7109E+00	1.2082E+00	NA	*
			Garrett & Shaffer	1378621	2.8191E+00	3.3369E+00	1.0011E+01	3.0780E+00	NA	*
			Combustion Engineering - (D)	1378631	9.7807E-01	1.2945E+00	3.8835E+00	1.1363E+00	NA	*
			Combustion Engineering - (D)	1378632	2.8767E-01	NA	8.6300E-01	2.8767E-01	NA	*
			Combustion Engineering - (D)	1378633	2.8767E-02	NA	8.6300E-02	2.8767E-02	NA	*
			Combustion Engineeering - (A)	1378641	9.4930E-01	3.1643E-01	2.8479E+00	6.3287E-01	NA	
033	14046	Lafarge North America Inc	Cement Kiln	1404611	6.3229E+01	8.0604E+01	2.4181E+02	7.1917E+01	NA	
			Slag Dryer	1404641	8.6300E-02	8.6300E-02	2.5890E-01	8.6300E-02	NA	

Source Information					Emissions					Notes
FIPS County Code	Source ID	Source Name	Emission Unit	Emission Unit ID	2006 (g/sec)	2007 (g/sec)	NAAQS 2-year Maximum x 3 (g/sec)	PSD Increments 2-year Average (g/sec)	Baseline (g/sec)	Notes
033	21147	Boeing Commercial Airplane NBF Plant 2	External Comb Boilers - Indus	2114711	5.1780E-01	6.0410E-01	1.8123E+00	NA	NA	*
			Internal Combustion Emergency Generators	21147141	2.8767E-02	2.8767E-02	8.6300E-02	NA	NA	
			Internal Combustion Turbine	21147151	2.8767E-01	2.8767E-02	8.6300E-01	NA	NA	
			Ext Combustion Boilers-Indust	2114781	5.7533E-02	1.4383E-01	4.3150E-01	NA	NA	*
033	21320	Washington University of Power Plant & Hospital	External Combustion Stack	2132011	1.3808E+00	2.7328E+00	8.1985E+00	2.0568E+00	NA	*
			External Combustion Stack	2132012	8.6300E-02	8.6300E-02	2.5890E-01	8.6300E-02	NA	*
033	21408	Seattle-Tacoma International Airport	Fuel Oil Burned In Boilers	2140812	8.9177E-01	NA	2.6753E+00	NA	NA	
035	21138	Naval Base Kitsap at Bremerton	External Combustion Boilers	2113811	2.8767E-02	2.8767E-02	8.6300E-02	NA	NA	*
			External Combustion Boilers	2113812	1.3233E+00	1.1219E+00	3.9698E+00	NA	NA	*
			External Combustion Boilers	2113813	2.8767E-02	2.8767E-02	8.6300E-02	NA	NA	*
			Internal Combustion Engines	2113821	5.1780E-01	3.1643E-01	1.5534E+00	NA	NA	*
			Internal Combustion Engines	2113822	5.7533E-02	5.7533E-02	1.7260E-01	NA	NA	*
045	0002	Simpson Timber Co	Boiler - Wood / Bark - EU1	000281	1.8698E+00	1.7260E+00	5.6095E+00	NA	NA	
053	10016	Georgia-Pacific Gypsum LLC	Dryer Stack 1	1001611a	--	--	3.5047E-01	1.1682E-01	NA	Provided by Puget Sound Clean Air Agency.
			Dryer Stack 2	1001611b	--	--	3.5047E-01	1.1682E-01	NA	
			Dryer Stack 3	1001611c	--	--	3.5047E-01	1.1682E-01	NA	
			Dryer Stack 4a	1001611d	--	--	3.5047E-01	1.1682E-01	NA	
			Dryer Stack 4b	1001611e	--	--	3.5047E-01	1.1682E-01	NA	
			Dryer Stack 5a	1001611f	--	--	3.5047E-01	1.1682E-01	NA	
			Dryer Stack 5b	1001611g	--	--	3.5047E-01	1.1682E-01	NA	
			Dryer Stack 6	1001611h	--	--	3.5047E-01	1.1682E-01	NA	
			Dryer Stack 7	1001611i	--	--	3.5047E-01	1.1682E-01	NA	
			Imp Mill 1 Stack	1001611j	--	--	1.9589E-01	6.5296E-02	NA	
			Imp Mill 2 Stack	1001611k	--	--	1.9589E-01	6.5296E-02	NA	
			Imp Mill 3 Stack	1001611l	--	--	1.9589E-01	6.5296E-02	NA	
			Imp Mill 4 Stack	1001611m	--	--	1.9589E-01	6.5296E-02	NA	
			Imp Mill 5 Stack	1001611n	--	--	1.9589E-01	6.5296E-02	NA	
			Imp Mill 6 Stack	1001611o	--	--	1.9589E-01	6.5296E-02	NA	
			Imp Mill 7 Stack	1001611p	--	--	1.9589E-01	6.5296E-02	NA	
			Imp Mill 8 Stack	1001611q	--	--	1.9589E-01	6.5296E-02	NA	
			FGD Building NOC 8546	1001621	--	--	6.0410E-01	2.0137E-01	NA	
053	10645	Frederickson Power LP	1-01-006-01External Combustion Boilers	1064511	8.6300E-01	1.0068E+00	3.0205E+00	9.3492E-01	NA	
053	10734	Tucci & Sons Inc Taylor Way	Asphaltic Concrete	1073411	5.7533E-02	2.8767E-02	1.7260E-01	4.3150E-02	NA	
053	10805	Sonoco Products Co Paper Div	Boilers	1080512	0.0000E+00	2.5890E-01	7.7670E-01	NA	NA	
053	11669	Rainier Veneer Inc	Wood Boiler Scrubber Stack	1166911	6.6163E-01	7.1917E-01	2.1575E+00	NA	NA	
053	11820	Graymont Western US Inc	Lime Manufacture	1182011	1.6685E+00	1.6397E+00	5.0054E+00	1.6541E+00	NA	
053	12315	Simpson Lumber Company, LLC	Planermill/Sawmill baghouse stack	1231513	NA	2.8767E-02	8.6300E-02	2.8767E-02	NA	
053	12593	US Oil & Refining Co	Internal Combustion Engines	1259322	3.3369E+00	3.4808E+00	1.0442E+01	3.4088E+00	NA	*
			Internal Combustion Engines	1259323	2.5890E-01	2.3013E-01	7.7670E-01	2.4452E-01	NA	*

Source Information					Emissions					Notes
FIPS County Code	Source ID	Source Name	Emission Unit	Emission Unit ID	2006 (g/sec)	2007 (g/sec)	NAAQS 2-year Maximum x 3 (g/sec)	PSD Increments 2-year Average (g/sec)	Baseline (g/sec)	Notes
053	21276	US Air Force McChord Air Force Base	Boiler Fuel Combustion	2127611	NA	8.9177E-01	2.6753E+00	8.9177E-01	NA	*
			Boiler Fuel Combustion	2127612	NA	5.7533E-02	1.7260E-01	5.7533E-02	NA	*
			Boiler Fuel Combustion	2127613	NA	5.7533E-02	1.7260E-01	5.7533E-02	NA	*
053	21277	US Army Fort Lewis DA Public Works	Fuel Oil Burned In Boilers	2127715	2.3013E-01	2.3013E-01	6.9040E-01	2.3013E-01	NA	*
			Landfill Gas Flares	21277111	2.8767E-02	2.8767E-02	8.6300E-02	2.8767E-02	NA	*
			Natural Gas & Methane In Boilers	2127721	4.6027E-01	4.3150E-01	1.3808E+00	4.4588E-01	NA	*
			Natural Gas & Methane In Boilers	2127722	4.0273E-01	4.0273E-01	1.2082E+00	4.0273E-01	NA	*
			Natural Gas & Methane In Boilers	2127726	2.0137E-01	2.5890E-01	7.7670E-01	2.3013E-01	NA	*
			Generators	2127731	8.6300E-02	2.5890E-01	7.7670E-01	1.7260E-01	NA	*
053	0008	SIMPSON TACO. KRAFT	RECOVERY BOILER #3	BASERB3	NA	NA	NA	NA	4.1999E-01	
			RECOVERY BOILER # 4	BASERB4	NA	NA	NA	NA	8.0292E+00	
			LIME KILN #1	BASELK1	NA	NA	NA	NA	1.7647E-01	
			LIME KILN #2	BASELK2	NA	NA	NA	NA	1.5625E-01	
			BOILER #1 STACK	BASEPB1	NA	NA	NA	NA	3.3636E+00	
			BOILER #2/SCRUBBER MV168 STACK	BASEPB2	NA	NA	NA	NA	3.8099E+00	
			BOILER #3-5/SCRUBBER MV204 STACK	BASEPB35	NA	NA	NA	NA	8.3998E+00	
			BOILER #6 STACK	BASEPB6	NA	NA	NA	NA	5.7599E+00	
053	0019	KAISER ALUMINUM AND	BOILERS STACK	BASEKAL1	NA	NA	NA	NA	2.8846E-02	
			ROD MILL & CASTING & AL MELTING	BASEKAL2	NA	NA	NA	NA	7.7883E-01	
045	0002	SIMPSON TIMBER	BOILER HOGGED FUEL (WOOD/BARK)	BASESIM1	NA	NA	NA	NA	4.3437E+00	

* Units with the same stack parameters are modeled as one point source with emissions summed.

APPENDIX C

INPUT AND OUTPUT FILES

PSD Amendment for Power Boiler #7
NO_2 Air Quality Analysis
Simpson Tacoma Kraft Company
801 Portland Avenue
Tacoma, WA 98421

August 2010
Project: 108.00217.00024

APPENDIX D

CLASS I VISIBILITY AND DEPOSITION ANALYSIS REPORT

PSD Amendment for Power Boiler No. 7
NO_2 Air Quality Analysis
Simpson Tacoma Kraft Company
801 Portland Avenue
Tacoma, WA 98421

August 2010
Project: 108.00217.00024

Class I Area Modeling in Support of a Proposed Revision to the Steam Turbine Generator Project Prevention of Significant Deterioration Permit

Simpson Tacoma Kraft Facility

Prepared for:
Simpson Tacoma Kraft Company, LLC
Tacoma, Washington

Prepared by:
ENVIRON International Corporation
Lynnwood, Washington

Date:
August 2010

Project Number:
29-24706A

ENVIRON

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Appendix A Disc Containing Modeling Files

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1 Introduction

Simpson Tacoma Kraft Company, LLC (Simpson) operates a pulp and paper mill located at 801 Portland Avenue in Tacoma. Simpson generates steam for general mill operations using the #4 Recovery Boiler, the #6 Power Boiler, and the #7 Power Boiler. In May 2007, Simpson received a permit to install a steam turbine generator driven by steam produced from the #4 Recovery Boiler and the #7 Power Boiler, allowing Simpson to generate and distribute electrical power.

Because the Tacoma Kraft mill is a major stationary source of emissions, and improvements to the #7 Power Boiler resulted in emission rate increases exceeding the significant emission rate (SER) thresholds, a Prevention of Significant Deterioration (PSD) permit was applied for and obtained from the Washington Department of Ecology (Ecology). Following installation of the steam turbine, continuous emission monitoring system (CEMS) data and compliance tests indicated that the #7 Power Boiler could not meet the oxides of nitrogen (NO_X) permit limit. A PSD permit application requesting a revision to the NO_X emission limits must address all topics and analyses included in the original PSD permit application that would be affected by the proposed NO_X emissions rate, including an analysis of impacts to Class I areas.

ENVIRON has been retained by Simpson to adapt an existing Class I modeling analysis developed for Simpson Lumber Company's Shelton facility to assess the impacts of the #7 Power Boiler Project (hereafter referred to as the "Project") on nearby Class I areas selected by the Federal land managers (FLMs). The methodology for this analysis, which has received approval from Ecology and the FLMs, differs from the Shelton facility analysis only in the emission units, the number of Class I areas included, and, at the request of the USFS, the inclusion of a pseudo-ozone station.

All modeling files are provided on a DVD in Appendix A of this report.

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2 Class I Air Quality Related Values Analysis

PSD guidance requires an analysis of potential impacts to air quality related values (AQRVs) in Federal Class I areas within 100 km (62.1 miles) of the facility from pollutants emitted by the Project subject to PSD review. In this case, the National Park Service (NPS) has requested analyses of AQRV impacts for four specific Class I areas, which are listed in Table 2-1. The domain selected for the PSD analysis was based on discussions with the National Park Service.[1] Figure 2-1 presents the CALPUFF modeling domain with the selected Class I areas.

The distances from the facility to the three Class I areas considered in this analysis are given in Table 2-1, along with the final "Q/D" values often used by FLMs as a screening tool. The "Q" value (545 tons per year) is the sum of the maximum short-term average emission rates of NO_X, SO_2, PM_{10} and H_2SO_4 in pounds per hour (lb/hr) associated with the Project, extrapolated to a year of continuous operation (8,760 hours per year) and converted to tons per year (tpy).

The AQRVs of concern include visibility, soil, flora, fauna, and aquatic resources. The CALPUFF modeling system is currently recommended for evaluating impacts to AQRVs in Class I areas affected by long-range transport. Potential impacts are characterized based on predictions of total nitrogen and/or sulfur deposition flux, change in light extinction, and pollutant concentrations. Pollutant concentration predictions were also used to assess Class I area increment consumption for pollutants subject to PSD review.

Table 2-1 Class I Areas and Q/D Analysis

Name	Distance to Class I area (km)	Q/D Value (tpy/km)
Alpine Lakes Wilderness Area	64	8.5
Mt. Rainier National Park	47	11.6
Olympic National Park	67	8.1

2.1 Model Selection

On April 15, 2003 EPA adopted the CALPUFF modeling system as the EPA's preferred model for long-range transport assessments and for evaluating potential impacts to Class I areas by including CALPUFF in Appendix A of the Guidelines. Features of the CALPUFF modeling system include the ability to consider: secondary aerosol formation; gaseous and particle deposition; wet and dry deposition processes; complex three-dimensional wind regimes; and the effects of humidity on regional visibility. As is currently required, CALPUFF Version 5.8 (release date June 23, 2007) was used.

[1] Mr. John Notar and Mr. Dee Morse, pre-PSD meeting (conference call) for the Simpson – Shelton cogeneration unit project on February 3, 2010

2.2 Modeling Procedures

The modeling procedures used for the Class I area analysis followed the recommendations of the Interagency Agency Workgroup on Air Quality Modeling (IWAQM) and the FLM Air Quality Related Values Workgroup (FLAG), outlined in the FLAG Phase I Report (December 2000). EPA endorsed these procedures in advance in the IWAQM Phase II report (December 1998), and reiterated this endorsement in the April 15, 2003 Federal Register notice (Volume 68, Number 72) that adopted CALPUFF as a Guideline model. EPA further clarified their required CALMET settings in a memo issued on August 31, 2009 (Fox, 2009).

2.2.1 Model Setup and Application

The CALPUFF modeling system is equipped with a host of modeling options, but, as stated in the previous section, ENVIRON used the procedures and defaults recommended by the FLAG Phase I Report and the EPA-FLM CALMET Clarification Memo.

For the regional haze assessment using the CALPUFF modeling system, PM_{10} emission rates must be speciated into six fractions: soot or elemental carbon (EC), PM fine (PMF), PM coarse (PMC), organic carbon (OC), sulfate (SO_4), and nitrate (NO_3). Table 2-2 shows the speciated PM_{10} emission rates used in the analysis. The speciation was accomplished using stack test data for Power Boiler No. 7.

To be conservative, the maximum 24-hour emission rate was used in the CALPUFF modeling for both the short-term and long-term (annual) assessments.

Table 2-2 Speciated Emission Rates for AQRV Analysis

Source	SO_2 (lb/hr)	NO_X (lb/hr)	Speciated PM_{10}[1] (lb/hr)					
			Coarse Mass	Fine Sulfate (as SO_4)	Fine Nitrate (as NO_3)	Fine Elemental Carbon	Fine Organic Carbon	Fine Crustal Material
#7 Power Boiler[2]	3.40	112.7	0	4.48	0	1.0	0.07	1.87
Cooling Tower, 2 cells combined [3]	0	0	0	0	0	0	0	0.90

1 PM_{10} is the sum of coarse mass and the fine PM ($PM_{2.5}$) components: ammonium sulfate, ammonium nitrate, fine crustal material, elemental carbon and organic carbon.

2 PM_{10} is assumed to be 100 percent $PM_{2.5}$. Source tests indicate 89 percent of the PM_{10} is in the condensable fraction. Subsequent analysis of this fraction indicated 76 percent was ammonium sulfate, 0 percent nitrate, and 1 percent organic matter. The remaining condensable fraction was assumed to be generic inorganic fine mass. The filterable portion (11 percent) was conservatively assumed to be all elemental carbon.

3 Cooling tower emissions were assumed to be 100 percent fine crustal mass.

2.2.2 Averaging Periods

CALPUFF-predicted hourly pollutant concentrations were averaged for comparison with 3-hour, 24-hour, and annual Class I PSD increments. Predicted extinction coefficients and total deposition fluxes were calculated as 24-hour and annual averages, respectively. In all instances, comparisons with regulatory criteria were based on the highest model-prediction of the three-year simulation for each averaging period.

2.2.3 Chemical Transformations

The NO_X chemistry in CALPUFF depends on the ambient ammonia concentration to establish the equilibrium between gaseous nitric acid and ammonium nitrate. However, ambient ammonia concentrations are not explicitly simulated by CALPUFF and the user must select an appropriate background concentration. The IWAQM Phase II Recommendations suggest typical ammonia concentrations as: 10 parts per billion (ppb) for grasslands, 0.5 ppb for forests, and 1 ppb for arid lands during warmer weather.

An ammonia monitoring program conducted by Environment Canada at Agassiz and Abbotsford, British Columbia observed average concentrations of 10 and 24 ppb, respectively.[2] These concentrations, measured in an area just north of the simulation domain, correlated with the application of fertilizer on agricultural land. The average concentration observed by Environment Canada (17 ppb) was used in the current study and is considered a conservative background ammonia concentration since the majority of the land use in the domain is forest and actual ammonia concentrations are likely lower. The 17 ppb background concentration has been used for past AQRV studies in the same region, and its use is also considered conservative because it ensures the conversion of NO_X to ammonium nitrate is not limited by a lack of ammonia for the range of NO_X concentrations predicted in this study. More recent ammonia measurements were obtained from Keith Jones of Environment Canada and Ken Reid of Metro Vancouver, BC. The recent data showed only a modest decrease in ammonia concentrations, leading to the decision to retain the use of 17 ppb for the current modeling effort.

Reaction rates in the CALPUFF chemistry algorithms are also influenced by background ozone concentrations. ENVIRON has obtained ozone data collected concurrent with the modeled period at various NPS, Ecology, Oregon Department of Environmental Quality (ODEQ), and British Columbia Ministry of Water, Land, and Air Protection (MWLAP) stations within and around the study area. CALPUFF uses a background ozone value (BCK03) for hours when *none* of the supplied ozone stations have valid data. A conservative value of 60 ppb was specified, to avoid artificially limiting chemical transformations (e.g. NO_X titration). However, there are no hours with all stations reporting missing values in the given ozone dataset.

[2] Belzer, W., C. Evans and A. Poon. 1998. Atmospheric Nitrogen Concentrations in the Lower Fraser Valley. Environment Canada. Aquatic and Atmospheric Sciences Division. Vancouver, B.C. DOE FRAP 1997-23.

Mr. Rick Graw of the USFS requested the addition of a single ozone "pseudo-station" near the Alpine Lakes Wilderness Area.[3] The ozone concentration data collected at the monitoring station located at the Mt. Rainier National Park Jackson Visitor Center was used as data for a pseudo-station located near the point where the Alpine Lakes Wilderness Area is closest to the facility. The intent of this addition is to ensure that high-elevation ozone concentrations are adequately represented in the sulfate and nitrate chemical transformation calculations within the Alpine Lakes Wilderness Area. [Would be nice to show the location on one of the figures.]

2.3 Domain and Receptors

The terrain for the CALPUFF simulations is shown in Figure 2-2. The 452 km-by-412 km domain is large enough to include the Class I areas of interest with at least a 50 km allowance for complex flows that might cause recirculation of plumes originating at the facility. A Lambert conformal coordinate system was used and selected to be a sub-domain of the coordinate system used by the University of Washington (UW) for their MM5 simulations of Pacific Northwest Weather[4]. The UW MM5 simulations were used to construct the three dimensional meteorological data used in the CALPUFF analysis.

The CALPUFF dispersion model simulations assessed AQRVs at discrete receptors obtained from the National Park Service. Figure 2-3 shows these receptor locations within each Class I area.[5]

In addition to the discrete Class I area receptors described above, AQRV predictions were obtained at each of the 4-km spacing grid points throughout the CALPUFF computational domain. The 4-km receptor grid was also used to construct plots showing the spatial variation of the calculated parameters throughout the modeling domain. Such plots are used for diagnostic purposes and to develop the figures presented in this application for Ecology and the FLMs. When summarized by area of interest, the AQRV impact results provided in this application were taken from the NPS discrete receptors within each area.

Land use and terrain data were prepared from the USGS 1:250,000 scale data sets available on the internet resulting in 4-km spacing fields. As described above, the same terrain grid used to develop the CALMET wind fields and used internally by CALPUFF was also used to obtain receptor and source base elevations.

2.4 Emission Rates and Stack Parameters

In order to reduce CALPUFF simulation run times, it is accepted practice to combine emissions from similar emission units and represent them in the CALPUFF model as a single emission unit with release parameters that reflect an average of the combined emission units. In this case,

[3] Email communication from Rick GRaw, USFS, to Eri Ottersburg, SLR International, on June 11, 2010.
[4] http://www.atmos.washington.edu/mm5rt/mm5info.html
[5] http://www2.nature.nps.gov/air/Maps/Receptors/index.cfm

PM_{10} emissions from two cooling tower cells were combined into a single emission unit. The emission units included in the CALPUFF simulations include:

- The #7 Power Boiler (pb7); and
- The two-cell cooling tower (cool).

The included emission units are presented in Table 2-2 with NO_X, SO_2, and speciated PM_{10} emission rates. The release parameters used to represent the emission units in the simulations are presented in Table 2-3. Building downwash parameters, which are considered optional by Ecology for a Class I analysis, were not included in the analysis.

Table 2-3 Emission Unit Release Parameters

Source	Stack Base Elevation (m)/(ft)	Release Height (m)/(ft)	Exhaust Temperature (K)/(F)	Exit Velocity (m/s)/(ft/s)	Inside Diameter (m)/(ft)
#7 Power Boiler	43.3 / 142	53.6 / 176	494 / 430	24.8 / 81.4	2.06 / 6.76
Cooling Tower (2 cells combined)	43.1 / 141	20.6 / 67.6	307 / 92	2.80 / 9.19	10.78 / 35.4 [1]

1 Equivalent diameter based on two adjacent 25 foot cells.

2.5 Meteorological Data

Meteorological data sets were obtained from the UW's numerical simulations of Pacific Northwest weather with the Penn State and National Center of Atmospheric Research Mesoscale Model (MM5). The AQRV analysis used three years of hourly 4-km horizontal mesh size MM5 output data from January 2003 to December 2005. The UW MM5 datasets with a 12-km horizontal mesh size have also been used to assess industrial sources subject to BART review, as part the EPA Regional Haze Rule. For the current analysis the 4-km mesh size simulations were used in order to better resolve the flow in the complex terrain.

CALMET (Version 5.8), the meteorological preprocessor component of the CALPUFF system, was used to combine the MM5 simulation data, surface observations, terrain elevations, and land use data into the format required by the dispersion modeling component CALPUFF. In addition to specifying the three-dimensional wind field, CALMET also estimates the boundary layer parameters used to characterize diffusion and deposition by the dispersion model.

The techniques used to construct the meteorological database follow the recent August 31, 2009 clarification memo from the USEPA and the FLMs (Fox, 2009). Major features of the CALMET application and input data preparation are as follows:

- The model domain is a subset of the UW's 4-km mesh size MM5 domain as shown in Figure 2-1. The horizontal mesh size is 4 km, with each CALMET grid point matched to a MM5 grid point. In order to match the MM5 simulations, a Lambert Conformal Conic (LCC)

coordinate system was used with an origin of 49N, 121W and standard latitudes of 30N and 60N.

- MM5 winds based on a 4-km grid spacing for January 2003 to December 2005 were used to initialize the three-dimensional wind field predictions. The MM5 data were processed with the CALMM5 utility for use by CALMET.
- Land use and terrain data were prepared using the processing tools accompanying the CALPUFF modeling system and the USGS GTOPO30 elevation data sets available on the Internet[6]. Figure 2-2 shows the 4-km mesh size terrain used in the simulations.
- Surface weather observations were extracted from the National Climatic Data Center (NCDC) Integrated Surface Hourly Observations (ISHO) dataset (TD-3505) for an area that extended 50 km beyond the study domain boundary.
- Twice daily upper air soundings from Quillayute, Washington were used[7].
- Buoy observations from seven stations off the Pacific Coast (Washington and Southern British Columbia) were obtained from the National Data Buoy Center. These data are used by CALMET to characterize winds, sea-air temperature differences, and air temperatures over marine areas of the domain. The buoy data were processed by the BUOY utility from the CALPUFF modeling system.
- Hourly precipitation data were obtained from the NCDC's TD-3240 (COOP) dataset and from Environment Canada, and processed with the CALMET utility PMERGE. Sites were selected based on the criteria that the locations must be near (within 50 km) or in the model domain and there must be at least a 50 percent data recovery.

A sample CALMET input file was submitted to the FLMs and subsequently approved as part of their review of the modeling protocol submitted for the Simpson Shelton Project.

Selected hours of the three-year CALMET/MM5 three-dimensional data set were examined by extracting data from the CALMET output files and plotting the meteorological fields with the CALDESK software package. Wind vector plots were examined for different times of year, different times of day, and for all 10 vertical levels.

2.6 AQRV Calculation Procedures

The CALPUFF modeling system was used to predict criteria pollutant concentrations, total deposition fluxes, and light extinction coefficients attributable to project emissions in regional Class I areas. These parameters were calculated from CALPUFF output files using the post-processor programs CALPOST and POSTUTIL.

Predictions of NO_X, SO_2, and PM_{10} concentrations in the Class I areas of interest were extracted using the CALPOST post-processor. PM_{10} concentration estimates include both primary and

[6] http://www.src.com/datasets/datasets_main.html
[7] FSL data obtained from http://esrl.noaa.gov/raobs/

secondary aerosols and account for the molecular weights of each resulting compound. The conversion to account for molecular weight and summing of species are accomplished using the POSTUTIL processor. Total nitrogen and sulfur deposition fluxes are similarly calculated by summing and converting the various species included in the wet and dry deposition CALPUFF output files. The nitrogen deposition fluxes include the nitrogen from the background ammonia to some extent. For comparison to FLM deposition criteria, the fluxes were converted to kilograms per hectare per year.

2.6.1 FLAG 2000 (CALPOST Method 2)

The potential impacts of emissions from the Project to regional haze in the Class I areas of interest were assessed using predictions of the 24-hour change to extinction. The FLMs recommend in the FLAG Phase I Report that a five percent change to extinction be used to indicate a "just perceptible" change to a landscape. CALPOST was used to calculate both the extinction coefficient attributable to the proposed emission increases as well as the background extinction coefficients. Specifically:

- Extinction coefficients were calculated using hourly predicted aerosol concentrations, hourly relative humidity, and background aerosol concentrations with CALPOST Method 2 (MVISBK = 2). Relative humidly was capped at 95 percent (RHMAX=95) and the FLAG relative humidity growth factors were applied to the hygroscopic aerosols (MFRH=2).
- Default light extinction scattering efficiencies were used for each aerosol species.
- Background visibility in all Class I areas of interest were based on the FLAG defaults for the western US by using the hygroscopic (0.6 Mm-1), dry (4.5 Mm-1), and Rayleigh scattering (10.0 Mm-1) portions of the extinction coefficient. These defaults were applied within CALPOST during post-processing with the following options: BKSO4=0.2, BKSOIL=4.5 and BEXTRAY=10.

The current FLAG recommended CALPOST method for extinction coefficients can be very sensitive to hourly relative humidity. High relative humidity in the Pacific Northwest is often associated with precipitation, fog, low overcast and weather-related visibility obscuring phenomena. During periods of natural visibility obscuration, the changes to visibility predicted by CALPUFF are suspect, and often discarded from the analysis.

2.6.2 FLAG 2008 (CALPOST Method 8)

In order to provide further information, extinction coefficients were calculated using the 2008 proposed revisions to the FLM FLAG procedures. The revised procedures employ the IMPROVE extinction equation to calculate b_{ext} (invoked with MVISCHECK=1 in CALPOST). This updated equation for extinction uses monthly relatively humidity adjustment factors with relative humidity capped at 95 percent. It uses annual background aerosol concentrations recommended by the FLMs for each Class I area, and assess the visibility using the 98th percentile modeled values at each receptor. In order to use Method 8, CALPOST Version 6.221 (Level 080724) was used to post-process the CALPUFF output files.

For FLAG 2008, a Project's extinction is calculated using the revised IMPROVE reconstructed mass extinction equation as follows:

$$
\begin{aligned}
b_{project} = {} & 2.2 \times f_S(RH) \times [\text{Small Sulfate}] + 4.8 \times f_L(RH) \times [\text{Large Sulfate}] \\
& + 2.4 \times f_S(RH) \times [\text{Small Nitrate}] + 5.1 \times f_L(RH) \times [\text{Large Nitrate}] \\
& + 2.8 \times [\text{Small Organic Mass}] + 6.1 \times [\text{Large Organic Mass}] \\
& + 10 \times [\text{Elemental Carbon}] \\
& + 1 \times [\text{Fine Soil}] \\
& + 0.6 \times [\text{Coarse Mass}] \\
& + 1.7 \times f_{SS}(RH) \times [\text{Sea Salt}] \\
& + \text{Rayleigh Scattering (Site Specific)} \\
& + 0.33 \times [NO_2\ (\text{ppb})]\ \{\text{or as: } 0.1755 \times [NO_2\ (\mu g/m^3)]\}
\end{aligned}
$$

Where:

[ ] indicates concentrations in μg/m3

$f_S(RH)$ = Relative humidity adjustment factor for small sulfate and nitrate

$f_L(RH)$ = Relative humidity adjustment factor for large sulfate and nitrate

$f_{SS}(RH)$ = Relative humidity adjustment factor for sea salt

For Total Sulfate < 20 $\mu g/m^3$:

[Large Sulfate] = ([Total Sulfate] / 20 $\mu g/m^3$) × [Total Sulfate]

For Total Sulfate ≥ 20 $\mu g/m^3$:

[Large Sulfate] = [Total Sulfate]

And:

[Small Sulfate] = [Total Sulfate] – [Large Sulfate]

To calculate large and small nitrate and organic mass, substitute ({Large, Small, Total} {Nitrate, Organic Mass}) for Sulfate.

2.7 Concentration, Deposition and Visibility Analysis Results

The CALPUFF modeling system was used to predict concentrations of NO_2, SO_2, and PM_{10} in regional Class I areas. Table 2-4 summarizes the predicted maximum concentrations and compares them to the Class I SILs and the Class I PSD increments. At this point, there are two sets of Class I SILs: those proposed by EPA, and those recommended by the FLMs. These proposed and recommended SILs were obtained from the Federal Register, Vol. 61, No. 143, p. 38292, July 23, 1996. As shown in Table 2-4, the CALPUFF simulations indicate neither the SILs nor the increments will be exceeded.

Table 2-4 Predicted Class I Area Criteria Pollutant Concentrations

Class I Area of Interest	Maximum Predicted Concentration ($\mu g/m^3$)
	NO_2[1]
	Annual Average
Alpine Lakes Wilderness	0.0097
Mount Rainier National Park	0.0100
Olympic National Park	0.0052
Class I Area Maximum Concentration	0.0100
EPA Proposed SIL[2]	0.1
FLM Recommended SIL[2]	0.03
Class I Area PSD Increment[3]	2.5

1 NO_X was conservatively assumed to be 100 percent converted to NO_2.

2 SIL = Significant Impact Level; EPA proposed and FLM recommended from the Federal Register, Vol. 61, No. 142, p. 38292, July 23, 1996.

3 PSD = Prevention of Significant Deterioration; from 40 CFR 52.21(c), adopted by reference in WAC 173-400-720(4)(a)(v)

Figure 2-4 presents the spatial variation of predicted maximum concentrations over the applicable averaging periods for NO_2 emissions attributable to the Project.

CALPUFF was also used to predict the impacts of acid-forming compounds emitted by the Project on soils and vegetation in regional Class I areas. The deposition analysis results are shown in Table 2-5. There are no promulgated standards for evaluation of these incremental impacts to soils and vegetation in Washington. However, the National Park Service has established Deposition Analysis Thresholds (DATs) for nitrogen of 0.005 kg/ha/yr.[8] These "thresholds" are based on natural background deposition estimates culled from various research efforts, a variability factor, and a safety factor that accounts for cumulative effects. The DATs are not adverse impact thresholds, but are intended as conservative screening criteria that allow the FLMs to identify potential deposition fluxes that require their consideration on a case-by-case basis. As shown in Table 2-5, predicted maximum nitrogen deposition fluxes do not exceed the DATs. Figure 2-5 shows the spatial variation of the predicted nitrogen fluxes attributable to the Project over the entire simulation domain.

[8] Guidance on Nitrogen and Sulfur Deposition Analysis Thresholds, available on the FLAG internet site at http://www2.nature.nps.gov/ard/flagfree/NSDATGuidance.htm

Table 2-5 Predicted Class I Area Deposition Fluxes

Class I Area of Interest	Nitrogen Deposition (kg/ha/yr)
Alpine Lakes Wilderness Area	0.0043
Mount Rainier National Park	0.0031
Olympic National Park	0.0017
NPS DAT	0.0050

Compliance with FLM-recommended criteria for regional visibility impacts was assessed by calculating the change in 24-hour extinction for each Class I receptor. The CALPUFF modeling system was used to predict both the extinction coefficient attributable to emissions from the Project as well as the background extinction coefficients for that day's meteorology. Tables 2-6 and 2-7 list the highest maximum predicted change in extinction at each Class I area using Method 2 and Method 8, respectively.

The only Class I areas with obscurations that might be of concern, where more investigation is warranted, are Mount Rainier NP and Olympic NP. When using Method 2, it is common to investigate whether the days predicted to be obscured due to the proposed project were in fact naturally obscured by weather. These "false positives" are due to the fact that Method 2 uses daily relative humidity values, and is therefore very sensitive to days with fog, rain, or other inclement weather that naturally degrades the visibility. This sensitivity is one of the reasons the FLMs are currently using Method 8 (i.e. following the guidance of FLAG 2008) when making decisions regarding visibility obscuration in Class I areas. Applications are still required to perform and present the results using Method 2, until the FLAG 2008 Draft document becomes official. To that end, Tables 2-8 and 2-9 shows the "top 10" days at Mount Rainier NP and Olympic NP using Method 2.

Rather than present weather codes for the days predicted to be obscured using Method 2, we instead focus on the FLAG 2008 guidance, which suggests a comparison between the 98th percentile visibility degradation predicted using Method 8 with the five percent "just perceptible" limit. As can be seen in Table 2-7, when using Method 8, the 1st highest (as opposed to the 98th percentile) is slightly above the five percent threshold. There is only one day in the 3-year period with over 5 percent change. The 98th percentile values for Mount Rainier NP are all below the five percent "just perceptible" limit. Table 2-10 presents the Method 8, 98th percentile values for Mount Rainier NP. The percent change is below 5 for Olympic NP and Alpine Lakes WA.

Figure 2-6 presents a contour plot of the maximum predicted visibility degradation (percent change) caused by emissions attributable to the Project, using Method 2. The overall maximum change in extinction predicted by Method 2 occurred on October 4, 2003, in Mount Rainier National Park. The local maximum can be seen in Figure 2-6.

The background extinction assumed in this figure is based on the EPA recommendations for "natural conditions" used to represent low aerosol concentrations and excellent visibility in Class I areas. As such, actual background extinction coefficients in most areas of the domain are considerably higher and the change to extinction would be much less than shown in the figure.

Figure 2-7 presents a contour plot of the maximum predicted visibility degradation using Method 8, which is less susceptible to weather-related obscuration. The overall maximum change in extinction predicted by Method 8 occurred on October 4, 2003, also in Mt. Rainier National Park.

Table 2-6 Maximum Predicted Extinction Change by Class I Area, Method 2

Class I Area	Date	b_{ext}[1] (1/Mm)			Change (%)
		Project	Background[2]	Total	
Mt. Rainier NP	10/4/2003	1.872	19.226	21.098	9.74
Olympic NP	12/2/2005	1.086	18.414	19.500	5.90
Alpine Lakes WA	4/26/2005	0.777	17.473	18.251	4.45

1 Project and background extinction values for daily period that resulted in the maximum percent change in extinction.

2 Background extinction derived from default annual average Western U.S. extinction components provided in FLAG 2000 guidance document.

Table 2-7 Maximum Predicted Extinction Change by Class I Area, Method 8

Class I Area	Date	b_{ext}[1] (1/Mm)			Change (%)
		Project	Background[2]	Total	
Mt. Rainier NP[3]	10/4/2003	0.927	17.946	18.873	5.16
Alpine Lakes WA	10/4/2003	0.829	17.201	18.030	4.82
Olympic NP	12/2/2005	0.800	18.558	19.358	4.31

1 Project and background extinction values for daily period that resulted in the maximum percent change in extinction.

2 Background extinction derived from default annual average extinction components provided in FLAG 2008 Tables.

3 Mt. Rainier NP had only one day during the 3-year period over 5 percent change (the 2nd highest change to extinction was 4.16 percent; and the highest 98th percentile change to extinction was 1.72 percent).

Table 2-8 Top 10 Predicted Extinction Change for Mt. Rainier NP, Method 2

Date	b_{ext}[1] (1/Mm)			Change (%)
	Project	Background[2]	Total	
10/4/2003	1.872	19.226	21.098	9.74
8/14/2005	1.264	15.868	17.132	7.96
5/11/2003	1.247	18.538	19.786	6.73
10/3/2003	0.99	17.569	18.559	5.64
10/4/2004	1.04	19.926	20.966	5.22
6/8/2004	0.688	17.183	17.871	4.00
10/2/2003	0.708	17.843	18.551	3.97
5/2/2003	0.658	16.818	17.476	3.91
5/14/2004	0.617	16.197	16.815	3.81
8/31/2004	0.623	17.912	18.536	3.48

1 Project and background extinction values for daily period that resulted in the maximum percent change in extinction.

2 Background extinction derived from default annual average Western U.S. extinction components provided in FLAG 2000 guidance document.

Table 2-9 Top 10 Predicted Extinction Change for Olympic NP, Method 2

Date	b_{ext}[1] (1/Mm)			Change (%)
	Project	Background[2]	Total	
12/2/2005	1.086	18.414	19.5	5.9
2/26/2005	1.018	18.551	19.569	5.49
12/18/2004	1.063	19.805	20.868	5.37
11/23/2005	1.007	19.152	20.159	5.26
1/2/2004	0.987	20.032	21.019	4.93
3/24/2003	0.786	17.543	18.329	4.48
12/3/2005	0.777	17.403	18.18	4.46
1/25/2005	0.823	18.821	19.645	4.37
12/18/2003	0.793	19.134	19.928	4.15
12/16/2005	0.72	18.673	19.393	3.86

1 Project and background extinction values for daily period that resulted in the maximum percent change in extinction.

2 Background extinction derived from default annual average Western U.S. extinction components provided in FLAG 2000 guidance document.

Table 2-10 98th Percentile Predicted Extinction Change for Mount Rainier NP, Method 8

Year	98th Percentile Change (%) [1]	
	One-Year	Three-Year
2003	1.72	1.58
2004	1.52	
2005	1.40	

1 The 98th percentile for one year is the 8th highest daily value, and the 98th percentile for the three year period is the 22nd highest daily value.

Figures

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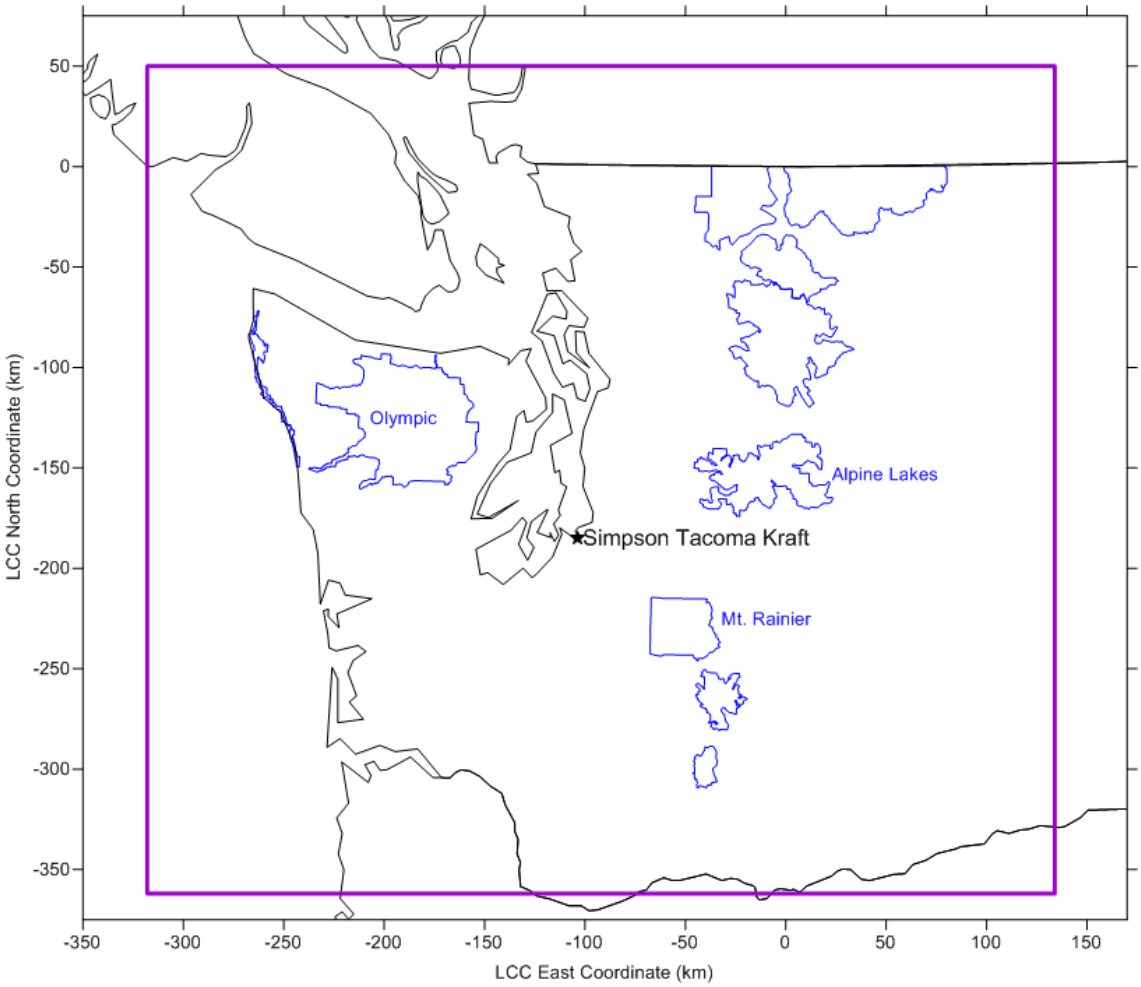

Figure 2-1. Simpson Tacoma Kraft Class I modeling domain (purple box) with selected Class I areas

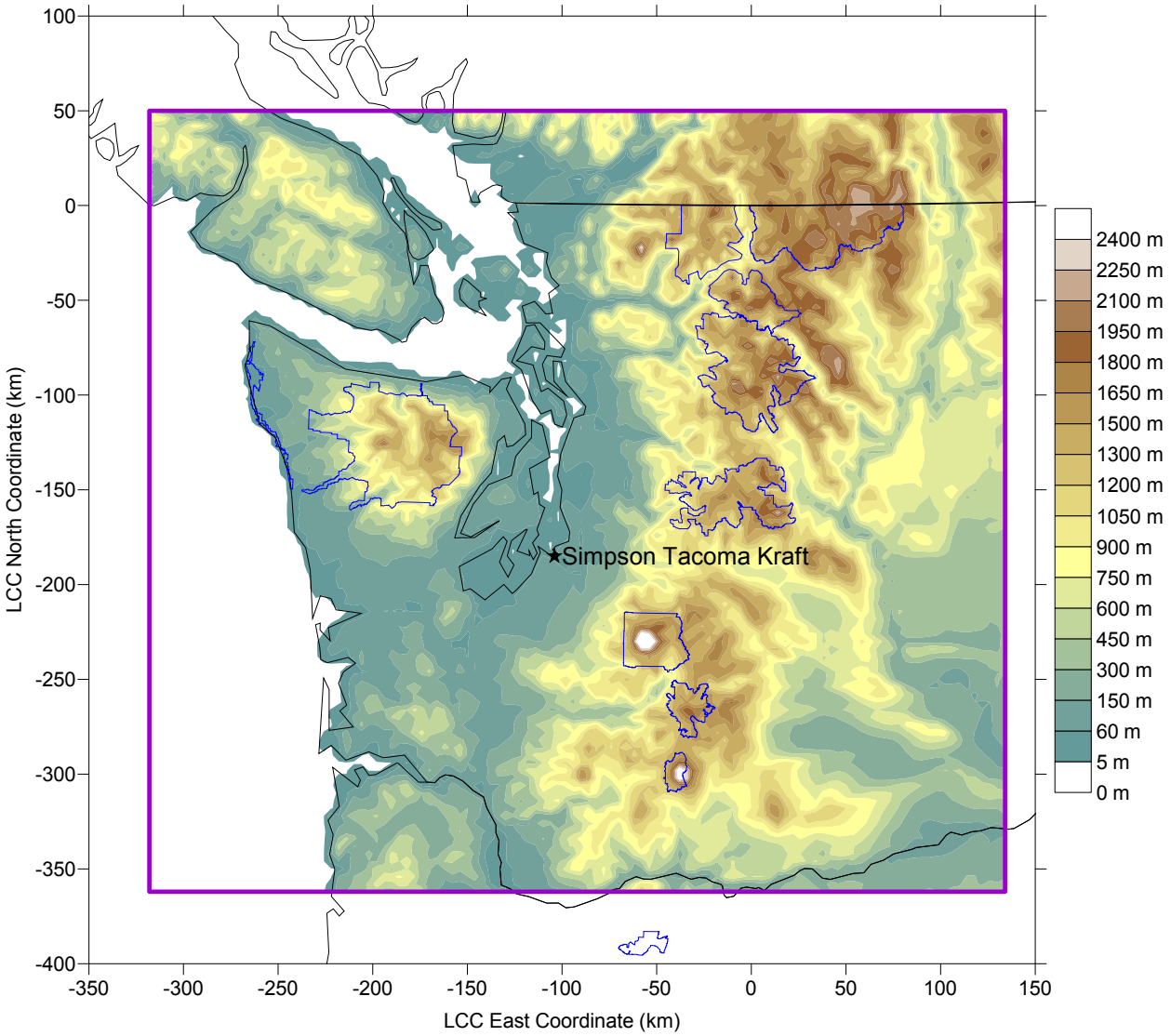

Figure 2-2. Simpson Tacoma Kraft Class I modeling domain terrain

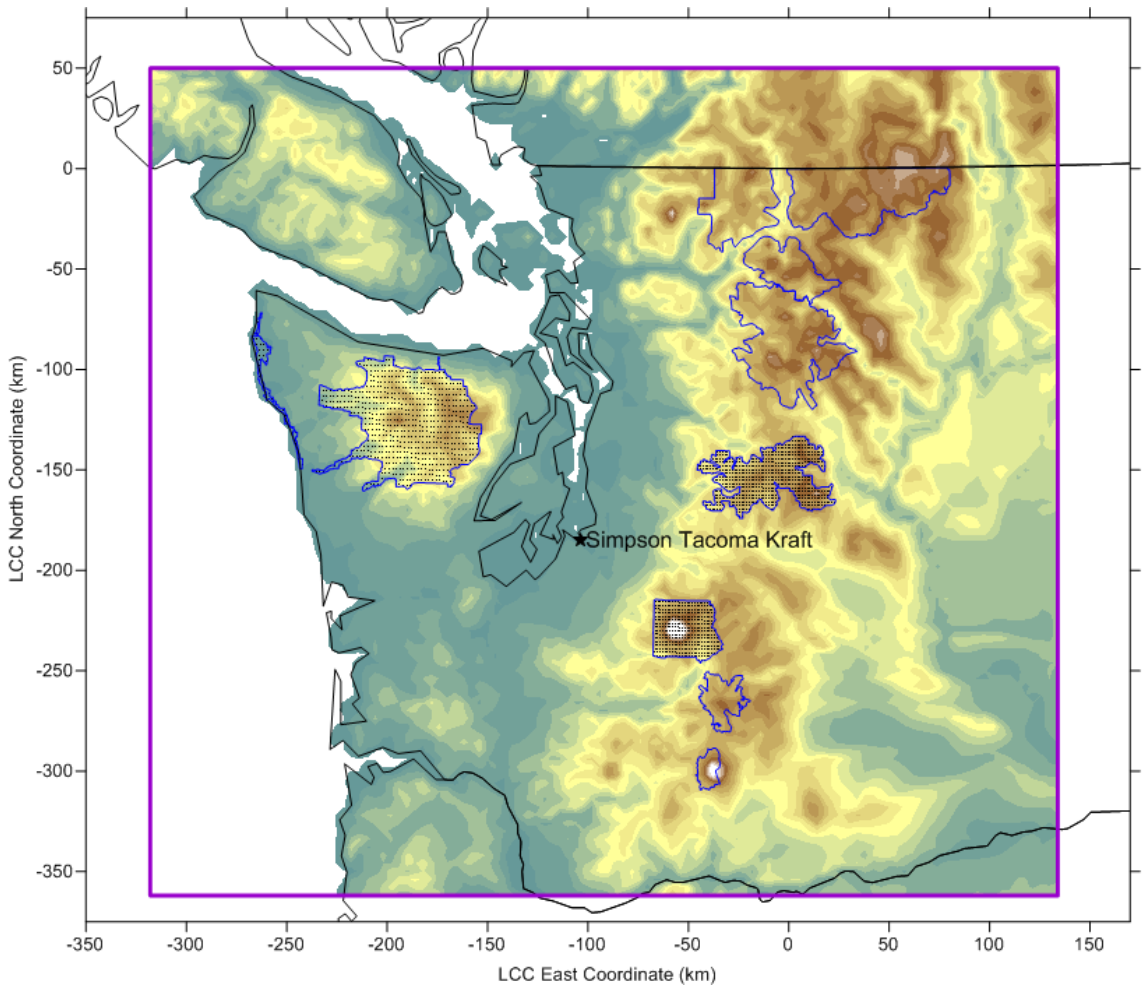

Figure 2-3. Simpson Tacoma Kraft Class I receptors

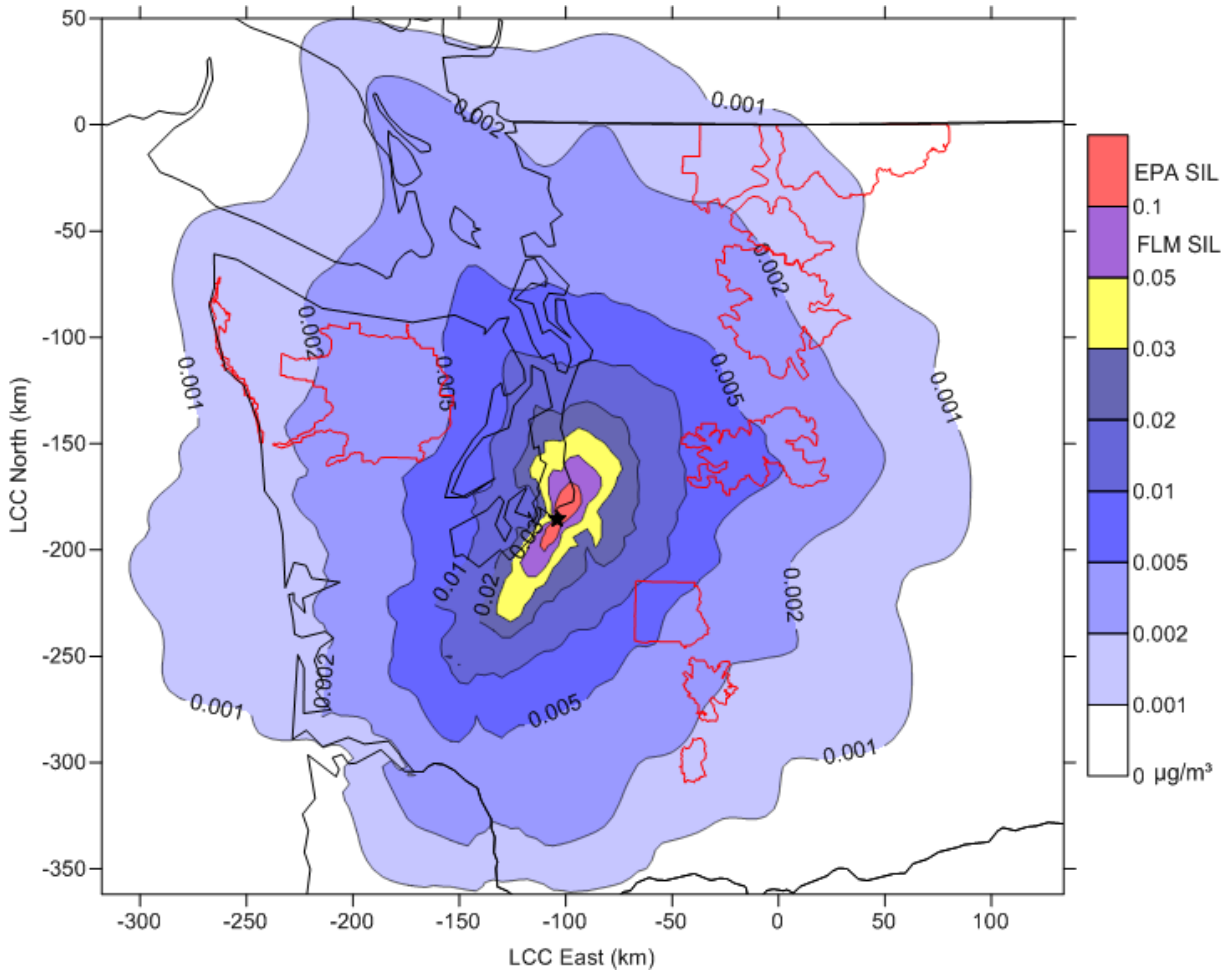

Figure 2-4. Maximum Predicted Annual NO_2 Concentration (µg/m^3)

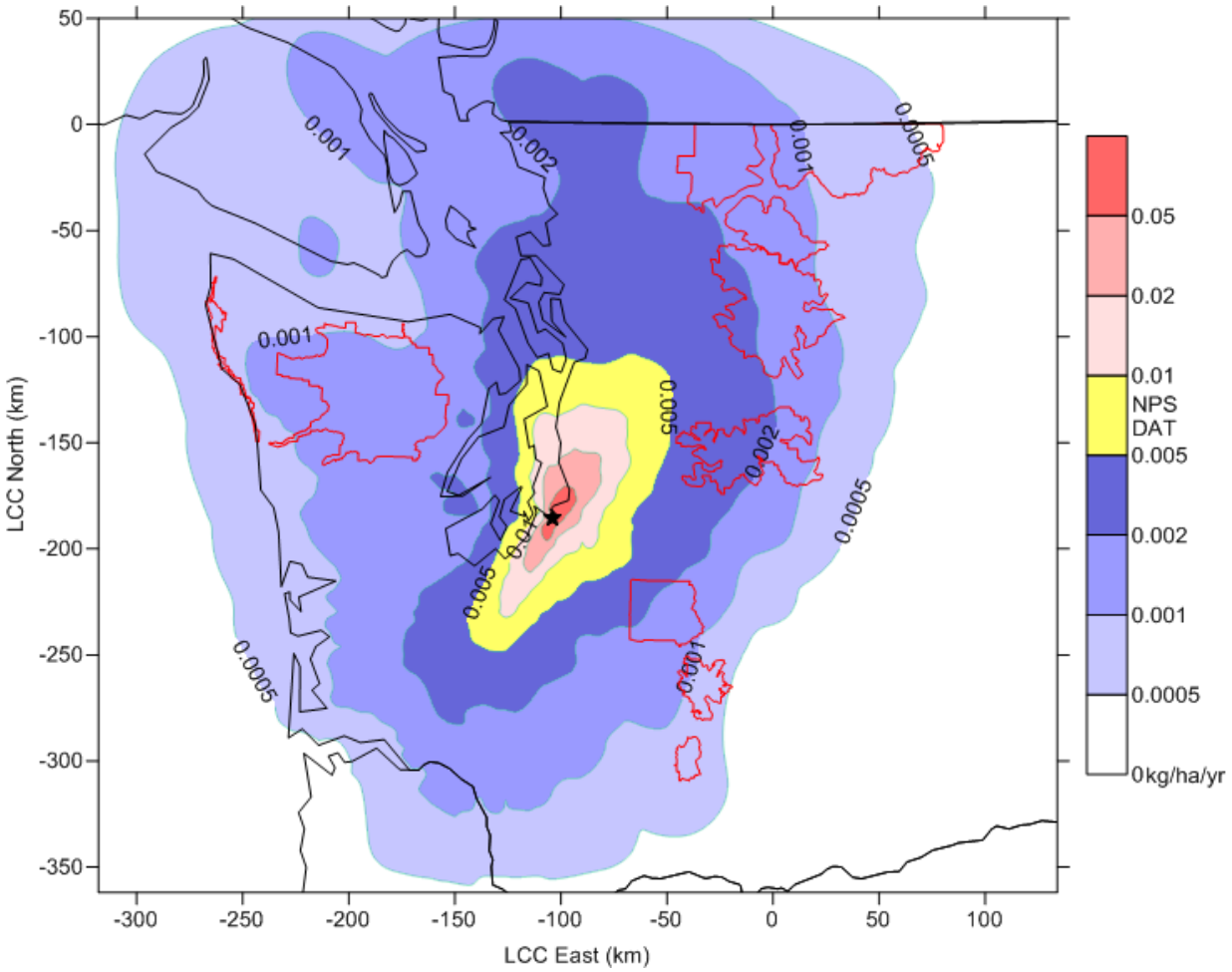

Figure 2-5. Maximum Predicted Annual Nitrogen Deposition (kg/ha/yr)

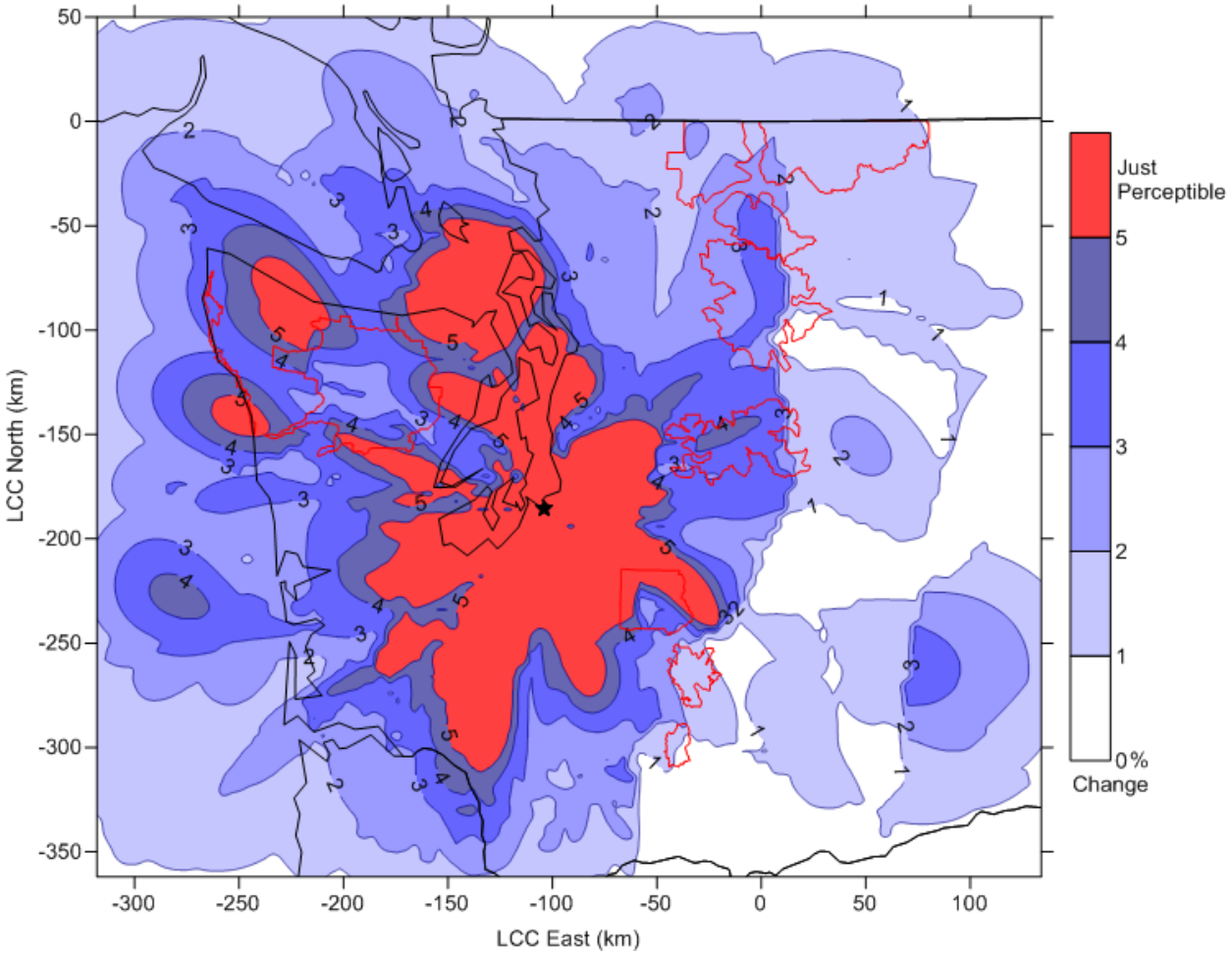

Figure 2-6. Maximum Predicted Daily Visibility Degradation, Method 2 (Percent Change)

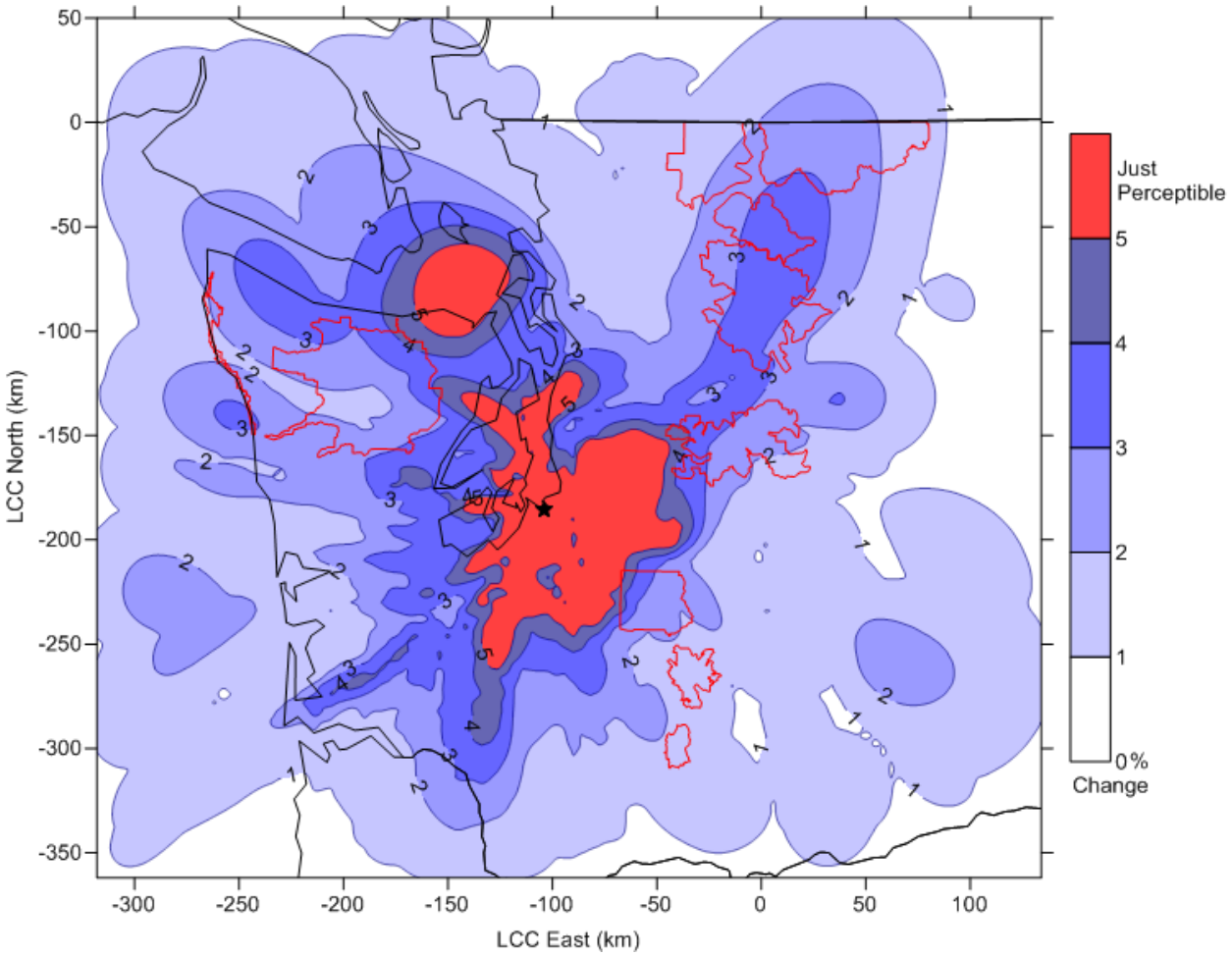

Figure 2-7. Maximum Predicted Daily Visibility Degradation, Method 8 (Percent Change)

APPENDIX E

OZONE AIR QUALITY ANALYSIS REPORT

PSD Amendment for Power Boiler No. 7
NO_2 Air Quality Analysis
Simpson Tacoma Kraft Company
801 Portland Avenue
Tacoma, WA 98421

August 2010
Project: 108.00217.00024

SIMPSON TACOMA KRAFT CMAQ MODELING STUDY REPORT

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March 24, 2010

EXECUTIVE SUMMARY

SLR International Corp (SLR) employed a team led by Professor Brian Lamb of the Washington State University Laboratory for Atmospheric Research (WSU), to conduct a modeling study of the air quality effects of proposed permit limit changes at the Simpson Tacoma Kraft Company, LLC (Simpson or STK) Kraft pulp and paper mill located in Tacoma, WA. The modeling team used the Community Multi-scale Air Quality ("CMAQ") modeling system (EPA, 1998; EPA, 1999). Effects on ambient ozone concentrations were simulated by applying CMAQ for two one-week scenarios that were selected in cooperation with SLR and the Washington Department of Ecology Air Quality ('Ecology'). Two cases were modeled for each scenario, a Base Case representing emissions prior to the Power Boiler No. 7 modifications and a STK case representing the new, revised limits for NOx and maximum potential emissions proposed in the 2006 PSD permit for VOCs and CO. There were also minor stack parameter changes that were associated with modifications to the modeled boiler. Thus, CMAQ modeling was performed to support Simpson's application to increase NOx permit limits being submitted to Ecology for the Power Boiler No. 7. The modeling effort is briefly described and the results are summarized in the remainder of this executive summary; a discussion of the modeling effort and results are also provided in more detail in the following sections of the report.

The modeling team represents extensive experience with the development and application of air quality simulation systems, such as the AIRPACT-3 system applied in this project. WSU has extensive experience applying the CMAQ chemical transport model (Barna et al., 2000; Barna, Lamb and Westberg, 2001; Avise et al., 2003; O'Neill and Lamb, 2004; O'Neill et al., 2004; Chen et al., 2004; Vaughan et al., 2004; and Chen et al., 2008).

The CMAQ model was used to simulate two one-week periods (scenarios) in summer 2008, during which periods elevated levels of ozone had occurred in the Puget Sound area: June 24 through July 1 (the 'June scenario') and August 12 through August 18 (the 'August scenario'). In order to quantify the potential contribution to ozone in the region from the new proposed emission limits at the STK plant, two cases, for two different emissions descriptions, were modeled for each scenario: the Base Case for pre-project emissions and the STK Case for the proposed new emission limits.

The modeling was conducted for the AIRPACT-3 domain, a tessellated 3-D computational space of 12-km grid cells (north-south and east-west) of 95 by 95 cells and 21 layers of increasing thickness with increasing height. The analysis was carried out for a sub-domain as shown in Figure 1.

CMAQ model results for the June 2008 scenario show 8-hr average ozone at a maximum of ~90 ppb for both cases (Figure 6). Model results for the June 2008 scenario show 8-hr average ozone was increased for the STK case over the Base Case by a maximum of 0.087 ppb (87 ppt; Figure 7), and also broad areas where ozone is suppressed. The maximum increase in 8-hr ozone for the June 2008 scenario during the occurrence of the scenario's maximum 8-hr ozone is 0.066 ppb (66 ppt) and is located some tens of km northwest from the location of the maximum (Figure 8).

CMAQ model results for the August 2008 scenario show 8-hr average ozone at a maximum of ~112 ppb for both cases (Figure 9). Model results for the August 2008 scenario show that the 8-hr average ozone was increased for the STK case over the Base Case by a maximum of 0.090 ppb (Figure 10). The maximum increase in 8-hr ozone for the August 2008 scenario during the occurrence of the scenario's maximum 8-hr ozone is ~0.052 ppb (52 ppt; Figure 11) and shares some co-location with the areas of high ozone (Figure 9). Taking both scenarios together, the maximum increases of 8-hr ozone are less than 0.1 ppb for scenario maxima of ≤ ~110 ppb, or less than 0.1% increase in 8-hr ozone.

Emissions changes specified by SLR for volatile organic compounds (VOCs), nitrogen oxides NO and NO2 (NOx) and carbon monoxide (CO) at STK, and as modeled by WSU, resulted in minor apparent changes to the total emissions of these pollutants within the modeling domain. The increases in potential emissions over baseline were factors of 2.3 for VOC, 2.7 for NOx and 2.6 for CO. The combination of the emissions changes and stack specific plume rise behavior result in differing emissions into the vertical layers of the model atmosphere, primarily into layers 3 and 4, with NOx increases of up to ~0.32 moles/s and occasionally, reduced emissions into a particular layer (Figures 2 and 3). These layer-specific increases are driven by the increases in total emissions, while the layer-specific reductions may reflect the specific interactions of the changes in stack parameters and the prevailing (hourly) meteorology. The VOC emissions exhibit similar increases for emissions into layers, with increases of up to ~0.021 moles/s and also similar layer-specific decreases observed (Figures 4 and 5).

For the June 2008 scenario, surface layer increases in modeled NOx for the STK Case over the Base Case were as much as 4% on June 29 (Figure 12), with a coincident VOC increase of 0.3%. Both of these NO_X and VOC increases are collocated in the cell containing the STK source (Figure 13). The August 2008 scenario shows similar results, with NOx increase of ~2% and a VOC increase of ~1% on August 16 (Figures 14 and 15).

To summarize, this modeling exercise suggests that ozone enhancement by the proposed (modeled) emissions limit changes will be quite small, and is not expected to affect significantly 8-hr ozone maximum values during conditions like those modeled. Therefore, the proposed increase in the NOx emissions limit is not expected to cause or contribute significantly to a violation of the National Air Quality Standard for ozone

(End of Executive Summary)

1. INTRODUCTION

Simpson currently operates a Kraft pulp and paper mill at 801 Portland Avenue in Tacoma, Washington as authorized under the Air Operating Permit 000085-0. Simpson received a PSD permit (PSD-06-02) from Ecology on May 22, 2007 to install a steam turbine electrical generator driven by steam produced from the existing Recovery Furnace No. 4 and Power Boiler No. 7 (referred to as the Cogen Project). This project allows the facility to cogenerate and distribute electric power to the grid. As part of this project, Power Boiler No. 7 was to be modified to increase its maximum continuous steaming capacity from 300,000 lb/hr to 340,000 lb/hr, produce higher pressure and temperature steam, and use biomass fuel to support the entire steam production.

Simpson is seeking to amend the PSD permit to increase the NOx emission limit for the Power Boiler No. 7. This requires reopening the air quality analysis and consideration of current regulatory requirements in the analysis. As such and per 40 CFR 52.21(i)(5), an ambient impact analysis is required for any net emissions increase of 100 tons per year or more of nitrogen oxides subject to Prevention of Significant Deterioration (PSD) permitting. Although Simpson is only requesting an increase in the NOx emission limit, the net emission increase (as that term is defined under 40 CFR 52.21 - PSD regulations) of VOC proposed in the 2006 PSD permit was also modeled in order to develop a more complete analysis of the effect on regional ozone formation as a result of the entire Cogen Project.

On behalf of Simpson, SLR employed a team led by Professor Brian Lamb of the Washington State University Laboratory for Atmospheric Research (WSU), to conduct a modeling study of the air quality effects of proposed permit limit changes at the Simpson Tacoma Kraft (STK) plant located in Tacoma, WA. The modeling team used the Community Multi-scale Air Quality ("CMAQ") modeling system (EPA, 1998). The CMAQ model and the AIRPACT-3 air quality forecasting system are further described below, following the description in Chen et al. (2008).

Effects on ambient ozone concentrations were simulated by applying CMAQ for two one-week scenarios that were selected in cooperation with SLR and the Washington Department of Ecology Air Quality ('Ecology'). Two cases were modeled for each scenario, a Base Case representing emissions prior to the Power Boiler No. 7 modifications and a STK case representing new,

revised limits for NOx and maximum potential emissions proposed in the 2006 PSD permit for for VOCs and CO. There were also minor stack parameter changes that were associated with modifications to the modeled boiler. A discussion of the modeling effort and results are provided in more detail in the following sections of the report.

The CMAQ model was used to simulate two one-week periods (scenarios) in summer 2008, during which periods elevated levels of ozone had occurred in the Puget Sound area: June 24 through July 1 (the 'June scenario') and August 12 through August 18 (the 'August scenario'). Meteorology for these scenarios was obtained from AIRPACT-3 runs archived at WSU in 2008. The modeling was conducted using the AIRPACT-3 domain, a tessellated 3-D computational space of 12-km grid cells (north-south and east-west) of 95 by 95 cells and 21 layers of increasing thickness with increasing height. The analysis was carried out for a sub-domain as shown in Figure 1.

2. MODEL DESCRIPTION

CMAQ and the AIRPACT-3 air quality forecasting system

This section ('2') provides a description of the CMAQ model and AIRPACT-3 system, and is largely an extraction of text from the paper by Chen et al., (2008), with some edits and simplifying elisions. Section numbers, and references to figures, tables and references correspond or refer to those in the original paper and are not reproduced here, except for Table 4, describing the modeling system skill for ozone simulation, which is included.

2.1. Chemical Transport Model

The core photochemical transport model (CTM) in AIRPACT-3 is the CMAQ Chemical Transport Model (CCTM, version 4.6). The model accounts for chemical interactions for compounds in gas, aqueous and aerosol phases. The chemical mechanism applied in the model is the ''saprac99_ae4_aq'', with the SAPRC99 gas-phase chemical mechanism [Carter, 2000] and aerosol module (version 4) that includes the ISORROPIA secondary inorganic aerosol algorithms [Nenes et al., 1998] and the SORGAM secondary organic aerosol formulations [Schell et al., 2001]. The aerosol module contains aerosol process dynamics for nucleation, coagulation, condensation, evaporation and dry deposition [Binkowski and Roselle, 2003]. Wet deposition of both aerosol and gas-phase compounds are included in cloud processes that scavenge chemical species via aqueous chemistry and attenuate incoming shortwave radiation that is important for photolytic reactions.

2.2. Model Domain

The AIRPACT-3 domain, shown in Figure 1, encompasses all of Washington, Oregon and Idaho along with portions of bordering states and Canadian provinces. The domain consists of 95 by 95 horizontal grids at 12 km grid resolution. Vertically, there are 21 layers, with the bottom first layer at approximately 35 m above the surface. In the configuration used for this evaluation, AIRPACT-3 provides a 24-h air quality forecast beginning at 8-h GMT (0-h PST) for the next day. The system is initiated daily at midnight and is able to complete the entire simulation and post processing in less than 4 h with graphical output available by approximately 4 am local time. Recently, the system was extended to provide 64-h forecasts, but these longer term forecasts are not considered in the evaluation presented here

2.3. Meteorology

The forecast meteorology for AIRPACT-3 comes from the Mesoscale Meteorological model (MM5 version 3.7.3) [Grell et al., 1994] operated by Mass and colleagues at the University of Washington (http://www.atmos.washington.edu/mm5rt). The MM5 forecast system provides hourly, 3-D gridded meteorological variables over the Pacific Northwest region at 36-, 12-, and 4-km grid resolutions with 37 vertical levels for the next 48 to 72 h. For the work presented here, the AIRPACT-3 system uses the 12-km MM5 output initialized with the 00Z-h data from the National Center for Environmental Prediction (NCEP) GFS model results. Initialization with global forecast model driven by observations is necessary for forecast meteorology to keep the model from going astray over an extended simulation period. In the AIRPACT-3 system, the 00Z initialized MM5 outputs are spun-up for 8 h before being used in the CMAQ for air quality forecast. More information, including model configuration and overall performance, of the MM5 forecast simulations are discussed by Mass et al. [2003] and on the University of Washington-MM5 website. The AIRPACT-3 system is initiated nightly after the meteorological results from MM5 become available.

2.4. Emissions

The AIRPACT-3 emission subsystem includes emission processing steps to generate gridded, hourly data that reflect the projected emission activity across the modeling domain. The subsystem is initiated daily to process emissions from four major categories: anthropogenic, biogenic, ammonia emissions from dairy operations, and wild fire emissions. Table 1 summarizes average emissions by source categories in the domain. Overall, the anthropogenic mobile sources represent the bulk of NOx emissions. VOC emissions for the modeling period are dominated by

biogenic and fire sources. Fire events also produce significant amounts of primary PM emissions compared to anthropogenic sources.

2.4.1. Anthropogenic Emissions

The Sparse Matrix Operator Kernel Emissions (SMOKE) model version 2.1 [Houyoux et al., 2000; Carolina Environment Programs, 2005] was modified to process anthropogenic emission categories for each forecast simulation. Area and non-road mobile emissions are based on the 2002 EPA National Emission Inventory data set (available at http://www.epa.gov/ttn/chief/net/2002inventory.html) and adjusted to year 2005 with county and source specific projection factors from the EPA Economic Growth Analysis System (EGAS) software [U.S. EPA, 2006]. On-road mobile emissions are generated outside the SMOKE framework using emission factors from the EPA MOBILE v6.2 model [U.S. EPA, 2003] and the 2005 state specific activity data. Emissions are generated at a normalized temperature of 30° C such that adjustments for the evaporative loss emission fraction can be applied during each forecast simulation. The mobile emission temperature adjustment factors were region specific and generated from the MOBILE v6.2 model. The point source inventory is based on the same national data set with updates by the emissions workgroup within NW-AIRQUEST to reflect 2005 operation activities for Washington, Idaho and Oregon. Anthropogenic emissions over provinces of British Columbia and Alberta, Canada are included from a 2000 inventory [GVRD Canada, 2002].

The hourly distribution of emissions in SMOKE accounts for month, weekday/weekend/holiday activity differences by source categories for each simulation day. Mobile source emissions are adjusted with temperature dependent emission factors and the hourly forecast MM5 temperatures. Point source emissions are distributed vertically for active plume rise with MM5 forecast meteorology.

In the current setup, due to a lack of specific dairy information, ammonia emissions for Idaho and other areas were taken from the EPA national inventory data set and processed in SMOKE. Ammonia emissions from other sources such as fertilizer application, feedlot operations and industrial activities are included and processed as part of the anthropogenic inventory.

2.5. Initial and Boundary Conditions

In AIRPACT-3, initial conditions for each forecast period are read from the results of last simulation hour of the previous day's forecast. This model restart approach maintains the continuity of chemical conditions between periods and reduces the need for model spin-up associated with static initial conditions. If the necessary hour is not available from a suitable, previous run, then default initial conditions are used to begin the run.

The chemical boundary conditions in AIRPACT-3 are compiled from the MOZART-2 (Ozone and Related Chemical Tracers version 2) [Horowitz et al., 2003] global chemical model to account for seasonal variability of ozone and other chemical species throughout the year [Weiss-Penzias et al., 2004]. Long-term MOZART-2 simulation results (1990–1999) were diurnally averaged by month and grid across the forecast domain. The resulting boundary conditions are diurnal concentrations of species that change by month and location. Recent model studies have investigated the effects of using global model output as boundary conditions for regional air quality modeling and showed improvements to model performances [Barna and Knipping, 2006; Tong and Mauzerall, 2006]. Since AIRPACT-3 operates throughout the year, results from global chemistry model provide the most complete and relevant information, and reflect the seasonality of pollutants and pollutant precursors into the forecast domain. For the month of August and September the ozone boundary conditions from MOZART-2 is similar to those defined in the CMAQ default profile with surface level mixing ratio at 30 to 35 ppbv. The ozone boundary condition starts to differ near the tropopause with MOZART-2 having higher levels than the default CMAQ profile.

2.6 Model performance for CMAQ inAIRPACT-3

Evaluation has shown that AIRPACT-3 running CMAQ has appreciable skill in simulating 8-hr ozone, as judged against standard ozone monitor results for the AIRPCT-3 domain (Table 1).

Table 1 (from Chen et al., 2008). Summary of AIRPACT-3 Forecast Performance Statistics for Daily Maximum 8-h Ozone for August–September 2004

Number of observations (from 30 stations)	1033
Mean Bias, ppbv	2.7
Mean Error, ppbv	7.2
Normalized Mean Bias	6%
Normalized Mean Error	17%
Predicted mean, ppbv	46
Measured mean, ppbv	43

(End of Model Description Section)

3. AIRPACT-3 AND CMAQ MODEL APPLICATION FOR STK STUDY

Scenarios and Cases for simulation of the STK application emission limits

The CMAQ model was used to simulate two one-week periods (scenarios) in summer 2008, during which periods elevated levels of ozone had occurred in the Puget Sound area: June 24 through July 1 (the 'June scenario') and August 12 through August 18 (the 'August scenario'). These scenarios were selected in cooperation with SLR and Ecology.

Meteorology for the scenarios

Meteorology for these scenarios was obtained from AIRPACT-3 runs archived at WSU in 2008 from the original AIRPACT-3 runs for those periods. In order to quantify the potential contribution to ozone in the region from the new proposed emissions at the STK plant, two cases, for two different emissions descriptions, were modeled for each scenario: the Base Case for emissions as usual and the STK Case for the proposed new emission limits.

Modeling domain

The modeling was conducted for the AIRPACT domain, a tessellated 3-D computational space of 12-km grid cells (north-south and east-west) of 95 by 95 cells and 21 layers of increasing thickness with increasing height. The analysis was carried out for a sub-domain of the AIRPACT-3 domain, as shown in Figure 1.

Initial Conditions

In contrast to the ongoing AIRPACT-3 forecasting applications described in section 2, in this STK study, the initial conditions at the beginning of each of the two scenarios are taken from generic initial conditions, not from model results from the preceding period. For all days after the first days of these two scenarios, the initial conditions are taken from the ending hour of the preceding day. The first day of results is ignored in the analysis, in effect discarding that day as a spin-up period.

Boundary Conditions

The boundary conditions are taken from MOZART-modeled results for the relevant month, as described in section 2.

Emissions

Different emissions conditions were represented in the two *cases* modeled for each scenario (period), a Base Case business-as-usual emissions case and a STK case representing the new emission limit for NOx and maximum potential emissions proposed in the 2006 PSD permit for VOC and CO. The STK case included increases in NOx, VOCs, and CO (Table 2). Emissions for the Base Case are the baseline actual emissions calculated in the 2006 PSD permit. These emissions are based on the 2-year average actual emissions from 2000 to 2001 for NOx, 2001 to 2002 for VOC, and 2004 to 2005 for CO.[1] Emissions for the STK case are the proposed potential emissions after the modification to Power Boiler No. 7. For VOC and CO these emission rates are the limits in the PSD-06-02 permit. The NOx emission rate is the proposed new limit in the amendment application. There were also minor stack parameter changes that were associated with the modifications to the modeled boiler (Table 3).

Emissions changes specified by SLR for volatile organic compounds (VOCs), nitrogen oxides NO and NO2 (NOx) and carbon monoxide (CO) at STK, and as modeled by WSU, resulted in minor apparent changes to the total local emissions of these pollutants within the modeling domain. The increases in potential emissions over baseline specified were factors of 2.3 for VOCs, 2.7 for NOx and 2.6 for CO. Theses emissions increases were coded into a revised point sources inventory file (Table 4) and processed using SMOKE.

The combination of the emissions changes and stack specific plume rise behavior result in differing emissions fluxes into the vertical layers of the model atmosphere, primarily into layers 3 and 4. NOx emissions show increases of up to ~0.32 moles/s and occasionally, reduced emissions into a particular layer (Figures 2 and 3). Increases are driven by the increases in total emissions, while the layer -specific reductions may reflect the specific interactions of the changes in stack parameters and the prevailing (hourly) meteorology. The VOC emissions exhibit similar increases for emissions into layers, with increases of up to ~0.021 moles/s and also similar layer-specific decreases (Figures 4 and 5).

[1] 40 CFR 52.21(b)(48)

Table 2. Simpson Tacoma Kraft Power Boiler No. 7 Emissions for Ozone Modeling (SLR).

	CO [tpy]	NOx [tpy]	VOC [tpy]
Base Case	357	289	23
STK Case	913	782	52

Table 3. Simpson Tacoma Kraft Power Boiler No. 7 Stack Parameters for Ozone Modeling

	Stack Height (ft)	Exit Temp (F)	Exit Vel. (ft/s)	Stack Diam. (ft)
Base Case (1)	175.0	384	129 (3)	7.0
STK Case (2)	175.0	430	81	7.0

(1) Provided by Washington Dept of Ecology, 2001-2002 emissions inventory.
(2) Provided by SLR.
(3) Erroneous exit velocity was used in Base Case. Subsequent modeling with corrected exit velocity of 65 ft/s showed negligible differences of less than1 ppb in hourly ozone between the corrected Base Case and STK run for a maximum ozone day.

Table 4. Results showing difference between Base Case (left) and STK Case (right) point source emissions specification files used for input to SMOKE processing, reflecting values shown in Tables 1 and 2 for Base Case and STK.

```
Base Case

530530008
25
25
02
SIMPSON TACOMA KRAFT
10200902
175 (stack height)
7.00  (stack diameter)
384    (exit gas temperature)
4983.33  (flow rate)
129.49  (exit velocity)
2621
47.26167
122.42278
0 0 0 0 0 0
3.5700e+02    (CO)
0 0
2.8900e+02    (NOx)
8.0000e+00
8.0000e+00
3.0000e+00
2.3000e+01    (VOC)
```

```
STK Case

530530008
25
25
02
SIMPSON TACOMA KRAFT
10200902
175
7.00
430
(flow rate - calculated if not given)
81.5
2621
47.26167
122.42278
0 0 0 0 0 0
9.1300e+02
0 0
7.8200e+02
8.0000e+00
8.0000e+00
3.0000e+00
5.2000e+01
```

In the Base Case, all other emission sources (besides Power Boiler No. 7), including point sources, biogenic sources, mobile sources, and anthropogenic area sources were modeled at estimated actual emission rates. Estimated actual emission rates for other Base Case sources were based upon the average of emissions for 2000 and 2001, as reported to the appropriate local/state agencies. In the STK Case, emissions are modeled as the maximum allowable emission rates proposed in the application to Ecology for Power Boiler No. 7, while all other sources, including other substantial point sources in the region, biogenic emission sources, mobile sources, and anthropogenic area sources are modeled at the same rates as in the Base Case. Thus, except for the Power Boiler No. 7 emissions, the Base Case and STK case emissions are essentially identical.

4. RESULTS DISCUSSION

Discussion of modeling results for comparison

In this discussion we review the results for differences between the two emissions cases modeled for the two scenarios. To analyze these two scenarios for the two cases several chemical species and emissions types were extracted, calculated, and visualized. Running 8-hr ozone averages were computed hourly for the second through last days of both cases for each scenario; the first day was regarded as a spin-up period and thus ignored, except that the last eight hours of the first day contributed to the first 8-hr average ozone result for 00 PST of the second day. The Base case results were used to identify the times and locations of scenario ozone maxima. The 8-hr ozone average results *bias*, computed as *STK Case minus Base Case*, were reviewed to identify the timing, location, sign and magnitude of the differences in results. Additionally, NOx and VOC emissions were extracted, for both point emissions and all emissions. Also, NOx and VOC concentrations (mixing ratios) were computed. Two additional topics are discussed next, the units being used in this discussion and the computation of the VOC values from emissions and CMAQ results. The remaining sections discuss the CMAQ results from the June scenario and then for the August scenario.

Units for CMAQ modeling for emissions and ambient species

In the CMAQ modeling system as implemented in AIRPACT and as applied in this project, gas phase (chemical species) emissions such as NOx, VOCs, CO are described as a flux in units of moles per second (moles/s) into a grid cell and layer (12 km square and with depth varying with

height. Ambient concentrations for NOx, VOCs and ozone are expressed by CMAQ in units of mixing ratio, or parts per billion (ppb). Because the differences between the mixing ratios modeled for the different cases are quite small, it is also appropriate to describe these mixing ratio differences in terms of parts per trillion (ppt).

VOC definition

The category of compounds referred to as VOCs includes numerous gas phase chemical species; and the reactive significance of these constituents varies across the component species. For the CMAQ model, VOC emissions are speciated into numerous constituents. When reporting results from CMAQ, for this project, the constituent species are summed resulting in units of moles/s for emissions and ppb or ppt for concentration (mixing ratio). Table 5 shows the species summed for VOCs.

Table 5. Species summed for VOCs in AIRPACT CMAQ results for Base Case and STK. (Species further defined in SAPRC mechanism documents at http://www.engr.ucr.edu/~carter/SAPRC).

HCHO	MEOH	MEK
CCHO	ACET	PHEN
RCHO	GLY	MGLY
CRES	BALD	ETHENE
ISOPRENE	TRP1	ALK1
ALK2	ALK3	ALK4
ALK5	ARO	ARO
OLE1	OLE2	

CMAQ results for June 2008 scenario

The 8-hour average ozone CMAQ results for the base case show an ozone maximum of ~90 ppb at 18 PST (6 PM) on June 29 in the Columbia Gorge area east of Portland with another weaker ozone maximum occurring at that time in eastern Pierce County WA (Figure 6). The June scenario maximum *bias* in 8-hr ozone, 87 ppt (or about 0.1 % of the 90 ppb maximum), also occurs on June 29, but at 8 PST (8 AM), ten hours earlier, and farther west in Pierce County, east of Tacoma and south of Seattle (Figure 7). By the time of the 8-hr ozone maxima noted above, the biases in the vicinity of both those maxima are negative, (Figure 8) indicating that those ozone maxima are reduced in the STK case. Elsewhere the maximum ozone enrichment at this time is 65 ppt in Jefferson County and Mason County; this ozone enrichment is less than 0.1% of the maxima shown in Figure 6. Where a maximum was found south-east of the Puget Sound, the STK case shows reduction of ozone, likely by NOx titration by ozone, by as much as 0.5 ppb (500 ppt).

CMAQ results for August 2008 scenario

The 8-hour average ozone CMAQ results for the base case show an ozone maximum of ~112 ppb at 19 PST (7 PM) on August 16 in the Portland area with another weaker ozone maximum of ~70-80 ppb stretching through Cowlitz, Lewis and Pierce Counties WA (Figure 9). However, the August scenario maximum *bias* in 8-hr ozone, 90 ppt (less than 0.1 % of the 112 ppb maximum) occurs on August 15, at 9 PST (9 AM), more than a day earlier, in Pierce County, south-east of Tacoma and Seattle (Figure 10). By the time of the 8-hr ozone August maxima, the biases in the vicinity of both those 8-hr ozone maxima (Figure 9) are broadly negative or weakly positive, except for ~50 ppt enhancement in Pierce County, WA, (Figure 11) indicating that those ozone maxima are at least partially reduced in the STK case.

CMAQ results for NOx and VOCs

For the June 2008 scenario, surface layer increases in modeled NOx for the STK Case over the Base Case were as much as 4% on June 29 (Figure 12) with a coincident VOC increase of 0.3% (Figure 13). These NOx and VOC changes are collocated in the cell containing the STK source (Figures 12 and 13). The August 2008 scenario shows similar results, with a NOx increase of ~2% and a VOC increase of ~0.1%, on August 16 (Figures 14 and 15).

CONCLUSION

To summarize, this modeling exercise suggests that ozone enhancement by the proposed emissions changes will not appreciably alter 8-hr ozone results. The maximum increases of 8-hour ozone modeled are less than or equal to about 90 ppt for scenario 8-hour ozone maxima of ~110 ppb, or less than 0.1% increase in 8-hr ozone, calculated as running 8-hr average. Based on these modeling results, we conclude that the emissions changes modeled, of and by themselves, are not expected to have an appreciable impact on ozone NAAQS violations in the Puget Sound region.

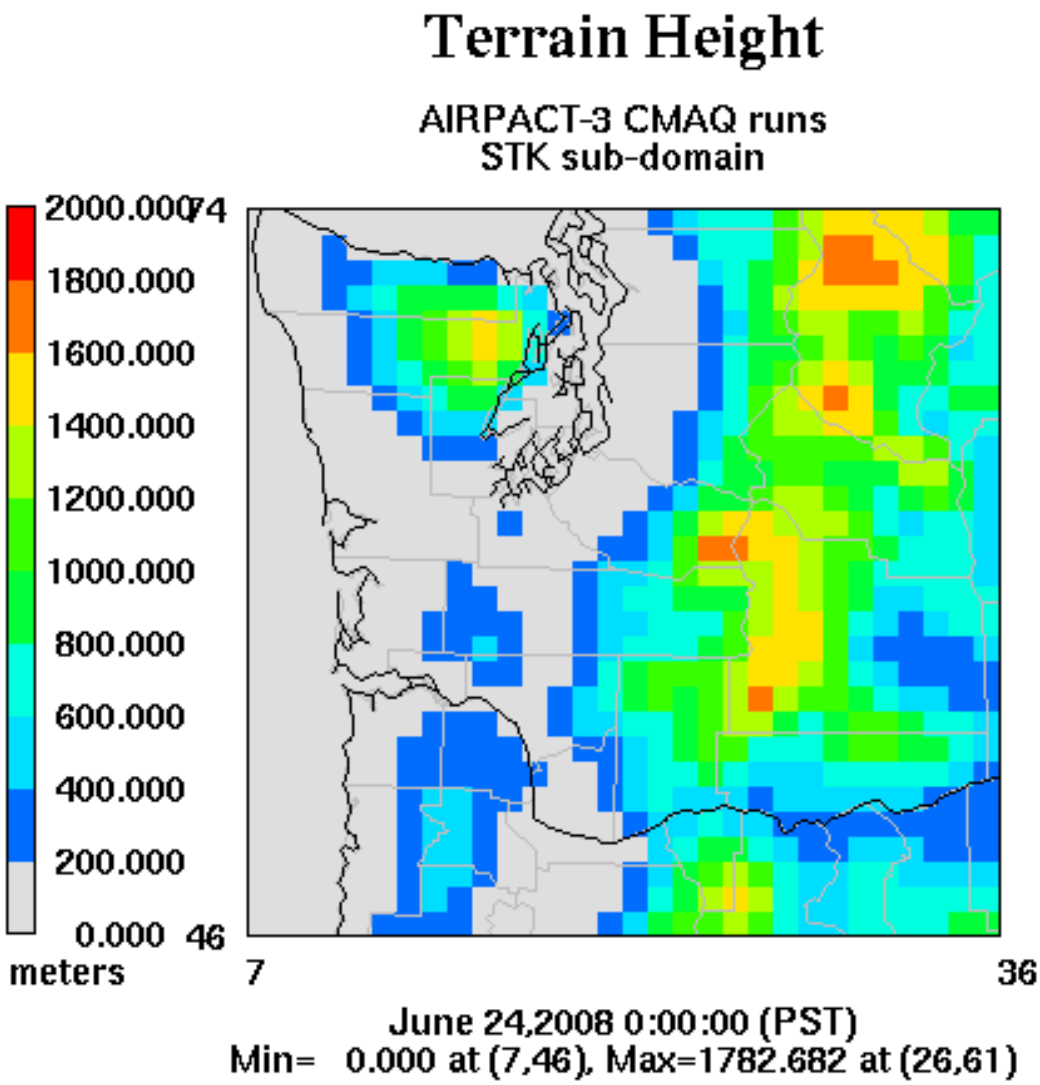

Figure 1. Terrain map of sub-domain of AIRPACT-3 modeling domain used for the Simpson Tacoma Kraft study.

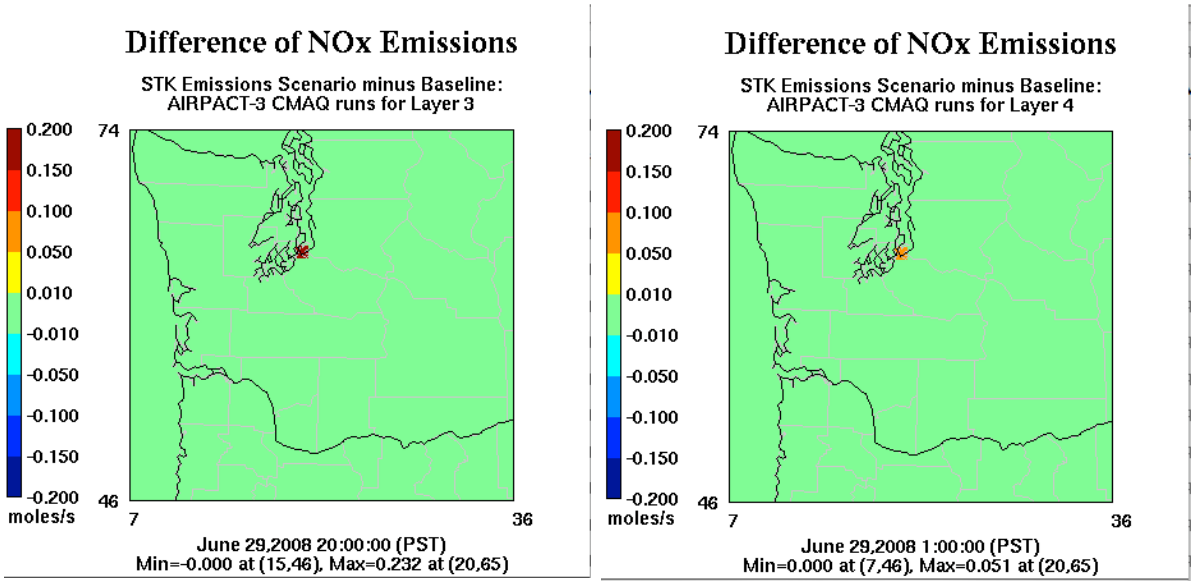

Figure 2. Bias (STK case minus Base Case) in NOx emissions emitted into Layer 3 (left) and into Layer 4 (right), examples from June 29, 2008

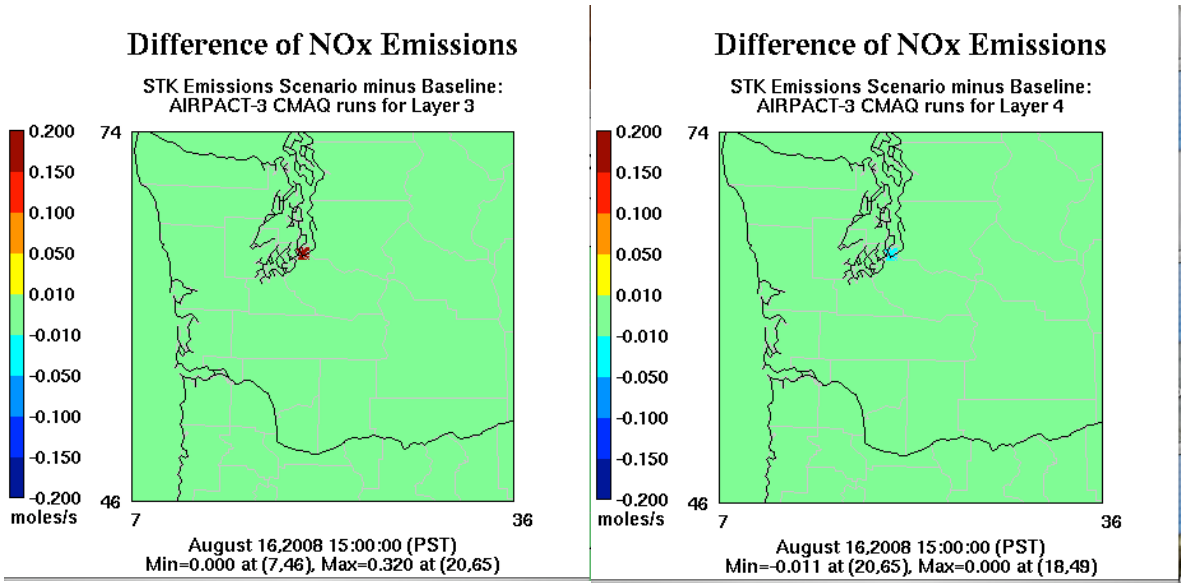

Figure 3. Bias (STK case minus Base Case) in NOx emissions emitted into Layer 3 (left) and into Layer 4 (right), examples from August 16, 2008

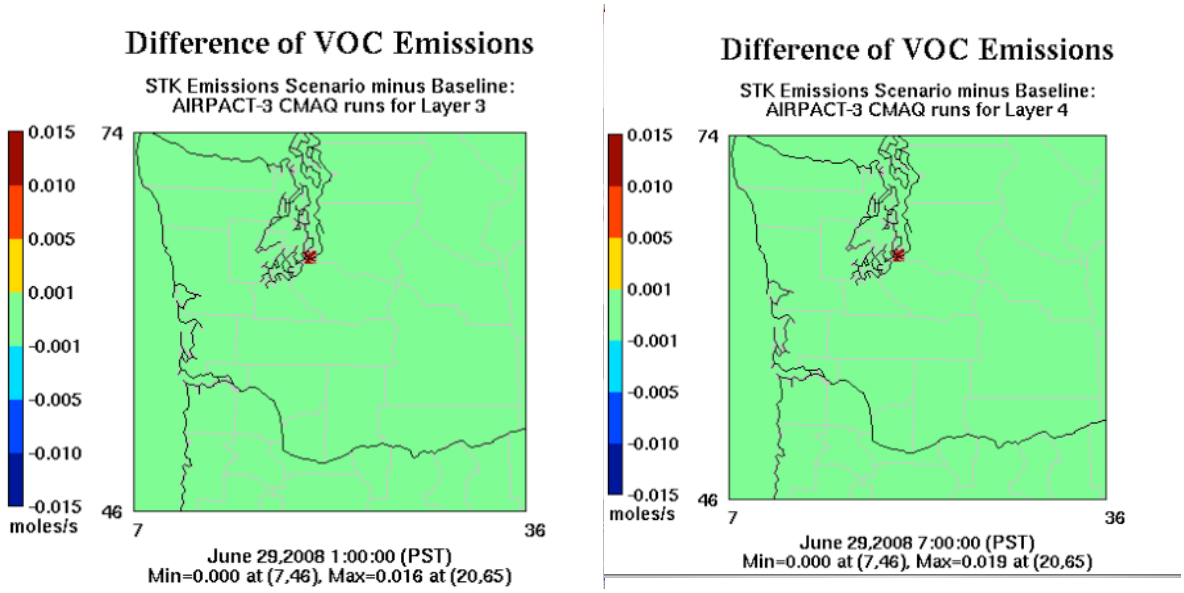

Figure 4. Bias (STK case minus Base Case) in VOC emissions emitted into Layer 3 (left) and into Layer 4 (right), examples from June 29, 2008

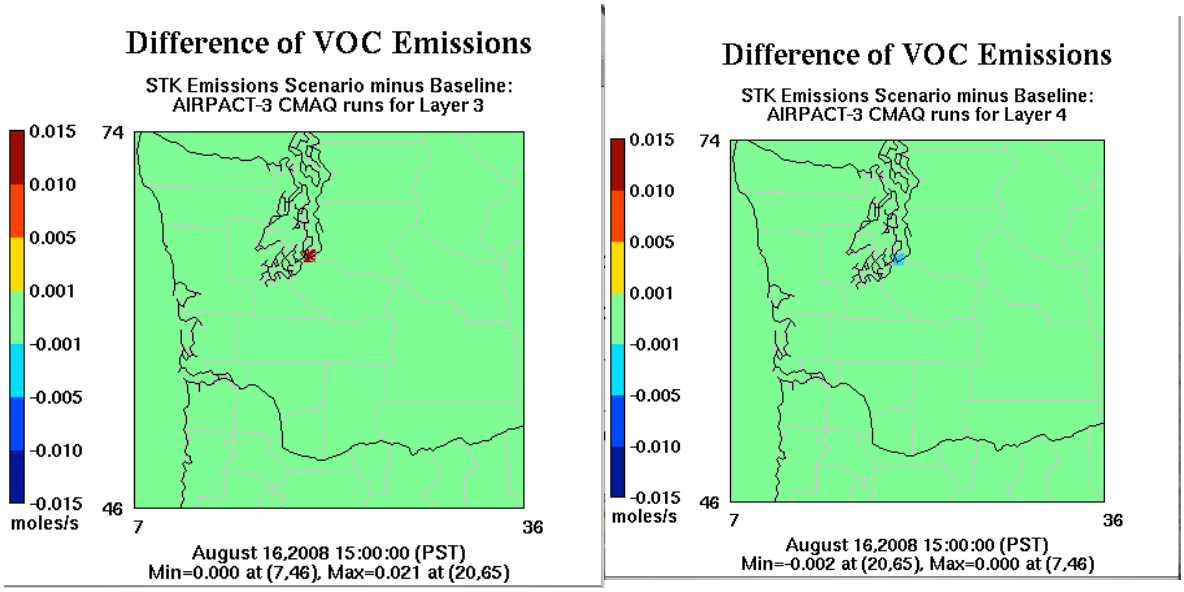

Figure 5. Bias (STK case minus Base Case) in VOC emissions emitted into Layer 3 (left) and into Layer 4 (right), examples from August 16, 2008

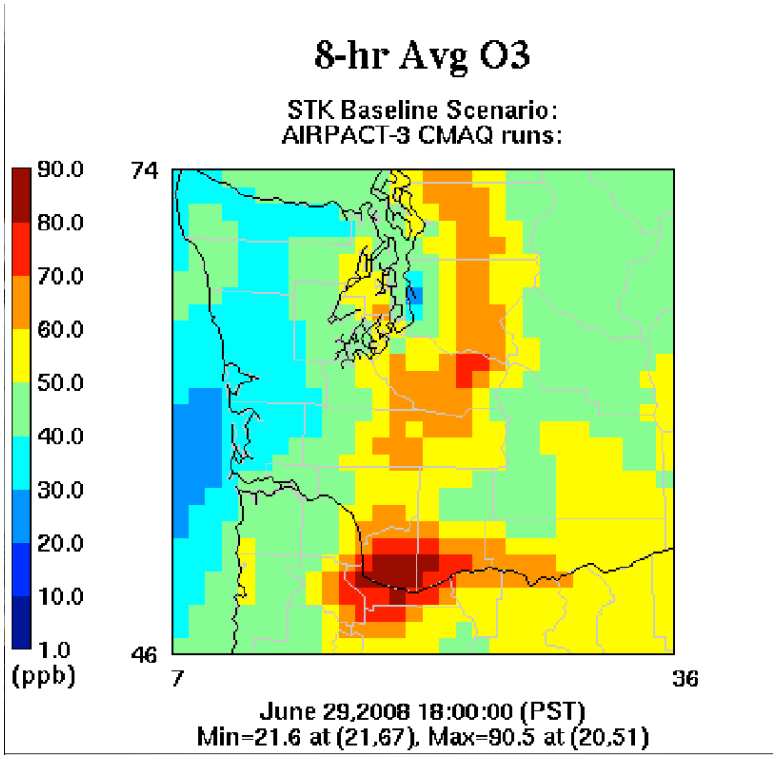

Figure 6. Maximum 8-hr average ozone in June 2008 scenario Base Case run. The STK case looks identical in this hour on this scale.

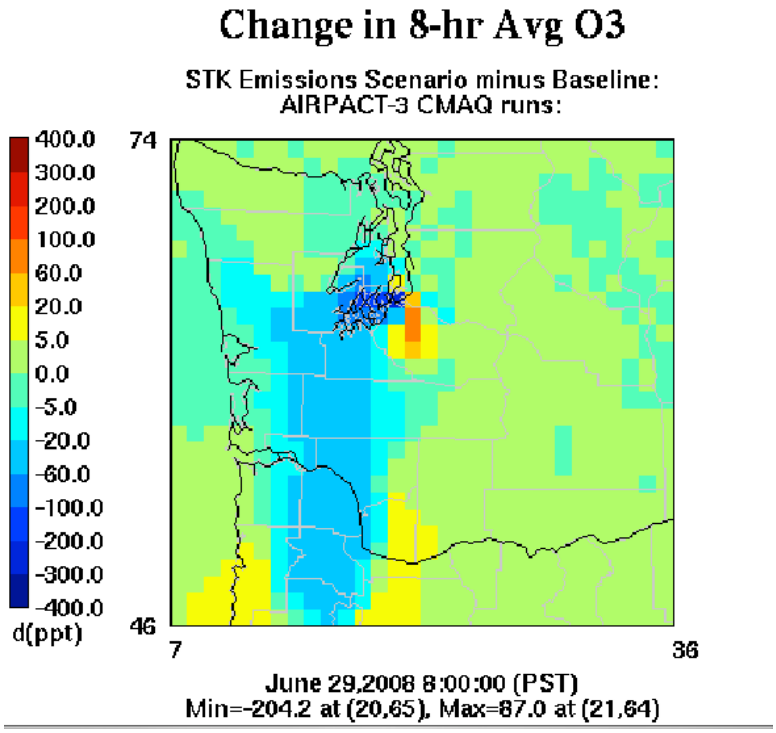

Figure 7. Maximum 8-hr average ozone Bias (STK - Base Case) in June 2008 scenario.

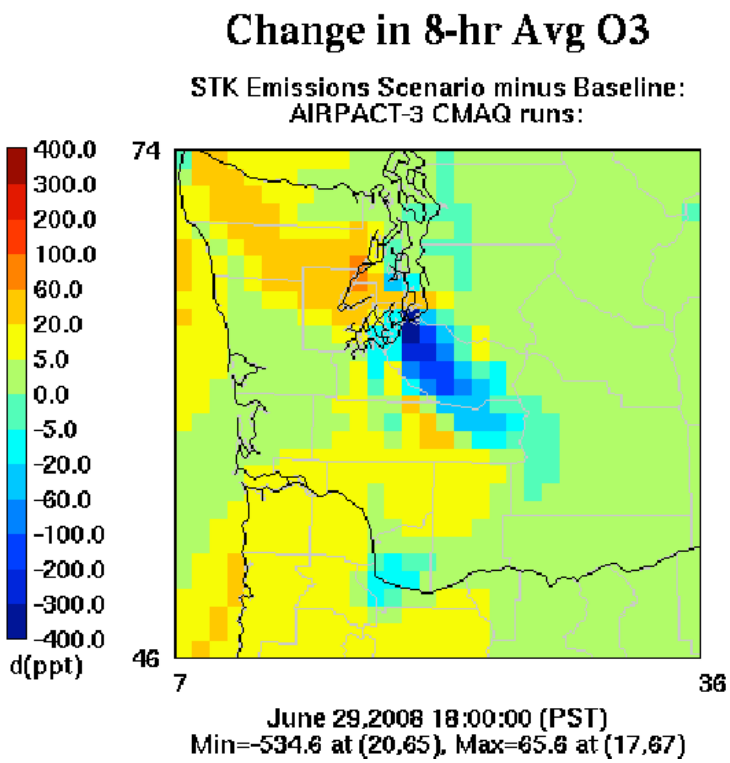

Figure 8. Bias (STK - Base Case) at time of maximum 8-hr O3 in June 2008 scenario.

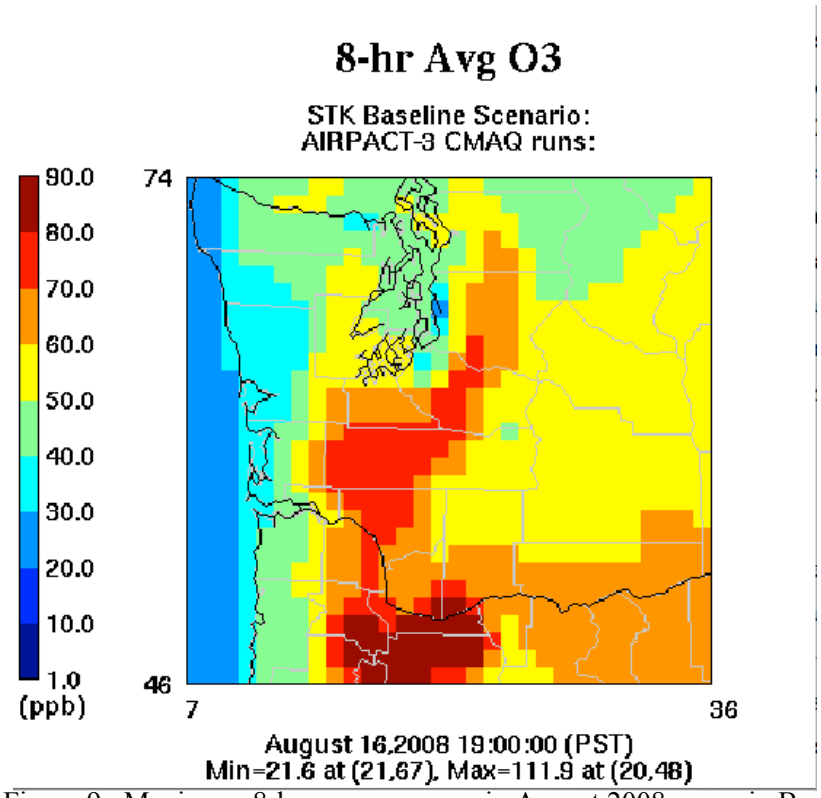

Figure 9. Maximum 8-hr average ozone in August 2008 scenario Base Case run.

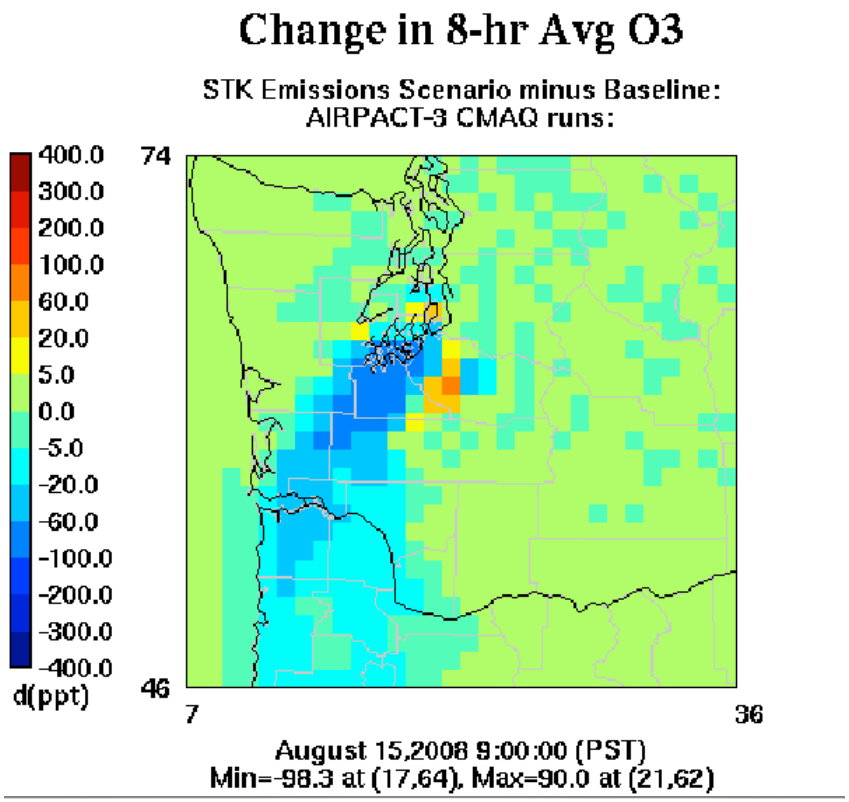

Figure 10. Maximum 8-hr average ozone Bias (STK - Base Case) in August 2008 scenario.

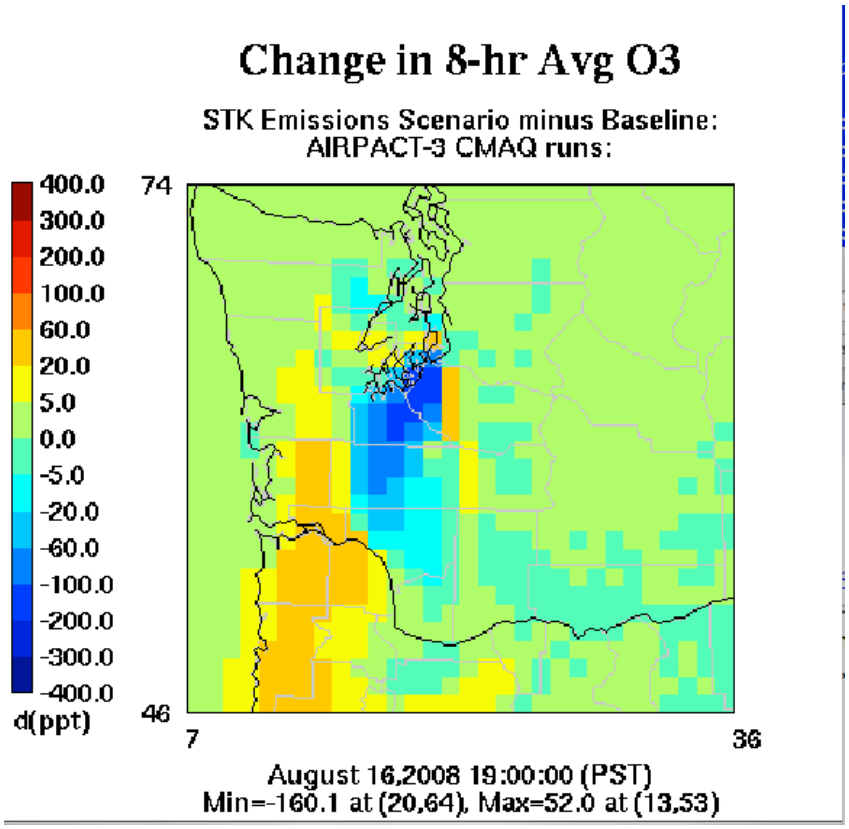

Figure 11. Bias (STK-Base Case) at time of maximum 8-hr O3 in August 2008 scenario.

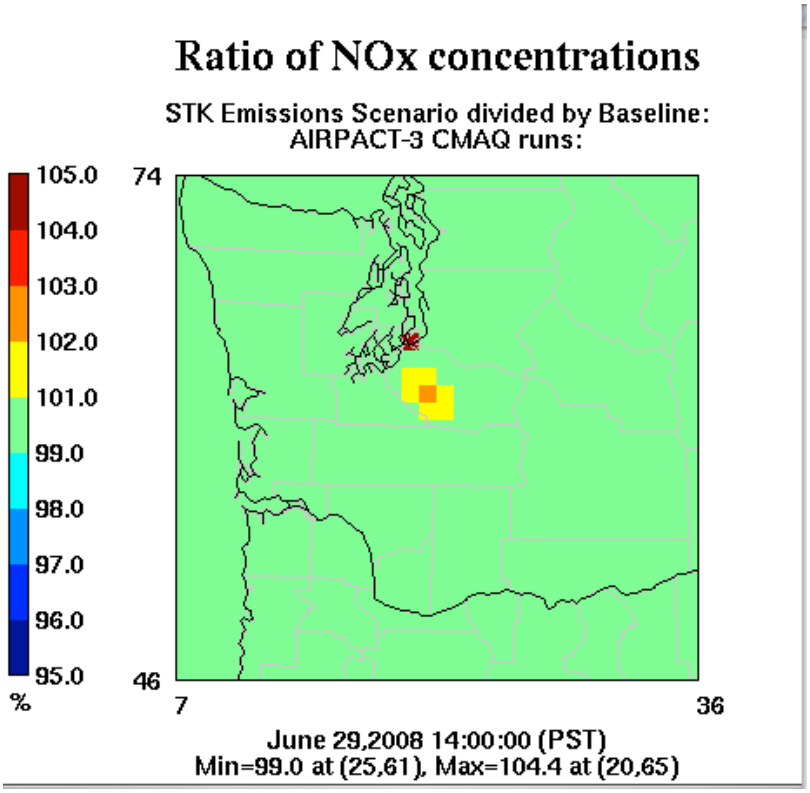

Figure 12. Ratio of NOx mixing ratios, STK Case over Base Case, June 29, 2008.

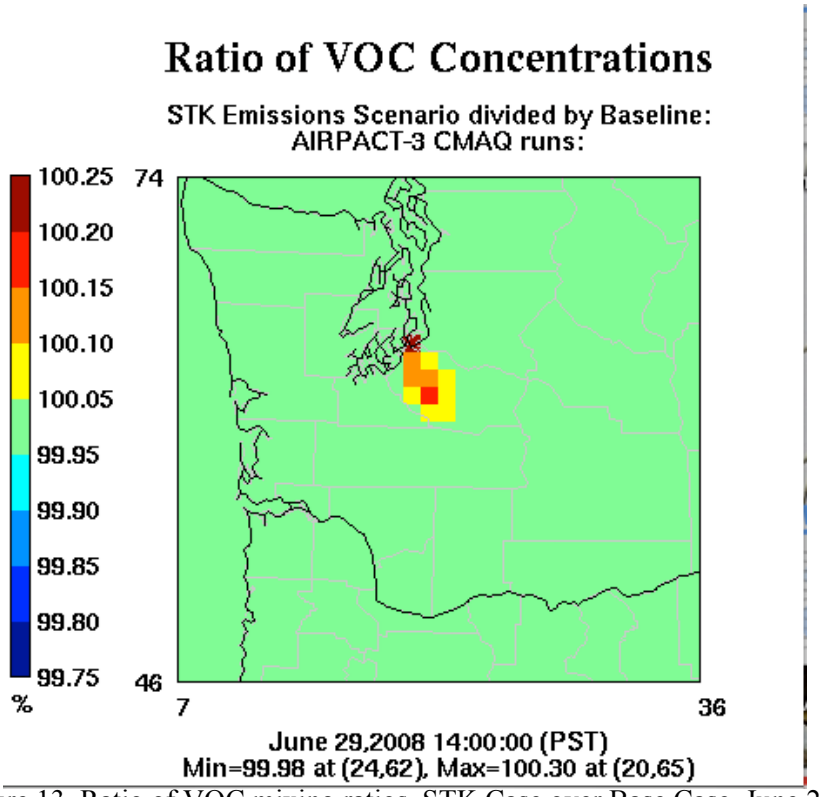

Figure 13. Ratio of VOC mixing ratios, STK Case over Base Case, June 29, 2008.

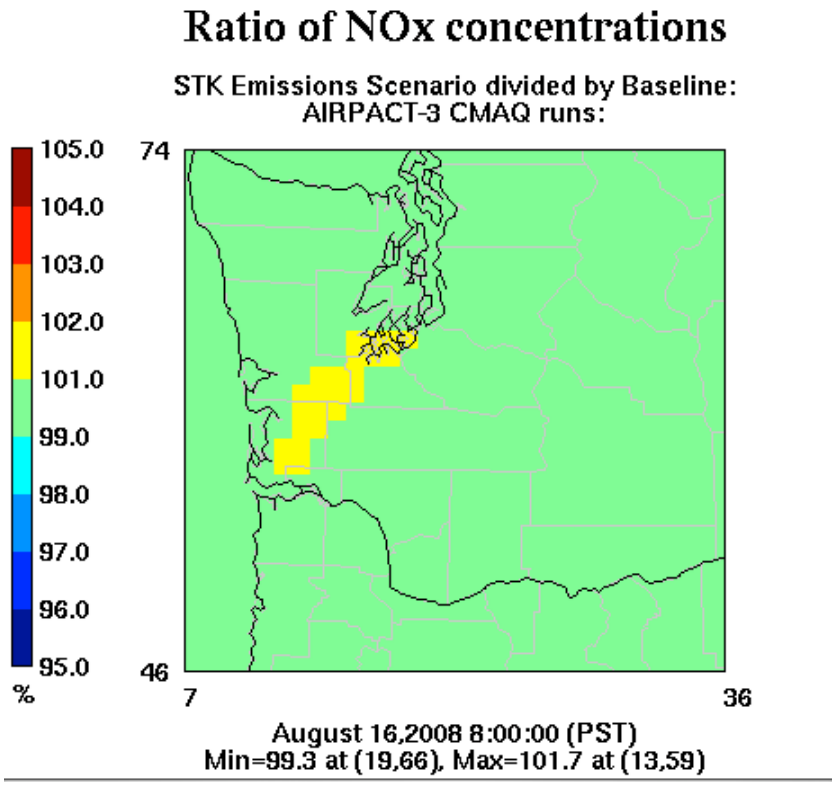

Figure 14. Ratio of NOx mixing ratios, STK Case over Base Case, August 16, 2008.

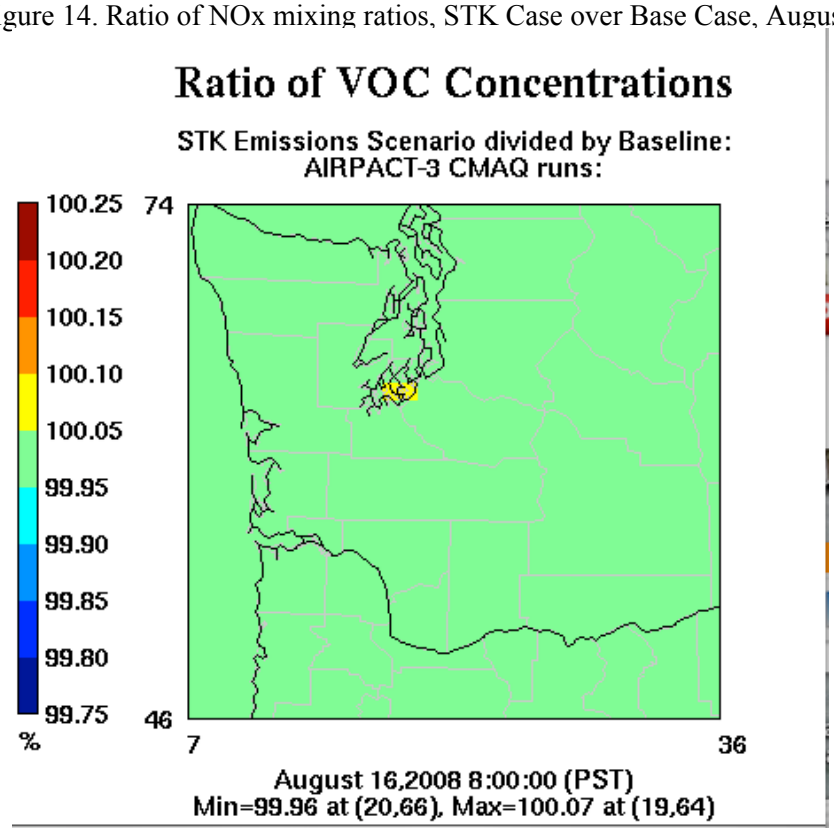

Figure 15. Ratio of VOC mixing ratios, STK Case over Base Case, August 16, 2008.

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