Biomass-Fired Cogeneration Project Authority to Construct Permit Application

Anderson, California

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Contents

Page

1 Introduction 1
  1.1 Organization 1
  1.2 Summary of Findings 2

2 Project Description 3
  2.1 Physical Description 3
  2.2 Fuel Supply 3
  2.3 Pollutant Emission Rates 4
    2.3.1 Criteria Pollutants 4
    2.3.2 Startup Emissions 5
    2.3.3 Toxic Air Contaminants 6

3 Regulatory Setting 7
  3.1 Federal Regulations 7
    3.1.1 Prevention of Significant Deterioration 7
    3.1.2 Acid Rain Program 7
    3.1.3 Air Operating Permit Program 7
    3.1.4 New Source Performance Standards 8
    3.1.5 Maximum Achievable Control Technology 8
  3.2 State And Local Emission Regulations 9
    3.2.1 Authority to Construct Permits 9
    3.2.2 District Air Pollution Control Regulations 9
    3.2.3 Air Toxics Hot Spots (AB 2588) 9
    3.2.4 California Environmental Quality Act (CEQA) 9
    3.2.5 Offsets 10

4 Air Quality Impacts Analysis 11
  4.1 Model Selection 11
  4.2 Modeling Procedures 11
    4.2.1 Model Setup and Application 11
    4.2.2 Averaging Periods 12
    4.2.3 Chemical Transformations 12
  4.3 Elevation Data and Receptor Network 12
  4.4 Meteorological Data 12
  4.5 Emission Source Release Parameters 13
  4.6 Analysis Results 14
  4.7 Startup Analysis 14

List of Tables

Table 2-1 Proposed Cogeneration Unit Emissions 19
Table 2-2 Baseline Actual Emission Rates for Existing Boiler 20
Table 2-3 Net Project Emissions Increase of Criteria Pollutants 21
Table 2-4 Project Emission Rates and BACT Thresholds 22
Table 2-5 Cogeneration Unit Toxic Air Contaminant Emission Rates 23
Table 3-1 Hazardous Air Pollutant Emission Rates 27
Table 4-1 Point Source Release Parameters 28
Table 4-2 Structure Heights 29
Table 4-3 Criteria Pollutant NAAQS Compliance Assessment 30
Table 4-4 Criteria Pollutant CAAQS Compliance Assessment 31

List of Figures

Figure 2-1. Project Schematic Flow Diagram 35
Figure 2-2. Vicinity of Facility and Modeling Domain 37
Figure 4-1. Final Receptor Locations 38
Figure 4-2. Wind Rose, Redding Municipal Airport, Jan. 2004 to Dec. 2008 39
Figure 4-3. Source and Significant Structure Locations 41
Figure 4-4. Maximum Predicted 1-Hour Average CO Concentrations 43
Figure 4-5. Maximum Predicted 8-Hour Average CO Concentrations 44
Figure 4-6. Maximum Predicted 1-Hour Average SO_2 Concentrations 45
Figure 4-7. Maximum Predicted 3-Hour Average SO_2 Concentrations 46
Figure 4-8. Maximum Predicted 24-Hour Average SO_2 Concentrations 47
Figure 4-9. Maximum Predicted Annual Average SO_2 Concentrations 48
Figure 4-10. Maximum Predicted 24-Hour Average PM_{10} Concentrations 49
Figure 4-11. Maximum Predicted Annual Average PM_{10} Concentrations 50
Figure 4-12. Maximum Predicted 1-Hour Average NO_2 Concentrations 51
Figure 4-13. Maximum Predicted Annual Average NO_2 Concentrations 52

List of Appendices

Appendix A: SCAQMD Forms
Appendix B: BACT Analysis
Appendix C: Air Quality Dispersion Modeling Files (CD)

1 Introduction

Sierra Pacific Industries (SPI) proposes to construct and operate a cogeneration unit at an existing lumber manufacturing facility located in Anderson, California. The boiler associated with the proposed cogeneration unit will burn biomass fuel (i.e., non-treated wood and agricultural crop residues, as well as urban wood-waste and other fuels subject to district approval) generated by the facility, regional lumber manufacturing facilities, and other biomass fuel sources to produce approximately 250,000 pounds of steam per hour. The steam will be used to dry lumber in existing kilns and for a steam turbine; the steam turbine will drive a generator that will produce electricity for on site use as well as for sale to the grid. Although no steam sales agreements are currently in place, steam may also be sold to other nearby businesses. The existing biomass-fired boiler will remain operational, but will not operate concurrently with the proposed unit other than periods of operational overlap necessary to ensure adequate uninterrupted steam production.

Although the existing lumber manufacturing facility is a major stationary source of emissions, the proposed cogeneration unit is considered a minor modification, and is therefore not subject to the requirements of the Prevention of Significant Deterioration (PSD). However, Shasta County Air Quality Management District (AQMD) Rule 2-1A requires a new or modified emission source to obtain an Authority to Construct (ATC) from the AQMD prior to commencing construction. SPI has retained ENVIRON International Corp. (ENVIRON) to prepare an ATC application to be submitted to the AQMD on its behalf.

This permit application is a revision and update of a permit application for a similar project involving a smaller version of the same boiler design (200,000 pounds steam per hour instead of 250,000 pounds of steam per hour) that was submitted to the AQMD in May 2007. In addition to revising the emission rate calculations and regulatory analysis to reflect the currently proposed boiler, the air quality modeling was updated to reflect the most current versions and guidance.

1.1 Organization

The key components of this permit application are:

- A description of the project and expected air pollutant emissions;
- A discussion of applicable air quality regulations;
- An analysis of Best Available Control Technology (BACT); and
- Analysis of compliance with ambient air quality standards.

Standard forms related to the ATC process are provided in Appendix A.

1.2 Summary of Findings

ENVIRON conducted an air quality impact assessment of the project using five years of hourly meteorological surface data collected at Redding Municipal Airport between January 1, 2004 and December 31, 2008. The analysis indicates that predicted ambient air pollutant concentrations attributable to the project will not cause or contribute to an exceedance of the National or California Ambient Air Quality Standards (NAAQS or CAAQS) established to protect human health and welfare.

2 Project Description

2.1 Physical Description

Sierra Pacific Industries (SPI) is a family-owned wood products company based in Redding, California. SPI currently operates an existing lumber manufacturing facility in Anderson, California. SPI intends to construct a new cogeneration unit at the Anderson facility that would burn biomass fuels in a boiler to produce steam that would be used to generate electricity and to heat existing lumber dry kilns at the facility.

The cogeneration unit will consist of a biomass-fired water-wall boiler with a vibrating grate, a steam turbine, and a generator. The boiler will burn biomass fuels to produce high-pressure steam for the steam turbine. The steam turbine generator will generate up to 23 megawatts (MW) of electricity. Approximately 7 MW will be used to power on-site equipment; the remainder will be sold to a public utility. Low-pressure steam will be extracted from the steam turbine through a controlled extraction and used to heat the dry kilns.

The final design of the biomass-fired boiler has not been determined, but it will be similar to a unit designed by the McBurney Corp. of Norcross, Georgia. It will have a maximum annual average heat input of approximately 425.4 million British thermal units per hour (MMBtu/hr) and a maximum steam generation rate of 250,000 pounds per hour (lb/hr). Over short-term periods, the boiler may be fired at heat input rates that exceed the annual average rate: an hourly maximum of 468.0 MMBtu/hr (10 percent greater than the annual average), and a maximum 24-hour average of 446.7 MMBtu/hr (5 percent greater than the annual average). The boiler will be equipped with two natural gas burners, each with a maximum rated heat input of 62.5 MMBtu/hr, for start up and flame stabilization. The cogeneration unit design will incorporate a selective non-catalytic reduction (SNCR) system that uses annhydrous ammonia to reduce emissions of oxides of nitrogen (NO_X), as well as a multiclone and electrostatic precipitator (ESP) to control emissions of particulate matter (PM/PM_{10}). A closed-loop two-cell cooling tower will be used to dispose of waste heat from the steam turbine. A schematic flow diagram for the cogeneration facility is presented in Figure 2-1.

The proposed cogeneration unit will be located near the existing biomass-fired boiler at SPI's Anderson lumber manufacturing facility. The existing facility is bordered on the northeast by the Sacramento River, on the northwest by a private parcel, on the southwest by Union Pacific Railroad tracks and State Route (SR) 273, and on the southeast by private parcels. The general vicinity of the facility and the modeling domain are shown in Figure 2-2.

2.2 Fuel Supply

Fuel for the cogeneration unit will come from the existing SPI facilities in California at Arcata, Anderson, Shasta Lake, and Red Bluff, as well as in-forest materials from SPI-owned or controlled timberlands, and various sources of agricultural and urban wood wastes. The available supply from SPI-owned or controlled facilities and timberlands totals 400,000 bone dry tons (BDT) per year. In addition, there are 50,000 BDT of agricultural and urban wood wastes available to SPI annually. The new boiler will consume an average of approximately 25 BDT of biomass fuel per hour which equates to 219,000 BDT per year since it is expected to operate as near to continuously as is practicable.

The Anderson facility currently produces approximately 160,000 BDT of wood wastes per year of which 60,000 BDT are consumed by the existing cogeneration facility, 20,000 BDT are trucked to other biomass power plants, and the balance is trucked to other markets (e.g., wood chips to pulp mills). The new facility will consume a maximum of 219,000 BDT per year, 80,000 BDT of which will be generated by SPI's Anderson facility at a minimum, while the balance (a maximum of 139,000 BDT) will transported by truck from other SPI sources. At a maximum, an additional 23 truck trips per day will be needed to deliver additional fuel to the facility.

The installation of the boiler will not increase emissions from any existing emission units at the Anderson mill. There have been no contemporaneous modifications at the Anderson mill.

2.3 Pollutant Emission Rates

This section addresses pollutant emission rates associated with the project. The proposed boiler will emit NO_X, carbon monoxide (CO), particulate matter smaller than ten microns (PM_{10}), PM, sulfur dioxide (SO_2), and volatile organic compounds (VOCs), as well as several substances identified as TACs by the Air Resources Board (ARB).

2.3.1 Criteria Pollutants

Table 2-1 presents anticipated criteria pollutant emission rates from the cogeneration unit during normal operation. Boiler emission factors for NO_X, CO, PM_{10}, and VOCs were based on guarantees from the boiler and control device manufacturers. The SO_2 emission factor is based on source test information from the existing biomass-fired boiler. Additional material handling operations associated with the project will be enclosed, and, as a result, fugitive dust emissions associated with the project are expected to be negligible.

The cooling tower will emit only PM_{10}. The drift eliminators to be used as part of the cooling tower design (DRU-1.5) will achieve a drift of 0.0005 percent or less. Assuming this drift rate, a water flow rate of 27,600 gallons per minute (gpm), and a conservative total dissolved solids (TDS) value of 725 milligrams per liter (mg/l), the PM_{10} emission rate from the cooling towers is 1.1 ton per year (TPY).

Consistent with the BACT analysis in Appendix B, SPI proposes the following emission limits:

- NO_X – 0.13 lb/MMBtu (30-day average)
- CO – 0.35 lb/MMBtu (3-hour average), 0.22 lb/MMBtu (annual average)
- PM_{10} – 0.02 lb/MMBtu (3-hour average) including filterable and condensable components

SPI does not believe limits are warranted for SO_2 or VOC emissions from the cogeneration unit or for PM_{10} emissions from the cooling tower because the emission rates are so low.

Table 2-2 summarizes the data used to calculate the baseline actual emissions (BAE) for the existing boiler. Table 2-3 presents the calculated net annual emission increases associated with the project, including the reduction in emission rates as a result of never operating the existing biomass-fired boiler concurrent with the proposed unit (other than some overlap during startup and shutdown to ensure continuous steam production). Table 2-4 presents the maximum hourly and daily emission rates compares them to the AQMD BACT thresholds. Chapter 4 presents dispersion modeling analyses used to assess compliance with ambient air quality standards.

2.3.2 Startup Emissions

SPI typically shuts down its boilers at least twice per year for maintenance. During the subsequent startup, the boiler is heated gradually to avoid stresses that could physically damage the boiler if it were heated too quickly. The startup period may last up to 24 hours when starting with a “cold” (ambient temperature) furnace, and will be accomplished using the natural gas-fired burners firing pipeline natural gas. Firing at full capacity, these burners will provide only thirty percent of rated boiler heat input and will initially be the sole source of heat input to the boiler during startup. Heating will continue using the natural gas burners until the furnace is hot enough to introduce biomass fuel to the furnace. After biomass fuel is introduced to the furnace, the natural gas firing rate will be reduced to maintain a steady heat rate. For the remainder of the startup period, the biomass-fuel feed rate will increase until the desired firing rate is achieved and the natural gas firing is no longer needed. The startup period will end when stable burning of biomass fuel is established under good combustion practices at the desired firing rate and the boiler reaches is design operating temperature.

During the startup period, CO emission rates will exceed those experienced under normal operation. Unlike normal operation, it is very difficult for the boiler manufacturer to estimate startup CO emission rates, which vary continuously during the startup process. Because exhaust levels of oxygen are high and CO_2 levels are low during startup, SPI proposes that the startup CO emission rate limit be a mass-per-unit-time limit rather than a concentration corrected to 12 percent CO_2 as is commonly done for normal operation limits. SPI proposes a startup and shutdown CO emission rate limit of 400 lb/hr averaged over 1 hour.

The natural gas burners are also used during boiler shutdown to burn any remaining wood ash in order to prevent temperature excursions in the ESP. The shutdown process is expected to require up to 24 hours for the furnace to reach ambient temperature, and to experience hourly average CO emission rates similar to those of startup. SPI proposes that the boiler be subject to the startup CO emission rate limits during shutdown.

A modeling analysis was performed to demonstrate that the proposed startup/shutdown emission limits will comply with the CO ambient air quality standards. This analysis is documented in Chapter 4.

2.3.3 Toxic Air Contaminants

Most TAC emission factors for wood-residue fuels were based on source tests used to develop emission factors for AP-42 Section 1.6. 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 using the subset of source tests in which wood-fired boilers were controlled by ESPs. For the hydrogen chloride (HCl) emission factor, this subset of ESP-controlled source tests was further reduced by removing source tests performed on units burning municipal solid waste. The hexavalent chromium emission factor was calculated using biomass-fired boiler source tests from AP-42 source test data, after excluding source tests that included values based on the detection limit. The ammonia (NH_3) emission rate was based on a maximum exhaust ammonia concentration of 20 parts per million (ppm). Ammonia emissions are a consequence of operating an SNCR system to reduce boiler NO_X emissions to 0.13 lbs/MMBtu.

In cases where no ESP-controlled source test results were available for a particular TAC, results associated with other particulate control equipment were used. Source test data from units not employing particulate controls or not reporting any control equipment were included where no other source test data were available. Table 2-5 presents the TAC emission factors and emission rates associated with the biomass-fired boiler. The cooling tower is not expected to emit any TACs.

3 Regulatory Setting

The proposed biomass-fired cogeneration unit project is subject to federal, state, and local regulations. The following section discusses the applicable regulations and why certain regulatory programs are not applicable. It should be noted that the project will be located in an area that is in attainment of all federal ambient air quality standards, but has been designated as not in attainment with the state ozone and PM_{10} standards.

3.1 Federal Regulations

3.1.1 Prevention of Significant Deterioration

For purposes of new source review, construction of the proposed cogeneration unit is a minor modification of a major source, and is therefore not subject to the requirements of the PSD program because, as shown in Table 2-3, net annual average potential emission rate increases are less than 250 tons per year.

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 SO_2 and NO_X, the primary causes of acid rain. The biomass-fired boiler proposed by SPI will not be subject to the requirements of the Acid Rain Program because it is a cogeneration unit with an electrical generating capacity below the program applicability threshold.

40 CFR 72.6 identifies criteria used to determine whether a facility is subject to the Acid Rain Program. Section 72.6(b)(4)(ii) states that a biomass-fired cogeneration unit is not subject to the program if it sells no more than one third of its potential annual electrical output capacity or if it sells less than 219,000 megawatt (electric)-hours (MWe-hrs) of electricity annually. A cogeneration unit meeting either of these criteria is not subject to the Acid Rain Program.

The biomass-fired cogeneration unit proposed by SPI meets the definition of a "cogeneration unit" in 40 CFR 72.2 because at least a portion of the steam generated by the boiler will be delivered first to the steam turbine and then used to heat lumber dry kilns at the existing lumber manufacturing facility. Thus, the steam will be "used twice." Although SPI expects to sell more than one-third of the boiler's annual potential electrical output capacity, the boiler will be an unaffected source because SPI expects to sell no more than 219,000 MWe-hrs of electricity annually. Due to the proposed boiler's cogeneration status and proposed electrical sales, this boiler is considered an unaffected source.

3.1.3 Air Operating Permit Program

The lumber manufacturing facility is a major source subject to the Title V air operating permit program. Because the proposed cogeneration unit is a major modification requiring a PSD permit, a significant permit modification is required under AQMD Rule 5, Section IV.B.3. The cogeneration unit may not commence operation until the permit revision is approved.

3.1.4 New Source Performance Standards

USEPA 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 cogeneration boiler because the maximum annual average heat input is expected to be 425.4 MMBtu/hr.

Subpart Db limits PM emissions to 0.03 lb/MMBtu for newly constructed units. At the proposed maximum firing rate, this limit translates into an emission rate of 43 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 emission rates proposed by SPI reflect BACT (which is more stringent than these NSPS limits), and the PM_{10} emission rates proposed for the cogeneration unit are less than those allowed by NSPS.

The cogeneration unit will burn natural gas during startup. Subpart Db prescribes SO_2 and NO_X limits on boilers that fire fossil fuels under certain conditions. The SO_2 limits do not apply to boilers that combust natural gas. The NO_X limits in Subpart Db do not apply to boilers that have an annual fossil fuel capacity factor of less than ten percent. SPI will maintain on-site records of the quantities and times that natural gas is fired in the boiler to ensure that gas provides less than 10 percent of the annual fuel input. Consequently, neither the SO_2 nor the NO_X emission limits identified in Subpart Db will apply.

3.1.5 Maximum Achievable Control Technology

The Clean Air Act Amendments of 1990 require USEPA to establish technology-based standards to control hazardous air pollutants (HAPs). For MACT 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 existing and proposed boiler will be the only sources of HAPs at the facility. The two would not operate concurrently other than some overlap during startup and shutdown, and the proposed boiler has a greater firing rate, therefore the annual HAP PTE of the proposed boiler constitutes the annual facility-wide HAP PTE, which is summarized in Table 3-1. The HAP emitted in greatest quantity will be hydrogen chloride at an annual rate 6.57 TPY. SPI anticipates that facility-wide emissions of all 47 HAPs combined will be 17.2 TPY. The project will not exceed either of the MACT thresholds used to designate a major source, and, as a result, will not be subject to the MACT program.

3.2 State And Local Emission Regulations

3.2.1 Authority to Construct Permits

Shasta County AQMD Rule 2, Part 100 requires new or modified stationary sources to obtain an ATC air quality permit. The ATC 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 predicted ambient concentrations attributable to these emissions to ensure compliance with ambient air quality standards.

BACT applicability is determined based on daily emission thresholds provided in AQMD Rule 2 Part 301. The daily emissions of each pollutant with the potential for requiring BACT are listed in Table 2-3, along with the daily PTE and regulatory threshold. As shown in the table, BACT is required for reactive organic compounds (ROG), NO_X, SO_2, PM_{10}, CO, and beryllium. BACT analyses are presented in Appendix B for the biomass-fired boiler and the cooling tower.

As stated in AQMD Rule 2, Part 300, an ATC permit cannot be granted unless the agency determines the project (1) will meet applicable state and federal emission limits; (2) will employ BACT where required; and (3) will not cause or contribute to violations of ambient air quality standards. This application provides the information to enable the AQMD to make those determinations.

3.2.2 District Air Pollution Control Regulations

Regulations addressing emissions of specific air contaminants from a single source are contained in AQMD Rule 3, Part 2. For sources constructed after July 1, 1986, PM emissions are limited to 0.15 grains per dry standard cubic foot (gr/dscf), while PM_{10} is limited to 0.05 gr/dscf, and combustion PM is limited to 0.10 gr/dscf. SO_2 emissions are limited to 200 ppm, and NO_X emissions are limited to 300 ppm for solid fuels, and 250 ppm for gaseous fuels. Opacity is limited to Ringelmann #2 and/or 40 percent.

3.2.3 Air Toxics Hot Spots (AB 2588)

The "Hot Spots" Act, also known as AB 2588 or the Health and Safety Code Section 44300 et seq., requires facilities to which the act applies to inventory and report air toxic emissions from stationary sources. In addition to the TAC emission increases discussed in Section 2.3.3 and summarized in Table 2-5, a Health Risk Assessment of TAC emission increases associated with the proposed project will be provided to AQMD and Shasta County Planning Department.

3.2.4 California Environmental Quality Act (CEQA)

All ATCs are required to undergo a preliminary review by the AQMD to determine if any possibility of a significant environmental effect exists. Following this review, the AQMD will determine whether further environmental review is required. If further review is warranted, a determination will be made as to whether or not the AQMD is the Lead Agency or a Responsible Agency, and the Environmental Review will proceed as described in AQMD Environmental Review Guidelines (November, 2003).

3.2.5 Offsets

Sections 40918, 40919, 40920, and 40920.5 of the California Health & Saftey (H&S) Code require areas that are designated as being in nonattainment with respect to one or more criteria pollutant State or Federal standards to achieve “no net increase” in emissions (i.e., offsets) of those pollutants and their precursors. Although Shasta County has been designated a nonattainment area with respect to the State ozone and PM_{10} ambient air quality standards, it has further been classified as having “moderate air pollution.” Areas that are not classified has having “extreme air pollution” are allowed, by H&S Section 40918.5, to not include a no-net-increase permitting program in their attainment plan, which the AQMD did in 1997 by repealing Parts 302 and 303 of AQMD Rule 2:1. Thus, no offsets are required by the AQMD new source review air permitting program.

4 Air Quality Impacts Analysis

An ATC permit cannot be issued unless the proposed new source or modification can demonstrate that the allowable emissions will not cause or contribute to violation of any ambient air quality standard or increment. This is typically accomplished using air quality dispersion modeling to predict ambient concentrations. This chapter discusses the methodology used to develop near-field modeling used to predict pollutant concentrations attributable to project emissions in the areas surrounding the proposed facility.

4.1 Model Selection

ENVIRON reviewed regulatory modeling techniques to select the most appropriate air quality dispersion model to simulate dispersion of air pollutants emitted by the proposed project for a near-field air quality impact analysis. The selection of a modeling tool is influenced by the potential for exhaust plumes from point sources to be influenced by nearby on-site structures and to impact complex terrain. The terrain at and immediately surrounding the facility, as well as in the north and east portions of the modeling domain, is relatively flat, however, intermediate and complex terrain exists in the southwest portion of the domain. The heights of proposed and existing structures, and the proposed cogeneration unit stack height, suggests that there is the potential for exhaust plume downwash to occur.

AERMOD is currently the model recommended by the USEPA's Guideline on Air Quality Models (codified as Appendix W to 40 CFR Part 51, hereafter referred to as 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 (called the PRIME algorithm) that include the downwash effects a structure may have on an exhaust plume implicitly. 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.

AERMOD was selected for the modeling analysis primarily because it is the most up-to-date dispersion model currently available. Additionally, the modeling domains and source configurations suggested the potential for exhaust plume downwash and plume impacts on intermediate and complex terrain.

4.2 Modeling Procedures

AERMOD was applied to both criteria pollutants and TACs using the regulatory defaults in addition to the options and data discussed in this section. Electronic versions of the modeling files are provided on a compact disk in Appendix C.

4.2.1 Model Setup and Application

The most recent version of AERMOD (Version 09292) was applied with the default options for dispersion that depend on local meteorological data, regional upper air data, and the local physical characteristics of land use surrounding the facility. AERMOD contains several options for urban dispersion that were not selected for these analyses. The facility is located near, Anderson, California, and the majority of the study domain is agricultural land, rangeland, or forest. The effects of surface roughness and other physical characteristics associated with the types of land use in the modeling domain were included in the analysis as part of the meteorological database, described in Section 4.4.

4.2.2 Averaging Periods

Criteria and toxic air 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 Chemical Transformations

Per Section 6.2.3 of the Guideline, ENVIRON assumed that 75 percent of the emitted NO_X is converted to NO_2.

4.3 Elevation Data and Receptor Network

Terrain elevations for receptors and emission sources were prepared using digital elevation models (DEMs) developed by the United States Geological Survey (USGS) of four 7.5-minute quadrangles obtained from the internet (http://www.mapmart.com): Cottonwood, Enterprise, Olinda, and Redding. These data have a horizontal spatial resolution of 10 meters (m). Terrain heights surrounding the facility indicate that some of the receptors used in the simulations were located in intermediate or complex terrain (above stack or plume height). The 10-kilometer (km) square simulation domain that was used to assess near-field impacts is shown in Figure 2-2.

Receptors were spaced 500 m apart covering the simulation domain, with 200-m, 50-m, and 25-m spacing receptors grids covering 5-km, 2.5-km, and 1.25-km nested square areas centered on the facility, respectively. Receptors were also located at 25-m intervals along the facility property boundary. The final receptor locations are shown in Figure 4-1.

4.4 Meteorological Data

ENVIRON has conducted a survey of available meteorological data for use in the simulations. A representative data set was prepared using a combination of surface data from meteorological station located at the nearby Redding Municipal Airport, supplemented by National Weather Service (NWS) upper air sounding data from Medford, Oregon.

According to the Guideline, five years of representative meteorological data are considered adequate for dispersion modeling applications. Hourly wind speed, wind direction, temperature, ceiling height, and cloud cover data collected from January 1, 2004 until December 31, 2008 at Redding Municipal Airport were extracted from the National Climatic Data Center's (NCDC's) Integrated Surface Hourly Weather Observations (ISHWO). The airport is located approximately 4.5 kilometers (2.8 miles) north-northwest of the facility. A wind rose describing the wind speed and wind direction data recorded at the Redding Municipal Airport meteorological monitoring station over the entire five-year dataset is shown in Figure 4-2. The wind rose shows that the winds are generally bimodal, with winds generally coming from the north and south, following the broad Sacramento River valley. Upper air radiosonde data for the same period were obtained for the monitoring station at Medford, Oregon, approximately 215 kilometers (134 miles) north of the facility.

The meteorological data were processed using the AERMOD meteorological preprocessor, AERMET (Version 06341). AERMET was used to check parameter ranges, identify missing data, and calculate boundary layer parameters for use by AERMOD. The program replaces missing or out-of-range data with missing value flags, and AERMOD treats these periods as calms. Data recovery across the 5-year surface meteorology dataset was found to be greater than 90 percent for all variables.

Surface parameters including the surface roughness length, albedo, and Bowen ratio were determined for the area surrounding the Redding Municipal Airport meteorological tower using the AERMET preprocessor, AERSURFACE (Version 08009), and the USGS 1992 National Land Cover (NLCD92) land-use data set.[1] The NLCD92 data set used in the analysis has 30 m data point spacing and 21 land-use categories. Seasonal surface parameters were determined using AERSURFACE according to USEPA's guidance.[2]

4.5 Emission Source Release Parameters

Figure 4-3 shows the proposed location of the cogeneration unit stack, as well as significant structures that could potentially influence emissions from the stack. Table 4-1 summarizes the release parameters that were used to represent the cogeneration unit stack and the cooling towers in the simulations.

In addition to the release parameters discussed in the previous section, the building dimensions and facility configuration were provided to AERMOD to assess potential plume downwash effects. Wind-direction-specific building profiles were prepared for the modeling using the USEPA's Building Profile Input Program for the PRIME algorithm (BPIP PRIME). The facility layout and building elevations provided by SPI were used to prepare data for BPIP PRIME, which provides the necessary input data for AERMOD. Figure 4-3 shows the configuration of significant structures, including those of the adjacent lumber manufacturing facility, that were used to develop the BPIP PRIME input files, and Table 4-2 presents the heights of the significant structures included in the simulations.

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[1] The USGS NLCD92 data set is described and can be accessed at http://landcover.usgs.gov/natllandcover.php.

[2] The AERMOD Implementation Guide (USEPA, 2008) and the AERSURFACE User's Guide (EPA-454/B-08-001, January 2008).

Based on the site layout shown in Figure 4-3 and the structure heights in Table 4-2, the most significant structure affecting the cogeneration unit stack in the simulations was the boiler building, which is 115 feet (ft), or 32 m, high. For the boiler stack, good engineering practice (GEP) stacks at the same location would have to exceed the maximum creditable GEP height (213 ft or 65 m) to ensure protection against downwash. Therefore, all necessary information provided by BPIP PRIME was included in the simulations to reflect downwash effects from nearby structures on the boiler stack. A similar analysis indicated that emissions from the cooling towers would also be subject to downwash effects, and the appropriate BPIP PRIME output was included in the simulations for that source as well.

4.6 Analysis Results

To evaluate the potential ambient air pollutant concentrations (i.e., impacts on air quality) attributable to the project, the emission rates and source release parameters described in the previous sections were applied in the dispersion modeling analysis. A preliminary analysis included only the emission increase associated with the proposed cogeneration unit and cooling tower, without accounting for the decreased emissions from the existing boiler. Table 4-3 summarizes the predicted maximum concentrations and compares them to both the applicable monitoring de minimis concentrations and the Significant Impact Levels (SILs) established in USEPA’s New Source Review Workshop Manual (October 1990). The SILs represent incremental, project-specific impact levels that USEPA generally accepts as insignificant with respect to maintaining compliance with the NAAQS. As shown in Table 4-3, none of the predicted concentrations exceeded the SILs or the monitoring de minimis concentrations. Figures 4-4 through 4-11 show the spatial variations in the maximum predicted criteria pollutant concentrations, averaged over periods consistent with the applicable ambient standards. The maximum predicted receptor and concentration are also shown.

The State of California has not established screening concentrations analogous to the SILs that can be used to determine compliance with the CAAQS without combining the proposed project with background concentrations. Table 4-4 presents predicted criteria pollutant concentrations, combines them with background concentrations and compares the totals with the applicable CAAQS.

4.7 Startup Analysis

AERMOD was applied using the methodology described in the previous sections to demonstrate that the proposed CO startup emission rate will comply with both the one- and eight-hour average ambient CO standards.

Both the forced-air and the induced-draft fans in the boiler will operate throughout the startup process, but the flow will be controlled by dampers to approximately 30 percent of normal operation flow (approximately 62,000 actual cubic feet per minute). This resulted in an exhaust velocity of 20.5 feet per second. The exhaust temperature during startup will be about 250 ºF, approximately 150 ºF 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 an hourly average CO emission rate during startup of 400 lb/hr, the maximum predicted 1-hour and 8-hour average concentrations were 249 and 182 μg/m^3, respectively. To determine compliance with the NAAQS, these results were combined with background values based on the most recent maximum monitored 1-hour and 8-hour average concentrations from the CO monitor in Chico, California[3] The maximum 1-hour and 8-hour average concentrations were 3.1 ppm (approximately 3,550 μg/m^3) and 2.4 ppm (approximately 2,750 μg/m^3), respectively. Because the Anderson area is likely to be less urban than the Chico area, these background values most likely overstate the actual CO concentrations near the facility.

Using the conservative background concentrations described above, the total predicted maximum concentrations (boiler startup emissions plus background) were a 1-hour average of 3,799 μg/m^3, and an 8-hour average of 2,932 μg/m^3. These concentrations are less than the 1-hour and 8-hour average CO CAAQS of 23,000 and 10,000 μg/m^3, respectively (the corresponding NAAQS are 40,000 and 10,000 μg/m^3). Based on this analysis, the proposed hourly CO emission startup limit of 400 lb/hr will not cause of contribute to exceedances of the NAAQS or CAAQS.

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[3] Maximum CO concentrations recorded in 2008 by the CO monitor located at 468 Manzantia Ave. in Chico, California; data obtained from EPA's AirData website (http://www.epa.gov/aqspubl1/annual_summary.html)

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Tables

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Table 2-1
Proposed Cogeneration Unit Emissions

Pollutant[1]	**Emission Factor**[1] **(lb/MMBtu)**	**Emission Rate**[2]	
		(lb/hr)	**(TPY)**
NO_x	0.13	60.8	242
CO[3]	0.35/0.22	164	410
SO_2	0.005	2.34	9.32
PM_{10}	0.02	9.36	37.3
VOC/ROC	0.017	7.96	31.7
Sulfuric Acid	0.0021	0.986	3.93
Lead	1.19E-05	0.00559	0.0222

1 NO_x, CO, and PM_{10} emission factors are based on BACT. The SO_2 emission factor is based on a source test conducted on the existing boiler at the facility. The VOC/ROG emission factor is based on a vendor guarantee. The sulfuric acid (H_2SO_4) emission factor is based on the assumption that sulfate comprises 10.038 percent of PM_{10} emissions, which was obtained from USEPA's SPECIATE 3.2 Profile # 12709 for Hogged Fuel Boiler/Stoker Boiler. The lead emission factor is based on source test data used to develop the emission factor is EPA's AP-42, Section 1.6.

2 Pound per hour emission rate is based on a maximum 1-hour average heat input of 468.0 MMBtu/hr, and the tons per year emission rates is based on an annual average heat input rate of 425.4 MMBtu/hr and continuous operation (8,760 hours per year).

3 The short-term CO emission rate is based on the 0.35 lb/MMBtu emission factor resulting from the BACT analysis. The annual emission rate is based on 0.22 lb/MMBtu, which, when reduced by the baseline actual emission rate calculated for the existing boiler, allows the project to avoid PSD review (see Table 2-3).

Table 2-2
Baseline Actual Emission Rates for Existing Boiler

Pollutant	2003	2004	2005	2006	2007	2008	2009	Max 2-Year Average
NO_X[1]	74.4	79.7	77.6	74.0	75.0	66.0	64.0	78.6
CO[1]	130	125	130	181	162	130	131	172
SO_2	1.27	1.28	1.28	1.27	1.28	1.25	1.28	1.28
PM	4.70	3.20	3.18	3.16	1.04	1.02	3.55	3.95
VOC	7.31	7.10	7.03	6.29	6.62	5.59	6.89	7.20
Sulfuric Acid	0.396	0.320	0.318	0.211	0.104	0.229	0.396	0.396
Lead	0.00671	0.00652	0.00645	0.00578	0.00608	0.00513	0.00633	0.00661

1 Annual averages calculated from hourly CEMS data

2 Based on 2002 source test and hours of operation

3 Based on annual source tests (2005 and 2007 source tests were used for 2006 and 2008, respectively, because PM source tests are required every other year starting in 2005) and hours of operation

4 Based on AP-42 emission factor (0.013 lb/MMBtu), fuel use, and an assumed fuel heat content (4,118 Btu/lb, wet basis)

5 Based on the assumption that sulfate comprises 10.038 percent of PM_{10} emissions, which was obtained from USEPA's SPECIATE 3.2 Profile # 12709 for Hogged Fuel Boiler/Stoker Boiler

6 Based on emission factor derived from AP-42 source test data (1.194e-5 lb/MMBtu), fuel use, and an assumed fuel heat content (4,118 Btu/lb, wet basis)

Table 2-3 (Revised)
Project Emission Rates and BACT Thresholds

Pollutant[1]	Hourly Emission Rate[2] (lb/hr)			24-Hr Emission Rate[3] (lb/day)			AQMD BACT Thresh.[4] (lb/day)	Over BACT Thresh?
	Cogen	CT	Total	Cogen	CT	Total		
NO_x	60.8	--	60.8	1,394	--	1,394	25.0	Yes
CO	164	--	164	3,752	--	3,752	500.0	Yes
SO_2	2.34	--	2.34	54	--	54	80.0	No
PM/PM_{10}	9.36	0.251	9.61	214	6.02	220	80.0	Yes
VOC/ROG	7.96	--	7.96	182	--	182	25.0	Yes
Sulfuric Acid	0.986	--	0.986	22.6	--	22.6	35.0	No
Lead	0.00559	--	0.00559	0.128	--	0.128	3.2	No
Beryllium	0.000726	--	0.000726	0.0166	--	0.0166	0.002	Yes
Mercury	0.000195	--	0.000195	0.00446	--	0.00446	0.5	No
Vinyl Chloride	0.00861	--	0.00861	0.197	--	0.197	5.0	No

1 NO_x, CO, PM_{10}, and VOC/ROG emission factors are based on vendor guarantees, while the SO_2 emission factor is based on a source test conducted on the existing boiler at the facility. The sulfuric acid (H_2SO_4) emission factor is based on the assumption that sulfate comprises 10.038 percent of PM_{10} emissions, which was obtained from USEPA's SPECIATE 3.2 Profile # 12709 for Hogged Fuel Boiler/Stoker Boiler. Lead, beryllium, mercury, and vinyl chloride emission factors were based on the source test data used to develop the emission factors in AP-42 Section 1.6.

2 Cogeneration unit hourly emission rates are based on a maximum hourly heat input of 468.0 MMBtu/hr

3 Cogeneration unit hourly emission rates are based on a maximum 24-hour average heat input of 446.7 MMBtu/hr

4 From Shasta County AQMD Rule 2:1, Part 301.

Table 2-4 (Revised)
Project Emission Rates and BACT Thresholds

	Hourly Emission Rate[2] (lb/hr)			24-Hr Emission Rate[3] (lb/day)			AQMD BACT Thresh.[4] (lb/day)	Over BACT Thresh?
Pollutant[1]	**Cogen**	**CT**	**Total**	**Cogen**	**CT**	**Total**		
NO_x	60.8	--	60.8	1,394	--	1,394	25.0	Yes
CO	164	--	164	3,752	--	3,752	500.0	Yes
SO_2	2.34	--	2.34	53.6	--	53.6	80.0	No
PM/PM_{10}	9.36	0.251	9.61	214	6.02	220	80.0	Yes
VOC/ROG	7.96	--	7.96	182	--	182	25.0	Yes
Sulfuric Acid	0.986	--	0.986	22.6	--	22.6	35.0	No
Lead	0.00559	--	0.00559	0.128	--	0.128	3.2	No
Beryllium	0.000726	--	0.000726	0.0166	--	0.0166	0.002	Yes
Mercury	0.000195	--	0.000195	0.00446	--	0.00446	0.5	No
Vinyl Chloride	0.00861	--	0.00861	0.197	--	0.197	5.0	No

1 NO_x, CO, PM_{10}, and VOC/ROG emission factors are based on vendor guarantees, while the SO_2 emission factor is based on a source test conducted on the existing boiler at the facility. The sulfuric acid (H_2SO_4) emission factor is based on the assumption that sulfate comprises 10.038 percent of PM_{10} emissions, which was obtained from USEPA's SPECIATE 3.2 Profile # 12709 for Hogged Fuel Boiler/Stoker Boiler. Lead, beryllium, mercury, and vinyl chloride emission factors were based on the source test data used to develop the emission factors in AP-42 Section 1.6.

2 Cogeneration unit hourly emission rates are based on a maximum hourly heat input of 468.0 MMBtu/hr

3 Cogeneration unit hourly emission rates are based on a maximum 24-hour average heat input of 446.7 MMBtu/hr

4 From Sierra County AQMD Rule 2:1, Part 301.

Table 2-5
Cogeneration Unit Toxic Air Contaminant Emission Rates

Compound	CAS No.	Emission Factor (lb/MMBtu)	Emission Rate		
			(lb/hr)[1]	(lb/day)[2]	(lb/yr)[3]
Acenaphthene	83-32-9	7.25E-09	0.00000339	0.0000777	0.027
Acenaphthylene	208-96-8	1.54E-06	0.000719	0.0165	5.73
Acetaldehyde	75-07-0	1.99E-04	0.093	2.13	741
Acetone	67-64-1	1.62E-04	0.0758	1.74	604
Acetophenone	98-86-2	3.23E-09	0.00000151	0.0000346	0.012
Acrolein	107-02-8	3.15E-05	0.0148	0.338	118
Ammonia[4]	7664-41-7	2.02E-02	9.46	217	75,300
Anthracene	120-12-7	4.95E-08	0.0000232	0.000531	0.185
Antimony	7440-36-0	4.61E-07	0.000215	0.00494	1.72
Arsenic	7440-38-2	4.94E-07	0.000231	0.0053	1.84
Barium	7440-39-3	1.52E-04	0.0711	1.63	567
Benzaldehyde	100-52-7	8.45E-07	0.000395	0.00906	3.15
Benzene	71-43-2	8.61E-04	0.403	9.23	3,210
Benzo(a)anthracene	56-55-3	2.52E-09	0.00000118	0.000027	0.00938
Benzo(a)pyrene	50-32-8	3.27E-09	0.00000153	0.0000351	0.0122
Benzo(b)fluoranthene	205-99-2	2.35E-09	0.0000011	0.0000252	0.00876
Benzo(e)pyrene	192-97-2	2.59E-09	0.00000121	0.0000278	0.00966
Benzo(g,h,i)perylene	191-24-2	4.62E-09	0.00000216	0.0000496	0.0172
Benzo(j)fluoranthene	205-82-3	1.56E-07	0.0000728	0.00167	0.58
Benzo(k)fluoranthene	207-08-9	2.38E-09	0.00000111	0.0000255	0.00888
Benzoic Acid	65-85-0	4.68E-08	0.0000219	0.000502	0.174
Beryllium	7440-41-7	1.55E-06	0.000726	0.0166	5.78
Bis(2-ethylhexyl)phthalate	117-81-7	4.65E-08	0.0000218	0.000499	0.173
Bromomethane	74-83-9	2.80E-05	0.0131	0.3	104
2-Butanone (MEK)	78-93-3	5.39E-06	0.00252	0.0578	20.1
Cadmium	7440-43-9	2.59E-06	0.00121	0.0278	9.65
Carbazole	86-74-8	1.79E-06	0.000838	0.0192	6.67
Carbon Dioxide (CO_2)[5]	37210-16-5	2.07E+02	96800	2,220,000	771,000,000
Carbon Tetrachloride	56-23-5	4.54E-05	0.0212	0.487	169
Chlorine	7782-50-5	7.92E-04	0.371	8.49	2,950

Compound	CAS No.	Emission Factor (lb/MMBtu)	Emission Rate		
			(lb/hr)[1]	(lb/day)[2]	(lb/yr)[3]
Chlorobenzene	108-90-7	3.32E-05	0.0155	0.356	124
Chloroform	67-66-3	2.75E-05	0.0129	0.295	103
Chloromethane	74-87-3	2.31E-05	0.0108	0.248	86.1
2-Chloronaphthalene	91-58-7	2.41E-09	0.00000113	0.0000258	0.00896
2-Chlorophenol	108-43-0	3.37E-08	0.0000158	0.000362	0.126
Chromium, hexavalent[4]	18540-29-9	1.75E-07	0.000082	0.00188	0.653
Chromium, trivalent	7440-47-3	1.24E-06	0.000582	0.0133	4.63
Chrysene	218-01-9	2.75E-09	0.00000129	0.0000295	0.0103
Cobalt	7440-48-4	8.93E-06	0.00418	0.0958	33.3
Copper	7440-50-8	4.11E-06	0.00192	0.044	15.3
Crotonaldehyde	4170-30-3	9.91E-06	0.00464	0.106	36.9
Decachlorobiphenyl	2051-24-3	2.65E-10	0.000000124	0.00000284	0.000988
Dibenzo(a,h)anthracene	53-70-3	2.35E-09	0.0000011	0.0000252	0.00875
1,2-Dibromoethene	106-93-4	5.48E-05	0.0256	0.587	204
Dichlorobiphenyl	2050-68-2	3.79E-10	0.000000177	0.00000406	0.00141
1,2-Dichloroethane	107-06-2	2.92E-05	0.0137	0.313	109
Dichloromethane	75-09-2	2.87E-04	0.134	3.08	1,070
1,2-Dichloropropane	78-87-5	3.33E-05	0.0156	0.357	124
2,4-Dinitrophenol	51-28-5	9.33E-08	0.0000436	0.001	0.348
Ethylbenzene	100-41-4	3.13E-05	0.0146	0.336	117
Fluoranthene	206-44-0	5.17E-07	0.000242	0.00554	1.93
Fluorene	86-73-7	5.31E-08	0.0000248	0.000569	0.198
Formaldehyde	50-00-0	1.96E-03	0.917	21	7,300
Heptachlorobiphenyl	28655-71-2	6.57E-11	3.07E-08	0.000000704	0.000245
Hexachlorobiphenyl	26601-64-9	2.89E-10	0.000000135	0.0000031	0.00108
HpCDD-Total	37871-00-4	3.09E-11	1.44E-08	0.000000331	0.000115
HpCDF-Total	38998-75-3	6.40E-12	2.99E-09	6.86E-08	0.0000238
HxCDD-Total	34465-46-8	8.55E-11	0.00000004	0.000000917	0.000319
HxCDF-Total	55684-94-1	1.53E-11	7.18E-09	0.000000164	0.0000571
Hexanal	66-25-1	6.96E-06	0.00326	0.0746	25.9
Hydrogen chloride	7647-01-0	3.52E-03	1.65	37.8	13,100
Indeno(1,2,3-c,d)pyrene	193-39-5	2.37E-09	0.00000111	0.0000255	0.00885

Compound	CAS No.	Emission Factor (lb/MMBtu)	Emission Rate		
			(lb/hr)[1]	(lb/day)[2]	(lb/yr)[3]
Iron	7439-89-6	9.93E-04	0.465	10.6	3,700
Isobutyraldehyde	78-84-2	1.15E-05	0.00538	0.123	42.9
Lead	7439-92-1	1.19E-05	0.00559	0.128	44.5
Manganese	7439-96-5	1.16E-04	0.0541	1.24	431
Mercury	7439-97-6	4.16E-07	0.000195	0.00446	1.55
Methane[5]	74-82-8	7.05E-02	33	756	263,000
Methanol[6]	67-56-1	8.30E-04	0.388	8.9	3,090
2-Methylnaphthalene	91-57-6	2.75E-07	0.000129	0.00295	1.02
Molybdenum	7439-98-7	1.13E-06	0.000526	0.0121	4.19
Monochlorobiphenyl	2051-60-7	2.18E-10	0.000000102	0.00000234	0.000812
Naphthalene	91-20-3	8.51E-05	0.0398	0.913	317
Nickel	7440-02-0	2.84E-06	0.00133	0.0304	10.6
Nitric Oxide (NO)[7]	10102-43-9	1.30E-01	60.8	1390	484,000
2-Nitrophenol	88-75-5	1.06E-07	0.0000497	0.00114	0.396
4-Nitrophenol	100-02-7	1.71E-07	0.0000801	0.00184	0.638
Nitrous Oxide (N_2O)[5]	10024-97-2	9.26E-03	4.33	99.3	34,500
OCDD	3268-87-9	2.34E-10	0.000000109	0.00000251	0.000871
OCDF	39001-02-0	1.43E-11	6.67E-09	0.000000153	0.0000531
PeCDD-Total	36088-22-9	1.72E-10	8.03E-08	0.00000184	0.000639
PeCDF-Total	30402-15-4	4.19E-11	1.96E-08	0.000000449	0.000156
Pentachlorobiphenyl	25429-29-2	6.49E-10	0.000000304	0.00000696	0.00242
Pentachlorophenol	87-86-5	2.27E-08	0.0000106	0.000243	0.0846
Perylene	198-55-0	5.18E-10	0.000000242	0.00000555	0.00193
Phenanthrene	86-01-8	1.69E-06	0.000793	0.0182	6.32
Phenol	108-95-2	1.25E-05	0.00587	0.134	46.7
Phosphorus	7723-14-0	3.54E-05	0.0166	0.38	132
Potassium	7440-09-7	3.88E-02	18.2	416	145,000
Propionaldehyde	123-38-6	3.15E-06	0.00147	0.0338	11.7
Pyrene	129-00-0	2.99E-07	0.00014	0.00321	1.11
Selenium	7782-49-2	3.38E-06	0.00158	0.0363	12.6
Sodium	7440-23-5	3.63E-04	0.17	3.89	1,350
Strontium	7440-24-6	1.01E-05	0.00471	0.108	37.5

Compound	CAS No.	Emission Factor (lb/MMBtu)	Emission Rate		
			(lb/hr)[1]	(lb/day)[2]	(lb/yr)[3]
Sulfuric Acid[7]	7664-93-9	2.11E-03	0.986	22.6	7,860
TCDD-Total	1746-01-6	2.05E-10	9.57E-08	0.00000219	0.000762
TCDF-Total	30402-14-3	1.63E-10	0.000000076	0.00000174	0.000606
Tetrachlorobiphenyl	26914-33-0	1.60E-09	0.000000749	0.0000172	0.00596
Tetrachloroethene	127-18-4	3.82E-05	0.0179	0.41	142
Tin	7440-31-5	3.91E-05	0.0183	0.419	146
Titanium	7440-32-6	2.01E-05	0.00941	0.215	74.9
o-Tolualdehyde	529-20-4	7.15E-06	0.00335	0.0767	26.6
p-Tolualdehyde	104-87-0	1.13E-05	0.00529	0.121	42.1
Toluene	108-88-3	2.13E-05	0.00994	0.228	79.2
Trichlorobiphenyl	15862-07-4	1.78E-09	0.000000833	0.0000191	0.00663
1,1,1-Trichloroethane	71-55-6	3.07E-05	0.0144	0.329	115
Trichloroethene	79-01-6	3.03E-05	0.0142	0.325	113
Trichlorofluoromethane	75-69-4	4.05E-05	0.019	0.434	151
2,4,6-Trichlorophenol	88-06-2	1.14E-08	0.00000531	0.000122	0.0423
Vanadium	1314-62-1	5.94E-07	0.000278	0.00637	2.21
Vinyl Chloride	75-01-4	1.84E-05	0.00861	0.197	68.6
Xylene	1330-20-7	2.45E-05	0.0115	0.262	91.2
Yttrium	7440-65-5	3.01E-07	0.000141	0.00323	1.12
Zinc	7440-66-6	1.74E-04	0.0814	1.86	648

1 Based on a maximum hourly heat input rate of 468.0 MMBtu/hr.

2 Based on a maximum daily average heat input rate of 446.7 MMBtu/hr and continuous 24-hour operation.

3 Based on an annual average heat input rate of 425.4 MMBtu/hr and 8,760 hours of operation per year.

4 Based on 20 ppm exhaust concentration

5 CO_2, CH_4, and N_2O emission factors taken from 40 CFR 98, Subpart C, Table C-1.

6 Methanol emission factor for wood-fired boilers from NCASI Technical Bulletin No. 858 (February 2003).

7 100 percent of NO_X was assumed be NO, which is conservative because 75 percent of NO_X was assumed to be converted to NO_2.

Table 3-1 (Revised)
Hazardous Air Pollutant Emission Rates

Compound	CAS No.	Emission Rate[1]	Compound	CAS No.	Emission Rate[1]
Acetaldehyde[2]	75-07-0	7.77	Formaldehyde[2]	50-00-0	3.82
Acetophenone	98-86-2	6.01E-06	Hydrogen chloride	7647-01-0	6.57
Acrolein[2]	107-02-8	0.156	Lead	7439-92-1	0.0222
Antimony	7440-36-0	0.000858	Manganese	7439-96-5	0.215
Arsenic	7440-38-2	0.000920	Mercury	7439-97-6	0.000775
Benzene	71-43-2	1.60	Methanol[2]	67-56-1	5.39
Beryllium	7440-41-7	0.00289	Naphthalene	91-20-3	0.159
Bis(2-ethylhexyl)phthalate	117-81-7	8.66E-05	Nickel	7440-02-0	0.00529
Bromomethane	74-83-9	0.0522	4-Nitrophenol	100-02-7	0.000319
2-Butanone (MEK)	78-93-3	0.0100	Pentachlorophenol	87-86-5	4.23E-05
Cadmium	7440-43-9	0.00483	Phenol	108-95-2	0.101
Carbon Tetrachloride	56-23-5	0.0846	Phosphorus	7723-14-0	0.0660
Chlorine	7782-50-5	1.48	Propionaldehyde[2]	123-38-6	0.0736
Chlorobenzene	108-90-7	0.0619	Selenium	7782-49-2	0.00630
Chloroform	67-66-3	0.0513	TCDD-Total	1746-01-6	3.81E-07
Chloromethane	74-87-3	0.0430	Tetrachloroethene	127-18-4	0.0712
Chromium, trivalent	7440-47-3	0.00232	Toluene	108-88-3	0.0396
Cobalt	7440-48-4	0.0166	1,1,1-Trichloroethane	71-55-6	0.0573
1,2-Dibromoethene	106-93-4	0.102	Trichloroethene	79-01-6	0.0565
1,2-Dichloroethane	107-06-2	0.0544	2,4,6-Trichlorophenol	88-06-2	2.11E-05
Dichloromethane	75-09-2	0.539	Vinyl Chloride	75-01-4	0.0343
1,2-Dichloropropane	78-87-5	0.0620	Xylene	1330-20-7	0.0456
2,4-Dinitrophenol	51-28-5	0.000174	Total HAPs		30.3
Ethylbenzene	100-41-4	0.0583	Maximum Ind. HAP		7.77

1 All emission rates in tons per year (tpy).

2 Cogeneration unit and lumber dry kiln emission rates combined.

Table 4-1
Point Source Release Parameters

Source	Height (ft)	Diameter (ft)	Exit Velocity (ft/s)	Temperature (°F)
Proposed Cogeneration Unit	115	8.0	68.4	400
Cooling Tower (each of 2 cells)	41	31.6	24.2	91

Table 4-2
Structure Heights

Structure	Height	
	(feet)	(meters)
Truck Shop	16	4.88
Equipment Shop	27	8.23
Fabrication Shop	43	13.11
Warehouse	32	9.75
Dry Shed	52	15.85
Planer	60	18.29
Kilns	24	7.32
Existing Cooling Tower	30	9.14
Diesel Fuel	16	4.88
Forestry Lab	29	8.84
Lumber Storage Shed	26	7.92
Existing Boiler	43	13.11
Sawmill	54	16.46
Chipper/Hog	29	8.84
Fuel House	52	15.85
Turbine	40	12.19
Proposed Cooling Tower	30	9.14
Proposed Boiler	115	35.05
Proposed Economizer	50	15.24
ESP	50	15.24
Truck Shop	16	4.88

Table 4-3
Criteria Pollutant NAAQS Compliance Assessment

Pollutant	Averaging Period	Maximum Predicted[1]	SIL[1,2]	Over SIL?	Monitoring de Minimis[1,3]	Over de Minimis?
NO_2[4]	Annual	0.906	1	No	14	No
CO	1-Hour	86.3	2,000	No	--	--
	8-Hour	63.0	500	No	575	No
PM_{10}	24-Hour	1.43	5	No	10	No
	Annual	0.213	1	No	--	--
$PM_{2.5}$[5]	24-Hour	1.43	--	--	--	--
	Annual	0.213	--	--	--	--
SO_2	3-Hour	2.04	25	No	--	--
	24-Hour	1.09	5	No	13	No
	Annual	0.149	1	No	--	--

1 Concentrations are in micrograms per cubic meter (μg/m^3)

2 SIL = Significant Impact Level, from USEPA's New Source Review Workshop Manual (October, 1990), Table C-4.

3 Monitoring de Minimis concentrations from 40 CFR 52.21(i)(8)(i).

4 NO_2 was assumed to be 75 percent of the emitted NO_X based on guidance in Section 6.2.3 of the USEPA's Guideline on Air Quality Models (codified as Appendix W to 40 CFR Part 51).

5 SILs and monitoring de minimis concentrations have not yet been established for $PM_{2.5}$. A NAAQS compliance assessment was performed by combining the modeling $PM_{2.5}$ concentrations (which assume that all PM_{10} is $PM_{2.5}$) with the most recent maximum concentrations from the monitor on the roof of the Redding Department of Health (24-hour average – 20.2 μg/m^3, and annual average – 5.49 μg/m^3), gives total concentrations of 21.7 μg/m^3 (24-hour average) and 5.73 μg/m^3 (annual average), which are less than the applicable NAAQS (24-hour average – 35 μg/m^3, and annual average – 15 μg/m^3).

Table 4-4
Criteria Pollutant CAAQS Compliance Assessment

Pollutant	Averaging Period	Maximum Predicted[1]	Background[2]	Total[3]	CAAQS	Over CAAQS?
NO_2[4]	1-Hour	14.0	80.9	94.9	339	No
	Annual	0.906	15.0	15.1	57	No
CO	1-Hour	86.3	3,550	3,636	23,000	No
	8-Hour	63.0	2,750	2,813	10,000	No
PM_{10}	24-Hour	1.43	37.0	38.4	50	No
	Annual	0.213	18.2	18.4	20	No
$PM_{2.5}$[5]	Annual	0.213	5.49	5.70	12	No
SO_2	1-Hour	2.30	7.85	10.1	655	No
	24-Hour	1.09	5.23	6.32	105	No

1 Concentrations are in micrograms per cubic meter (μg/m^3)

2 Background concentrations are the most recent maximum monitored concentrations (with exceptional event data removed, where applicable) from the following stations and years:

NO_2 & CO: Chico – Manzanita Ave; 2008
PM_{10}: Anderson – North Street; 2009
$PM_{2.5}$: Redding – Health Department Roof; 2009
SO_2: North Highlands – Blackfoot Way; 2009
Monitoring data are from EPA's AirData website (http://www.epa.gov/aqspubl1/annual_summary.html)

3 Total = Maximum Predicted + Background

4 NO_2 was assumed to be 75 percent of the emitted NO_X based on guidance in Section 6.2.3 of the USEPA's Guideline on Air Quality Models (codified as Appendix W to 40 CFR Part 51).

5 All PM_{10} was assumed to be $PM_{2.5}$

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Figures

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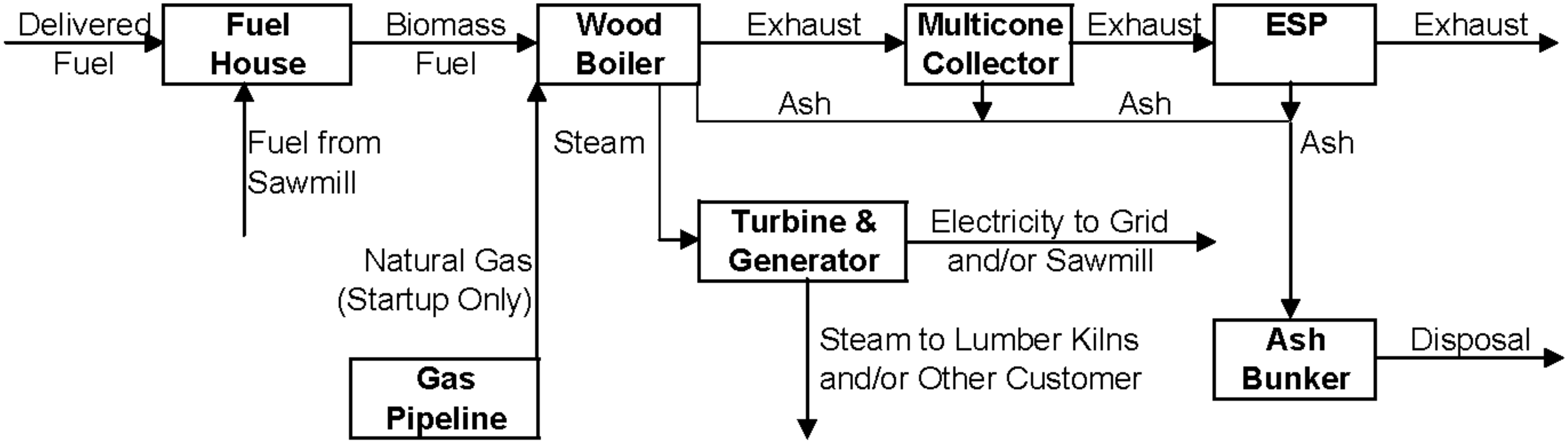

Figure 2-1. Project Schematic Flow Diagram

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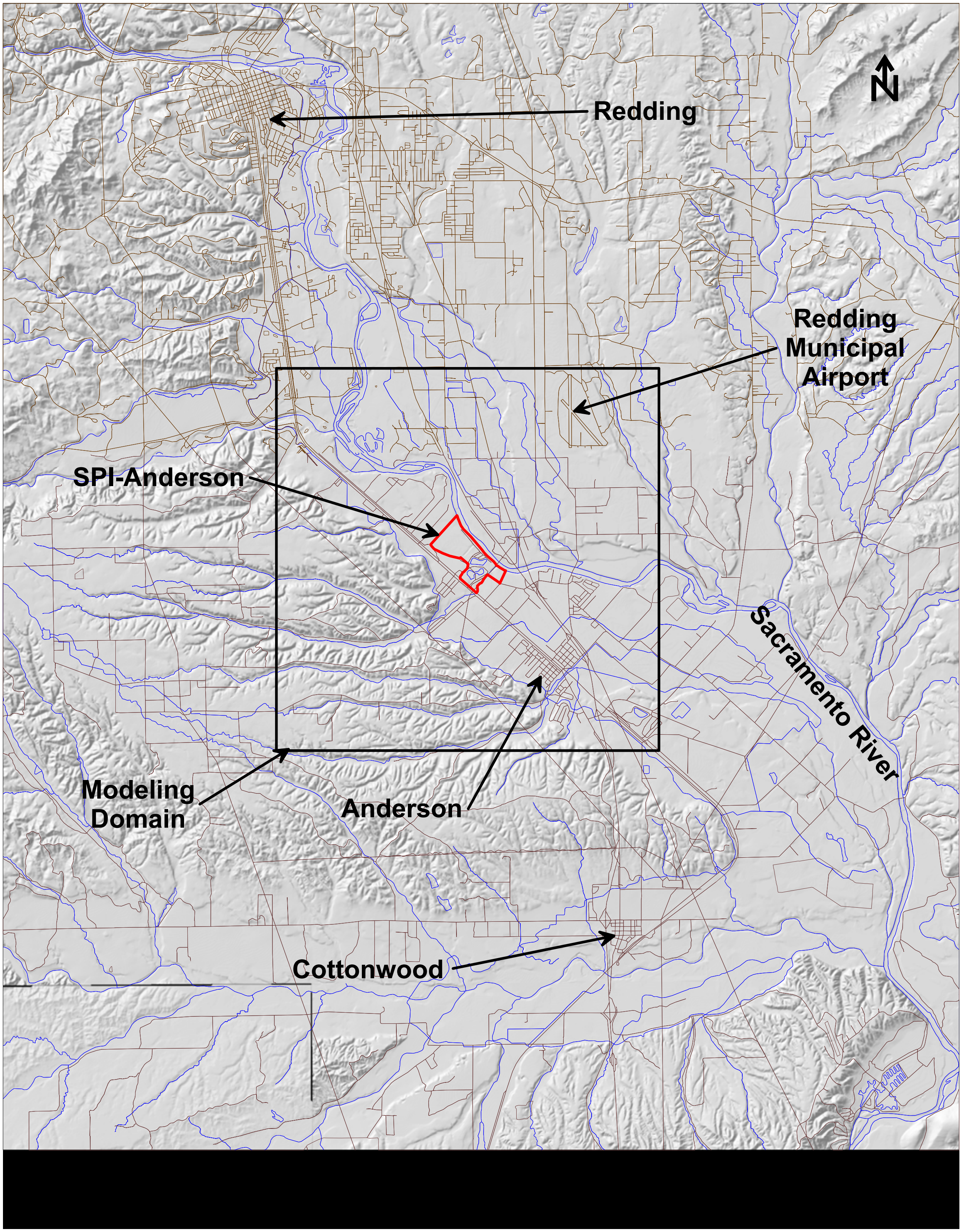

Figure 2-2. Vicinity of Facility and Modeling Domain

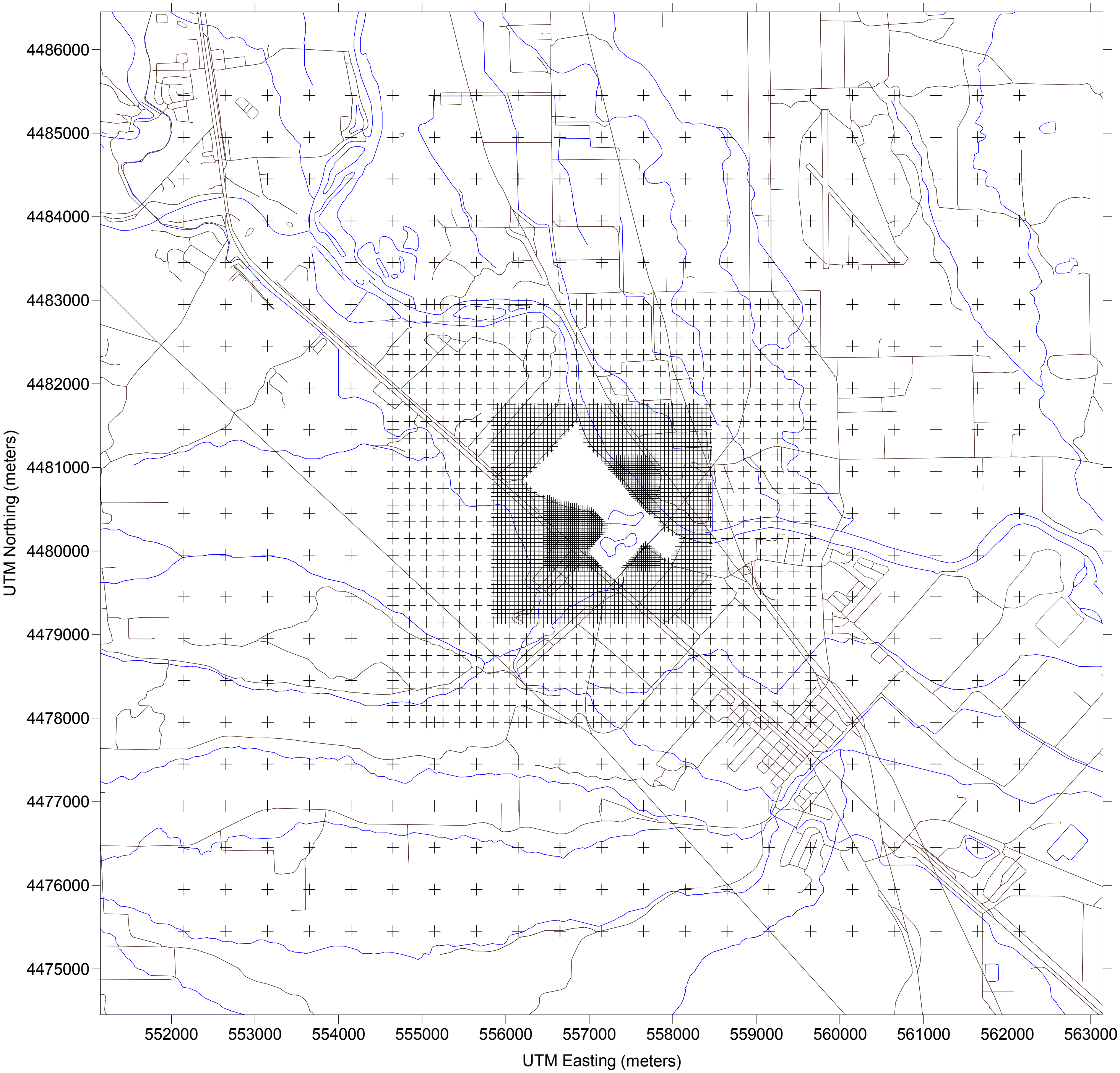

Figure 4-1. Final Receptor Locations

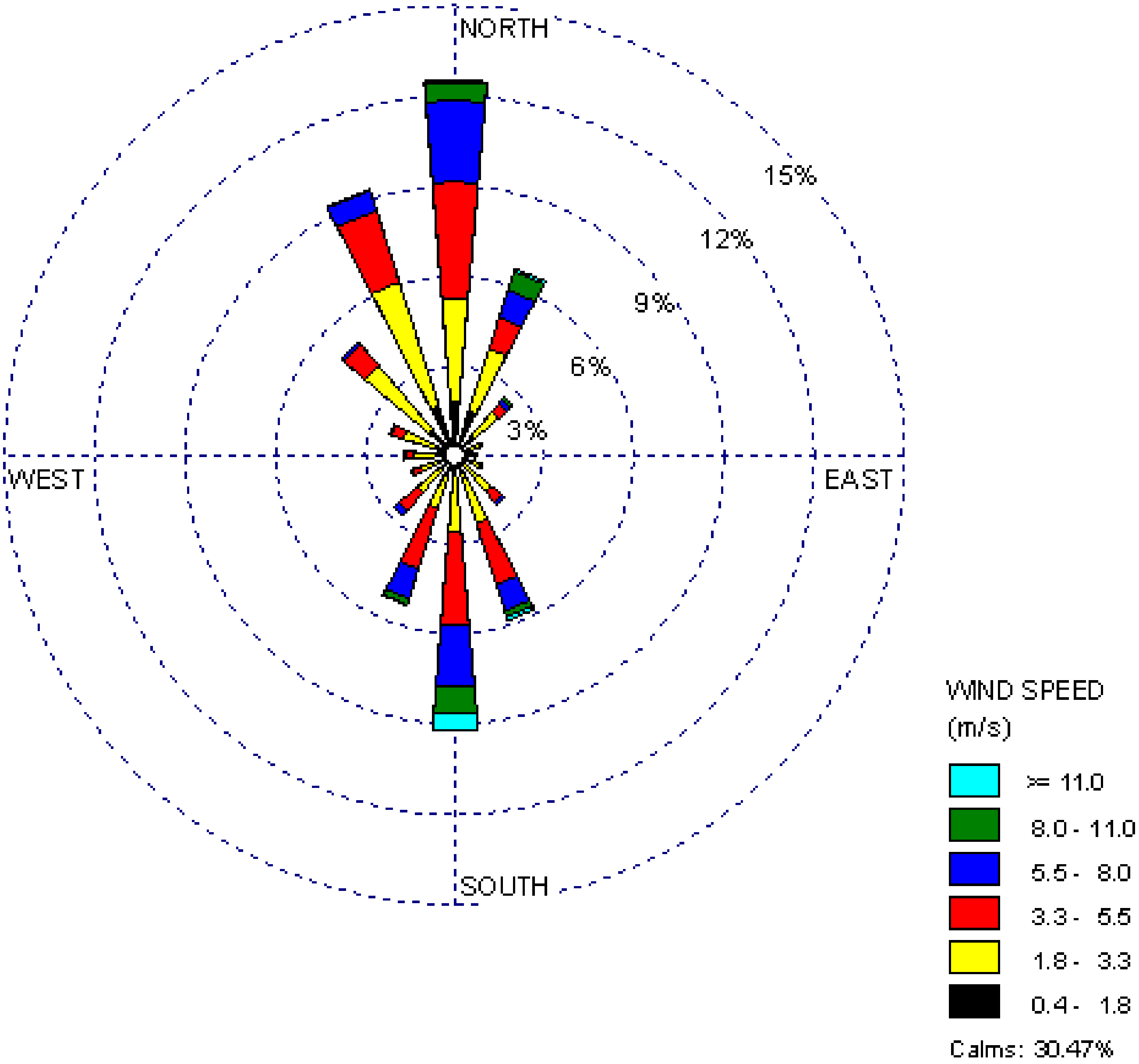

Figure 4-2. Wind Rose, Redding Municipal Airport, Jan. 2004 to Dec. 2008

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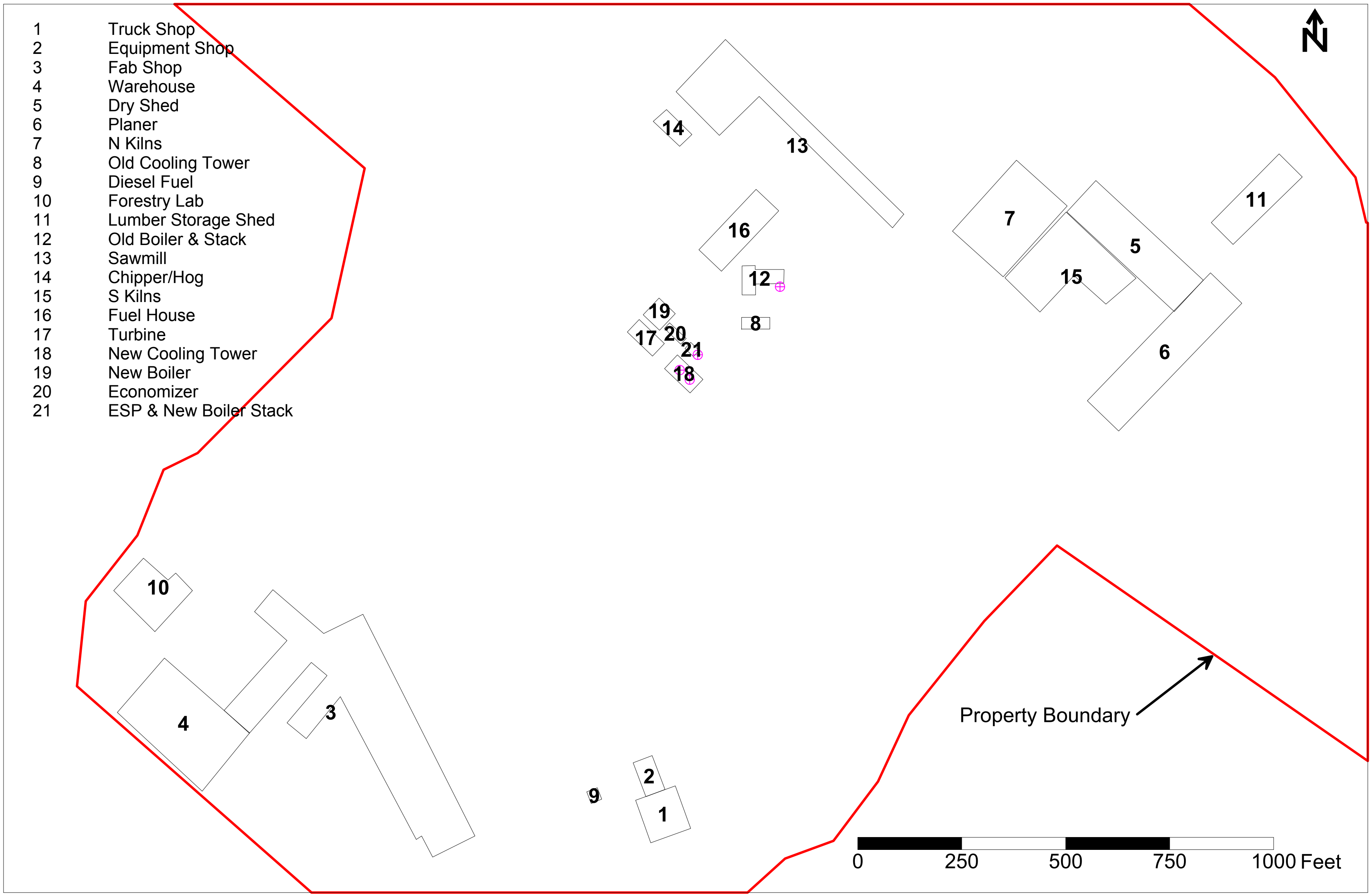

Figure 4-3. Source and Significant Structure Locations

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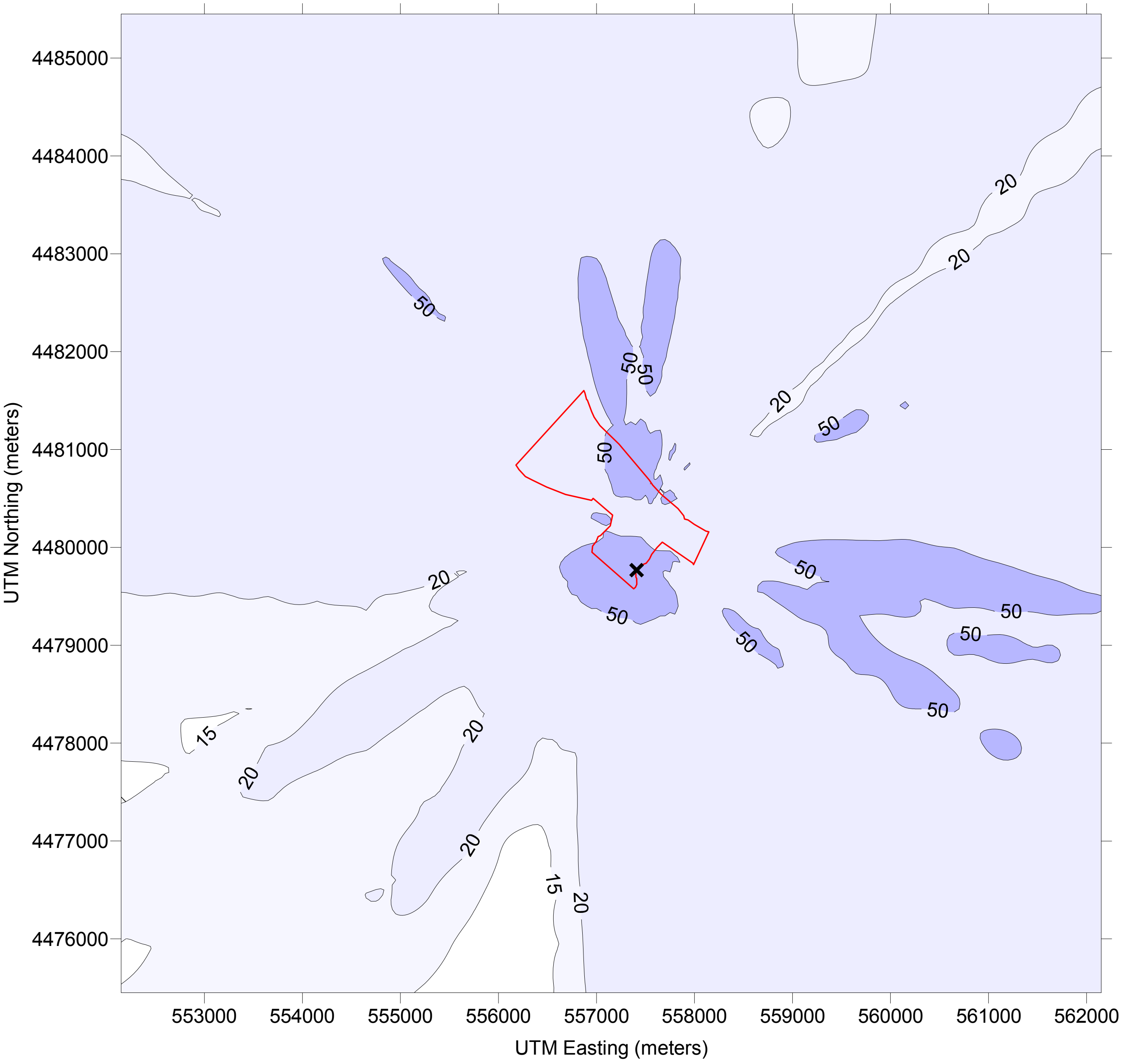
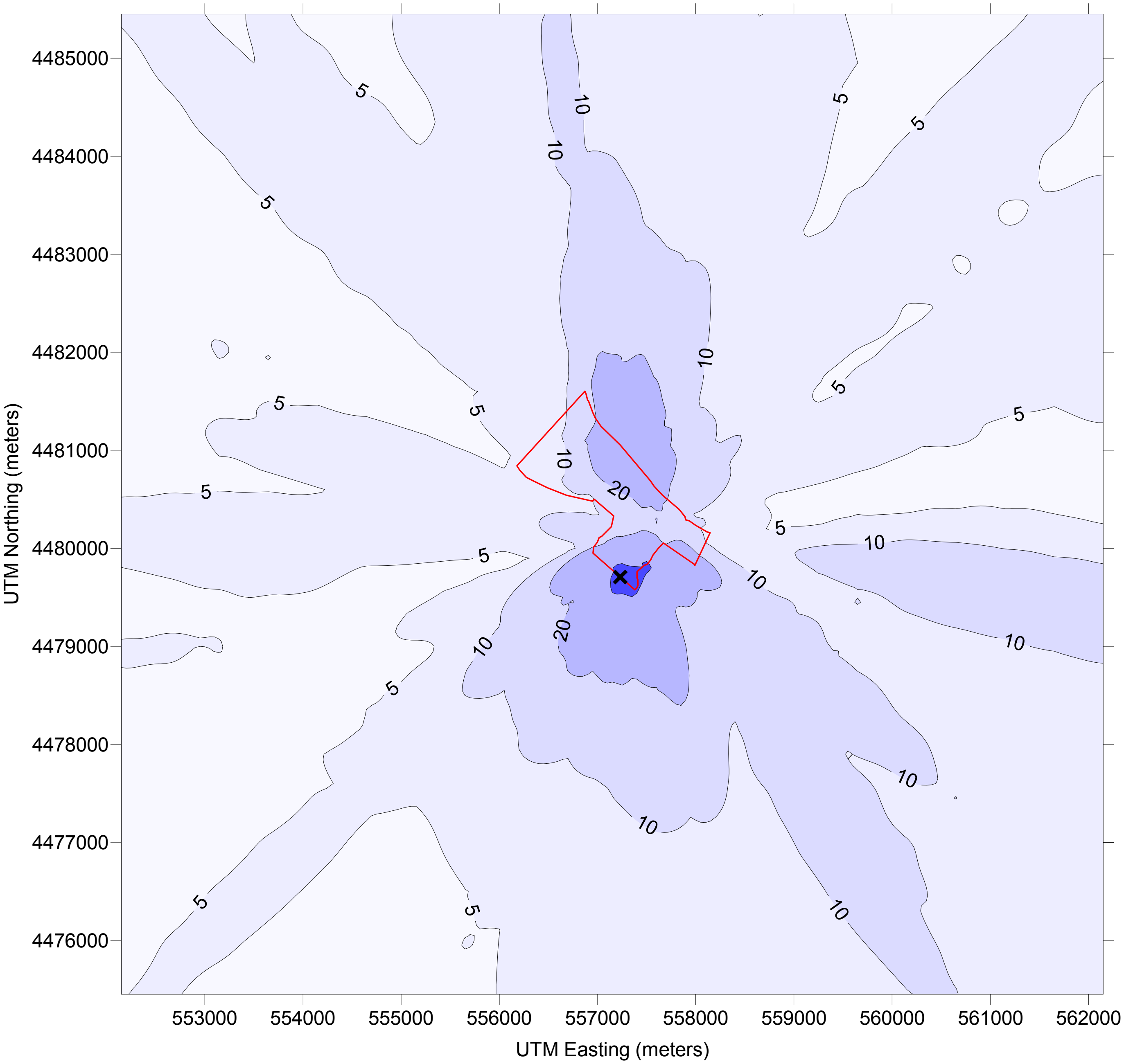


✕ = maximum predicted concentration (86.3 µg/m3)

Concentration isopleths in micrograms per cubic meter (µg/m^3)

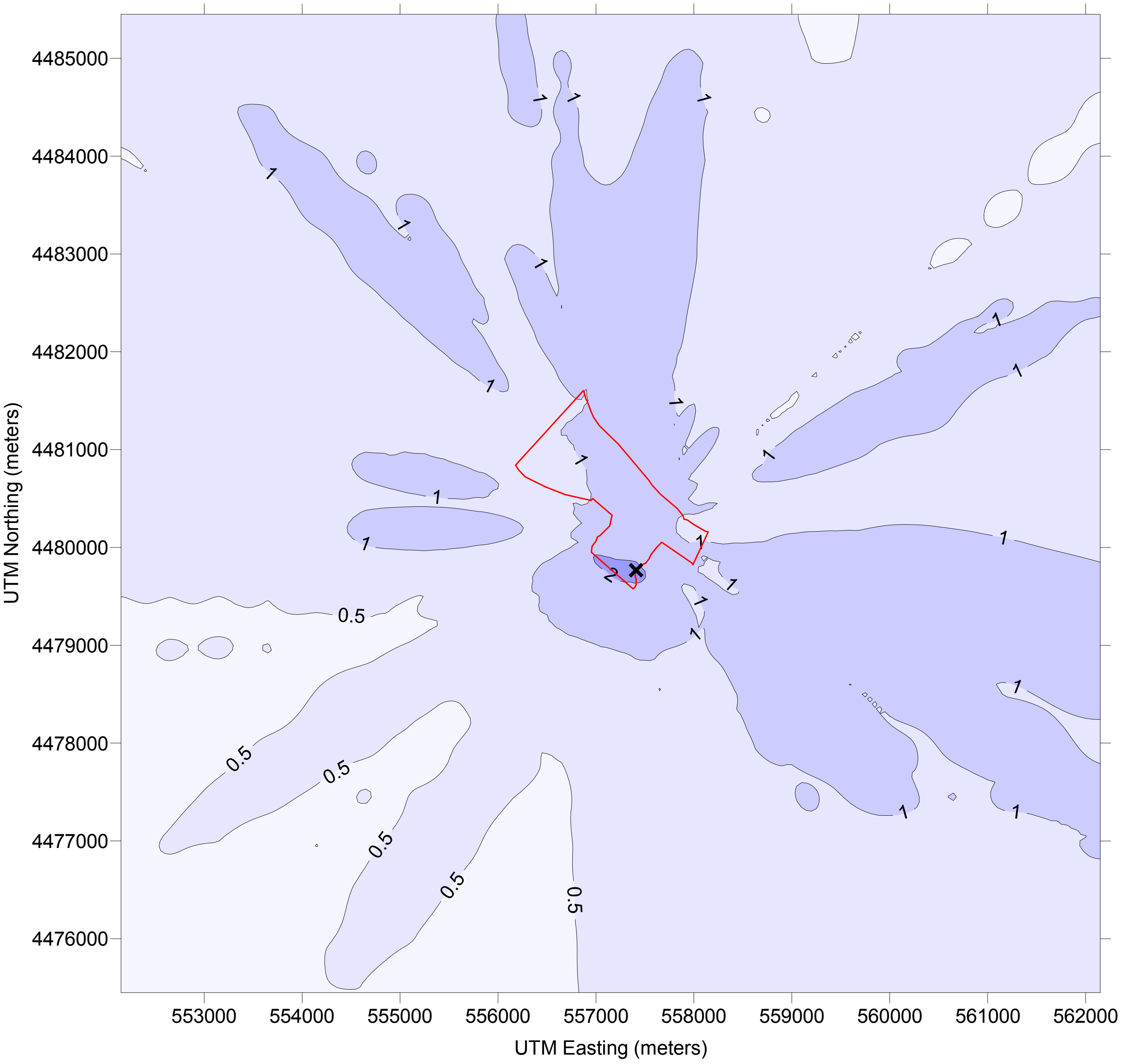
Figure 4-4. Maximum Predicted 1-Hour Average CO Concentrations



✕ = maximum predicted concentration (63.0 µg/m3)

Concentration isopleths in micrograms per cubic meter (µg/m^3)

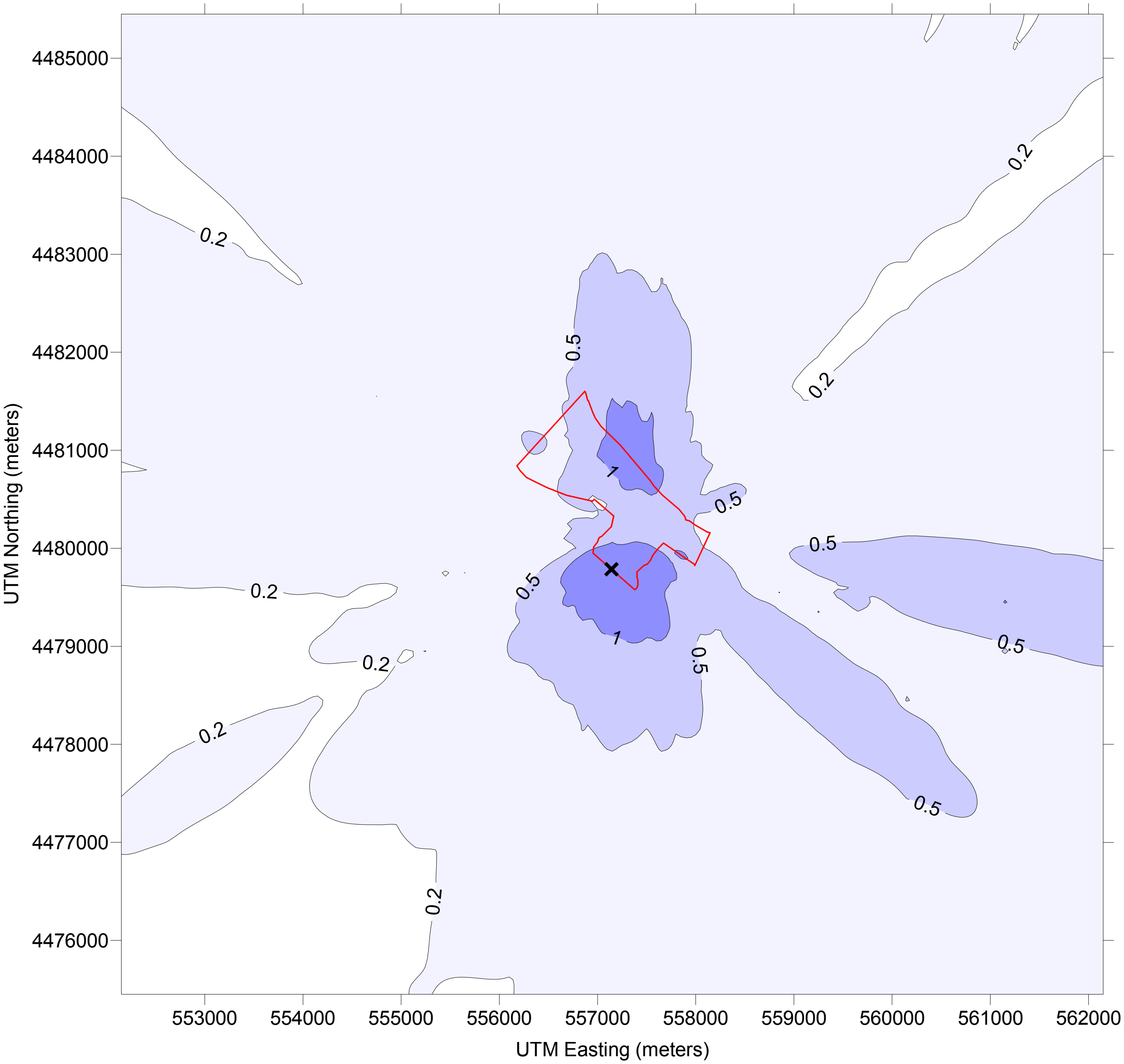
Figure 4-5. Maximum Predicted 8-Hour Average CO Concentrations



✕ = maximum predicted concentration (2.30 µg/m3)

Concentration isopleths in micrograms per cubic meter (µg/m^3)

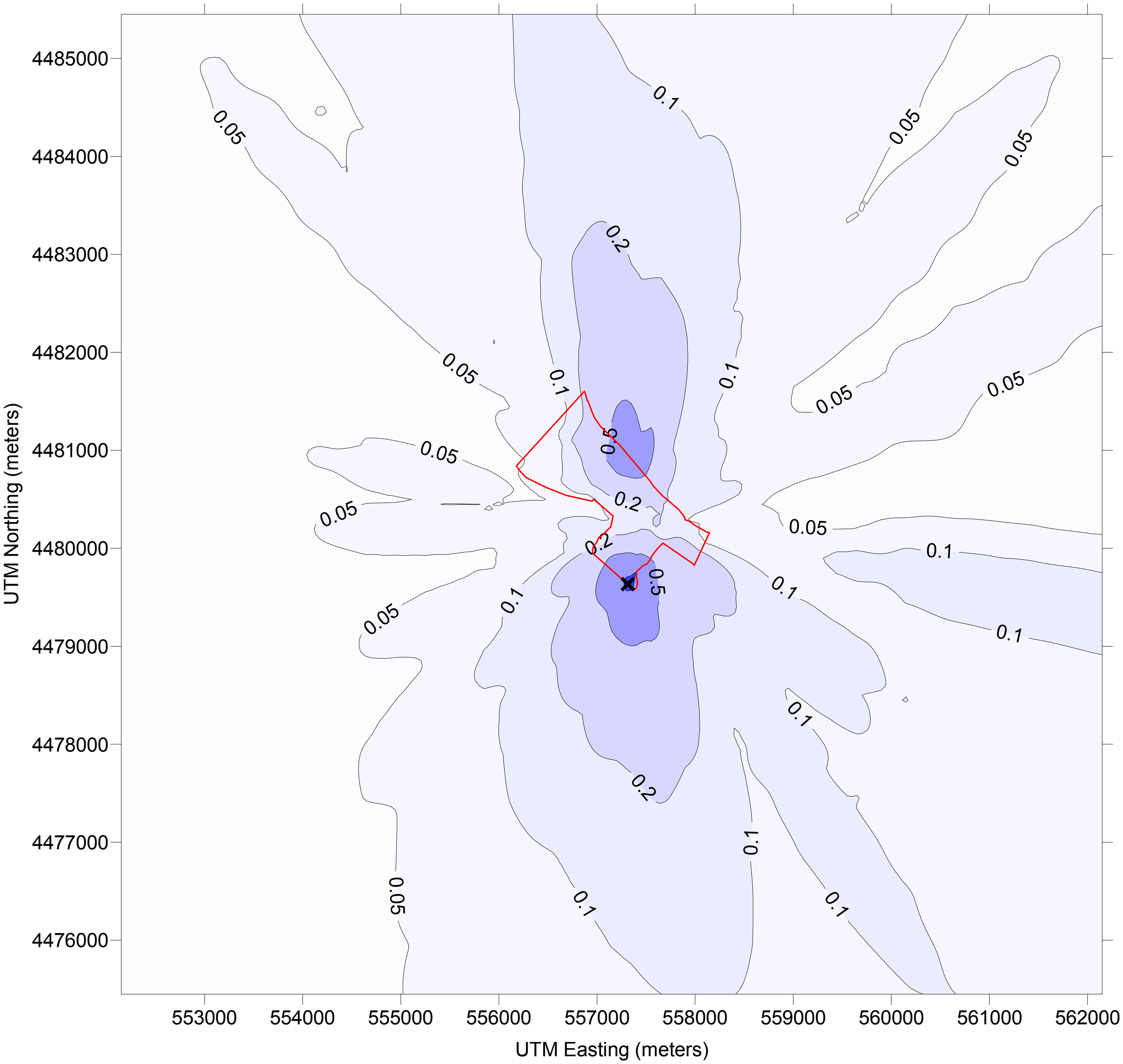
Figure 4-6. Maximum Predicted 1-Hour Average SO_2 Concentrations



× = maximum predicted concentration (2.04 µg/m3)

Concentration isopleths in micrograms per cubic meter (µg/m^3)

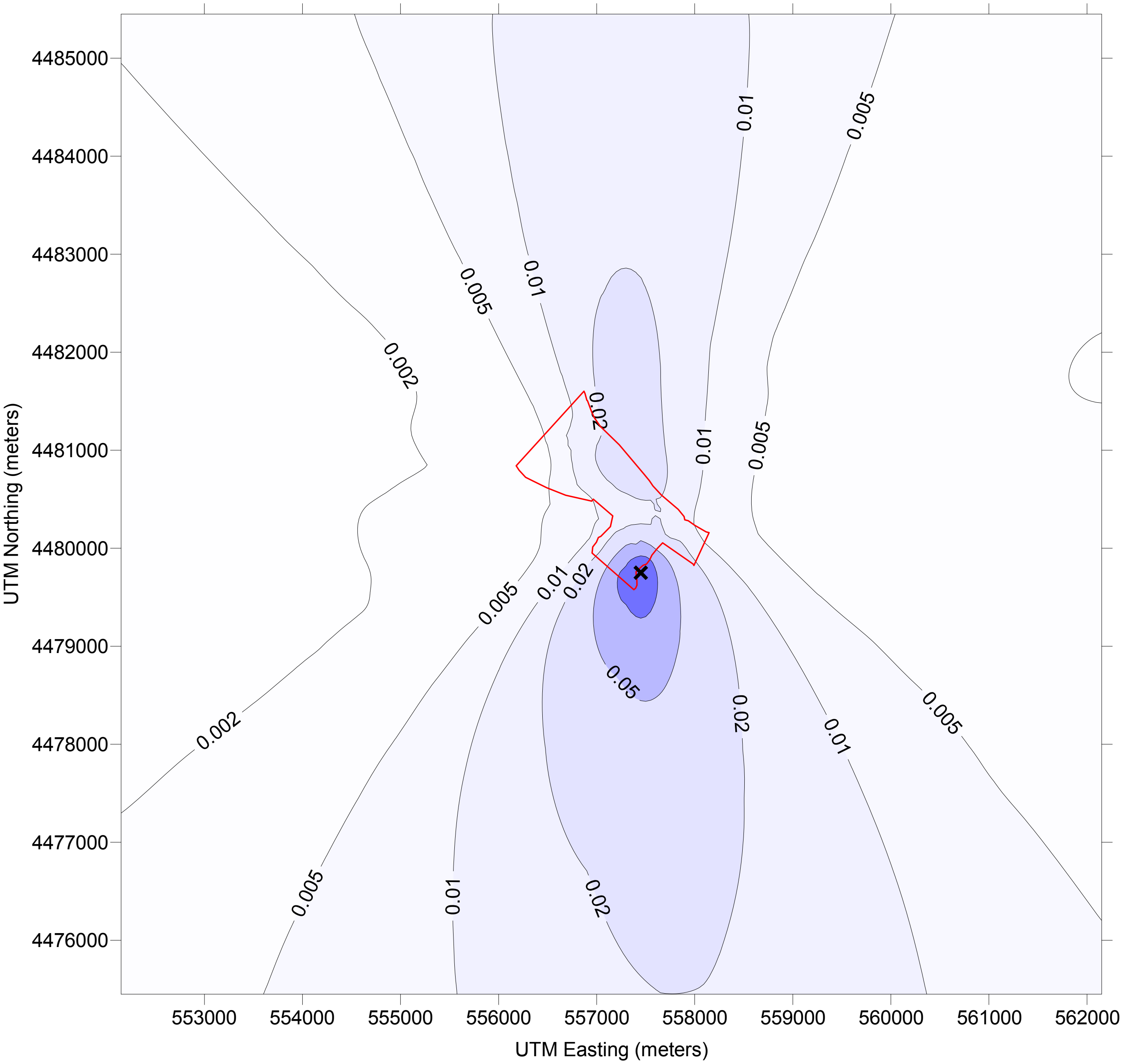
Figure 4-7. Maximum Predicted 3-Hour Average SO_2 Concentrations



✕ = maximum predicted concentration (1.09 µg/m3)

Concentration isopleths in micrograms per cubic meter (µg/m^3)

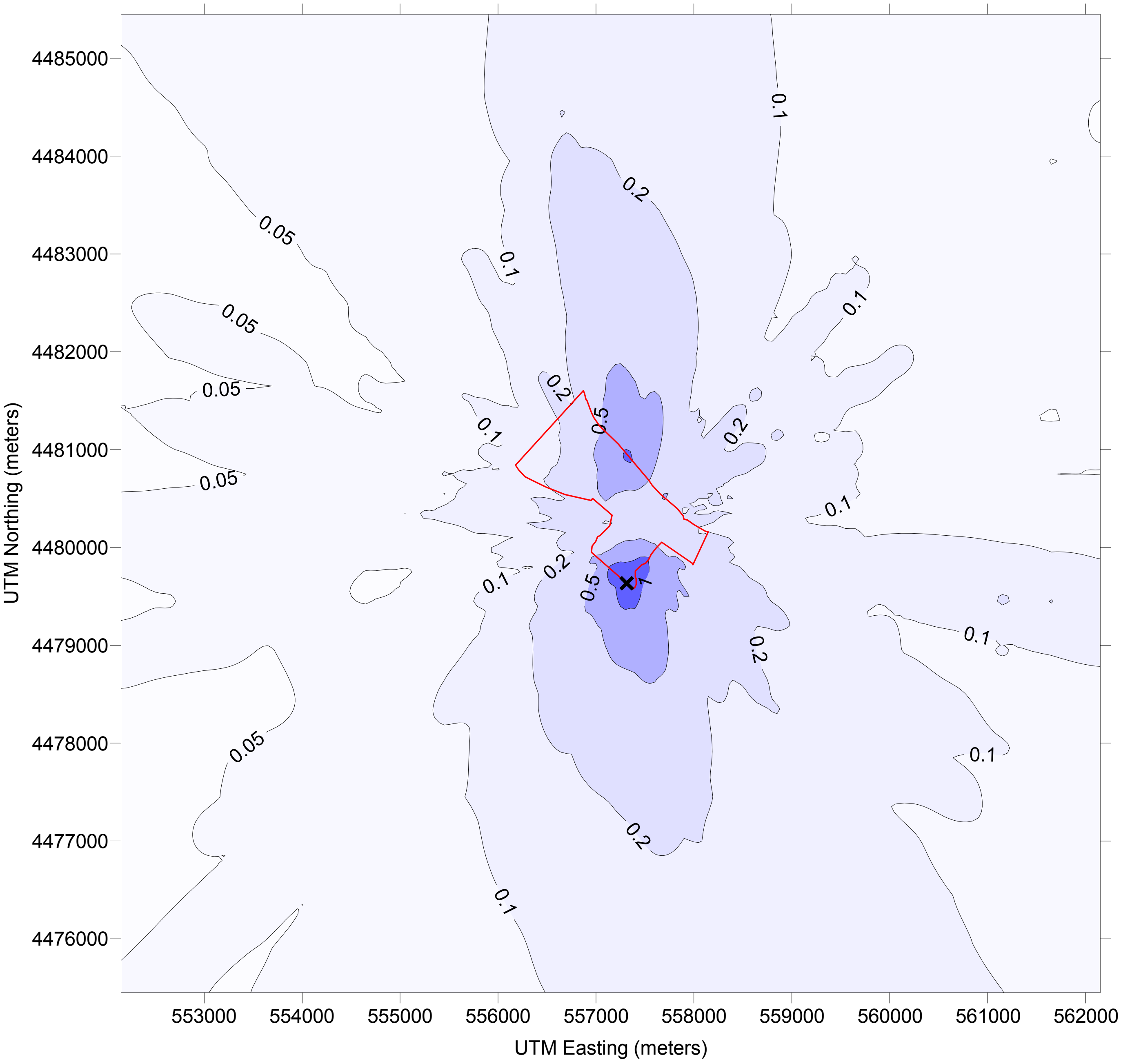
Figure 4-8. Maximum Predicted 24-Hour Average SO_2 Concentrations



× = maximum predicted concentration (0.149 μg/m3)

Concentration isopleths in micrograms per cubic meter (μg/m^3)

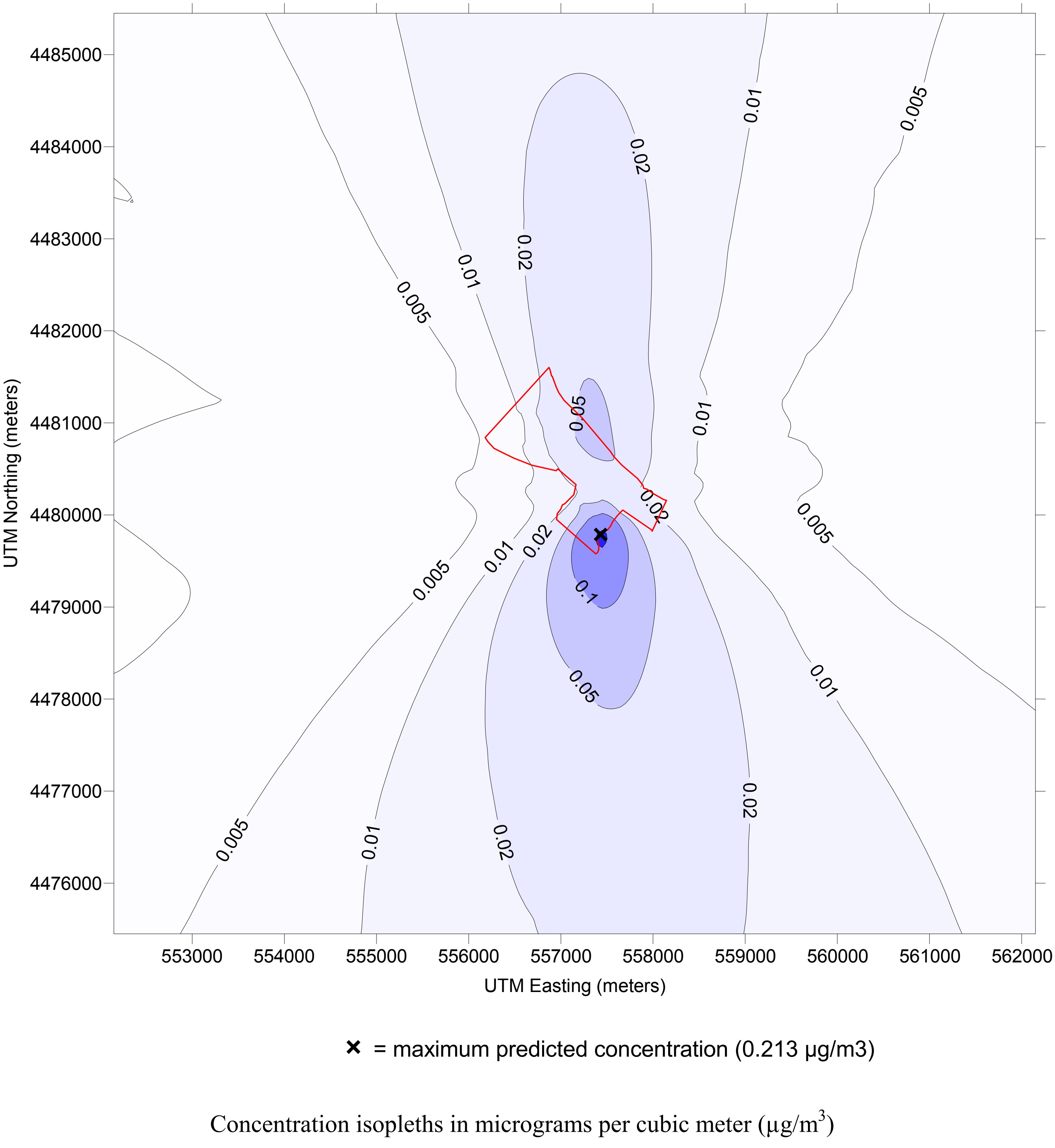
Figure 4-9. Maximum Predicted Annual Average SO_2 Concentrations



× = maximum predicted concentration (1.43 µg/m3)

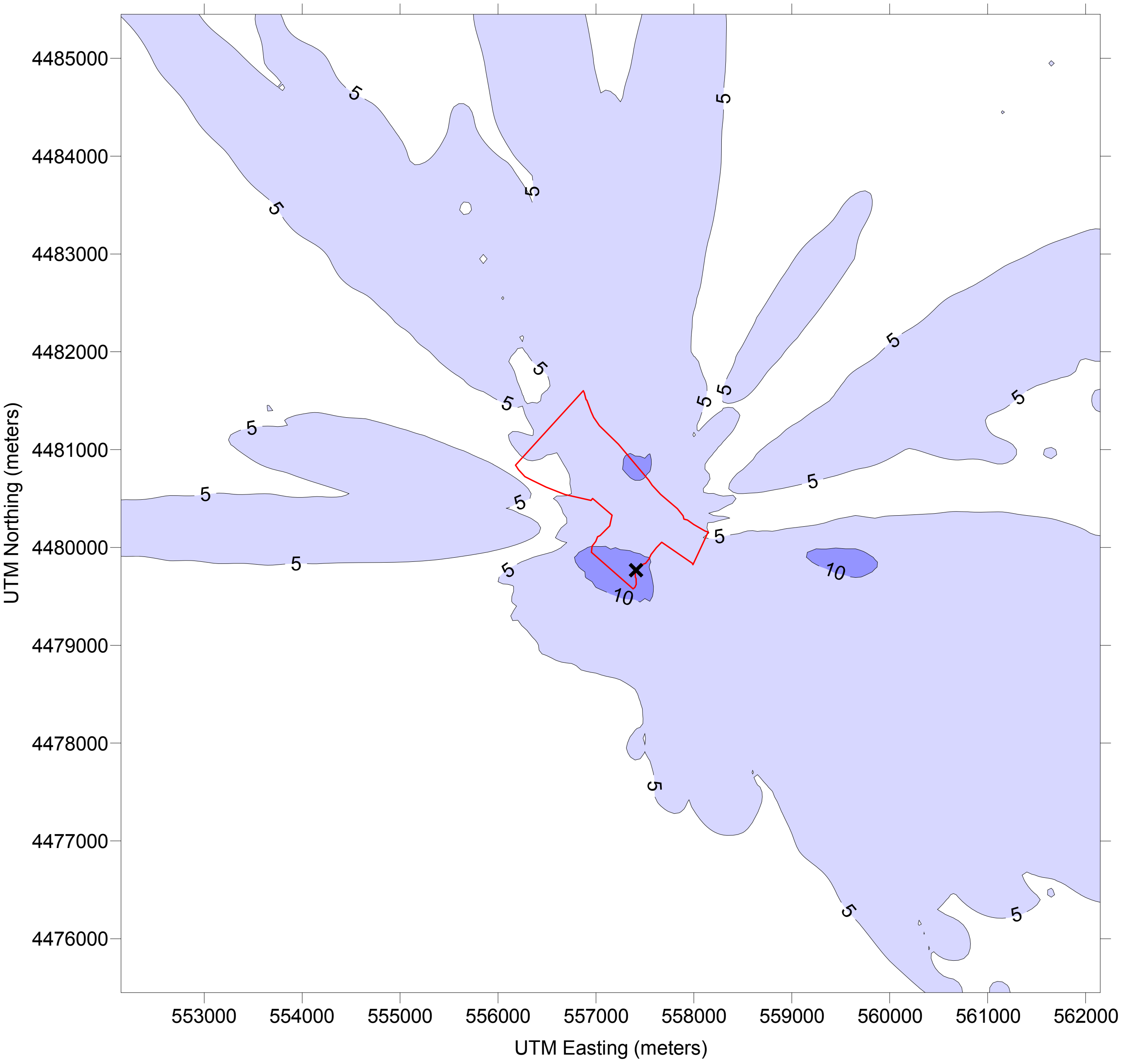
Concentration isopleths in micrograms per cubic meter ($\mu g/m^3$)

Figure 4-10. Maximum Predicted 24-Hour Average PM_{10} Concentrations



Concentration isopleths in micrograms per cubic meter (μg/m^3)

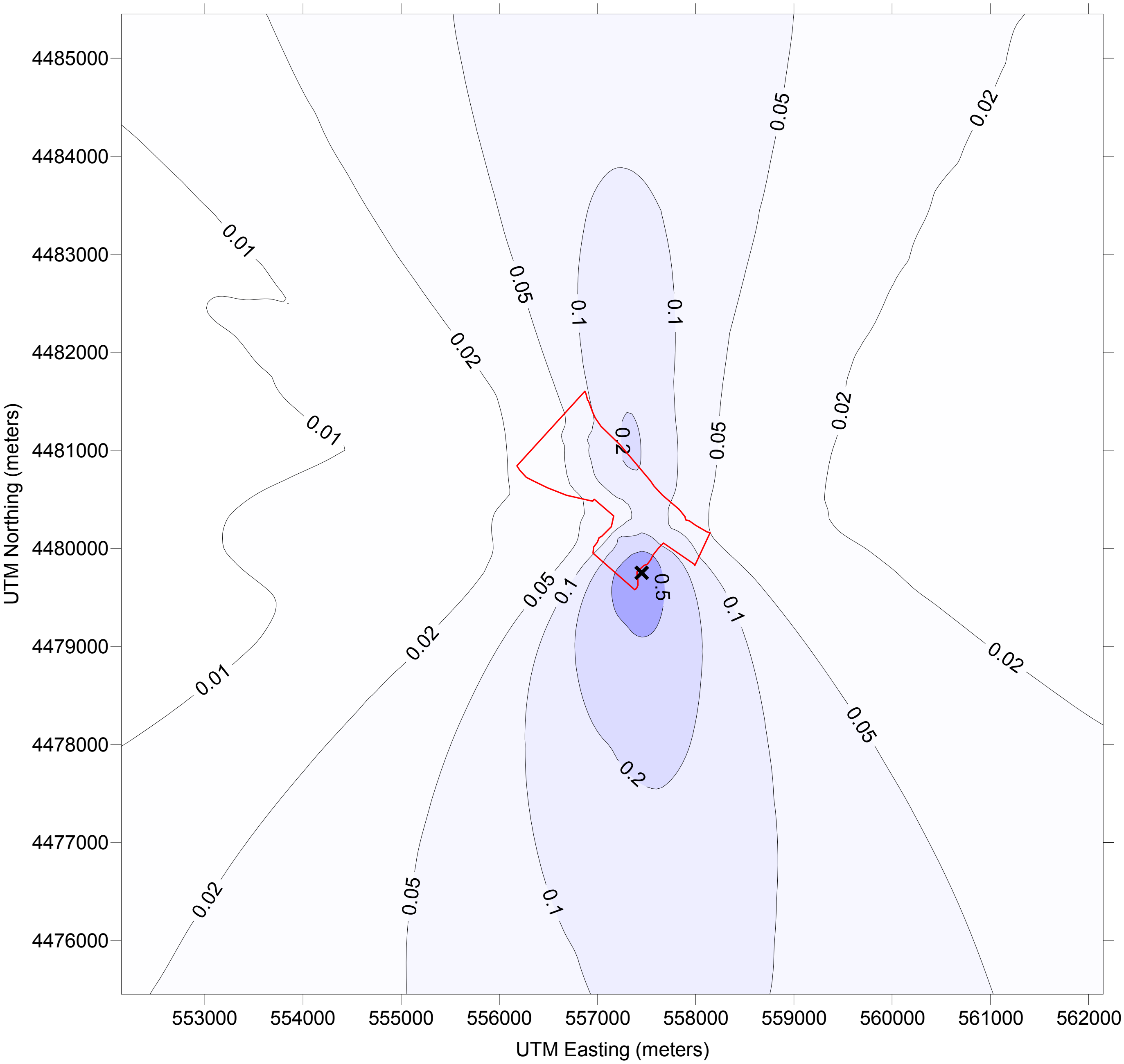
Figure 4-11. Maximum Predicted Annual Average PM_{10} Concentrations



× = maximum predicted concentration (14.0 µg/m3)

Concentration isopleths in micrograms per cubic meter (µg/m^3)

Figure 4-12. Maximum Predicted 1-Hour Average NO_2 Concentrations



× = maximum predicted concentration (0.906 µg/m3)

Concentration isopleths in micrograms per cubic meter ($\mu g/m^3$)

Figure 4-13. Maximum Predicted Annual Average NO_2 Concentrations

Appendix A:

SCAQMD Forms

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SHASTA COUNTY DEPARTMENT OF RESOURCE MANAGEMENT
AIR QUALITY MANAGEMENT DISTRICT
1855 PLACER STREET, SUITE 101, REDDING, CALIFORNIA 96001 VOICE (530)225-5674/FAX (530)225-5237
APPLICATION FOR AUTHORITY TO CONSTRUCT/PERMIT TO OPERATE

INSTRUCTIONS **PERMIT NUMBER # -PO-**

Each applicant for an Authority to Construct shall provide to the District the following:

A. One application form for each emission unit or multi-component system at the facility.
B. A $75 one time filing fee for each application or a $15 transfer of ownership * or name change fee made payable to the Shasta County AQMD. (*Furnish a copy of the sales agreement or a signed statement from the seller.)
C. Adequate drawings of each emissions unit, including plot plan and area map indicating receptors within 1/4 mile of the facility. Any public or private school with an outer boundary within 1000 feet of the emissions unit must be included on the map.
D. A signature of a responsible member of the organization on each application.
E. An annual permit fee must be paid before a Permit to Operate is granted. The District shall notify the applicant of the appropriate amount due following an initial inspection of the permitted device(s).

1. Business Name: Sierra Pacific Industries

2. Email: syoung@spi-ind.com

3. Assessor's Parcel Number: 05011025 Telephone: (530) 378-8350 Fax: (530) 378-8360

4. Type of Business: Lumber manufacturing

5. Mailing Address: P.O. Box 10939, Anderson, CA 96007

6. Address of Equipment: 19758 Riverside Ave., Anderson, CA 96007

7. Equipment Description (use additional sheets if required): See permit application documentation

8.	Application to: (check one)		9.	Type of Organization:	
	Operate Existing Equipment			Corporation	x
	New Construction			Partnership	
	Change of Location			Individual Owner	
	Modification	x		Government Agency	
	Exempt Equipment				
	Change of Ownership*			(Copy of agreement **or** statement attached? Yes ____ No ____)	

10. Planned construction dates; Start: 9/1/2010 End: 8/31/2011

11. Is a plot plan attached? Yes: See permit application documentation No:

12. Is this emission unit within 1000 feet from the outer boundary of any public or private school? Yes: No: X

13. Name of Owner(s)/Principles: Sierra Pacific Industries

14. Signature of Applicant: Date: February 25, 2010

15. Type/Print Signer's Name: Shane Young Title: Division Manager

BY SIGNING THIS APPLICATION, THE APPLICANT/PROPERTY OWNER AGREES TO DEFEND, INDEMNIFY, AND HOLD THE SHASTA COUNTY AIR QUALITY MANAGEMENT DISTRICT HARMLESS FROM ANY CLAIM, ACTION, OR PROCEEDING BROUGHT TO ATTACK, SET ASIDE, VOID OR ANNUL THE DISTRICT'S APPROVAL OF THIS APPLICATION, ISSUANCE OF ANY ASSOCIATED PERMIT, AND ANY ENVIRONMENTAL REVIEW ASSOCIATED WITH THE PROPOSED PROJECT.

Other Division Review **Air Quality Fees Collected**

General Plan/Zoning:			**Type**	**Date**	**Amount**	**Receipt #**	**Rec'd By**
Use requires use permit: Yes No			Filing				
Use requires building permit: Yes No			Permit				
Planning: Date:	Building: Date:						

SHASTA COUNTY DEPARTMENT OF RESOURCE MANAGEMENT
AIR QUALITY MANAGEMENT DISTRICT

1855 PLACER STREET, SUITE 101, REDDING, CA 96001
VOICE (530)225-5674/FAX (530)225-5237

SUPPLEMENTAL INFORMATION: BOILER/PROCESS HEATER

Company: Sierra Pacific Industries, Inc.

Specifications / Information:

Manufacturer: To be determined   Model Number: To be determined

Fuel Type(s): Biomass, including: wood, agricultural, and urban wood waste   Serial Number: To be determined

Rated heat input capacity (specified on nameplate): 425,419,000 (estimated) BTU/hr

What is the primary purpose of the boiler or process heater? Generate steam for lumber drying kilns and to generate electricity

Operation schedule (maximum): 24 hours/day 7 days/week 52 weeks/year

If operated seasonally, indicate the percent use in each quarter: 25 % Jan-Mar 25 % Apr-Jun 25 % Jul-Sep 25 %Oct-Dec

Fuel Usage Rate (maximum-daily): 1,380 tons/day N/A cuft/day N/A gallons/day

Fuel Usage Rate (maximum-annual): 503,989 tons/yr N/A cuft/yr N/A gallons/yr

Exhaust Emission Information:

HEIGHT OF EXHAUST STACK ABOVE THE GROUND (in feet)	115 feet
INSIDE DIAMETER OF EXHAUST STACK (in feet)	8.0 feet
AVERAGE FLOW OF EXHAUST AIR (specify acfm or dscfm)	206,425 acfm
MAXIMUM FLOW OF EXHAUST AIR (specify acfm or dscfm)	237,486 acfm
PERCENT MOISTURE OF EXHAUST AIR	21.19%
TEMPERATURE OF EXHAUST AIR (in ^{O}F)	400 °F

NO_2 (as ppmv at 7% O_2, dry, or lb/MMBtu)	0.13 lb/MMBtu
CO (as ppmv at 7% O_2, dry or lb/MMBtu)	0.35 lb/MMBtu 3-hr avg 0.22 lb/MMBtu annual avg
AMMONIA SLIP (as ppmv at 3% O_2, dry)	20 ppmvd @ 3% O_2
STACK GAS OXYGEN (as %)	6.04% (dry basis)
SO_2 (as ppmv at 12% CO_2, std conditions)	2.0 ppmvd @ 12% CO_2
PARTICULATE MATTER (as gr/dscf or lb/MMBtu)	0.02 lb/MMBtu 0.01 gr/dscf

If the boiler/process heater has a rated heat input of more than 1,000,000 BTU/hr and less than 5,000,000 BTU/hr, check one of the following options you will accept as a permit condition to control NOx emissions:

	Perform an annual tune-up for compliance (tune-up procedures specified in District Rule 3:26)
	Compliance to emission limit set for NOx (as specified in District Rule 3:26 -- NOx ≤ 70 ppmvd at 3% O_2, dry)
	Operate with a stack gas oxygen trim system set at 3% oxygen by volume.
	Operate with a stack gas oxygen concentration less than or equal to 3% by volume for any 15 minute averaging period.

If the boiler/process heater has a rated heat input of greater than 5,000,000 BTU/hr, regulations require installation of a dedicated non-resettable totalizing volumetric or mass-flow fuel meter (if gaseous and/or liquid fuel only). Meter specifications are requested.

Filer's Printed Name: Shane Young Signature: Shane W. Young Date: February 25, 2010

NOTICE: After the Authority to Construct is granted, any deviation from approved plans is not permitted without first securing additional approval from the Air Pollution Control Officer. As stated in the Health and Safety Code Sections 41510, 41511, and 42304, the Air Quality Management District shall make random audits on submitted data to insure the appropriateness of such data. The willful submission of false or inaccurate data constitutes a misdemeanor per Health and Safety Code Section 42400.

Appendix B:

BACT Analysis

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Biomass-Fired Cogeneration Project Best Available Control Technology Analysis

Anderson, California

Prepared for:
Sierra Pacific Industries, Inc.
Redding, California

Prepared by:
ENVIRON International Corporation
Lynnwood, Washington

Date:
February 2010

Project Number:
29-23586A

Contents

Page

1 Introduction 1
1.1 BACT Review Process 1
1.2 Technical Feasibility 2
1.3 Economic Justifiability 3

2 NO_X BACT Analysis 5
2.1 Identification of Possible Control Alternatives 5
2.1.1 Combustion Controls 5
2.1.2 Add-on Controls 5
2.1.3 Control Alternative Review 6
2.1.4 Summary of Possible Control Alternatives 8
2.2 Technical Feasibility of Control Alternatives 8
2.2.1 Proper Combustion 8
2.2.2 DLN Burner 8
2.2.3 SNCR 9
2.2.4 SCR and related variations 9
2.2.5 EMx 9
2.2.6 Summary of Technically Feasible Control Alternatives 9
2.3 Effectiveness of Remaining Technologies 10
2.3.1 Proper Combustion 10
2.3.2 SNCR 10
2.3.3 SCR and related variations 10
2.3.4 Ranking by Effectiveness 10
2.4 Cost-Effectiveness Evaluation 11
2.5 Selection of BACT for NO_X 12

3 CO BACT Analysis 13
3.1 Identification of Possible Control Alternatives 13
3.1.1 Combustion Controls 13
3.1.2 Add-On Controls 13
3.1.3 Control Alternative Review 14
3.1.4 Summary of Possible Control Alternatives 15
3.2 Technical Feasibility of Control Alternatives 15
3.2.1 Proper Combustion 15
3.2.2 Oxidation Catalyst 15
3.2.3 EMx 15
3.2.4 Summary of Technically Feasible Control Alternatives 16
3.3 Effectiveness of Remaining Technologies 16
3.3.1 Proper Combustion 16
3.3.2 Catalytic Oxidation 16
3.3.3 Ranking by Effectiveness 16
3.4 Cost Effectiveness Evaluation 17
3.5 Selection of BACT for CO 17

4 PM_{10} BACT ANALYSIS 19
4.1 Identification of Possible Control Alternatives 19

List of Tables

Page

Table 1 NO_X Control Technology Search Results 33

Table 2 NO_X Control Technology Cost-Effectiveness Comparison 34

Table 3 CO Control Technology Search Results 35

Table 4 PM_{10} Control Technology Search Results 36

Table 5 ROG/VOC Control Technology Search Results 37

Table 6 SO_2 Control Technology Search Results 38

List of Appendices

Appendix A: Cost Effectiveness Calculations

1 Introduction

Sierra Pacific Industries (SPI) proposes to construct and operate a new biomass-fired cogeneration unit at an existing lumber manufacturing facility in Anderson, California. The project would consist of a biomass-fired cogeneration unit, a steam turbine, and a cooling tower. The boiler associated with the cogeneration unit would have a maximum annual average heat input of up to 425 million British thermal units per hour (MMBtu/hr).

A new or modified source requiring an air permit, and required by regulations to apply the best available control technology (BACT) for a given pollutant to one or more emission units, must conduct an analysis to ensure that BACT is being proposed in the permit application. The project is a major modification of a major source, and is therefore subject to U.S. Environmental Protection Agency's (USEPA's) Prevention of Significant Deterioration (PSD) program.[1] In addition, Shasta County has established daily emission rate thresholds for various pollutants, which, if exceeded by the proposed project, require each proposed emission unit to apply BACT to control emissions of that pollutant.[2]

As new sources of emissions, BACT analyses are required for the biomass-fired cogeneration unit and the cooling tower. Based on the calculated annual emission rates for the proposed project and USEPA and Shasta County BACT thresholds, analyses are required for oxides of nitrogen (NO_X), carbon monoxide (CO), particulate matter equal to or less than ten microns in diameter (PM_{10}), reactive organic compounds (ROG), sulfur dioxide (SO_2), and beryllium.

1.1 BACT Review Process

A BACT analysis evaluates the energy, environmental, economic, and other costs associated with each potential control technology, and weighs those costs against the reduced emissions the technology would provide. The BACT analysis presented here is consistent with general EPA guidance. The EPA BACT guidance document details a "top-down" approach for selecting the appropriate control technology. The steps are as follows:

- Step 1. Identify all control technologies. Identify all available control techniques that could potentially be applied to control emissions of regulated pollutants from the proposed boiler.
- Step 2. Eliminate technically infeasible options. If any of the control techniques cannot be successfully used on plant units due to technical difficulties, document this finding. Such control techniques would not be considered further in the BACT analysis.

---

[1] 40 CFR 51.21(b)(23)(i)
[2] Shasta County Air Quality Management District Rule 2:1, Part 301.

- Step 3. Rank remaining control technologies by control effectiveness. Assess the performance of each control technique and rank them beginning with the most effective control technique.
- Step 4. Evaluate most cost effective controls. Estimate emission reductions, annual costs, cost effectiveness, energy impacts, and other environmental impacts of the controls techniques. Detailed cost effectiveness information is presented for the most effective control and for other control techniques that are in the least cost envelope.
- Step 5. Select BACT. This will generally be the most effective option not rejected based on energy, environmental, and economic impacts.

The only new emission unit proposed by the project is the wood-fired stoker-type boiler, so ENVIRON queried EPA's Reasonably Available Control Technology (RACT)/BACT/Lowest Achievable Control Technology (LAER) Clearinghouse (RBLC) database for BACT determinations involving biomass-fired, stoker-type boilers made after January 1, 1990. This initial broad search was refined by adding similar sources of which ENVIRON is aware that are not included in the RBLC database, and eliminating sources that operate in a significantly different manner.

USEPA's Reasonably Available Control Technology (RACT)/BACT/Lowest Achievable Control Technology (LAER) Clearinghouse (RBLC) database was queried for recent BACT determinations involving biomass-fired boilers. The search included all entries made after January 1, 1990 for biomass-fired, stoker-type boilers. This initial broad search was refined by eliminating sources that did not emit pollutants as a result of similar operation (e.g., fluidized bed boiler designs, use of fuels other than or in combination with wood). The sections that follow discuss the control alternatives available, the effectiveness and feasibility of those alternatives, and, ultimately, the selection of BACT for each pollutant.

All biomass-fired boiler permits meeting the criteria outlined above were included in the review. Permitted emission limits were compared on a heat input rate basis in units of pounds per million British thermal unit (lb/MMBtu). Equivalent emission limits, in lb/MMBtu, were calculated for sources with permit limits expressed only as an emission rate over some period (e.g., pounds per hour [lb/hr], pounds per day [lb/day], or tons per year [tpy]) by combining the permitted emission rate with a provided heat input rate.

1.2 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.

1.3 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 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 NO_2.

2.1 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.

2.1.1 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. Generally, use of DLN burners requires a wall-fired furnace and pulverized biomass fuel that is burned in suspension with coal or natural gas.

2.1.2 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 ºF for SCR as opposed to 1,650 ºF for SNCR). While SCR systems have been utilized to reduce NO_X 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 the use more advanced catalysts that enable the reduction reaction to proceed at lower temperatures (350 ºF to 450 ºF). 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 lower exhaust temperature limit required for the reactions to take place is less than that of SCR (300 ºF as opposed to 450 to 600 ºF, depending on the catalyst used). The EMx system is also said to control CO and VOCs by oxidation.

2.1.3 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 traffic volumes and routes.

The most recently permitted biomass-fired, stoker-type boiler in California is a 289 MMBtu/hr unit at the Sierra Pacific Industries facility in Lincoln, California, which was permitted in 2004 with a NO_X limit of 0.13 lb/MMBtu. A larger boiler (430 MMBtu/hr) of similar design was permitted in 2006 at an SPI facility near Burlington, Washington with the same NO_X permit limit.[3] 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 basis[4], and 0.0055 lb/MMBtu on an annual average in order to avoid purchasing offsets in an ozone nonattainment area. The facility has been neither permitted nor 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

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[3] 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.

[4] For the initial 12-month period following startup, the 24-hour average NO_X limit would be 0.024 lb/MMBtu. During 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.

(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. With some flue gas recirculation and staged combustion, a NO_X emission rate 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.

2.1.4 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

2.2 Technical Feasibility of Control Alternatives

2.2.1 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 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.

2.2.2 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 0.20 lb/MMBtu), so this technology will be eliminated from consideration as BACT.

2.2.3 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 popular add-on NO_X control technology for biomass-fired boilers.

2.2.4 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 particulate collector (e.g., a multiclone and an ESP) is likely to be cost-effective operation while reducing NO_X emissions to 0.060 lb/MMBtu. Because most of these installations have been within the past year or two, experience with this application of SCR technology is limited. Many of the projects using SCR have experienced catalyst deactivation and/or erosion at rates that were higher than anticipated, and, as a result, have required additional assistance from catalyst suppliers and control technology consultants. 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 the economic performance of the boiler is questionable.

2.2.5 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 SO_2 emission factor for wood-fired boilers is 0.025 lb/MMBtu, which is equivalent to about 7.2 lb/hr of SO_2. 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 SO_2 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.

2.2.6 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/CSCR/RSCR

2.3 Effectiveness of Remaining Technologies

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

2.3.1 Proper Combustion

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

2.3.2 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 the ammonia into the furnace at the proper temperature window to increase NOx 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.

2.3.3 SCR/CSCR/RSCR

The recently permitting 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 permit has not been issued for Valley BioEnergy in Modesto, California, though the pemit application has been deemed complete; the proposal is to use both an SNCR as well as an SCR system with the catalyst placed downstream of particulate control devices.

2.3.4 Ranking by Effectiveness

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

- SCR/CSCR/RSCR
- SNCR

- Proper combustion

2.4 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 0.20 lb/MMBtu to 0.13 lb/MMBtu would cost $661 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. SPI estimates that approximately $150,000 in revenue would be lost each time the boiler was shut down to replace or wash the catalyst. Additionally, SPI'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 130 tons year at an annual expense of $86,000, while an SCR system, under best-case operating conditions, would reduce NO_X emissions by approximately 260 tons per year at an annual expense of over $1,250,000. Thus, an additional $1,164,000 per year would be spent to capture an additional 130 tons of NO_X, which is equivalent to an incremental cost effectiveness of nearly $9,000 per ton of NO_X removed. However, judging by the experiences of other biomass-fired boiler facilities employing SCR systems, this cost-effectiveness analysis likely underestimates the number of catalyst beds needed (2), as well as the number downtime events needed to replace or clean the catalyst(3) each year, 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.

2.5 Selection of BACT for NO_X

Based on the analysis presented in this section, SPI proposes that BACT for the control of NO_X from biomass-fired, stoker-type boilers is the use of an integral SNCR system. NO_X emissions would be limited to 0.13 lb/MMBtu, which is approximately equivalent to 242 tpy at the anticipated annual average operating capacity.

3 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 CO_2 into CO which can occur in high-temperature regions (above 1,700 °C) of the combustion zone.

3.1 Identification of Possible Control Alternatives

As for NO_X, the control technology options available for reducing CO emissions from combustion sources include combustion controls that encourage complete combustion to reduce CO formation, as well as add-on control devices that oxidize CO to CO_2 after leaving the combustion area.

3.1.1 Combustion Controls

Combustion controls for CO include adequate fuel residence times to ensure CO_2 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 allow lower CO emissions in comparison to combustion of wet biomass fuels because of lower combustion zone temperatures.

3.1.2 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 CO_2). 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 CO_2 by the catalyst, the exhaust temperature must be increased, resulting in higher fuel use. In order to reduce catalyst masking and pressure drop across the device, a particulate control device must be located upstream of the catalyst bed. Also, the size of the particulate control system must be increased to accommodate the higher temperature, and therefore higher volume, exhaust flow. Although the catalyst would be located downstream of a particulate control device, a steam injection system is used to periodically remove particulate matter from the catalyst.

EMx (described in the NO_X BACT analysis section) also utilizes a catalytic technique that oxidizes CO to CO_2 in addition to controlling NO_X emissions.

3.1.3 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 were considered in the 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 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 limit that would limit CO emission to 0.046 lb/MMBtu on a 24-hour average basis to avoid PSD review.

3.1.4 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

3.2 Technical Feasibility of Control Alternatives

3.2.1 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.

3.2.2 Oxidation Catalyst

The only instances of a biomass-fired stoker-type boiler utilizing, or proposing to utilize, an oxidation catalyst to control CO emissions are a project that operated for a limited period with uncertain reliability (Bio Energy), and permits issued for projects that may never be realized (South Point, Concord Steam, and Valley BioEnergy). Therefore, catalytic oxidation is considered technically feasible, but not yet fully demonstrated in practice for reliably controlling CO emissions from a base-load biomass-fired stoker boiler while not negatively impacting facility operations.

3.2.3 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 SPI. Therefore, EMx is not considered technically feasible for controlling CO emissions from a wood-fired boiler.

3.2.4 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

3.3 Effectiveness of Remaining Technologies

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

3.3.1 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 20 parts per million (ppm) ammonia slip, as required by Shasta County (Shasta County AQMD Rule 3:26.c.4), boiler operation will favor reduced NO_X creation over reduced CO creation.

SPI currently operates biomass-fired boilers at their Lincoln, California, Burlington, Washington, and Aberdeen, Washington lumber manufacturing facilities that are similar in design to the proposed boiler. Each of these boilers was permitted with a CO permit limit of (or equivalent to) 0.35 lb/MMBtu. Based on source test data from those boilers, SPI believes that the proposed boiler design will be able to meet an annual average emission limit of 0.22 lb/MMBtu though use of proper combustion techniques.

3.3.2 Catalytic Oxidation

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.

3.3.3 Ranking by Effectiveness

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

- Catalytic oxidation
- Proper combustion

3.4 Cost Effectiveness Evaluation

No cost effectiveness evaluation was performed for CO emissions from the proposed boiler, because, in addition to a 24-hour average CO BACT emission limit of 0.35 lb/MMBtu, SPI proposes an annual average CO emission limit of 0.22 lb/MMBtu to avoid being a major source subject to PSD review. The boiler exhaust system will be designed such that an oxidation catalyst can be installed if projections based on initial operation indicate that the annual limit cannot be met without it.

3.5 Selection of BACT for CO

Based on the analysis presented in this section, SPI proposes that BACT for CO emitted from the proposed biomass-fired stoker boiler is 0.35 lb/MMBtu on a 24-hour average basis, which is equivalent to 156.3 lb/hr at the maximum 24-hour average operating rate of the proposed boiler. SPI also proposes an annual average emission limit of 0.22 lb/MMBtu, which is equivalent to 410 tpy at the maximum annual average operating rate of the proposed boiler. It should be noted that, because the existing boiler at the facility will not be operated concurrent with the proposed boiler, the net CO emission rate increase is less than 250 tpy, and therefore not subject to PSD review.

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4 PM_{10} BACT ANALYSIS

PM_{10} 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).

4.1 Identification of Possible Control Alternatives

4.1.1 Combustion Controls

The concept of applying combustion controls or “proper combustion” to minimize PM_{10} 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 the maximum amount of fuel is combusted. As discussed in the analysis of BACT for CO emissions, optimization of these factors for PM_{10} 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.

4.1.2 Add-On Controls

The two most popular add-on control technologies for control of PM_{10} emissions from a boiler are electrostatic precipitators (ESPs) and baghouses. ESPs remove particles from an exhaust stream by imposing an electrical charge on the particles and then attracting them to an oppositely charged plate. The dust collected on the charged plates is periodically removed by vibrating or rapping of the plates.

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. Often a mechanical collector, such as a multiclone, is used to remove larger particulate matter before the exhaust reaches the primary control device.

Wet scrubbers, such as venturi scrubbers are less common because they typically have lower control efficiencies than either ESPs or baghouses. They also complicate waste disposal by introducing liquids that create sludge when combined with the removed PM_{10}. A venturi is a narrowed section of duct followed by an expanded section of duct, with scrubbing liquid injected at the constricted section. The liquid in atomized by the increased velocity exhaust flow, and the particles impact the droplets and are collected. Because the liquid must be atomized to ensure high collection efficiency, a high-energy exhaust flow is required.

4.1.3 Control Alternative Review

The results of the database queries for PM_{10} control technologies are presented in Table 4, sorted by permit limit, beginning with the PM_{10} limit proposed by SPI for the new biomass-fired cogeneration unit.

A review of the RBL Clearinghouse indicates that the most stringent control technology for PM_{10} is use of an ESP or a baghouse. The most stringent permit limit employing ESP technology to control PM_{10} 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_{10} 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 PM_{10} 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_{10} test method to confirm compliance with the permit limit. The proposed Valley BioEnergy facility in Modesto would use an ESP to limit PM_{10} emissions to 0.02 lb/MMBtu.

4.1.4 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
- Venturi scrubber

4.2 Technical Feasibility of Control Alternatives

The most common technology for controlling PM_{10} emissions from a biomass-fired boiler is an ESP preceded by a multiclone. Baghouses have been employed to control PM_{10} 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 downstream ducting or control devices is significant because of the high carbon content of the ash from boilers that burn biomass fuels, but many operators and manufacturers have engineered designs to minimize this risk. ESPs, constructed mostly of metal, 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_{10} from smaller boilers with lower exhaust flow, and typically have lower control efficiencies than ESPs or baghouses

4.3 Effectiveness of Remaining Technologies

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

4.3.1 Venturi Scrubbers

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

4.3.2 Baghouses

Baghouses typically operate with pressure drops between 2 and 12 inches of water. PM_{10} control efficiencies are capable of removing over 99 percent of PM_{10} from gas streams.

4.3.3 ESPs

ESPs, which typically experience pressure losses of around 0.5 inches of water, are capable of removing over 99 percent of PM_{10} from exhaust flows.

4.3.4 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

4.4 Cost Effectiveness Evaluation

No cost effectiveness evaluation comparing the baghouse or scrubber is presented because SPI is proposing ESP to control PM_{10} emissions from the biomass-fired, stoker-type boiler.

4.5 Selection of BACT for PM_{10}

SPI proposes that BACT for PM_{10} emissions from a biomass-fired, stoker-type boiler is an emission rate of 0.02 lb/MMBtu, equivalent to 37.3 TPY at the anticipated annual operating capacity, and achieved using a mechanical collector followed by an ESP.

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5 ROG/VOC BACT Analysis

With the exception of various chloro- and fluorocarbons, ROG is the same as EPA's definition of volatile organic compounds (VOC). Because most permits include limits for VOCs instead of ROG, and because they are so similar, this BACT analysis is for VOC, but all statements and conclusions could be drawn for ROG as well.

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.

5.1 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.

5.1.1 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 SPI for the new cogeneration unit.

The only technology employed as BACT for VOC emissions from a biomass-fired boiler is maintaining proper combustion of the fuel. 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 the tradeoffs between emissions of NO_X, CO, and VOC that are inherent to maintaining proper combustion. Two permit limits have been identified that are lower than the VOC limit proposed by SPI for the new wood-fired cogeneration unit. In both cases, higher permit limits have been deemed BACT after the lower permit limits were approved. In one case, the Maine Department of Environmental Protection determined that a limit of 0.02 lb/MMBtu was BACT for a facility constructed in 1991, and that 0.03 lb/MMBtu was BACT for another facility in 1999. In Washington, SPI's facility in Aberdeen received permit limit for 0.025 lb/MMBtu in 2002, and SPI's 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.

5.1.2 Summary of Possible Control Alternatives

Based on database queries and other research, proper combustion is the only possible VOC control alternative for a biomass-fired boiler.

5.2 Technical Feasibility of Control Alternatives

Proper combustion is a technically feasible control alternative that is used to control VOC emissions from most biomass-fired boilers. As for CO, oxidation catalysts have been installed on stoker-type, biomass-fired boilers, but this application of the technology is not mature, and has not been demonstrated in practice.

5.3 Effectiveness of Remaining Technologies

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).

5.3.1 Ranking by Effectiveness

Proper combustion is the only feasible, proven control technology for limiting VOCs from a stoker-type, biomass-fired boiler, therefore it is the most effective.

5.4 Cost Effectiveness Evaluation

Because proper combustion is the only remaining alternative, it is, by default, the most cost effective.

5.5 Selection of BACT for ROG/VOCs

Based on the above discussion, proper combustion is proposed to be BACT for VOC emissions from the biomass-fired boiler. SPI proposes a VOC emission rate of 0.017 lb/MMBtu, equivalent to 31.7 TPY at the anticipated annual operating capacity.

6 SO_2 BACT ANALYSIS

Sulfur dioxide (SO_2) 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 SO_2.

6.1 Identification of Possible Control Alternatives

There are two alternatives for reducing SO_2 emissions combustion sources: removal of sulfur from the fuel before it is combusted, and removal of SO_2 from the exhaust gas after combustion.

Removing sulfur from fuel before it is combusted has been employed to remove sulfur-containing nonorganically-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 SO_2 control requirement other than the exclusive use of biomass, and perhaps a limit on the sulfur content of a start-up or co-fired fuel.

Scrubbing, or flue gas desulfurization (FGD) systems remove SO_2 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 SO_2 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 SO_2 control system. Both wet and dry FGD systems require significantly expanded waste handling operations to remove the reacted sorbent material.

6.1.1 Control Alternative Review

The results of the database queries for SO_2 control technologies are presented in Table 6, sorted by permit limit, beginning with the SO_2 limit proposed by SPI for the new boiler. The RBLC does not indicate that any FGD systems have been used to reduce SO_2 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 SO_2 emissions. The Valley BioEnergy has been deemed complete, but no permit has been issued, and it has not been constructed or operated.

6.1.2 Summary of Possible Control Alternatives

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

- None

- FGD

6.2 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 to reduce SO_2 emissions from a biomass-fired boiler.

6.3 Effectiveness of Remaining Technologies

Wet FGD systems are considered the most effective, and can achieve greater than 90 percent reduction in SO_2 emissions. Dry scrubbers and spray driers are capable of control efficiencies on the order of 90 percent.

6.3.1 Ranking by Effectiveness

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

- None
- FGD

6.4 Cost Effectiveness Evaluation

Based on a source test conducted on the existing boiler in 2002, an SO_2 emission factor of approximately 0.0025 lb/MMBtu is likely, as the fuel supply for the proposed boiler is not expected to differ significantly from that of the existing boiler. Assuming that the maximum SO_2 emission factor for the proposed boiler is twice that indicated by the 2002 source test (0.005 lb/MMBtu), and using the trona injection system capital and operating costs used by Valley BioEnergy for a slightly smaller boiler (402 MMBtu/hr versus 425.4 MMBtu/hr), the cost per ton of SO_2 controlled is more than $45,000, which is clearly outside the envelope of acceptable costs.

6.5 Selection of BACT for SO_2

SPI proposes that no control system is BACT for reducing SO_2 emissions from a biomass-fired boiler, and that the SO_2 permit limit will be determined by the initial source test.

7 Beryllium BACT Analysis

Beryllium emissions are entirely a function of the beryllium content of the fuel. The RBLC contains three biomass-fired units with beryllium permit limits: one co-fires fossil fuels (oil and coal), and the other two burn tires in addition to biomass fuel. SPI proposes that no control system is BACT for reducing beryllium emissions from a biomass-fired boiler. An AP-42 source test-derived emission factor of 1.55×10^{-6} lb/MMBtu was used to calculate emissions from the proposed cogeneration unit (approximately 5.78 lb/yr).

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8 Cooling Tower BACT Analysis

In 2002, the Olympic Region Clean Air Agency (ORCAA) permitted a cooling tower for a new Sierra Pacific sawmill in Aberdeen, Washington. ORCAA determined that BACT for cooling towers was the use of DRU-1.5 high-efficiency mist eliminators with a drift loss of less than 0.0005 percent. This drift eliminator design is based on the D-15, originated by Munters Corporation, which is now owned by Brentwood Industries, Inc. The principal difference is that the DRU-1.5 removes the side plates on each panel, allowing the panels to be nested for a seamless installation. The water loading expected for the cooling towers is 4.24 gallons per minute per square foot (gpm/ft^2) and an air velocity of 503 feet per minute (fpm). The D-15 drift test results indicate that the drift rate associated with these values should be less than 0.0005 percent.

Of the three most recent instances of permits issued for projects including cooling towers in the RBLC, one (Western Greenbrier Cogeneration in West Virginia, permit issued April 26, 2006) deemed 0.00005 percent drift eliminators BACT, another (Marathon Petroleum in Louisiana, permit issued December 27, 2006) deemed 0.005 percent drift eliminators BACT, and the third (Valero Refining in Louisiana, permit issued Feburary 8, 2007) deemed drift eliminators BACT without specifying an effectiveness. The cooling tower proposed for the new cogeneration unit project at SPI’s Anderson lumber manufacturing facility would use the same high-efficiency mist eliminators as the cogeneration unit cooling towers at SPI’s Aberdeen and Burlington facilities in Washington, and SPI proposes that this technology remains BACT for cooling towers.

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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
Sierra Pacific Industries	Anderson, CA	Proposed	425	0.13	SNCR	BACT-OTHER	
Valley BioEnergy	Modesto, CA	Proposed	402	0.012	SNCR/SCR	BACT-OTHER	Not permitted
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
Darrington Cogeneration	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	
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	
District Energy St. Paul	St. Paul, MN	11/15/01	550	0.15	SNCR	BACT-PSD	
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	
U.S. Sugar	Clewiston, FL	12/6/07	738	0.31	Proper combustion	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
South Point Power	South Point, OH	4/4/06	318	0.44	SCR	BACT-PSD	Not constructed

Table 2
NO_X Control Technology Cost-Effectiveness Comparison

Control System	Annual Cost ($/yr)	NO_X Reduction (tpy)	Cost Effectivness ($/ton)	Incremental Cost Effectiveness ($/ton)
SNCR	86,222	130.4	661	N/A
SCR	1,251,192	260.9	4,796	8,932

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
Sierra Pacific Industries	Anderson, CA	Proposed	425	0.35	Proper combustion	BACT-OTHER	
Valley Bio-Energy	Modesto, CA	Proposed	402	0.046	Oxidation catalyst	BACT-OTHER	Not permitted
Russell Biomass	Russell, MA	12/30/08	740	0.075	Oxidation catalyst	BACT-OTHER	Not constructed; annual avg
South Point Power	South Point, OH	4/4/06	318	0.10	Oxidation catalyst	BACT-PSD	Not constructed
Hampton Lumber	Darrington, WA	6/1/05	245	0.23	Proper combustion	BACT-OTHER	Fuel-cell design
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	
Boralex Ashland	Ashland, ME	4/2/92	586	0.3	Proper combustion	BACT-OTHER	
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	
KES Chateaugay Project	Chateaugay, NY	12/19/94	275	0.35	Proper combustion	BACT-OTHER	
Pittsylvania Power	Hurt, VA	2/21/92	374	0.35	Proper combustion	BACT-PSD	
Smurfit-Stone Container	Stevenson, AL	1/15/97	620	0.4	Proper combustion	BACT-PSD	
Weyerhaeuser Company	Bruce, MS	5/9/95	90	0.4	Proper combustion	BACT-PSD	
Gulf States Paper Corp	Moundville, AL	10/14/98	98	0.5	Proper combustion	BACT-PSD	
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_{10} Control Technology Search Results

Facility Name	Location	Date of Permit	Heat Input (MMBtu/hr)	Permit Limit (lb/MMBtu)	Control Technology	Basis	Notes
Sierra Pacific Industries	Anderson, CA	Proposed	425	0.015	Multiclone, ESP	BACT-OTHER	
Valley Bio-Energy	Modesto, CA	Proposed	402	0.02	Multiclone, ESP	BACT-OTHER	Not permitted
South Point Power	South Point, OH	4/4/06	318	0.0125	Baghouse	BACT-PSD	Not constructed; filterable only
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	Mulitclone, 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	
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
ROG/VOC Control Technology Search Results

Facility Name	Location	Date of Permit	Heat Input (MMBtu/hr)	Emission Factor (lb/MMBtu)	Control Technology	Basis	Notes
Sierra Pacific Industries	Anderson, CA	Proposed	425	0.017	Proper combustion	BACT-OTHER	
Valley Bio-Energy	Modesto, CA	Proposed	402	0.005	Oxidation catalyst	BACT-OTHER	Not permitted
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
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
SO_2 Control Technology Search Results

Facility Name	Location	Date of Permit	Heat Input (MMBtu/hr)	Emission Factor (lb/MMBtu)	Control Technology	Basis	Notes
Sierra Pacific Industries	Anderson, CA	Proposed	425	--	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 required
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	

Appendix A:

Cost-Effectiveness Calculations

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TABLE A-1

SNCR COST ESTIMATE
FOR BIOMASS-FIRED COGENERATION UNIT

Sierra Pacific Industries Biomass-Fired Cogeneration Project
Anderson, California

CAPITAL COSTS			
DIRECT COSTS		**COST**	**Source**
I. Purchased Equipment			
a. Primary Equipment (catalyst bed and additional ductwork)		$50,000	SPI (2009)
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])		$5,222	OAQPS
Total Indirect Costs [TIC](III+IV)		$24,287	Calculation
Total Capital Costs [TCC] (TEC+TDC+TIC)		$104,237	Calculation
Total Annualized Capital Costs [TACC] (20 years @ 7% interest)		**$9,839**	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 maintance labor)		$8,213	OAQPS
V. Utility costs (none)		$0	
VI. Ammonia costs (anhydrous) =(21 lb/hr)*(8760 hr/yr)*($0.2/lb)		$36,792	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)		$2,085	OAQPS
X. Insurance (0.01*TCC)		$1,042	OAQPS
Total Direct and Indirect Annualized Costs [TDIAC] (DOC+IOC)		**$76,383**	Calculation
TOTAL ANNUALIZED COSTS OXIDATION CATALYST [TAC $_{OC}$] (TACC+TDIAC)		**$86,222**	Calculation
Baseline emissions (w/proper combustion - 0.20 lb/MMBtu)	tons/year	372.7	McBurney (2009)
Emissions w/SNCR (assuming 0.13 lb/MMBtu)	tons/year	242.2	SPI (2009)
Reduction from baseline	Percent	35.0	Calculation
Total Emissions Reduction	tons/year	130.4	Calculation
Cost per ton Conrolled	***$/ton***	**$ 661**	Calculation

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

TABLE A-2

SCR COST ESTIMATE
FOR BIOMASS-FIRED COGENERATION UNIT

Sierra Pacific Industries Biomass-Fired Cogeneration Project
Anderson, California

CAPITAL COSTS			
DIRECT COSTS		**COST**	**Source**
I. Purchased Equipment			
a. Primary Equipment		$258,500	FERCo (2010)
b. Instrumentation (0.1*a)		$25,850	OAQPS
c. Sales tax (0.08*a)		$20,680	OAQPS
d. Freight (0.05*a)		$12,925	OAQPS
Total Purchases Equipment Cost [TEC]		$317,955	Calculation
II. Direct Installation Costs			
a. Foundations and Supports (0.08*TEC)		$25,436	OAQPS
b. Handling and Erection (0.14*TEC)		$44,514	OAQPS
c. Electrical (0.04*TEC)		$12,718	OAQPS
d. Piping (0.02*TEC)		$6,359	OAQPS
e. Insulation for Ductwork (0.01*TEC)		$3,180	OAQPS
f. Painting (0.01*TEC)		$3,180	OAQPS
Total Direct Costs [TDC](I+II)		$95,387	Calculation
INDIRECT COSTS			
III. Indirect Installation			
a. Engineering and Supervision (0.10*TEC)		$31,796	OAQPS
b. Construction and Field Expenses (0.05*TEC)		$15,898	OAQPS
c. Contractor Fee (0.10*TEC)		$31,796	OAQPS
d. Contingencies (0.03*TEC)		$9,539	OAQPS
IV. Other Indirect Costs			
a. Startup and Testing (0.03*TEC)		$9,539	OAQPS
b. Working Capital (30 days of direct operating costs [I-VII below/12])		$58,736	OAQPS
Total Indirect Costs [TIC](III+IV)		$157,302	Calculation
Total Capital Costs [TCC] (TEC+TDC+TIC)		$570,643	Calculation
Total Annualized Capital Costs [TACC] (20 years @ 7% interest)		**$53,865**	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)(1 hr/shift)(3 shifts/day)(365 day/yr)		$32,850	Engineering Estimate
IV. Replacement Parts			
a. Catalyst (2 sets every year), $129,000 per year		$258,000	FERCo (2010)
b. Other (100% of maintance 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) =(21 lb/hr)*(8760 hr/yr)*($0.83/lb)		$152,687	FERCo (2010)
VII. Lost revenue during downtime (3 per year @ $150,000 per shutdown)		$450,000	
INDIRECT OPERATING COSTS (IOC)			
VIII. Overhead (0.6*O&M costs(I-III of DOC)		$25,377	OAQPS
IX. Administration (0.02*TCC)		$11,413	OAQPS
X. Insurance (0.01*TCC)		$5,706	OAQPS
Total Direct and Indirect Annualized Costs [TDIAC] (DOC+IOC)		**$1,197,327**	Calculation
TOTAL ANNUALIZED COSTS OXIDATION CATALYST [TAC $_{OC}$] (TACC+TDIAC)		**$1,251,192**	Calculation
Ucontrolled NOx emission factor (0.20 lb/MMBtu)	tons/year	372.7	McBurney (2009)
Emissions w/SCR (0.06 lb/MMBtu)	tons/year	111.8	FERCo (2010)
Reduction from baseline	Percent	70.0	Calculation
Total Emissions Reduction	tons/year	260.9	Calculation
Cost per ton Conrolled	***$/ton***	$ 4,796	Calculation

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

Appendix C:

Air Quality Dispersion Modeling Files (CD)

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February 2010

Project No.
29-23586A

Sierra Pacific Industries
Biomass-Fired Cogeneration
Project Authority to Construct
Permit Application
Anderson, CA
Air Quality Dispersion
Modeling Files