

## **STANDARD AIR CONTAMINANT DISCHARGE PERMIT REVIEW REPORT**

Department of Environmental Quality  
Eastern Region

**Source Information:**

SIC	4911
NAICS	221119

Source Categories (Table 1 Part, code)	B, #27
Public Notice Category	III

**Compliance and Emissions Monitoring Requirements:**

FCE	X
Compliance schedule	
Unassigned emissions	
Emission credits	
Special Conditions	

Source test date(s)	60 to 180 days after startup
COMS	X
CEMS	X
Ambient Monitoring	

**Reporting Requirements**

Annual report (due date)	Feb. 15 <sup>th</sup>
Quarterly report (due dates)	
Monthly report (due dates)	

Excess emissions report	X
Other (specify): Subpart Db NSPS opacity semi-annual excess emissions report	X

**Air Programs**

Synthetic Minor (SM)	
SM -80	
NSPS (list subparts)	Db, IIII
NESHAP (list subparts)	ZZZZ
Part 68 Risk Management	
CFC	

NSR	
PSD	
RACT	
TACT	X
Other (specify)	

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## **PERMITTING**

### PERMITTING ACTION

1. The proposed permit is a new permit for a new source.

### OTHER PERMITS

2. No other permits have been issued by the Department of Environmental Quality for this source. Water quality and solid waste permits may be required by the Department.

### ATTAINMENT STATUS

3. The source will be located in an attainment area for all pollutants. The source will be located near the Klamath Falls PM<sub>10</sub> maintenance area, as well as the PM<sub>2.5</sub> nonattainment area.
4. The source is not located within 10 kilometers of the any Class I Air Quality Protection Areas.

### LAND USE COMPATIBILITY STATEMENT

5. Pursuant to ORS 469, Oregon Department of Energy's Energy Facility Siting Council will determine that the proposed land use complies with state-wide planning goals prior to granting a Site Certificate.

## **SOURCE DESCRIPTION**

### PERMITTEE IDENTIFICATION

6. Klamath Falls Bioenergy, LLC (KFB) proposes to construct and operate a biomass-fired electrical generation facility in Klamath Falls, Oregon. The project site is on 106.6 acres located in an industrial zoned property east of State Highway 66 between State Highway 66 and a private road known as 100 Line Road. The expected street address is 8000 Highway 66, Klamath Falls, Oregon.

### OVERVIEW

7. The main components of the KFB facility will consist of a fluidized bed combustor and waste heat boiler (FBB), steam turbine generator, cooling tower, fuel handling equipment (truck dumper, conveyors, storage piles and screens), and firewater pump diesel engine for emergencies. This report uses information provided in the application based a preliminary design of the boiler. DEQ acknowledges that some of the engineering values

listed in the this review report, such as steam temperature, pressure, or maximum steam generating capacity could increase or decrease slightly as the design is finalized. These changes in boiler design could also affect power output (lower or higher). If changes are significant enough to affect emissions, DEQ will evaluate whether the changes affect the conclusions provided in this review report.

## PROCESS AND CONTROL DEVICES

Air contaminant sources at the facility will consist of the following:

8. **Fuel storage and handling:** The biomass fuel for the facility will be delivered by truck and off-loaded to a fuel storage and reclaim area. The fuel will be stored on an asphalt pavement pad, with an appropriate storm water collection and treatment system. The fuel delivery trucks will drive on to a mechanical lift that tilts the truck to unload the biomass, and the fuel will be conveyed to a stacker system which will place it onto the fuel piles. Telescoping download chutes will be provided to minimize the distance the fuel falls in open air so as to minimize the dust released from the falling fuel. The fuel will be reclaimed onto a conveyor system for transport to the boiler for combustion. All conveyors will be covered to minimize fugitive dust emissions.

The clean, renewable biomass (wood waste) fuel will come primarily from the thinning of Ponderosa Pine trees. The fuel supplier may also provide clean wood debris from landscape trimmings, storm damage to tree stands, land clearing and untreated wood construction debris. The biomass fuel consumption rate of the boiler is estimated to be approximately 350,000 tons per year. The “as-received” fuel consists of actual fuel with an average moisture content of approximately 40 percent.

Fuel deliveries will be scheduled during normal work weeks to arrive on a 10-hour-per-day, 6-day-per-week basis, excluding holidays. Fuel deliveries will commence prior to initial facility operation to ensure a 6-month supply in the fuel pile. KFB intends to maintain the storage piles with a minimum of two month supply of fuel at all times because access to the forests is limited during the winter. In the past, during years with severe winters, access to the wood stands has not been practical for up to 6 months.

9. **Fluidized bed boiler:** The FBB will be enclosed in a building approximately 112 feet tall. The FBB will include a sand bed that has air injected into it to “fluidize” the sand, and to provide a controlled combustion environment where the fuel will be burned. The boiler design is based on combusting a variety of woody biomass fuel blends, but the primary fuel will be tree trimmings and forest slash. The boiler will be compatible with fuel moisture contents ranging between 25 and 50 percent; the design value of the fuel is 4,805 British thermal units per pound (Btu/lb) at 40 percent moisture.

Natural gas will be used to bring the sand bed up to temperature during startup. It is estimated each boiler startup sequence will require approximately 1.36 million standard

cubic feet (scf) of natural gas over a 10-hour period. Boiler startup is not anticipated to occur more than three times a year.

The heat produced from the FBB will generate steam in water-filled boiler tubes located after the combustion zone. The boiler will be capable of producing up to 322,400 pounds per hour of steam at 1,500 pounds per square inch gauge (psig) and 955 degrees Fahrenheit (°F). Hot flue gas leaving the steam generator enters the multiclone, economizer and air heater sections. The multiclone uses high efficiency cyclonic tubes to centrifugally de-entrain ash particles from the gas stream. The economizer is a single pass, finned tube design. Flue gas flows downward so ash is de-entrained at the bottom of the unit. Feed water flows counter-current or upward to prevent steam bubbles from being trapped. A dual path air heater is included to recover energy in the flue gas by transferring it to the under-fire and over-fire combustion air streams. Parallel flue gas paths with separate flow balancing dampers control the outlet gas temperature and balance the flows for the split air streams. Downstream of the air heater, the flue gas continues on to additional emission control systems.

The boiler will employ Typically Available Control Technology (TACT) to limit air pollutant emissions. However, controls and practices beyond what is considered TACT may also be used to limit emissions and remain below regulatory limits.

A selective non-catalytic reduction system (SNCR) will be installed and used to supplement combustion control as necessary to maintain emissions of oxides of nitrogen (NO<sub>x</sub>) below the federal major source level of 250 tons per year. The SNCR process is a post-combustion reduction method that reduces NO<sub>x</sub> emissions through a controlled injection of urea solution into the combustion gases of the boiler. The SNCR system consists of (1) a urea storage area; (2) a urea pumping and distribution area; and (3) separate urea injection levels. The urea will be delivered by truck in a pre-mixed solution and stored in a 1,000 gallon tank. NO<sub>x</sub> reduction occurs between 1,500 and 2,200 °F, and the reagent is injected into the boiler at multiple levels. The injection rate is controlled in proportion to load and outlet NO<sub>x</sub> levels.

A sorbent injection system will be installed to reduce emissions of acid gases such as sulfuric and hydrochloric acid. Sorbents under consideration for injection are sodium bisulfate, hydrated lime and trona. The sorbent injection system consists of (1) the sorbent storage area; (2) sorbent distribution skid; and (3) separate injection lances. The sorbent will be delivered by truck, packaged in super-sacks. The sorbent is fed into a hopper and metering device, from which powder is conveyed and injected into the flue gas. Neutralization of SO<sub>2</sub> and HCl in the flue gas occurs with adsorption onto the surface of the sorbents. The injection rate is controlled automatically in proportion to flue gas flow (unit load). The injection points for the sorbent are downstream of the air heater and upstream of the fabric filter. Limestone may also be added to the fluidized bed as a secondary control measure.

A pulse jet fabric filter baghouse will be employed to minimize particulate matter emissions and opacity. The flue gas enters the fabric filter and passes through cloth filter bags. Essentially all of the fly ash and solid reaction products (including those from the sorbent injection system) are collected on the cloth surface, while the cleaned flue gas passes through. A cake of solids builds up on the bags and is subsequently removed by pulsing the bags with compressed air. The cake drops into hoppers located below the bags and is periodically transferred to the by-product silo awaiting transfer to its final disposal site.

NO<sub>x</sub>, and CO emissions will be monitored with continuous emissions monitoring systems (CEMS). A continuous opacity monitoring system (COMS) will be used to monitor visible emissions as a surrogate for particulate matter emissions.

10. **Cooling tower:** A four-cell cooling tower will be used to remove waste heat from the condenser cooling water. Constructed of fiberglass, the tower will be approximately 24 feet high and 130 feet long. Aside from water vapor, the cooling tower emits only particulate matter (PM) that is contained in the local water supply. The PM emission rate will depend upon the quantity of solids dissolved in the cooling water, the number of times the cooling water is circulated through the tower and the efficiency of the mist eliminators used in the cooling tower. High efficiency drift eliminators will be employed to minimize water loss and entrained PM. Because all emitted particles are expected to be aerosols formed from condensation nuclei, PM, PM<sub>10</sub> and PM<sub>2.5</sub> emission rates are assumed to be equivalent.
11. **Firewater Pump Diesel Engine:** KFB proposes to install two high capacity water pumps for fire protection. One pump will be powered by electric motor, the other will be powered by a diesel engine. The engine will meet the emission standards prescribed by 40 CFR Part 60, Subpart IIII (Standards of Performance for Stationary Compression Ignition Internal Combustion Engines). Subpart IIII limits non-emergency operation to 100 hours per year, and ordinarily, the engines will each operate at most an hour per week for maintenance and testing.

## **REGULATORY REQUIREMENTS**

12. The proposed project is not subject to the Prevention of Significant Deterioration requirements because the potential emissions of each pollutant are less than 250 tons per year. [OAR Chapter 340, Division 224]
13. The FBB is subject to the New Source Performance Standards (NSPS) for electric steam generating units with heat inputs greater than 250 million Btu per hour. The PM standard, while burning biomass, is 0.030 lb/MMBtu heat input, as measured by EPA Method 5. The visible emissions standard is 20% opacity, 6-minute average as measured by a COMS. [40 CFR Part 60, subpart Db] The NO<sub>x</sub> standards do not apply because the annual capacity factor while burning natural gas will be less than 10%. Other NSPS for

boilers do not apply because the facility either does not burn the specified fuel or is not within the size range specified in the standards. Pursuant to 40 CFR 60.8 and 60.11, the particulate matter standards do not apply during periods of startup, shutdown or malfunction.

14. The fire water pump engine is subject to the NSPS for compression ignition internal combustion engines, specifically 40 CFR 60.4202(a) and (d); respectively. The permittee will use engines certified by the manufacturer to meet the emission limits. The engines will be operated and maintained in accordance with the manufacturer's instructions and hour meters will be installed to monitor operating time. Only low sulfur diesel (15 ppm) will be burned in the engines. [40 CFR Part 60, Subpart III]
15. The fire water pump engine is also subject to the National Emissions Standards for Hazardous Air Pollutant (NESHAP) for stationary reciprocating internal combustion engines. Since the facility is not a major source of hazardous air pollutants, compliance with NSPS subpart IIII will ensure compliance with the NESHAP. [40 CFR Part 63, subpart ZZZZ]
16. EPA proposed a NESHAP for industrial, commercial and institutional boilers in June 2010 for both major and area sources of hazardous air pollutants. The KFB facility is a minor source of HAPs, so the standards for area sources will be incorporated into the permit when the NESHAP is finalized. [40 CFR Part 63, subpart JJJJJ]
17. Based on the information provided in the application, DEQ has determined that no other NSPS or NESHAP are applicable to the proposed facility.
18. The proposed facility is subject to both state and federal greenhouse gas reporting requirements, but greenhouse gases will not become a regulated pollutant for permitting until January 2011. Any requirements associated with greenhouse gases will be incorporated when the facility becomes subject to the requirements.
19. Other state requirements include:
  - a. General emissions standards for visible emissions and particulate matter in OAR 340, Division 208 and 228 include a 20% opacity limit and 0.1 gr/dscf; respectively. These limits are included in the permit and apply at all times.
  - b. The sulfur dioxide limit for solid fuels in OAR 340-228-0200(2)(b) is applicable to the facility, but wood does not typically contain enough sulfur to emit anywhere near the limit.
  - c. The permit also includes requirements from OAR 340, Division 208 that prohibit nuisance conditions such as particulate fallout and odors as well as requirements to minimize fugitive emissions.
  - d. The Typically Achievable Control Technology (TACT)/Highest and Best Rules in OAR 340, Division 226 apply to the wood-fired boiler for nitrogen oxides and carbon monoxide because the potential emissions are greater than 10 tons per year and there are no other state or federal standards for these pollutants. DEQ has

determined that the proposed selective non-catalytic reduction system is better than TACT for nitrogen oxide emissions because no other wood-fired boiler operating in the state has emission controls for nitrogen oxides. For carbon monoxide, no other wood-fired boilers in the state have add-on controls, so operation of the boiler in accordance with good combustion practices is considered TACT. As discussed above, the proposed NESHAP for boilers will include a carbon monoxide emissions limit that will ensure the boiler is operated in accordance with good combustion practices.

- e. The Reasonably Available Control Technology rules in OAR 340, Division 232 are not applicable to this source because it is not in the Portland AQMA, Medford AQMA, or Salem SKATS.
  - f. The source is subject to the federal Acid Rain Program because it will serve a generator with a rated capacity greater than 25 MW and will burn fossil fuel (e.g., natural gas during startup). The permittee is required to submit an application for an Acid Rain permit 24 months prior to commencing commercial operation.
20. The facility is a Title V major source because both the nitrogen oxides and carbon monoxide potential emissions are greater than 100 tons per year. Therefore, the permittee is required to submit an application for an Oregon Title V Operating Permit within one year after startup. The Title V permit will replace the Standard ACDP.

## **COMPLIANCE**

- 21. The facility will be inspected by Department personnel to ensure compliance with the permit conditions.
- 22. An initial performance test is required for particulate matter and nitrogen oxides to demonstrate compliance with the emissions limits.
- 23. The following continuous monitoring devices are required for the wood-fired boiler:
  - a. Continuous opacity monitoring system;
  - b. Continuous nitrogen oxides emissions monitoring system; and
  - c. Continuous carbon monoxide emissions monitoring system.

## **EMISSIONS**

24. Proposed PSEL information:

<b>Pollutant</b>	<b>Baseline Emissions Rate (tons/yr)</b>	<b>Proposed Netting Basis (tons/yr)</b>	<b>Proposed PSEL (tons/yr)</b>
PM <sub>10</sub>	0	0	35
PM <sub>2.5</sub>	0	0	25
SO <sub>2</sub>	0	0	39
NO <sub>x</sub>	0	0	230
CO	0	0	230
VOC	0	0	39

- a. This is a new source, so the baseline emission rate for the baseline period of 1977/1978 is zero for all pollutants.
- b. This permit action is not subject to the New Source Review requirements in OAR 340, Division 224, so the netting basis is zero for all pollutants.
- c. The proposed PSELs for SO<sub>2</sub>, and VOC are equal to the Generic PSEL in accordance with OAR 340-222-0041(1).
- d. The proposed PSELs for PM<sub>10</sub>, PM<sub>2.5</sub>, NO<sub>x</sub> and CO are equal to the potential to emit in accordance with OAR 340-222-0041(2) and (3).
- e. The PSEL is a federally enforceable limit on the potential to emit.

### SIGNIFICANT EMISSION RATE ANALYSIS

25. An analysis of the proposed PSEL increases over the Netting Basis is shown in the following table.

<b>Pollutant</b>	<b>SER</b>	<b>Requested Increase Over Previous Netting Basis</b>	<b>Increase Due to Physical Changes or Changes in the Method of Operation</b>	<b>Increase Due to the Generic PSEL</b>
PM <sub>10</sub>	15	35	35	0
PM <sub>2.5</sub>	10	25	25	0
SO <sub>2</sub>	40	39	38	1
NO <sub>x</sub>	40	230	230	0
CO	100	230	200	0
VOC	40	39	36	3

26. For SO<sub>2</sub> and VOC, the proposed PSELs are less than the significant emission rate for each pollutant, thus no further air quality analysis is required in accordance with OAR 340-222-0041.

27. For PM<sub>10</sub>, PM<sub>2.5</sub>, NO<sub>x</sub> and CO, the proposed PSELs are greater than the significant emission rate for each pollutant. Therefore, an air quality impact analysis is required in accordance with OAR 340-222-0041(3)(b)(C). The permittee conducted an air quality impact analysis in accordance with a modeling protocol approved by DEQ. The worst case emissions scenarios were used in the model to determine the highest impacts. The air quality analysis includes two steps. The first step determines whether any of the pollutant emissions from the proposed source would have impacts greater than the significant impact levels (SIL). If not, no further modeling is required. If the impacts are greater than a SIL, then additional modeling must be performed to determine whether the proposed source's emissions would exceed an ambient air quality standard or the proposed source's emissions along with other source's emissions in the area would exceed increments designed to protect the area from significant deterioration of air quality. The CO emissions from the proposed source were modeled and the impacts were determined to be less than SILs. Therefore, no further modeling was required for CO. For PM<sub>10</sub>, PM<sub>2.5</sub> and NO<sub>x</sub>, the model showed that the impacts would be greater than SILs, so additional modeling was required.

**Significant Impact Level (SIL):**

<b>Pollutant</b>	<b>Averaging Time</b>	<b>Maximum Modeled Concentration (µg/m<sup>3</sup>)</b>	<b>Significant Impact Level (µg/m<sup>3</sup>)</b>	<b>Exceed SIL (yes/no)</b>
PM <sub>10</sub>	24-hour	1.59	1.0	<b>Yes</b>
	Annual	0.32	0.2	<b>Yes</b>
PM <sub>2.5</sub>	24-hour	1.36	1.0	<b>Yes</b>
	Annual	0.23	0.2	<b>Yes</b>
CO	1-hour	258	2,000	No
	8-hour	43	500	No
NO <sub>2</sub>	Annual	1.59	1.0	<b>Yes</b>

**National Ambient Air Quality Standards (NAAQS):**

<b>Pollutant</b>	<b>Averaging Time</b>	<b>Increment Consuming Sources Plus Background (µg/m<sup>3</sup>)</b>	<b>Nation Ambient Air Quality Standard (µg/m<sup>3</sup>)</b>	<b>Exceed NAAQS (yes/no)</b>
PM <sub>10</sub>	24-hour	101	150	No
	Annual	22.9	50	No
PM <sub>2.5</sub>	24-hour	35.3	35	<b>Yes</b>
	Annual	7.6	15	No
NO <sub>2</sub>	Annual	16.7	100	No

**Class II Prevention of Significant Deterioration Increments:**

Pollutant	Averaging Time	Increment Consuming Sources ( $\mu\text{g}/\text{m}^3$ )	Class II Increment ( $\mu\text{g}/\text{m}^3$ )	Exceed Increment (yes/no)
PM <sub>10</sub>	24-hour	30.5	30	Yes
	Annual	1.8	17	No
PM <sub>2.5</sub>	24-hour	10.3	9	Yes
	Annual	0.6	4	No
NO <sub>2</sub>	Annual	2.2	25	No

The modeled NO<sub>2</sub> impacts are below both the ambient air quality standards and the prevention of significant deterioration increment. Therefore, DEQ concludes that the proposed source will not have an adverse impact on the NO<sub>2</sub> ambient air quality. The modeled impacts exceed the 24-hour ambient air quality standard for PM<sub>2.5</sub> and the 24-hour increment for both PM<sub>2.5</sub> and PM<sub>10</sub>. Therefore, DEQ requested additional analysis to determine if the exceedances are due to the proposed source. For this analysis, the cumulative impacts are evaluated at each receptor and time that the source's impacts exceed the SIL. If the cumulative impacts are less than the ambient air quality standards and increments at the receptors and times where the source's impacts are greater than the SIL, then the exceedances must occur at receptors and times when the source's impacts are less than SIL and the source is not considered to contribute to the exceedances. Another way to say this is that for all receptors and times that the source's impacts are less than the SIL, the source is not considered to contribute to any exceedances that may occur at those receptors and times. The supplemental analysis demonstrates that there are no exceedances at any of the receptors and times that the source's impacts are greater than the SIL as shown in the following table:

**Cumulative Impact Analysis:**

Pollutant	Averaging Time/Standard	Maximum Concentration ( $\mu\text{g}/\text{m}^3$ )	Increment or NAAQS ( $\mu\text{g}/\text{m}^3$ )	Exceed Standard (yes/no)
PM <sub>10</sub>	24-hour Increment	22.9	30	No
PM <sub>2.5</sub>	24-hour Increment	8.92	9	No
	24-hour NAAQS	15.9	35	No

DEQ has determined that while there may be some exceedances of the ambient air quality standards and prevention of significant deterioration increments for PM<sub>10</sub> and PM<sub>2.5</sub>, the exceedances are not due to the proposed source's emissions.

DEQ acknowledges that the modeling further demonstrates concerns with the air quality in the Klamath Falls area. The area had been designated as not meeting the PM<sub>10</sub> ambient air quality standards in the past. A plan was developed that brought the area back into compliance with the standards. The strategies developed to improve the air quality primarily addressed area sources of emissions, such as wood stoves. The area recently was designated as not meeting the PM<sub>2.5</sub>

24-hour ambient air quality standard. DEQ is in the process of developing a plan to get the area into compliance with the ambient air quality standard. It will take nearly three years to develop the plan, which will address all sources of emissions and include strategies for reducing emissions from those sources that contribute significantly to the air quality problem.

### **Class I Impact Analysis**

In addition to the analysis conducted for the area surrounding the proposed source, additional analysis is required to determine if the emissions will significantly impact pristine wilderness areas and national parks, referred to as Class I airsheds. The results of the analysis demonstrate that the proposed source will not have an adverse effect on the air quality in Class I areas because the impacts are less than the significant impact levels as shown in the following table.

#### **Class I Area Impacts:**

<b>Pollutant</b>	<b>Averaging Time</b>	<b>Maximum Class I Concentration (<math>\mu\text{g}/\text{m}^3</math>)</b>	<b>Class I Significant Impact Level (<math>\mu\text{g}/\text{m}^3</math>)</b>
PM <sub>10</sub>	24-hour	0.07	0.3
	Annual	0.01	0.2
PM <sub>2.5</sub>	24-hour	0.07	0.08
	Annual	0.007	0.04
NO <sub>2</sub>	Annual	0.07	0.1

The ambient air quality impact analysis is currently under review by DEQ. Based on the results of the applicant's analysis, DEQ has determined that the proposed project will not have an adverse affect on the air quality in the Klamath Falls area and the surrounding wilderness areas. The permit will be modified if DEQ determines that the modeling results are not correct and would require additional controls to protect the ambient air quality.

## ***TITLE V MAJOR SOURCE APPLICABILITY***

### CRITERIA POLLUTANTS

28. For purposes of the Oregon Title V permitting program, a major source is a facility that has the potential to emit 100 tons/yr or more of any criteria pollutant. This facility is a major source of criteria pollutant emissions. A summary of the projected maximum criteria pollutant emissions is provided at the end of this report. The permittee is required to submit an application for a Title V Operating permit within one year after startup in accordance with OAR 340-218-0040(1)(a)(B).

## HAZARDOUS AIR POLLUTANTS

29. A major source is a facility that has the potential to emit 10 tons/yr or more of any single HAP or 25 tons/yr or more of combined HAPs. This source is not a major source of hazardous air pollutants. A summary of the projected maximum hazardous air pollutant emissions is provided at the end of this report.

## **SOURCE TESTING**

30. The permittee is required to conduct testing to demonstrate compliance with the particulate matter and nitrogen oxide emission limits. In addition, the permittee is required to conduct testing to verify that the emission factors for estimating PM<sub>10</sub>, PM<sub>2.5</sub> and HCl emissions are valid. If the test results are significantly different than the factors used to estimate the emissions in the permit application, the Plant Site Emission Limits will be adjusted accordingly and DEQ will conduct a review of the regulations that may be triggered as a result of the adjustments.

## **PUBLIC NOTICE**

31. Pursuant to OAR 340-216-0066(4)(a)(A), issuance of Standard Air Contaminant Discharge Permits require public notice in accordance with OAR 340-209-0030(3)(c), which requires that the Department provide notice of the proposed permit action and a minimum of 35 days for interested persons to submit written comments. In addition, the Department must provide 30 day notice of a hearing, if one is required. **The public notice for the comment period and a hearing was mailed on November 17, 2010. The public hearing was held on December 16, 2010 at the Klamath Falls Extension Service. The public comment period ended on December 21, 2010.**

Approximately 38 people attended the public hearing and several people commented on the permit. The Hearing Officer's report and response to comments is provided as Attachment 2. The report includes a summary of the comments and the Department's response, as well as the complete text of all comments received during the comment period.

DEQ has reviewed the comments. Most of the comments are related to issues beyond the scope of the air quality permit. DEQ has provided responses to comments that are within the scope of the air quality permit regulations. The permit will be issued with a minor revision to condition 5.2 and the addition of condition 11.c. In addition, DEQ provided additional clarification for boiler design parameters in section 7 of the review report. The review report provides an analysis of regulatory requirements but it is not an enforceable document.

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***ATTACHMENT 1: DETAIL SHEETS***

<b>Fluidized Bed Boiler Emissions:</b>			
Heat input ( daily maximum)	459.2	MMBtu/hr	
Heat input (annual average)	437.3	MMBtu/hr	
Steam production	332,400	lb/hr	
Normal operations (wood)	8760	hours/yr	
Heat input to Steam ratio	1.3815	MMBtu/1000 lb steam	
Startup PM	5	hours/event	
Startup CO	7	hours/event	
Starup events	6	events/year	
<b>Normal operation - wood</b>	EF (lb/MMBtu)	Emissions (tons/yr)	EF (lb/10 <sup>3</sup> lb steam)
PM	0.018	34.5	0.0249
PM10	0.018	34.5	0.0249
PM2.5	0.013	24.9	0.0180
SO2	0.02	38.3	0.0276
Nox	0.12	229.8	0.1658
CO	0.12	229.8	0.1658
VOC	0.01	19.2	0.0138
Startup emissions:			
PM10	22.0	lb/startup	
PM2.5	15.7	lb/startup	
CO	221.0	lb/startup	
EF References:			
PM, PM10, PM2.5, NOx, CO, VOC	Boiler manufacturer estimate		
SO2	EPA AP-42		

<b>Cooling Tower Emissions:</b>	
Water circulation rate (lpm)	115700
Maximum total dissolved solids (mg/l)	144
Number of recirculation cycles	6
Drift, fraction of circulating water	0.001
PM/PM10/PM2.5 emission rate (lb/hr)	0.132
PM/PM10/PM2.5 emission rate (ton/yr)	0.579

<b>Fire Water Pump Emissions:</b>			
Operating time	100	hrs/year	
Engine size	305	hP	
Pollutant	Emission factor	units	Annual emissions (tons/yr)
PM10	0.00013	lb/hr-hr	0.0020
PM2.5	0.00011	lb/hr-hr	0.0017
SO2	0.000012	lb/hr-hr	0.0002
Nox	0.00595	lb/hr-hr	0.0907
CO	0.00088	lb/hr-hr	0.0134
VOC	0.00022	lb/hr-hr	0.0034
Emission factors (except SO2) for a representative fire pump engine (Clarke Model JU6H-UFADX8)			
SO2 factor based on AP-42, table 3.4.1 (.0015%S)			

Fugitive emissions from fuel transfer					
Steam Production	2911824	thousand pounds per year			
Throughput for all activities	398543	BDT/yr			
	Emission Factors:			Annual Emissions:	
Activity	Uncontrolled PM10 (lb/ton)	Controlled PM10 (lb/ton)	PM2.5 (lb/ton)	PM 10 (tons/yr)	PM2.5 (tons/yr)
truck dump	0.00032197	8.04926E-05	1.21889E-05	0.0160	0.0024
fuel from stacker to pile	0.00032197	0.00032197	4.87555E-05	0.0642	0.0097
pile reclaim	fully enclosed	0	0	0.0000	0.0000
fuel screening	fully enclosed	0	0	0.0000	0.0000
Total				0.080	0.012
Emission Factor References and Controls:					
AP-42 section 13.2.4:					
k (particle size multiplier)	0.35 for PM10, 0.053 for PM2.5				
U (mean wind speed)	4.92 mph				
M (moisture content)	4.80%				
$E = k(0.032)(U/5)^{1.3}/(M/2)^{1.4}$					

<b>Fugitive emissions from storage piles:</b>						
EPA-450//3-88-008, section 4.1.3, estimates are based on a coal pile as worst case analysis						
$E \text{ (lb PM/acre-day)} = 1.7 * (s/1.5) * (365 - p/235) * (f/15)$						
	s =	silt content percentage				
	p =	number of days with precipitation >0.01 inches				
	f =	percent of time wind speed exceeds 5.4 mph				
Variable	Value	Units	Basis			
s	1	%	estimate			
p	120	days	AP-42, Figure 13.2.1-1			
f	25	%	estimate			
Pollutant	EF	Units	Basis			
PM	1.97	lb/acre-day				
PM10	0.98	lb/acre-day	PM10 to PM ratio of 0.5, EPA-450/3/88/008			
PM2.5	0.15	lb/acre-day	15% of PM10			
<b>Fuel pile emissions:</b>						
	Daily Emissions			Annual Emissions		
Surface Area (acres)	PM (lb/day)	PM10 (lb/day)	PM2.5 (lb/day)		PM10 (tons/yr)	PM2.5 (tons/yr)
1.2	2.4	1.2	0.2		0.22	0.03

Fugitive PM emissions from vehicle traffic: AP-42 13.2.1 (June 2010 draft)						
$E \text{ (LB/VMT)} = k * (sL/2)^{0.98} * (W/3)^{.53} - (S/30)^{.16}$						
$E_{ext} \text{ (lb/VMT)} = E * (1-P/4N)$						
E =	emission factor (lb PM/VMT)					
k =	particle size multiplier					
sL =	road surface silt loading (g/m <sup>2</sup> )					
W =	mean vehicle weight (tons)					
S =	average speed of vehicles (mph)					
E <sub>ext</sub> =	mitigated emission factor for natural mitigation of dust emissions due to rainfall and other precipitation					
P =	number of days with at least 0.01 inches of precipitation					
N =	number of days in a year (365)					
k =	0.015 for PM10					
	0.0037 for PM2.5					
E - PM10	0.010	controlled	0.0078	20% control from watering		
E - PM2.5	0.0024	controlled	0.0019	20% control from watering		
Variable	Value	Units	Basis			
sL	0.6	g/m <sup>2</sup>	AP-42 Table 13.2.1-3			
P	80	days	AP-42 Figure 13.2.1-2			
W-fuel trucks	24	tons	40 tons fule, 16 tons empty			
Employee veh.	2	tons	30 tons full, 15 tons empty			
Mean veh. Wt.	17	tons				
Miles (fuel)	1.5	miles/trip	89 trips/day	312	days/year	
Miles employee	1.5	miles/trip	45 trips/day	312	days/year	
Average speed	15	mph				
			Emission Factor		Annual	
Vehicle	trips/yr	VMT/yr	PM10 (lb/VMT)	PM2.5 (lb/VMT)	PM10 (tons/yr)	PM2.5 (tons/yr)
fuel trucks	27768	20826	0.0078	0.0019	0.08	0.020
employee veh.	14040	21060	0.0078	0.0019	0.08	0.020
Total					0.16	0.04
						Total

<b>Summary of Fugitive and Insignificant Activity Emissions</b>			
	PM10	PM2.5	
	tons/yr	tons/yr	
Fuel Handling	0.08	0.01	
Fuel Pile	0.22	0.03	
Vehicles	0.16	0.04	
Cooling tower	0.58	0.58	
Fire water pump	0.00	0.00	
<b>Total</b>	<b>0.46</b>	<b>0.08</b>	
<b>Annual Steam</b>	2911824	1000 lb steam/yr	
<b>Fugitive and Insignificant Activity Emission Factor</b>			
	PM10	PM2.5	
Emission factor based on annual steam	0.0003	0.0001	lb/1000 lb steam

<b>Hazardous Air Pollutant Emissions:</b>					
Boiler	3829872	MMBtu/yr			
Fire Pump	213.5				
<b>HAP (wood fuel)</b>	Boiler Emission Factor (lb/MMBtu)	Fire Pump Emission Factor (lb/MMBtu)	Boiler Emissions (tons/yr)	Fire Pump Emissions (tons/yr)	Total Emissions (tons/yr)
Acetaldehyde	7.31E-05	7.67E-04	1.40E-01	8.19E-05	1.401E-01
Acetophenone	3.23E-09		6.19E-06	0.00E+00	6.185E-06
Acrolein	3.12E-06	9.25E-05	5.97E-03	9.87E-06	5.984E-03
Antimony	1.16E-07		2.22E-04	0.00E+00	2.221E-04
Arsenic	5.83E-07		1.12E-03	0.00E+00	1.116E-03
Benzene	1.52E-05	9.33E-04	2.91E-02	9.96E-05	2.921E-02
Beryllium	5.76E-08		1.10E-04	0.00E+00	1.103E-04
Bis (2-ethylhexyl)phthalate	4.65E-08		8.90E-05	0.00E+00	8.904E-05
Bromomethane	2.80E-05		5.36E-02	0.00E+00	5.362E-02
2-Butanone (MEK)	5.39E-06		1.03E-02	0.00E+00	1.032E-02
1,3 Butadiene	8.76E-07	3.91E-05	1.68E-03	4.17E-06	1.682E-03
Cadmium	7.27E-07		1.39E-03	0.00E+00	1.392E-03
Carbon tetrachloride	4.54E-05		8.69E-02	0.00E+00	8.694E-02
Chlorine	1.34E-04		2.57E-01	0.00E+00	2.566E-01
Chlorobenzene	3.32E-05		6.36E-02	0.00E+00	6.358E-02
Chloroform	2.75E-05		5.27E-02	0.00E+00	5.266E-02
Chloromethane	2.31E-05		4.42E-02	0.00E+00	4.424E-02
Chromium (trivalent)	4.50E-06		8.62E-03	0.00E+00	8.617E-03
Cobalt	7.50E-07		1.44E-03	0.00E+00	1.436E-03
1,2-Dibromoethene	5.48E-05		1.05E-01	0.00E+00	1.049E-01
1,2-dichloroethane	2.92E-05		5.59E-02	0.00E+00	5.592E-02
Dichloromethane	2.87E-04		5.50E-01	0.00E+00	5.496E-01
1,2-Dichloropropane	3.33E-05		6.38E-02	0.00E+00	6.377E-02
2,4-dinitrophenol	9.33E-08		1.79E-04	0.00E+00	1.787E-04
Ethylbenzene	1.72E-06		3.29E-03	0.00E+00	3.294E-03
Formaldehyde	7.78E-05	1.18E-03	1.49E-01	1.26E-04	1.491E-01
Hydrogen chloride	3.88E-03		7.43E+00	0.00E+00	7.430E+00
Lead	3.70E-06		7.09E-03	0.00E+00	7.085E-03
Manganese	1.05E-05		2.01E-02	0.00E+00	2.011E-02
Mercury	2.18E-05		4.17E-02	0.00E+00	4.175E-02
Methanol	8.30E-04		1.59E+00	0.00E+00	1.589E+00
Naphthalene	1.17E-06	8.48E-05	2.24E-03	9.05E-06	2.250E-03
Nickel	8.55E-07		1.64E-03	0.00E+00	1.637E-03
4-Nitrophenol	1.71E-07		3.27E-04	0.00E+00	3.275E-04
Pentachlorophenol	2.27E-08		4.35E-05	0.00E+00	4.347E-05
Phenol	1.88E-05		3.60E-02	0.00E+00	3.600E-02
PCBs	6.86E-08		1.31E-04	0.00E+00	1.314E-04
Propionaldehyde	6.11E-05		1.17E-01	0.00E+00	1.170E-01
Propylene		2.58E-04		2.75E-05	2.754E-05

Selenium	5.38E-06		1.03E-02	0.00E+00	1.030E-02
TCDD-Total	1.37E-10		2.62E-07	0.00E+00	2.623E-07
Tetrachloroethane	3.82E-05	4.09E-04	7.32E-02	4.37E-05	7.319E-02
Toluene	1.88E-05		3.60E-02	0.00E+00	3.600E-02
1,1,1 Trichloroethane	3.07E-05		5.88E-02	0.00E+00	5.879E-02
Trichloroethene	3.03E-05		5.80E-02	0.00E+00	5.802E-02
2,4,6-Trichlorophenol	1.14E-08		2.18E-05	0.00E+00	2.183E-05
Vinyl chloride	9.69E-06		1.86E-02	0.00E+00	1.856E-02
Xylenes	1.02E-05	2.85E-04	1.95E-02	3.04E-05	1.956E-02
<b>Total HAP</b>					<b>11.2</b>
<b>Maximum HAP (hydrogen chloride)</b>					<b>7.43</b>
<b>Emission factors from AP-42</b>					

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***ATTACHMENT 2: HEARING REPORT***