

August 25, 2010

Mr. Mark Goodin
Professional Engineer
Olympic Region Clean Air Agency
2940-B Limited Lane NW
Olympia, WA 98502

Re: Solomon Renewable Energy Company, LLC
Biomass Cogeneration Boiler Project Air Quality Permit Application
Shelton, Washington

Dear Mr. Goodin,

Enclosed is a Notice of Construction air quality permit application submitted on behalf of Solomon Renewable Energy Company, LLC (SREC) for a proposed wood-fired boiler cogeneration plant in Shelton, Washington. Through a Project Pre-Construction Services Agreement, SREC retained Simpson Lumber Company, LLC (SLC) to obtain pre-construction permits for the Project. SLC, in turn, retained ENVIRON International Corporation to prepare this minor source permit application for the SREC project.

The completed permit application forms are included in Appendix A of the permit application and an electronic version of the entire permit application in Portable Document Format (PDF) will be provided separately. The \$3,100 filing fee for this application will be delivered under separate cover.

A completed SEPA Environmental Checklist was submitted to the City of Shelton on May 3, 2010.

Please do not hesitate to contact me at 425.412.1811 if you have any questions about this application.

Sincerely,
ENVIRON International Corp.



Eric Hansen
Principal

Enclosure



**Biomass Cogeneration Boiler Project
Notice of Construction Permit Application
Solomon Renewable Energy Company, LLC**

Prepared for:
**Simpson Lumber Company, LLC
Shelton, Washington**

On behalf of:
**Solomon Renewable Energy Co., LCC
Shelton, Washington**

Prepared by:
**ENVIRON International Corporation
Lynnwood, Washington**

Date:
August 2010

Project Number:
03-21679C

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1 Introduction

Solomon Renewable Energy Company, LLC (SREC) proposes to construct and operate a 31 megawatt (MW) biomass-fired cogeneration facility in Shelton, Washington. The facility will be located on property leased from Simpson Lumber Company, LLC (SLC), in the same industrial complex that houses the SLC sawmill and the Olympic Panel Products (OPP) plywood mill, but on a separate tax parcel. The SREC boiler will be designed to burn biomass fuel, including sawmill by-products such as sawdust, bark and shavings, as well as forest slash from logging operations.

The proposed project will be comprised of a stoker wood-fired boiler, a steam turbine generator, a two-cell evaporative cooling tower, a condenser, and a fuel storage building with associated fuel delivery and handling equipment. These new unit installations at the Shelton location constitute the proposed facility ("the Project"). The boiler will have a rated heat input of 435.5 million British thermal units per hour (MMBtu/hr), and be designed to produce up to 250,000 lb/hr of steam at full load to supply a steam turbine generator with a nominal gross electrical output rating of 31 MW. The turbine generator will be designed with two extraction ports in order to provide 300 pound per square inch (psi) steam to the OPP plywood mill and 100 psi steam to the SLC sawmill. The primary function of the facility, however, will be to produce power that qualifies as biomass renewable energy under state law for sale to the power grid.

As discussed in Chapter 3 of this application, the Project will be a minor source of air emissions with respect to the Prevention of Significant Deterioration (PSD) program, and therefore requires an Order of Approval from the Olympic Region Clean Air Agency (ORCAA). Through a Project Pre-Construction Services Agreement, SREC retained SLC to obtain pre-construction permits for the Project. SLC, in turn, retained ENVIRON International Corporation (ENVIRON) to prepare this minor source permit application for the SREC Project.

The City of Shelton is the lead agency for the State Environmental Policy Act (SEPA) and is currently reviewing the environmental checklist. Completed and signed permit application forms are provided in Appendix A.

2 Project Description

2.1 Location

The SREC Project is proposed for installation on property leased from SLC in Shelton, Washington, approximately 15 miles northwest of Olympia, Washington in Mason County. Figure 2-1 shows the facility in relation to the surrounding area and the dispersion modeling domain.

Mason County is designated as attainment or unclassifiable for all criteria pollutants, and is located in Universal Transverse Mercator (UTM) Zone 10.

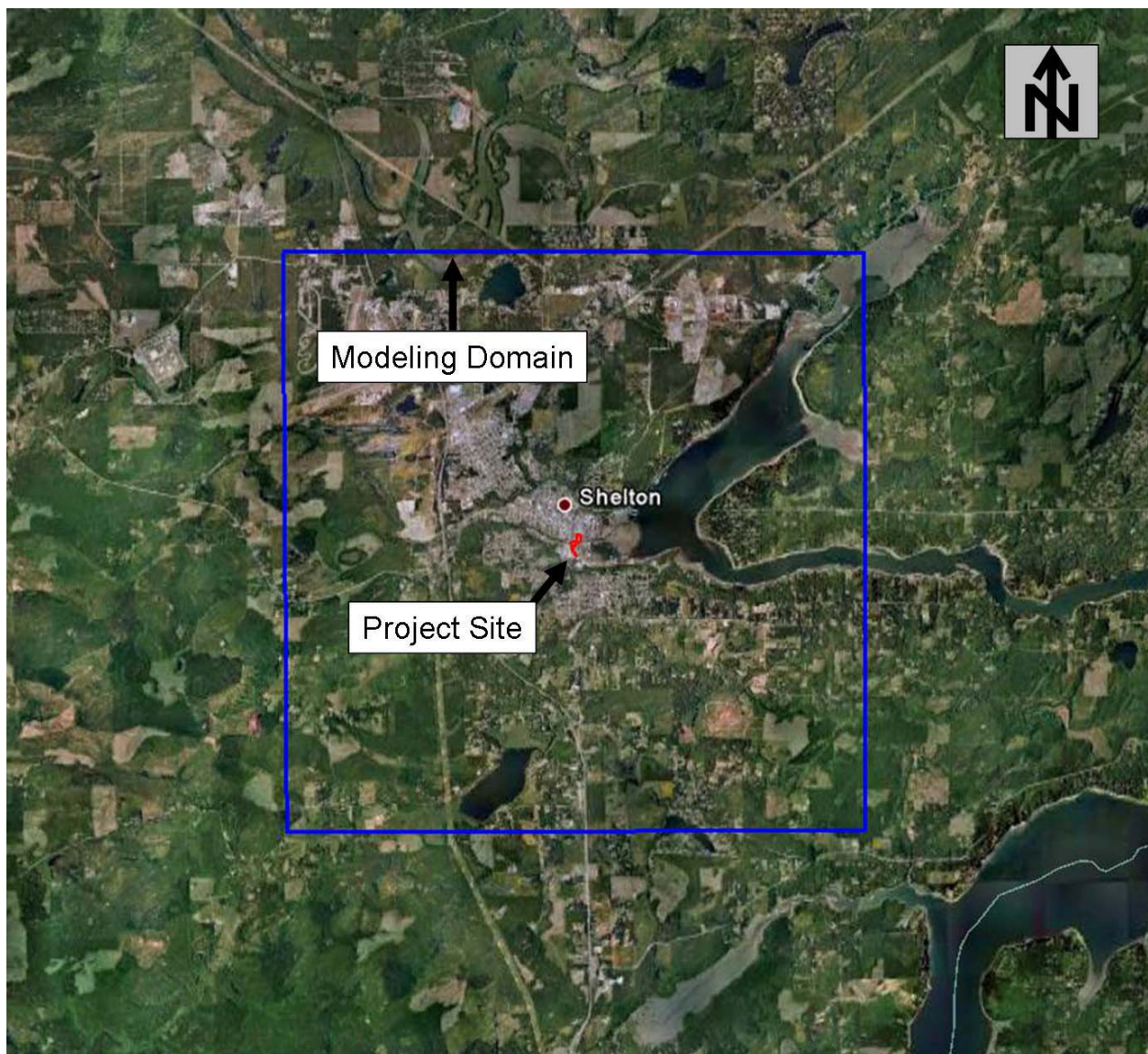


Figure 2-1. Vicinity of Project and Overlaid Dispersion Model Domain

2.2 Construction Schedule

SREC proposes to begin installation of the boiler as soon as necessary permits and approvals are issued. Construction is anticipated to begin in November 2010. Final engineering, equipment installation, system commissioning, and start up to full operation will require an additional twenty-four months.

2.3 Physical Description

The proposed Project consists of the following equipment for installation:

- A stoker wood-fired boiler rated at 435.5 MMBtu/hr with two natural gas burners, each rated at 62.5 MMBtu/hr, used exclusively for start up and shut down for a total heat input of 125 MMBtu/hr¹;
- A fuel storage building;
- A steam turbine, condenser and generator unit with a nominal gross electrical output rating of 31 MW, powered by dedicated steam produced by the new wood-fired boiler; and
- An evaporative cooling tower.

Figure 2-2 presents a site plan showing the location and layout of the new units at the Shelton site.

The new boiler would combust clean wood residue from the Shelton lumber mill and other nearby mills, as well as wood residue from OPP. Forest slash and other land clearing and forest health residuals may also be used as bio-mass fuel. Wood residues derived from logs transported in saltwater may be used for up to 13 percent of the boiler's fuel source.

¹ The preliminary Project plan prescribes the use of two natural gas burners for boiler start up and shut down. Given the potential for changes in the final design of the Project, SREC requests the flexibility of eliminating the need for the natural gas burners to achieve similar start up and shut down operational conditions by firing only hog fuel.

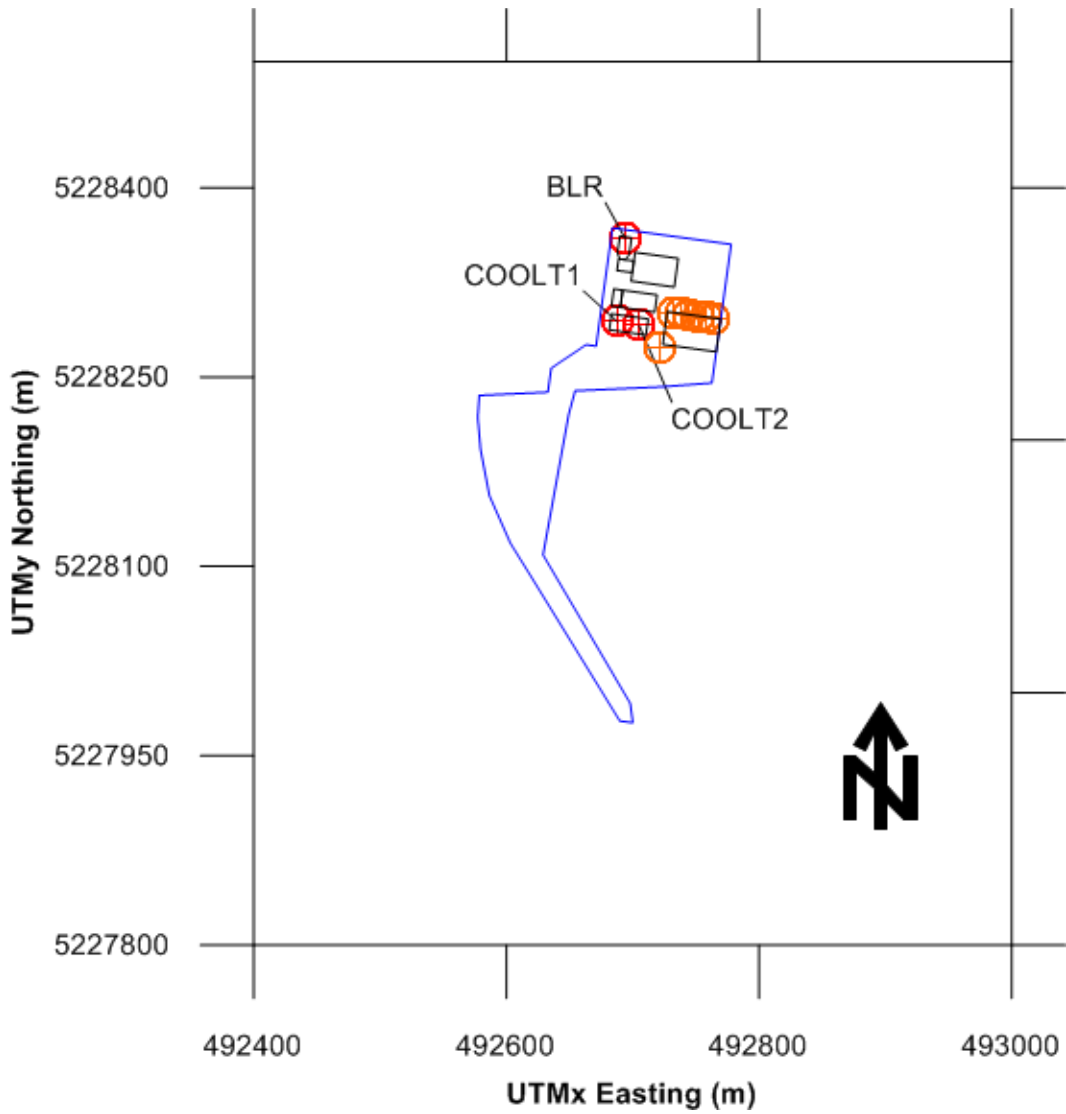


Figure 2-2. Significant Structure and Emission Source Locations (Unlabeled symbols represent fugitives modeled as volume sources). SREC facility property line in blue.

2.4 Physical Description

The boiler is intended to run as close to continuously as possible, but maintenance will require occasional shutdowns. This application identifies annual emissions based on continuous operation (8,760 hours per year), but also evaluates short-term emissions and consequences of boiler startups.

2.5 Short-Term Normal Operation Emission Rates

The proposed 435.5 MMBtu/hr stoker wood-fired boiler will be capable of supplying up to 250,000 lb/hr of process steam. SREC proposes to inject trona and/or bicarbonate to remove acid gases – including sulfur dioxide (SO₂) and hydrogen chloride (HCl) – from the boiler exhaust, ammonia injection and selective non-catalytic reduction (SNCR) control equipment for removal of oxides of nitrogen (NO_x) emissions, an oxidation catalyst to reduce carbon monoxide (CO) emissions, and an electrostatic precipitator (ESP) for control of particulate matter (PM).

To evaluate the air quality implications of the Project, ENVIRON examined the boiler's operating mode at maximum steam production. Table 2-1 presents maximum short-term air pollutant emission rates for the Project. Criteria pollutant emission factors for the boiler were based on the results of a best available control technology (BACT) analysis presented in Appendix B, as well as vendor emission rate guarantees from the pollution control equipment providers. The sulfur dioxide (SO₂) emission rate was based on fuel sampling test results obtained in April and May 2010, coupled with a safety factor applied to vendor guarantees. Sulfuric acid (H₂SO₄) emissions were assumed to be a fraction of the PM emission rate.²

The Project also has the potential to emit non-criteria air pollutants. "Hazardous air pollutants" (HAPs) are regulated at the federal level by Clean Air Act (CAA) Section 112, and compounds defined as "toxic air pollutants" (TAPs) under WAC 173-460 are regulated at the state level by the Washington Department of Ecology (Ecology) and ORCAA.

TAP and HAP emissions expected from the new boiler are based, with some exceptions, on the source tests used to calculate the emission factors in Section 1.6 of the U.S. Environmental Protection Agency's (USEPA's) AP-42 emission factor document (Wood Residue Combustion in Boilers). However, whereas the USEPA combined all source test data to calculate the AP-42 emission factors regardless of control technology, the emission factors used here were calculated, when such data were available, using a subset of source tests conducted on stoker boilers controlled by ESPs. For compounds lacking source test data reflecting that specific equipment, more generally applicable source test data were used.

² The sulfuric acid (H₂SO₄) emission factor was based on the assumption that sulfate comprises 10.038 percent of PM₁₀ emissions, which was obtained from USEPA's SPECIATE 3.2 Profile # 12709 for Hogged Fuel Boiler/Stoker Boiler. The H₂SO₄ emission rate was not subtracted from the PM₁₀ emission rate total, in effect double-counting these emissions.

Fuel test results and a safety factor applied to vendor guarantees were also used to determine a conservative estimate of the hydrogen chloride (HCl) emission factor. The hexavalent chromium emission factor was calculated using biomass-fired boiler source tests from the industrial boiler source test database developed for the Industrial Combustion Coordinated Rulemaking (ICCR) Federal Advisory Committee, after excluding source tests that included values based on the detection limit. The ammonia (NH₃) emission rate was based on a maximum exhaust ammonia concentration of 25 parts per million (ppm). Ammonia emissions are a consequence of ammonia injection in conjunction with the SNCR system to reduce boiler NO_x emissions to 0.13 pounds per million British thermal unit (lb/MMBtu).

Table 2-2 presents TAP emissions attributable to the Project along with the Small Quantity Emission Rates (SQERs) prescribed by WAC 173-460 for evaluating TAP emissions. TAP emission increases that do not exceed the SQERs are assumed to be sufficiently low that no additional analyses are warranted. If a particular TAP emission increase exceeds the applicable SQER, the applicant must demonstrate, typically using an air dispersion modeling analysis, that the ambient impact of that compound is less than the corresponding ASIL. If the predicted concentration exceeds the ASIL, the applicant must conduct a second tier analysis as described in WAC 173-460.

The proposed cooling tower will condense the steam generated by the boiler so that the water can be recycled. The cooling tower releases water droplets that contain dissolved solids that are naturally-occurring in the water supply and concentrated by the cooling process. Short-term maximum potential PM emissions from the cooling tower were calculated based on the assumption that water throughput is maximized in all cooling tower cells. Table 2-1 presents facility-wide emissions, including cooling tower emissions associated with the Project.

A new fuel storage house will be constructed on-site for the new boiler's fuel supply. Fugitive dust emission rates were calculated based on anticipated maximum activity levels associated with fuel deliveries and fuel reclaim activities inside the fuel house. The fugitive dust calculations reflect the maximum expected daily boiler fuel consumption (603 BDT/day) and an emission factor calculated using the methodology in EPA's AP-42 Section 13.2.4 (Aggregate Handling and Storage Piles). Short-term fugitive dust emission factors and emission rates are summarized in Table 2-1.

2.6 Annual Average Normal Operation Emission Rates

Annual emissions (typically expressed as tons per year or tpy) depend on how many hours a unit operates and that unit's operating rate during those periods. Table 2-1 presents potential annual emissions for the new wood-fired boiler, cooling tower, and fuel house fugitives, assuming the boiler will operate every hour of the year in the operating mode with the highest emission rates; this occurs when the boiler is operating at 100 percent load.

Annual PM₁₀ emissions from the cooling towers are based on the assumption that the water flow rate is maximized in both cells every hour of the year. In practice, water flow may be reduced

as outdoor temperatures drop or when the boiler load decreases. Consequently, this assumption provides a conservative estimate of cooling tower emissions.

Appendix C provides emission rate calculations for the new boiler, cooling tower and fugitive sources at the facility.

2.7 Startup and Shutdown Emission Rates

Emissions of some pollutants are higher during startup than during normal operations because combustion is not yet optimized. During startup and shutdown periods, CO emission rates are expected to exceed those experienced under normal operation. Unlike normal operation, it is difficult for the boiler manufacturer to estimate CO emission rates that vary continuously during the startup or shutdown process. Because of the lack of manufacturer data surrounding startup and shutdown emission rate profiles, ENVIRON assumed a worst-case mass emission rate of 400 lb/hr for modeling purposes to assess startup and shutdown air quality impacts. This estimate is based on a permit limit established by the Washington Department of Ecology for the hogged fuel boiler at Sierra Pacific Industries' Burlington facility.

Table 2-1: Emission Factors and Projected Criteria Emission Rates

Pollutant	Wood-Fired Boiler			Cooling Tower			Fuel House Fugitives		
	Emission Factor ¹ (lb/MMBtu)	Short-term Emissions (lb/hr)	Annual Emissions (tpy)	TDS ² (ppm)	Short-term Emissions ³ (lb/hr)	Annual Emissions ³ (tpy)	Emission Factor ⁴ (lb/ton)	Short-term Emissions (lb/hr)	Annual Emissions (tpy)
NO _x	0.130	56.62	248.0	--	--	--	--	--	--
CO	0.130	56.62	248.0	--	--	--	--	--	--
SO ₂	0.077	33.5	146.9	--	--	--	--	--	--
PM ₁₀	0.020	8.7	38.2	228	0.042	0.185	3.94E-04	5.33E-03	2.00E-02
PM/PM _{2.5} ⁵	0.015	6.53	28.6	228	0.042	0.185	1.24E-04	1.68E-03	6.27E-03
VOC	0.017	7.4	32.4	--	--	--	--	--	--
Sulfuric Acid	0.002	0.9	3.83	--	--	--	--	--	--
Lead	1.19E-05	0.01	0.0228	--	--	--	--	--	--

¹ Emission factors based on BACT for wood-fired boilers for all pollutants except: SO₂, which is based on 2010 fuel test results and vendor guarantees (95% SO₂ control); CO, which is based on vendor guarantees; and sulfuric acid, which is based on EPA speciation profiles.

² Total dissolved solids (TDS) were determined by a water lab report from November 2009; TDS is assumed to be equivalent to conductivity after communications with the testing lab. Cooling tower emissions were based on a 0.0005% drift rate, 5 cycles and a flow rate of 29,600 gallons per minute (gpm). Should ORCAA elect to develop a permitted emission limit for the cooling tower, an added safety factor may be applied to this conservative TDS estimate.

³ Emissions are for both cells in a 2-cell cooling tower.

⁴ Emission factor calculated using the methodology in AP-42 Section 13.2.4 (Aggregate Handling and Storage Piles)

⁵ PM and PM_{2.5} are assumed equal to the filterable component of PM₁₀ for the wood-fired boiler. Based on 1995 stack test data, filterable PM₁₀ from the wood-fired boiler is assumed to be 2/3 of total PM₁₀. PM₁, PM_{2.5} and PM₁₀ are assumed to be equivalent for the cooling tower and fuel house fugitive PM_{2.5} emissions are based on AP-42 Section 13.2.4.

Table 2-2: Emission Factors and Projected Toxic Air Pollutant Emission Rates

Pollutant	CAS Number	Averaging Time	Emission Factor		Emission Rate			Significant Quantity Emission Rate			Over SQER? (Y/N)
			(lb/MMBtu)	Source	(lb/yr)	(lb/hr)	(lb/day)	(lb/yr)	(lb/hr)	(lb/day)	
Acetaldehyde	75-07-0	year	1.99E-04	Stoker/ESP	758	8.65E-02	2	N/A	N/A	N/A	Yes
Acrolein	107-02-8	24-hr	3.15E-05	Stoker/ESP	1.20E+02	1.37E-02	3.30E-01	N/A	N/A	0.000329	Yes
Ammonia	7664-41-7	24-hr	2.73E-02	25 ppm limit	104242	1.19E+01	2.86E+02	N/A	N/A	9.31	Yes
Arsenic	7440-38-2	year	4.94E-07	Stoker/ESP	2	2.E-04	5.E-03	0.0581	N/A	N/A	Yes

Table 2-2: Emission Factors and Projected Toxic Air Pollutant Emission Rates

Pollutant	CAS Number	Averaging Time	Emission Factor		Emission Rate			Significant Quantity Emission Rate			Over SQER? (Y/N)
			(lb/MMBtu)	Source	(lb/yr)	(lb/hr)	(lb/day)	(lb/yr)	(lb/hr)	(lb/day)	
Benzene	71-43-2	year	8.61E-04	Stoker/ESP	3286	3.75E-01	9.00E+00	6.62	N/A	N/A	Yes
Benzo(a)anthracene	56-55-3	year	2.52E-09	Stoker/ESP	0	1.10E-06	2.63E-05	1.74	N/A	N/A	No
Benzo(a)pyrene	50-32-8	year	3.27E-09	Stoker/ESP	0	1.42E-06	3.5E-05	0.174	N/A	N/A	No
Benzo(b)fluoranthene	205-99-2	year	2.35E-09	Stoker/ESP	8.97E-03	1.02E-06	2.46E-05	1.74	N/A	N/A	No
Benzo(f)fluoranthene	205-82-3	year	1.56E-07	Stoker/Controlled	5.93E-01	6.77E-05	1.63E-03	1.74	N/A	N/A	No
Benzo(k)fluoranthene	207-08-9	year	2.38E-09	Stoker/ESP	9.09E-03	1.04E-06	2.49E-05	1.74	N/A	N/A	No
Beryllium	7440-41-7	year	1.55E-06	Stoker/ESP	6	6.76E-04	1.62E-02	0.08	N/A	N/A	Yes
Bis(2-ethylhexyl)phthalate	117-81-7	year	4.65E-08	Stoker/Controlled	1.77E-01	2.03E-05	4.86E-04	8	N/A	N/A	No
Bromomethane	74-83-9	24-hr	2.80E-05	Stoker/ESP	107	1.22E-02	2.93E-01	N/A	N/A	0.0274	Yes
Butanone-2 (MEK)	78-93-3	24-hr	5.39E-06	Controlled	2.06E+01	2.35E-03	5.63E-02	N/A	N/A	27.4	No
Cadmium	7440-43-9	year	2.59E-06	Stoker/ESP	10	1.13E-03	2.71E-02	0.0457	N/A	N/A	Yes
Carbon Monoxide	630-08-0	1-hr	1.30E-01	Vendor Guarantee	495978	5.66E+01	1.36E+03	N/A	N/A	N/A	Yes
Carbon Tetrachloride	56-23-5	year	4.54E-05	Stoker/ESP	173	1.98E-02	4.75E-01	4.57	N/A	N/A	Yes
Chlorine	7782-50-5	24-hr	7.92E-04	Stoker/Controlled	3021	3.5E-01	8	N/A	N/A	0.0011	Yes
Chlorobenzene	108-90-7	24-hr	3.32E-05	Stoker/ESP	127	1.45E-02	3.47E-01	N/A	N/A	5.48	No
Chloroform	67-66-3	year	2.75E-05	Stoker/ESP	105	1.20E-02	3.5E-01	8.35	N/A	N/A	Yes
Chloromethane	74-87-3	24-hr	2.31E-05	Controlled	88	1.01E-02	2.41E-01	N/A	N/A	0.493	No
Chromium	7440-47-3	year	1.24E-06	Stoker/ESP	5	5.42E-04	1.30E-02	N/A	N/A	N/A	No
Chromium, hexavalent	18540-29-9	year	1.75E-07	ETDBAS	1	7.63E-05	1.83E-03	0.00128	N/A	N/A	Yes
Chrysene	218-01-9	year	2.75E-09	Stoker/ESP	0	1.20E-06	2.88E-05	17.4	N/A	N/A	No
Cobalt	7440-48-4	24-hr	8.93E-06	Stoker/Controlled	34	3.89E-03	9.34E-02	N/A	N/A	0.000548	Yes
Copper	7440-50-8	1-hr	4.11E-06	Stoker/ESP	1.57E+01	1.79E-03	4.29E-02	N/A	N/A	N/A	No
Dibenzo(a,h)anthracene	53-70-3	year	2.35E-09	Stoker/ESP	0	1.02E-06	2.46E-05	0.16	N/A	N/A	No
Dibromoethane-12	106-93-4	year	5.48E-05	Stoker/ESP	209	2.39E-02	5.73E-01	2.71	N/A	N/A	Yes
Dichloroethane-12	107-06-2	year	2.92E-05	Stoker/ESP	1.11E+02	1.27E-02	3.05E-01	7.39	N/A	N/A	Yes
Dichloromethane	75-09-2	year	2.87E-04	Stoker/ESP	1095	1.25E-01	3	192	N/A	N/A	Yes
Dichloropropane-12	78-87-5	year	3.33E-05	Stoker/ESP	127	1.45E-02	3.48E-01	19.2	N/A	N/A	Yes

Table 2-2: Emission Factors and Projected Toxic Air Pollutant Emission Rates

Pollutant	CAS Number	Averaging Time	Emission Factor		Emission Rate			Significant Quantity Emission Rate			Over SQER? (Y/N)
			(lb/MMBtu)	Source	(lb/yr)	(lb/hr)	(lb/day)	(lb/yr)	(lb/hr)	(lb/day)	
Ethylbenzene	100-41-4	year	3.13E-05	Stoker/ESP	119	1.36E-02	3.E-01	76.8	N/A	N/A	Yes
Formaldehyde	50-00-0	year	1.99E-03	Stoker/ESP	7475	8.53E-01	2.05E+01	32	N/A	N/A	Yes
Heptachlorobiphenyl	28655-71-2	year	6.57E-11	Stoker/ESP	2.51E-04	2.86E-08	6.87E-07	0.0505	N/A	N/A	No
Hexachlorobiphenyl	26601-64-9	year	2.89E-10	Stoker/ESP	0	1.26E-07	3.02E-06	0.0101	N/A	N/A	No
HpCDD-Total	37871-00-4	year	3.09E-11	Stoker/ESP	0	1.E-08	3.E-07	0.000505	N/A	N/A	No
HxCDD-Total	34465-46-8	year	8.55E-11	Stoker/ESP	3.26E-04	3.72E-08	8.94E-07	0.0000505	N/A	N/A	Yes
Hydrogen chloride	7647-01-0	24-hr	4.63E-03	Fuel Test Results and Vendor Guaranteed Control Efficiency (98.5%)	1.77E+04	2.02E+00	4.84E+01	N/A	N/A	0.0493	Yes
Indeno(1,2,3-c,d)pyrene	193-39-5	year	2.37E-09	Stoker/ESP	9.06E-03	1.03E-06	2.48E-05	1.74	N/A	N/A	No
Lead	7439-92-1	year	1.19E-05	Stoker/ESP	4.55E+01	5.20E-03	1.25E-01	16	N/A	N/A	Yes
Manganese	7439-96-5	24-hr	1.16E-04	Stoker/ESP	441	5.E-02	1	N/A	N/A	0.000219	Yes
Mercury	7439-97-6	24-hr	4.16E-07	Stoker/ESP	1.59E+00	1.81E-04	4.35E-03	N/A	N/A	0.000493	Yes
Methanol	67-56-1	24-hr	8.30E-04	EF from NCASI	3167	3.61E-01	8.68E+00	N/A	N/A	21.9	No
Naphthalene	91-20-3	year	8.51E-05	Stoker/ESP	325	3.71E-02	1	5.64	N/A	N/A	Yes
Nickel	7440-02-0	year	2.84E-06	Stoker/ESP	11	1.24E-03	2.97E-02	0.806	N/A	N/A	Yes
Nitrogen Dioxide	10102-44-0	1-hr	1.30E-01	Vendor Guarantee	495978	5.66E+01	1359	N/A	N/A	N/A	Yes
OCDD	3268-87-9	year	2.34E-10	Stoker/ESP	0	1.02E-07	2.E-06	0.0505	N/A	N/A	No
OCDF	39001-02-0	year	1.43E-11	Stoker/ESP	0	6.21E-09	1.49E-07	0.0505	N/A	N/A	No
Pentachlorophenol	87-86-5	year	2.27E-08	Stoker/ESP	0	9.89E-06	2.37E-04	41.6	N/A	N/A	No
Phenol	108-95-2	24-hr	1.25E-05	Stoker/ESP	48	5.E-03	1.E-01	N/A	N/A	1.1	No
Phosphorus	7723-14-0	24-hr	3.54E-05	Stoker/Controlled	1.35E+02	1.54E-02	3.70E-01	N/A	N/A	0.11	Yes
Selenium	7782-49-2	24-hr	3.38E-06	Stoker/ESP	1.29E+01	1.47E-03	3.54E-02	N/A	N/A	0.11	No
Styrene	100-42-5	24-hr	1.86E-03	Stoker/Controlled	7.10E+03	8.10E-01	1.94E+01	N/A	N/A	4.93	Yes
Sulfur Dioxide	7446-09-05	24-hr	7.70E-02	Fuel Tests and Vendor Guarantee	293772	3.35E+01	8.05E+02	N/A	N/A	0.146	Yes

Table 2-2: Emission Factors and Projected Toxic Air Pollutant Emission Rates

Pollutant	CAS Number	Averaging Time	Emission Factor		Emission Rate			Significant Quantity Emission Rate			Over SQER? (Y/N)
			(lb/MMBtu)	Source	(lb/yr)	(lb/hr)	(lb/day)	(lb/yr)	(lb/hr)	(lb/day)	
Sulfuric Acid	7664-93-9	24-hr	2.01E-03	EPA SPECIATE	7659	8.74E-01	2.10E+01	N/A	N/A	0.00548	Yes
TCDD-Total	1746-01-6	year	2.05E-10	Stoker/ESP	0	8.91E-08	2.14E-06	0.00000505	N/A	N/A	Yes
Tetrachloroethene	127-18-4	year	3.82E-05	Stoker/ESP	146	1.67E-02	4.00E-01	32.4	N/A	N/A	Yes
Toluene	108-88-3	24-hr	2.13E-05	Stoker/ESP	81	9.E-03	2.E-01	N/A	N/A	27.4	No
Trichloroethane-111	71-55-6	24-hr	3.07E-05	Stoker/ESP	117	1.E-02	3.E-01	N/A	N/A	5.48	No
Trichloroethene	79-01-6	year	3.03E-05	Stoker/ESP	116	1.E-02	3.E-01	95.9	N/A	N/A	Yes
Trichlorophenol-246	88-06-2	year	1.14E-08	Stoker/ESP	4.33E-02	4.94E-06	1.19E-04	9.59	N/A	N/A	No
Vanadium	1314-62-1	24-hr	5.94E-07	Stoker/ Controlled	2	2.59E-04	6.21E-03	N/A	N/A	0.0657	No
Vinyl Chloride	75-01-4	year	1.84E-05	Stoker/ESP	70	8.01E-03	1.92E-01	2.46	N/A	N/A	Yes
Xylene-o	1330-20-7	24-hr	2.45E-05	Stoker/ESP	93	1.07E-02	2.56E-01	N/A	N/A	1.21	No
Total # TAPs to model:											36

3 Regulatory Setting

The proposed Project is subject to Federal, State and local regulations. The following section discusses the applicable regulations and why certain regulatory programs or specific regulations are or are not applicable. It should be noted that the project will be located in an area that is in attainment of all Federal and State ambient air quality standards.

This application approaches the proposed Project as a separate, single source for air regulation applicability purposes, including new source review and National Emission Standards for Hazardous Air Pollutants. The reasons for treating the Project as a separate source from the adjacent SLC and OPP mills are detailed in a July 23, 2010 "Separate Source Determination Request" for the proposed SREC facility, submitted to the Department of Ecology and ORCAA.

Ecology responded to the July 23 "Separate Source Determination Request" with a Source Determination Letter dated August 4, 2010. In it, Ecology concludes: "... that the power plant proposed by SREC is not under common control or ownership of Simpson or Olympic, that the power plant is not a support facility to either of those companies, and that Simpson and Olympic are not support facilities to SREC. As a result, ORCAA should process this permit under its implementation of the state Notice of Construction Program [...]."³

3.1 Federal Regulations

3.1.1 Prevention of Significant Deterioration (PSD)

A Prevention of Significant Deterioration (PSD) permit would be required if potential facility-wide emissions of a PSD pollutant from the cogeneration facility exceed 250 tpy. As discussed in Chapter 2, and shown in Table 2-1, the Project would not emit any pollutants at or above this threshold. Consequently, the Project does not require a PSD permit.

3.1.2 Acid Rain Program

The USEPA's Acid Rain Program, Title IV of the Clean Air Act, is intended to achieve significant environmental and public health benefits through reductions in emissions of SO₂ and NO_x, the primary causes of acid rain.

The Project will not trigger applicability of the federal Acid Rain regulations because the new boiler will qualify for the cogeneration unit exemption. To qualify, the boiler must supply "equal to or less than one-third of its potential electrical output capacity or equal to or less than 219,000 MWe-hrs actual electrical output on an annual basis to any utility power distribution system for sale (on a gross basis)." 40 C.F.R. § 72.6(b)(4)(i). The boiler meets these criteria and so qualifies for the exemption.

³ Letter from Jeff Johnston, Air Quality Program, WA Department of Ecology, to Kirk A. Lilley, Kirk Lilley PLLC, August 4, 2010.

First, as a result of the project, the new boiler will be a “cogeneration unit” under the Acid Rain regulations. It is a “unit” because it is a combustion device that burns fossil fuel (even though its primary fuel is not fossil fuel). It will also be a “cogeneration unit” because, along with the associated steam turbine, it is a unit that will “produce electric energy and useful thermal energy for industrial ... heating ... purposes, through sequential use of the original fuel energy.” 40 C.F.R. § 72.2. In this case, the boiler and the turbine will be used to produce steam first for power generation, then for use in kiln and veneer drying operations at the nearby SLC and OPP facilities.

The SREC boiler qualifies for the cogeneration unit exemption by supplying “equal to or less than 219,000 MWe-hrs actual electrical output on an annual basis to any utility power distribution system for sale (on a gross basis).” 40 C.F.R. § 72.6(b)(4)(i).

Based on the current steam turbine design, the Project is expected to generate an annual average power production of 23.2 MWe. This value represents the actual electrical production on an annual basis of the cogeneration unit. The anticipated actual power production is therefore equivalent to 203,232 MWe-hrs, which is less than the 219,000 MWe-hrs threshold for Acid Rain program applicability to cogeneration units.

Because the boiler involved in the Project meets the criteria for the cogeneration facility exemption in 40 C.F.R. § 72.6(b)(4)(i), the Project will not trigger Acid Rain program applicability.

3.1.3 Air Operating Permit Program

Because emissions of one or more pollutants from the facility exceed 100 tpy, the Project will be a major stationary source of emissions with respect to Title V of the Clean Air Act. An Air Operating Permit (AOP) application must be submitted to ORCAA within one year of commencing operation of the power plant.

3.1.4 New Source Performance Standards

EPA has established performance standards for a number of air pollution sources in 40 CFR Part 60. These New Source Performance Standards (NSPS) usually represent a minimum level of control that is required of a new source. NSPS Subpart Db addresses emissions from boilers that have a heat input of greater than 100 MMBtu/hr, and will apply to the proposed boiler because the maximum heat input is expected to be 435.5 MMBtu/hr.

Subpart Db limits PM emissions to 0.1 lb/MMBtu for newly constructed units. At the proposed maximum firing rate, this limit translates into an emission rate of 44 lb PM/hr. Subpart Db also requires exhaust opacity to be 20 percent or less (6-minute average), except for one 6-minute period per hour, which cannot exceed 27 percent opacity. These standards do not apply during startup, shutdown, or a malfunction. The PM emission rate proposed by SREC reflects BACT (which is more stringent than these NSPS limits).

3.1.5 National Emission Standards for Hazardous Air Pollutants

The National Emission Standards for Hazardous Air Pollutants (NESHAP) establish technology-based standards to control hazardous air pollutants (HAPs). For NESHAP purposes, a major source is defined as one with a potential to emit (PTE) greater than 10 tpy of a single HAP or more than 25 tpy of all HAPs combined.

The facility-wide annual HAP PTE is summarized in Table 3-1. HAP emissions are based on AP-42 emission factors, with the exception of HCl. HCl emissions were calculated based on vendor guarantees of the trona and/or bicarbonate injection pollution control equipment, coupled with results from fuel sampling tests performed in April and May 2010.

The HAP emitted in the greatest quantity is hydrogen chloride at a rate of 8.84 tpy. The maximum potential facility-wide emissions of all 44 HAPs combined would be 23.1 tpy. As a result, the Project will not emit HAPs at a level that exceeds the PTE thresholds for either a single or combined HAP source; therefore, it will not be subject to associated major source Maximum Available Control Technology (MACT) standards.

Pollutant	CAS Number	Emission Factor	Emission Rate
		(lb/MMBtu)	(tpy)
Acetaldehyde	75-07-0	1.99E-04	3.79E-01
Acetophenone	98-86-2	3.23E-09	6.15E-06
Acrolein	107-02-8	3.15E-05	6.02E-02
Antimony	7440-36-0	4.61E-07	8.78E-04
Arsenic	7440-38-2	4.94E-07	9.42E-04
Benzene	71-43-2	8.61E-04	1.64E+00
Beryllium	7440-41-7	1.55E-06	2.96E-03
Bis(2-ethylhexyl)phthalate	117-81-7	4.65E-08	8.87E-05
Bromomethane	74-83-9	2.80E-05	5.34E-02
Butanone-2 (MEK)	78-93-3	5.39E-06	1.03E-02
Cadmium	7440-43-9	2.59E-06	4.94E-03
Carbon Tetrachloride	56-23-5	4.54E-05	8.66E-02
Chlorine	7782-50-5	7.92E-04	1.51E+00
Chlorobenzene	108-90-7	3.32E-05	6.33E-02
Chloroform	67-66-3	2.75E-05	5.25E-02
Chloromethane	74-87-3	2.31E-05	4.41E-02
Chromium	7440-47-3	1.24E-06	2.37E-03
Cobalt	7440-48-4	8.93E-06	1.70E-02
Dichloroethane-12	107-06-2	2.92E-05	5.57E-02
Dichloromethane	75-09-2	2.87E-04	5.48E-01
Dichloropropane-12	78-87-5	3.33E-05	6.35E-02
Dinitrophenol-24	51-28-5	9.33E-08	1.78E-04

Table 3-1: Emission Factors and Projected Hazardous Air Pollutant Emission Rates			
Pollutant	CAS Number	Emission Factor	Emission Rate
		(lb/MMBtu)	(tpy)
Ethylbenzene	100-41-4	3.13E-05	5.97E-02
Formaldehyde	50-00-0	1.96E-03	3.74E+00
Hydrogen chloride	7647-01-0	4.63E-03	8.84E+00
Lead	7439-92-1	1.19E-05	2.28E-02
Manganese	7439-96-5	1.16E-04	2.21E-01
Mercury	7439-97-6	4.16E-07	7.93E-04
Methanol	67-56-1	8.30E-04	1.58E+00
Naphthalene	91-20-3	8.51E-05	1.62E-01
Nickel	7440-02-0	2.84E-06	5.41E-03
Nitrophenol-4	100-02-7	1.71E-07	3.27E-04
Pentachlorophenol	87-86-5	2.27E-08	4.33E-05
Phenol	108-95-2	1.25E-05	2.39E-02
Propionaldehyde	123-38-6	3.15E-06	6.01E-03
Selenium	7782-49-2	3.38E-06	6.45E-03
Styrene	100-42-5	1.86E-03	3.55E+00
Tetrachloroethene	127-18-4	3.82E-05	7.29E-02
Toluene	108-88-3	2.13E-05	4.05E-02
Trichloroethane-111	71-55-6	3.07E-05	5.86E-02
Trichloroethene	79-01-6	3.03E-05	5.78E-02
Trichlorophenol-246	88-06-2	1.14E-08	2.17E-05
Vinyl Chloride	75-01-4	1.84E-05	3.51E-02
Xylene-o	1330-20-7	2.45E-05	4.67E-02
TOTAL			23.1

On April 29, 2010 the US EPA signed proposals to revise National Emission Standards for Hazardous Air Pollutants (NESHAPs) for industrial, institutional and commercial boilers and process heaters at major sources (40 CFR 63 Subpart DDDDD) and area sources (40 CFR 63 Subpart JJJJJJ). On June 4, 2010 the US EPA proposed national emission standards for control of hazardous air pollutants from two area source categories: Industrial boilers and commercial and institutional boilers. Because the Project will not be a major source of HAPs, it would be subject to area source standards for biomass fueled boilers. The final area source standards have yet to be published and promulgated; however, vendor guarantees on boiler performance demonstrate that the proposed area source emission limits for new boilers can be met by the new boiler. The proposed area source emission limits for new biomass boilers are:

- 0.03 lb/MMBtu (filterable) PM; and
- 100 ppm CO (at 7 percent O₂, monthly average).

3.2 State and Local Emission Regulations

3.2.1 General Air Pollution Control Regulations

Regulations addressing general air pollution sources in Washington are contained in WAC 173-400. ORCAA has also established regulations that apply locally. Note that all of these general conditions will apply to the Project.

General standards for maximum emissions from air pollution sources in Washington are outlined in WAC 173-400-040 and in ORCAA regulations. These regulations: limit visible emissions to 20 percent opacity except for 3 minutes per hour; control nuisance particulate fallout, fugitive dust, and odors; and limit PM emission from hogged fuel boilers to 0.20 grains per dry standard cubic foot (gr/dscf) at 7 percent O₂. SREC is proposing PM emission rates from the new boiler that reflect BACT and are well below these limits.

3.2.2 Notice of Construction Permits

Washington requires new or modified industrial sources to obtain an NOC air quality permit. The NOC permit application must provide a description of the facility, an inventory of pollutant emissions, and proposed control systems for the applicable pollutants. The reviewing agency considers whether BACT has been employed and evaluates ambient concentrations resulting from these emissions to ensure compliance with ambient air quality standards. As stated in WAC 173-400-113, an NOC permit cannot be granted unless the agency determines the project (1) will meet applicable state and federal emission limits; (2) will employ BACT; and (3) will not cause or contribute to violations of ambient air quality standards or Acceptable Source Impact Levels. This application provides the information to enable Ecology and ORCAA to make those determinations.

Washington NOC regulations require a BACT analysis for all air pollutants emitted by a project. 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. A BACT analysis for the proposed boiler is presented in Appendix B. NOC regulations also require a modeling analysis to demonstrate compliance with the applicable air quality standards and impact levels. Descriptions of the air quality modeling analysis methodology and results are provided in Chapter 4.

3.2.3 Toxic Air Pollutants

Section 2 presents expected TAP emission rates associated with the Project along with the Small Quantity Emission Rates (SQERs) prescribed by WAC 173-460 for evaluating TAP emissions. As discussed in that section, a TAP with an emission rate exceeding the SQER must demonstrate compliance with the appropriate ASIL, also prescribed by WAC 173-460. If the predicted ambient concentration increase attributable to the project exceeds the ASIL, a second tier analysis is required. Table 2-2 indicates that the calculated facility-wide emission rates of 36 TAPs exceed the applicable SQERs, and the air quality dispersion analysis

conducted for those compounds to determine compliance with the ASILs is presented in Section 4.

ORCAA regulations require a demonstration that TAP emission increases are sufficiently low to protect human health and safety from potential carcinogenic and other toxic effects. TAP emission increases that do not exceed the SQERs are assumed to be sufficiently low that no additional analyses are warranted. Additionally, new emission units must use Best Available Control Technology for toxics (tBACT). tBACT applies to each TAP that is discharged.

ORCAA regulations also limit formaldehyde emissions in ambient air to 0.05 ppm (1-hour average) or 61 micrograms per cubic meter ($\mu\text{g}/\text{m}^3$) (1-hour average) from any emission source. The modeling analysis provided in Section 4 demonstrates that the Project will not exceed this formaldehyde limit prescribed by ORCAA.

3.2.4 State Environmental Policy Act

Because construction of the proposed boiler requires SREC to obtain an Order of Approval from ORCAA and other government agency approvals, the requirements of Washington's State Environmental Policy Act (SEPA) must be satisfied. A SEPA checklist was submitted to the City of Shelton, the SEPA lead agency, on May 3, 2010.

4 Air Quality Impact Analysis

Air quality impact assessments (AQIAs) are performed using dispersion modeling techniques in accordance with the EPA's Guideline on Air Quality Models (codified as Appendix W to 40 CFR Part 51, hereafter referred to as the Guideline). The purpose of the AQIA is to assess potential impacts of the proposed project on air quality in the area surrounding the Shelton facility.

ENVIRON applied computer-based dispersion modeling techniques were applied to simulate criteria and toxic air pollutant releases from the facility to assess compliance with the NAAQS and WAAQS and Ecology's Acceptable Source Impact Levels (ASILs) for toxic air pollutants. This section describes the techniques for and results of the AQIA. A disc containing modeling files is provided as Appendix D to this application.

4.1 Dispersion Model Selection and Application

AERMOD is currently the model recommended by the Guideline as the preferred dispersion model for complex source configurations and for sources subject to exhaust plume downwash. AERMOD incorporates numerical plume rise algorithms, including the PRIME algorithm, which calculates the downwash effects a structure may have on an exhaust plume. Importantly, the PRIME algorithm also treats the geometry of upwind and downwind structures and their relationship to the emission point more precisely, and is able to calculate concentrations within building cavities.

4.2 Modeling Procedures

AERMOD was applied to calculate criteria pollutant and TAP concentrations using the regulatory defaults in addition to the options and data discussed in this section.

4.2.1 Model Setup and Application

The most recent version of AERMOD (version 09292) was applied with the default options for dispersion that reflect local meteorological data, regional upper air data, and the local physical characteristics of land use surrounding the primary meteorological site. AERMOD contains several options for urban dispersion that were not selected for these analyses due to the predominantly rural characteristics of the modeling domain.

4.2.2 Averaging Periods

Pollutant concentrations predicted by the model were averaged over short-term (1-, 3-, 8-, and 24-hour) and annual averaging periods as required by the applicable ambient criteria for each modeled pollutant.

4.2.3 Emission Source Release Parameters

Figure 2-2 shows the locations of the proposed boiler and cooling tower in relation to the surrounding Simpson Shelton facility as well as significant structures that could potentially

influence emissions. Table 4-1 summarizes the parameters used to represent the boiler and cooling tower as point sources in the modeling. Table 4-2 summarizes the parameters used to represent fugitive fuel house emissions as volume sources in the modeling. The volume sources are represented in Figure 2-2 as well.

Table 4-1: Point Source Release Parameters

Name	UTMx (m)	UTMy (m)	Height (ft)	Temperature (F)	Exit Velocity (ft/s)	Stack Diameter (ft)
Boiler	492694	5228360	130	325	60.8	8.00
Cooling Tower – Cell 1	492688	5228294	46.0	92.1	24.5	30.0
Cooling Tower – Cell 2	492705	5228291	46.0	92.1	24.5	30.0

Table 4-2: Volume Source Release Parameters

Name	UTMx (m)	UTMy (m)	Release Height (m)	σ_y (m)	σ_z (m)
Fuel House Fugitives - North Side 1	492732	5228301	10.35	3.31	4.81
Fuel House Fugitives - North Side 2	492739	5228300	10.35	3.31	4.81
Fuel House Fugitives - North Side 3	492745	5228299	10.35	3.31	4.81
Fuel House Fugitives - North Side 4	492752	5228298	10.35	3.31	4.81
Fuel House Fugitives - North Side 5	492758	5228297	10.35	3.31	4.81
Fuel House Fugitives - North Side 6	492764	5228297	10.35	3.31	4.81
Fuel House Fugitives - South (Truck Unload)	492721	5228274	5.1816	11.34	2.41

In addition to the release parameters discussed above, the SREC building dimensions and facility configuration were provided to AERMOD to assess potential downwash effects. Wind-direction-specific building profiles were prepared for the modeling using the EPA's Building Profile Input Program for the PRIME algorithm (BPIP PRIME).

Based on the site layout shown and the structure heights, it was assumed that the facility point and volume sources are potentially subject to downwash effects from nearby on-site structures, and the necessary information calculated by BPIP PRIME was included in the simulations to reflect these effects.

4.2.4 Good Engineering Practice Analysis

A good engineering practice (GEP) stack height design analysis was conducted based on the specifications of facility buildings according to EPA procedures (EPA 1985a). Releases below the GEP stack height are potentially subject to building wake effects, which can result in relatively high ground level predictions from the EPA's regulatory models.

A GEP stack height determination was made for the proposed exhaust stacks for each new emission unit. GEP stack height is equal to the height of the building which has the dominant wake effect ("zone of influence") on the stack plume plus 1.5 times the lesser of (1) that building's maximum projected width, or (2) the building height. This GEP stack height is expressed in the following equation:

$$H_g = H + 1.5 L \text{ (Equation 1)}$$

where

H_g = GEP stack height

H = Building height

L = Lesser of the maximum projected building width or the building height

Use of a stack with the GEP stack height removes the plume completely from the building wake zone.

The cavity height is the stack height required to prevent the stack plume from entering the cavity region of the building. Pollutant plumes which are entrained into the cavity region of a building often produce extremely high concentrations. EPA defines cavity height by the following equation:

$$H_c = H + 0.5 L \text{ (Equation 2)}$$

where

H_c = Cavity height

H = Building height

L = Lesser of the maximum projected building width or the building height

ENVIRON used the EPA's BPIP Prime for the GEP analysis. The boiler and cooling tower GEP stack heights were calculated as 78.5 m (258 ft). SREC is proposing emission unit stack heights that are below GEP stack heights as determined by EPA's BPIP Prime GEP analysis. The proposed boiler stack height is 130 ft; the cooling tower stack height is 46 ft.

4.2.5 Meteorology

A five-year meteorological database was constructed using available surface and upper air data for the dispersion modeling analysis. A meteorological data set was prepared using surface data observations from the Shelton Airport for the period 2004 – 2008. Upper air data was prepared using National Weather Service (NWS) data from Quillayute, Washington.

The meteorological data were processed using the AERMOD meteorological preprocessor, AERMET (version 06341). A wind rose describing the wind speed and wind direction data recorded at the Shelton Airport meteorological site over the five-year period is shown in Figure 4-1. The wind rose indicates that the winds are generally from the west and south directions.

EPA guidance indicates that surface parameters (albedo, Bowen ratio, and surface roughness) surrounding the meteorological site should be used in AERMET to construct the meteorological profiles used by AERMOD. Seasonal surface parameters were determined for the Shelton Airport meteorological site according to USEPA guidance⁴ using the AERMET preprocessor AERSURFACE (version 08009), and the USGS 1992 National Land Cover (NLCD92) land-use data set.⁵ Figure 4-2 represents the land use processing domain employed for the AQIA.

⁴ The AERMOD Implementation Guide (EPA, 2009) and the AERSURFACE User's Guide (EPA-454/B-08-001, January 2008).

⁵ The USGS NLCD92 data set is described and can be accessed at <http://landcover.usgs.gov/natl/landcover.php>.

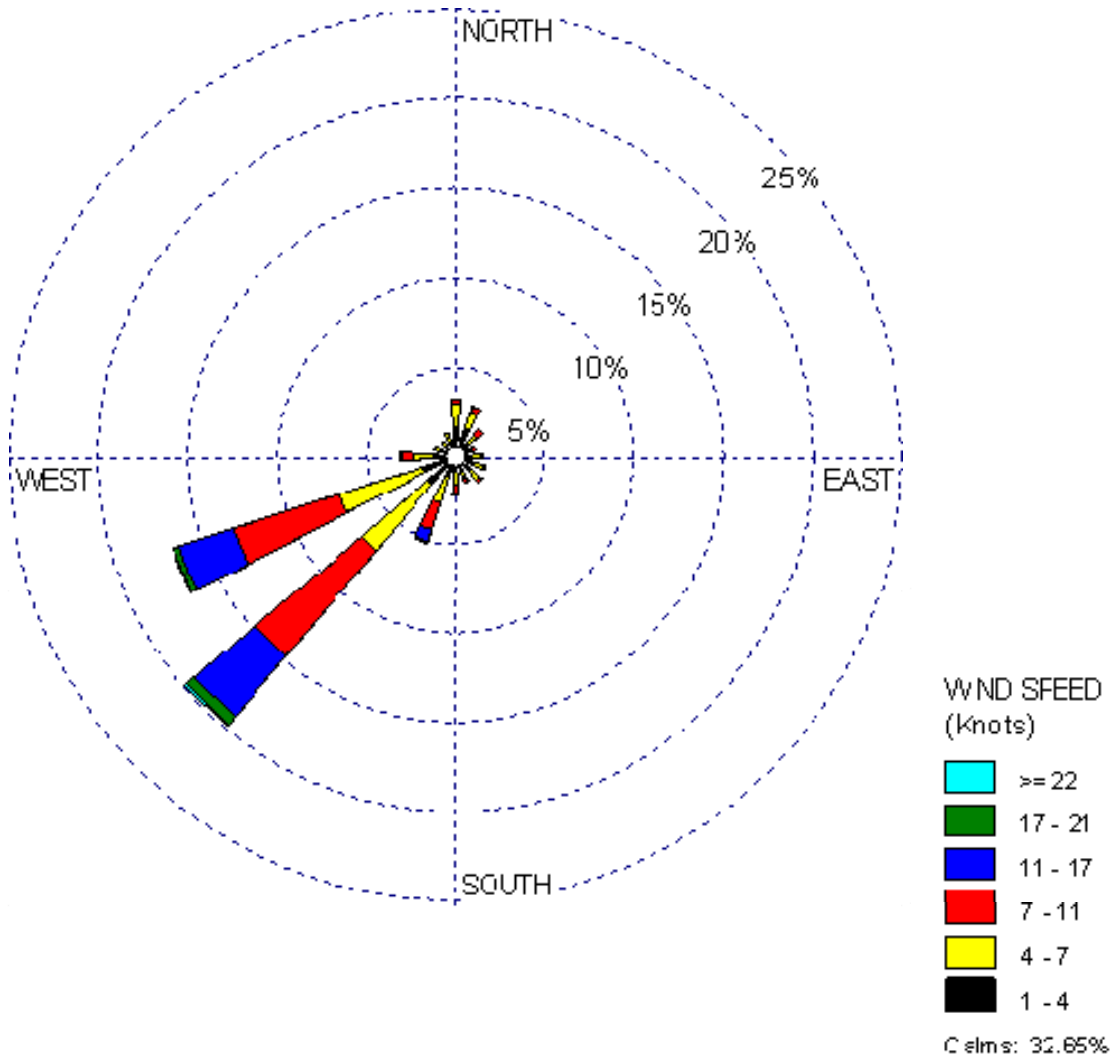


Figure 4-1. Shelton Airport Wind Rose for 2004 - 2008

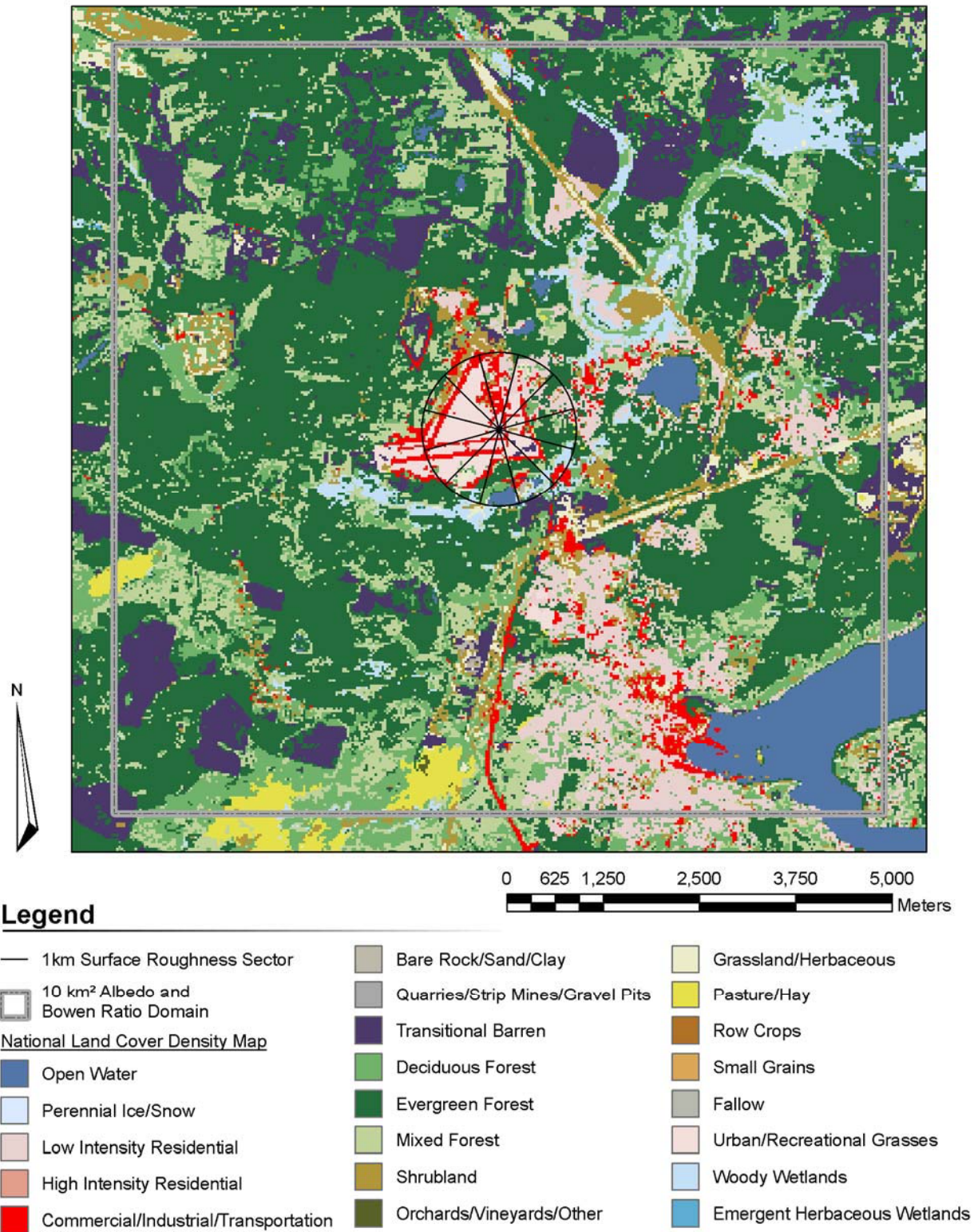


Figure 4-2. AERMET Land Use Analysis

4.2.6 Receptors and Terrain

The 10-kilometer (km) by 10 km modeling domain used for the AQIA is shown in Figure 4-3. Terrain elevations for receptors and emission units were prepared using available data from the National Elevation Dataset (NED) at 1/9th arc-second resolution developed by the United States Geological Survey (USGS).

A receptor set was developed for the AQIA which included receptors spaced 500 m apart covering the outermost portion of the simulation domain. Nested grids of 25-m, 50-m, and 200-m spaced receptors covered 1-km, 2-km, and 5-km square areas centered on the facility. Receptors were also located at 10-m intervals along the facility property boundaries. The receptor locations are shown in Figure 4-3. The base elevation and hill height scale for each receptor were determined using AERMAP (version 09040).

4.3 Criteria Pollutant Significant Impact Level Assessment

Ambient concentrations of criteria pollutants due to emission releases from the proposed project were predicted using AERMOD. Maximum short-term and annual average concentrations were obtained for comparison with Significant Impact Levels (SILs), established for various criteria pollutants. Table 4-3 presents the maximum modeled concentrations of each criteria pollutant and the respective SILs established for each pollutant. If all ambient impact concentrations from a specific pollutant modeled for facility operations are less than the SILs, no further analysis is required. If pollutant concentrations are greater than the SILs, estimates of background concentrations are added to Project predictions to demonstrate compliance with the National Ambient Air Quality Standards (NAAQS) and Washington Ambient Air Quality Standards (WAAQS). Pollutants with proposed SILs or without SILs, such as PM_{2.5} or the 1-hour averaging periods for NO₂ and SO₂, were combined with background concentrations and compared against NAAQS and WAAQS.

As shown in Table 4-3, the criteria pollutant concentrations that are greater than a SIL are the annual averaging periods for NO₂ and SO₂ and the 3- and 24-hour averaging times for SO₂. Modeled PM_{2.5} concentrations for 24-hour and annual averaging times also are greater than proposed SILs for that pollutant. As a next step, an air quality analysis of combined modeled and ambient pollutant concentrations is required to determine compliance with the NAAQS for these pollutants.

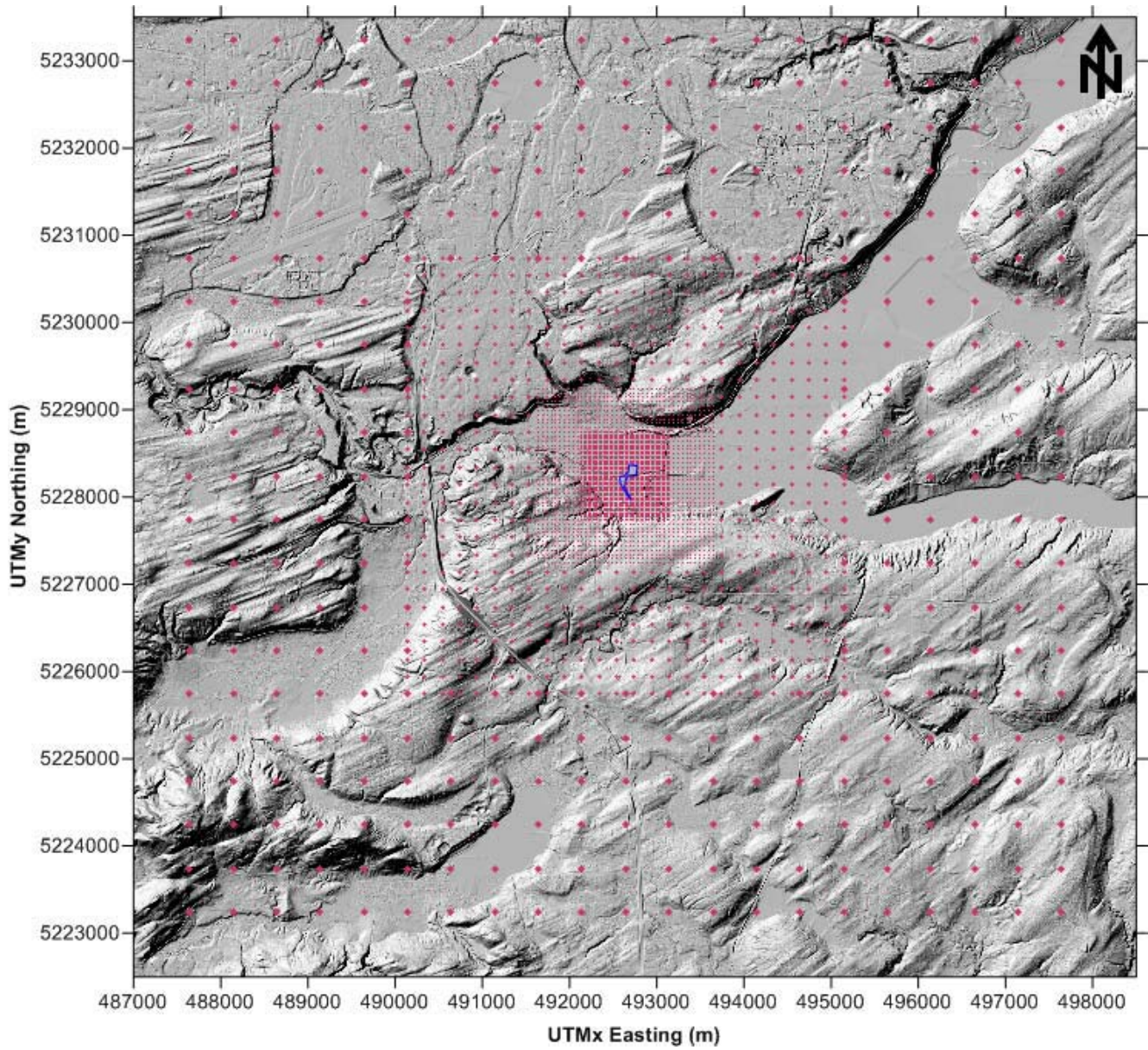


Figure 4-3. SREC Hog Fuel Boiler Project Receptor Locations

Table 4-3: Maximum Predicted Criteria Pollutant Concentrations

Pollutant	Averaging Period	Maximum Concentration ($\mu\text{g}/\text{m}^3$)	SIL ($\mu\text{g}/\text{m}^3$)	Over the SIL?
NO ₂	1-Hour	160.62	None	-
	Annual	4.86	1	Yes
CO	1-Hour	160.6	2,000	No
	8-Hour	64.1	500	No
SO ₂	1-Hour	95.1	None	-
	3-Hour	64.1	25	Yes
	24-Hour	15.4221	5	Yes
	Annual	2.88	1	Yes
PM ₁₀	24-Hour	4.05	5	No
	Annual	0.76	1	No
PM _{2.5} ¹	24-Hour	2.72	1.2	Yes
	Annual	0.51	0.3	Yes

¹ Values represent lowest of three proposed PM_{2.5} SILs.
None – No SIL has been established

4.4 NAAQS Analysis

As indicated in Section 4.3, model simulations of potential emissions from the proposed wood-fired boiler predicted that the maximum ambient annual average NO₂ and SO₂ concentrations as well as the 3- and 24-hour SO₂ concentrations will be greater than the applicable SILs. Also, the maximum predicted 24-hour average PM_{2.5} concentration is above the most stringent proposed SIL for that standard. The recently promulgated Federal 1-hour average NO₂ and SO₂ ambient standards have no SIL, either proposed or promulgated, and current guidance indicates that the appropriate design concentrations should be combined with representative background concentrations to assess compliance with those standards.

Based on recently issued guidance regarding a three-tiered approach to modeling NO₂ concentrations, ENVIRON assumed that 90% of all NO_x emissions are converted to NO₂. The result of this conversion is represented in the discussion of the NAAQS analysis presented in Section 4.4.1.

4.4.1 Results

To demonstrate compliance with the more stringent NAAQS or WAAQS for pollutants that are above the established and proposed SILs (annual NO₂ and PM_{2.5}) or do not have SILs (1-hour NO₂ and SO₂), this application refers to background pollutant concentrations from monitoring stations in Washington State in areas with similar population densities as Shelton. The only historic reported ambient air monitoring stations in Washington State that measure NO₂ and SO₂ concentration values are located in Seattle, on Beacon Hill, and in Anacortes (NO₂ only). Due to the urban and industrial locations of these monitors, monitoring values from Moyie

Springs, Idaho—a town with an active lumber industry, similar to Shelton—were referenced as background or ambient concentrations for NAAQS and WAAQS comparison for NO₂. The Shelton PM_{2.5} monitor was referenced for most recent PM_{2.5} background concentrations in Shelton in 2009. Because of the lack of background concentration measurements in Shelton, and the urban and industrial nature of Beacon Hill background concentrations, site-specific monitored ambient concentrations from the Grays Harbor Energy complex in Satsop, Washington were referenced as estimates for SO₂ ambient values. Table 4-4 demonstrates Project compliance with the more stringent NAAQS and WAAQS.

When combined with background concentrations, maximum modeled Project concentrations remain below applicable NAAQS and WAAQS. Although no proposed SIL currently exists for the 1-hour NO₂ and SO₂ averaging times, background concentrations were added to modeled Project concentrations to demonstrate compliance with the 1-hour NO₂ and SO₂ NAAQS. The five-year average of the daily maximum modeled 1-hour 98th and 99th percentile of NO₂ and SO₂, respectively, was added to background concentrations. This approach is as prescribed for air quality analyses in The Guideline.

Table 4-4: NAAQS Compliance Comparison

Pollutant	Averaging Period	Maximum Concentration ($\mu\text{g}/\text{m}^3$)	Background Concentration ($\mu\text{g}/\text{m}^3$) ¹	Total Concentration ($\mu\text{g}/\text{m}^3$) ²	National Ambient Air Quality Standards ($\mu\text{g}/\text{m}^3$)		Washington Ambient Air Quality Standards ($\mu\text{g}/\text{m}^3$)	Over the AAQS?
					Primary	Secondary		
NO ₂	Annual	4.37	26	30	100	- ⁶	94	No
	1-Hour	114	49	163	188 ³	-	-	No
	1-Hour	83.6	29.9	113.5	196 ⁴	-	-	No
	3-Hour	64.1	9.99	74.1	-	1300 ⁵	-	No
SO ₂	24-Hour	15.42	1.38	16.8	365 ⁵	-	262	No
	Annual	2.88	0.0311	2.9	80	-	52	No
	Annual	0.51	7	7.5	15	- ⁶	-	No
PM _{2.5}	24-Hour	2.72	30.1	32.8	35	- ⁶	-	No

¹ NO₂ monitor located near Division Street in Moyie Springs, ID; data provided for the year 2003 from USEPA's AQS Data Mart database (<http://www.epa.gov/ttn/airs/aqsdata/mart/>). The 1-hour NO₂ background concentration presented represents the 98th percentile of the daily maximum 1-hour average at the monitor. SO₂ monitor located at the Grays Harbor Energy facility (Satsop, WA); data values measured from May 2002 – May 2003. PM_{2.5} monitor located at Mt. View Drive in Shelton, WA; data provided for the year 2009 from Washington DOE Enview website (<https://fortress.wa.gov/ecy/environ/>) as accessed May 2010.

² Because the 1-hour NO₂, SO₂ and PM_{2.5} averaging times do not have established corresponding SILs, background concentrations were combined with the 5-year average 98th percentile of the daily maximum 1-hour NO₂ concentration and the 5-year average 99th percentile of the daily maximum 1-hour SO₂ concentration, as well as annual and 24-hour PM_{2.5} averaging time maximum Project concentrations, to determine compliance with NAAQS and WAAQS.

³ To attain this standard, the 3-year average of the 98th percentile of the daily maximum 1-hour average at each monitor within an area must not exceed 0.100 ppm (effective January 22, 2010).

⁴ Final rule signed June 2, 2010. To attain this standard, the 3-year average of the 99th percentile of the daily maximum 1-hour average at each monitor within an area must not exceed 75 ppb.

⁵ Concentration not to be exceeded more than once per year.

⁶ Same as primary NAAQS.

4.4.2 Startup Analysis

ENVIRON also applied AERMOD to demonstrate CO emissions during startup will result in ambient concentrations that will comply with both the one- and eight-hour average ambient CO standards.

The startup air flow rate is anticipated to be controlled by dampers to approximately 10 percent of normal operation flow (ENVIRON conservatively assumed 15,000 actual cubic feet per minute). This results in an exhaust velocity of 5.0 feet per second. The exhaust temperature during startup is presumed to be about 175 °F, approximately 150 °F cooler than normal operation. These conditions were assumed to be constant throughout the startup process regardless of the fuel mix used after the first two hours of startup.

Assuming a worst-case, 1-hour average emission rate of 400 lb/hr, the predicted 1-hour and 8-hour average design concentrations were 2,482 and 1031 $\mu\text{g}/\text{m}^3$, respectively. These concentrations are around or less than 10% of the NAAQS established for CO (40,000 $\mu\text{g}/\text{m}^3$ on a one-hour average and 10,000 $\mu\text{g}/\text{m}^3$ on an 8-hour average). Based on this analysis, an estimated worst-case startup CO emission rate of 400 lb/hr is expected to comply with the NAAQS.

4.4.3 Toxic Air Pollutant Acceptable Source Impact Level Assessment

For those TAPs that require modeling, the ambient impact concentration of each TAP was compared with its ASIL as found in WAC 173-460. Table 4-5 illustrates that all TAP concentrations modeled are below respective ASILs.

Table 4-5: Maximum Predicted Toxic Air Pollutant Concentrations

Pollutant	CAS Number	Averaging Time	ASIL ($\mu\text{g}/\text{m}^3$)	Concentration ($\mu\text{g}/\text{m}^3$)	Over ASIL? (Y/N)
Acetaldehyde	75-07-0	year	0.37	0.007423	No
Acrolein	107-02-8	24-hr	0.06	0.006318	No
Ammonia	7664-41-7	24-hr	70.8	5.472368	No
Arsenic	7440-38-2	year	0.000303	1.84E-05	No
Benzene	71-43-2	year	0.0345	0.032174	No
Beryllium	7440-41-7	year	0.000417	5.8E-05	No
Bromomethane	74-83-9	24-hr	5	0.005608	No
Cadmium	7440-43-9	year	0.000238	9.67E-05	No
Carbon Monoxide	630-08-0	1-hr	23000	160.6208	No
Carbon Tetrachloride	56-23-5	year	0.0238	0.001696	No
Chlorine	7782-50-5	24-hr	0.2	0.158577	No
Chloroform	67-66-3	year	0.0435	0.001028	No
Chromium, hexavalent	18540-29-9	year	6.67E-06	6.55E-06	No

Pollutant	CAS Number	Averaging Time	ASIL ($\mu\text{g}/\text{m}^3$)	Concentration ($\mu\text{g}/\text{m}^3$)	Over ASIL? (Y/N)
Cobalt	7440-48-4	24-hr	0.1	0.001789	No
Dibromoethene-12	106-93-4	year	0.0141	0.002047	No
Dichloroethane-12	107-06-2	year	0.0385	0.001091	No
Dichloromethane	75-09-2	year	1	0.010722	No
Dichloropropane-12	78-87-5	year	0.1	0.001244	No
Ethylbenzene	100-41-4	year	0.4	0.001169	No
Formaldehyde	50-00-0	year	0.167	0.073185	No
HxCDD-Total	34465-46-8	year	2.63E-07	3.19E-09	No
Hydrogen chloride*	7647-01-0	24-hr	9	0.927742	No
Lead	7439-92-1	year	0.0833	0.000446	No
Manganese	7439-96-5	24-hr	0.04	0.023155	No
Mercury	7439-97-6	24-hr	0.09	8.33E-05	No
Naphthalene	91-20-3	year	0.0294	0.00318	No
Nickel	7440-02-0	year	0.0042	0.000106	No
Nitrogen Dioxide	10102-44-0	1-hr	470	160.6208	No
Phosphorus	7723-14-0	24-hr	20	0.00709	No
Styrene	100-42-5	24-hr	900	0.372533	No
Sulfur Dioxide	7446-09-05	24-hr	26.7	15.42208	No
Sulfuric Acid	7664-93-9	24-hr	1	0.402096	No
TCDD-Total	1746-01-6	year	2.63E-08	7.64E-09	No
Tetrachloroethene	127-18-4	year	0.169	0.001428	No
Trichloroethene	79-01-6	year	0.5	0.001133	No
Vinyl Chloride	75-01-4	year	0.0128	0.000687	No

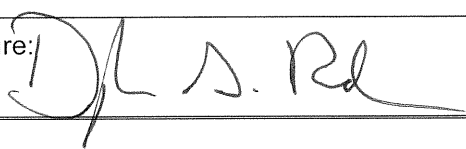
Appendix A: Permit Application Forms

OLYMPIC REGION CLEAN AIR AGENCY

2940 B Limited Lane NW - Olympia, Washington 98502 - 360-539-7610 – Fax 360-491-6308

FORM 1 NOTICE OF CONSTRUCTION

TO CONSTRUCT - INSTALL - ESTABLISH OR MODIFY AN AIR CONTAMINANT SOURCE

Business Name: Solomon Renewable Energy Company, LLC	For ORCAA use only
Mailing Address (address, city, state, zip): P.O. Box 21866 Seattle, WA 98111	File No: County No: Source No: Application No:
Physical Address of Project/New Source (address, city, state, zip): Front & Railroad, Shelton, WA 98584	Date Received:
Billing Address (address, city, state, zip): P.O. Box 21866 Seattle, WA 98111	
Are you currently registered with ORCAA? Yes <input type="checkbox"/> No <input checked="" type="checkbox"/>	
Previous business name (if any):	
Process/ Equipment to be installed: Hog fuel boiler, steam turbine, cooling tower and fuel storage building	
Do you request confidentiality? Yes <input type="checkbox"/> No <input checked="" type="checkbox"/> If yes, provide a separate copy of the application void of the materials considered confidential. Each page considered confidential must be individually identified by stamping "confidential" or similar method. [Confidentiality reasons: Trade secrecy and similar concepts whereby limited disclosure is necessary to retain business advantages.]	
This project must meet the requirements of the State Environmental Policy Act (SEPA) and applicable building and fire codes before ORCAA can issue final approval. Complete one of the following options. <input type="checkbox"/> SEPA was satisfied by _____ (government agency) on ___/___/___ (date). I copy of the final determination and the environmental checklist is enclosed. <input checked="" type="checkbox"/> SEPA is pending approval by <u>City of Shelton</u> (government agency). A copy of the environmental checklist is enclosed and a copy of the final determination will be forwarded to ORCAA when issued. <input type="checkbox"/> ORCAA is the only government agency requiring a permit. A completed environmental checklist or documentation that the project or new source is/will be in compliance with local building and fire codes is enclosed. This project is exempt from SEPA per _____ (WAC citation).	
I hereby certify that the information contained in this request is, to the best of my knowledge, complete and correct.	Agency Use Only
Name of Applicant or Owner of Business: Douglas Reed	
Title: Administrative and General Manager	Phone: 206-224-5264
Contact Name (if different than above):	
Title:	Phone:
Signature: 	Date: 8-6-10

FORM 4 FACILITY EMISSIONS SUMMARY

Facility: Solomon Renewable Energy Company

Page ___ of ___

Instructions: on back.

Emission Unit ID#	TSP	PM-10	SOx	NOx	VOC	CO
	PLEASE REFER TO TABLE 2-1 OF THE NOC PERMIT APPLICATION FOR A COMPLETE EMISSIONS SUMMARY FOR THE PROJECT.					
Facility Total						

FORM 5 EMISSIONS OF HAZARDOUS AIR POLLUTANTS

Facility: Solomon Renewable Energy Company Emission Unit ID#: _____

Page _____ of _____

Pollutant Name	CAS #	Maximum Emission Rate lbs/hr	Annual Emission Rate tons/yr
PLEASE REFER TO TABLE 3-1 OF THE NOC PERMIT APPLICATION FOR A COMPLETE HAP EMISSIONS SUMMARY FOR THE PROJECT.			
Facility Total			

**FORM 6
BACT ANALYSIS TABLE**

CONTROL OPTIONS	CONTROL EFFICIENCY % removal	POTENTIAL EMISSIONS lbs/hr	EXPECTED EMISSIONS tons/yr	ANNUAL EMISSION REDUCTIONS tons	ANNUAL COST \$	COST EFFECTIVENES \$/ton	ENERGY, ENVIRONMENTAL ECONOMIC IMPACTS (list)
1.							
2.							
3.							
4.							
5.							
6.							

PLEASE REFER TO APPENDIX B OF THE NOC PERMIT APPLICATION FOR A COMPLETE BACT ANALYSIS FOR THE PROJECT.



FORM 7
PSD APPLICABILITY FORM

This form is an aid to help determine if a proposed project will be required to undergo PSD review. Please submit this form with the cover sheet of the Notice of Construction application to the Local Air Authority. For locations in eastern Washington where the Department of Ecology is the delegated local air authority, submit this form to the appropriate Ecology Regional Office.

It is the responsibility of the applicant to ensure that all preconstruction permits are obtained before commencement of construction.

COMPANY INFORMATION

Company or owner name: Solomon Renewable Energy Company, LLC

Mailing address: PO BOX 21866
Seattle, WA 98111

Facility address: Front and Railroad
Shelton, WA 98584

Contact: Douglas Reed

Telephone: 206-224-5264

Facility industrial classification and SIC: 4911

PROCESS INFORMATION AND EMISSIONS CALCULATIONS

This section is intended to furnish a best estimate of annual emissions and sufficient information for agency technical staff to verify the applicant's conclusions in answering the questions in the next section. Please provide:

- (1) A description of the process with a flow diagram indicating points of emissions to the air.
- (2) Design and operating parameters for the process (i.e., hours of operation per year, maximum and normal production rates, fuel and raw material requirements).
- (3) Estimates of the potential emissions for all air pollutants from each emissions point and a description of the method or basis used to make the emission estimates (in enough detail so that one can follow the logic and the calculation steps). Potential emissions are based on the maximum rate from each emission point taking into account air pollution control equipment.

For either a new or modified source, calculate its potential to emit each regulated pollutant based on operation at maximum capacity (such as 8760 hours/year) with emissions control equipment operating.

For a modified source, subtract the actual emissions of the existing source from the potential to emit of the modified source to calculate the emissions increase(decrease). Actual emissions are the average of the last 24 months of operation, if that period is representative of normal operations.

Regulated Pollutant Under PSD	Potential To Emit Tons/Year	Actual Emissions Tons/Year	Emissions Increase (Decrease)	Significant PSD Rate Tons/Year
Carbon Monoxide	248			100
Nitrogen oxides	248			40
Sulfur dioxide	147			40
Particulate matter PM ₁₀	39			25 15
Ozone (VOCs)	32			40
Lead (elemental)	0.02			0.6
Fluorides	0			3
Sulfuric acid mist	3.8			7
Total reduced sulfur (including H ₂ S)	0			10
Reduced sulfur compounds (including H ₂ S)	0			10
Municipal waste combustor organics				
Dioxins and furans	0			3.5x10 ⁻⁶
Metals	0			15
Municipal waste combustor acid gasses	0			40

QUESTION 1

Does the proposed source or, in the case of a modification to a source, the existing source fall within one of the following 28 source categories?

- | | |
|---------------------------------------------------------------------------------------|--------------------------------------------------------------------------------------------------|
| 1. Fossil fuel-fired steam electric plants of more than 250 million Btu/hr heat input | 16. Coke oven batteries |
| 2. Coal cleaning plants with thermal dryers | 17. Sulfur recovery plants |
| 3. Kraft pulp mills | 18. Carbon black plants (furnace process) |
| 4. Portland cement plants | 19. Primary lead smelters |
| 5. Primary zinc smelters | 20. Fuel conversion plants |
| 6. Iron and steel mill plants | 21. Sintering plants |
| 7. Primary aluminum ore reduction plants | 22. Secondary metal production plants |
| 8. Primary copper smelters | 23. Chemical process plants |
| 9. Municipal incinerators capable of charging more than 250 tons of refuse per day | 24. Fossil fuel boilers (or combinations) totaling more than 250 million Btu/hr heat input |
| 10. Hydrofluoric acid plants | 25. Petroleum storage and transfer units with a total storage capacity exceeding 300,000 barrels |
| 11. Sulfuric acid plants | 26. Taconite ore processing plants |
| 12. Nitric acid plants | 27. Glass fiber processing plants |
| 13. Petroleum refineries | 28. Charcoal production plants |
| 14. Lime plants | |
| 15. Phosphate rock processing plants | |

YES (Please circle number.) GO TO QUESTION 2.

NO GO TO QUESTION 3.

QUESTION 2

Will emissions of any one regulated pollutant (including fugitive emissions) from the proposed or existing source exceed 100 tons per year?

YES GO TO QUESTION 6.

NO PSD IS NOT REQUIRED. DO NOT ANSWER ANY MORE QUESTIONS. SUBMIT THIS FORM WITH THE NOTICE OF CONSTRUCTION APPLICATION.

QUESTION 3

Does the proposed source or, in the case of a modification to a source, the existing source fall within one of the following source categories?

1. Municipal Incinerators (50 tons/day)
2. Asphalt concrete plants
3. Storage vessels for petroleum liquids, 40,000 gallons, construction after 06/11/73 and prior to 05/19/78.
4. Storage vessels for petroleum liquids, 40,000 gallons, construction after 05/18/78
5. Sewage treatment plants with sludge incinerators
6. Phosphate fertilizer industry: Plants manufacturing wet-process phosphoric acid, superphosphoric acid, diammonium phosphate, triple superphosphate, and granular triple superphosphate storage facilities.
7. Glass melting furnace 4,555 kilograms glass/day, (except all electric melters)
8. Grain elevators
9. Stationary gas turbines 10.7 gigajoules/hour heat input
10. Lead acid battery manufacturing plants
11. Automobile and light-duty truck assembly plant surface coating operations

YES (Please Circle Number) GO TO QUESTION 4

NO GO TO QUESTION 5

QUESTION 4

Will the emissions of any one regulated pollutant (including fugitive emissions) from the proposed or existing source exceed 250 tons/year?

YES GO TO QUESTION 6

NO PSD IS NOT REQUIRED. DO NOT ANSWER ANY MORE QUESTIONS. SUBMIT THIS FORM WITH THE NOTICE OF CONSTRUCTION APPLICATION.

QUESTION 5

Will emissions of any one pollutant (not including fugitive emissions) from the proposed or existing source exceed 250 tons per year?

YES GO TO QUESTION 6.

NO PSD IS NOT REQUIRED. DO NOT ANSWER ANY MORE QUESTIONS. SUBMIT THIS FORM WITH THE NOTICE OF CONSTRUCTION APPLICATION.

QUESTION 6

Is the project located within 10 kilometers (6.2 miles) of the boundary of a Class I area? Class I areas in Washington State are Mount Rainier National Park, North Cascade National Park, Olympic National Park, Alpine Lakes Wilderness Area, Glacier Peak Wilderness Area, Goat Rocks Wilderness Area, Mount Adams Wilderness Area, Pasayten Wilderness Area, and the Spokane Indian Reservation.

YES PSD REVIEW IS REQUIRED IF THE IMPACT OF ANY REGULATED POLLUTANT IS EQUAL TO OR GREATER THAN 1 g/m³, (24-hour average).

NO CONTINUE

QUESTION 7

Is the proposed project a

1. new source? GO TO QUESTION 8.

2. modification, expansion, or addition to an existing source? GO TO QUESTION 9.

QUESTION 8

For which regulated pollutants does the potential to emit of the new source exceed the PSD significant rate?

PSD REVIEW IS REQUIRED FOR THESE POLLUTANTS. YOU MUST MEET WITH THE DEPARTMENT OF ECOLOGY TO DISCUSS THE PSD APPLICATION PROCEDURE.

QUESTION 9

For which regulated pollutants do the emissions increase from the modified source exceed the PSD significant rate?

PSD REVIEW IS REQUIRED FOR THESE POLLUTANTS. YOU MUST MEET WITH THE DEPARTMENT OF ECOLOGY TO DISCUSS THE PSD APPLICATION PROCEDURE.

Appendix B: BACT Analysis



**Wood-Fired Cogeneration Unit Project
Best Available Control Technology Analysis
Solomon Renewable Energy Co., LLC**

Prepared for:
**Simpson Lumber Company, LLC
Olympia, Washington**

On behalf of:
**Solomon Renewable Energy Co., LCC
Shelton, Washington**

Prepared by:
**ENVIRON International Corporation
Lynnwood, Washington**

Date:
August 2010

Project Number:
03-21679C

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1 Introduction

Solomon Renewable Energy Company (SREC) proposes to construct and operate a biomass-fired cogeneration facility in Shelton, Washington. Shelton is in Mason County, which is designated as attainment or unclassified for all criteria pollutants. According to Washington Administrative Code (WAC) 173-400-113, as well as Olympic Region Clean Air Agency (ORCAA) Rule 6.1.4(a)(2), new sources of air pollutant emissions in such areas are required to employ best available control technology (BACT) for all pollutants not previously emitted. The intent of this document is to present BACT analyses for emission units associated with the proposed cogeneration facility to satisfy the requirements of these regulations.

1.1 Project Overview

The facility will be comprised of a stoker-type wood-fired boiler, a steam turbine generator, a two-cell evaporative cooling tower, a condenser, and a fuel storage building with associated fuel delivery and handling equipment. Emission units include the wood-fired boiler, the cooling tower, and the fuel delivery and handling equipment.

1.2 BACT Review Process

BACT is defined by WAC 173-400-030(12) as:

“... an emission limitation based on the maximum degree of reduction for each pollutant subject to regulation under the Act which would be emitted from any proposed major stationary source ... which [is determined to be achievable], on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs”

In a December 1, 1987 memorandum from the EPA Assistant Administrator for Air and Radiation, the agency provided guidance on the “top-down” methodology for determining BACT. The “top-down” process involves the identification of all applicable control technologies according to control effectiveness. Evaluation begins with the “top,” or most stringent, control alternative. If the most stringent option is shown to be technically or economically infeasible, or if environmental impacts are severe enough to preclude its use, then it is eliminated from consideration and then the next most stringent control technology is similarly evaluated. This process continues until the BACT level under consideration cannot be eliminated by technical or economic considerations, energy impacts, or environmental impacts. The top control alternative that is not eliminated in this process becomes the proposed BACT basis.

This top-down BACT analysis process can be considered to contain five basic steps described below:¹

¹ “New Source Review Workshop Manual”, DRAFT October 1990, EPA Office of Air Quality Planning and Standards

- Step 1: Identify all available control technologies with practical potential for application to the specific emission unit for the regulated pollutant under evaluation;
- Step 2: Eliminate all technically infeasible control technologies;
- Step 3: Rank remaining control technologies by control effectiveness and tabulate a control hierarchy;
- Step 4: Evaluate most effective controls and document results; and
- Step 5: Select BACT, which will be the most effective practical option not rejected, based on economic, environmental, and/or energy impacts.

Formal use of these steps is not always necessary. However, EPA has consistently interpreted the statutory and regulatory BACT definitions as containing two core requirements, which EPA believes must be met by any BACT determination, irrespective of whether it is conducted in a “top-down” manner. First, the BACT analysis must include consideration of the most stringent available technologies: i.e., those that provide the “maximum degree of emissions reduction.” Second, any decision to require a lesser degree of emissions reduction must be justified by an objective analysis of “energy, environmental, and economic impacts” contained in the record of the permit decisions.

Additionally, the minimum control efficiency to be considered in a BACT analysis must result in an emission rate no less stringent than the applicable New Source Performance Standard (NSPS) emission rate, if any NSPS standard for that pollutant is applicable to the source.

This BACT analysis was conducted in a manner consistent with this stepwise approach. Control options for potential reductions in criteria pollution emissions were identified for each source. These options were identified by researching the EPA database known as the RACT/BACT/LAER Clearinghouse (RBLC), drawing upon previous environmental permitting experience for similar units and surveying available literature. Available controls that are judged to be technically feasible are further evaluated based on an analysis of economic, environmental, and energy impacts.

Assessing the technical feasibility of emission control alternatives is discussed in EPA's draft "New Source Review Workshop Manual." Using terminology from this manual, if a control technology has been "demonstrated" successfully for the type of emission unit under review, then it would normally be considered technically feasible. For an undemonstrated technology, “availability” and “applicability” determine technical feasibility. An available technology is one that is commercially available; meaning that it has advanced through the following steps:

- Concept stage;
- Research and patenting;
- Bench scale or laboratory testing;
- Pilot scale testing;
- Licensing and commercial demonstration; and

- Commercial sales.

Suitability for consideration as a BACT measure involves not only commercial availability (as evidenced by past or expected near-term deployment on the same or similar type of emission unit), but also involves consideration of the physical and chemical characteristics of the gas stream to be controlled. A control method applicable to one emission unit may not be applicable to a similar unit, depending on differences in the gas streams' physical and chemical characteristics.

1.3 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.
- The emission limit associated with the control technology, including consideration for normal and reasonable variability in the level control, 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.

1.4 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.

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2 Wood-Fired Boiler BACT Analysis

The wood-fired boiler will have a design heat input of 435.5 million British thermal units per hour (MMBtu/hr), and be designed to produce up to 250,000 pounds per hour (lb/hr) of steam at full load to supply the steam turbine generator. As a new source of emissions, a BACT analysis is required for the proposed boiler. Based on the pollutants expected to be emitted, analyses are required for oxides of nitrogen (NO_x), carbon monoxide (CO), particulate matter equal to or less than ten microns in diameter (PM₁₀), volatile organic compounds (VOC), and sulfur dioxide (SO₂), as well as toxic air pollutant (TAPs).

2.1 NO_x BACT Analysis

NO_x is generated when combustion temperatures are high enough for the nitrogen in the combustion air or bound in the fuel to combine with oxygen to form NO. Depending upon conditions in the exhaust stream, some portion of the NO will react to form NO₂.

2.1.1 Identification of Possible Control Alternatives

There are a variety of options available for controlling NO_x emissions from combustion sources. Some options involve combustion controls that reduce NO_x formation, while others utilize add-on control devices to remove NO_x after it is formed.

Combustion Controls

Combustion controls reduce NO_x 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 NO_x.” The oxidation of nitrogen that is chemically bound in fuel sources can also form what is called “fuel-bound NO_x.”

Proper combustion generally refers to control, generally computerized, of the amount of flue gas recirculation (FGR), the fuel feed rate, and the amount of over- or under-fire combustion air in the furnace. This type of control is common on boilers constructed in the last few decades.

Dry low-NO_x (DLN) burners control thermal NO_x 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. Use of DLN burners requires a wall-fired furnace and finely pulverized biomass fuel that is typically burned in suspension with coal or natural gas.

Add-on Controls

Add-on controls such as selective non-catalytic reduction (SNCR) and selective catalytic reduction (SCR) systems are widely used technologies for controlling NO_x emissions from combustion sources. In the SNCR process, ammonia is mixed with the exhaust from the combustion device and the NO_x in the exhaust reacts with the introduced ammonia to form

nitrogen and water. The reagent, which can be anhydrous ammonia, aqueous ammonia, or urea dissolved in water, is typically injected at the exit of the furnace to mix with the hot flue gases.

The SCR process is similar to SNCR in that a reagent reacts with NO_x to form nitrogen and water, but a catalyst matrix is used to allow the reduction reaction to take place at lower temperatures (600 °F for SCR as opposed to 1,650 °F for SNCR). While, SCR systems have been utilized to reduce NO_x emissions from biomass-fired boilers, such installations are relatively rare because the ash in the exhaust tends to obstruct and deactivate the catalyst. Schemes that position the SCR downstream of a particulate control device to reduce the amount of ash that reaches the catalyst have resulted in exhaust gas temperatures too low for conventional catalysts to promote the reduction reaction. Additionally, potassium in the fuel vaporizes and becomes an extremely fine aerosol that often eludes particulate controls in sufficient quantities to accelerate deactivation of the catalyst. Solutions to these problems have included: reheating the flue gas with natural gas or diesel fuel, using low-temperature catalysts located downstream of particulate controls, and increasing catalyst size and replacement frequency to maintain the desired effectiveness. Unfortunately, each of these approaches involve significant additional expense: exhaust reheat is expensive and an inefficient use of fuel, low-temperature catalysts are expensive and even more prone to deactivation than conventional catalysts, and increasing the size and replacement frequency of conventional catalyst is inherently expensive.

There are several SCR variants that have been applied to biomass-fired boilers including: SNCR/SCR hybrids, Regenerative SCR (RSCR), and low-temperature, or “cold-side,” SCR (CSCR). Hybrid SNCR/SCR systems locate the catalyst bed downstream of an SNCR system, and the unreacted ammonia injected by the SNCR system (and additional ammonia, if necessary) is used by the SCR catalyst to further reduce NO_x emissions. In practice, unreacted ammonia from the SNCR is not distributed evenly enough in the exhaust gases to be used effectively by the catalyst, and, as a result, ammonia use and ammonia slip levels tend to be higher than for a similarly effective SCR-only system.

RSCR systems were developed to make application of an SCR system downstream of a particulate control device more economical by using a regenerative ceramic bed to recover heat from reheated exhaust gas. RSCR applications have typically been limited to existing boilers, where it would be expensive and difficult to rearrange the exhaust system to locate an SCR or CSCR system for the optimum range of exhaust temperatures.

CSCR systems are also positioned downstream of a particulate control device, but use more advanced catalysts that enable the reduction reaction to proceed at lower temperatures (350 °F to 450 °F). These catalysts are typically more expensive and are even more prone to deactivation by potassium and sulfur than standard SCR catalysts.

EMx (formerly called SCONOX) is similar to SCR, except that NO_x in the exhaust stream reacts with potassium carbonate (K_2CO_3) to form potassium nitrate (KNO_3). This compound is reacted with hydrogen to form gaseous nitrogen (N_2), and regenerate the K_2CO_3 . The exhaust

temperature required for the reactions to take place is lower than that of SCR (300 °F as opposed to 450 to 600 °F, depending on the catalyst used). The EMx system is also said to control CO and VOCs by oxidation.

2.1.2 Control Alternative Review

The database queries did not produce any instances of NO_x emissions from biomass-fired boilers controlled by DLN burner or SNCR/SCR hybrid systems. The most recent biomass-fired, stoker-type boiler BACT determination in the RBLC was by the New Hampshire Department of Environmental Services (NHDES) in a permit issued to Concord Steam for a 305 MMBtu/hr wood-fired, stoker-type boiler on January 16, 2009. NHDES determined that a “cold-side” SCR system (2 catalyst beds with a 450 °F inlet temperature) that would limit NO_x emissions to 0.065 lb/MMBtu on a 30-day rolling average was LAER.

In 2007 and 2008, several New England facilities received permits allowing them to add RSCR or SNCR/SCR hybrid systems to biomass-fired stoker-type boilers to achieve a quarterly average NO_x emission rate of 0.075 lb/MMBtu and qualify for Connecticut’s Renewable Portfolio Standard (RPS) program. RSCR systems were installed at Boralex Energy in Stratton, Maine, Bridgewater Power in Bridgewater, New Hampshire, and DG Energy in Whitefield, New Hampshire. SNCR/SCR hybrid systems were installed at Springfield Power in Springfield, New Hampshire, and the Pinetree Power facilities in Tamworth and Bethlehem, New Hampshire. All of these facilities were originally permitted before 1990, and have less stringent short-term NO_x permit limits based on either a PSD permit or RACT. It should be noted that while these emission units have demonstrated the ability to meet the Connecticut RPS qualification threshold, compliance is entirely voluntary, and none have corresponding enforceable permit limits.

Also not represented in the RBLC is a recently issued conditional permit for Russell Biomass in Massachusetts, which includes an option to construct a stoker-type biomass boiler that would limit NO_x emissions to 0.060 lb/MMBtu using a two-layer RSCR system. The Massachusetts RPS program has a more stringent NO_x emissions criterion (0.065 lb/MMBtu with no averaging period). This air and water permits issued for this project have been appealed, the facility has not yet obtained a wetlands permit, and there is significant public opposition to the fuel delivery truck volumes and routes.

The most recently permitted biomass-fired, stoker-type boiler in Washington is a 430 MMBtu/hr unit at the Sierra Pacific Industries facility in Burlington, Washington, which was permitted in 2006 with a NO_x limit of 0.13 lb/MMBtu.² Valley BioEnergy, LLC has submitted a permit application for a biomass-fired boiler in Modesto, California that proposes to use an SNCR/SCR hybrid system to limit NO_x emissions to 0.012 lb/MMBtu on a short-term basis³, and

2 The original permit included a 24-hour average NO_x limit of 0.13 lb/MMBtu, and a 12-month rolling average NO_x limit of 0.1 lb/MMBtu. In August 2009, the 12-month rolling average NO_x limit was eliminated in an effort to address a secondary plume that resulted from excessive ammonia use in the SNCR system.

3 For the initial 12-month period following startup, the 24-hour average NO_x limit would be 0.024 lb/MMBtu. During

0.0055 lb/MMBtu on an annual average in order to avoid purchasing offsets in an ozone nonattainment area. The facility has not received a permit, and has not been constructed.

There are several instances of biomass-fired boilers using DLN burner technology to limit the amount of NO_x generated during combustion. Coen manufactures the Dual Air Zone (DAZ) scroll burner, which can be used to fire pulverized wood along with some natural gas (approximately ten percent of total heat input). These burners have generally been installed in units with a maximum heat input of less than 100 MMBtu/hr, and require additional fuel processing to reduce the fuel to an average size of approximately 1/32 of an inch (0.8 mm). With some flue gas recirculation and staged combustion, a NO_x emission factor of 0.35 lb/MMBtu at the furnace exit has been achieved.

The results of the database queries and permit investigations for NO_x control alternatives are presented in Table 1, sorted by permit limit.

2.1.3 Summary of Possible Control Alternatives

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

- Proper combustion
- DLN burner
- SNCR
- SCR and variations
- EMx

2.1.4 Technical Feasibility of Control Alternatives

Most of the control alternatives described in the previous section have been shown to be technically feasible for controlling NO_x emissions from biomass-fired, stoker-type boilers. Several of the alternatives have either not been applied to biomass-fired boilers, or been applied to boilers with significantly lower heat input than that proposed for the project in question.

Proper Combustion

Proper combustion refers to the application of state-of-the-art design to, and appropriate operation of, a combustion unit. Current design biomass-fired mass-burner-type boilers can generally achieve NO_x emission rates of between 0.20 to 0.26 lb/MMBtu, depending upon the degree of optimization for controlling NO_x emissions (lower NO_x emissions mean higher CO

that period, a study would determine whether or not the 0.012 lb/MMBtu limit was achievable, and, if not, an alternative NO_x limit would be proposed.

and VOC emissions), when operated in the manner recommended by the boiler designer and manufacturer. Proper combustion is a ubiquitous and technically feasible technology for controlling NO_x emissions from biomass-fired boilers.

DLN Burner

For a boiler of the size proposed, two or more DLN burners would be required. With such burners, the fuel would be pulverized and burned in suspension using wall-mounted burners, which would be a significant departure from the proposed boiler design, which has combustion occurring on a moving grate. These burners are generally intended to limit the amount of fuel-bound nitrogen that is converted to NO_x during combustion, and are generally suited to smaller boilers that burn wood products industry residuals containing a high percentage of resins, such as residuals from medium density fiberboard (MDF), plywood, or veneer operations. In this case, the emission rate with DLN burners (0.35 lb/MMBtu) is higher than could be achieved by a current state-of-the-art mass burner-type boiler using a combustion grate and no add-on controls (approximately 0.25 lb/MMBtu), so this technology will be eliminated from consideration as BACT.

SNCR

Ammonia injection nozzles are positioned in the furnace where temperatures are expected to be between 1600 °F and 1800 °F and use the relatively high temperatures there to promote the reaction of NO_x and ammonia. SNCR system design is often incorporated into biomass-fired boiler design because SNCR systems do not rely on a catalyst which is subject to plugging from particulate matter in the flue gases. The relative simplicity of SNCR systems makes them technically feasible, and has resulted in them becoming the most common add-on NO_x control technology for biomass-fired boilers.

SCR and related variations

As indicated in the previous section, SCR, SNCR/SCR hybrid, RSCR, and CSCR systems have been applied to a limited number of biomass-fired, stoker-type boilers. Among the variations, an SCR system placed downstream of a particulate collection system (e.g., a multiclone and an ESP) has the best chance of providing cost-effective operation while reducing NO_x emissions to 0.060 lb/MMBtu. Because most of these installations have been within the past few years, experience with this application of SCR technology is limited. Many of the biomass-fired boiler projects using SCR to control NO_x have experienced catalyst deactivation and/or erosion at rates that are higher than was anticipated during the design process, and, as a result, have required additional assistance from catalyst suppliers and control technology consultants to maintain compliance with permit limits. SCR systems are known to effectively control NO_x emitted by biomass-fired boilers, but the ability of such systems to remain effective over time, and not negatively impact economic performance of the facility for which the boiler produces steam, is questionable.

EMx

To date, EMx has been designed and used only on small- to medium-sized natural gas-fired stationary turbines for demonstration purposes. The technology has never been applied to a biomass-fired boiler. Also, the EMx system is sensitive to sulfur in the exhaust, which can degrade the performance of the system. While biomass fuels are not generally considered high-sulfur fuels, the AP-42 SO₂ emission factor for wood-fired boilers is 0.025 lb/MMBtu, which is equivalent to about 7.2 lb/hr of SO₂. Natural gas, the combustion fuel most commonly associated with EMx applications, has maximum sulfur limit of one grain per 100 standard cubic feet (gr/scf) of gas in California, where EMx has been applied. On a heat input basis, this is equivalent to an SO₂ emission rate of 0.43 lb/hr. The sensitivity to sulfur, combined with a lack of comparable existing applications suggests that EMx is technologically infeasible as a control technology for controlling NO_x emissions from a biomass-fired boiler.

2.1.5 Summary of Technically Feasible Control Alternatives

The following is a list of control alternatives determined to be technically feasible for controlling NO_x emitted by a biomass-fired, stoker-type boiler:

- Proper combustion
- SNCR
- SCR and related variations

2.1.6 Effectiveness of Remaining Technologies

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

Proper Combustion

A modern biomass-fired boiler furnace, operated with computerized controls to ensure proper combustion would result in a NO_x emission factor of between 0.20 and 0.26 lb/MMBtu. The proposed boiler design would emit 0.25 lb/MMBtu when utilizing only proper combustion techniques to reduce NO_x emissions.

SNCR

Currently, SNCR systems are the most common add-on control device used to reduce NO_x emissions from large biomass-fired boilers. SNCR systems rely on high temperatures to promote the reaction of NO_x with the introduced ammonia. As a result, the control system is incorporated into the boiler design to facilitate the introduction of ammonia into the furnace at the proper temperature window to increase NO_x reduction effectiveness. Short-term emission limits of between 0.13 and 0.2 lb/MMBtu have been achieved using SNCR systems to control NO_x emitted by biomass-fired, stoker-type boilers. It should be noted that this range of limits associated with boilers employing SNCR systems to control NO_x emissions, predates the issuance of 40 CFR 63 Subpart JJJJJJ (a.k.a., "area source boiler MACT") which proposes to reduce CO emissions from new biomass-fired boilers to 100 parts per million (ppm), corrected

to 7 percent oxygen. Because an SNCR system is located upstream of where an oxidation catalyst, employed to reduce CO emissions, is located, the oxidation catalyst will tend to reverse some of the reduction reaction achieved by the SNCR, and effectively re-create some NO_x. This means that NO_x limits in future permits may have to increase somewhat to accommodate the decrease in CO emissions mandated by the area source boiler MACT.

SCR and related variations

The recently permitted Concord Steam project proposed to use a CSCR system to limit NO_x emissions to 0.065 lb/MMBtu on a 30-day rolling average. Russell Biomass, if constructed, would use a two-layer RSCR to limit NO_x emissions to 0.060 lb/MMBtu. The Concord Steam LAER determination issued by NHDES acknowledged the Russell Biomass limit, while pointing out that the limit would be “difficult to meet” using the proposed system, and that the project is not likely to be built. A draft permit has been issued for Valley BioEnergy in Modesto, California; the proposal is to use both an SNCR as well as an SCR system with the catalyst placed downstream of particulate control devices. Two of the three most recent entries in the RBLC (Montville Power in Connecticut and Lufkin Generating in Texas) are proposing to employ RSCR or SCR to limit NO_x emissions to 0.06 and 0.075 lb/MMBtu, respectively. However, the trend towards SCR is not universal: the remaining recent entry (Lindale Renewable Energy) was issued a permit for a similar-sized boiler that proposes use SNCR to achieve 0.15 lb/MMBtu.

2.1.7 Ranking by Effectiveness

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

- SCR and related variations
- SNCR
- Proper combustion

2.1.8 Cost-Effectiveness Evaluation

SNCR is the most common add-on technology used to reduce NO_x emissions from a stoker-type, biomass-fired boiler. The uncertainties that drive the ranges of cost and control effectiveness are well understood by manufacturers and vendors. Biomass-fired boiler projects can propose well-established emission limits as BACT with confidence that, based on an extensive body of knowledge and experience, an SNCR system will be able to achieve the proposed emission limits. A cost-effectiveness analysis indicates that utilizing an SNCR system to reduce biomass-fired boiler emissions from 0.25 lb/MMBtu to 0.13 lb/MMBtu would cost \$856 per ton of NO_x reduced (see Attachment A).

Although application of an SCR system to a biomass-fired boiler is not considered experimental, it cannot be assumed that, due to a lack of practical experience, such a system will perform in a reliable and cost-effective manner. Because of the high level of uncertainty associated with the

rate of deactivation of the SCR catalyst by trace amounts of alkaline elements in the exhaust (e.g., potassium), it is difficult, if not impossible, to determine both capital and operating cost ranges in advance. In addition to the number of catalyst beds that the project must purchase, the catalyst deactivation rate determines how often a boiler will be required to shut down for installation of fresh catalyst in order to continually comply with a permit limit. SREC estimates that approximately \$80,000 in revenue would be lost each time the boiler was shut down to replace or wash the catalyst. Additionally, SREC's power contract, which stipulates a minimum level of power availability, could be jeopardized if a high deactivation rate required frequent catalyst replacement or washing.

Despite the difficulty in estimating the actual operating and capital costs associated with such a system, the cost-effectiveness of an SCR control system, as applied to a biomass-fired boiler, was calculated. The calculations are presented in Attachment A, and summarized, along with those of the SNCR system, in Table 2. The SNCR system would reduce NO_x emissions by 229 tons year at an annual expense of approximately \$196,000, while an SCR system (assumed to reduce NO_x emissions to 0.075 lb/MMBtu), under best-case operating conditions, would reduce NO_x emissions by approximately 334 tons per year at an annual expense of over \$1,088,000. Thus, an additional \$890,000 per year would be spent to capture an additional 105 tons of NO_x, which is equivalent to an incremental cost effectiveness of \$8,500 per ton of NO_x removed. However, judging by the experiences of other biomass-fired boiler facilities currently employing SCR systems, this cost-effectiveness analysis likely underestimates the number of times the catalyst would need replacement each year (assumed to be 1), as well as the number downtime events needed each year to replace or clean the catalyst beds (assumed to be 3), so the cost effectiveness could easily be twice that of the calculated "best case" scenario. Based on this analysis, SNCR is deemed to be the most reliable, cost-effective NO_x control technology for biomass-fired, stoker-type boilers.

2.1.9 Selection of BACT for NO_x

Based on the analysis presented in this section, SREC proposes that BACT for the control of NO_x from biomass-fired, stoker-type boilers is the use of an SNCR system that would limit NO_x emissions to 0.13 lb/MMBtu, which is equivalent to approximately 248 tons per year (tpy) at the anticipated maximum annual operating capacity.

2.2 CO BACT Analysis

Carbon monoxide (CO) is a product of the chemical reaction between carbonaceous fuels and oxygen. In fuel-rich mixtures, CO occurs as the product of combustion. In fuel-lean mixtures CO can result due to poor mixing of fuel and air in the combustion zone (so the sub-region is fuel-rich) or through dissociation of CO₂ into CO which can occur in high-temperature regions (above 1,700 °C) of the combustion zone.

2.2.1 Identification of Possible Control Alternatives

The control technology options available for reducing CO emissions from combustion sources include both combustion controls and add-on control devices. CO combustion controls encourage complete combustion to reduce CO formation, and the add-on control devices oxidize CO to CO₂ after leaving the combustion area. Unfortunately, these efforts tend to increase NO_x emissions by encouraging oxidation of nitrogen in the exhaust gases. In the past, NO_x reduction has been favored over CO reduction. This trend can be seen in the RBLC, where NO_x limits tend to be quite a bit lower than CO limits. However, the recently proposed area source boiler MACT includes a requirement to limit CO emissions to 100 parts per million (ppm), corrected to 7 percent oxygen. While area source boiler MACT has not yet been promulgated, it is all the regulated community has on which to base control equipment decisions, and, as a result, more emphasis is being placed on CO control, even at the expense of NO_x emissions.

Combustion Controls

Combustion controls for CO include adequate fuel residence times to ensure CO₂ formation, proper fuel-air mixing, and temperature control. These measures, however, can result in an increase in the NO_x emissions from a combustion unit. Modern boiler designs strive to balance these competing factors, and when combined with appropriate operation of the boiler, are commonly referred to as “proper combustion” practices. The design of the boiler and the type of fuel combusted can significantly influence the level of CO emissions that can be achieved through the use of proper combustion practices. Older boiler designs tend to provide less combustion gas residence time within the boiler and have less extensive over-fire air supply systems. These factors typically result in higher CO emissions in comparison to newer boiler designs. Dry fuel tends to reduce CO emissions in comparison to combustion of wet biomass fuels because lower fuel moisture results in higher combustion zone temperatures.

Add-On Controls

Catalytic oxidizers use a matrix or “bed” coated with noble metals (e.g., platinum) to facilitate the conversion of a criteria pollutant to a non-pollutant (in this case CO to CO₂). Catalytic oxidizers operate in a temperature range of approximately 650 °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 to CO₂ by the catalyst, the catalyst must be located upstream in the exhaust system. However, in order to reduce catalyst masking and pressure drop across the device, a particulate control device must be located upstream of the catalyst bed. As a result, the physical size of the particulate control system must be increased to accommodate the higher temperature and higher volume exhaust flow. Although particulate control device would remove the majority of the particulates in the exhaust, a steam injection system or “air knife” would be used to periodically remove any particulate matter that does collect on the catalyst.

EMx (described in the NO_x BACT analysis section) also utilizes a catalytic technique that oxidizes CO to CO₂ in addition to controlling NO_x emissions.

2.2.2 Control Alternative Review

The results of the database queries for CO control technologies are presented in Table 3, sorted by permit limit, beginning with the CO limit proposed for the project.

Several biomass-fired stoker-type boilers have CO permit limits of 0.3 lb/MMBtu that are met using proper combustion practices. The most recent of these are two 230 MMBtu/hr public utility boilers in Minnesota (Hibbing and Virginia Departments of Public Utilities in association with the Laurentian Energy Authority) that were permitted on June 30, 2005. Several boilers of different design (e.g., a fuel-cell design boiler in Darrington, Washington, and fluidized bed units at Schiller Station in New Hampshire and Tate & Lyle Ingredients in Fort Dodge, Iowa) have lower CO permit limits, but only stoker boilers are relevant to this BACT analysis.

Oxidation using a catalyst has been employed to reduce CO emissions from a stoker boiler in at least one instance (Bio Energy in West Hopkinton, NH), and is therefore considered technically feasible, although the facility employing the technology is no longer operating. The CO permit limits for the project are not especially stringent (equivalent to 1.0 lb/MMBtu on a daily average basis and 0.25 lb/MMBtu on a rolling annual average basis), and the permit requires periodic steam sootblowing and periodic chemical cleaning or replacement of the catalyst, so the reliability of the control system when the facility was operating is questionable.

A project in South Point, OH has proposed to use oxidation catalysts to limit CO emissions from retrofitted coal boilers to 0.1 lb/MMBtu, and, while the project was issued a permit (January 5, 2004) as well as a reissued permit (April 4, 2006), construction has not commenced, and a vendor has not been identified that will supply the catalyst to meet the permit limit. A more recent permit issued by Minnesota Pollution Control Agency (Koda Energy, issued on August 3, 2007) determined that an oxidation catalyst was technically infeasible for a biomass-fired boiler because of catalyst poisoning concerns.

In 2005, DG Energy in Whitefield, NH added an oxidation catalyst to a previously-installed RSCR system. No CO permit limits were associated with the installation, and the facility is not required to use the catalyst.

Russell Biomass was issued a conditional permit by Massachusetts Department of Environmental Protection on December 30, 2008 for a project that has the option to build a biomass-fired boiler of either a fluidized bed or a vibrating-grate stoker design. The stoker design was issued a permit limit of 0.075 lb/MMBtu that would be achieved using an oxidation catalyst added to the RSCR system used to control NO_x. As of writing of this analysis, the facility has not commenced construction.

Concord Steam Corp. received a permit for a 305 MMBtu/hr biomass-fired stoker boiler on January 16, 2009 from NHDES which indicated that good combustion control and/or an

oxidation catalyst would be used to achieve a CO permit limit of 0.18 lb/MMBtu. This limit was requested by Concord Steam to avoid PSD review and was not part of a BACT analysis, so it is not considered a BACT determination. The currently unpermitted and unconstructed Valley BioEnergy project in Modesto, California proposes to add an oxidation catalyst to the SCR system that would limit CO emission to 0.046 lb/MMBtu on a 24-hour average basis to avoid the purchase of costly offsets, not as the result of a BACT analysis.

2.2.3 Summary of Possible Control Alternatives

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

- Proper combustion
- Catalytic oxidation
- EMx

2.2.4 Technical Feasibility of Control Alternatives

Proper Combustion

Proper combustion is the most common technique used to limit CO emissions from wood-fired stoker-type boilers. Boiler designs tend to focus on limiting NO_x creation, at the expense of slightly higher CO emissions, to reduce the reduction burden placed on add-on NO_x control systems.

Oxidation Catalyst

Using oxidation catalysts to reduce CO emissions from stoker-type biomass-fired boilers is technically feasible, but application has been extremely limited. The only instance of a biomass-fired stoker-type boiler utilizing an oxidation catalyst to control CO emissions was Bio Energy in West Hopkinton, NH, a project that operated for a limited period with uncertain reliability. Recently, several stoker-type biomass-fired boiler permits featuring control of CO using an oxidation catalyst have been issued for projects that have not begun construction and may never be realized (South Point, Concord Steam, Valley BioEnergy, and Montville Power). Now, with the issuance of the proposed area source boiler MACT, the incentive to reduce CO emissions has been increased, and, at the same time, manufacturers are learning more about designing the catalyst beds to maximize longevity and reduce cost. Because application of this technology to stoker-type biomass-fired boiler is just now beginning to increase, the direct (longevity of the catalyst) and indirect (lost revenue from decreased availability) costs are poorly understood, and application of this technology amounts to what is, to some extent, a leap of faith for the boiler owner or operator.

EMx

As discussed in the NO_x BACT analysis section, EMx is extremely sensitive to presence of sulfur in the exhaust stream, and has never been demonstrated on a boiler of the size proposed by SREC. Therefore, EMx is not considered technically feasible for controlling CO emissions from a wood-fired boiler.

2.2.5 Summary of Technically Feasible Control Alternatives

The following is a list of control alternatives determined to be technically feasible for controlling CO emitted by a biomass-fired, stoker-type boiler:

- Proper combustion
- Oxidation Catalyst

2.2.6 Effectiveness of Remaining Technologies

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

Proper Combustion

Proper combustion provides 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 (NO_x) to achieve optimally low emissions of all pollutants. However, in order to achieve the proposed NO_x emission limit (0.13 lb/MMBtu) while not exceeding 50 parts per million (ppm) ammonia slip, boiler operation will favor reduced NO_x creation over reduced CO creation.

Boilers of similar design to that of the proposed unit have been permitted, and are currently operating at lumber manufacturing facilities in Burlington, Washington, Lincoln, California, and Aberdeen, Washington. Each of these boilers has a CO permit limit of (or equivalent to) 0.35 lb/MMBtu. Several biomass-fired boilers permitted in Minnesota have a CO permit limit 0.30 lb/MMBtu, and two recently permitted stoker-type biomass-fired boilers in Texas have had a CO limit of 0.31 lb/MMBtu determined to be BACT.

Oxidation Catalyst

Oxidation catalysts are capable of providing between 40 and 90 percent reduction in CO emissions, depending upon the amount of catalyst used and the exhaust gas temperature. Because combusting fuel (e.g., natural gas) to increase the exhaust temperature is not a realistic option, and the catalyst would be positioned downstream of the particulate control devices (i.e., multiclones and ESP), the catalyst temperature would be in the lower portion of the range over which the oxidation reaction occurs (~ 600 °F). However, control efficiencies up to 90 percent can still be achieved by adding larger quantities of catalyst, though doing so would add considerable additional expense, as well as increase the overall pressure drop of the

exhaust system and decrease overall system reliability due to more frequent catalyst cleaning and replacement.

2.2.7 Ranking by Effectiveness

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

- Catalytic oxidation
- Proper combustion

2.2.8 Cost Effectiveness Evaluation

Analogous to the application of SCR systems to control NO_x emissions from a biomass-fired boiler discussed in the previous section, applying oxidation catalyst technology to control CO emissions from a biomass-fired boiler is not considered experimental. As with SCR systems, there is some financial risk involved with using oxidation catalysts because they are subject to the same, if not more, uncertainty related to deactivation of the catalyst by trace amounts of alkaline compounds and metals in the exhaust. Because of the natural variability of biomass fuel, the rate of catalyst deactivation cannot be accurately predicted, and while it is possible that catalyst beds can be reactivated by removal and washing, it is impossible to know how many wash cycles will result in adequate reactivation.

Despite the difficulty in estimating the actual operating and capital costs associated with such a system, the cost-effectiveness of an oxidation catalyst control system, as applied to a biomass-fired boiler, was calculated (see Attachment A). The oxidation catalyst would reduce CO emissions by approximately 326 tons year at an annual expense of approximately \$991,000, which is equivalent to an incremental cost effectiveness of approximately \$3,000 per ton of NO_x removed. However, judging by the experiences of the few biomass-fired boiler facilities that have attempted to employ an oxidation catalyst, this cost-effectiveness analysis likely underestimates the number of times the catalyst would need replacement each year (assumed to be 1), as well as the number downtime events needed each year to replace or clean the catalyst beds (assumed to be 4), so the cost effectiveness could easily be twice that of the calculated “best case” scenario. Based on this analysis, proper combustion is deemed to be the most reliable, cost-effective CO control technology for biomass-fired, stoker-type boilers.

As a result of discussions with control technology vendors, SREC’s need to position itself to comply with the proposed area source boiler MACT, and a desire to more quickly realize the project by avoiding a PSD permitting path, SREC is proposing to reduce CO emissions to 0.13 lb/MMBtu through use of proper combustion, and, to the extent necessary to achieve that limit, an oxidation catalyst.

2.2.9 Selection of BACT for CO

Based on the analysis presented in this section, SREC proposes that BACT for CO emitted from the proposed biomass-fired stoker boiler is 0.3 lb/MMBtu, achieved by employing proper combustion practices. However, SREC is proposing to install an oxidation catalyst and limit CO emissions to 0.13 lb/MMBtu, which is equivalent to approximately 248 tpy at the anticipated maximum annual operating capacity of the proposed boiler.

2.3 PM BACT Analysis

PM is produced by combustion processes as unburned solid carbon (soot), unburned vapors or gases that subsequently condense, and the unburnable portion of the fuel (ash). This BACT analysis is intended to address PM, PM₁₀, and PM_{2.5} pollutant size definitions.

2.3.1 Identification of Possible Control Alternatives

Combustion Controls

The concept of applying combustion controls or “proper combustion” to minimize PM emissions is similar to the strategy used to control CO and includes adequate fuel residence time, proper fuel-air mixing, and temperature control to ensure complete combustion. As discussed in the analysis of BACT for CO emissions, optimization of these factors for PM control can result in an increase in the NO_x emissions. Thus, operators strive to balance the factors under their control to achieve the lowest possible emissions of all pollutants.

Add-On Controls

The two most common add-on control technologies for control of PM emissions from a boiler are electrostatic precipitators (ESPs) and baghouses. Often, a mechanical collector, such as a multiclone, is used to remove larger particulate matter before the exhaust reaches the primary control device. 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.

Baghouses, or 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, by blowing jets of air, or by using sonic horns.

A venturi scrubber is a narrowed section of duct followed by an expanded section of duct, with scrubbing liquid injected at the constricted section. The liquid is 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. Wet scrubbers, such as a venturi scrubber, are less common because they typically have lower control efficiencies, and higher energy costs, than either an ESP or baghouse. Wet scrubbers also complicate waste disposal by introducing liquids that create sludge when combined with the removed PM.

2.3.2 Control Alternative Review

The results of the database queries for PM control technologies are presented in Table 4, sorted by permit limit, beginning with the PM limit proposed by SREC for the new biomass-fired cogeneration unit.

A review of the RBL Clearinghouse indicates that the most stringent control technology for PM is use of an ESP or a baghouse. The most stringent permit limit employing ESP technology to control PM₁₀ emissions is 0.02 lb/MMBtu at Sierra Pacific Industries facilities in Aberdeen and Skagit County, Washington, Boralex in Livermore Falls, Maine, Multitrade Limited Partnership in Hurt, Virginia, and Hampton Lumber in Darrington, Washington. Until recently, many permit limits did not include both the filterable and condensable portions of particulate emissions, so some of the emission limits from permits issued several years ago may be less stringent than they appear.

The most stringent permit limit employing baghouse technology is at Kimberly-Clark in Everett, Washington, which has a PM permit limit of 0.0084 gr/dscf at 7 percent oxygen, equivalent to 0.016 lb/MMBtu. However, the testing required for the Kimberly-Clark boiler is for filterable PM₁₀ only. The Wheelabrator Ridge Energy facility in Ashland, Florida, has a permit limit of 0.008 gr/dscf at 7 percent oxygen, equivalent to 0.02 lb/MMBtu. This facility also requires only a filterable PM test method to confirm compliance with the permit limit. The proposed Valley BioEnergy facility in Modesto would use an ESP to limit total PM emissions to 0.02 lb/MMBtu.

2.3.3 Summary of Possible Control Alternatives

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

- ESP preceded by a multiclone
- Baghouse preceded by a multiclone
- Venturi scrubber

2.3.4 Technical Feasibility of Control Alternatives

The most common technology for controlling PM emissions from a biomass-fired boiler is an ESP preceded by a multiclone. Baghouses have been employed to control PM₁₀ emissions from fluidized-bed boilers, and boilers in which biomass is fired with solid fossil fuels such as coal or tires. The likelihood of fires in ducting or control devices downstream from boilers that burn biomass fuels is significant because of the high carbon content of the ash, but many operators and manufacturers have engineered designs to minimize this risk. ESPs, constructed mostly of steel, suffer considerably less damage from fires than baghouses, which generally have combustible fabric filters, unless expensive flame-proof bags are purchased. Venturi scrubbers are generally employed to control PM from smaller boilers with lower exhaust flow, and typically have lower control efficiencies than ESPs or baghouses.

2.3.5 Summary of Technically Feasible Control Alternatives

The following is a list of control alternatives determined to be technically feasible for controlling PM emitted by a biomass-fired, stoker-type boiler:

- Venturi Scrubber
- Baghouse
- ESP

2.3.6 Effectiveness of Remaining Technologies

This section briefly describes the effectiveness of the remaining technologies ranks them in order of effectiveness.

Venturi Scrubber

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

Baghouse

Baghouses typically operate with pressure drops between 2 and 12 inches of water. PM control efficiencies are capable of removing over 99 percent of PM from gas streams.

ESP

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

2.3.7 Ranking by Effectiveness

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

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

2.3.8 Cost Effectiveness Evaluation

No cost effectiveness evaluation comparing the baghouse or scrubber is presented because SREC is proposing to use one of the two most effective available technologies (i.e., a baghouse) to control PM₁₀ emissions from the biomass-fired, stoker-type boiler.

2.3.9 Selection of BACT for PM

SREC proposes that BACT for PM emissions from a biomass-fired, stoker-type boiler is an emission rate of 0.02 lb/MMBtu, achieved using a baghouse, and equivalent to approximately 38.2 tpy at the anticipated maximum annual operating capacity.

2.4 VOC BACT Analysis

VOC emissions are generally the result of incomplete fuel combustion. In the case of biomass, volatiles are released as the fuel is heated in the furnace, some portion of which escapes combustion by improper mixing with oxygen or zones of relatively low temperature.

2.4.1 Identification of Possible Control Alternatives

Combustion controls, or proper combustion techniques, provide 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 (NO_x) to achieve optimally low emissions of all pollutants.

Add-on controls used to reduce VOCs generally fall into three categories: adsorption onto a solid (e.g., activated carbon), absorption by a liquid, and incineration by a flame or using a catalyst. There are no instances in the RBLC of any of these approaches having been used to control VOCs from a biomass-fired boiler.

2.4.2 Control Alternative Review

The results of the database queries for VOC control technologies are presented in Table 5, sorted by permit limit, beginning with the VOC limit proposed by SREC for the new cogeneration unit.

Maintaining furnace conditions conducive to proper combustion of the fuel is the most common technique employed to limit VOC emissions from a biomass-fired boiler. As shown in Table 5, permit limits vary considerably, ranging over an order of magnitude. Clearly, agencies approving permit limits for VOC have been flexible, understanding that proper combustion involves tradeoffs to maintain the lowest collective NO_x, CO, and VOC emission rates.

Several permits have been issued recently that have VOC limits that are lower than that proposed by SREC for the new wood-fired cogeneration unit. In most of these cases, the project includes an oxidation catalyst to control CO, which provides incidental control of VOC. As shown in Table 5, none of these projects have been constructed and operated. In Washington, the Sierra Pacific Industries' facility in Aberdeen received permit limit for 0.025 lb/MMBtu in 2002, and then, in 2006, their Burlington facility received a permit limit of 0.019 lb/MMBtu in 2006. The Valley BioEnergy facility in Modesto, California proposes to limit VOC emissions to 0.005 lb/MMBtu through incidental control provided by an oxidation catalyst installed primarily to reduce CO emissions and avoid PSD review.

2.4.3 Summary of Possible Control Alternatives

Based on database queries and other research the following control alternatives are possible for the boiler:

- Proper combustion
- Catalytic oxidation

2.4.4 Technical Feasibility of Control Alternatives

Proper Combustion

Proper combustion is a technically feasible control alternative that is used to control VOC emissions from most biomass-fired boilers.

Oxidation Catalyst

Oxidation catalysts have been installed on stoker-type, biomass-fired boilers, but this application of the technology is not mature, and the longevity of the catalyst is unpredictable.

2.4.5 Summary of Technically Feasible Control Alternatives

The following is a list of control alternatives determined to be technically feasible for controlling VOC emitted by a biomass-fired, stoker-type boiler:

- Proper combustion
- Oxidation Catalyst

2.4.6 Effectiveness of Remaining Technologies

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

Proper Combustion

The effectiveness of proper combustion as a VOC control technology varies considerably, and is largely dependent on tradeoffs made in the design and operation of the boiler to minimize other pollutants (e.g., NO_x).

Oxidation Catalyst

Oxidation catalysts are capable of providing up to a 50 percent reduction in VOC emissions, depending upon the quantity of catalyst used and the exhaust gas temperature.

2.4.7 Ranking by Effectiveness

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

- Catalytic oxidation
- Proper combustion

2.4.8 Cost Effectiveness Evaluation

Proper combustion is, by far, the most prevalent technique for reducing VOC emissions from biomass-fired boilers. Recently, several projects have proposed to utilize oxidation catalysts to reduce CO emissions, typically to avoid PSD review or having the purchase offsets. Oxidation catalyst systems that target CO emissions are known to provide incidental control of VOCs. Undoubtedly, the oxidation catalyst installed on the proposed boiler will reduce VOC emissions to some extent, though the effectiveness is unclear. Because the most stringent available technology, an oxidation catalyst, will be employed, and the true costs of utilizing this technology are not reliably understood, no cost-effectiveness analysis was completed.

2.4.9 Selection of BACT for VOCs

Based on the above discussion, proper combustion is proposed to be BACT for VOC emissions from the biomass-fired boiler. SREC anticipates a VOC emission rate of 0.017 lb/MMBtu, which is equivalent to 32.4 tpy at the anticipated maximum annual operating capacity.

2.5 SO₂ BACT Analysis

Sulfur dioxide (SO₂) emissions are entirely dependent upon the amount of sulfur present in the fuel. Sulfur contained in the fuel combines with oxygen at combustion temperatures to form SO₂.

2.5.1 Identification of Possible Control Alternatives

There are two alternatives for reducing SO₂ emissions combustion sources: removal of sulfur from the fuel before it is combusted, and removal of SO₂ from the exhaust gas after combustion.

Removing sulfur from fuel before it is combusted has been employed to remove sulfur-containing non-organically-bound minerals (e.g., pyrites) from coal, but this practice is not feasible for biomass fuels, where the sulfur is organically bound in the fuel. All permitted biomass-fired boilers have no SO₂ control requirement other than the exclusive use of biomass, which is considered a low-sulfur fuel, and perhaps a limit on the sulfur content of a start-up or co-fired fuel.

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 and 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 significantly expanded waste handling operations to remove the reacted sorbent material.

Duct injection of dry trona or sodium bicarbonate, also called acid-gas scrubbing, is a relatively recent approach that mitigates the increased waste handling typically associated with FGD systems. The dry sorbent is pulverized into a talc-like powder and injected in to the exhaust duct upstream of the particulate control device. The sorbent reacts with acid gases in the exhaust and is collected by the particulate control system. These systems are most effective at reducing hydrogen chloride in the exhaust, and are typically applied for that purpose, but they also provide incidental control of SO₂.

2.5.2 Control Alternative Review

The results of the database queries for SO₂ control technologies are presented in Table 6, sorted by permit limit, beginning with the SO₂ limit proposed by SREC for the new boiler. The RBLC does not indicate that any FGD systems have been used to reduce SO₂ emissions from a stoker-type, biomass-fired boiler. Based on analysis of the anticipated fuel source (almond and walnut orchard trimmings), Valley BioEnergy in Modesto, California has proposed to utilize a dry sorbent duct injection system to reduce acid gases, particularly hydrogen chloride, but the system will also reduce SO₂ emissions. The Valley BioEnergy has been deemed complete, but the permit has not been issued, and it has not been constructed or operated.

2.5.3 Summary of Possible Control Alternatives

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

- Use of Biomass Fuel
- Acid-Gas Scrubber
- Wet FGD

2.5.4 Technical Feasibility of Control Alternatives

FGD systems are more commonly applied to coal-fired boilers, and, while there are no apparent technical restrictions to application of FGD systems to biomass-fired boilers, there are no instances of this technology being used at a constructed and operating facility to reduce SO₂ emissions from a biomass-fired boiler. Use of biomass fuel is inherent in the operation of a biomass-fired boiler, and is considered the baseline for evaluating add-on control alternatives.

2.5.5 Summary of Technically Feasible Control Alternatives

The following is a list of add-on control alternatives determined to be technically feasible for controlling SO₂ emitted by a biomass-fired, stoker-type boiler:

- Wet FGD
- Acid-Gas Scrubber

2.5.6 Effectiveness of Remaining Technologies

Wet FGD systems are considered the most effective, and can achieve greater than 90 percent reduction in SO₂ emissions. Acid gas scrubbing (i.e., duct injection of dry trona and/or sodium bicarbonate) is capable of control efficiencies on the order of 40 to 60 percent.

2.5.7 Ranking by Effectiveness

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

- Wet FGD
- Acid-Gas Scrubbing

2.5.8 Cost Effectiveness Evaluation

Most stoker-type biomass-fired boilers do not incorporate any add-on control system to reduce SO₂ emissions. A cost-effectiveness analysis (see Attachment A) indicates that an acid-gas scrubbing system would cost approximately \$213,000 per year to operate, and would reduce SO₂ emission by approximately 53 tpy, for a cost effectiveness of approximately \$4,000 per ton of SO₂ reduced. It should be noted both the controlled and uncontrolled SO₂ emission rates used in this analysis are based on relatively few fuel tests, and may overstate the amount of SO₂ available for control in the exhaust, which would decrease the cost per ton controlled, and tend to make the control technology appear more cost effective. SREC proposes that an acid-gas scrubbing system is outside the envelope of reasonable costs, and is not considered BACT for control of SO₂ emissions from biomass-fired boilers. Nevertheless, because SREC expects to receive a small amount of fuel (approximately 10 percent) that has been in salt water, an acid-gas scrubber will be employed to ensure compliance with the Acceptable Source Impact Level (ASIL) for HCl provided in the Washington Department of Ecology's toxic regulations (WAC 173-460).

A wet FGD system, the costs for which were estimated by scaling a cost-effectiveness analysis for a system to be applied to a large (930 MW) coal-fired boiler, would cost approximately \$2,230,000 per year to operate, and reduce SO₂ by approximately 111 tpy, for a cost effectiveness of approximately \$20,200 per ton of SO₂ reduced. It is clear that a wet FGD system is not cost-effective for reducing SO₂ from a biomass-fired boiler.

2.5.9 Selection of BACT for SO₂

SREC proposes that use of biomass fuel with no add-on control system is BACT for reducing SO₂ emissions from a biomass-fired boiler, and that no SO₂ permit limit is required.

2.6 BACT During Startup, Shutdown and Upset Periods

During startup, shutdown, and periods of upset, CO and VOC concentrations in the flue gas will exceed those experienced under normal operation. This is a characteristic of all biomass-fueled combustion devices because the temperature required for optimum combustion conditions is not achieved immediately. Similarly, SNCR and SCR technologies require flue gas temperatures above approximately 1,500°F and 550°F, respectively, before as-designed NO_x emission abatement will occur. During startup, shutdown, and periods of upset it is not technologically feasible to meet CO or NO_x BACT limits that are specified on the basis of normal boiler operation. SREC proposes that, during startup and shutdown periods, BACT for CO, VOCs, and NO_x is to limit the frequency and duration of startups, shutdowns and periods of upset through the implementation of best practices and training.

2.7 Toxic Air Pollutant BACT Analysis

The proposed boiler would be the only source of toxic air pollutants at the facility. Because TAPs are a component of either PM or VOC, or an acid gas, toxic air pollutant BACT (tBACT) determinations typically rely on PM, VOC, and SO₂ BACT determinations. PM emissions from the proposed boiler will be limited by use of a fabric filter (i.e., baghouse), VOC emissions through use of proper combustion techniques designed to facilitate complete combustion of organic compounds, and acid gases by limiting the quantities of acid-creating compounds in the fuel. SREC proposes that tBACT be equivalent to the PM, VOC, and SO₂ BACT proposals outlined in this document.

As for the SO₂ BACT analysis, an acid-gas scrubber will be employed to ensure that the ASIL established for HCl is met, but such a system is not a cost-effective control, and is therefore not proposed as BACT for HCl.

3 Cooling Tower BACT Analysis

3.1 Process Description

The proposed facility includes a circulating water system that will utilize a 2-cell mechanical draft cooling tower to support operations of the steam turbine generator. Wet (evaporative) cooling towers emit aqueous aerosol “drift” particles that evaporate to leave crystallized solid particles that are considered PM emissions. The proposed control technology for PM is high-efficiency drift eliminators to capture drift aerosols upstream of the release point to the atmosphere. Although PM emissions from cooling towers are not all PM₁₀ or PM_{2.5}, our analysis has assumed that is the case, so PM, PM₁₀, and PM_{2.5} emissions are all equivalent, and this analysis is intended for all three pollutant definitions.

3.2 Commercially Available Control Technologies

Electrical generating facilities, refineries, and other large chemical processing plants utilize wet mechanical draft cooling towers for heat rejection. This portion of the proposed facility can be viewed as substantially similar to such processes.

Review of the federal RBLC database for large-scale cooling towers indicates that high efficiency drift eliminators and limits on total dissolved solids (TDS) concentration in the circulating water are the techniques which set the basis for cooling tower BACT emission limits. The efficiency of drift eliminator designs is characterized by the percentage of the circulating water flow rate that is lost to drift. The drift eliminators to be used on the proposed cooling tower will be designed such that the drift rate is less than a specified percentage of the circulating water. Typical geometries for the drift eliminators include chevron blade, honeycomb, or wave form patterns, which attempt to optimize droplet impingement with minimal pressure drop.

Table 7 summarizes recent BACT determinations for utility-scale mechanical draft cooling towers. The commercially available techniques listed to limit drift PM releases from utility-scale cooling towers include:

- Use of Dry Cooling (no water circulation) Heat Exchanger Units
- High-Efficiency Drift Eliminators, as low as 0.0005 percent of circulating flow
- Limitations on TDS concentrations in the circulating water
- Combinations of Drift Eliminator efficiency rating and TDS limit
- Installation of Drift Eliminators (no efficiency specified)

The use of high-efficiency drift eliminating media to de-entrain aerosol droplets from the air flow exiting the wetted-media tower is a commercially proven technique to reduce PM emissions. Compared to “conventional” drift eliminators, advanced drift eliminators reduce the PM₁₀ emission rate by more than 90 percent.

In addition to the use of high efficiency drift eliminators, management of the tower water balance to control the concentration of dissolved solids in the cooling water can also reduce particulate emissions. Dissolved solids accumulate in the cooling water due to increasing concentration of dissolved solids in the make-up water as the circulating water evaporates, and, secondarily, the addition of anti-corrosion, anti-biocide additives. However, to maintain reliable operation of the tower without the environmental impact of frequent acid wash cleanings, the water balance must be considered. The proposed cooling tower design will be based on 5 cooling water cycles (i.e., the concentration of dissolved solids in the circulating water will be, on average, 5 times that of the introduced make-up water), and a total dissolved solids (TDS) concentration of 228 ppmw in the make up water, which translates to a cooling water TDS concentration of 1,140 ppmw.

Lastly, the substitution of a dry cooling tower is a commercially available option that has been adopted by utility-scale combined cycle plants in arid climates, usually because of concerns other than air emissions. This option involves use of a very large, finned-tube water-to-air heat exchanger through which one or more large fans force a stream of ambient dry air to remove heat from the circulating water in the tube-side of the exchanger.

3.3 Infeasible Control Measures

One measure that has been adopted in arid, low precipitation climates is the use of a dry, i.e., non-evaporative cooling tower for heat rejection from combined-cycle power plants. Where it has been adopted, this measure is usually a means to reduce the water consumption of the plant, rather than as BACT for PM₁₀ emissions. There is a very substantial capital cost penalty in adopting this technology, in addition to the process changes (e.g., operating pressures) necessary to condense water at the ambient dry bulb temperature, rather than at ambient wet bulb temperature.

Because of the high capital cost and process design changes involved in the use of a dry cooling tower, that option would not be cost effective and is removed from consideration.

3.4 Ranking Of Available Control Measures

Because all of the commercially available options that could form the basis for a BACT emission limit for PM₁₀ from the cooling tower are also technically feasible, this section will rank these options. The technically feasible option of high-efficiency drift eliminators can be implemented at different levels of stringency. Development of increasingly effective de-entrainment structures now allows a cooling tower to be specified to achieve drift release no higher than 0.0005 percent of the circulating water rate. This is the most stringent BACT option. There are no significant costs or environmental factors which favor implementation of a less-stringent drift eliminator option.

In “top down” order from most to less stringent, the potentially available candidate control techniques are:

- Combinations of high-efficiency drift eliminators and TDS limit

- High-Efficiency drift eliminators to control drift to as low as 0.0005 percent of circulating flow
- High-efficiency drift eliminators, as low as 0.001 percent of circulating flow
- Limitations on TDS concentrations in the circulating water
- Installation of Drift Eliminators (no efficiency specified)

3.5 Consideration of Energy, Environmental and Cost Factors

Development of increasingly effective de-entrainment structures has resulted in equipment vendors claims that a cooling tower may be specified to achieve drift release no higher than 0.0005 percent of the circulating water rate. This is the most stringent BACT for cooling towers in current permits.

Even incremental improvement in drift control involves substantial changes in the tower design. First, the velocity of the draft air that is drawn through the tower media must be reduced compared to “conventional” specifications. This is necessary to use drift eliminator media with smaller passages (to improve droplet capture) without encountering unacceptably high pressure drop. Since reducing the air velocity also reduces the heat transfer coefficient of the tower, it is likely that a proportional increase in the overall size of the media will be needed. For example, a 6-cell tower may need to be expanded to 12 cells in order to accommodate higher drift eliminator efficiency for the same heat rejection duty. These changes will also result in an energy penalty in the form of larger and higher powered fans to accommodate the improved droplet capture. More importantly, there is a substantial increase in both tower operating costs and capital costs that deliver relatively few tons of PM₁₀ abatement.

Adopting a TDS limit for the circulating water is usually viewed as a measure that benefits air quality by reducing the dissolved salts that can be precipitated from drift aerosols. To reduce TDS the facility must introduce a higher volume flow of make-up water to the tower. This has the potential environmental disadvantage of increasing the overall plant water requirements.

3.6 Proposed BACT Limits and Control Option

Based on the information from the RBLC database survey, and the energy and cost factors described above, the proposed BACT option for the proposed cooling towers is use of drift eliminators achieving a maximum drift of 0.0005 percent of the circulating water.

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4 Fugitive Dust BACT Analysis

Fugitive dust emissions will be generated by fuel deliveries and by activities in the fuel house. Approximately 30 percent of the fuel combusted by the proposed boiler is expected to be delivered by trucks, which will deliver the fuel by backing into a vertical dumper that deposits the fuel into a hopper. Some fugitive dust emissions will occur when air is displaced when the fuel enters the hopper. A covered conveyor system will move the fuel from the hopper to the fuel house, which will be a three-sided structure with a roof. The remaining 70 percent of the fuel will be delivered to the fuel house from the adjacent sawmill and plywood plant by covered conveyors. Additional fugitive dust emissions will be generated by fuel dropping from conveyors onto piles, and then being loaded from the piles into a reclaim bin for delivery, by covered conveyor, to the boiler fuel hopper.

SREC proposes BACT for fugitive dust emissions to be mitigated by the use of structures (covered conveyors, truck dump hopper, and fuel house) and paved areas, as well as water sprays and sweeping as needed to limit visible emissions.

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Tables

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Table 1 NO_x Control Technology Search Results

Facility Name	Location	Date of Permit	Heat Input (MMBtu/hr)	Permit Limit (lb/MMBtu)	Control Technology	Basis	Notes
SREC	Shelton, WA	Proposed	436	0.13	SNCR	BACT-OTHER	
Valley BioEnergy	Modesto, CA	Proposed	402	0.012	SNCR/SCR	BACT-OTHER	Permit pending
Montville Power	Uncasville, CT	4/6/10	600	0.06	RSCR	LAER	Not constructed; 24-hour block avg.
Russell Biomass	Russell, MA	12/30/08	740	0.06	RSCR	LAER-OTHER	Not constructed; annual avg
Concord Steam	Concord, NH	2/27/09	305	0.065	SCR	LAER-OTHER	Not constructed; 30-day rolling avg
Lufkin Generating Plant	Lufkin, TX	10/26/09	693	0.075	SCR	BACT-PSD	Under construction 30-day rolling avg.
South Point Power	South Point, OH	4/4/06	318	0.088	SCR	BACT-PSD	Not constructed
Darrington Cogen.	Darrington, WA	1/18/05	403	0.12/0.1	SNCR	BACT-PSD	Not constructed; 0.1 annual avg
Sierra Pacific Industries	Burlington, WA	1/25/06	430	0.13	SNCR	BACT-PSD	
Lindale Renewable	Lindale, TX	1/8/10	683	0.15	SNCR	BACT-PSD	Under construction 30-day rolling avg.
Sierra Pacific Industries	Aberdeen, WA	10/17/02	310	0.15/0.1	SNCR	BACT-PSD	0.1 is annual avg
Virginia DPU	Virginia, MN	6/30/06	230	0.15	SNCR	BACT-PSD	30-day average
Hibbing PUC	Hibbing, MN	6/30/06	230	0.15	SNCR	BACT-PSD	30-day average
Hampton Lumber	Darrington, WA	6/1/05	245	0.15	SNCR	BACT-OTHER	
Simpson Tacoma Kraft	Tacoma, WA	5/22/07	595	0.20	Proper combustion	BACT-PSD	
Boise Cascade	Florien, LA	7/18/07	225	0.22	Proper combustion	BACT-PSD	
Boralex, Stratton	Stratton, ME	1/4/05	672	0.24	SNCR/RSCR	BACT-OTHER	
Koda Energy	Shakopee, MN	8/23/07	308	0.25	SNCR	BACT-PSD	
Bridgewater Power	Bridgewater, NH	9/12/07	250	0.33/0.075	SNCR/RSCR	RACT/OTHER	0.075 quarterly avg
DG Whitefield	Whitefield, NH	9/10/04	220	0.33/0.075	RSCR	RACT/OTHER	0.075 quarterly avg

Table 2
NO_x Control Technology Cost-Effectiveness Comparison

Control System	Annual Cost (\$/yr)	NO_x Reduction (tpy)	Cost Effectiveness (\$/ton)	Incremental Cost Effectiveness (\$/ton)
SNCR	195,972	229	856	N/A
SCR	1,088,269	334	3,626	8,633

Table 3 CO Control Technology Search Results

Facility Name	Location	Date of Permit	Heat Input (MMBtu/hr)	Permit Limit (lb/MMBtu)	Control Technology	Basis	Notes
SREC	Shelton, WA	Proposed	436	0.3/0.13	Proper combustion/ Oxidation Catalyst	BACT-OTHER/ OTHER	
Valley BioEnergy	Modesto, CA	Proposed	402	0.046	Oxidation catalyst	OTHER	Permit pending
Russell Biomass	Russell, MA	12/30/08	740	0.075	Oxidation catalyst	BACT-OTHER	Not constructed; annual avg
Montville Power	Uncasville, CT	4/6/10	600	0.1	Oxidation catalyst	BACT-PSD	Not constructed; 8-hour block avg.
South Point Power	South Point, OH	4/4/06	318	0.1	Oxidation catalyst	BACT-PSD	Not constructed
Hampton Lumber	Darrington, WA	6/1/05	245	0.23	Proper combustion	BACT-OTHER	Fuel-cell design; Not constructed
Virginia DPU	Virginia, MN	6/30/06	230	0.3	Proper combustion	BACT-PSD	
Hibbing PUC	Hibbing, MN	6/30/06	230	0.3	Proper combustion	BACT-PSD	
District Energy St. Paul	St. Paul, MN	11/15/01	550	0.3	Proper combustion	BACT-PSD	
Willamette Industries, Inc.	Marlboro, SC	4/17/96	470	0.3	Proper combustion	BACT-OTHER	
Lindale Renewable	Lindale, TX	1/8/10	683	0.31	Proper combustion	BACT-PSD	Under construction; 30-day rolling avg.
Lufkin Generating Plant	Lufkin, TX	10/26/09	693	0.31/0.075	Proper combustion	BACT-PSD/ OTHER	Under construction; 30-day rolling avg.
Sierra Pacific Industries	Burlington, WA	1/25/06	430	0.35	Proper combustion	BACT-PSD	
Darrington Cogeneration	Darrington, WA	1/18/05	403	0.35	Proper combustion	BACT-PSD	Not constructed
Sierra Pacific Industries	Aberdeen, WA	10/17/02	310	0.35	Proper combustion	BACT-PSD	
Smurfit-Stone Container	Stevenson, AL	1/15/97	620	0.4	Proper combustion	BACT-PSD	
Gulf States Paper Corp	Moundville, AL	10/14/98	98	0.5	Proper combustion	BACT-PSD	
Bio Energy Corp.	West Hopkinton, NH	7/23/98	225	1.0/0.253	Oxidation catalyst	BACT-OTHER	Not operating; 0.253 annual avg
Plum Creek – Columbia Falls	Columbia Falls, MT	7/26/95	292	1.6	Proper combustion	BACT-PSD	

Table 4 PM Control Technology Search Results

Facility Name	Location	Date of Permit	Heat Input (MMBtu/hr)	Permit Limit (lb/MMBtu)	Control Technology	Basis	Notes
SREC	Shelton, WA	Proposed	436	0.02	Multiclone, ESP	BACT-OTHER	
South Point Power	South Point, OH	4/4/06	318	0.0125	Baghouse	BACT-PSD	Not constructed; filterable only
Valley Bio-Energy	Modesto, CA	Proposed	402	0.02	Multiclone, ESP	BACT-OTHER	Not permitted
Simpson Tacoma Kraft	Tacoma, WA	5/22/07	595	0.02	ESP	BACT-PSD	
Sierra Pacific Industries	Burlington, WA	1/25/06	430	0.02	Multiclone, ESP	BACT-PSD	
Hampton Lumber	Darrington, WA	6/1/05	245	0.02	Multiclone, ESP	BACT-OTHER	
Darrington Cogeneration	Darrington, WA	1/18/05	403	0.02	Multiclone, ESP	BACT-PSD	Not constructed
Sierra Pacific Industries	Aberdeen, WA	10/17/02	315	0.02	Multiclone, ESP	BACT-PSD	
Decker Energy International	East Ryegate, VT	7/11/90	300	0.02	Mech. Collector, ESP	BACT-PSD	
Boralex	Livermore Falls, ME	9/5/91	534	0.02	Multiclone, ESP	BACT-PSD	
Pittsylvania Power	Hurt, VA	2/21/92	374	0.02	Multiclone, ESP	BACT-PSD	
Lufkin Generating Plant	Lufkin, TX	10/26/09	693	0.025	ESP	BACT-PSD	Under construction; 30-day rolling avg.
Montville Power	Uncasville, CT	4/6/10	600	0.026	ESP	BACT-PSD	Not constructed
Lindale Renewable	Lindale, TX	1/8/10	683	0.026	ESP	BACT-PSD	Under construction; 30-day rolling avg.
Russell Biomass	Russell, MA	12/30/08	740	0.026	Multiclone, ESP	BACT-OTHER	Not constructed; annual avg
Smurfit-Stone Container	Stevenson, AL	1/15/97	620	0.03	Multiclone, ESP	BACT-PSD	
Wheelabrator Sherman Energy	Sherman Station, ME	4/9/99	630	0.036	Baghouse	BACT-PSD	
Boralex	Chateaugay, NY	12/19/94	275	0.038	Multiclone, ESP	BACT	
Willamette Industries, Inc.	Marlboro, SC	4/17/96	470	0.05	ESP	BACT-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	

Table 5 VOC Control Technology Search Results

Facility Name	Location	Date of Permit	Heat Input (MMBtu/hr)	Emiss. Factor (lb/MMBtu)	Control Technology	Basis	Notes
SREC	Shelton, WA	Proposed	436	0.017	Proper combustion	BACT-OTHER	
Valley Bio-Energy	Modesto, CA	Proposed	402	0.005	Oxidation catalyst	BACT-OTHER	Not permitted
Montville Power	Uncasville, CT	4/6/10	600	0.01	Oxidation catalyst	BACT-PSD	Not constructed
Lufkin Generating Plant	Lufkin, TX	10/26/09	693	0.01	Proper combustion	OTHER	Under construction; 30-day rolling avg.
Russell Biomass	Russell, MA	12/30/08	740	0.01	Oxidation catalyst	BACT-OTHER	Not constructed; annual avg
Duke Solutions	Evendale, OH	11/24/99	28.7	0.01	Proper combustion	OTHER	No testing required
South Point Power	South Point, OH	4/4/06	318	0.013	Oxidation catalyst	BACT-PSD	Not constructed
Lindale Renewable	Lindale, TX	1/8/10	683	0.017	Proper combustion	BACT-PSD	Under construction
Boise Cascade	Florien, LA	7/18/07	225	0.017	Proper combustion	BACT-PSD	
Sierra Pacific Industries	Burlington, WA	1/25/06	430	0.019	Proper combustion	BACT-PSD	
Hampton Lumber	Darrington, WA	6/1/05	245	0.025	Proper combustion	BACT-OTHER	
Darrington Cogeneration	Darrington, WA	1/18/05	403	0.025	Proper combustion	BACT-OTHER	Not constructed
Sierra Pacific Industries	Aberdeen, WA	10/17/02	310	0.025	Proper combustion	BACT-PSD	
Wheelabrator Sherman Energy Co.	Penobscott, ME	4/9/99	315	0.03	Proper combustion	BACT-PSD	
Potlatch Corp.	Ozan, AR	7/26/05	175	0.034	Proper combustion	BACT-PSD	
Southern Soya Corp.	Estill, SC	10/2/95	58	0.05	Proper combustion	LAER	

Table 6 SO₂ Control Technology Search Results

Facility Name	Location	Date of Permit	Heat Input (MMBtu/hr)	Emiss. Factor (lb/MMBtu)	Control Technology	Basis	Notes
SREC	Shelton, WA	Proposed	436	--	None	BACT-OTHER	EF to be determined
Valley Bio-Energy	Modesto, CA	Proposed	402	0.012	Acid gas scrubber	BACT-OTHER	Not permitted
Duke Solutions	Evendale, OH	11/24/99	28.7	0.01	None	OTHER	No testing req.
Montville Power	Uncasville, CT	4/6/10	600	0.025	Fuel specification	BACT-PSD	Not constructed; 3-hour block avg.
Lindale Renewable	Lindale, TX	1/8/10	683	0.025	None	BACT-PSD	Under construction; 30-day rolling avg.
Lufkin Generating Plant	Lufkin, TX	10/26/09	693	0.025	None	BACT-PSD	Under construction; 30-day rolling avg.
Russell Biomass	Russell, MA	12/30/08	740	0.025	Fuel specification	BACT-OTHER	Not constructed
Sierra Pacific Industries	Burlington, WA	1/25/06	430	0.025	None	BACT-PSD	
Hampton Lumber	Darrington, WA	6/1/05	245	0.025	None	BACT-OTHER	
Darrington Cogeneration	Darrington, WA	1/18/05	403	0.025	None	BACT-OTHER	Not constructed
Sierra Pacific Industries	Aberdeen, WA	10/17/02	310	0.025	None	BACT-PSD	
South Point Power	South Point, OH	4/4/06	318	0.087	Acid gas scrubber	BACT-PSD	Not constructed
Smurfit-Stone Container	Stevenson, AL	7/14/06	620	0.15	None	BACT-PSD	
Willamette Industries, Inc.	Marlboro, SC	4/17/96	470	0.1	None	BACT-OTHER	
Wheelabrator Sherman Energy Co.	Penobscott, ME	4/9/99	315	0.12	Fuel specification	BACT-PSD	
Gulf States Paper Corp	Demopolis, AL	12/10/97	775	0.46	Proper combustion	BACT-PSD	
Northern Sun ADM	Enderlin, ND	5/1/06	280	0.47	None	BACT-PSD	

Table 7 Recent BACT Determinations for Cooling Towers

Permit or RBL ID	Date of Permit	Company	Location	System Description	Maximum Throughput	PM Limit(s)	Control Option	Basis
TX-0552	03-03-10	Stark Power Generation II	Hood County, TX	Cooling tower	Not Provided	0.0005% drift	Drift Eliminators	BACT-PSD
TX-0551	02-03-10	Panda Sherman Power, LLC	Grayson County, TX	Cooling tower	Not Provided	0.0005% drift	Drift Eliminators	BACT-PSD
TX-0553	01-08-10	Lindale Renewable Energy	Smith County, TX	Cooling Tower	Not Provided	0.0005% drift	Drift Eliminators	BACT-PSD
NV-0050	11-30-09	MGM Mirage	Clark County, NV	Cooling Towers	10,890 gal/min	0.091 lb/hr; 0.001% drift; 3,600 ppm TDS	Drift Eliminator, TDS limit	LAER
MN-0078	10-28-09	Sappi Fine Paper	Carlton County, MN	Cooling Tower	Not Provided	0.01 lb/hr; 0.02% drift	Drift Eliminators	BACT-PSD
*NV-0049	08-20-09	Harrah's	Clark County, NV	Cooling Tower	7,200 gal/min	0.215 lb/hr 0.005% drift; 2,520 ppm TDS	Drift Eliminator, TDS limit	Other - Case-by-Case
*NV-0049	08-20-09	Harrah's	Clark County, NV	Cooling Tower	6,900 gal/min	0.425 lb/hr 0.005% drift; 3,000 ppm TDS	Drift Eliminator, TDS limit	Other - Case-by-Case
*NV-0049	08-20-09	Harrah's	Clark County, NV	Cooling Tower	20,400 gal/min	0.744 lb/hr 0.005% drift; 3,000 ppm TDS	Drift Eliminator, TDS limit	Other - Case-by-Case
LA-0204	02-27-09	Shintech Louisiana, LLC	Iberville Parish, LA	Cooling Tower	38,750 gal/min	0.08 lb/MMgal	Drift Eliminators	BACT-PSD
LA-0204	02-27-09	Shintech Louisiana, LLC	Iberville Parish, LA	Cooling Tower	106,000 gal/min	0.06 lb/MMgal	Drift Eliminators	BACT-PSD
LA-0204	02-27-09	Shintech Louisiana, LLC	Iberville Parish, LA	Cooling Tower	43,000 gal/min	0.057 lb/MMgal	Drift Eliminators	BACT-PSD
ID-0017	02-10-09	Southeast Idaho Energy	Power County, ID	Cooling Tower	121,000 gal/min	0.0005% drift	Drift Eliminators	BACT-PSD
MT-0030	11-19-08	ConocoPhillips	Yellowstone County, MT	Cooling Tower	10,000 gal/min	0.0005% drift	Drift Eliminators	BACT-PSD
IA-0095	09-19-08	Tate & Lyle Ingredients.	Webster County, IA	Cooling Tower	Not Provided	0.0005% drift	Drift Eliminators	BACT-PSD
FL-0304	09-08-08	Florida Municipal Power Agency (FMPA)	Osceola County, FL	Cooling Tower	Not Provided	0.0005% drift	Mist Eliminators	BACT-PSD

Permit or RBL ID	Date of Permit	Company	Location	System Description	Maximum Throughput	PM Limit(s)	Control Option	Basis
FL-0303	07-30-08	Florida Power And Light Company (FP&L)	Palm Beach County, FL	Cooling Tower	Not Provided	0.0005% drift	Mist Eliminators	BACT-PSD
LA-0148	05-28-08	Red River Environmental Products, LLC	Red River Parish, LA	Cooling Towers	10,750 gal/min	0.41 lb/hr	Drift Elimination System	BACT-PSD
OK-0124	05-01-08	Koch Nitrogen Co.	Garfield County, OK	Cooling Tower	Not Provided	None	Drift Eliminator	BACT-PSD
LA-0224	03-20-08	Southwest Electric Power Company	Caddo Parish, LA	Cooling Tower	140,000 gal/min	1.4 lb/hr	Mist Eliminators	BACT-PSD
NV-0047	02-26-08	Nellis Air Force Base	Clark County, NV	Cooling Towers	1,200 gal/min	0.005% drift; TDS 0.3 lb/gal	Drift Eliminator, TDS limit	Other - Case-by-Case
LA-0221	11-30-07	Entergy Louisiana, LLC	St. Charles Parish, LA	Cooling Tower	5,000 gal/min	0.5 lb/hr	Drift Eliminator with 99.999% Control Eff.	BACT-PSD
ND-0024	09-14-07	Great River Energy	Stutsman County, ND	Cooling Tower	80,000 gal/min	0.0005% drift	Drift Eliminator	BACT-PSD
MN-0070	09-07-07	Minnesota Steel Industries, LLC	Itasca County, MN	Cooling Tower	Not Provided	0.005% drift rate	Design to minimize drift	BACT-PSD
IA-0089	08-08-07	Homeland Energy Solutions, LLC	Chickasaw County, IA	Cooling Tower	5,000 gal/min	0.0005% drift	Drift Eliminator/Demister	BACT-PSD
IA-0088	06-29-07	Archer Daniels Midland	Linn County, IA	Cooling Tower	150,000 gal/min	0.0005% drift	Drift Eliminator	BACT-PSD
LA-0211	12-27-06	Marathon Petroleum Co., LLC	St. John the Baptist Parish, LA	Cooling Towers	30,000 & 96,250 gal/min	0.005% drift	High Efficiency Drift Eliminators	BACT-PSD
FL-0294	12-22-06	Progress Energy Florida	Pasco County, FL	Cooling Towers	660,000 gal/min	108 tons/year	Drift Eliminators	BACT-PSD
WV-0024	04-26-06	Western Greenbrier Co-Generation, LLC	Greenbrier County, WV	Cooling Tower	55,000 gal/min	0.79 lb/hr	Drift Eliminators with 0.0005% drift	BACT-PSD
IA-0082	04-19-06	Golden Grain Energy	Cerro Gordo County, IA	Cooling Tower	Not Provided	1.33 lb/hr	Mist Eliminators	BACT-PSD
LA-0202	02-23-06	Cleco Power, LLC	Rapides Parish, LA	Cooling Tower	301,874 gal/min	1.13 lb/hr 3.31 tons/year	Drift Eliminators	BACT-PSD
OR-0041	08-08-05	Diamond Wanapa I LP	Umatilla County, OR	Cooling Tower	6.2 ft ³ /sec	TDS 3,532 ppm	High Efficiency 0.0005% Drift Eliminators; Limit TDS to < 3,532 PPMW.	BACT-PSD

Permit or RBL ID	Date of Permit	Company	Location	System Description	Maximum Throughput	PM Limit(s)	Control Option	Basis
CO-0057	07-05-05	Public Service Company of Colorado	Pueblo County, CO	Cooling tower	140,650 gal/min	None	RACT is drift eliminators to achieve 0.0005 % drift or less.	BACT-PSD
LA-0192	06-06-05	Crescent City Power LLC	Orleans Parish, LA	Cooling Tower	290,200 gal.min	2.61 lb/hr	TDS = 30,000 PPM 0.0001% drift annual average	BACT-PSD
IN-0119	05-31-05	Auburn Nugget	Dekalb County, IA	Cooling Tower	23,450 gal/min	0.0050% drift 20% opacity	None	BACT-PSD
NV-0036	05-05-05	Newmont Nevada Energy Investment LLC	Eureka County, NV	Cooling Tower	Not Provided	0.0005% drift	Drift Eliminators	BACT-PSD
AZ-0046	04-14-05	Arizona Clean Fuels LLC	Yuma, AZ	Cooling Tower	Not Provided	1.6 lb/hr	High Efficiency Drift Eliminators	BACT-PSD
NY-0093	03-31-05	Igen-Nassau Energy Corporation	Nassau County, NY	Cooling Tower	Not Provided	0.0005% drift	None	BACT-PSD
NE-0031	03-09-05	Omaha Public Power District OPPD	Otoe County, NE	Cooling Tower	Not Provided	0.0010 lb/hr	High Efficiency Mist Eliminators - 0.0005% drift	BACT-PSD

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Attachment A: Cost-Effectiveness Calculations

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TABLE A-1
SNCR COST ESTIMATE
FOR BIOMASS-FIRED COGENERATION UNIT

Solomon Renewable Energy Co. Wood-Fired Cogeneration Unit Project
Shelton, Washington

CAPITAL COSTS		
DIRECT COSTS	COST	Source
I. Purchased Equipment		
a. Primary Equipment (injector nozzles, piping, storage tank)	\$50,000	McBurney (2010)
b. Instrumentation (0.1*a)	\$5,000	OAQPS
c. Sales tax (0.08*a)	\$4,000	OAQPS
d. Freight (0.05*a)	\$2,500	OAQPS
Total Purchases Equipment Cost [TEC]	\$61,500	Calculation
II. Direct Installation Costs		
a. Foundations and Supports (0.08*TEC)	\$4,920	OAQPS
b. Handling and Erection (0.14*TEC)	\$8,610	OAQPS
c. Electrical (0.04*TEC)	\$2,460	OAQPS
d. Piping (0.02*TEC)	\$1,230	OAQPS
e. Insulation for Ductwork (0.01*TEC)	\$615	OAQPS
f. Painting (0.01*TEC)	\$615	OAQPS
Total Direct Costs [TDC](I+II)	\$18,450	Calculation
INDIRECT COSTS		
III. Indirect Installation		
a. Engineering and Supervision (0.10*TEC)	\$6,150	OAQPS
b. Construction and Field Expenses (0.05*TEC)	\$3,075	OAQPS
c. Contractor Fee (0.10*TEC)	\$6,150	OAQPS
d. Contingencies (0.03*TEC)	\$1,845	OAQPS
IV. Other Indirect Costs		
a. Startup and Testing (0.03*TEC)	\$1,845	OAQPS
b. Working Capital (30 days of direct operating costs [I-VII below/12])	\$14,274	OAQPS
Total Indirect Costs [TIC](III+IV)	\$33,339	Calculation
Total Capital Costs [TCC] (TEC+TDC+TIC)	\$113,289	Calculation
Total Annualized Capital Costs [TACC] (20 years @ 7% interest)	\$10,694	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)	\$8,213	Engineering Estimate
IV. Replacement Parts		
a. Catalyst (none)	\$0	
b. Other (100% of maintenance labor)	\$8,213	OAQPS
V. Utility costs (none)		
V. Utility costs (none)	\$0	
VI. Ammonia costs (anhydrous) =(20 lb/hr)*(8760 hr/yr)*(\$0.83/lb)	\$145,416	Engineering Estimate
INDIRECT OPERATING COSTS (IOC)		
VIII. Overhead (0.6*O&M costs(I-III of DOC)	\$10,594	OAQPS
IX. Administration (0.02*TCC)	\$2,266	OAQPS
X. Insurance (0.01*TCC)	\$1,133	OAQPS
Total Direct and Indirect Annualized Costs [TDIAC] (DOC+IOC)	\$185,278	Calculation
TOTAL ANNUALIZED COSTS [TAC] (TACC+TDIAC)	\$195,972	Calculation
Baseline emissions (w/proper combustion - 0.25 lb/MMBtu)	tons/year 476.9	McBurney (2010)
Emissions w/SNCR (assuming 0.13 lb/MMBtu)	tons/year 248.0	McBurney (2010)
Reduction from baseline	Percent 48.0	Calculation
Total Emissions Reduction	tons/year 228.9	Calculation
Cost per ton Controlled	\$/ton \$ 856	Calculation

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TABLE A-2
SCR COST ESTIMATE
FOR BIOMASS-FIRED COGENERATION UNIT

Solomon Renewable Energy Co. Wood-Fired Cogeneration Unit Project
Shelton, Washington

CAPITAL COSTS			
	COST	Source	
DIRECT COSTS			
I. Purchased Equipment			
a. Primary Equipment (catalyst beds, nozzles, piping, ductwork, storage tank)	\$622,000	PPC (2010)	
b. Instrumentation (0.1*a)	\$62,200	OAQPS	
c. Sales tax (0.08*a)	\$49,760	OAQPS	
d. Freight (0.05*a)	\$31,100	OAQPS	
<i>Total Purchases Equipment Cost [TEC]</i>	\$765,060	Calculation	
II. Direct Installation Costs			
a. Foundations and Supports (0.08*TEC)	\$61,205	OAQPS	
b. Handling and Erection (0.14*TEC)	\$107,108	OAQPS	
c. Electrical (0.04*TEC)	\$30,602	OAQPS	
d. Piping (0.02*TEC)	\$15,301	OAQPS	
e. Insulation for Ductwork (0.01*TEC)	\$7,651	OAQPS	
f. Painting (0.01*TEC)	\$7,651	OAQPS	
<i>Total Direct Costs [TDC](I+II)</i>	\$229,518	Calculation	
INDIRECT COSTS			
III. Indirect Installation			
a. Engineering and Supervision (0.10*TEC)	\$76,506	OAQPS	
b. Construction and Field Expenses (0.05*TEC)	\$38,253	OAQPS	
c. Contractor Fee (0.10*TEC)	\$76,506	OAQPS	
d. Contingencies (0.03*TEC)	\$22,952	OAQPS	
IV. Other Indirect Costs			
a. Startup and Testing (0.03*TEC)	\$22,952	OAQPS	
b. Working Capital (30 days of direct operating costs [I-VII below/12])	\$63,291	OAQPS	
<i>Total Indirect Costs [TIC](III+IV)</i>	\$300,459	Calculation	
<i>Total Capital Costs [TCC] (TEC+TDC+TIC)</i>	\$1,295,037	Calculation	
<i>Total Annualized Capital Costs [TACC] (20 years @ 7% interest)</i>	\$122,242	Calculation	
DIRECT AND INDIRECT ANNUALIZED COSTS			
DIRECT OPERATING COSTS (DOC)			
I. Labor for operations (\$40/person-hour)(1 hr/shift)(3 shifts/day)(365 day/yr)	\$43,800	Engineering Estimate	
II. Supervisory Labor (0.15* operations labor)	\$6,570	OAQPS	
III. Maintenance Labor (\$35/person-hour)(1 hr/shift)(3 shifts/day)(365 day/yr)	\$32,850	Engineering Estimate	
IV. Replacement Parts			
a. Catalyst (1 set every year), \$279,000 each	\$279,000	PPC (2010)	
b. Other (100% of maintenance labor)	\$32,850	OAQPS	
V. Utility costs (Elect.) = (500kW)(\$0.05/kW-hr)(8,760 hr/yr)	\$219,000	Engineering Estimate	
VI. Ammonia costs (anhydrous) = (20 lb/hr)*(8760 hr/yr)*(\$0.83/lb)	\$145,416	Engineering Estimate	
VII. Lost revenue during downtime (3 per year @ \$80,000 per shutdown)	\$240,000	SREC (2010)	
INDIRECT OPERATING COSTS (IOC)			
VIII. Overhead (0.6*O&M costs(I-III of DOC))	\$49,932	OAQPS	
IX. Administration (0.02*TCC)	\$25,901	OAQPS	
X. Insurance (0.01*TCC)	\$12,950	OAQPS	
<i>Total Direct and Indirect Annualized Costs [TDIAC] (DOC+IOC)</i>	\$1,088,269	Calculation	
<i>TOTAL ANNUALIZED COSTS [TAC] (TACC+TDIAC)</i>	\$1,210,511	Calculation	
Uncontrolled NOx emission factor (0.25 lb/MMBtu)	tons/year	476.9	McBurney (2010)
Emissions w/SCR (0.075 lb/MMBtu)	tons/year	143.1	PPC (2010)
Reduction from baseline	Percent	70.0	Calculation
Total Emissions Reduction	tons/year	333.8	Calculation
<i>Cost per ton Controlled</i>	<i>\$/ton</i>	<i>\$ 3,626</i>	Calculation

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TABLE A-3

**OXIDATION CATALYST COST ESTIMATE
FOR BIOMASS-FIRED COGENERATION UNIT**

Solomon Renewable Energy Co. Wood-Fired Cogeneration Unit Project
Shelton, Washington

CAPITAL COSTS		
DIRECT COSTS	COST	Source
I. Purchased Equipment		
a. Primary Equipment	\$716,000	PPC (2010)
b. Instrumentation (0.1*a)	\$71,600	OAQPS
c. Sales tax (0.08*a)	\$57,280	OAQPS
d. Freight (0.05*a)	\$35,800	OAQPS
	Total Purchases Equipment Cost [TEC]	Calculation
	\$880,680	
II. Direct Installation Costs		
a. Foundations and Supports (0.08*TEC)	\$70,454	OAQPS
b. Handling and Erection (0.14*TEC)	\$123,295	OAQPS
c. Electrical (0.04*TEC)	\$35,227	OAQPS
d. Piping (0.02*TEC)	\$17,614	OAQPS
e. Insulation for Ductwork (0.01*TEC)	\$8,807	OAQPS
f. Painting (0.01*TEC)	\$8,807	OAQPS
	Total Direct Costs [TDC](I+II)	Calculation
	\$264,204	
INDIRECT COSTS		
III. Indirect Installation		
a. Engineering and Supervision (0.10*TEC)	\$88,068	OAQPS
b. Construction and Field Expenses (0.05*TEC)	\$44,034	OAQPS
c. Contractor Fee (0.10*TEC)	\$88,068	OAQPS
d. Contingencies (0.03*TEC)	\$26,420	OAQPS
IV. Other Indirect Costs		
a. Startup and Testing (0.03*TEC)	\$26,420	OAQPS
b. Working Capital (30 days of direct operating costs [I-VII below/12])	\$38,524	OAQPS
	Total Indirect Costs [TIC](III+IV)	Calculation
	\$311,535	
	Total Capital Costs [TCC] (TEC+TDC+TIC)	Calculation
	\$1,456,419	
	Total Annualized Capital Costs [TACC] (20 years @ 7% interest)	Calculation
	\$137,476	
DIRECT AND INDIRECT ANNUALIZED COSTS		
DIRECT OPERATING COSTS (DOC)		
I. Labor for operations (\$40/person-hour)(0.25 hr/shift)(3 shifts/day)(365 day/yr)	\$10,950	Engineering Estimate
II. Supervisory Labor (0.15* operations labor)	\$1,643	OAQPS
III. Maintenance Labor (\$35/person-hour)(1 hr/shift)(3 shifts/day)(365 day/yr)	\$32,850	Engineering Estimate
IV. Replacement Parts		
a. Catalyst (1 set every year), \$165,000 each	\$165,000	Engineering Estimate
b. Other (100% of maintenance labor)	\$32,850	OAQPS
V. Utility costs (Elect.) = (500kW)(\$0.05/kW-hr)(8,760 hr/yr) (reheat fuel) = none	\$219,000 \$0	Engineering Estimate
VI. Ammonia costs (none)	\$0	
VII. Lost revenue during downtime (4 per year @ \$80,000 per shutdown)	\$320,000	Engineering Estimate
INDIRECT OPERATING COSTS (IOC)		
VIII. Overhead (0.6*O&M costs(I-III of DOC)	\$27,266	OAQPS
IX. Administration (0.02*TCC)	\$29,128	OAQPS
X. Insurance (0.01*TCC)	\$14,564	OAQPS
	Total Direct and Indirect Annualized Costs [TDIAC] (DOC+IOC)	Calculation
	\$853,251	
	TOTAL ANNUALIZED COSTS [TAC] (TACC+TDIAC)	Calculation
	\$990,726	
Emissions w/proper combustion (0.3 lb/MMBtu)	tons/year 574.2	McBurney (2010)
Emissions w/oxidation catalyst (0.1 lb/MMBtu)	tons/year 248.0	PPC (2010) & Calculation
Reduction from baseline	Percent 56.8	Calculation
Total Emissions Reduction	tons/year 326.2	Calculation
Cost per ton Controlled	\$/ton \$ 3,037	Calculation

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TABLE A-4

**ACID-GAS SCRUBBER COST ESTIMATE
FOR BIOMASS-FIRED COGENERATION UNIT**

Solomon Renewable Energy Co. Wood-Fired Cogeneration Unit Project
Shelton, Washington

CAPITAL COSTS			
DIRECT COSTS	COST	Source	
I. Purchased Equipment			
a. Primary Equipment	\$452,000	PPC (2009)	
b. Instrumentation (0.1*a)	\$45,200	OAQPS	
c. Sales tax (0.08*a)	\$36,160	OAQPS	
d. Freight (0.05*a)	\$22,600	OAQPS	
<i>Total Purchases Equipment Cost [TEC]</i>	\$555,960	<i>Calculation</i>	
II. Direct Installation Costs			
a. Foundations and Supports (0.08*TEC)	\$44,477	OAQPS	
b. Handling and Erection (0.14*TEC)	\$77,834	OAQPS	
c. Electrical (0.04*TEC)	\$22,238	OAQPS	
d. Piping (0.02*TEC)	\$11,119	OAQPS	
e. Insulation for Ductwork (0.01*TEC)	\$5,560	OAQPS	
f. Painting (0.01*TEC)	\$5,560	OAQPS	
<i>Total Direct Costs [TDC](I+II)</i>	\$166,788	<i>Calculation</i>	
INDIRECT COSTS			
III. Indirect Installation			
a. Engineering and Supervision (0.10*TEC)	\$55,596	OAQPS	
b. Construction and Field Expenses (0.05*TEC)	\$27,798	OAQPS	
c. Contractor Fee (0.10*TEC)	\$55,596	OAQPS	
d. Contingencies (0.03*TEC)	\$16,679	OAQPS	
IV. Other Indirect Costs			
a. Startup and Testing (0.03*TEC)	\$16,679	OAQPS	
b. Working Capital (30 days of direct operating costs [I-VII below/12])	\$6,674	OAQPS	
<i>Total Indirect Costs [TIC](III+IV)</i>	\$179,022	<i>Calculation</i>	
<i>Total Capital Costs [TCC] (TEC+TDC+TIC)</i>	\$901,770	<i>Calculation</i>	
<i>Total Annualized Capital Costs [TACC] (20 years @ 7% interest)</i>	\$85,121	<i>Calculation</i>	
DIRECT AND INDIRECT ANNUALIZED COSTS			
DIRECT OPERATING COSTS (DOC)			
I. Labor for operations (\$30/person-hour)(0.5 hr/shift)(3 shifts/day)(365 day/yr)	\$16,425	Engineering Estimate	
II. Supervisory Labor (0.15* operations labor)	\$2,464	OAQPS	
III. Maintenance Labor (\$35/person-hour)(0.5 hr/shift)(3 shifts/day)(365 day/yr)	\$16,425	Engineering Estimate	
IV. Replacement Parts (100% of maintenance labor)	\$16,425	OAQPS	
V. Utility costs		Engineering Estimate	
a. Fan elect. = (\$0.05/kW-hr)(8,760 hr/yr)(30hp)(0.75 efficiency)(0.7457kW/hp)	\$7,349	PPC (2009) & Eng. Est.	
VI. Trona costs =(150 tpy)*(\$140/ton)	\$21,000	Solvay (2009) & Eng. Est.	
INDIRECT OPERATING COSTS (IOC)			
VIII. Overhead (0.6*O&M costs(I-III of DOC)	\$21,188	OAQPS	
IX. Administration (0.02*TCC)	\$18,035	OAQPS	
X. Insurance (0.01*TCC)	\$9,018	OAQPS	
<i>Total Direct and Indirect Annualized Costs [TDIAC] (DOC+IOC)</i>	\$128,329	<i>Calculation</i>	
<i>TOTAL ANNUALIZED COSTS [TAC] (TACC+TDIAC)</i>	\$213,450	<i>Calculation</i>	
Baseline emissions (Fuel testing - 0.061 lb/MMBtu)	tons/year	116.4	<i>Calculation</i>
Emissions w/trona injection (0.033 lb/MMBtu)	tons/year	62.9	PPC (2010)
Reduction from baseline	Percent	45.9	<i>Calculation</i>
Total Emissions Reduction	tons/year	53.4	<i>Calculation</i>
<i>Cost per ton Controlled</i>	<i>\$/ton</i>	<i>\$ 3,996</i>	<i>Calculation</i>

OAQPS "EPA Air Pollution Cost Manual" Sixth Edition, January 2002, EPA/452/B-02-001
Office of Air Quality Planning and Standards (OAQPS).

TABLE A-5
FGD COST ESTIMATE
FOR BIOMASS-FIRED COGENERATION UNIT

Solomon Renewable Energy Co. Wood-Fired Cogeneration Unit Project
Shelton, Washington

CAPITAL COSTS			
DIRECT COSTS	COST	Source	
I. Purchased Equipment			
a1. Primary Equipment	\$4,131,135	Consumers Energy (2009)	
a2. Buildings	\$2,165,163	Consumers Energy (2009)	
b. Instrumentation (0.1*a1)	\$413,113	OAQPS	
c. Sales tax (0.08*a1)	\$330,491	OAQPS	
d. Freight (0.05*a1)	\$206,557	OAQPS	
Total Purchases Equipment Cost [TEC]	\$7,246,459	<i>Calculation</i>	
II. Direct Installation Costs			
a. Foundations and Supports (0.08*TEC)	\$579,717	OAQPS	
b. Handling and Erection (0.14*TEC)	\$1,014,504	OAQPS	
c. Electrical (0.04*TEC)	\$289,858	OAQPS	
d. Piping (0.02*TEC)	\$144,929	OAQPS	
e. Insulation for Ductwork (0.01*TEC)	\$72,465	OAQPS	
f. Painting (0.01*TEC)	\$72,465	OAQPS	
Total Direct Costs [TDC](I+II)	\$2,173,938	<i>Calculation</i>	
INDIRECT COSTS			
III. Indirect Installation			
a. Engineering and Supervision (0.10*TEC)	\$724,646	OAQPS	
b. Construction and Field Expenses (0.05*TEC)	\$362,323	OAQPS	
c. Contractor Fee (0.10*TEC)	\$724,646	OAQPS	
d. Contingencies (0.03*TEC)	\$217,394	OAQPS	
IV. Other Indirect Costs			
a. Startup and Testing (0.03*TEC)	\$217,394	OAQPS	
b. Working Capital (30 days of direct operating costs [I-VII below/12])	\$60,863	OAQPS	
Total Indirect Costs [TIC](III+IV)	\$2,307,266	<i>Calculation</i>	
Total Capital Costs [TCC] (TEC+TDC+TIC)	\$11,727,663	<i>Calculation</i>	
Total Annualized Capital Costs [TACC] (20 years @ 7% interest)	\$1,107,008	<i>Calculation</i>	
DIRECT AND INDIRECT ANNUALIZED COSTS			
DIRECT OPERATING COSTS (DOC)			
I. Labor for operations (\$40/person-hour)(1 hr/shift)(3 shifts/day)(365 day/yr)	\$43,800	Engineering Estimate	
II. Supervisory Labor (0.15* operations labor)	\$6,570	OAQPS	
III. Maintenance Labor (\$35/person-hour)(0.5 hr/shift)(3 shifts/day)(365 day/yr)	\$16,425	Engineering Estimate	
IV. Replacement Parts (3% of purchased primary equipment)	\$123,934	Consumers Energy (2009) & Eng. Est.	
V. Utility costs			
a. Elect. = (500 kWh)(\$0.05/kWh)(8,760 hr/yr)	\$219,000	Consumers Energy (2009) & Eng. Est.	
b. Water = (20,000 gal/yr)(\$0.46/gal)	\$9,200	Consumers Energy (2009) & Eng. Est.	
c. Sewer = (\$0.30/gal)(160,000gal/yr)	\$48,000	Consumers Energy (2009) & Eng. Est.	
d. Waste disposal = (\$12/ton)(7,700 tons/yr)	\$92,400	Consumers Energy (2009) & Eng. Est.	
e. Pressure drop = (185 kWh)(\$0.05/kWh)(8,760 hr/yr)	\$81,030	Consumers Energy (2009) & Eng. Est.	
VI. Limestone costs =(4,500 tons/yr)*(\$20/ton)	\$90,000	Consumers Energy (2009) & Eng. Est.	
INDIRECT OPERATING COSTS (IOC)			
VIII. Overhead (0.6*O&M costs(I-III of DOC)	\$40,077	OAQPS	
IX. Administration (0.02*TCC)	\$234,553	OAQPS	
X. Insurance (0.01*TCC)	\$117,277	OAQPS	
Total Direct and Indirect Annualized Costs [TDIAC] (DOC+IOC)	\$1,122,266	<i>Calculation</i>	
TOTAL ANNUALIZED COSTS [TAC] (TACC+TDIAC)	\$2,229,274	<i>Calculation</i>	
Baseline emissions (Fuel testing - 0.061 lb/MMBtu)	tons/year	116.4	<i>Calculation</i>
Emissions w/FGD (assuming 0.0061 lb/MMBtu)	tons/year	5.8	<i>Calculation</i>
Reduction from baseline	Percent	95.0	<i>Calculation</i>
Total Emissions Reduction	tons/year	110.5	<i>Calculation</i>
Cost per ton Controlled	\$/ton	\$ 20,167	<i>Calculation</i>

OAQPS "EPA Air Pollution Cost Manual" Sixth Edition, January 2002, EPA/452/B-02-001
Office of Air Quality Planning and Standards (OAQPS).

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Appendix C: Emissions Calculations

**Boiler Emissions Estimate
Criteria Pollutants**

<u>Pollutant</u>	<u>lb/MMBtu</u>	<u>Source</u>	<u>Proposed lb/hr</u>	<u>Tons/year</u>
NO _x	0.130	Vendor Guarantee	56.62	248.0
CO	0.130	Vendor Guarantee	56.62	248.0
SO ₂	0.077	Fuel Tests and Vendor Guarantee	33.5	146.9
PM ₁₀	0.020	BACT	8.7	38.2
PM/PM _{2.5}	0.015	BACT	6.53	28.6
VOC	0.017	BACT	7.4	32.4
Sulfuric Acid	0.002	EPA SPECIATE	0.9	3.83
Lead	1.19E-05	AP-42	0.01	0.0228
CO at Startup	-	-	300.0	-

435.527 MMBtu/hr

Sulfuric Acid Mist Emissions

PM10	0.02 lb/MMBtu
sulfate in PM10	10.038%
Sulfate	0.0020076 lb/MMBtu
Sulfate	0.874364005 lb/hr
	3.83 TPY

NSPS Subpart Db Calculation

0.1 lb/mmbtu PM10
43.5527 lb/hr

Cooling Tower PM10 emissions

		# of cells:	2			
Flow rate (gpm)	29,600 ---->		112,048 liters/min			
Drift rate:	0.0005%		PM10			
TDS (mg/l)	228	mg/min	lb/hr	g/sec	tpy	
cycles:	4	511	0.07	0.0085	0.3	
	5	639	0.084	0.0106	0.4	
	10	1,277	0.17	0.0213	0.7	

(mg/min=lpm*mg/l*driftrate%*#cycles)

check	77,789 gallons of drift per year	
	67,137,273 mg PM/yr	
	148 lb pm/yr =	0.02 lb/hr PM
	0.07 tpy	
after 4x concentration:	0.30 tpy	
after 5x concentration:	0.37 tpy	
after 10x concentration:	0.74 tpy	

Parameters (each cell)

Height	46 feet ---->	14.02 meters
Diameter	30.0 feet ---->	9.14 meters
Area (each cell)		65.67 m ²
Temperature	92 F ---->	307 K
Flow Rate (air)	1,039,867 cfm ---->	491 m ³ /s
Exit Velocity	24.52 ft/s	7.47 m/s

Fugitive Emissions Estimate - Shelton

Fuel House Loadout/Reclaim

Design Capacity	603 BDT/day
Uncontrolled emissions factor (lbs/ton)	0.00039
Uncontrolled fugitive emissions	174 lbs/yr
Percent PM-10	100%
Uncontrolled fugitive PM-10 emissions	174 lbs/yr
Hours of operation per year	7,488 hrs
Assume 24 hours/day, 6 days/week, 52 weeks/year	
Uncontrolled fugitive PM-10 emissions	0.02317 lbs/hr
Controlled fugitive PM-10 emissions	0.00463 lbs/hr
Controlled fugitive PM-2.5 emissions	0.00146 lbs/hr
Controlled fugitive PM-10 emissions	0.00058 g/s
Controlled fugitive PM-2.5 emissions	0.00018 g/s
Long-term fugitive PM-10 emissions	0.00050 g/s
Long-term fugitive PM-2.5 emissions	0.00016 g/s
Total # of Volume Sources Modeled	6
Short-Term Emission Rate per Volume Source	0.00010 g/s
Long-Term Emission Rate per Volume Source	0.00008 g/s
Short-Term Emission Rate per Volume Source	0.000031 g/s
Long-Term Emission Rate per Volume Source	0.000026 g/s

Truck Unloading

Percent of fuel unloaded by truck	30%
Controlled fugitive PM-10 emissions	8.8E-05 g/s
Long-term fugitive PM-10 emissions	7.5E-05 g/s
Controlled fugitive PM-2.5 emissions	2.8E-05 g/s
Long-term fugitive PM-2.5 emissions	2.4E-05 g/s

Calculating Emission Factors

From Control of Open Fugitive Dust Sources (EPA-450/3-88-008, September, 1988, page 4-3)

$$E = k * (0.0032) * (U/5)^{1.3} / (M/2)^{1.4}$$

k10	0.35
k2.5	0.11
k10:k2.5	0.31
U	2.6 m/s
M	4.80 %
E10	0.00039 lb/ton
E2.5	0.000123894 lb/ton

**Appendix D:
Air Quality Dispersion Modeling Files
(Compact Disc)**