

This section describes the regional air quality, current attainment status of the air basin, local sensitive receptors, emission sources, hazardous air pollutants, green house gas (GHG) emissions, climate change, and impacts that are likely to result from project implementation. Following this discussion is an assessment of consistency of the proposed project with applicable policies and local plans. The climate change and GHG analysis is located at the end of this chapter, under Section 3.2.4.

During the NOP comment period, three comment letters were received related to this environmental topic.

- A letter to Shasta County from resident Kirk Sanders, dated July 31, 2009 indicated that the EIR should address potential impacts associated with an increase in cancer risk.
- An undated letter to Shasta County signed by residents Ashley Wayman, Tim Wedan, and Barbara Wedan, received on August 3, 2009 requested that the EIR address potential impacts to air quality, including the release of toxic air contaminants and the generation of odors.
- A letter to Shasta County from Justin Augustine with the Center for Biological Diversity, dated July 30, 2009 indicated that the project may result in direct air quality impacts and also requested that the EIR address impacts related to climate change.

Information in this section is derived primarily from the following:

- Biomass-Fired Cogeneration Project, Authority to Construct and Prevention of Significant Deterioration Permit Application, prepared by ENVIRON International Corporation, March 2010 (**Appendix B**).
- Bio-mass-Fired Cogeneration Project Health Risk Assessment, prepared by ENVIRON International Corporation, February 2010 (**Appendix C**).
- Northern Sacramento Valley Planning Area 2006 Air Quality Attainment Plan.
- Meteorology Today: An Introduction to Weather, Climate, & the Environment, 2003, D.C. Ahrens
- Inventory of California Greenhouse Gas Emissions and Sinks: 1990 to 2004. (Staff Final Report), California Energy Commission, 2006
- Interim Opinion on Phase 1 Issues: Greenhouse Gas Emissions Performance Standard, California Public Utilities Commission, 2007.
- Bioenergy and Greenhouse Gasses, Pacific Institute, 2008.

### 3.2.1 EXISTING SETTING

#### NORTHERN SACRAMENTO VALLEY AIR BASIN

The study area for this analysis is the Northern Sacramento Valley Air Basin, which comprises Butte, Colusa, Glenn, Shasta, Sutter, Tehama, and Yuba Counties. The Shasta County Air Quality Management District (SCAQMD) has jurisdiction over air quality issues throughout Shasta County.

Shasta County encompasses the northernmost portion of the Sacramento Valley and the surrounding mountainous areas, approximately 160 miles northwest of Sacramento. The area has a moderate year-round climate where the average daily temperature remains above freezing. The average annual temperature is approximately 62°F, and annual precipitation averages about 30 inches.

The Sacramento Valley portion of the air basin forms a bowl, bounded on the west by the Coast Ranges, on the north by the Cascade Range, and on the east by the Sierra Nevada. These mountain ranges reach heights exceeding 6,000 feet above sea level. During summer, the wide, flat expanse of the Sacramento Valley provides an ideal environment for the formation of photochemical smog. Moreover, the prevailing winds in the Sacramento Valley blow from south to north, driven by the marine air traveling through the Carquinez Strait. These winds can transport pollutants from the broader Sacramento area and from the San Francisco Bay Area to the Northern Sacramento Valley Air Basin. The mountain ranges that surround the Northern Sacramento Valley Air Basin (NSVAB) provide a physical barrier to continued movement of the air mass, significantly hindering the dispersal of pollutants.

### **Air Movement and Wind**

As with all of Central California, climate in the Shasta County area is dominated by the strength and location of a semi-permanent, subtropical high-pressure cell over the northeastern Pacific Ocean. Climate is also affected by the temperature moderating effects of the nearby oceanic heat reservoir. Warm summers, cool winters, rainfall, daytime onshore breezes, and moderate humidity characterize regional climatic conditions.

In summer, when the high-pressure cell is strongest, temperatures are very warm and humidity is low. The daily incursion of the sea breeze into the Central Valley, however, creates persistent breezes that moderate the summer heat. In winter, when the high-pressure cell is weakest, conditions are characterized by occasional rain and snow storms interspersed with stagnant conditions and sometimes heavy fog.

### **Sunlight**

The presence and intensity of sunlight are necessary prerequisites for the formation of photochemical smog. Under the influence of the ultraviolet radiation of sunlight, certain original or “primary” pollutants (mainly reactive hydrocarbons and oxides of nitrogen) react to form “secondary” pollutants (primarily oxidants). Since this process is time dependent, secondary pollutants can be formed many miles downwind from the emission sources. Because of the prevailing daytime winds and time delayed nature of photochemical smog, oxidant concentrations are highest in the inland areas of the NSVAB.

### **Temperature Inversions**

A temperature inversion is a reversal in the normal decrease of temperature as altitude increases. In most parts of the country, air near ground level is warmer than the air above it. Semi-permanent systems of high barometric pressure fronts establish themselves over the basin,

deflecting low-pressure systems that might otherwise bring cleansing rain and winds. The height of the base of the inversion is known as the "mixing height" and controls the volume of air available for the mixing and dispersion of air pollutants.

The interrelationship of air pollutants and climatic factors are most critical on days of greatly reduced atmospheric ventilation. On days such as these, air pollutants accumulate because of the simultaneous occurrence of three favorable factors: low inversions, low maximum mixing heights and low wind speeds. Although these conditions may occur throughout the year, the months of July, August and September generally account for more than 40 percent of these occurrences.

The potential for high contaminant levels varies seasonally for many contaminants. During late spring, summer and early fall, light winds, low mixing heights and sunshine combine to produce conditions favorable for the maximum production of oxidants, mainly ozone. When strong surface inversions are formed on winter nights, especially during the hours before sunrise, coupled with near-calm winds, carbon monoxide from automobile exhausts becomes highly concentrated. The highest yearly concentrations of carbon monoxide and oxides of nitrogen are measured during November, December and January.

### CRITERIA POLLUTANTS

The United States Environmental Protection Agency (EPA) uses six "criteria pollutants" as indicators of air quality, and has established for each of them a maximum concentration above which adverse effects on human health may occur. These threshold concentrations are called National Ambient Air Quality Standards (NAAQS). Each criteria pollutant is described below.

**Ozone (O<sub>3</sub>)** is a photochemical oxidant and the major component of smog. While O<sub>3</sub> in the upper atmosphere is beneficial to life by shielding the earth from harmful ultraviolet radiation from the sun, high concentrations of O<sub>3</sub> at ground level are a major health and environmental concern. O<sub>3</sub> is not emitted directly into the air but is formed through complex chemical reactions between precursor emissions of volatile organic compounds (VOC) and oxides of nitrogen (NOx) in the presence of sunlight. These reactions are stimulated by sunlight and temperature so that peak O<sub>3</sub> levels occur typically during the warmer times of the year. Both VOCs and NOx are emitted by transportation and industrial sources. VOCs are emitted from sources as diverse as autos, chemical manufacturing, dry cleaners, paint shops and other sources using solvents.

The reactivity of O<sub>3</sub> causes health problems because it damages lung tissue, reduces lung function and sensitizes the lungs to other irritants. Scientific evidence indicates that ambient levels of O<sub>3</sub> not only affect people with impaired respiratory systems, such as asthmatics, but healthy adults and children as well. Exposure to O<sub>3</sub> for several hours at relatively low concentrations has been found to significantly reduce lung function and induce respiratory inflammation in normal, healthy people during exercise. This decrease in lung function generally is accompanied by symptoms including chest pain, coughing, sneezing and pulmonary congestion.

**Carbon monoxide (CO)** is a colorless, odorless and poisonous gas produced by incomplete burning of carbon in fuels. When CO enters the bloodstream, it reduces the delivery of oxygen to the

body's organs and tissues. Health threats are most serious for those who suffer from cardiovascular disease, particularly those with angina or peripheral vascular disease. Exposure to elevated CO levels can cause impairment of visual perception, manual dexterity, learning ability and performance of complex tasks.

**Nitrogen dioxide (NO<sub>2</sub>)** is a brownish, highly reactive gas that is present in all urban atmospheres. NO<sub>2</sub> can irritate the lungs, cause bronchitis and pneumonia, and lower resistance to respiratory infections. Nitrogen oxides are an important precursor both to ozone (O<sub>3</sub>) and acid rain, and may affect both terrestrial and aquatic ecosystems. The major mechanism for the formation of NO<sub>2</sub> in the atmosphere is the oxidation of the primary air pollutant nitric oxide (NO). NO plays a major role, together with VOCs, in the atmospheric reactions that produce O<sub>3</sub>. NO forms when fuel is burned at high temperatures. The two major emission sources are transportation and stationary fuel combustion sources such as electric utility and industrial boilers.

**Sulfur dioxide (SO<sub>2</sub>)** affects breathing and may aggravate existing respiratory and cardiovascular disease in high doses. Sensitive populations include asthmatics, individuals with bronchitis or emphysema, children and the elderly. SO<sub>2</sub> is also a primary contributor to acid deposition, or acid rain, which causes acidification of lakes and streams and can damage trees, crops, historic buildings and statues. In addition, sulfur compounds in the air contribute to visibility impairment in large parts of the country. This is especially noticeable in national parks. Ambient SO<sub>2</sub> results largely from stationary sources such as coal and oil combustion, steel mills, refineries, pulp and paper mills and from nonferrous smelters.

**Particulate matter (PM)** includes dust, dirt, soot, smoke and liquid droplets directly emitted into the air by sources such as factories, power plants, cars, construction activity, fires and natural windblown dust. Particles formed in the atmosphere by condensation or the transformation of emitted gases such as SO<sub>2</sub> and VOCs are also considered particulate matter.

Based on studies of human populations exposed to high concentrations of particles (sometimes in the presence of SO<sub>2</sub>) and laboratory studies of animals and humans, there are major effects of concern for human health. These include effects on breathing and respiratory symptoms, aggravation of existing respiratory and cardiovascular disease, alterations in the body's defense systems against foreign materials, damage to lung tissue, carcinogenesis and premature death.

**Respirable particulate matter (PM<sub>10</sub>)** consists of small particles, less than 10 microns in diameter, of dust, smoke, or droplets of liquid which penetrate the human respiratory system and cause irritation by themselves, or in combination with other gases. Particulate matter in Shasta County is caused by many sources, including but not limited to, dust from grading and excavation activities, from agricultural uses (as created by soil preparation activities, fertilizer and pesticide spraying, weed burning and animal husbandry), road dust, wildfires, residential fuel combustion and from motor vehicles, particularly diesel-powered vehicles. PM<sub>10</sub> causes a greater health risk than larger particles, since these fine particles can more easily penetrate the defenses of the human respiratory system.

**Fine particulate matter (PM<sub>2.5</sub>)** consists of small particles, which are less than 2.5 microns in size. Similar to PM<sub>10</sub>, these particles are primarily the result of combustion in motor vehicles, particularly diesel engines, as well as from industrial sources and residential/agricultural activities such as burning. It is also formed through the reaction of other pollutants. As with PM<sub>10</sub>, these particulates can increase the chance of respiratory disease, and cause lung damage and cancer. In 1997, the EPA created new Federal air quality standards for PM<sub>2.5</sub>.

The major subgroups of the population that appear to be most sensitive to the effects of particulate matter include individuals with chronic obstructive pulmonary or cardiovascular disease or influenza, asthmatics, the elderly and children. Particulate matter also soils and damages materials, and is a major cause of visibility impairment.

**Lead (Pb)** exposure can occur through multiple pathways, including inhalation of air and ingestion of Pb in food, water, soil or dust. Excessive Pb exposure can cause seizures, mental retardation and/or behavioral disorders. Low doses of Pb can lead to central nervous system damage. Recent studies have also shown that Pb may be a factor in high blood pressure and subsequent heart disease.

### ODORS

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Typically odors are regarded as an annoyance rather than a health hazard. However, manifestations of a person's reaction to foul odors can range from psychological (e.g., irritation, anger, or anxiety) to physiological (e.g., circulatory and respiratory effects, nausea, vomiting, and headache).

With respect to odors, the human nose is the sole sensing device. The ability to detect odors varies considerably among the population and overall is quite subjective. Some individuals have the ability to smell minute quantities of specific substances; others may not have the same sensitivity but may have sensitivities to odors of other substances. In addition, people may have different reactions to the same odor; in fact, an odor that is offensive to one person (e.g., from a fast-food restaurant) may be perfectly acceptable to another.

It is also important to note that an unfamiliar odor is more easily detected and is more likely to cause complaints than a familiar one. This is because of the phenomenon known as odor fatigue, in which a person can become desensitized to almost any odor and recognition only occurs with an alteration in the intensity.

Quality and intensity are two properties present in any odor. The quality of an odor indicates the nature of the smell experience. For instance, if a person describes an odor as flowery or sweet, then the person is describing the quality of the odor. Intensity refers to the strength of the odor. For example, a person may use the word "strong" to describe the intensity of an odor. Odor intensity depends on the odorant concentration in the air.

When an odorous sample is progressively diluted, the odorant concentration decreases. As this occurs, the odor intensity weakens and eventually becomes so low that the detection or recognition of the odor is quite difficult. At some point during dilution, the concentration of the

odorant reaches a detection threshold. An odorant concentration below the detection threshold means that the concentration in the air is not detectable by the average human.

### TOXIC AIR CONTAMINANTS

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TACs are pollutants that may be expected to result in an increase in mortality or serious illness or that may pose a present or potential hazard to human health. Health effects include cancer, birth defects, neurological damage, damage to the body's natural defense system, and diseases that lead to death. Although ambient air quality standards exist for criteria pollutants, no such standards exist for TACs.

Many pollutants are identified as TACs because of their potential to increase the risk of developing cancer or because of their acute or chronic health risks. For TACs that are known or suspected carcinogens, the California Air Resources Board (ARB) has consistently found that there are no levels or thresholds below which exposure is free of risk. Individual TACs vary greatly in the risk they present. At a given level of exposure, one TAC may pose a hazard that is many times greater than another. For certain TACs, a unit risk factor can be developed to evaluate cancer risk. For acute and chronic health risks, a similar factor called a Hazard Index is used to evaluate risk. In the early 1980s, ARB established a statewide comprehensive air toxics program to reduce exposure to air toxics. The Toxic Air Contaminant Identification and Control Act (Assembly Bill [AB] 1807) created California's program to reduce exposure to air toxics. The Air Toxics "Hot Spots" Information and Assessment Act (AB 2588) supplements the AB 1807 program by requiring a statewide air toxics inventory, notification of people exposed to a significant health risk, and facility plans to reduce these risks.

### SENSITIVE RECEPTORS

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A sensitive receptor is a location where human populations, especially children, seniors, and sick persons, are present and where there is a reasonable expectation of continuous human exposure to pollutants. Examples of sensitive receptors include residences, hospitals and schools. There are a number of existing residences located within a half-mile of the project site with the closest residences being those located across the Sacramento River and across SR 273 to the southwest of the project site. The nearest school to the project site is Verde Vale Elementary School, which is located approximately 0.38 miles to the southwest of the proposed cogeneration facility. While not formally considered to be sensitive receptors, wildlife and vegetation may also be adversely impacted by continuous exposure to pollutant concentrations.

### AMBIENT AIR QUALITY

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Both the U.S. Environmental Protection Agency (U.S. EPA) and the California Air Resources Board (CARB) have established ambient air quality standards for common pollutants. These ambient air quality standards represent safe levels of contaminants that avoid specific adverse health effects associated with each pollutant.

The federal and California state ambient air quality standards are summarized in Table 3.2-1 for important pollutants. The federal and state ambient standards were developed independently,

although both processes attempted to avoid health-related effects. As a result, the federal and state standards differ in some cases. In general, the California state standards are more stringent. This is particularly true for ozone and particulate matter between 2.5 and 10 microns in diameter (PM<sub>10</sub>).

**TABLE 3.2-1: FEDERAL AND STATE AMBIENT AIR QUALITY STANDARDS**

<i>POLLUTANT</i>	<i>AVERAGING TIME</i>	<i>FEDERAL PRIMARY STANDARD</i>	<i>STATE STANDARD</i>
Ozone	1-Hour	--	0.09 ppm
	8-Hour	0.075 ppm	0.070 ppm
Carbon Monoxide	8-Hour	9.0 ppm	9.0 ppm
	1-Hour	35.0 ppm	20.0 ppm
Nitrogen Dioxide	Annual	0.05 ppm	--
	1-Hour	--	0.25 ppm
Sulfur Dioxide	Annual	0.03 ppm	--
	24-Hour	0.14 ppm	0.04 ppm
	1-Hour	--	0.25 ppm
PM <sub>10</sub>	Annual	--	20 ug/m <sup>3</sup>
	24-Hour	150 ug/m <sup>3</sup>	50 ug/m <sup>3</sup>
PM <sub>2.5</sub>	Annual	15 ug/m <sup>3</sup>	12 ug/m <sup>3</sup>
	24-Hour	35 ug/m <sup>3</sup>	--
Lead	30-Day Avg.	--	1.5 ug/m <sup>3</sup>
	3-Month Avg.	1.5 ug/m <sup>3</sup>	--

SOURCE: CALIFORNIA AIR RESOURCES BOARD, 2010

Notes: ppm = parts per million, ug/m<sup>3</sup> = Micrograms per Cubic Meter

### Attainment Status

In accordance with the California Clean Air Act (CCAA), the CARB is required to designate areas of the state as attainment, nonattainment, or unclassified with respect to applicable standards. An “attainment” designation for an area signifies that pollutant concentrations did not violate the applicable standard in that area. A “nonattainment” designation indicates that a pollutant concentration violated the applicable standard at least once, excluding those occasions when a violation was caused by an exceptional event, as defined in the criteria.

Depending on the frequency and severity of pollutants exceeding applicable standards, the nonattainment designation can be further classified as serious nonattainment, severe nonattainment, or extreme nonattainment, with extreme nonattainment being the most severe of the classifications. An “unclassified” designation signifies that the data do not support either an attainment or nonattainment status. The CCAA divides districts into moderate, serious, and severe air pollution categories, with increasingly stringent control requirements mandated for each category.

The U.S. EPA designates areas for ozone (O<sub>3</sub>), carbon monoxide (CO), and nitrogen dioxide (NO<sub>2</sub>) as “does not meet the primary standards,” “cannot be classified,” or “better than national standards.” For sulfur dioxide (SO<sub>2</sub>), areas are designated as “does not meet the primary standards,” “does not meet the secondary standards,” “cannot be classified,” or “better than

national standards.” However, the CARB terminology of attainment, nonattainment, and unclassified is more frequently used.

The sub-categories for nonattainment status (serious, severe, and extreme) are also used by U.S. EPA. In 1991, new nonattainment designations were assigned to areas that had previously been classified as Group I, II, or III for PM<sub>10</sub> based on the likelihood that they would violate national PM<sub>10</sub> standards. All other areas are designated “unclassified.”

Federal and state air quality laws require identification of areas not meeting the ambient air quality standards. These areas must develop regional air quality plans to eventually attain the standards.

The U.S. Environmental Protection Agency (EPA) has classified Shasta County as an unclassified/attainment area for the 8-hour ozone, CO, PM<sub>10</sub>, and PM<sub>2.5</sub> standards. However, it should be noted that the EPA has proposed lowering the 8-hour ozone standard to a range of values between 0.060 and 0.070, which if approved, would place Shasta County’s National Designation as Non-Attainment for this standard.

The CARB has classified Shasta County as a moderate nonattainment area for the 1-hour ozone standard, an unclassified area for the CO and PM<sub>2.5</sub> standards, and a nonattainment area for the PM<sub>10</sub> standard. Shasta County’s attainment status for each of these pollutants relative to the NAAQS and CAAQS is summarized in **Table 3.2-2**.

**TABLE 3.2-2: FEDERAL AND STATE ATTAINMENT STATUS FOR SHASTA COUNTY**

<i>CRITERIA POLLUTANTS</i>	<i>STATE DESIGNATIONS</i>	<i>NATIONAL DESIGNATIONS</i>
1-Hour Ozone	Moderate Nonattainment	--
8-Hour Ozone	Nonattainment	Unclassified/Attainment
PM <sub>10</sub>	Nonattainment	Unclassified
PM <sub>2.5</sub>	Unclassified	Unclassified/Attainment
Carbon Monoxide	Unclassified	Unclassified/Attainment
Nitrogen Dioxide	Attainment	Unclassified/Attainment
Sulfur Dioxide	Attainment	Unclassified
Sulfates	Attainment	
Lead	Attainment	
Hydrogen Sulfide	Unclassified	
Visibility Reducing Particles	Unclassified	

SOURCES: CALIFORNIA AIR RESOURCES BOARD (2010).

### Air Quality Monitoring

In combination, local air quality management districts and the California Air Resources Board (CARB) monitor ambient air quality at approximately 250 air-monitoring stations across the state. Air quality monitoring stations usually measure pollutant concentrations ten feet above ground level; therefore, air quality is often referred to in terms of ground-level concentrations. The AQMD currently operates monitoring stations in Redding, Anderson and Shasta Lake. At these sites, inhalable particulate matter (PM<sub>10</sub>) samplers are operated, every sixth day, year-round. The Anderson-North Street monitoring station collects PM<sub>2.5</sub> data via beta attenuation monitor (BAM),



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and does not collect this data for the PM<sub>2.5</sub> federal reference method. The highest concentrations of PM<sub>10</sub> typically occur during the open burning/wood stove use season in Shasta County which is from October through April each year. Additionally, during the summer/fall wildfire season wildfires in and around Shasta County create high levels of PM<sub>10</sub>, as evident from the data for 2008, as shown in the tables below. Continuous sampling of ground-level ozone concentration is conducted from May 1st through October 31st on a 24-hr/day basis, with sampling for other pollutants being conducted year round.

The Anderson-North Street monitoring station is nearest the project site, located approximately 1.6 miles southeast of the project site. However, the Anderson-North Street monitoring station does not collect data for PM<sub>2.5</sub>. Therefore, it was necessary to use monitoring data from the Redding- Health Department Roof monitoring station to provide monitoring data for PM<sub>2.5</sub>. The Redding monitoring station is located approximately 6 miles northwest of the project site. PM<sub>10</sub> data is also collected at the Shasta Lake-La Mesa Avenue monitoring site, which is located approximately 14.5 miles north of the project site. Air Quality data from 2006-2009 are provided in Tables 3.2-3, 3.2-4 and 3.2-5.

**TABLE 3.2-3: AMBIENT AIR QUALITY MONITORING DATA (ANDERSON – NORTH STREET)**

POLLUTANT	CAL.	FED.	YEAR	MAX CONCENTRATION	DAYS (SAMPLES) STATE/FED STANDARD EXCEEDED
	PRIMARY STANDARD				
Ozone (O <sub>3</sub> ) (1-hour)	0.09 ppm for 1 hour	NA	2006	0.092	0 / *
			2007	0.084	0 / *
			2008	0.097	1 / *
			2009	0.091	0 / *
Ozone (O <sub>3</sub> ) (8-hour)	0.07 ppm for 8 hour	0.075 ppm for 8 hour	2006	0.080	7 / 1
			2007	0.080	19 / 3
			2008 <sup>1</sup>	0.091	24 / 11
			2009	0.077	9 / 1
Particulate Matter (PM <sub>10</sub> )	50 ug/m3 for 24 hours	150 ug/m3 for 24 hours	2006	53.0	6.1 / 0
			2007	46.0	0 / 0
			2008 <sup>1</sup>	135.9	24.4 / 0
			2009	37.9	0 / 0
Fine Particulate Matter (PM <sub>2.5</sub> )	No 24 hour State Standard	35 ug/m3 for 24 hours	Not collected at this site.		

SOURCES: CALIFORNIA AIR RESOURCES BOARD (ADAM) AIR POLLUTION SUMMARIES, 2006-2009.

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**TABLE 3.2-4: AMBIENT AIR QUALITY MONITORING DATA (REDDING – HEALTH DEPARTMENT ROOF)**

POLLUTANT	CAL.	FED.	YEAR	MAX CONCENTRATION	DAYS (SAMPLES) STATE/FED STANDARD EXCEEDED
	PRIMARY STANDARD				
Ozone (O <sub>3</sub> ) (1-hour)	0.09 ppm for 1 hour	NA	2006	0.107	2 / *
			2007	0.089	0 / *
			2008	0.090	0 / *
			2009	0.084	0 / *
Ozone (O <sub>3</sub> ) (8-hour)	0.07 ppm for 8 hour	0.075 ppm for 8 hour	2006	0.087	19 / 9
			2007	0.073	5 / 0
			2008	0.083	13 / 4
			2009	0.069	0 / 0
Particulate Matter (PM <sub>10</sub> )	50 ug/m3 for 24 hours	150 ug/m3 for 24 hours	2006	54.0	6.1 / 0
			2007	36.0	0 / 0
			2008 <sup>1</sup>	236.2	32.7 / 6.6
			2009	33.7	0 / 0
Fine Particulate Matter (PM <sub>2.5</sub> )	No 24 hour State Standard	35 ug/m3 for 24 hours	2006	31.0	* / 0
			2007	18.6	* / 0
			2008 <sup>1</sup>	200.2	* / 29.8
			2009	20.2	* / 0

SOURCES: CALIFORNIA AIR RESOURCES BOARD (ADAM) AIR POLLUTION SUMMARIES, 2006-2009.

**TABLE 3.2-5: AMBIENT AIR QUALITY MONITORING DATA (SHASTA LAKE- LA MESA AVENUE)**

POLLUTANT	CAL.	FED.	YEAR	MAX CONCENTRATION	DAYS (SAMPLES) STATE/FED STANDARD EXCEEDED
	PRIMARY STANDARD				
Ozone (O <sub>3</sub> ) (1-hour)	0.09 ppm for 1 hour	NA	Not collected at this site.		
Ozone (O <sub>3</sub> ) (8-hour)	0.07 ppm for 8 hour	0.075 ppm for 8 hour	Not collected at this site.		
Particulate Matter (PM <sub>10</sub> )	50 ug/m3 for 24 hours	150 ug/m3 for 24 hours	2006	43.0	0 / 0
			2007	55.0	0 / 0
			2008 <sup>1</sup>	108.9	19.5 / 0
			2009	31.9	0 / 0
Fine Particulate Matter (PM <sub>2.5</sub> )	No 24 hour State Standard	35 ug/m3 for 24 hours	Not collected at this site.		

SOURCES: CALIFORNIA AIR RESOURCES BOARD (ADAM) AIR POLLUTION SUMMARIES, 2006-2009.

**Notes:**

ppm = parts per million.

Ug/m3 = microns per cubic meter.

NA= not applicable

\* = There was insufficient (or no) data available to determine the value

<sup>1</sup> = An exceptional event was granted for wildfires this season

As shown in the tables above, concentrations of ozone and particulate matter monitored at the stations in Shasta County trended downward from 2006 through 2009. The exception to this trend occurred in 2008, a year in which exceptional wildfire events resulted in significantly increased concentrations of particulate matter (PM<sub>10</sub> and PM<sub>2.5</sub>) and slightly increased levels of ozone.

Factors that have contributed to this trend are likely varied and whether this positive trend will be projected into the future has not been evaluated, but the data indicates that over this period ambient air quality conditions in Shasta County have generally improved.

### 3.2.2 REGULATORY SETTING

#### FEDERAL

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##### **Clean Air Act**

The Federal Clean Air Act (CAA) was first signed into law in 1970. In 1977, and again in 1990, the law was substantially amended. The CAA is the foundation for a national air pollution control effort, and it is composed of the following basic elements: National Ambient Air Quality Standards (NAAQS) for criteria air pollutants, hazardous air pollutant standards, state attainment plans, motor vehicle emissions standards, stationary source emissions standards and permits, acid rain control measures, stratospheric ozone protection, and enforcement provisions.

The EPA is responsible for administering the CAA. The CAA requires the EPA to set NAAQS for several problem air pollutants based on human health and welfare criteria. Two types of NAAQS were established: primary standards, which protect public health, and secondary standards, which protect the public welfare from non-health-related adverse effects such as visibility reduction.

##### **Prevention of Significant Deterioration**

The Prevention of Significant Deterioration, or PSD, permit program was developed by the United States Congress to prevent significant environmental impacts on “attainment areas” or unclassifiable areas with the NAAQS from large industrial sources of air pollution. The PSD program is implemented by both federal and State regulations. The regulations apply to new or modified air pollution sources that are classified as “major” relative to air pollution emissions potential, and that are proposing construction projects that may “significantly” increase their air pollutant emissions. Under the PSD program, the new construction or modification must use air pollution control equipment and procedures determined by the Shasta County Air Quality Management District and/or US EPA to be the most effective for the project (Best Available Control Technology, or BACT). The applicant must also provide a detailed evaluation of the proposed project’s air quality impact on the local and regional environment.

##### **Acid Rain Program**

The EPA’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<sub>2</sub> and NO<sub>x</sub>, the primary causes of acid rain. 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. In other words, if the cogeneration unit were to sell more than 219,000 megawatt (electric)-hours (MWe-hrs) of electricity annually, it would be subject to the 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.

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, and is not subject to the Acid Rain Program.

### **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.

### **New Source Performance Standards**

EPA has established performance standards for a number of air pollution sources in 40 CFR Part 60. These New Source Performance Standards (NSPS) usually represent a minimum level of control that is required of a new source. NSPS Subpart Db addresses emissions from boilers that have a heat input of greater than 100 MMBtu/hr. This will apply to the proposed 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<sub>10</sub> 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<sub>2</sub> and NO<sub>x</sub> limits on boilers that fire fossil fuels under certain conditions. The SO<sub>2</sub> limits do not apply to boilers that combust natural gas. The NO<sub>x</sub> 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<sub>2</sub> nor the NO<sub>x</sub> emission limits identified in Subpart Db will apply.

### **Maximum Achievable Control Technology (MACT)**

The Clean Air Act Amendments of 1990 require EPA 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 tons per year (TPY) of a single HAP or more than 25 TPY of all HAPs combined. It should be noted that there is a Maximum Achievable Control Technology (MACT) rule proposed for Industrial/Commercial/Institutional Boilers and Process Heaters. The boiler MACT proposal was signed by the EPA Administrator on April 29, 2010. A copy of the signed proposed rule can be downloaded at: <http://www.epa.gov/airquality/combustion/>.

The existing and proposed boiler would not operate concurrently and the proposed boiler has a greater firing rate, therefore the calculated maximum HAP emissions from the proposed boiler represents the maximum annual HAP PTE for any combined operation of the two boilers (i.e., not concurrent operation, but some combination of the two boilers operating during a given 12-month period).

Considering HAP emissions from the proposed boiler and the existing lumber dry kilns, the HAP emitted in greatest quantity will be acetaldehyde at an annual rate 7.77 TPY, and emissions of all 47 HAPs combined will be 30.3 TPY. Consequently, the facility's post-project HAP potential to emit will exceed the combined HAPs MACT threshold, and the facility will be subject to the MACT program.

### STATE

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#### **California Clean Air Act**

The California Clean Air Act (CCAA) was first signed into law in 1988. The CCAA provides a comprehensive framework for air quality planning and regulation, and spells out, in statute, the state's air quality goals, planning and regulatory strategies, and performance. CARB is the agency responsible for administering the CCAA. CARB established ambient air quality standards pursuant to the California Health and Safety Code (CH&SC) [§39606(b)], which are similar to the federal standards.

#### **Air Quality Standards**

NAAQS are determined by the EPA. The standards include both primary and secondary ambient air quality standards. Primary standards are established with a safety margin. Secondary standards are more stringent than primary standards and are intended to protect public health and welfare. States have the ability to set standards that are more stringent than the federal standards. As such, California established more stringent ambient air quality standards.

Federal and state ambient air quality standards have been established for ozone, carbon monoxide, nitrogen dioxide, sulfur dioxide, suspended particulates (PM<sub>10</sub>) and lead. In addition, California has created standards for pollutants that are not covered by federal standards. The state and federal primary standards for major pollutants are shown in Table 3.2-1.

Like the EPA, CARB also designates areas within California as either attainment or nonattainment for each criteria pollutant based on whether the CAAQS have been achieved. Under the CCAA, areas are designated as nonattainment for a pollutant if air quality data shows that a State standard for the pollutant was violated at least once during the previous three calendar years. Exceedances that are affected by highly irregular or infrequent events are not considered violations of a State standard, and are not used as a basis for designating areas as nonattainment.

### **Tanner Air Toxics Act**

California regulates TACs primarily through the Tanner Air Toxics Act (AB 1807) and the Air Toxics Hot Spots Information and Assessment Act of 1987 (AB 2588). The Tanner Act sets forth a formal procedure for ARB to designate substances as TACs. This includes research, public participation, and scientific peer review before ARB can designate a substance as a TAC. To date, ARB has identified more than 21 TACs and has adopted EPA's list of HAPs as TACs. Most recently, diesel PM was added to the ARB list of TACs. Once a TAC is identified, ARB then adopts an Airborne Toxics Control Measure (ATCM) for sources that emit that particular TAC. If there is a safe threshold for a substance at which there is no toxic effect, the control measure must reduce exposure below that threshold. If there is no safe threshold, the measure must incorporate BACT to minimize emissions.

The AB 2588 requires that existing facilities that emit toxic substances above a specified level prepare a toxic-emission inventory, prepare a risk assessment if emissions are significant, notify the public of significant risk levels, and prepare and implement risk reduction measures. Upcoming and recent milestones include the low-sulfur diesel-fuel requirement, and tighter emission standards for heavy-duty diesel trucks (2007) and off-road diesel equipment (2011) nationwide.

### **Offsets**

As required by Sections 40918, 40919, 40920, and 40920.5 of the California Health & Safety (H&S) Code, areas designated as being in nonattainment for one or more of the criteria pollutants identified in State or Federal standards must 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<sub>10</sub> ambient air quality standards, it has further been classified as having "moderate air pollution." Shasta County maintains a bank of Emissions Reduction Credits (ERCs) to be used as mitigation offsets for emissions increases. This ERC program is described in greater detail below.

## **SHASTA COUNTY AQMD REGULATIONS**

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### **Authority to Construct (ATC) 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 3.2-11, along with the daily PTE and regulatory threshold. As shown in the table, BACT is required for reactive organic compounds (ROG), NO<sub>x</sub>, PM<sub>10</sub>, CO, and beryllium. 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.

### **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<sub>10</sub> is limited to 0.05 gr/dscf, and combustion PM is limited to 0.10 gr/dscf. SO<sub>2</sub> emissions are limited to 200 parts per million (ppm), and NO<sub>x</sub> 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.

### **District Emission Reduction Credit and Banking Rule (Rule 2:2)**

The purpose of District Rule 2:2 is to provide a mechanism for permitted and non-permitted emission sources to deposit, transfer, and use emission reduction credits (ERCs) as offsets as allowed by applicable laws and regulations. To ensure that all emission reductions are transferred through the District's emission reduction credit bank pursuant to the Health and Safety Code. All transfers and uses of emission reductions that are required under the District's New Source Review (NSR) Rule shall be processed in accordance with this rule. The ERC program provides a mechanism for intrabasin transfers and use of banked ERCs. The provisions of Rule 2:2 apply to the deposit, transfer, and use of emission reduction credits (ERCs) from stationary sources and open biomass burning sources of air pollution emissions. Any person, entity, landowner, or authorized agent, which owns or operates an emission unit for which an eligible emission reduction has occurred or will occur may apply for an ERC certificate in accordance with the requirements of this Rule. To verify emission reductions claimed in conjunction with an application for an ERC certificate, the District may require source tests by ARB approved methods, continuous monitoring, production records, fuel use records, or any other appropriate means. The District maintains a bank register, which contains a record of all deposits, withdrawals and other transactions with regard to the District's banking system.

SPI currently has ERCs banked with the District. The ERCs may be used at the time of, or anytime after deposit into the District's banking system by the registered owner, or owner's designee of the ERC certificate to provide offsets for increase in emissions from new or modified sources subject to the NSR Rule.

### 3.2.3 IMPACTS AND MITIGATION MEASURES

#### THRESHOLDS OF SIGNIFICANCE

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Consistent with Appendix G of the CEQA Guidelines, the proposed project will have a significant impact on the environment associated with air quality if it will:

- Conflict with or obstruct implementation of the applicable air quality plan;
- Cause a violation of any air quality standard or contribute substantially to an existing or projected air quality violation;
- Result in a cumulatively considerable net increase of any criteria pollutant for which the project region is in non-attainment under an applicable federal or state ambient air quality standard (including releasing emissions which exceed quantitative thresholds for ozone precursors);
- Expose sensitive receptors to substantial pollutant concentrations;
- Create objectionable odors affecting a substantial number of people.

#### **SCAQMD Thresholds**

For the purposes of this air quality analysis, actions that violate Federal standards for criteria pollutants (i.e., primary standards designed to safeguard the health of people considered to be sensitive receptors while outdoors and secondary standards designed to safeguard human welfare) are considered significant impacts. Additionally, actions that violate State standards developed by the CARB or criteria developed by the SCAQMD, including thresholds for criteria pollutants, are considered significant impacts. As described in SCAQMD Rule 2:1, Part 301 the following thresholds of significance (shown in Table 3.2-6) for criteria pollutants and other regulated pollutants shall be used to determine significance. Shasta County has two levels of emission thresholds for Nox, ROG and PM<sub>10</sub>; these are used to determine the appropriate level of required mitigation measures. If Level A thresholds are exceeded by a project, then standard mitigation measures (SMMs) are required. If Level B thresholds are exceeded by a project, then best available mitigation measures (BAMMs) are required.



**TABLE 3.2-6: SCAQMD EMISSIONS THRESHOLDS OF SIGNIFICANCE**

<i>POLLUTANT</i>	<i>THRESHOLD A (LBS/DAY)</i>	<i>THRESHOLD B (LBS/DAY)</i>
NOx	25.0	137
CO	500.0	NA
SO <sub>2</sub>	80.0	NA
PM/PM <sub>10</sub>	80.0	137
VOC/ROG	25.0	137
Sulfuric Acid	35.0	NA
Lead	3.2	NA
Asbestos	0.03	NA
Beryllium	0.002	NA
Mercury	0.5	NA
Vinyl Chloride	5.0	NA
Fluorides	15.0	NA
TRS/H <sub>2</sub> S/RS*	50.0	NA

SOURCE: SCAQMD RULE 2:1, PART 301

\*TRS= TOTAL REDUCED SULFUR COMPOUNDS, H<sub>2</sub>S= HYDROGEN SULFIDE, AND RS= REDUCED SULFUR COMPOUNDS.

### Construction Specific Thresholds

Thresholds of significance for construction emissions are contained in Table 3.2-6. If construction emissions exceed the thresholds listed in this table, they would be considered significant. The SCAQMD has standard mitigation measures (SMMs) and best available mitigation measures (BAMMs) that must be implemented during construction activities in order to reduce emissions from trucks and heavy machinery, as well as fugitive dust that may result from construction activities. The analysis in this section includes a quantification of the estimated construction emissions that are likely to occur.

### Odor Based Thresholds

Projects that would potentially generate objectionable odorous emissions that would be located near existing sensitive receptors or other land uses where people may congregate could constitute a significant air quality impact to existing uses. Also, residential or other sensitive receptor projects built for the intent of attracting people locating near existing odor sources could also cause a significant air quality impact for the proposed uses. While the SCAQMD does not have a specific threshold used to measure the significance of odors, other AQMDs in California suggest a threshold based on the distance of the odor source from people and complaint records for a facility or similar facility. The threshold would be more than one confirmed complaint per year averaged over a three-year period, or three unconfirmed complaints per year averaged over a three-year period.

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**METHODOLOGY**

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**Construction Impact Methods**

Construction emissions would originate from construction equipment exhaust, employee vehicle exhaust, dust from grading the land, exposed soil eroded by wind, and ROG<sub>s</sub> from architectural coating and asphalt paving. Construction-related emissions would vary substantially depending on the level of activity, length of the construction period, specific construction operations, types of equipment, number of personnel, wind and precipitation conditions, and soil moisture content.

Site clearing, grading, excavating, use of heavy equipment or trucks on unpaved surfaces, and loading/unloading trucks release fugitive dust, including PM<sub>10</sub>. Fugitive dust emissions from construction activities are temporary; however, they could have a significant impact on localized air quality. Construction equipment exhaust emissions were estimated and analyzed using URBEMIS 2007, which is a computer program used to estimate emissions from construction, vehicle trips, fuel use resulting from land use development projects, and ROG<sub>s</sub> from architectural coatings and asphalt paving (California Air Resources Board 2007). To estimate construction emissions, URBEMIS 2007 analyzes the type of construction equipment used and the duration of the construction period. The results of the URBEMIS calculations are included as **Appendix J**.

A detailed inventory of construction equipment that will be used for the proposed project has not yet been developed. Because construction plans for the proposed project have not been finalized, estimated construction emissions were based on default equipment inventories calculated by URBEMIS 2007, and professional judgment. The assumptions for each phase of construction are provided below.

**Demolition and site prep**

- 1 Concrete/Industrial Saws (10 hp) operating at a 0.73 load factor for 8 hours per day
- 1 Rubber Tired Dozers (357 hp) operating at a 0.59 load factor for 1 hours per day
- 2 Tractors/Loaders/Backhoes (108 hp) operating at a 0.55 load factor for 6 hours per day

**Fine site grading**

Total Acres Disturbed: 4.75

Maximum Daily Acreage Disturbed: 1.19

Off-Road Equipment:

- 1 Graders (174 hp) operating at a 0.61 load factor for 6 hours per day
- 1 Rubber Tired Dozers (357 hp) operating at a 0.59 load factor for 6 hours per day
- 1 Tractors/Loaders/Backhoes (108 hp) operating at a 0.55 load factor for 7 hours per day

- 1 Water Trucks (189 hp) operating at a 0.5 load factor for 8 hours per day

**Mass site grading**

Total Acres Disturbed: 4.75

Maximum Daily Acreage Disturbed: 1.19

Off-Road Equipment:

- 1 Graders (174 hp) operating at a 0.61 load factor for 6 hours per day
- 1 Rubber Tired Dozers (357 hp) operating at a 0.59 load factor for 6 hours per day
- 1 Tractors/Loaders/Backhoes (108 hp) operating at a 0.55 load factor for 7 hours per day
- 1 Water Trucks (189 hp) operating at a 0.5 load factor for 8 hours per day

**Trenching**

Off-Road Equipment:

2 Excavators (168 hp) operating at a 0.57 load factor for 8 hours per day

- 1 Other General Industrial Equipment (238 hp) operating at a 0.51 load factor for 8 hours per day
- 1 Tractors/Loaders/Backhoes (108 hp) operating at a 0.55 load factor for 0 hours per day

**Building construction**

Off-Road Equipment:

- 1 Cranes (399 hp) operating at a 0.43 load factor for 6 hours per day
- 2 Forklifts (145 hp) operating at a 0.3 load factor for 6 hours per day
- 1 Generator Sets (49 hp) operating at a 0.74 load factor for 8 hours per day
- 1 Tractors/Loaders/Backhoes (108 hp) operating at a 0.55 load factor for 8 hours per day
- 3 Welders (45 hp) operating at a 0.45 load factor for 8 hours per day

**Operational Emissions Impact Methods**

Operational emissions associated with the proposed project would come primarily from two sources: 1) emissions from increased truck and vehicle trips associated with the delivery of bio-mass material to the project site and the increase in employees generated by the proposed project; and 2) emissions associated with operation of the cogeneration facility, primarily the boiler and the handling and disposal of ash from the boiler.

Mobile source emissions associated with the increase in heavy truck and passenger vehicle trips were quantified using the CARB-approved URBEMIS 2007 model. The trips generated by the proposed project were calculated in the project's Traffic Impact Study (OMNI-MEANS, 2010), which is attached as **Appendix G**.

Emissions from operation of the proposed cogeneration facility were quantified within the Prevention of Significant Deterioration and Authority to Construct Permit Application (ENVIRON, 2010), which is included as **Appendix B**.

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.

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## IMPACTS AND MITIGATION MEASURES

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### **Short-term (Construction) Impacts**

#### **Impact 3.2-1: Construction of the proposed project would result in temporary dust and vehicle emission impacts in the project vicinity during site preparation and construction activities (Less than Significant with Mitigation)**

As described above, the approach to this CEQA analysis of construction impacts is to require implementation of effective and comprehensive control measures. PM<sub>10</sub> and other criteria

pollutants emitted during construction can vary greatly depending on the level of activity, the specific operations taking place, the equipment being operated, and other factors.

Construction would result in numerous activities that would generate dust. The fine, silty soils in the project area and often strong afternoon winds exacerbate the potential for dust, particularly in the summer months. Grading, leveling, earthmoving and excavation are the activities that generate the most particulate emissions. Impacts would be localized and variable. Construction impacts would last for a period of several months.

Construction activities that could generate dust and vehicle emissions are primarily related to grading and other ground-preparation activities in order to prepare the project site for the installation of the various components of the cogeneration facility.

The estimated construction emissions are presented below in Table 3.2-7.

**TABLE 3.2-7: CONSTRUCTION EMISSIONS (UNMITIGATED)**

POLLUTANT	CONSTRUCTION EMISSIONS (POUNDS PER DAY)	THRESHOLD A/B (POUNDS PER DAY)	OVER THRESHOLD A/B?
NO <sub>x</sub>	50.15	25/137	Yes/No
CO	28.33	500/NA	No/NA
SO <sub>2</sub>	0.00	80/NA	No/NA
ROG	6.10	25/137	No/No
PM <sub>10</sub>	50.12	80/137	No/No
PM <sub>2.5</sub>	12.25	80/NA	No/NA

*SOURCE: DE NOVO PLANNING GROUP, 2010 (URBEMIS 2007 MODELING)*

As shown in Table 3.2-7, construction activities associated with the proposed project would not exceed SCAQMD thresholds A or B for CO, SO<sub>2</sub>, ROG, PM<sub>10</sub> or PM<sub>2.5</sub>. However, project construction may result in up to 50.15 lbs/day of NO<sub>x</sub>, which exceeds the District threshold A of 25 lbs/day. Project construction would not exceed any of the Level B thresholds of significance, and would exceed the Level A threshold for NO<sub>x</sub>, which requires the implementation of SMMs. This is considered a **potentially significant** impact.

### **Naturally Occurring Asbestos (NOA)**

Pursuant to guidance issued by the Governor’s Office of Planning and Research (OPR), State Clearinghouse, Lead Agencies are encouraged to analyze potential impacts related to naturally occurring asbestos. NOA can be released from serpentine soils and ultramafic rocks when the rocks are broken or crushed or when soils are disturbed. At the point of release, the asbestos fibers may become airborne, causing air quality and human health hazards.

Serpentine soils and/or ultramafic rock are known to be present in 44 of California’s 58 counties. These rocks and soils are particularly abundant in the counties of the Sierra Nevada foothills, the Klamath Mountains and Coast Ranges. According to the *General Location Guide for Ultramafic Rock in California- Areas More Likely to Contain Naturally Occurring Asbestos*, serpentine soils and

ultramafic rocks are not known to occur within the proposed project site, and thus, there is no potential that the proposed project would disturb NOA. This is considered a **less than significant impact**.

### Odors

Odors generated during construction activities would be limited and temporary. This impact is considered **less than significant**. It should be noted that emissions produced during grading and construction activities are “short-term” in nature as they occur for only the duration of construction.

### MITIGATION MEASURES

**Mitigation Measure 3.2-1:** *Prior to the commencement of construction activities, the project applicant shall prepare a construction emissions reduction plan that meets the requirements of the SCAQMD. The construction emissions reduction plan shall be submitted to the SCAQMD for review and approval. Said plan shall conform to SCAQMD rules governing Fugitive, Indirect, or Non-Traditional Sources. The construction emissions reduction plan should include the following requirements and measures: The project applicant shall require any and all persons/entities involved in the construction of the project to implement all feasible the following measures and any other Reasonably Available Control Measures (RACMs) such that operations comply with SCAQMD rules governing Fugitive, Indirect, or Non-Traditional Sources. Such measures include, but are not limited to those listed below:*

#### **PM<sub>10</sub> Controls:**

- *The applicant will be responsible for ensuring that all adequate dust control measures are implemented in a timely and effective manner during all phases of project development and construction.*
- *All material excavated, stockpiled, or graded should be sufficiently watered to prevent fugitive dust from leaving property boundaries and causing a public nuisance or a violation of an ambient air standard. Watering should occur at least twice daily with complete site coverage, preferably in the mid-morning and after work is completed each day.*
- *All areas (including unpaved roads) with vehicle traffic should be watered periodically or have dust palliatives applied for stabilization of dust emissions.*
- *All onsite vehicles should be limited to a speed of 15 miles per hour on unpaved roads.*
- *All land clearing, grading, earth moving, and excavation activities on a project will be suspended when winds are expected to exceed 20 miles per hour.*
- *All inactive portions of the development site should be seeded and watered until suitable grass cover is established.*

- *The applicant will be responsible for applying (according to manufacturer's specifications) nontoxic soil stabilizers to all inactive construction areas (previously graded areas that remain inactive for 96 hours) in accordance with the Shasta County Grading Ordinance.*
- *All trucks hauling dirt, sand, soil, or other loose material should be covered or should maintain at least 2 feet of freeboard (i.e., minimum vertical distance between top of the load and top of the trailer) in accordance with the requirements of California Vehicle Code Section 23114. This provision will be enforced by local law enforcement agencies.*
- *All material transported off site will be either sufficiently watered or securely covered to prevent a public nuisance.*
- *Paved streets adjacent to the development site should be swept or washed at the end of each day to remove excessive accumulations of silt and/or mud that may have accumulated as a result of activities on the development site.*
- *Adjacent paved streets will be swept (recommend water sweeper with reclaimed water) at the end of each day if substantial volumes of soil materials have been carried onto adjacent public paved roads from the project site.*
- *Wheel washers will be installed where project vehicles and/or equipment enter and/or exit onto paved streets from unpaved roads. Vehicles and/or equipment will be washed prior to each trip.*
- *Prior to final occupancy, the applicant will reestablish ground cover on the construction site through seeding and watering in accordance with the Shasta County Grading Ordinance.*

*Implementation of this mitigation shall occur during all construction activities. The County and the project applicant shall be responsible for monitoring.*

**Mitigation Measure 3.2-2:** *The following mitigation measure shall be implemented by the applicant's contractor during all phases of project construction to reduce construction emissions:*

- *Limit the area subject to excavation, grading, and other construction activity at any given time.*
- *Limit the hours of operation of heavy-duty equipment and/or the amount of equipment in use.*
- *Replace fossil-fueled equipment with electrically driven equivalents (provided they are not run by a portable generator set).*
- *Require that all diesel engines be shut off when not in use to reduce emissions from idling.*
- *During the smog season (May through October), lengthen the construction period to minimize the number of vehicles and equipment operating at the same time.*

- *Off-road trucks should be equipped with on-road engines when possible.*
- *Minimize obstruction of traffic on adjacent roadways.*
- *Power construction equipment with diesel engines fueled by alternative diesel fuel blends or ultra low sulfur diesel (ULSD). Only fuels that have been certified by ARB should be used. ARB has verified specific alternative diesel fuel blends for NOx and PM emission reduction. The applicant should also use ARB-certified alternative fueled (compressed natural gas [CNG], liquid propane gas [LPG], electric motors, or other ARB certified off-road technologies) engines in construction equipment where practicable.*
- *Use construction equipment that meets the current off-road engine emission standard (as certified by ARB) or that is re-powered with an engine that meets this standard. Tier I, Tier II, and Tier III engines produce significantly less NOx and PM emissions than uncontrolled engines.*

*Implementation of this mitigation shall occur during all construction activities. The County and the project applicant shall be responsible for monitoring.*

#### SIGNIFICANCE AFTER MITIGATION

Implementation of MM 3.2-1 and 3.2-2 would require the preparation of specific and detailed construction emissions reduction plans and the implementation of SMMs, which would reduce construction-related impacts associated with dust and construction vehicle emissions to a **less than significant** level, consistent with SCAQMD requirements.

### **Long-term (Operational) Impacts**

#### **Impact 3.2-2: Project implementation may conflict with, or obstruct, the applicable air quality plan, cause a violation of air quality standards, contribute substantially to an existing air quality violation, or result in a cumulatively considerable net increase of a criteria pollutant in a non-attainment area (Significant and Unavoidable)**

The project would be both a stationary and mobile source of emissions. Stationary source emissions would come from operation of the proposed cogeneration facility, which includes the use of the boiler, which would be the primary source of operational emissions, the disposal of ash from the boiler, and the use of heavy equipment to move boiler fuel around the project site. Impacts associated with ash transport and the use of heavy equipment are addressed below under Impact 3.2-5.

Mobile source emissions would be generated by an increase in heavy truck trips generated by the project. The heavy truck trips are associated with the transport of biomass fuels to the project site, which would be burned in the boiler. The project would also require six additional employees at the SPI facility, each of which is expected to drive to and from work each day in a single-occupancy vehicle.



**MOBILE SOURCE EMISSIONS**

As described in the Traffic Impact Study (OMNI-MEANS, 2010), the proposed project would result in an increase of 23 heavy truck trips per day. These heavy truck trips would be generated by SPI transporting biomass materials from other facilities in the state to the Anderson Mill site, where the proposed cogeneration facility would be located. Fuel for the cogeneration unit would 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. An average heavy truck trip length of 45 miles per trip was assumed for the vehicle emissions analysis presented in Table 3.2-8. The project would also generate demand for six additional employees at the project site. The total emissions from the heavy truck trips and the employee commute trips are shown in Table 3.2-8.

**TABLE 3.2-8: VEHICLE EMISSIONS FROM THE PROPOSED PROJECT**

<i>POLLUTANT</i>	<i>PROJECT VEHICLE EMISSIONS (LBS/DAY)</i>	<i>THRESHOLD A (LBS/DAY)</i>	<i>PROJECT VEHICLE EMISSIONS (TPY)</i>
NO <sub>x</sub>	8.24	25.0	1.62
CO	3.90	500.0	0.71
SO <sub>2</sub>	0.01	80.0	0.0
PM <sub>10</sub>	1.02	80.0	0.19
ROG	0.63	25.0	0.11

*SOURCE: DE NOVO PLANNING GROUP, 2010 (URBEMIS 2007 MODELING)*

As shown in the table above, emissions from mobile sources (vehicles) associated with the proposed project would not individually exceed the SCAQMD Level A thresholds of significance for criteria pollutants. However, mobile source emissions would contribute to total pollutant emissions from the project.

**STATIONARY SOURCE EMISSIONS**

**Introduction**

The analysis in this section was derived from the Authority to Construct and Prevention of Significant Deterioration Permit Application, prepared by ENVIRON International Corporation, February 2010. (Hereafter referred to as the PSD report). ENVIRON was hired by SPI, the project applicant, to prepare the PSD report as part of SPI’s application package to the SCAQMD. The PSD report was independently peer reviewed by Urban Crossroads, Inc., a firm under contract with De Novo Planning Group, who is preparing the EIR under contract to Shasta County. The PSD report was also reviewed for adequacy by the SCAQMD. Both Urban Crossroads and the SCAQMD determined that the PSD report prepared by ENVIRON was adequate, complete, and suitable for use in the preparation of this EIR.

**Pollutant Emission Rates**

This section addresses pollutant emission rates associated with the proposed project. The proposed boiler will emit NOx, carbon monoxide (CO), particulate matter smaller than ten microns (PM<sub>10</sub>), sulfur dioxide (SO<sub>2</sub>), and volatile organic compounds (VOCs), as well as several substances identified as toxic air contaminants (TACs) by the Air Resources Board (ARB).

Table 3.2-9 presents anticipated criteria pollutant emission rates from the cogeneration unit during normal operation. Boiler emission factors for NOx, CO, PM<sub>10</sub>, and VOCs were based on guarantees from the boiler and control device manufacturers. The SO<sub>2</sub> 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.

**TABLE 3.2-9: PROPOSED COGENERATION UNIT EMISSIONS**

POLLUTANT <sup>1</sup>	EMISSION FACTOR (LB/MMBTU)	EMISSION RATE <sup>2</sup>		
		(LB/HR)	(LB/DAY)	(TPY)
NOx	0.13	60.8	1,394	242
CO	0.35	164	3,752	652
SO <sub>2</sub>	0.005	2.34	54	9.32
PM <sub>10</sub>	0.02	9.36	214	37.3
VOC/ROG	0.017	7.96	182	31.7
Sulfuric Acid	0.0021	0.986	22.6	3.93
Lead	1.19E-05	0.00559	0.128	0.0222

SOURCE: PSD REPORT, ENVIRON, 2010

1 NOx, CO, AND PM<sub>10</sub> EMISSION FACTORS ARE BASED ON BACT AND VENDOR GUARANTEES. THE SO<sub>2</sub> 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<sub>2</sub>SO<sub>4</sub>) EMISSION FACTOR IS BASED ON THE ASSUMPTION THAT SULFATE COMPRISES 10.038 PERCENT OF PM<sub>10</sub> 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 YR).

As described in the Project Description Section of this EIR, the proposed cogeneration plant would not be permitted to operate simultaneously with the existing cogeneration plant on the SPI site. Operation of the existing cogeneration plant on the SPI site, and the associated emissions generated by the existing facility, constitute the environmental baseline for the purposes of this analysis. Therefore, impacts related to air quality emissions are calculated based on the net increase of emissions that would occur if the proposed project were approved.

The net increase in operational emissions associated with the proposed project can be calculated by subtracting the existing emissions generated from the current cogeneration plant on site from the emissions that would be generated by the proposed cogeneration plant. Table 3.2-10 shows actual emissions generated by the existing cogeneration plant for the past seven years. Table 3.2-

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11 shows the net increase in emissions of criteria pollutants associated with project implementation.

**TABLE 3.2-10: BASELINE ACTUAL EMISSION RATES FOR EXISTING BOILER (TONS/YEAR)**

POLLUTANT	2003	2004	2005	2006	2007	2008	2009	MAX 2-YEAR AVG.
NO <sub>x</sub> <sup>1</sup>	74.4	79.7	77.6	74.0	75.0	66.0	64.0	78.6
CO <sup>1</sup>	130	125	130	181	162	130	131	172
SO <sub>2</sub>	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	0.0063	0.00661

SOURCE: PSD REPORT, ENVIRON, FEBRUARY 2010

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<sub>10</sub> 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 3.2-11: NET PROJECT EMISSIONS INCREASE OF CRITERIA POLLUTANTS**

POLLUTANT <sup>1</sup>	ANNUAL EMISSION RATE <sup>2</sup> (TONS/YEAR)				
	COGEN	CT	TOTAL	EXISTING	NET
NO <sub>x</sub>	242	--	242	78.6	164
CO	652	--	652	172	480
SO <sub>2</sub>	9.32	--	9.32	1.28	8.04
PM/PM <sub>10</sub>	37.3	1.10	38.4	3.95	34.4
VOC/ROG	31.7	--	31.7	7.20	24.5
Sulfuric Acid	3.93	--	3.93	0.396	3.53
Lead	0.0222	--	0.0222	0.00661	0.0156

SOURCE: PSD REPORT, ENVIRON, 2010

1 NO<sub>x</sub>, CO, PM<sub>10</sub>, AND VOC/ROG EMISSION FACTORS ARE BASED ON VENDOR GUARANTEES, WHILE THE SO<sub>2</sub> EMISSION FACTOR IS BASED ON A SOURCE TEST CONDUCTED ON THE EXISTING BOILER AT THE FACILITY. THE SULFURIC ACID (H<sub>2</sub>SO<sub>4</sub>) EMISSION FACTOR IS BASED ON THE ASSUMPTION THAT SULFATE COMPRISES 10.038 PERCENT OF PM<sub>10</sub> EMISSIONS, WHICH WAS OBTAINED FROM USEPA'S SPECIATE 3.2 PROFILE # 12709 FOR HOGGED FUEL BOILER/STOKER BOILER.

2 COGENERATION UNIT ANNUAL EMISSION RATES BASED ON MAXIMUM ANNUAL AVERAGE HOURLY HEAT INPUT (425.4 MMBTU/HR). TOTAL PROPOSED = COGEN (COGENERATION UNIT) + CT (COOLING TOWER). NET ANNUAL EMISSIONS = TOTAL PROPOSED - EXISTING (FROM TABLE 3.2-9).

Table 3.2-12 summarizes the hourly and daily 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, and compares them to the AQMD Best Available Control Technology (BACT) thresholds.

**TABLE 3.2-12: PROJECT EMISSION RATES AND BACT THRESHOLDS**

POLLUTANT <sup>1</sup>	HOURLY EMISSION RATE <sup>2</sup> (LB/HR)			24-HOUR EMISSION RATE <sup>3</sup> (LB/DAY)			AQMD BACT THRESH. <sup>4</sup> (LB/DAY)	OVER BACT THRESH?
	COGEN	CT <sup>7</sup>	TOTAL	COGEN	CT	TOTAL		
NO <sub>x</sub>	60.8	--	60.8	1,394	--	1,394	25.0	Yes
CO	164	--	164	3,752	--	3,752	500.0	Yes
SO <sub>2</sub>	2.34	--	2.34	54	--	54	80.0	No
PM/PM <sub>10</sub>	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	--	0.0045	0.5	No
CVinyl Chloride	0.00861	--	0.00861	0.197	--	0.197	5.0	No

SOURCE: PSD REPORT, ENVIRON, 2010

1 NO<sub>x</sub>, CO, PM<sub>10</sub>, AND VOC/ROG EMISSION FACTORS ARE BASED ON VENDOR GUARANTEES, WHILE THE SO<sub>2</sub> EMISSION FACTOR IS BASED ON A SOURCE TEST CONDUCTED ON THE EXISTING BOILER AT THE FACILITY. THE SULFURIC ACID (H<sub>2</sub>SO<sub>4</sub>) EMISSION FACTOR IS BASED ON THE ASSUMPTION THAT SULFATE COMPRISES 10.038 PERCENT OF PM<sub>10</sub> 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.

The U.S. Environmental Protection Agency (EPA) has classified Shasta County as an unclassified/attainment area for the federal 8-hour ozone, CO, PM<sub>10</sub>, and PM<sub>2.5</sub> standards. The CARB has classified Shasta County as a moderate nonattainment area for the state 1-hour ozone standard, an unclassified area for the state CO and PM<sub>2.5</sub> standards, and a nonattainment area for the state PM<sub>10</sub> standard.

As shown in Table 3.2-12 above, operation of the proposed cogeneration facility would exceed the SCAQMD thresholds of significance for NO<sub>x</sub>, CO, PM<sub>10</sub>, VOC/ROG and Beryllium. This is considered a **potentially significant impact**.

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 EPA's Prevention of Significant Deterioration (PSD) program requires that all proposed emission units apply BACT to control any pollutant for which the proposed project would exceed the PSD Significant Emission Rate (SER) for the pollutant in question (40 CFR 51.21(b)(23)(i)). 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 (SCAQMD Rule 2:1, Part 301).

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 proposed cogeneration power facility would be considered a new source of emissions, therefore, 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 EPA and Shasta County BACT thresholds, analyses are required for oxides of nitrogen (NO<sub>x</sub>), carbon monoxide (CO), particulate matter equal to or less than ten microns in diameter (PM<sub>10</sub>), reactive organic compounds (ROG), and beryllium. The full BACT analysis prepared for the proposed project is included as Appendix B of the attached PSD Report. A summary of the BACT analysis for criteria pollutants that exceed SCAQMD BACT thresholds is provided below.

### **Biomass-Fired Cogeneration Unit BACT Analysis**

ENVIRON queried EPA's Reasonably Available Control Technology (RACT)/BACT/Lowest Achievable Control Technology (LAER) Clearinghouse (RBLCL) database for recent BACT determinations involving wood-fired boilers. This initial broad search was refined by eliminating sources that did not emit pollutants as a result of similar operation. The California Air Resources Board BACT Clearinghouse was also searched for applicable permits, either pending or issued. Additionally, a review of EPA's RBLCL database was conducted for biomass-fired boilers. The search included all entries made after January 1, 1990 for biomass-fired, stoker-type boilers. The initial search was further refined by eliminating sources that operate in a significantly different manner (e.g., fluidized bed boiler designs, use of fuels other than or in combination with biomass).

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

#### 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.

### 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.

### NO<sub>x</sub> BACT ANALYSIS

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NO<sub>x</sub> 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<sub>2</sub>.

#### **Identification of Possible NO<sub>x</sub> Control Alternatives**

There are a variety of options available for controlling NO<sub>x</sub> emissions from combustion sources. Some options involve combustion controls that reduce NO<sub>x</sub> formation, while others utilize add-on control devices to remove NO<sub>x</sub> after it is formed.

#### COMBUSTION CONTROLS

Combustion controls reduce NO<sub>x</sub> 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<sub>x</sub>. The oxidation of nitrogen that is chemically bound in fuel sources can also form what is called fuel-bound NO<sub>x</sub>.

Dry low-NO<sub>x</sub> (DLN) burners control thermal NO<sub>x</sub> 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.

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.

### ADD-ON CONTROLS

Add-on controls such as selective catalytic reduction (SCR) and selective non-catalytic reduction (SNCR) systems are widely used technologies for controlling NO<sub>x</sub> emissions from combustion sources. In the SNCR process, ammonia is mixed with the exhaust from the combustion device and the NO<sub>x</sub> 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<sub>x</sub> to form nitrogen and water, but a catalyst matrix is used to allow the reduction reaction to take place at lower temperatures (600 °F for SCR as opposed to 1,650 °F for SNCR). While SCR systems have been utilized to reduce NO<sub>x</sub> 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<sub>x</sub> 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 they use more advanced catalysts that enable the reduction reaction to proceed at lower temperatures (350 °F to 450 °F). These catalysts are typically more expensive and are even more prone to deactivation by potassium and sulfur than standard SCR catalysts.

EMx (formerly called SCONOx) is similar to SCR, except that NOx in the exhaust stream reacts with potassium carbonate (K<sub>2</sub>CO<sub>3</sub>) to form potassium nitrate (KNO<sub>3</sub>). This compound is reacted with hydrogen to form gaseous nitrogen (N<sub>2</sub>), and regenerate the K<sub>2</sub>CO<sub>3</sub>. The lower exhaust temperature limit required for the reactions to take place is less than that of SCR (300 °F as opposed to 450 to 600 °F, depending on the catalyst used). The EMx system is also said to control CO and VOCs by oxidation.

#### NOx CONTROL ALTERNATIVE REVIEW

The database queries did not produce any instances of NOx 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 NOx emissions to 0.065 lb/MMBtu on a 30-day rolling average was lowest achievable emission rate (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 NOx 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 NOx 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 NOx emissions to 0.060 lb/MMBtu using a two-layer RSCR system. The Massachusetts RPS program has a more stringent NOx emissions criterion (0.065 lb/MMBtu with no averaging period). The 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 NOx 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 NOx permit limit. 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 NOx emissions to 0.012 lb/MMBtu on a short-term basis, 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<sub>x</sub> generated during combustion. Coen manufactures the Dual Air Zone (DAZ) scroll burner, which can be used to fire pulverized wood along with some natural gas (approximately ten percent of total heat input). These burners have generally been installed in units with a maximum heat input of less than 100 MMBtu/hr, and require additional fuel processing to reduce the fuel to an average size of approximately 1/32 of an inch. With some flue gas recirculation and staged combustion, a NO<sub>x</sub> emission rate of 0.35 lb/MMBtu at the furnace exit has been achieved.

### SUMMARY OF POSSIBLE NO<sub>x</sub> CONTROL ALTERNATIVES

Based on literature and database searches the following alternatives are possible for controlling NO<sub>x</sub> emissions from a biomass-fired boiler:

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

### Technical Feasibility of NO<sub>x</sub> Control Alternatives

#### 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<sub>x</sub> emission rates of between 0.20 to 0.26 lb/MMBtu, depending upon the degree of optimization for controlling NO<sub>x</sub> emissions (lower NO<sub>x</sub> 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<sub>x</sub> emissions from biomass-fired boilers.

#### DLN BURNER

For a boiler of the size proposed, two or more DLN burners would be required. With such burners, the fuel would be pulverized and burned in suspension using wall-mounted burners, which would be a significant departure from the proposed boiler design, which has combustion occurring on a moving grate. These burners are generally intended to limit the amount of fuel-bound nitrogen that is converted to NO<sub>x</sub> 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.

### 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<sub>x</sub> 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<sub>x</sub> control technology for biomass-fired boilers.

### SCR AND RELATED VARIATIONS

As indicated in the previous section, SCR, SNCR/SCR hybrid, RSCR, and CSCR systems have been applied to a limited number of biomass-fired, stoker-type boilers. Among the variations, an SCR system placed downstream of particulate collector (e.g., a multiclone and an ESP) is likely to be a cost-effective alternative and would reduce NO<sub>x</sub> 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<sub>x</sub> 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.

### EMx

To date, EMx has been designed and used only on small- to medium-sized natural gas-fired stationary turbines. 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<sub>2</sub> emission factor for wood-fired boilers is 0.025 lb/MMBtu, which is equivalent to about 7.2 lb/hr of SO<sub>2</sub>. 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<sub>2</sub> 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<sub>x</sub> emissions from a biomass-fired boiler.

### SUMMARY OF TECHNICALLY FEASIBLE NO<sub>x</sub> CONTROL ALTERNATIVES

The following is a list of control alternatives determined to be technically feasible for controlling NO<sub>x</sub> emitted by a biomass-fired, stoker-type boiler:

- Proper combustion
- SNCR

- SCR/CSCR/RSCR

### **Effectiveness of Remaining NO<sub>x</sub> BACT Technologies**

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

#### PROPER COMBUSTION

A modern biomass-fired boiler furnace, operated with computerized controls to ensure proper combustion would result in a NO<sub>x</sub> 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<sub>x</sub> emissions.

#### SNCR

Currently, SNCR systems are the most common add-on control device used to reduce NO<sub>x</sub> emissions from large biomass-fired boilers. SNCR systems rely on high temperatures to promote the reaction of NO<sub>x</sub> 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 NO<sub>x</sub> reduction effectiveness. Short-term emission limits of between 0.13 and 0.2 lb/MMBtu have been achieved using SNCR systems to control NO<sub>x</sub> emitted by biomass-fired, stoker-type boilers.

#### SCR/CSCR/RSCR

The recently permitting Concord Steam project proposed to use a CSCR system to limit NO<sub>x</sub> 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<sub>x</sub> 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 permit 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.

#### RANKING BY EFFECTIVENESS

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

- SCR/CSCR/RSCR
- SNCR
- Proper Combustion

### **NO<sub>x</sub> BACT Cost Effectiveness Evaluation**

SNCR is the most common add-on technology used to reduce NO<sub>x</sub> 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<sub>x</sub> reduced (see Appendix B).

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 of the PSD BACT Analysis, which is included as Appendix B to this EIR, and summarized, along with those of the SNCR system, in Table 2 of the above referenced attachment. The SNCR system would reduce NO<sub>x</sub> emissions by 130 tons/year at an annual expense of approximately \$203,000, while an SCR system, under best-case operating conditions, would reduce NO<sub>x</sub> emissions by approximately 260 tons per year at an annual expense of nearly \$1,320,000. Thus, an additional \$1,116,000 per year would be spent to capture an additional 130 tons of NO<sub>x</sub>, which is equivalent to an incremental cost effectiveness of over \$8,500 per ton of NO<sub>x</sub> removed. However, judging by the experiences of other biomass-fired boiler facilities employing SCR systems, this cost-effectiveness analysis likely underestimates the number of replacement catalyst beds needed each year (2), as well as the number downtime events needed each year to replace or clean the catalyst beds (3), so the cost effectiveness could easily be twice that of the calculated "best case" scenario. Based on this analysis, SNCR is deemed to be the most reliable, cost-effective NO<sub>x</sub> control technology for biomass-fired, stoker-type boilers.

### **Selection of BACT for NO<sub>x</sub>**

Based on the analysis presented in this section, SPI proposes that BACT for the control of NO<sub>x</sub> from biomass-fired, stoker-type boilers is the use of an integral SNCR system. NO<sub>x</sub> emissions would be

limited to 0.13 lb/MMBtu, which is approximately equivalent to 242 tpy at the anticipated annual average operating capacity.

### 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<sub>2</sub> into CO which can occur in high-temperature regions (above 1,700 °C) of the combustion zone.

#### Identification of Possible CO Control Alternatives

As for NO<sub>x</sub>, 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<sub>2</sub> after leaving the combustion area.

#### COMBUSTION CONTROLS

Combustion controls for CO include adequate fuel residence times to ensure CO<sub>2</sub> formation, proper fuel-air mixing, and temperature control. These measures, however, can result in an increase in the NO<sub>x</sub> 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.

#### 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<sub>2</sub>). Catalytic oxidizers operate in a temperature range of approximately 500 F to 1,000 F. At lower temperatures the CO conversion efficiency falls off rapidly.

Because higher temperatures are desirable for improved conversion of CO to CO<sub>2</sub> 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 system (e.g., an ESP) 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 NOx BACT analysis section) also utilizes a catalytic technique that oxidizes CO to CO<sub>2</sub> in addition to controlling NOx emissions.

#### CO CONTROL ALTERNATIVE REVIEW

The results of the database queries for CO control technologies are presented in Table 3 of the BACT analysis in the PSD, which is attached as Appendix B of this EIR, and are 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 NOx. As of writing of this analysis, the facility has not commenced construction.

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

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

### SUMMARY OF POSSIBLE CO CONTROL ALTERNATIVES

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

- Proper combustion
- Catalytic oxidation
- EMx

### Technical Feasibility of CO Control Alternatives

#### PROPER COMBUSTION

Proper combustion is the most common technique used to limit CO emissions from wood-fired stoker-type boilers. Boiler designs tend to focus on limiting NO<sub>x</sub> creation, at the expense of slightly higher CO emissions, to reduce the reduction burden placed on add-on NO<sub>x</sub> control systems.

#### 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.

#### EMx

As discussed in the NO<sub>x</sub> 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.

### 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

### **Effectiveness of Remaining Technologies**

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

#### **PROPER COMBUSTION**

Proper combustion provides a wide range of control effectiveness, depending on the configuration of the system. Generally, emissions resulting from incomplete combustion (CO and VOC) are balanced with emissions related to high furnace temperatures (NO<sub>x</sub>) to achieve optimally low emissions of all pollutants. However, in order to achieve the proposed NO<sub>x</sub> 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<sub>x</sub> 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.

#### **OXIDATION CATALYST**

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

#### **RANKING BY EFFECTIVENESS**

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

- Catalytic oxidation
- Proper combustion

### **CO BACT Cost Effectiveness Evaluation**

Proper combustion is the most common technique used to control CO emissions from a stoker-type, biomass-fired boiler. Boiler designers and boiler operators have decades of experience to draw on to deal with situations that can cause excess CO emissions such as variations in fuel



moisture, or boiler operation transients. Because proper combustion design and techniques are so common in boilers, it is considered the baseline control scheme, and no additional cost is associated with it.

Similar to the situation with applying SCR to a biomass-fired boiler as discussed in the previous section, while oxidation catalysts are not considered experimental, it cannot be assumed that this control technology will perform in a reliable and cost-effective manner. Oxidation catalysts are subject to the same, if not more, uncertainty related to deactivation of the catalyst by trace amounts of alkaline compounds and metals in the exhaust. The rate of catalyst deactivation cannot be predicted, and while it is possible that catalyst beds can be reactivated by removal and washing, it is impossible to know how many wash cycles will result in adequate reactivation.

Table 3 in Attachment A (located within Appendix B of this EIR) summarizes cost-effectiveness calculations for an oxidation catalyst system that uses assumptions similar to those of the SCR cost-effectiveness calculations. An additional 466 tons per year of CO would be reduced at an annual cost of nearly \$2,400,000, or over \$5,100 per ton of CO removed. As for the SCR analysis, this estimate probably underestimates the number of catalyst beds needed each year (2), and the number of downtime events needed to replace or clean the catalyst (6) each year, so the cost effectiveness could easily be twice that of this “best case” scenario. Based on this analysis, proper combustion is deemed to be the most reliable, cost-effective CO control strategy for biomass-fired, stoker-type boilers.

### **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, and 652 tpy at the maximum annual average operating rate of the proposed boiler.

### **PM<sub>10</sub> BACT ANALYSIS**

PM<sub>10</sub> 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).

### **Identification of Possible PM<sub>10</sub> Control Alternatives**

#### **COMBUSTION CONTROLS**

The concept of applying combustion controls or “proper combustion” to minimize PM<sub>10</sub> 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<sub>10</sub> control can result in an increase in the NO<sub>x</sub> emissions. Thus, operators strive to balance the factors under their control to achieve the lowest possible emissions of all pollutants.

The two most popular add-on control technologies for control of PM<sub>10</sub> 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<sub>10</sub>. 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 is atomized by the increased velocity exhaust flow, and the particles impact the droplets and are collected. Because the liquid must be atomized to ensure high collection efficiency, a high-energy exhaust flow is required.

### PM<sub>10</sub> CONTROL ALTERNATIVE REVIEW

The results of the database queries for PM<sub>10</sub> control technologies are presented in Table 4 of the PSD BACT analysis (Appendix B of this EIR), sorted by permit limit, beginning with the PM<sub>10</sub> 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<sub>10</sub> is use of an ESP or a baghouse. The most stringent permit limit employing ESP technology to control PM<sub>10</sub> 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<sub>10</sub> 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<sub>10</sub> 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<sub>10</sub> test method to confirm compliance with the permit limit. The proposed Valley BioEnergy facility in Modesto would use an ESP to limit PM<sub>10</sub> emissions to 0.02 lb/MMBtu.

### SUMMARY OF POSSIBLE PM<sub>10</sub> 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

### **Technical Feasibility of PM<sub>10</sub> Control Alternatives**

The most common technology for controlling PM<sub>10</sub> emissions from a biomass-fired boiler is an ESP preceded by a multiclone. Baghouses have been employed to control PM<sub>10</sub> 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<sub>10</sub> from smaller boilers with lower exhaust flow, and typically have lower control efficiencies than ESPs or baghouses.

### **Effectiveness of Remaining PM<sub>10</sub> Control Technologies**

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

#### VENTURI SCRUBBERS

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

#### BAGHOUSES

Baghouses typically operate with pressure drops between 2 and 12 inches of water. PM<sub>10</sub> control efficiencies are capable of removing over 99 percent of PM<sub>10</sub> from gas streams.

#### ESPS

ESPs, which typically experience pressure losses of around 0.5 inches of water, are capable of removing over 99 percent of PM<sub>10</sub> from exhaust flows.

#### 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

**Cost Effectiveness Evaluation for PM<sub>10</sub> Controls**

No cost effectiveness evaluation comparing the baghouse or scrubber is presented because SPI is proposing ESP to control PM<sub>10</sub> emission from the biomass-fired, stoker-type boiler, which is the most effective control technology available.

**Section of BACT for PM<sub>10</sub>**

SPI proposes that BACT for PM<sub>10</sub> 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.

**ROG/VOC BACT ANALYSIS**

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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.

**Identification of Possible VOC Control Alternatives**

Combustion controls, or proper combustion techniques, provide a wide range of control effectiveness depending on the configuration of the system. Generally, emissions resulting from incomplete combustion (CO and VOC) are balanced with emissions related to high furnace temperatures (NO<sub>x</sub>) 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.

**VOC CONTROL ALTERNATIVE REVIEW**

The results of the database queries for VOC control technologies are presented in Table 5 of the BACT analysis in the PSD (attached as Appendix B of this EIR), 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 of the PSD BACT analysis, 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<sub>x</sub>, 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.

### SUMMARY OF POSSIBLE VOC CONTROL ALTERNATIVES

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

### TECHNICAL FEASIBILITY OF VOC 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.

### EFFECTIVENESS OF REMAINING VOC CONTROL 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., NOx).

### 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.

### COST EFFECTIVENESS EVALUATION OF VOC CONTROLS

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

### 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.

## SO<sub>2</sub> BACT ANALYSIS

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Sulfur dioxide (SO<sub>2</sub>) 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<sub>2</sub>.

### **Identification of Possible SO<sub>2</sub> Control Alternatives**

There are two alternatives for reducing SO<sub>2</sub> emissions combustion sources: removal of sulfur from the fuel before it is combusted, and removal of SO<sub>2</sub> from the exhaust gas after combustion.

Removing sulfur from fuel before it is combusted has been employed to remove sulfur containing non-organically bound minerals (e.g., pyrites) from coal, but this practice is not feasible for biomass fuels, where the sulfur is organically bound in the fuel. All permitted biomass-fired boilers have no SO<sub>2</sub> 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<sub>2</sub> from the exhaust gases by directing the flue gas through a chamber filled with a slurry of lime or limestone (some systems use sodium or other sorbent materials) and water. The sorbent in the slurry comes in contact with the SO<sub>2</sub> 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<sub>2</sub> control system. Both wet and dry FGD systems require waste handling operations to remove the reacted sorbent material.

#### SO<sub>2</sub> CONTROL ALTERNATIVE REVIEW

The results of the database queries for SO<sub>2</sub> control technologies are presented in Table 6 of the PSD BACT analysis (attached as Appendix B to this EIR), sorted by permit limit, beginning with the SO<sub>2</sub> limit proposed by SPI for the new boiler. The RBLC does not indicate that any FGD systems have been used to reduce SO<sub>2</sub> 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<sub>2</sub> emissions. The Valley BioEnergy has been deemed complete, but no permit has been issued, and it has not been constructed or operated.

#### SUMMARY OF POSSIBLE SO<sub>2</sub> CONTROL ALTERNATIVES

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

- None
- FGD

### **Technical Feasibility of SO<sub>2</sub> 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<sub>2</sub> emissions from a biomass-fired boiler.

### Effectiveness of Remaining SO<sub>2</sub> Control Technologies

Wet FGD systems are considered the most effective, and can achieve greater than 90 percent reduction in SO<sub>2</sub> emissions. Dry scrubbers and spray driers are capable of control efficiencies on the order of 90 percent.

#### RANKING BY EFFECTIVENESS

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

- None
- FGD

### Cost Effectiveness Evaluation for SO<sub>2</sub> Controls

Based on a source test conducted on the existing boiler in 2002, an SO<sub>2</sub> 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<sub>2</sub> 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<sub>2</sub> controlled is more than \$45,000, which is clearly outside the envelope of acceptable costs.

### Selection of BACT for SO<sub>2</sub>

SPI proposes that no control system is BACT for reducing SO<sub>2</sub> emissions from a biomass-fired boiler, and that the SO<sub>2</sub> permit limit will be determined by the initial source test.

### 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. 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  $1.55 \times 10^{-6}$  lb/MMBtu was used to calculate emissions from the proposed cogeneration unit (approximately 5.78 lb/yr).

### IMPACT SUMMARY

As described in the analysis above, emissions from operation of the proposed project would come from two sources: mobile sources and stationary sources. The mobile source emissions from worker commutes and heavy truck trips delivering biomass material to the facility are shown in Table 3.2-8. Stationary source emissions from operation of the proposed cogeneration facility are shown in Table 3.2-9 and Table 3.2-12. Tables 3.2-9 and 3.2-12 show the total emissions generated by the proposed facility. However, as part of the proposed project, SPI will take their existing cogeneration facility “off-line”. Therefore, the actual net increase in emissions from the

proposed project is lower than the emissions levels shown in Tables 3.2-9 and 3.2-12, as shown in Table 3.2-11.

As described above, the proposed project would exceed the SCAQMD thresholds of significance for NO<sub>x</sub>, CO, PM<sub>10</sub>, ROG/VOC and Beryllium, which represents a **potentially significant** impact for these emissions. BACT has been incorporated into the project design in order to reduce emissions levels from these pollutants to the greatest extent feasible, however, even after the incorporation of BACT, these emissions levels remain above the established thresholds of significance. The project would not exceed the threshold of significance for SO<sub>2</sub>. Therefore, impacts associated with SO<sub>2</sub> emissions are **less than significant**.

As described above in the Regulatory Setting section of this chapter, the SCAQMD maintains a bank of emissions reduction credits (ERCs), which can be used by land owners and project applicants to offset emissions generated by a new or proposed project or operation. Sierra Pacific Industries maintains ERCs in this bank. The ERCs can be used to offset the increase in emissions generated by the proposed project. SPI has adequate ERCs to offset emissions of NO<sub>x</sub>, CO, PM<sub>10</sub>, and ROG/VOC. The ERC program does not include offsets for Beryllium. Because the project would emit Beryllium in excess of the SCAQMD thresholds, and there is no BACT for Beryllium, impacts associated with Beryllium emissions are **significant and unavoidable**.

The use of offsets that SPI has banked in the ERC program administered through the SCAQMD, as required by Mitigation Measure 3.2-3, would reduce impacts associated with NO<sub>x</sub>, CO, PM<sub>10</sub>, and ROG/VOC to a **less than significant** level.

#### MITIGATION MEASURES

***Mitigation Measure 3.2-3:*** *Prior to operation of the proposed cogeneration facility, the Shasta County Air Quality Management District shall “withdraw” emission reduction credits for NO<sub>x</sub>, CO, PM<sub>10</sub>, and ROG/VOC banked by SPI in the ERC program to offset emissions generated by the project. The offsets withdrawn shall be equal to or greater than the total net increase of each emission type generated by operation of the project. The final calculation of the ERCs to be withdrawn shall be completed by the SCAQMD. In the event that SPI does not have enough credits banked in the ERC program to fully offset project-generated emissions, SPI shall be required to purchase additional credits in order to fully mitigate for the emissions generated by the project.*

#### SIGNIFICANCE AFTER MITIGATION

Implementation of MM 3.2-3 would reduce impacts associated with NO<sub>x</sub>, CO, PM<sub>10</sub>, and ROG/VOC to a **less than significant** level.

Impacts associated with Beryllium would remain **significant and unavoidable**.



**Impact 3.2-3: Project implementation may create objectionable odors affecting a substantial number of people (Less than Significant with Mitigation)**

Operation of the proposed project has the potential to generate odors in excess of the existing baseline environmental conditions. SPI is currently operating a 4 MW cogeneration facility on the project site. According to the Shasta County Department of Resource Management, there have been no formal complaints of odors received against the existing SPI facility at Anderson, or from any other SPI facilities throughout the County.

The County has, however, received complaints about odor at the nearby Wheelabrator facility. The Wheelabrator facility is a wood-fired cogeneration plant located in the City of Anderson, and has a generating capacity of 58 MW and processes 750,000 tons of mill waste and forest residues from Shasta County and surrounding areas.

Fuels that are stored outdoors at the Wheelabrator facility have been cited as the source of the odor. Odor generation is attributed to the varied fuel types and condition in which it is received; for example yard waste that may be in an advanced state of decomposition upon arrival at the facility; fuel stored on-site for lengthy periods of time; and lack of aeration of the fuel stored on site. At the Wheelabrator facility a wide variety and large volume of fuel is stored outdoors (open to the air), sometimes for lengthy periods. This leads to decomposition of the fuel being stored. The decomposition of fuel in turn generates odor.

Based on historical trends from other cogeneration facilities in Shasta County, odor issues are generally related more to the fuel that is stored than emission from the boiler. Therefore, odor impacts from operation of the proposed boiler are anticipated to be less than significant. However, odor impacts from storage of fuels to be burned in the boiler are considered to be **potentially significant**.

**MITIGATION MEASURES**

**Mitigation Measure 3.2-3:** *The following conditions shall be included in the project's Conditional Use Permit:*

- *All fuels for the proposed boiler shall be kept indoors, covered, and dry to the maximum extent feasible. In any event, no fuels shall remain uncovered or outdoors for a period greater than two months unless unforeseeable circumstances require that said fuel be stored outdoors for a greater length of time in which case the applicant shall notify the Department of Resource Management of the particular circumstances and provide a plan that details the length of time needed to normalize operations such that it is feasible to comply with the two month limitation. The Planning Director shall review the particular circumstances and reasonableness of the plan to normalize operations, and shall notify the applicant as to whether or not the Department finds reasonable cause to temporarily defer the limitation until operations have been normalized or if, more information or alternative actions to address the circumstance are necessary.*

- *Any fuels that show signs of rot or decomposition, or stored fuels that begin to generate significant odor shall either be burned in the boiler immediately, or removed from the premises and disposed of in a permitted landfill.*

#### SIGNIFICANCE AFTER MITIGATION

Implementation of MM 3.2-3 would ensure that fuels stored on the project site for use in the proposed boiler would be stored in a way as to minimize the potential for rot and decomposition that could generate odors. Implementation of this measure would reduce potential odor impacts to a **less than significant** level.

#### **Impact 3.2-4: Development of the proposed project may expose sensitive receptors to toxic air contaminants (Less than Significant)**

In order to determine if the proposed cogeneration facility would expose sensitive receptors to toxic air contaminants (TACs), a project-specific Health Risk Assessment (HRA) was prepared (ENVIRON, 2010). The HRA is included as **Appendix C** of this EIR.

#### **Introduction**

The purpose of the HRA prepared for this EIR is to quantify potential human health risks associated with toxic air contaminant (TAC) emissions attributable to the proposed project. The analysis has been conducted in accordance with the Office of Environmental Health Hazard Assessment's (OEHHA's) Air Toxic Hot Spots Program Risk Assessment Guidelines: The Air Toxics Hot Spots Program Guidance Manual for Preparation of Health Risk Assessments (Air Toxics Guidance, August 2003). The HARP model (version 1.4a) developed by CARB (2008) was used to conduct the risk analysis for the HRA (Appendix C). Air dispersion modeling was used to estimate off-site concentrations of toxic air pollutants associated with emission rate increases attributable to the project. The HARP model uses the output from the air dispersion model to predict TAC exposure and risk to the surrounding community.

Projected emissions are used by the air districts to categorize the various facilities as high, intermediate and low priority. A project is prioritized based on the following: (1) toxicity of the substances emitted, (2) the quantity of each emitted substance, (3) the proximity of the emission sources to potential receptors, and (4) any other factors that indicate the potential for a significant health risk to the surrounding community. Based on this process, emissions attributable to the proposed project were prioritized as part of the initial permit application submitted to the SCAQMD, which designated the project as "high priority" and required that an HRA be prepared. According to the California Air Resources Board (CARB) and the California Air Pollution Control Officers Association (CAPCOA), the designation of a facility as high priority does not necessarily mean that it is emitting substances at a level that will significantly impact the surrounding community (CAPCOA, 1990). Only after an HRA is conducted can the possible health hazards resulting from project emissions be properly evaluated.

The objectives of the HRA prepared for this EIR are to: (1) estimate off-site air concentrations of the substances emitted by the proposed cogeneration unit and increased fuel delivery truck traffic,

(2) evaluate potential exposures to the surrounding community, and (3) characterize the potential health risks to individuals associated with those levels of exposure. This assessment presents the results of this analysis based on refined air dispersion modeling, following the guidance provided by OEHHA (2003).

Emission rates of 114 compounds expected to be emitted by the cogeneration unit are presented in Exhibit 3.2-1 at the end of this section. In addition to the compounds shown in Exhibit 3.2-1, the HRA included diesel particulate matter (DPM) emitted by increased fuel haul truck traffic to and from the facility.

### **TAC Source Identification**

The proposed biomass-fired boiler 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 to reduce emissions of oxides of nitrogen (NOx), as well as a multiclone and electrostatic precipitator (ESP) to control emissions of particulate matter (PM<sub>10</sub>). The exhaust system will be designed to accommodate an oxidation catalyst, which can be installed, if necessary, following startup to reduce carbon monoxide (CO) emissions to the level proposed in the air permit application. A closed-loop two-cell cooling tower will be used to dispose of waste heat from the steam turbine.

The proposed cogeneration unit will be located near the existing biomass-fired boiler at the facility.

The proposed project is expected to require a maximum of 23 additional truck trips per day to either remove excess fuel for sale when the facility is producing more than the boiler can consume (and economic conditions are favorable for fuel sales), or to deliver fuel when the facility is producing less fuel than the cogeneration facility requires to maintain the desired level of electricity generation. The trucks were assumed to arrive from or depart to north- or south-bound Interstate Highway 5.

### **Emissions Estimates**

The cogeneration unit emission rates used in the HRA prepared for this EIR are based on those reported by SPI in the air permit application submitted to the AQMD in February and March 2010. The emission rates are presented in Exhibit 3.2-1. Background air concentrations for all emitted TACs were assumed to be zero.

For the increased fuel truck traffic, the motor vehicle emission factor model EMFAC2007 (Version 2.3) was used to calculate annual average DPM emission rates from 2010 until 2040, after which emission rates were assumed to be static. Because the trucks used to haul fuel will not be from a specific fleet, the model default fleet was used for each year.

The emission rates for the truck sources vary depending on the period calculation in HARP. For example, 70-year residential chronic and cancer calculations used 70-year average emission rates for trucks (2010-2080), and the 40-year worker chronic and cancer calculations used 40-year average emission rates for trucks (2010-2050). Because EMFAC2007 does not estimate emission factors past the year 2040, emission factors were assumed to remain the same after 2040. The 40- and 70-year average emission factors for each vehicle speed are presented in Table 3.2-13.

**TABLE 3.2-13: FUEL HAUL TRUCK EMISSION FACTORS BY VEHICLE SPEED**

<i>SPEED LIMIT (MPH)</i>	<i>40-YEAR EMISSION FACTOR</i>	<i>70-YEAR EMISSION FACTOR</i>	<i>EMISSION FACTOR UNIT</i>
0	0.432	0.350	Grams/idle-hour
15	0.190	0.152	Grams/mile
25	0.129	0.107	Grams/mile
35	0.113	0.096	Grams/mile
45	0.120	0.104	Grams/mile
65	0.201	0.173	Grams/mile

*SOURCE: ENVIRON, HRA (FEBRUARY 2010)*

Truck traffic emission rates were varied based on the speed limit of each section of road along the route that will actually be travelled by the trucks. Figure 3.2-1 shows the routes taken by the trucks as they travel from Interstate 5 to the facility, and vice-versa. Table 3.2-14 shows the distance, number of one-way trips per day, and the average speed traveled used by EMFAC2007 to calculate the emission factor for each road segment in the project vicinity. Because there are currently no signalized intersections in the routes taken by trucks in the analysis, potential stops were not given additional emissions. Instead, the speed decrease caused by un-signalized stops was taken into account in the estimation of average speed traveled for each segment. This is consistent with intersection modeling guidelines.

**TABLE 3.2-14: MODELED ROAD SEGMENT PARAMETERS AND CALCULATED DPM EMISSION RATES**

<i>ROAD SEGMENT ID</i>	<i>AVERAGE SPEED (MPH)</i>	<i>SEGMENT LENGTH (METERS)</i>	<i>ONE-WAY TRIPS PER DAY</i>	<i>40-YEAR EMISSION RATE (LB/HR)</i>	<i>70-YEAR EMISSION RATE (LB/HR)</i>
1	15	738	46	3.68E-04	2.94E-05
2	25	125	23	2.12E-05	1.76E-05
3	25	129	23	2.18E-05	1.81E-05
4	25	260	46	8.80E-05	7.30E-05
5	45	141	23	2.22E-05	1.92E-05
6	25	162	23	2.74E-05	2.28E-05
7	40	547	46	1.67E-05	1.43E-05
8	30	345	11.5	2.74E-05	2.30E-05
9	30	462	11.5	3.66E-05	3.08E-05
10	40	223	23	3.40E-05	2.92E-05
11	45	302	11.5	2.37E-05	2.06E-05
12	30	551	11.5	4.20E-05	3.61E-05

*SOURCE: ENVIRON, HRA (FEBRUARY 2010)*

### **Potentially Exposed Populations**

According to OEHHA guidance, risk assessments that utilize refined air dispersion modeling must provide a detailed analysis of the potentially exposed population to the air emissions from the facility. The HRA analysis includes identification of maximum exposed individuals in residential (MEIR) and commercial/industrial areas (MEIW) and identification of sensitive receptors within the Zone of Impact (ZOI).

The location of maximum potential hazard indexes or carcinogenic risk is referred to as the point of maximum impact (PMI). Designation of the PMI, as well as residential, and commercial/industrial receptors, was determined using an aerial photo, as shown in Figure 3.2-2. The nearest residential receptors are approximately 100 to 200 meters south of the facility, across SR-273, and approximately 200 meters northeast of the facility property boundary, across the Sacramento River. Commercial/industrial receptors are located adjacent to the facility to the south, southeast, and southwest. Receptor grids with 25- and 50-meter spacing were placed in the surrounding residential and commercial areas, and with 10-meter spacing on the property boundary. As described below, the grid increased in spacing as distance from the facility increased. The receptors were identified as being in industrial or residential areas to identify maximum exposed individuals for chronic and acute non-carcinogenic, and carcinogenic effects for the residential population (MEIR) and worker population (MEIW). Property boundary receptors were also used to identify the theoretical maximum exposed off-site individuals (PMI).

### **Identification of the Zone of Impact**

The ZOI, as defined by the California Air Pollution Control Officers Association (CAPCOA), is the area within which there is a theoretical increased cancer risk of one-in-one million or greater based on a continuous, 70-year lifetime exposure to carcinogenic air emissions from the facility.

The results from the HARP model for the evaluated receptor grids provides the information necessary to identify the ZOI by generating the isopleths (i.e., a geographical presentation of areas of equal risk) for the on-in-one million theoretical cancer risk. The modeling results indicated that the ZOI of impact extended approximately 1.1 kilometers north and south and approximately 0.5 kilometer east to west. The ZOI is presented in Figure 3.2-2.

In accordance with the CAPCOA guidance, potential risks at locations of sensitive receptors within the ZOI such as schools and hospitals, should be identified. United States Geological Survey (USGS) maps were used to locate sensitive receptors. No sensitive receptors were identified within the ZOI.

### **Non-carcinogenic Health Effects**

Potential chronic and acute non-carcinogenic health effects associated with exposure to TAC emissions attributable to the proposed project have been evaluated using the HARP model. For acute inhalation exposure, the HARP model divides the predicted maximum hourly concentration by the appropriate acute REL provided by OEHHA (Table 4-1 of the attached HRA in **Appendix C**). Non-inhalation pathways are not applicable to acute exposures (OEHHA, 2003). For chronic inhalation exposures, the predicted annual average air concentration for each TAC is divided by the chronic inhalation REL. For chronic non-inhalation exposure, the predicted oral dose is divided by the chronic, oral REL as appropriate. These ratios are TAC-specific chronic or acute hazard quotients. The total hazard quotient reported for TACs with non-inhalation effects is the sum of the individual hazard quotients for inhalation and non-inhalation exposure.

Chronic and acute non-carcinogenic health effects were also evaluated in terms of their assumed potential additive effect on target organs or systems (e.g., central nervous system). For acute and chronic exposures, up to 13 target organs or systems were evaluated using the HARP model. The TACs that may affect the same target organ or system were evaluated by summing the individual hazard quotients to calculate a target organ-specific hazard index (HI). Chronic and acute hazard indexes less than or equal to 1.0 (i.e., the exposure is less than the health criteria) are considered to be without significant public health impact with a substantial margin of safety due to the manner in which the REL is developed. Additionally, hazard indexes greater than 1.0 do not necessarily mean that adverse health effects would be expected. Rather, on a TAC specific basis, as the hazard index increases above 1 to 10 or higher, the level of regulatory concern and need for control increases.

### **Acute Non-carcinogenic Results**

The PMI for acute non-carcinogenic effects occurred at the southeastern fenceline at a property boundary receptor (#4300); the highest target organ-specific hazard index at that location was estimated to be 0.064. The highest target organ-specific hazard index in a residential area occurred south of the facility at a grid receptor (#2804) representing the MEIR; the hazard index at that location was estimated to be 0.050. The highest target organ-specific hazard index in a commercial/industrial area occurred south of the facility at a grid receptor (#2968) representing

the MEIW; the hazard index at that location was estimated to be 0.051. The hazard indexes for the MEIW and MEIR are substantially below the regulatory significance level of 1.0.

### **Chronic Non-Carcinogenic Results**

The PMI for chronic non-carcinogenic health effects occurred at the southeastern fenceline at a property boundary receptor (#4297); the highest target organ-specific hazard index at that location was estimated to be 0.086. The highest target organ-specific hazard index in a residential area near the facility (MEIR) was at receptor #2890 with a hazard index at that location estimated to be 0.061. The highest target organ-specific hazard index in a commercial area near the facility (MEIW) was at receptor #2892 with a hazard index at that location estimated to be 0.065. The hazard indexes for the MEIW and MEIR are well below the regulatory significance level of 1.0.

### **Carcinogenic Health Effects**

In accordance with the OEHHA and CAPCOA guidance, cancer risk estimates based on the theoretical upper-bound excess cancer risk should be evaluated for the maximum exposed individuals, and a peak cancer receptor, if different.

For inhalation exposures, the theoretical upper-bound excess cancer risk is estimated assuming that an individual is exposed continuously to the annual average air concentrations over a 70-year lifetime. Once these annual average air concentrations are estimated for each of the receptors of interest, then the cancer risk is calculated for the carcinogenic AB 2588 TACs. Pursuant to the California Safe Drinking Water & Toxic Enforcement Act of 1986, the Office of Environmental Health Hazard Assessment has established a no significant risk level at  $1 \times 10^{-5}$  (California Code of Regulations Division 21.5, Title 22 Section 12703).

### **Estimated Theoretical Cancer Risks at Maximum Exposure Locations**

The maximum off-site receptors for carcinogenic health effects occurred along the fenceline east of the facility at property boundary receptor #4310; the potential cancer risk at that location was estimated to be  $2.1 \times 10^{-6}$ . The maximum potential cancer risk predicted in a residential area south of the facility (MEIR) was at grid receptor #2890; the potential cancer risk at that location was estimated to be  $1.3 \times 10^{-6}$ . The maximum potential cancer risk predicted in a commercial/industrial area east of the facility (MEIW) was at grid receptor #3105; the potential cancer risk at that location was estimated to be  $2.8 \times 10^{-7}$ .

TACs that contribute significantly to the total cancer risks vary between the key off-site receptors, but include arsenic, benzene, cadmium, diesel particulate matter, dioxin (2,3,7,8- TCDD), formaldehyde, and hexavalent chromium. Table 4-5 in the attached HRA presents the TAC-specific risk for the maximum off-site receptor, the MEIR, and the MEIW. Based on this evaluation, the total excess cancer risk at the MEIR does not exceed the commonly applied level of significance ( $1 \times 10^{-5}$ ).

### Lead Health Effects

The maximum estimated 30-day average concentrations of lead in air were 0.00051, 0.00040, and 0.00043  $\mu\text{g}/\text{m}^3$  for the PMI (property boundary receptor #4301), the MEIR (receptor #2804), and the MEIW (receptor #2758), respectively (see Table 4-6 in the attached HRA in **Appendix C**). All of the air concentrations were below the lead risk management level presented in the lead guidance (CARB, 2001) for neurodevelopmental effects in children assuming an average background exposure (0.3  $\mu\text{g}/\text{m}^3$ ). This is a conservative comparison for other potential health endpoints since the guidance value was calculated for the most sensitive target population (children). The results indicate that receptors at these locations would not experience adverse non-cancer health effects related to exposure to lead.

### Conclusions

The results of the risk evaluation are based on the operating conditions proposed in SPI's combined Authority to Construct/Potential for Significant Deterioration permit application and the TAC emissions calculated for the new proposed boiler. Based on the information provided in the HRA, prepared by ENVIRON, 2010; the following conclusions can be made regarding the TAC emissions from the proposed boiler:

#### ACUTE NON-CARCINOGENIC HEALTH HAZARDS

The hazard indexes for acute target organ-specific non-carcinogenic effects were 0.064 for the PMI, 0.05 for the MEIR, and 0.051 for the MEIW. These values are all below 1.0, indicating that off-site impacts from boiler emissions should not result in unacceptable acute non-carcinogenic health effects under the conditions evaluated. This is a **less than significant** impact.

#### CHRONIC NON-CARCINOGENIC HEALTH HAZARDS

The hazard indexes for chronic target organ-specific non-carcinogenic effects were 0.086 for the PMI, 0.061 for the MEIR, and 0.065 for the MEIW. These values are all below 1.0, indicating that off-site impacts from boiler emissions should not result in unacceptable chronic non-carcinogenic health effects under the conditions evaluated. This is a **less than significant** impact.

#### POTENTIAL CARCINOGENIC RISKS

The potential carcinogenic risks were  $2.1 \times 10^{-6}$  for the PMI,  $1.3 \times 10^{-6}$  for the MEIR, and  $2.8 \times 10^{-7}$  for the MEIW. These values do not exceed the commonly applied level of significance ( $1 \times 10^{-5}$  or ten-in-one million), indicating that off-site impacts from boiler emissions should not result in unacceptable carcinogenic health effects under the conditions evaluated. This is a **less than significant** impact.

Implementation of the proposed project would not expose sensitive receptors to toxic air contaminants above the thresholds identified above. This is a **less than significant** impact and no mitigation is required.



**Impact 3.2-5: Operation of the project may result in increased emissions associated with ash hauling and the movement of biomass materials within the project site (Less than Significant with Mitigation)**

## ASH DISPOSAL

Ash would be moved within the boiler using conveyor belts to an enclosed overhead ash bin. Ash from the bin would be gravity fed into a trailer for transport. The ash bin would need to be emptied approximately once every 19 hours.

The existing cogeneration facility generates approximately 4,300 tons/year of ash, which has been utilized on the adjoining agricultural fields as a soil amendment. When ash is added to the adjacent agricultural fields, it is trucked along existing private dirt roads using an SPI truck. The ash is deposited on the fields, spread uniformly, wetted with water and disked into the soil. Under the existing agricultural crop rotation, it has not been necessary for SPI to truck ash to the Anderson Landfill.

The proposed facility would generate approximately 11,155 tons/year of ash, which is an increase of approximately 6,855 tons/year over the baseline condition, since ash from the existing boiler would not be generated once the proposed boiler is operational. Ash from the proposed facility would either be disked into the adjacent agricultural fields as a soil amendment, used as an amendment in bagged soil and compost products, as a cement amendment, or it would be sent to the Anderson Landfill. The project applicant estimates fewer than one (1) truck trip per month to dispose of ash at the landfill would be required.

The movement of ash within the boiler to the overhead bins is not anticipated to result in the release of particulate matter (PM) into the air, since this operation would occur within an enclosed building area. However, the transfer of ash from the overhead ash bin into a transport truck has the potential to release PM into the air surrounding the API. Additionally, the transport of ash to offsite locations, such as the Anderson Landfill, could result in the release of PM into the air if loads are not properly wetted and covered. This is considered a **potentially significant** impact.

## ONSITE HEAVY EQUIPMENT USE

Although the capacity of the proposed cogeneration unit will be greater than that of the existing unit, and the quantities of fuel consumed and ash produced at the facility will increase as a result, on-site diesel-powered heavy equipment usage is not expected to similarly increase as a result of the proposed project. The new fuel house associated with the proposed cogeneration unit will include considerably more electric-powered automation (e.g., a hydraulic truck dump, fuel reclaimers, and covered conveyor belts) than the existing fuel house, which is expected to result in equivalent, or potentially decreased, diesel-powered heavy equipment usage when the proposed cogeneration unit is operational. Due to the fact that heavy equipment usage associated with onsite operations would not increase over the existing baseline condition, there would not be an increase in emissions associated with these operations. This is a **less than significant** impact.

### MITIGATION MEASURES

**Mitigation Measure 3.2-5** *The following conditions shall be included in the project's Conditional Use Permit:*

- *All trucks transporting waste ash shall have their loads wetted and covered **OR** all material transported off site will be either sufficiently watered or securely covered to prevent a public nuisance in conformance with SCAQMD rules governing Fugitive, Indirect, or Non-Traditional Sources .*
- *All trucks hauling dirt, sand, soil, or other loose material should be covered or should maintain at least 2 feet of freeboard (i.e., minimum vertical distance between top of the load and top of the trailer) in accordance with the requirements of California Vehicle Code Section 23114. This provision will be enforced by local law enforcement agencies.*
- *Require that all diesel engines be shut off when not in use to reduce emissions from idling.*

### SIGNIFICANCE AFTER MITIGATION

Implementation of MM 3.2-5 would reduce this impact to a **less than significant** level.

### 3.2.4 GREENHOUSE GASSES AND CLIMATE CHANGE

#### ENVIRONMENTAL SETTING

##### **Greenhouse Gases and Climate Change Linkages**

Various gases in the Earth's atmosphere, classified as atmospheric greenhouse gases (GHGs), play a critical role in determining the Earth's surface temperature. Solar radiation enters Earth's atmosphere from space, and a portion of the radiation is absorbed by the Earth's surface. The Earth emits this radiation back toward space, but the properties of the radiation change from high-frequency solar radiation to lower-frequency infrared radiation.

Greenhouse gases, which are transparent to solar radiation, are effective in absorbing infrared radiation. As a result, this radiation that otherwise would have escaped back into space is now retained, resulting in a warming of the atmosphere. This phenomenon is known as the greenhouse effect. Among the prominent GHGs contributing to the greenhouse effect are carbon dioxide (CO<sub>2</sub>), methane (CH<sub>4</sub>), ozone (O<sub>3</sub>), water vapor, nitrous oxide (N<sub>2</sub>O), and chlorofluorocarbons (CFCs).

Human-caused emissions of these GHGs, in excess of natural ambient concentrations, are responsible for enhancing the greenhouse effect (Ahrens 2003). Emissions of GHGs contributing to global climate change are attributable in large part to human activities associated with the industrial/manufacturing, utility, transportation, residential, and agricultural sectors (California Energy Commission 2006a). In California, the transportation sector is the largest emitter of GHGs, followed by electricity generation (California Energy Commission 2006a).

As the name implies, global climate change is a global problem. GHGs are global pollutants, unlike criteria air pollutants and toxic air contaminants, which are pollutants of regional and local concern, respectively. California is the 12th to 16th largest emitter of CO<sub>2</sub> in the world and produced 492 million gross metric tons of carbon dioxide equivalents in 2004 (California Energy Commission 2006a).

Carbon dioxide equivalents are a measurement used to account for the fact that different GHGs have different potential to retain infrared radiation in the atmosphere and contribute to the greenhouse effect. This potential, known as the global warming potential of a GHG, is also dependent on the lifetime, or persistence, of the gas molecule in the atmosphere. Expressing GHG emissions in carbon dioxide equivalents takes the contribution of all GHG emissions to the greenhouse effect and converts them to a single unit equivalent to the effect that would occur if only CO<sub>2</sub> were being emitted.

Consumption of fossil fuels in the transportation sector was the single largest source of California's GHG emissions in 2004, accounting for 40.7% of total GHG emissions in the state (California Energy Commission 2006a). This category was followed by the electric power sector (including both in-state and out of-state sources) (22.2%) and the industrial sector (20.5%) (California Energy Commission 2006a).

### **Effects of Global Climate Change**

The effects of increasing global temperature are far reaching and extremely difficult to quantify. The scientific community continues to study the effects of global climate change. In general, increases in the ambient global temperature as a result of increased GHGs is anticipated to result in rising sea levels, which could threaten coastal areas through accelerated coastal erosion, threats to levees and inland water systems and disruption to coastal wetlands and habitat.

If the temperature of the ocean warms, it is anticipated that the winter snow season would be shortened. Snowpack in the Sierra Nevada provides both water supply (runoff) and storage (within the snowpack before melting), which is a major source of supply for the state. According to a California Energy Commission report, the snowpack portion of the supply could potentially decline by 70% to 90% by the end of the 21<sup>st</sup> century (CEC 2006c). This phenomenon could lead to significant challenges securing an adequate water supply for a growing state population. Further, the increased ocean temperature could result in increased moisture flux into the state; however, since this would likely increasingly come in the form of rain rather than snow in the high elevations, increased precipitation could lead to increased potential and severity of flood events, placing more pressure on California's levee/flood control system.

Sea level has risen approximately seven inches during the last century and, according to the CEC report, it is predicted to rise an additional 22 to 35 inches by 2100, depending on the future GHG emissions levels (CEC 2006c). If this occurs, resultant effects could include increased coastal flooding, saltwater intrusion and disruption of wetlands (CEC 2006c). As the existing climate throughout California changes over time, mass migration of species, or failure of species to migrate in time to adapt to the perturbations in climate, could also result. Under the emissions scenarios of the Climate Scenarios report (California Climate Change Center 2006), the impacts of global warming in California are anticipated to include, but are not limited to, the following.

#### **PUBLIC HEALTH**

Higher temperatures are expected to increase the frequency, duration, and intensity of conditions conducive to air pollution formation. For example, days with weather conducive to ozone formation are projected to increase from 25 to 35 percent under the lower warming range, to 75 to 85 percent under the medium warming range. In addition, if global background ozone levels increase as predicted in some scenarios, it may become impossible to meet local air quality standards. Air quality could be further compromised by increases in wildfires, which emit fine particulate matter that can travel long distances depending on wind conditions. The Climate Scenarios report indicates that large wildfires could become up to 55 percent more frequent if GHG emissions are not significantly reduced.

In addition, under the higher warming scenario, there could be up to 100 more days per year with temperatures above 90°F in Los Angeles and 95°F in Sacramento by 2100. This is a large increase over historical patterns and approximately twice the increase projected if temperatures remain within or below the lower warming range. Rising temperatures will increase the risk of death from

dehydration, heat stroke/exhaustion, heart attack, stroke, and respiratory distress caused by extreme heat.

### WATER RESOURCES

A vast network of man-made reservoirs and aqueducts capture and transport water throughout the state from northern California rivers and the Colorado River. The current distribution system relies on Sierra Nevada snow pack to supply water during the dry spring and summer months. Rising temperatures, potentially compounded by decreases in precipitation, could severely reduce spring snow pack, increasing the risk of summer water shortages.

The state's water supplies are also at risk from rising sea levels. An influx of saltwater would degrade California's estuaries, wetlands, and groundwater aquifers. Saltwater intrusion caused by rising sea levels is a major threat to the quality and reliability of water within the southern edge of the Sacramento/San Joaquin River Delta, a major state fresh water supply. Global warming is also projected to seriously affect agricultural areas, with California farmers projected to lose as much as 25 percent of the water supply they need; decrease the potential for hydropower production within the state (although the effects on hydropower are uncertain); and seriously harm winter tourism. Under the lower warming range, the snow dependent winter recreational season at lower elevations could be reduced by as much as one month. If temperatures reach the higher warming range and precipitation declines, there might be many years with insufficient snow for skiing and snowboarding and other snow dependent recreational activities.

If GHG emissions continue unabated, more precipitation will fall as rain instead of snow, and the snow that does fall will melt earlier, reducing the Sierra Nevada spring snow pack by as much as 70 to 90 percent. Under the lower warming scenario, snow pack losses are expected to be only half as large as those expected if temperatures were to rise to the higher warming range. How much snow pack will be lost depends in part on future precipitation patterns, the projections for which remain uncertain. However, even under the wetter climate projections, the loss of snow pack would pose challenges to water managers, hamper hydropower generation, and nearly eliminate all skiing and other snow-related recreational activities.

### AGRICULTURE

Increased GHG emissions are expected to cause widespread changes to the agriculture industry reducing the quantity and quality of agricultural products statewide. Although higher carbon dioxide levels can stimulate plant production and increase plant water-use efficiency, California's farmers will face greater water demand for crops and a less reliable water supply as temperatures rise.

Plant growth tends to be slow at low temperatures, increasing with rising temperatures up to a threshold. However, faster growth can result in less-than optimal development for many crops, so rising temperatures are likely to worsen the quantity and quality of yield for a number of California's agricultural products. Products likely to be most affected include wine grapes, fruits and nuts, and milk.

Crop growth and development will be affected, as will the intensity and frequency of pest and disease outbreaks. Rising temperatures will likely aggravate ozone pollution, which makes plants more susceptible to disease and pests and interferes with plant growth.

In addition, continued global warming will likely shift the ranges of existing invasive plants and weeds and alter competition patterns with native plants. Range expansion is expected in many species while range contractions are less likely in rapidly evolving species with significant populations already established. Should range contractions occur, it is likely that new or different weed species will fill the emerging gaps. Continued global warming is also likely to alter the abundance and types of many pests, lengthen pests' breeding season, and increase pathogen growth rates.

### FORESTS AND LANDSCAPES

Global warming is expected to alter the distribution and character of natural vegetation thereby resulting in a possible increased risk of large wildfires. If temperatures rise into the medium warming range, the risk of large wildfires in California could increase by as much as 55 percent, which is almost twice the increase expected if temperatures stay in the lower warming range. However, since wildfire risk is determined by a combination of factors, including precipitation, winds, temperature, and landscape and vegetation conditions, future risks will not be uniform throughout the state. For example, if precipitation increases as temperatures rise, wildfires in southern California are expected to increase by approximately 30 percent toward the end of the century. In contrast, precipitation decreases could increase wildfires in northern California by up to 90 percent.

Moreover, continued global warming will alter natural ecosystems and biological diversity within the state. For example, alpine and sub-alpine ecosystems are expected to decline by as much as 60 to 80 percent by the end of the century as a result of increasing temperatures. The productivity of the state's forests is also expected to decrease as a result of global warming.

### RISING SEA LEVELS

Rising sea levels, more intense coastal storms, and warmer water temperatures will increasingly threaten the state's coastal regions. Under the higher warming scenario, sea level is anticipated to rise 22 to 35 inches by 2100. Elevations of this magnitude would inundate coastal areas with saltwater, accelerate coastal erosion, threaten vital levees and inland water systems, and disrupt wetlands and natural habitats.

## REGULATORY SETTING

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### **Federal**

#### ENERGY POLICY AND CONSERVATION ACT

The Energy Policy and Conservation Act of 1975 sought to ensure that all vehicles sold in the U.S. would meet certain fuel economy goals. Through this Act, Congress established the first fuel

economy standards for on-road motor vehicles in the United States (U.S.). Pursuant to the Act, the National Highway Traffic and Safety Administration, which is part of the U.S. Department of Transportation (USDOT), is responsible for establishing additional vehicle standards and for revising existing standards.

Since 1990, the fuel economy standard for new passenger cars has been 27.5 mpg. Since 1996, the fuel economy standard for new light trucks (gross vehicle weight of 8,500 pounds or less) has been 20.7 mpg. Heavy-duty vehicles (i.e., vehicles and trucks over 8,500 pounds gross vehicle weight) are not currently subject to fuel economy standards. Compliance with federal fuel economy standards is determined on the basis of each manufacturer's average fuel economy for the portion of its vehicles produced for sale in the U.S. The Corporate Average Fuel Economy (CAFE) program, which is administered by the U.S. Environmental Protection Agency (EPA), was created to determine vehicle manufacturers' compliance with the fuel economy standards. The EPA calculates a CAFE value for each manufacturer based on city and highway fuel economy test results and vehicle sales. Based on the information generated under the CAFE program, the USDOT is authorized to assess penalties for noncompliance.

### ENERGY POLICY ACT OF 1992 (EPACT)

The Energy Policy Act of 1992 (EPAct) was passed to reduce the country's dependence on foreign petroleum and improve air quality. EPAct includes several parts intended to build an inventory of alternative fuel vehicles (AFVs) in large, centrally fueled fleets in metropolitan areas. EPAct requires certain federal, state, and local government and private fleets to purchase a percentage of light duty AFVs capable of running on alternative fuels each year. In addition, financial incentives are included in EPAct. Federal tax deductions will be allowed for businesses and individuals to cover the incremental cost of AFVs. States are also required by the act to consider a variety of incentive programs to help promote AFVs.

### ENERGY POLICY ACT OF 2005

The Energy Policy Act of 2005 was signed into law on August 8, 2005. Generally, the act provides for renewed and expanded tax credits for electricity generated by qualified energy sources, such as landfill gas; provides bond financing, tax incentives, grants, and loan guarantees for a clean renewable energy and rural community electrification; and establishes a federal purchase requirement for renewable energy.

### FEDERAL CLIMATE CHANGE POLICY

According to the EPA, "the United States government has established a comprehensive policy to address climate change" that includes slowing the growth of emissions; strengthening science, technology, and institutions; and enhancing international cooperation. To implement this policy, "the Federal government is using voluntary and incentive-based programs to reduce emissions and has established programs to promote climate technology and science." The federal government's goal is to reduce the greenhouse gas (GHG) intensity (a measurement of GHG emissions per unit of economic activity) of the American economy by 18 percent over the 10-year period from 2002 to

2012. In addition, the EPA administers multiple programs that encourage voluntary GHG reductions, including “ENERGY STAR”, “Climate Leaders”, and Methane Voluntary Programs. However, as of this writing, there are no adopted federal plans, policies, regulations, or laws directly regulating GHG emissions.

### **State**

#### **CALIFORNIA STRATEGY TO REDUCE PETROLEUM DEPENDENCE (AB 2076)**

AB 2076 (Chapter 936, Statutes of 2000) requires the CEC and the ARB to develop and submit to the Legislature a strategy to reduce petroleum dependence in California. The statute requires the strategy to include goals for reducing the rate of growth in the demand for petroleum fuels. In addition, the strategy is required to include recommendations to increase transportation energy efficiency as well as the use of non-petroleum fuels and advanced transportation technologies including alternative fuel vehicles, hybrid vehicles, and high-fuel efficiency vehicles.

The strategy, *Reducing California’s Petroleum Dependence*, was adopted by the CEC and CARB in 2003. The strategy recommends that California reduce inroad gasoline and diesel fuel demand to 15 percent below 2003 demand levels by 2020 and maintain that level for the foreseeable future; the Governor and Legislature work to establish national fuel economy standards that double the fuel efficiency of new cars, light trucks, and sport utility vehicles (SUVs); and increase the use of non- petroleum fuels to 20 percent of on-road fuel consumption by 2020 and 30 percent by 2030.

#### **BIOENERGY ACTION PLAN – EXECUTIVE ORDER #S-06-06**

Executive Order #S-06-06 establishes targets for the use and production of biofuels and biopower and directs state agencies to work together to advance biomass programs in California while providing environmental protection and mitigation. The executive order establishes the following target to increase the production and use of bioenergy, including ethanol and biodiesel fuels made from renewable resources: produce a minimum of 20 percent of its biofuels within California by 2010, 40 percent by 2020, and 75 percent by 2050. The executive order also calls for the state to meet a target for use of biomass electricity, including biomass cogeneration facilities.

#### **GOVERNOR’S LOW CARBON FUEL STANDARD (EXECUTIVE ORDER #S-01-07)**

Executive Order #S-01-07 establishes a statewide goal to reduce the carbon intensity of California’s transportation fuels by at least 10 percent by 2020 through establishment of a Low Carbon Fuel Standard. The Low Carbon Fuel Standard shall be incorporated into the State Alternative Fuels Plan required by AB 1007 and is one of the proposed discrete early action GHG reduction measures identified by CARB pursuant to AB 32.

#### **SENATE BILL 97 (SB 97)**

Senate Bill 97 was signed by the Governor on August 24, 2007. This bill would provide that in an environmental impact report, negative declaration, mitigated negative declaration, or other document required by CEQA for either transportation projects funded under the Highway Safety,



Traffic Reduction, Air Quality and Port Security Bond Act of 2006, or projects funded under the Disaster Preparedness and Flood Prevention Bond Act of 2006, the failure to analyze adequately the effects of greenhouse gas emissions otherwise required to be reduced pursuant to regulations adopted under the Global Warming Solutions Act of 2006 does not create a cause of action for a violation of CEQA. The bill would provide that this provision shall apply retroactively for any of the above documents that are not final and shall be repealed on January 1, 2010.

The bill would require the Office of Planning and Research (OPR), by July 1, 2009, to prepare, develop, and transmit to the Resources Agency guidelines for the feasible mitigation of greenhouse gas emissions or the effects of greenhouse gas emissions, as required by CEQA, including, but not limited to, effects associated with transportation or energy consumption. The Resources Agency would be required to certify and adopt those guidelines by January 1, 2010. The OPR would be required to periodically update the guidelines to incorporate new information or criteria established by the CARB pursuant to the California Global Warming Solutions Act of 2006.

### CLIMATE ACTION PROGRAM AT CALTRANS

In December 2006, the California Department of Transportation, Business, Transportation, and Housing Agency, issued a Climate Action Program. The goal of the Climate Action Program is to promote clean and energy efficient transportation, and provide guidance for mainstreaming energy and climate change issues into business operations. The overall approach to lower fuel consumption and CO<sub>2</sub> from transportation is twofold: (1) reduce congestion and improve efficiency of transportation systems through smart land use, operational improvements, and Intelligent Transportation Systems; and (2) institutionalize energy efficiency and GHG emission reduction measures and technology into planning, project development, operations, and maintenance of transportation facilities, fleets, buildings, and equipment.

The reasoning underlying the Climate Action Program is the conclusion that “the most effective approach to addressing GHG reduction, in the short-to-medium term, is strong technology policy and market mechanisms to encourage innovations. Rapid development and availability of alternative fuels and vehicles, increased efficiency in new cars and trucks (light and heavy duty), and super clean fuels are the most direct approach to reducing GHG emissions from motor vehicles (emission performance standards and fuel or carbon performance standards).”

### ASSEMBLY BILL 1493

In 2002, then Governor Gray Davis signed AB 1493. AB 1493 required the CARB to develop and adopt, by January 1, 2005, regulations that achieve “the maximum feasible reduction of greenhouse gases emitted by passenger vehicles and light-duty truck and other vehicles determined by the ARB to be vehicles whose primary use is noncommercial personal transportation in the state.” To meet the requirements of AB 1493, CARB approved amendments to the California Code of Regulations (CCR) adding GHG emission standards to California’s existing motor vehicle emission standards in 2004.

Amendments to CCR Title 13 Sections 1900 (CCR 13 1900) and 1961 (CCR 13 1961), and adoption of Section 1961.1 (CCR 13 1961.1) require automobile manufacturers to meet fleet average GHG emission limits for all passenger cars, light-duty trucks within various weight criteria, and medium-duty passenger vehicle weight classes beginning with the 2009 model year. Emission limits are further reduced each model year through 2016. For passenger cars and light-duty trucks 3,750 pounds or less loaded vehicle weight (LVW), the 2016 GHG emission limits are approximately 37 percent lower than the during the first year of the regulations in 2009. For medium-duty passenger vehicles and light-duty trucks 3,751 LVW to 8,500 pounds gross vehicle weight (GVW), GHG emissions are reduced approximately 24 percent between 2009 and 2016.

In December 2004, a group of car dealerships, automobile manufacturers, and trade groups representing automobile manufactures filed suit against the CARB to prevent enforcement of CCR 13 1900 and CCR 13 1961 as amended by AB 1493 and CCR 13 1961.1 (Central Valley Chrysler-Jeep et al., v. Catherine E. Witherspoon, in her official capacity as Executive Director of the California Air Resources Board et al.). The suit, being heard in the U.S. District Court for the Eastern District of California, contends that California's implementation of regulations that in effect regulate vehicle fuel economy violates various federal laws, regulations, and policies. To date, the suit has not been settled, and the judge has issued an injunction stating CARB cannot enforce the regulations in question before receiving appropriate authorization from the EPA.

### CALIFORNIA EXECUTIVE ORDERS S-3-05 AND S-20-06, AND ASSEMBLY BILL 32

On June 1, 2005, Governor Arnold Schwarzenegger signed Executive Order S-3-05. The goal of this Executive Order is to reduce California's GHG emissions to: 1) 2000 levels by 2010, 2) 1990 levels by the 2020 and 3) 80% below the 1990 levels by the year 2050.

In 2006, this goal was further reinforced with the passage of Assembly Bill 32 (AB 32), the Global Warming Solutions Act of 2006. AB 32 sets the same overall GHG emissions reduction goals while further mandating that ARB create a plan, which includes market mechanisms, and implement rules to achieve "real, quantifiable, cost-effective reductions of greenhouse gases." Executive Order S-20-06 further directs state agencies to begin implementing AB 32, including the recommendations made by the state's Climate Action Team.

Climate change and GHG reduction is also a concern at the federal level; however, at this time, no legislation or regulations have been enacted specifically addressing GHG emissions reductions and climate change.

CARB, which is part of Cal-EPA, develops air quality regulations at the state level. The state regulations mirror federal regulations by establishing industry-specific pollution controls for criteria, toxic, and nuisance pollutants. California also requires areas to develop plans and strategies for attaining state ambient air quality standards as set forth in the California Clean Air Act of 1988. In addition to developing regulations, CARB develops motor vehicle emission standards for California vehicles.

### SENATE BILL 1368

SB 1368 requires the California Energy Commission (CEC) and the California Public Utilities Commission (CPUC) to set a global warming emissions standard for electricity used in California — regardless of whether it's generated in-state or purchased from plants in other states. The new standard applies to any new long-term financial contracts for base load electricity, and applies both to investor-owned utilities and municipal utilities. The standard for baseload generation owned by, or under long-term contract to publicly owned utilities, is and emissions performance standard (EPS) of 1,100 lbs CO<sub>2</sub> per megawatt-hour (MWh). However, the CPUS has determined that biomass generation of electricity is EPS compliant because alternative means of disposing biomass such as open air burning and landfill deposition have the potential to generate greater concentrations of greenhouse gas in the atmosphere, including methane. This concept is described in greater detail under the impact analysis below.

### CALIFORNIA RENEWABLES PORTFOLIO STANDARD (RPS)

Established in 2002 under Senate Bill 1078 and accelerated in 2006 under Senate Bill 107, California's Renewables Portfolio Standard (RPS) is one of the most ambitious renewable energy standards in the country. The RPS program requires electric corporations to increase procurement from eligible renewable energy resources by at least 1% of their retail sales annually, until they reach 20% by 2010. Biomass generated electricity is considered an eligible renewable energy source for the RPS program.

## GHG THRESHOLDS OF SIGNIFICANCE AND METHODOLOGY

### *Methodology*

Operational GHG emissions were calculated as part of the Cogeneration Unit Toxic Air Contaminant Emission Rates by ENVIRON, 2010. This information is contained in the ATC/PSD permit application to the SCAQMD, which is attached to this EIR as **Appendix B**. GHG emissions would be generated primarily through operation of the proposed boiler. However, additional GHG emissions would also be generated by the increase in heavy truck and passenger vehicle trips as a result of project operations. Emissions associated with an increase in vehicle trips were calculated using the URBEMIS 2007 software (Appendix J).

Construction-related GHGs were calculated the URBEMIS 2007 software (Appendix J). The assumptions regarding construction equipment and software model inputs are described in greater detail under the methodology in the Air Quality section of this EIR chapter.

### *Thresholds of Significance*

As described previously, the State Legislature and the global scientific community have found that global climate change poses significant adverse effects to the environment of California and the entire world.

To mitigate these adverse effects, the State Legislature, through AB 32, has required statewide GHG reductions of 25 percent, to 1990 levels, by 2020. AB 32 and S-3-05 target the reduction of statewide emissions. It should be made clear that AB 32 and S-3-05 do not specify that the

emissions reductions should be achieved through uniform reduction by geographic location or by emission source characteristics. For example, it is conceivable, although unlikely, that AB 32 goals could be achieved by new regulations that only apply to urban areas or that only apply to the transportation and/or energy sector.

Additionally, the Renewables Portfolio Standard (RPS) program, as authorized by SB 1078 and SB 107, requires electric corporations to increase procurement from eligible renewable energy resources by at least 1% of their retail sales annually, until they reach 20% by 2010.

At the time of the preparation of this EIR, the SCAQMD had not adopted specific thresholds of significance for GHGs in CEQA documents. Therefore, the analysis in this section is based on methodologies presented in the California Air Pollution Control Officers Association’s (CAPCOA) white paper, “CEQA and Climate Change” for selecting a GHG analysis methodology and establishing a GHG threshold of significance.

- For the purposes of this EIR only, a GHG impact would be considered significant if implementation of the proposed project does not assist in meeting the Statewide GHG reduction goals outlined in AB 32, and the Statewide renewable energy goals outlined in the RPS.

## GHG IMPACTS AND MITIGATION MEASURES

### **Impact 3.2.6: Project implementation could result in cumulative effects on climate change and global warming or conflict with a locally adopted plan to reduce climate change impacts (Cumulatively Considerable and Significant and Unavoidable)**

Construction-related GHGs would be generated through the use of heavy equipment and machinery during construction of the proposed project. Construction activities that could generate GHG emissions are primarily related to grading and other ground-preparation activities in order to prepare the project site for the installation of the various components of the cogeneration facility.

The estimated construction GHG emissions are presented below in Table 3.2-15.

**TABLE 3.2-15: UNMITIGATED CONSTRUCTION GREENHOUSE GASSES**

<i>GREENHOUSE GAS</i>	<i>UNMITIGATED EMISSIONS (TONS/YEAR)</i>
Carbon dioxide	120.29

*SOURCE: DE NOVO PLANNING GROUP, 2010 (URBEMIS 2007 MODELING)*

As described above, the SCAQMD has not established a numerical threshold of significance for GHGs associated with construction activities or project operational activities. Implementation of MM 3.2-1 and 3.2-2 would require the preparation of specific and detailed construction emissions reduction plans and the implementation of SMMs, which would reduce construction-related

impacts associated with dust and construction vehicle emissions to a less than significant level, consistent with SCAQMD requirements. These measures would also reduce construction related GHG emissions to a **less than significant** level, as they would require implementation of a wide range of measures to reduce emissions from construction activities.

Operational greenhouse gasses generated by the proposed project would come from two sources: 1) emissions from employee vehicles and heavy truck trips associated with the transport of biomass materials to the project site, and 2) operation of the proposed cogeneration plant.

Carbon dioxide equivalents (CO<sub>2</sub> eq) provide a universal standard of measurement against which the impacts of releasing (or avoiding the release of) different greenhouse gases can be evaluated. Every greenhouse gas has a Global Warming Potential (GWP), a measurement of the impact that particular gas has on 'radiative forcing'; that is, the additional heat/energy which is retained in the Earth's ecosystem through the addition of this gas to the atmosphere.

The GWP of a given gas describes its effect on climate change relative to a similar amount of carbon dioxide. According to the USEPA, the following five gasses are considered GHGs, and their respective GWP is shown in Table 3.2-16 below.

**TABLE 3.2-16: GLOBAL WARMING POTENTIAL OF GREENHOUSE GASSES**

<i>GREENHOUSE GAS</i>	<i>GLOBAL WARMING POTENTIAL</i>
Carbon dioxide	1
Methane	21
Nitrous oxide	310
Halocarbons (HFC)	140 to 11,700
Sulphur Hexafluoride	23,900

*SOURCE: INTERNATIONAL EMISSIONS TRADING ASSOCIATION, 2010*

This means that one pound of methane will have an effect on global warming that is 21 times greater than one pound of carbon dioxide, and so forth.

Employee vehicle trips and heavy truck trips associated with the transport of materials to the project site would generate approximately 231 tons per year of CO<sub>2</sub> (URBEMIS, 2007). No other types of GHGs would be generated by the project-related vehicle and truck trips.

Operation of the proposed cogeneration plant would generate CO<sub>2</sub>, methane, and nitrous oxide (N<sub>2</sub>O). Halocarbons (HFC) and Sulphur Hexafluoride would not be generated by the proposed project. Table 3.2-17 identifies the tons per year of each GHG that would be generated by the proposed project if it were to operate at 100% capacity throughout the year; identifies the GWP conversion factor of each GHG; and identifies the CO<sub>2</sub> equivalents for each GHG generated by the proposed project.

**TABLE 3.2-17: PROJECT GENERATED GREENHOUSE GASSES**

GREENHOUSE GAS	TOTAL PROJECT EMISSIONS (TONS/YEAR) <sup>2</sup>	GWP CONVERSION FACTOR	CO <sub>2</sub> EQUIVALENT (TONS/YEAR)
Carbon Dioxide <sup>1</sup>	385,731	1	385,731
Methane	1,315	21	27,615
Nitrous Oxide	1,725	310	53,475
Total CO <sub>2</sub> Equivalents			466,821

1 INCLUDES CO<sub>2</sub> FROM VEHICLE TRIPS AND COGENERATION OPERATIONS (231 TPY FROM VEHICLE TRIPS)

2 DATA SOURCE IS ENVIRON, PSD (2010), TABLE 2-5

As shown in Table 3.2-17, the proposed project would generate up to 466,821 tons/year of CO<sub>2</sub> equivalents from all sources of emissions.

Shasta County has not adopted a Climate Action Plan or other form of GHG mitigation program. The Shasta County General Plan does not include any policies or programs aimed at reducing GHG impacts. Therefore, the project would not conflict with any locally adopted plans related to GHGs or climate change.

Neither Shasta County nor the SCAQMD have adopted numerical thresholds of significance for GHG impacts related to individual projects. As described above, the project would have a significant impact to climate change and global warming if it does not assist in meeting the Statewide GHG reduction goals outlined in AB 32, and the Statewide renewable energy goals outlined in the RPS.

The first regulation adopted by the Air Resources Board (ARB) pursuant to AB 32 was the regulation requiring mandatory reporting of GHG emissions. The regulation requires large industrial sources to report and verify their GHG emissions from combustion of both fossil fuels and biomass-derived fuels. Therefore, the proposed facility may be required to report its GHG emissions to the ARB. The draft ARB regulation for a California Cap and Trade program was issued on November 24, 2009 for public review and comment. The draft regulation states as follows with regard to biomass fuels: “Most biomass fuel combustion emissions from stationary sources would not create an obligation to surrender (GHG) allowances. Therefore, for combustion emissions of stationary sources, only fossil fuel combustion emissions are counted toward the 25,000 metric tons CO<sub>2</sub> per year threshold (for GHG regulation).” The USEPA has issued an endangerment finding for GHG emissions but has not proposed any regulations for reducing GHG emissions. The CPUC has decided that electric generation using biomass would cause a net reduction of GHG emissions (as described in greater detail below), and the proposed ARB Cap and Trade program indicate that this facility would not result in GHG emissions that would be subject to reduction by regulatory means.

As described in the Project Description Section of this EIR, the steam turbine generator would produce up to 31 MW of electricity. Approximately 7 MW will be used to power on-site equipment at the SPI site, and the remaining 24 MW would be sold to a public utility. The proposed cogeneration plant is considered a renewable energy source, as identified by the California Energy Commission (CEC).

Because the biomass fuel that would be used by the proposed boiler consumes CO<sub>2</sub> throughout its growth, the fuel is considered to be “carbon-neutral” when combusted in an energy production cycle. In a January 25, 2007 publication titled “*Interim Opinion on Phase 1 Issues: Greenhouse Gas Emissions Performance Standards*”, the California Public Utilities Commission (CPUC) has found that “electric generation using biomass that would otherwise be disposed of under a variety of conventional methods results in a net reduction in GHG emissions” (CPUC, 2007). The CPUC explains that this net reduction finding is due to the avoidance of large quantities of CH<sub>4</sub> (methane) gas emissions that would occur by the alternate fate of biomass fuels (e.g., landfilling, composting, forest accumulation, open burning) in the absence of a biomass generation plant. The “net” GHG reduction by a biomass plant operation considers not only the avoided CH<sub>4</sub> of the alternate fates of disposal of the biomass wastes, but also considers the GHG emissions of the fossil-fueled vehicles and machinery that are used in the biomass collection, chipping, and transportation activities. The referenced CPUC decision states that, “Since CH<sub>4</sub> gas is on the order of twenty to twenty-five times more potent as a GHG than CO<sub>2</sub>, and since CH<sub>4</sub> has an atmospheric residence time of twelve years, after which it is converted to atmospheric CO<sub>2</sub>, trading off CH<sub>4</sub> for CO<sub>2</sub> emissions from energy recovery operations leads to a net reduction of the greenhouse effect.” A study by the Pacific Institute (Pacific Institute, 2008) provided complete technical detail and calculations supporting the “net negative” GHG emission profile of biomass generation, as expressed in the above-mentioned CPUC decision. A copy of the full report from the Pacific Institute can be viewed at: [http://www.pacinst.org/reports/Bioenergy\\_and\\_Greenhouse\\_Gases/Bioenergy\\_and\\_Greenhouse\\_Gases.pdf](http://www.pacinst.org/reports/Bioenergy_and_Greenhouse_Gases/Bioenergy_and_Greenhouse_Gases.pdf).

Table 3.2-17 shows the total GHG emissions that would be emitted annually during operation of the proposed project. As shown in the table, the project would directly generate up to 466,821 tons/year of GHGs. However, it is important to note that the GHG emissions shown in Table 3.2-17 do not account for the reduction in GHGs that occur through the disposal of biomass material in a cogeneration boiler, as opposed to disposal through open burning or decomposition in a landfill. As described above, the use of biomass material in a cogeneration facility is considered to be carbon neutral, as determined by the CPUC. Additionally, the project meets the requirements of the RPS and SB 1368 in that it will provide an expanded source of renewable energy to a local utility provider’s portfolio. However, because the biomass fuel that would be burned in the boiler would come from a variety of sources, it is not possible to accurately calculate the actual reduction in emissions that would occur if the fuel from these various sources were disposed of by other means, and not burned in the proposed boiler.

Due to the fact that the USEPA and the ARB have not finalized the legislative requirements for GHGs from biomass electricity generating facilities; the project would directly generate up to 466,821 tons/year of GHGs; and the GHG reductions that may be realized by burning the biomass in a boiler rather than allowing for other means of disposal cannot be accurately calculated at this time, Shasta County is unable to verify that the project would actually be a carbon-neutral source of GHGs. Based on the analysis presented above, while the project may assist in meeting the Statewide renewable energy goals outlined in the RPS, the project may not assist in meeting the GHG reduction goals established by AB 32. This is considered to be a **significant** impact.

As described throughout this section, a wide range of BACT has been incorporated into the project design. While the BACT required for the project does not specifically address or reduce GHG emissions, it would result in a “cleaner” burning boiler, which would assist in reducing GHGs emissions to a certain degree. There are no additional feasible mitigation measures available to reduce GHG emissions from the proposed project. Therefore, impacts to climate change and the generation of greenhouse gasses are considered to be **cumulatively considerable and significant and unavoidable**.



**Exhibit 3.2-1  
Cogeneration Unit Air Toxic Contaminant Emission Rates**

<b>CAS No.</b>	<b>Chemical Name<sup>1</sup></b>	<b>Annual Emissions<sup>1,2</sup> (lb/yr)</b>	<b>Maximum Hourly Emissions<sup>1,2</sup> (lb/hr)</b>
83329	Acenaphthene	2.70E-02	3.39E-06
208968	Acenaphthylene	5.73E+00	7.19E-04
75070	Acetaldehyde	7.41E+02	9.30E-02
67641	Acetone	6.04E+02	7.58E-02
98862	Acetophenone	1.20E-02	1.51E-06
107028	Acrolein	1.18E+02	1.48E-02
7664417	Ammonia	7.53E+04	9.46E+00
120127	Anthracene	1.85E-01	2.32E-05
7440360	Antimony	1.72E+00	2.15E-04
7440382	Arsenic	1.84E+00	2.31E-04
7440393	Barium	5.67E+02	7.11E-02
100527	Benzaldehyde	3.15E+00	3.95E-04
71432	Benzene	3.21E+03	4.03E-01
56553	Benzo(a)anthracene	9.38E-03	1.18E-06
50328	Benzo(a)pyrene	1.22E-02	1.53E-06
205992	Benzo(b)fluoranthene	8.76E-03	1.10E-06
192972	Benzo(e)pyrene	9.66E-03	1.21E-06
191242	Benzo(g,h,i)perylene	1.72E-02	2.16E-06
205823	Benzo(j)fluoranthene	5.80E-01	7.28E-05
207089	Benzo(k)fluoranthene	8.88E-03	1.11E-06
65850	Benzoic Acid	1.74E-01	2.19E-05
7440417	Beryllium	5.78E+00	7.26E-04
117817	Bis(2-ethylhexyl)phthalate	1.73E-01	2.18E-05
74839	Bromomethane	1.04E+02	1.31E-02
78933	2-Butanone (MEK)	2.01E+01	2.52E-03
7440439	Cadmium	9.65E+00	1.21E-03
86748	Carbazole	6.67E+00	8.38E-04
37210165	Carbon Dioxide (CO <sub>2</sub> )	7.71E+08	9.68E+04
56235	Carbon Tetrachloride	1.69E+02	2.12E-02
7782505	Chlorine	2.95E+03	3.71E-01
108907	Chlorobenzene	1.24E+02	1.55E-02
67663	Chloroform	1.03E+02	1.29E-02
74873	Chloromethane	8.61E+01	1.08E-02
91587	2-Chloronaphthalene	8.96E-03	1.13E-06
108430	2-Chlorophenol	1.26E-01	1.58E-05
18540299	Chromium, hexavalent	6.53E-01	8.20E-05
7440473	Chromium, trivalent	4.63E+00	5.82E-04
218019	Chrysene	1.03E-02	1.29E-06
7440484	Cobalt	3.33E+01	4.18E-03
7440508	Copper	1.53E+01	1.92E-03
4170303	Crotonaldehyde	3.69E+01	4.64E-03

CAS No.	Chemical Name <sup>1</sup>	Annual Emissions <sup>1,2</sup> (lb/yr)	Maximum Hourly Emissions <sup>1,2</sup> (lb/hr)
2051243	Decachlorobiphenyl	9.88E-04	1.24E-07
53703	Dibenzo(a,h)anthracene	8.75E-03	1.10E-06
106934	1,2-Dibromoethene	2.04E+02	2.56E-02
2050682	Dichlorobiphenyl	1.41E-03	1.77E-07
107062	1,2-Dichloroethane	1.09E+02	1.37E-02
75092	Dichloromethane	1.07E+03	1.34E-01
78875	1,2-Dichloropropane	1.24E+02	1.56E-02
51285	2,4-Dinitrophenol	3.48E-01	4.36E-05
100414	Ethylbenzene	1.17E+02	1.46E-02
206440	Fluoranthene	1.93E+00	2.42E-04
86737	Fluorene	1.98E-01	2.48E-05
50000	Formaldehyde	7.30E+03	9.17E-01
28655712	Heptachlorobiphenyl	2.45E-04	3.07E-08
26601649	Hexachlorobiphenyl	1.08E-03	1.35E-07
37871004	HpCDD-Total	1.15E-04	1.44E-08
38998753	HpCDF-Total	2.38E-05	2.99E-09
34465468	HxCDD-Total	3.19E-04	4.00E-08
55684941	HxCDF-Total	5.71E-05	7.18E-09
66251	Hexanal	2.59E+01	3.26E-03
7647010	Hydrogen chloride	1.31E+04	1.65E+00
193395	Indeno(1,2,3-c,d)pyrene	8.85E-03	1.11E-06
7439896	Iron	3.70E+03	4.65E-01
78842	Isobutyraldehyde	4.29E+01	5.38E-03
7439921	Lead	4.45E+01	5.59E-03
7439965	Manganese	4.31E+02	5.41E-02
7439976	Mercury	1.55E+00	1.95E-04
74828	Methane	2.63E+05	3.30E+01
67561	Methanol	3.09E+03	3.88E-01
91576	2-Methylnaphthalene	1.02E+00	1.29E-04
7439987	Molybdenum	4.19E+00	5.26E-04
2051607	Monochlorobiphenyl	8.12E-04	1.02E-07
91203	Naphthalene	3.17E+02	3.98E-02
7440020	Nickel	1.06E+01	1.33E-03
10102439	Nitric Oxide (NO)	4.84E+05	6.08E+01
88755	2-Nitrophenol	3.96E-01	4.97E-05
100027	4-Nitrophenol	6.38E-01	8.01E-05
10024972	Nitrous Oxide (N <sub>2</sub> O)	3.45E+04	4.33E+00
3268879	OCDD	8.71E-04	1.09E-07
39001020	OCDF	5.31E-05	6.67E-09
36088229	PeCDD-Total	6.39E-04	8.03E-08
30402154	PeCDF-Total	1.56E-04	1.96E-08
25429292	Pentachlorobiphenyl	2.42E-03	3.04E-07
87865	Pentachlorophenol	8.46E-02	1.06E-05

CAS No.	Chemical Name <sup>1</sup>	Annual Emissions <sup>1,2</sup> (lb/yr)	Maximum Hourly Emissions <sup>1,2</sup> (lb/hr)
198550	Perylene	1.93E-03	2.42E-07
86018	Phenanthrene	6.32E+00	7.93E-04
108952	Phenol	4.67E+01	5.87E-03
7723140	Phosphorus	1.32E+02	1.66E-02
7440097	Potassium	1.45E+05	1.82E+01
123386	Propionaldehyde	1.17E+01	1.47E-03
129000	Pyrene	1.11E+00	1.40E-04
7782492	Selenium	1.26E+01	1.58E-03
7440235	Sodium	1.35E+03	1.70E-01
7440246	Strontium	3.75E+01	4.71E-03
7664939	Sulfuric Acid	7.86E+03	9.86E-01
1746016	TCDD-Total	7.62E-04	9.57E-08
30402143	TCDF-Total	6.06E-04	7.60E-08
26914330	Tetrachlorobiphenyl	5.96E-03	7.49E-07
127184	Tetrachloroethene	1.42E+02	1.79E-02
7440315	Tin	1.46E+02	1.83E-02
7440326	Titanium	7.49E+01	9.41E-03
529204	o-Tolualdehyde	2.66E+01	3.35E-03
104870	p-Tolualdehyde	4.21E+01	5.29E-03
108883	Toluene	7.92E+01	9.94E-03
15862074	Trichlorobiphenyl	6.63E-03	8.33E-07
71556	1,1,1-Trichloroethane	1.15E+02	1.44E-02
79016	Trichloroethene	1.13E+02	1.42E-02
75694	Trichlorofluoromethane	1.51E+02	1.90E-02
88062	2,4,6-Trichlorophenol	4.23E-02	5.31E-06
1314621	Vanadium	2.21E+00	2.78E-04
75014	Vinyl Chloride	6.86E+01	8.61E-03
1330207	Xylene	9.12E+01	1.15E-02
7440655	Yttrium	1.12E+00	1.41E-04
7440666	Zinc	6.48E+02	8.14E-02

1. Abbreviations:

- HpCDD-Total = Total Heptachlorodibenzo-p-dioxin
- HpCDF-Total = Total Heptachlorodibenzofuran
- HxCDD-Total = Total Hexachlorodibenzo-p-dioxin
- HxCDF-Total = Total Hexachlorodibenzofuran
- OCDD = 1,2,3,4,6,7,8,9-Octachlorodibenzo-p-dioxin
- OCDF = 1,2,3,4,6,7,8,9-Octachlorodibenzofuran
- PeCDD-Total = Total Pentachlorodibenzo-p-dioxin
- PeCDF-Total = Total Pentachlorodibenzofuran
- TCDD-Total = 2,3,7,8-Tetrachlorodibenzo-p-dioxin
- TCDF-Total = Total Tetrachlorodibenzofuran

2. Chemical emission rates reported for the cogeneration unit in the Authority to Construct permit application submitted to Shasta County Air Quality Management District in February 2010.

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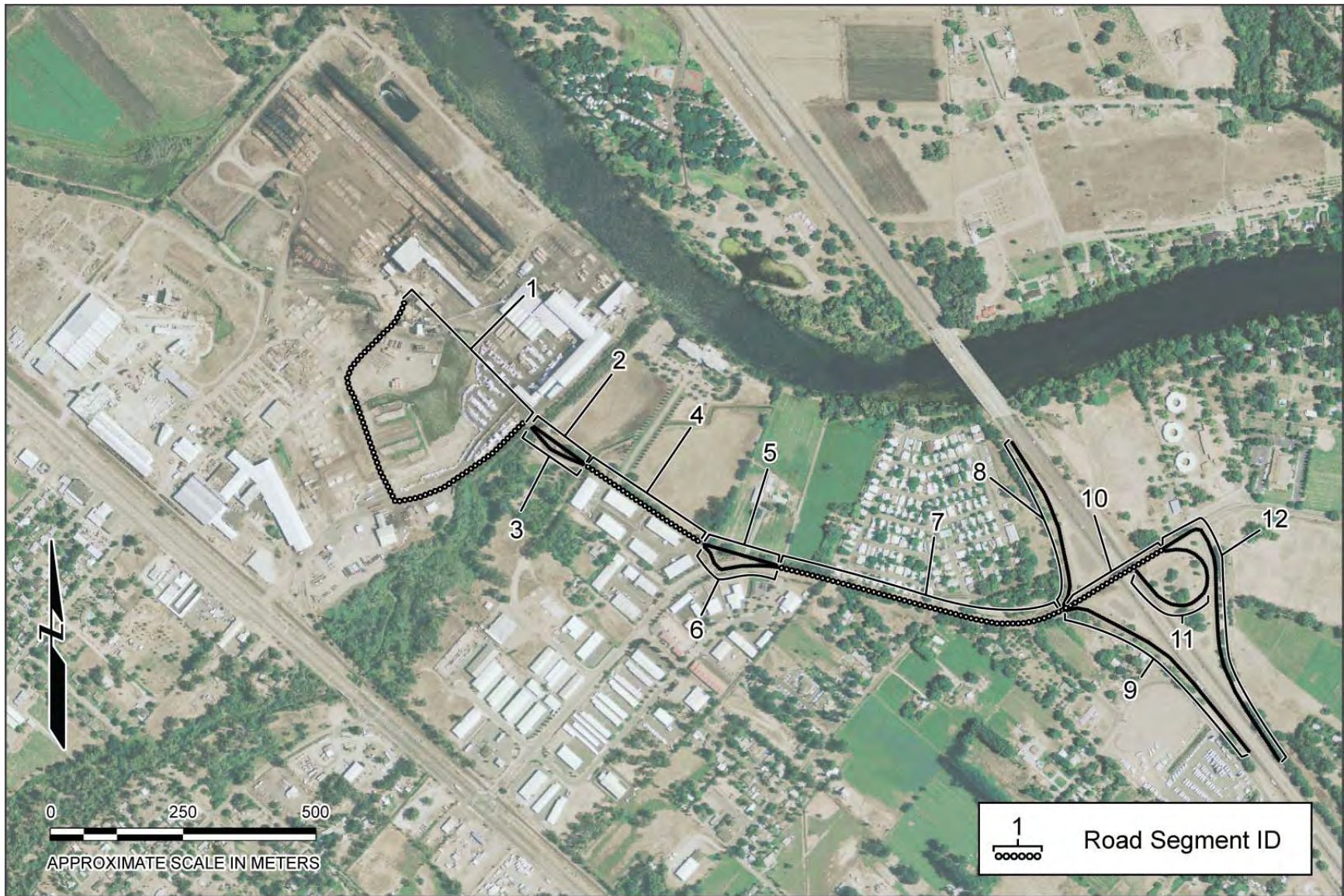


Figure 3.2-1 Fuel Haul Truck Route

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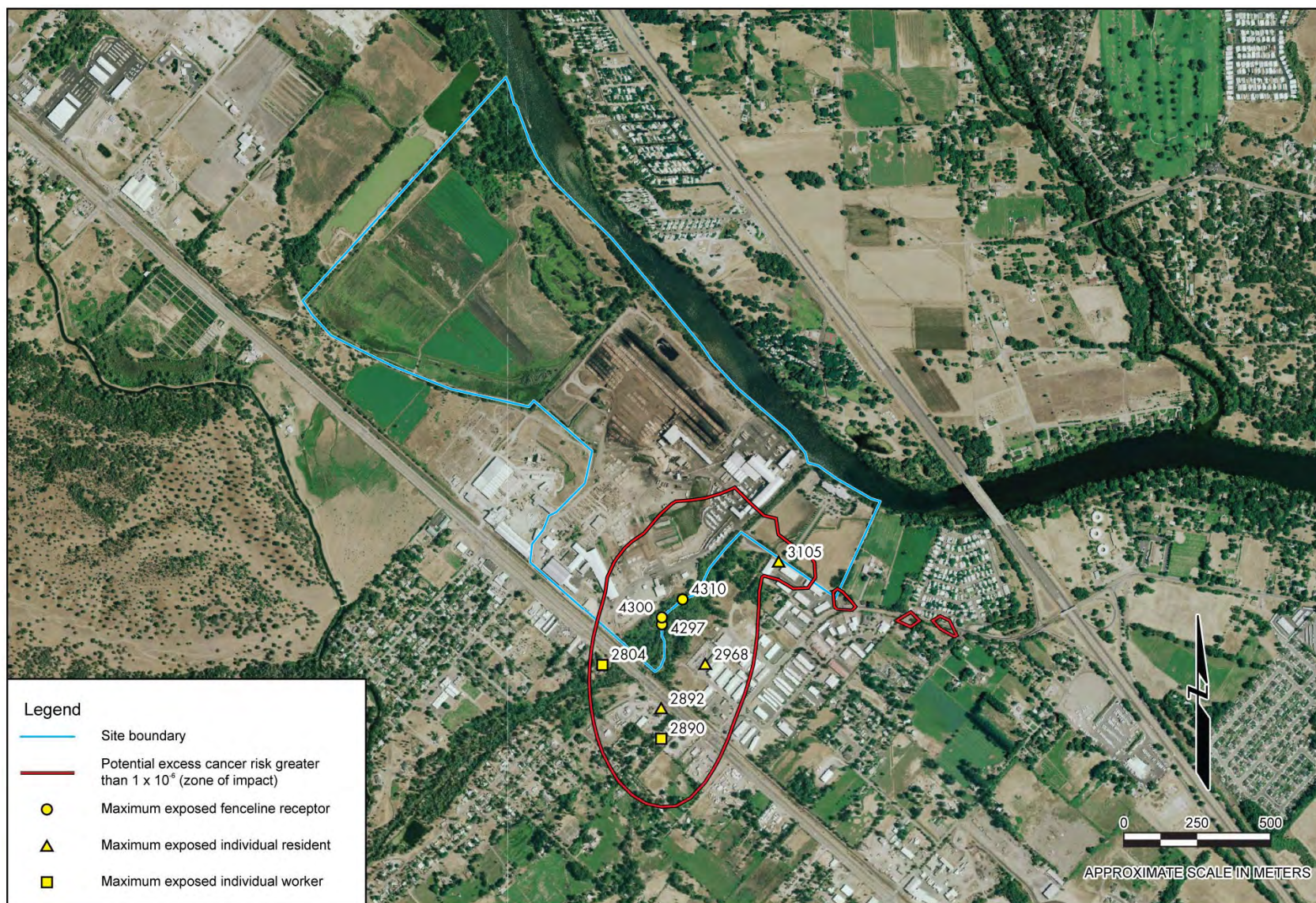


Figure 3.2-2 Locations of Key Off-Site Receptors and Excess Carcinogenic Risk

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