PROJECT REPORT

Centennial Renewable Energy > Potlach, ID

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Permit-To-Construct Application

Prepared By:

Shannon K. Manoulian, P.E. – Senior Consultant

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DEPARTMENT OF ENVIRONMENTAL QUALITY
STATE A Q PROGRAM

TRINITY CONSULTANTS
702 W. Idaho Street
Suite 1100
Boise, ID 83702
(208) 472-8837

May 2016

Project 151301.0005

Trinity Consultants

Environmental solutions delivered uncommonly well

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1. EXECUTIVE SUMMARY

Centennial Renewable Energy (CRE) is proposing to construct and operate a Greenfield wood pellet production facility near Potlach, Idaho. The facility will produce a proprietary type of wood pellet known as SteamEx Pellets from the Andritz Corporation The facility will utilize short fiber wood waste (primarily sawdust and planer shavings) from regional mills as feedstock. The proprietary SteamEx process involves a confidential steam explosion process after the feed stock enters the facility. The steam for the facility will be provided via a fluidized bed boiler combusting hog fuel. The pelletizing operation will also include the use of hammer mills, pellet mills and pellet coolers. The wood pellets produced will be transported off-site via railcar or truck.

The proposed CRE Potlach facility will be a non-PSD major source of NO_x, CO and HAPs and will be subject to Title V of the Clean Air Act. In addition, the facility will be subject to 40 CFR Part 60, Subpart Db - Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units and 40 CFR Part 63, Subpart DDDDD—National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters.

Air dispersion modeling will be conducted for those criteria pollutants which exceed the Idaho Level I modeling thresholds and TAPs which exceed the screening emissions level (EL) in Idaho Air Rules Section 585 and 586. However, per IDEQ policy and guidance, TAPs that are regulated by a federal NSPS or NESHAPS will not be included in the modeling analysis.

The purpose of this document is to present all necessary and applicable information regarding the facility in support of a Permit to Construct (PTC) Application for the facility. All information provided in this PTC application, including Air Dispersion Modeling Report, is based on preliminary facility design. Due to the structure of the project financing (grant allocation), final design information will not be available until after PTC issuance. All available manufacturer and vendor information has been provided; CRE will accept permit conditions related to assumptions and information that has been presented that does not meet DEQ's interpretation of what constitutes adequate documentation and/or justification. If, upon final design and construction, information or parameters differ from the values presented in this modeling report and PTC application and/or PTC, CRE will review the applicability of a modification to the PTC including impacts to the NAAQS analyses completed as part of this initial PTC application.

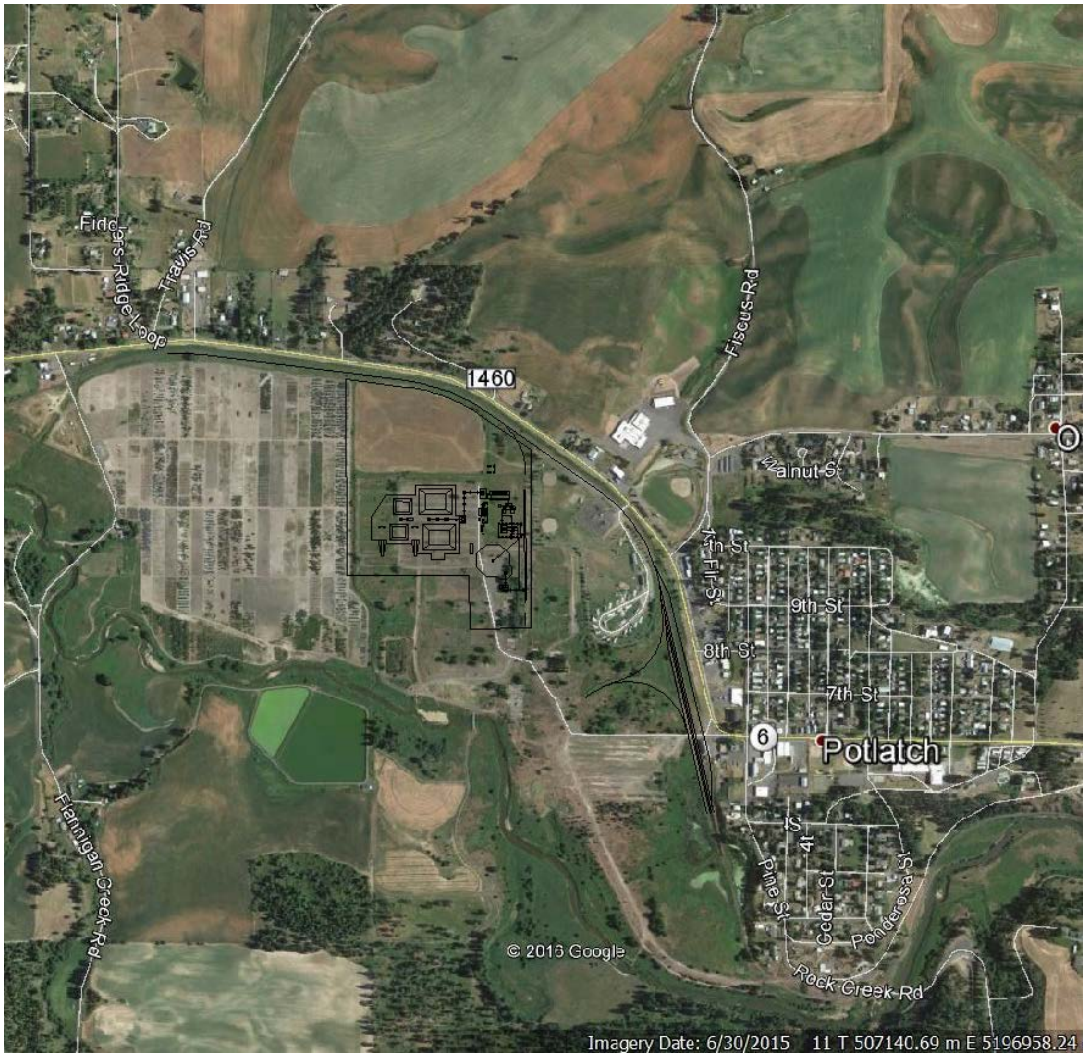
2. DESCRIPTION OF FACILITY

2.1. PROJECT LOCATION

The proposed CRE facility will be located on the former Potlach Mill site, near State Highway 6 and Forest Road 1460, approximately 0.7 miles northwest of the Potlach city center in Latah County, ID. The UTM coordinates for the facility are approximately 506,829 m E, 5,196,968 m N, Zone 11 (NAD83 coordinate system). Latah County is an attainment area for all criteria pollutants. Land use in the area includes agricultural, small commercial and residential properties. Terrain surrounding the project site is relatively flat. A map showing the location of the proposed facility is provided as **Figure 2-1.** The closest industrial facility to the project site is the Bennett Lumber facility, located approximately six (6) miles east of the proposed CRE facility.

The wood pelletizing mill will be constructed on approximately 48 acres. There are currently existing structures on the site from a previous wood chipping operation that will be removed prior to construction, except for the existing shop on the southeast part of the site. The site has an existing entrance from ID Hwy 3 on the north portion of the site which will be utilized for the new operation. Running along the southern portion of the site is the St. Maries Railroad, which splits off two spurs. An existing fire water storage pond is also located on the south central area of the property. It is insufficiently sized to hold the required amount of fire water and will be required to be upgraded.

Figure 2-1. Proposed Facility Location



2.2. PROCESS OVERVIEW

Wood mill residues will be brought in from various lumber mills in the area for process feedstock and Fluidized Bed Combustor (FBC) fuel. Received sawdust and shavings will be co-mingled upon delivery and stored in 15 day storage piles. Feedstock and hogged fuel will be received by truck and stacked by front end loader in the appropriate open storage pile in the storage yard area. Feedstock will be reclaimed by front-end loader and deposited into a metered bin, then conveyed to the process steam explosion process. Hogged fuel will be received and fed into a green hammer mill prior to being stacked. Hogged fuel will then be feed into a metered feed bin to be conveyed to the boiler island as fuel.

Reclaimed feedstock will be conveyed to screeners where material meeting size requirements will bypass the green hammer milling area. Product that exceeds the maximum size, will be run through a green hammer mill and then be fed back onto the screeners. Sized product will then proceed to the steam pre-heat bin where it will conditioned prior to being fed into the steam explosion process.

Once steam exploded, the material will be fed into a belt dryer to be dried to 8%-10% moisture content. After the dryer, product will be final screened and sized using two hammer mills. After final sizing the steam exploded feedstock will be feed into a conditioning bid where the feedstock will be moisture conditioned to the optimum moisture content and stored in short-term storage bins. Steam exploded Feedstock reclaimed from the storage bins will proceed to processing, before going into the pellet mills. Produced pellets will then be cooled to near ambient and then screened and fines removed and fed into the boiler heating system.

After the pelletizing process, product will be conveyed through a belt conveyor to a storage pile. Black Pellets will be reclaimed by a front end loader and fed into a loading bin. The pellets will be conveyed to a pellet screener prior to being loaded onto railcar. Fines from the screener will be conveyed to a metal bin to be hauled to the hogged fuel pile. Wood pellets will pass through the screener and be loaded into 91 MT (100 t) capacity covered hopper rail cars. Train cars will be loaded in 12 car blocks with a track mobile used to advance the cars into position. After the block has been loaded it will be connected to the unit train. The outbound trains will be approximately 110-115 car units. Received product will be transferred directly to ship at the Port of Longview in Longview, WA.

The facility proposes to operate 8,760 hours per year, with the exception of the finished product loading. Finished product loading, which includes transfer via front loader from the pellet product stockpile through to railcar filling, will only occur between the hours of 6am and 6pm. Draft process flow diagrams are included in **Appendix A.**

3.1. PELLET PRODUCTION

Feedstock will be received via a truck receiving area equipped to receive five trucks per hour. The trucks will enter the truck tipper, where material will be unloaded to the truck tipper pit. A front end loader will move the material from the truck tipper pit to the feedstock stockpiles located near Conveyor 1. Feedstock will be fed into one of three metering bins equipped with feed screws which in turn transfer the material onto Conveyor 1. The raw feedstock is then transferred to a second set of feed screws and into the green hammer mills for sizing. The green hammer mill will be sized to process 100% of the green fiber flow for pellet production and will be equipped with an in-feed drop chute magnet to remove tramp metals and protect the hammer mill. Green milled fiber will be mechanically conveyed to the Steam Explosion (SteamEx) system via Conveyors 2 and 3. After going through the SteamEx process, the material is transferred via Conveyor 4 to the Belt Dryer. The steam exploded material travels through the belt dryer where it is dried to 8-10% moisture by downdraft airflow at a temperature of approximately 100 ^{o}F. Since the airflow of the dryer is through the belt material, the belt acts as both a conveyance method and an emissions control for the product. The steam exploded material exit the dryer and are transferred to feed screws and into the dry hammer mill via Conveyor 5. Sized pellets from the dry hammer mill are transferred to the pneumatic conveying system via the dry cyclone; emissions from the dry hammer mill and cyclone are controlled by the hammer mill baghouse.

Sized pellets are discharged from the pneumatic conveying system into a metering surge bin. The pellets then travel via conveyor system to the mill feed bins, from the bins to the pellet mills via the mill feed screws and conditioning screws to pellet mills, and from the pellet mills via conveyor to the pellet coolers. The pellet coolers are necessary due to the increase in pellet temperature that is caused by the mechanical processing through the milling processes. After exiting the pellet coolers, the product is conveyed to the pellet screens and then transferred via pneumatic system to the product stockpile. The finished pellets are then transferred via front loader to a hopper and conveyed to the shipping screen. Sized finished pellets are transferred from the screen via conveyor to the filling spout and into railcars for shipment off-site.

Emission sources associated with pellet production include particulate emissions from material handling and product transfers, material stockpile wind erosion and the belt dryer. Exhaust from the SteamEx process is routed to the FBC for destruction of VOC, particulate and HAPs. SteamEx emissions are included in the FBC baghouse exhaust.

3.2. HEAT ENERGY SYSTEM

Hogged Fuel will be received by in the hogged fuel truck tipper. The hog fuel will be removed from the tipper pit and fed into hopper, screw feeder and screen. Material from the hog fuel screen will be transferred to the bucket elevator and into the surge bin. Materials from the surge bin will be conveyed pneumatically to the energy system, which includes the 200 MMBtu/hr Fluidized Bed Combustor (FBC).

The FBC will combust the hogged fuel to provide energy for the equipment in the rest of the facility. The energy system will be capable of exporting heat via high-pressure steam and glycol hot water.

A forced draft fan will supply air flow through a preheat burner prior to the inlet duct of the FBC to provide warming air to assist during startup of the fluid bed combustor from cold conditions. The burner will be propane fired with a capacity of 8 MMBtu/hr. Once the bed is heated to approximately 700 ^{o}F, wood is fed into the FBC and combustion is started. The preheat burner is turned off once the fluid bed temperature is above 1000 ^{o}F and the FBC operates only on wood fuel.

Wood waste fuel screened to a three inch minus size will be supplied to the FBC system via metering bin (surge bin) with twin screws. The counter rotating augers inside the metering bin will pull fuel on demand and discharge into a knifing rotary seal valve for feeding into the FBC via a pneumatic 10 inch diameter feed line. The fuel conveyance system will use a positive displacement blower with inlet and exit silencers to convey the fuel to the FBC.

The FBC is a vertical cylinder with an outlet transition where the combustion gas exits into a refractory lined ducting for conveying the combustion gas to provide the energy for the High Pressure Boiler and Glycol Hot Water Heater. The FBC is capable of accepting several of the streams of air and steam from the wood processing facility, including the high pressure boiler, glycol heater, FBC Pre-Burner, Multiclone Cyclones, Flash Steam from Steam Explosion (SteamEx) process, Pre-Steaming Bin Exhaust, and pellet coolers exhaust. These streams are capable of being directly injected to the FBC bed section or vapor space; any air or steam injected in this way will be subjected to temperatures of over 1600 F, for a residence time of 1.5 seconds or greater. Given the temperature and residence time of any stream introduced into the FBC it is very likely all VOC's will be destroyed at a high level of efficiency. Additional information on the FBC is included in **Appendix B.**

At the exhaust of both the High Pressure Boiler and the Glycol Hot Water boiler, there will be a flue gas treatment system consisting of a multi-cyclone, air-heater heat recovery, and baghouse particulate control device before entering the ID Fan and stack to be discharged to the atmosphere in a single point. Fine non-combustible materials from the fuel, (fine ash and dirt) are entrained in the flue gases rising from the bed. An ash drop will be provided to drop out material in the blended hot gas stream to the boilers. Oversized heavier non-combustible materials (gravel, rocks and metal) from the fuel remain in the bed. An automated bed cleaning system periodically withdraws sand from the bottom cone and onto a vibrating screen conveyor housed within the base skirt.

This bed cleaning system separates out larger non-combustible debris. Accepted sand is directed to a bucket elevator that lifts it up and directs it back into the combustor bed from above. "Rejected" oversize material, is directed to a small tote bin for disposal. The ash present in the combustion gases will be collected in the dropout with a seal assemble for the removal of the ash. An ash silo will be used to support the ash drop and ducting. Ash will be discharged into the silo which will be periodically unloaded via dustless load spout which will lower and seal against a tanker truck. A vacuum will be applied to the load spout to collect the air displaced during tank fill up.

Emission sources associated with the heat energy system include particulate emissions from hogged fuel handling and transfers and hogged fuel stockpile wind erosion. Particulate and gaseous criteria pollutant emissions and HAPs from the FBC system, including pre-heater, as well as the multiclone cyclones, flash steam from the SteamEx process and pellet cooler are emitted through the FBC system baghouse stack.

3.3. EMISSIONS SOURCES

Emission sources at the facility are described in the subsections below. IDEQ emission unit forms are included in **Appendix C.** Detailed emissions calculations along with all available manufacturer specifications are included in **Appendix D.**

3.3.1. Material Handling

3.3.1.1. Hogged Fuel

Hogged fuel handling begins with unloading of the material from trucks to stock piles, and transfer to the sizing and conveying processes via front loader. Hogged fuel is loaded into hoppers, travels through the screw feeder into the fuel screen, then through the bucket elevator into the surge bin. Hogged fuel is conveyed pneumatically from the surge bin to the FBC. A detailed description of this process is provided in Section 3.2 above and shown visually on the PFD's included in **Appendix A.**

Emissions from the hogged fuel handling were calculated using AP-42 Section 11.19.2 for conveyor transfers and screening; however, no data are available for $PM_{2.5}$ emissions for uncontrolled sources. Therefore, the particle size multiplier of 0.0053 from AP-42 Section 13.2.4 was multiplied by the PM emission factor to develop the $PM_{2.5}$ emission factor for these sources. The hogged fuel will have a moisture content of approximately 50%; therefore a 50% control efficiency was applied to the calculations. Transfers from the surge bin to the pneumatic system and from the pneumatic system to the FBC occur within the pneumatic enclosure, therefore a 100% control efficiency was applied to those sources. Detailed emissions calculations are included in **Appendix D.**

Requested process throughputs vary by equipment, however, for all emissions sources, an annual throughput of 100,000 tons per year is requested. The hogged fuel process will operate a maximum of 8,760 hours per year. Specific requested hourly throughputs are shown in the emissions calculations in **Appendix D.**

3.3.1.2. Feedstock

Feedstock handling begins with unloading of the material from trucks to stock piles, and transfer to the sizing and conveying processes via front loader. Feedstock is loaded into hoppers, travels through the screw feeder on to a conveyor belt, then through another set of screw feeders into the green hammer mills. The green hammer mills are equipped with cyclones which are used to transfer materials to conveyors that feed the SteamEx system. The cyclones are used as process equipment and are not considered emission control equipment. After going through the SteamEx process, the material is transferred via conveyor to the Belt Dryer.

The steam exploded material exit the dryer and are transferred to feed screws and into the dry hammer mill via conveyor. Sized pellets from the dry hammer mill are transferred to the pneumatic conveying system via the dry cyclone. The cyclones are used as process equipment and are not considered emission control equipment. Sized pellets are discharged from the pneumatic conveying system into a metering surge bin. The pellets then travel via conveyor system to the mill feed bins, from the bins to the pellet mills via the mill feed screws and conditioning screws to pellet mills, and from the pellet mills via conveyor to the pellet coolers. After exiting the pellet coolers, the product is conveyed to the pellet screens and then transferred via pneumatic system to the product stockpile.

The finished pellets are then transferred via front loader to a hopper and conveyed to the shipping screen. Sized finished pellets are transferred from the screen via conveyor to the filling spout and into railcars for shipment off-site. A detailed description of this process is provided in Section 3.1 above and shown visually on the PFD's included in **Appendix A.**

Emissions from the feedstock/pellet handling were calculated using AP-42 Section 11.19.2 for conveyor transfers and screening; however, no data are available for $PM_{2.5}$ emissions for uncontrolled sources. Therefore, the particle size multiplier of 0.0053 from AP-42 Section 13.2.4 was multiplied by the PM emission factor to develop the $PM_{2.5}$ emission factor for these sources.

Prior to entering the belt dryer, the feedstock will have initial moisture content of 34%; therefore a 34% control efficiency was applied to the calculation for sources upstream of the belt dryer (Emission Unit IDs [EU ID] FS1 through FS9); a control efficiency of 8% was applied to the calculation for sources downstream of the dryer (EU ID FS15, FS16, and FS20), based on the material moisture content of the 'dried' pellet.The transfer from Conveyor #2 to Conveyor #3 occurs inside an enclosure; a 50% control efficiency was applied to this emission point (EUID FS10). Transfers into and out of the SteamEx process and Belt Dryer occur inside the SteamEx building, therefore a 100% control efficiency was applied to EUID FS11 through FS14.

Emissions from the dry hammer mill and cyclone are controlled by the hammer mill baghouse with a control efficiency of 99%. Transfers from the dry cyclone to the pneumatic system and from the pneumatic system to the surge bin occur within the pneumatic enclosure, therefore a 100% control efficiency was applied to those sources (FS18 – FS19). The pellet conditioning process (FS21-FS40) occurs inside the pellet building and transfer from the pneumatic system to the pellet surge bin (FS41) occurs within the pneumatic enclosure; a 100% control efficiency is applied to those sources.

There will be no controls on the finished product material handling (FS42-FS49), with the exception of transfer in and out of the pneumatic system (FS46, FS49) which will have 50% control for the pneumatic enclosure, and the shipping screens and associated transfers (FS45) which will be partially enclosed (50% control). Finished product material will have a moisture content of 4%, which was applied as control to FS42-44 and FS47-48. In addition, finished product handling and transfers (FS42-45,47-48) will only occur between the hours of 6am and 6pm.

Requested process throughputs vary by equipment, however, for emissions sources FS1-FS42, an annual throughput of 220,500 tpy is requested. The feedstock handling process will operate a maximum of 8,760 hours per year, with the exception of the finished product handling and transfers as described above. Specific requested hourly throughputs are shown in the emissions calculations in **Appendix D.**

3.3.2. Stockpile Wind Erosion

The pellet production process, including the FBC system begins with unloading of the material from trucks to stock piles. Hogged fuel will be unloaded from the tipper trucks and placed into two 20' tall fuel piles. The annual requested throughput of the hogged fuel piles is 100,000 tpy. Feedstock will be unloaded from the tipper trucks and placed into two 30' tall feedstock piles. The annual requested throughput of the feedstock piles is 220,500 tpy. Finished product pellets are conveyed pneumatically from the process to the 70' tall product stockpile; the requested throughput of the product piles is 220,500 tpy.

Wind erosion emissions from stockpiles were calculated based on emission factors calculated per AP-42 Section 13.2.4. Detailed emissions calculations are provided in **Appendix D.**

3.3.3. Fluidized Bed Combustor, Pre-Heater and FBC Baghouse

As described in Section 3.2, the FBC will be fired using hog fuel. Particulate emissions from the FBC will be controlled by the FBC system baghouse. Emissions of other criteria pollutants from the FBC were calculated using emission factors from AP-42 Section 1.6 Wood Residue Combustion in Boilers, Tables 1.6-1, 1.6-2, and 1.6-3 for uncontrolled bark/bark and wet wood/wet wood-fired boiler. Hazardous air pollutant (HAPs) and Toxic Air Pollutant (TAPs) emissions were calculated using emission factors from AP-42 Section 1.6, Tables 1.6-3 and 1.6-4.

A forced draft fan will used to force air through a preheat burner prior to the inlet duct of the FBC to provide warming air to assist during startup of the FBC from cold conditions. One the FBC bed is heated to the appropriate temperature, the pre-heat burner is turned off. The pre-heater will have a capacity of 8.0 MMBtu/hr and will combust propane. Particulate emissions from the FBC will be controlled by the FBC system baghouse. Emissions of other criteria pollutants were calculated using AP-42 Section 1.5 Liquified Petroleum Gas Combustion. Section 1.5 does not contain emission factors for HAPs; therefore HAPs were calculated using AP-42 Section 1.4 Natural Gas Combustion, Tables 1.4-3 and 1.4-4.

The FBC system will be equipped with a baghouse for control of particulate emissions. The baghouse will have an output PM grain loading rate of 0.0027 gr/acfm. It was assumed that PM_{10} and $PM_{2.5}$ emissions will be equal to PM emissions. In addition to controlling particulate from the FBC and pre-heater, the FBC system baghouse will control particulate emissions from the SteamEx unit and Pellet Coolers (exhaust from the SteamEx unit and Pellet Coolers is fed to the FBC for destruction of VOC, HAPs, TAPs and control of PM).

The FBC, pre-heater and FBC system baghouse will operate a maximum of 8,760 hr/year. Detailed emissions calculations are provided in **Appendix D**.

3.3.4. Steam Explosion System

The SteamEx unit will be a source of PM, VOC, HAPs and TAPs. Emission factors obtained from stack testing conducted at Quebec City pilot plant with a similar steam explosion process. This stack testing data is confidential, therefore, CRE will accept a permit condition requiring stack testing to verify the emission rates. Exhaust from the SteamEx unit is fed to the FBC for destruction of VOC, HAPs, TAPs and control of PM. The SteamEx unit will operate a maximum of 8,760 hr/year. Detailed emissions calculations are provided in **Appendix D**.

3.3.5. Belt Dryer

The Belt Dryer will be a source of particulate emission. Dust emissions have a manufacturer's guarantee of less than 10 mg/Nm^3 (dry). It is assumed that 50% of dust emissions consist of PM500, 90% of PM500 emissions consist of PM_{10}, and 50% of PM500 emissions consist of $PM_{2.5}$. The dryer will be operated at a temperature much lower than the upstream SteamEx process and therefore volatilization is not expected to occur during the drying process. The Belt Dryer will operate a maximum of 8,760 hr/year. Detailed emissions calculations are provided in **Appendix D**.

3.3.6. Pellet Coolers

The Pellet Coolers will be a source of PM, VOC, HAPs and TAPs emissions. Emissions were calculated based on engineering testing of the total gaseous organics emissions from pellet coolers at a similar facility. The most conservative emission factors from testing were used. Exhaust from the Pellet Coolers will be fed to the FBC for destruction and control of VOC, HAPs, TAPs and PM. The Pellet Coolers will operate a maximum of 8,760 hr/year. Detailed emissions calculations are provided in **Appendix D**.

3.4. POTENTIAL TO EMIT

The proposed CRE Potlach facility will be a non-PSD major source of NO_x, CO and HAPs. The facility-wide potential to emit is shown in **Table 3-1, Table 3-2** and **Table 3-3** below. Hourly emission rates are based on the maximum material throughputs and equipment capacities. Annual emission rates are based on 8,760 operating hours per year. Individual emission source calculations are provided in **Appendix D.**

Air dispersion modeling will be conducted for those criteria pollutants which exceed the Idaho Level I modeling thresholds and TAPs which exceed the screening emissions level (EL) in Idaho Air Rules Section 585 and 586. However, per IDEQ policy and guidance, TAPs that are regulated by a federal NSPS or NESHAPS will not be included in the modeling analysis. Air dispersion modeling, as well as comparison of the facility PTE to applicable modeling thresholds in discussed in Section 5.0.

Table 3-1. Facility-wide Potential to Emit (lb/hr)

Emission Sources	CO	NO_X	PM	PM_{10}	$PM_{2.5}$	SO_2	VOC	Lead
FBC System	34.0	44.0	-	-	-	5.0	3.4	0.01
Propane Pre-Heater	0.7	1.1	-	-	-	1.31E-01	8.74E-05	-
Steam Explosion Process	-	-	-	-	-	-	5.25E-06	-
Wood Dryer			7.7	6.9	3.8			
Pellet Coolers							1.52E-04	
Material Handling			9.4	3.3	0.5			
Boiler Baghouse			3.1	3.1	3.1			
TOTAL	34.7	45.1	20.2	13.3	7.4	5.1	3.4	0.01

Table 3-2. Facility-wide Potential to Emit (tpy)

Emission Sources	CO	NO_X	PM	PM_{10}	$PM_{2.5}$	SO_2	VOC	Lead
FBC System	148.9	192.7				21.9	14.9	0.04
Propane Pre-Heater	2.9	5.0				0.57	3.83E-04	-
Steam Explosion Process							2.30E-05	
Wood Dryer			33.5	30.2	16.8			
Pellet Coolers							6.64E-04	
Material Handling			6.8	2.5	0.4			
Boiler Baghouse			13.7	13.7	13.7			
TOTAL	151.8	197.7	54.0	46.4	30.9	22.5	14.9	0.04

Table 3-3. Facility-wide Potential to Emit (HAPs/TAPs)

Pollutant	HAP?	Non-Carcinogenic TAP?	Carcinogenic TAP?	Potential Emissions	
				lb/hr	tpy
Acenaphthene	Yes	No	Yes	1.82E-04	7.97E-04
Acenaphthylene	Yes	No	Yes	1.00E-03	4.38E-03
Acetaldehyde	Yes	No	Yes	1.66E-01	7.27E-01
Acetone	No	Yes	No	3.80E-02	1.66E-01
Acetophenone	Yes	No	Yes	6.40E-07	2.80E-06
Acrolein	Yes	Yes	No	8.00E-01	3.50E+00
Anthracene	Yes	No	Yes	6.00E-04	2.63E-03
Antimony	Yes	Yes	No	1.58E-03	6.92E-03
Arsenic	Yes	No	Yes	4.40E-03	1.93E-02
Barium	No	Yes	No	3.45E-05	1.51E-04
Benzene	Yes	No	Yes	8.40E-01	3.68E+00
Benzo(a)anthracene	Yes	No	Yes	1.30E-05	5.70E-05
Benzo(a)pyrene	Yes	No	Yes	5.20E-04	2.28E-03
Benzo(b)fluoranthene	Yes	No	Yes	2.00E-05	8.77E-05
Benzo(e)pyrene	Yes	No	Yes	5.20E-07	2.28E-06
Benzo(g,h,i)perylene	Yes	No	Yes	1.86E-05	8.15E-05
Benzo(j,k)fluoranthene	Yes	No	Yes	3.20E-05	1.40E-04
Benzo(k)fluoranthene	Yes	No	Yes	7.21E-06	3.16E-05
Beryllium	Yes	No	Yes	2.20E-04	9.64E-04
Bis(2-ethylhexyl)phthalate	Yes	No	Yes	9.40E-06	4.12E-05
Bromomethane	Yes	Yes	No	3.00E-03	1.31E-02
2-Butanone (MEK)	No	Yes	No	1.08E-03	4.73E-03
Cadmium	Yes	No	Yes	8.29E-04	3.63E-03
Carbon tetrachloride	Yes	No	Yes	9.00E-03	3.94E-02
Chlorine	Yes	Yes	No	1.58E-01	6.92E-01
Chlorobenzene	Yes	Yes	No	6.60E-03	2.89E-02
Chloroform (Trichloromethane)	Yes	No	Yes	5.60E-03	2.45E-02
2-Chlorophenol	No	Yes	No	4.80E-06	2.10E-05
Chrysene	Yes	No	Yes	7.61E-06	3.33E-05
Crotonaldehyde	No	Yes	No	1.98E-03	8.67E-03
Chromium	Yes	Yes	Yes	4.21E-03	1.84E-02

Pollutant	HAP?	Non-Carcinogenic TAP?	Carcinogenic TAP?	Potential Emissions	
				lb/hr	tpy
Chromium VI	Yes	No	Yes	7.00E-04	3.07E-03
Cobalt	Yes	Yes	No	1.30E-03	5.70E-03
Copper	No	Yes	No	6.67E-06	2.92E-05
Cyclohexene	No	Yes	No	6.94E-08	3.04E-07
Dibenzo(a,h)anthracene	Yes	No	Yes	1.83E-06	8.01E-06
Dichlorobenzene	Yes	Yes	No	9.41E-06	4.12E-05
Dichlorobiphenyl	Yes	No	Yes	1.48E-07	6.48E-07
1,2-Dichloroethane	Yes	No	Yes	5.80E-03	2.54E-02
1,2-Dichloropropane	Yes	Yes	No	6.60E-03	2.89E-02
Ethyl benzene	Yes	Yes	No	6.20E-03	2.72E-02
Fluoranthene	Yes	No	Yes	3.20E-04	1.40E-03
Fluorene	Yes	No	Yes	6.80E-04	2.98E-03
Formaldehyde	Yes	No	Yes	8.81E-01	3.86E+00
Furfural	No	Yes	No	5.04E-09	2.21E-08
Heptachlorodibenzo-p-dioxins	Yes	No	Yes	4.00E-07	1.75E-06
Heptachlorodibenzo-p-furans	Yes	No	Yes	4.80E-08	2.10E-07
Hexachlorodibenzo-p-dioxins	Yes	No	Yes	3.20E-04	1.40E-03
Hexachlorodibenzo-p-furans	Yes	No	Yes	5.60E-08	2.45E-07
Hexane	Yes	Yes	No	1.41E-02	6.18E-02
Hydrogen Chloride	Yes	Yes	No	3.80E+00	1.66E+01
Indeno(1,2,3-cd)pyrene	Yes	No	Yes	1.74E-05	7.63E-05
Iron	No	Yes	No	1.98E-01	8.67E-01
Manganese	Yes	Yes	No	3.20E-01	1.40E+00
Methyl Acetate	No	Yes	No	5.28E-08	2.31E-07
Methylene chloride (dichloromethane)	Yes	No	Yes	5.80E-02	2.54E-01
Molybdenum	No	Yes	No	4.29E-04	1.88E-03
Naphthalene	Yes	Yes	No	1.94E-02	8.50E-02
Nickel	Yes	No	Yes	6.62E-03	2.90E-02
Octachlorodibenzo-p-dioxins	Yes	No	Yes	1.32E-05	5.78E-05

Pollutant	HAP?	Non-Carcinogenic TAP?	Carcinogenic TAP?	Potential Emissions	
				lb/hr	tpy
Octachlorodibenzo-p-furans	Yes	No	Yes	1.76E-08	7.71E-08
Pentachlorodibenzo-p-dioxins	Yes	No	Yes	3.00E-07	1.31E-06
Pentachlorodibenzo-p-furans	Yes	No	Yes	8.40E-08	3.68E-07
Pentachlorobiphenyl	Yes	No	Yes	2.40E-07	1.05E-06
Pentachlorophenol	Yes	Yes	No	1.02E-05	4.47E-05
Pentane	No	Yes	No	2.04E-02	8.93E-02
Perylene	Yes	No	Yes	1.04E-07	4.56E-07
Phenanthrene	Yes	No	Yes	1.40E-03	6.13E-03
Phenol	Yes	Yes	No	1.02E-02	4.47E-02
Phosphorus	Yes	Yes	No	5.40E-03	2.37E-02
Propionaldehyde	Yes	Yes	No	1.22E-02	5.34E-02
Pyrene	Yes	No	Yes	7.40E-04	3.24E-03
Selenium	Yes	Yes	No	5.60E-04	2.45E-03
Silver	No	Yes	No	3.40E-01	1.49E+00
Styrene	Yes	Yes	No	3.80E-01	1.66E+00
2,3,7,8-Tetrachlorodibenzo-p-dioxins	Yes	No	Yes	1.72E-09	7.53E-09
Tetrachlorodibenzo-p-dioxins	Yes	No	Yes	9.40E-08	4.12E-07
2,3,7,8-Tetrachlorodibenzo-p-furans	Yes	No	Yes	1.80E-08	7.88E-08
Tetrachlorodibenzo-p-furans	Yes	No	Yes	1.50E-07	6.57E-07
Tetrachlorobiphenyl	Yes	No	Yes	5.00E-07	2.19E-06
Tin	No	Yes	No	4.60E-03	2.01E-02
Toluene	Yes	Yes	No	1.84E-01	8.06E-01
Trichlorobiphenyl	Yes	No	Yes	5.20E-07	2.28E-06
Trichloroethylene (trichloroethene)	Yes	No	Yes	6.00E-03	2.63E-02
2,4,6-Trichlorophenol	Yes	No	Yes	4.40E-06	1.93E-05
Vanadium	No	Yes	No	2.14E-04	9.37E-04

Pollutant	HAP?	Non-Carcinogenic TAP?	Carcinogenic TAP?	Potential Emissions	
				lb/hr	tpy
Vinyl chloride	Yes	No	Yes	3.60E-03	1.58E-02
m,p-Xylene	Yes	Yes	No	4.80E-08	2.10E-07
o-Xylene	Yes	Yes	No	5.00E-03	2.19E-02
Yttrium	No	Yes	No	6.00E-05	2.63E-04
Zinc	No	Yes	No	8.40E-02	3.68E-01
7-PAH	Yes	No	Yes	5.87E-04	2.57E-03
Dioxins/Furans	Yes	No	Yes	3.25E-05	1.42E-04

4. APPLICABLE REGULATIONS AND REQUIREMENTS

The proposed CRE Potlach facility will be a non-PSD major source of NOX, CO and HAPs and will be subject to Title V of the Clean Air Act. In addition, the facility will be subject to 40 CFR Part 60, Subpart Db - Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units and 40 CFR Part 63, Subpart DDDDD—National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters.

A review of applicable State and Federal Rules is provided in Sections 4.1 and 4.2 below.

4.1. STATE REGULATORY APPLICABILITY

A review of applicable requirements of the Rules for the Control of Air Pollution in Idaho is provided in **Table 4-1**. Each regulation is described in the sections following the table.

Table 4-1. State Regulatory Applicability

Section	Description	Regulatory Citation	Applicable?
4.1.1	Certification of Documents	IDAPA 58.01.01.123	Yes
4.1.2	Excess Emissions	IDAPA 58.01.01.130-136	Yes
4.1.3	Test Methods and Procedures	IDAPA 58.010.01.157	Yes
4.1.4	Procedures and Requirements for Permits To Construct	IDAPA 58.01.01.200-203	Yes
4.1.5	Permit Requirements For New Major Facilities Or Major Modifications In Nonattainment Areas	IDAPA 58.01.01.204	No
4.1.6	Permit Requirements For New Major Facilities Or Major Modifications In Attainment Or Unclassifiable Areas.	IDAPA 58.01.01.205	No
4.1.7	Demonstration of Preconstruction Compliance with Toxic Standards	IDAPA 58.01.01.210	Yes
4.1.8	Mercury Emission Standard for New or Modified Sources	IDAPA 58.01.01.215	Yes
4.1.9	Procedures And Requirements For Tier I Operating Permits.	IDAPA 58.01.01.300-399	Yes
4.1.10	Air Pollution Emergency Rule	IDAPA 58.01.01.550-562	Yes
4.1.11	Toxic Air Pollutants	IDAPA 58.01.01.585 and 586	Yes
4.1.12	New Source Performance Standards	IDAPA 58.01.01.590	Yes
4.1.13	National Emissions Standards for Hazardous Air Pollutants	IDAPA 58.01.01.591	Yes
4.1.14	Open Burning	IDAPA 58.01.01.600-617	Yes
4.1.15	Visible Emissions	IDAPA 58.01.01.625	Yes

Section	Description	Regulatory Citation	Applicable?
4.1.16	Rules for Control of Fugitive Dust	IDAPA 58.01.01.650-651	Yes
4.1.17	Fuel Burning Equipment – Particulate Matter	IDAPA 58.01.01.675-681	Yes
4.1.18	Particulate Matter – Process Weight Limitations	IDAPA 58.01.01.700-701	Yes
4.1.19	Rules For Sulfur Content Of Fuels	IDAPA 58.01.01.725	No
4.1.20	Odors	IDAPA 58.01.01.775-776	Yes

4.1.1. Certification of Documents

IDAPA 58.01.01.123 requires all documents including application forms for permits to construct, records, and monitoring reports submitted to the Department shall contain a certification by a responsible official. CRE will comply with this requirement and the appropriate certifications by a responsible official are being submitted with this application.

4.1.2. Excess Emissions

IDAPA 58.01.01.130-136 establishes procedures and requirements to be implemented in all excess emissions events. CRE will comply with the procedures and requirements outlined in Section 131-136 and submit the necessary information and reports to DEQ related to excess emissions due to startup, shutdown, scheduled maintenance, safety measures, upsets and breakdowns.

4.1.3. Test Methods and Procedures

IDAPA 58.01.01.157 establishes procedures and requirements for test methods and results. If a source test is required to be performed to satisfy a performance test requirement or a compliance test requirement imposed by state or federal regulation, rule, permit, order or consent decree, then the test methods and procedures shall be conducted in accordance with the requirements of Section 157.

4.1.4. Procedures and Requirements for Permits To Construct

IDAPA 58.01.01.200-203 establish uniform procedures and requirements for the issuance of PTCs. CRE will not commence construction of the Potlach facility without first obtaining a permit to construct from the Department which satisfies the requirements of Sections 200 through 228. The PTC application will be made using forms furnished by the Department, or by other means prescribed by the Department.

4.1.5. Permit Requirements For New Major Facilities Or Major Modifications In Nonattainment Areas

The proposed CRE will be located in Latah County. Latah County is in attainment for all criteria pollutants, therefore the requirements of IDAPA 58.01.01.204 do not apply to the CRE facility.

4.1.6. Permit Requirements For New Major Facilities Or Major Modifications In Attainment Or Unclassifiable Areas

The intent of IDAPA 58.01.01.205 is to incorporate the federal PSD rule requirements. The CRE facility will be a non-PSD major source; therefore the requirements of this section do not apply to the CRE facility.

4.1.7. Demonstration of Preconstruction Compliance with Toxic Standards

IDAPA 58.01.01.210 establishes requirements for preconstruction compliance with toxic standards. CRE will comply with this rule by identifying and calculating the toxic pollutant emission rates from all applicable emissions units at the facility.

As described in Section 5.0 Emission Summary, CRE calculated the increase in Toxic Air Pollutant (TAP) emission rates from the facility and compared them to the screening levels. Air dispersion modeling was conducted for those TAPs which exceed the screening emissions level (EL) in Idaho Air Rules Section 585 and 586. However, per IDEQ policy and guidance, TAPs that are regulated by a federal NSPS or NESHAPS were not included in the modeling analysis. A complete Modeling Report (Ambient Impact Assessment) is included in **Appendix E** which documents how CRE demonstrates preconstruction compliance with toxic air quality preconstruction standards.

4.1.8. Mercury Emission Standard for New or Modified Sources

IDAPA 58.01.01.215 requires an owner or operator of a stationary source or facility to include a mercury BACT (MBACT) analysis in the permit to construct application if a facility has annual potential emissions of mercury of 25 pounds or more. The estimated mercury emissions from the CRE facility will be 1.79E-02 pounds/year, therefore an MBACT analysis is not required with the permit application.

4.1.9. Procedures And Requirements For Tier I Operating Permits

IDAPA 58.01.01.300-399 establish requirements and procedures for the issuance of Tier I operating permits. The CRE facility will be a non-PSD major source of CO, NOx and HAPs and will be subject to Title V of the Clean Air Act, therefore a Tier I operating permit will be required. Section 313 states that the owner or operator of the Tier I source shall submit to the Department a complete application for an original Tier I operating permit within twelve (12) months after becoming a Tier I source or commencing operation. CRE will submit a Tier I operating permit to the Department in accordance with requirements in Sections 314 through 399 within 12 months of commencing operation.

4.1.10. Air Pollution Emergency Rule

IDAPA 58.01.01.550 through 562 define criteria for an air pollution emergency, formulates a plan for preventing or alleviating such an emergency, and specifies rules for carrying out the plan. In the event of an air pollution emergency, CRE will comply with applicable requirements as specified by the Director based on the specific episode conditions which then exist.

4.1.11. Toxic Air Pollutants

IDAPA 58.01.01.585 and 586 establishes requirements for compliance with toxic air pollutants. CRE demonstrates compliance with the standards in the modeling report included in **Appendix E**.

4.1.12. New Source Performance Standards

New Source Performance Standards (NSPS) in 40 CFR Part 60 are applicable to new, modified, or reconstructed stationary sources that meet or exceed specified applicability thresholds. Subpart Db - Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units applies to the FBC. CRE will comply with the applicable requirements of Subpart Db as documented on IDEQ Form FRA included in **Appendix F**.

4.1.13. National Emissions Standards for Hazardous Air Pollutants

Two sets of National Emissions Standards for Hazardous Air Pollutants (NESHAPs) may potentially apply to the CRE facility. The first NESHAP regulations were developed under the auspices of the original Clean Air Act. These standards are codified in 40 CFR Part 61, and address a limited number of pollutants and industries. The CRE facility does not fall under any of the industries or have the potential to emit any of the pollutants listed in 40 CFR Part 61, and therefore, 40 CFR Part 61 regulations do not apply to this facility.

Newer regulations are codified in 40 CFR Part 63 under the authority of the 1990 Clean Air Act Amendments (CAAA). These standards regulate hazardous air pollutant (HAP) emissions from specific source categories and typically affect only major sources of HAPs. Part 63 regulations are frequently called Maximum Achievable Control Technology (MACT) standards. Major HAP sources have a potential to emit (PTE) of 10 tpy or more of any single HAP or 25 tpy or more of all combined HAP emissions. The CRE facility will be a major source of HAPs.

40 CFR Part 63 Subpart DDDDD—National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters applies to the FBC. CRE will comply with the applicable requirements of Subpart DDDDD as documented on IDEQ Form FRA included in **Appendix F**.

4.1.14. Open Burning

IDAPA 58.01.01.600-617 establish requirements for open burning. CRE does not expect to conduct open burning at the facility however will comply with the requirements under Section 600-617 if any allowable burning is to be conducted at the facility.

4.1.15. Visible Emissions

IDAPA 58.01.01.625 restricts discharge of air pollutants into the atmosphere which is greater than 20% opacity for a period or periods aggregating more than three (3) minutes in any sixty (60) minute period. CRE will comply with the IDAPA rule by conducting monthly facility-wide inspections of potential sources of visible emissions, during daylight hours and under normal operating conditions. The inspection will consist of a see/no see evaluation for each potential source. If any visible emissions are observed CRE will take corrective action or perform a Method 9 opacity test in accordance with the procedures outlined in IDAPA 58.01.01.625. CRE will keep records onsite documenting the monthly visible emission inspection and Method 9 test conducted.

4.1.16. Rules for Control of Fugitive Dust

IDAPA 58.01.01.650-651 requires that all reasonable precautions be taken to prevent the generation of fugitive dust. CRE will comply with fugitive particulate matter regulations through the use of hoods, fans and fabric filters to enclose and vent potential fugitive particulate matter.

4.1.17. Fuel Burning Equipment – Particulate Matter

IDAPA 58.01.01.675-681 restricts fuel burning sources (larger than 10 MMBtu/hr) to limit the PM combustion emissions to 0.080 gr/dscf for wood product fuel. The FBC capacity is greater than 10 MMBtu/hr; PM emissions from the unit are controlled by the FBC baghouse which has an output grain loading of 0.0027 gr/dscf. The FBC pre-heater will combust propane, however the capacity is less than 10 MMBtu/hr.

4.1.18. Particulate Matter – Process Weight Limitations

IDAPA 58.01.01.701 promulgates restrictions on PM for the entire facility based on process weight. Fuel burning equipment at the facility is not subject to this requirement. Process weight calculations are included in **Appendix G**.

4.1.19. Rules For Sulfur Content Of Fuels

IDAPA 58.01.01.725 applies to fuel burning sources in Idaho. Its purpose is to prevent excessive ground level concentrations of sulfur dioxide. However, the requirements only apply to sources that sell, distribute, use or make available for use distillate oil, residual oil or coal. Therefore the requirements of this subpart do not apply to CRE.

4.1.20. Odors

IDAPA 58.01.01.775-776 requires no emissions of odorous gases, liquids, or solids to the atmosphere in such quantities as to cause air pollution. CRE will comply with this requirement by keeping records of any odor complaints received and will take appropriate action for each complaint which has merit.

4.2. FEDERAL REGULATORY APPLICABILITY

A review of applicable Federal Rules is provided in **Table 4-2**. Included in **Appendix F** is the completed NSPS/NESHAP Regulation Review and Applicability Form FRA.

Table 4-2. Federal Regulatory Applicability

Section	Description	Regulatory Citation	Applicable?
4.2.1	National Ambient Air Quality Standards (NAAQS)- (dispersion modeling)	40 CFR Part 50	Yes
4.2.2	New Source Review (NSR)	40 CFR Part 52	No
4.2.3	New Source Performance Standards (NSPS)	40 CFR Part 60	Yes
4.2.4	National Emissions Standards for Hazardous Air Pollutants (NESHAPs)	40 CFR Parts 61, 63	Yes
4.2.5	Risk Management Programs For Chemical Accidental Release Prevention	40 CFR Part 68	No
4.2.6	Title V Operating Permit	40 CFR Part 70	Yes
4.2.7	Acid Rain Requirements	40 CFR Parts 72–78	No

Section	Description	Regulatory Citation	Applicable?
4.2.8	Mandatory Greenhouse Gas Reporting	40 CFR Part 98	No

4.2.1. National Ambient Air Quality Standards (NAAQS)

Primary National Ambient Air Quality Standards (NAAQS) are identified in 40 CFR Part 50 and define levels of air quality, which the United States Environmental Protection Agency (USEPA) deems necessary to protect the public health. Secondary NAAQS define levels of air quality, which the USEPA judges necessary to protect public welfare from any known, or anticipated adverse effects of a pollutant. Examples of public welfare include protecting wildlife, buildings, national monuments, vegetation, visibility, and property values from degradation due to excessive emissions of criteria pollutants.

Specific standards for the following pollutants have been promulgated by USEPA: $PM_{2.5}$, PM_{10}, SO_2, NO_x, CO, ozone, and lead. The CRE facility will emit $PM_{2.5}$, PM_{10}, SO_2, NO_x, CO, lead, and VOCs, a precursor to ozone. Air dispersion modeling will be conducted to show compliance with the NAAQs.

4.2.2. New Source Review (NSR)

Latah County is designated as an attainment area for all criteria pollutants. Therefore, the prevention of significant deterioration (PSD) regulations codified in 40 CFR Part 52 could potentially apply to the proposed facility. The PSD rule applies to: (1) a new major source that has the potential to emit 100 tons per year or more for any criteria pollutant for a facility that is one of the 28 industrial source categories listed in 40 CFR § 52.21(b)(1)(i)(a); or (2) a new major source that has the potential to emit 250 tons per year or more of a regulated pollutant if the facility is not on the list of industrial source categories; or (3) a modification to an existing major source that results in a net emission increase greater than a PSD significant emission rate as specified in 40 CFR § 52.21 (b)(23)(i); or (4) a modification to an existing minor source that is major in itself. The CRE facility does not fall under one of the 28 industrial source categories, nor will the PTE exceed 250 tpy for any regulated pollutant. Therefore, CRE is not subject to PSD regulations.

4.2.3. New Source Performance Standards (NSPS)

NSPS are discussed in Section 4.1.12 above.

4.2.4. National Emissions Standards for Hazardous Air Pollutants (NESHAPs)

NESHAPS are discussed in Section 4.1.13 above.

4.2.5. Risk Management Programs For Chemical Accidental Release Prevention

The facility is not subject to the Chemical Accidental Release Prevention Program and will not be required to develop a Risk Management Plan (RMP). Facilities that produce, process, store, or use any regulated toxic or flammable substance in excess of the thresholds listed in 40 CFR Part 68 must develop a RMP. The facility does not store any regulated toxic or flammable substances in excess of the applicable thresholds. A RMP is not necessary for this facility.

4.2.6. Title V Operating Permit

Title V of the Clean Air Act (CAA) created the federal operating permit program. These permitting requirements are codified in 40 CFR Part 70. These permits are required for major sources with a PTE (considering federally enforceable limitations) greater than 100 tpy for any criteria pollutant, 25 tpy for all hazardous air pollutants (HAPs) in aggregate, or 10 tpy of any single HAP. CRE potential to emit for NOx and CO is greater than 100 tons per year, and the potential to emit of all HAPs in aggregate is greater than 25 tpy. Therefore, CRE will be subject to Title V requirements. As discussed in Section 4.1.9, CRE will apply for a Tier 1 Operating permit from the State of Idaho within one year of commencement of operations.

4.2.7. Acid Rain Requirements

The acid rain requirements codified in 40 CFR Parts 72-78 apply only to utilities and other facilities that combust fossil fuel and generate electricity for wholesale or retail sale. The proposed facility will not combust fossil fuel as the primary fuel nor will it generate electricity for wholesale or retail sale. Therefore, the facility is not subject to the acid rain provisions and will not require an acid rain permit.

4.2.8. Mandatory Greenhouse Gas Reporting

Greenhouse gas reporting requirements are codified under 40 CFR Part 98. Part 98.2 describes facilities who are subject to mandatory reporting requirement. The CRE facility does not fall under any source category that is listed in Table A–3 or A-4 of the subpart. However, Part 98.2(a)(3) states the following:

> (3) A facility that in any calendar year starting in 2010 meets all three of the conditions listed in this paragraph (a)(3) . For these facilities, the annual GHG report must cover emissions from stationary fuel combustion sources only.
>
> > (i) The facility does not meet the requirements of either paragraph (a)(1) or (a)(2) of this section.
> >
> > (ii) The aggregate maximum rated heat input capacity of the stationary fuel combustion units at the facility is 30 MMBtu/hr or greater.
> >
> > (iii) The facility emits 25,000 metric tons CO2e or more per year in combined emissions from all stationary fuel combustion sources.

The heat input capacity of the facility will be greater than 30 MMBtu/hr. Per 98.2(b)(2), carbon dioxide emission from the combustion of biomass may be excluded from the calculation of annual CO2e emissions. Emissions of CO2e, taking into account the biomass deferral, from the CRE facility are estimated to be 3,592 tonne/yr (3,960 ton/yr). Therefore, CRE will not be subject to the GHG reporting requirements in 40 CFR Part 98.

Air dispersion modeling was conducted for those criteria pollutants which exceeded the Idaho Level I modeling thresholds and TAPs which exceed the screening emissions level (EL) in Idaho Air Rules Section 585 and 586. However, per IDEQ policy and guidance, TAPs that are regulated by a federal NSPS or NESHAPS were not included in the modeling analysis. A complete Modeling Report (Ambient Impact Assessment) is included in **Appendix E** which documents how CRE demonstrates compliance with the NAAQs and AAC/AACC for TAPs.

5.1. MODELING THRESHOLDS

The facility-wide PTE was compared to the Idaho Level I Modeling Thresholds to determine the criteria pollutants required to be modeled, as show in **Table 5-1**. The facility-wide PTE includes material handling and processing, however does not include fugitive emissions from vehicle traffic on facility roadways or wind erosion from storage piles.

Table 5-1 Criteria Pollutant PTE vs. Modeling Thresholds

Pollutant	Facility-Wide PTE	Idaho Level I Modeling Threshold	Modeling Required?
CO (lb/hr)	34.7	15	Yes
NOx (lb/hr)	45.1	0.20	Yes
NOx (tpy)	197.7	1.2	Yes
SO2 (lb/hr)	5.1	0.21	Yes
SO2 (tpy)	22.5	1.2	Yes
PM10 (lb/hr)	13.4	0.22	Yes
PM2.5 (lb/hr)	7.4	0.054	Yes
PM2.5 (tpy)	30.8	0.35	Yes
Lead (lb/month)	7.0	14	No

As stated above, TAPs that are regulated by a federal NSPS or NESHAPS will not be included in the modeling analysis. The facility will be subject to 40 CFR Part 63 Subpart DDDDD - National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters. Subpart DDDDD contains emissions limits for several TAPs, including include acetaldehyde, acrolein, arsenic, benzene, beryllium, cadmium, chromium VI, hydrogen chloride, nickel, POM, and dioxins and furans.

Table 5-2 presents the facility-wide TAPs PTE, IDAPA 58.01.01.585 and 586 ELs, and modeling applicability.

Table 5-2 TAPs PTE vs. Modeling Thresholds

Pollutant	HAP?	Non-Carc. TAP?	Carc. TAP?	Potential Emissions		IDAPA EL	Exceeds EL?	Exempt from Modeling due to NSPS/ NESHAP?
				lb/hr	tpy	lb/hr		
Acenaphthene	Yes	No	Yes	1.82E-04	7.97E-04	9.10E-05	Yes	Yes
Acenaphthylene	Yes	No	Yes	1.00E-03	4.38E-03	9.10E-05	Yes	Yes
Acetaldehyde	Yes	No	Yes	1.66E-01	7.27E-01	3.00E-03	Yes	Yes
Acetone	No	Yes	No	3.80E-02	1.66E-01	1.19E+02	No	No
Acetophenone	Yes	No	Yes	6.40E-07	2.80E-06	9.10E-05	No	Yes
Acrolein	Yes	Yes	No	8.00E-01	3.50E+00	1.70E-02	Yes	Yes
Anthracene	Yes	No	Yes	6.00E-04	2.63E-03	9.10E-05	Yes	Yes
Antimony	Yes	Yes	No	1.58E-03	6.92E-03	3.30E-02	No	Yes
Arsenic	Yes	No	Yes	4.40E-03	1.93E-02	1.50E-06	Yes	Yes
Barium	No	Yes	No	3.45E-05	1.51E-04	3.30E-02	No	No
Benzene	Yes	No	Yes	8.40E-01	3.68E+00	8.00E-04	Yes	Yes
Benzo(a)anthracene	Yes	No	Yes	1.30E-05	5.70E-05	7-PAH	No	Yes
Benzo(a)pyrene	Yes	No	Yes	5.20E-04	2.28E-03	7-PAH	No	Yes
Benzo(b)fluoranthene	Yes	No	Yes	2.00E-05	8.77E-05	7-PAH	No	Yes
Benzo(e)pyrene	Yes	No	Yes	5.20E-07	2.28E-06	9.10E-05	No	Yes
Benzo(g,h,i)perylene	Yes	No	Yes	1.86E-05	8.15E-05	9.10E-05	No	Yes
Benzo(j,k)fluoranthene	Yes	No	Yes	3.20E-05	1.40E-04	9.10E-05	No	Yes
Benzo(k)fluoranthene	Yes	No	Yes	7.21E-06	3.16E-05	7-PAH	No	Yes
Beryllium	Yes	No	Yes	2.20E-04	9.64E-04	2.80E-05	Yes	Yes
Bis(2-ethylhexyl)phthalate	Yes	No	Yes	9.40E-06	4.12E-05	2.80E-02	No	No
Bromomethane	Yes	Yes	No	3.00E-03	1.31E-02	1.27E+00	No	No
2-Butanone (MEK)	No	Yes	No	1.08E-03	4.73E-03	3.93E+01	No	No
Cadmium	Yes	No	Yes	8.29E-04	3.63E-03	3.70E-06	Yes	Yes
Carbon tetrachloride	Yes	No	Yes	9.00E-03	3.94E-02	4.40E-04	Yes	No
Chlorine	Yes	Yes	No	1.58E-01	6.92E-01	2.00E-01	No	No
Chlorobenzene	Yes	Yes	No	6.60E-03	2.89E-02	2.33E+01	No	No
Chloroform (Trichloromethane)	Yes	No	Yes	5.60E-03	2.45E-02	2.80E-04	Yes	No
2-Chlorophenol	No	Yes	No	4.80E-06	2.10E-05	3.30E-02	No	No
Chrysene	Yes	No	Yes	7.61E-06	3.33E-05	7-PAH	No	Yes

Pollutant	HAP?	Non-Carc. TAP?	Carc. TAP?	Potential Emissions		IDAPA EL	Exceeds EL?	Exempt from Modeling due to NSPS/ NESHAP?
				lb/hr	tpy	lb/hr		
Crotonaldehyde	No	Yes	No	1.98E-03	8.67E-03	3.80E-01	No	No
Chromium	Yes	Yes	Yes	4.21E-03	1.84E-02	3.30E-02	No	Yes
Chromium VI	Yes	No	Yes	7.00E-04	3.07E-03	5.60E-07	Yes	Yes
Cobalt	Yes	Yes	No	1.30E-03	5.70E-03	3.30E-03	No	Yes
Copper	No	Yes	No	6.67E-06	2.92E-05	6.70E-02	No	No
Cyclohexene	No	Yes	No	6.94E-08	3.04E-07	6.77E+01	No	No
Dibenzo(a,h)anthracene	Yes	No	Yes	1.83E-06	8.01E-06	7-PAH	No	Yes
Dichlorobenzene	Yes	Yes	No	9.41E-06	4.12E-05	3.00E+01	No	No
Dichlorobiphenyl	Yes	No	Yes	1.48E-07	6.48E-07	6.60E-05	No	Yes
1,2-Dichloroethane	Yes	No	Yes	5.80E-03	2.54E-02	2.70E+01	No	No
1,2-Dichloropropane	Yes	Yes	No	6.60E-03	2.89E-02	2.31E+01	No	No
Ethyl benzene	Yes	Yes	No	6.20E-03	2.72E-02	2.90E+01	No	No
Fluoranthene	Yes	No	Yes	3.20E-04	1.40E-03	9.10E-05	Yes	Yes
Fluorene	Yes	No	Yes	6.80E-04	2.98E-03	9.10E-05	Yes	Yes
Formaldehyde	Yes	No	Yes	8.81E-01	3.86E+00	5.10E-04	Yes	Yes
Furfural	No	Yes	No	5.04E-09	2.21E-08	5.33E-01	No	No
Heptachlorodibenzo-p-dioxins	Yes	No	Yes	4.00E-07	1.75E-06	Dioxin/Furan	No	Yes
Heptachlorodibenzo-p-furans	Yes	No	Yes	4.80E-08	2.10E-07	Dioxin/Furan	No	Yes
Hexachlorodibenzo-p-dioxins	Yes	No	Yes	3.20E-04	1.40E-03	Dioxin/Furan	No	Yes
Hexachlorodibenzo-p-furans	Yes	No	Yes	5.60E-08	2.45E-07	Dioxin/Furan	No	Yes
Hexane	Yes	Yes	No	1.41E-02	6.18E-02	1.20E+01	No	No
Hydrogen Chloride	Yes	Yes	No	3.80E+00	1.66E+01	5.00E-02	Yes	Yes
Indeno(1,2,3-cd)pyrene	Yes	No	Yes	1.74E-05	7.63E-05	7-PAH	No	Yes
Iron	No	Yes	No	1.98E-01	8.67E-01	6.70E-02	Yes	No
Manganese	Yes	Yes	No	3.20E-01	1.40E+00	3.33E-01	No	Yes
Methyl Acetate	No	Yes	No	5.28E-08	2.31E-07	4.07E+01	No	No
Methylene chloride (dichloromethane)	Yes	No	Yes	5.80E-02	2.54E-01	1.60E-03	Yes	No
Molybdenum	No	Yes	No	4.29E-04	1.88E-03	3.33E-01	No	No

Pollutant	HAP?	Non-Carc. TAP?	Carc. TAP?	Potential Emissions		IDAPA EL	Exceeds EL?	Exempt from Modeling due to NSPS/ NESHAP?
				lb/hr	tpy	lb/hr		
Naphthalene	Yes	Yes	No	1.94E-02	8.50E-02	3.33E+00	No	No
Nickel	Yes	No	Yes	6.62E-03	2.90E-02	2.70E-05	Yes	Yes
Octachlorodibenzo-p-dioxins	Yes	No	Yes	1.32E-05	5.78E-05	Dioxin/Furan	No	Yes
Octachlorodibenzo-p-furans	Yes	No	Yes	1.76E-08	7.71E-08	Dioxin/Furan	No	Yes
Pentachlorodibenzo-p-dioxins	Yes	No	Yes	3.00E-07	1.31E-06	Dioxin/Furan	No	Yes
Pentachlorodibenzo-p-furans	Yes	No	Yes	8.40E-08	3.68E-07	Dioxin/Furan	No	Yes
Pentachlorobiphenyl	Yes	No	Yes	2.40E-07	1.05E-06	6.60E-05	No	Yes
Pentachlorophenol	Yes	Yes	No	1.02E-05	4.47E-05	3.30E-02	No	No
Pentane	No	Yes	No	2.04E-02	8.93E-02	1.18E+02	No	No
Perylene	Yes	No	Yes	1.04E-07	4.56E-07	9.10E-05	No	Yes
Phenanthrene	Yes	No	Yes	1.40E-03	6.13E-03	9.10E-05	Yes	Yes
Phenol	Yes	Yes	No	1.02E-02	4.47E-02	1.27E+00	No	No
Phosphorus	Yes	Yes	No	5.40E-03	2.37E-02	7.00E-03	No	No
Propionaldehyde	Yes	Yes	No	1.22E-02	5.34E-02	2.87E-02	No	No
Pyrene	Yes	No	Yes	7.40E-04	3.24E-03	9.10E-05	Yes	Yes
Selenium	Yes	Yes	No	5.60E-04	2.45E-03	1.30E-02	No	Yes
Silver	No	Yes	No	3.40E-01	1.49E+00	1.00E-03	Yes	No
Styrene	Yes	Yes	No	3.80E-01	1.66E+00	6.67E+00	No	No
2,3,7,8-Tetrachlorodibenzo-p-dioxins	Yes	No	Yes	1.72E-09	7.53E-09	Dioxin/Furan	No	No
Tetrachlorodibenzo-p-dioxins	Yes	No	Yes	9.40E-08	4.12E-07	Dioxin/Furan	No	No
2,3,7,8-Tetrachlorodibenzo-p-furans	Yes	No	Yes	1.80E-08	7.88E-08	Dioxin/Furan	No	No
Tetrachlorodibenzo-p-furans	Yes	No	Yes	1.50E-07	6.57E-07	Dioxin/Furan	No	No
Tetrachlorobiphenyl	Yes	No	Yes	5.00E-07	2.19E-06	6.60E-05	No	Yes
Tin	No	Yes	No	4.60E-03	2.01E-02	7.00E-03	No	No
Toluene	Yes	Yes	No	1.84E-01	8.06E-01	2.50E+01	No	No

Pollutant	HAP?	Non-Carc. TAP?	Carc. TAP?	Potential Emissions		IDAPA EL	Exceeds EL?	Exempt from Modeling due to NSPS/ NESHAP?
				lb/hr	tpy	lb/hr		
Trichlorobiphenyl	Yes	No	Yes	5.20E-07	2.28E-06	6.60E-05	No	Yes
Trichloroethylene (trichloroethene)	Yes	No	Yes	6.00E-03	2.63E-02	1.79E+01	No	No
2,4,6-Trichlorophenol	Yes	No	Yes	4.40E-06	1.93E-05	1.20E-03	No	No
Vanadium	No	Yes	No	2.14E-04	9.37E-04	3.00E-03	No	No
Vinyl chloride	Yes	No	Yes	3.60E-03	1.58E-02	9.40E-04	Yes	No
m,p-Xylene	Yes	Yes	No	4.80E-08	2.10E-07	2.90E+01	No	No
o-Xylene	Yes	Yes	No	5.00E-03	2.19E-02	2.90E+01	No	No
Yttrium	No	Yes	No	6.00E-05	2.63E-04	6.70E-02	No	No
Zinc	No	Yes	No	8.40E-02	3.68E-01	6.67E-01	No	No
7-PAH	Yes	No	Yes	5.87E-04	2.57E-03	2.00E-06	Yes	Yes
Dioxins/Furans	Yes	No	Yes	3.25E-05	1.42E-04	1.50E-10	Yes	Yes

5.2. MODEL DESCRIPTION

The model used for this application is AERMOD (version 15181), the USEPA–approved model for near-field new source review. Based on EPA guidance AERMOD is the most appropriate of the EPA-approved models given the site's physical characteristics and the facility emission sources. AERMOD was applied as recommended in EPA's Guideline on Air Quality Models and consistent with guidance in IDEQ's Dispersion Modeling Guidelines. An air dispersion modeling protocol was submitted to IDEQ for concurrence; concurrence was received on May 10, 2016. In general, the modeling was conducted as outlined in the protocol; however slight modifications were made to the modeling methodology. A description of the modifications as well as responses to comments in DEQ's protocol approval are provided in the Modeling Report.

5.3. MODEL RESULTS

As shown in **Table 5-3**, the facility is in compliance with the applicable NAAQs for criteria pollutants and AAC or AACC for TAPs. A complete Modeling Report (Ambient Impact Assessment) is included in **Appendix E.**

Table 5-3. Air Dispersion Modeling Results

Pollutant	Averaging Period	Modeled Impact (µg/m³)	Background Concentration (µg/m³)	Total Concentration (µg/m³)	NAAQS/ ACC/AACC (µg/m³)	Modeled Value Used (5 yrs Met Data)
PM_{10}	24-hour	96.6	53	149.6	150	Maximum 6th highest
$PM_{2.5}$	24-hour	17.3	14	31.3	35	Mean of maximum 8th highest

Pollutant	Averaging Period	Modeled Impact (µg/m³)	Background Concentration (µg/m³)	Total Concentration (µg/m³)	NAAQS/ ACC/AACC (µg/m³)	Modeled Value Used (5 yrs Met Data)
	Annual	5.19	4.6	9.79	12	Mean of maximum 1st highest
NO_2	1-hour	116.8	11.8	128.6	188	Mean of maximum 8th highest
	Annual	2.90	1.88	4.78	100	Maximum 1st highest
SO_2	1-hour	16.4	3.92	20.1	196	Mean of maximum 4th highest
	Annual	0.51	0.75	1.26	80	Maximum 1st highest
CO	1-hour	148.9	1307	1456	40,000	Maximum 2nd highest
	8-hour	39.4	816	816	10,000	Maximum 2nd highest
Carbon Tetrachloride	Annual	8.91E-04	0	6.30E-04	6.70E-02	Maximum 1st highest
Chloroform	Annual	5.54E-04	0	3.92E-04	4.30E-02	Maximum 1st highest
Methylene Chloride	Annual	5.74E-03	0	4.06E-03	2.40E-01	Maximum 1st highest
Vinyl Chloride	Annual	3.56E-04	0	2.52E-04	1.40E-01	Maximum 1st highest
Iron	24-hour	1.23E-01	0	1.47E-01	50	Maximum 1st highest
Silver	24-hour	2.11E-01	0	2.52E-01	5	Maximum 1st highest

APPENDIX A: PROCESS FLOW DIAGRAMS

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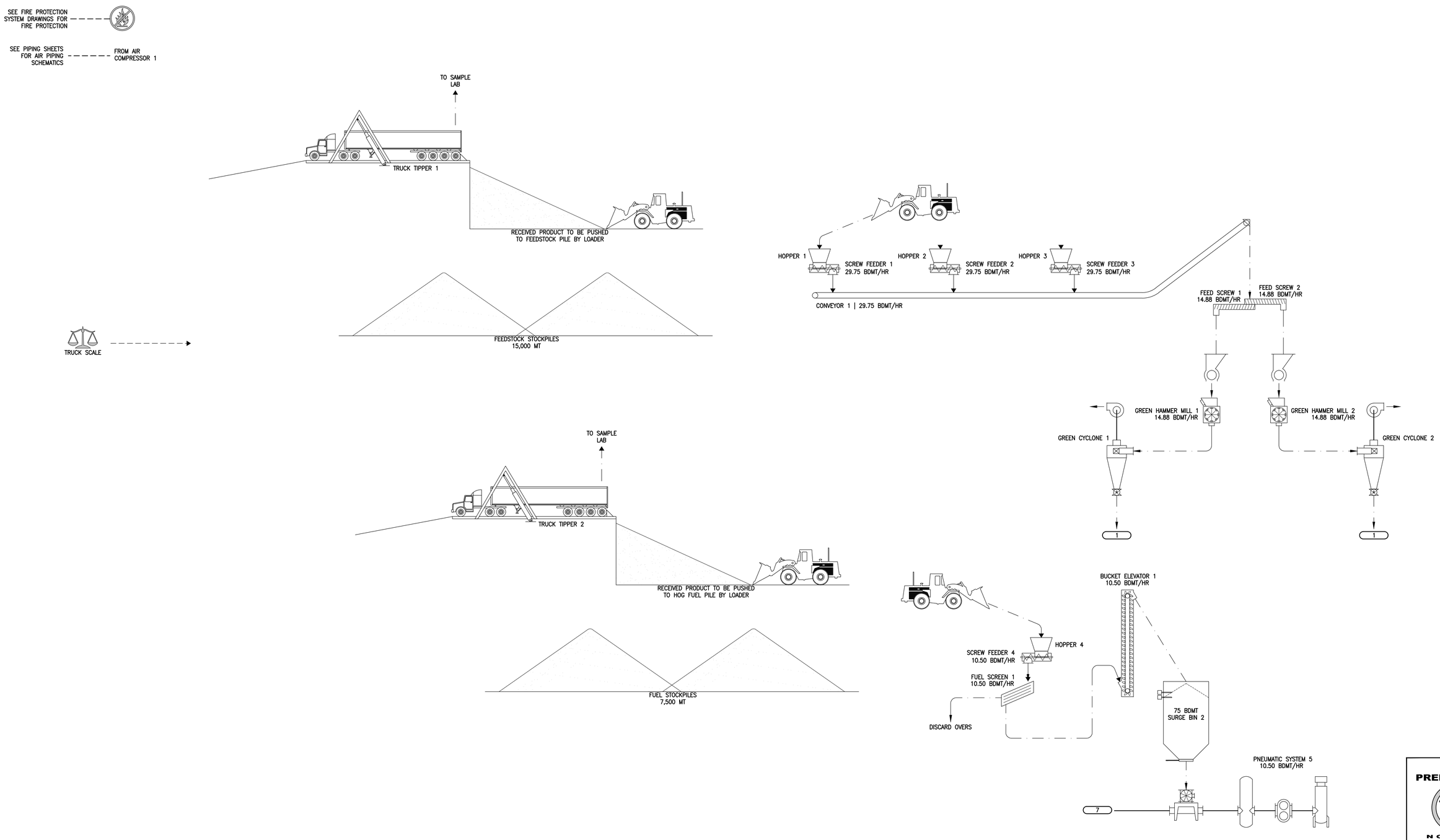
NOTES:

A. (1) TO CONVEYOR 2

B. (7) TO ENERGY SYSTEM



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tel: (208) 529-0833 fax: (208) 529-0854

ENGINEERING SYSTEM SOLUTIONS
4943 NORTH 29TH EAST, STE A
IDAHO FALLS, IDAHO 83401
Phone: (208) 552-9874
Fax: (208) 552-9302

PROJECT:
CENTENNIAL RENEWABLE ENERGY
FOR
DOME TECHNOLOGY

LOCATION:
FERNWOOD, ID

REV.	REVISION NOTE	DATE YY.MM.DD	DT ✓
A	ISSUED FOR PRICING	15.06.01	--
B	VALUE ENGINEERING	15.07.01	--
C	UPDATED TO POTLATCH SITE	16.02.14	--

REVISION DESCRIPTION | REV. | C

DESIGNED	DRAWN	CHECKED	APPROVED
AA	AA	--	--

SHEET TITLE:
RECEIVING FLOW SCHEMATIC

REF NUMBER: 1507 -000.01-REV C-16.02.24

START DATE: MARCH 30, 2015
PROJECT NUMBER: IND15116
SCALE: NO SCALE
SHEET NUMBER: 000.01

NOTES:

A. (1) FROM GREEN HAMMER MILLS

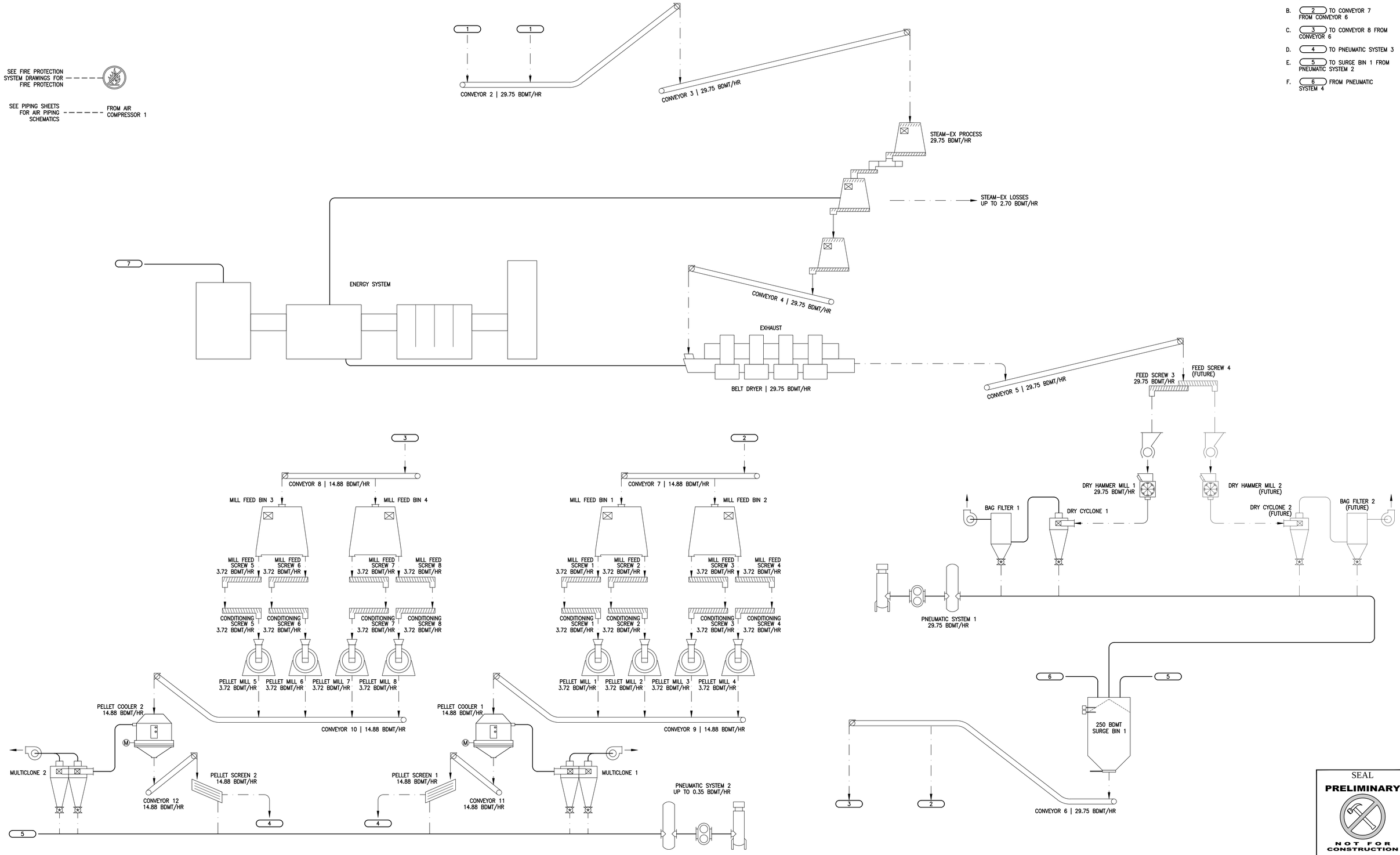
B. (2) TO CONVEYOR 7 FROM CONVEYOR 6

C. (3) TO CONVEYOR 8 FROM CONVEYOR 6

D. (4) TO PNEUMATIC SYSTEM 3

E. (5) TO SURGE BIN 1 FROM PNEUMATIC SYSTEM 2

F. (6) FROM PNEUMATIC SYSTEM 4



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Engineering and Construction Services
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www.evergreenengineering.com

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tel: (208) 529-0833 fax: (208) 529-0854

ENGINEERING SYSTEM SOLUTIONS
4943 NORTH 29TH EAST, STE A
IDAHO FALLS, IDAHO 83401
Phone: (208) 552-9874
Fax: (208) 552-9302

PROJECT: CENTENNIAL RENEWABLE ENERGY FOR DOME TECHNOLOGY

LOCATION: FERNWOOD, ID

REV.	REVISION NOTE	DATE YY.MM.DD	DT ✓
A	ISSUED FOR PRICING	15.06.01	--
B	VALUE ENGINEERING	15.07.01	--
C	UPDATED TO POTLATCH SITE	16.02.14	--

REVISION DESCRIPTION | REV. | C

DESIGNED	DRAWN	CHECKED	APPROVED
AA/VENDORS	AA	--	--

SHEET TITLE: PROCESSING FLOW SCHEMATIC

REF NUMBER: 1507 -000.02-REV C-16.02.24

START DATE: MARCH 30, 2015
PROJECT NUMBER: IND15116
SCALE: NONE
SHEET NUMBER: 000.02

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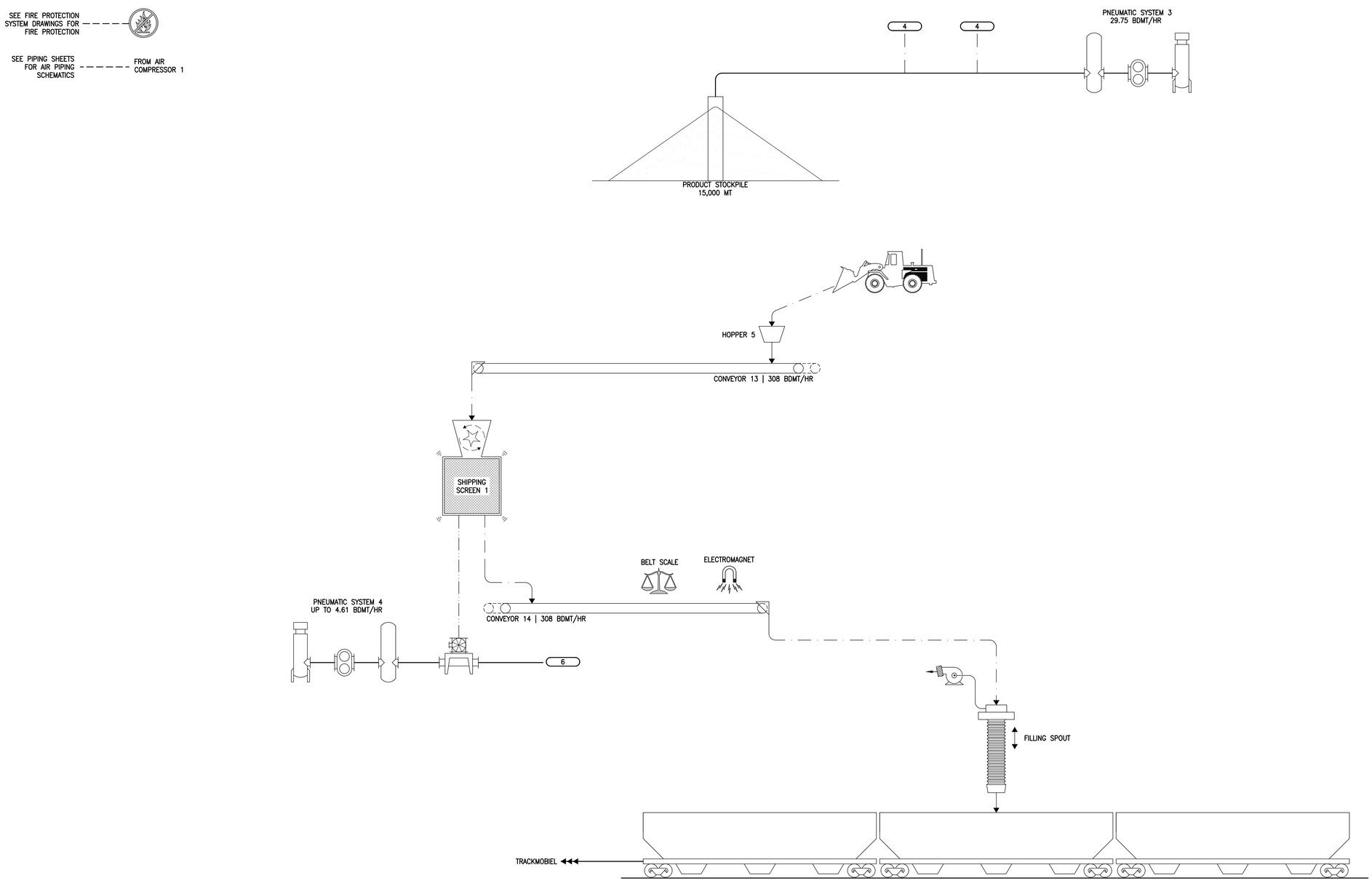
NOTES:

A. (4) FROM PELLET SCREENS

B. (6) TO SURGE BIN 1



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tel: (208) 529-0833 fax: (208) 529-0854

ENGINEERING SYSTEM SOLUTIONS
4943 NORTH 29TH EAST, STE A
IDAHO FALLS, IDAHO 83401
Phone: (208) 552-9874
Fax: (208) 552-9302

PROJECT: CENTENNIAL RENEWABLE ENERGY
FOR
DOME TECHNOLOGY

LOCATION: FERNWOOD, ID

REV.	REVISION NOTE	DATE YY.MM.DD	DT ✓
A	ISSUED FOR PRICING	15.06.01	--
B	VALUE ENGINEERING	15.07.01	--
C	UPDATED TO POTLATCH SITE	16.02.14	--

REVISION DESCRIPTION — REV. C

DESIGNED	DRAWN	CHECKED	APPROVED
AA	AA	--	--

SHEET TITLE: SHIPPING FLOW SCHEMATIC

REF NUMBER: 1507 -000.03-REV C-16.02.24

START DATE: MARCH 30, 2015
PROJECT NUMBER: IND15116
SCALE: NO SCALE
SHEET NUMBER: 000.03

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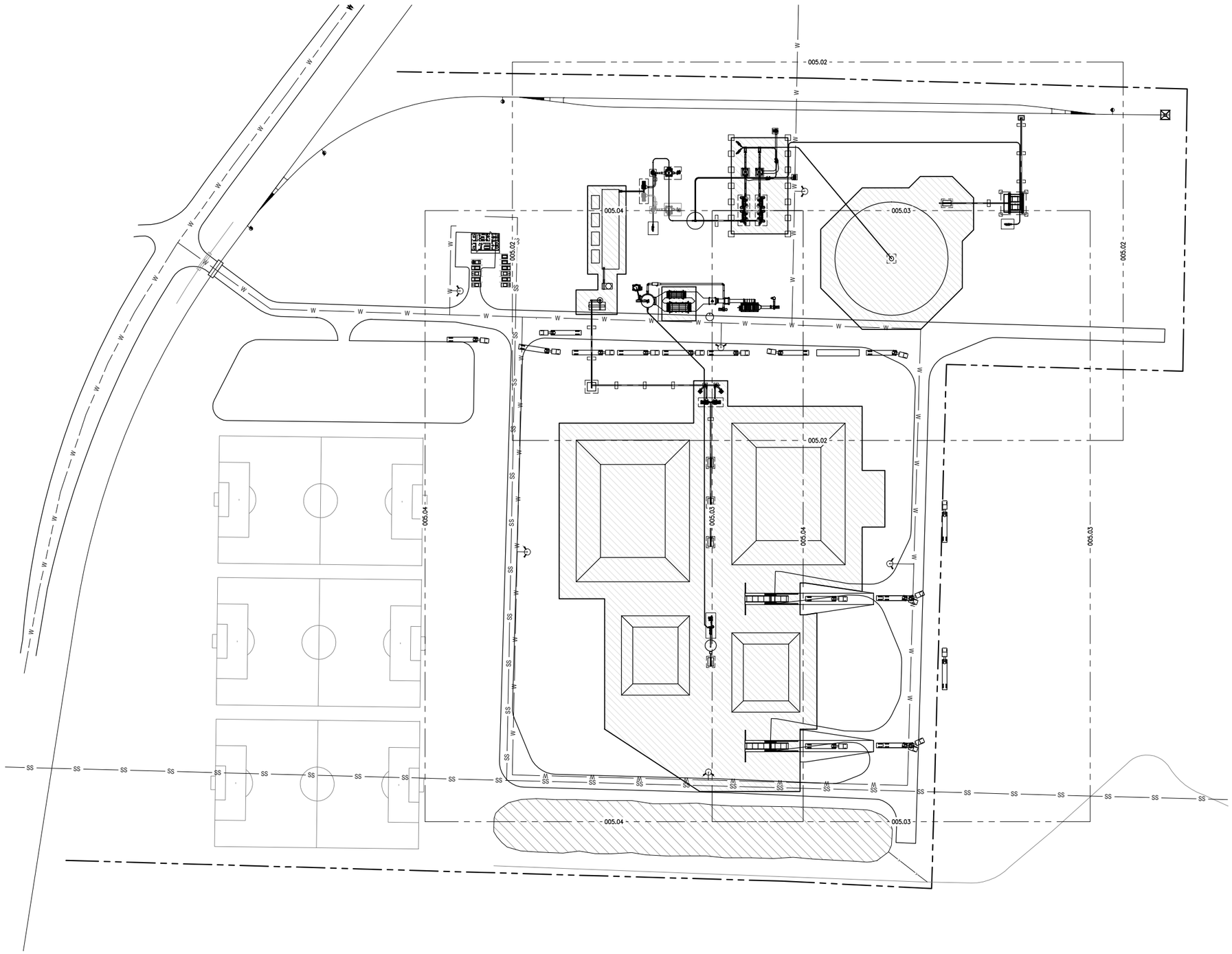

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tel: (208) 529-0833 fax: (208) 529-0854

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4943 NORTH 29TH EAST, STE A
IDAHO FALLS, IDAHO 83401
Phone: (208) 552-9874
Fax: (208) 552-9302

PROJECT:
CENTENNIAL RENEWABLE ENERGY
FOR
DOME TECHNOLOGY

LOCATION:
POTLATCH, ID

REV.	REVISION NOTE	DATE YY.MM.DD	DT ✓
A	ISSUED WITH FEED STUDY	15.12.24	--
B	REVISED LAYOUT PER CONF. CALL	16.01.13	--
C	ISSUED WITH FEED STUDY	16.01.29	--

REVISION DESCRIPTION | REV. | C

DESIGNED	DRAWN	CHECKED	APPROVED
AA	AA	?	?

SHEET TITLE:
OVERALL SITE LAYOUT

REF NUMBER: 1507 -005.01-REV C-16.01.29

START DATE: MARCH 30, 2015
PROJECT NUMBER: IND15116
SCALE: NONE
SHEET NUMBER: 005.01

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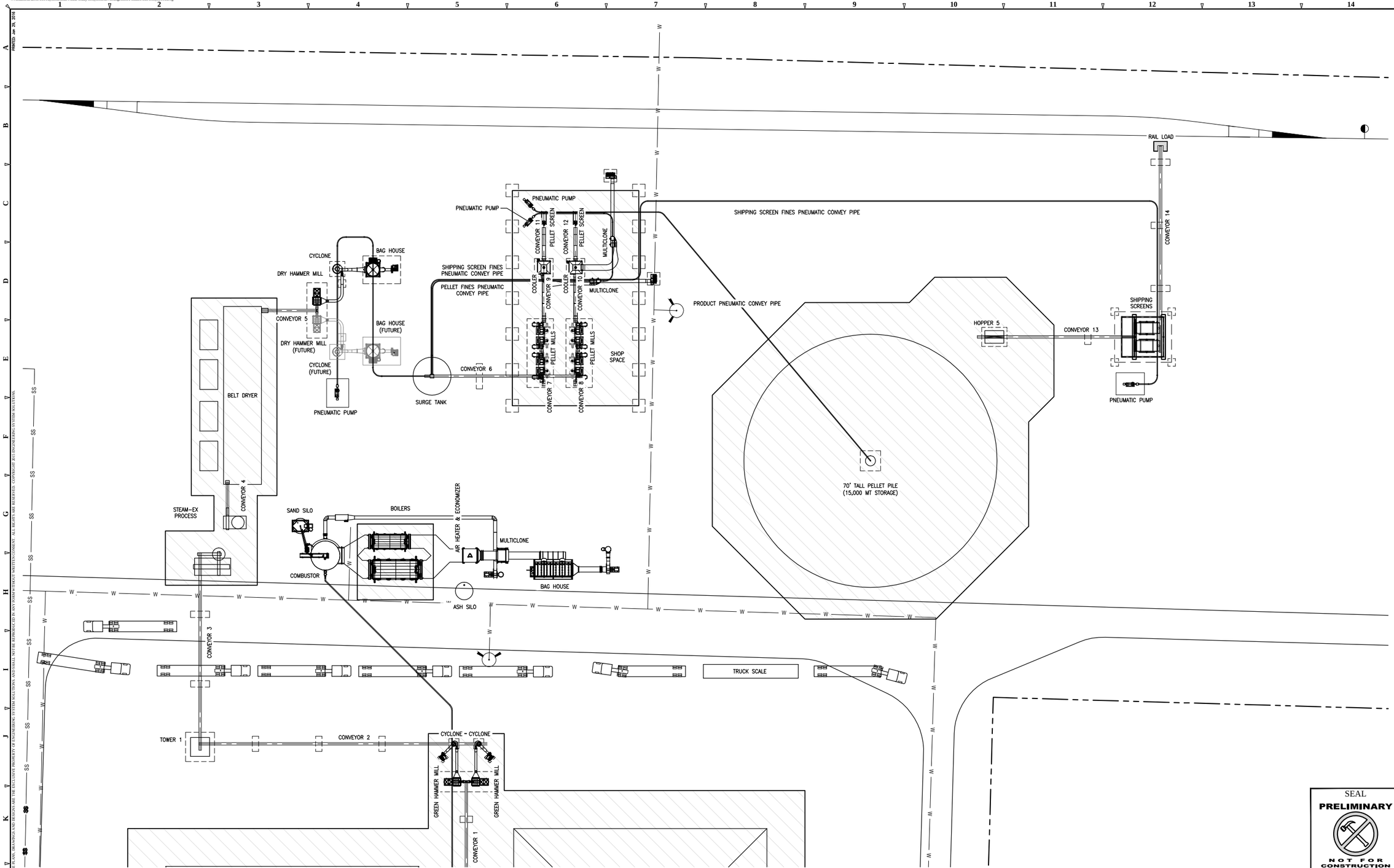

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tel: (208) 529-0833 fax: (208) 529-0854

ENGINEERING SYSTEM SOLUTIONS
4943 NORTH 29TH EAST, STE A
IDAHO FALLS, IDAHO 83401
Phone: (208) 552-9874
Fax: (208) 552-9302

PROJECT:
CENTENNIAL RENEWABLE ENERGY
FOR
DOME TECHNOLOGY

LOCATION:
POTLATCH, ID

REV.	REVISION NOTE	DATE YY.MM.DD	DT ✓
A	ISSUED WITH FEED STUDY	15.12.24	--
B	REVISED LAYOUT PER CONF. CALL	16.01.13	--
C	ISSUED WITH FEED STUDY	16.01.29	--

REVISION DESCRIPTION

REV. C

DESIGNED	DRAWN	CHECKED	APPROVED
AA	AA	?	?

SHEET TITLE:
SITE LAYOUT (1)

REF NUMBER 1507 -005.02-REV C-16.01.29

START DATE: MARCH 30, 2015
PROJECT NUMBER: IND15116
SCALE: NONE
SHEET NUMBER: 005.02

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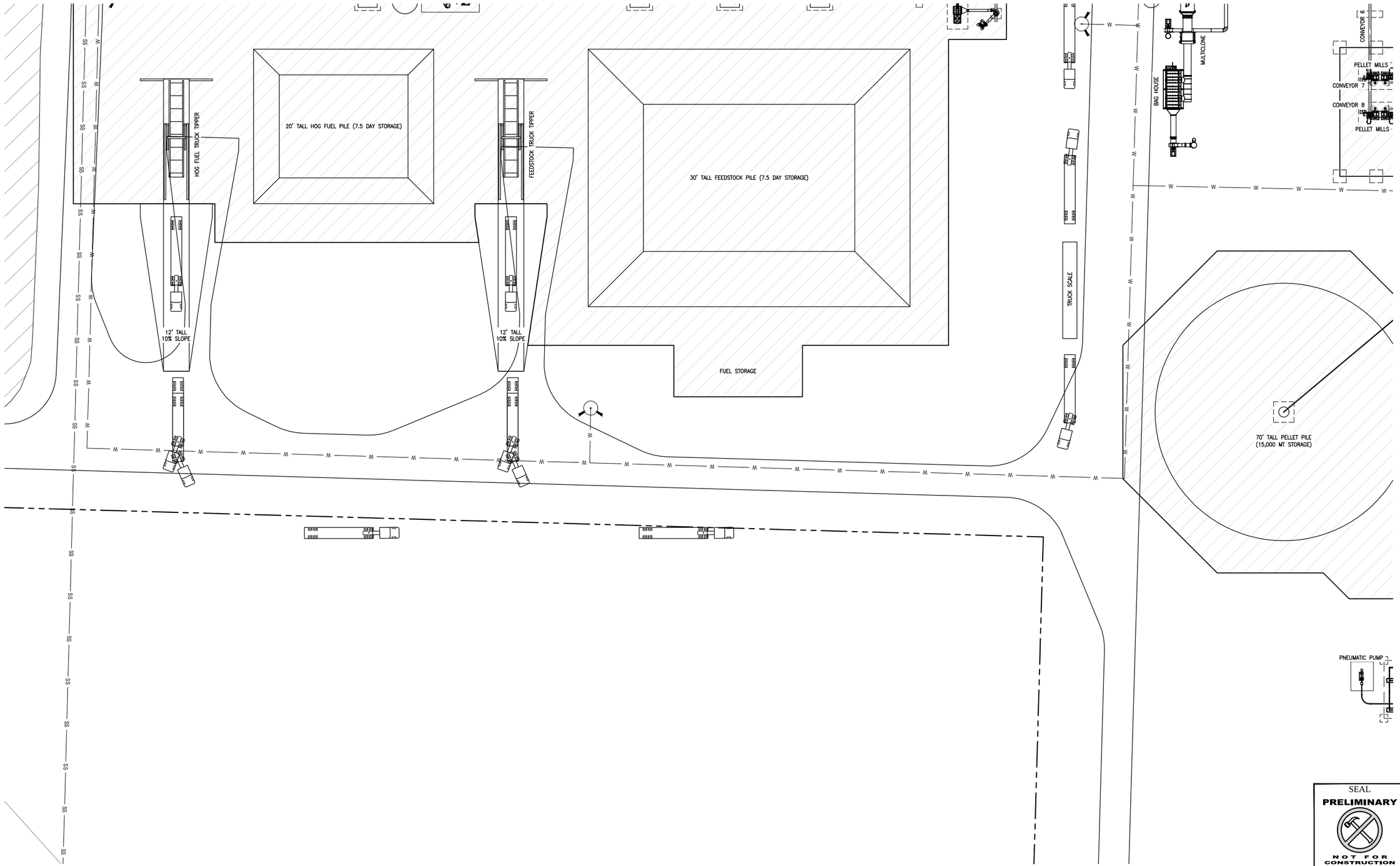

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DOME TECHNOLOGY
4946 North 2900 East, Idaho Falls, ID 83401
tel: (208) 529-0833 fax: (208) 529-0854

ENGINEERING SYSTEM SOLUTIONS
4943 NORTH 29TH EAST, STE A
IDAHO FALLS, IDAHO 83401
Phone: (208) 552-9874
Fax: (208) 552-9302

PROJECT:
CENTENNIAL RENEWABLE ENERGY
FOR
DOME TECHNOLOGY

LOCATION:
POTLATCH, ID

REV.	REVISION NOTE	DATE YY.MM.DD	DT ✓
A	ISSUED WITH FEED STUDY	15.12.24	--
B	REVISED LAYOUT PER CONF. CALL	16.01.13	--
C	ISSUED WITH FEED STUDY	16.01.29	--

REVISION DESCRIPTION | REV. | C

DESIGNED	DRAWN	CHECKED	APPROVED
AA	AA	?	?

SHEET TITLE:
SITE LAYOUT (2)

REF NUMBER: 1507 -005.03-REV C-16.01.29

START DATE: MARCH 30, 2015
PROJECT NUMBER: IND15116
SCALE: NONE
SHEET NUMBER: 005.03

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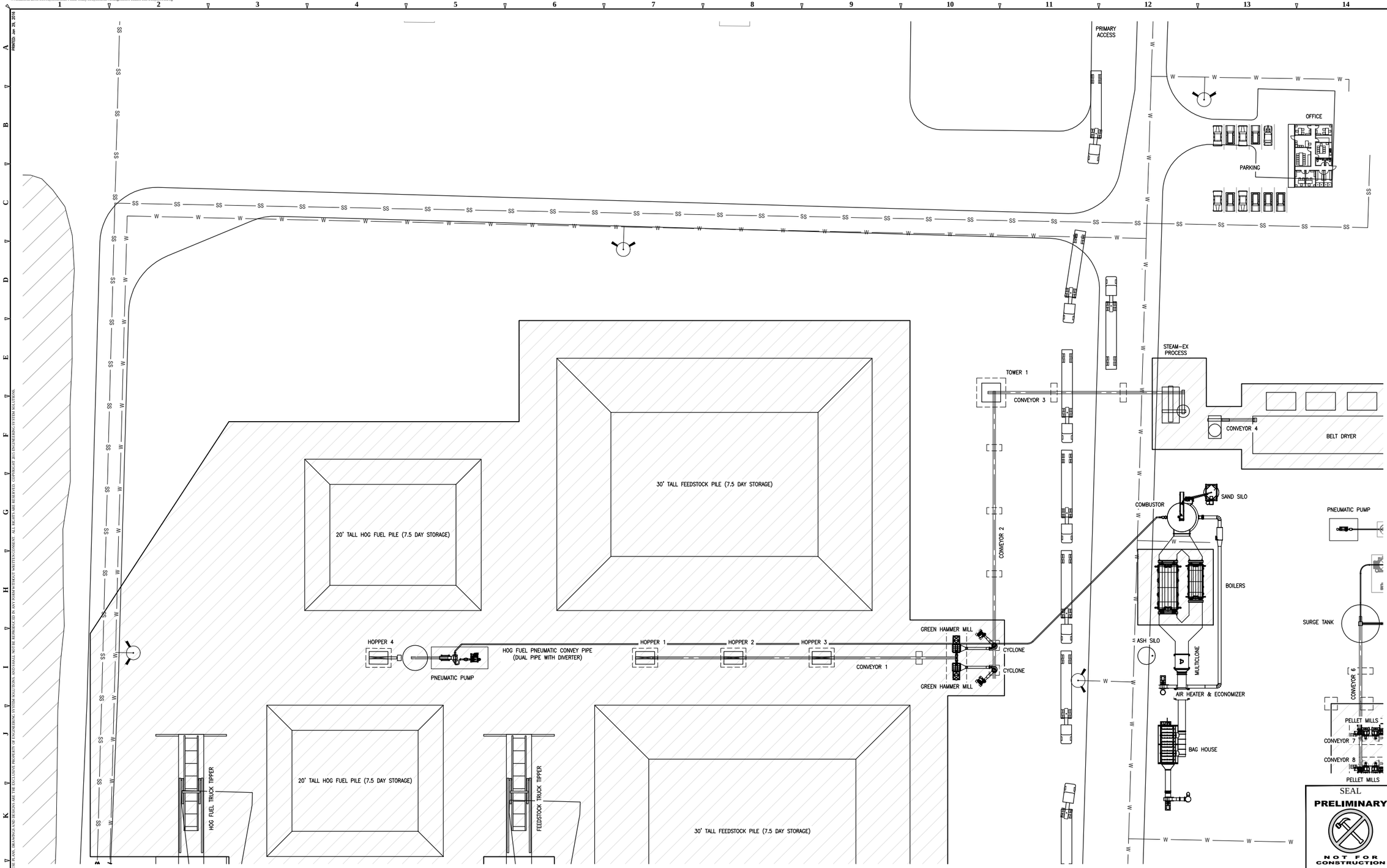
PRINTED: Jan 29, 2016



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SEAL

PRELIMINARY

NOT FOR CONSTRUCTION

Jan 29, 2016

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PROJECT:
CENTENNIAL RENEWABLE ENERGY
FOR
DOME TECHNOLOGY

LOCATION:
POTLATCH, ID

REV.	REVISION NOTE	DATE YY.MM.DD	DT ✓
A	ISSUED WITH FEED STUDY	15.12.24	--
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C	ISSUED WITH FEED STUDY	16.01.29	--

REVISION DESCRIPTION

REV.	C

DESIGNED	DRAWN	CHECKED	APPROVED
AA	AA	?	?

SHEET TITLE:
SITE LAYOUT (3)

REF NUMBER: 1507 -005.04-REV C-16.01.29

START DATE: MARCH 30, 2015
PROJECT NUMBER: IND15116
SCALE: NONE
SHEET NUMBER: 005.04

APPENDIX B: FLUIDIZED BED COMBUSTOR INFORMATION

PRECISION ENERGY SERVICES INC.

THEORY OF FLUIDIZED BED COMBUSTION

INTRODUCTION

The AFBB (Atmospheric Fluid Bed Burner) utilizes a heated bed of sand suspended (fluidized) within a rising column of air to burn many types and classes of fuel. This technique results in a vast improvement in combustion efficiency of high moisture content fuels, and is adaptable to a variety of "waste" type fuels this type of fuel ranges from wood product waste (hog fuel) to refuse derived fuel. The combustion products from the burner, in the form of a hot gas, can be adapted for use in various plant processes.

A basic understanding of the factors involved in the combustion of various fuels in a fluidized bed incinerator and how they interact with each other is essential for the successful operation of the AFBB system. This section summarizes theories of basic combustion and overall system operation.

COMBUSTION OF A FUEL PARTICLE

Fuels which are burned in a fluidized bed normally contain water, part of it "bound" in the structure of the fuel particle, and the remainder of it "free" or clinging to the outer surface of the particle.

Before any fuel particle can be ignited and burned, all the free water must be evaporated from the surface, and most of the "bound" water must be driven off. While this is happening, the particle stays relatively cool, approximately 200°F. The rate at which the particle dries is largely dependent upon the particle size and the temperature of the gas surrounding it.

After the water has been driven off as steam, the temperature of the particle rises rapidly and the combustible volatile components are boiled out as a gas. These volatiles represent a major portion of the heating value of fuel. They may burn either in the fluidized bed or in the vapor space above the bed, depending upon where they were generated and the availability of air required to complete the combustion reaction.

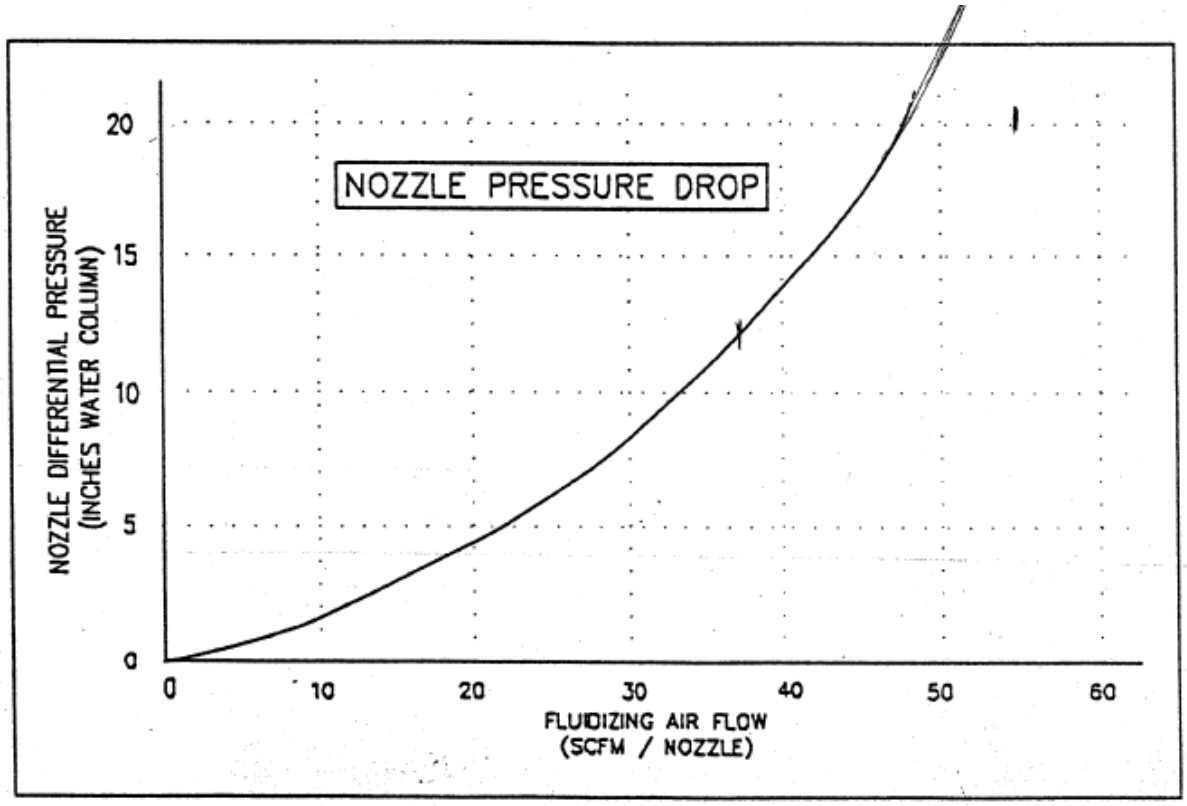
After both the water and volatiles have boiled off the fuel particle, the remaining material is charcoal. The larger particles of charcoal burn more slowly than the volatile material and ordinarily, due to their mass, burn in the fluid bed. The smaller particles may burn either in the bed or in the vapor space, depending upon their mass, and upward velocity of the combustion products in the combustion cell.

THE FLUIDIZATION PROCESS

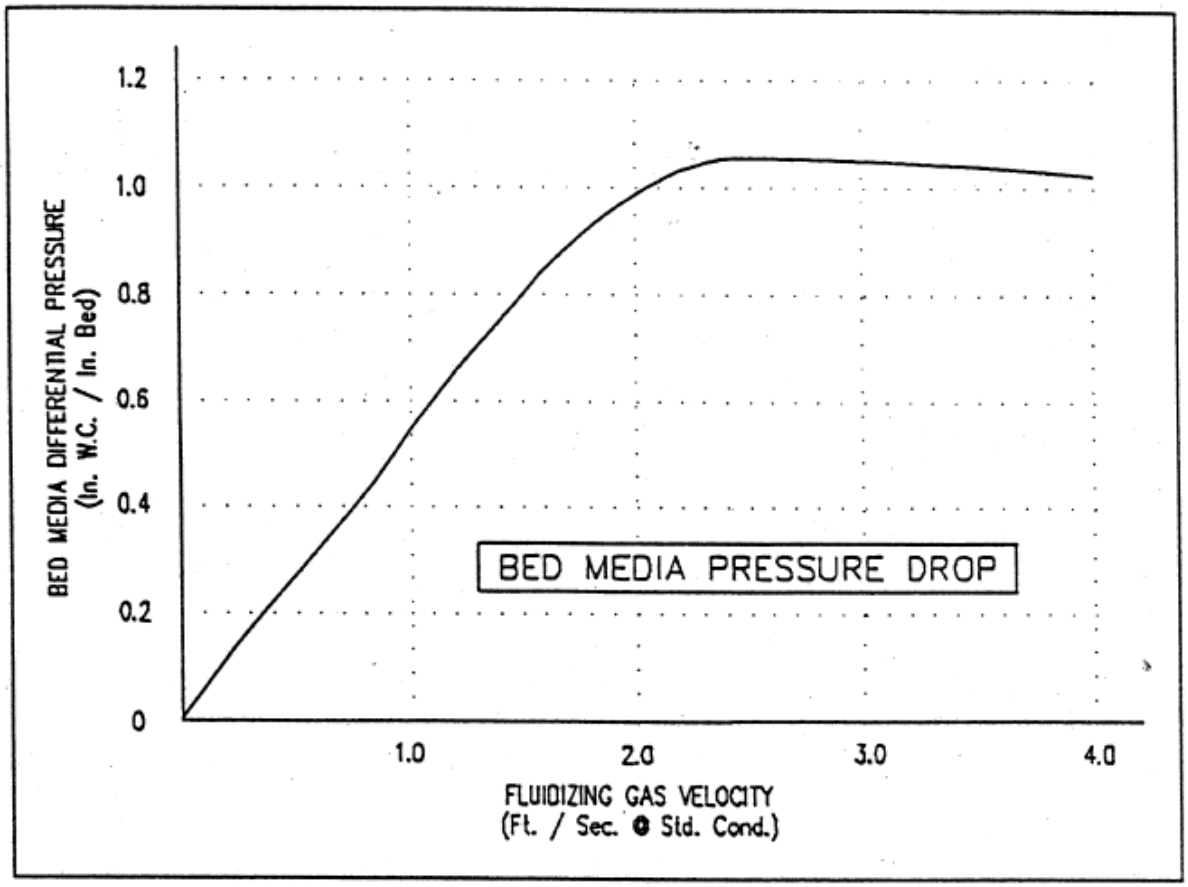
In order for a fluid bed to operate properly, the gas passing upward through the bed material must be at some minimum velocity. The required velocity is dependent upon the size, shape and density of the bed material.

The bed material depth, in expanded, or fluidized, condition, increases to about 1 1/2 times its static depth. As the fuel is distributed over the surface of the expanded bed, the heavier particles sink below the surface, becoming mixed with hot bed material and ignited, thereby giving up energy to maintain the bed temperature. Scrubbing action of the bed material on the fuel particle enhances the combustion process by stripping away the carbon dioxide and char layer which normally forms around the fuel particle. This allows the oxygen to reach the combustible material much more readily, thus increasing the rate and efficiency of the combustion process. The lighter fuel particles may burn on the surface of the bed or may be carried upward by the raising gases in the vessel to be consumed in the vapor space.

Lower gas velocities are required for a bed of small, light particles than would be required for a bed of large, heavy particles. For any given bed material, theoretical minimum gas velocity for fluidization can be determined. Gas velocities which greatly exceed the minimum value required for fluidization do not necessarily improve operation. In fact, excess gas velocities may cause localized spouting, excessive bed material carryover, and a residence time which is too short for proper combustion to take place. All these conditions reduce the effectiveness of the fluidized bed as an aid to combustion.

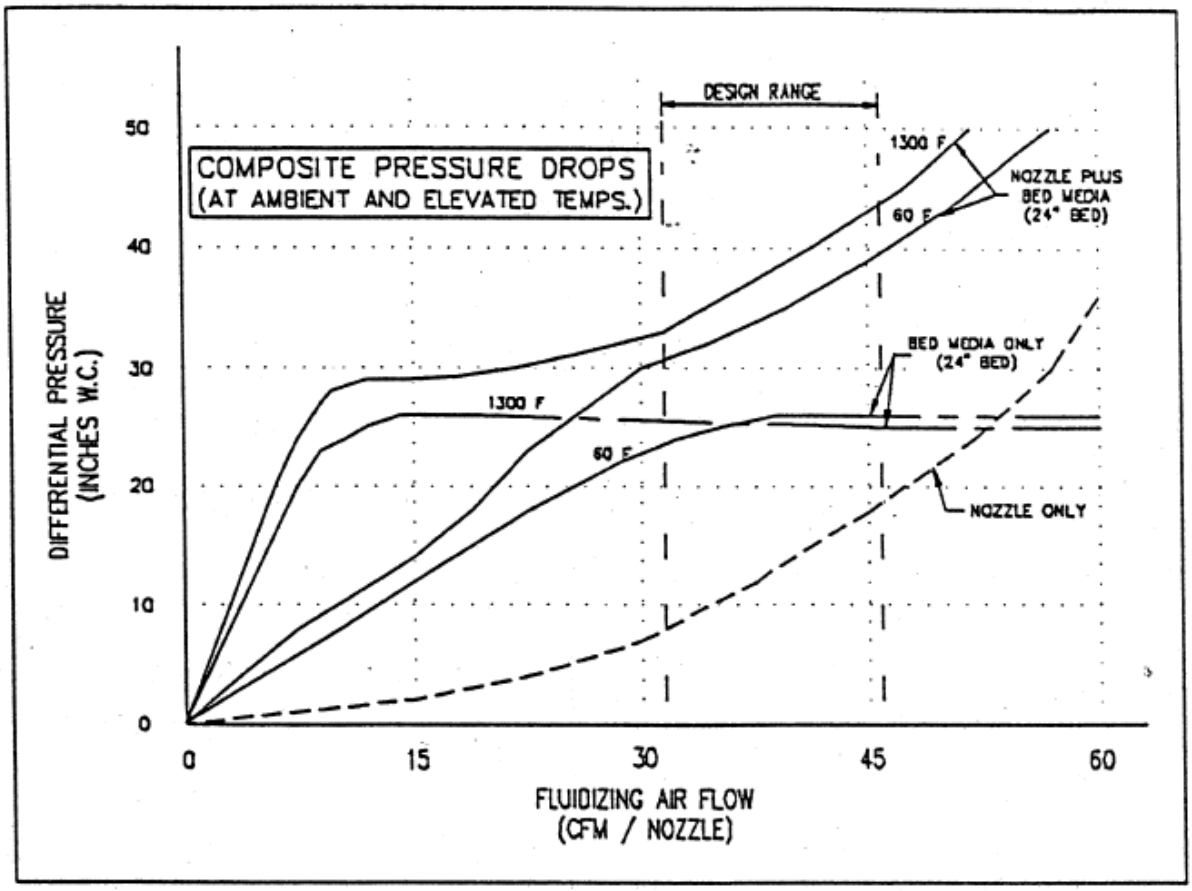


This graph depicts the air flow versus the nozzle differential pressure in a typical fluidized bed system. A nozzle pressure drop of about 8-12" WC is required to ensure an even distribution of air flow across the total bed area, based on a bed depth of 18 to 24 inches above the nozzles.



This graph depicts the typical relationship between fluidizing velocity and air pressure drop across the bed material. The straight section of the curve shows that the pressure drop across the bed material increases almost linearly with air flow, up to about one inch WC per inch of bed depth. In this region, the air velocity is insufficient to overcome the weight of the bed material and the bed material remains in a static (motionless) state. The air is simply percolating up through minute voids which exist between the particles of bed material. At a velocity of about 2.25 feet per second, the pressure drop no longer increases linearly with flow. The particles are now being lifted by the upwardly moving air, resulting in the voids between the particles increasing in size to accommodate the additional air flow. At this point, each particle of the bed material is suspended in the air stream and is free to circulate much like water. This is the condition referred to by the term fluidization.

An important point to note is that the knee of the curve represents a definite air flow in pounds per unit time this minimum air flow value also corresponds to a definite fuel feedrate needed to produce a given amount of energy at a given temperature. This minimum amount of energy represents the maximum turndown obtainable from a fluidized bed. An air flow which is less than the minimum fluidizing velocity will not provide adequate mixing of fuel with bed material. The bed material will then become static, with ambient air percolating up through it which rapidly cools the bed material below combustion sustaining temperatures.



This graph depicts the effects of different conditions on the fluidization process. The NOZZLE ONLY curve shows the pressure drop across the nozzles (in inches WC) versus the fluidizing air flow (in CFM per nozzle). The BED MEDIA ONLY curves show the pressure drop measured across 24 inches of bed material (above the top of the nozzles) at two different air temperatures, 60°F and 1300°F, respectively. The difference in these two curves illustrates the effect of bed temperatures on minimum fluidizing air flow. Fluidization occurs at a much lower air flow at the higher temperature.

The NOZZLE PLUS BED MEDIA curves are generated by summing each point on the NOZZLE ONLY curve with each point on the BED MEDIA curves. Thus, the curves show the relationship of total bed differential pressure (measured from the inlet vessel plenum upstream of the nozzles to the upper combustion cell above the active bed). Note the difference in minimum air flow (the knee of the curves) required to achieve fluidization at the two different temperatures.

It is important to remember that the total volume of air that is being blown by the forced draft (FD) fan is only one of the many factors involved in establishing optimum air velocity required for fluidization of the bed material. During normal operation when the bed material is at hg temperature, heat is transferred to the air as it passes up through the bed material. As

the air is heated, it expands, thus increasing in volume. This increase in volume results in a higher air velocity, as much as three to four times that occurring in a cold bed, particularly in the upper regions of the bed material. It is therefore possible to maintain optimum bed material fluidization with less air from the blower when the bed is hot than when it is cool.

The outside ambient air temperature will affect the density of air pumped by the main blower at a given damper position. Since density of the air is greater at lower temperatures, the proper fluidizing air damper setting for a 90°F summer day will generally provide excessive air flows on a 20°F winter day.

Under normal operating conditions, the actual air flow through the bed may be less than the theoretical air necessary to burn the fuel. Therefore, additional air is supplied to the combustion space above the bed to ensure that complete combustion occurs.

A portion of the additional overfire air required enters with the fuel from the fuel chute at a relatively constant rate. The remainder must be injected through the overfire air system.

RATIO OF AIR TO FUEL

Many types of biomass fuels have nearly the same fuel composition, therefore, require about the same amount of air for complete combustion. The combustion air is normally a mixture of oxygen (21 percent by volume), and nitrogen (79 percent by volume), with trace amounts of other gases.

When fuel burns, the oxygen is consumed, leaving a flue gas comprised of nitrogen, a small amount of oxygen and the combustion products, carbon dioxide and water. If exactly the right amount of air is used, there will be no oxygen left in the flue gas. This amount of air is referred to as **theoretical air**. Any extra air available over the theoretical air required for combustion is called excess air. In actual practice, no combustion processes are carried out using theoretical air, regardless of the fuel being burned (coal, oil, gas, RDF, wood, agri-waste, etc.) Some excess air is always used to ensure that the fuel is burned as completely as possible.

EFFECT OF WATER ON AIR/FUEL RATIO

The water content of the fuel being burned has a large effect on the amount of air needed to burn it. The amount of air required is directly proportional to the ratio of the bone-dry fuel content to the wet weight of fuel. For example, 50 percent water fuel requires only half as much air per pound of fuel as does bone-dry fuel since there is only half as much -dry fuel per pound after it is dried.

Under carefully controlled conditions in a small fluid bed system, it is possible to burn fuels containing more than 65 percent water (wet basis). However, in production units, it becomes increasingly difficult to maintain good combustion conditions as the water content of the fuel increases over 55 percent. The allowable water percentage also depends on the fuel particle

size. Since small particles have less residence time in the bed, combustion of these particles is less successful when the moisture content is high.

As water content of the fuel increases several changes in the combustion process take place:

1. The additional water must be boiled off before the dry combustible material can ignite and burn.
2. Less dry combustible material is available per pound of fuel to provide the heat necessary to boil off the water.
3. The total amount of air required for combustion of the fuel (on a pound per-pound basis) decreases.

The combination of these factors normally results in a decrease in operating bed temperature in relation to fuel moisture content. Vapor temperatures will also decrease during this period, but not as rapidly as the bed temperature.

The amount of air required to burn fuel is strongly dependent upon the water content on a pound-per-pound basis. As the water content increases, more pounds of wet fuel must be burned to produce the energy required by the plant process. The end result, at a constant energy requirement, will be a relatively large increase in the fuel feedrate as the water content increases, with a smaller increase in total air flow requirements, based more on the change in the equivalent bone-dry fuel feedrate.

FLUIDIZED COMBUSTION SYSTEM

Combustion of the material occurs in the fluidized bed and vapor space of the combustor vessel. Air to support combustion is supplied to the burner by the forced draft (FD) fan (through the fluidized bed) and by the overfire air system (through the overfire air nozzles).

The bed change out system removes the bed material, screens it to remove any oversize particles, and re-injects the acceptable bed material back into the combustor bed. The bed material may also be diverted from the discharge of the bucket elevator into a storage bin so that maintenance activities can be performed on the empty combustor bed. A natural gas burner is used during startup to preheat the bed material to - a temperature which will sustain combustion of the fuel.

APPENDIX C: IDEQ EMISSIONS UNIT FORMS

DEQ AIR QUALITY PROGRAM
1410 N. Hilton, Boise, ID 83706
For assistance, call the
Air Permit Hotline – 1-877-5PERMIT

General Information - **Form GI**
4/7/16

Please see instructions on second page before filling out the form.

FACILITY AND PERMIT INFORMATION

1. Facility Name:	2. Facility ID Number:
Centennial Renewable Energy	
3. Brief Project Description:	CRE is proposing to construct and operate a Greenfield wood pellet production facility near Potlach, Idaho. The facility will produce a proprietary product known as SteamEx Pellets with technology from the Andritz Corporation. The final product will utilize short fiber wood waste from regional mills as feedstock.
4. Facility Contact Name:	5. Facility Contact Title:
Rick Fawcett	Owner
6. Facility Contact Telephone Number:	7. Facility Contact Email:
208-241-1664	rick.fawcett@centennial-res.com
8. Mailing address where permit will be sent (street/city/state/zip code):	9. Physical address of facility (if different than mailing address) (street/city/state/zip code):
P.O. Box 2334 Pocatello, ID 83206	Highway 6, Potlach, Latah County, ID 83855 (506,829 m E; 5,196,968 m N, Zone 11)
10. County Facility is located	Latah
11. Is the equipment portable?	☒ No ☐ Yes
12. NAICS codes	Primary NAICS: 321999 / Secondary NAICS (if applicable):
13. Brief business description and principal product produced:	CRE is proposing to construct and operate a Greenfield wood pellet production facility near Potlach, Idaho. The facility will produce a proprietary product known as SteamEx Pellets with technology from the Andritz Corporation.
14. Describe any contiguous or adjacent facility this company owns or operates:	N/A
15. Permit Application Type. Provide Permit Number for existing permit. For a PTC, an application fee is required.	☒ Initial Permit to Construct (PTC) ☐ PTC Modification — PTC No. _____ Issued Date _____
	☐ Initial Tier II ☐ Tier II Modification ☐ Tier II Renewal — Tier II No. _____ Issued Date _____
	☐ Initial Tier I ☐ Tier I Administrative Amendment ☐ Tier I Minor Modification ☐ Tier I Significant Modification ☐ Tier I Renewal — Tier I No. _____ Issued Date _____
16. **For Tier I permitted facilities only:** If you are applying for a PTC then you must specify how the PTC will be incorporated into the Tier I permit.	☐ Incorporate PTC at the time of Tier I renewal (IDAPA 58.01.01.209.05.a) ☐ Co-process PTC with Tier I Modification (IDAPA 58.01.01.209.05.b) ☐ Administrative amend the Tier I to incorporate PTC upon applicant's request (IDAPA 58.01.01.209.05.c)
17. ☒ Check here to request facility draft permit before final issuance.	

Certification of Truth, Accuracy, and Completeness (by Responsible Official)
I hereby certify that based on information and belief formed after reasonable inquiry, the statements and information contained in this and any attached and/or referenced document(s) are true, accurate, and complete in accordance with IDAPA 58.01.01.123 124.

	Owner	
Responsible Official Signature	*Responsible Official Title*	*Date*

DEQ AIR QUALITY PROGRAM
1410 N. Hilton, Boise, ID 83706
For assistance, call the
Air Permit Hotline: 1-877-5PERMIT

Cyclone Separator - **Form CYS**
Revision 2
08/28/08

Please see instructions on page 3 before filling out the form.

IDENTIFICATION

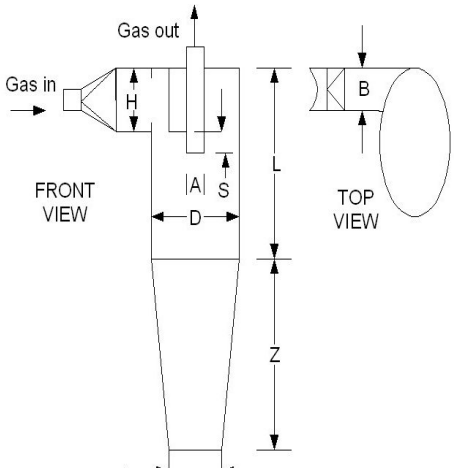
1. Company Name:	Centennial Renewable Energy	2. Facility Name:	Potlach Facility	3. Facility ID No.:	
4. Brief Project Description:	CRE is proposing to construct and operate a Greenfield wood pellet production facility near Potlach, Idaho. The facility will produce a proprietary product known as SteamEx Pellets with technology from the Andritz Corporation. The final product will utilize short fiber wood waste from regional mills as feedstock.				

CYCLONE SEPARATOR INFORMATION

Equipment Description

5. Manufacturer:	Kice	6. Model Number:	CK84

7. Dimensions



Give dimensions of cyclone. (See sample diagram above.)

1. B: 14 in.
2. H: 39 in.
3. S: in.
4. L: 48 in.
5. Z: 144 in.
6. D: 84 in.
7. A: 39 in.
8. J: in.

8. Particulate Size Distribution Data

Micron range	Particle size distribution weight %	Manufacturer's guaranteed removal efficiency for each micron range
0.5-1.0		
1.0-5.0		
5-10		
10-20		
Over 20		

9. Type of Cyclone	☐ Wet	☒ Dry
10. Type of Cyclone Unit	☒ Single ☐ Dual	☐ Quadruple ☐ Multiclone
11. Blower	Blower horsepower: hp Design flow rate: scfm Draft: ☐ Forced ☐ Induced	

12. Design Criteria	Cyclone configuration: ☐ Positive pressure	☐ Negative pressure	
13. Pre-Treatment Device	☒ Cyclone ☐ Precooler ☐ Preheater	☐ Knock-out chamber ☐ None	14. Post-Treatment Device: ☒ Baghouse/Cartridge ☐ HEPA ☐ Other:

Process Stream Characteristics	
15. Brief Description of Process	.
16. Flow Data	Gas stream temperature: 80 degrees F Moisture content: grams of water/cubic feet (ft^3) of dry air <u>Pressure drop range</u> High: 4 in. H_2O Low: 5 in. H_2O Dew point temperature of process stream: degrees F Inlet flow rate: 11300 ACFM
17. Dust Collection Device	☐ Pneumatic conveyor ☒ Rotary airlock values ☐ Screw conveyors ☐ Closed container ☐ Double dump ☐ Drag conveyor ☐ Manual discharge device: ☐ Slide gate OR ☐ Hinged doors or drawers
18. Operating Schedule	Normal: 24 hours/day 7 days/week 52 weeks/year Maximum: 24 hours/day 7 days/week 52 weeks/year

DEQ AIR QUALITY PROGRAM
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For assistance, call the
Air Permit Hotline: 1-877-5PERMIT

Cyclone Separator - **Form CYS**
Revision 2
08/28/08

Please see instructions on page 3 before filling out the form.

IDENTIFICATION

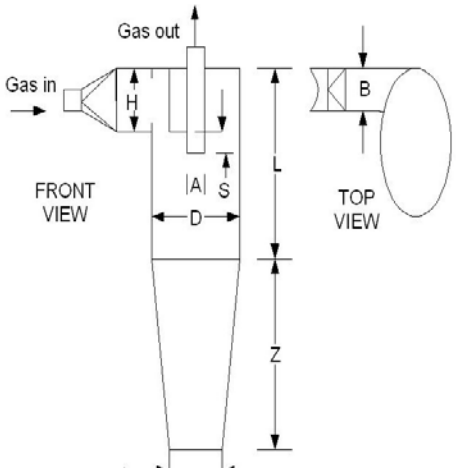
1. Company Name:	Centennial Renewable Energy	2. Facility Name:	Potlach Facility	3. Facility ID No.:	
4. Brief Project Description:	CRE is proposing to construct and operate a Greenfield wood pellet production facility near Potlach, Idaho. The facility will produce a proprietary product known as SteamEx Pellets with technology from the Andritz Corporation. The final product will utilize short fiber wood waste from regional mills as feedstock.				

CYCLONE SEPARATOR INFORMATION

Equipment Description

5. Manufacturer:	Kice	6. Model Number:	CH42

7. Dimensions



Give dimensions of cyclone. (See sample diagram above.)

1. B: 15 in. 5. Z: 72 in.
2. H: 26 in. 6. D: 42 in.
3. S: in. 7. A: 26 in.
4. L: 96 in. 8. J: in.

8. Particulate Size Distribution Data

Micron range	Particle size distribution weight %	Manufacturer's guaranteed removal efficiency for each micron range
0.5-1.0		
1.0-5.0		
5-10		
10-20		
Over 20		

9. Type of Cyclone	☐ Wet	☐ Dry
10. Type of Cyclone Unit	☐ Single ☐ Dual	☐ Quadruple ☐ Multiclone
11. Blower	Blower horsepower: 125 hp Design flow rate: 10100 scfm Draft: ☒ Forced ☐ Induced	

12. Design Criteria	Cyclone configuration: ☐ Positive pressure	☐ Negative pressure	
13. Pre-Treatment Device	☒ Cyclone ☐ Precooler ☐ Preheater	☐ Knock-out chamber ☐ None	14. Post-Treatment Device: ☐ Baghouse/Cartridge ☐ HEPA ☒ Other:

Process Stream Characteristics	
15. Brief Description of Process	.
16. Flow Data	Gas stream temperature: 100 degrees F Moisture content: grams of water/cubic feet (ft^3) of dry air <u>Pressure drop range</u> High: 8 in. H_2O Low: 9 in. H_2O Dew point temperature of process stream: degrees F Inlet flow rate: 10100 ACFM
17. Dust Collection Device	☐ Pneumatic conveyor ☒ Rotary airlock values ☐ Screw conveyors ☐ Closed container ☐ Double dump ☐ Drag conveyor ☐ Manual discharge device: ☐ Slide gate OR ☐ Hinged doors or drawers
18. Operating Schedule	Normal: 24 hours/day 7 days/week 52 weeks/year Maximum: 24 hours/day 7 days/week 52 weeks/year

DEQ AIR QUALITY PROGRAM
1410 N. Hilton, Boise, ID 83706
For assistance, call the
Air Permit Hotline: 1-877-5PERMIT

Cyclone Separator - **Form CYS**
Revision 2
08/28/08

Please see instructions on page 3 before filling out the form.

IDENTIFICATION

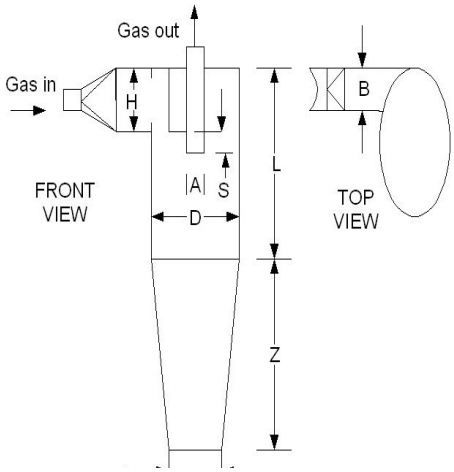
1. Company Name:	Centennial Renewable Energy	2. Facility Name:	Potlach Facility	3. Facility ID No.:	
4. Brief Project Description:	CRE is proposing to construct and operate a Greenfield wood pellet production facility near Potlach, Idaho. The facility will produce a proprietary product known as SteamEx Pellets with technology from the Andritz Corporation. The final product will utilize short fiber wood waste from regional mills as feedstock.				

CYCLONE SEPARATOR INFORMATION

Equipment Description

5. Manufacturer:	TBD	6. Model Number:	Multi-Clone Cyclone

7. Dimensions



Give dimensions of cyclone. (See sample diagram above.)

1. B:	in.	5. Z:	in.
2. H:	in.	6. D:	in.
3. S:	in.	7. A:	in.
4. L:	in.	8. J:	in.

8. Particulate Size Distribution Data

Micron range	Particle size distribution weight %	Manufacturer's guaranteed removal efficiency for each micron range
0.5-1.0		
1.0-5.0		
5-10		
10-20		
Over 20		

9. Type of Cyclone	☐ Wet	☐ Dry
10. Type of Cyclone Unit	☐ Single ☐ Dual	☐ Quadruple ☐ Multiclone
11. Blower	Blower horsepower: hp Design flow rate: scfm Draft: ☐ Forced ☐ Induced	

12. Design Criteria	Cyclone configuration: ☐ Positive pressure	☐ Negative pressure	
13. Pre-Treatment Device	☐ Cyclone ☐ Precooler ☐ Preheater	☐ Knock-out chamber ☐ None	
14. Post-Treatment Device	☐ Baghouse/Cartridge ☐ HEPA ☐ Other:		

Process Stream Characteristics	
15. Brief Description of Process	.
16. Flow Data	Gas stream temperature: degrees F Moisture content: grams of water/cubic feet (ft^3) of dry air <u>Pressure drop range</u> High: in. H_2O Low: in. H_2O Dew point temperature of process stream: degrees F Inlet flow rate: ACFM
17. Dust Collection Device	☐ Pneumatic conveyor ☐ Rotary airlock values ☐ Screw conveyors ☐ Closed container ☐ Double dump ☐ Drag conveyor ☐ Manual discharge device: ☐ Slide gate OR ☐ Hinged doors or drawers
18. Operating Schedule	Normal: 24 hours/day 7 days/week 52 weeks/year Maximum: 24 hours/day 7 days/week 52 weeks/year

DEQ AIR QUALITY PROGRAM
1410 N. Hilton, Boise, ID 83706
For assistance, call the
Air Permit Hotline – 1-877-5PERMIT

Emissions Unit - General **Form EU0**
Revision 4
08/28/08

Please see instructions on page 2 before filling out the form.

IDENTIFICATION

1. Company Name:	2. Facility Name:	3. Facility ID No:
Centennial Renewable Energy	Potlach Facility	

4. Brief Project Description:	CRE is proposing to construct and operate a Greenfield wood pellet production facility near Potlach, Idaho. The facility will produce a proprietary product known as SteamEx Pellets with technology from

EMISSIONS UNIT (PROCESS) IDENTIFICATION & DESCRIPTION

5.	Emissions Unit (EU) Name:	BELT DRYER
6.	EU ID Number:	BELTDRY
7.	EU Type:	☒ New Source ☐ Unpermitted Existing Source ☐ Modification to a Permitted Source -- Previous Permit #: Date Issued:
8.	Manufacturer:	Andritz
9.	Model:	N/A
10..	Maximum Capacity:	33 TON/HR
11.	Date of Construction:	TBD
12.	Date of Modification (if any):	N/A
13.	Is this a Controlled Emission Unit?	☒ No ☐ Yes If Yes, complete the following section. If No, go to line 22.

EMISSIONS CONTROL EQUIPMENT

14. Control Equipment Name and ID:	
15. Date of Installation:	16. Date of Modification (if any):
17. Manufacturer and Model Number:	
18. ID(s) of Emission Unit Controlled:	
19. Is operating schedule different than emission units(s) involved?	☐ Yes ☐ No
20. Does the manufacturer guarantee the control efficiency of the control equipment?	☐ Yes ☐ No (If Yes, attach and label manufacturer guarantee)

	Pollutant Controlled					
	PM	PM10	SO_2	NOx	VOC	CO
Control Efficiency						

21. If manufacturer's data is not available, attach a separate sheet of paper to provide the control equipment design specifications and performance data to support the above mentioned control efficiency.

EMISSION UNIT OPERATING SCHEDULE (hours/day, hours/year, or other)

22.	Actual Operation:	TBD
23.	Maximum Operation:	8760 HRS/YEAR

REQUESTED LIMITS

24.	Are you requesting any permit limits?	☐ Yes ☒ No (If Yes, indicate all that apply below)
	☐ Operation Hour Limit(s):	
	☐ Production Limit(s):	
	☐ Material Usage Limit(s):	
	☐ Limits Based on Stack Testing:	Please attach all relevant stack testing summary reports
	☐ Other:	
25.	Rationale for Requesting the Limit(s):	

DEQ AIR QUALITY PROGRAM
1410 N. Hilton, Boise, ID 83706
For assistance, call the
Air Permit Hotline – 1-877-5PERMIT

Emissions Unit - General **Form EU0**
Revision 4
08/28/08

Please see instructions on page 2 before filling out the form.

IDENTIFICATION

1. Company Name:	2. Facility Name:	3. Facility ID No:
Centennial Renewable Energy	Potlach Facility	

4. Brief Project Description:	CRE is proposing to construct and operate a Greenfield wood pellet production facility near Potlach, Idaho. The facility will produce a proprietary product known as SteamEx Pellets with technology from

EMISSIONS UNIT (PROCESS) IDENTIFICATION & DESCRIPTION

5.	Emissions Unit (EU) Name:	TRUCK UNLOADING TO FEEDSTOCK TIPPER #1
6.	EU ID Number:	FS1
7.	EU Type:	☒ New Source ☐ Unpermitted Existing Source ☐ Modification to a Permitted Source -- Previous Permit #: Date Issued:
8.	Manufacturer:	N/A
9.	Model:	N/A
10..	Maximum Capacity:	94 TON/HR, 220,500 TON/YEAR
11.	Date of Construction:	TBD
12.	Date of Modification (if any):	N/A
13.	Is this a Controlled Emission Unit?	☐ No ☒ Yes If Yes, complete the following section. If No, go to line 22.

EMISSIONS CONTROL EQUIPMENT

14. Control Equipment Name and ID:	Material Moisture Content		
15. Date of Installation:	N/A	16. Date of Modification (if any):	N/A
17. Manufacturer and Model Number:	N/A		
18. ID(s) of Emission Unit Controlled:	FS1		
19. Is operating schedule different than emission units(s) involved?	☐ Yes ☒ No		
20. Does the manufacturer guarantee the control efficiency of the control equipment?	☐ Yes ☒ No (If Yes, attach and label manufacturer guarantee)		

	Pollutant Controlled					
	PM	PM10	SO_2	NOx	VOC	CO
Control Efficiency	34%	34%				

21. If manufacturer's data is not available, attach a separate sheet of paper to provide the control equipment design specifications and performance data to support the above mentioned control efficiency.

EMISSION UNIT OPERATING SCHEDULE (hours/day, hours/year, or other)

22.	Actual Operation:	TBD
23.	Maximum Operation:	8760 HRS/YEAR

REQUESTED LIMITS

24.	Are you requesting any permit limits?	☐ Yes ☒ No (If Yes, indicate all that apply below)
	☐ Operation Hour Limit(s):	
	☐ Production Limit(s):	
	☐ Material Usage Limit(s):	
	☐ Limits Based on Stack Testing:	Please attach all relevant stack testing summary reports
	☐ Other:	
25.	Rationale for Requesting the Limit(s):	

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IDENTIFICATION

1. Company Name:	2. Facility Name:	3. Facility ID No:
Centennial Renewable Energy	Potlach Facility	

4. Brief Project Description:	CRE is proposing to construct and operate a Greenfield wood pellet production facility near Potlach, Idaho. The facility will produce a proprietary product known as SteamEx Pellets with technology from

EMISSIONS UNIT (PROCESS) IDENTIFICATION & DESCRIPTION

5.	Emissions Unit (EU) Name:	FEEDSTOCK PILE TO HOPPER #1, 2 OR 3 VIA LOADER
6.	EU ID Number:	FS2
7.	EU Type:	☒ New Source ☐ Unpermitted Existing Source ☐ Modification to a Permitted Source -- Previous Permit #: Date Issued:
8.	Manufacturer:	N/A
9.	Model:	N/A
10..	Maximum Capacity:	33 TON/HR, 220,500 TON/YEAR
11.	Date of Construction:	TBD
12.	Date of Modification (if any):	N/A
13.	Is this a Controlled Emission Unit?	☐ No ☒ Yes If Yes, complete the following section. If No, go to line 22.

EMISSIONS CONTROL EQUIPMENT

14. Control Equipment Name and ID:	Material Moisture Content		
15. Date of Installation:	N/A	16. Date of Modification (if any):	N/A
17. Manufacturer and Model Number:	N/A		
18. ID(s) of Emission Unit Controlled:	FS2		
19. Is operating schedule different than emission units(s) involved?	☐ Yes ☒ No		
20. Does the manufacturer guarantee the control efficiency of the control equipment?	☐ Yes ☒ No (If Yes, attach and label manufacturer guarantee)		

	Pollutant Controlled					
	PM	PM10	SO_2	NOx	VOC	CO
Control Efficiency	34%	34%				

21. If manufacturer's data is not available, attach a separate sheet of paper to provide the control equipment design specifications and performance data to support the above mentioned control efficiency.

EMISSION UNIT OPERATING SCHEDULE (hours/day, hours/year, or other)

22.	Actual Operation:	TBD
23.	Maximum Operation:	8760 HRS/YEAR

REQUESTED LIMITS

24.	Are you requesting any permit limits?	☐ Yes ☒ No (If Yes, indicate all that apply below)
	☐ Operation Hour Limit(s):	
	☐ Production Limit(s):	
	☐ Material Usage Limit(s):	
	☐ Limits Based on Stack Testing:	Please attach all relevant stack testing summary reports
	☐ Other:	
25.	Rationale for Requesting the Limit(s):	

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IDENTIFICATION

1. Company Name:	2. Facility Name:	3. Facility ID No:
Centennial Renewable Energy	Potlach Facility	

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EMISSIONS UNIT (PROCESS) IDENTIFICATION & DESCRIPTION

5.	Emissions Unit (EU) Name:	HOPPER #1, 2 OR 3 TO CONVEYOR #1
6.	EU ID Number:	FS3
7.	EU Type:	☒ New Source ☐ Unpermitted Existing Source ☐ Modification to a Permitted Source -- Previous Permit #: Date Issued:
8.	Manufacturer:	N/A
9.	Model:	N/A
10..	Maximum Capacity:	33 TON/HR, 220,500 TON/YEAR
11.	Date of Construction:	TBD
12.	Date of Modification (if any):	N/A
13.	Is this a Controlled Emission Unit?	☐ No ☒ Yes If Yes, complete the following section. If No, go to line 22.

EMISSIONS CONTROL EQUIPMENT

14. Control Equipment Name and ID:	Material Moisture Content		
15. Date of Installation:	N/A	16. Date of Modification (if any):	N/A
17. Manufacturer and Model Number:	N/A		
18. ID(s) of Emission Unit Controlled:	FS3		
19. Is operating schedule different than emission units(s) involved?	☐ Yes ☒ No		
20. Does the manufacturer guarantee the control efficiency of the control equipment?	☐ Yes ☒ No (If Yes, attach and label manufacturer guarantee)		

	Pollutant Controlled					
	PM	PM10	SO_2	NOx	VOC	CO
Control Efficiency	34%	34%				

21. If manufacturer's data is not available, attach a separate sheet of paper to provide the control equipment design specifications and performance data to support the above mentioned control efficiency.

EMISSION UNIT OPERATING SCHEDULE (hours/day, hours/year, or other)

22.	Actual Operation:	TBD
23.	Maximum Operation:	8760 HRS/YEAR

REQUESTED LIMITS

24.	Are you requesting any permit limits?	☐ Yes ☒ No (If Yes, indicate all that apply below)
	☐ Operation Hour Limit(s):	
	☐ Production Limit(s):	
	☐ Material Usage Limit(s):	
	☐ Limits Based on Stack Testing:	Please attach all relevant stack testing summary reports
	☐ Other:	
25.	Rationale for Requesting the Limit(s):	

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4. Brief Project Description:	CRE is proposing to construct and operate a Greenfield wood pellet production facility near Potlach, Idaho. The facility will produce a proprietary product known as SteamEx Pellets with technology from

EMISSIONS UNIT (PROCESS) IDENTIFICATION & DESCRIPTION

5.	Emissions Unit (EU) Name:	CONVEYOR #1 TO FEED SCREW #1
6.	EU ID Number:	FS4
7.	EU Type:	☒ New Source ☐ Unpermitted Existing Source ☐ Modification to a Permitted Source -- Previous Permit #: Date Issued:
8.	Manufacturer:	N/A
9.	Model:	N/A
10..	Maximum Capacity:	16 TON/HR, 220,500 TON/YEAR
11.	Date of Construction:	TBD
12.	Date of Modification (if any):	N/A
13.	Is this a Controlled Emission Unit?	☐ No ☒ Yes If Yes, complete the following section. If No, go to line 22.

EMISSIONS CONTROL EQUIPMENT

14. Control Equipment Name and ID:	Material Moisture Content		
15. Date of Installation:	N/A	16. Date of Modification (if any):	N/A
17. Manufacturer and Model Number:	N/A		
18. ID(s) of Emission Unit Controlled:	FS4		
19. Is operating schedule different than emission units(s) involved?	☐ Yes ☒ No		
20. Does the manufacturer guarantee the control efficiency of the control equipment?	☐ Yes ☒ No (If Yes, attach and label manufacturer guarantee)		

	Pollutant Controlled					
	PM	PM10	SO_2	NOx	VOC	CO
Control Efficiency	34%	34%				

21. If manufacturer's data is not available, attach a separate sheet of paper to provide the control equipment design specifications and performance data to support the above mentioned control efficiency.

EMISSION UNIT OPERATING SCHEDULE (hours/day, hours/year, or other)

22.	Actual Operation:	TBD
23.	Maximum Operation:	8760 HRS/YEAR

REQUESTED LIMITS

24.	Are you requesting any permit limits?	☐ Yes ☒ No (If Yes, indicate all that apply below)
	☐ Operation Hour Limit(s):	
	☐ Production Limit(s):	
	☐ Material Usage Limit(s):	
	☐ Limits Based on Stack Testing:	Please attach all relevant stack testing summary reports
	☐ Other:	
25.	Rationale for Requesting the Limit(s):	

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EMISSIONS UNIT (PROCESS) IDENTIFICATION & DESCRIPTION

5.	Emissions Unit (EU) Name:	CONVEYOR #1 TO FEED SCREW #2
6.	EU ID Number:	FS5
7.	EU Type:	☒ New Source ☐ Unpermitted Existing Source ☐ Modification to a Permitted Source -- Previous Permit #: Date Issued:
8.	Manufacturer:	N/A
9.	Model:	N/A
10..	Maximum Capacity:	16 TON/HR, 220,500 TON/YEAR
11.	Date of Construction:	TBD
12.	Date of Modification (if any):	N/A
13.	Is this a Controlled Emission Unit?	☐ No ☒ Yes If Yes, complete the following section. If No, go to line 22.

EMISSIONS CONTROL EQUIPMENT

14. Control Equipment Name and ID:	Material Moisture Content		
15. Date of Installation:	N/A	16. Date of Modification (if any):	N/A
17. Manufacturer and Model Number:	N/A		
18. ID(s) of Emission Unit Controlled:	FS5		
19. Is operating schedule different than emission units(s) involved?	☐ Yes ☒ No		
20. Does the manufacturer guarantee the control efficiency of the control equipment?	☐ Yes ☒ No (If Yes, attach and label manufacturer guarantee)		

	Pollutant Controlled					
	PM	PM10	SO_2	NOx	VOC	CO
Control Efficiency	34%	34%				

21. If manufacturer's data is not available, attach a separate sheet of paper to provide the control equipment design specifications and performance data to support the above mentioned control efficiency.

EMISSION UNIT OPERATING SCHEDULE (hours/day, hours/year, or other)

22.	Actual Operation:	TBD
23.	Maximum Operation:	8760 HRS/YEAR

REQUESTED LIMITS

24.	Are you requesting any permit limits?	☐ Yes ☒ No (If Yes, indicate all that apply below)
	☐ Operation Hour Limit(s):	
	☐ Production Limit(s):	
	☐ Material Usage Limit(s):	
	☐ Limits Based on Stack Testing:	Please attach all relevant stack testing summary reports
	☐ Other:	
25.	Rationale for Requesting the Limit(s):	

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EMISSIONS UNIT (PROCESS) IDENTIFICATION & DESCRIPTION

5.	Emissions Unit (EU) Name:	GREEN HAMMER MILL #1 AND TRANSFERS
6.	EU ID Number:	FS6
7.	EU Type:	☒ New Source ☐ Unpermitted Existing Source ☐ Modification to a Permitted Source -- Previous Permit #: Date Issued:
8.	Manufacturer:	N/A
9.	Model:	N/A
10..	Maximum Capacity:	16 TON/HR, 220,500 TON/YEAR
11.	Date of Construction:	TBD
12.	Date of Modification (if any):	N/A
13.	Is this a Controlled Emission Unit?	☐ No ☒ Yes If Yes, complete the following section. If No, go to line 22.

EMISSIONS CONTROL EQUIPMENT

14. Control Equipment Name and ID:	Material Moisture Content		
15. Date of Installation:	N/A	16. Date of Modification (if any):	N/A
17. Manufacturer and Model Number:	N/A		
18. ID(s) of Emission Unit Controlled:	FS6		
19. Is operating schedule different than emission units(s) involved?	☐ Yes ☒ No		
20. Does the manufacturer guarantee the control efficiency of the control equipment?	☐ Yes ☒ No (If Yes, attach and label manufacturer guarantee)		

	Pollutant Controlled					
	PM	PM10	SO_2	NOx	VOC	CO
Control Efficiency	34%	34%				

21. If manufacturer's data is not available, attach a separate sheet of paper to provide the control equipment design specifications and performance data to support the above mentioned control efficiency.

EMISSION UNIT OPERATING SCHEDULE (hours/day, hours/year, or other)

22.	Actual Operation:	TBD
23.	Maximum Operation:	8760 HRS/YEAR

REQUESTED LIMITS

24.	Are you requesting any permit limits?	☐ Yes ☒ No (If Yes, indicate all that apply below)
	☐ Operation Hour Limit(s):	
	☐ Production Limit(s):	
	☐ Material Usage Limit(s):	
	☐ Limits Based on Stack Testing:	Please attach all relevant stack testing summary reports
	☐ Other:	
25.	Rationale for Requesting the Limit(s):	

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IDENTIFICATION

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4. Brief Project Description:	CRE is proposing to construct and operate a Greenfield wood pellet production facility near Potlach, Idaho. The facility will produce a proprietary product known as SteamEx Pellets with technology from

EMISSIONS UNIT (PROCESS) IDENTIFICATION & DESCRIPTION

5.	Emissions Unit (EU) Name:	GREEN HAMMER MILL #2 AND TRANSFERS
6.	EU ID Number:	FS7
7.	EU Type:	☒ New Source ☐ Unpermitted Existing Source ☐ Modification to a Permitted Source -- Previous Permit #: Date Issued:
8.	Manufacturer:	N/A
9.	Model:	N/A
10..	Maximum Capacity:	16 TON/HR, 220,500 TON/YEAR
11.	Date of Construction:	TBD
12.	Date of Modification (if any):	N/A
13.	Is this a Controlled Emission Unit?	☐ No ☒ Yes If Yes, complete the following section. If No, go to line 22.

EMISSIONS CONTROL EQUIPMENT

14. Control Equipment Name and ID:	Material Moisture Content		
15. Date of Installation:	N/A	16. Date of Modification (if any):	N/A
17. Manufacturer and Model Number:	N/A		
18. ID(s) of Emission Unit Controlled:	FS7		
19. Is operating schedule different than emission units(s) involved?	☐ Yes ☒ No		
20. Does the manufacturer guarantee the control efficiency of the control equipment?	☐ Yes ☒ No (If Yes, attach and label manufacturer guarantee)		

	Pollutant Controlled					
	PM	PM10	SO_2	NOx	VOC	CO
Control Efficiency	34%	34%				

21. If manufacturer's data is not available, attach a separate sheet of paper to provide the control equipment design specifications and performance data to support the above mentioned control efficiency.

EMISSION UNIT OPERATING SCHEDULE (hours/day, hours/year, or other)

22.	Actual Operation:	TBD
23.	Maximum Operation:	8760 HRS/YEAR

REQUESTED LIMITS

24.	Are you requesting any permit limits?	☐ Yes ☒ No (If Yes, indicate all that apply below)
	☐ Operation Hour Limit(s):	
	☐ Production Limit(s):	
	☐ Material Usage Limit(s):	
	☐ Limits Based on Stack Testing:	Please attach all relevant stack testing summary reports
	☐ Other:	
25.	Rationale for Requesting the Limit(s):	

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IDENTIFICATION

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4. Brief Project Description:	CRE is proposing to construct and operate a Greenfield wood pellet production facility near Potlach, Idaho. The facility will produce a proprietary product known as SteamEx Pellets with technology from

EMISSIONS UNIT (PROCESS) IDENTIFICATION & DESCRIPTION

5.	Emissions Unit (EU) Name:	GREEN CYCLONE #1 TO CONVEYOR #2
6.	EU ID Number:	FS8
7.	EU Type:	☒ New Source ☐ Unpermitted Existing Source ☐ Modification to a Permitted Source -- Previous Permit #: Date Issued:
8.	Manufacturer:	N/A
9.	Model:	N/A
10..	Maximum Capacity:	16 TON/HR, 220,500 TON/YEAR
11.	Date of Construction:	TBD
12.	Date of Modification (if any):	N/A
13.	Is this a Controlled Emission Unit?	☐ No ☒ Yes If Yes, complete the following section. If No, go to line 22.

EMISSIONS CONTROL EQUIPMENT

14. Control Equipment Name and ID:	Material Moisture Content		
15. Date of Installation:	N/A	16. Date of Modification (if any):	N/A
17. Manufacturer and Model Number:	N/A		
18. ID(s) of Emission Unit Controlled:	FS8		
19. Is operating schedule different than emission units(s) involved?	☐ Yes ☒ No		
20. Does the manufacturer guarantee the control efficiency of the control equipment?	☐ Yes ☒ No (If Yes, attach and label manufacturer guarantee)		

	Pollutant Controlled					
	PM	PM10	SO_2	NOx	VOC	CO
Control Efficiency	34%	34%				

21. If manufacturer's data is not available, attach a separate sheet of paper to provide the control equipment design specifications and performance data to support the above mentioned control efficiency.

EMISSION UNIT OPERATING SCHEDULE (hours/day, hours/year, or other)

22.	Actual Operation:	TBD
23.	Maximum Operation:	8760 HRS/YEAR

REQUESTED LIMITS

24.	Are you requesting any permit limits?	☐ Yes ☒ No (If Yes, indicate all that apply below)
	☐ Operation Hour Limit(s):	
	☐ Production Limit(s):	
	☐ Material Usage Limit(s):	
	☐ Limits Based on Stack Testing:	Please attach all relevant stack testing summary reports
	☐ Other:	
25.	Rationale for Requesting the Limit(s):	

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EMISSIONS UNIT (PROCESS) IDENTIFICATION & DESCRIPTION

5.	Emissions Unit (EU) Name:	GREEN CYCLONE #2 TO CONVEYOR #2
6.	EU ID Number:	FS9
7.	EU Type:	☒ New Source ☐ Unpermitted Existing Source ☐ Modification to a Permitted Source -- Previous Permit #: Date Issued:
8.	Manufacturer:	N/A
9.	Model:	N/A
10..	Maximum Capacity:	16 TON/HR, 220,500 TON/YEAR
11.	Date of Construction:	TBD
12.	Date of Modification (if any):	N/A
13.	Is this a Controlled Emission Unit?	☐ No ☒ Yes If Yes, complete the following section. If No, go to line 22.

EMISSIONS CONTROL EQUIPMENT

14. Control Equipment Name and ID:	Material Moisture Content		
15. Date of Installation:	N/A	16. Date of Modification (if any):	N/A
17. Manufacturer and Model Number:	N/A		
18. ID(s) of Emission Unit Controlled:	FS9		
19. Is operating schedule different than emission units(s) involved?	☐ Yes ☒ No		
20. Does the manufacturer guarantee the control efficiency of the control equipment?	☐ Yes ☒ No (If Yes, attach and label manufacturer guarantee)		

	Pollutant Controlled					
	PM	PM10	SO_2	NOx	VOC	CO
Control Efficiency	34%	34%				

21. If manufacturer's data is not available, attach a separate sheet of paper to provide the control equipment design specifications and performance data to support the above mentioned control efficiency.

EMISSION UNIT OPERATING SCHEDULE (hours/day, hours/year, or other)

22.	Actual Operation:	TBD
23.	Maximum Operation:	8760 HRS/YEAR

REQUESTED LIMITS

24.	Are you requesting any permit limits?	☐ Yes ☒ No (If Yes, indicate all that apply below)
	☐ Operation Hour Limit(s):	
	☐ Production Limit(s):	
	☐ Material Usage Limit(s):	
	☐ Limits Based on Stack Testing:	Please attach all relevant stack testing summary reports
	☐ Other:	
25.	Rationale for Requesting the Limit(s):	

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EMISSIONS UNIT (PROCESS) IDENTIFICATION & DESCRIPTION

5.	Emissions Unit (EU) Name:	CONVEYOR #2 TO CONVEYOR #3 (INSIDE TOWER 1)
6.	EU ID Number:	FS10
7.	EU Type:	☒ New Source ☐ Unpermitted Existing Source ☐ Modification to a Permitted Source -- Previous Permit #: Date Issued:
8.	Manufacturer:	N/A
9.	Model:	N/A
10..	Maximum Capacity:	33 TON/HR, 220,500 TON/YEAR
11.	Date of Construction:	TBD
12.	Date of Modification (if any):	N/A
13.	Is this a Controlled Emission Unit?	☐ No ☒ Yes If Yes, complete the following section. If No, go to line 22.

EMISSIONS CONTROL EQUIPMENT

14. Control Equipment Name and ID:	ENCLOSURE		
15. Date of Installation:	TBD	16. Date of Modification (if any):	N/A
17. Manufacturer and Model Number:	TBD		
18. ID(s) of Emission Unit Controlled:	FS10		
19. Is operating schedule different than emission units(s) involved?	☐ Yes ☒ No		
20. Does the manufacturer guarantee the control efficiency of the control equipment?	☐ Yes ☒ No (If Yes, attach and label manufacturer guarantee)		

	Pollutant Controlled					
	PM	PM10	SO_2	NOx	VOC	CO
Control Efficiency	50%	50%				

21. If manufacturer's data is not available, attach a separate sheet of paper to provide the control equipment design specifications and performance data to support the above mentioned control efficiency.

EMISSION UNIT OPERATING SCHEDULE (hours/day, hours/year, or other)

22.	Actual Operation:	TBD
23.	Maximum Operation:	8760 HRS/YEAR

REQUESTED LIMITS

24.	Are you requesting any permit limits?	☐ Yes ☒ No (If Yes, indicate all that apply below)
	☐ Operation Hour Limit(s):	
	☐ Production Limit(s):	
	☐ Material Usage Limit(s):	
	☐ Limits Based on Stack Testing:	Please attach all relevant stack testing summary reports
	☐ Other:	
25.	Rationale for Requesting the Limit(s):	

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EMISSIONS UNIT (PROCESS) IDENTIFICATION & DESCRIPTION

5.	Emissions Unit (EU) Name:	CONVEYOR #3 TO STEAM EX PREHEAT BIN
6.	EU ID Number:	FS11
7.	EU Type:	☒ New Source ☐ Unpermitted Existing Source ☐ Modification to a Permitted Source -- Previous Permit #: Date Issued:
8.	Manufacturer:	N/A
9.	Model:	N/A
10..	Maximum Capacity:	33 TON/HR, 220,500 TON/YEAR
11.	Date of Construction:	TBD
12.	Date of Modification (if any):	N/A
13.	Is this a Controlled Emission Unit?	☐ No ☒ Yes If Yes, complete the following section. If No, go to line 22.

EMISSIONS CONTROL EQUIPMENT

14. Control Equipment Name and ID:	Inside Building		
15. Date of Installation:	TBD	16. Date of Modification (if any):	N/A
17. Manufacturer and Model Number:	TBD		
18. ID(s) of Emission Unit Controlled:	FS11		
19. Is operating schedule different than emission units(s) involved?	☐ Yes ☒ No		
20. Does the manufacturer guarantee the control efficiency of the control equipment?	☐ Yes ☒ No (If Yes, attach and label manufacturer guarantee)		

	Pollutant Controlled					
	PM	PM10	SO_2	NOx	VOC	CO
Control Efficiency	100%	100%				

21. If manufacturer's data is not available, attach a separate sheet of paper to provide the control equipment design specifications and performance data to support the above mentioned control efficiency.

EMISSION UNIT OPERATING SCHEDULE (hours/day, hours/year, or other)

22.	Actual Operation:	TBD
23.	Maximum Operation:	8760 HRS/YEAR

REQUESTED LIMITS

24.	Are you requesting any permit limits?	☐ Yes ☒ No (If Yes, indicate all that apply below)
	☐ Operation Hour Limit(s):	
	☐ Production Limit(s):	
	☐ Material Usage Limit(s):	
	☐ Limits Based on Stack Testing:	Please attach all relevant stack testing summary reports
	☐ Other:	
25.	Rationale for Requesting the Limit(s):	

DEQ AIR QUALITY PROGRAM
1410 N. Hilton, Boise, ID 83706
For assistance, call the
Air Permit Hotline – 1-877-5PERMIT

Emissions Unit - General **Form EU0**
Revision 4
08/28/08

Please see instructions on page 2 before filling out the form.

IDENTIFICATION

1. Company Name:	2. Facility Name:	3. Facility ID No:
Centennial Renewable Energy	Potlach Facility	

4. Brief Project Description:	CRE is proposing to construct and operate a Greenfield wood pellet production facility near Potlach, Idaho. The facility will produce a proprietary product known as SteamEx Pellets with technology from

EMISSIONS UNIT (PROCESS) IDENTIFICATION & DESCRIPTION

5.	Emissions Unit (EU) Name:	STEAMEX PREHEAT BIN TO CONVEYOR #4
6.	EU ID Number:	FS12
7.	EU Type:	☒ New Source ☐ Unpermitted Existing Source ☐ Modification to a Permitted Source -- Previous Permit #: Date Issued:
8.	Manufacturer:	N/A
9.	Model:	N/A
10..	Maximum Capacity:	33 TON/HR, 220,500 TON/YEAR
11.	Date of Construction:	TBD
12.	Date of Modification (if any):	N/A
13.	Is this a Controlled Emission Unit?	☐ No ☒ Yes If Yes, complete the following section. If No, go to line 22.

EMISSIONS CONTROL EQUIPMENT

14. Control Equipment Name and ID:	Inside Building		
15. Date of Installation:	TBD	16. Date of Modification (if any):	N/A
17. Manufacturer and Model Number:	TBD		
18. ID(s) of Emission Unit Controlled:	FS12		
19. Is operating schedule different than emission units(s) involved?	☐ Yes ☒ No		
20. Does the manufacturer guarantee the control efficiency of the control equipment?	☐ Yes ☒ No (If Yes, attach and label manufacturer guarantee)		

	Pollutant Controlled					
	PM	PM10	SO_2	NOx	VOC	CO
Control Efficiency	100%	100%				

21. If manufacturer's data is not available, attach a separate sheet of paper to provide the control equipment design specifications and performance data to support the above mentioned control efficiency.

EMISSION UNIT OPERATING SCHEDULE (hours/day, hours/year, or other)

22.	Actual Operation:	TBD
23.	Maximum Operation:	8760 HRS/YEAR

REQUESTED LIMITS

24.	Are you requesting any permit limits?	☐ Yes ☒ No (If Yes, indicate all that apply below)
	☐ Operation Hour Limit(s):	
	☐ Production Limit(s):	
	☐ Material Usage Limit(s):	
	☐ Limits Based on Stack Testing:	Please attach all relevant stack testing summary reports
	☐ Other:	
25.	Rationale for Requesting the Limit(s):	

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Emissions Unit - General **Form EU0**
Revision 4
08/28/08

Please see instructions on page 2 before filling out the form.

IDENTIFICATION

1. Company Name:	2. Facility Name:	3. Facility ID No:
Centennial Renewable Energy	Potlach Facility	

4. Brief Project Description:	CRE is proposing to construct and operate a Greenfield wood pellet production facility near Potlach, Idaho. The facility will produce a proprietary product known as SteamEx Pellets with technology from

EMISSIONS UNIT (PROCESS) IDENTIFICATION & DESCRIPTION

5.	Emissions Unit (EU) Name:	CONVEYOR #4 TO BELT DRYER
6.	EU ID Number:	FS13
7.	EU Type:	☒ New Source ☐ Unpermitted Existing Source ☐ Modification to a Permitted Source -- Previous Permit #: Date Issued:
8.	Manufacturer:	N/A
9.	Model:	N/A
10..	Maximum Capacity:	33 TON/HR, 220,500 TON/YEAR
11.	Date of Construction:	TBD
12.	Date of Modification (if any):	N/A
13.	Is this a Controlled Emission Unit?	☐ No ☒ Yes If Yes, complete the following section. If No, go to line 22.

EMISSIONS CONTROL EQUIPMENT

14. Control Equipment Name and ID:	Inside Building		
15. Date of Installation:	TBD	16. Date of Modification (if any):	N/A
17. Manufacturer and Model Number:	TBD		
18. ID(s) of Emission Unit Controlled:	FS13		
19. Is operating schedule different than emission units(s) involved?	☐ Yes ☒ No		
20. Does the manufacturer guarantee the control efficiency of the control equipment?	☐ Yes ☒ No (If Yes, attach and label manufacturer guarantee)		

	Pollutant Controlled					
	PM	PM10	SO_2	NOx	VOC	CO
Control Efficiency	100%	100%				

21. If manufacturer's data is not available, attach a separate sheet of paper to provide the control equipment design specifications and performance data to support the above mentioned control efficiency.

EMISSION UNIT OPERATING SCHEDULE (hours/day, hours/year, or other)

22.	Actual Operation:	TBD
23.	Maximum Operation:	8760 HRS/YEAR

REQUESTED LIMITS

24.	Are you requesting any permit limits?	☐ Yes ☒ No (If Yes, indicate all that apply below)
	☐ Operation Hour Limit(s):	
	☐ Production Limit(s):	
	☐ Material Usage Limit(s):	
	☐ Limits Based on Stack Testing:	Please attach all relevant stack testing summary reports
	☐ Other:	
25.	Rationale for Requesting the Limit(s):	

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Emissions Unit - General **Form EU0**
Revision 4
08/28/08

Please see instructions on page 2 before filling out the form.

IDENTIFICATION

1. Company Name:	2. Facility Name:	3. Facility ID No:
Centennial Renewable Energy	Potlach Facility	

4. Brief Project Description:	CRE is proposing to construct and operate a Greenfield wood pellet production facility near Potlach, Idaho. The facility will produce a proprietary product known as SteamEx Pellets with technology from

EMISSIONS UNIT (PROCESS) IDENTIFICATION & DESCRIPTION

5.	Emissions Unit (EU) Name:	BELT DRYER TO CONVEYOR #5
6.	EU ID Number:	FS14
7.	EU Type:	☒ New Source ☐ Unpermitted Existing Source ☐ Modification to a Permitted Source -- Previous Permit #: Date Issued:
8.	Manufacturer:	N/A
9.	Model:	N/A
10..	Maximum Capacity:	33 TON/HR, 220,500 TON/YEAR
11.	Date of Construction:	TBD
12.	Date of Modification (if any):	N/A
13.	Is this a Controlled Emission Unit?	☐ No ☒ Yes If Yes, complete the following section. If No, go to line 22.

EMISSIONS CONTROL EQUIPMENT

14. Control Equipment Name and ID:	Inside Building		
15. Date of Installation:	TBD	16. Date of Modification (if any):	N/A
17. Manufacturer and Model Number:	TBD		
18. ID(s) of Emission Unit Controlled:	FS14		
19. Is operating schedule different than emission units(s) involved?	☐ Yes ☒ No		
20. Does the manufacturer guarantee the control efficiency of the control equipment?	☐ Yes ☒ No (If Yes, attach and label manufacturer guarantee)		

	Pollutant Controlled					
	PM	PM10	SO_2	NOx	VOC	CO
Control Efficiency	100%	100%				

21. If manufacturer's data is not available, attach a separate sheet of paper to provide the control equipment design specifications and performance data to support the above mentioned control efficiency.

EMISSION UNIT OPERATING SCHEDULE (hours/day, hours/year, or other)

22.	Actual Operation:	TBD
23.	Maximum Operation:	8760 HRS/YEAR

REQUESTED LIMITS

24.	Are you requesting any permit limits?	☐ Yes ☒ No (If Yes, indicate all that apply below)
	☐ Operation Hour Limit(s):	
	☐ Production Limit(s):	
	☐ Material Usage Limit(s):	
	☐ Limits Based on Stack Testing:	Please attach all relevant stack testing summary reports
	☐ Other:	
25.	Rationale for Requesting the Limit(s):	

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Emissions Unit - General **Form EU0**
Revision 4
08/28/08

Please see instructions on page 2 before filling out the form.

IDENTIFICATION

1. Company Name:	2. Facility Name:	3. Facility ID No:
Centennial Renewable Energy	Potlach Facility	

4. Brief Project Description:	CRE is proposing to construct and operate a Greenfield wood pellet production facility near Potlach, Idaho. The facility will produce a proprietary product known as SteamEx Pellets with technology from

EMISSIONS UNIT (PROCESS) IDENTIFICATION & DESCRIPTION

5.	Emissions Unit (EU) Name:	CONVEYOR #5 TO FEED SCREW #3
6.	EU ID Number:	FS15
7.	EU Type:	☒ New Source ☐ Unpermitted Existing Source ☐ Modification to a Permitted Source -- Previous Permit #: Date Issued:
8.	Manufacturer:	N/A
9.	Model:	N/A
10..	Maximum Capacity:	33 TON/HR, 220,500 TON/YEAR
11.	Date of Construction:	TBD
12.	Date of Modification (if any):	N/A
13.	Is this a Controlled Emission Unit?	☐ No ☒ Yes If Yes, complete the following section. If No, go to line 22.

EMISSIONS CONTROL EQUIPMENT

14. Control Equipment Name and ID:	Material Moisture Content		
15. Date of Installation:	N/A	16. Date of Modification (if any):	N/A
17. Manufacturer and Model Number:	N/A		
18. ID(s) of Emission Unit Controlled:	FS15		
19. Is operating schedule different than emission units(s) involved?	☐ Yes ☒ No		
20. Does the manufacturer guarantee the control efficiency of the control equipment?	☐ Yes ☒ No (If Yes, attach and label manufacturer guarantee)		

	Pollutant Controlled					
	PM	PM10	SO_2	NOx	VOC	CO
Control Efficiency	8%	8%				

21. If manufacturer's data is not available, attach a separate sheet of paper to provide the control equipment design specifications and performance data to support the above mentioned control efficiency.

EMISSION UNIT OPERATING SCHEDULE (hours/day, hours/year, or other)

22.	Actual Operation:	TBD
23.	Maximum Operation:	8760 HRS/YEAR

REQUESTED LIMITS

24.	Are you requesting any permit limits?	☐ Yes ☒ No (If Yes, indicate all that apply below)
	☐ Operation Hour Limit(s):	
	☐ Production Limit(s):	
	☐ Material Usage Limit(s):	
	☐ Limits Based on Stack Testing:	Please attach all relevant stack testing summary reports
	☐ Other:	
25.	Rationale for Requesting the Limit(s):	

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Emissions Unit - General **Form EU0**
Revision 4
08/28/08

Please see instructions on page 2 before filling out the form.

IDENTIFICATION

1. Company Name:	2. Facility Name:	3. Facility ID No:
Centennial Renewable Energy	Potlach Facility	

4. Brief Project Description:	CRE is proposing to construct and operate a Greenfield wood pellet production facility near Potlach, Idaho. The facility will produce a proprietary product known as SteamEx Pellets with technology from

EMISSIONS UNIT (PROCESS) IDENTIFICATION & DESCRIPTION

5.	Emissions Unit (EU) Name:	FEED SCREW #3 TO DRY HAMMER MILL
6.	EU ID Number:	FS16
7.	EU Type:	☒ New Source ☐ Unpermitted Existing Source ☐ Modification to a Permitted Source -- Previous Permit #: Date Issued:
8.	Manufacturer:	N/A
9.	Model:	N/A
10..	Maximum Capacity:	33 TON/HR, 220,500 TON/YEAR
11.	Date of Construction:	TBD
12.	Date of Modification (if any):	N/A
13.	Is this a Controlled Emission Unit?	☐ No ☒ Yes If Yes, complete the following section. If No, go to line 22.

EMISSIONS CONTROL EQUIPMENT

14. Control Equipment Name and ID:	Material Moisture Content		
15. Date of Installation:	N/A	16. Date of Modification (if any):	N/A
17. Manufacturer and Model Number:	N/A		
18. ID(s) of Emission Unit Controlled:	FS16		
19. Is operating schedule different than emission units(s) involved?	☐ Yes ☒ No		
20. Does the manufacturer guarantee the control efficiency of the control equipment?	☐ Yes ☒ No (If Yes, attach and label manufacturer guarantee)		

	Pollutant Controlled					
	PM	PM10	SO_2	NOx	VOC	CO
Control Efficiency	8%	8%				

21. If manufacturer's data is not available, attach a separate sheet of paper to provide the control equipment design specifications and performance data to support the above mentioned control efficiency.

EMISSION UNIT OPERATING SCHEDULE (hours/day, hours/year, or other)

22.	Actual Operation:	TBD
23.	Maximum Operation:	8760 HRS/YEAR

REQUESTED LIMITS

24.	Are you requesting any permit limits?	☐ Yes ☒ No (If Yes, indicate all that apply below)
	☐ Operation Hour Limit(s):	
	☐ Production Limit(s):	
	☐ Material Usage Limit(s):	
	☐ Limits Based on Stack Testing:	Please attach all relevant stack testing summary reports
	☐ Other:	
25.	Rationale for Requesting the Limit(s):	

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Emissions Unit - General **Form EU0**
Revision 4
08/28/08

Please see instructions on page 2 before filling out the form.

IDENTIFICATION

1. Company Name:	2. Facility Name:	3. Facility ID No:
Centennial Renewable Energy	Potlach Facility	

4. Brief Project Description:	CRE is proposing to construct and operate a Greenfield wood pellet production facility near Potlach, Idaho. The facility will produce a proprietary product known as SteamEx Pellets with technology from

EMISSIONS UNIT (PROCESS) IDENTIFICATION & DESCRIPTION

5.	Emissions Unit (EU) Name:	Dry Hammer Mill to Dry Cyclone #1
6.	EU ID Number:	FS17
7.	EU Type:	☒ New Source ☐ Unpermitted Existing Source ☐ Modification to a Permitted Source -- Previous Permit #: Date Issued:
8.	Manufacturer:	N/A
9.	Model:	N/A
10..	Maximum Capacity:	33 TON/HR, 220,500 TON/YEAR
11.	Date of Construction:	TBD
12.	Date of Modification (if any):	N/A
13.	Is this a Controlled Emission Unit?	☐ No ☒ Yes If Yes, complete the following section. If No, go to line 22.

EMISSIONS CONTROL EQUIPMENT

14. Control Equipment Name and ID:	Bag Filter		
15. Date of Installation:	TBD	16. Date of Modification (if any):	N/A
17. Manufacturer and Model Number:	TBD		
18. ID(s) of Emission Unit Controlled:	FS17		
19. Is operating schedule different than emission units(s) involved?	☐ Yes ☒ No		
20. Does the manufacturer guarantee the control efficiency of the control equipment?	☒ Yes ☐ No (If Yes, attach and label manufacturer guarantee)		

	Pollutant Controlled					
	PM	PM10	SO_2	NOx	VOC	CO
Control Efficiency	99%	99%				

21. If manufacturer's data is not available, attach a separate sheet of paper to provide the control equipment design specifications and performance data to support the above mentioned control efficiency.

EMISSION UNIT OPERATING SCHEDULE (hours/day, hours/year, or other)

22.	Actual Operation:	TBD
23.	Maximum Operation:	8760 HRS/YEAR

REQUESTED LIMITS

24.	Are you requesting any permit limits?	☐ Yes ☒ No (If Yes, indicate all that apply below)
	☐ Operation Hour Limit(s):	
	☐ Production Limit(s):	
	☐ Material Usage Limit(s):	
	☐ Limits Based on Stack Testing:	Please attach all relevant stack testing summary reports
	☐ Other:	
25.	Rationale for Requesting the Limit(s):	

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Emissions Unit - General **Form EU0**
Revision 4
08/28/08

Please see instructions on page 2 before filling out the form.

IDENTIFICATION

1. Company Name:	2. Facility Name:	3. Facility ID No:
Centennial Renewable Energy	Potlach Facility	

4. Brief Project Description:	CRE is proposing to construct and operate a Greenfield wood pellet production facility near Potlach, Idaho. The facility will produce a proprietary product known as SteamEx Pellets with technology from

EMISSIONS UNIT (PROCESS) IDENTIFICATION & DESCRIPTION

5.	Emissions Unit (EU) Name:	DRY CYCLONE #1 TO PNEUMATIC SYSTEM #1
6.	EU ID Number:	FS18
7.	EU Type:	☒ New Source ☐ Unpermitted Existing Source ☐ Modification to a Permitted Source -- Previous Permit #: Date Issued:
8.	Manufacturer:	N/A
9.	Model:	N/A
10..	Maximum Capacity:	33 TON/HR, 220,500 TON/YEAR
11.	Date of Construction:	TBD
12.	Date of Modification (if any):	N/A
13.	Is this a Controlled Emission Unit?	☐ No ☒ Yes If Yes, complete the following section. If No, go to line 22.

EMISSIONS CONTROL EQUIPMENT

14. Control Equipment Name and ID:	Pnuematic Enclosure		
15. Date of Installation:	TBD	16. Date of Modification (if any):	N/A
17. Manufacturer and Model Number:	TBD		
18. ID(s) of Emission Unit Controlled:	FS18		
19. Is operating schedule different than emission units(s) involved?	☐ Yes ☒ No		
20. Does the manufacturer guarantee the control efficiency of the control equipment?	☐ Yes ☒ No (If Yes, attach and label manufacturer guarantee)		

	Pollutant Controlled					
	PM	PM10	SO_2	NOx	VOC	CO
Control Efficiency	100%	100%				

21. If manufacturer's data is not available, attach a separate sheet of paper to provide the control equipment design specifications and performance data to support the above mentioned control efficiency.

EMISSION UNIT OPERATING SCHEDULE (hours/day, hours/year, or other)

22.	Actual Operation:	TBD
23.	Maximum Operation:	8760 HRS/YEAR

REQUESTED LIMITS

24.	Are you requesting any permit limits?	☐ Yes ☒ No (If Yes, indicate all that apply below)
	☐ Operation Hour Limit(s):	
	☐ Production Limit(s):	
	☐ Material Usage Limit(s):	
	☐ Limits Based on Stack Testing:	Please attach all relevant stack testing summary reports
	☐ Other:	
25.	Rationale for Requesting the Limit(s):	

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Emissions Unit - General **Form EU0**
Revision 4
08/28/08

Please see instructions on page 2 before filling out the form.

IDENTIFICATION

1. Company Name:	2. Facility Name:	3. Facility ID No:
Centennial Renewable Energy	Potlach Facility	

4. Brief Project Description:	CRE is proposing to construct and operate a Greenfield wood pellet production facility near Potlach, Idaho. The facility will produce a proprietary product known as SteamEx Pellets with technology from

EMISSIONS UNIT (PROCESS) IDENTIFICATION & DESCRIPTION

5.	Emissions Unit (EU) Name:	PNUEMATIC SYSTEM #1 TO SURGE BIN #1
6.	EU ID Number:	FS19
7.	EU Type:	☒ New Source ☐ Unpermitted Existing Source ☐ Modification to a Permitted Source -- Previous Permit #: Date Issued:
8.	Manufacturer:	N/A
9.	Model:	N/A
10..	Maximum Capacity:	33 TON/HR, 220,500 TON/YEAR
11.	Date of Construction:	TBD
12.	Date of Modification (if any):	N/A
13.	Is this a Controlled Emission Unit?	☐ No ☒ Yes If Yes, complete the following section. If No, go to line 22.

EMISSIONS CONTROL EQUIPMENT

14. Control Equipment Name and ID:	Pnuematic Enclosure		
15. Date of Installation:	TBD	16. Date of Modification (if any):	N/A
17. Manufacturer and Model Number:	TBD		
18. ID(s) of Emission Unit Controlled:	FS19		
19. Is operating schedule different than emission units(s) involved?	☐ Yes ☒ No		
20. Does the manufacturer guarantee the control efficiency of the control equipment?	☐ Yes ☒ No (If Yes, attach and label manufacturer guarantee)		

	Pollutant Controlled					
	PM	PM10	SO_2	NOx	VOC	CO
Control Efficiency	100%	100%				

21. If manufacturer's data is not available, attach a separate sheet of paper to provide the control equipment design specifications and performance data to support the above mentioned control efficiency.

EMISSION UNIT OPERATING SCHEDULE (hours/day, hours/year, or other)

22.	Actual Operation:	TBD
23.	Maximum Operation:	8760 HRS/YEAR

REQUESTED LIMITS

24.	Are you requesting any permit limits?	☐ Yes ☒ No (If Yes, indicate all that apply below)
	☐ Operation Hour Limit(s):	
	☐ Production Limit(s):	
	☐ Material Usage Limit(s):	
	☐ Limits Based on Stack Testing:	Please attach all relevant stack testing summary reports
	☐ Other:	
25.	Rationale for Requesting the Limit(s):	

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Emissions Unit - General **Form EU0**
Revision 4
08/28/08

Please see instructions on page 2 before filling out the form.

IDENTIFICATION

1. Company Name:	2. Facility Name:	3. Facility ID No:
Centennial Renewable Energy	Potlach Facility	

4. Brief Project Description:	CRE is proposing to construct and operate a Greenfield wood pellet production facility near Potlach, Idaho. The facility will produce a proprietary product known as SteamEx Pellets with technology from

EMISSIONS UNIT (PROCESS) IDENTIFICATION & DESCRIPTION

5.	Emissions Unit (EU) Name:	SURGE BIN #1 TO CONVEYOR #6
6.	EU ID Number:	FS20
7.	EU Type:	☒ New Source ☐ Unpermitted Existing Source ☐ Modification to a Permitted Source -- Previous Permit #: Date Issued:
8.	Manufacturer:	N/A
9.	Model:	N/A
10..	Maximum Capacity:	33 TON/HR, 220,500 TON/YEAR
11.	Date of Construction:	TBD
12.	Date of Modification (if any):	N/A
13.	Is this a Controlled Emission Unit?	☐ No ☒ Yes If Yes, complete the following section. If No, go to line 22.

EMISSIONS CONTROL EQUIPMENT

14. Control Equipment Name and ID:	Material Moisture Content		
15. Date of Installation:	N/A	16. Date of Modification (if any):	N/A
17. Manufacturer and Model Number:	N/A		
18. ID(s) of Emission Unit Controlled:	FS20		
19. Is operating schedule different than emission units(s) involved?	☐ Yes ☒ No		
20. Does the manufacturer guarantee the control efficiency of the control equipment?	☐ Yes ☒ No (If Yes, attach and label manufacturer guarantee)		

	Pollutant Controlled					
	PM	PM10	SO_2	NOx	VOC	CO
Control Efficiency	8%	8%				

21. If manufacturer's data is not available, attach a separate sheet of paper to provide the control equipment design specifications and performance data to support the above mentioned control efficiency.

EMISSION UNIT OPERATING SCHEDULE (hours/day, hours/year, or other)

22.	Actual Operation:	TBD
23.	Maximum Operation:	8760 HRS/YEAR

REQUESTED LIMITS

24.	Are you requesting any permit limits?	☐ Yes ☒ No (If Yes, indicate all that apply below)
	☐ Operation Hour Limit(s):	
	☐ Production Limit(s):	
	☐ Material Usage Limit(s):	
	☐ Limits Based on Stack Testing:	Please attach all relevant stack testing summary reports
	☐ Other:	
25.	Rationale for Requesting the Limit(s):	

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Emissions Unit - General **Form EU0**
Revision 4
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IDENTIFICATION

1. Company Name:	2. Facility Name:	3. Facility ID No:
Centennial Renewable Energy	Potlach Facility	

4. Brief Project Description:	CRE is proposing to construct and operate a Greenfield wood pellet production facility near Potlach, Idaho. The facility will produce a proprietary product known as SteamEx Pellets with technology from

EMISSIONS UNIT (PROCESS) IDENTIFICATION & DESCRIPTION

5.	Emissions Unit (EU) Name:	CONVEYOR #6 TO CONVEYOR #7
6.	EU ID Number:	FS21
7.	EU Type:	☒ New Source ☐ Unpermitted Existing Source ☐ Modification to a Permitted Source -- Previous Permit #: Date Issued:
8.	Manufacturer:	N/A
9.	Model:	N/A
10..	Maximum Capacity:	16 TON/HR, 220,500 TON/YEAR
11.	Date of Construction:	TBD
12.	Date of Modification (if any):	N/A
13.	Is this a Controlled Emission Unit?	☐ No ☒ Yes If Yes, complete the following section. If No, go to line 22.

EMISSIONS CONTROL EQUIPMENT

14. Control Equipment Name and ID:	Inside Buildingt		
15. Date of Installation:	TBD	16. Date of Modification (if any):	N/A
17. Manufacturer and Model Number:	TBD		
18. ID(s) of Emission Unit Controlled:	FS21		
19. Is operating schedule different than emission units(s) involved?	☐ Yes ☒ No		
20. Does the manufacturer guarantee the control efficiency of the control equipment?	☐ Yes ☒ No (If Yes, attach and label manufacturer guarantee)		

	Pollutant Controlled					
	PM	PM10	SO_2	NOx	VOC	CO
Control Efficiency	100%	100%				

21. If manufacturer's data is not available, attach a separate sheet of paper to provide the control equipment design specifications and performance data to support the above mentioned control efficiency.

EMISSION UNIT OPERATING SCHEDULE (hours/day, hours/year, or other)

22.	Actual Operation:	TBD
23.	Maximum Operation:	8760 HRS/YEAR

REQUESTED LIMITS

24.	Are you requesting any permit limits?	☐ Yes ☒ No (If Yes, indicate all that apply below)
	☐ Operation Hour Limit(s):	
	☐ Production Limit(s):	
	☐ Material Usage Limit(s):	
	☐ Limits Based on Stack Testing:	Please attach all relevant stack testing summary reports
	☐ Other:	
25.	Rationale for Requesting the Limit(s):	

DEQ AIR QUALITY PROGRAM
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For assistance, call the
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Emissions Unit - General **Form EU0**
Revision 4
08/28/08

Please see instructions on page 2 before filling out the form.

IDENTIFICATION

1. Company Name:	2. Facility Name:	3. Facility ID No:
Centennial Renewable Energy	Potlach Facility	

4. Brief Project Description:	CRE is proposing to construct and operate a Greenfield wood pellet production facility near Potlach, Idaho. The facility will produce a proprietary product known as SteamEx Pellets with technology from

EMISSIONS UNIT (PROCESS) IDENTIFICATION & DESCRIPTION

5.	Emissions Unit (EU) Name:	CONVEYOR #7 TO MILL FEED BIN #1 AND #2
6.	EU ID Number:	FS22
7.	EU Type:	☒ New Source ☐ Unpermitted Existing Source ☐ Modification to a Permitted Source -- Previous Permit #: Date Issued:
8.	Manufacturer:	N/A
9.	Model:	N/A
10..	Maximum Capacity:	16 TON/HR, 220,500 TON/YEAR
11.	Date of Construction:	TBD
12.	Date of Modification (if any):	N/A
13.	Is this a Controlled Emission Unit?	☐ No ☒ Yes If Yes, complete the following section. If No, go to line 22.

EMISSIONS CONTROL EQUIPMENT

14. Control Equipment Name and ID:	Inside Building		
15. Date of Installation:	TBD	16. Date of Modification (if any):	N/A
17. Manufacturer and Model Number:	TBD		
18. ID(s) of Emission Unit Controlled:	FS22		
19. Is operating schedule different than emission units(s) involved?	☐ Yes ☒ No		
20. Does the manufacturer guarantee the control efficiency of the control equipment?	☐ Yes ☒ No (If Yes, attach and label manufacturer guarantee)		

	Pollutant Controlled					
	PM	PM10	SO_2	NOx	VOC	CO
Control Efficiency	100%	100%				

21. If manufacturer's data is not available, attach a separate sheet of paper to provide the control equipment design specifications and performance data to support the above mentioned control efficiency.

EMISSION UNIT OPERATING SCHEDULE (hours/day, hours/year, or other)

22.	Actual Operation:	TBD
23.	Maximum Operation:	8760 HRS/YEAR

REQUESTED LIMITS

24.	Are you requesting any permit limits?	☐ Yes ☒ No (If Yes, indicate all that apply below)
	☐ Operation Hour Limit(s):	
	☐ Production Limit(s):	
	☐ Material Usage Limit(s):	
	☐ Limits Based on Stack Testing:	Please attach all relevant stack testing summary reports
	☐ Other:	
25.	Rationale for Requesting the Limit(s):	

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Emissions Unit - General **Form EU0**
Revision 4
08/28/08

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IDENTIFICATION

1. Company Name:	2. Facility Name:	3. Facility ID No:
Centennial Renewable Energy	Potlach Facility	

4. Brief Project Description:	CRE is proposing to construct and operate a Greenfield wood pellet production facility near Potlach, Idaho. The facility will produce a proprietary product known as SteamEx Pellets with technology from

EMISSIONS UNIT (PROCESS) IDENTIFICATION & DESCRIPTION

5.	Emissions Unit (EU) Name:	MILL FEED BIN #1 & #2 TO MILL FEED SCREWS #1-4
6.	EU ID Number:	FS23
7.	EU Type:	☒ New Source ☐ Unpermitted Existing Source ☐ Modification to a Permitted Source -- Previous Permit #: Date Issued:
8.	Manufacturer:	N/A
9.	Model:	N/A
10..	Maximum Capacity:	16 TON/HR, 220,500 TON/YEAR
11.	Date of Construction:	TBD
12.	Date of Modification (if any):	N/A
13.	Is this a Controlled Emission Unit?	☐ No ☒ Yes If Yes, complete the following section. If No, go to line 22.

EMISSIONS CONTROL EQUIPMENT

14. Control Equipment Name and ID:	Inside Building		
15. Date of Installation:	TBD	16. Date of Modification (if any):	N/A
17. Manufacturer and Model Number:	TBD		
18. ID(s) of Emission Unit Controlled:	FS23		
19. Is operating schedule different than emission units(s) involved?	☐ Yes ☒ No		
20. Does the manufacturer guarantee the control efficiency of the control equipment?	☐ Yes ☒ No (If Yes, attach and label manufacturer guarantee)		

	Pollutant Controlled					
	PM	PM10	SO_2	NOx	VOC	CO
Control Efficiency	100%	100%				

21. If manufacturer's data is not available, attach a separate sheet of paper to provide the control equipment design specifications and performance data to support the above mentioned control efficiency.

EMISSION UNIT OPERATING SCHEDULE (hours/day, hours/year, or other)

22.	Actual Operation:	TBD
23.	Maximum Operation:	8760 HRS/YEAR

REQUESTED LIMITS

24.	Are you requesting any permit limits?	☐ Yes ☒ No (If Yes, indicate all that apply below)
	☐ Operation Hour Limit(s):	
	☐ Production Limit(s):	
	☐ Material Usage Limit(s):	
	☐ Limits Based on Stack Testing:	Please attach all relevant stack testing summary reports
	☐ Other:	
25.	Rationale for Requesting the Limit(s):	

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1. Company Name:	2. Facility Name:	3. Facility ID No:
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EMISSIONS UNIT (PROCESS) IDENTIFICATION & DESCRIPTION

5.	Emissions Unit (EU) Name:	MILL FEED SCREWS #1-4 TO CONDITIONING SCREWS #1-4
6.	EU ID Number:	FS24
7.	EU Type:	☒ New Source ☐ Unpermitted Existing Source ☐ Modification to a Permitted Source -- Previous Permit #: Date Issued:
8.	Manufacturer:	N/A
9.	Model:	N/A
10..	Maximum Capacity:	16 TON/HR, 220,500 TON/YEAR
11.	Date of Construction:	TBD
12.	Date of Modification (if any):	N/A
13.	Is this a Controlled Emission Unit?	☐ No ☒ Yes If Yes, complete the following section. If No, go to line 22.

EMISSIONS CONTROL EQUIPMENT

14. Control Equipment Name and ID:	Inside Building		
15. Date of Installation:	TBD	16. Date of Modification (if any):	N/A
17. Manufacturer and Model Number:	TBD		
18. ID(s) of Emission Unit Controlled:	FS24		
19. Is operating schedule different than emission units(s) involved?	☐ Yes ☒ No		
20. Does the manufacturer guarantee the control efficiency of the control equipment?	☐ Yes ☒ No (If Yes, attach and label manufacturer guarantee)		

	Pollutant Controlled					
	PM	PM10	SO_2	NOx	VOC	CO
Control Efficiency	100%	100%				

21. If manufacturer's data is not available, attach a separate sheet of paper to provide the control equipment design specifications and performance data to support the above mentioned control efficiency.

EMISSION UNIT OPERATING SCHEDULE (hours/day, hours/year, or other)

22.	Actual Operation:	TBD
23.	Maximum Operation:	8760 HRS/YEAR

REQUESTED LIMITS

24.	Are you requesting any permit limits?	☐ Yes ☒ No (If Yes, indicate all that apply below)
	☐ Operation Hour Limit(s):	
	☐ Production Limit(s):	
	☐ Material Usage Limit(s):	
	☐ Limits Based on Stack Testing:	Please attach all relevant stack testing summary reports
	☐ Other:	
25.	Rationale for Requesting the Limit(s):	

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1. Company Name:	2. Facility Name:	3. Facility ID No:
Centennial Renewable Energy	Potlach Facility	

4. Brief Project Description:	CRE is proposing to construct and operate a Greenfield wood pellet production facility near Potlach, Idaho. The facility will produce a proprietary product known as SteamEx Pellets with technology from

EMISSIONS UNIT (PROCESS) IDENTIFICATION & DESCRIPTION

5.	Emissions Unit (EU) Name:	PELLET MILLS #1-4 & TRANSFERS
6.	EU ID Number:	FS25
7.	EU Type:	☒ New Source ☐ Unpermitted Existing Source ☐ Modification to a Permitted Source -- Previous Permit #: Date Issued:
8.	Manufacturer:	N/A
9.	Model:	N/A
10..	Maximum Capacity:	16 TON/HR, 220,500 TON/YEAR
11.	Date of Construction:	TBD
12.	Date of Modification (if any):	N/A
13.	Is this a Controlled Emission Unit?	☐ No ☒ Yes If Yes, complete the following section. If No, go to line 22.

EMISSIONS CONTROL EQUIPMENT

14. Control Equipment Name and ID:	Inside Building		
15. Date of Installation:	TBD	16. Date of Modification (if any):	N/A
17. Manufacturer and Model Number:	TBD		
18. ID(s) of Emission Unit Controlled:	FS25		
19. Is operating schedule different than emission units(s) involved?	☐ Yes ☒ No		
20. Does the manufacturer guarantee the control efficiency of the control equipment?	☐ Yes ☒ No (If Yes, attach and label manufacturer guarantee)		

	Pollutant Controlled					
	PM	PM10	SO_2	NOx	VOC	CO
Control Efficiency	100%	100%				

21. If manufacturer's data is not available, attach a separate sheet of paper to provide the control equipment design specifications and performance data to support the above mentioned control efficiency.

EMISSION UNIT OPERATING SCHEDULE (hours/day, hours/year, or other)

22.	Actual Operation:	TBD
23.	Maximum Operation:	8760 HRS/YEAR

REQUESTED LIMITS

24.	Are you requesting any permit limits?	☐ Yes ☒ No (If Yes, indicate all that apply below)
	☐ Operation Hour Limit(s):	
	☐ Production Limit(s):	
	☐ Material Usage Limit(s):	
	☐ Limits Based on Stack Testing:	Please attach all relevant stack testing summary reports
	☐ Other:	
25.	Rationale for Requesting the Limit(s):	

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Emissions Unit - General **Form EU0**
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IDENTIFICATION

1. Company Name:	2. Facility Name:	3. Facility ID No:
Centennial Renewable Energy	Potlach Facility	

4. Brief Project Description:	CRE is proposing to construct and operate a Greenfield wood pellet production facility near Potlach, Idaho. The facility will produce a proprietary product known as SteamEx Pellets with technology from

EMISSIONS UNIT (PROCESS) IDENTIFICATION & DESCRIPTION

5.	Emissions Unit (EU) Name:	CONVEYOR #9 TO PELLET COOLER #1
6.	EU ID Number:	FS26
7.	EU Type:	☒ New Source ☐ Unpermitted Existing Source ☐ Modification to a Permitted Source -- Previous Permit #: Date Issued:
8.	Manufacturer:	N/A
9.	Model:	N/A
10..	Maximum Capacity:	16 TON/HR, 220,500 TON/YEAR
11.	Date of Construction:	TBD
12.	Date of Modification (if any):	N/A
13.	Is this a Controlled Emission Unit?	☐ No ☒ Yes If Yes, complete the following section. If No, go to line 22.

EMISSIONS CONTROL EQUIPMENT

14. Control Equipment Name and ID:	Inside Building		
15. Date of Installation:	TBD	16. Date of Modification (if any):	N/A
17. Manufacturer and Model Number:	TBD		
18. ID(s) of Emission Unit Controlled:	FS26		
19. Is operating schedule different than emission units(s) involved?	☐ Yes ☒ No		
20. Does the manufacturer guarantee the control efficiency of the control equipment?	☐ Yes ☒ No (If Yes, attach and label manufacturer guarantee)		

	Pollutant Controlled					
	PM	PM10	SO_2	NOx	VOC	CO
Control Efficiency	100%	100%				

21. If manufacturer's data is not available, attach a separate sheet of paper to provide the control equipment design specifications and performance data to support the above mentioned control efficiency.

EMISSION UNIT OPERATING SCHEDULE (hours/day, hours/year, or other)

22.	Actual Operation:	TBD
23.	Maximum Operation:	8760 HRS/YEAR

REQUESTED LIMITS

24.	Are you requesting any permit limits?	☐ Yes ☒ No (If Yes, indicate all that apply below)
	☐ Operation Hour Limit(s):	
	☐ Production Limit(s):	
	☐ Material Usage Limit(s):	
	☐ Limits Based on Stack Testing:	Please attach all relevant stack testing summary reports
	☐ Other:	
25.	Rationale for Requesting the Limit(s):	

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IDENTIFICATION

1. Company Name:	2. Facility Name:	3. Facility ID No:
Centennial Renewable Energy	Potlach Facility	

4. Brief Project Description:	CRE is proposing to construct and operate a Greenfield wood pellet production facility near Potlach, Idaho. The facility will produce a proprietary product known as SteamEx Pellets with technology from

EMISSIONS UNIT (PROCESS) IDENTIFICATION & DESCRIPTION

5.	Emissions Unit (EU) Name:	PELLET COOLER #1 TO CONVEYOR #11
6.	EU ID Number:	FS27
7.	EU Type:	☒ New Source ☐ Unpermitted Existing Source ☐ Modification to a Permitted Source -- Previous Permit #: Date Issued:
8.	Manufacturer:	N/A
9.	Model:	N/A
10..	Maximum Capacity:	16 TON/HR, 220,500 TON/YEAR
11.	Date of Construction:	TBD
12.	Date of Modification (if any):	N/A
13.	Is this a Controlled Emission Unit?	☐ No ☒ Yes If Yes, complete the following section. If No, go to line 22.

EMISSIONS CONTROL EQUIPMENT

14. Control Equipment Name and ID:	Inside Building		
15. Date of Installation:	TBD	16. Date of Modification (if any):	N/A
17. Manufacturer and Model Number:	TBD		
18. ID(s) of Emission Unit Controlled:	FS27		
19. Is operating schedule different than emission units(s) involved?	☐ Yes ☒ No		
20. Does the manufacturer guarantee the control efficiency of the control equipment?	☐ Yes ☒ No (If Yes, attach and label manufacturer guarantee)		

	Pollutant Controlled					
	PM	PM10	SO_2	NOx	VOC	CO
Control Efficiency	100%	100%				

21. If manufacturer's data is not available, attach a separate sheet of paper to provide the control equipment design specifications and performance data to support the above mentioned control efficiency.

EMISSION UNIT OPERATING SCHEDULE (hours/day, hours/year, or other)

22.	Actual Operation:	TBD
23.	Maximum Operation:	8760 HRS/YEAR

REQUESTED LIMITS

24.	Are you requesting any permit limits?	☐ Yes ☒ No (If Yes, indicate all that apply below)
	☐ Operation Hour Limit(s):	
	☐ Production Limit(s):	
	☐ Material Usage Limit(s):	
	☐ Limits Based on Stack Testing:	Please attach all relevant stack testing summary reports
	☐ Other:	
25.	Rationale for Requesting the Limit(s):	

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IDENTIFICATION

1. Company Name:	2. Facility Name:	3. Facility ID No:
Centennial Renewable Energy	Potlach Facility	

4. Brief Project Description:	CRE is proposing to construct and operate a Greenfield wood pellet production facility near Potlach, Idaho. The facility will produce a proprietary product known as SteamEx Pellets with technology from

EMISSIONS UNIT (PROCESS) IDENTIFICATION & DESCRIPTION

5.	Emissions Unit (EU) Name:	PELLET COOLER #1 TO MULTICLONE #1
6.	EU ID Number:	FS28
7.	EU Type:	☒ New Source ☐ Unpermitted Existing Source ☐ Modification to a Permitted Source -- Previous Permit #: Date Issued:
8.	Manufacturer:	N/A
9.	Model:	N/A
10..	Maximum Capacity:	0.39 TON/HR, 220,500 TON/YEAR
11.	Date of Construction:	TBD
12.	Date of Modification (if any):	N/A
13.	Is this a Controlled Emission Unit?	☐ No ☒ Yes If Yes, complete the following section. If No, go to line 22.

EMISSIONS CONTROL EQUIPMENT

14. Control Equipment Name and ID:	Inside Building		
15. Date of Installation:	TBD	16. Date of Modification (if any):	N/A
17. Manufacturer and Model Number:	TBD		
18. ID(s) of Emission Unit Controlled:	FS28		
19. Is operating schedule different than emission units(s) involved?	☐ Yes ☒ No		
20. Does the manufacturer guarantee the control efficiency of the control equipment?	☐ Yes ☒ No (If Yes, attach and label manufacturer guarantee)		

	Pollutant Controlled					
	PM	PM10	SO_2	NOx	VOC	CO
Control Efficiency	100%	100%				

21. If manufacturer's data is not available, attach a separate sheet of paper to provide the control equipment design specifications and performance data to support the above mentioned control efficiency.

EMISSION UNIT OPERATING SCHEDULE (hours/day, hours/year, or other)

22.	Actual Operation:	TBD
23.	Maximum Operation:	8760 HRS/YEAR

REQUESTED LIMITS

24.	Are you requesting any permit limits?	☐ Yes ☒ No (If Yes, indicate all that apply below)
	☐ Operation Hour Limit(s):	
	☐ Production Limit(s):	
	☐ Material Usage Limit(s):	
	☐ Limits Based on Stack Testing:	Please attach all relevant stack testing summary reports
	☐ Other:	
25.	Rationale for Requesting the Limit(s):	

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IDENTIFICATION

1. Company Name:	2. Facility Name:	3. Facility ID No:
Centennial Renewable Energy	Potlach Facility	

4. Brief Project Description:	CRE is proposing to construct and operate a Greenfield wood pellet production facility near Potlach, Idaho. The facility will produce a proprietary product known as SteamEx Pellets with technology from

EMISSIONS UNIT (PROCESS) IDENTIFICATION & DESCRIPTION

5.	Emissions Unit (EU) Name:	PELLET SCREEN #1 & TRANSFERS
6.	EU ID Number:	FS29
7.	EU Type:	☒ New Source ☐ Unpermitted Existing Source ☐ Modification to a Permitted Source -- Previous Permit #: Date Issued:
8.	Manufacturer:	N/A
9.	Model:	N/A
10..	Maximum Capacity:	16 TON/HR, 220,500 TON/YEAR
11.	Date of Construction:	TBD
12.	Date of Modification (if any):	N/A
13.	Is this a Controlled Emission Unit?	☐ No ☒ Yes If Yes, complete the following section. If No, go to line 22.

EMISSIONS CONTROL EQUIPMENT

14. Control Equipment Name and ID:	Inside Building		
15. Date of Installation:	N/A	16. Date of Modification (if any):	N/A
17. Manufacturer and Model Number:	N/A		
18. ID(s) of Emission Unit Controlled:	FS29		
19. Is operating schedule different than emission units(s) involved?	☐ Yes ☒ No		
20. Does the manufacturer guarantee the control efficiency of the control equipment?	☐ Yes ☒ No (If Yes, attach and label manufacturer guarantee)		

	Pollutant Controlled					
	PM	PM10	SO_2	NOx	VOC	CO
Control Efficiency	100%	100%				

21. If manufacturer's data is not available, attach a separate sheet of paper to provide the control equipment design specifications and performance data to support the above mentioned control efficiency.

EMISSION UNIT OPERATING SCHEDULE (hours/day, hours/year, or other)

22.	Actual Operation:	TBD
23.	Maximum Operation:	8760 HRS/YEAR

REQUESTED LIMITS

24.	Are you requesting any permit limits?	☐ Yes ☒ No (If Yes, indicate all that apply below)
	☐ Operation Hour Limit(s):	
	☐ Production Limit(s):	
	☐ Material Usage Limit(s):	
	☐ Limits Based on Stack Testing:	Please attach all relevant stack testing summary reports
	☐ Other:	
25.	Rationale for Requesting the Limit(s):	

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4. Brief Project Description:	CRE is proposing to construct and operate a Greenfield wood pellet production facility near Potlach, Idaho. The facility will produce a proprietary product known as SteamEx Pellets with technology from

EMISSIONS UNIT (PROCESS) IDENTIFICATION & DESCRIPTION

5.	Emissions Unit (EU) Name:	MULTICLONE #1 TO PNEUMATIC SYSTEM #2
6.	EU ID Number:	FS30
7.	EU Type:	☒ New Source ☐ Unpermitted Existing Source ☐ Modification to a Permitted Source -- Previous Permit #: Date Issued:
8.	Manufacturer:	N/A
9.	Model:	N/A
10..	Maximum Capacity:	0.39 TON/HR, 220,500 TON/YEAR
11.	Date of Construction:	TBD
12.	Date of Modification (if any):	N/A
13.	Is this a Controlled Emission Unit?	☐ No ☒ Yes If Yes, complete the following section. If No, go to line 22.

EMISSIONS CONTROL EQUIPMENT

14. Control Equipment Name and ID:	Inside Building		
15. Date of Installation:	N/A	16. Date of Modification (if any):	N/A
17. Manufacturer and Model Number:	N/A		
18. ID(s) of Emission Unit Controlled:	FS30		
19. Is operating schedule different than emission units(s) involved?	☐ Yes ☒ No		
20. Does the manufacturer guarantee the control efficiency of the control equipment?	☐ Yes ☒ No (If Yes, attach and label manufacturer guarantee)		

	Pollutant Controlled					
	PM	PM10	SO_2	NOx	VOC	CO
Control Efficiency	100%	100%				

21. If manufacturer's data is not available, attach a separate sheet of paper to provide the control equipment design specifications and performance data to support the above mentioned control efficiency.

EMISSION UNIT OPERATING SCHEDULE (hours/day, hours/year, or other)

22.	Actual Operation:	TBD
23.	Maximum Operation:	8760 HRS/YEAR

REQUESTED LIMITS

24.	Are you requesting any permit limits?	☐ Yes ☒ No (If Yes, indicate all that apply below)
	☐ Operation Hour Limit(s):	
	☐ Production Limit(s):	
	☐ Material Usage Limit(s):	
	☐ Limits Based on Stack Testing:	Please attach all relevant stack testing summary reports
	☐ Other:	
25.	Rationale for Requesting the Limit(s):	

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EMISSIONS UNIT (PROCESS) IDENTIFICATION & DESCRIPTION

5.	Emissions Unit (EU) Name:	CONVEYOR #6 TO CONVEYOR #8
6.	EU ID Number:	FS31
7.	EU Type:	☒ New Source ☐ Unpermitted Existing Source ☐ Modification to a Permitted Source -- Previous Permit #: Date Issued:
8.	Manufacturer:	N/A
9.	Model:	N/A
10..	Maximum Capacity:	16 TON/HR, 220,500 TON/YEAR
11.	Date of Construction:	TBD
12.	Date of Modification (if any):	N/A
13.	Is this a Controlled Emission Unit?	☐ No ☒ Yes If Yes, complete the following section. If No, go to line 22.

EMISSIONS CONTROL EQUIPMENT

14. Control Equipment Name and ID:	Inside Building		
15. Date of Installation:	TBD	16. Date of Modification (if any):	N/A
17. Manufacturer and Model Number:	TBD		
18. ID(s) of Emission Unit Controlled:	FS31		
19. Is operating schedule different than emission units(s) involved?	☐ Yes ☒ No		
20. Does the manufacturer guarantee the control efficiency of the control equipment?	☐ Yes ☒ No (If Yes, attach and label manufacturer guarantee)		

	Pollutant Controlled					
	PM	PM10	SO_2	NOx	VOC	CO
Control Efficiency	100%	100%				

21. If manufacturer's data is not available, attach a separate sheet of paper to provide the control equipment design specifications and performance data to support the above mentioned control efficiency.

EMISSION UNIT OPERATING SCHEDULE (hours/day, hours/year, or other)

22.	Actual Operation:	TBD
23.	Maximum Operation:	8760 HRS/YEAR

REQUESTED LIMITS

24.	Are you requesting any permit limits?	☐ Yes ☒ No (If Yes, indicate all that apply below)
	☐ Operation Hour Limit(s):	
	☐ Production Limit(s):	
	☐ Material Usage Limit(s):	
	☐ Limits Based on Stack Testing:	Please attach all relevant stack testing summary reports
	☐ Other:	
25.	Rationale for Requesting the Limit(s):	

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IDENTIFICATION

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Centennial Renewable Energy	Potlach Facility	

4. Brief Project Description:	CRE is proposing to construct and operate a Greenfield wood pellet production facility near Potlach, Idaho. The facility will produce a proprietary product known as SteamEx Pellets with technology from

EMISSIONS UNIT (PROCESS) IDENTIFICATION & DESCRIPTION

5.	Emissions Unit (EU) Name:	CONVEYOR #8 TO MILL FEED BIN #3 AND #4
6.	EU ID Number:	FS32
7.	EU Type:	☒ New Source ☐ Unpermitted Existing Source ☐ Modification to a Permitted Source -- Previous Permit #: Date Issued:
8.	Manufacturer:	N/A
9.	Model:	N/A
10..	Maximum Capacity:	16 TON/HR, 220,500 TON/YEAR
11.	Date of Construction:	TBD
12.	Date of Modification (if any):	N/A
13.	Is this a Controlled Emission Unit?	☐ No ☒ Yes If Yes, complete the following section. If No, go to line 22.

EMISSIONS CONTROL EQUIPMENT

14. Control Equipment Name and ID:	Inside Building		
15. Date of Installation:	TBD	16. Date of Modification (if any):	N/A
17. Manufacturer and Model Number:	TBD		
18. ID(s) of Emission Unit Controlled:	FS32		
19. Is operating schedule different than emission units(s) involved?	☐ Yes ☒ No		
20. Does the manufacturer guarantee the control efficiency of the control equipment?	☐ Yes ☒ No (If Yes, attach and label manufacturer guarantee)		

	Pollutant Controlled					
	PM	PM10	SO_2	NOx	VOC	CO
Control Efficiency	100%	100%				

21. If manufacturer's data is not available, attach a separate sheet of paper to provide the control equipment design specifications and performance data to support the above mentioned control efficiency.

EMISSION UNIT OPERATING SCHEDULE (hours/day, hours/year, or other)

22.	Actual Operation:	TBD
23.	Maximum Operation:	8760 HRS/YEAR

REQUESTED LIMITS

24.	Are you requesting any permit limits?	☐ Yes ☒ No (If Yes, indicate all that apply below)
	☐ Operation Hour Limit(s):	
	☐ Production Limit(s):	
	☐ Material Usage Limit(s):	
	☐ Limits Based on Stack Testing:	Please attach all relevant stack testing summary reports
	☐ Other:	
25.	Rationale for Requesting the Limit(s):	

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Emissions Unit - General **Form EU0**
Revision 4
08/28/08

Please see instructions on page 2 before filling out the form.

IDENTIFICATION

1. Company Name:	2. Facility Name:	3. Facility ID No:
Centennial Renewable Energy	Potlach Facility	

4. Brief Project Description:	CRE is proposing to construct and operate a Greenfield wood pellet production facility near Potlach, Idaho. The facility will produce a proprietary product known as SteamEx Pellets with technology from

EMISSIONS UNIT (PROCESS) IDENTIFICATION & DESCRIPTION

5.	Emissions Unit (EU) Name:	MILL FEED BIN #3 AND #4 TO MILL FEED SCREWS #5-8
6.	EU ID Number:	FS33
7.	EU Type:	☒ New Source ☐ Unpermitted Existing Source ☐ Modification to a Permitted Source -- Previous Permit #: Date Issued:
8.	Manufacturer:	N/A
9.	Model:	N/A
10..	Maximum Capacity:	16 TON/HR, 220,500 TON/YEAR
11.	Date of Construction:	TBD
12.	Date of Modification (if any):	N/A
13.	Is this a Controlled Emission Unit?	☐ No ☒ Yes If Yes, complete the following section. If No, go to line 22.

EMISSIONS CONTROL EQUIPMENT

14. Control Equipment Name and ID:	Inside BuildinG		
15. Date of Installation:	TBD	16. Date of Modification (if any):	N/A
17. Manufacturer and Model Number:	TBD		
18. ID(s) of Emission Unit Controlled:	FS33		
19. Is operating schedule different than emission units(s) involved?	☐ Yes ☒ No		
20. Does the manufacturer guarantee the control efficiency of the control equipment?	☐ Yes ☒ No (If Yes, attach and label manufacturer guarantee)		

	Pollutant Controlled					
	PM	PM10	SO_2	NOx	VOC	CO
Control Efficiency	100%	100%				

21. If manufacturer's data is not available, attach a separate sheet of paper to provide the control equipment design specifications and performance data to support the above mentioned control efficiency.

EMISSION UNIT OPERATING SCHEDULE (hours/day, hours/year, or other)

22.	Actual Operation:	TBD
23.	Maximum Operation:	8760 HRS/YEAR

REQUESTED LIMITS

24.	Are you requesting any permit limits?	☐ Yes ☒ No (If Yes, indicate all that apply below)
	☐ Operation Hour Limit(s):	
	☐ Production Limit(s):	
	☐ Material Usage Limit(s):	
	☐ Limits Based on Stack Testing:	Please attach all relevant stack testing summary reports
	☐ Other:	
25.	Rationale for Requesting the Limit(s):	

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Emissions Unit - General **Form EU0**
Revision 4
08/28/08

Please see instructions on page 2 before filling out the form.

IDENTIFICATION

1. Company Name:	2. Facility Name:	3. Facility ID No:
Centennial Renewable Energy	Potlach Facility	

4. Brief Project Description:	CRE is proposing to construct and operate a Greenfield wood pellet production facility near Potlach, Idaho. The facility will produce a proprietary product known as SteamEx Pellets with technology from

EMISSIONS UNIT (PROCESS) IDENTIFICATION & DESCRIPTION

5.	Emissions Unit (EU) Name:	MILL FEED SCREWS #5-8 TO CONDITIONING SCREWS #5-8
6.	EU ID Number:	FS6
7.	EU Type:	☒ New Source ☐ Unpermitted Existing Source ☐ Modification to a Permitted Source -- Previous Permit #: Date Issued:
8.	Manufacturer:	N/A
9.	Model:	N/A
10..	Maximum Capacity:	16 TON/HR, 220,500 TON/YEAR
11.	Date of Construction:	TBD
12.	Date of Modification (if any):	N/A
13.	Is this a Controlled Emission Unit?	☐ No ☒ Yes If Yes, complete the following section. If No, go to line 22.

EMISSIONS CONTROL EQUIPMENT

14. Control Equipment Name and ID:	Inside Building		
15. Date of Installation:	TBD	16. Date of Modification (if any):	N/A
17. Manufacturer and Model Number:	TBD		
18. ID(s) of Emission Unit Controlled:	FS6		
19. Is operating schedule different than emission units(s) involved?	☐ Yes ☒ No		
20. Does the manufacturer guarantee the control efficiency of the control equipment?	☐ Yes ☒ No (If Yes, attach and label manufacturer guarantee)		

	Pollutant Controlled					
	PM	PM10	SO_2	NOx	VOC	CO
Control Efficiency	100%	100%				

21. If manufacturer's data is not available, attach a separate sheet of paper to provide the control equipment design specifications and performance data to support the above mentioned control efficiency.

EMISSION UNIT OPERATING SCHEDULE (hours/day, hours/year, or other)

22.	Actual Operation:	TBD
23.	Maximum Operation:	8760 HRS/YEAR

REQUESTED LIMITS

24.	Are you requesting any permit limits?	☐ Yes ☒ No (If Yes, indicate all that apply below)
	☐ Operation Hour Limit(s):	
	☐ Production Limit(s):	
	☐ Material Usage Limit(s):	
	☐ Limits Based on Stack Testing:	Please attach all relevant stack testing summary reports
	☐ Other:	
25.	Rationale for Requesting the Limit(s):	

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Emissions Unit - General **Form EU0**
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IDENTIFICATION

1. Company Name:	2. Facility Name:	3. Facility ID No:
Centennial Renewable Energy	Potlach Facility	

4. Brief Project Description:	CRE is proposing to construct and operate a Greenfield wood pellet production facility near Potlach, Idaho. The facility will produce a proprietary product known as SteamEx Pellets with technology from

EMISSIONS UNIT (PROCESS) IDENTIFICATION & DESCRIPTION

5.	Emissions Unit (EU) Name:	PELLET MILLS #5-8 & TRANSFERS
6.	EU ID Number:	FS35
7.	EU Type:	☒ New Source ☐ Unpermitted Existing Source ☐ Modification to a Permitted Source -- Previous Permit #: Date Issued:
8.	Manufacturer:	N/A
9.	Model:	N/A
10..	Maximum Capacity:	16 TON/HR, 220,500 TON/YEAR
11.	Date of Construction:	TBD
12.	Date of Modification (if any):	N/A
13.	Is this a Controlled Emission Unit?	☐ No ☒ Yes If Yes, complete the following section. If No, go to line 22.

EMISSIONS CONTROL EQUIPMENT

14. Control Equipment Name and ID:	Inside Building		
15. Date of Installation:	TBD	16. Date of Modification (if any):	N/A
17. Manufacturer and Model Number:	TBD		
18. ID(s) of Emission Unit Controlled:	FS35		
19. Is operating schedule different than emission units(s) involved?	☐ Yes ☒ No		
20. Does the manufacturer guarantee the control efficiency of the control equipment?	☐ Yes ☒ No (If Yes, attach and label manufacturer guarantee)		

	Pollutant Controlled					
	PM	PM10	SO_2	NOx	VOC	CO
Control Efficiency	100%	100%				

21. If manufacturer's data is not available, attach a separate sheet of paper to provide the control equipment design specifications and performance data to support the above mentioned control efficiency.

EMISSION UNIT OPERATING SCHEDULE (hours/day, hours/year, or other)

22.	Actual Operation:	TBD
23.	Maximum Operation:	8760 HRS/YEAR

REQUESTED LIMITS

24.	Are you requesting any permit limits?	☐ Yes ☒ No (If Yes, indicate all that apply below)
	☐ Operation Hour Limit(s):	
	☐ Production Limit(s):	
	☐ Material Usage Limit(s):	
	☐ Limits Based on Stack Testing:	Please attach all relevant stack testing summary reports
	☐ Other:	
25.	Rationale for Requesting the Limit(s):	

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Emissions Unit - General **Form EU0**
Revision 4
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IDENTIFICATION

1. Company Name:	2. Facility Name:	3. Facility ID No:
Centennial Renewable Energy	Potlach Facility	

4. Brief Project Description:	CRE is proposing to construct and operate a Greenfield wood pellet production facility near Potlach, Idaho. The facility will produce a proprietary product known as SteamEx Pellets with technology from

EMISSIONS UNIT (PROCESS) IDENTIFICATION & DESCRIPTION

5.	Emissions Unit (EU) Name:	CONVEYOR #10 TO PELLET COOLER #2
6.	EU ID Number:	FS36
7.	EU Type:	☒ New Source ☐ Unpermitted Existing Source ☐ Modification to a Permitted Source -- Previous Permit #: Date Issued:
8.	Manufacturer:	N/A
9.	Model:	N/A
10..	Maximum Capacity:	16 TON/HR, 220,500 TON/YEAR
11.	Date of Construction:	TBD
12.	Date of Modification (if any):	N/A
13.	Is this a Controlled Emission Unit?	☐ No ☒ Yes If Yes, complete the following section. If No, go to line 22.

EMISSIONS CONTROL EQUIPMENT

14. Control Equipment Name and ID:	Inside Building		
15. Date of Installation:	TBD	16. Date of Modification (if any):	N/A
17. Manufacturer and Model Number:	TBD		
18. ID(s) of Emission Unit Controlled:	FS36		
19. Is operating schedule different than emission units(s) involved?	☐ Yes ☒ No		
20. Does the manufacturer guarantee the control efficiency of the control equipment?	☐ Yes ☒ No (If Yes, attach and label manufacturer guarantee)		

	Pollutant Controlled					
	PM	PM10	SO_2	NOx	VOC	CO
Control Efficiency	100%	100%				

21. If manufacturer's data is not available, attach a separate sheet of paper to provide the control equipment design specifications and performance data to support the above mentioned control efficiency.

EMISSION UNIT OPERATING SCHEDULE (hours/day, hours/year, or other)

22.	Actual Operation:	TBD
23.	Maximum Operation:	8760 HRS/YEAR

REQUESTED LIMITS

24.	Are you requesting any permit limits?	☐ Yes ☒ No (If Yes, indicate all that apply below)
	☐ Operation Hour Limit(s):	
	☐ Production Limit(s):	
	☐ Material Usage Limit(s):	
	☐ Limits Based on Stack Testing:	Please attach all relevant stack testing summary reports
	☐ Other:	
25.	Rationale for Requesting the Limit(s):	

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Emissions Unit - General **Form EU0**
Revision 4
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IDENTIFICATION

1. Company Name:	2. Facility Name:	3. Facility ID No:
Centennial Renewable Energy	Potlach Facility	

4. Brief Project Description:	CRE is proposing to construct and operate a Greenfield wood pellet production facility near Potlach, Idaho. The facility will produce a proprietary product known as SteamEx Pellets with technology from

EMISSIONS UNIT (PROCESS) IDENTIFICATION & DESCRIPTION

5.	Emissions Unit (EU) Name:	PELLET COOLER #2 TO CONVEYOR #12
6.	EU ID Number:	FS37
7.	EU Type:	☒ New Source ☐ Unpermitted Existing Source ☐ Modification to a Permitted Source -- Previous Permit #: Date Issued:
8.	Manufacturer:	N/A
9.	Model:	N/A
10..	Maximum Capacity:	16 TON/HR, 220,500 TON/YEAR
11.	Date of Construction:	TBD
12.	Date of Modification (if any):	N/A
13.	Is this a Controlled Emission Unit?	☐ No ☒ Yes If Yes, complete the following section. If No, go to line 22.

EMISSIONS CONTROL EQUIPMENT

14. Control Equipment Name and ID:	Inside Building		
15. Date of Installation:	TBD	16. Date of Modification (if any):	N/A
17. Manufacturer and Model Number:	TBD		
18. ID(s) of Emission Unit Controlled:	FS37		
19. Is operating schedule different than emission units(s) involved?	☐ Yes ☒ No		
20. Does the manufacturer guarantee the control efficiency of the control equipment?	☐ Yes ☒ No (If Yes, attach and label manufacturer guarantee)		

	Pollutant Controlled					
	PM	PM10	SO_2	NOx	VOC	CO
Control Efficiency	100%	100%				

21. If manufacturer's data is not available, attach a separate sheet of paper to provide the control equipment design specifications and performance data to support the above mentioned control efficiency.

EMISSION UNIT OPERATING SCHEDULE (hours/day, hours/year, or other)

22.	Actual Operation:	TBD
23.	Maximum Operation:	8760 HRS/YEAR

REQUESTED LIMITS

24.	Are you requesting any permit limits?	☐ Yes ☒ No (If Yes, indicate all that apply below)
	☐ Operation Hour Limit(s):	
	☐ Production Limit(s):	
	☐ Material Usage Limit(s):	
	☐ Limits Based on Stack Testing:	Please attach all relevant stack testing summary reports
	☐ Other:	
25.	Rationale for Requesting the Limit(s):	

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Emissions Unit - General **Form EU0**
Revision 4
08/28/08

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IDENTIFICATION

1. Company Name:	2. Facility Name:	3. Facility ID No:
Centennial Renewable Energy	Potlach Facility	

4. Brief Project Description:	CRE is proposing to construct and operate a Greenfield wood pellet production facility near Potlach, Idaho. The facility will produce a proprietary product known as SteamEx Pellets with technology from

EMISSIONS UNIT (PROCESS) IDENTIFICATION & DESCRIPTION

5.	Emissions Unit (EU) Name:	PELLET COOLER #2 TO MULTICLONE #2
6.	EU ID Number:	FS38
7.	EU Type:	☒ New Source ☐ Unpermitted Existing Source ☐ Modification to a Permitted Source -- Previous Permit #: Date Issued:
8.	Manufacturer:	N/A
9.	Model:	N/A
10..	Maximum Capacity:	0.39 TON/HR, 220,500 TON/YEAR
11.	Date of Construction:	TBD
12.	Date of Modification (if any):	N/A
13.	Is this a Controlled Emission Unit?	☐ No ☒ Yes If Yes, complete the following section. If No, go to line 22.

EMISSIONS CONTROL EQUIPMENT

14. Control Equipment Name and ID:	Inside Building		
15. Date of Installation:	TBD	16. Date of Modification (if any):	N/A
17. Manufacturer and Model Number:	TBD		
18. ID(s) of Emission Unit Controlled:	FS38		
19. Is operating schedule different than emission units(s) involved?	☐ Yes ☒ No		
20. Does the manufacturer guarantee the control efficiency of the control equipment?	☐ Yes ☒ No (If Yes, attach and label manufacturer guarantee)		

	Pollutant Controlled					
	PM	PM10	SO_2	NOx	VOC	CO
Control Efficiency	100%	100%				

21. If manufacturer's data is not available, attach a separate sheet of paper to provide the control equipment design specifications and performance data to support the above mentioned control efficiency.

EMISSION UNIT OPERATING SCHEDULE (hours/day, hours/year, or other)

22.	Actual Operation:	TBD
23.	Maximum Operation:	8760 HRS/YEAR

REQUESTED LIMITS

24.	Are you requesting any permit limits?	☐ Yes ☒ No (If Yes, indicate all that apply below)
	☐ Operation Hour Limit(s):	
	☐ Production Limit(s):	
	☐ Material Usage Limit(s):	
	☐ Limits Based on Stack Testing:	Please attach all relevant stack testing summary reports
	☐ Other:	
25.	Rationale for Requesting the Limit(s):	

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Emissions Unit - General **Form EU0**
Revision 4
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IDENTIFICATION

1. Company Name:	2. Facility Name:	3. Facility ID No:
Centennial Renewable Energy	Potlach Facility	

4. Brief Project Description:	CRE is proposing to construct and operate a Greenfield wood pellet production facility near Potlach, Idaho. The facility will produce a proprietary product known as SteamEx Pellets with technology from

EMISSIONS UNIT (PROCESS) IDENTIFICATION & DESCRIPTION

5.	Emissions Unit (EU) Name:	PELLET SCREEN #2 & TRANSFERS
6.	EU ID Number:	FS39
7.	EU Type:	☒ New Source ☐ Unpermitted Existing Source ☐ Modification to a Permitted Source -- Previous Permit #: Date Issued:
8.	Manufacturer:	N/A
9.	Model:	N/A
10..	Maximum Capacity:	16 TON/HR, 220,500 TON/YEAR
11.	Date of Construction:	TBD
12.	Date of Modification (if any):	N/A
13.	Is this a Controlled Emission Unit?	☐ No ☒ Yes If Yes, complete the following section. If No, go to line 22.

EMISSIONS CONTROL EQUIPMENT

14. Control Equipment Name and ID:	Inside Building		
15. Date of Installation:	TBD	16. Date of Modification (if any):	N/A
17. Manufacturer and Model Number:	TBD		
18. ID(s) of Emission Unit Controlled:	FS39		
19. Is operating schedule different than emission units(s) involved?	☐ Yes ☒ No		
20. Does the manufacturer guarantee the control efficiency of the control equipment?	☐ Yes ☒ No (If Yes, attach and label manufacturer guarantee)		

	Pollutant Controlled					
	PM	PM10	SO_2	NOx	VOC	CO
Control Efficiency	100%	100%				

21. If manufacturer's data is not available, attach a separate sheet of paper to provide the control equipment design specifications and performance data to support the above mentioned control efficiency.

EMISSION UNIT OPERATING SCHEDULE (hours/day, hours/year, or other)

22.	Actual Operation:	TBD
23.	Maximum Operation:	8760 HRS/YEAR

REQUESTED LIMITS

24.	Are you requesting any permit limits?	☐ Yes ☒ No (If Yes, indicate all that apply below)
	☐ Operation Hour Limit(s):	
	☐ Production Limit(s):	
	☐ Material Usage Limit(s):	
	☐ Limits Based on Stack Testing:	Please attach all relevant stack testing summary reports
	☐ Other:	
25.	Rationale for Requesting the Limit(s):	

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Emissions Unit - General **Form EU0**
Revision 4
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IDENTIFICATION

1. Company Name:	2. Facility Name:	3. Facility ID No:
Centennial Renewable Energy	Potlach Facility	

4. Brief Project Description:	CRE is proposing to construct and operate a Greenfield wood pellet production facility near Potlach, Idaho. The facility will produce a proprietary product known as SteamEx Pellets with technology from

EMISSIONS UNIT (PROCESS) IDENTIFICATION & DESCRIPTION

5.	Emissions Unit (EU) Name:	MULTICLONE #2 TO PNEUMATIC SYSTEM #2
6.	EU ID Number:	FS40
7.	EU Type:	☒ New Source ☐ Unpermitted Existing Source ☐ Modification to a Permitted Source -- Previous Permit #: Date Issued:
8.	Manufacturer:	N/A
9.	Model:	N/A
10..	Maximum Capacity:	0.39 TON/HR, 220,500 TON/YEAR
11.	Date of Construction:	TBD
12.	Date of Modification (if any):	N/A
13.	Is this a Controlled Emission Unit?	☐ No ☒ Yes If Yes, complete the following section. If No, go to line 22.

EMISSIONS CONTROL EQUIPMENT

14. Control Equipment Name and ID:	Inside Building		
15. Date of Installation:	TBD	16. Date of Modification (if any):	N/A
17. Manufacturer and Model Number:	TBD		
18. ID(s) of Emission Unit Controlled:	FS40		
19. Is operating schedule different than emission units(s) involved?	☐ Yes ☒ No		
20. Does the manufacturer guarantee the control efficiency of the control equipment?	☐ Yes ☒ No (If Yes, attach and label manufacturer guarantee)		

	Pollutant Controlled					
	PM	PM10	SO_2	NOx	VOC	CO
Control Efficiency	100%	100%				

21. If manufacturer's data is not available, attach a separate sheet of paper to provide the control equipment design specifications and performance data to support the above mentioned control efficiency.

EMISSION UNIT OPERATING SCHEDULE (hours/day, hours/year, or other)

22.	Actual Operation:	TBD
23.	Maximum Operation:	8760 HRS/YEAR

REQUESTED LIMITS

24.	Are you requesting any permit limits?	☐ Yes ☒ No (If Yes, indicate all that apply below)
	☐ Operation Hour Limit(s):	
	☐ Production Limit(s):	
	☐ Material Usage Limit(s):	
	☐ Limits Based on Stack Testing:	Please attach all relevant stack testing summary reports
	☐ Other:	
25.	Rationale for Requesting the Limit(s):	

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Emissions Unit - General **Form EU0**
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IDENTIFICATION

1. Company Name:	2. Facility Name:	3. Facility ID No:
Centennial Renewable Energy	Potlach Facility	

4. Brief Project Description:	CRE is proposing to construct and operate a Greenfield wood pellet production facility near Potlach, Idaho. The facility will produce a proprietary product known as SteamEx Pellets with technology from

EMISSIONS UNIT (PROCESS) IDENTIFICATION & DESCRIPTION

5.	Emissions Unit (EU) Name:	PNEUMATIC SYSTEM #2 TO SURGE BIN #1
6.	EU ID Number:	FS41
7.	EU Type:	☒ New Source ☐ Unpermitted Existing Source ☐ Modification to a Permitted Source -- Previous Permit #: Date Issued:
8.	Manufacturer:	N/A
9.	Model:	N/A
10..	Maximum Capacity:	0.39 TON/HR, 220,500 TON/YEAR
11.	Date of Construction:	TBD
12.	Date of Modification (if any):	N/A
13.	Is this a Controlled Emission Unit?	☐ No ☒ Yes If Yes, complete the following section. If No, go to line 22.

EMISSIONS CONTROL EQUIPMENT

14. Control Equipment Name and ID:	Pnuematic Enclosure		
15. Date of Installation:	TBD	16. Date of Modification (if any):	N/A
17. Manufacturer and Model Number:	TBD		
18. ID(s) of Emission Unit Controlled:	FS41		
19. Is operating schedule different than emission units(s) involved?	☐ Yes ☒ No		
20. Does the manufacturer guarantee the control efficiency of the control equipment?	☐ Yes ☒ No (If Yes, attach and label manufacturer guarantee)		

	Pollutant Controlled					
	PM	PM10	SO_2	NOx	VOC	CO
Control Efficiency	100%	100%				

21. If manufacturer's data is not available, attach a separate sheet of paper to provide the control equipment design specifications and performance data to support the above mentioned control efficiency.

EMISSION UNIT OPERATING SCHEDULE (hours/day, hours/year, or other)

22.	Actual Operation:	TBD
23.	Maximum Operation:	8760 HRS/YEAR

REQUESTED LIMITS

24.	Are you requesting any permit limits?	☐ Yes ☒ No (If Yes, indicate all that apply below)
	☐ Operation Hour Limit(s):	
	☐ Production Limit(s):	
	☐ Material Usage Limit(s):	
	☐ Limits Based on Stack Testing:	Please attach all relevant stack testing summary reports
	☐ Other:	
25.	Rationale for Requesting the Limit(s):	

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Emissions Unit - General **Form EU0**
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IDENTIFICATION

1. Company Name:	2. Facility Name:	3. Facility ID No:
Centennial Renewable Energy	Potlach Facility	

4. Brief Project Description:	CRE is proposing to construct and operate a Greenfield wood pellet production facility near Potlach, Idaho. The facility will produce a proprietary product known as SteamEx Pellets with technology from

EMISSIONS UNIT (PROCESS) IDENTIFICATION & DESCRIPTION

5.	Emissions Unit (EU) Name:	PNUEMATIC SYSTEM #3 TO PELLET PRODUCT STOCKPILE
6.	EU ID Number:	FS42
7.	EU Type:	☒ New Source ☐ Unpermitted Existing Source ☐ Modification to a Permitted Source -- Previous Permit #: Date Issued:
8.	Manufacturer:	N/A
9.	Model:	N/A
10..	Maximum Capacity:	33 TON/HR, 220,500 TON/YEAR
11.	Date of Construction:	TBD
12.	Date of Modification (if any):	N/A
13.	Is this a Controlled Emission Unit?	☐ No ☒ Yes If Yes, complete the following section. If No, go to line 22.

EMISSIONS CONTROL EQUIPMENT

14. Control Equipment Name and ID:	Material Moisture Content		
15. Date of Installation:	N/A	16. Date of Modification (if any):	N/A
17. Manufacturer and Model Number:	N/A		
18. ID(s) of Emission Unit Controlled:	FS42		
19. Is operating schedule different than emission units(s) involved?	☐ Yes ☒ No		
20. Does the manufacturer guarantee the control efficiency of the control equipment?	☐ Yes ☒ No (If Yes, attach and label manufacturer guarantee)		

	Pollutant Controlled					
	PM	PM10	SO_2	NOx	VOC	CO
Control Efficiency	4%	4%				

21. If manufacturer's data is not available, attach a separate sheet of paper to provide the control equipment design specifications and performance data to support the above mentioned control efficiency.

EMISSION UNIT OPERATING SCHEDULE (hours/day, hours/year, or other)

22.	Actual Operation:	TBD
23.	Maximum Operation:	8760 HRS/YEAR

REQUESTED LIMITS

24.	Are you requesting any permit limits?	☒ Yes ☐ No (If Yes, indicate all that apply below)
	☒ Operation Hour Limit(s):	6AM TO 6PM
	☐ Production Limit(s):	
	☐ Material Usage Limit(s):	
	☐ Limits Based on Stack Testing:	Please attach all relevant stack testing summary reports
	☐ Other:	
25.	Rationale for Requesting the Limit(s):	AMBIENT AIR IMPACTS

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For assistance, call the
Air Permit Hotline – 1-877-5PERMIT

Emissions Unit - General **Form EU0**
Revision 4
08/28/08

Please see instructions on page 2 before filling out the form.

IDENTIFICATION

1. Company Name:	2. Facility Name:	3. Facility ID No:
Centennial Renewable Energy	Potlach Facility	

4. Brief Project Description:	CRE is proposing to construct and operate a Greenfield wood pellet production facility near Potlach, Idaho. The facility will produce a proprietary product known as SteamEx Pellets with technology from

EMISSIONS UNIT (PROCESS) IDENTIFICATION & DESCRIPTION

5.	Emissions Unit (EU) Name:	PELLET PRODUCT STOCKPILE TO HOPPER #5
6.	EU ID Number:	FS43
7.	EU Type:	☒ New Source ☐ Unpermitted Existing Source ☐ Modification to a Permitted Source -- Previous Permit #: Date Issued:
8.	Manufacturer:	N/A
9.	Model:	N/A
10..	Maximum Capacity:	336 TON/HR, 184,118 TON/YEAR
11.	Date of Construction:	TBD
12.	Date of Modification (if any):	N/A
13.	Is this a Controlled Emission Unit?	☐ No ☒ Yes If Yes, complete the following section. If No, go to line 22.

EMISSIONS CONTROL EQUIPMENT

14. Control Equipment Name and ID:	Material Moisture Content		
15. Date of Installation:	N/A	16. Date of Modification (if any):	N/A
17. Manufacturer and Model Number:	N/A		
18. ID(s) of Emission Unit Controlled:	FS43		
19. Is operating schedule different than emission units(s) involved?	☐ Yes ☒ No		
20. Does the manufacturer guarantee the control efficiency of the control equipment?	☐ Yes ☒ No (If Yes, attach and label manufacturer guarantee)		

	Pollutant Controlled					
	PM	PM10	SO_2	NOx	VOC	CO
Control Efficiency	4%	4%				

21. If manufacturer's data is not available, attach a separate sheet of paper to provide the control equipment design specifications and performance data to support the above mentioned control efficiency.

EMISSION UNIT OPERATING SCHEDULE (hours/day, hours/year, or other)

22.	Actual Operation:	TBD
23.	Maximum Operation:	8760 HRS/YEAR

REQUESTED LIMITS

24.	Are you requesting any permit limits?	☒ Yes ☐ No (If Yes, indicate all that apply below)
	☒ Operation Hour Limit(s):	6AM TO 6PM
	☐ Production Limit(s):	
	☐ Material Usage Limit(s):	
	☐ Limits Based on Stack Testing:	Please attach all relevant stack testing summary reports
	☐ Other:	
25.	Rationale for Requesting the Limit(s):	AMBIENT AIR IMPACTS

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Emissions Unit - General **Form EU0**
Revision 4
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IDENTIFICATION

1. Company Name:	2. Facility Name:	3. Facility ID No:
Centennial Renewable Energy	Potlach Facility	

4. Brief Project Description:	CRE is proposing to construct and operate a Greenfield wood pellet production facility near Potlach, Idaho. The facility will produce a proprietary product known as SteamEx Pellets with technology from

EMISSIONS UNIT (PROCESS) IDENTIFICATION & DESCRIPTION

5.	Emissions Unit (EU) Name:	HOPPER #5 TO CONVEYOR #13
6.	EU ID Number:	FS44
7.	EU Type:	☒ New Source ☐ Unpermitted Existing Source ☐ Modification to a Permitted Source -- Previous Permit #: Date Issued:
8.	Manufacturer:	N/A
9.	Model:	N/A
10..	Maximum Capacity:	336 TON/HR, 184,118 TON/YEAR
11.	Date of Construction:	TBD
12.	Date of Modification (if any):	N/A
13.	Is this a Controlled Emission Unit?	☐ No ☒ Yes If Yes, complete the following section. If No, go to line 22.

EMISSIONS CONTROL EQUIPMENT

14. Control Equipment Name and ID:	Material Moisture Content		
15. Date of Installation:	N/A	16. Date of Modification (if any):	N/A
17. Manufacturer and Model Number:	N/A		
18. ID(s) of Emission Unit Controlled:	FS44		
19. Is operating schedule different than emission units(s) involved?	☐ Yes ☒ No		
20. Does the manufacturer guarantee the control efficiency of the control equipment?	☐ Yes ☒ No (If Yes, attach and label manufacturer guarantee)		

	Pollutant Controlled					
	PM	PM10	SO_2	NOx	VOC	CO
Control Efficiency	4%	4%				

21. If manufacturer's data is not available, attach a separate sheet of paper to provide the control equipment design specifications and performance data to support the above mentioned control efficiency.

EMISSION UNIT OPERATING SCHEDULE (hours/day, hours/year, or other)

22.	Actual Operation:	TBD
23.	Maximum Operation:	8760 HRS/YEAR

REQUESTED LIMITS

24.	Are you requesting any permit limits?	☒ Yes ☐ No (If Yes, indicate all that apply below)
	☒ Operation Hour Limit(s):	6AM TO 6PM
	☐ Production Limit(s):	
	☐ Material Usage Limit(s):	
	☐ Limits Based on Stack Testing:	Please attach all relevant stack testing summary reports
	☐ Other:	
25.	Rationale for Requesting the Limit(s):	AMBIENT AIR IMPACTS

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Emissions Unit - General **Form EU0**
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IDENTIFICATION

1. Company Name:	2. Facility Name:	3. Facility ID No:
Centennial Renewable Energy	Potlach Facility	

4. Brief Project Description:	CRE is proposing to construct and operate a Greenfield wood pellet production facility near Potlach, Idaho. The facility will produce a proprietary product known as SteamEx Pellets with technology from

EMISSIONS UNIT (PROCESS) IDENTIFICATION & DESCRIPTION

5.	Emissions Unit (EU) Name:	SHIPPING SCREENS & TRANSFERS
6.	EU ID Number:	FS45
7.	EU Type:	☒ New Source ☐ Unpermitted Existing Source ☐ Modification to a Permitted Source -- Previous Permit #: Date Issued:
8.	Manufacturer:	N/A
9.	Model:	N/A
10..	Maximum Capacity:	336 TON/HR, 184,118 TON/YEAR
11.	Date of Construction:	TBD
12.	Date of Modification (if any):	N/A
13.	Is this a Controlled Emission Unit?	☐ No ☒ Yes If Yes, complete the following section. If No, go to line 22.

EMISSIONS CONTROL EQUIPMENT

14. Control Equipment Name and ID:	Enclosure		
15. Date of Installation:	TBD	16. Date of Modification (if any):	N/A
17. Manufacturer and Model Number:	TBD		
18. ID(s) of Emission Unit Controlled:	FS45		
19. Is operating schedule different than emission units(s) involved?	☐ Yes ☒ No		
20. Does the manufacturer guarantee the control efficiency of the control equipment?	☐ Yes ☒ No (If Yes, attach and label manufacturer guarantee)		

	Pollutant Controlled					
	PM	PM10	SO_2	NOx	VOC	CO
Control Efficiency	50%	50%				

21. If manufacturer's data is not available, attach a separate sheet of paper to provide the control equipment design specifications and performance data to support the above mentioned control efficiency.

EMISSION UNIT OPERATING SCHEDULE (hours/day, hours/year, or other)

22.	Actual Operation:	TBD
23.	Maximum Operation:	8760 HRS/YEAR

REQUESTED LIMITS

24.	Are you requesting any permit limits?	☒ Yes ☐ No (If Yes, indicate all that apply below)
	☒ Operation Hour Limit(s):	6AM TO 6PM
	☐ Production Limit(s):	
	☐ Material Usage Limit(s):	
	☐ Limits Based on Stack Testing:	Please attach all relevant stack testing summary reports
	☐ Other:	
25.	Rationale for Requesting the Limit(s):	AMBIENT AIR IMPACTS

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Emissions Unit - General **Form EU0**
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IDENTIFICATION

1. Company Name:	2. Facility Name:	3. Facility ID No:
Centennial Renewable Energy	Potlach Facility	

4. Brief Project Description:	CRE is proposing to construct and operate a Greenfield wood pellet production facility near Potlach, Idaho. The facility will produce a proprietary product known as SteamEx Pellets with technology from

EMISSIONS UNIT (PROCESS) IDENTIFICATION & DESCRIPTION

5.	Emissions Unit (EU) Name:	SHIPPING SCREEN TO PNEUMATIC SYSTEM #4
6.	EU ID Number:	FS46
7.	EU Type:	☒ New Source ☐ Unpermitted Existing Source ☐ Modification to a Permitted Source -- Previous Permit #: Date Issued:
8.	Manufacturer:	N/A
9.	Model:	N/A
10..	Maximum Capacity:	4.61 TON/HR, 40,384 TON/YEAR
11.	Date of Construction:	TBD
12.	Date of Modification (if any):	N/A
13.	Is this a Controlled Emission Unit?	☐ No ☒ Yes If Yes, complete the following section. If No, go to line 22.

EMISSIONS CONTROL EQUIPMENT

14. Control Equipment Name and ID:	Pnuematic Enclosure		
15. Date of Installation:	TBD	16. Date of Modification (if any):	N/A
17. Manufacturer and Model Number:	TBD		
18. ID(s) of Emission Unit Controlled:	FS46		
19. Is operating schedule different than emission units(s) involved?	☐ Yes ☒ No		
20. Does the manufacturer guarantee the control efficiency of the control equipment?	☐ Yes ☒ No (If Yes, attach and label manufacturer guarantee)		

	Pollutant Controlled					
	PM	PM10	SO_2	NOx	VOC	CO
Control Efficiency	100%	100%				

21. If manufacturer's data is not available, attach a separate sheet of paper to provide the control equipment design specifications and performance data to support the above mentioned control efficiency.

EMISSION UNIT OPERATING SCHEDULE (hours/day, hours/year, or other)

22.	Actual Operation:	TBD
23.	Maximum Operation:	8760 HRS/YEAR

REQUESTED LIMITS

24.	Are you requesting any permit limits?	☒ Yes ☐ No (If Yes, indicate all that apply below)
	☒ Operation Hour Limit(s):	6AM TO 6PM
	☐ Production Limit(s):	
	☐ Material Usage Limit(s):	
	☐ Limits Based on Stack Testing:	Please attach all relevant stack testing summary reports
	☐ Other:	
25.	Rationale for Requesting the Limit(s):	AMBIENT AIR IMPACTS

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Emissions Unit - General **Form EU0**
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IDENTIFICATION

1. Company Name:	2. Facility Name:	3. Facility ID No:
Centennial Renewable Energy	Potlach Facility	

4. Brief Project Description:	CRE is proposing to construct and operate a Greenfield wood pellet production facility near Potlach, Idaho. The facility will produce a proprietary product known as SteamEx Pellets with technology from

EMISSIONS UNIT (PROCESS) IDENTIFICATION & DESCRIPTION

5.	Emissions Unit (EU) Name:	CONVEYOR #14 TO FILLING SPOUT
6.	EU ID Number:	FS47
7.	EU Type:	☒ New Source ☐ Unpermitted Existing Source ☐ Modification to a Permitted Source -- Previous Permit #: Date Issued:
8.	Manufacturer:	N/A
9.	Model:	N/A
10..	Maximum Capacity:	336 TON/HR, 184,118 TON/YEAR
11.	Date of Construction:	TBD
12.	Date of Modification (if any):	N/A
13.	Is this a Controlled Emission Unit?	☐ No ☒ Yes If Yes, complete the following section. If No, go to line 22.

EMISSIONS CONTROL EQUIPMENT

14. Control Equipment Name and ID:	Material Moisture Content		
15. Date of Installation:	N/A	16. Date of Modification (if any):	N/A
17. Manufacturer and Model Number:	N/A		
18. ID(s) of Emission Unit Controlled:	FS47		
19. Is operating schedule different than emission units(s) involved?	☐ Yes ☒ No		
20. Does the manufacturer guarantee the control efficiency of the control equipment?	☐ Yes ☒ No (If Yes, attach and label manufacturer guarantee)		

	Pollutant Controlled					
	PM	PM10	SO_2	NOx	VOC	CO
Control Efficiency	4%	4%				

21. If manufacturer's data is not available, attach a separate sheet of paper to provide the control equipment design specifications and performance data to support the above mentioned control efficiency.

EMISSION UNIT OPERATING SCHEDULE (hours/day, hours/year, or other)

22.	Actual Operation:	TBD
23.	Maximum Operation:	8760 HRS/YEAR

REQUESTED LIMITS

24.	Are you requesting any permit limits?	☒ Yes ☐ No (If Yes, indicate all that apply below)
	☒ Operation Hour Limit(s):	6AM TO 6PM
	☐ Production Limit(s):	
	☐ Material Usage Limit(s):	
	☐ Limits Based on Stack Testing:	Please attach all relevant stack testing summary reports
	☐ Other:	
25.	Rationale for Requesting the Limit(s):	AMBIENT AIR IMPACTS

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Emissions Unit - General **Form EU0**
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IDENTIFICATION

1. Company Name:	2. Facility Name:	3. Facility ID No:
Centennial Renewable Energy	Potlach Facility	

4. Brief Project Description:	CRE is proposing to construct and operate a Greenfield wood pellet production facility near Potlach, Idaho. The facility will produce a proprietary product known as SteamEx Pellets with technology from

EMISSIONS UNIT (PROCESS) IDENTIFICATION & DESCRIPTION

5.	Emissions Unit (EU) Name:	FILLING SPOUT TO RAIL CAR
6.	EU ID Number:	FS48
7.	EU Type:	☒ New Source ☐ Unpermitted Existing Source ☐ Modification to a Permitted Source -- Previous Permit #: Date Issued:
8.	Manufacturer:	N/A
9.	Model:	N/A
10..	Maximum Capacity:	336 TON/HR, 184,118 TON/YEAR
11.	Date of Construction:	TBD
12.	Date of Modification (if any):	N/A
13.	Is this a Controlled Emission Unit?	☐ No ☒ Yes If Yes, complete the following section. If No, go to line 22.

EMISSIONS CONTROL EQUIPMENT

14. Control Equipment Name and ID:	Material Moisture Content		
15. Date of Installation:	N/A	16. Date of Modification (if any):	N/A
17. Manufacturer and Model Number:	N/A		
18. ID(s) of Emission Unit Controlled:	FS48		
19. Is operating schedule different than emission units(s) involved?	☐ Yes ☒ No		
20. Does the manufacturer guarantee the control efficiency of the control equipment?	☐ Yes ☒ No (If Yes, attach and label manufacturer guarantee)		

	Pollutant Controlled					
	PM	PM10	SO_2	NOx	VOC	CO
Control Efficiency	4%	4%				

21. If manufacturer's data is not available, attach a separate sheet of paper to provide the control equipment design specifications and performance data to support the above mentioned control efficiency.

EMISSION UNIT OPERATING SCHEDULE (hours/day, hours/year, or other)

22.	Actual Operation:	TBD
23.	Maximum Operation:	8760 HRS/YEAR

REQUESTED LIMITS

24.	Are you requesting any permit limits?	☒ Yes ☐ No (If Yes, indicate all that apply below)
	☒ Operation Hour Limit(s):	6AM TO 6PM
	☐ Production Limit(s):	
	☐ Material Usage Limit(s):	
	☐ Limits Based on Stack Testing:	Please attach all relevant stack testing summary reports
	☐ Other:	
25.	Rationale for Requesting the Limit(s):	AMBIENT AIR IMPACTS

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Emissions Unit - General **Form EU0**
Revision 4
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IDENTIFICATION

1. Company Name:	2. Facility Name:	3. Facility ID No:
Centennial Renewable Energy	Potlach Facility	

4. Brief Project Description:	CRE is proposing to construct and operate a Greenfield wood pellet production facility near Potlach, Idaho. The facility will produce a proprietary product known as SteamEx Pellets with technology from

EMISSIONS UNIT (PROCESS) IDENTIFICATION & DESCRIPTION

5.	Emissions Unit (EU) Name:	PNEUMATIC SYSTEM #4 TO SURGE BIN #1
6.	EU ID Number:	FS49
7.	EU Type:	☒ New Source ☐ Unpermitted Existing Source ☐ Modification to a Permitted Source -- Previous Permit #: Date Issued:
8.	Manufacturer:	N/A
9.	Model:	N/A
10..	Maximum Capacity:	4.61 TON/HR, 40,384 TON/YEAR
11.	Date of Construction:	TBD
12.	Date of Modification (if any):	N/A
13.	Is this a Controlled Emission Unit?	☐ No ☒ Yes If Yes, complete the following section. If No, go to line 22.

EMISSIONS CONTROL EQUIPMENT

14. Control Equipment Name and ID:	Pneumatic Enclosure		
15. Date of Installation:	TBD	16. Date of Modification (if any):	N/A
17. Manufacturer and Model Number:	TBD		
18. ID(s) of Emission Unit Controlled:	FS49		
19. Is operating schedule different than emission units(s) involved?	☐ Yes ☒ No		
20. Does the manufacturer guarantee the control efficiency of the control equipment?	☐ Yes ☒ No (If Yes, attach and label manufacturer guarantee)		

	Pollutant Controlled					
	PM	PM10	SO_2	NOx	VOC	CO
Control Efficiency	100%	100%				

21. If manufacturer's data is not available, attach a separate sheet of paper to provide the control equipment design specifications and performance data to support the above mentioned control efficiency.

EMISSION UNIT OPERATING SCHEDULE (hours/day, hours/year, or other)

22.	Actual Operation:	TBD
23.	Maximum Operation:	8760 HRS/YEAR

REQUESTED LIMITS

24.	Are you requesting any permit limits?	☐ Yes ☒ No (If Yes, indicate all that apply below)
	☐ Operation Hour Limit(s):	
	☐ Production Limit(s):	
	☐ Material Usage Limit(s):	
	☐ Limits Based on Stack Testing:	Please attach all relevant stack testing summary reports
	☐ Other:	
25.	Rationale for Requesting the Limit(s):	

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IDENTIFICATION

1. Company Name:	2. Facility Name:	3. Facility ID No:
Centennial Renewable Energy	Potlach Facility	

4. Brief Project Description:	CRE is proposing to construct and operate a Greenfield wood pellet production facility near Potlach, Idaho. The facility will produce a proprietary product known as SteamEx Pellets with technology from

EMISSIONS UNIT (PROCESS) IDENTIFICATION & DESCRIPTION

5.	Emissions Unit (EU) Name:	TRUCK UNLOADING TO HOG FUEL TIPPER
6.	EU ID Number:	HF1
7.	EU Type:	☒ New Source ☐ Unpermitted Existing Source ☐ Modification to a Permitted Source -- Previous Permit #: Date Issued:
8.	Manufacturer:	N/A
9.	Model:	N/A
10..	Maximum Capacity:	36 TON/HR, 100,000 TON/YEAR
11.	Date of Construction:	TBD
12.	Date of Modification (if any):	N/A
13.	Is this a Controlled Emission Unit?	☐ No ☒ Yes If Yes, complete the following section. If No, go to line 22.

EMISSIONS CONTROL EQUIPMENT

14. Control Equipment Name and ID:	Material Moisture Content		
15. Date of Installation:	N/A	16. Date of Modification (if any):	N/A
17. Manufacturer and Model Number:	N/A		
18. ID(s) of Emission Unit Controlled:	HF1		
19. Is operating schedule different than emission units(s) involved?	☐ Yes ☒ No		
20. Does the manufacturer guarantee the control efficiency of the control equipment?	☐ Yes ☒ No (If Yes, attach and label manufacturer guarantee)		

	Pollutant Controlled					
	PM	PM10	SO_2	NOx	VOC	CO
Control Efficiency	50%	50%				

21. If manufacturer's data is not available, attach a separate sheet of paper to provide the control equipment design specifications and performance data to support the above mentioned control efficiency.

EMISSION UNIT OPERATING SCHEDULE (hours/day, hours/year, or other)

22.	Actual Operation:	TBD
23.	Maximum Operation:	8760 HRS/YEAR

REQUESTED LIMITS

24.	Are you requesting any permit limits?	☐ Yes ☒ No (If Yes, indicate all that apply below)
	☐ Operation Hour Limit(s):	
	☐ Production Limit(s):	
	☐ Material Usage Limit(s):	
	☐ Limits Based on Stack Testing:	Please attach all relevant stack testing summary reports
	☐ Other:	
25.	Rationale for Requesting the Limit(s):	

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1. Company Name:	2. Facility Name:	3. Facility ID No:
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4. Brief Project Description:	CRE is proposing to construct and operate a Greenfield wood pellet production facility near Potlach, Idaho. The facility will produce a proprietary product known as SteamEx Pellets with technology from

EMISSIONS UNIT (PROCESS) IDENTIFICATION & DESCRIPTION

5.	Emissions Unit (EU) Name:	Hog Fuel Pile to Hop#4/Screw Feeder #4 via Loader
6.	EU ID Number:	HF2
7.	EU Type:	☒ New Source ☐ Unpermitted Existing Source ☐ Modification to a Permitted Source -- Previous Permit #: Date Issued:
8.	Manufacturer:	N/A
9.	Model:	N/A
10..	Maximum Capacity:	12 TON/HR, 100,000 TON/YEAR
11.	Date of Construction:	TBD
12.	Date of Modification (if any):	N/A
13.	Is this a Controlled Emission Unit?	☐ No ☒ Yes If Yes, complete the following section. If No, go to line 22.

EMISSIONS CONTROL EQUIPMENT

14. Control Equipment Name and ID:	Material Moisture Content		
15. Date of Installation:	N/A	16. Date of Modification (if any):	N/A
17. Manufacturer and Model Number:	N/A		
18. ID(s) of Emission Unit Controlled:	HF2		
19. Is operating schedule different than emission units(s) involved?	☐ Yes ☒ No		
20. Does the manufacturer guarantee the control efficiency of the control equipment?	☐ Yes ☒ No (If Yes, attach and label manufacturer guarantee)		

	Pollutant Controlled					
	PM	PM10	SO_2	NOx	VOC	CO
Control Efficiency	50%	50%				

21. If manufacturer's data is not available, attach a separate sheet of paper to provide the control equipment design specifications and performance data to support the above mentioned control efficiency.

EMISSION UNIT OPERATING SCHEDULE (hours/day, hours/year, or other)

22.	Actual Operation:	TBD
23.	Maximum Operation:	8760 HRS/YEAR

REQUESTED LIMITS

24.	Are you requesting any permit limits?	☐ Yes ☒ No (If Yes, indicate all that apply below)
	☐ Operation Hour Limit(s):	
	☐ Production Limit(s):	
	☐ Material Usage Limit(s):	
	☐ Limits Based on Stack Testing:	Please attach all relevant stack testing summary reports
	☐ Other:	
25.	Rationale for Requesting the Limit(s):	

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1. Company Name:	2. Facility Name:	3. Facility ID No:
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4. Brief Project Description:	CRE is proposing to construct and operate a Greenfield wood pellet production facility near Potlach, Idaho. The facility will produce a proprietary product known as SteamEx Pellets with technology from

EMISSIONS UNIT (PROCESS) IDENTIFICATION & DESCRIPTION

5.	Emissions Unit (EU) Name:	FUEL SCREEN #1 AND TRANSFERS
6.	EU ID Number:	HF3
7.	EU Type:	☒ New Source ☐ Unpermitted Existing Source ☐ Modification to a Permitted Source -- Previous Permit #: Date Issued:
8.	Manufacturer:	N/A
9.	Model:	N/A
10..	Maximum Capacity:	12 TON/HR, 100,000 TON/YEAR
11.	Date of Construction:	TBD
12.	Date of Modification (if any):	N/A
13.	Is this a Controlled Emission Unit?	☐ No ☒ Yes If Yes, complete the following section. If No, go to line 22.

EMISSIONS CONTROL EQUIPMENT

14. Control Equipment Name and ID:	Material Moisture Content		
15. Date of Installation:	N/A	16. Date of Modification (if any):	N/A
17. Manufacturer and Model Number:	N/A		
18. ID(s) of Emission Unit Controlled:	HF3		
19. Is operating schedule different than emission units(s) involved?	☐ Yes ☒ No		
20. Does the manufacturer guarantee the control efficiency of the control equipment?	☐ Yes ☒ No (If Yes, attach and label manufacturer guarantee)		

	Pollutant Controlled					
	PM	PM10	SO_2	NOx	VOC	CO
Control Efficiency	50%	50%				

21. If manufacturer's data is not available, attach a separate sheet of paper to provide the control equipment design specifications and performance data to support the above mentioned control efficiency.

EMISSION UNIT OPERATING SCHEDULE (hours/day, hours/year, or other)

22.	Actual Operation:	TBD
23.	Maximum Operation:	8760 HRS/YEAR

REQUESTED LIMITS

24.	Are you requesting any permit limits?	☐ Yes ☒ No (If Yes, indicate all that apply below)
	☐ Operation Hour Limit(s):	
	☐ Production Limit(s):	
	☐ Material Usage Limit(s):	
	☐ Limits Based on Stack Testing:	Please attach all relevant stack testing summary reports
	☐ Other:	
25.	Rationale for Requesting the Limit(s):	

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1. Company Name:	2. Facility Name:	3. Facility ID No:
Centennial Renewable Energy	Potlach Facility	

4. Brief Project Description:	CRE is proposing to construct and operate a Greenfield wood pellet production facility near Potlach, Idaho. The facility will produce a proprietary product known as SteamEx Pellets with technology from

EMISSIONS UNIT (PROCESS) IDENTIFICATION & DESCRIPTION

5.	Emissions Unit (EU) Name:	Bucket Elevator #1 to Surge Bin #2
6.	EU ID Number:	HF4
7.	EU Type:	☒ New Source ☐ Unpermitted Existing Source ☐ Modification to a Permitted Source -- Previous Permit #: Date Issued:
8.	Manufacturer:	N/A
9.	Model:	N/A
10..	Maximum Capacity:	12 TON/HR, 100,000 TON/YEAR
11.	Date of Construction:	TBD
12.	Date of Modification (if any):	N/A
13.	Is this a Controlled Emission Unit?	☐ No ☒ Yes If Yes, complete the following section. If No, go to line 22.

EMISSIONS CONTROL EQUIPMENT

14. Control Equipment Name and ID:	Material Moisture Content		
15. Date of Installation:	N/A	16. Date of Modification (if any):	N/A
17. Manufacturer and Model Number:	N/A		
18. ID(s) of Emission Unit Controlled:	HF4		
19. Is operating schedule different than emission units(s) involved?	☐ Yes ☒ No		
20. Does the manufacturer guarantee the control efficiency of the control equipment?	☐ Yes ☒ No (If Yes, attach and label manufacturer guarantee)		

	Pollutant Controlled					
	PM	PM10	SO_2	NOx	VOC	CO
Control Efficiency	50%	50%				

21. If manufacturer's data is not available, attach a separate sheet of paper to provide the control equipment design specifications and performance data to support the above mentioned control efficiency.

EMISSION UNIT OPERATING SCHEDULE (hours/day, hours/year, or other)

22.	Actual Operation:	TBD
23.	Maximum Operation:	8760 HRS/YEAR

REQUESTED LIMITS

24.	Are you requesting any permit limits?	☐ Yes ☒ No (If Yes, indicate all that apply below)
	☐ Operation Hour Limit(s):	
	☐ Production Limit(s):	
	☐ Material Usage Limit(s):	
	☐ Limits Based on Stack Testing:	Please attach all relevant stack testing summary reports
	☐ Other:	
25.	Rationale for Requesting the Limit(s):	

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1410 N. Hilton, Boise, ID 83706
For assistance, call the
Air Permit Hotline – 1-877-5PERMIT

Emissions Unit - General **Form EU0**
Revision 4
08/28/08

Please see instructions on page 2 before filling out the form.

IDENTIFICATION

1. Company Name:	2. Facility Name:	3. Facility ID No:
Centennial Renewable Energy	Potlach Facility	

4. Brief Project Description:	CRE is proposing to construct and operate a Greenfield wood pellet production facility near Potlach, Idaho. The facility will produce a proprietary product known as SteamEx Pellets with technology from

EMISSIONS UNIT (PROCESS) IDENTIFICATION & DESCRIPTION

5.	Emissions Unit (EU) Name:	SURGE BIN #2 TO PNUEMATIC SYSTEM #5
6.	EU ID Number:	HF5
7.	EU Type:	☒ New Source ☐ Unpermitted Existing Source ☐ Modification to a Permitted Source -- Previous Permit #: Date Issued:
8.	Manufacturer:	N/A
9.	Model:	N/A
10..	Maximum Capacity:	12 TON/HR, 100,000 TON/YEAR
11.	Date of Construction:	TBD
12.	Date of Modification (if any):	N/A
13.	Is this a Controlled Emission Unit?	☐ No ☒ Yes If Yes, complete the following section. If No, go to line 22.

EMISSIONS CONTROL EQUIPMENT

14. Control Equipment Name and ID:	Pneumatic Enclosure		
15. Date of Installation:	N/A	16. Date of Modification (if any):	N/A
17. Manufacturer and Model Number:	N/A		
18. ID(s) of Emission Unit Controlled:	HF5		
19. Is operating schedule different than emission units(s) involved?	☐ Yes ☒ No		
20. Does the manufacturer guarantee the control efficiency of the control equipment?	☐ Yes ☒ No (If Yes, attach and label manufacturer guarantee)		

	Pollutant Controlled					
	PM	PM10	SO_2	NOx	VOC	CO
Control Efficiency	100%	100%				

21. If manufacturer's data is not available, attach a separate sheet of paper to provide the control equipment design specifications and performance data to support the above mentioned control efficiency.

EMISSION UNIT OPERATING SCHEDULE (hours/day, hours/year, or other)

22.	Actual Operation:	TBD
23.	Maximum Operation:	8760 HRS/YEAR

REQUESTED LIMITS

24.	Are you requesting any permit limits?	☐ Yes ☒ No (If Yes, indicate all that apply below)
	☐ Operation Hour Limit(s):	
	☐ Production Limit(s):	
	☐ Material Usage Limit(s):	
	☐ Limits Based on Stack Testing:	Please attach all relevant stack testing summary reports
	☐ Other:	
25.	Rationale for Requesting the Limit(s):	

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Emissions Unit - General **Form EU0**
Revision 4
08/28/08

Please see instructions on page 2 before filling out the form.

IDENTIFICATION

1. Company Name:	2. Facility Name:	3. Facility ID No:
Centennial Renewable Energy	Potlach Facility	

4. Brief Project Description:	CRE is proposing to construct and operate a Greenfield wood pellet production facility near Potlach, Idaho. The facility will produce a proprietary product known as SteamEx Pellets with technology from

EMISSIONS UNIT (PROCESS) IDENTIFICATION & DESCRIPTION

5.	Emissions Unit (EU) Name:	PNEUMATIC SYSTEM #5 TO COMBUSTOR
6.	EU ID Number:	HF6
7.	EU Type:	☒ New Source ☐ Unpermitted Existing Source ☐ Modification to a Permitted Source -- Previous Permit #: Date Issued:
8.	Manufacturer:	N/A
9.	Model:	N/A
10..	Maximum Capacity:	12 TON/HR, 100,000 TON/YEAR
11.	Date of Construction:	TBD
12.	Date of Modification (if any):	N/A
13.	Is this a Controlled Emission Unit?	☐ No ☒ Yes If Yes, complete the following section. If No, go to line 22.

EMISSIONS CONTROL EQUIPMENT

14. Control Equipment Name and ID:	Pneumatic Enclosure		
15. Date of Installation:	N/A	16. Date of Modification (if any):	N/A
17. Manufacturer and Model Number:	N/A		
18. ID(s) of Emission Unit Controlled:	HF6		
19. Is operating schedule different than emission units(s) involved?	☐ Yes ☒ No		
20. Does the manufacturer guarantee the control efficiency of the control equipment?	☐ Yes ☒ No (If Yes, attach and label manufacturer guarantee)		

	Pollutant Controlled					
	PM	PM10	SO_2	NOx	VOC	CO
Control Efficiency	100%	100%				

21. If manufacturer's data is not available, attach a separate sheet of paper to provide the control equipment design specifications and performance data to support the above mentioned control efficiency.

EMISSION UNIT OPERATING SCHEDULE (hours/day, hours/year, or other)

22.	Actual Operation:	TBD
23.	Maximum Operation:	8760 HRS/YEAR

REQUESTED LIMITS

24.	Are you requesting any permit limits?	☐ Yes ☒ No (If Yes, indicate all that apply below)
	☐ Operation Hour Limit(s):	
	☐ Production Limit(s):	
	☐ Material Usage Limit(s):	
	☐ Limits Based on Stack Testing:	Please attach all relevant stack testing summary reports
	☐ Other:	
25.	Rationale for Requesting the Limit(s):	

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Emissions Unit - General **Form EU0**
Revision 4
08/28/08

Please see instructions on page 2 before filling out the form.

IDENTIFICATION

1. Company Name:	2. Facility Name:	3. Facility ID No:
Centennial Renewable Energy	Potlach Facility	

4. Brief Project Description:	CRE is proposing to construct and operate a Greenfield wood pellet production facility near Potlach, Idaho. The facility will produce a proprietary product known as SteamEx Pellets with technology from

EMISSIONS UNIT (PROCESS) IDENTIFICATION & DESCRIPTION

5.	Emissions Unit (EU) Name:	PELLET COOLERS
6.	EU ID Number:	PELLET COOLER
7.	EU Type:	☒ New Source ☐ Unpermitted Existing Source ☐ Modification to a Permitted Source -- Previous Permit #: Date Issued:
8.	Manufacturer:	ANDRITZ
9.	Model:	N/A
10..	Maximum Capacity:	33 ton/hr
11.	Date of Construction:	TBD
12.	Date of Modification (if any):	N/A
13.	Is this a Controlled Emission Unit?	☐ No ☒ Yes If Yes, complete the following section. If No, go to line 22.

EMISSIONS CONTROL EQUIPMENT

14. Control Equipment Name and ID:	FBC Baghouse for PM, FBC for VOC		
15. Date of Installation:	TBD	16. Date of Modification (if any):	N/A
17. Manufacturer and Model Number:	TBD		
18. ID(s) of Emission Unit Controlled:	Pellet Cooler		
19. Is operating schedule different than emission units(s) involved?	☐ Yes ☒ No		
20. Does the manufacturer guarantee the control efficiency of the control equipment?	☒ Yes ☐ No (If Yes, attach and label manufacturer guarantee)		

	Pollutant Controlled					
	PM	PM10	SO_2	NOx	VOC	CO
Control Efficiency	0.0027 gr/acfm	0.0027 gr/acfm			99.9%	

21. If manufacturer's data is not available, attach a separate sheet of paper to provide the control equipment design specifications and performance data to support the above mentioned control efficiency.

EMISSION UNIT OPERATING SCHEDULE (hours/day, hours/year, or other)

22.	Actual Operation:	TBD
23.	Maximum Operation:	8760 HRS/YEAR

REQUESTED LIMITS

24.	Are you requesting any permit limits?	☐ Yes ☒ No (If Yes, indicate all that apply below)
	☐ Operation Hour Limit(s):	
	☐ Production Limit(s):	
	☐ Material Usage Limit(s):	
	☐ Limits Based on Stack Testing:	Please attach all relevant stack testing summary reports
	☐ Other:	
25.	Rationale for Requesting the Limit(s):	

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Emissions Unit - General **Form EU0**
Revision 4
08/28/08

Please see instructions on page 2 before filling out the form.

IDENTIFICATION

1. Company Name:	2. Facility Name:	3. Facility ID No:
Centennial Renewable Energy	Potlach Facility	

4. Brief Project Description:	CRE is proposing to construct and operate a Greenfield wood pellet production facility near Potlach, Idaho. The facility will produce a proprietary product known as SteamEx Pellets with technology from

EMISSIONS UNIT (PROCESS) IDENTIFICATION & DESCRIPTION

5.	Emissions Unit (EU) Name:	STEAM EXPLOSION UNIT
6.	EU ID Number:	SteamEx
7.	EU Type:	☒ New Source ☐ Unpermitted Existing Source ☐ Modification to a Permitted Source -- Previous Permit #: Date Issued:
8.	Manufacturer:	ANDRITZ
9.	Model:	N/A
10..	Maximum Capacity:	65,599 lb/hr
11.	Date of Construction:	TBD
12.	Date of Modification (if any):	N/A
13.	Is this a Controlled Emission Unit?	☐ No ☒ Yes If Yes, complete the following section. If No, go to line 22.

EMISSIONS CONTROL EQUIPMENT

14. Control Equipment Name and ID:	FBC Baghouse for PM, FBC for VOC		
15. Date of Installation:	TBD	16. Date of Modification (if any):	N/A
17. Manufacturer and Model Number:	TBD		
18. ID(s) of Emission Unit Controlled:	SteamEx		
19. Is operating schedule different than emission units(s) involved?	☐ Yes ☒ No		
20. Does the manufacturer guarantee the control efficiency of the control equipment?	☒ Yes ☐ No (If Yes, attach and label manufacturer guarantee)		

	Pollutant Controlled					
	PM	PM10	SO_2	NOx	VOC	CO
Control Efficiency	0.0027 gr/acfm	0.0027 gr/acfm			99.9%	

21. If manufacturer's data is not available, attach a separate sheet of paper to provide the control equipment design specifications and performance data to support the above mentioned control efficiency.

EMISSION UNIT OPERATING SCHEDULE (hours/day, hours/year, or other)

22.	Actual Operation:	TBD
23.	Maximum Operation:	8760 HRS/YEAR

REQUESTED LIMITS

24.	Are you requesting any permit limits?	☐ Yes ☒ No (If Yes, indicate all that apply below)
	☐ Operation Hour Limit(s):	
	☐ Production Limit(s):	
	☐ Material Usage Limit(s):	
	☐ Limits Based on Stack Testing:	Please attach all relevant stack testing summary reports
	☐ Other:	
25.	Rationale for Requesting the Limit(s):	

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Emissions Units - Industrial Boiler Information **Form EU5**
Revision 5
08/28/08

Please see instructions on page 2 before filling out the form.

IDENTIFICATION

1. Company Name:	2. Facility Name:	3 Facility ID No:
Centennial Renewable Energy	Potlach Facility	

4. Brief Project Description: CRE is proposing to construct and operate a Greenfield wood pellet production facility near Potlach, Idaho. The facility will produce a proprietary product known as SteamEx Pellets with

EXEMPTION

Please see IDAPA 58.01.01.222 for a list of industrial boilers that are exempt from Permit to Construct requirements.

BOILER (EMISSION UNIT) DESCRIPTION AND SPECIFICATIONS

5. Type of Request: ☒ New Unit ☐ Unpermitted Existing Unit ☐ Modification to a Unit with Permit #:

6. Use of Boiler: ☒ % Used For Process ☐ % Used For Space Heat ☐ % Used For Generating Electricity ☐ Other:

7. Boiler ID Number: FBC	8. Rated Capacity: ☒ 200 Million British Thermal Units Per Hour (MMBtu/hr) ☐ 1,000 Pounds Steam Per Hour (1,000 lb steam/hr)	
9. Construction Date: 2016	10. Manufacturer: Precision Energy Services	11. Model: N/A
12. Date of Modification (if applicable): N/A	13. Serial Number (if available): N/A	14. Control Device (if any): Baghouse **Note: Attach applicable control equipment form(s)**

FUEL DESCRIPTION AND SPECIFICATIONS

15. Fuel Type	☐ Diesel Fuel (#) (gal/hr)	☐ Natural Gas (cf/hr)	☐ Coal (unit: /hr)	☒ Other Fuels (unit:ton per year /hr)
16. Full Load Consumption Rate				250,286
17. Actual Consumption Rate				TBD
18. Fuel Heat Content (Btu/unit, LHV)				3,500
19. Sulfur Content wt%				0.02% dry basis
20. Ash Content wt%		N/A		5.0% dry basis

STEAM DESCRIPTION AND SPECIFICATIONS

21. Steam Heat Content	NA	NA		2,780 kJ/kg
22. Steam Temperature (^{o}F)	N/A	N/A		428 F
23. Steam Pressure (psi)	N/A	N/A		350 PSIG
24 Steam Type	N/A	N/A	☐ Saturated ☐ Superheated	☒ Saturated ☐ Superheated

OPERATING LIMITS & SCHEDULE

25. Imposed Operating Limits (hours/year, or gallons fuel/year, etc.):		8,760 hours/year	
26. Operating Schedule (hours/day, months/year, etc.):		24 hours/day, 12 months/year, 8760 hours/year	
27. NSPS Applicability:	☒ Yes ☐ No	If Yes, which subpart:	Db

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Baghouse Control Equipment **Form BCE**
Revision 6
2/18/10

Complete this form for each baghouse. Please see instructions on page 2 before filling out the form.

IDENTIFICATION

1. Company Name	2. Facility Name:
Centennial Renewable Energy	Potlach Facility

3. Brief Project Description: CRE is proposing to construct and operate a Greenfield wood pellet production facility near Potlach, Idaho. The facility will produce a proprietary product known as SteamEx Pellets with technology from the Andritz Corporation. The final product will utilize short fiber wood waste from regional mills as feedstock.

BAGHOUSE INFORMATION

4. Baghouse Manufacturer: Industrial Air Company	5. Baghouse Model: 'M' pulse jet	6. Baghouse Equipment ID: FBC Baghouse

7 (a). Baghouse particulate matter emission concentration. **Note: Provide information in 7(a)-(c) or answer question #8 below.**	0.0027 gr/acf OR 0.005 gr/dscf	*Manufacturers typically provide guarantees in grains per dry standard cubic foot (gr/dscf). Provide a copy of the guarantee, or other documentation, with the application along with a description of the types of bags that must be used to achieve the emission concentration.* ***Emission concentrations less than 0.01 gr/dscf will receive additional scrutiny by DEQ and a source test of the baghouse may be required.*** *If a guarantee is not provided then you must document how you obtained the emission concentration. Without documentation the application is not complete.*
7 (b). Percentage PM_{10} Or Provide PM_{10} Emission Concentration	99 % 0.0027 gr/acf OR 0.005 gr/dscf	*What percentage of the PM concentration listed in question #7(a) is PM_{10}. You must provide documentation as to how the percentage was determined (i.e per the baghouse manufacturer). Without documentation the application is not complete.*
7 (c). Baghouse flow rate	135,000 acfm dscfm	*Provide the baghouse flow rate in dry standard cubic feet per minute. Actual cubic feet per minute may be given in lieu of dscfm* ***if it is documented*** *that moisture content is insignificant. You must provide documentation as to how this flow rate was determined (i.e. per the exhaust fan manufacturer, combustion evaluation, etc.). Without documentation the application is not complete.*
8. Baghouse particulate matter control efficiency. **Note: Not needed if section #7 is completed.**	99.99 % PM control 99.0 % PM_{10} control	*Applicant's providing the control efficiency of the baghouse must provide control efficiency for both PM and PM_{10}. Provide a copy of the control efficiency documentation with the application. Documentation must include a description of the types of bags that must be used to achieve the control efficiency. Without documentation the application is not complete.*
9. Is the baghouse equipped with a bag leak detector?	☐ Yes ☒ No	*If a bag leak detector is installed provide documentation on the leak detector, including; how the leak detector functions and what level of the output signal indicates that a bag is leaking. Without documentation the application is not complete.*

DEQ AIR QUALITY PROGRAM
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Air Permit Hotline – 1-877-5PERMIT

Baghouse Control Equipment **Form BCE**
Revision 6
2/18/10

Complete this form for each baghouse. Please see instructions on page 2 before filling out the form.

IDENTIFICATION

1. Company Name	2. Facility Name:
Centennial Renewable Energy	Potlach Facility

3. Brief Project Description: CRE is proposing to construct and operate a Greenfield wood pellet production facility near Potlach, Idaho. The facility will produce a proprietary product known as SteamEx Pellets with technology from the Andritz Corporation. The final product will utilize short fiber wood waste from regional mills as feedstock.

BAGHOUSE INFORMATION

4. Baghouse Manufacturer: Industrial Air Company	5. Baghouse Model: TBD	6. Baghouse Equipment ID: Dry Hammer Mill Bag Filter

7 (a). Baghouse particulate matter emission concentration. **Note: Provide information in 7(a)-(c) or answer question #8 below.**	_ gr/dscf	*Manufacturers typically provide guarantees in grains per dry standard cubic foot (gr/dscf). Provide a copy of the guarantee, or other documentation, with the application along with a description of the types of bags that must be used to achieve the emission concentration.* ***Emission concentrations less than 0.01 gr/dscf will receive additional scrutiny by DEQ and a source test of the baghouse may be required.*** *If a guarantee is not provided then you must document how you obtained the emission concentration. Without documentation the application is not complete.*
7 (b). Percentage PM_{10} Or Provide PM_{10} Emission Concentration	_____ % _____ gr/dscf	*What percentage of the PM concentration listed in question #7(a) is PM_{10}. You must provide documentation as to how the percentage was determined (i.e per the baghouse manufacturer). Without documentation the application is not complete.*
7 (c). Baghouse flow rate	_____ dscfm	*Provide the baghouse flow rate in dry standard cubic feet per minute. Actual cubic feet per minute may be given in lieu of dscfm* ***if it is documented*** *that moisture content is insignificant. You must provide documentation as to how this flow rate was determined (i.e. per the exhaust fan manufacturer, combustion evaluation, etc.). Without documentation the application is not complete.*
8. Baghouse particulate matter control efficiency. **Note: Not needed if section #7 is completed.**	99.99 % PM control 99 % PM_{10} control	*Applicant's providing the control efficiency of the baghouse must provide control efficiency for both PM and PM_{10}. Provide a copy of the control efficiency documentation with the application. Documentation must include a description of the types of bags that must be used to achieve the control efficiency. Without documentation the application is not complete.*
9. Is the baghouse equipped with a bag leak detector?	☐ Yes ☒ No	*If a bag leak detector is installed provide documentation on the leak detector, including; how the leak detector functions and what level of the output signal indicates that a bag is leaking. Without documentation the application is not complete.*

APPENDIX D: EMISSIONS INVENTORY

Controlled PM Emissions from Boiler Baghouse

Emission Source Description	Exhaust Flow Rate (acfm)	Grain Loading Rate (gr/acfm)	Operating Hours (hr/yr)	PM Potential Emissions[1] (lb/hr)	PM Potential Emissions[1] (tpy)	PM_{10} Potential Emissions[1] (lb/hr)	PM_{10} Potential Emissions[1] (tpy)	$PM_{2.5}$ Potential Emissions[1] (lb/hr)	$PM_{2.5}$ Potential Emissions[1] (tpy)
Boiler Baghouse	135,000	0.0027	8,760	3.12	13.68	3.12	13.68	3.12	13.68

[1] PM_{10} and $PM_{2.5}$ emissions assumed to equal PM emissions.

[2] Emission parameters from "Questions for CRE and PES - ANSWERS (2) CRE Comments" word document, received from CRE and PES on March 3, 2016

[3] The Boiler Baghouse controls emissions from the high pressure boiler, glycol heater, FBC Combustor, FBC Pre-Burner, Multiclone Cyclones, Flash Steam from SteamEx process, Pre-Steaming Bin Exhaust, Pellet Cooler Exhaust

[4] Stack diameter measured in Breeze based on imported CAD drawing. Diameter estimated at 1.34 meters (4.39 ft)

Dryer Potential Emissions

Potential Operation	8,760	hr/yr
Dryer Air Flow Rate	694,382	Nm^3/hr
Dryer Capacity	33	tons/hr

Pollutant	Wood Drying Emission Factor (mg/Nm^3)	Potential Emissions (lb/hr)	(tpy)
CO	-	0.0	0.0
NO_X	-	0.0	0.0
Total PM	5.0	7.7	33.5
Total PM_{10}	4.5	6.9	30.2
Total $PM_{2.5}$	2.5	3.8	16.8
SO_2	-	0.0	0.0
VOC[2]	-	0.0	0.0
Lead	-	0.0	0.0
CH_4	-	0.0	0.0
N_2O	-	0.0	0.0
CO_2		0.0	0.0
CO_2e	-	0.0	0.0
$CO_2e_{biomass\ deferral}$	-	0.0	0.0

[1] Dust emissions have a manufacturer's guarantee of less than 10 mg/Nm^3 (dry). It is assumed that 50% of dust emissions consist of PM_{500}, 90% of PM_{500} emissions consist of PM_{10}, and 50% of PM_{500} emissions consist of $PM_{2.5}$.

[2] The dryer will be operated at a temperature much lower than the upstream SteamEx process. Volatilization is not expected to occur during the drying process.

FBC System Potential HAP and TAP Emissions

Heat Source - Heat Input Capacity	200	MMBtu/hr
Hours of Operation per Year	8,760	hr/yr

Pollutant	HAP?	Non-Carcinogenic TAP?	Carcinogenic TAP?	Biomass Combustion Emission Factor[1] (lb/MMBtu)	Potential HAP Emissions (lb/hr)	Potential HAP Emissions (tpy)	Potential TAP Emissions (lb/hr)	Potential TAP Emissions (tpy)
1,1,1-Trichloroethane	Yes	No	No	3.10E-05	6.20E-03	2.72E-02	-	-
1,2-Dibromoethene	Yes	No	No	5.50E-05	1.10E-02	4.82E-02	-	-
Acenaphthene	Yes	No	Yes	9.10E-07	1.82E-04	7.97E-04	1.82E-04	7.97E-04
Acenaphthylene	Yes	No	Yes	5.00E-06	1.00E-03	4.38E-03	1.00E-03	4.38E-03
Acetaldehyde	Yes	No	Yes	8.30E-04	1.66E-01	7.27E-01	1.66E-01	7.27E-01
Acetone	No	Yes	No	1.90E-04	-	-	3.80E-02	1.66E-01
Acetophenone	Yes	No	Yes	3.20E-09	6.40E-07	2.80E-06	6.40E-07	2.80E-06
Acrolein	Yes	Yes	No	4.00E-03	8.00E-01	3.50E+00	8.00E-01	3.50E+00
Anthracene	Yes	No	Yes	3.00E-06	6.00E-04	2.63E-03	6.00E-04	2.63E-03
Antimony	Yes	Yes	No	7.90E-06	1.58E-03	6.92E-03	1.58E-03	6.92E-03
Arsenic	Yes	No	Yes	2.20E-05	4.40E-03	1.93E-02	4.40E-03	1.93E-02
Benzene	Yes	No	Yes	4.20E-03	8.40E-01	3.68E+00	8.40E-01	3.68E+00
Benzo(a)anthracene	Yes	No	Yes	6.50E-08	1.30E-05	5.69E-05	1.30E-05	5.69E-05
Benzo(a)pyrene	Yes	No	Yes	2.60E-06	5.20E-04	2.28E-03	5.20E-04	2.28E-03
Benzo(b)fluoranthene	Yes	No	Yes	1.00E-07	2.00E-05	8.76E-05	2.00E-05	8.76E-05
Benzo(e)pyrene	Yes	No	Yes	2.60E-09	5.20E-07	2.28E-06	5.20E-07	2.28E-06
Benzo(g,h,i)perylene	Yes	No	Yes	9.30E-08	1.86E-05	8.15E-05	1.86E-05	8.15E-05
Benzo(j,k)fluoranthene	Yes	No	Yes	1.60E-07	3.20E-05	1.40E-04	3.20E-05	1.40E-04
Benzo(k)fluoranthene	Yes	No	Yes	3.60E-08	7.20E-06	3.15E-05	7.20E-06	3.15E-05
Beryllium	Yes	No	Yes	1.10E-06	2.20E-04	9.64E-04	2.20E-04	9.64E-04
Bis(2-ethylhexyl)phthalate	Yes	No	Yes	4.70E-08	9.40E-06	4.12E-05	9.40E-06	4.12E-05
Bromomethane	Yes	Yes	No	1.50E-05	3.00E-03	1.31E-02	3.00E-03	1.31E-02
2-Butanone (MEK)	No	Yes	No	5.40E-06	-	-	1.08E-03	4.73E-03
Cadmium	Yes	No	Yes	4.10E-06	8.20E-04	3.59E-03	8.20E-04	3.59E-03
Carbon tetrachloride	Yes	No	Yes	4.50E-05	9.00E-03	3.94E-02	9.00E-03	3.94E-02
Chlorine	Yes	Yes	No	7.90E-04	1.58E-01	6.92E-01	1.58E-01	6.92E-01
Chlorobenzene	Yes	Yes	No	3.30E-05	6.60E-03	2.89E-02	6.60E-03	2.89E-02
Chloroform	Yes	No	Yes	2.80E-05	5.60E-03	2.45E-02	5.60E-03	2.45E-02
2-Chlorophenol	No	Yes	No	2.40E-08	-	-	4.80E-06	2.10E-05
Chrysene	Yes	No	Yes	3.80E-08	7.60E-06	3.33E-05	7.60E-06	3.33E-05
Crotonaldehyde	No	Yes	No	9.90E-06	-	-	1.98E-03	8.67E-03
Chromium	Yes	Yes	Yes	2.10E-05	4.20E-03	1.84E-02	4.20E-03	1.84E-02
Chromium VI	Yes	No	Yes	3.50E-06	7.00E-04	3.07E-03	7.00E-04	3.07E-03
Cobalt	Yes	Yes	No	6.50E-06	1.30E-03	5.69E-03	1.30E-03	5.69E-03
Dibenzo(a,h)anthracene	Yes	No	Yes	9.10E-09	1.82E-06	7.97E-06	1.82E-06	7.97E-06
Dichlorobiphenyl	Yes	No	Yes	7.40E-10	1.48E-07	6.48E-07	1.48E-07	6.48E-07
1,2-Dichloroethane	Yes	No	Yes	2.90E-05	5.80E-03	2.54E-02	5.80E-03	2.54E-02
1,2-Dichloropropane	Yes	Yes	No	3.30E-05	6.60E-03	2.89E-02	6.60E-03	2.89E-02
2,4-Dinitrophenol	Yes	No	No	1.80E-07	3.60E-05	1.58E-04	-	-
Ethyl benzene	Yes	Yes	No	3.10E-05	6.20E-03	2.72E-02	6.20E-03	2.72E-02
Fluoranthene	Yes	No	Yes	1.60E-06	3.20E-04	1.40E-03	3.20E-04	1.40E-03
Fluorene	Yes	No	Yes	3.40E-06	6.80E-04	2.98E-03	6.80E-04	2.98E-03
Formaldehyde	Yes	No	Yes	4.40E-03	8.80E-01	3.85E+00	8.80E-01	3.85E+00
Heptachlorodibenzo-p-dioxins	Yes	No	Yes	2.00E-09	4.00E-07	1.75E-06	4.00E-07	1.75E-06
Heptachlorodibenzo-p-furans	Yes	No	Yes	2.40E-10	4.80E-08	2.10E-07	4.80E-08	2.10E-07
Hexachlorodibenzo-p-dioxins	Yes	No	Yes	1.60E-06	3.20E-04	1.40E-03	3.20E-04	1.40E-03
Hexachlorodibenzo-p-furans	Yes	No	Yes	2.80E-10	5.60E-08	2.45E-07	5.60E-08	2.45E-07
Hydrogen Chloride	Yes	Yes	No	1.90E-02	3.80E+00	1.66E+01	3.80E+00	1.66E+01
Indeno(1,2,3-cd)pyrene	Yes	No	Yes	8.70E-08	1.74E-05	7.62E-05	1.74E-05	7.62E-05
Iron	No	Yes	No	9.90E-04	-	-	1.98E-01	8.67E-01
Manganese	Yes	Yes	No	1.60E-03	3.20E-01	1.40E+00	3.20E-01	1.40E+00
Mercury	Yes	No	No	3.50E-06	7.00E-04	3.07E-03	-	-
Methanol	Yes	Yes	No	-	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Methyl chloride (chloromethane)	Yes	No	No	2.30E-05	4.60E-03	2.01E-02	-	-
Methylene chloride (dichloromethane)	Yes	No	Yes	2.90E-04	5.80E-02	2.54E-01	5.80E-02	2.54E-01
2-Methylnaphthalene	No	No	No	1.60E-07	-	-	-	-
Molybdenum	No	Yes	No	2.10E-06	-	-	4.20E-04	1.84E-03
Naphthalene	Yes	Yes	No	9.70E-05	1.94E-02	8.50E-02	1.94E-02	8.50E-02
Nickel	Yes	No	Yes	3.30E-05	6.60E-03	2.89E-02	6.60E-03	2.89E-02
4-Nitrophenol	Yes	No	No	1.10E-07	2.20E-05	9.64E-05	-	-
Octachlorodibenzo-p-dioxins	Yes	No	Yes	6.60E-08	1.32E-05	5.78E-05	1.32E-05	5.78E-05
Octachlorodibenzo-p-furans	Yes	No	Yes	8.80E-11	1.76E-08	7.71E-08	1.76E-08	7.71E-08
Pentachlorodibenzo-p-dioxins	Yes	No	Yes	1.50E-09	3.00E-07	1.31E-06	3.00E-07	1.31E-06

FBC System Potential HAP and TAP Emissions

Heat Source - Heat Input Capacity	200	MMBtu/hr
Hours of Operation per Year	8,760	hr/yr

Pollutant	HAP?	Non-Carcinogenic TAP?	Carcinogenic TAP?	Biomass Combustion Emission Factor[1] (lb/MMBtu)	Potential HAP Emissions (lb/hr)	Potential HAP Emissions (tpy)	Potential TAP Emissions (lb/hr)	Potential TAP Emissions (tpy)
Pentachlorodibenzo-p-furans	Yes	No	Yes	4.20E-10	8.40E-08	3.68E-07	8.40E-08	3.68E-07
Pentachlorobiphenyl	Yes	No	Yes	1.20E-09	2.40E-07	1.05E-06	2.40E-07	1.05E-06
Pentachlorophenol	Yes	Yes	No	5.10E-08	1.02E-05	4.47E-05	1.02E-05	4.47E-05
Perylene	Yes	No	Yes	5.20E-10	1.04E-07	4.56E-07	1.04E-07	4.56E-07
Phenanthrene	Yes	No	Yes	7.00E-06	1.40E-03	6.13E-03	1.40E-03	6.13E-03
Phenol	Yes	Yes	No	5.10E-05	1.02E-02	4.47E-02	1.02E-02	4.47E-02
Phosphorus	Yes	Yes	No	2.70E-05	5.40E-03	2.37E-02	5.40E-03	2.37E-02
Propanal	No	No	No	3.20E-06	-	-	-	-
Propionaldehyde	Yes	Yes	No	6.10E-05	1.22E-02	5.34E-02	1.22E-02	5.34E-02
Pyrene	Yes	No	Yes	3.70E-06	7.40E-04	3.24E-03	7.40E-04	3.24E-03
Selenium	Yes	Yes	No	2.80E-06	5.60E-04	2.45E-03	5.60E-04	2.45E-03
Silver	No	Yes	No	1.70E-03	-		3.40E-01	1.49E+00
Styrene	Yes	Yes	No	1.90E-03	3.80E-01	1.66E+00	3.80E-01	1.66E+00
2,3,7,8-Tetrachlorodibenzo-p-dioxins	Yes	No	Yes	8.60E-12	1.72E-09	7.53E-09	1.72E-09	7.53E-09
Tetrachlorodibenzo-p-dioxins	Yes	No	Yes	4.70E-10	9.40E-08	4.12E-07	9.40E-08	4.12E-07
2,3,7,8-Tetrachlorodibenzo-p-furans	Yes	No	Yes	9.00E-11	1.80E-08	7.88E-08	1.80E-08	7.88E-08
Tetrachlorodibenzo-p-furans	Yes	No	Yes	7.50E-10	1.50E-07	6.57E-07	1.50E-07	6.57E-07
Tetrachlorobiphenyl	Yes	No	Yes	2.50E-09	5.00E-07	2.19E-06	5.00E-07	2.19E-06
Tin	No	Yes	No	2.30E-05	-	-	4.60E-03	2.01E-02
Toluene	Yes	Yes	No	9.20E-04	1.84E-01	8.06E-01	1.84E-01	8.06E-01
Trichlorobiphenyl	Yes	No	Yes	2.60E-09	5.20E-07	2.28E-06	5.20E-07	2.28E-06
Trichloroethylene (trichloroethene)	Yes	No	Yes	3.00E-05	6.00E-03	2.63E-02	6.00E-03	2.63E-02
2,4,6-Trichlorophenol	Yes	No	Yes	2.20E-08	4.40E-06	1.93E-05	4.40E-06	1.93E-05
Vanadium	No	Yes	No	9.80E-07	-	-	1.96E-04	8.58E-04
Vinyl chloride	Yes	No	Yes	1.80E-05	3.60E-03	1.58E-02	3.60E-03	1.58E-02
o-Xylene	Yes	Yes	No	2.50E-05	5.00E-03	2.19E-02	5.00E-03	2.19E-02
Yttrium	No	Yes	No	3.00E-07	-	-	6.00E-05	2.63E-04
Zinc	No	Yes	No	4.20E-04	-	-	8.40E-02	3.68E-01
7-PAH	Yes	No	Yes	-	5.87E-04	2.57E-03	5.87E-04	2.57E-03
Dioxins/Furans	Yes	No	Yes	-	3.25E-05	1.42E-04	3.25E-05	1.42E-04
Maximum Individual HAP					**3.80**	**16.64**	**3.80**	**16.64**
Total HAP					**7.74**	**33.90**	**8.38**	**36.73**

[1] Emission factors from AP-42 Section 1.6, Tables 1.6-3 and 1.6-4 (9/03).

Emissions from FBC System

Heat Input Capacity		200 MMBtu/hr	
Hours of Operation per Year		8,760 hr/yr	
Pollutant[1]	**Wood Combustion Emission Factor**[2] (lb/MMBtu)	**Potential Emissions** (lb/hr)	(tpy)
CO	0.17	34.0	148.9
NO_X	0.22	44.0	192.7
SO_2	0.03	5.0	21.9
VOC	0.02	3.4	14.9
Lead	0.00	0.01	4.20E-02
CH_4	0.02	4.2	18.4
N_2O	0.01	2.6	11.4
CO_2	195.00	39000.0	170,820
CO_2e[3]	-	39,880	174,674
$CO_2e_{biomass\ deferral}$[4]	-	879.8	3,854

[1] PM emissions are accounted for in Table 10: Controlled PM Emissions from Boiler Baghouse.

[2] AP-42 Section 1.6 Wood Residue Combustion in Boilers, Tables 1.6-1, 1.6-2, and 1.6-3. Uncontrolled with wet wood fuel.

[3] Global warming potential (GWP) for CH_4 is 25, for N_2O is 298, and for CO_2 is 1 for estimating CO_2e emissions, based on 40 CFR 98, Subpart A, Table A-1 effective January 1, 2014.

[4] CO_2e based on the biomass deferral excludes biogenic CO_2 emissions (e.g., from biomass) per the Biomass Deferral published in Federal Register Vol. 76, No. 139, on July 20, 2011.

Emissions from FBC System Pre-Burner

Furnace Fuel Usage		8.00 MMBtu/hr		
Hours of Operation per Year		8,760 hr/yr		
Pollutant[1]	**Propane Combustion Emission Factor**[2] (lb/10^3 gal)	**Control Efficiency**[3]	**Potential Emissions** (lb/hr)	(tpy)
CO	7.5	0	0.7	2.9
NO_X	13	0	1.1	5.0
SO_2	1.5	0	0.1	0.6
VOC	1.0	99.9%	8.74E-05	3.83E-04
Lead	-	0	0.00E+00	0.00E+00
CH_4	0.2	0	0.0	0.1
N_2O	0.9	0	0.1	0.3
CO_2	12,500	0	1092.9	4,787
CO_2e[4]	-	-	1,117	4,892
$CO_2e_{biomass\ deferral}$[5]	-	-	23.9	105

[1] PM emissions are accounted for in Table 10: Controlled PM Emissions from Boiler Baghouse.

[2] AP-42 Section 1.5 Liquified Petroleum Gas Combustion, Table 1.5-1 (7/08). Heat content of 91.5 x 10^6 Btu/10^3 gallon for propane, sulfur content of commercial propane = 15gr/100 scf.

[3] Pre-burner VOC emissions are controlled by the FBC system.

[4] Global warming potential (GWP) for CH_4 is 25, for N_2O is 298, and for CO_2 is 1 for estimating CO_2e emissions, based on 40 CFR 98, Subpart A, Table A-1 effective January 1, 2014.

[5] CO_2e based on the biomass deferral excludes biogenic CO_2 emissions (e.g., from biomass) per the Biomass Deferral published in Federal Register Vol. 76, No. 139, on July 20, 2011.

Emission Unit No.	System Description	Requested Process Rate (ton/hr)	Requested Process Rate (ton/yr)	Requested Daily Operating Hours (hrs/day)	Requested Annual Operating Hours (hrs/yr)	PM Emission Factor	PM_{10} Emission Factor	$PM_{2.5}$ Emission Factor[1]	Emission Factor Units	Control Tech.	Control Efficiency (%)	PM Emission Rate (lb/hr)	PM Emission Rate (ton/yr)	PM_{10} Emission Rate (lb/hr)	PM_{10} Emission Rate (ton/yr)	$PM_{2.5}$ Emission Rate (lb/hr)	$PM_{2.5}$ Emission Rate (ton/yr)	Emission Factor Source
	HOG FUEL PROCESS																	
HF1	Truck Unloading to Hog Fuel Tipper	36	100,000	24	8,760	0.00300	0.00110	0.00016	lb/ton	Material moisture content	50%	0.055	0.075	0.020	0.028	0.003	0.004	AP-42, Crushed Stone 11.19.2-2, Conveyor Transfer Point
HF2	Hog Fuel Pile to Hopper #4/Screw Feeder #4 via Front Loader	12	100,000	24	8,760	0.00300	0.00110	0.00016	lb/ton	Material moisture content	50%	0.017	0.075	0.006	0.028	0.001	0.004	AP-42, Crushed Stone 11.19.2-2, Conveyor Transfer Point
HF3	Fuel Screen #1 and transfers (in from Hopper #4, out to Bucket Elevator #1)	12	100,000	24	8,760	0.02500	0.00870	0.00133	lb/ton	Material moisture content	50%	0.145	0.625	0.050	0.218	0.008	0.033	AP-42, Crushed Stone 11.19.2-2, Screening
HF4	Bucket Elevator #1 to Surge Bin #2	12	100,000	24	8,760	0.00300	0.00110	0.00016	lb/ton	Material moisture content	50%	0.017	0.075	0.006	0.028	0.001	0.004	AP-42, Crushed Stone 11.19.2-2, Conveyor Transfer Point
HF5	Surge Bin #2 to Pnuematic System #5	12	100,000	24	8,760	0.00300	0.00110	0.00016	lb/ton	Pnuematic Enclosure	100%	0.000	0.000	0.000	0.000	0.000	0.000	AP-42, Crushed Stone 11.19.2-2, Conveyor Transfer Point
HF6	Pneumatic System #5 to Combustor	12	100,000	24	8,760	0.00300	0.00110	0.00016	lb/ton	Pnuematic Enclosure	100%	0.000	0.000	0.000	0.000	0.000	0.000	AP-42, Crushed Stone 11.19.2-2, Conveyor Transfer Point
	FEEDSTOCK PROCESS																	
FS1	Truck Unloading to Feedstock Tipper #1	94	220,500	24	8,760	0.00300	0.00110	0.00016	lb/ton	Material Moisture Content	34%	0.186	0.218	0.068	0.080	0.010	0.012	AP-42, Crushed Stone 11.19.2-2, Conveyor Transfer Point
FS2	Feedstock Pile to Hopper #1, 2 or 3 via Front Loader	33	220,500	24	8,760	0.00300	0.00110	0.00016	lb/ton	Material Moisture Content	34%	0.065	0.218	0.024	0.080	0.003	0.012	AP-42, Crushed Stone 11.19.2-2, Conveyor Transfer Point
FS3	Hopper #1, 2 or 3 to Conveyor #1	33	220,500	24	8,760	0.00300	0.00110	0.00016	lb/ton	Material Moisture Content	34%	0.065	0.218	0.024	0.080	0.003	0.012	AP-42, Crushed Stone 11.19.2-2, Conveyor Transfer Point
FS4	Conveyor #1 to Feed Screw #1	16	220,500	24	8,760	0.00300	0.00110	0.00016	lb/ton	Material Moisture Content	34%	0.032	0.218	0.012	0.080	0.002	0.012	AP-42, Crushed Stone 11.19.2-2, Conveyor Transfer Point
FS5	Conveyor #1 to Feed Screw #2	16	220,500	24	8,760	0.00300	0.00110	0.00016	lb/ton	Material Moisture Content	34%	0.032	0.218	0.012	0.080	0.002	0.012	AP-42, Crushed Stone 11.19.2-2, Conveyor Transfer Point
FS6	Green Hammer Mill #1 and transfers (in from Feed Screw #1, out to Green Cyclone #1)	16	220,500	24	8,760	0.00540	0.00240	0.00029	lb/ton	Material Moisture Content	34%	0.058	0.393	0.026	0.175	0.003	0.021	AP-42, Crushed Stone 11.19.2-2, Tertiary Crushing
FS7	Green Hammer Mill #2 and transfers (in from Feed Screw #2, out to Green Cyclone #2)	16	220,500	24	8,760	0.00540	0.00240	0.00029	lb/ton	Material Moisture Content	34%	0.058	0.393	0.026	0.175	0.003	0.021	AP-42, Crushed Stone 11.19.2-2, Tertiary Crushing
FS8	Green Cyclone #1 to Conveyor #2	16	220,500	24	8,760	0.00300	0.00110	0.00016	lb/ton	Material Moisture Content	34%	0.032	0.218	0.012	0.080	0.002	0.012	AP-42, Crushed Stone 11.19.2-2, Conveyor Transfer Point
FS9	Green Cyclone #2 to Conveyor #2	16	220,500	24	8,760	0.00300	0.00110	0.00016	lb/ton	Material Moisture Content	34%	0.032	0.218	0.012	0.080	0.002	0.012	AP-42, Crushed Stone 11.19.2-2, Conveyor Transfer Point
FS10	Conveyor #2 to Conveyor #3 (Inside Tower 1)	33	220,500	24	8,760	0.00300	0.00110	0.00016	lb/ton	Enclosure	50%	0.049	0.165	0.018	0.061	0.003	0.009	AP-42, Crushed Stone 11.19.2-2, Conveyor Transfer Point
FS11	Conveyor #3 to Steam Ex Preheat Bin	33	220,500	24	8,760	0.00300	0.00110	0.00016	lb/ton	Inside Building	100%	0.000	0.000	0.000	0.000	0.000	0.000	AP-42, Crushed Stone 11.19.2-2, Conveyor Transfer Point
FS12	SteamEx Preheat Bin to Conveyor #4	33	220,500	24	8,760	0.00300	0.00110	0.00016	lb/ton	Inside Building	100%	0.000	0.000	0.000	0.000	0.000	0.000	AP-42, Crushed Stone 11.19.2-2, Conveyor Transfer Point
FS13	Conveyor #4 to Belt Dryer	33	220,500	24	8,760	0.00300	0.00110	0.00016	lb/ton	Inside Building	100%	0.000	0.000	0.000	0.000	0.000	0.000	AP-42, Crushed Stone 11.19.2-2, Conveyor Transfer Point
FS14	Belt Dryer to Conveyor #5	33	220,500	24	8,760	0.00300	0.00110	0.00016	lb/ton	Inside Building	100%	0.000	0.000	0.000	0.000	0.000	0.000	AP-42, Crushed Stone 11.19.2-2, Conveyor Transfer Point
FS15	Conveyor #5 to Feed Screw #3	33	220,500	24	8,760	0.00300	0.00110	0.00016	lb/ton	Material Moisture Content	8%	0.091	0.304	0.033	0.112	0.005	0.016	AP-42, Crushed Stone 11.19.2-2, Conveyor Transfer Point
FS16	Feed Screw #3 to Dry Hammer Mill	33	220,500	24	8,760	0.00300	0.00110	0.00016	lb/ton	Material Moisture Content	8%	0.091	0.304	0.033	0.112	0.005	0.016	AP-42, Crushed Stone 11.19.2-2, Conveyor Transfer Point
FS17	Dry Hammer Mill to Dry Cyclone #1	33	220,500	24	8,760	0.00300	0.00110	0.00016	lb/ton	Bag Filter	99%	0.001	0.003	0.0004	0.001	0.0001	0.000	AP-42, Crushed Stone 11.19.2-2, Conveyor Transfer Point
FS18	Dry Cyclone #1 to Pneumatic System #1	33	220,500	24	8,760	0.00300	0.00110	0.00016	lb/ton	Pnuematic Enclosure	100%	0.000	0.000	0.000	0.000	0.000	0.000	AP-42, Crushed Stone 11.19.2-2, Conveyor Transfer Point
FS19	Pnuematic System #1 to Surge Bin #1	33	220,500	24	8,760	0.00300	0.00110	0.00016	lb/ton	Pnuematic Enclosure	100%	0.000	0.000	0.000	0.000	0.000	0.000	AP-42, Crushed Stone 11.19.2-2, Conveyor Transfer Point
FS20	Surge Bin #1 to Conveyor #6	33	220,500	24	8,760	0.00300	0.00110	0.00016	lb/ton	Material Moisture Content	8%	0.091	0.304	0.033	0.112	0.005	0.016	AP-42, Crushed Stone 11.19.2-2, Conveyor Transfer Point
FS21	Conveyor #6 to Conveyor #7	16	220,500	24	8,760	0.00300	0.00110	0.00016	lb/ton	Inside Building	100%	0.000	0.000	0.000	0.000	0.000	0.000	AP-42, Crushed Stone 11.19.2-2, Conveyor Transfer Point
FS22	Conveyor #7 to Mill Feed Bin #1 and #2	16	220,500	24	8,760	0.00300	0.00110	0.00016	lb/ton	Inside Building	100%	0.000	0.000	0.000	0.000	0.000	0.000	AP-42, Crushed Stone 11.19.2-2, Conveyor Transfer Point
FS23	Mill Feed Bin #1 and #2 to Mill Feed Screws #1, 2, 3 and 4	16	220,500	24	8,760	0.00300	0.00110	0.00016	lb/ton	Inside Building	100%	0.000	0.000	0.000	0.000	0.000	0.000	AP-42, Crushed Stone 11.19.2-2, Conveyor Transfer Point
FS24	Mill Feed Screws #1, 2, 3, and 4 to Conditioning Screws #1, 2, 3 and 4	16	220,500	24	8,760	0.00300	0.00110	0.00016	lb/ton	Inside Building	100%	0.000	0.000	0.000	0.000	0.000	0.000	AP-42, Crushed Stone 11.19.2-2, Conveyor Transfer Point
FS25	Pellet Mills #1, 2, 3 and 4 and transfers (in from Conditioning Screws #1-4 and out to Conveyor #9)	16	220,500	24	8,760	0.00540	0.00240	0.00029	lb/ton	Inside Building	100%	0.000	0.000	0.000	0.000	0.000	0.000	AP-42, Crushed Stone 11.19.2-2, Tertiary Crushing
FS26	Conveyor #9 to Pellet Cooler #1	16	220,500	24	8,760	0.00300	0.00110	0.00016	lb/ton	Inside Building	100%	0.000	0.000	0.000	0.000	0.000	0.000	AP-42, Crushed Stone 11.19.2-2, Conveyor Transfer Point
FS27	Pellet Cooler #1 to Conveyor #11	16	220,500	24	8,760	0.00300	0.00110	0.00016	lb/ton	Inside Building	100%	0.000	0.000	0.000	0.000	0.000	0.000	AP-42, Crushed Stone 11.19.2-2, Conveyor Transfer Point
FS28	Pellet Cooler #1 to Multiclone #1	0.39	220,500	24	8,760	0.00300	0.00110	0.00016	lb/ton	Inside Building	100%	0.000	0.000	0.000	0.000	0.000	0.000	AP-42, Crushed Stone 11.19.2-2, Conveyor Transfer Point
FS29	Pellet Screen #1 and transfers (in from Conveyor #11, out to Pneumatic System #3)	16	220,500	24	8,760	0.02500	0.00870	0.00133	lb/ton	Inside Building	100%	0.000	0.000	0.000	0.000	0.000	0.000	AP-42, Crushed Stone 11.19.2-2, Screening
FS30	Multiclone #1 to Pneumatic System #2	0.39	220,500	24	8,760	0.00300	0.00110	0.00016	lb/ton	Inside Building	100%	0.000	0.000	0.000	0.000	0.000	0.000	AP-42, Crushed Stone 11.19.2-2, Conveyor Transfer Point
FS31	Conveyor #6 to Conveyor #8	16	220,500	24	8,760	0.00300	0.00110	0.00016	lb/ton	Inside Building	100%	0.000	0.000	0.000	0.000	0.000	0.000	AP-42, Crushed Stone 11.19.2-2, Conveyor Transfer Point
FS32	Conveyor #8 to Mill Feed Bin #3 and #4	16	220,500	24	8,760	0.00300	0.00110	0.00016	lb/ton	Inside Building	100%	0.000	0.000	0.000	0.000	0.000	0.000	AP-42, Crushed Stone 11.19.2-2, Conveyor Transfer Point
FS33	Mill Feed Bin #3 and #4 to Mill Feed Screws #5, 6, 7 and 8	16	220,500	24	8,760	0.00300	0.00110	0.00016	lb/ton	Inside Building	100%	0.000	0.000	0.000	0.000	0.000	0.000	AP-42, Crushed Stone 11.19.2-2, Conveyor Transfer Point
FS34	Mill Feed Screws #5, 6, 7, and 8 to Conditioning Screws #5, 6, 7 and 8	16	220,500	24	8,760	0.00300	0.00110	0.00016	lb/ton	Inside Building	100%	0.000	0.000	0.000	0.000	0.000	0.000	AP-42, Crushed Stone 11.19.2-2, Conveyor Transfer Point
FS35	Pellet Mills #5, 6, 7 and 8 and transfers (in from Conditioning Screws #5-8 and out to Conveyor #10)	16	220,500	24	8,760	0.00540	0.00240	0.00029	lb/ton	Inside Building	100%	0.000	0.000	0.000	0.000	0.000	0.000	AP-42, Crushed Stone 11.19.2-2, Tertiary Crushing
FS36	Conveyor #10 to Pellet Cooler #2	16	220,500	24	8,760	0.00300	0.00110	0.00016	lb/ton	Inside Building	100%	0.000	0.000	0.000	0.000	0.000	0.000	AP-42, Crushed Stone 11.19.2-2, Conveyor Transfer Point
FS37	Pellet Cooler #2 to Conveyor #12	16	220,500	24	8,760	0.00300	0.00110	0.00016	lb/ton	Inside Building	100%	0.000	0.000	0.000	0.000	0.000	0.000	AP-42, Crushed Stone 11.19.2-2, Conveyor Transfer Point
FS38	Pellet Cooler #2 to Multiclone #2	0.39	220,500	24	8,760	0.00300	0.00110	0.00016	lb/ton	Inside Building	100%	0.000	0.000	0.000	0.000	0.000	0.000	AP-42, Crushed Stone 11.19.2-2, Conveyor Transfer Point
FS39	Pellet Screen #2 and transfers (in from Conveyor #12, out to Pneumatic System #3)	16	220,500	24	8,760	0.02500	0.00870	0.00133	lb/ton	Inside Building	100%	0.000	0.000	0.000	0.000	0.000	0.000	AP-42, Crushed Stone 11.19.2-2, Screening
FS40	Multiclone #2 to Pneumatic System #2	0.39	220,500	24	8,760	0.00300	0.00110	0.00016	lb/ton	Inside Building	100%	0.000	0.000	0.000	0.000	0.000	0.000	AP-42, Crushed Stone 11.19.2-2, Conveyor Transfer Point
FS41	Pneumatic System #2 to Surge Bin #1	0.39	220,500	24	8,760	0.00300	0.00110	0.00016	lb/ton	Pnuematic Enclosure	100%	0.000	0.000	0.000	0.000	0.000	0.000	AP-42, Crushed Stone 11.19.2-2, Conveyor Transfer Point
FS42	Pnuematic System #3 to Pellet Product Stockpile	33	220,500	24	8,760	0.00300	0.00110	0.00016	lb/ton	Material Moisture Content	4%	0.094	0.318	0.035	0.116	0.005	0.017	AP-42, Crushed Stone 11.19.2-2, Conveyor Transfer Point
FS43	Pellet Product Stockpile to Hopper #5 via Front Loader	340	184,118	24	8,760	0.00300	0.00110	0.00016	lb/ton	Material Moisture Content	4%	0.978	0.265	0.359	0.097	0.052	0.014	AP-42, Crushed Stone 11.19.2-2, Conveyor Transfer Point
FS44	Hopper #5 to Conveyor #13	340	184,118	24	8,760	0.00300	0.00110	0.00016	lb/ton	Material Moisture Content	4%	0.978	0.265	0.359	0.097	0.052	0.014	AP-42, Crushed Stone 11.19.2-2, Conveyor Transfer Point
FS45	Shipping Screens and transfers (in from Conveyor #13, out to Conveyor #14)	340	184,118	24	8,760	0.02500	0.00870	0.00133	lb/ton	Enclosure	50%	4.245	1.151	1.477	0.400	0.225	0.061	AP-42, Crushed Stone 11.19.2-2, Screening
FS46	Shipping Screen to Pneumatic System #4	4.61	40,384	24	8,760	0.02500	0.00870	0.00133	lb/ton	Pnuematic Enclosure	100%	0.000	0.000	0.000	0.000	0.000	0.000	AP-42, Crushed Stone 11.19.2-2, Screening
FS47	Conveyor #14 to Filling Spout	340	184,118	24	8,760	0.00300	0.00110	0.00016	lb/ton	Material Moisture Content	4%	0.978	0.265	0.359	0.097	0.052	0.014	AP-42, Crushed Stone 11.19.2-2, Conveyor Transfer Point
FS48	Filling Spout to Rail Car	340	184,118	24	8,760	0.00300	0.00110	0.00016	lb/ton	Material Moisture Content	4%	0.978	0.265	0.359	0.097	0.052	0.014	AP-42, Crushed Stone 11.19.2-2, Conveyor Transfer Point
FS49	Pneumatic System #4 to Surge Bin #1	4.61	40,384	24	8,760	0.00300	0.00110	0.00016	lb/ton	Pneumatic Enclosure	100%	0.000	0.000	0.000	0.000	0.000	0.000	AP-42, Crushed Stone 11.19.2-2, Conveyor Transfer Point
												9.369	6.774	3.362	2.512	0.497	0.359	Totals

[1] No data available for PM2.5 emissions for uncontrolled sources. Therefore, the particle size multiplier of 0.0053 from AP-42 Section 13.2.4, September 2006, was mulitplied by the PM emission factor to develop the PM2.5 emission factor.

VOC Potential Emissions from Pellet Coolers

Facility-Wide Pellet Production Capacity	33	ton/hr
Potential Hours of Operation	8,760	hr/yr

Process	Number of Units	VOC Emission Factor[1] (lb/ton)	Methanol Emission Factor[1] (lb/ton)	Formaldehyde Emission Factor[1] (lb/ton)	Acetaldehyde Emission Factor[1] (lb/ton)	Uncontrolled VOC Potential Emissions (lb/hr)	Uncontrolled VOC Potential Emissions (tpy)	Controlled VOC Potential Emissions[2] (lb/hr)	Controlled VOC Potential Emissions[2] (tpy)
Pellet Coolers	2	4.62E-04	2.06E-05	1.18E-05	3.44E-06	0.02	0.07	0.0002	0.0007
Total						**0.02**	**0.07**	**0.0002**	**0.0007**

[1] Per engineering testing of the total gaseous organics emissions from pellet coolers at a similar facility. The most conservative emission factors from testing were used.

[2] Exhaust from the Pellet Coolers will be fed to the FBC for 99% control/destruction of VOC and PM

FBC System Potential HAP and TAP Emissions

Heat Source - Heat Input Capacity	200	MMBtu/hr
Hours of Operation per Year	8,760	hr/yr

Pollutant	HAP?	Non-Carcinogenic TAP?	Carcinogenic TAP?	Biomass Combustion Emission Factor[1] (lb/MMBtu)	Potential HAP Emissions (lb/hr)	Potential HAP Emissions (tpy)	Potential TAP Emissions (lb/hr)	Potential TAP Emissions (tpy)

FBC System Pre-Burner Potential HAP and TAP Emissions

Furnace Fuel Usage	0.01	MMscf/hr
Hours of Operation per Year	8,760.00	hr/yr

Pollutant	HAP?	Non-Carcinogenic TAP?	Carcinogenic TAP?	Natural Gas Combustion Emission Factor[1] (lb/MMscf)	Potential HAP Emissions (lb/hr)	Potential HAP Emissions (tpy)	Potential TAP Emissions (lb/hr)	Potential TAP Emissions (tpy)
Benzene	Yes	No	Yes	2.10E-03	1.65E-05	7.21E-05	1.65E-05	7.21E-05
Formaldehyde	Yes	No	Yes	7.50E-02	5.88E-04	2.58E-03	5.88E-04	2.58E-03
Toluene	Yes	Yes	No	3.40E-03	2.67E-05	1.17E-04	2.67E-05	1.17E-04
2-Methylnaphthalene	Yes	No	No	2.40E-05	1.88E-07	8.24E-07	-	-
3-Methylchloranthrene	Yes	No	No	1.80E-06	1.41E-08	6.18E-08	-	-
7,12-Dimethylbenz(a)anthracene	Yes	No	No	1.60E-05	1.25E-07	5.50E-07	-	-
Acenaphthylene	Yes	No	Yes	1.80E-06	1.41E-08	6.18E-08	1.41E-08	6.18E-08
Benzo(a)pyrene	Yes	No	Yes	1.20E-06	9.41E-09	4.12E-08	9.41E-09	4.12E-08
Benzo(b)fluoranthene	Yes	No	Yes	1.80E-06	1.41E-08	6.18E-08	1.41E-08	6.18E-08
Benzo(k)fluoranthene	Yes	No	Yes	1.80E-06	1.41E-08	6.18E-08	1.41E-08	6.18E-08
Dibenzo(a,h)anthracene	Yes	No	Yes	1.20E-06	9.41E-09	4.12E-08	9.41E-09	4.12E-08
Dichlorobenzene	Yes	Yes	No	1.20E-03	9.41E-06	4.12E-05	9.41E-06	4.12E-05
Hexane	Yes	Yes	No	1.80E+00	1.41E-02	6.18E-02	1.41E-02	6.18E-02
Naphthalene	Yes	Yes	No	6.10E-04	4.78E-06	2.10E-05	4.78E-06	2.10E-05
Acenaphthene	Yes	No	Yes	1.80E-06	1.41E-08	6.18E-08	1.41E-08	6.18E-08
Anthracene	Yes	No	Yes	2.40E-06	1.88E-08	8.24E-08	1.88E-08	8.24E-08
Benzo(a)anthracene	Yes	No	Yes	1.80E-06	1.41E-08	6.18E-08	1.41E-08	6.18E-08
Benzo(g,h,i)perylene	Yes	No	Yes	1.20E-06	9.41E-09	4.12E-08	9.41E-09	4.12E-08
Chrysene	Yes	No	Yes	1.80E-06	1.41E-08	6.18E-08	1.41E-08	6.18E-08
Fluoranthene	Yes	No	Yes	3.00E-06	2.35E-08	1.03E-07	2.35E-08	1.03E-07
Fluorene	Yes	No	Yes	2.80E-06	2.20E-08	9.62E-08	2.20E-08	9.62E-08
Indeno(1,2,3-cd)pyrene	Yes	No	Yes	1.80E-06	1.41E-08	6.18E-08	1.41E-08	6.18E-08
Phenanthrene	Yes	No	Yes	1.70E-05	1.33E-07	5.84E-07	1.33E-07	5.84E-07
Pentane	No	Yes	No	2.60E+00	-	-	2.04E-02	8.93E-02
Pyrene	Yes	No	Yes	5.00E-06	3.92E-08	1.72E-07	3.92E-08	1.72E-07
Arsenic	Yes	No	Yes	2.00E-04	1.57E-06	6.87E-06	1.57E-06	6.87E-06
Barium	No	Yes	No	4.40E-03	-	-	3.45E-05	1.51E-04
Beryllium	Yes	No	Yes	1.20E-05	9.41E-08	4.12E-07	9.41E-08	4.12E-07
Cadmium	Yes	No	Yes	1.10E-03	8.63E-06	3.78E-05	8.63E-06	3.78E-05
Chromium	Yes	Yes	Yes	1.40E-03	1.10E-05	4.81E-05	1.10E-05	4.81E-05
Cobalt	Yes	Yes	No	8.40E-05	6.59E-07	2.89E-06	6.59E-07	2.89E-06
Copper	No	Yes	No	8.50E-04	-	-	6.67E-06	2.92E-05
Lead	Yes	No	No	5.00E-04	3.92E-06	1.72E-05	-	-
Manganese	Yes	Yes	No	3.80E-04	2.98E-06	1.31E-05	2.98E-06	1.31E-05
Mercury	Yes	No	No	2.60E-04	2.04E-06	8.93E-06	-	-
Molybdenum	No	Yes	No	1.10E-03	-	-	8.63E-06	3.78E-05
Nickel	Yes	No	Yes	2.10E-03	1.65E-05	7.21E-05	1.65E-05	7.21E-05
Selenium	Yes	Yes	No	2.40E-05	1.88E-07	8.24E-07	1.88E-07	8.24E-07
Vanadium	No	Yes	No	2.30E-03	-	-	1.80E-05	7.90E-05
Maximum Individual HAP					**0.01**	**0.06**	**0.02**	**0.09**
Total HAP					**0.01**	**0.06**	**0.04**	**0.15**

[1] AP-42 Section 1.4 Natural Gas Combustion, Tables 1.4-3 and 1.4-4 (7/98). HAPs emissions factors not available for LPG in AP-42, Section 1.5.

Steam Explosion System Emissions

Dry Material Throughput	65,599	lb/hr
Hours of Operation per Year	8,760	hr/yr

Pollutant[1]	HAP?	Non-Carcinogenic TAP?	Carcinogenic TAP?	Emission Factor[2] (lb/lb dry fiber)	Control Efficiency[3] (%)	Potential Emissions (lb/hr)	Potential Emissions (tpy)	Potential HAP Emissions (lb/hr)	Potential HAP Emissions (tpy)	Potential TAP Emissions (lb/hr)	Potential TAP Emissions (tpy)
Methyl acetate	No	Yes	No	8.05E-10	99.9%	5.28E-08	2.31E-07	-	-	5.28E-08	2.31E-07
1,3-Pentadiene	No	No	No	6.88E-10	99.9%	4.52E-08	1.98E-07	-	-	-	-
Isobutyraldehyde	No	No	No	1.00E-09	99.9%	6.56E-08	2.87E-07	-	-	-	-
2,3-Butanedione	No	No	No	7.68E-10	99.9%	5.04E-08	2.21E-07	-	-	-	-
2-Butanone	No	No	Yes	1.45E-10	99.9%	9.50E-09	4.16E-08	-	-	9.50E-09	4.16E-08
2-Methyl-furan	No	No	No	1.67E-08	99.9%	1.09E-06	4.80E-06	-	-	-	-
3-Methyl-furan	No	No	No	1.29E-09	99.9%	8.49E-08	3.72E-07	-	-	-	-
Isovaleraldehyde	No	No	No	2.80E-09	99.9%	1.84E-07	8.06E-07	-	-	-	-
2-Methyl-butanal	No	No	No	1.56E-09	99.9%	1.02E-07	4.48E-07	-	-	-	-
1-Methyl-cyclopentene	No	No	No	1.41E-10	99.9%	9.28E-09	4.06E-08	-	-	-	-
Benzene	Yes	No	Yes	1.92E-09	99.9%	1.26E-07	5.51E-07	1.26E-07	5.51E-07	1.26E-07	5.51E-07
Cyclohexene	No	Yes	No	1.06E-09	99.9%	6.94E-08	3.04E-07	-	-	6.94E-08	3.04E-07
Cyclopentanol	No	No	No	1.06E-09	99.9%	6.94E-08	3.04E-07	-	-	-	-
2-Ethyl-furan	No	No	No	9.03E-10	99.9%	5.92E-08	2.59E-07	-	-	-	-
2,5-Dimethyl-furan	No	No	No	9.08E-10	99.9%	5.96E-08	2.61E-07	-	-	-	-
2,4-Dimethyl-furan	No	No	No	1.19E-09	99.9%	7.78E-08	3.41E-07	-	-	-	-
Vinylfuran	No	No	No	4.85E-10	99.9%	3.18E-08	1.39E-07	-	-	-	-
Disulfide, dimethyl	No	No	No	1.68E-09	99.9%	1.10E-07	4.82E-07	-	-	-	-
Toluene	Yes	Yes	No	1.96E-09	99.9%	1.29E-07	5.64E-07	1.29E-07	5.64E-07	1.29E-07	5.64E-07
Hexanal	No	No	No	3.50E-10	99.9%	2.29E-08	1.00E-07	-	-	-	-
2-Ethyl-5-methyl-furan	No	No	No	1.69E-10	99.9%	1.11E-08	4.86E-08	-	-	-	-
4,4-Dimethyl-2-cyclopenten-1-one	No	No	No	3.58E-10	99.9%	2.35E-08	1.03E-07	-	-	-	-
Furfural	No	Yes	No	7.68E-11	99.9%	5.04E-09	2.21E-08	-	-	5.04E-09	2.21E-08
2-Isopropyl-1-hexene	No	No	No	3.58E-10	99.9%	2.35E-08	1.03E-07	-	-	-	-
Ethyl benzene	Yes	Yes	No	1.37E-10	99.9%	8.96E-09	3.93E-08	8.96E-09	3.93E-08	8.96E-09	3.93E-08
m,p-Xylene	Yes	Yes	No	7.32E-10	99.9%	4.80E-08	2.10E-07	4.80E-08	2.10E-07	4.80E-08	2.10E-07
o-Xylene	Yes	Yes	No	1.90E-10	99.9%	1.25E-08	5.45E-08	1.25E-08	5.45E-08	1.25E-08	5.45E-08
Tricyclene	No	No	No	3.44E-10	99.9%	2.26E-08	9.89E-08	-	-	-	-
a-Pinene	No	No	No	1.79E-08	99.9%	1.17E-06	5.13E-06	-	-	-	-
Camphene	No	No	No	2.83E-09	99.9%	1.86E-07	8.13E-07	-	-	-	-
Trisulfide, dimethyl	No	No	No	3.60E-10	99.9%	2.36E-08	1.03E-07	-	-	-	-
B-Pinene	No	No	No	2.04E-09	99.9%	1.34E-07	5.85E-07	-	-	-	-
Benzofuran	No	No	No	2.46E-10	99.9%	1.61E-08	7.07E-08	-	-	-	-
Decane	No	No	No	4.38E-10	99.9%	2.87E-08	1.26E-07	-	-	-	-
a-Terpinene	No	No	No	3.51E-10	99.9%	2.30E-08	1.01E-07	-	-	-	-
o-Cymene	No	No	No	5.42E-09	99.9%	3.56E-07	1.56E-06	-	-	-	-
D-Limonene	No	No	No	8.97E-09	99.9%	5.88E-07	2.58E-06	-	-	-	-
y-Terpinene	No	No	No	5.87E-10	99.9%	3.85E-08	1.69E-07	-	-	-	-
Terpinolene	No	No	No	1.13E-09	99.9%	7.41E-08	3.25E-07	-	-	-	-
Total VOC				8.00E-08	99.9%	5.25E-06	2.30E-05	-	-	-	-

[1] PM emissions are accounted for in Table 10: Controlled PM Emissions from Boiler Baghouse.

[2] Emission factors obtained from stack testing conducted at Quebec City pilot plant with a similar steam explosion process.

[3] Exhaust from the SteamEx Unit is fed to the FBC for destruction/control of PM and VOC

Stockpile Wind Erosion Potential Fugitive PM Emissions

Emission Source Description	Annual Throughput (tpy)	Operating Hours (hr/yr)	Control	Material Moisture Content (%)	PM Emission Factor (lb/ton)	PM_{10} Emission Factor (lb/ton)	$PM_{2.5}$ Emission Factor (lb/ton)	Control Efficiency (%)	PM Potential Emissions (lb/hr)	PM Potential Emissions (tpy)	PM_{10} Potential Emissions (lb/hr)	PM_{10} Potential Emissions (tpy)	$PM_{2.5}$ Potential Emissions (lb/hr)	$PM_{2.5}$ Potential Emissions (tpy)
Hog Fuel Piles	100,000	8,760	None	50%	1.36E-02	6.41E-03	9.71E-04	0%	1.55E-01	6.78E-01	7.32E-02	3.21E-01	1.11E-02	4.85E-02
Pellet Pile	220,500	8,760	None	4%	4.65E-01	2.20E-01	3.33E-02	0%	1.17E+01	5.13E+01	5.54E+00	2.43E+01	8.39E-01	3.67E+00
Feedstock Piles	220,500	8,760	None	34%	2.33E-02	1.10E-02	1.67E-03	0%	5.85E-01	2.56E+00	2.77E-01	1.21E+00	4.19E-02	1.84E-01
TOTAL									**1.25E+01**	**5.45E+01**	**5.89E+00**	**2.58E+01**	**8.92E-01**	**3.91E+00**

[1] Based emission factors calculated per AP-42 Section 13.2.4, September 2006.

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

E = emission factor (lb/ton)

k = particle size multiplier (dimensionless) for PM: 0.74

k = particle size multiplier (dimensionless) for PM_{10}: 0.35

k = particle size multiplier (dimensionless) for $PM_{2.5}$: 0.053

U = mean wind speed (mph): 4.30

M = material moisture content (%)

Jim Beck PES

From: Jim Beck PES <jim.beck@pes-world.com>
Sent: Friday, May 6, 2016 3:15 PM
To: Jim.beck@pes-world.com
Subject: Mpulse / IAC Baghouse PM10 Emission Question

FYI,
Bag Material, As Quoted:

- TTG PTFE membrane laminated to 22 oz. Fiberglass with I-625 Acid Resistant Finish
- Galvanized Filter Bag Cages to be 20 Vertical Wire; 6" Ring Spacing and 11 gauge construction; RFT top; galvanized carbon steel.
- Design Pressure Loss: Max -8" W.C. – baghouse inlet flange to baghouse outlet flange

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From: Glenn Smith [mailto:gsmith@iac-intl.com]
Sent: Monday, April 11, 2016 3:13 PM
To: 'jim.beck@pes-world.com' <jim.beck@pes-world.com>
Cc: Mike Gregory <mgregory@iac-intl.com>; Gregg Zoltek <gzoltek@iac-intl.com>; Jason Dowse <jdowse@iac-intl.com>; Pramodh Nijhawan <pnijhawan@iac-intl.com>
Subject: RE: 15141, Mpulse / IAC Baghouse PM10 Emission Question

Jim,

Below are our Bag Efficiency standards:

Total Particulate Removal Efficiency = 99.99%
Particulate 10 microns in size and greater = 99.99%
Particulate between 2.5 microns in size and 10 microns in size = 99%
Particulate between 1 microns in size and 2.5 microns in size = 99%
Particulate under 0.5 microns in size to 1 micron in size = 85%

Respectfully,

Glenn A. Smith, Jr.
CEO
Industrial Accessories Company
4800 Lamar Avenue
Mission, Kansas 66202
Phone: (913) 384-5511
Toll Free: 1-800-334-7431
Fax: (913) 384-6577
Email: gsmith@iac-intl.com
Website: www.iac-intl.com
Follow Us On: Linkedin Facebook Twitter Google+

IAC will be exhibiting at the following trade conferences in 2016:
Air Quality Workshop Presentation, April 5, 2016, Asheville NC, Grove Park Inn
Frac Sand Insider Conference, May 10-11, 2016, La Crosse WI, La Crosse Center: Booth # 508

IEEE Cement Conference, May 15-19 (exhibits May 15-17,) 2016, Dallas TX**,** Gaylord Texan Resort & Convention Center, Grapevine TX: Booth # 200
DUG Eagle Ford Conference, September 12-14, 2016, San Antonio TX, Henry B. Gonzalez Convention Center: Booth 5055
Air Quality Workshop Presentation, September 28, 2016, Pittsburgh PA, Renaissance Pittsburgh Hotel
Frac Sand Supply and Logistics Conference, October 13-14, 2016, San Antonio TX, JW Marriott Hill Country Resort: Booth #10

From: jim.beck@pes-world.com [mailto:jim.beck@pes-world.com]
Sent: Monday, April 11, 2016 12:43 PM
To: Jason Dowse
Cc: chris.mcmullen@pes-world.com; Jim.beck@pes-world.com; Chuck.White@pes-world.com; Mike Gregory
Subject: IAC Baghouse PM10 Emission Question

Jason,
I have a question about the IAC baghouse for the AP20445 Project.

The Ministry of the Environment wants to know about PM10 outlet emissions (amount of ash out the stack that is less than 10 micrometers in diameter); the data provided by IAC so far has been only for PM (ANY particulate matter).

What is the collection efficiency of the selected bag material for PM10?

I believe this is the bag material used:
TTG PTFE membrane laminated to 22 oz. Fiberglass with I-625 Acid Resistant Finish (Qty. 640)

Regards,

James Beck
Project Manager/Engineer
Precision Energy Services, Inc.
P.O. Box 1004
Hayden, ID 83835
Office: 208-772-4457
Cell: 208-699-7319
www.pes-world.com

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Shannon Manoulian

From: Turner Allen (Atlanta) <Allen.Turner@andritz.com>
Sent: Wednesday, October 21, 2015 5:39 PM
To: Rick Fawcett (rick.fawcett@centennial-res.com); Dave Strohm
Cc: adam@es2eng.com; 'Dan South' (dan.south@dometechnology.com); Curci Mike; Piche Denis
Subject: ANDRITZ: Post Dryer (belt) dust emissions

Gentlemen:

The following are expected values from our belt dryer group for the Steam Explosion Post-Dryer application.

Dust emissions out of belt dryer <10 mg/m³; thereof assume for
PM 500: about 5 mg/Nm³;
PM10= 90% of PM500
PM2.5= 50% of PM500

In order to confirm these values and offer a binding proposal for the belt dryer after steam explosion, we will need about 500 kg (dry) of steam exploded material to test in Europe.
I propose we plan to generate this material as part of the planned Quebec trials.

Best regards,

Allen

Allen Turner
ANDRITZ PULP & PAPER
Fiber Technologies Division
Sales Manager, BioRefinery

ANDRITZ INC
5405 Windward Pkwy
Suite 100W
Alpharetta, GA 30004
Phone: +1 770 640-2558
Fax: +1 770 640-2569
Mobile: +1 770 329-6187
allen.turner@andritz.com
www.andritz.com

We accept the challenge!

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Thank You.

---

5. Design, process and consumption data

The below mentioned data refer to the plant operation at design conditions (ambient air temperature of -6°C in Winter and +28°C in Summer and corresponding relative moistures of 80%). Changes in the ambient conditions will entail changes in the data/performance of the dryer.
Data are given per dryer line.

DESIGN BELT DRYING SYSTEM	Design Winter - -6°C, 80% relative humidity	Design Summer - +28°C, 80% relative humidity	Unit
Drying product	Saw Dust	Saw Dust	
Particle size	maximum 2 w-% P < 0,25 mm; minimum 50 w-% 1 mm < P < 4 mm; all particles P < 7 mm		mm
Wet Biomass quantity	44.86	44.86	t/hr
Dry solids quantity	24	24	t_{DS}/hr
Biomass dry solids content average	53.5	53.5	%DS*
DRIED PRODUCT			
Biomass quantity after drying	25.5	25.5	t/hr
Dried Biomass solids content	95	95	%DS*
Water evaporation capacity	19.3	19.3	t/hr
Operation time	8,000	8,000	hr/a
LOCATION			
Country	US	US	
Plant	TBA	TBA	
Number of Lines	1 x BDS SI 170	1 x BDS SI 170	
Dimensions of plant (LxWxH, approx.)	Please refer to attached layout	Please refer to attached layout	m
CONSUMPTION FIGURES	**(expected values)**		
Heat consumption	approx. 19.1	approx. 18.5	MW
Glycol / Hot water @ 110 °C	approx. 465	approx. 350	m³/hr
Glycol / Hot water return flow @ 70°C	approx. 460	approx. 346	m³/hr
Active belt dimension	288	288	m2
Electrical energy complete installed	approx. 535**	approx. 535**	kW
Electrical energy average consumption	approx. 305**	approx. 345**	kW
EMISSIONS	(expected values)		
Quantity exhaust air	approx. 696,000	approx. 756,000	m³/hr
Temperature exhaust air	approx. 37	approx. 46	°C
Quantity Cleaning Water for Belt (discontinuously)	approx. 4	approx. 4	m³/d

DESIGN BELT DRYING SYSTEM	Design Winter - -6°C, 80% relative humidity	Design Summer - +28°C, 80% relative humidity	Unit
Fire fighting water (in case of emergency only)	86	86	m³/hr
Compressed air for belt cleaning (discontinuously)	200	200	m³/hr
Noise emission	≤ 85 dB(A)***	≤ 85 dB(A)***	measured in 1m horizontal distance of each single noice source at normal ear height (1,5 m)

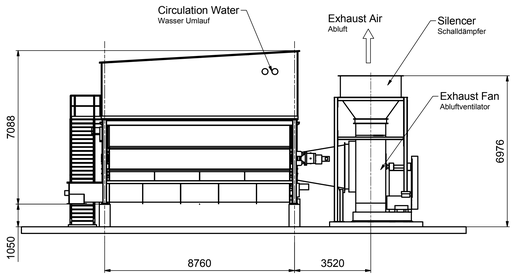
* DS … dry substance

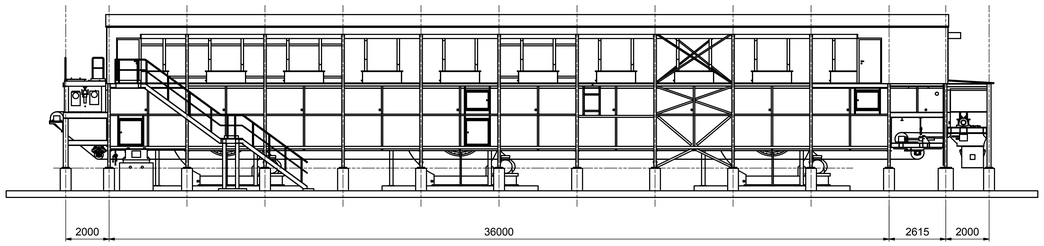
** Installed electrical power and power consumption: estimated values given for Andritz Scope of Supply (not including any Options !)

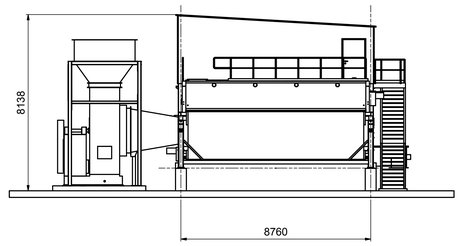
*** Related Standards:

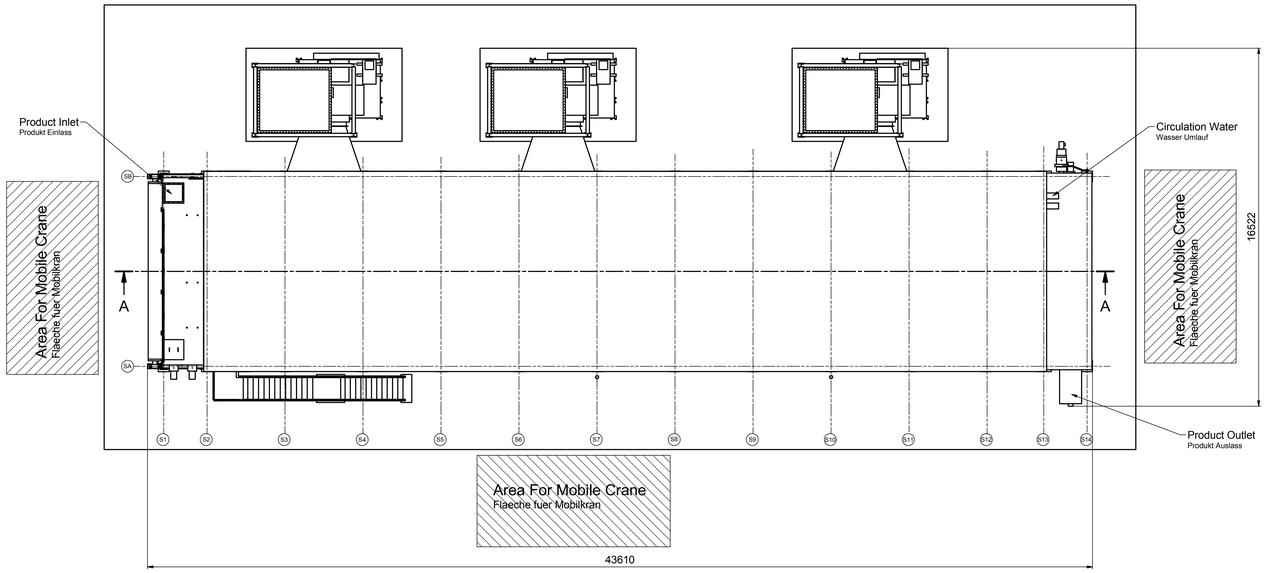
Determination of sound power levels and mechanical vibration produced by gears units shall be subject to ISO 45635.

Sound pressure levels shall be measured in dB (A) using a calibrated sound meter meeting the requirements of EN 60651.

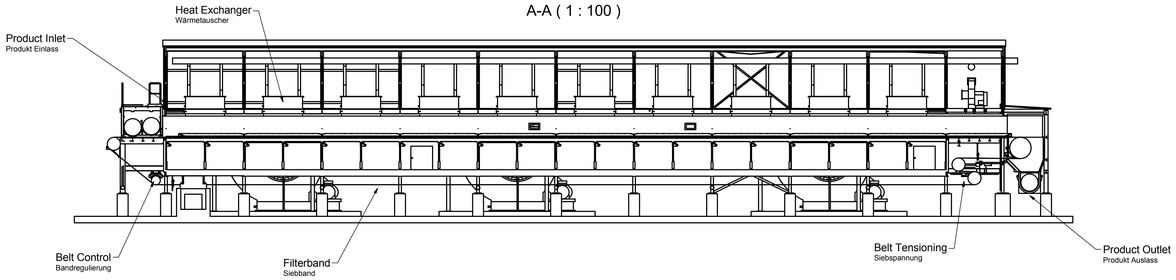


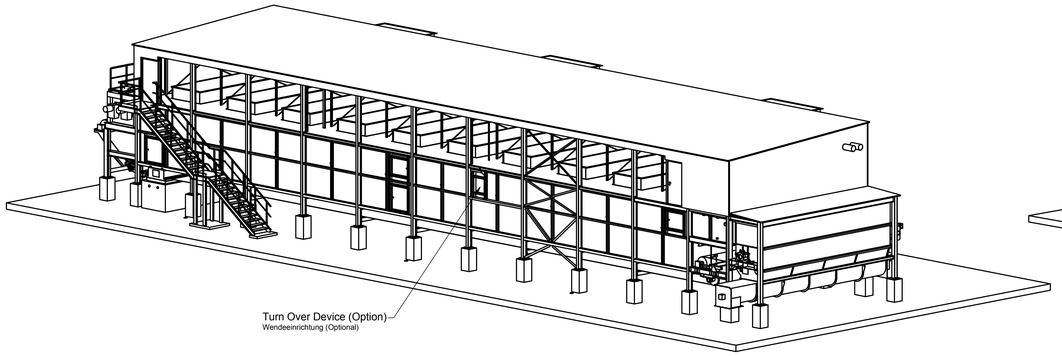


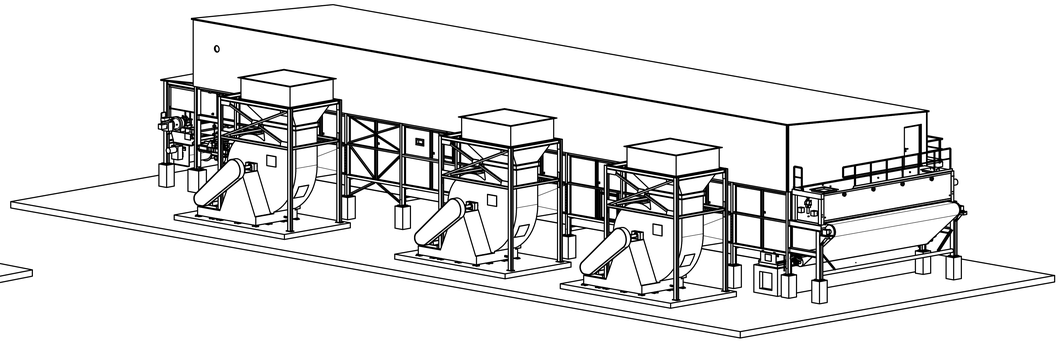




A-A (1 : 100)







FOR INFORMATION ONLY
NUR ZUR INFORMATION

General Tolerances		Tolerances for linear dimensions (except chamfers)																			
	ISO 2768-mK-E (Machining)	over	0.4	6	30	120	400	1000	2000	4000	8000	12000	16000	20000
		up to	6	± 0.1	± 0.2	± 0.5	± 1	± 2	± 3	± 4	± 5	± 6	± 7	± 8
	ISO 13920-BA-F (Steel fabric) ±2000 B. >2000 A	over	0	1	30	120	400	1000	2000	4000	8000	12000	16000	20000
		up to	30	± 1	± 1.2	± 2	± 3	± 4	± 6	± 8	± 10	± 12	± 14	± 16

Add Material - Item name	Mfg	Basic Material Name		Basic Material Weight: 0.000 kg
Product Type		Product Code		
	Initial Revision		Actual Revision	
Drawn	P Veigl	grzpet48	04.10.2012	
Checked				
Revision				

Replacement for Drawing No: Rev:
Copy from Drawing No: Rev:
Old Drawing No: Rev:

Description:
DRYER PLANT
BDS SI 170

TROCKNUNGSANLAGE
BDS SI 170

Drawing No: 702206347 Rev: -
Size: A0 Sheet/Sheets: 1 / 1 Scale: 1 : 100

ANDRITZ

Filename: as-p-drying_r&d-565-000615-3000001170-dryer pla_-22771559586.idw
CAD Drawing: SE_CDLL_001

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Drawing sheet ISO 5457:1999 - A0

Some additional emissions data for CRE.

David E.B. Strohm II | Managing Consultant

Trinity Consultants | 702 W. Idaho St Suite 1100 | Boise, Idaho 83702

P: 208.472.8837| M: 208.999.2327 | E: dstrohm@trinityconsultants.com

From: Adam Aagard [mailto:adam@es2eng.com]
Sent: Monday, November 02, 2015 8:03 AM
To: Dave Strohm <DStrohm@trinityconsultants.com>
Subject: FW: Potlatch Pellet Facility - Emission Calculations Status

FYI…

Adam Aagard, PE

Project Manager

adam@es2eng.com

Engineering System Solutions, ES^2
Phone: 208.552.9874

From: Curci Mike [mailto:Mike.Curci@andritz.com]
Sent: Sunday, November 01, 2015 7:31 AM
To: Rick Fawcett <rick.fawcett@centennial-res.com>; Turner Allen (Atlanta) <Allen.Turner@andritz.com>; adam@es2eng.com; 'Dan South' <dan.south@dometechnology.com>; 'Mike Oswald' <oswaldmw@pes-world.com>
Subject: RE: Potlatch Pellet Facility - Emission Calculations Status

Good day all,

Below are a few tables and references in regards to the hammer mill, pellet mill, and cooling equipment.

The VOC test data provided was a test using Baltic spruce which should provide a good reference point.

	Air Volume	PM 2.5	PM 10	CPM	TPM
Andritz 4360 Hammermill x1	9100 CFM	N/A	N/A	N/A	N/A
Andritz 26WLM Pelletmill x9	600-1200 CFM	N/A	N/A	N/A	N/A
LMM VC-119H Cooler x2	900-1000 CFM per ton				
Totals					

In response to the PM 2.5, PM 10, CPM, and TPM, these are functions of the dust control systems which are connected to the hammermill and pelletmill. I will request data from each vendor.

VOC Test

Plant / stack: Exhaust after pellet cooler

Parameter	Unit	Sample 1	Sample 2	Average
Date	dd-mm-yy	12/8/2014	12/8/2014	12/8/2014
Measuring period	hh:mm	17:47 - 18:16	18:17 - 18:46	17:47 - 18:46
Measuring period, flow	hh:mm	-	-	-
Cross section area	m²	0,5027		-

Operating parameters

Temperature	°C	29	29	29
Moisture (stated or calculated)	Vol %	2,00	2,00	2,00
Flowrate	m³(s,d)/h	37	37	37
Flowrate, operating conditions	m³/h	43	43	43

Concentrations

VOC	mg C/m³(s,d)	41	47	44

Organic solvents

Formaldehyde	mg/m³(s,d)	1,2	1,2	1,2

Acetaldehyde	mg/m³(s,d)	0,35	0,30	0,32
Acrolein	mg/m³(s,d)	0,11	0,12	0,12
Acetone	mg/m³(s,d)	0,035	0,028	0,031
Propanal	mg/m³(s,d)	0,060	0,057	0,058
2-butanone	mg/m³(s,d)	< 0,002	0,0054	0,0035
Butanal	mg/m³(s,d)	0,11	0,096	0,10
Benzaldehyde	mg/m³(s,d)	0,54	0,45	0,49
Pentanal	mg/m³(s,d)	0,70	0,63	0,66
Hexanal	mg/m³(s,d)	3,2	2,8	3,0
Methanol	mg/m³(s,d)	2,1	2,1	2,1
Sum, all components	mg/m³(s,d)	8,4	5,7	7,0

Mass flow rate

VOC	g C/h	1.5	1.7	1.6
Formaldehyd	g/h	44	43	44
Acetaldehyd	g/h	13	11	12
Methanol	g/h	78	-	78
Production	tons/h	8,30	8,30	8,30
VOC	g C/ton	0,400	0,459	0,430
VOC	lb/ton	0.00088	0.00101	0.00095
Formaldehyde	lb/ton	0,0118	0,0114	0,0116
Acetaldehyde	lb/ton	0,00341	0,00293	0,00317

Methanol	lb/ton	0,0206	0,0206	0,0206

(s,d) indicates dry gas at standard conditions (0°C, 101,3 kPa)

* means "not included in accreditation no. 51"

Thanks

Mike

Mike Curci

Capital Sales Manager, Biomass

ANDRITZ Inc.
336 West Penn Street

Muncy, PA 17756

Mobile: +1 850 557 7674
Fax: +1 770 640 2521

Mike.Curci@andritz.com
www.andritz.com

3/3/2016

Questions for CRE and PES – Received from CRE and Precision Energy Systems via Email to Dave Strohm, Trinity on 3/29/2015

a. FBC/Boiler Baghouse – The expected performance of the baghouse is 0.0027 gr/acfm dry particulate. Based on this and the PES combustion calculation the baghouse will emit a maximum of 3.11 lb./hr. of PM.
    i. Output grain loading or control efficiency and input grain loading – 0.0027 gr/acfm dry particulate outlet grain loading.
    ii. Exhaust flow: 135,000 ACFM @ 350F & 1 atm pressure.
    iii. Dimensions including height of exhaust stack: .Typical exhaust stack height is 75 Ft.
    iv. Temperature of effluent : 300 to 350 F

b. Please confirm that the following exhaust through the FBC/Boiler baghouse:
    i. Boilers (high pressure boiler and glycol heater)
    ii. FBC Combustor
    iii. FBC Pre-Burner
    iv. Multiclone cyclone
    v. Flash steam from SteamEx process – Line 5 from Andritz Design Criteria (SteamEx Blow Tank Exhaust) – fed into FBC
    vi. Line 4 from Andritz Design Criteria – (Pre-Steaming Bin Exhaust) – Fed into FBC
    vii. Line 16 from Andritz Design Criteria - (Pellet Mill Exhaust) – Fed into FBC
    viii. Pellet Cooling/De-dusting Air – Fed into FBC (2 points on DWG 000.02, grid J1 & J7) – Fed to FBC, labeled 'Multiclone 1' and 'Multiclone 2'

APPENDIX E: AIR DISPERSION MODELING REPORT

PROJECT REPORT

Centennial Renewable Energy > Potlach, ID

Air Dispersion Modeling Report

Prepared By:

Shannon K. Manoulian, P.E. – Senior Consultant

TRINITY CONSULTANTS
702 W. Idaho Street
Suite 1100
Boise, ID 83702
(208) 472-8837

May 2016

Project 151301.0005

Environmental solutions delivered uncommonly well

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1. EXECUTIVE SUMMARY

This air quality modeling report documents the methodology and results of the air quality analyses prepared in support of an Idaho Department of Environmental Quality (IDEQ) Permit to Construct (PTC) application for the Centennial Renewable Energy (CRE) wood pellet production facility near Potlach, Idaho. This report seeks to fully document and report the methods and techniques used to perform the modeling as well as the results of the modeling analysis, in support of the PTC application.

All information provided in this report and the PTC application is based on preliminary facility design. Due to the structure of the project financing (grant allocation), final design information will not be available until after PTC issuance. All available manufacturer and vendor information has been provided; CRE will accept permit conditions related to assumptions and information that has been presented that does not meet DEQ's interpretation of what constitutes adequate documentation and/or justification. If, upon final design and construction, information or parameters differ from the values presented in this modeling report and PTC application and/or PTC, CRE will review the applicability of a modification to the PTC including impacts to the NAAQS analyses completed as part of this initial PTC application.

CRE is proposing to construct and operate a Greenfield wood pellet production facility near Potlach, Idaho. The facility will produce a proprietary type of wood pellet known as SteamEx Pellets from the Andritz Corporation. The facility will utilize short fiber wood waste (primarily sawdust and planer shavings) from regional mills as feedstock.

The proposed CRE Potlach facility will be a non-PSD major source of NO_X, CO and HAPs and will be subject to Title V of the Clean Air Act. In addition, the facility will be subject to 40 CFR Part 60, Subpart Db - Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units and 40 CFR Part 63, Subpart DDDDD—National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters.

Air dispersion modeling was conducted for those criteria pollutants which exceed the Idaho Level I modeling thresholds and TAPs which exceed the screening emissions level (EL) in Idaho Air Rules Section 585 and 586. The criteria pollutants which exceed the modeling threshold at the CRE facility are PM_{10}, $PM_{2.5}$, NO_X, CO and SO_2. In addition, several TAPs exceed the screening emission levels (ELs) in IDAPA 58.01.01.585 and 586. However, the facility will be subject to 40 CFR Part 60, Subpart Db - Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units and 40 CFR Part 63, Subpart DDDDD—National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters. Per IDEQ policy and guidance, TAPs that are regulated by a federal NSPS or NESHAPS were not included in the modeling analysis.

The model used for this application is AERMOD (version 15181), the USEPA–approved model for near-field new source review. AERMOD was applied as recommended in EPA's Guideline on Air Quality Models and consistent with guidance in IDEQ's Dispersion Modeling Guidelines and the model protocol submitted to IDEQ on April 26, 2016, with minor exceptions as noted in Section 3.4. CRE did not employ any non-regulatory or beta options within AERMOD; regulatory defaults were used. The results of the modeling show that the facility is in compliance with all applicable NAAQS and TAP AACs and AACCs.

2. PROJECT DESCRIPTION AND BACKGROUND AS IT RELATES TO MODELING ANALYSES

CRE is proposing to construct and operate a Greenfield wood pellet production facility near Potlach, Idaho. The facility will produce a proprietary type of wood pellet known as SteamEx Pellets from the Andritz Corporation. The facility will utilize short fiber wood waste (primarily sawdust and planer shavings) from regional mills as feedstock.

The steam for the facility will be provided via a fluidized bed boiler combusting hog fuel. The pelletizing operation will also include the use of hammer mills, pellet mills and pellet coolers. The wood pellets produced will be transported off-site via railcar or truck.

Emissions from the project include criteria pollutants and several IDAPA TAPs.

2.1. GENERAL FACILITY/PROJECT DESCRIPTION

Wood mill residues will be brought in from various lumber mills in the area for process feedstock and Fluidized Bed Combustor (FBC) fuel. Received sawdust and shavings will be co-mingled upon delivery and stored in 15 day storage piles. Feedstock and hogged fuel will be received by truck and stacked by front end loader in the appropriate open storage pile in the storage yard area. Feedstock will be reclaimed by front-end loader and deposited into a metered bin, then conveyed to the process steam explosion process. Hogged fuel will be received and fed into a green hammer mill prior to being stacked. Hogged fuel will then be fed into a metered feed bin to be conveyed to the boiler island as fuel.

Reclaimed feedstock will be conveyed to screeners where material meeting size requirements will bypass the green hammer milling area. Product that exceeds the maximum size, will be run through a green hammer mill and then be fed back onto the screeners. Sized product will then proceed to the steam pre-heat bin where it will conditioned prior to being fed into the steam explosion process.

Once steam exploded, the material will be fed into a belt dryer to be dried to 8%-10% moisture content. After the dryer, product will be final screened and sized using two hammer mills. After final sizing the steam exploded feedstock will be fed into a conditioning bin where the feedstock will be moisture conditioned to the optimum moisture content and stored in short-term storage bins. Steam exploded feedstock reclaimed from the storage bins will proceed to processing, before going into the pellet mills. Produced pellets will then be cooled to near ambient and then screened and fines removed and fed into the boiler heating system.

After the pelletizing process, product will be conveyed through a belt conveyor to a storage pile. Black Pellets will be reclaimed by a front end loader and fed into a loading bin. The pellets will be conveyed to a pellet screener prior to being loaded onto railcar. Fines from the screener will be conveyed to a metal bin to be hauled to the hogged fuel pile. Wood pellets will pass through the screener and be loaded into 91 MT (100 t) capacity covered hopper rail cars. Train cars will be loaded in 12 car blocks with a track mobile used to advance the cars into position. After the block has been loaded it will be connected to the unit train. The outbound trains will be approximately 110-115 car units. Received product will be transferred directly to ship at the Port of Longview in Longview, WA.

Emissions from the facility will include PM_{10} and $PM_{2.5}$ from material handling, processing and combustion; NO_x, CO, SO_2 and Lead from biomass and propane combustion; and VOC and HAPs from combustion, the steam explosion process and material processing. The facility proposes to operate 8,760 hours per year, with the

exception of the finished product loading. Finished product loading, which includes transfer from the pneumatic system to the pellet product stockpile through to railcar filling, will only occur between the hours of 6am and 6pm. Draft process flow diagrams are included in **Appendix A.**

Specific emission sources at the facility are described in the subsections below.

2.1.1. Material Handling

2.1.1.1. Hogged Fuel

Hogged fuel handling begins with unloading of the material from trucks to stock piles, and transfer to the sizing and conveying processes via front loader. Hogged fuel is loaded into hoppers, travels through the screw feeder into the fuel screen, then through the bucket elevator into the surge bin. Hogged fuel is conveyed pneumatically from the surge bin to the FBC. A detailed description of this process is provided in Section 3.2 above and shown visually on the PFD's included in **Appendix A.**

Emissions from the hogged fuel handling were calculated using AP-42 Section 11.19.2 for conveyor transfers and screening; however, no data are available for $PM_{2.5}$ emissions for uncontrolled sources. Therefore, the particle size multiplier of 0.0053 from AP-42 Section 13.2.4 was multiplied by the PM emission factor to develop the $PM_{2.5}$ emission factor for these sources. The hogged fuel will have a moisture content of approximately 50%; therefore a 50% control efficiency was applied to the calculations. Transfers from the surge bin to the pneumatic system and from the pneumatic system to the FBC occur within the pneumatic enclosure, therefore a 100% control efficiency was applied to those sources. Detailed emissions calculations are included in **Appendix B.**

Requested process throughputs vary by equipment, however, for all emissions sources, an annual throughput of 100,000 tons per year is requested. The hogged fuel process will operate a maximum of 8,760 hours per year. Specific requested hourly throughputs are shown in the emissions calculations in **Appendix B.**

2.1.1.2. Feedstock

Feedstock handling begins with unloading of the material from trucks to stock piles, and transfer to the sizing and conveying processes via front loader. Feedstock is loaded into hoppers, travels through the screw feeder on to a conveyor belt, then through another set of screw feeders into the green hammer mills. The green hammer mills are equipped with cyclones which are used to transfer materials to conveyors that feed the SteamEx system. The cyclones are used as process equipment and are not considered emission control equipment. After going through the SteamEx process, the material is transferred via conveyor to the Belt Dryer.

The steam exploded material exit the dryer and are transferred to feed screws and into the dry hammer mill via conveyor. Sized pellets from the dry hammer mill are transferred to the pneumatic conveying system via the dry cyclone. The cyclones are used as process equipment and are not considered emission control equipment. Sized pellets are discharged from the pneumatic conveying system into a metering surge bin. The pellets then travel via conveyor system to the mill feed bins, from the bins to the pellet mills via the mill feed screws and conditioning screws to pellet mills, and from the pellet mills via conveyor to the pellet coolers. After exiting the pellet coolers, the product is conveyed to the pellet screens and then transferred via pneumatic system to the product stockpile.

The finished pellets are then transferred via front loader to a hopper and conveyed to the shipping screen. Sized finished pellets are transferred from the screen via conveyor to the filling spout and into railcars for shipment

off-site. A detailed description of this process is provided in Section 3.1 above and shown visually on the PFD's included in **Appendix A.**

Emissions from the feedstock/pellet handling were calculated using AP-42 Section 11.19.2 for conveyor transfers and screening; however, no data are available for $PM_{2.5}$ emissions for uncontrolled sources. Therefore, the particle size multiplier of 0.0053 from AP-42 Section 13.2.4 was multiplied by the PM emission factor to develop the $PM_{2.5}$ emission factor for these sources.

Prior to entering the belt dryer, the feedstock will have initial moisture content of 34%; therefore a 34% control efficiency was applied to the calculation for sources upstream of the belt dryer (Emission Unit IDs [EU ID] FS1 through FS9); a control efficiency of 8% was applied to the calculation for sources downstream of the dryer (EU ID FS15, FS16, and FS20), based on the material moisture content of the 'dried' pellet. The transfer from Conveyor #2 to Conveyor #3 occurs inside an enclosure; a 50% control efficiency was applied to this emission point (EUID FS10). Transfers into and out of the SteamEx process and Belt Dryer occur inside the SteamEx building, therefore a 100% control efficiency was applied to EUID FS11 through FS14.

Emissions from the dry hammer mill and cyclone are controlled by the hammer mill baghouse with a control efficiency of 99%. Transfers from the dry cyclone to the pneumatic system and from the pneumatic system to the surge bin occur within the pneumatic enclosure, therefore a 100% control efficiency was applied to those sources (FS18 – FS19). The pellet conditioning process (FS21-FS40) occurs inside the pellet building and transfer from the pneumatic system to the pellet surge bin (FS41) occurs within the pneumatic enclosure; a 100% control efficiency is applied to those sources.

There will be no controls on the finished product material handling (FS42-FS49), with the exception of transfer in and out of the pneumatic system (FS46, FS49) which will have 50% control for the pneumatic enclosure, and the shipping screens and associated transfers (FS45) which will be partially enclosed (50% control). Finished product material will have a moisture content of 4%, which was applied as control to FS42-44 and FS47-48. In addition, finished product handling and transfers (FS42-45, 47-48) will only occur between the hours of 6am and 6pm.

Requested process throughputs vary by equipment, however, for emissions sources FS1-FS42, an annual throughput of 220,500 tpy is requested. The feedstock handling process will operate a maximum of 8,760 hours per year, with the exception of the finished product handling and transfers as described above. Specific requested hourly throughputs are shown in the emissions calculations in **Appendix B.**

2.1.2. Fluidized Bed Combustor, Pre-Heater and FBC Baghouse

As described in Section 3.2, the FBC will be fired using hog fuel. Particulate emissions from the FBC will be controlled by the FBC system baghouse. Emissions of other criteria pollutants from the FBC were calculated using emission factors from AP-42 Section 1.6 Wood Residue Combustion in Boilers, Tables 1.6-1, 1.6-2, and 1.6-3 for uncontrolled bark/bark and wet wood/wet wood-fired boiler. Hazardous air pollutant (HAPs) and Toxic Air Pollutant (TAPs) emissions were calculated using emission factors from AP-42 Section 1.6, Tables 1.6-3 and 1.6-4.

A forced draft fan will used to force air through a preheat burner prior to the inlet duct of the FBC to provide warming air to assist during startup of the FBC from cold conditions. One the FBC bed is heated to the appropriate temperature, the pre-heat burner is turned off. The pre-heater will have a capacity of 8.0 MMBtu/hr and will combust propane. Particulate emissions from the FBC will be controlled by the FBC system baghouse.

Emissions of other criteria pollutants were calculated using AP-42 Section 1.5 Liquefied Petroleum Gas Combustion. Section 1.5 does not contain emission factors for HAPs; therefore HAPs were calculated using AP-42 Section 1.4 Natural Gas Combustion, Tables 1.4-3 and 1.4-4.

The FBC system will be equipped with a baghouse for control of particulate emissions. The baghouse will have an output PM grain loading rate of 0.0027 gr/acfm. It was assumed that PM_{10} and $PM_{2.5}$ emissions will be equal to PM emissions. In addition to controlling particulate from the FBC and pre-heater, the FBC system baghouse will control particulate emissions from the SteamEx unit and Pellet Coolers (exhaust from the SteamEx unit and Pellet Coolers is fed to the FBC for destruction of VOC, HAPs, TAPs and control of PM).

The FBC, pre-heater and FBC system baghouse will operate a maximum of 8,760 hr/year. Detailed emissions calculations are provided in **Appendix B**.

2.1.3. Steam Explosion System

The SteamEx unit will be a source of PM, VOC, HAPs and TAPs. Emission factors obtained from stack testing conducted at Quebec City pilot plant with a similar steam explosion process. This stack testing data is confidential, therefore, CRE will accept a permit condition requiring stack testing to verify the emission rates. Exhaust from the SteamEx unit is fed to the FBC for destruction of VOC, HAPs, TAPs and control of PM. The SteamEx unit will operate a maximum of 8,760 hr/year. Detailed emissions calculations are provided in **Appendix B**.

2.1.4. Belt Dryer

The Belt Dryer will be a source of particulate emission. Dust emissions have a manufacturer's guarantee of less than 10 mg/Nm^3 (dry). It is assumed that 50% of dust emissions consist of PM500, 90% of PM500 emissions consist of PM_{10}, and 50% of PM500 emissions consist of $PM_{2.5}$. The dryer will be operated at a temperature much lower than the upstream SteamEx process and therefore volatilization is not expected to occur during the drying process. The Belt Dryer will operate a maximum of 8,760 hr/year. Detailed emissions calculations are provided in **Appendix B**.

2.1.5. Pellet Coolers

The Pellet Coolers will be a source of PM, VOC, HAPs and TAPs emissions. Emissions were calculated based on engineering testing of the total gaseous organics emissions from pellet coolers at a similar facility. The most conservative emission factors from testing were used. Exhaust from the Pellet Coolers will be fed to the FBC for destruction and control of VOC, HAPs, TAPs and PM. The Pellet Coolers will operate a maximum of 8,760 hr/year. Detailed emissions calculations are provided in **Appendix B**.

2.2. LOCATION OF PROJECT

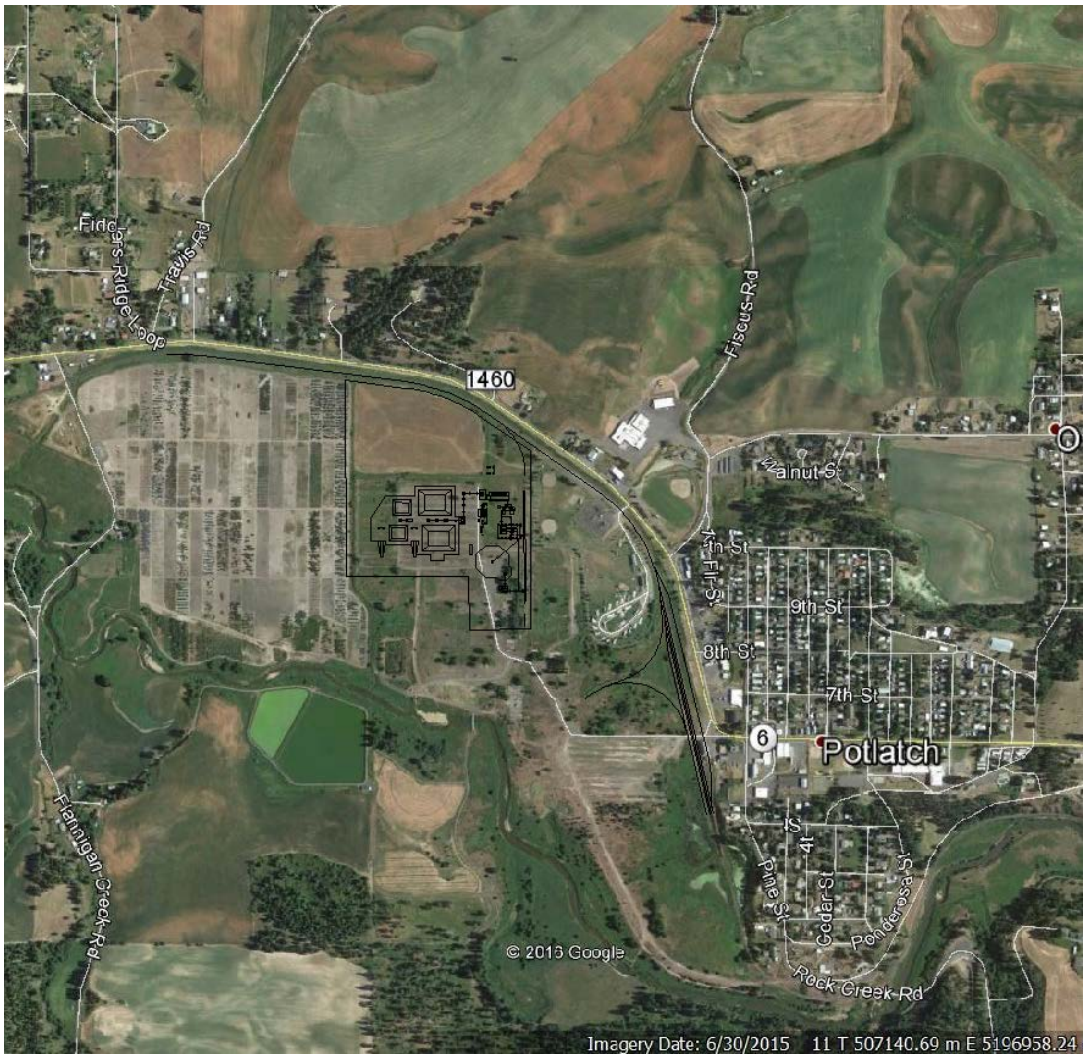
The proposed CRE facility will be located on the former Potlach Mill site, near State Highway 6 and Forest Road 1460, approximately 0.7 miles northwest of the Potlach city center in Latah County, ID. The UTM coordinates for the facility are approximately 506,829 m E, 5,196,968 m N, Zone 11 (NAD83 coordinate system). Latah County is an attainment or unclassified area for all criteria pollutants. Land use in the area includes agricultural, small commercial and residential properties. Terrain surrounding the project site is relatively flat. A map showing the

location of the proposed facility is provided as **Figure 2 1**. The closest industrial facility to the project site is the Bennett Lumber facility, located approximately six (6) miles east of the proposed CRE facility.

The wood pelletizing mill will be constructed on approximately 48 acres. There are currently existing structures on the site from a previous wood chipping operation that will be removed prior to construction, except for the existing shop on the southeast part of the site. The site has an existing entrance from ID Hwy 3 on the north portion of the site which will be utilized for the new operation. Running along the southern portion of the site is the St. Maries Railroad, which splits off 2 spurs. An existing fire water storage pond is also located on the south central area of the property. It is insufficiently sized to hold the required amount of fire water and will be required to be upgraded.

X A map showing the geographical location of the facility is provided in this section or a reference is provided to another location in the application where a map is provided.

Figure 2-1. Proposed Facility Location



2.3. EXISTING PERMITS AND MODELING ANALYSES PERFORMED

The proposed CRE facility is a Greenfield facility; there are no existing air quality permits, and no previous modeling analyses have been performed.

X (n/a) Any existing air quality permits are listed and described in this section, and any associated air quality modeling analyses have been described and referenced, and submitted if appropriate.

3. MODELING ANALYSES APPLICABILITY AND PROTOCOL

Air dispersion modeling was conducted for those criteria pollutants which exceeded the Idaho Level I modeling thresholds, which include CO, NO_x, PM_{10}, $PM_{2.5}$ and SO_2, and TAPs which exceed the screening emissions level (EL) in Idaho Air Rules Section 585 and 586. However, per IDEQ policy and guidance, TAPs that are regulated by a federal NSPS or NESHAPS were not included in the modeling analysis. These federally regulated TAPs include acetaldehyde, acrolein, arsenic, benzene, beryllium, cadmium, chromium VI, hydrogen chloride, nickel, POM, and dioxins and furans. Therefore the modeling analysis only included carbon tetrachloride, chloroform, iron, methylene chloride, silver and vinyl chloride.

3.1. APPLICABLE STANDARDS

Criteria pollutant National Ambient Air Quality Standards (NAAQS) are listed in **Table 3-1**, along with significant impact levels (SILs).

Table 3-1. Applicable Regulatory Limits

Pollutant	Averaging Period	Significant Impact Levels[a] (µg/m³)[b]	Regulatory Limit[c] (µg/m³)	Modeled Design Value Used[d]
PM_{10}[e]	24-hour	5.0	150[f]	Maximum 6th highest[g]
$PM_{2.5}$[h]	24-hour	1.2	35[i]	Mean of maximum 8th highest[j]
	Annual	0.3	12[k]	Mean of maximum 1st highest[l]
Carbon monoxide (CO)	1-hour	2,000	40,000[m]	Maximum 2nd highest[n]
	8-hour	500	10,000[m]	Maximum 2nd highest[n]
Sulfur Dioxide (SO_2)	1-hour	3 ppb[o] (7.8 µg/m³)	75 ppb[p] (196 µg/m³)	Mean of maximum 4th highest[q]
	3-hour	25	1,300[m]	Maximum 2nd highest[n]
	24-hour	5	365[m]	Maximum 2nd highest[n]
	Annual	1.0	80[r]	Maximum 1st highest[n]
Nitrogen Dioxide (NO_2)	1-hour	4 ppb (7.5 µg/m³)	100 ppb[s] (188 µg/m³)	Mean of maximum 8th highest[t]
	Annual	1.0	100[r]	Maximum 1st highest[n]
Lead (Pb)	3-month[u]	NA	0.15[r]	Maximum 1st highest[n]
	Quarterly	NA	1.5[r]	Maximum 1st highest[n]
Ozone (O_3)	8-hour	40 TPY VOC[v]	75 ppb[w]	Not typically modeled

a. Idaho Air Rules Section 006 (definition for significant contribution) or as incorporated by reference as per Idaho Air Rules Section 107.03.b.
b. Micrograms/cubic meter.
c. Incorporated into Idaho Air Rules by reference, as per Idaho Air Rules Section 107.
d. The maximum 1st highest modeled value is always used for the significant impact analysis unless indicated otherwise. Modeled design values are calculated for each ambient air receptor.

Pollutant	Averaging Period	Significant Impact Levels[a] (μg/m³)[b]	Regulatory Limit[c] (μg/m³)	Modeled Design Value Used[d]

e. Particulate matter with an aerodynamic diameter less than or equal to a nominal 10 micrometers.
f. Not to be exceeded more than once per year on average over 3 years.
g. Concentration at any modeled receptor when using five years of meteorological data.
h. Particulate matter with an aerodynamic diameter less than or equal to a nominal 2.5 micrometers.
i. 3-year mean of the upper 98th percentile of the annual distribution of 24-hour concentrations.
j. 5-year mean of the 8th highest modeled 24-hour concentrations at the modeled receptor for each year of meteorological data modeled. For the SIL analysis, the 5-year mean of the 1st highest modeled 24-hour impacts at the modeled receptor for each year.
k. 3-year mean of annual concentration.
l. 5-year mean of annual averages at the modeled receptor.
m. Not to be exceeded more than once per year.
n. Concentration at any modeled receptor.
o. Interim SIL established by EPA policy memorandum.
p. 3-year mean of the upper 99th percentile of the annual distribution of maximum daily 1-hour concentrations.
q. 5-year mean of the 4th highest daily 1-hour maximum modeled concentrations for each year of meteorological data modeled. For the significant impact analysis, the 5-year mean of 1st highest modeled 1-hour impacts for each year is used.
r. Not to be exceeded in any calendar year.
s. 3-year mean of the upper 98th percentile of the annual distribution of maximum daily 1-hour concentrations.
t. 5-year mean of the 8th highest daily 1-hour maximum modeled concentrations for each year of meteorological data modeled. For the significant impact analysis, the 5-year mean of maximum modeled 1-hour impacts for each year is used.
u. 3-month rolling average.
v. An annual emissions rate of 40 ton/year of VOCs is considered significant for O_3.
w. Annual 4th highest daily maximum 8-hour concentration averaged over three years.

TAP emissions increases resulting from the project are identified in **Table 3-2.**

Table 3-2. TAP ELs and AACS/AACCS

TAP	Non-Carcinogen or Carcinogen	Screening Emissions Level (EL)[a] (lb/hr)	AAC or AACC[b] (μg/m³)
Acenaphthene	Carcinogen	9.10E-05	1.40E-02
Acenaphthylene	Carcinogen	9.10E-05	1.40E-02
Acetaldehyde	Carcinogen	3.00E-03	4.50E-01
Acetone	Non-Carcinogen	1.19E+02	8.90E+04
Acetophenone	Carcinogen	9.10E-05	1.40E-02
Acrolein	Non-Carcinogen	1.70E-02	1.25E+01
Anthracene	Carcinogen	9.10E-05	1.40E-02
Antimony	Non-Carcinogen	3.30E-02	2.50E+01
Arsenic	Carcinogen	1.50E-06	2.30E-04
Barium	Non-Carcinogen	3.30E-02	2.50E+01
Benzene	Carcinogen	8.00E-04	1.20E-01
Benzo(a)anthracene	Carcinogen	7-PAH	N/A
Benzo(a)pyrene	Carcinogen	7-PAH	N/A
Benzo(b)fluoranthene	Carcinogen	7-PAH	N/A
Benzo(e)pyrene	Carcinogen	9.10E-05	1.40E-02

TAP	Non-Carcinogen or Carcinogen	Screening Emissions Level (EL)[a] (lb/hr)	AAC or AACC[b] (µg/m³)
Benzo(g,h,i)perylene	Carcinogen	9.10E-05	1.40E-02
Benzo(j,k)fluoranthene	Carcinogen	9.10E-05	1.40E-02
Benzo(k)fluoranthene	Carcinogen	7-PAH	N/A
Beryllium	Carcinogen	2.80E-05	4.20E-03
Bis(2-ethylhexyl)phthalate	Carcinogen	2.80E-02	4.20E+00
Bromomethane	Non-Carcinogen	1.27E+00	9.50E+02
2-Butanone (MEK)	Non-Carcinogen	3.93E+01	2.95E+04
Cadmium	Carcinogen	3.70E-06	5.60E-04
Carbon tetrachloride	Carcinogen	4.40E-04	6.70E-02
Chlorine	Non-Carcinogen	2.00E-01	1.50E+02
Chlorobenzene	Non-Carcinogen	2.33E+01	1.75E+04
Chloroform (Trichloromethane)	Carcinogen	2.80E-04	4.30E-02
2-Chlorophenol	Non-Carcinogen	3.30E-02	2.50E+01
Chrysene	Carcinogen	7-PAH	N/A
Crotonaldehyde	Non-Carcinogen	3.80E-01	2.85E+02
Chromium	Non-Carcinogen	3.30E-02	2.50E+01
Chromium VI	Carcinogen	5.60E-07	8.30E-05
Cobalt	Non-Carcinogen	3.30E-03	2.50E+00
Copper	Non-Carcinogen	6.70E-02	5.00E+01
Cyclohexene	Non-Carcinogen	6.77E+01	5.08E+04
Dibenzo(a,h)anthracene	Carcinogen	7-PAH	N/A
Dichlorobenzene	Non-Carcinogen	3.00E+01	2.25E+04
Dichlorobiphenyl	Carcinogen	6.60E-05	1.00E-02
1,2-Dichloroethane	Carcinogen	2.70E+01	3.80E-02
1,2-Dichloropropane	Non-Carcinogen	2.31E+01	1.74E+04
Ethyl benzene	Non-Carcinogen	2.90E+01	2.18E+04
Fluoranthene	Carcinogen	9.10E-05	1.40E-02
Fluorene	Carcinogen	9.10E-05	1.40E-02
Formaldehyde	Carcinogen	5.10E-04	7.70E-02
Furfural	Non-Carcinogen	5.33E-01	4.00E+02
Heptachlorodibenzo-p-dioxins	Carcinogen	Dioxin/Furan	N/A
Heptachlorodibenzo-p-furans	Carcinogen	Dioxin/Furan	N/A
Hexachlorodibenzo-p-dioxins	Carcinogen	Dioxin/Furan	N/A
Hexachlorodibenzo-p-furans	Carcinogen	Dioxin/Furan	N/A
Hexane	Non-Carcinogen	1.20E+01	9.00E+03
Hydrogen Chloride	Non-Carcinogen	5.00E-02	3.75E+02
Indeno(1,2,3-cd)pyrene	Carcinogen	7-PAH	N/A
Iron	Non-Carcinogen	6.70E-02	5.00E+01
Manganese	Non-Carcinogen	3.33E-01	2.50E+02
Methyl Acetate	Non-Carcinogen	4.07E+01	3.05E+04
Methylene chloride (dichloromethane)	Carcinogen	1.60E-03	2.40E-01
Molybdenum	Non-Carcinogen	3.33E-01	2.50E+02
Naphthalene	Non-Carcinogen	3.33E+00	2.50E+03
Nickel	Carcinogen	2.70E-05	4.20E-03

TAP	Non-Carcinogen or Carcinogen	Screening Emissions Level (EL)[a] (lb/hr)	AAC or AACC[b] (μg/m³)
Octachlorodibenzo-p-dioxins	Carcinogen	Dioxin/Furan	N/A
Octachlorodibenzo-p-furans	Carcinogen	Dioxin/Furan	N/A
Pentachlorodibenzo-p-dioxins	Carcinogen	Dioxin/Furan	N/A
Pentachlorodibenzo-p-furans	Carcinogen	Dioxin/Furan	N/A
Pentachlorobiphenyl	Carcinogen	6.60E-05	1.00E-02
Pentachlorophenol	Non-Carcinogen	3.30E-02	2.50E+01
Pentane	Non-Carcinogen	1.18E+02	8.85E+04
Perylene	Carcinogen	9.10E-05	1.40E-02
Phenanthrene	Carcinogen	9.10E-05	1.40E-02
Phenol	Non-Carcinogen	1.27E+00	9.50E+02
Phosphorus	Non-Carcinogen	7.00E-03	5.00E+00
Propionaldehyde	Non-Carcinogen	2.87E-02	2.15E+01
Pyrene	Carcinogen	9.10E-05	1.40E-02
Selenium	Non-Carcinogen	1.30E-02	1.00E+01
Silver	Non-Carcinogen	1.00E-03	5.00E+00
Styrene	Non-Carcinogen	6.67E+00	1.00E+03
2,3,7,8-Tetrachlorodibenzo-p-dioxins	Carcinogen	Dioxin/Furan	N/A
Tetrachlorodibenzo-p-dioxins	Carcinogen	Dioxin/Furan	N/A
2,3,7,8-Tetrachlorodibenzo-p-furans	Carcinogen	Dioxin/Furan	N/A
Tetrachlorodibenzo-p-furans	Carcinogen	Dioxin/Furan	N/A
Tetrachlorobiphenyl	Carcinogen	6.60E-05	1.00E-02
Tin	Non-Carcinogen	7.00E-03	5.00E+00
Toluene	Non-Carcinogen	2.50E+01	1.88E+04
Trichlorobiphenyl	Carcinogen	6.60E-05	1.00E-02
Trichloroethylene (trichloroethene)	Carcinogen	1.79E+01	7.70E-01
2,4,6-Trichlorophenol	Carcinogen	1.20E-03	1.80E-01
Vanadium	Non-Carcinogen	3.00E-03	2.50E+00
Vinyl chloride	Carcinogen	9.40E-04	1.40E-01
m,p-Xylene	Non-Carcinogen	2.90E+01	2.18E+04
o-Xylene	Non-Carcinogen	2.90E+01	2.18E+04
Yttrium	Non-Carcinogen	6.70E-02	5.00E+01
Zinc	Non-Carcinogen	6.67E-01	5.00E+01
7-PAH	Carcinogen	2.00E-06	3.00E-04
Dioxins/Furans	Carcinogen	1.50E-10	2.20E-08

a. ELs from Idaho Air Rules Section 585 and 586 in pounds/hour.

b. Acceptable Ambient Concentration (AAC) or Acceptable Ambient Concentration for a Carcinogen (AACC) from Idaho Air Rules Section 585 and 586, in micrograms/cubic meter or milligrams/cubic meter. Note that AACs listed in Idaho Air Rules Section 585 are expressed in units of milligrams/cubic meter rather than micrograms/cubic meter.

__X__ All TAPs identified in the emissions inventory for the project are listed in the TAPs EL and AAC/AACC Table in this section.

3.2. CRITERIA POLLUTANT MODELING APPLICABILITY

Air dispersion modeling was conducted for those criteria pollutants which exceeded the Idaho Level I modeling thresholds, which include CO, NO_x, PM_{10}, $PM_{2.5}$ and SO_2. The facility-wide PTE as compared to the modeling thresholds is shown in **Table 3-3** below. Specific emission unit calculations are provided in **Appendix B**.

Table 3-3. Criteria Pollutant PTE vs. Modeling Thresholds

Pollutant	Facility-Wide PTE	Idaho Level I Modeling Threshold	Modeling Required?
CO (lb/hr)	34.7	15	Yes
NO_x (lb/hr)	45.1	0.20	Yes
NO_x (tpy)	197.7	1.2	Yes
SO_2 (lb/hr)	5.1	0.21	Yes
SO_2 (tpy)	22.5	1.2	Yes
PM_{10} (lb/hr)	19.3	0.22	Yes
$PM_{2.5}$ (lb/hr)	8.3	0.054	Yes
$PM_{2.5}$ (tpy)	34.7	0.35	Yes
Lead (lb/month)	7.0	14	No

Table 3-4 lists criteria pollutants for which site-specific modeling analyses were performed to demonstrate compliance with NAAQS.

Table 3-4. Modeling Applicability

Criteria Pollutant	Modeled (yes/no)	Basis for Exclusion from Modeling
$PM_{2.5}$ 24-hour	Yes	___BRC Exempt[a] ___Emissions Below Level l Thresholds[b] ___Emissions Below Level II Thresholds[c]
$PM_{2.5}$ annual	Yes	___BRC Exempt ___Emissions Below Level l Thresholds ___Emissions Below Level II Thresholds
PM_{10} 24-hour	Yes	___BRC Exempt ___Emissions Below Level l Thresholds ___Emissions Below Level II Thresholds
NO_2 1-hour	Yes	___BRC Exempt ___Emissions Below Level l Thresholds ___Emissions Below Level II Thresholds
NO_2 annual	Yes	___BRC Exempt ___Emissions Below Level l Thresholds ___Emissions Below Level II Thresholds
SO_2 1-hour, 3-hour	Yes	___BRC Exempt ___Emissions Below Level l Thresholds

Criteria Pollutant	Modeled (yes/no)	Basis for Exclusion from Modeling
		___Emissions Below Level II Thresholds
SO_2 annual	Yes	___BRC Exempt ___Emissions Below Level l Thresholds ___Emissions Below Level II Thresholds
CO 1-hour, 8-hour	Yes	___BRC Exempt ___Emissions Below Level l Thresholds ___Emissions Below Level II Thresholds

a. If the project would have qualified for a Category I BRC permitting exemption for the criteria pollutant in question, as per Idaho Air Rules Section 221.01, except for the emissions quantities of another criteria pollutant, then a NAAQS compliance analysis is not required under Section 203.02 or 403.02 for that criteria pollutant.

b. Level I Modeling Thresholds from Table 2 in Section 3 of the DEQ Modeling Guideline. NAAQS compliance is assured through DEQ's non-site-specific modeling analyses.

c. Level II Modeling Thresholds from Table 2 in Section 3 of the DEQ Modeling Guideline. NAAQS compliance is assured through DEQ's non-site-specific modeling analyses. Level II Modeling Thresholds can only be used with prior DEQ approval.

__X__Explanations/documentation why modeling was or was not performed for each criteria pollutant are provided in this section.

__X__Emissions calculations that clearly show how the modeling applicability determination was performed are provided in this section. Detailed emissions calculations are provided in **Appendix B.**

3.3. TAP MODELING APPLICABILITY

CRE calculated the increase in Toxic Air Pollutant (TAP) emission rates from the facility and compared them to the screening levels. Air dispersion modeling was conducted for those TAPs which exceed the screening emissions level (EL) in Idaho Air Rules Section 585 and 586. However, TAPs that are regulated by a federal NSPS or NESHAPS will not be included in the modeling analysis. The facility will be subject to 40 CFR Part 63 Subpart DDDDD - National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters. Subpart DDDDD contains emissions limits for several TAPs, including include acetaldehyde, acrolein, arsenic, benzene, beryllium, cadmium, chromium VI, hydrogen chloride, nickel, POM, and dioxins and furans. As such, modeling was conducted for carbon tetrachloride, chloroform, iron, methylene chloride, silver and vinyl chloride. A comparison of the facility-wide TAPs emissions to the EL is shown in **Table 3-5**. Detailed emissions calculations are provided in **Appendix B**.

Table 3-5. TAPs PTE vs. Modeling Thresholds

				Potential Emissions		IDAPA EL		
Pollutant	HAP?	Non-Carc. TAP?	Carc. TAP?	lb/hr	tpy	lb/hr	Exceeds EL?	Exempt from Modeling due to NSPS/ NESHAP?
Acenaphthene	Yes	No	Yes	1.82E-04	7.97E-04	9.10E-05	Yes	Yes
Acenaphthylene	Yes	No	Yes	1.00E-03	4.38E-03	9.10E-05	Yes	Yes
Acetaldehyde	Yes	No	Yes	1.66E-01	7.27E-01	3.00E-03	Yes	Yes

Pollutant	HAP?	Non-Carc. TAP?	Carc. TAP?	Potential Emissions lb/hr	Potential Emissions tpy	IDAPA EL lb/hr	Exceeds EL?	Exempt from Modeling due to NSPS/ NESHAP?
Acetone	No	Yes	No	3.80E-02	1.66E-01	1.19E+02	No	No
Acetophenone	Yes	No	Yes	6.40E-07	2.80E-06	9.10E-05	No	Yes
Acrolein	Yes	Yes	No	8.00E-01	3.50E+00	1.70E-02	Yes	Yes
Anthracene	Yes	No	Yes	6.00E-04	2.63E-03	9.10E-05	Yes	Yes
Antimony	Yes	Yes	No	1.58E-03	6.92E-03	3.30E-02	No	Yes
Arsenic	Yes	No	Yes	4.40E-03	1.93E-02	1.50E-06	Yes	Yes
Barium	No	Yes	No	3.45E-05	1.51E-04	3.30E-02	No	No
Benzene	Yes	No	Yes	8.40E-01	3.68E+00	8.00E-04	Yes	Yes
Benzo(a)anthracene	Yes	No	Yes	1.30E-05	5.70E-05	7-PAH	No	Yes
Benzo(a)pyrene	Yes	No	Yes	5.20E-04	2.28E-03	7-PAH	No	Yes
Benzo(b)fluoranthene	Yes	No	Yes	2.00E-05	8.77E-05	7-PAH	No	Yes
Benzo(e)pyrene	Yes	No	Yes	5.20E-07	2.28E-06	9.10E-05	No	Yes
Benzo(g,h,i)perylene	Yes	No	Yes	1.86E-05	8.15E-05	9.10E-05	No	Yes
Benzo(j,k)fluoranthene	Yes	No	Yes	3.20E-05	1.40E-04	9.10E-05	No	Yes
Benzo(k)fluoranthene	Yes	No	Yes	7.21E-06	3.16E-05	7-PAH	No	Yes
Beryllium	Yes	No	Yes	2.20E-04	9.64E-04	2.80E-05	Yes	Yes
Bis(2-ethylhexyl)phthalate	Yes	No	Yes	9.40E-06	4.12E-05	2.80E-02	No	No
Bromomethane	Yes	Yes	No	3.00E-03	1.31E-02	1.27E+00	No	No
2-Butanone (MEK)	No	Yes	No	1.08E-03	4.73E-03	3.93E+01	No	No
Cadmium	Yes	No	Yes	8.29E-04	3.63E-03	3.70E-06	Yes	Yes
Carbon tetrachloride	Yes	No	Yes	9.00E-03	3.94E-02	4.40E-04	Yes	No
Chlorine	Yes	Yes	No	1.58E-01	6.92E-01	2.00E-01	No	No
Chlorobenzene	Yes	Yes	No	6.60E-03	2.89E-02	2.33E+01	No	No
Chloroform (Trichloromethane)	Yes	No	Yes	5.60E-03	2.45E-02	2.80E-04	Yes	No
2-Chlorophenol	No	Yes	No	4.80E-06	2.10E-05	3.30E-02	No	No
Chrysene	Yes	No	Yes	7.61E-06	3.33E-05	7-PAH	No	Yes
Crotonaldehyde	No	Yes	No	1.98E-03	8.67E-03	3.80E-01	No	No
Chromium	Yes	Yes	Yes	4.21E-03	1.84E-02	3.30E-02	No	Yes
Chromium VI	Yes	No	Yes	7.00E-04	3.07E-03	5.60E-07	Yes	Yes
Cobalt	Yes	Yes	No	1.30E-03	5.70E-03	3.30E-03	No	Yes
Copper	No	Yes	No	6.67E-06	2.92E-05	6.70E-02	No	No

Pollutant	HAP?	Non-Carc. TAP?	Carc. TAP?	Potential Emissions lb/hr	Potential Emissions tpy	IDAPA EL lb/hr	Exceeds EL?	Exempt from Modeling due to NSPS/ NESHAP?
Cyclohexene	No	Yes	No	6.94E-08	3.04E-07	6.77E+01	No	No
Dibenzo(a,h)anthracene	Yes	No	Yes	1.83E-06	8.01E-06	7-PAH	No	Yes
Dichlorobenzene	Yes	Yes	No	9.41E-06	4.12E-05	3.00E+01	No	No
Dichlorobiphenyl	Yes	No	Yes	1.48E-07	6.48E-07	6.60E-05	No	Yes
1,2-Dichloroethane	Yes	No	Yes	5.80E-03	2.54E-02	2.70E+01	No	No
1,2-Dichloropropane	Yes	Yes	No	6.60E-03	2.89E-02	2.31E+01	No	No
Ethyl benzene	Yes	Yes	No	6.20E-03	2.72E-02	2.90E+01	No	No
Fluoranthene	Yes	No	Yes	3.20E-04	1.40E-03	9.10E-05	Yes	Yes
Fluorene	Yes	No	Yes	6.80E-04	2.98E-03	9.10E-05	Yes	Yes
Formaldehyde	Yes	No	Yes	8.81E-01	3.86E+00	5.10E-04	Yes	Yes
Furfural	No	Yes	No	5.04E-09	2.21E-08	5.33E-01	No	No
Heptachlorodibenzo-p-dioxins	Yes	No	Yes	4.00E-07	1.75E-06	Dioxin/Furan	No	Yes
Heptachlorodibenzo-p-furans	Yes	No	Yes	4.80E-08	2.10E-07	Dioxin/Furan	No	Yes
Hexachlorodibenzo-p-dioxins	Yes	No	Yes	3.20E-04	1.40E-03	Dioxin/Furan	No	Yes
Hexachlorodibenzo-p-furans	Yes	No	Yes	5.60E-08	2.45E-07	Dioxin/Furan	No	Yes
Hexane	Yes	Yes	No	1.41E-02	6.18E-02	1.20E+01	No	No
Hydrogen Chloride	Yes	Yes	No	3.80E+00	1.66E+01	5.00E-02	Yes	Yes
Indeno(1,2,3-cd)pyrene	Yes	No	Yes	1.74E-05	7.63E-05	7-PAH	No	Yes
Iron	No	Yes	No	1.98E-01	8.67E-01	6.70E-02	Yes	No
Manganese	Yes	Yes	No	3.20E-01	1.40E+00	3.33E-01	No	Yes
Methyl Acetate	No	Yes	No	5.28E-08	2.31E-07	4.07E+01	No	No
Methylene chloride (dichloromethane)	Yes	No	Yes	5.80E-02	2.54E-01	1.60E-03	Yes	No
Molybdenum	No	Yes	No	4.29E-04	1.88E-03	3.33E-01	No	No
Naphthalene	Yes	Yes	No	1.94E-02	8.50E-02	3.33E+00	No	No
Nickel	Yes	No	Yes	6.62E-03	2.90E-02	2.70E-05	Yes	Yes
Octachlorodibenzo-p-dioxins	Yes	No	Yes	1.32E-05	5.78E-05	Dioxin/Furan	No	Yes
Octachlorodibenzo-p-furans	Yes	No	Yes	1.76E-08	7.71E-08	Dioxin/Furan	No	Yes

Pollutant	HAP?	Non-Carc. TAP?	Carc. TAP?	Potential Emissions lb/hr	Potential Emissions tpy	IDAPA EL lb/hr	Exceeds EL?	Exempt from Modeling due to NSPS/ NESHAP?
Pentachlorodibenzo-p-dioxins	Yes	No	Yes	3.00E-07	1.31E-06	Dioxin/Furan	No	Yes
Pentachlorodibenzo-p-furans	Yes	No	Yes	8.40E-08	3.68E-07	Dioxin/Furan	No	Yes
Pentachlorobiphenyl	Yes	No	Yes	2.40E-07	1.05E-06	6.60E-05	No	Yes
Pentachlorophenol	Yes	Yes	No	1.02E-05	4.47E-05	3.30E-02	No	No
Pentane	No	Yes	No	2.04E-02	8.93E-02	1.18E+02	No	No
Perylene	Yes	No	Yes	1.04E-07	4.56E-07	9.10E-05	No	Yes
Phenanthrene	Yes	No	Yes	1.40E-03	6.13E-03	9.10E-05	Yes	Yes
Phenol	Yes	Yes	No	1.02E-02	4.47E-02	1.27E+00	No	No
Phosphorus	Yes	Yes	No	5.40E-03	2.37E-02	7.00E-03	No	No
Propionaldehyde	Yes	Yes	No	1.22E-02	5.34E-02	2.87E-02	No	No
Pyrene	Yes	No	Yes	7.40E-04	3.24E-03	9.10E-05	Yes	Yes
Selenium	Yes	Yes	No	5.60E-04	2.45E-03	1.30E-02	No	Yes
Silver	No	Yes	No	3.40E-01	1.49E+00	1.00E-03	Yes	No
Styrene	Yes	Yes	No	3.80E-01	1.66E+00	6.67E+00	No	No
2,3,7,8-Tetrachlorodibenzo-p-dioxins	Yes	No	Yes	1.72E-09	7.53E-09	Dioxin/Furan	No	No
Tetrachlorodibenzo-p-dioxins	Yes	No	Yes	9.40E-08	4.12E-07	Dioxin/Furan	No	No
2,3,7,8-Tetrachlorodibenzo-p-furans	Yes	No	Yes	1.80E-08	7.88E-08	Dioxin/Furan	No	No
Tetrachlorodibenzo-p-furans	Yes	No	Yes	1.50E-07	6.57E-07	Dioxin/Furan	No	No
Tetrachlorobiphenyl	Yes	No	Yes	5.00E-07	2.19E-06	6.60E-05	No	Yes
Tin	No	Yes	No	4.60E-03	2.01E-02	7.00E-03	No	No
Toluene	Yes	Yes	No	1.84E-01	8.06E-01	2.50E+01	No	No
Trichlorobiphenyl	Yes	No	Yes	5.20E-07	2.28E-06	6.60E-05	No	Yes
Trichloroethylene (trichloroethene)	Yes	No	Yes	6.00E-03	2.63E-02	1.79E+01	No	No
2,4,6-Trichlorophenol	Yes	No	Yes	4.40E-06	1.93E-05	1.20E-03	No	No
Vanadium	No	Yes	No	2.14E-04	9.37E-04	3.00E-03	No	No

Pollutant	HAP?	Non-Carc. TAP?	Carc. TAP?	Potential Emissions lb/hr	Potential Emissions tpy	IDAPA EL lb/hr	Exceeds EL?	Exempt from Modeling due to NSPS/ NESHAP?
Vinyl chloride	Yes	No	Yes	3.60E-03	1.58E-02	9.40E-04	Yes	No
m,p-Xylene	Yes	Yes	No	4.80E-08	2.10E-07	2.90E+01	No	No
o-Xylene	Yes	Yes	No	5.00E-03	2.19E-02	2.90E+01	No	No
Yttrium	No	Yes	No	6.00E-05	2.63E-04	6.70E-02	No	No
Zinc	No	Yes	No	8.40E-02	3.68E-01	6.67E-01	No	No
7-PAH	Yes	No	Yes	5.87E-04	2.57E-03	2.00E-06	Yes	Yes
Dioxins/Furans	Yes	No	Yes	3.25E-05	1.42E-04	1.50E-10	Yes	Yes

__X__Explanation/documentation on why modeling was or was not performed for emissions of each TAP identified in the emissions inventory of the application are provided in this section.

3.4. MODELING PROTOCOL

A modeling protocol was submitted to DEQ prior to the application, on April 26, 2016 by Trinity Consultants; approval of the protocol was received on May 10, 2016 from Mr. Thomas Swain, DEQ. A copy of the model protocol and approval is included in **Appendix C**. Project-specific modeling and other required impact analyses were generally conducted using data and methods described in the protocol and in the Idaho Air Quality Modeling Guideline; however, slight modifications were made to the modeling methodology including:

- Change in hour of day factor used: Finished product loading, which includes transfer from the pneumatic system to the pellet product stockpile through to railcar filling, will only occur between the hours of 6am and 6pm (formerly 6am to 7pm).

- Change in volume source release heights: Per review and clarification by CRE, the release heights of transfers from hoppers to conveyors were updated.

- Change in emission rates: Emission rates were updated to reflect moisture content of all materials.

In addition, the protocol approval included several comments; CRE's response to selected comments is included below.

> ***Comment 1:*** *Documentation and justification of release parameters must be provided in the application. Refer to Section 3.4.3 of the State of Idaho Guideline for Performing Air Quality Impact Analyses, September 2013. Simply stating that values are "manufacturer data" does not constitute adequate documentation and/or justification. DEQ requests that the application describe how the values were obtained (measurement, similar source, combustion evaluation, fan curves, etc.). If values were obtained from an equipment/engineering firm, then those forms, specification sheets, etc. provided by the firm should be included in the application as documentation for the values used in the modeling analyses. The application should be treated as a stand-alone document. If data was taken from a stack test, then the stack test report and data should also be included in the document. The applicant states that exit velocities have been taken*

from the vendor, while stack diameters have been reduced from CAD drawings. The applicant should confirm that the resultant exit exhausts as modeled should be equal to the design exit flows (in ACFM).

All information provided in this report and the PTC application is based on preliminary facility design. Due to the structure of the project financing (grant allocation), final design information will not be available until after PTC issuance. All available manufacturer and vendor information has been provided; CRE will accept permit conditions related to assumptions and information that has been presented that does not meet DEQ's interpretation of what constitutes adequate documentation and/or justification. If, upon final design and construction, information or parameters differ from the values presented in this modeling report and PTC application and/or PTC, CRE will review the applicability of a modification to the PTC including impacts to the NAAQS analyses completed as part of this initial PTC application.

Comment 2*: The protocol discusses various modes of operation of the FBC, with temperatures varying from perhaps 200 F when preheating to 1600 F degrees at full operation, with different fuel proponents. The applicant needs to provide adequate modeling information or justification to demonstrate that the NAAQS will be complied with for all possible worst case conditions.*

A propane fired pre-heater is used to heat the fluidized bed. During pre-heating, the only emissions are from the propane combustion. While the exhaust temperature will be lower during this time, until the full operating temperature of the FBC is reached, other process as the plant, including the SteamEx and Belt Dryer process are not occurring, as the FBC steam is the energy source for those units. Once the bed is heated to the appropriate temperature wood is fed into the FBC and combustion is started. The preheat burner is turned off once the fluid bed temperature is above 1000 ^{o}F and the FBC operates only on wood fuel. However, modeled emissions from the FBC baghouse (exhaust point for the FBC and pre-heater) included both propane and hogged fuel combustion. Therefore, the emissions and exhaust parameters provided in the modeling provide the worst case conditions.

Comment 3*: In the protocol the applicant does not discuss any non-default treatment of NO2/NOX stack chemistry. If TC wishes to utilize a non-default method, prior DEQ acceptance is required.*

NO2/NOx stack chemistry and non-default methods are not requested for the modeling analyses.

Comment 4: *In the protocol the applicant states that all transfer points are treated as volume sources and are separated from building structures. DEQ is uncertain if there are any vented emissions from the building structure(s) that reflect process activities not directly attributable to the dryer point sources.*

The preliminary design does not include any direct venting of emissions from building structures.

__**X**__If a protocol was submitted to DEQ prior to performing the modeling analyses, the protocol and DEQ's conditional protocol approval notice is included in **Appendix C** of this Modeling Report.

__**X**__Concerns identified by DEQ in the protocol approval notice have been addressed in the analyses performed and in this Modeling Report.

Descriptions of specific emission sources are provided in Section 2.1. Manufacturer information provided in **Appendix D**.

4.1. CRITERIA POLLUTANTS

Criteria pollutant emission rates used in the modeling analysis are consistent with the emission rates listed in the permit application, however, some minor differences exist. Emissions from the belt dryer will exhaust through three separate stacks, therefore the total lb/hr emission rate from the belt dryer (6.9 lb/hr PM_{10}, 3.8 lb/hr $PM_{2.5}$) is divided by three and allocated to each stack (2.3 lb/hr PM_{10} each, 1.27 lb/hr $PM_{2.5}$ each). Also, exhaust from the FBC, FBC Pre-Burner, Multiclone Cyclones, SteamEx process, and Pellet Coolers will all be routed to the FBC and will therefore exhaust through the single FBC system baghouse stack. The emissions from each of these sources have been combined and are represented in the model as emission source BOILER.

4.1.1. Modeled Emission Rates for Significant Impact Level Analysis

CRE did not conduct a Significant Impact Level (SIL) analyses; a full Cumulative Impact Analyses was performed for the initial modeling.

4.1.2. Modeled Emission Rates for the Cumulative Impact Analyses

The lb/hr emission rates for all averaging periods were calculated assuming continuous operation at the maximum hourly rate. As described above, the modeled emission rate for the belt dryer differs from the emission rate in the emission inventory. In addition, several emission sources exhaust through the single FBC system baghouse stack.

The proposed CRE facility is located in an agricultural, light commercial and residential area. The closest industrial facility to the project site is the Bennett Lumber facility, located approximately six (6) miles east of the proposed CRE facility. As such, no co-contributing sources were included in the cumulative impact analyses.

Table 4-1 lists criteria pollutant emission rates used in the cumulative NAAQS impact analysis.

Table 4-1. Modeled Emission Rates for Cumulative NAAQS Impact Analyses

Source ID	Source Description	Pollutant	Averaging Period	Emissions[a] (lb/hr)
BELTDRY1	Belt Dryer Exhaust Stack #1	$PM_{2.5}$	24-hour	1.27
			Annual	1.27
		PM_{10}	24-hour	2.30
BELTDRY2	Belt Dryer Exhaust Stack #2	$PM_{2.5}$	24-hour	1.27
			Annual	1.27
		PM_{10}	24-hour	2.30
BELTDRY3	Belt Dryer Exhaust Stack #3	$PM_{2.5}$	24-hour	1.27
			Annual	1.27
		PM_{10}	24-hour	2.30
BOILER	Boiler & Baghouse Exhaust	$PM_{2.5}$	24-hour	3.12

Source ID	Source Description	Pollutant	Averaging Period	Emissions[a] (lb/hr)
			Annual	3.12
		PM_{10}	24-hour	3.12
		NOx	1-hour	45.1
			Annual	45.1
		SO_2	1-hour	5.1
		CO	1-hour	34.7
			8-hour	34.7
HF1	Truck Unloading to Hog Fuel Tipper	$PM_{2.5}$	24-hour	0.003
			Annual	0.003
		PM_{10}	24-hour	0.02
HF2	Hog Fuel Pile to Hopper #4/Screw Feeder #4 via Front Loader	$PM_{2.5}$	24-hour	0.001
			Annual	0.001
		PM_{10}	24-hour	0.006
HF3	Fuel Screen #1 and transfers (in from Hopper #4, out to Bucket Elevator #1)	$PM_{2.5}$	24-hour	0.008
			Annual	0.008
		PM_{10}	24-hour	0.05
HF4	Bucket Elevator #1 to Surge Bin #2	$PM_{2.5}$	24-hour	0.001
			Annual	0.001
		PM_{10}	24-hour	0.006
FS1	Truck Unloading to Feedstock Tipper #1	$PM_{2.5}$	24-hour	0.010
			Annual	0.010
		PM_{10}	24-hour	0.068
FS2	Feedstock Pile to Hopper #1, 2 or 3 via Front Loader	$PM_{2.5}$	24-hour	0.003
			Annual	0.003
		PM_{10}	24-hour	0.024
FS3	Hopper #1, 2 or 3 to Conveyor #1	$PM_{2.5}$	24-hour	0.003
			Annual	0.003
		PM_{10}	24-hour	0.024
FS4	Conveyor #1 to Feed Screw #1	$PM_{2.5}$	24-hour	0.002
			Annual	0.002
		PM_{10}	24-hour	0.012
FS5	Conveyor #1 to Feed Screw #2	$PM_{2.5}$	24-hour	0.002
			Annual	0.002
		PM_{10}	24-hour	0.012
FS6	Green Hammer Mill #1 and transfers (in from Feed Screw #1, out to Green Cyclone #1)	$PM_{2.5}$	24-hour	0.003
			Annual	0.003
		PM_{10}	24-hour	0.026
FS7	Green Hammer Mill #2 and transfers (in from Feed Screw #2, out to Green Cyclone #2)	$PM_{2.5}$	24-hour	0.003
			Annual	0.003
		PM_{10}	24-hour	0.026
FS8	Green Cyclone #1 to Conveyor #2	$PM_{2.5}$	24-hour	0.002
			Annual	0.002
		PM_{10}	24-hour	0.012
FS9	Green Cyclone #2 to Conveyor #2	$PM_{2.5}$	24-hour	0.002
			Annual	0.002
		PM_{10}	24-hour	0.012

Source ID	Source Description	Pollutant	Averaging Period	Emissions[a] (lb/hr)
FS10	Conveyor #2 to Conveyor #3 (Inside Tower 1)	$PM_{2.5}$	24-hour	0.003
			Annual	0.003
		PM_{10}	24-hour	0.018
FS15	Conveyor #5 to Feed Screw #3	$PM_{2.5}$	24-hour	0.005
			Annual	0.005
		PM_{10}	24-hour	0.033
FS16	Feed Screw #3 to Dry Hammer Mill	$PM_{2.5}$	24-hour	0.005
			Annual	0.005
		PM_{10}	24-hour	0.033
FS17	Dry Hammer Mill to Dry Cyclone #1	$PM_{2.5}$	24-hour	0.0001
			Annual	0.0001
		PM_{10}	24-hour	0.0004
FS20	Surge Bin #1 to Conveyor #6	$PM_{2.5}$	24-hour	0.005
			Annual	0.005
		PM_{10}	24-hour	0.033
FS42	Pneumatic System #3 to Pellet Product Stockpile	$PM_{2.5}$	24-hour	0.005
			Annual	0.005
		PM_{10}	24-hour	0.035
FS43	Pellet Product Stockpile to Hopper #5 via Front Loader	$PM_{2.5}$	24-hour	0.052
			Annual	0.051
		PM_{10}	24-hour	0.359
FS44	Hopper #5 to Conveyor #13	$PM_{2.5}$	24-hour	0.052
			Annual	0.051
		PM_{10}	24-hour	0.359
FS45	Shipping Screens and transfers (in from Conveyor #13, out to Conveyor #14)	$PM_{2.5}$	24-hour	0.225
			Annual	0.225
		PM_{10}	24-hour	1.477
FS47	Conveyor #14 to Filling Spout	$PM_{2.5}$	24-hour	0.052
			Annual	0.052
		PM_{10}	24-hour	0.359
FS48	Filling Spout to Railcar	$PM_{2.5}$	24-hour	0.052
			Annual	0.052
		PM_{10}	24-hour	0.359

[a.] Pounds/hour emissions rate modeled is the potential/allowable emissions for the averaging period specified for the pollutant.

__X__ Emissions rates in Table 4-1 are identical to those in the model input files for the cumulative NAAQS impact analyses.

__X__ Calculation of modeled emissions are thoroughly documented in this section (unless already described in Section 4.1.1), and any unique handling of emissions in the model have been described.

4.1.3. NO_2/NO_x Ratio for NOx Chemistry Modeling

NO_x chemistry was not considered in the compliance demonstration for 1-hour NO_2.

4.1.4. Special Methods for Modeling Critical Pollutant Emissions

Finished product loading, which includes transfer from the pneumatic system to the pellet product stockpile through to railcar filling, will only occur between the hours of 6am and 6pm. The HROFDY factor was applied to these sources (FS42-FS48) in the model.

4.2. TOXIC AIR POLLUTANTS

The sources of TAPs at the CRE facility include the FBC, the FBC pre-burner, the SteamEx Unit and the Pellet Coolers. Each of these sources exhausts through the FBC baghouse. A unit emission of 1.0 lb/hr was used to represent all TAPs in the modeling The model result was then multiplied by each TAPs' pound per hour emission rate to determine the ambient concentration and compliance with the applicable Acceptable Ambient Concentration (AAC) for non-carcinogens or Acceptable Ambient Concentration for Carcinogens (AACC) for carcinogens.

Table 4-2 lists TAP emissions rates that were included in the modeling analyses. Modeling was performed for each TAP having total project emissions exceeding the TAP specific Screening EL, with the exception of those TAPs that are regulated under 40 CFR Part 63 Subpart DDDDD, as discussed in Section 3.3.

Table 4-2. Modeled Emissions Rates for TAP Analyses

Source ID	Source Description	TAP	Averaging Period	Emissions[a] (lb/hr)
BOILER	Boiler & Baghouse Exhaust	Carbon Tetrachloride	Annual	1.0
		Chloroform	Annual	1.0
		Iron	24-hour	1.0
		Methylene Chloride	Annual	1.0
		Silver	24-hour	1.0
		Vinyl Chloride	Annual	1.0

a. Pounds/hour emissions rate modeled is the project-specific increase in potential/allowable emissions increase for the averaging period specified for the TAP.

__X__ TAP emissions rates have been listed for each TAP that has project cumulative emissions exceeding the applicable EL.

__X__ Emissions rates in Table 4-2 are identical to those in the model input file for TAP analyses.

4.3. EMISSIONS RELEASE PARAMETERS

The emissions sources were represented in the model as point or volume sources. Sources were 'placed' into the model using the BREEZE AERMOD graphical user interface (GUI). A geo-referenced CAD drawing was imported into the model, and point and volume sources were added at the corresponding locations.

Emissions from the belt dryer and FBC system baghouse are represented in the model as point sources. The point source parameters are shown in **Table 4-3** below. The belt dryer exhaust is emitted through three identical stacks. The total emission rate was divided evenly between the three stacks.

Table 4-3. Point Source Parameters

Source ID/ Pollutant ID	Description	UTM[a]		Elev. (m)	Stack Height (m)	Stack Temp (K)[c]	Stack Velocity (m/s)[d]	Stack Diameter (m)	Orient. Of Release[e]
		East - X (m)[b]	North - Y (m)						
BELTDRY1	Belt Dryer Exhaust #1	506971	5197046	760.99	7.0	310.15	7.20	3.38	V
BELTDRY2	Belt Dryer Exhaust #2	5069811	5197045.6	761.03	7.0	310.15	7.20	3.38	V
BELTDRY3	Belt Dryer Exhaust #3	5070012	5197045.2	761.19	7.0	310.15	7.20	3.38	V
BOILER	Boiler & Baghouse Exhaust	506949	5196949.5	760.17	22.9	449.82	45.2	1.34	V

a. Universal Transverse Mercator.
b. Meters.
c. Kelvin.
d. Meters per second.
e.. Vertical uninterrupted, rain-capped, or horizontal release.

The stack height, stack temperature, exit velocity were provided by the equipment manufacturer. Stack diameters were measured off of the scaled CAD design drawing imported into the BREEZE model interface. Documentation from the equipment vendors is included in **Appendix D.**

Material handling, including loading and unloading, conveyor transfers, drop points, milling and screening, is represented in the modeled as volume sources. Each volume source was calculated to be a single volume source with the initial lateral dimension equal to the length of a side divided by 4.3 The volume sources are elevated and not on the side of a building, therefore the initial vertical dimension was calculated to be the vertical dimension divided by 4.3. Sources located inside the building were not included in the modeling, as there will be no venting from the buildings. The volume source parameters are shown in **Table 4-4** below. Assumptions used to calculate the volume source parameters are included in **Appendix E.**

Table 4-4. Volume Source Parameters

Source ID/ Pollutant ID	Description	UTM[a]		Elev. (m)	Release Height (m)	Init. Lat. Dim (m)	Init. Vert. Dim. (m)
		East - X (m)	North - Y (m)				
HF1	Truck Unloading to Hog Fuel Tipper	506707.7	5196966.5	759.58	2.06	0.57	0.96
HF2	Transfer to Hopper #4	506753.8	5196983.4	759.79	2.74	1.06	0.64
HF3	Fuel Screen #1 and transfers	506756.7	5196983.8	759.81	1.52	0.28	0.07
HF4	Bucket Elevator #1 to Surge Bin #2	506758.9	5196983.8	759.83	6.10	0.14	0.07

Source ID/ Pollutant ID	Description	UTM[a]		Elev. (m)	Release Height (m)	Init. Lat. Dim (m)	Init. Vert. Dim. (m)
		East - X (m)	North - Y (m)				
FS1	Truck Unloading to Feedstock Tipper #1	506787.7	5196966.5	759.8	2.06	0.57	0.96
FS2	Feedstock Pile to Hopper #1, 2 or 3	506839.2	5196983.8	760.09	2.74	1.06	0.07
FS3	Hopper to Conveyor #1	506842.6	5196983.9	760.09	1.98	0.28	0.07
FS4	Conveyor #1 to Feed Screw #1	506884.1	5196982.6	760.27	2.44	0.28	0.07
FS5	Conveyor #1 to Feed Screw #2	506883.5	5196985.5	760.29	2.44	0.28	0.07
FS6	Green Hammer Mill #1 and transfers	506894	5196981.6	760.25	2.13	0.28	0.07
FS7	Green Hammer Mill #2 and transfers	506893.8	5196986.6	760.3	2.13	0.28	0.07
FS8	Green Cyclone #1 to Conveyor #2	506902.8	5196981.1	760.25	1.52	0.28	0.07
FS9	Green Cyclone #2 to Conveyor #2	506902.1	5196986.5	760.3	1.52	0.28	0.07
FS10	Conveyor #2 to Conveyor #3	506902.1	5197047.8	760.72	13.72	0.28	0.07
FS15	Conveyor #5 to Feed Screw #3	507006.5	5197019.9	760.93	2.44	0.28	0.07
FS16	Feed Screw #3 to Dry Hammer Mill	507004.6	5197017	760.88	2.13	0.28	0.07
FS17	Dry Hammer Mill to Dry Cyclone #1	507000.4	5197013.4	760.8	1.22	0.14	0.07
FS20	Surge Bin #1 to Conveyor #6	506990.9	5196991.9	760.6	0.91	0.14	0.07
FS42	Pneumatic System #3 to	506970.2	5196886.2	759.85	21.34	0.07	2.48

Source ID/ Pollutant ID	Description	UTM[a]		Elev. (m)	Release Height (m)	Init. Lat. Dim (m)	Init. Vert. Dim. (m)
		East - X (m)	North - Y (m)				
	Pellet Stockpile						
FS43	Hopper #5	507000	5196856.5	759.8	2.74	0.71	0.07
FS44	Hopper #5 to Conveyor #13	507000	5196853.8	759.77	1.98	0.28	0.07
FS45	Shipping Screens and transfers	507000.2	5196819.2	759.53	7.62	0.28	0.07
FS47	Conveyor #14 to Filling Spout	507042	5196816.5	759.76	6.10	0.28	0.07
FS48	Filling Spout to Rail Car	507045.4	5196816.7	759.78	4.57	0.14	0.07

Per the IDEQ Guideline for Performing Air Quality Impact Analyses, fugitive emissions from vehicle traffic on roads and wind erosion from material storage piles are normally not included in the modeling analyses. This information was confirmed by Kevin Schilling, IDEQ, during the pre-application meeting held on April 15, 2016.

_X_ Thorough justification/documentation of release parameters for all modeled sources is provided in this section.

_X_ The specific methods used to determine/calculate given release parameters is described in this section.

_X_ The release orientation of all point source stacks (horizontal, rain-capped, or uninterrupted vertical release) has been verified and is documented in this section.

5. MODELING METHODOLOGY

The section of the report will describe and justify the specific methods and data used in the air impact analyses.

Table 5-1 summarizes the key modeling parameters used in the impact analyses.

Table 5-1. Modeling Parameters

Parameter	Description/Values	Documentation/Addition Description
General Facility Location	Approx. 0.7 miles NW of the Potlach city center in Latah County, ID.	Facility will be located on the former Potlach Mill site, near State Highway 6 and Forest Road 1460, approximately 0.7 miles northwest of the Potlach city center in Latah County, ID. Latah County is in attainment for all pollutants.
Model	AERMOD	AERMOD with the PRIME downwash algorithm, version 15181
Meteorological Data	Pullman/Potlach surface data Pullman/Potlach upper air data	The meteorological model input files for this project were developed by IDEQ. See Section 5.2 of this report for additional details of the meteorological data.
Terrain	Considered	3-dimensional receptor coordinates were obtained from USGS National Elevation Dataset (NED) files and were used to establish elevation of ground level receptors. AERMAP was used to determine each receptor elevation and hill height scale.
Building Downwash	Considered	Plume downwash was considered for the structures associated with the facility. BPIP-PRIME was used to evaluate building dimensions for consideration of downwash effects in AERMOD.
NOx Chemistry	None	Regulatory Default
Receptor Grid	**NAAQS/TAPs Analyses (No SIL Analyses performed)**	
	Grid 1	25-meter spacing along the ambient air boundary
	Grid 2	25-meter spacing in a 700 meter (easting) by 700 meter (northing) grid centered on the facility
	Grid 3	50-meter spacing in a 1700 meter (easting) by 1700 meter (northing) grid centered on the facility
	Grid 4	150-meter spacing in a 4700 meter (easting) by 4700meter (northing) grid centered on the facility
	Grid 5	500-meter spacing in a 10700 meter (easting) by 10700 meter (northing) grid centered on the facility

5.1. MODEL SELECTION

The model used for this application is AERMOD (version 15181), the USEPA–approved model for near-field new source review. AERMOD was applied as recommended in EPA's Guideline on Air Quality Models and consistent with guidance in IDEQ's Dispersion Modeling Guidelines and the model protocol submitted to IDEQ on April 26, 2015 with exceptions as noted in Section 3.4. CRE did not employ any non-regulatory or beta options within AERMOD; regulatory defaults were used.

The Prime building downwash algorithm was applied for the facility. Terrain data will be processed consistent with this protocol and EPA guidance for AERMAP (version 11103). Meteorological data recommended for this analysis was provided by IDEQ.

__X__The current versions of all models and associated programs were used in analyses, or alternate versions were specifically approved by DEQ.

__N/A__ Any non-default model options used were approved by DEQ in advance.

5.2. METEOROLOGICAL DATA

Preprocessed AERMOD ready meteorological files were provided upon request from Thomas Swain of IDEQ. The data was processed by IDEQ using the ASOS airport site data set from Pullman, Washington, which contains the best available data for cloud cover, ceiling height, and temperature. The wind flows at the Pullman location, however, differ by approximately one sector clockwise from that seen in the RAWS data from Potlatch, which is in a more open topography. Therefore, DEQ shifted the winds in the Pullman data one sector counterclockwise, creating a new "revised" data set hereby referred to as "Pullman/Potlatch" data set. The data files cover the years 2010-2015; the year 2013 is not used due to substantial missing periods of 1 minute data. The data presented by IDEQ is model-ready, and was used without alteration or processing.

A memorandum from IDEQ to Trinity Consultants, describing the meteorological data in further detail is provided in **Appendix F.**

__X__ Meteorological data files are provided with the application.

__N/A__ If meteorological data used for modeling were not provided by DEQ, then a detailed discussion of the data is provided along with documentation of the processing steps.

5.3. EFFECTS OF TERRAIN

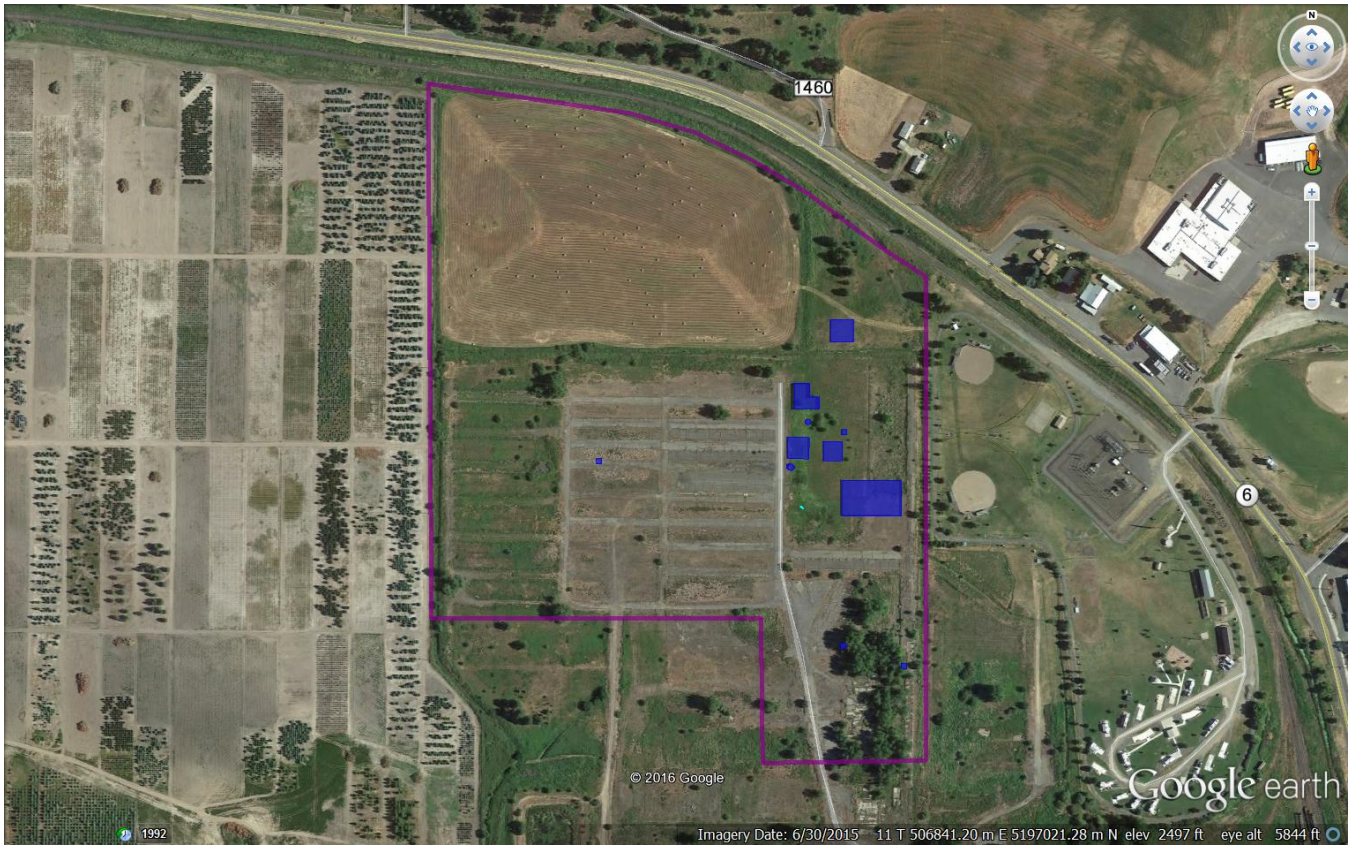
All source, building and receptor elevations were obtained from USGS NED data using the AERMAP preprocessing system in BREEZE. One-third arc second seamless NED data were downloaded from the Multi-Resolution Land Characteristics Consortium website. The datum of the terrain data is UTM NAD83, which is consistent with the datum used to specify locations of buildings, emissions points, and the ambient air boundary. All stack heights are referenced to ground surface elevations.

__X__ The datum of terrain data, building corner locations, emissions sources, and the ambient air boundary are specified and are consistent such that the modeled plot plan accurately represents the facility and surroundings.

5.4. FACILITY LAYOUT

Sources were 'placed' into the model using the BREEZE AERMOD GUI. A geo-referenced CAD drawing (UTM meters, NAD83 datum) was imported into the model, and point and volume sources were added at the corresponding locations. The accuracy of the CAD drawing and model layout was confirmed by exporting the model property boundary and model sources to Google Earth, as shown in **Figure 5-1.** A facility plot plan is included in **Appendix A.** It should be noted that smaller buildings such as the MCC and blower buildings are included in the model layout, however have not been added to the facility plot plan at this time.

Figure 5-1. Google Earth Model Overlay



__X__The facility layout plot plan is provided in this section that clearly and accurately depicts buildings, emissions points, and the ambient air boundary.

__X__This section of the Modeling Report has thoroughly described how locations of emissions sources, building corners, and the ambient air boundary were determined, specifying the datum used.

5.5. EFFECTS OF BUILDING DOWNWASH

The Prime building downwash algorithm was applied for the facility to account for downwash effects from on-site structures. Buildings were 'placed' into the model using the BREEZE AERMOD GUI. A geo-referenced CAD drawing (UTM meters, NAD83 datum) of the facility layout was imported into the model, and buildings were added at the corresponding locations. CRE personnel provided building height data to Trinity Consultants via email. It should be noted that smaller buildings such as the MCC and blower buildings are included in the model layout, however have not been added to the facility plot plan at this time. The proposed facility is located in a predominately agricultural area. As such, there are no offsite buildings within close enough proximity to affect downwash.

5.6. AMBIENT AIR BOUNDARY

The CRE property covers approximately 48 acres. Consistent with IDEQ guidance the ambient air boundary used in this analysis will be the property boundary, which also serves as the public access boundary. The project area is private property; the property boundary will be fenced and CRE will control access to the property through posting of signage and by training facility personnel to patrol and prevent public access.

__N/A__ If any of the following apply, the effect on areas excluded from ambient air is thoroughly described in this section: a river/stream bisecting the facility; the facility is on leased property or is leasing property to another entity; the facility is not completely fenced; there are right-of-way areas on the facility; the nature of business is such that the general public have access to part or all of the facility.

__X__ This section thoroughly describes how the facility can legally preclude public access (and practically preclude access) to areas excluded from ambient air in the modeling analyses.

5.7. RECEPTOR NETWORK

Receptor density will be set to a spacing of 25 meters along the ambient air boundary, 25 meters for the first 350 meters from the center of the property, then receptors will be set a density of one per 50 meters out to 850 meters away from the property center, 150 meters out to 2,350 meters from the property center, and 500 meters out to 5.3 kilometers from the center of the property. The receptor network ensures that the analysis meets or exceeds EPA receptor network requirements and captures the maximum impact from the facility. Therefore, no supplemental receptor network or expansion of the model domain is required or included.

__X__ This section of the Modeling Report provides justification that receptor spacing used in the air impact analyses was adequate to reasonably resolve the maximum modeled concentrations to the point that NAAQS or TAP compliance is assured.

5.8. BACKGROUND CONCENTRATIONS

Background concentrations for criteria pollutants were obtained from the Northwest International Air Quality Environmental Science and Technology Consortium (NW AIRQUEST) and are shown in **Table 5-2** below. Background values for TAPs are zero.

Table 5-2. Background Concentration Data

Pollutant	Averaging Period	Background Concentration (µg/m³)	Source
PM_{10}	24-hour	53	NW AIRQUEST, 2009-2011. The 'no extremes' value was used.
$PM_{2.5}$	24-hour	14	NW AIRQUEST, 2009-2011
	Annual	4.6	NW AIRQUEST, 2009-2011
NO_2	1-hour	11.8	NW AIRQUEST, 2009-2011
	Annual	1.88	NW AIRQUEST, 2009-2011
SO_2	1-hour	3.69	NW AIRQUEST, 2009-2011
	Annual	0.75	NW AIRQUEST, 2009-2011
CO	1-hour	1307	NW AIRQUEST, 2009-2011

Pollutant	Averaging Period	Background Concentration (µg/m³)	Source
	Annual	816	NW AIRQUEST, 2009-2011

__X__Background concentrations have been thoroughly documented and justified for all criteria pollutants where a cumulative NAAQS impact analysis was performed.

5.9. NO_X CHEMISTRY

NO_x chemistry was not considered in the compliance demonstration for 1-hour NO_2

__N/A__If OLM or PVMRM was used to address NO_x chemistry, reasons for selecting one algorithm over the other are provided in this section.

This section of the report discusses the model output results. The results of the modeling show that the facility is in compliance with all applicable NAAQS and TAP AACs and AACCs.

6.1. CRITERIA POLLUTANT IMPACT RESULTS

Modeling analyses were conducted for the criteria pollutants which exceed the modeling threshold at the CRE facility, which include PM_{10}, $PM_{2.5}$, NO_X, CO and SO_2. Model input and output files are included on CD in **Appendix G.**

6.1.1. Significant Impact Level Analyses

CRE did not conduct a Significant Impact Level (SIL) analyses; a full Cumulative Impact Analyses was performed for the initial modeling.

6.1.2. Cumulative NAAQs Impact Analyses

CRE did not conduct a Significant Impact Level (SIL) analyses; therefore a Cumulative Impact Analyses was performed for all receptors. The results of the Cumulative Impact Analyses are provided in **Table 6-1.** Background concentrations for 3-hour and 24-hour SO_2 were not available from the NW AIRQUEST site.

Table 6-1. Results for Cumulative NAAQS Impact Analyses

Pollutant	Averaging Period	Modeled Design Concentration (µg/m³)[a]	Background Concentration (µg/m³)	Total Impact (µg/m³)	NAAQS (µg/m³)
$PM_{2.5}$[b]	24-hour	17.3[g]	14.0	31.3[g]	35
	Annual	5.19[h]	4.60	9.79[h]	12
PM_{10}[c]	24-hour	96.6[i]	53.0	149.6[i]	150
NO_2[d]	1-hour	116.8[g]	11.8	128.6[g]	188
	Annual	2.90	1.88	4.78	100
SO_2[e]	1-hour	16.4[j]	3.7	20.1[j]	196
	3-hour	11.3[k]	N/A	11.3[k]	1,300
	24-hour	2.86[k]	N/A	2.86[k]	365
	Annual	0.51	0.75	1.26	80
CO[f]	1-hour	148.9[k]	1307	1456[k]	40,000
	8-hour	39.4[k]	816	855[k]	10,000

a. Micrograms/cubic meter
b. Particulate matter with an aerodynamic diameter less than or equal to a nominal 2.5 micrometers.
c. Particulate matter with an aerodynamic diameter less than or equal to a nominal 10 micrometers.
d. Nitrogen dioxide.
e. Sulfur dioxide.
f. Carbon Monoxide.
g. Maximum of 5-year means (or a lesser averaging period if less than 5 years of meteorological data were used in the analyses) of 8th highest modeled concentrations for each year modeled.

Pollutant	Averaging Period	Modeled Design Concentration (µg/m³)[a]	Background Concentration (µg/m³)	Total Impact (µg/m³)	NAAQS (µg/m³)
h. Maximum of 5-year means (or a lesser averaging period if less than 5 years of meteorological data were used in the analyses) of maximum modeled concentrations for each year modeled. i. Maximum of 6th highest modeled concentrations for a 5-year period (or the maximum of the 2nd highest modeled concentrations if only 1 year of meteorological data are modeled). j. Maximum of 5-year means (or a lesser averaging period if less than 5 years of meteorological data were used in the analyses) of 4th highest modeled concentrations for each year modeled. k. Maximum of 2nd highest modeled concentrations for each year modeled.					

__X__ Model input and output files for the cumulative NAAQS impact analyses are provided with the application.

__N/A__ If there were modeled NAAQS violations, all violations were analyzed and clearly show that the project did not significantly contribute to those modeled violations. If there were multiple violations at a given receptor, all cumulative impacts (including background) for the averaging period analyzed were ranked along with the project contribution, and the project contributions were below the applicable SIL. A table was included to show all ranked impacts above the NAAQS along with the project contribution

6.2. TAP IMPACT ANALYSES

Table 6-2 provides the results of the TAP impact analyses. A unit emission rate of 1.0 lb/hr was modeled for both the 24-hour and annual standards. The emission rate for each pollutant was then multiplied by the appropriate modeled value (0.62 µg/m³ for the 24-hour standard and 0.099 µg/m³ for the annual standard) to determine the modeled impact. The modeled impacts for all TAPs are below their respective AAC or AACC.

Table 6-2. Results for TAP Impact Analyses

TAP	Averaging Period	Maximum Modeled Impact (µg/m³)[a]	AAC or AACC (µg/m³)
Carbon Tetrachloride	Annual	8.91E-04	6.72E-02
Chloroform	Annual	5.54E-04	4.30E-02
Methylene Chloride	Annual	5.74E-03	2.40E-01
Vinyl Chloride	Annual	3.56E-04	1.40E-01
Iron	24-hour	1.23E-01	5.00E+01
Silver	24-hour	2.11E-01	5.00E+00

a. Micrograms/cubic meter.

7. QUALITY ASSURANCE/CONTROL

This analysis meets IDEQ expectations for quality assurance / quality control (QAQC).

Trinity Consultants provided services to develop this modeling analysis. Trinity's air quality and dispersion modeling expertise are unmatched in the professional environmental world. Trinity is ISO 9001:2008 certified at its corporate office in Dallas, Texas. Trinity's Quality Management System, based on the ISO standard, is implemented throughout its consulting operations company-wide. Trinity's system requires certified peer-reviewed validation of dispersion modeling analyses prepared by Trinity. Furthermore, Trinity has been developing and publishing air dispersion modeling software for 30 years.

Trinity dispersion modeling staff with 5 or more years of modeling experience were involved in designing the analysis and providing ongoing critical commentary on its preparation. After completing this modeling analysis, Trinity conducted a thorough internal peer review of its content.

Supplementing Trinity's expertise, Trinity has worked alongside modeling staff at IDEQ since July 2014 to ensure that the final analysis meets IDEQ's specifications and desires.

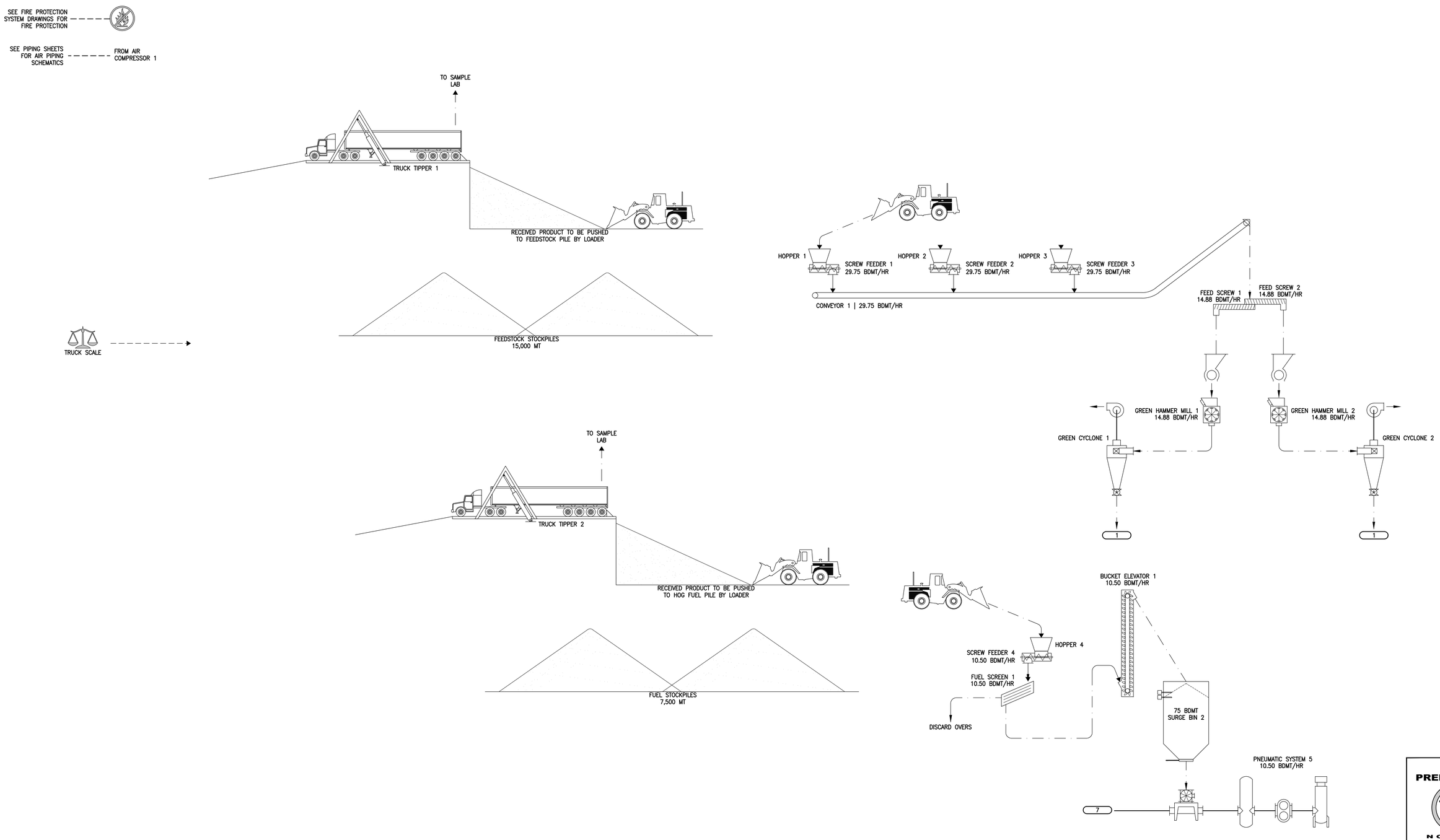
APPENDIX A: PROCESS FLOW DIAGRAMS AND PLOT PLAN

PRINTED: Feb 24, 2016

NOTES:

A. (1) TO CONVEYOR 2

B. (7) TO ENERGY SYSTEM



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Feb 24, 2016

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DOME TECHNOLOGY
4946 North 2900 East, Idaho Falls, ID 83401
tel: (208) 529-0833 fax: (208) 529-0854

ENGINEERING SYSTEM SOLUTIONS
4943 NORTH 29TH EAST, STE A
IDAHO FALLS, IDAHO 83401
Phone: (208) 552-9874
Fax: (208) 552-9302

PROJECT:
CENTENNIAL RENEWABLE ENERGY
FOR
DOME TECHNOLOGY

LOCATION:
FERNWOOD, ID

REV.	REVISION NOTE	DATE YY.MM.DD	DT ✓
A	ISSUED FOR PRICING	15.06.01	--
B	VALUE ENGINEERING	15.07.01	--
C	UPDATED TO POTLATCH SITE	16.02.14	--

REVISION DESCRIPTION | REV. | C

DESIGNED	DRAWN	CHECKED	APPROVED
AA	AA	--	--

SHEET TITLE:
RECEIVING FLOW SCHEMATIC

REF NUMBER: 1507 -000.01-REV C-16.02.24

START DATE: MARCH 30, 2015
PROJECT NUMBER: IND15116
SCALE: NO SCALE
SHEET NUMBER: 000.01

NOTES:

A. (1) FROM GREEN HAMMER MILLS

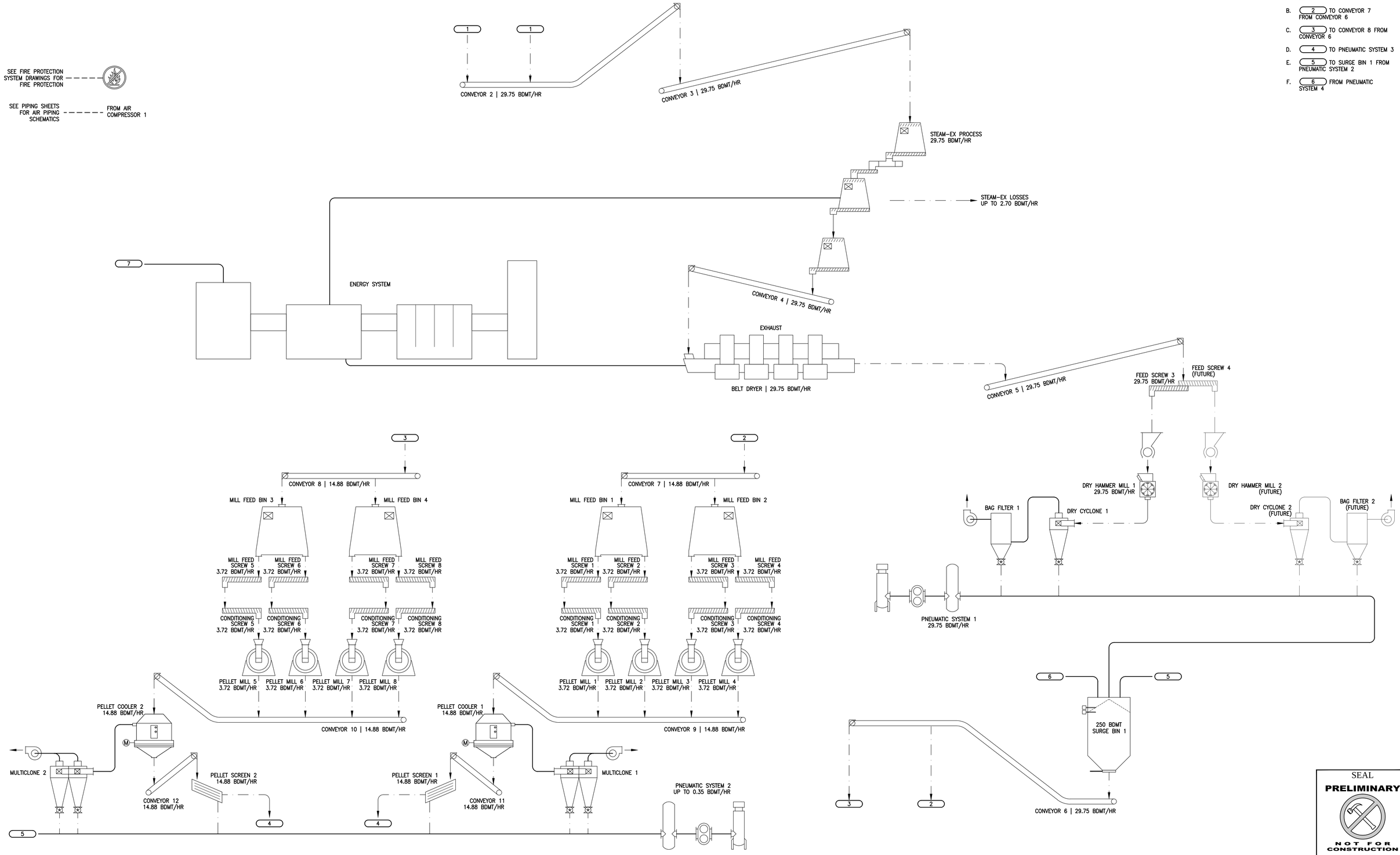
B. (2) TO CONVEYOR 7 FROM CONVEYOR 6

C. (3) TO CONVEYOR 8 FROM CONVEYOR 6

D. (4) TO PNEUMATIC SYSTEM 3

E. (5) TO SURGE BIN 1 FROM PNEUMATIC SYSTEM 2

F. (6) FROM PNEUMATIC SYSTEM 4



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EVERGREEN ENGINEERING
Engineering and Construction Services
EUGENE, OREGON
www.evergreenengineering.com

DOME TECHNOLOGY
4946 North 2900 East, Idaho Falls, ID 83401
tel: (208) 529-0833 fax: (208) 529-0854

ENGINEERING SYSTEM SOLUTIONS
4943 NORTH 29TH EAST, STE A
IDAHO FALLS, IDAHO 83401
Phone: (208) 552-9874
Fax: (208) 552-9302

PROJECT: CENTENNIAL RENEWABLE ENERGY FOR DOME TECHNOLOGY

LOCATION: FERNWOOD, ID

REV.	REVISION NOTE	DATE YY.MM.DD	DT ✓
A	ISSUED FOR PRICING	15.06.01	--
B	VALUE ENGINEERING	15.07.01	--
C	UPDATED TO POTLATCH SITE	16.02.14	--

REVISION DESCRIPTION | REV. | C

DESIGNED	DRAWN	CHECKED	APPROVED
AA/VENDORS	AA	--	--

SHEET TITLE: PROCESSING FLOW SCHEMATIC

REF NUMBER: 1507 -000.02-REV C-16.02.24

START DATE: MARCH 30, 2015
PROJECT NUMBER: IND15116
SCALE: NONE
SHEET NUMBER: 000.02

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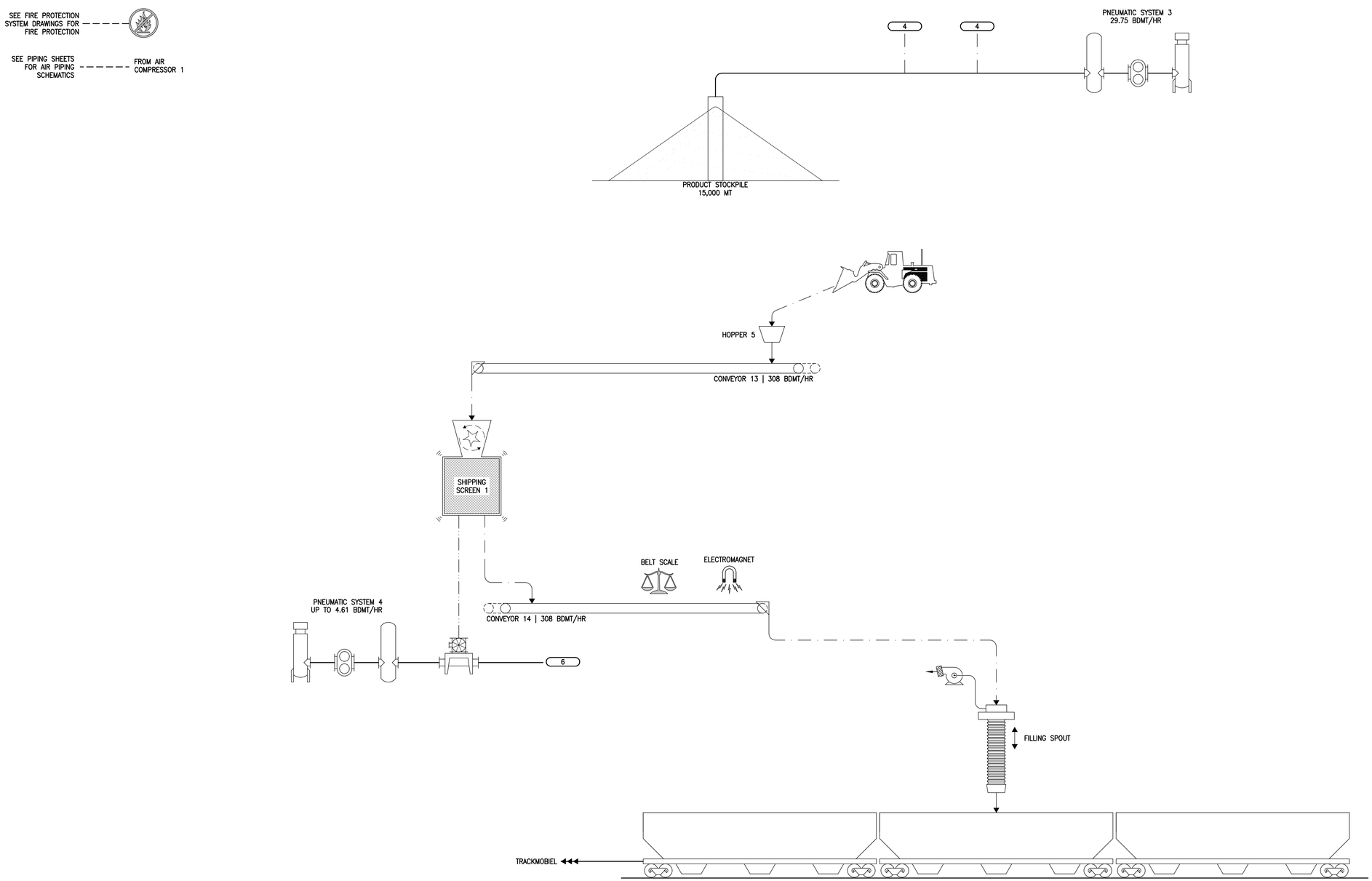
PRINTED: Feb 24, 2016

NOTES:

A. (4) FROM PELLET SCREENS

B. (6) TO SURGE BIN 1



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Feb 24, 2016

DOME TECHNOLOGY
4946 North 2900 East, Idaho Falls, ID 83401
tel: (208) 529-0833 fax: (208) 529-0854

ENGINEERING SYSTEM SOLUTIONS
4943 NORTH 29TH EAST, STE A
IDAHO FALLS, IDAHO 83401
Phone: (208) 552-9874
Fax: (208) 552-9302

PROJECT: CENTENNIAL RENEWABLE ENERGY
FOR
DOME TECHNOLOGY

LOCATION: FERNWOOD, ID

REV.	REVISION NOTE	DATE YY.MM.DD	DT ✓
A	ISSUED FOR PRICING	15.06.01	--
B	VALUE ENGINEERING	15.07.01	--
C	UPDATED TO POTLATCH SITE	16.02.14	--

REVISION DESCRIPTION — REV. C

DESIGNED	DRAWN	CHECKED	APPROVED
AA	AA	--	--

SHEET TITLE: SHIPPING FLOW SCHEMATIC

REF NUMBER: 1507 -000.03-REV C-16.02.24

START DATE: MARCH 30, 2015
PROJECT NUMBER: IND15116
SCALE: NO SCALE
SHEET NUMBER: 000.03

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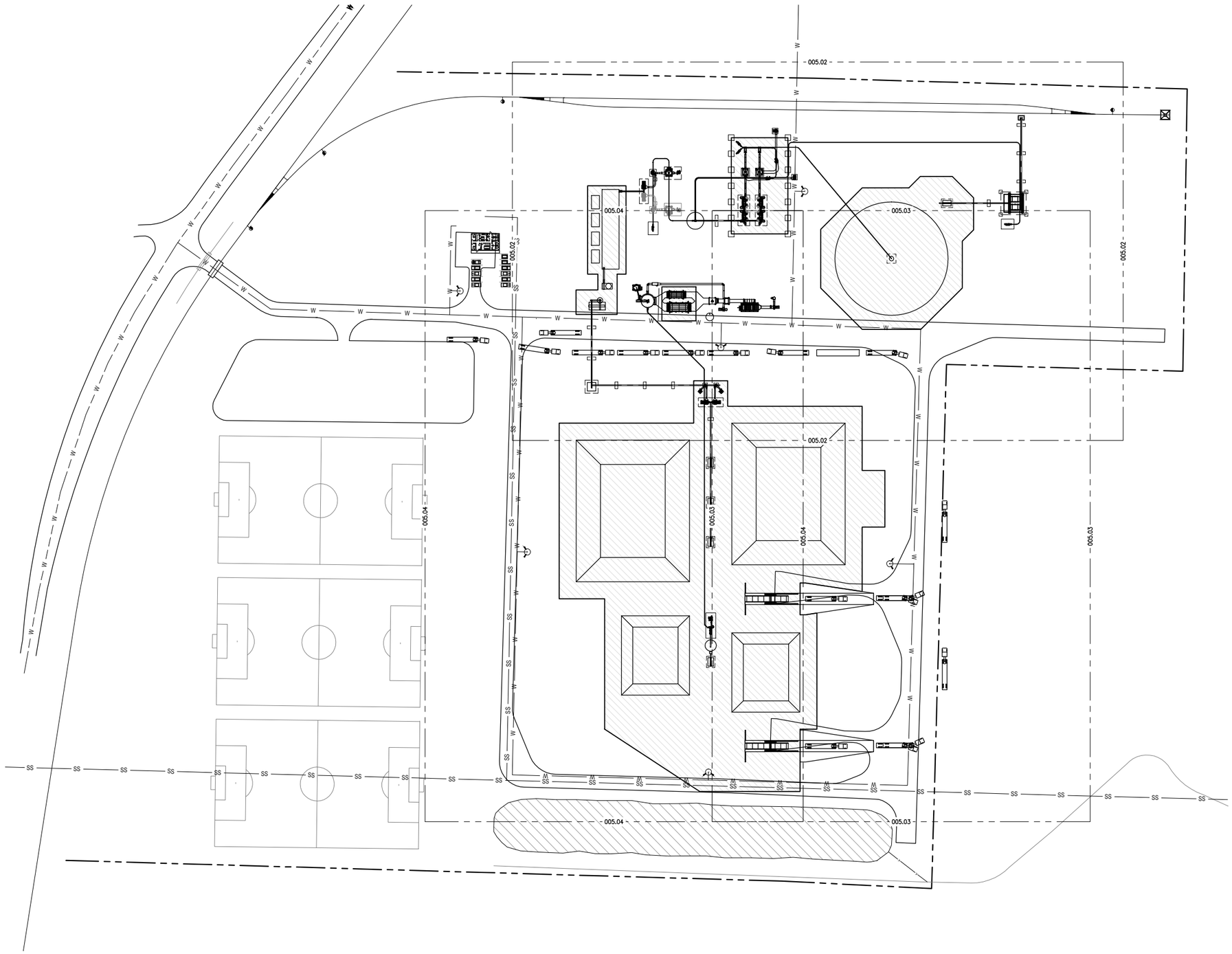
PRINTED: Jan 29, 2016



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4946 North 2900 East, Idaho Falls, ID 83401
tel: (208) 529-0833 fax: (208) 529-0854

ENGINEERING SYSTEM SOLUTIONS
4943 NORTH 29TH EAST, STE A
IDAHO FALLS, IDAHO 83401
Phone: (208) 552-9874
Fax: (208) 552-9302

PROJECT:
CENTENNIAL RENEWABLE ENERGY
FOR
DOME TECHNOLOGY

LOCATION:
POTLATCH, ID

REV.	REVISION NOTE	DATE YY.MM.DD	DT ✓
A	ISSUED WITH FEED STUDY	15.12.24	--
B	REVISED LAYOUT PER CONF. CALL	16.01.13	--
C	ISSUED WITH FEED STUDY	16.01.29	--

REVISION DESCRIPTION | REV. | C

DESIGNED	DRAWN	CHECKED	APPROVED
AA	AA	?	?

SHEET TITLE:
OVERALL SITE LAYOUT

REF NUMBER: 1507 -005.01-REV C-16.01.29

START DATE: MARCH 30, 2015
PROJECT NUMBER: IND15116
SCALE: NONE
SHEET NUMBER: 005.01

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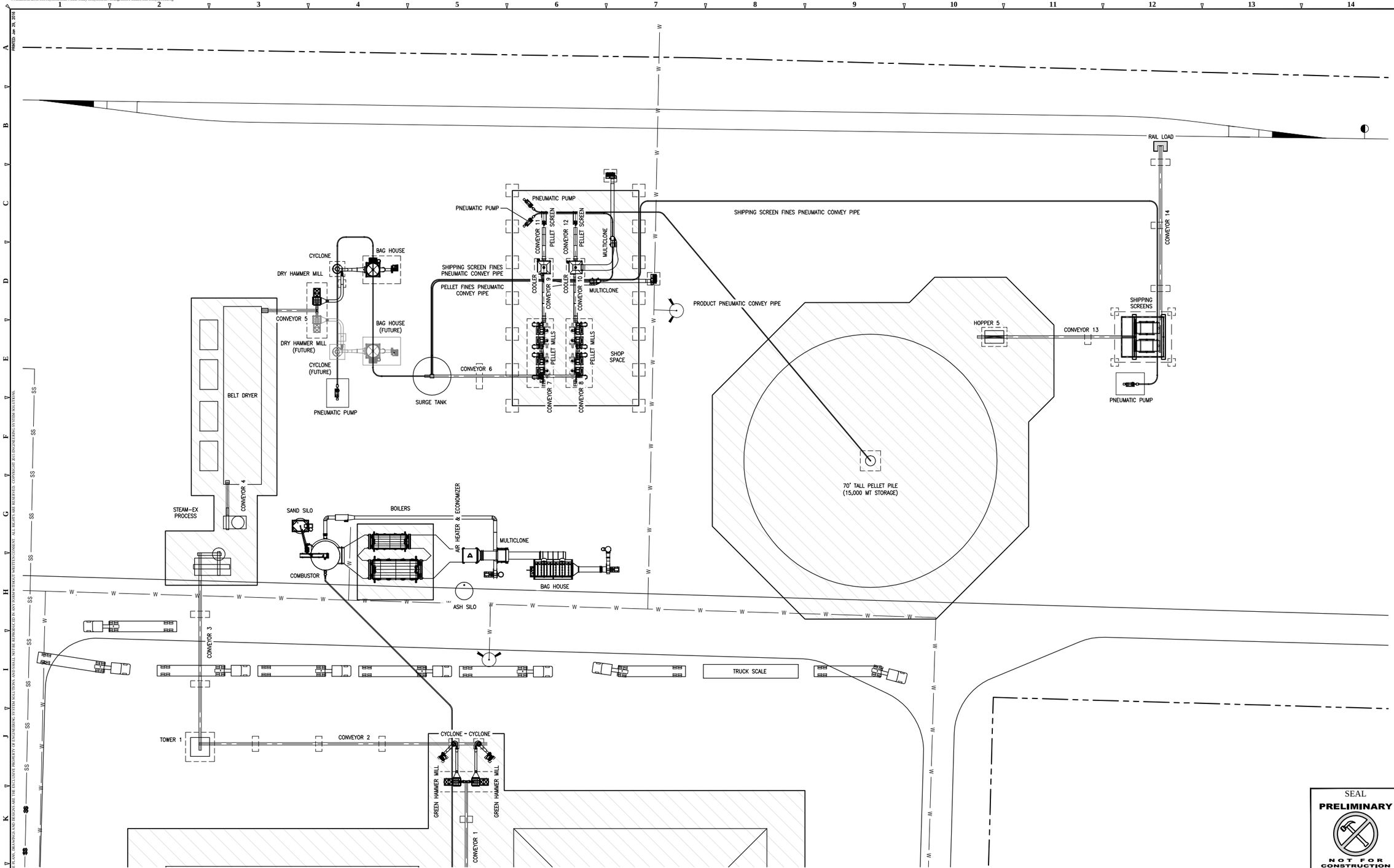

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tel: (208) 529-0833 fax: (208) 529-0854

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4943 NORTH 29TH EAST, STE A
IDAHO FALLS, IDAHO 83401
Phone: (208) 552-9874
Fax: (208) 552-9302

PROJECT:
CENTENNIAL RENEWABLE ENERGY
FOR
DOME TECHNOLOGY

LOCATION:
POTLATCH, ID

REV.	REVISION NOTE	DATE YY.MM.DD	DT ✓
A	ISSUED WITH FEED STUDY	15.12.24	--
B	REVISED LAYOUT PER CONF. CALL	16.01.13	--
C	ISSUED WITH FEED STUDY	16.01.29	--

REVISION DESCRIPTION

REV. C

DESIGNED	DRAWN	CHECKED	APPROVED
AA	AA	?	?

SHEET TITLE:
SITE LAYOUT (1)

REF NUMBER 1507 -005.02-REV C-16.01.29

START DATE: MARCH 30, 2015
PROJECT NUMBER: IND15116
SCALE: NONE
SHEET NUMBER: 005.02

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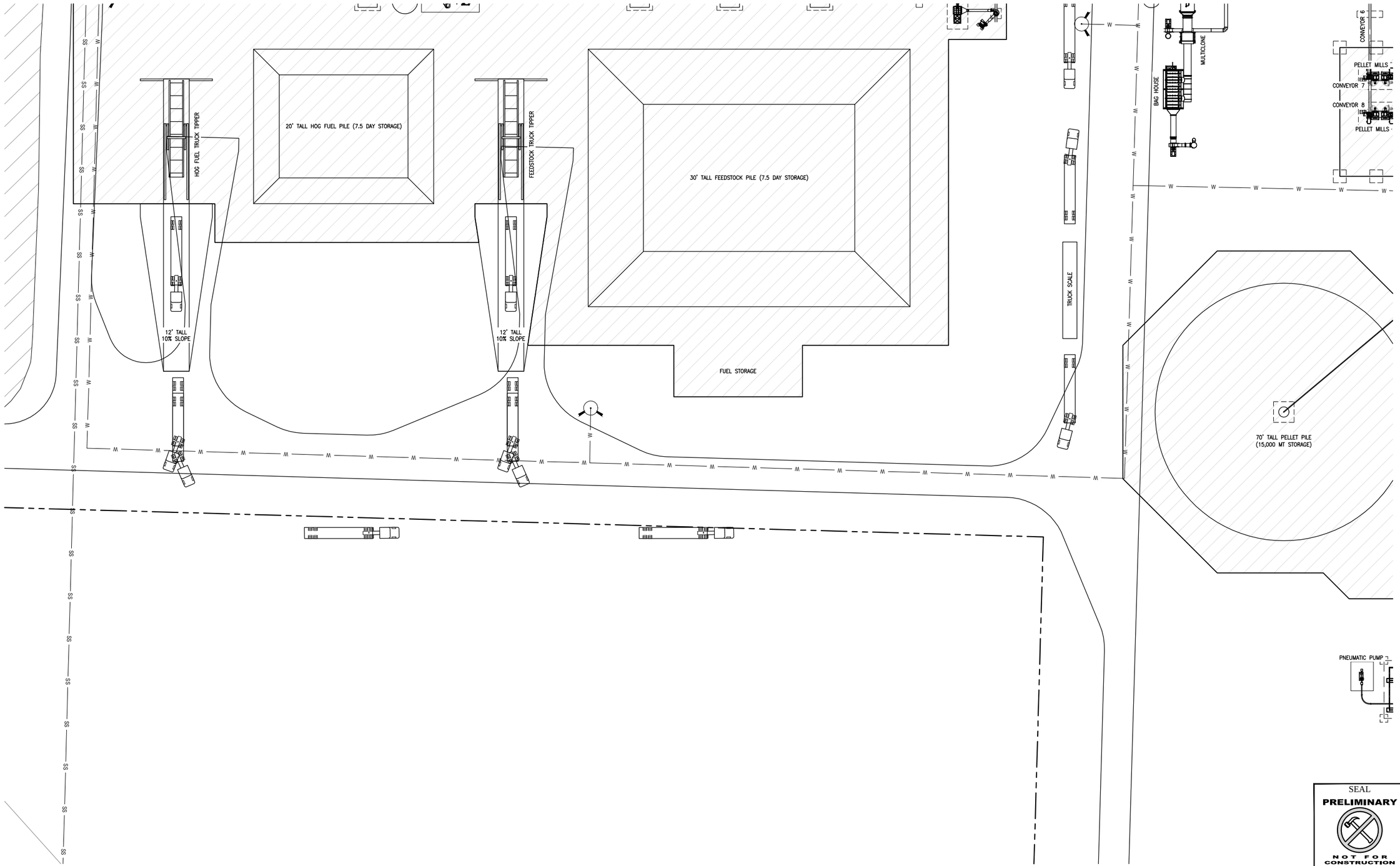

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DOME TECHNOLOGY
4946 North 2900 East, Idaho Falls, ID 83401
tel: (208) 529-0833 fax: (208) 529-0854

ENGINEERING SYSTEM SOLUTIONS
4943 NORTH 29TH EAST, STE A
IDAHO FALLS, IDAHO 83401
Phone: (208) 552-9874
Fax: (208) 552-9302

PROJECT:
CENTENNIAL RENEWABLE ENERGY
FOR
DOME TECHNOLOGY

LOCATION:
POTLATCH, ID

REV.	REVISION NOTE	DATE YY.MM.DD	DT ✓
A	ISSUED WITH FEED STUDY	15.12.24	--
B	REVISED LAYOUT PER CONF. CALL	16.01.13	--
C	ISSUED WITH FEED STUDY	16.01.29	--

REVISION DESCRIPTION | REV. | C

DESIGNED	DRAWN	CHECKED	APPROVED
AA	AA	?	?

SHEET TITLE:
SITE LAYOUT (2)

REF NUMBER: 1507 -005.03-REV C-16.01.29

START DATE: MARCH 30, 2015
PROJECT NUMBER: IND15116
SCALE: NONE
SHEET NUMBER: 005.03

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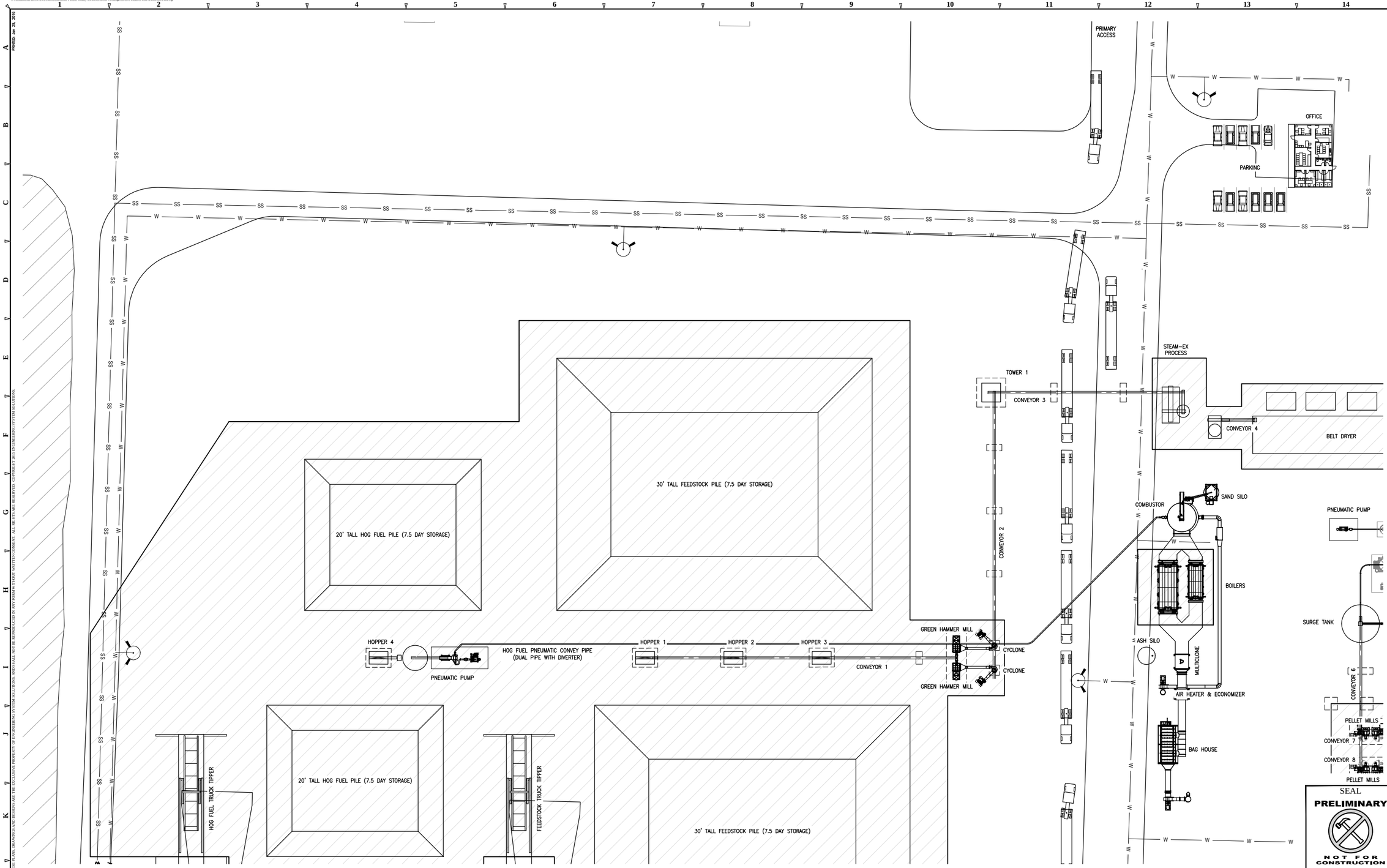
PRINTED: Jan 29, 2016



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IDAHO FALLS, IDAHO 83401
Phone: (208) 552-9874
Fax: (208) 552-9302

PROJECT:
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FOR
DOME TECHNOLOGY

LOCATION:
POTLATCH, ID

REV.	REVISION NOTE	DATE YY.MM.DD	DT ✓
A	ISSUED WITH FEED STUDY	15.12.24	--
B	REVISED LAYOUT PER CONF. CALL	16.01.13	--
C	ISSUED WITH FEED STUDY	16.01.29	--

REVISION DESCRIPTION

REV.	C

DESIGNED	DRAWN	CHECKED	APPROVED
AA	AA	?	?

SHEET TITLE:
SITE LAYOUT (3)

REF NUMBER: 1507 -005.04-REV C-16.01.29

START DATE: MARCH 30, 2015
PROJECT NUMBER: IND15116
SCALE: NONE
SHEET NUMBER: 005.04

APPENDIX B: EMISSIONS INVENTORY

Controlled PM Emissions from Boiler Baghouse

Emission Source Description	Exhaust Flow Rate (acfm)	Grain Loading Rate (gr/acfm)	Operating Hours (hr/yr)	PM Potential Emissions[1] (lb/hr)	PM Potential Emissions[1] (tpy)	PM_{10} Potential Emissions[1] (lb/hr)	PM_{10} Potential Emissions[1] (tpy)	$PM_{2.5}$ Potential Emissions[1] (lb/hr)	$PM_{2.5}$ Potential Emissions[1] (tpy)
Boiler Baghouse	135,000	0.0027	8,760	3.12	13.68	3.12	13.68	3.12	13.68

[1] PM_{10} and $PM_{2.5}$ emissions assumed to equal PM emissions.

[2] Emission parameters from "Questions for CRE and PES - ANSWERS (2) CRE Comments" word document, received from CRE and PES on March 3, 2016

[3] The Boiler Baghouse controls emissions from the high pressure boiler, glycol heater, FBC Combustor, FBC Pre-Burner, Multiclone Cyclones, Flash Steam from SteamEx process, Pre-Steaming Bin Exhaust, Pellet Cooler Exhaust

[4] Stack diameter measured in Breeze based on imported CAD drawing. Diameter estimated at 1.34 meters (4.39 ft)

Dryer Potential Emissions

Potential Operation	8,760	hr/yr
Dryer Air Flow Rate	694,382	Nm^3/hr
Dryer Capacity	33	tons/hr

Pollutant	Wood Drying Emission Factor (mg/Nm^3)	Potential Emissions (lb/hr)	(tpy)
CO	-	0.0	0.0
NO_X	-	0.0	0.0
Total PM	5.0	7.7	33.5
Total PM_{10}	4.5	6.9	30.2
Total $PM_{2.5}$	2.5	3.8	16.8
SO_2	-	0.0	0.0
VOC[2]	-	0.0	0.0
Lead	-	0.0	0.0
CH_4	-	0.0	0.0
N_2O	-	0.0	0.0
CO_2		0.0	0.0
CO_2e	-	0.0	0.0
$CO_2e_{biomass\ deferral}$	-	0.0	0.0

[1] Dust emissions have a manufacturer's guarantee of less than 10 mg/Nm^3 (dry). It is assumed that 50% of dust emissions consist of PM_{500}, 90% of PM_{500} emissions consist of PM_{10}, and 50% of PM_{500} emissions consist of $PM_{2.5}$.

[2] The dryer will be operated at a temperature much lower than the upstream SteamEx process. Volatilization is not expected to occur during the drying process.

FBC System Potential HAP and TAP Emissions

Heat Source - Heat Input Capacity	200	MMBtu/hr
Hours of Operation per Year	8,760	hr/yr

Pollutant	HAP?	Non-Carcinogenic TAP?	Carcinogenic TAP?	Biomass Combustion Emission Factor[1] (lb/MMBtu)	Potential HAP Emissions (lb/hr)	Potential HAP Emissions (tpy)	Potential TAP Emissions (lb/hr)	Potential TAP Emissions (tpy)
1,1,1-Trichloroethane	Yes	No	No	3.10E-05	6.20E-03	2.72E-02	-	-
1,2-Dibromoethene	Yes	No	No	5.50E-05	1.10E-02	4.82E-02	-	-
Acenaphthene	Yes	No	Yes	9.10E-07	1.82E-04	7.97E-04	1.82E-04	7.97E-04
Acenaphthylene	Yes	No	Yes	5.00E-06	1.00E-03	4.38E-03	1.00E-03	4.38E-03
Acetaldehyde	Yes	No	Yes	8.30E-04	1.66E-01	7.27E-01	1.66E-01	7.27E-01
Acetone	No	Yes	No	1.90E-04	-	-	3.80E-02	1.66E-01
Acetophenone	Yes	No	Yes	3.20E-09	6.40E-07	2.80E-06	6.40E-07	2.80E-06
Acrolein	Yes	Yes	No	4.00E-03	8.00E-01	3.50E+00	8.00E-01	3.50E+00
Anthracene	Yes	No	Yes	3.00E-06	6.00E-04	2.63E-03	6.00E-04	2.63E-03
Antimony	Yes	Yes	No	7.90E-06	1.58E-03	6.92E-03	1.58E-03	6.92E-03
Arsenic	Yes	No	Yes	2.20E-05	4.40E-03	1.93E-02	4.40E-03	1.93E-02
Benzene	Yes	No	Yes	4.20E-03	8.40E-01	3.68E+00	8.40E-01	3.68E+00
Benzo(a)anthracene	Yes	No	Yes	6.50E-08	1.30E-05	5.69E-05	1.30E-05	5.69E-05
Benzo(a)pyrene	Yes	No	Yes	2.60E-06	5.20E-04	2.28E-03	5.20E-04	2.28E-03
Benzo(b)fluoranthene	Yes	No	Yes	1.00E-07	2.00E-05	8.76E-05	2.00E-05	8.76E-05
Benzo(e)pyrene	Yes	No	Yes	2.60E-09	5.20E-07	2.28E-06	5.20E-07	2.28E-06
Benzo(g,h,i)perylene	Yes	No	Yes	9.30E-08	1.86E-05	8.15E-05	1.86E-05	8.15E-05
Benzo(j,k)fluoranthene	Yes	No	Yes	1.60E-07	3.20E-05	1.40E-04	3.20E-05	1.40E-04
Benzo(k)fluoranthene	Yes	No	Yes	3.60E-08	7.20E-06	3.15E-05	7.20E-06	3.15E-05
Beryllium	Yes	No	Yes	1.10E-06	2.20E-04	9.64E-04	2.20E-04	9.64E-04
Bis(2-ethylhexyl)phthalate	Yes	No	Yes	4.70E-08	9.40E-06	4.12E-05	9.40E-06	4.12E-05
Bromomethane	Yes	Yes	No	1.50E-05	3.00E-03	1.31E-02	3.00E-03	1.31E-02
2-Butanone (MEK)	No	Yes	No	5.40E-06	-	-	1.08E-03	4.73E-03
Cadmium	Yes	No	Yes	4.10E-06	8.20E-04	3.59E-03	8.20E-04	3.59E-03
Carbon tetrachloride	Yes	No	Yes	4.50E-05	9.00E-03	3.94E-02	9.00E-03	3.94E-02
Chlorine	Yes	Yes	No	7.90E-04	1.58E-01	6.92E-01	1.58E-01	6.92E-01
Chlorobenzene	Yes	Yes	No	3.30E-05	6.60E-03	2.89E-02	6.60E-03	2.89E-02
Chloroform	Yes	No	Yes	2.80E-05	5.60E-03	2.45E-02	5.60E-03	2.45E-02
2-Chlorophenol	No	Yes	No	2.40E-08	-	-	4.80E-06	2.10E-05
Chrysene	Yes	No	Yes	3.80E-08	7.60E-06	3.33E-05	7.60E-06	3.33E-05
Crotonaldehyde	No	Yes	No	9.90E-06	-	-	1.98E-03	8.67E-03
Chromium	Yes	Yes	Yes	2.10E-05	4.20E-03	1.84E-02	4.20E-03	1.84E-02
Chromium VI	Yes	No	Yes	3.50E-06	7.00E-04	3.07E-03	7.00E-04	3.07E-03
Cobalt	Yes	Yes	No	6.50E-06	1.30E-03	5.69E-03	1.30E-03	5.69E-03
Dibenzo(a,h)anthracene	Yes	No	Yes	9.10E-09	1.82E-06	7.97E-06	1.82E-06	7.97E-06
Dichlorobiphenyl	Yes	No	Yes	7.40E-10	1.48E-07	6.48E-07	1.48E-07	6.48E-07
1,2-Dichloroethane	Yes	No	Yes	2.90E-05	5.80E-03	2.54E-02	5.80E-03	2.54E-02
1,2-Dichloropropane	Yes	Yes	No	3.30E-05	6.60E-03	2.89E-02	6.60E-03	2.89E-02
2,4-Dinitrophenol	Yes	No	No	1.80E-07	3.60E-05	1.58E-04	-	-
Ethyl benzene	Yes	Yes	No	3.10E-05	6.20E-03	2.72E-02	6.20E-03	2.72E-02
Fluoranthene	Yes	No	Yes	1.60E-06	3.20E-04	1.40E-03	3.20E-04	1.40E-03
Fluorene	Yes	No	Yes	3.40E-06	6.80E-04	2.98E-03	6.80E-04	2.98E-03
Formaldehyde	Yes	No	Yes	4.40E-03	8.80E-01	3.85E+00	8.80E-01	3.85E+00
Heptachlorodibenzo-p-dioxins	Yes	No	Yes	2.00E-09	4.00E-07	1.75E-06	4.00E-07	1.75E-06
Heptachlorodibenzo-p-furans	Yes	No	Yes	2.40E-10	4.80E-08	2.10E-07	4.80E-08	2.10E-07
Hexachlorodibenzo-p-dioxins	Yes	No	Yes	1.60E-06	3.20E-04	1.40E-03	3.20E-04	1.40E-03
Hexachlorodibenzo-p-furans	Yes	No	Yes	2.80E-10	5.60E-08	2.45E-07	5.60E-08	2.45E-07
Hydrogen Chloride	Yes	Yes	No	1.90E-02	3.80E+00	1.66E+01	3.80E+00	1.66E+01
Indeno(1,2,3-cd)pyrene	Yes	No	Yes	8.70E-08	1.74E-05	7.62E-05	1.74E-05	7.62E-05
Iron	No	Yes	No	9.90E-04	-	-	1.98E-01	8.67E-01
Manganese	Yes	Yes	No	1.60E-03	3.20E-01	1.40E+00	3.20E-01	1.40E+00
Mercury	Yes	No	No	3.50E-06	7.00E-04	3.07E-03	-	-
Methanol	Yes	Yes	No	-	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Methyl chloride (chloromethane)	Yes	No	No	2.30E-05	4.60E-03	2.01E-02	-	-
Methylene chloride (dichloromethane)	Yes	No	Yes	2.90E-04	5.80E-02	2.54E-01	5.80E-02	2.54E-01
2-Methylnaphthalene	No	No	No	1.60E-07	-	-	-	-
Molybdenum	No	Yes	No	2.10E-06	-	-	4.20E-04	1.84E-03
Naphthalene	Yes	Yes	No	9.70E-05	1.94E-02	8.50E-02	1.94E-02	8.50E-02
Nickel	Yes	No	Yes	3.30E-05	6.60E-03	2.89E-02	6.60E-03	2.89E-02
4-Nitrophenol	Yes	No	No	1.10E-07	2.20E-05	9.64E-05	-	-
Octachlorodibenzo-p-dioxins	Yes	No	Yes	6.60E-08	1.32E-05	5.78E-05	1.32E-05	5.78E-05
Octachlorodibenzo-p-furans	Yes	No	Yes	8.80E-11	1.76E-08	7.71E-08	1.76E-08	7.71E-08
Pentachlorodibenzo-p-dioxins	Yes	No	Yes	1.50E-09	3.00E-07	1.31E-06	3.00E-07	1.31E-06

FBC System Potential HAP and TAP Emissions

Heat Source - Heat Input Capacity	200	MMBtu/hr
Hours of Operation per Year	8,760	hr/yr

Pollutant	HAP?	Non-Carcinogenic TAP?	Carcinogenic TAP?	Biomass Combustion Emission Factor[1] (lb/MMBtu)	Potential HAP Emissions (lb/hr)	Potential HAP Emissions (tpy)	Potential TAP Emissions (lb/hr)	Potential TAP Emissions (tpy)
Pentachlorodibenzo-p-furans	Yes	No	Yes	4.20E-10	8.40E-08	3.68E-07	8.40E-08	3.68E-07
Pentachlorobiphenyl	Yes	No	Yes	1.20E-09	2.40E-07	1.05E-06	2.40E-07	1.05E-06
Pentachlorophenol	Yes	Yes	No	5.10E-08	1.02E-05	4.47E-05	1.02E-05	4.47E-05
Perylene	Yes	No	Yes	5.20E-10	1.04E-07	4.56E-07	1.04E-07	4.56E-07
Phenanthrene	Yes	No	Yes	7.00E-06	1.40E-03	6.13E-03	1.40E-03	6.13E-03
Phenol	Yes	Yes	No	5.10E-05	1.02E-02	4.47E-02	1.02E-02	4.47E-02
Phosphorus	Yes	Yes	No	2.70E-05	5.40E-03	2.37E-02	5.40E-03	2.37E-02
Propanal	No	No	No	3.20E-06	-	-	-	-
Propionaldehyde	Yes	Yes	No	6.10E-05	1.22E-02	5.34E-02	1.22E-02	5.34E-02
Pyrene	Yes	No	Yes	3.70E-06	7.40E-04	3.24E-03	7.40E-04	3.24E-03
Selenium	Yes	Yes	No	2.80E-06	5.60E-04	2.45E-03	5.60E-04	2.45E-03
Silver	No	Yes	No	1.70E-03	-		3.40E-01	1.49E+00
Styrene	Yes	Yes	No	1.90E-03	3.80E-01	1.66E+00	3.80E-01	1.66E+00
2,3,7,8-Tetrachlorodibenzo-p-dioxins	Yes	No	Yes	8.60E-12	1.72E-09	7.53E-09	1.72E-09	7.53E-09
Tetrachlorodibenzo-p-dioxins	Yes	No	Yes	4.70E-10	9.40E-08	4.12E-07	9.40E-08	4.12E-07
2,3,7,8-Tetrachlorodibenzo-p-furans	Yes	No	Yes	9.00E-11	1.80E-08	7.88E-08	1.80E-08	7.88E-08
Tetrachlorodibenzo-p-furans	Yes	No	Yes	7.50E-10	1.50E-07	6.57E-07	1.50E-07	6.57E-07
Tetrachlorobiphenyl	Yes	No	Yes	2.50E-09	5.00E-07	2.19E-06	5.00E-07	2.19E-06
Tin	No	Yes	No	2.30E-05	-	-	4.60E-03	2.01E-02
Toluene	Yes	Yes	No	9.20E-04	1.84E-01	8.06E-01	1.84E-01	8.06E-01
Trichlorobiphenyl	Yes	No	Yes	2.60E-09	5.20E-07	2.28E-06	5.20E-07	2.28E-06
Trichloroethylene (trichloroethene)	Yes	No	Yes	3.00E-05	6.00E-03	2.63E-02	6.00E-03	2.63E-02
2,4,6-Trichlorophenol	Yes	No	Yes	2.20E-08	4.40E-06	1.93E-05	4.40E-06	1.93E-05
Vanadium	No	Yes	No	9.80E-07	-	-	1.96E-04	8.58E-04
Vinyl chloride	Yes	No	Yes	1.80E-05	3.60E-03	1.58E-02	3.60E-03	1.58E-02
o-Xylene	Yes	Yes	No	2.50E-05	5.00E-03	2.19E-02	5.00E-03	2.19E-02
Yttrium	No	Yes	No	3.00E-07	-	-	6.00E-05	2.63E-04
Zinc	No	Yes	No	4.20E-04	-	-	8.40E-02	3.68E-01
7-PAH	Yes	No	Yes	-	5.87E-04	2.57E-03	5.87E-04	2.57E-03
Dioxins/Furans	Yes	No	Yes	-	3.25E-05	1.42E-04	3.25E-05	1.42E-04
Maximum Individual HAP					**3.80**	**16.64**	**3.80**	**16.64**
Total HAP					**7.74**	**33.90**	**8.38**	**36.73**

[1] Emission factors from AP-42 Section 1.6, Tables 1.6-3 and 1.6-4 (9/03).

Emissions from FBC System

Heat Input Capacity		200 MMBtu/hr	
Hours of Operation per Year		8,760 hr/yr	
Pollutant[1]	**Wood Combustion Emission Factor**[2] (lb/MMBtu)	**Potential Emissions** (lb/hr)	(tpy)
CO	0.17	34.0	148.9
NO_X	0.22	44.0	192.7
SO_2	0.03	5.0	21.9
VOC	0.02	3.4	14.9
Lead	0.00	0.01	4.20E-02
CH_4	0.02	4.2	18.4
N_2O	0.01	2.6	11.4
CO_2	195.00	39000.0	170,820
CO_2e[3]	-	39,880	174,674
$CO_2e_{biomass\ deferral}$[4]	-	879.8	3,854

[1] PM emissions are accounted for in Table 10: Controlled PM Emissions from Boiler Baghouse.

[2] AP-42 Section 1.6 Wood Residue Combustion in Boilers, Tables 1.6-1, 1.6-2, and 1.6-3. Uncontrolled with wet wood fuel.

[3] Global warming potential (GWP) for CH_4 is 25, for N_2O is 298, and for CO_2 is 1 for estimating CO_2e emissions, based on 40 CFR 98, Subpart A, Table A-1 effective January 1, 2014.

[4] CO_2e based on the biomass deferral excludes biogenic CO_2 emissions (e.g., from biomass) per the Biomass Deferral published in Federal Register Vol. 76, No. 139, on July 20, 2011.

Emissions from FBC System Pre-Burner

Furnace Fuel Usage		8.00 MMBtu/hr		
Hours of Operation per Year		8,760 hr/yr		
Pollutant[1]	**Propane Combustion Emission Factor**[2] (lb/10^3 gal)	**Control Efficiency**[3]	**Potential Emissions** (lb/hr)	(tpy)
CO	7.5	0	0.7	2.9
NO_X	13	0	1.1	5.0
SO_2	1.5	0	0.1	0.6
VOC	1.0	99.9%	8.74E-05	3.83E-04
Lead	-	0	0.00E+00	0.00E+00
CH_4	0.2	0	0.0	0.1
N_2O	0.9	0	0.1	0.3
CO_2	12,500	0	1092.9	4,787
CO_2e[4]	-	-	1,117	4,892
$CO_2e_{biomass\ deferral}$[5]	-	-	23.9	105

[1] PM emissions are accounted for in Table 10: Controlled PM Emissions from Boiler Baghouse.

[2] AP-42 Section 1.5 Liquified Petroleum Gas Combustion, Table 1.5-1 (7/08). Heat content of 91.5 x 10^6 Btu/10^3 gallon for propane, sulfur content of commercial propane = 15gr/100 scf.

[3] Pre-burner VOC emissions are controlled by the FBC system.

[4] Global warming potential (GWP) for CH_4 is 25, for N_2O is 298, and for CO_2 is 1 for estimating CO_2e emissions, based on 40 CFR 98, Subpart A, Table A-1 effective January 1, 2014.

[5] CO_2e based on the biomass deferral excludes biogenic CO_2 emissions (e.g., from biomass) per the Biomass Deferral published in Federal Register Vol. 76, No. 139, on July 20, 2011.

Emission Unit No.	System Description	Requested Process Rate (ton/hr)	Requested Process Rate (ton/yr)	Requested Daily Operating Hours (hrs/day)	Requested Annual Operating Hours (hrs/yr)	PM Emission Factor	PM_{10} Emission Factor	$PM_{2.5}$ Emission Factor[1]	Emission Factor Units	Control Tech.	Control Efficiency (%)	PM Emission Rate (lb/hr)	PM Emission Rate (ton/yr)	PM_{10} Emission Rate (lb/hr)	PM_{10} Emission Rate (ton/yr)	$PM_{2.5}$ Emission Rate (lb/hr)	$PM_{2.5}$ Emission Rate (ton/yr)	Emission Factor Source
	HOG FUEL PROCESS																	
HF1	Truck Unloading to Hog Fuel Tipper	36	100,000	24	8,760	0.00300	0.00110	0.00016	lb/ton	Material moisture content	50%	0.055	0.075	0.020	0.028	0.003	0.004	AP-42, Crushed Stone 11.19.2-2, Conveyor Transfer Point
HF2	Hog Fuel Pile to Hopper #4/Screw Feeder #4 via Front Loader	12	100,000	24	8,760	0.00300	0.00110	0.00016	lb/ton	Material moisture content	50%	0.017	0.075	0.006	0.028	0.001	0.004	AP-42, Crushed Stone 11.19.2-2, Conveyor Transfer Point
HF3	Fuel Screen #1 and transfers (in from Hopper #4, out to Bucket Elevator #1)	12	100,000	24	8,760	0.02500	0.00870	0.00133	lb/ton	Material moisture content	50%	0.145	0.625	0.050	0.218	0.008	0.033	AP-42, Crushed Stone 11.19.2-2, Screening
HF4	Bucket Elevator #1 to Surge Bin #2	12	100,000	24	8,760	0.00300	0.00110	0.00016	lb/ton	Material moisture content	50%	0.017	0.075	0.006	0.028	0.001	0.004	AP-42, Crushed Stone 11.19.2-2, Conveyor Transfer Point
HF5	Surge Bin #2 to Pnuematic System #5	12	100,000	24	8,760	0.00300	0.00110	0.00016	lb/ton	Pnuematic Enclosure	100%	0.000	0.000	0.000	0.000	0.000	0.000	AP-42, Crushed Stone 11.19.2-2, Conveyor Transfer Point
HF6	Pneumatic System #5 to Combustor	12	100,000	24	8,760	0.00300	0.00110	0.00016	lb/ton	Pnuematic Enclosure	100%	0.000	0.000	0.000	0.000	0.000	0.000	AP-42, Crushed Stone 11.19.2-2, Conveyor Transfer Point
	FEEDSTOCK PROCESS																	
FS1	Truck Unloading to Feedstock Tipper #1	94	220,500	24	8,760	0.00300	0.00110	0.00016	lb/ton	Material Moisture Content	34%	0.186	0.218	0.068	0.080	0.010	0.012	AP-42, Crushed Stone 11.19.2-2, Conveyor Transfer Point
FS2	Feedstock Pile to Hopper #1, 2 or 3 via Front Loader	33	220,500	24	8,760	0.00300	0.00110	0.00016	lb/ton	Material Moisture Content	34%	0.065	0.218	0.024	0.080	0.003	0.012	AP-42, Crushed Stone 11.19.2-2, Conveyor Transfer Point
FS3	Hopper #1, 2 or 3 to Conveyor #1	33	220,500	24	8,760	0.00300	0.00110	0.00016	lb/ton	Material Moisture Content	34%	0.065	0.218	0.024	0.080	0.003	0.012	AP-42, Crushed Stone 11.19.2-2, Conveyor Transfer Point
FS4	Conveyor #1 to Feed Screw #1	16	220,500	24	8,760	0.00300	0.00110	0.00016	lb/ton	Material Moisture Content	34%	0.032	0.218	0.012	0.080	0.002	0.012	AP-42, Crushed Stone 11.19.2-2, Conveyor Transfer Point
FS5	Conveyor #1 to Feed Screw #2	16	220,500	24	8,760	0.00300	0.00110	0.00016	lb/ton	Material Moisture Content	34%	0.032	0.218	0.012	0.080	0.002	0.012	AP-42, Crushed Stone 11.19.2-2, Conveyor Transfer Point
FS6	Green Hammer Mill #1 and transfers (in from Feed Screw #1, out to Green Cyclone #1)	16	220,500	24	8,760	0.00540	0.00240	0.00029	lb/ton	Material Moisture Content	34%	0.058	0.393	0.026	0.175	0.003	0.021	AP-42, Crushed Stone 11.19.2-2, Tertiary Crushing
FS7	Green Hammer Mill #2 and transfers (in from Feed Screw #2, out to Green Cyclone #2)	16	220,500	24	8,760	0.00540	0.00240	0.00029	lb/ton	Material Moisture Content	34%	0.058	0.393	0.026	0.175	0.003	0.021	AP-42, Crushed Stone 11.19.2-2, Tertiary Crushing
FS8	Green Cyclone #1 to Conveyor #2	16	220,500	24	8,760	0.00300	0.00110	0.00016	lb/ton	Material Moisture Content	34%	0.032	0.218	0.012	0.080	0.002	0.012	AP-42, Crushed Stone 11.19.2-2, Conveyor Transfer Point
FS9	Green Cyclone #2 to Conveyor #2	16	220,500	24	8,760	0.00300	0.00110	0.00016	lb/ton	Material Moisture Content	34%	0.032	0.218	0.012	0.080	0.002	0.012	AP-42, Crushed Stone 11.19.2-2, Conveyor Transfer Point
FS10	Conveyor #2 to Conveyor #3 (Inside Tower 1)	33	220,500	24	8,760	0.00300	0.00110	0.00016	lb/ton	Enclosure	50%	0.049	0.165	0.018	0.061	0.003	0.009	AP-42, Crushed Stone 11.19.2-2, Conveyor Transfer Point
FS11	Conveyor #3 to Steam Ex Preheat Bin	33	220,500	24	8,760	0.00300	0.00110	0.00016	lb/ton	Inside Building	100%	0.000	0.000	0.000	0.000	0.000	0.000	AP-42, Crushed Stone 11.19.2-2, Conveyor Transfer Point
FS12	SteamEx Preheat Bin to Conveyor #4	33	220,500	24	8,760	0.00300	0.00110	0.00016	lb/ton	Inside Building	100%	0.000	0.000	0.000	0.000	0.000	0.000	AP-42, Crushed Stone 11.19.2-2, Conveyor Transfer Point
FS13	Conveyor #4 to Belt Dryer	33	220,500	24	8,760	0.00300	0.00110	0.00016	lb/ton	Inside Building	100%	0.000	0.000	0.000	0.000	0.000	0.000	AP-42, Crushed Stone 11.19.2-2, Conveyor Transfer Point
FS14	Belt Dryer to Conveyor #5	33	220,500	24	8,760	0.00300	0.00110	0.00016	lb/ton	Inside Building	100%	0.000	0.000	0.000	0.000	0.000	0.000	AP-42, Crushed Stone 11.19.2-2, Conveyor Transfer Point
FS15	Conveyor #5 to Feed Screw #3	33	220,500	24	8,760	0.00300	0.00110	0.00016	lb/ton	Material Moisture Content	8%	0.091	0.304	0.033	0.112	0.005	0.016	AP-42, Crushed Stone 11.19.2-2, Conveyor Transfer Point
FS16	Feed Screw #3 to Dry Hammer Mill	33	220,500	24	8,760	0.00300	0.00110	0.00016	lb/ton	Material Moisture Content	8%	0.091	0.304	0.033	0.112	0.005	0.016	AP-42, Crushed Stone 11.19.2-2, Conveyor Transfer Point
FS17	Dry Hammer Mill to Dry Cyclone #1	33	220,500	24	8,760	0.00300	0.00110	0.00016	lb/ton	Bag Filter	99%	0.001	0.003	0.0004	0.001	0.0001	0.000	AP-42, Crushed Stone 11.19.2-2, Conveyor Transfer Point
FS18	Dry Cyclone #1 to Pneumatic System #1	33	220,500	24	8,760	0.00300	0.00110	0.00016	lb/ton	Pnuematic Enclosure	100%	0.000	0.000	0.000	0.000	0.000	0.000	AP-42, Crushed Stone 11.19.2-2, Conveyor Transfer Point
FS19	Pnuematic System #1 to Surge Bin #1	33	220,500	24	8,760	0.00300	0.00110	0.00016	lb/ton	Pnuematic Enclosure	100%	0.000	0.000	0.000	0.000	0.000	0.000	AP-42, Crushed Stone 11.19.2-2, Conveyor Transfer Point
FS20	Surge Bin #1 to Conveyor #6	33	220,500	24	8,760	0.00300	0.00110	0.00016	lb/ton	Material Moisture Content	8%	0.091	0.304	0.033	0.112	0.005	0.016	AP-42, Crushed Stone 11.19.2-2, Conveyor Transfer Point
FS21	Conveyor #6 to Conveyor #7	16	220,500	24	8,760	0.00300	0.00110	0.00016	lb/ton	Inside Building	100%	0.000	0.000	0.000	0.000	0.000	0.000	AP-42, Crushed Stone 11.19.2-2, Conveyor Transfer Point
FS22	Conveyor #7 to Mill Feed Bin #1 and #2	16	220,500	24	8,760	0.00300	0.00110	0.00016	lb/ton	Inside Building	100%	0.000	0.000	0.000	0.000	0.000	0.000	AP-42, Crushed Stone 11.19.2-2, Conveyor Transfer Point
FS23	Mill Feed Bin #1 and #2 to Mill Feed Screws #1, 2, 3 and 4	16	220,500	24	8,760	0.00300	0.00110	0.00016	lb/ton	Inside Building	100%	0.000	0.000	0.000	0.000	0.000	0.000	AP-42, Crushed Stone 11.19.2-2, Conveyor Transfer Point
FS24	Mill Feed Screws #1, 2, 3, and 4 to Conditioning Screws #1, 2, 3 and 4	16	220,500	24	8,760	0.00300	0.00110	0.00016	lb/ton	Inside Building	100%	0.000	0.000	0.000	0.000	0.000	0.000	AP-42, Crushed Stone 11.19.2-2, Conveyor Transfer Point
FS25	Pellet Mills #1, 2, 3 and 4 and transfers (in from Conditioning Screws #1-4 and out to Conveyor #9)	16	220,500	24	8,760	0.00540	0.00240	0.00029	lb/ton	Inside Building	100%	0.000	0.000	0.000	0.000	0.000	0.000	AP-42, Crushed Stone 11.19.2-2, Tertiary Crushing
FS26	Conveyor #9 to Pellet Cooler #1	16	220,500	24	8,760	0.00300	0.00110	0.00016	lb/ton	Inside Building	100%	0.000	0.000	0.000	0.000	0.000	0.000	AP-42, Crushed Stone 11.19.2-2, Conveyor Transfer Point
FS27	Pellet Cooler #1 to Conveyor #11	16	220,500	24	8,760	0.00300	0.00110	0.00016	lb/ton	Inside Building	100%	0.000	0.000	0.000	0.000	0.000	0.000	AP-42, Crushed Stone 11.19.2-2, Conveyor Transfer Point
FS28	Pellet Cooler #1 to Multiclone #1	0.39	220,500	24	8,760	0.00300	0.00110	0.00016	lb/ton	Inside Building	100%	0.000	0.000	0.000	0.000	0.000	0.000	AP-42, Crushed Stone 11.19.2-2, Conveyor Transfer Point
FS29	Pellet Screen #1 and transfers (in from Conveyor #11, out to Pneumatic System #3)	16	220,500	24	8,760	0.02500	0.00870	0.00133	lb/ton	Inside Building	100%	0.000	0.000	0.000	0.000	0.000	0.000	AP-42, Crushed Stone 11.19.2-2, Screening
FS30	Multiclone #1 to Pneumatic System #2	0.39	220,500	24	8,760	0.00300	0.00110	0.00016	lb/ton	Inside Building	100%	0.000	0.000	0.000	0.000	0.000	0.000	AP-42, Crushed Stone 11.19.2-2, Conveyor Transfer Point
FS31	Conveyor #6 to Conveyor #8	16	220,500	24	8,760	0.00300	0.00110	0.00016	lb/ton	Inside Building	100%	0.000	0.000	0.000	0.000	0.000	0.000	AP-42, Crushed Stone 11.19.2-2, Conveyor Transfer Point
FS32	Conveyor #8 to Mill Feed Bin #3 and #4	16	220,500	24	8,760	0.00300	0.00110	0.00016	lb/ton	Inside Building	100%	0.000	0.000	0.000	0.000	0.000	0.000	AP-42, Crushed Stone 11.19.2-2, Conveyor Transfer Point
FS33	Mill Feed Bin #3 and #4 to Mill Feed Screws #5, 6, 7 and 8	16	220,500	24	8,760	0.00300	0.00110	0.00016	lb/ton	Inside Building	100%	0.000	0.000	0.000	0.000	0.000	0.000	AP-42, Crushed Stone 11.19.2-2, Conveyor Transfer Point
FS34	Mill Feed Screws #5, 6, 7, and 8 to Conditioning Screws #5, 6, 7 and 8	16	220,500	24	8,760	0.00300	0.00110	0.00016	lb/ton	Inside Building	100%	0.000	0.000	0.000	0.000	0.000	0.000	AP-42, Crushed Stone 11.19.2-2, Conveyor Transfer Point
FS35	Pellet Mills #5, 6, 7 and 8 and transfers (in from Conditioning Screws #5-8 and out to Conveyor #10)	16	220,500	24	8,760	0.00540	0.00240	0.00029	lb/ton	Inside Building	100%	0.000	0.000	0.000	0.000	0.000	0.000	AP-42, Crushed Stone 11.19.2-2, Tertiary Crushing
FS36	Conveyor #10 to Pellet Cooler #2	16	220,500	24	8,760	0.00300	0.00110	0.00016	lb/ton	Inside Building	100%	0.000	0.000	0.000	0.000	0.000	0.000	AP-42, Crushed Stone 11.19.2-2, Conveyor Transfer Point
FS37	Pellet Cooler #2 to Conveyor #12	16	220,500	24	8,760	0.00300	0.00110	0.00016	lb/ton	Inside Building	100%	0.000	0.000	0.000	0.000	0.000	0.000	AP-42, Crushed Stone 11.19.2-2, Conveyor Transfer Point
FS38	Pellet Cooler #2 to Multiclone #2	0.39	220,500	24	8,760	0.00300	0.00110	0.00016	lb/ton	Inside Building	100%	0.000	0.000	0.000	0.000	0.000	0.000	AP-42, Crushed Stone 11.19.2-2, Conveyor Transfer Point
FS39	Pellet Screen #2 and transfers (in from Conveyor #12, out to Pneumatic System #3)	16	220,500	24	8,760	0.02500	0.00870	0.00133	lb/ton	Inside Building	100%	0.000	0.000	0.000	0.000	0.000	0.000	AP-42, Crushed Stone 11.19.2-2, Screening
FS40	Multiclone #2 to Pneumatic System #2	0.39	220,500	24	8,760	0.00300	0.00110	0.00016	lb/ton	Inside Building	100%	0.000	0.000	0.000	0.000	0.000	0.000	AP-42, Crushed Stone 11.19.2-2, Conveyor Transfer Point
FS41	Pneumatic System #2 to Surge Bin #1	0.39	220,500	24	8,760	0.00300	0.00110	0.00016	lb/ton	Pnuematic Enclosure	100%	0.000	0.000	0.000	0.000	0.000	0.000	AP-42, Crushed Stone 11.19.2-2, Conveyor Transfer Point
FS42	Pnuematic System #3 to Pellet Product Stockpile	33	220,500	24	8,760	0.00300	0.00110	0.00016	lb/ton	Material Moisture Content	4%	0.094	0.318	0.035	0.116	0.005	0.017	AP-42, Crushed Stone 11.19.2-2, Conveyor Transfer Point
FS43	Pellet Product Stockpile to Hopper #5 via Front Loader	340	184,118	24	8,760	0.00300	0.00110	0.00016	lb/ton	Material Moisture Content	4%	0.978	0.265	0.359	0.097	0.052	0.014	AP-42, Crushed Stone 11.19.2-2, Conveyor Transfer Point
FS44	Hopper #5 to Conveyor #13	340	184,118	24	8,760	0.00300	0.00110	0.00016	lb/ton	Material Moisture Content	4%	0.978	0.265	0.359	0.097	0.052	0.014	AP-42, Crushed Stone 11.19.2-2, Conveyor Transfer Point
FS45	Shipping Screens and transfers (in from Conveyor #13, out to Conveyor #14)	340	184,118	24	8,760	0.02500	0.00870	0.00133	lb/ton	Enclosure	50%	4.245	1.151	1.477	0.400	0.225	0.061	AP-42, Crushed Stone 11.19.2-2, Screening
FS46	Shipping Screen to Pneumatic System #4	4.61	40,384	24	8,760	0.02500	0.00870	0.00133	lb/ton	Pnuematic Enclosure	100%	0.000	0.000	0.000	0.000	0.000	0.000	AP-42, Crushed Stone 11.19.2-2, Screening
FS47	Conveyor #14 to Filling Spout	340	184,118	24	8,760	0.00300	0.00110	0.00016	lb/ton	Material Moisture Content	4%	0.978	0.265	0.359	0.097	0.052	0.014	AP-42, Crushed Stone 11.19.2-2, Conveyor Transfer Point
FS48	Filling Spout to Rail Car	340	184,118	24	8,760	0.00300	0.00110	0.00016	lb/ton	Material Moisture Content	4%	0.978	0.265	0.359	0.097	0.052	0.014	AP-42, Crushed Stone 11.19.2-2, Conveyor Transfer Point
FS49	Pneumatic System #4 to Surge Bin #1	4.61	40,384	24	8,760	0.00300	0.00110	0.00016	lb/ton	Pneumatic Enclosure	100%	0.000	0.000	0.000	0.000	0.000	0.000	AP-42, Crushed Stone 11.19.2-2, Conveyor Transfer Point
												9.369	6.774	3.362	2.512	0.497	0.359	Totals

[1] No data available for PM2.5 emissions for uncontrolled sources. Therefore, the particle size multiplier of 0.0053 from AP-42 Section 13.2.4, September 2006, was mulitplied by the PM emission factor to develop the PM2.5 emission factor.

VOC Potential Emissions from Pellet Coolers

Facility-Wide Pellet Production Capacity	33	ton/hr
Potential Hours of Operation	8,760	hr/yr

Process	Number of Units	VOC Emission Factor[1] (lb/ton)	Methanol Emission Factor[1] (lb/ton)	Formaldehyde Emission Factor[1] (lb/ton)	Acetaldehyde Emission Factor[1] (lb/ton)	Uncontrolled VOC Potential Emissions (lb/hr)	Uncontrolled VOC Potential Emissions (tpy)	Controlled VOC Potential Emissions[2] (lb/hr)	Controlled VOC Potential Emissions[2] (tpy)
Pellet Coolers	2	4.62E-04	2.06E-05	1.18E-05	3.44E-06	0.02	0.07	0.0002	0.0007
Total						**0.02**	**0.07**	**0.0002**	**0.0007**

[1] Per engineering testing of the total gaseous organics emissions from pellet coolers at a similar facility. The most conservative emission factors from testing were used.

[2] Exhaust from the Pellet Coolers will be fed to the FBC for 99% control/destruction of VOC and PM

FBC System Potential HAP and TAP Emissions

Heat Source - Heat Input Capacity	200	MMBtu/hr
Hours of Operation per Year	8,760	hr/yr

Pollutant	HAP?	Non-Carcinogenic TAP?	Carcinogenic TAP?	Biomass Combustion Emission Factor[1] (lb/MMBtu)	Potential HAP Emissions (lb/hr)	Potential HAP Emissions (tpy)	Potential TAP Emissions (lb/hr)	Potential TAP Emissions (tpy)

FBC System Pre-Burner Potential HAP and TAP Emissions

Furnace Fuel Usage	0.01	MMscf/hr
Hours of Operation per Year	8,760.00	hr/yr

Pollutant	HAP?	Non-Carcinogenic TAP?	Carcinogenic TAP?	Natural Gas Combustion Emission Factor[1] (lb/MMscf)	Potential HAP Emissions (lb/hr)	Potential HAP Emissions (tpy)	Potential TAP Emissions (lb/hr)	Potential TAP Emissions (tpy)
Benzene	Yes	No	Yes	2.10E-03	1.65E-05	7.21E-05	1.65E-05	7.21E-05
Formaldehyde	Yes	No	Yes	7.50E-02	5.88E-04	2.58E-03	5.88E-04	2.58E-03
Toluene	Yes	Yes	No	3.40E-03	2.67E-05	1.17E-04	2.67E-05	1.17E-04
2-Methylnaphthalene	Yes	No	No	2.40E-05	1.88E-07	8.24E-07	-	-
3-Methylchloranthrene	Yes	No	No	1.80E-06	1.41E-08	6.18E-08	-	-
7,12-Dimethylbenz(a)anthracene	Yes	No	No	1.60E-05	1.25E-07	5.50E-07	-	-
Acenaphthylene	Yes	No	Yes	1.80E-06	1.41E-08	6.18E-08	1.41E-08	6.18E-08
Benzo(a)pyrene	Yes	No	Yes	1.20E-06	9.41E-09	4.12E-08	9.41E-09	4.12E-08
Benzo(b)fluoranthene	Yes	No	Yes	1.80E-06	1.41E-08	6.18E-08	1.41E-08	6.18E-08
Benzo(k)fluoranthene	Yes	No	Yes	1.80E-06	1.41E-08	6.18E-08	1.41E-08	6.18E-08
Dibenzo(a,h)anthracene	Yes	No	Yes	1.20E-06	9.41E-09	4.12E-08	9.41E-09	4.12E-08
Dichlorobenzene	Yes	Yes	No	1.20E-03	9.41E-06	4.12E-05	9.41E-06	4.12E-05
Hexane	Yes	Yes	No	1.80E+00	1.41E-02	6.18E-02	1.41E-02	6.18E-02
Naphthalene	Yes	Yes	No	6.10E-04	4.78E-06	2.10E-05	4.78E-06	2.10E-05
Acenaphthene	Yes	No	Yes	1.80E-06	1.41E-08	6.18E-08	1.41E-08	6.18E-08
Anthracene	Yes	No	Yes	2.40E-06	1.88E-08	8.24E-08	1.88E-08	8.24E-08
Benzo(a)anthracene	Yes	No	Yes	1.80E-06	1.41E-08	6.18E-08	1.41E-08	6.18E-08
Benzo(g,h,i)perylene	Yes	No	Yes	1.20E-06	9.41E-09	4.12E-08	9.41E-09	4.12E-08
Chrysene	Yes	No	Yes	1.80E-06	1.41E-08	6.18E-08	1.41E-08	6.18E-08
Fluoranthene	Yes	No	Yes	3.00E-06	2.35E-08	1.03E-07	2.35E-08	1.03E-07
Fluorene	Yes	No	Yes	2.80E-06	2.20E-08	9.62E-08	2.20E-08	9.62E-08
Indeno(1,2,3-cd)pyrene	Yes	No	Yes	1.80E-06	1.41E-08	6.18E-08	1.41E-08	6.18E-08
Phenanthrene	Yes	No	Yes	1.70E-05	1.33E-07	5.84E-07	1.33E-07	5.84E-07
Pentane	No	Yes	No	2.60E+00	-	-	2.04E-02	8.93E-02
Pyrene	Yes	No	Yes	5.00E-06	3.92E-08	1.72E-07	3.92E-08	1.72E-07
Arsenic	Yes	No	Yes	2.00E-04	1.57E-06	6.87E-06	1.57E-06	6.87E-06
Barium	No	Yes	No	4.40E-03	-	-	3.45E-05	1.51E-04
Beryllium	Yes	No	Yes	1.20E-05	9.41E-08	4.12E-07	9.41E-08	4.12E-07
Cadmium	Yes	No	Yes	1.10E-03	8.63E-06	3.78E-05	8.63E-06	3.78E-05
Chromium	Yes	Yes	Yes	1.40E-03	1.10E-05	4.81E-05	1.10E-05	4.81E-05
Cobalt	Yes	Yes	No	8.40E-05	6.59E-07	2.89E-06	6.59E-07	2.89E-06
Copper	No	Yes	No	8.50E-04	-	-	6.67E-06	2.92E-05
Lead	Yes	No	No	5.00E-04	3.92E-06	1.72E-05	-	-
Manganese	Yes	Yes	No	3.80E-04	2.98E-06	1.31E-05	2.98E-06	1.31E-05
Mercury	Yes	No	No	2.60E-04	2.04E-06	8.93E-06	-	-
Molybdenum	No	Yes	No	1.10E-03	-	-	8.63E-06	3.78E-05
Nickel	Yes	No	Yes	2.10E-03	1.65E-05	7.21E-05	1.65E-05	7.21E-05
Selenium	Yes	Yes	No	2.40E-05	1.88E-07	8.24E-07	1.88E-07	8.24E-07
Vanadium	No	Yes	No	2.30E-03	-	-	1.80E-05	7.90E-05
Maximum Individual HAP					**0.01**	**0.06**	**0.02**	**0.09**
Total HAP					**0.01**	**0.06**	**0.04**	**0.15**

[1] AP-42 Section 1.4 Natural Gas Combustion, Tables 1.4-3 and 1.4-4 (7/98). HAPs emissions factors not available for LPG in AP-42, Section 1.5.

Steam Explosion System Emissions

Dry Material Throughput	65,599	lb/hr
Hours of Operation per Year	8,760	hr/yr

Pollutant[1]	HAP?	Non-Carcinogenic TAP?	Carcinogenic TAP?	Emission Factor[2] (lb/lb dry fiber)	Control Efficiency[3] (%)	Potential Emissions (lb/hr)	Potential Emissions (tpy)	Potential HAP Emissions (lb/hr)	Potential HAP Emissions (tpy)	Potential TAP Emissions (lb/hr)	Potential TAP Emissions (tpy)
Methyl acetate	No	Yes	No	8.05E-10	99.9%	5.28E-08	2.31E-07	-	-	5.28E-08	2.31E-07
1,3-Pentadiene	No	No	No	6.88E-10	99.9%	4.52E-08	1.98E-07	-	-	-	-
Isobutyraldehyde	No	No	No	1.00E-09	99.9%	6.56E-08	2.87E-07	-	-	-	-
2,3-Butanedione	No	No	No	7.68E-10	99.9%	5.04E-08	2.21E-07	-	-	-	-
2-Butanone	No	No	Yes	1.45E-10	99.9%	9.50E-09	4.16E-08	-	-	9.50E-09	4.16E-08
2-Methyl-furan	No	No	No	1.67E-08	99.9%	1.09E-06	4.80E-06	-	-	-	-
3-Methyl-furan	No	No	No	1.29E-09	99.9%	8.49E-08	3.72E-07	-	-	-	-
Isovaleraldehyde	No	No	No	2.80E-09	99.9%	1.84E-07	8.06E-07	-	-	-	-
2-Methyl-butanal	No	No	No	1.56E-09	99.9%	1.02E-07	4.48E-07	-	-	-	-
1-Methyl-cyclopentene	No	No	No	1.41E-10	99.9%	9.28E-09	4.06E-08	-	-	-	-
Benzene	Yes	No	Yes	1.92E-09	99.9%	1.26E-07	5.51E-07	1.26E-07	5.51E-07	1.26E-07	5.51E-07
Cyclohexene	No	Yes	No	1.06E-09	99.9%	6.94E-08	3.04E-07	-	-	6.94E-08	3.04E-07
Cyclopentanol	No	No	No	1.06E-09	99.9%	6.94E-08	3.04E-07	-	-	-	-
2-Ethyl-furan	No	No	No	9.03E-10	99.9%	5.92E-08	2.59E-07	-	-	-	-
2,5-Dimethyl-furan	No	No	No	9.08E-10	99.9%	5.96E-08	2.61E-07	-	-	-	-
2,4-Dimethyl-furan	No	No	No	1.19E-09	99.9%	7.78E-08	3.41E-07	-	-	-	-
Vinylfuran	No	No	No	4.85E-10	99.9%	3.18E-08	1.39E-07	-	-	-	-
Disulfide, dimethyl	No	No	No	1.68E-09	99.9%	1.10E-07	4.82E-07	-	-	-	-
Toluene	Yes	Yes	No	1.96E-09	99.9%	1.29E-07	5.64E-07	1.29E-07	5.64E-07	1.29E-07	5.64E-07
Hexanal	No	No	No	3.50E-10	99.9%	2.29E-08	1.00E-07	-	-	-	-
2-Ethyl-5-methyl-furan	No	No	No	1.69E-10	99.9%	1.11E-08	4.86E-08	-	-	-	-
4,4-Dimethyl-2-cyclopenten-1-one	No	No	No	3.58E-10	99.9%	2.35E-08	1.03E-07	-	-	-	-
Furfural	No	Yes	No	7.68E-11	99.9%	5.04E-09	2.21E-08	-	-	5.04E-09	2.21E-08
2-Isopropyl-1-hexene	No	No	No	3.58E-10	99.9%	2.35E-08	1.03E-07	-	-	-	-
Ethyl benzene	Yes	Yes	No	1.37E-10	99.9%	8.96E-09	3.93E-08	8.96E-09	3.93E-08	8.96E-09	3.93E-08
m,p-Xylene	Yes	Yes	No	7.32E-10	99.9%	4.80E-08	2.10E-07	4.80E-08	2.10E-07	4.80E-08	2.10E-07
o-Xylene	Yes	Yes	No	1.90E-10	99.9%	1.25E-08	5.45E-08	1.25E-08	5.45E-08	1.25E-08	5.45E-08
Tricyclene	No	No	No	3.44E-10	99.9%	2.26E-08	9.89E-08	-	-	-	-
a-Pinene	No	No	No	1.79E-08	99.9%	1.17E-06	5.13E-06	-	-	-	-
Camphene	No	No	No	2.83E-09	99.9%	1.86E-07	8.13E-07	-	-	-	-
Trisulfide, dimethyl	No	No	No	3.60E-10	99.9%	2.36E-08	1.03E-07	-	-	-	-
B-Pinene	No	No	No	2.04E-09	99.9%	1.34E-07	5.85E-07	-	-	-	-
Benzofuran	No	No	No	2.46E-10	99.9%	1.61E-08	7.07E-08	-	-	-	-
Decane	No	No	No	4.38E-10	99.9%	2.87E-08	1.26E-07	-	-	-	-
a-Terpinene	No	No	No	3.51E-10	99.9%	2.30E-08	1.01E-07	-	-	-	-
o-Cymene	No	No	No	5.42E-09	99.9%	3.56E-07	1.56E-06	-	-	-	-
D-Limonene	No	No	No	8.97E-09	99.9%	5.88E-07	2.58E-06	-	-	-	-
y-Terpinene	No	No	No	5.87E-10	99.9%	3.85E-08	1.69E-07	-	-	-	-
Terpinolene	No	No	No	1.13E-09	99.9%	7.41E-08	3.25E-07	-	-	-	-
Total VOC				8.00E-08	99.9%	5.25E-06	2.30E-05	-	-	-	-

[1] PM emissions are accounted for in Table 10: Controlled PM Emissions from Boiler Baghouse.

[2] Emission factors obtained from stack testing conducted at Quebec City pilot plant with a similar steam explosion process.

[3] Exhaust from the SteamEx Unit is fed to the FBC for destruction/control of PM and VOC

Stockpile Wind Erosion Potential Fugitive PM Emissions

Emission Source Description	Annual Throughput (tpy)	Operating Hours (hr/yr)	Control	Material Moisture Content (%)	PM Emission Factor (lb/ton)	PM_{10} Emission Factor (lb/ton)	$PM_{2.5}$ Emission Factor (lb/ton)	Control Efficiency (%)	PM Potential Emissions (lb/hr)	PM Potential Emissions (tpy)	PM_{10} Potential Emissions (lb/hr)	PM_{10} Potential Emissions (tpy)	$PM_{2.5}$ Potential Emissions (lb/hr)	$PM_{2.5}$ Potential Emissions (tpy)
Hog Fuel Piles	100,000	8,760	None	50%	1.36E-02	6.41E-03	9.71E-04	0%	1.55E-01	6.78E-01	7.32E-02	3.21E-01	1.11E-02	4.85E-02
Pellet Pile	220,500	8,760	None	4%	4.65E-01	2.20E-01	3.33E-02	0%	1.17E+01	5.13E+01	5.54E+00	2.43E+01	8.39E-01	3.67E+00
Feedstock Piles	220,500	8,760	None	34%	2.33E-02	1.10E-02	1.67E-03	0%	5.85E-01	2.56E+00	2.77E-01	1.21E+00	4.19E-02	1.84E-01
TOTAL									**1.25E+01**	**5.45E+01**	**5.89E+00**	**2.58E+01**	**8.92E-01**	**3.91E+00**

[1] Based emission factors calculated per AP-42 Section 13.2.4, September 2006.

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

E = emission factor (lb/ton)

k = particle size multiplier (dimensionless) for PM: 0.74

k = particle size multiplier (dimensionless) for PM_{10}: 0.35

k = particle size multiplier (dimensionless) for $PM_{2.5}$: 0.053

U = mean wind speed (mph): 4.30

M = material moisture content (%)

APPENDIX C: MODELING PROTOCOL

PROJECT REPORT

Centennial Renewable Energy > Potlatch Pellet Mill

Air Dispersion Modeling Protocol

Prepared By:

Shannon Manoulian – Senior Consultant

TRINITY CONSULTANTS
702 W. Idaho St.
Suite 1100
Boise, ID 83702
(208) 472-8837

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Project 151301.0005

Environmental solutions delivered uncommonly well

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1. EXECUTIVE SUMMARY

This air quality modeling protocol documents the proposed methodology to prepare an air quality analyses in support of an Idaho Department of Environmental Quality (IDEQ) Permit to Construct (PTC) application for the Centennial Renewable Energy (CRE) wood pellet production facility near Potlach, Idaho. This report seeks to fully document and report the methods and techniques proposed to perform the modeling in support of the PTC application in order to gain concurrence from IDEQ staff.

2. PROJECT OVERVIEW

CRE is proposing to construct and operate a Greenfield wood pellet production facility near Potlach, Idaho. The facility will produce a type of wood pellet known as "Black Pellets". The facility will utilize short fiber wood waste (primarily sawdust and planer shavings) from regional mills as feedstock. The proprietary Black Pellet process involves a confidential steam explosion process after the feed stock enters the facility.

The steam for the facility will be provided via a fluidized bed boiler combusting hog fuel. The pelletizing operation will also include the use of hammer mills, pellet mills and pellet coolers. The wood pellets produced will be transported off-site via railcar or truck.

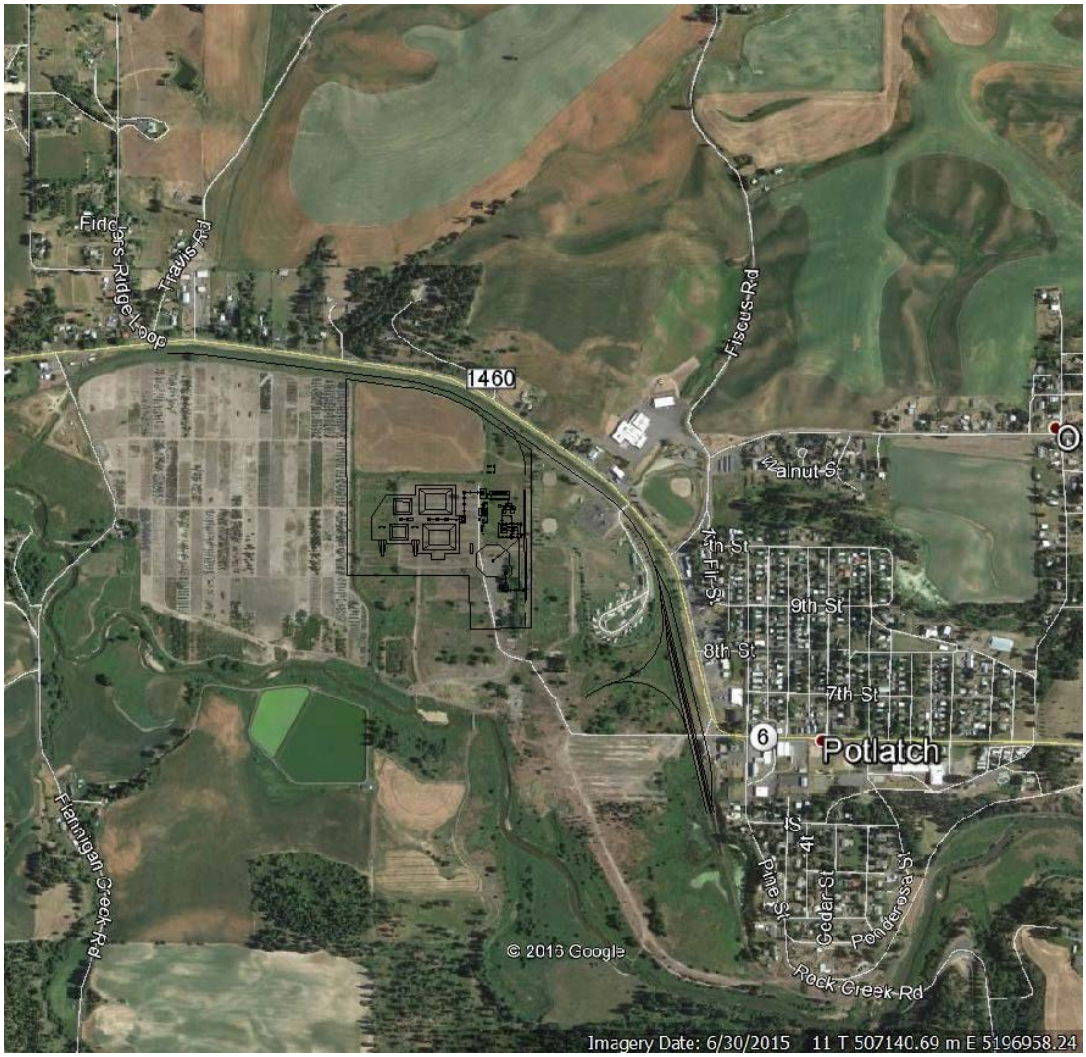
Emissions from the project include criteria pollutants and several IDAPA TAPs.

2.1. LOCATION OF PROJECT

The proposed CRE facility will be located on the former Potlach Mill site, near State Highway 6 and Forest Road 1460, approximately 0.7 miles northwest of the Potlach city center in Latah County, ID. The UTM coordinates for the facility are approximately 506,829 m E, 5,196,968 m N, Zone 11 (NAD83 coordinate system). Latah County is an attainment area for all criteria pollutants. Land use in the area includes agricultural, small commercial and residential properties. Terrain surrounding the project site is relatively flat. A map showing the location of the proposed facility is provided as Figure 2-1**.** The closest industrial facility to the project site is the Bennett Lumber facility, located approximately six (6) miles east of the proposed CRE facility.

The wood pelletizing mill will be constructed on approximately 48 acres. There are currently existing structures on the site from a previous wood chipping operation that will be removed prior to construction, except for the existing shop on the southeast part of the site. The site has an existing entrance from ID Hwy 3 on the north portion of the site which will be utilized for the new operation. Running along the southern portion of the site is the St. Maries Railroad, which splits off 2 spurs. An existing fire water storage pond is also located on the south central area of the property. It is insufficiently sized to hold the required amount of fire water and will be required to be upgraded.

Figure 2-1. Proposed Facility Location



2.2. GENERAL FACILITY / PROJECT DESCRIPTION

Wood mill residues will be brought in from various lumber mills in the area for process feedstock and Fluidized Bed Combustor (FBC) fuel. Received sawdust and shavings will be co-mingled upon delivery and stored in 15 day storage piles. Feedstock and hogged fuel will be received by truck and stacked by front end loader in the appropriate open storage pile in the storage yard area. Feedstock will be reclaimed by front-end loader and deposited into a metered bin, then conveyed to the process steam explosion process. Hogged fuel will be received and fed into a green hammer mill prior to being stacked. Hogged fuel will then be feed into a metered feed bin to be conveyed to the boiler island as fuel.

Reclaimed feedstock will be conveyed to screeners where material meeting size requirements will bypass the green hammer milling area. Product that exceeds the maximum size, will be run through a green hammer mill and then be fed back onto the screeners. Sized product will then proceed to the steam pre-heat bin where it will conditioned prior to being fed into the steam explosion process.

Once steam exploded, the material will be fed into a belt dryer to be dried to 8%-10% moisture content. After the dryer, product will be final screened and sized using two hammer mills. After final sizing the steam exploded feedstock will be feed into a conditioning bid where the feedstock will be moisture conditioned to the optimum moisture content and stored in short-term storage bins. Steam exploded Feedstock reclaimed from the storage bins will proceed to processing, before going into the pellet mills. Produced pellets will then be cooled to near ambient and then screened and fines removed and fed into the boiler heating system.

After the pelletizing process, product will be conveyed through a belt conveyor to a storage pile. Black Pellets will be reclaimed by a front end loader and fed into a loading bin. The pellets will be conveyed to a pellet screener prior to being loaded onto railcar. Fines from the screener will be conveyed to a metal bin to be hauled to the hogged fuel pile. Wood pellets will pass through the screener and be loaded into 91 MT (100 t) capacity covered hopper rail cars. Train cars will be loaded in 12 car blocks with a track mobile used to advance the cars into position. After the block has been loaded it will be connected to the unit train. The outbound trains will be approximately 110-115 car units. Received product will be transferred directly to ship at the Port of Longview in Longview, WA.

The facility proposes to operate 8,760 hours per year, with the exception of the finished product loading. Finished product loading, which includes transfer via front loader from the pellet product stockpile through to railcar filling, will only occur between the hours of 6am and 7pm. Draft process flow diagrams are included in **Appendix A.**

2.3. EMISSION SOURCES

2.3.1. Pellet Production

Feedstock will be received via a truck receiving area equipped to receive five trucks per hour. The trucks will enter the truck tipper, where material will be unloaded to the truck tipper pit. A front end loader will move the material from the truck tipper pit to the feedstock stockpiles located near Conveyor 1. Feedstock will be fed into one of three metering bins equipped with feed screws which in turn transfer the material onto Conveyor 1. The raw feedstock is then transferred to a second set of feed screws and into the green hammer mills for sizing. The green hammer mill will be sized to process 100% of the green fiber flow for pellet production and will be equipped with an in-feed drop chute magnet to remove tramp metals and protect the hammer mill. Green milled fiber will be mechanically conveyed to the Steam Explosion (SteamEx) system via Conveyors 2 and 3. After going through the SteamEx process, the material is transferred via Conveyor 4 to the Belt Dryer. The steam exploded material travels through the belt dryer where it is dried to 8-10% moisture by downdraft airflow at a temperature of approximately 100 ^{o}F. Since the airflow of the dryer is through the belt material, the belt acts as both a conveyance method and an emissions control for the product. The steam exploded material exit the dryer and are transferred to feed screws and into the dry hammer mill via Conveyor 5. Sized pellets from the dry hammer mill are transferred to the pneumatic conveying system via the dry cyclone; emissions from the dry hammer mill and cyclone are controlled by the hammer mill baghouse.

Sized pellets are discharged from the pneumatic conveying system into a metering surge bin. The pellets then travel via conveyor system to the mill feed bins, from the bins to the pellet mills via the mill feed screws and conditioning screws to pellet mills, and from the pellet mills via conveyor to the pellet coolers. The pellet coolers are necessary due to the increase in pellet temperature that is caused by the mechanical processing through the milling processes. After exiting the pellet coolers, the product is conveyed to the pellet screens and then transferred via pneumatic system to the product stockpile. The finished pellets are then transferred via front loader to a hopper and conveyed to the shipping screen. Sized finished pellets are transferred from the screen via conveyor to the filling spout and into railcars for shipment off-site.

Emission sources associated with pellet production include particulate emissions from material handling and product transfers, material stockpile wind erosion and the belt dryer. Exhaust from the SteamEx process is routed to the FBC for destruction of VOC, particulate and HAPs. SteamEx emissions are included in the FBC baghouse exhaust.

2.3.2. Heat Energy System

Hogged Fuel will be received by in the hogged fuel truck tipper. The hog fuel will be removed from the tipper pit and fed into hopper, screw feeder and screen. Material from the hog fuel screen will be transferred to the bucket elevator and into the surge bin. Materials from the surge bin will be conveyed pneumatically to the energy system, which includes the 200 MMBtu/hr Fluidized Bed Combustor (FBC).

The FBC will combust the hogged fuel to provide energy for the equipment in the rest of the facility. The energy system will be capable of exporting heat via high-pressure steam and glycol hot water.

A forced draft fan will supply air flow through a preheat burner prior to the inlet duct of the FBC to provide warming air to assist during startup of the fluid bed combustor from cold conditions. The burner will be propane fired with a capacity of 8 MMBtu/hr. Once the bed is heated to approximately 700 ^{o}F, wood is fed into the FBC and combustion is started. The preheat burner is turned off once the fluid bed temperature is above 1000 ^{o}F and the FBC operates only on wood fuel.

Wood waste fuel screened to a three inch minus size will be supplied to the FBC system via metering bin (surge bin) with twin screws. The counter rotating augers inside the metering bin will pull fuel on demand and discharge into a knifing rotary seal valve for feeding into the FBC via a pneumatic 10 inch diameter feed line. The fuel conveyance system will use a positive displacement blower with inlet and exit silencers to convey the fuel to the FBC.

The FBC is a vertical cylinder with an outlet transition where the combustion gas exits into a refractory lined ducting for conveying the combustion gas to provide the energy for the High Pressure Boiler and Glycol Hot Water Heater. The FBC is capable of accepting several of the streams of air and steam from the wood processing facility, including the high pressure boiler, glycol heater, FBC Pre-Burner, Multiclone Cyclones, Flash Steam from Steam Explosion (SteamEx) process, Pre-Steaming Bin Exhaust, and pellet coolers exhaust. These streams are capable of being directly injected to the FBC bed section or vapor space; any air or steam injected in this way will be subjected to temperatures of over 1600 F, for a residence time of 1.5 seconds or greater. Given the temperature and residence time of any stream introduced into the FBC it is very likely all VOC's will be destroyed at a high level of efficiency. Additional information on the FBC is included in **Appendix B.**

At the exhaust of both the High Pressure Boiler and the Glycol Hot Water boiler, there will be a flue gas treatment system consisting of a multi-cyclone, air-heater heat recovery, and baghouse particulate control device before entering the ID Fan and stack to be discharged to the atmosphere in a single point. Fine non-combustible materials from the fuel, (fine ash and dirt) are entrained in the flue gases rising from the bed. An ash drop will be provided to drop out material in the blended hot gas stream to the boilers. Oversized heavier non-combustible materials (gravel, rocks and metal) from the fuel remain in the bed. An automated bed cleaning system periodically withdraws sand from the bottom cone and onto a vibrating screen conveyor housed within the base skirt.

This bed cleaning system separates out larger non-combustible debris. Accepted sand is directed to a bucket elevator that lifts it up and directs it back into the combustor bed from above. "Rejected" oversize material, is

directed to a small tote bin for disposal. The ash present in the combustion gases will be collected in the dropout with a seal assemble for the removal of the ash. An ash silo will be used to support the ash drop and ducting. Ash will be discharged into the silo which will be periodically unloaded via dustless load spout which will lower and seal against a tanker truck. A vacuum will be applied to the load spout to collect the air displaced during tank fill up.

Emission sources associated with the heat energy system include particulate emissions from hogged fuel handling and transfers and hogged fuel stockpile wind erosion. Particulate and gaseous criteria pollutant emissions and HAPs from the FBC system, including pre-heater, as well as the multiclone cyclones, flash steam from the SteamEx process and pellet cooler are emitted through the FBC system baghouse stack.

2.4. POTENTIAL TO EMIT

The facility-wide potential to emit is shown in Table 2-1 and Table 2-2 below. Hourly emission rates are based on the maximum material throughputs and equipment capacities. Annual emission rates are based on 8,760 operating hours per year. Individual emission source calculations are provided in **Appendix C**.

Table 2-1. Facility-wide Potential to Emit (lb/hr)

Emission Sources	CO	NO_X	PM	PM_{10}	$PM_{2.5}$	SO_2	VOC	Lead
FBC System	34.0	44.0	-	-	-	5.0	3.4	0.01
FBC Pre-Heater	0.7	1.1	-	-	-	1.31E-01	8.74E-05	-
Steam Explosion Process	-	-	-	-	-	-	5.25E-06	-
Wood Dryer			7.7	6.9	3.8			
Pellet Coolers							1.52E-04	
Material Handling			11.6	4.1	0.6			
Boiler Baghouse			3.1	3.1	3.1			
TOTAL	34.7	45.1	22.4	14.1	7.5	5.1	3.4	0.01

Table 2-2. Facility-wide Potential to Emit (tpy)

Emission Sources	CO	NO_X	PM	PM_{10}	$PM_{2.5}$	SO_2	VOC	Lead
FBC System	148.9	192.7				21.9	14.9	0.04
FBC Pre-Heater	2.9	5.0				0.57	3.83E-04	
Steam Explosion Process							2.30E-05	
Wood Dryer			33.5	30.2	16.8			
Pellet Coolers							6.64E-04	
Material Handling			7.5	2.8	0.4			
Boiler Baghouse			13.7	13.7	13.7			
TOTAL	151.8	197.7	54.7	46.7	30.9	22.5	14.9	0.04

2.5. APPLICABLE REGULATIONS AND REQUIREMENTS

The proposed CRE Potlach facility will be a non-PSD major source of NO_X, CO and HAPs and will be subject to Title V of the Clean Air Act. In addition, the facility will be subject to 40 CFR Part 60, Subpart Db - Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units and 40 CFR Part 63, Subpart DDDDD—National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters.

Air dispersion modeling will be conducted for those criteria pollutants which exceed the Idaho Level I modeling thresholds and TAPs which exceed the screening emissions level (EL) in Idaho Air Rules Section 585 and 586. However, per IDEQ policy and guidance, TAPs that are regulated by a federal NSPS or NESHAPS will not be included in the modeling analysis. The pollutants modeled are detailed in section 3.0 below.

2.6. EXISTING PERMITS AND MODELING ANALYSES PERFORMED

The proposed CRE facility is a Greenfield facility; there are no existing air quality permits, and no previous modeling analyses have been performed.

3. MODELING DESCRIPTION

The model proposed for this application is AERMOD (version 15181), the USEPA–approved model for near-field new source review. Based on EPA guidance AERMOD is the most appropriate of the EPA-approved models given the site's physical characteristics and the facility emission sources. AERMOD will be applied as recommended in EPA's Guideline on Air Quality Models and consistent with guidance in IDEQ's Dispersion Modeling Guidelines.

The Prime building downwash algorithm will be applied for the facility. Terrain data will be processed consistent with this protocol and EPA guidance for AERMAP. Meteorological data recommended for this analysis has been provided by IDEQ. IDEQ requires modeling of criteria pollutants if emissions from the proposed source exceed the modeling thresholds set forth the IDEQ Dispersion Modeling Guidelines.

The criteria pollutants which exceed the modeling threshold at the CRE facility are PM_{10}, $PM_{2.5}$, NO_X, CO and SO_2. In addition, several TAPs exceed the screening emission levels (ELs) in IDAPA 58.01.01.585 and 586. However, the facility will be subject to 40 CFR Part 60, Subpart Db - Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units and 40 CFR Part 63, Subpart DDDDD—National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters. Per IDEQ policy and guidance, TAPs that are regulated by a federal NSPS or NESHAPS will not be included in the modeling analysis. These TAPs include acetaldehyde, acrolein, arsenic, benzene, beryllium, cadmium, chromium VI, hydrogen chloride, nickel, POM, and dioxins and furans. Therefore the modeling analysis will only include carbon tetrachloride, chloroform, iron, methylene chloride, silver and vinyl chloride.

In general, the AERMOD model application will use model source data consistent with the permit emission inventory. The model receptor network and model domain proposed will meet all EPA and IDEQ recommendations, and ensure a complete dispersion analysis that will capture maximum potential impacts. Only direct chemical emissions and transport will be considered in this analysis; chemical transformation of emissions will not be considered in this analysis.

3.1. RECEPTOR NETWORK

The CRE facility will be located just outside of the city of Potlach, on the former Potlach Mill site and is bordered by agricultural property. The CRE property covers approximately 48 acres. Consistent with IDEQ guidance the ambient air boundary used in this analysis will be the property boundary, which also serves as the public access boundary. The property boundary will be fenced and CRE will control access to the property through posting of signage and by training facility personnel to patrol and prevent public access.

Receptor density will be set to a spacing of 25 meters along the ambient air boundary, 25 meters for the first 350 meters from the center of the property, then receptors will be set a density of one per 50 meters out to 850 meters away from the property center, 150 meters out to 2,350 meters from the property center, and 500 meters out to 5.3 kilometers from the center of the property. The receptor network proposed ensures that the analysis meets or exceeds EPA receptor network requirements and captures the maximum impact from the facility. Therefore, no supplemental receptor network or expansion of the model domain will be required or included.

3.2. ELEVATION DATA

All source, building and receptor elevations will be from USGS NED data using the AERMAP preprocessing system in BREEZE. All stack heights will be referenced to ground surface elevations.

3.3. METEOROLOGICAL DATA

Preprocessed AERMOD ready meteorological files were provided upon request from Thomas Swain of IDEQ. The data was processed by IDEQ using the ASOS airport site data set from Pullman, Washington, which contains the best available data for cloud cover, ceiling height, and temperature. The wind flows at the Pullman location, however, differ by approximately one sector clockwise from that seen in the RAWS data from Potlatch, which is in a more open topography. Therefore, DEQ shifted the winds in the Pullman data one sector counterclockwise, creating a new "revised" data set hereby referred to as "Pullman/Potlatch" data set. The data files cover the years 2010-2015; the year 2013 is not used due to substantial missing periods of 1 minute data. The data presented by IDEQ is model-ready, and will be used without alteration or processing.

A memorandum from IDEQ to Trinity Consultants, describing the meteorological data in further detail is provided in **Appendix D.**

3.4. LAND USE CLASSIFICATION

AERMOD includes rural and urban algorithm options. These options affect the wind speed profile, dispersion rates, and mixing-height formula used in calculating ground-level pollutant concentrations. A protocol was developed by USEPA to classify an area as either rural or urban for dispersion modeling purposes. The classification is based on average heat flux, land use, or population density within a three-km radius from the plant site. Of these techniques, the USEPA has specified that land use is the most definitive criterion (USEPA, 1987). The urban/rural classification scheme based on land use is as follows:

> *The land use within the total area, A_0, circumscribed by a 3-km circle about the source, is classified using the meteorological land use typing scheme proposed by Auer (1978). The classification scheme requires that more than 50% of the area, A_0, be from the following land use types in order to be considered urban for dispersion modeling purposes: heavy industrial (I1); light-moderate industrial (I2); commercial (C1); single-family compact residential (R2); and multi-family compact residential (R3). Otherwise, the use of rural dispersion coefficients is appropriate.*

The CRE facility is located just outside of the city of Potlach and is bordered by agricultural landuse on all sides. Site and map reconnaissance showed that the area A_0 within a 3-km circle of the source is below the 50% urban land use criteria necessary for use of urban dispersion coefficients. Rural dispersion coefficients will therefore be used in the air quality dispersion modeling.

3.5. SPECIAL METHODS FOR MODELING CRITICAL POLLUTANT EMISSIONS

The facility proposes to operate 8,760 hours per year, with the exception of the finished product loading. Finished product loading, which includes transfer via front loader from the pellet product stockpile through to railcar filling, will only occur between the hours of 6am and 7pm. CRE is not proposing the use of any non-regulatory or beta options within AERMOD; regulatory defaults will be used.

3.6. BACKGROUND CONCENTRATIONS

Background concentrations for criteria pollutants were obtained from the Northwest International Air Quality Environmental Science and Technology Consortium (NW AIRQUEST) and are shown in Table 3-1 below. Background values for TAPs are zero.

Table 3-1. Background Concentration Data

Pollutant	Averaging Period	Background Concentration (µg/m³)	Source
PM_{10}	24-hour	53	NW AIRQUEST, 2009-2011. The 'no extremes' value was used.
$PM_{2.5}$	24-hour	14	NW AIRQUEST, 2009-2011
	Annual	4.6	NW AIRQUEST, 2009-2011
NO_2	1-hour	11.8	NW AIRQUEST, 2009-2011
	Annual	1.88	NW AIRQUEST, 2009-2011
SO_2	1-hour	3.69	NW AIRQUEST, 2009-2011
	Annual	0.75	NW AIRQUEST, 2009-2011
CO	1-hour	1307	NW AIRQUEST, 2009-2011
	Annual	816	NW AIRQUEST, 2009-2011

4. MODEL SOURCE DATA

The emissions sources described in Section 2 will be represented in the model as point or volume sources. Sources were 'placed' into the model using the BREEZE AERMOD interface map tool. A geo-referenced CAD drawing was imported into the model, and point and volume sources were added at the corresponding locations.

4.1. POINT SOURCES

Emissions from the belt dryer and FBC system baghouse are represented in the model as point sources. The point source parameters are shown in Table 4-1 below. The belt dryer exhaust is emitted through three identical stacks. The total emission rate was divided evenly between the three stacks.

Table 4-1. Point Source Parameters

Source ID/ Pollutant ID	Description	UTM		Elev. (m)	Emission Rate (m)	Stack Height (m)	Stack Temp (K)	Stack Velocity (m/s)	Stack Diameter (m)
		East (m)	North (m)						
BELTDRY1	Belt Dryer Exhaust #1	506971	5197046	760.97	0.160	7.0	310.15	7.20	3.38
BELTDRY2	Belt Dryer Exhaust #2	5069811	5197045.6	761.03	0.160	7.0	310.15	7.20	3.39
BELTDRY3	Belt Dryer Exhaust #3	5070012	5197045.2	761.16	0.160	7.0	310.15	7.20	3.39
BOILER	Boiler & Baghouse Exhaust	506949	5196949.5	760.17	0.393	22.9	449.82	37.6	1.34

The stack height, stack temperature, exit velocity were provided by the equipment manufacturer. Stack diameters were measured off of the scaled CAD design drawing imported into the BREEZE model interface. Documentation from the equipment vendors is included in **Appendix E.**

4.2. VOLUME SOURCES

Material handling, including loading and unloading, conveyor transfers, drop points, milling and screening, is represented in the modeled as volume sources. Each volume source was calculated to be a single volume source with the initial lateral dimension equal to the length of a side divided by 4.3 The volume sources are elevated and not on the side of building, therefore the initial vertical dimension was calculated to be the vertical dimension divided by 4.3. The volume source parameters are shown in Table 4-2 below. Assumptions used to calculate the volume source parameters are included in **Appendix F.**

Table 4-2. Volume Source Parameters

Source ID/ Pollutant ID	Description	UTM		Elev. (m)	Emission Rate (g/s)	Release Height (m)	Init. Lat. Dim (m)	Init. Vert. Dim. (m)
		East (m)	North (m)					
HF1	Truck Unloading to Hog Fuel Tipper	506707.7	5196966.5	759.58	3.78E-04	2.06	0.57	0.96
HF2	Transfer to Hopper #4	506753.8	5196983.4	759.8	1.26E-04	2.74	1.06	0.64
HF3	Fuel Screen #1 and transfers	506756.7	5196983.8	759.82	1.01E-03	1.52	0.28	0.07
HF4	Bucket Elevator #1 to Surge Bin #2	506758.9	5196983.8	759.83	1.26E-04	6.10	0.14	0.07
FS1	Truck Unloading to Feedstock Tipper #1	506787.7	5196966.5	759.79	1.26E-03	2.06	0.57	0.96
FS2	Feedstock Pile to Hopper #1, 2 or 3	506839.2	5196983.8	760.08	3.78E-04	2.74	1.06	0.07
FS3	Hopper to Conveyor #1	506842.6	5196983.9	760.09	3.78E-04	1.52	0.28	0.07
FS4	Conveyor #1 to Feed Screw #1	506884.1	5196982.6	760.23	2.52E-04	2.44	0.28	0.07
FS5	Conveyor #1 to Feed Screw #2	506883.5	5196985.5	760.27	2.52E-04	2.44	0.28	0.07
FS6	Green Hammer Mill #1 and transfers	506894	5196981.6	760.21	3.78E-04	2.13	0.28	0.07
FS7	Green Hammer Mill #2 and transfers	506893.8	5196986.6	760.27	3.78E-04	2.13	0.28	0.07
FS8	Green Cyclone #1 to Conveyor #2	506902.8	5196981.1	760.22	2.52E-04	1.52	0.28	0.07

Table 4-3. Volume Source Parameters (continued)

Source ID/ Pollutant ID	Description	UTM		Elev. (m)	Emission Rate (g/s)	Release Height (m)	Init. Lat. Dim (m)	Init. Vert. Dim. (m)
		East (m)	North (m)					
FS9	Green Cyclone #2 to Conveyor #2	506902.1	5196986.5	760.27	2.52E-04	1.52	0.28	0.07
FS10	Conveyor #2 to Conveyor #3	506902.1	5197047.8	760.7	3.78E-04	13.72	0.28	0.07
FS15	Conveyor #5 to Feed Screw #3	507006.5	5197019.9	760.9	6.30E-04	2.44	0.28	0.07
FS16	Feed Screw #3 to Dry Hammer Mill	507004.6	5197017	760.86	6.30E-04	2.13	0.28	0.07
FS17	Dry Hammer Mill to Dry Cyclone #1	507000.4	5197013.4	760.8	6.30E-04	1.22	0.14	0.07
FS20	Surge Bin #1 to Conveyor #6	506990.9	5196991.9	760.59	6.30E-04	0.91	0.14	0.07
FS42	Pnuematic System #3 to Pellet Stockpile	506970.2	5196886.2	759.85	6.30E-04	21.34	0.07	2.48
FS43	Hopper #5	507000	5196856.5	759.77	6.68E-03	2.74	0.71	0.07
FS44	Hopper #5 to Conveyor #13	507000	5196853.8	759.75	6.68E-03	1.52	0.28	0.07
FS45	Shipping Screens and transfers	507000.2	5196819.2	759.52	4.21E-02	7.62	0.28	0.07
FS47	Conveyor #14 to Filling Spout	507042	5196816.5	759.75	6.68E-03	6.10	0.28	0.07
FS48	Filling Spout to Rail Car	507045.4	5196816.7	759.76	6.68E-03	4.57	0.14	0.07

Per the IDEQ Guideline for Performing Air Quality Impact Analyses, fugitive emissions from vehicle traffic on roads and wind erosion from material storage piles are normally not included in the modeling analyses. This information was confirmed by Kevin Schilling, IDEQ, during the pre-application meeting held on April 15, 2016.

4.3. MODEL LAYOUT

The proposed model layout showing the locations of sources, emissions points, buildings and the property boundary are shown in Figure 4-1 and Figure 4-2 below.

Figure 4-1. Model Layout

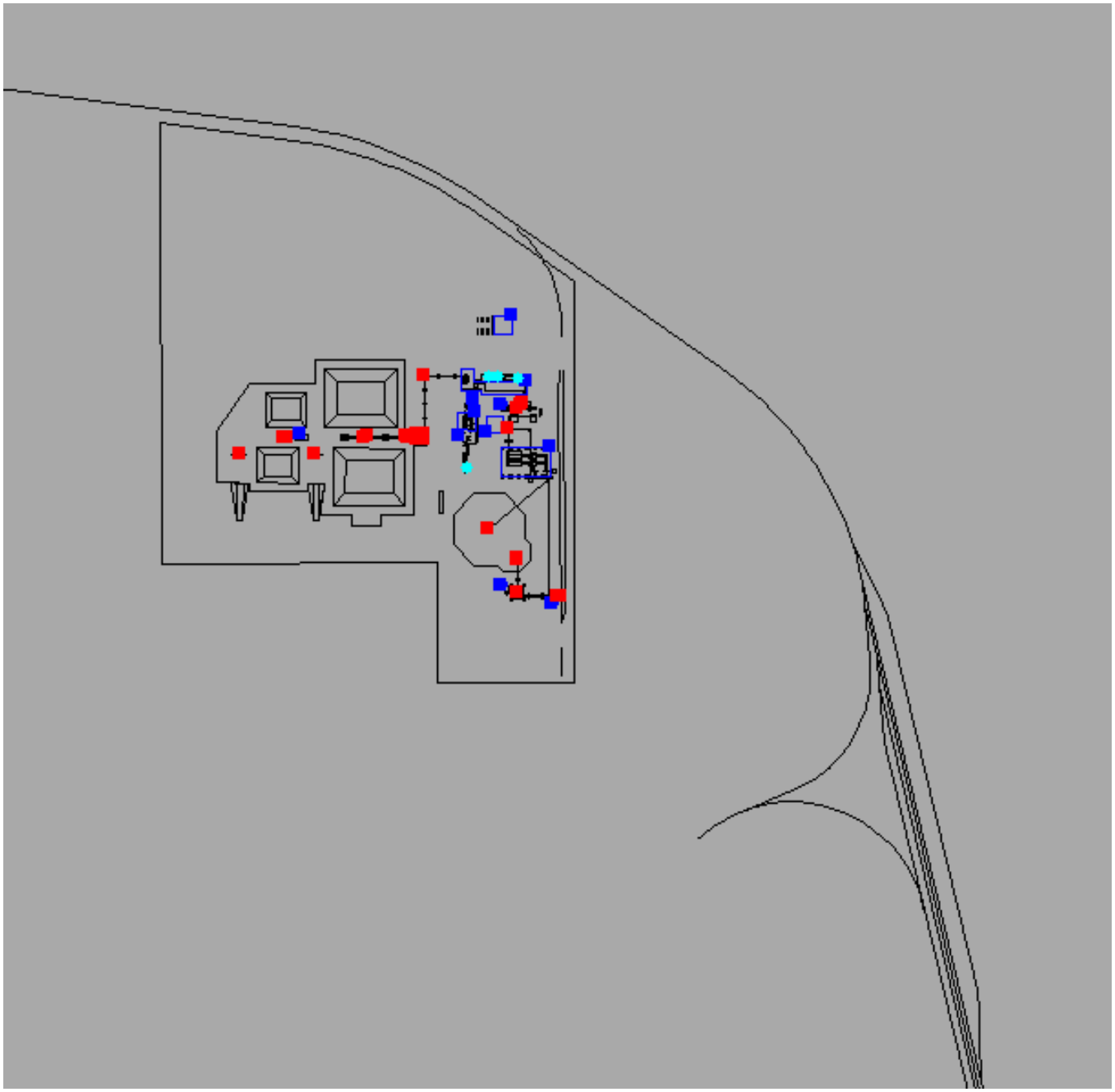
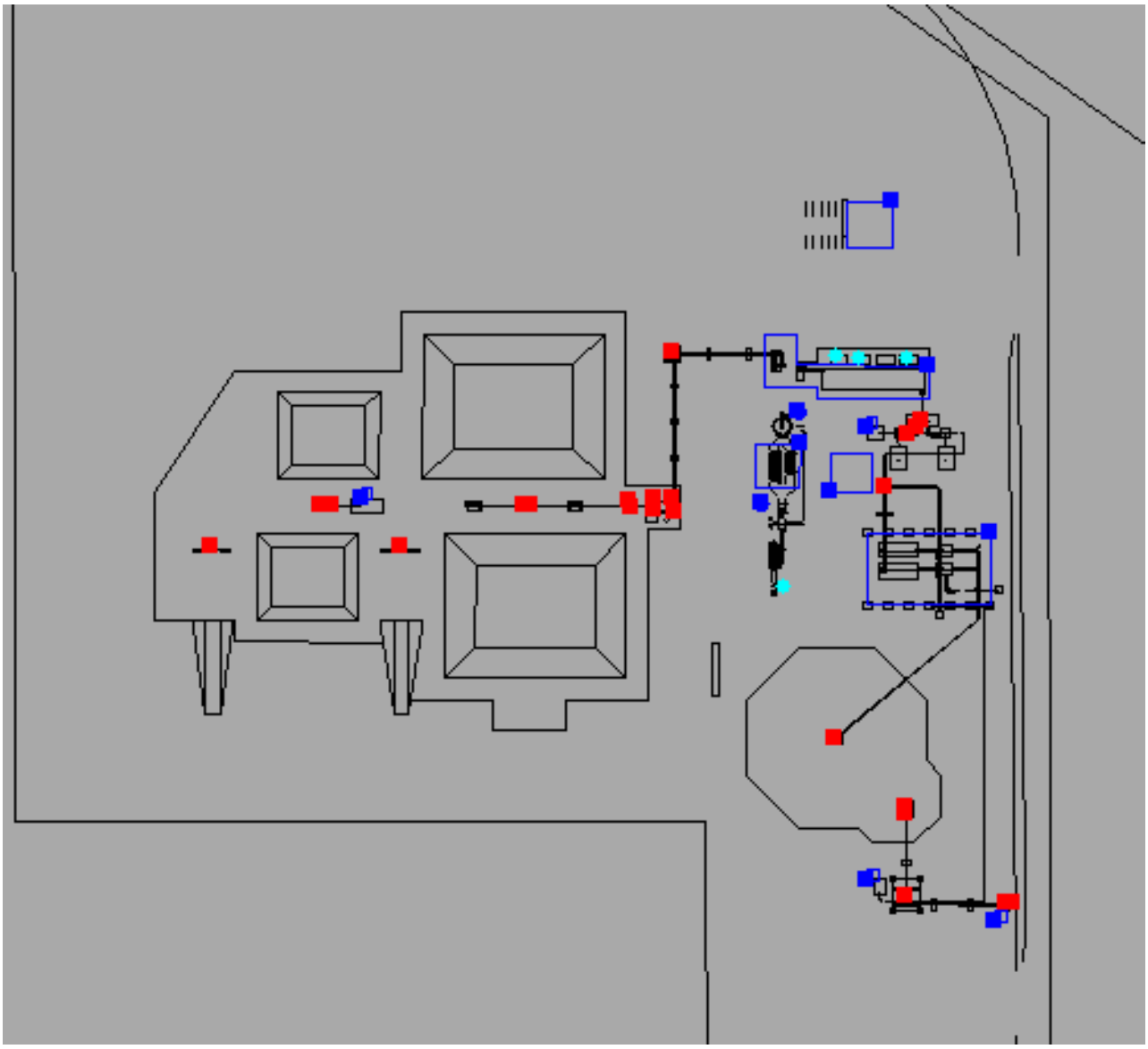


Figure 4-2. Model Layout Detail



5. APPLICABLE STANDARDS

The air quality impact limits applicable to this analysis are both the National Ambient Air Quality Standards and the Idaho ambient impact limits for Toxic Air Pollutants. Model results will be added to the background concentrations and the sum compared to the applicable limits, as shown in Table 5-1 below.

Table 5-1. Sample Model Results and Applicable Standards Table

Pollutant	Averaging Period	Modeled Impact (µg/m³)	Background Concentration (µg/m³)	Total Concentration (µg/m³)	NAAQS/ ACC/AACC (µg/m³)	Modeled Value Used (5 yrs Met Data)
PM_{10}	24-hour		53		150	Maximum 6th highest
$PM_{2.5}$	24-hour		14		35	Mean of maximum 8th highest
	Annual		4.6		12	Mean of maximum 1st highest
NO_2	1-hour		11.8		188	Mean of maximum 8th highest
	Annual		1.88		100	Maximum 1st highest
SO_2	1-hour		3.92		196	Mean of maximum 4th highest
	Annual		0.75		80	Maximum 1st highest
CO	1-hour		1307		40,000	Maximum 2nd highest
	Annual		816		10,000	Maximum 2nd highest
Carbon Tetrachloride	Annual		0		6.70E-02	Maximum 1st highest
Chloroform	Annual		0		4.30E-02	Maximum 1st highest
Methylene Chloride	Annual		0		2.40E-01	Maximum 1st highest
Vinyl Chloride	Annual		0		1.40E-01	Maximum 1st highest
Iron	24-hour		0		50	Maximum 1st highest
Silver	24-hour		0		5	Maximum 1st highest

6. MODEL RESULTS

Model results will be presented using the IDEQ Air Impact Modeling Analyses Report Template Form; the IDEQ Modeling Information Workbook, Forms MI1-MI4, have not been updated to reflect the current NAAQs and therefore will not be used. Model files will be provided to DEQ on CD.

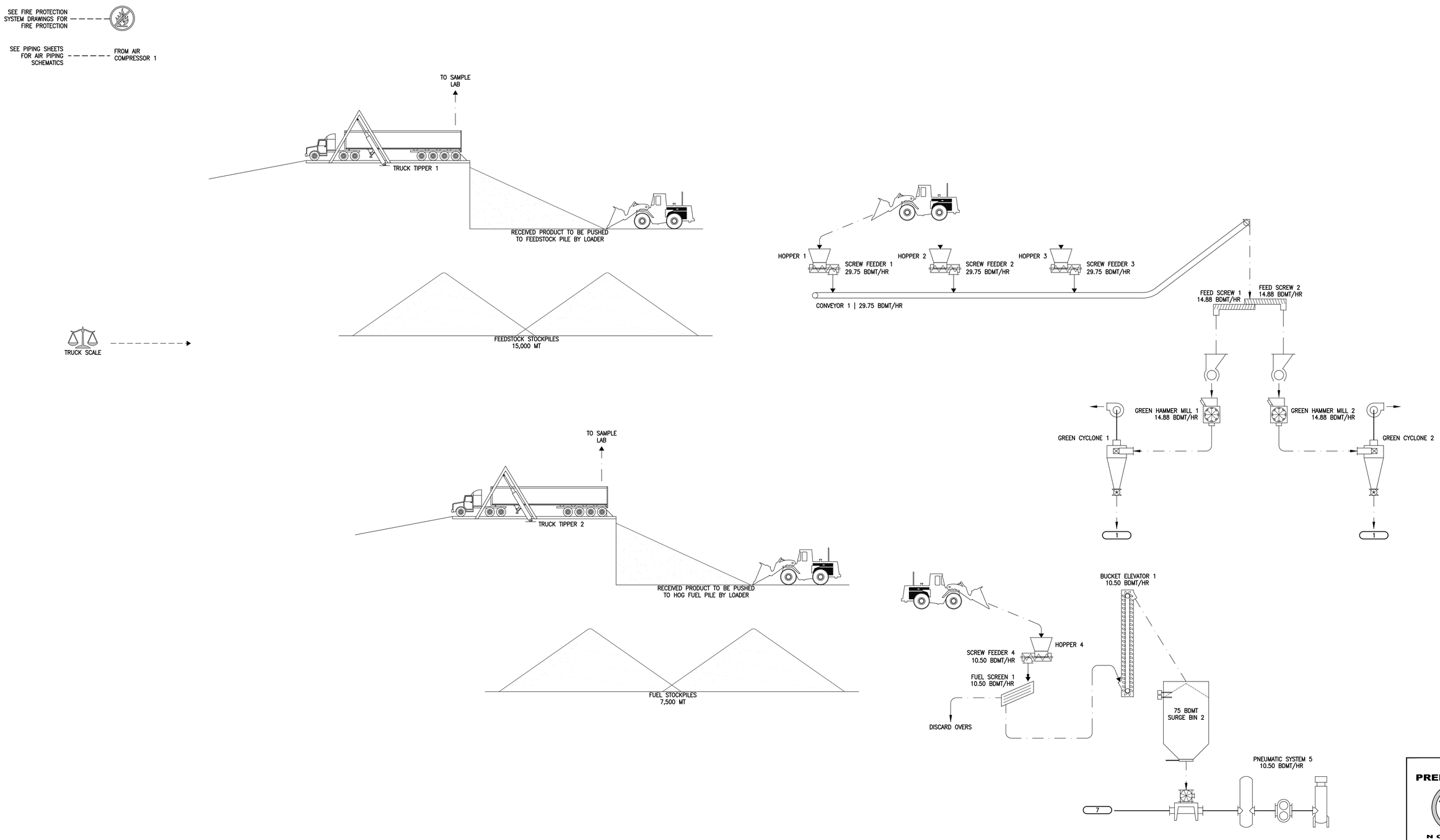
APPENDIX A: PROCESS FLOW DIAGRAMS

PRINTED: Feb 24, 2016

NOTES:

A. (1) TO CONVEYOR 2

B. (7) TO ENERGY SYSTEM



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DOME TECHNOLOGY
4946 North 2900 East, Idaho Falls, ID 83401
tel: (208) 529-0833 fax: (208) 529-0854

ENGINEERING SYSTEM SOLUTIONS
4943 NORTH 29TH EAST, STE A
IDAHO FALLS, IDAHO 83401
Phone: (208) 552-9874
Fax: (208) 552-9302

PROJECT:
CENTENNIAL RENEWABLE ENERGY
FOR
DOME TECHNOLOGY

LOCATION:
FERNWOOD, ID

REV.	REVISION NOTE	DATE YY.MM.DD	DT ✓
A	ISSUED FOR PRICING	15.06.01	--
B	VALUE ENGINEERING	15.07.01	--
C	UPDATED TO POTLATCH SITE	16.02.14	--

REVISION DESCRIPTION | REV. | C

DESIGNED	DRAWN	CHECKED	APPROVED
AA	AA	--	--

SHEET TITLE:
RECEIVING FLOW SCHEMATIC

REF NUMBER: 1507 -000.01-REV C-16.02.24

START DATE: MARCH 30, 2015
PROJECT NUMBER: IND15116
SCALE: NO SCALE
SHEET NUMBER: 000.01

NOTES:

A. (1) FROM GREEN HAMMER MILLS

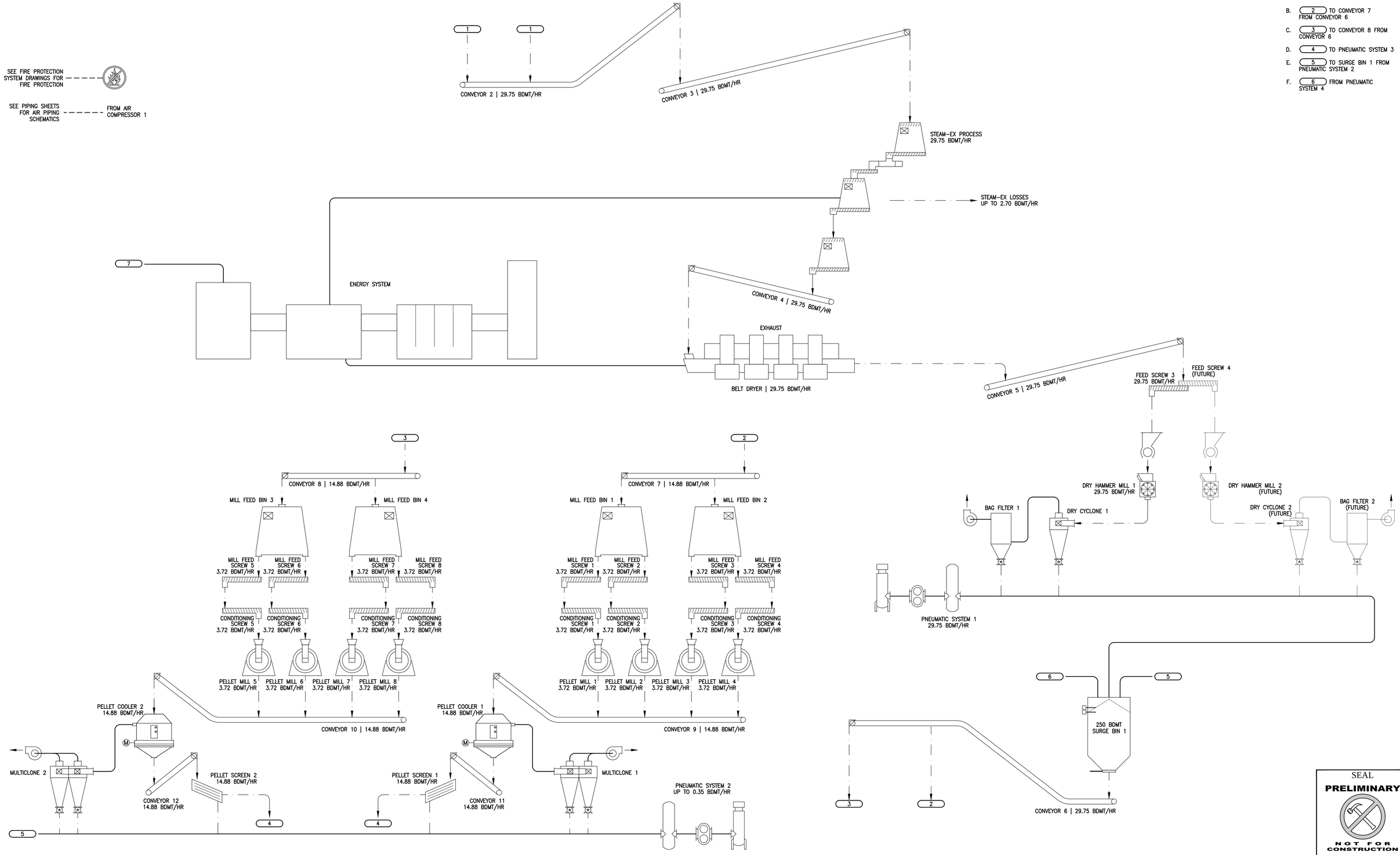
B. (2) TO CONVEYOR 7 FROM CONVEYOR 6

C. (3) TO CONVEYOR 8 FROM CONVEYOR 6

D. (4) TO PNEUMATIC SYSTEM 3

E. (5) TO SURGE BIN 1 FROM PNEUMATIC SYSTEM 2

F. (6) FROM PNEUMATIC SYSTEM 4



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EVERGREEN ENGINEERING
Engineering and Construction Services
EUGENE, OREGON
www.evergreenengineering.com

DOME TECHNOLOGY
4946 North 2900 East, Idaho Falls, ID 83401
tel: (208) 529-0833 fax: (208) 529-0854

ENGINEERING SYSTEM SOLUTIONS
4943 NORTH 29TH EAST, STE A
IDAHO FALLS, IDAHO 83401
Phone: (208) 552-9874
Fax: (208) 552-9302

PROJECT: CENTENNIAL RENEWABLE ENERGY FOR DOME TECHNOLOGY

LOCATION: FERNWOOD, ID

REV.	REVISION NOTE	DATE YY.MM.DD	DT ✓
A	ISSUED FOR PRICING	15.06.01	--
B	VALUE ENGINEERING	15.07.01	--
C	UPDATED TO POTLATCH SITE	16.02.14	--

REVISION DESCRIPTION | REV. | C

DESIGNED	DRAWN	CHECKED	APPROVED
AA/VENDORS	AA	--	--

SHEET TITLE: PROCESSING FLOW SCHEMATIC

REF NUMBER: 1507 -000.02-REV C-16.02.24

START DATE: MARCH 30, 2015
PROJECT NUMBER: IND15116
SCALE: NONE
SHEET NUMBER: 000.02

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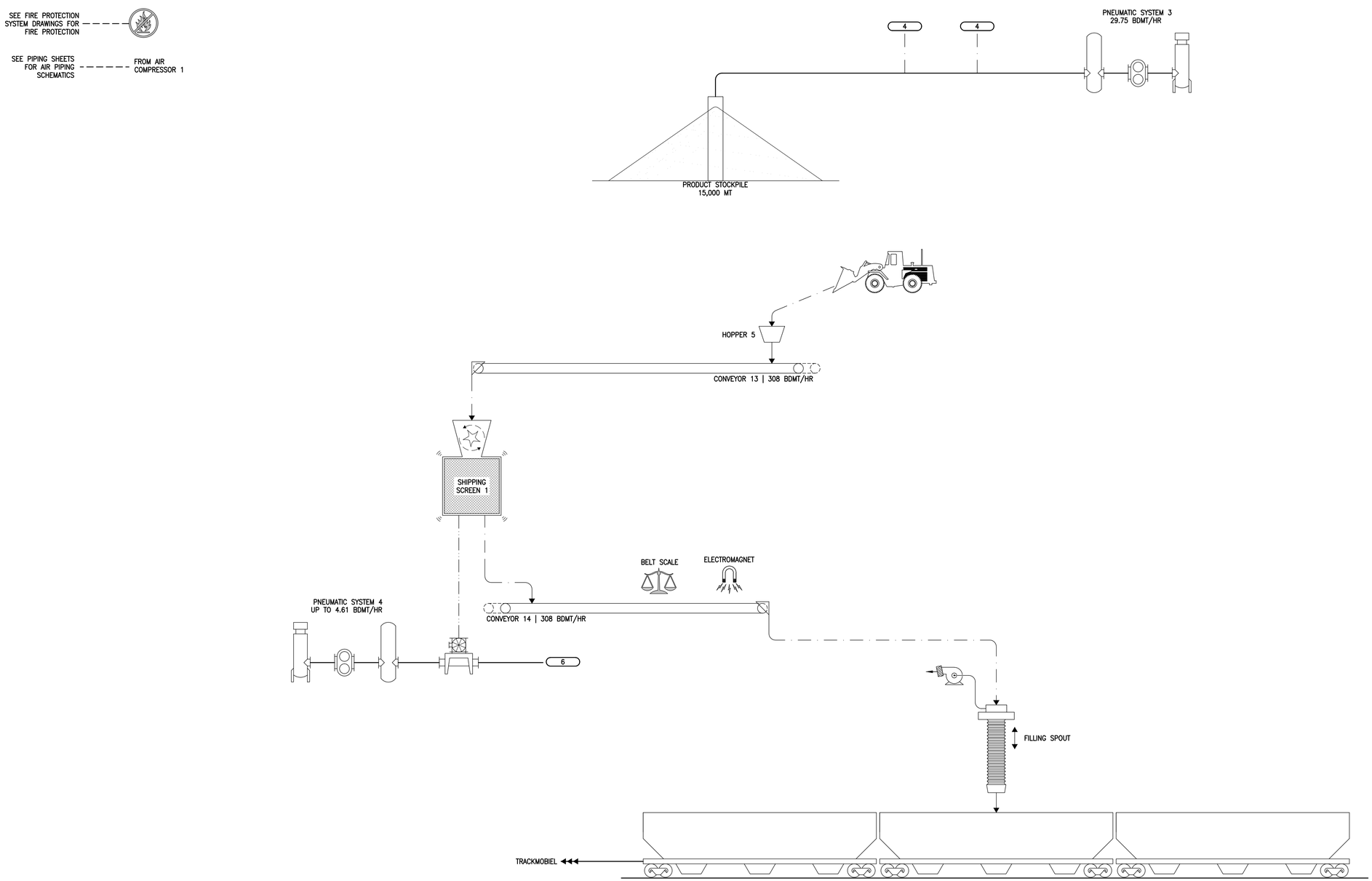
W:\industrial\2015\15116_Centennial FEEL\Study\000_General Arrangement\Potatch Site\000.01 (Potatch)_15116.dwg

PRINTED: Feb 24, 2016

NOTES:

A. (4) FROM PELLET SCREENS

B. (6) TO SURGE BIN 1



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Feb 24, 2016

DOME TECHNOLOGY
4946 North 2900 East, Idaho Falls, ID 83401
tel: (208) 529-0833 fax: (208) 529-0854

ENGINEERING SYSTEM SOLUTIONS
4943 NORTH 29TH EAST, STE A
IDAHO FALLS, IDAHO 83401
Phone: (208) 552-9874
Fax: (208) 552-9302

PROJECT: CENTENNIAL RENEWABLE ENERGY
FOR
DOME TECHNOLOGY

LOCATION: FERNWOOD, ID

REV.	REVISION NOTE	DATE YY.MM.DD	DT ✓
A	ISSUED FOR PRICING	15.06.01	--
B	VALUE ENGINEERING	15.07.01	--
C	UPDATED TO POTLATCH SITE	16.02.14	--

REVISION DESCRIPTION — REV. C

DESIGNED	DRAWN	CHECKED	APPROVED
AA	AA	--	--

SHEET TITLE: SHIPPING FLOW SCHEMATIC

REF NUMBER: 1507 -000.03-REV C-16.02.24

START DATE: MARCH 30, 2015
PROJECT NUMBER: IND15116
SCALE: NO SCALE
SHEET NUMBER: 000.03

APPENDIX B: FLUIDIZED BED COMBUSTOR INFORMATION

PRECISION ENERGY SERVICES INC.

THEORY OF FLUIDIZED BED COMBUSTION

INTRODUCTION

The AFBB (Atmospheric Fluid Bed Burner) utilizes a heated bed of sand suspended (fluidized) within a rising column of air to burn many types and classes of fuel. This technique results in a vast improvement in combustion efficiency of high moisture content fuels, and is adaptable to a variety of "waste" type fuels this type of fuel ranges from wood product waste (hog fuel) to refuse derived fuel. The combustion products from the burner, in the form of a hot gas, can be adapted for use in various plant processes.

A basic understanding of the factors involved in the combustion of various fuels in a fluidized bed incinerator and how they interact with each other is essential for the successful operation of the AFBB system. This section summarizes theories of basic combustion and overall system operation.

COMBUSTION OF A FUEL PARTICLE

Fuels which are burned in a fluidized bed normally contain water, part of it "bound" in the structure of the fuel particle, and the remainder of it "free" or clinging to the outer surface of the particle.

Before any fuel particle can be ignited and burned, all the free water must be evaporated from the surface, and most of the "bound" water must be driven off. While this is happening, the particle stays relatively cool, approximately 200°F. The rate at which the particle dries is largely dependent upon the particle size and the temperature of the gas surrounding it.

After the water has been driven off as steam, the temperature of the particle rises rapidly and the combustible volatile components are boiled out as a gas. These volatiles represent a major portion of the heating value of fuel. They may burn either in the fluidized bed or in the vapor space above the bed, depending upon where they were generated and the availability of air required to complete the combustion reaction.

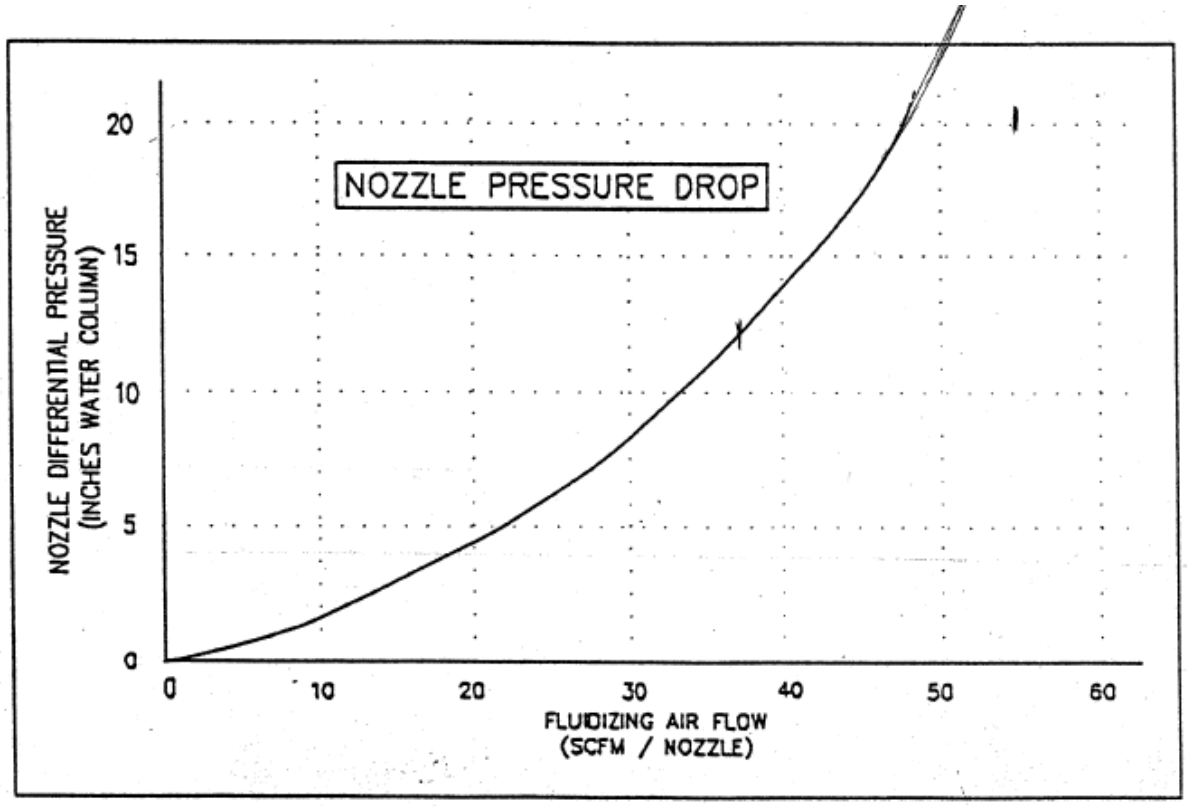
After both the water and volatiles have boiled off the fuel particle, the remaining material is charcoal. The larger particles of charcoal burn more slowly than the volatile material and ordinarily, due to their mass, burn in the fluid bed. The smaller particles may burn either in the bed or in the vapor space, depending upon their mass, and upward velocity of the combustion products in the combustion cell.

THE FLUIDIZATION PROCESS

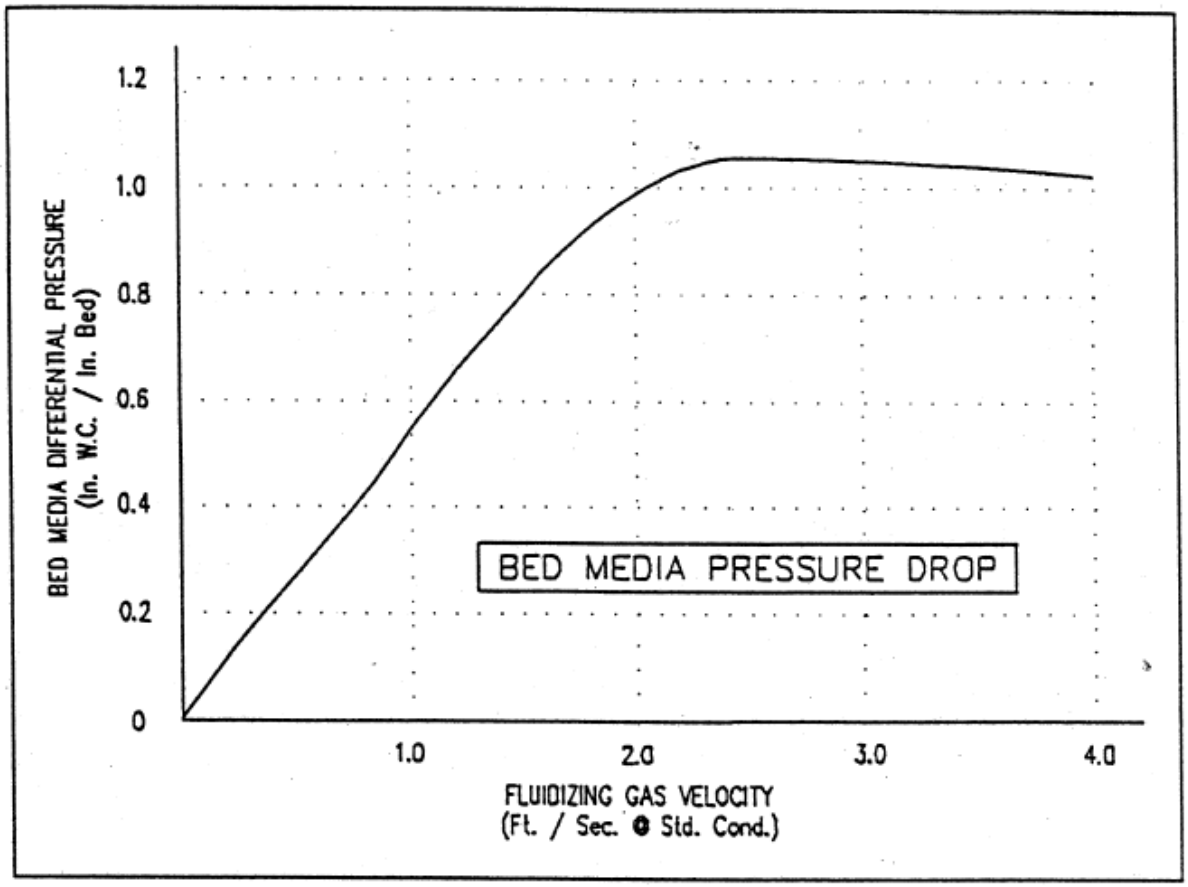
In order for a fluid bed to operate properly, the gas passing upward through the bed material must be at some minimum velocity. The required velocity is dependent upon the size, shape and density of the bed material.

The bed material depth, in expanded, or fluidized, condition, increases to about 1 1/2 times its static depth. As the fuel is distributed over the surface of the expanded bed, the heavier particles sink below the surface, becoming mixed with hot bed material and ignited, thereby giving up energy to maintain the bed temperature. Scrubbing action of the bed material on the fuel particle enhances the combustion process by stripping away the carbon dioxide and char layer which normally forms around the fuel particle. This allows the oxygen to reach the combustible material much more readily, thus increasing the rate and efficiency of the combustion process. The lighter fuel particles may burn on the surface of the bed or may be carried upward by the raising gases in the vessel to be consumed in the vapor space.

Lower gas velocities are required for a bed of small, light particles than would be required for a bed of large, heavy particles. For any given bed material, theoretical minimum gas velocity for fluidization can be determined. Gas velocities which greatly exceed the minimum value required for fluidization do not necessarily improve operation. In fact, excess gas velocities may cause localized spouting, excessive bed material carryover, and a residence time which is too short for proper combustion to take place. All these conditions reduce the effectiveness of the fluidized bed as an aid to combustion.

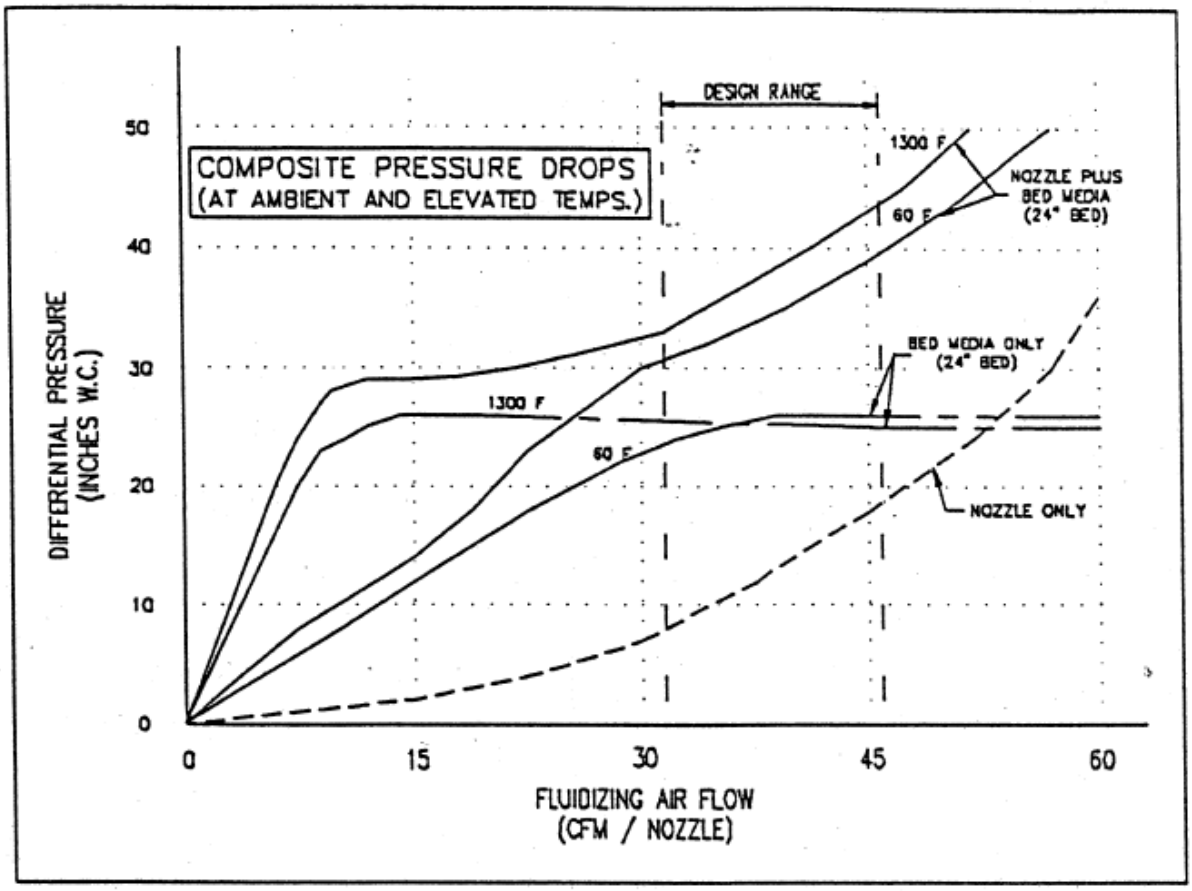


This graph depicts the air flow versus the nozzle differential pressure in a typical fluidized bed system. A nozzle pressure drop of about 8-12" WC is required to ensure an even distribution of air flow across the total bed area, based on a bed depth of 18 to 24 inches above the nozzles.



This graph depicts the typical relationship between fluidizing velocity and air pressure drop across the bed material. The straight section of the curve shows that the pressure drop across the bed material increases almost linearly with air flow, up to about one inch WC per inch of bed depth. In this region, the air velocity is insufficient to overcome the weight of the bed material and the bed material remains in a static (motionless) state. The air is simply percolating up through minute voids which exist between the particles of bed material. At a velocity of about 2.25 feet per second, the pressure drop no longer increases linearly with flow. The particles are now being lifted by the upwardly moving air, resulting in the voids between the particles increasing in size to accommodate the additional air flow. At this point, each particle of the bed material is suspended in the air stream and is free to circulate much like water. This is the condition referred to by the term fluidization.

An important point to note is that the knee of the curve represents a definite air flow in pounds per unit time this minimum air flow value also corresponds to a definite fuel feedrate needed to produce a given amount of energy at a given temperature. This minimum amount of energy represents the maximum turndown obtainable from a fluidized bed. An air flow which is less than the minimum fluidizing velocity will not provide adequate mixing of fuel with bed material. The bed material will then become static, with ambient air percolating up through it which rapidly cools the bed material below combustion sustaining temperatures.



This graph depicts the effects of different conditions on the fluidization process. The NOZZLE ONLY curve shows the pressure drop across the nozzles (in inches WC) versus the fluidizing air flow (in CFM per nozzle). The BED MEDIA ONLY curves show the pressure drop measured across 24 inches of bed material (above the top of the nozzles) at two different air temperatures, 60°F and 1300°F, respectively. The difference in these two curves illustrates the effect of bed temperatures on minimum fluidizing air flow. Fluidization occurs at a much lower air flow at the higher temperature.

The NOZZLE PLUS BED MEDIA curves are generated by summing each point on the NOZZLE ONLY curve with each point on the BED MEDIA curves. Thus, the curves show the relationship of total bed differential pressure (measured from the inlet vessel plenum upstream of the nozzles to the upper combustion cell above the active bed). Note the difference in minimum air flow (the knee of the curves) required to achieve fluidization at the two different temperatures.

It is important to remember that the total volume of air that is being blown by the forced draft (FD) fan is only one of the many factors involved in establishing optimum air velocity required for fluidization of the bed material. During normal operation when the bed material is at hg temperature, heat is transferred to the air as it passes up through the bed material. As

the air is heated, it expands, thus increasing in volume. This increase in volume results in a higher air velocity, as much as three to four times that occurring in a cold bed, particularly in the upper regions of the bed material. It is therefore possible to maintain optimum bed material fluidization with less air from the blower when the bed is hot than when it is cool.

The outside ambient air temperature will affect the density of air pumped by the main blower at a given damper position. Since density of the air is greater at lower temperatures, the proper fluidizing air damper setting for a 90°F summer day will generally provide excessive air flows on a 20°F winter day.

Under normal operating conditions, the actual air flow through the bed may be less than the theoretical air necessary to burn the fuel. Therefore, additional air is supplied to the combustion space above the bed to ensure that complete combustion occurs.

A portion of the additional overfire air required enters with the fuel from the fuel chute at a relatively constant rate. The remainder must be injected through the overfire air system.

RATIO OF AIR TO FUEL

Many types of biomass fuels have nearly the same fuel composition, therefore, require about the same amount of air for complete combustion. The combustion air is normally a mixture of oxygen (21 percent by volume), and nitrogen (79 percent by volume), with trace amounts of other gases.

When fuel burns, the oxygen is consumed, leaving a flue gas comprised of nitrogen, a small amount of oxygen and the combustion products, carbon dioxide and water. If exactly the right amount of air is used, there will be no oxygen left in the flue gas. This amount of air is referred to as **theoretical air**. Any extra air available over the theoretical air required for combustion is called excess air. In actual practice, no combustion processes are carried out using theoretical air, regardless of the fuel being burned (coal, oil, gas, RDF, wood, agri-waste, etc.) Some excess air is always used to ensure that the fuel is burned as completely as possible.

EFFECT OF WATER ON AIR/FUEL RATIO

The water content of the fuel being burned has a large effect on the amount of air needed to burn it. The amount of air required is directly proportional to the ratio of the bone-dry fuel content to the wet weight of fuel. For example, 50 percent water fuel requires only half as much air per pound of fuel as does bone-dry fuel since there is only half as much -dry fuel per pound after it is dried.

Under carefully controlled conditions in a small fluid bed system, it is possible to burn fuels containing more than 65 percent water (wet basis). However, in production units, it becomes increasingly difficult to maintain good combustion conditions as the water content of the fuel increases over 55 percent. The allowable water percentage also depends on the fuel particle

size. Since small particles have less residence time in the bed, combustion of these particles is less successful when the moisture content is high.

As water content of the fuel increases several changes in the combustion process take place:

1. The additional water must be boiled off before the dry combustible material can ignite and burn.
2. Less dry combustible material is available per pound of fuel to provide the heat necessary to boil off the water.
3. The total amount of air required for combustion of the fuel (on a pound per-pound basis) decreases.

The combination of these factors normally results in a decrease in operating bed temperature in relation to fuel moisture content. Vapor temperatures will also decrease during this period, but not as rapidly as the bed temperature.

The amount of air required to burn fuel is strongly dependent upon the water content on a pound-per-pound basis. As the water content increases, more pounds of wet fuel must be burned to produce the energy required by the plant process. The end result, at a constant energy requirement, will be a relatively large increase in the fuel feedrate as the water content increases, with a smaller increase in total air flow requirements, based more on the change in the equivalent bone-dry fuel feedrate.

FLUIDIZED COMBUSTION SYSTEM

Combustion of the material occurs in the fluidized bed and vapor space of the combustor vessel. Air to support combustion is supplied to the burner by the forced draft (FD) fan (through the fluidized bed) and by the overfire air system (through the overfire air nozzles).

The bed change out system removes the bed material, screens it to remove any oversize particles, and re-injects the acceptable bed material back into the combustor bed. The bed material may also be diverted from the discharge of the bucket elevator into a storage bin so that maintenance activities can be performed on the empty combustor bed. A natural gas burner is used during startup to preheat the bed material to - a temperature which will sustain combustion of the fuel.

APPENDIX C: EMISSIONS INVENTORY

Controlled PM Emissions from Boiler Baghouse

Emission Source Description	Exhaust Flow Rate (acfm)	Grain Loading Rate (gr/acfm)	Operating Hours (hr/yr)	PM Potential Emissions[1] (lb/hr)	PM Potential Emissions[1] (tpy)	PM_{10} Potential Emissions[1] (lb/hr)	PM_{10} Potential Emissions[1] (tpy)	$PM_{2.5}$ Potential Emissions[1] (lb/hr)	$PM_{2.5}$ Potential Emissions[1] (tpy)
Boiler Baghouse	135,000	0.0027	8,760	3.12	13.68	3.12	13.68	3.12	13.68

[1] PM_{10} and $PM_{2.5}$ emissions assumed to equal PM emissions.

[2] Emission parameters from "Questions for CRE and PES - ANSWERS (2) CRE Comments" word document, received from CRE and PES on March 3, 2016

[3] The Boiler Baghouse controls emissions from the high pressure boiler, glycol heater, FBC Combustor, FBC Pre-Burner, Multiclone Cyclones, Flash Steam from SteamEx process, Pre-Steaming Bin Exhaust, Pellet Cooler Exhaust

[4] Stack diameter measured in Breeze based on imported CAD drawing. Diameter estimated at 1.34 meters (4.39 ft)

Dryer Potential Emissions

Potential Operation	8,760	hr/yr
Dryer Air Flow Rate	694,382	Nm^3/hr
Dryer Capacity	33	tons/hr

Pollutant	Wood Drying Emission Factor (mg/Nm^3)	Potential Emissions (lb/hr)	(tpy)
CO	-	0.0	0.0
NO_X	-	0.0	0.0
Total PM	5.0	7.7	33.5
Total PM_{10}	4.5	6.9	30.2
Total $PM_{2.5}$	2.5	3.8	16.8
SO_2	-	0.0	0.0
VOC[2]	-	0.0	0.0
Lead	-	0.0	0.0
CH_4	-	0.0	0.0
N_2O	-	0.0	0.0
CO_2		0.0	0.0
CO_2e	-	0.0	0.0
$CO_2e_{biomass\ deferral}$	-	0.0	0.0

[1] Dust emissions have a manufacturer's guarantee of less than 10 mg/Nm^3 (dry). It is assumed that 50% of dust emissions consist of PM_{500}, 90% of PM_{500} emissions consist of PM_{10}, and 50% of PM_{500} emissions consist of $PM_{2.5}$.

[2] The dryer will be operated at a temperature much lower than the upstream SteamEx process. Volatilization is not expected to occur during the drying process.

FBC System Potential HAP and TAP Emissions

Heat Source - Heat Input Capacity	200	MMBtu/hr
Hours of Operation per Year	8,760	hr/yr

Pollutant	HAP?	Non-Carcinogenic TAP?	Carcinogenic TAP?	Biomass Combustion Emission Factor[1] (lb/MMBtu)	Potential HAP Emissions (lb/hr)	Potential HAP Emissions (tpy)	Potential TAP Emissions (lb/hr)	Potential TAP Emissions (tpy)
1,1,1-Trichloroethane	Yes	No	No	3.10E-05	6.20E-03	2.72E-02	-	-
1,2-Dibromoethene	Yes	No	No	5.50E-05	1.10E-02	4.82E-02	-	-
Acenaphthene	Yes	No	No	9.10E-07	1.82E-04	7.97E-04	-	-
Acenaphthylene	Yes	No	No	5.00E-06	1.00E-03	4.38E-03	-	-
Acetaldehyde	Yes	No	Yes	8.30E-04	1.66E-01	7.27E-01	1.66E-01	7.27E-01
Acetone	No	Yes	No	1.90E-04	-	-	3.80E-02	1.66E-01
Acetophenone	Yes	No	No	3.20E-09	6.40E-07	2.80E-06	-	-
Acrolein	Yes	Yes	No	4.00E-03	8.00E-01	3.50E+00	8.00E-01	3.50E+00
Anthracene	Yes	No	No	3.00E-06	6.00E-04	2.63E-03	-	-
Antimony	Yes	Yes	No	7.90E-06	1.58E-03	6.92E-03	1.58E-03	6.92E-03
Arsenic	Yes	No	Yes	2.20E-05	4.40E-03	1.93E-02	4.40E-03	1.93E-02
Benzene	Yes	No	Yes	4.20E-03	8.40E-01	3.68E+00	8.40E-01	3.68E+00
Benzo(a)anthracene	Yes	No	Yes	6.50E-08	1.30E-05	5.69E-05	1.30E-05	5.69E-05
Benzo(a)pyrene	Yes	No	Yes	2.60E-06	5.20E-04	2.28E-03	5.20E-04	2.28E-03
Benzo(b)fluoranthene	Yes	No	Yes	1.00E-07	2.00E-05	8.76E-05	2.00E-05	8.76E-05
Benzo(e)pyrene	Yes	No	No	2.60E-09	5.20E-07	2.28E-06	-	-
Benzo(g,h,i)perylene	Yes	No	No	9.30E-08	1.86E-05	8.15E-05	-	-
Benzo(j,k)fluoranthene	Yes	No	No	1.60E-07	3.20E-05	1.40E-04	-	-
Benzo(k)fluoranthene	Yes	No	Yes	3.60E-08	7.20E-06	3.15E-05	7.20E-06	3.15E-05
Beryllium	Yes	No	Yes	1.10E-06	2.20E-04	9.64E-04	2.20E-04	9.64E-04
Bis(2-ethylhexyl)phthalate	Yes	No	Yes	4.70E-08	9.40E-06	4.12E-05	9.40E-06	4.12E-05
Bromomethane	Yes	No	No	1.50E-05	3.00E-03	1.31E-02	-	-
2-Butanone (MEK)	No	Yes	No	5.40E-06	-	-	1.08E-03	4.73E-03
Cadmium	Yes	No	Yes	4.10E-06	8.20E-04	3.59E-03	8.20E-04	3.59E-03
Carbon tetrachloride	Yes	No	Yes	4.50E-05	9.00E-03	3.94E-02	9.00E-03	3.94E-02
Chlorine	Yes	Yes	No	7.90E-04	1.58E-01	6.92E-01	1.58E-01	6.92E-01
Chlorobenzene	Yes	Yes	No	3.30E-05	6.60E-03	2.89E-02	6.60E-03	2.89E-02
Chloroform	Yes	No	Yes	2.80E-05	5.60E-03	2.45E-02	5.60E-03	2.45E-02
2-Chlorophenol	No	Yes	No	2.40E-08	-	-	4.80E-06	2.10E-05
Chrysene	Yes	No	Yes	3.80E-08	7.60E-06	3.33E-05	7.60E-06	3.33E-05
Crotonaldehyde	No	Yes	No	9.90E-06	-	-	1.98E-03	8.67E-03
Chromium	Yes	Yes	Yes	2.10E-05	4.20E-03	1.84E-02	4.20E-03	1.84E-02
Chromium VI	Yes	No	Yes	3.50E-06	7.00E-04	3.07E-03	7.00E-04	3.07E-03
Cobalt	Yes	Yes	No	6.50E-06	1.30E-03	5.69E-03	1.30E-03	5.69E-03
Dibenzo(a,h)anthracene	Yes	No	Yes	9.10E-09	1.82E-06	7.97E-06	1.82E-06	7.97E-06
Dichlorobiphenyl	Yes	No	No	7.40E-10	1.48E-07	6.48E-07	-	-
1,2-Dichloroethane	Yes	No	Yes	2.90E-05	5.80E-03	2.54E-02	5.80E-03	2.54E-02
1,2-Dichloropropane	Yes	Yes	No	3.30E-05	6.60E-03	2.89E-02	6.60E-03	2.89E-02
2,4-Dinitrophenol	Yes	No	No	1.80E-07	3.60E-05	1.58E-04	-	-
Ethyl benzene	Yes	Yes	No	3.10E-05	6.20E-03	2.72E-02	6.20E-03	2.72E-02
Fluoranthene	Yes	No	No	1.60E-06	3.20E-04	1.40E-03	-	-
Fluorene	Yes	No	No	3.40E-06	6.80E-04	2.98E-03	-	-
Formaldehyde	Yes	No	No	4.40E-03	8.80E-01	3.85E+00	-	-
Heptachlorodibenzo-p-dioxins	Yes	No	Yes	2.00E-09	4.00E-07	1.75E-06	4.00E-07	1.75E-06
Heptachlorodibenzo-p-furans	Yes	No	Yes	2.40E-10	4.80E-08	2.10E-07	4.80E-08	2.10E-07
Hexachlorodibenzo-p-dioxins	Yes	No	Yes	1.60E-06	3.20E-04	1.40E-03	3.20E-04	1.40E-03
Hexachlorodibenzo-p-furans	Yes	No	Yes	2.80E-10	5.60E-08	2.45E-07	5.60E-08	2.45E-07
Hydrogen Chloride	Yes	Yes	No	1.90E-02	3.80E+00	1.66E+01	3.80E+00	1.66E+01
Indeno(1,2,3-cd)pyrene	Yes	No	Yes	8.70E-08	1.74E-05	7.62E-05	1.74E-05	7.62E-05
Iron	No	Yes	No	9.90E-04	-	-	1.98E-01	8.67E-01
Manganese	Yes	Yes	No	1.60E-03	3.20E-01	1.40E+00	3.20E-01	1.40E+00
Mercury	Yes	No	No	3.50E-06	7.00E-04	3.07E-03	-	-
Methanol	Yes	Yes	No	-	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Methyl chloride (chloromethane)	Yes	No	No	2.30E-05	4.60E-03	2.01E-02	-	-
Methylene chloride (dichloromethane)	Yes	No	Yes	2.90E-04	5.80E-02	2.54E-01	5.80E-02	2.54E-01
2-Methylnaphthalene	No	No	No	1.60E-07	-	-	-	-
Molybdenum	No	Yes	No	2.10E-06	-	-	4.20E-04	1.84E-03
Naphthalene	Yes	Yes	No	9.70E-05	1.94E-02	8.50E-02	1.94E-02	8.50E-02
Nickel	Yes	No	Yes	3.30E-05	6.60E-03	2.89E-02	6.60E-03	2.89E-02
4-Nitrophenol	Yes	No	No	1.10E-07	2.20E-05	9.64E-05	-	-
Octachlorodibenzo-p-dioxins	Yes	No	Yes	6.60E-08	1.32E-05	5.78E-05	1.32E-05	5.78E-05
Octachlorodibenzo-p-furans	Yes	No	Yes	8.80E-11	1.76E-08	7.71E-08	1.76E-08	7.71E-08
Pentachlorodibenzo-p-dioxins	Yes	No	Yes	1.50E-09	3.00E-07	1.31E-06	3.00E-07	1.31E-06

FBC System Potential HAP and TAP Emissions

Heat Source - Heat Input Capacity	200	MMBtu/hr
Hours of Operation per Year	8,760	hr/yr

Pollutant	HAP?	Non-Carcinogenic TAP?	Carcinogenic TAP?	Biomass Combustion Emission Factor[1] (lb/MMBtu)	Potential HAP Emissions (lb/hr)	Potential HAP Emissions (tpy)	Potential TAP Emissions (lb/hr)	Potential TAP Emissions (tpy)
Pentachlorodibenzo-p-furans	Yes	No	Yes	4.20E-10	8.40E-08	3.68E-07	8.40E-08	3.68E-07
Pentachlorobiphenyl	Yes	No	Yes	1.20E-09	2.40E-07	1.05E-06	2.40E-07	1.05E-06
Pentachlorophenol	Yes	Yes	No	5.10E-08	1.02E-05	4.47E-05	1.02E-05	4.47E-05
Perylene	Yes	No	No	5.20E-10	1.04E-07	4.56E-07	-	-
Phenanthrene	Yes	No	No	7.00E-06	1.40E-03	6.13E-03	-	-
Phenol	Yes	Yes	No	5.10E-05	1.02E-02	4.47E-02	1.02E-02	4.47E-02
Phosphorus	Yes	Yes	No	2.70E-05	5.40E-03	2.37E-02	5.40E-03	2.37E-02
Propanal	No	No	No	3.20E-06	-	-	-	-
Propionaldehyde	Yes	Yes	No	6.10E-05	1.22E-02	5.34E-02	1.22E-02	5.34E-02
Pyrene	Yes	No	No	3.70E-06	7.40E-04	3.24E-03	-	-
Selenium	Yes	Yes	No	2.80E-06	5.60E-04	2.45E-03	5.60E-04	2.45E-03
Silver	No	Yes	No	1.70E-03	-		3.40E-01	1.49E+00
Styrene	Yes	Yes	No	1.90E-03	3.80E-01	1.66E+00	3.80E-01	1.66E+00
2,3,7,8-Tetrachlorodibenzo-p-dioxins	Yes	No	Yes	8.60E-12	1.72E-09	7.53E-09	1.72E-09	7.53E-09
Tetrachlorodibenzo-p-dioxins	Yes	No	Yes	4.70E-10	9.40E-08	4.12E-07	9.40E-08	4.12E-07
2,3,7,8-Tetrachlorodibenzo-p-furans	Yes	No	Yes	9.00E-11	1.80E-08	7.88E-08	1.80E-08	7.88E-08
Tetrachlorodibenzo-p-furans	Yes	No	Yes	7.50E-10	1.50E-07	6.57E-07	1.50E-07	6.57E-07
Tetrachlorobiphenyl	Yes	No	Yes	2.50E-09	5.00E-07	2.19E-06	5.00E-07	2.19E-06
Tin	No	Yes	No	2.30E-05	-	-	4.60E-03	2.01E-02
Toluene	Yes	Yes	No	9.20E-04	1.84E-01	8.06E-01	1.84E-01	8.06E-01
Trichlorobiphenyl	Yes	No	Yes	2.60E-09	5.20E-07	2.28E-06	5.20E-07	2.28E-06
Trichloroethylene (trichloroethene)	Yes	No	Yes	3.00E-05	6.00E-03	2.63E-02	6.00E-03	2.63E-02
2,4,6-Trichlorophenol	Yes	No	Yes	2.20E-08	4.40E-06	1.93E-05	4.40E-06	1.93E-05
Vanadium	No	Yes	No	9.80E-07	-	-	1.96E-04	8.58E-04
Vinyl chloride	Yes	No	Yes	1.80E-05	3.60E-03	1.58E-02	3.60E-03	1.58E-02
o-Xylene	Yes	Yes	No	2.50E-05	5.00E-03	2.19E-02	5.00E-03	2.19E-02
Yttrium	No	Yes	No	3.00E-07	-	-	6.00E-05	2.63E-04
Zinc	No	Yes	No	4.20E-04	-	-	8.40E-02	3.68E-01
7-PAH	Yes	No	Yes	-	5.87E-04	2.57E-03	5.87E-04	2.57E-03
Dioxins/Furans	Yes	No	Yes	-	3.25E-05	1.42E-04	3.25E-05	1.42E-04
Maximum Individual HAP					**3.80**	**16.64**	**3.80**	**16.64**
Total HAP					**7.74**	**33.90**	**7.50**	**32.84**

[1] Emission factors from AP-42 Section 1.6, Tables 1.6-3 and 1.6-4 (9/03).

FBC System Pre-Burner Potential HAP and TAP Emissions

Furnace Fuel Usage	0.01	MMscf/hr
Hours of Operation per Year	8,760.00	hr/yr

Pollutant	HAP?	Non-Carcinogenic TAP?	Carcinogenic TAP?	Natural Gas Combustion Emission Factor[1] (lb/MMscf)	Potential HAP Emissions (lb/hr)	Potential HAP Emissions (tpy)	Potential TAP Emissions (lb/hr)	Potential TAP Emissions (tpy)
Benzene	Yes	No	Yes	2.10E-03	1.65E-05	7.21E-05	1.65E-05	7.21E-05
Formaldehyde	Yes	No	No	7.50E-02	5.88E-04	2.58E-03	-	-
Toluene	Yes	Yes	No	3.40E-03	2.67E-05	1.17E-04	2.67E-05	1.17E-04
2-Methylnaphthalene	Yes	No	No	2.40E-05	1.88E-07	8.24E-07	-	-
3-Methylchloranthrene	Yes	No	No	1.80E-06	1.41E-08	6.18E-08	-	-
7,12-Dimethylbenz(a)anthracene	Yes	No	No	1.60E-05	1.25E-07	5.50E-07	-	-
Acenaphthylene	Yes	No	No	1.80E-06	1.41E-08	6.18E-08	-	-
Benzo(a)pyrene	Yes	No	Yes	1.20E-06	9.41E-09	4.12E-08	9.41E-09	4.12E-08
Benzo(b)fluoranthene	Yes	No	Yes	1.80E-06	1.41E-08	6.18E-08	1.41E-08	6.18E-08
Benzo(k)fluoranthene	Yes	No	Yes	1.80E-06	1.41E-08	6.18E-08	1.41E-08	6.18E-08
Dibenzo(a,h)anthracene	Yes	No	Yes	1.20E-06	9.41E-09	4.12E-08	9.41E-09	4.12E-08
Dichlorobenzene	Yes	Yes	No	1.20E-03	9.41E-06	4.12E-05	9.41E-06	4.12E-05
Hexane	Yes	Yes	No	1.80E+00	1.41E-02	6.18E-02	1.41E-02	6.18E-02
Naphthalene	Yes	Yes	No	6.10E-04	4.78E-06	2.10E-05	4.78E-06	2.10E-05
Acenaphthene	Yes	No	No	1.80E-06	1.41E-08	6.18E-08	-	-
Anthracene	Yes	No	No	2.40E-06	1.88E-08	8.24E-08	-	-
Benzo(a)anthracene	Yes	No	Yes	1.80E-06	1.41E-08	6.18E-08	1.41E-08	6.18E-08
Benzo(g,h,i)perylene	Yes	No	No	1.20E-06	9.41E-09	4.12E-08	-	-
Chrysene	Yes	No	Yes	1.80E-06	1.41E-08	6.18E-08	1.41E-08	6.18E-08
Fluoranthene	Yes	No	No	3.00E-06	2.35E-08	1.03E-07	-	-
Fluorene	Yes	No	No	2.80E-06	2.20E-08	9.62E-08	-	-
Indeno(1,2,3-cd)pyrene	Yes	No	Yes	1.80E-06	1.41E-08	6.18E-08	1.41E-08	6.18E-08
Phenanthrene	Yes	No	No	1.70E-05	1.33E-07	5.84E-07	-	-
Pentane	No	Yes	No	2.60E+00	-	-	2.04E-02	8.93E-02
Pyrene	Yes	No	No	5.00E-06	3.92E-08	1.72E-07	-	-
Arsenic	Yes	No	Yes	2.00E-04	1.57E-06	6.87E-06	1.57E-06	6.87E-06
Barium	No	Yes	No	4.40E-03	-	-	3.45E-05	1.51E-04
Beryllium	Yes	No	Yes	1.20E-05	9.41E-08	4.12E-07	9.41E-08	4.12E-07
Cadmium	Yes	No	Yes	1.10E-03	8.63E-06	3.78E-05	8.63E-06	3.78E-05
Chromium	Yes	Yes	Yes	1.40E-03	1.10E-05	4.81E-05	1.10E-05	4.81E-05
Cobalt	Yes	Yes	No	8.40E-05	6.59E-07	2.89E-06	6.59E-07	2.89E-06
Copper	No	Yes	No	8.50E-04	-	-	6.67E-06	2.92E-05
Lead	Yes	No	No	5.00E-04	3.92E-06	1.72E-05	-	-
Manganese	Yes	Yes	No	3.80E-04	2.98E-06	1.31E-05	2.98E-06	1.31E-05
Mercury	Yes	No	No	2.60E-04	2.04E-06	8.93E-06	-	-
Molybdenum	No	Yes	No	1.10E-03	-	-	8.63E-06	3.78E-05
Nickel	Yes	No	Yes	2.10E-03	1.65E-05	7.21E-05	1.65E-05	7.21E-05
Selenium	Yes	Yes	No	2.40E-05	1.88E-07	8.24E-07	1.88E-07	8.24E-07
Vanadium	No	Yes	No	2.30E-03	-	-	1.80E-05	7.90E-05
Maximum Individual HAP					**0.01**	**0.06**	**0.02**	**0.09**
Total HAP					**0.01**	**0.06**	**0.03**	**0.15**

1 AP-42 Section 1.4 Natural Gas Combustion, Tables 1.4-3 and 1.4-4 (7/98). HAPs emissions factors not available for LPG in AP-42, Section 1.5.

Emissions from FBC System

Heat Input Capacity		200 MMBtu/hr	
Hours of Operation per Year		8,760 hr/yr	
Pollutant[1]	**Wood Combustion Emission Factor**[2] (lb/MMBtu)	**Potential Emissions** (lb/hr)	(tpy)
CO	0.17	34.0	148.9
NO_X	0.22	44.0	192.7
SO_2	0.03	5.0	21.9
VOC	0.02	3.4	14.9
Lead	0.00	0.01	4.20E-02
CH_4	0.02	4.2	18.4
N_2O	0.01	2.6	11.4
CO_2	195.00	39000.0	170,820
CO_2e[3]	-	39,880	174,674
$CO_2e_{biomass\ deferral}$[4]	-	879.8	3,854

[1] PM emissions are accounted for in Table 10: Controlled PM Emissions from Boiler Baghouse.

[2] AP-42 Section 1.6 Wood Residue Combustion in Boilers, Tables 1.6-1, 1.6-2, and 1.6-3. Uncontrolled with wet wood fuel.

[3] Global warming potential (GWP) for CH_4 is 25, for N_2O is 298, and for CO_2 is 1 for estimating CO_2e emissions, based on 40 CFR 98, Subpart A, Table A-1 effective January 1, 2014.

[4] CO_2e based on the biomass deferral excludes biogenic CO_2 emissions (e.g., from biomass) per the Biomass Deferral published in Federal Register Vol. 76, No. 139, on July 20, 2011.

Emissions from FBC System Pre-Burner

Furnace Fuel Usage		8.00 MMBtu/hr		
Hours of Operation per Year		8,760 hr/yr		
Pollutant[1]	**Propane Combustion Emission Factor**[2] (lb/10^3 gal)	**Control Efficiency**[3]	**Potential Emissions** (lb/hr)	(tpy)
CO	7.5	0	0.7	2.9
NO_X	13	0	1.1	5.0
SO_2	1.5	0	0.1	0.6
VOC	1.0	99.9%	8.74E-05	3.83E-04
Lead	-	0	0.00E+00	0.00E+00
CH_4	0.2	0	0.0	0.1
N_2O	0.9	0	0.1	0.3
CO_2	12,500	0	1092.9	4,787
CO_2e[4]	-	-	1,117	4,892
$CO_2e_{biomass\ deferral}$[5]	-	-	23.9	105

[1] PM emissions are accounted for in Table 10: Controlled PM Emissions from Boiler Baghouse.

[2] AP-42 Section 1.5 Liquified Petroleum Gas Combustion, Table 1.5-1 (7/08). Heat content of 91.5 x 10^6 Btu/10^3 gallon for propane, sulfur content of commercial propane = 15gr/100 scf.

[3] Pre-burner VOC emissions are controlled by the FBC system.

[4] Global warming potential (GWP) for CH_4 is 25, for N_2O is 298, and for CO_2 is 1 for estimating CO_2e emissions, based on 40 CFR 98, Subpart A, Table A-1 effective January 1, 2014.

[5] CO_2e based on the biomass deferral excludes biogenic CO_2 emissions (e.g., from biomass) per the Biomass Deferral published in Federal Register Vol. 76, No. 139, on July 20, 2011.

Emission Unit No.	System Description	Requested Process Rate (ton/hr)	Requested Process Rate (ton/yr)	Requested Daily Operating Hours (hrs/day)	Requested Annual Operating Hours (hrs/yr)	PM Emission Factor	PM_{10} Emission Factor	$PM_{2.5}$ Emission Factor[1]	Emission Factor Units	Control Tech.	Control Efficiency (%)	PM Emission Rate (lb/hr)	PM Emission Rate (ton/yr)	PM_{10} Emission Rate (lb/hr)	PM_{10} Emission Rate (ton/yr)	$PM_{2.5}$ Emission Rate (lb/hr)	$PM_{2.5}$ Emission Rate (ton/yr)	Emission Factor Source
	HOG FUEL PROCESS																	
HF1	Truck Unloading to Hog Fuel Tipper	36	100,000	24	8,760	0.00300	0.00110	0.00016	lb/ton	Material moisture content	50%	0.055	0.075	0.020	0.028	0.003	0.004	AP-42, Crushed Stone 11.19.2-2, Conveyor Transfer Point
HF2	Hog Fuel Pile to Hopper #4/Screw Feeder #4 via Front Loader	12	100,000	24	8,760	0.00300	0.00110	0.00016	lb/ton	Material moisture content	50%	0.017	0.075	0.006	0.028	0.001	0.004	AP-42, Crushed Stone 11.19.2-2, Conveyor Transfer Point
HF3	Fuel Screen #1 and transfers (in from Hopper #4, out to Bucket Elevator #1)	12	100,000	24	8,760	0.02500	0.00870	0.00133	lb/ton	Material moisture content	50%	0.145	0.625	0.050	0.218	0.008	0.033	AP-42, Crushed Stone 11.19.2-2, Screening
HF4	Bucket Elevator #1 to Surge Bin #2	12	100,000	24	8,760	0.00300	0.00110	0.00016	lb/ton	Material moisture content	50%	0.017	0.075	0.006	0.028	0.001	0.004	AP-42, Crushed Stone 11.19.2-2, Conveyor Transfer Point
HF5	Surge Bin #2 to Pnuematic System #5	12	100,000	24	8,760	0.00300	0.00110	0.00016	lb/ton	Pnuematic Enclosure	100%	0.000	0.000	0.000	0.000	0.000	0.000	AP-42, Crushed Stone 11.19.2-2, Conveyor Transfer Point
HF6	Pneumatic System #5 to Combustor	12	100,000	24	8,760	0.00300	0.00110	0.00016	lb/ton	Pnuematic Enclosure	100%	0.000	0.000	0.000	0.000	0.000	0.000	AP-42, Crushed Stone 11.19.2-2, Conveyor Transfer Point
								0.00000										
	FEEDSTOCK PROCESS							0.00000										
FS1	Truck Unloading to Feedstock Tipper #1	94	220,500	24	8,760	0.00300	0.00110	0.00016	lb/ton	Material Moisture Content	34%	0.186	0.218	0.068	0.080	0.010	0.012	AP-42, Crushed Stone 11.19.2-2, Conveyor Transfer Point
FS2	Feedstock Pile to Hopper #1, 2 or 3 via Front Loader	33	220,500	24	8,760	0.00300	0.00110	0.00016	lb/ton	Material Moisture Content	34%	0.065	0.218	0.024	0.080	0.003	0.012	AP-42, Crushed Stone 11.19.2-2, Conveyor Transfer Point
FS3	Hopper #1, 2 or 3 to Conveyor #1	33	220,500	24	8,760	0.00300	0.00110	0.00016	lb/ton	Material Moisture Content	34%	0.065	0.218	0.024	0.080	0.003	0.012	AP-42, Crushed Stone 11.19.2-2, Conveyor Transfer Point
FS4	Conveyor #1 to Feed Screw #1	16	220,500	24	8,760	0.00300	0.00110	0.00016	lb/ton	Material Moisture Content	34%	0.032	0.218	0.012	0.080	0.002	0.012	AP-42, Crushed Stone 11.19.2-2, Conveyor Transfer Point
FS5	Conveyor #1 to Feed Screw #2	16	220,500	24	8,760	0.00300	0.00110	0.00016	lb/ton	Material Moisture Content	34%	0.032	0.218	0.012	0.080	0.002	0.012	AP-42, Crushed Stone 11.19.2-2, Conveyor Transfer Point
FS6	Green Hammer Mill #1 and transfers (in from Feed Screw #1, out to Green Cyclone #1)	16	220,500	24	8,760	0.00540	0.00240	0.00029	lb/ton	Material Moisture Content	34%	0.058	0.393	0.026	0.175	0.003	0.021	AP-42, Crushed Stone 11.19.2-2, Tertiary Crushing
FS7	Green Hammer Mill #2 and transfers (in from Feed Screw #2, out to Green Cyclone #2)	16	220,500	24	8,760	0.00540	0.00240	0.00029	lb/ton	Material Moisture Content	34%	0.058	0.393	0.026	0.175	0.003	0.021	AP-42, Crushed Stone 11.19.2-2, Tertiary Crushing
FS8	Green Cyclone #1 to Conveyor #2	16	220,500	24	8,760	0.00300	0.00110	0.00016	lb/ton	Material Moisture Content	34%	0.032	0.218	0.012	0.080	0.002	0.012	AP-42, Crushed Stone 11.19.2-2, Conveyor Transfer Point
FS9	Green Cyclone #2 to Conveyor #2	16	220,500	24	8,760	0.00300	0.00110	0.00016	lb/ton	Material Moisture Content	34%	0.032	0.218	0.012	0.080	0.002	0.012	AP-42, Crushed Stone 11.19.2-2, Conveyor Transfer Point
FS10	Conveyor #2 to Conveyor #3 (Inside Tower 1)	33	220,500	24	8,760	0.00300	0.00110	0.00016	lb/ton	Enclosure	50%	0.049	0.165	0.018	0.061	0.003	0.009	AP-42, Crushed Stone 11.19.2-2, Conveyor Transfer Point
FS11	Conveyor #3 to Steam Ex Preheat Bin	33	220,500	24	8,760	0.00300	0.00110	0.00016	lb/ton	Inside Building	100%	0.000	0.000	0.000	0.000	0.000	0.000	AP-42, Crushed Stone 11.19.2-2, Conveyor Transfer Point
FS12	SteamEx Preheat Bin to Conveyor #4	33	220,500	24	8,760	0.00300	0.00110	0.00016	lb/ton	Inside Building	100%	0.000	0.000	0.000	0.000	0.000	0.000	AP-42, Crushed Stone 11.19.2-2, Conveyor Transfer Point
FS13	Conveyor #4 to Belt Dryer	33	220,500	24	8,760	0.00300	0.00110	0.00016	lb/ton	Inside Building	100%	0.000	0.000	0.000	0.000	0.000	0.000	AP-42, Crushed Stone 11.19.2-2, Conveyor Transfer Point
FS14	Belt Dryer to Conveyor #5	33	220,500	24	8,760	0.00300	0.00110	0.00016	lb/ton	Inside Building	100%	0.000	0.000	0.000	0.000	0.000	0.000	AP-42, Crushed Stone 11.19.2-2, Conveyor Transfer Point
FS15	Conveyor #5 to Feed Screw #3	33	220,500	24	8,760	0.00300	0.00110	0.00016	lb/ton	None - BOP	0%	0.098	0.331	0.036	0.121	0.005	0.018	AP-42, Crushed Stone 11.19.2-2, Conveyor Transfer Point
FS16	Feed Screw #3 to Dry Hammer Mill	33	220,500	24	8,760	0.00300	0.00110	0.00016	lb/ton	None - BOP	0%	0.098	0.331	0.036	0.121	0.005	0.018	AP-42, Crushed Stone 11.19.2-2, Conveyor Transfer Point
FS17	Dry Hammer Mill to Dry Cyclone #1	33	220,500	24	8,760	0.00300	0.00110	0.00016	lb/ton	Bag Filter	99%	0.001	0.003	0.000	0.001	0.000	0.000	AP-42, Crushed Stone 11.19.2-2, Conveyor Transfer Point
FS18	Dry Cyclone #1 to Pneumatic System #1	33	220,500	24	8,760	0.00300	0.00110	0.00016	lb/ton	Pnuematic Enclosure	100%	0.000	0.000	0.000	0.000	0.000	0.000	AP-42, Crushed Stone 11.19.2-2, Conveyor Transfer Point
FS19	Pnuematic System #1 to Surge Bin #1	33	220,500	24	8,760	0.00300	0.00110	0.00016	lb/ton	Pnuematic Enclosure	100%	0.000	0.000	0.000	0.000	0.000	0.000	AP-42, Crushed Stone 11.19.2-2, Conveyor Transfer Point
FS20	Surge Bin #1 to Conveyor #6	33	220,500	24	8,760	0.00300	0.00110	0.00016	lb/ton	None - BOP	0%	0.098	0.331	0.036	0.121	0.005	0.018	AP-42, Crushed Stone 11.19.2-2, Conveyor Transfer Point
FS21	Conveyor #6 to Conveyor #7	16	220,500	24	8,760	0.00300	0.00110	0.00016	lb/ton	Inside Building	100%	0.000	0.000	0.000	0.000	0.000	0.000	AP-42, Crushed Stone 11.19.2-2, Conveyor Transfer Point
FS22	Conveyor #7 to Mill Feed Bin #1 and #2	16	220,500	24	8,760	0.00300	0.00110	0.00016	lb/ton	Inside Building	100%	0.000	0.000	0.000	0.000	0.000	0.000	AP-42, Crushed Stone 11.19.2-2, Conveyor Transfer Point
FS23	Mill Feed Bin #1 and #2 to Mill Feed Screws #1, 2, 3 and 4	16	220,500	24	8,760	0.00300	0.00110	0.00016	lb/ton	Inside Building	100%	0.000	0.000	0.000	0.000	0.000	0.000	AP-42, Crushed Stone 11.19.2-2, Conveyor Transfer Point
FS24	Mill Feed Screws #1, 2, 3, and 4 to Conditioning Screws #1, 2, 3 and 4	16	220,500	24	8,760	0.00300	0.00110	0.00016	lb/ton	Inside Building	100%	0.000	0.000	0.000	0.000	0.000	0.000	AP-42, Crushed Stone 11.19.2-2, Conveyor Transfer Point
FS25	Pellet Mills #1, 2, 3 and 4 and transfers (in from Conditioning Screws #1-4 and out to Conveyor #9)	16	220,500	24	8,760	0.00540	0.00240	0.00029	lb/ton	Inside Building	100%	0.000	0.000	0.000	0.000	0.000	0.000	AP-42, Crushed Stone 11.19.2-2, Tertiary Crushing
FS26	Conveyor #9 to Pellet Cooler #1	16	220,500	24	8,760	0.00300	0.00110	0.00016	lb/ton	Inside Building	100%	0.000	0.000	0.000	0.000	0.000	0.000	AP-42, Crushed Stone 11.19.2-2, Conveyor Transfer Point
FS27	Pellet Cooler #1 to Conveyor #11	16	220,500	24	8,760	0.00300	0.00110	0.00016	lb/ton	Inside Building	100%	0.000	0.000	0.000	0.000	0.000	0.000	AP-42, Crushed Stone 11.19.2-2, Conveyor Transfer Point
FS28	Pellet Cooler #1 to Multiclone #1	0.39	220,500	24	8,760	0.00300	0.00110	0.00016	lb/ton	Inside Building	100%	0.000	0.000	0.000	0.000	0.000	0.000	AP-42, Crushed Stone 11.19.2-2, Conveyor Transfer Point
FS29	Pellet Screen #1 and transfers (in from Conveyor #11, out to Pneumatic System #3)	16	220,500	24	8,760	0.02500	0.00870	0.00133	lb/ton	Inside Building	100%	0.000	0.000	0.000	0.000	0.000	0.000	AP-42, Crushed Stone 11.19.2-2, Screening
FS30	Multiclone #1 to Pneumatic System #2	0.39	220,500	24	8,760	0.00300	0.00110	0.00016	lb/ton	Inside Building	100%	0.000	0.000	0.000	0.000	0.000	0.000	AP-42, Crushed Stone 11.19.2-2, Conveyor Transfer Point
FS31	Conveyor #6 to Conveyor #8	16	220,500	24	8,760	0.00300	0.00110	0.00016	lb/ton	Inside Building	100%	0.000	0.000	0.000	0.000	0.000	0.000	AP-42, Crushed Stone 11.19.2-2, Conveyor Transfer Point
FS32	Conveyor #8 to Mill Feed Bin #3 and #4	16	220,500	24	8,760	0.00300	0.00110	0.00016	lb/ton	Inside Building	100%	0.000	0.000	0.000	0.000	0.000	0.000	AP-42, Crushed Stone 11.19.2-2, Conveyor Transfer Point
FS33	Mill Feed Bin #3 and #4 to Mill Feed Screws #5, 6, 7 and 8	16	220,500	24	8,760	0.00300	0.00110	0.00016	lb/ton	Inside Building	100%	0.000	0.000	0.000	0.000	0.000	0.000	AP-42, Crushed Stone 11.19.2-2, Conveyor Transfer Point
FS34	Mill Feed Screws #5, 6, 7, and 8 to Conditioning Screws #5, 6, 7 and 8	16	220,500	24	8,760	0.00300	0.00110	0.00016	lb/ton	Inside Building	100%	0.000	0.000	0.000	0.000	0.000	0.000	AP-42, Crushed Stone 11.19.2-2, Conveyor Transfer Point
FS35	Pellet Mills #5, 6, 7 and 8 and transfers (in from Conditioning Screws #5-8 and out to Conveyor #10)	16	220,500	24	8,760	0.00540	0.00240	0.00029	lb/ton	Inside Building	100%	0.000	0.000	0.000	0.000	0.000	0.000	AP-42, Crushed Stone 11.19.2-2, Tertiary Crushing
FS36	Conveyor #10 to Pellet Cooler #2	16	220,500	24	8,760	0.00300	0.00110	0.00016	lb/ton	Inside Building	100%	0.000	0.000	0.000	0.000	0.000	0.000	AP-42, Crushed Stone 11.19.2-2, Conveyor Transfer Point
FS37	Pellet Cooler #2 to Conveyor #12	16	220,500	24	8,760	0.00300	0.00110	0.00016	lb/ton	Inside Building	100%	0.000	0.000	0.000	0.000	0.000	0.000	AP-42, Crushed Stone 11.19.2-2, Conveyor Transfer Point
FS38	Pellet Cooler #2 to Multiclone #2	0.39	220,500	24	8,760	0.00300	0.00110	0.00016	lb/ton	Inside Building	100%	0.000	0.000	0.000	0.000	0.000	0.000	AP-42, Crushed Stone 11.19.2-2, Conveyor Transfer Point
FS39	Pellet Screen #2 and transfers (in from Conveyor #12, out to Pneumatic System #3)	16	220,500	24	8,760	0.02500	0.00870	0.00133	lb/ton	Inside Building	100%	0.000	0.000	0.000	0.000	0.000	0.000	AP-42, Crushed Stone 11.19.2-2, Screening
FS40	Multiclone #2 to Pneumatic System #2	0.39	220,500	24	8,760	0.00300	0.00110	0.00016	lb/ton	Inside Building	100%	0.000	0.000	0.000	0.000	0.000	0.000	AP-42, Crushed Stone 11.19.2-2, Conveyor Transfer Point
FS41	Pneumatic System #2 to Surge Bin #1	0.39	220,500	24	8,760	0.00300	0.00110	0.00016	lb/ton	Pnuematic Enclosure	100%	0.000	0.000	0.000	0.000	0.000	0.000	AP-42, Crushed Stone 11.19.2-2, Conveyor Transfer Point
FS42	Pnuematic System #3 to Pellet Product Stockpile	33	220,500	24	8,760	0.00300	0.00110	0.00016	lb/ton	None - BOP	0%	0.098	0.331	0.036	0.121	0.005	0.018	AP-42, Crushed Stone 11.19.2-2, Conveyor Transfer Point
FS43	Pellet Product Stockpile to Hopper #5 via Front Loader	336	184,118	24	8,760	0.00300	0.00110	0.00016	lb/ton	None - BOP	0%	1.009	0.276	0.370	0.101	0.053	0.015	AP-42, Crushed Stone 11.19.2-2, Conveyor Transfer Point
FS44	Hopper #5 to Conveyor #13	336	184,118	24	8,760	0.00300	0.00110	0.00016	lb/ton	None - BOP	0%	1.009	0.276	0.370	0.101	0.053	0.015	AP-42, Crushed Stone 11.19.2-2, Conveyor Transfer Point
FS45	Shipping Screens and transfers (in from Conveyor #13, out to Conveyor #14)	336	184,118	24	8,760	0.02500	0.00870	0.00133	lb/ton	Enclosure	25%	6.305	1.726	2.194	0.601	0.334	0.091	AP-42, Crushed Stone 11.19.2-2, Screening
FS46	Shipping Screen to Pneumatic System #4	4.61	40,384	24	8,760	0.02500	0.00870	0.00133	lb/ton	Pnuematic Enclosure	100%	0.000	0.000	0.000	0.000	0.000	0.000	AP-42, Crushed Stone 11.19.2-2, Screening
FS47	Conveyor #14 to Filling Spout	336	184,118	24	8,760	0.00300	0.00110	0.00016	lb/ton	None - BOP	0%	1.009	0.276	0.370	0.101	0.053	0.015	AP-42, Crushed Stone 11.19.2-2, Conveyor Transfer Point
FS48	Filling Spout to Rail Car	336	184,118	24	8,760	0.00300	0.00110	0.00016	lb/ton	None - BOP	0%	1.009	0.276	0.370	0.101	0.053	0.015	AP-42, Crushed Stone 11.19.2-2, Conveyor Transfer Point
FS49	Pneumatic System #4 to Surge Bin #1	4.61	40,384	24	8,760	0.00300	0.00110	0.00016	lb/ton	Pneumatic Enclosure	100%	0.000	0.000	0.000	0.000	0.000	0.000	AP-42, Crushed Stone 11.19.2-2, Conveyor Transfer Point
												11.580	7.486	4.135	2.762	0.614	0.397	Totals

[1] No data available for PM2.5 emissions for uncontrolled sources. Therefore, the particle size multiplier of 0.0053 from AP-42 Section 13.2.4, September 2006, was mulitplied by the PM emission factor to develop the PM2.5 emission factor.

VOC Potential Emissions from Pellet Coolers

Facility-Wide Pellet Production Capacity	33	ton/hr
Potential Hours of Operation	8,760	hr/yr

Process	Number of Units	VOC Emission Factor[1] (lb/ton)	Methanol Emission Factor[1] (lb/ton)	Formaldehyde Emission Factor[1] (lb/ton)	Acetaldehyde Emission Factor[1] (lb/ton)	Uncontrolled VOC Potential Emissions (lb/hr)	Uncontrolled VOC Potential Emissions (tpy)	Controlled VOC Potential Emissions[2] (lb/hr)	Controlled VOC Potential Emissions[2] (tpy)
Pellet Coolers	2	4.62E-04	2.06E-05	1.18E-05	3.44E-06	0.02	0.07	0.0002	0.0007
Total						**0.02**	**0.07**	**0.0002**	**0.0007**

[1] Per engineering testing of the total gaseous organics emissions from pellet coolers at a similar facility. The most conservative emission factors from testing were used.

[2] Exhaust from the Pellet Coolers will be fed to the FBC for 99% control/destruction of VOC and PM

Steam Explosion System Emissions

Dry Material Throughput	65,599	lb/hr
Hours of Operation per Year	8,760	hr/yr

Pollutant[1]	HAP?	Non-Carcinogenic TAP?	Carcinogenic TAP?	Emission Factor[2] (lb/lb dry fiber)	Control Efficiency[3] (%)	Potential Emissions (lb/hr)	Potential Emissions (tpy)	Potential HAP Emissions (lb/hr)	Potential HAP Emissions (tpy)	Potential TAP Emissions (lb/hr)	Potential TAP Emissions (tpy)
Methyl acetate	No	Yes	No	8.05E-10	99.9%	5.28E-08	2.31E-07	-	-	5.28E-08	2.31E-07
1,3-Pentadiene	No	No	No	6.88E-10	99.9%	4.52E-08	1.98E-07	-	-	-	-
Isobutyraldehyde	No	No	No	1.00E-09	99.9%	6.56E-08	2.87E-07	-	-	-	-
2,3-Butanedione	No	No	No	7.68E-10	99.9%	5.04E-08	2.21E-07	-	-	-	-
2-Butanone	No	No	Yes	1.45E-10	99.9%	9.50E-09	4.16E-08	-	-	9.50E-09	4.16E-08
2-Methyl-furan	No	No	No	1.67E-08	99.9%	1.09E-06	4.80E-06	-	-	-	-
3-Methyl-furan	No	No	No	1.29E-09	99.9%	8.49E-08	3.72E-07	-	-	-	-
Isovaleraldehyde	No	No	No	2.80E-09	99.9%	1.84E-07	8.06E-07	-	-	-	-
2-Methyl-butanal	No	No	No	1.56E-09	99.9%	1.02E-07	4.48E-07	-	-	-	-
1-Methyl-cyclopentene	No	No	No	1.41E-10	99.9%	9.28E-09	4.06E-08	-	-	-	-
Benzene	Yes	No	Yes	1.92E-09	99.9%	1.26E-07	5.51E-07	1.26E-07	5.51E-07	1.26E-07	5.51E-07
Cyclohexene	No	Yes	No	1.06E-09	99.9%	6.94E-08	3.04E-07	-	-	6.94E-08	3.04E-07
Cyclopentanol	No	No	No	1.06E-09	99.9%	6.94E-08	3.04E-07	-	-	-	-
2-Ethyl-furan	No	No	No	9.03E-10	99.9%	5.92E-08	2.59E-07	-	-	-	-
2,5-Dimethyl-furan	No	No	No	9.08E-10	99.9%	5.96E-08	2.61E-07	-	-	-	-
2,4-Dimethyl-furan	No	No	No	1.19E-09	99.9%	7.78E-08	3.41E-07	-	-	-	-
Vinylfuran	No	No	No	4.85E-10	99.9%	3.18E-08	1.39E-07	-	-	-	-
Disulfide, dimethyl	No	No	No	1.68E-09	99.9%	1.10E-07	4.82E-07	-	-	-	-
Toluene	Yes	Yes	No	1.96E-09	99.9%	1.29E-07	5.64E-07	1.29E-07	5.64E-07	1.29E-07	5.64E-07
Hexanal	No	No	No	3.50E-10	99.9%	2.29E-08	1.00E-07	-	-	-	-
2-Ethyl-5-methyl-furan	No	No	No	1.69E-10	99.9%	1.11E-08	4.86E-08	-	-	-	-
4,4-Dimethyl-2-cyclopenten-1-one	No	No	No	3.58E-10	99.9%	2.35E-08	1.03E-07	-	-	-	-
Furfural	No	Yes	No	7.68E-11	99.9%	5.04E-09	2.21E-08	-	-	5.04E-09	2.21E-08
2-Isopropyl-1-hexene	No	No	No	3.58E-10	99.9%	2.35E-08	1.03E-07	-	-	-	-
Ethyl benzene	Yes	Yes	No	1.37E-10	99.9%	8.96E-09	3.93E-08	8.96E-09	3.93E-08	8.96E-09	3.93E-08
m,p-Xylene	Yes	Yes	No	7.32E-10	99.9%	4.80E-08	2.10E-07	4.80E-08	2.10E-07	4.80E-08	2.10E-07
o-Xylene	Yes	Yes	No	1.90E-10	99.9%	1.25E-08	5.45E-08	1.25E-08	5.45E-08	1.25E-08	5.45E-08
Tricyclene	No	No	No	3.44E-10	99.9%	2.26E-08	9.89E-08	-	-	-	-
a-Pinene	No	No	No	1.79E-08	99.9%	1.17E-06	5.13E-06	-	-	-	-
Camphene	No	No	No	2.83E-09	99.9%	1.86E-07	8.13E-07	-	-	-	-
Trisulfide, dimethyl	No	No	No	3.60E-10	99.9%	2.36E-08	1.03E-07	-	-	-	-
B-Pinene	No	No	No	2.04E-09	99.9%	1.34E-07	5.85E-07	-	-	-	-
Benzofuran	No	No	No	2.46E-10	99.9%	1.61E-08	7.07E-08	-	-	-	-
Decane	No	No	No	4.38E-10	99.9%	2.87E-08	1.26E-07	-	-	-	-
a-Terpinene	No	No	No	3.51E-10	99.9%	2.30E-08	1.01E-07	-	-	-	-
o-Cymene	No	No	No	5.42E-09	99.9%	3.56E-07	1.56E-06	-	-	-	-
D-Limonene	No	No	No	8.97E-09	99.9%	5.88E-07	2.58E-06	-	-	-	-
y-Terpinene	No	No	No	5.87E-10	99.9%	3.85E-08	1.69E-07	-	-	-	-
Terpinolene	No	No	No	1.13E-09	99.9%	7.41E-08	3.25E-07	-	-	-	-
Total VOC				8.00E-08	99.9%	5.25E-06	2.30E-05	-	-	-	-

[1] PM emissions are accounted for in Table 10: Controlled PM Emissions from Boiler Baghouse.

[2] Emission factors obtained from stack testing conducted at Quebec City pilot plant with a similar steam explosion process.

[3] Exhaust from the SteamEx Unit is fed to the FBC for destruction/control of PM and VOC

Stockpile Wind Erosion Potential Fugitive PM Emissions

Emission Source Description	Annual Throughput (tpy)	Operating Hours (hr/yr)	Control	Material Moisture Content (%)	PM Emission Factor (lb/ton)	PM_{10} Emission Factor (lb/ton)	$PM_{2.5}$ Emission Factor (lb/ton)	Control Efficiency (%)	PM Potential Emissions (lb/hr)	PM Potential Emissions (tpy)	PM_{10} Potential Emissions (lb/hr)	PM_{10} Potential Emissions (tpy)	$PM_{2.5}$ Potential Emissions (lb/hr)	$PM_{2.5}$ Potential Emissions (tpy)
Hog Fuel Piles	100,000	8,760	None	50%	1.36E-02	6.41E-03	9.71E-04	0%	1.55E-01	6.78E-01	7.32E-02	3.21E-01	1.11E-02	4.85E-02
Pellet Pile	220,500	8,760	None	4%	4.65E-01	2.20E-01	3.33E-02	0%	1.17E+01	5.13E+01	5.54E+00	2.43E+01	8.39E-01	3.67E+00
Feedstock Piles	220,500	8,760	None	34%	2.33E-02	1.10E-02	1.67E-03	0%	5.85E-01	2.56E+00	2.77E-01	1.21E+00	4.19E-02	1.84E-01
TOTAL									**1.25E+01**	**5.45E+01**	**5.89E+00**	**2.58E+01**	**8.92E-01**	**3.91E+00**

[1] Based emission factors calculated per AP-42 Section 13.2.4, September 2006.

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

E = emission factor (lb/ton)

k = particle size multiplier (dimensionless) for PM: 0.74

k = particle size multiplier (dimensionless) for PM_{10}: 0.35

k = particle size multiplier (dimensionless) for $PM_{2.5}$: 0.053

U = mean wind speed (mph): 4.30

M = material moisture content (%)

APPENDIX D: METEOROLOGICAL DATA MEMO

M E M O R A N D U M

DATE: **April 7**, 2016

TO: Shannon Manoulian , Trinity Consultants

FROM: Thomas Swain, Air Quality Modeler, Analyst 3, Air Program

PROJECT: Proposed Facility in Potlatch, Idaho

SUBJECT: Request for available meteorological to be used for air quality modeling in Potlatch, Idaho

Shannon

This memorandum is in response to your request for available meteorological data that could be used in air quality modeling analyses in the Potlatch, Idaho area. It appears that DEQ does not have a model ready data set for Potlatch in its archive files. We have looked at the available data sets from the regional ASOS airport sites (Spokane, WA, Couer D'Alene, ID, and Pullman WA/ Moscow ID, and compared them to a RAWS site (ID POTI1) that exists in Potlatch, Idaho. This site, as shown in Figure 1, is located near your proposed facility location. Enclosed are wind roses and frequency graphs for the RAWS site and the three airport ASOS locations. The RAWS data is probably not adequate for large air quality modeling efforts, but certainly should demonstrate local wind flow characteristics.

None of the airport data sets match ideally with the POTI1 data. In general, the Spokane data compares better than the other two, although the south/southeast flows are more pronounced. However, Spokane and Couer D'Alene are both over 50 miles to the north and located in different topographical regions. By far the nearest data set (less than 20 miles) is from Pullman, and would contain the best available data for cloud cover, ceiling height, and temperature (essential for AERMET/AERMOD processing). The wind flows at the Pullman location, however, are characterized by the hills surrounding the airport, and a predominant east – west flow pattern is created. It appears that the flows have been "redirected" about a sector clockwise from that seen in the data from Potlatch, which is in a more open topography. By shifting the winds in the Pullman data one sector counterclockwise, a new "revised" data set was created implementing this shift, and is hereby referred to as "Pullman/Potlatch" data set. The wind roses created from this data set seem to match very well with those created from the POTI1 data.

DEQ agrees that this is a non-standard approach, but it will allow the applicant to use the "revised Pullman data" for air quality modeling in an analysis to support a minor source permit application in Potlatch. The applicant always has the option to demonstrate that another meteorological data set is

adequate, and can submit that analyses to DEQ for review. Please be advised that the process of reviewing an alternate data set may take additional time. Also, if the facility becomes “major” and/or PSD, then it is up to the applicant to demonstrate that an adequate meteorological data set will be used in the ensuing modeling analyses, and it is likely that the applicant may need to consider onsite monitoring of meteorological data.

If the applicant would like to use this data please contact Thomas Swain at 208 373 0220 or Darrin Mehr at 208-373-0536.

Thomas M Swain

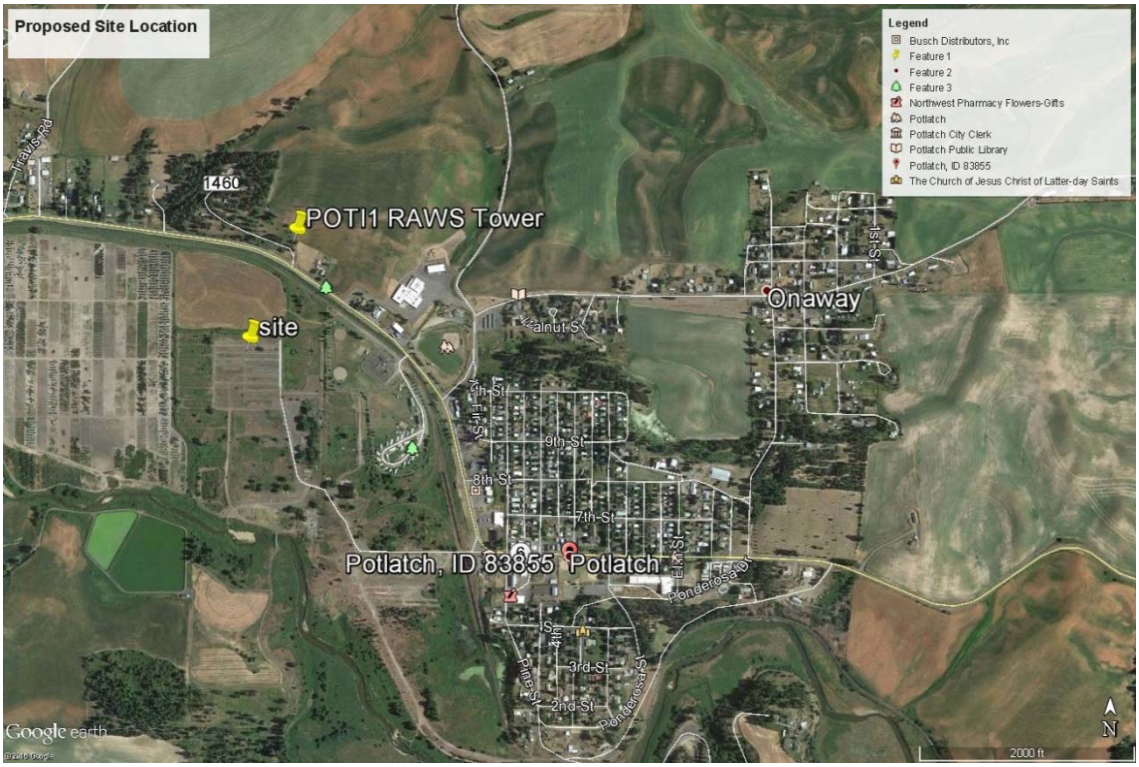
Department of Environmental Quality

Analysyt 3/ Air Quality Modeler

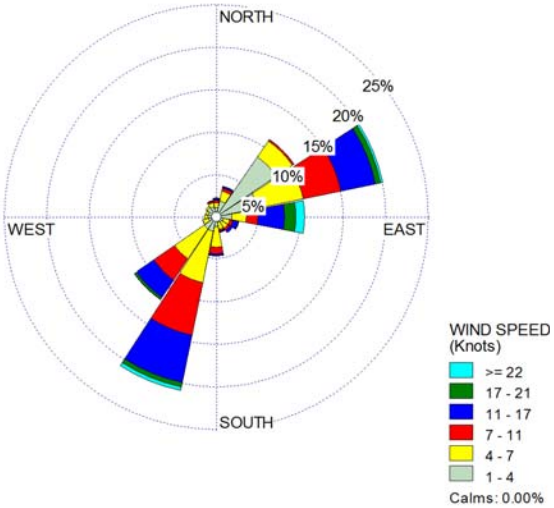
Thomas.swain@deq.idaho.gov

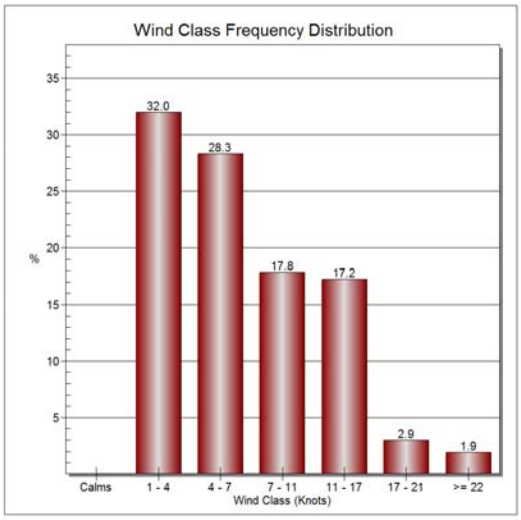
208 373 0220

Figure 1 Proposed Site Location and RAWS Tower location

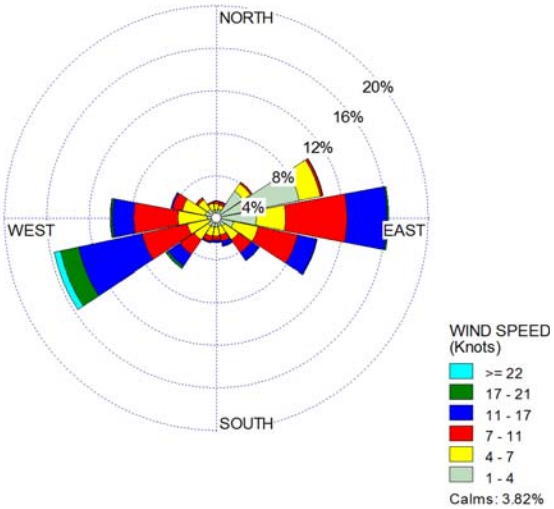


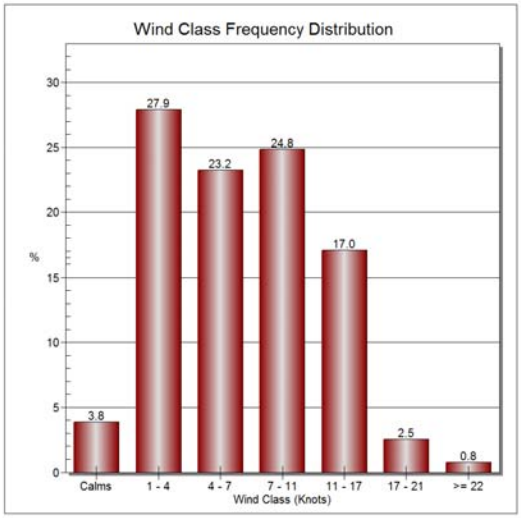
POTLATCH RAWS data 2015



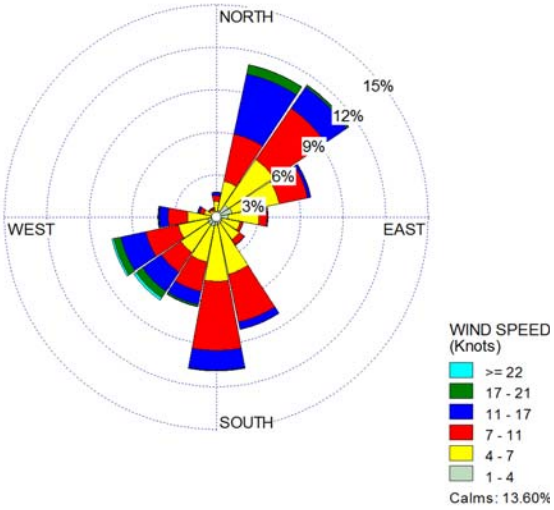


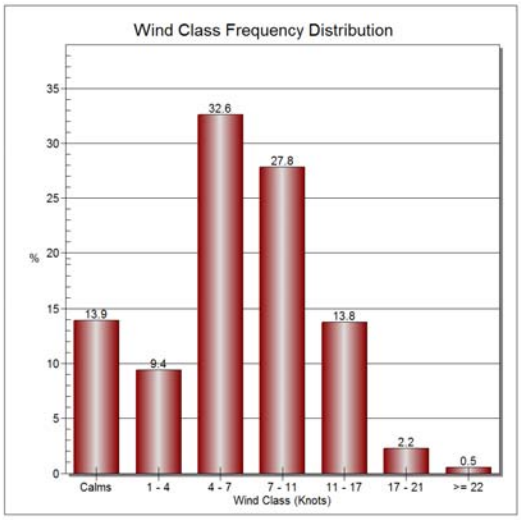
Pullman/Moscow



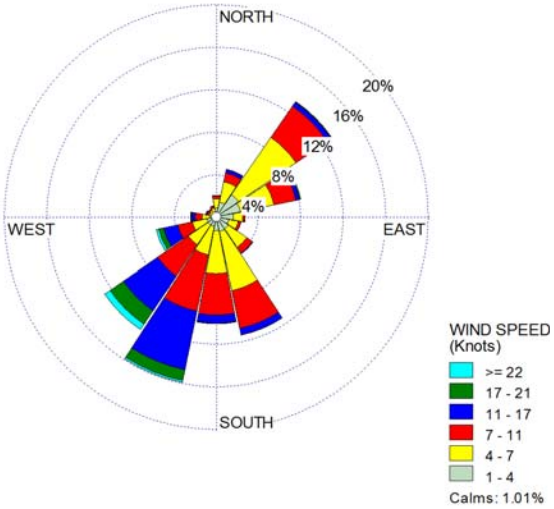


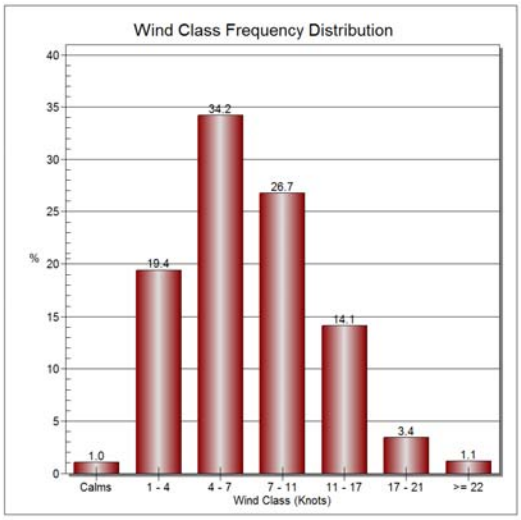
Couer D' Alene



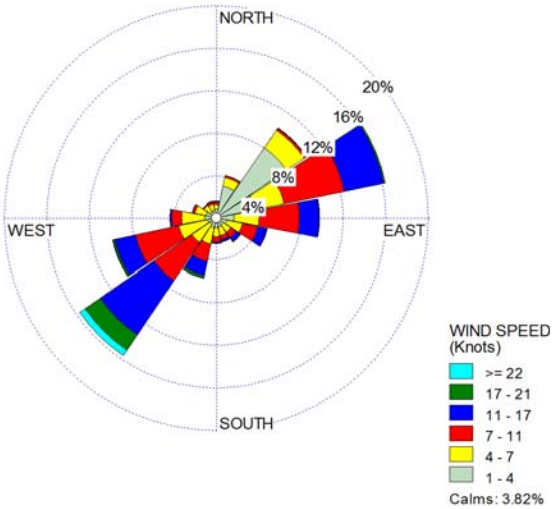


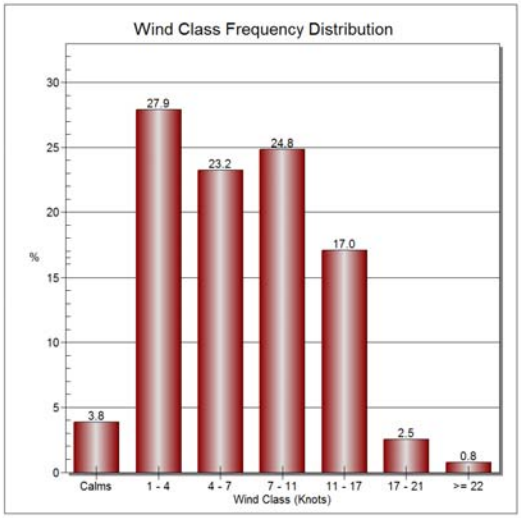
Spokane





Shifted Pullman one sector/ "Pullman/Potlatch"





APPENDIX E: EQUIPMENT VENDOR DATA

5. Design, process and consumption data

The below mentioned data refer to the plant operation at design conditions (ambient air temperature of -6°C in Winter and +28°C in Summer and corresponding relative moistures of 80%). Changes in the ambient conditions will entail changes in the data/performance of the dryer.
Data are given per dryer line.

DESIGN BELT DRYING SYSTEM	Design Winter - -6°C, 80% relative humidity	Design Summer - +28°C, 80% relative humidity	Unit
Drying product	Saw Dust	Saw Dust	
Particle size	maximum 2 w-% P < 0,25 mm; minimum 50 w-% 1 mm < P < 4 mm; all particles P < 7 mm		mm
Wet Biomass quantity	44.86	44.86	t/hr
Dry solids quantity	24	24	t_{DS}/hr
Biomass dry solids content average	53.5	53.5	%DS*
DRIED PRODUCT			
Biomass quantity after drying	25.5	25.5	t/hr
Dried Biomass solids content	95	95	%DS*
Water evaporation capacity	19.3	19.3	t/hr
Operation time	8,000	8,000	hr/a
LOCATION			
Country	US	US	
Plant	TBA	TBA	
Number of Lines	1 x BDS SI 170	1 x BDS SI 170	
Dimensions of plant (LxWxH, approx.)	Please refer to attached layout	Please refer to attached layout	m
CONSUMPTION FIGURES	**(expected values)**		
Heat consumption	approx. 19.1	approx. 18.5	MW
Glycol / Hot water @ 110 °C	approx. 465	approx. 350	m³/hr
Glycol / Hot water return flow @ 70°C	approx. 460	approx. 346	m³/hr
Active belt dimension	288	288	m2
Electrical energy complete installed	approx. 535**	approx. 535**	kW
Electrical energy average consumption	approx. 305**	approx. 345**	kW
EMISSIONS	(expected values)		
Quantity exhaust air	approx. 696,000	approx. 756,000	m³/hr
Temperature exhaust air	approx. 37	approx. 46	°C
Quantity Cleaning Water for Belt (discontinuously)	approx. 4	approx. 4	m³/d

DESIGN BELT DRYING SYSTEM	Design Winter - -6°C, 80% relative humidity	Design Summer - +28°C, 80% relative humidity	Unit
Fire fighting water (in case of emergency only)	86	86	m³/hr
Compressed air for belt cleaning (discontinuously)	200	200	m³/hr
Noise emission	≤ 85 dB(A)***	≤ 85 dB(A)***	measured in 1m horizontal distance of each single noice source at normal ear height (1,5 m)

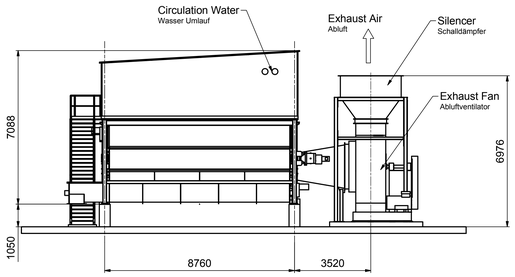
* DS … dry substance

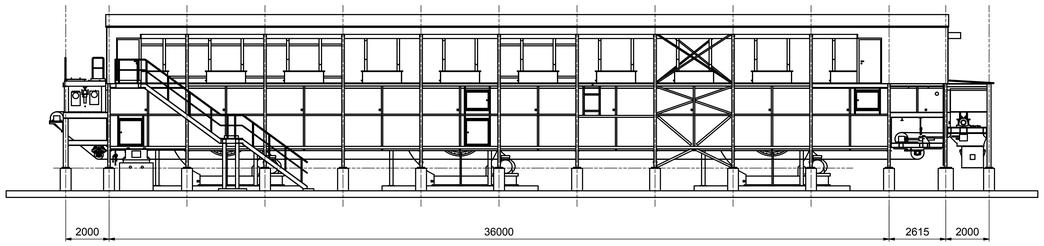
** Installed electrical power and power consumption: estimated values given for Andritz Scope of Supply (not including any Options !)

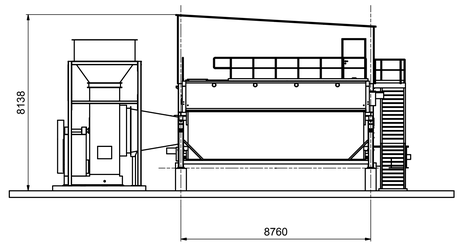
*** Related Standards:

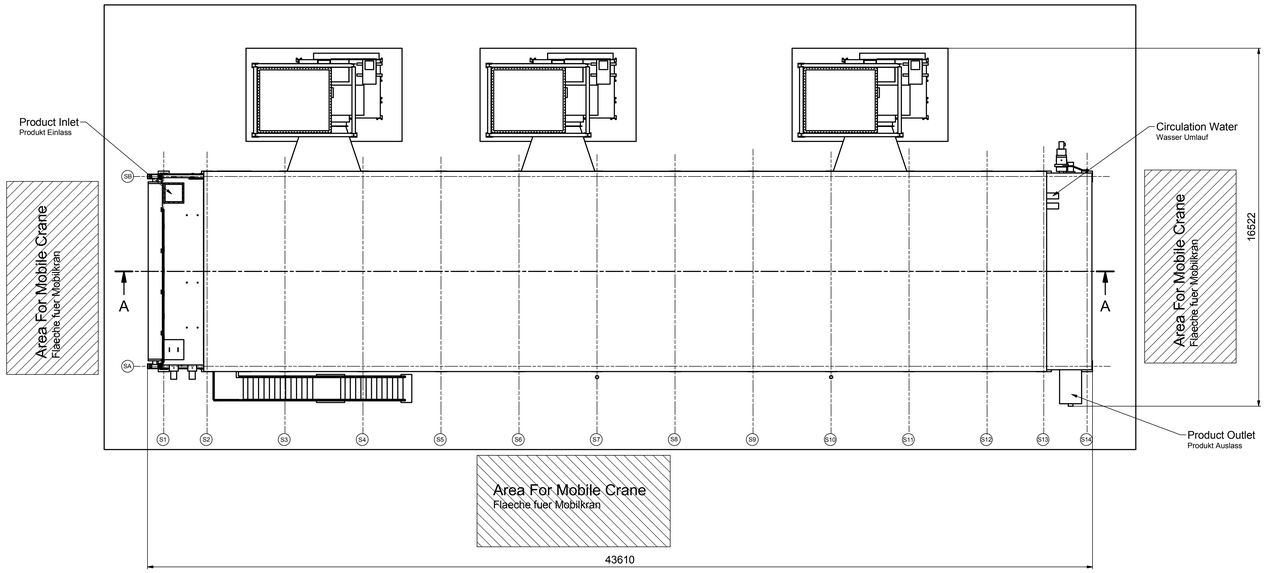
Determination of sound power levels and mechanical vibration produced by gears units shall be subject to ISO 45635.

Sound pressure levels shall be measured in dB (A) using a calibrated sound meter meeting the requirements of EN 60651.









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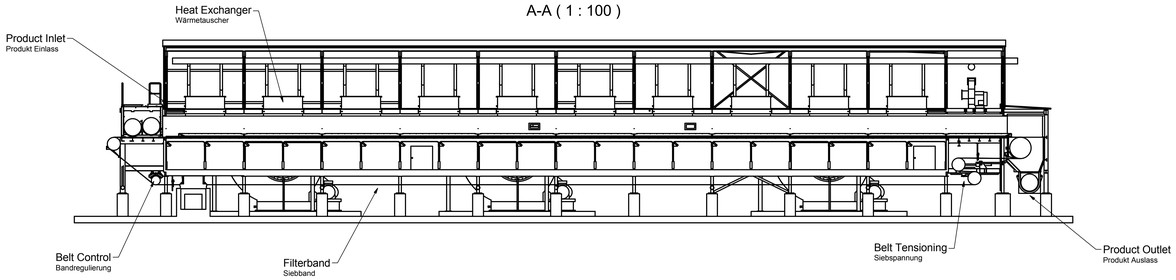

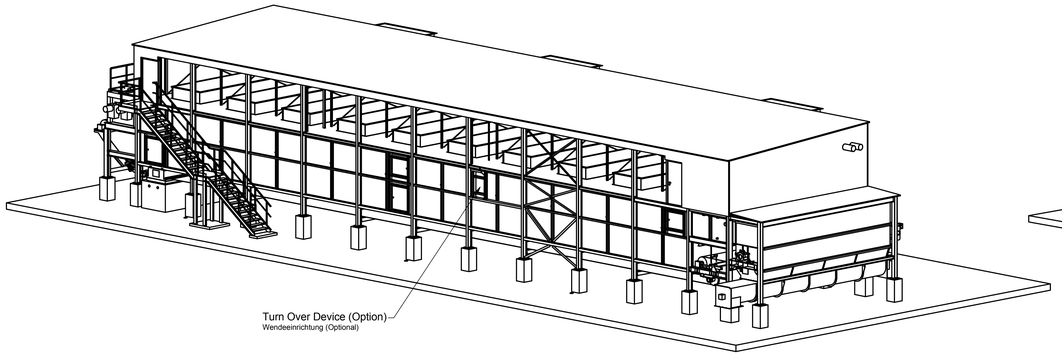

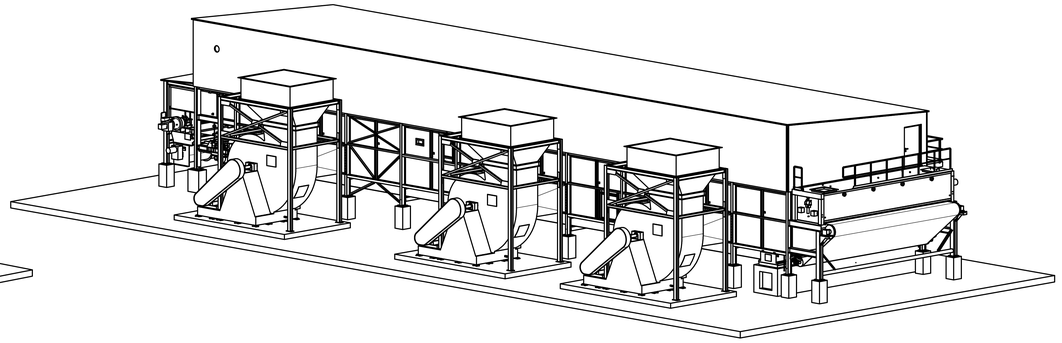

FOR INFORMATION ONLY
NUR ZUR INFORMATION

General Tolerances		Tolerances for linear dimensions (except chamfers)																			
	ISO 2768-mK-E (Machining)	over	0.4	6	30	120	400	1000	2000	4000	8000	12000	16000	20000
		up to	6	± 0.1	± 0.2	± 0.5	± 1	± 2	± 3	± 4	± 5	± 6	± 7	± 8
	ISO 13920-BA-F (Steel fabric) ±2000 B. >2000 A	over	0	1	30	120	400	1000	2000	4000	8000	12000	16000	20000
		up to	30	± 1	± 1.2	± 2	± 3	± 4	± 6	± 8	± 10	± 12	± 14	± 16

Add Material - Item name	Mfg	Basic Material Name		Basic Material Weight: 0.000 kg
Product Type		Product Code		
	Initial Revision		Actual Revision	
Drawn	P Veigl	grzpet48	04.10.2012	
Checked				
Revision				

Replacement for Drawing No: Rev:
Copy from Drawing No: Rev:
Old Drawing No: Rev:

Description:
DRYER PLANT
BDS SI 170

TROCKNUNGSANLAGE
BDS SI 170

Drawing No: 702206347 Rev: -
Size: A0 Sheet/Sheets: 1 / 1 Scale: 1 : 100

ANDRITZ

Filename: as-p-drying_r&d-565-000615-3000001170-dryer pla_-22771559586.idw
CAD Drawing: SE_CDLL_001

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Drawing sheet ISO 5457:1999 - A0

3/3/2016

Questions for CRE and PES – Received from CRE and Precision Energy Systems via Email to Dave Strohm, Trinity on 3/29/2015

a. FBC/Boiler Baghouse – The expected performance of the baghouse is 0.0027 gr/acfm dry particulate. Based on this and the PES combustion calculation the baghouse will emit a maximum of 3.11 lb./hr. of PM.
    i. Output grain loading or control efficiency and input grain loading – 0.0027 gr/acfm dry particulate outlet grain loading.
    ii. Exhaust flow: 135,000 ACFM @ 350F & 1 atm pressure.
    iii. Dimensions including height of exhaust stack: .Typical exhaust stack height is 75 Ft.
    iv. Temperature of effluent : 300 to 350 F

b. Please confirm that the following exhaust through the FBC/Boiler baghouse:
    i. Boilers (high pressure boiler and glycol heater)
    ii. FBC Combustor
    iii. FBC Pre-Burner
    iv. Multiclone cyclone
    v. Flash steam from SteamEx process – Line 5 from Andritz Design Criteria (SteamEx Blow Tank Exhaust) – fed into FBC
    vi. Line 4 from Andritz Design Criteria – (Pre-Steaming Bin Exhaust) – Fed into FBC
    vii. Line 16 from Andritz Design Criteria - (Pellet Mill Exhaust) – Fed into FBC
    viii. Pellet Cooling/De-dusting Air – Fed into FBC (2 points on DWG 000.02, grid J1 & J7) – Fed to FBC, labeled 'Multiclone 1' and 'Multiclone 2'

APPENDIX F: VOLUME SOURCE PARAMETERS

System	Description	Dimensions			Volume Source Parameters				Control	Comments
		Length (ft)	Width (ft)	Height (ft)	Source Horiz. Width (ft)	Source Release Height (ft)	Initial Lateral Dimension (ft)	Initial Vertical Dimension (ft)		
	HOG FUEL PROCESS									
HF1	Truck Unloading to Hog Fuel Tipper		8	13.5	8	6.75	1.86	3.14	Material moisture content	Truck material transfer opening size
HF2	Hog Fuel Pile to Hopper #4/Screw Feeder #4 via Front Loader	15	10	9.0	10	9.0	3.49	2.09	Material moisture content	Hopper Dimensions
HF3	Fuel Screen #1 and transfers (in from Hopper #4, out to Bucket Elevator #1)		4	5.0	4	5.0	0.93	0.23	Material moisture content	Assume screen is 4ft wide and 5ft tall. Drop distance is 1ft
HF4	Bucket Elevator #1 to Surge Bin #2		2	20.0	2	20.0	0.47	0.23	Material moisture content	Assume bucket elevator spout is 2ft wide and 20ft tall. Drop distance is 1ft
HF5	Surge Bin #2 to Pnuematic System #5								Pnuematic Enclosure	
HF6	Pneumatic System #5 to Combustor								Pnuematic Enclosure	
	FEEDSTOCK PROCESS									**ALL DROP DISTANCES ARE ASSUMED TO BE 1 foot.**
FS1	Truck Unloading to Feedstock Tipper #1		8	13.5	8	6.75	1.86	3.14	Material Moisture Content	Truck material transfer opening size
FS2	Feedstock Pile to Hopper #1, 2 or 3 via Front Loader	15	10	9.0	10	9.0	3.49	0.23	Material Moisture Content	Hopper Dimensions
FS3	Hopper #1, 2 or 3 to Conveyor #1		4	5.0	4	5.0	0.93	0.23	Material Moisture Content	Conveyor is 4 ft wide. Hopper is 9 ft tall, assume bottom of hopper is 5 ft above ground.
FS4	Conveyor #1 to Feed Screw #1		4	8.0	4	8.0	0.93	0.23	Material Moisture Content	Conveyor is 4 ft wide. Assume conveyor rises at incline from 4 ft to 8 ft above ground.
FS5	Conveyor #1 to Feed Screw #2		4	8.0	4	8.0	0.93	0.23	Material Moisture Content	Conveyor is 4 ft wide. Assume conveyor rises at incline from 4 ft to 8 ft above ground.
FS6	Green Hammer Mill #1 and transfers (in from Feed Screw #1, out to Green Cyclone #1)		4	7.0	4	7	0.93	0.23	Material Moisture Content	Assume Green Hammer Mill is 4 ft wide and 7 ft tall.
FS7	Green Hammer Mill #2 and transfers (in from Feed Screw #2, out to Green Cyclone #2)		4	7.0	4	7	0.93	0.23	Material Moisture Content	Assume Green Hammer Mill is 4 ft wide and 7 ft tall.
FS8	Green Cyclone #1 to Conveyor #2		4	5.0	4	5.0	0.93	0.23	Material Moisture Content	Conveyor is 4 ft wide. Assume bottom of cyclone is 5 ft tall.
FS9	Green Cyclone #2 to Conveyor #2		4	5.0	4	5.0	0.93	0.23	Material Moisture Content	Conveyor is 4 ft wide. Assume bottom of cyclone is 5 ft tall.
FS10	Conveyor #2 to Conveyor #3 (Inside Tower 1)		4	45.0	4	45.0	0.93	0.23	Enclosure	Conveyor is 4 ft wide. Tower 1 is 45 ft tall.
FS11	Conveyor #3 to Steam Ex Preheat Bin								Inside Building	
FS12	SteamEx Preheat Bin to Conveyor #4								Inside Building	
FS13	Conveyor #4 to Belt Dryer								Inside Building	
FS14	Belt Dryer to Conveyor #5								Inside Building	
FS15	Conveyor #5 to Feed Screw #3		4	8.0	4	8.0	0.93	0.23	None - BOP	Conveyor is 4 ft wide. Assume conveyor rises at incline from 4 ft to 8 ft above ground.
FS16	Feed Screw #3 to Dry Hammer Mill		4	7.0	4	7.0	0.93	0.23	None - BOP	Assume screen and hammer mill are 4 ft wide, feed screw is 7 ft tall.
FS17	Dry Hammer Mill to Dry Cyclone #1		2	4.0	2	4.0	0.47	0.23	Bag Filter	Assume chute from hammer to cyclone is 2 ft wide, cyclone is 4 ft tall.
FS18	Dry Cyclone #1 to Pneumatic System #1								Pnuematic Enclosure	
FS19	Pnuematic System #1 to Surge Bin #1								Pnuematic Enclosure	
FS20	Surge Bin #1 to Conveyor #6		2	3.0	2	3.0	0.47	0.23	None - BOP	Assume chute from bin to conveyor is 2 ft wide, bottom of bin is 3 ft above ground.
FS21	Conveyor #6 to Conveyor #7								Inside Building	
FS22	Conveyor #7 to Mill Feed Bin #1 and #2								Inside Building	
FS23	Mill Feed Bin #1 and #2 to Mill Feed Screws #1, 2, 3 and 4								Inside Building	
FS24	Mill Feed Screws #1, 2, 3, and 4 to Conditioning Screws #1, 2, 3 and 4								Inside Building	
FS25	Pellet Mills #1, 2, 3 and 4 and transfers (in from Conditioning Screws #1-4 and out to Conveyor #9)								Inside Building	
FS26	Conveyor #9 to Pellet Cooler #1								Inside Building	
FS27	Pellet Cooler #1 to Conveyor #11								Inside Building	
FS28	Pellet Cooler #1 to Multiclone #1								Inside Building	
FS29	Pellet Screen #1 and transfers (in from Conveyor #11, out to Pneumatic System #3)								Inside Building	
FS30	Multiclone #1 to Pneumatic System #2								Inside Building	
FS31	Conveyor #6 to Conveyor #8								Inside Building	
FS32	Conveyor #8 to Mill Feed Bin #3 and #4								Inside Building	
FS33	Mill Feed Bin #3 and #4 to Mill Feed Screws #5, 6, 7 and 8								Inside Building	
FS34	Mill Feed Screws #5, 6, 7, and 8 to Conditioning Screws #5, 6, 7 and 8								Inside Building	
FS35	Pellet Mills #5, 6, 7 and 8 and transfers (in from Conditioning Screws #5-8 and out to Conveyor #10)								Inside Building	
FS36	Conveyor #10 to Pellet Cooler #2								Inside Building	
FS37	Pellet Cooler #2 to Conveyor #12								Inside Building	
FS38	Pellet Cooler #2 to Multiclone #2								Inside Building	
FS39	Pellet Screen #2 and transfers (in from Conveyor #12, out to Pneumatic System #3)								Inside Building	

System	Description	Dimensions			Volume Source Parameters				Control	Comments
		Length (ft)	Width (ft)	Height (ft)	Source Horiz. Width (ft)	Source Release Height (ft)	Initial Lateral Dimension (ft)	Initial Vertical Dimension (ft)		
FS40	Multiclone #2 to Pneumatic System #2								Inside Building	
FS41	Pneumatic System #2 to Surge Bin #1								Pnuematic Enclosure	
FS42	Pnuematic System #3 to Pellet Product Stockpile		1	70.0	1	70.0	0.23	8.14	None - BOP	Assume pipe is 1 ft wide, stockpile is 70 ft tall. Average drop distance is 35 ft.
FS43	Pellet Product Stockpile to Hopper #5 via Front Loader		10	9.0	10	9.0	2.33	0.23	None - BOP	Hopper Dimensions
FS44	Hopper #5 to Conveyor #13		4	5.0	4	5.0	0.93	0.23	None - BOP	Conveyor is 4 ft wide. Hopper is 9 ft tall, assume bottom of hopper is 5 ft above ground.
FS45	Shipping Screens and transfers (in from Conveyor #13, out to Conveyor #14)		4	25.0	4	25.0	0.93	0.23	Enclosure	Conveyor is 4 ft wide. Assume screens are 25 ft tall.
FS46	Shipping Screen to Pneumatic System #4								Pnuematic Enclosure	
FS47	Conveyor #14 to Filling Spout		4	20.0	4	20.0	0.93	0.23	None - BOP	Conveyor is 4 ft wide. Assume top of filling spout is 20 ft tall.
FS48	Filling Spout to Rail Car		2	15.0	2	15	0.47	0.23	None - BOP	Conveyor is 4 ft wide. Assume bottom of filling spout is 15 ft tall.
FS49	Pneumatic System #4 to Surge Bin #1								Pneumatic Enclosure	

STATE OF IDAHO
DEPARTMENT OF
ENVIRONMENTAL QUALITY

1410 NORTH HILTON, BOISE, ID 83706 · (208) 373-0502

C. L. "BUTCH" OTTER, GOVERNOR

JOHN TIPPETS, DIRECTOR

May 10, 2016
Shannon Manoulian of Trinity Consultants on behalf of Centennial Renewable Energy, Potlatch Pellet Mill
Potlatch, Idaho

Re: Modeling Protocol for the Centennial Renewable Energy Facility in Potlatch, Idaho

Dear Shannon:

DEQ received your dispersion modeling protocol via email on April 26, 2016 on behalf of the Centennial Renewable Energy (CRE) facility in Potlatch, Idaho. The modeling protocol was submitted by Shannon Manoulian of Trinity Consultants (TC). The modeling protocol proposes methods and data for use in the ambient impact analyses of a Permit to Construct (PTC) application for a new facility in order to show compliance for their facility. DEQ has the following comments:

- Comment 1: Documentation and justification of release parameters must be provided in the application. Refer to Section 3.4.3 of the *State of Idaho Guideline for Performing Air Quality Impact Analyses*, September 2013. Simply stating that values are "manufacturer data" does not constitute adequate documentation and/or justification. DEQ requests that the application describe how the values were obtained (measurement, similar source, combustion evaluation, fan curves, etc.). If values were obtained from an equipment/engineering firm, then those forms, specification sheets, etc. provided by the firm should be included in the application as documentation for the values used in the modeling analyses. The application should be treated as a stand-alone document. If data was taken from a stack test, then the stack test report and data should also be included in the document. The applicant states that exit velocities have been taken from the vendor, while stack diameters have been reduced from CAD drawings. The applicant should confirm that the resultant exit exhausts as modeled should be equal to the design exit flows (in ACFM).

- Comment 2: The protocol discusses various modes of operation of the FBC, with temperatures varying from perhaps 200 F when preheating to 1600 F degrees at full operation, with different fuel proponents. The applicant needs to provide adequate modeling information or justification to demonstrate that the NAAQS will be complied with for all possible worst case conditions.

- Comment 3: In the protocol the applicant does not discuss any non-default treatment of NO_2/NO_X stack chemistry. If TC wishes to utilize a non-default method, prior DEQ acceptance is required.

- Comment 4: In the protocol the applicant states that all transfer points are treated as volume sources and are separated from building structures. DEQ is uncertain if there are any vented emissions from the building structure(s) that reflect process activities not directly attributable to the dryer point sources.

- Comment 5: All emission calculations will be reviewed by the permit writer during review of the permit application, including an assessment of TAPS that might be exempt due to various regulations.

- Comment 6: Descriptions of the facility process are generally adequate. The ambient air boundary, as stated in the State of Idaho Guideline for Performing Air Quality Impact Analyses, should be defined by an area where the public access is precluded. This includes separation from areas of habitation or activities by people not employed by the facility. If a physical barrier is not used to preclude public access from areas excluded from ambient air, then the application must thoroughly describe the methods used to practically preclude access.

- Comment 7: TC has proposed to use the meteorological data provided by DEQ. This data was collected at the nearby Pullman, WA airport for the period 2011-2015, and is deemed to be appropriately representative of the facility locale. The wind flows have been modified to reflect consistency with the local RAWS station.

- Comment 8: the proposed spacing for a receptor grid appears adequate; however, the applicant must be sure to include receptors with refined spacing in the area of maximum concentrations if those locales are not in an area of fine grid receptors. This typically can occur in areas of elevated terrain.

- Comment 9: TC has provided printouts of various calculations in support of the application. DEQ appreciates this information, but will only analyze them later in an electronic format at the time the application is submitted.

- Comment 10: DEQ has recently developed a modeling report template form for consultants/applicants to use when submitting modeling analyses. An electronic copy of this

template should have been attached to the email delivering this protocol approval notice. DEQ now **requires** that this template be used for the submitted modeling analyses.

DEQ modeling staff considers the submitted dispersion modeling protocol, with consideration and resolution of the additional items noted above, to be approved. It should be noted, however, that the approval of this modeling protocol is not meant to imply approval of a completed dispersion modeling analysis. Please refer to the *State of Idaho Air Quality Modeling Guideline*, which is available on the Internet at http://www.deq.state.id.us/air/permits_forms/permitting/modeling_guideline.pdf, for further guidance.

DEQ modeling staff requests submission of electronic copies of all modeling input and output files (including BPIP and AERMAP input and output files) with an analysis report. Also, please include with the application materials a copy of the protocol and this protocol approval in the appendix of the application. If you have any questions, please call at 208 373 0220

Sincerely,

Thomas Swain
Analyst 3 , Air Modeling
Idaho Department of Environmental Quality
208 373-0220
thomas.swain@deq.idaho.gov

APPENDIX D: MANUFACTURER SPECIFICATIONS

Jim Beck PES

From: Jim Beck PES <jim.beck@pes-world.com>
Sent: Friday, May 6, 2016 3:15 PM
To: Jim.beck@pes-world.com
Subject: Mpulse / IAC Baghouse PM10 Emission Question

FYI,
Bag Material, As Quoted:

- TTG PTFE membrane laminated to 22 oz. Fiberglass with I-625 Acid Resistant Finish
- Galvanized Filter Bag Cages to be 20 Vertical Wire; 6" Ring Spacing and 11 gauge construction; RFT top; galvanized carbon steel.
- Design Pressure Loss: Max -8" W.C. – baghouse inlet flange to baghouse outlet flange

---

From: Glenn Smith [mailto:gsmith@iac-intl.com]
Sent: Monday, April 11, 2016 3:13 PM
To: 'jim.beck@pes-world.com' <jim.beck@pes-world.com>
Cc: Mike Gregory <mgregory@iac-intl.com>; Gregg Zoltek <gzoltek@iac-intl.com>; Jason Dowse <jdowse@iac-intl.com>; Pramodh Nijhawan <pnijhawan@iac-intl.com>
Subject: RE: 15141, Mpulse / IAC Baghouse PM10 Emission Question

Jim,

Below are our Bag Efficiency standards:

Total Particulate Removal Efficiency = 99.99%
Particulate 10 microns in size and greater = 99.99%
Particulate between 2.5 microns in size and 10 microns in size = 99%
Particulate between 1 microns in size and 2.5 microns in size = 99%
Particulate under 0.5 microns in size to 1 micron in size = 85%

Respectfully,

Glenn A. Smith, Jr.
CEO
Industrial Accessories Company
4800 Lamar Avenue
Mission, Kansas 66202
Phone: (913) 384-5511
Toll Free: 1-800-334-7431
Fax: (913) 384-6577
Email: gsmith@iac-intl.com
Website: www.iac-intl.com
Follow Us On: Linkedin Facebook Twitter Google+

IAC will be exhibiting at the following trade conferences in 2016:
Air Quality Workshop Presentation, April 5, 2016, Asheville NC, Grove Park Inn
Frac Sand Insider Conference, May 10-11, 2016, La Crosse WI, La Crosse Center: Booth # 508

IEEE Cement Conference, May 15-19 (exhibits May 15-17,) 2016, Dallas TX**,** Gaylord Texan Resort & Convention Center, Grapevine TX: Booth # 200
DUG Eagle Ford Conference, September 12-14, 2016, San Antonio TX, Henry B. Gonzalez Convention Center: Booth 5055
Air Quality Workshop Presentation, September 28, 2016, Pittsburgh PA, Renaissance Pittsburgh Hotel
Frac Sand Supply and Logistics Conference, October 13-14, 2016, San Antonio TX, JW Marriott Hill Country Resort: Booth #10

From: jim.beck@pes-world.com [mailto:jim.beck@pes-world.com]
Sent: Monday, April 11, 2016 12:43 PM
To: Jason Dowse
Cc: chris.mcmullen@pes-world.com; Jim.beck@pes-world.com; Chuck.White@pes-world.com; Mike Gregory
Subject: IAC Baghouse PM10 Emission Question

Jason,
I have a question about the IAC baghouse for the AP20445 Project.

The Ministry of the Environment wants to know about PM10 outlet emissions (amount of ash out the stack that is less than 10 micrometers in diameter); the data provided by IAC so far has been only for PM (ANY particulate matter).

What is the collection efficiency of the selected bag material for PM10?

I believe this is the bag material used:
TTG PTFE membrane laminated to 22 oz. Fiberglass with I-625 Acid Resistant Finish (Qty. 640)

Regards,

James Beck
Project Manager/Engineer
Precision Energy Services, Inc.
P.O. Box 1004
Hayden, ID 83835
Office: 208-772-4457
Cell: 208-699-7319
www.pes-world.com

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Shannon Manoulian

From: Turner Allen (Atlanta) <Allen.Turner@andritz.com>
Sent: Wednesday, October 21, 2015 5:39 PM
To: Rick Fawcett (rick.fawcett@centennial-res.com); Dave Strohm
Cc: adam@es2eng.com; 'Dan South' (dan.south@dometechnology.com); Curci Mike; Piche Denis
Subject: ANDRITZ: Post Dryer (belt) dust emissions

Gentlemen:

The following are expected values from our belt dryer group for the Steam Explosion Post-Dryer application.

Dust emissions out of belt dryer <10 mg/m³; thereof assume for
PM 500: about 5 mg/Nm³;
PM10= 90% of PM500
PM2.5= 50% of PM500

In order to confirm these values and offer a binding proposal for the belt dryer after steam explosion, we will need about 500 kg (dry) of steam exploded material to test in Europe.
I propose we plan to generate this material as part of the planned Quebec trials.

Best regards,

Allen

Allen Turner
ANDRITZ PULP & PAPER
Fiber Technologies Division
Sales Manager, BioRefinery

ANDRITZ INC
5405 Windward Pkwy
Suite 100W
Alpharetta, GA 30004
Phone: +1 770 640-2558
Fax: +1 770 640-2569
Mobile: +1 770 329-6187
allen.turner@andritz.com
www.andritz.com

We accept the challenge!

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Thank You.

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5. Design, process and consumption data

The below mentioned data refer to the plant operation at design conditions (ambient air temperature of -6°C in Winter and +28°C in Summer and corresponding relative moistures of 80%). Changes in the ambient conditions will entail changes in the data/performance of the dryer.
Data are given per dryer line.

DESIGN BELT DRYING SYSTEM	Design Winter - -6°C, 80% relative humidity	Design Summer - +28°C, 80% relative humidity	Unit
Drying product	Saw Dust	Saw Dust	
Particle size	maximum 2 w-% P < 0,25 mm; minimum 50 w-% 1 mm < P < 4 mm; all particles P < 7 mm		mm
Wet Biomass quantity	44.86	44.86	t/hr
Dry solids quantity	24	24	t_{DS}/hr
Biomass dry solids content average	53.5	53.5	%DS*
DRIED PRODUCT			
Biomass quantity after drying	25.5	25.5	t/hr
Dried Biomass solids content	95	95	%DS*
Water evaporation capacity	19.3	19.3	t/hr
Operation time	8,000	8,000	hr/a
LOCATION			
Country	US	US	
Plant	TBA	TBA	
Number of Lines	1 x BDS SI 170	1 x BDS SI 170	
Dimensions of plant (LxWxH, approx.)	Please refer to attached layout	Please refer to attached layout	m
CONSUMPTION FIGURES	**(expected values)**		
Heat consumption	approx. 19.1	approx. 18.5	MW
Glycol / Hot water @ 110 °C	approx. 465	approx. 350	m³/hr
Glycol / Hot water return flow @ 70°C	approx. 460	approx. 346	m³/hr
Active belt dimension	288	288	m2
Electrical energy complete installed	approx. 535**	approx. 535**	kW
Electrical energy average consumption	approx. 305**	approx. 345**	kW
EMISSIONS	(expected values)		
Quantity exhaust air	approx. 696,000	approx. 756,000	m³/hr
Temperature exhaust air	approx. 37	approx. 46	°C
Quantity Cleaning Water for Belt (discontinuously)	approx. 4	approx. 4	m³/d

DESIGN BELT DRYING SYSTEM	Design Winter - -6°C, 80% relative humidity	Design Summer - +28°C, 80% relative humidity	Unit
Fire fighting water (in case of emergency only)	86	86	m³/hr
Compressed air for belt cleaning (discontinuously)	200	200	m³/hr
Noise emission	≤ 85 dB(A)***	≤ 85 dB(A)***	measured in 1m horizontal distance of each single noice source at normal ear height (1,5 m)

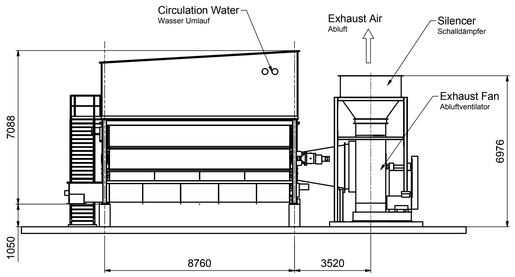
* DS … dry substance

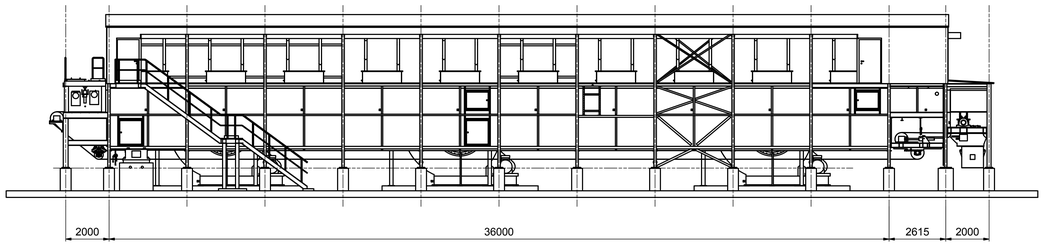
** Installed electrical power and power consumption: estimated values given for Andritz Scope of Supply (not including any Options !)

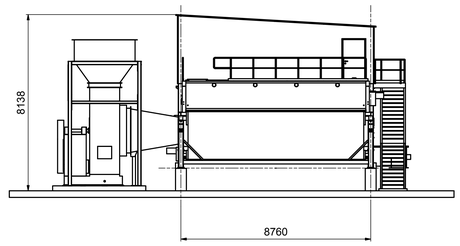
*** Related Standards:

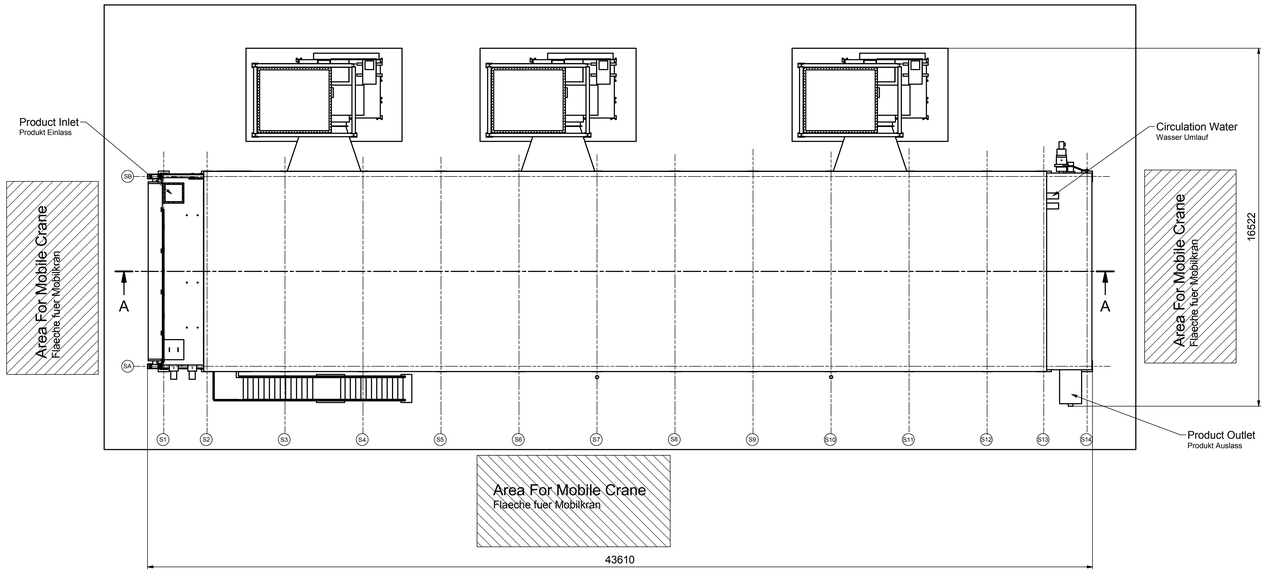
Determination of sound power levels and mechanical vibration produced by gears units shall be subject to ISO 45635.

Sound pressure levels shall be measured in dB (A) using a calibrated sound meter meeting the requirements of EN 60651.









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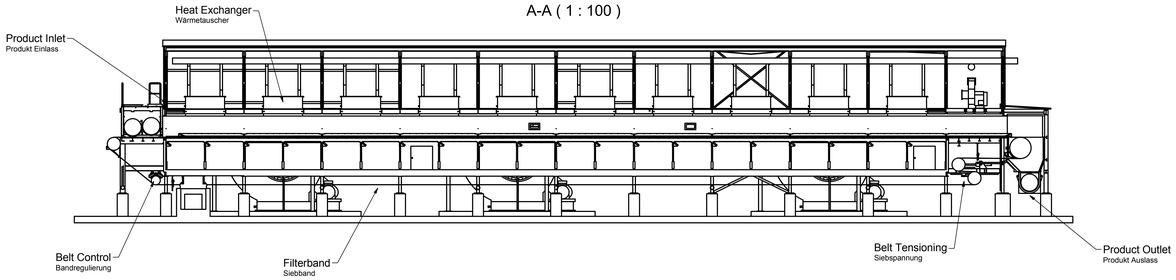

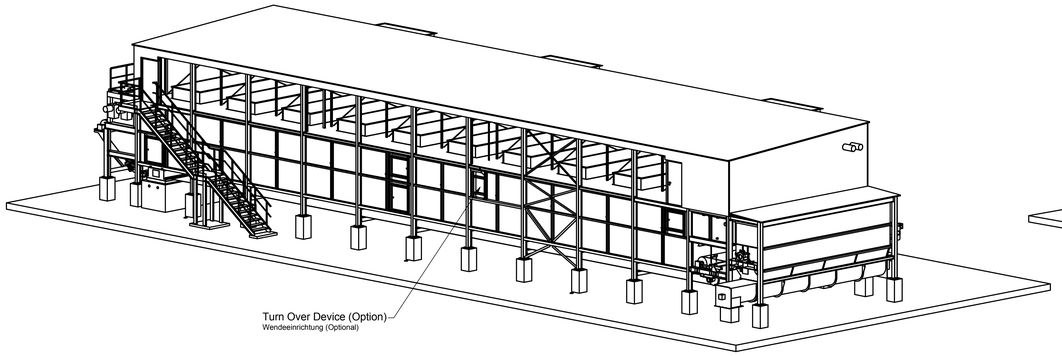

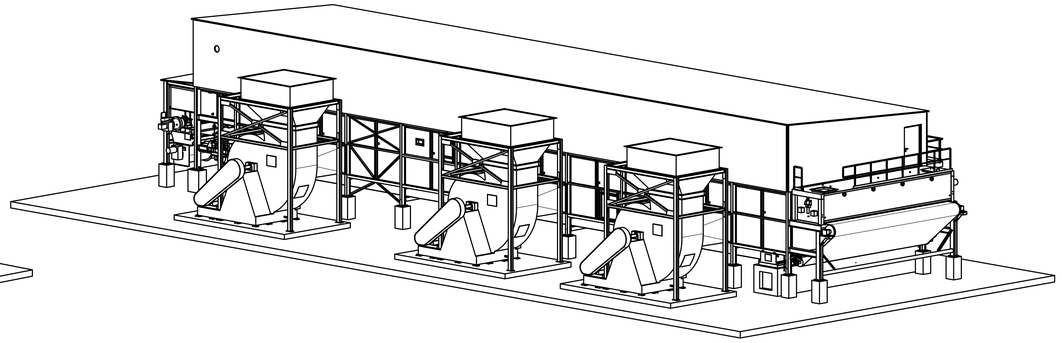

FOR INFORMATION ONLY
NUR ZUR INFORMATION

General Tolerances		Tolerances for linear dimensions (except chamfers)																			
	ISO 2768-mK-E (Machining)	over	0.4	6	30	120	400	1000	2000	4000	8000	12000	16000	20000
		up to	6	± 0.1	± 0.2	± 0.5	± 1	± 2	± 3	± 4	± 5	± 6	± 7	± 8
	ISO 13920-BA-F (Steel fabric) ±2000 B. >2000 A	over	0	1	30	120	400	1000	2000	4000	8000	12000	16000	20000
		up to	30	± 1	± 1.2	± 2	± 3	± 4	± 6	± 8	± 10	± 12	± 14	± 16

Add Material - Item name	Mfg	Basic Material Name		Basic Material Weight: 0.000 kg
Product Type		Product Code		
	Initial Revision		Actual Revision	
Drawn	P Veigl	grzpet48	04.10.2012	
Checked				
Revision				

Replacement for Drawing No: Rev:
Copy from Drawing No: Rev:
Old Drawing No: Rev:

Description:
DRYER PLANT
BDS SI 170

TROCKNUNGSANLAGE
BDS SI 170

Drawing No: 702206347 Rev: -
Size: A0 Sheet/Sheets: 1 / 1 Scale: 1 : 100

ANDRITZ

Filename: as-p-drying_r&d-565-000615-3000001170-dryer pla_-22771559586.idw
CAD Drawing: SE_CDLL_001

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Drawing sheet ISO 5457:1999 - A0

Some additional emissions data for CRE.

David E.B. Strohm II | Managing Consultant

Trinity Consultants | 702 W. Idaho St Suite 1100 | Boise, Idaho 83702

P: 208.472.8837| M: 208.999.2327 | E: dstrohm@trinityconsultants.com

From: Adam Aagard [mailto:adam@es2eng.com]
Sent: Monday, November 02, 2015 8:03 AM
To: Dave Strohm <DStrohm@trinityconsultants.com>
Subject: FW: Potlatch Pellet Facility - Emission Calculations Status

FYI…

Adam Aagard, PE

Project Manager

adam@es2eng.com

Engineering System Solutions, ES^2
Phone: 208.552.9874

From: Curci Mike [mailto:Mike.Curci@andritz.com]
Sent: Sunday, November 01, 2015 7:31 AM
To: Rick Fawcett <rick.fawcett@centennial-res.com>; Turner Allen (Atlanta) <Allen.Turner@andritz.com>; adam@es2eng.com; 'Dan South' <dan.south@dometechnology.com>; 'Mike Oswald' <oswaldmw@pes-world.com>
Subject: RE: Potlatch Pellet Facility - Emission Calculations Status

Good day all,

Below are a few tables and references in regards to the hammer mill, pellet mill, and cooling equipment.

The VOC test data provided was a test using Baltic spruce which should provide a good reference point.

	Air Volume	PM 2.5	PM 10	CPM	TPM
Andritz 4360 Hammermill x1	9100 CFM	N/A	N/A	N/A	N/A
Andritz 26WLM Pelletmill x9	600-1200 CFM	N/A	N/A	N/A	N/A
LMM VC-119H Cooler x2	900-1000 CFM per ton				
Totals					

In response to the PM 2.5, PM 10, CPM, and TPM, these are functions of the dust control systems which are connected to the hammermill and pelletmill. I will request data from each vendor.

VOC Test

Plant / stack: Exhaust after pellet cooler

Parameter	Unit	Sample 1	Sample 2	Average
Date	dd-mm-yy	12/8/2014	12/8/2014	12/8/2014
Measuring period	hh:mm	17:47 - 18:16	18:17 - 18:46	17:47 - 18:46
Measuring period, flow	hh:mm	-	-	-
Cross section area	m²	0,5027		-

Operating parameters

Temperature	°C	29	29	29
Moisture (stated or calculated)	Vol %	2,00	2,00	2,00
Flowrate	m³(s,d)/h	37	37	37
Flowrate, operating conditions	m³/h	43	43	43

Concentrations

VOC	mg C/m³(s,d)	41	47	44

Organic solvents

Formaldehyde	mg/m³(s,d)	1,2	1,2	1,2

Acetaldehyde	mg/m³(s,d)	0,35	0,30	0,32
Acrolein	mg/m³(s,d)	0,11	0,12	0,12
Acetone	mg/m³(s,d)	0,035	0,028	0,031
Propanal	mg/m³(s,d)	0,060	0,057	0,058
2-butanone	mg/m³(s,d)	< 0,002	0,0054	0,0035
Butanal	mg/m³(s,d)	0,11	0,096	0,10
Benzaldehyde	mg/m³(s,d)	0,54	0,45	0,49
Pentanal	mg/m³(s,d)	0,70	0,63	0,66
Hexanal	mg/m³(s,d)	3,2	2,8	3,0
Methanol	mg/m³(s,d)	2,1	2,1	2,1
Sum, all components	mg/m³(s,d)	8,4	5,7	7,0

Mass flow rate

VOC	g C/h	1.5	1.7	1.6
Formaldehyd	g/h	44	43	44
Acetaldehyd	g/h	13	11	12
Methanol	g/h	78	-	78
Production	tons/h	8,30	8,30	8,30
VOC	g C/ton	0,400	0,459	0,430
VOC	lb/ton	0.00088	0.00101	0.00095
Formaldehyde	lb/ton	0,0118	0,0114	0,0116
Acetaldehyde	lb/ton	0,00341	0,00293	0,00317

Methanol	lb/ton	0,0206	0,0206	0,0206

(s,d) indicates dry gas at standard conditions (0°C, 101,3 kPa)

* means "not included in accreditation no. 51"

Thanks

Mike

Mike Curci

Capital Sales Manager, Biomass

ANDRITZ Inc.
336 West Penn Street

Muncy, PA 17756

Mobile: +1 850 557 7674
Fax: +1 770 640 2521

Mike.Curci@andritz.com
www.andritz.com

3/3/2016

Questions for CRE and PES – Received from CRE and Precision Energy Systems via Email to Dave Strohm, Trinity on 3/29/2015

a. FBC/Boiler Baghouse – The expected performance of the baghouse is 0.0027 gr/acfm dry particulate. Based on this and the PES combustion calculation the baghouse will emit a maximum of 3.11 lb./hr. of PM.
    i. Output grain loading or control efficiency and input grain loading – 0.0027 gr/acfm dry particulate outlet grain loading.
    ii. Exhaust flow: 135,000 ACFM @ 350F & 1 atm pressure.
    iii. Dimensions including height of exhaust stack: .Typical exhaust stack height is 75 Ft.
    iv. Temperature of effluent : 300 to 350 F

b. Please confirm that the following exhaust through the FBC/Boiler baghouse:
    i. Boilers (high pressure boiler and glycol heater)
    ii. FBC Combustor
    iii. FBC Pre-Burner
    iv. Multiclone cyclone
    v. Flash steam from SteamEx process – Line 5 from Andritz Design Criteria (SteamEx Blow Tank Exhaust) – fed into FBC
    vi. Line 4 from Andritz Design Criteria – (Pre-Steaming Bin Exhaust) – Fed into FBC
    vii. Line 16 from Andritz Design Criteria - (Pellet Mill Exhaust) – Fed into FBC
    viii. Pellet Cooling/De-dusting Air – Fed into FBC (2 points on DWG 000.02, grid J1 & J7) – Fed to FBC, labeled 'Multiclone 1' and 'Multiclone 2'

APPENDIX E: VOLUME SOURCE PARAMETERS

System	Description	Dimensions			Volume Source Parameters				Control	Comments
		Length (ft)	Width (ft)	Height (ft)	Source Horiz. Width (ft)	Source Release Height (ft)	Initial Lateral Dimension (ft)	Initial Vertical Dimension (ft)		
	HOG FUEL PROCESS									
HF1	Truck Unloading to Hog Fuel Tipper		8	13.5	8	6.75	1.86	3.14	Material moisture content	Truck material transfer opening size
HF2	Hog Fuel Pile to Hopper #4/Screw Feeder #4 via Front Loader	15	10	9.0	10	9.0	3.49	2.09	Material moisture content	Hopper Dimensions
HF3	Fuel Screen #1 and transfers (in from Hopper #4, out to Bucket Elevator #1)		4	5.0	4	5.0	0.93	0.23	Material moisture content	Assume screen is 4ft wide and 5ft tall. Drop distance is 1ft
HF4	Bucket Elevator #1 to Surge Bin #2		2	20.0	2	20.0	0.47	0.23	Material moisture content	Assume bucket elevator spout is 2ft wide and 20ft tall. Drop distance is 1ft
HF5	Surge Bin #2 to Pnuematic System #5								Pnuematic Enclosure	
HF6	Pneumatic System #5 to Combustor								Pnuematic Enclosure	
	FEEDSTOCK PROCESS									**ALL DROP DISTANCES ARE ASSUMED TO BE 1 foot.**
FS1	Truck Unloading to Feedstock Tipper #1		8	13.5	8	6.75	1.86	3.14	Material Moisture Content	Truck material transfer opening size
FS2	Feedstock Pile to Hopper #1, 2 or 3 via Front Loader	15	10	9.0	10	9.0	3.49	0.23	Material Moisture Content	Hopper Dimensions
FS3	Hopper #1, 2 or 3 to Conveyor #1		4	5.0	4	6.5	0.93	0.23	Material Moisture Content	Conveyor is 4 ft wide. Hopper is 9 ft tall, assume bottom of hopper is 6.5 ft above ground.
FS4	Conveyor #1 to Feed Screw #1		4	8.0	4	8.0	0.93	0.23	Material Moisture Content	Conveyor is 4 ft wide. Assume conveyor rises at incline from 4 ft to 8 ft above ground.
FS5	Conveyor #1 to Feed Screw #2		4	8.0	4	8.0	0.93	0.23	Material Moisture Content	Conveyor is 4 ft wide. Assume conveyor rises at incline from 4 ft to 8 ft above ground.
FS6	Green Hammer Mill #1 and transfers (in from Feed Screw #1, out to Green Cyclone #1)		4	7.0	4	7	0.93	0.23	Material Moisture Content	Assume Green Hammer Mill is 4 ft wide and 7 ft tall.
FS7	Green Hammer Mill #2 and transfers (in from Feed Screw #2, out to Green Cyclone #2)		4	7.0	4	7	0.93	0.23	Material Moisture Content	Assume Green Hammer Mill is 4 ft wide and 7 ft tall.
FS8	Green Cyclone #1 to Conveyor #2		4	5.0	4	5.0	0.93	0.23	Material Moisture Content	Conveyor is 4 ft wide. Assume bottom of cyclone is 5 ft tall.
FS9	Green Cyclone #2 to Conveyor #2		4	5.0	4	5.0	0.93	0.23	Material Moisture Content	Conveyor is 4 ft wide. Assume bottom of cyclone is 5 ft tall.
FS10	Conveyor #2 to Conveyor #3 (Inside Tower 1)		4	45.0	4	45.0	0.93	0.23	Enclosure	Conveyor is 4 ft wide. Tower 1 is 45 ft tall.
FS11	Conveyor #3 to Steam Ex Preheat Bin								Inside Building	
FS12	SteamEx Preheat Bin to Conveyor #4								Inside Building	
FS13	Conveyor #4 to Belt Dryer								Inside Building	
FS14	Belt Dryer to Conveyor #5								Inside Building	
FS15	Conveyor #5 to Feed Screw #3		4	8.0	4	8.0	0.93	0.23	Material Moisture Content	Conveyor is 4 ft wide. Assume conveyor rises at incline from 4 ft to 8 ft above ground.
FS16	Feed Screw #3 to Dry Hammer Mill		4	7.0	4	7.0	0.93	0.23	Material Moisture Content	Assume screen and hammer mill are 4 ft wide, feed screw is 7 ft tall.
FS17	Dry Hammer Mill to Dry Cyclone #1		2	4.0	2	4.0	0.47	0.23	Bag Filter	Assume chute from hammer to cyclone is 2 ft wide, cyclone is 4 ft tall.
FS18	Dry Cyclone #1 to Pneumatic System #1								Pnuematic Enclosure	
FS19	Pnuematic System #1 to Surge Bin #1								Pnuematic Enclosure	
FS20	Surge Bin #1 to Conveyor #6		2	3.0	2	3.0	0.47	0.23	Material Moisture Content	Assume chute from bin to conveyor is 2 ft wide, bottom of bin is 3 ft above ground.
FS21	Conveyor #6 to Conveyor #7								Inside Building	
FS22	Conveyor #7 to Mill Feed Bin #1 and #2								Inside Building	
FS23	Mill Feed Bin #1 and #2 to Mill Feed Screws #1, 2, 3 and 4								Inside Building	
FS24	Mill Feed Screws #1, 2, 3, and 4 to Conditioning Screws #1, 2, 3 and 4								Inside Building	
FS25	Pellet Mills #1, 2, 3 and 4 and transfers (in from Conditioning Screws #1-4 and out to Conveyor #9)								Inside Building	
FS26	Conveyor #9 to Pellet Cooler #1								Inside Building	
FS27	Pellet Cooler #1 to Conveyor #11								Inside Building	
FS28	Pellet Cooler #1 to Multiclone #1								Inside Building	
FS29	Pellet Screen #1 and transfers (in from Conveyor #11, out to Pneumatic System #3)								Inside Building	
FS30	Multiclone #1 to Pneumatic System #2								Inside Building	
FS31	Conveyor #6 to Conveyor #8								Inside Building	
FS32	Conveyor #8 to Mill Feed Bin #3 and #4								Inside Building	
FS33	Mill Feed Bin #3 and #4 to Mill Feed Screws #5, 6, 7 and 8								Inside Building	
FS34	Mill Feed Screws #5, 6, 7, and 8 to Conditioning Screws #5, 6, 7 and 8								Inside Building	
FS35	Pellet Mills #5, 6, 7 and 8 and transfers (in from Conditioning Screws #5-8 and out to Conveyor #10)								Inside Building	
FS36	Conveyor #10 to Pellet Cooler #2								Inside Building	
FS37	Pellet Cooler #2 to Conveyor #12								Inside Building	
FS38	Pellet Cooler #2 to Multiclone #2								Inside Building	
FS39	Pellet Screen #2 and transfers (in from Conveyor #12, out to Pneumatic System #3)								Inside Building	
FS40	Multiclone #2 to Pneumatic System #2								Inside Building	

System	Description	Dimensions			Volume Source Parameters				Control	Comments
		Length (ft)	Width (ft)	Height (ft)	Source Horiz. Width (ft)	Source Release Height (ft)	Initial Lateral Dimension (ft)	Initial Vertical Dimension (ft)		
FS41	Pneumatic System #2 to Surge Bin #1								Pnuematic Enclosure	
FS42	Pnuematic System #3 to Pellet Product Stockpile		1	70.0	1	70.0	0.23	8.14	Material Moisture Content	Assume pipe is 1 ft wide, stockpile is 70 ft tall. Average drop distance is 35 ft.
FS43	Pellet Product Stockpile to Hopper #5 via Front Loader		10	9.0	10	9.0	2.33	0.23	Material Moisture Content	Hopper Dimensions
FS44	Hopper #5 to Conveyor #13		4	5.0	4	6.5	0.93	0.23	Material Moisture Content	Conveyor is 4 ft wide. Hopper is 9 ft tall, assume bottom of hopper is 6.5 ft above ground.
FS45	Shipping Screens and transfers (in from Conveyor #13, out to Conveyor #14)		4	25.0	4	25.0	0.93	0.23	Enclosure	Conveyor is 4 ft wide. Assume screens are 25 ft tall.
FS46	Shipping Screen to Pneumatic System #4								Pnuematic Enclosure	
FS47	Conveyor #14 to Filling Spout		4	20.0	4	20.0	0.93	0.23	Material Moisture Content	Conveyor is 4 ft wide. Assume top of filling spout is 20 ft tall.
FS48	Filling Spout to Rail Car		2	15.0	2	15	0.47	0.23	Material Moisture Content	Conveyor is 4 ft wide. Assume bottom of filling spout is 15 ft tall.
FS49	Pneumatic System #4 to Surge Bin #1								Pneumatic Enclosure	

APPENDIX F: METEOROLOGICAL DATA MEMO

M E M O R A N D U M

DATE: **April 7**, 2016

TO: Shannon Manoulian , Trinity Consultants

FROM: Thomas Swain, Air Quality Modeler, Analyst 3, Air Program

PROJECT: Proposed Facility in Potlatch, Idaho

SUBJECT: Request for available meteorological to be used for air quality modeling in Potlatch, Idaho

Shannon

This memorandum is in response to your request for available meteorological data that could be used in air quality modeling analyses in the Potlatch, Idaho area. It appears that DEQ does not have a model ready data set for Potlatch in its archive files. We have looked at the available data sets from the regional ASOS airport sites (Spokane, WA, Couer D'Alene, ID, and Pullman WA/ Moscow ID, and compared them to a RAWS site (ID POTI1) that exists in Potlatch, Idaho. This site, as shown in Figure 1, is located near your proposed facility location. Enclosed are wind roses and frequency graphs for the RAWS site and the three airport ASOS locations. The RAWS data is probably not adequate for large air quality modeling efforts, but certainly should demonstrate local wind flow characteristics.

None of the airport data sets match ideally with the POTI1 data. In general, the Spokane data compares better than the other two, although the south/southeast flows are more pronounced. However, Spokane and Couer D'Alene are both over 50 miles to the north and located in different topographical regions. By far the nearest data set (less than 20 miles) is from Pullman, and would contain the best available data for cloud cover, ceiling height, and temperature (essential for AERMET/AERMOD processing). The wind flows at the Pullman location, however, are characterized by the hills surrounding the airport, and a predominant east – west flow pattern is created. It appears that the flows have been "redirected" about a sector clockwise from that seen in the data from Potlatch, which is in a more open topography. By shifting the winds in the Pullman data one sector counterclockwise, a new "revised" data set was created implementing this shift, and is hereby referred to as "Pullman/Potlatch" data set. The wind roses created from this data set seem to match very well with those created from the POTI1 data.

DEQ agrees that this is a non-standard approach, but it will allow the applicant to use the "revised Pullman data" for air quality modeling in an analysis to support a minor source permit application in Potlatch. The applicant always has the option to demonstrate that another meteorological data set is

adequate, and can submit that analyses to DEQ for review. Please be advised that the process of reviewing an alternate data set may take additional time. Also, if the facility becomes “major” and/or PSD, then it is up to the applicant to demonstrate that an adequate meteorological data set will be used in the ensuing modeling analyses, and it is likely that the applicant may need to consider onsite monitoring of meteorological data.

If the applicant would like to use this data please contact Thomas Swain at 208 373 0220 or Darrin Mehr at 208-373-0536.

Thomas M Swain

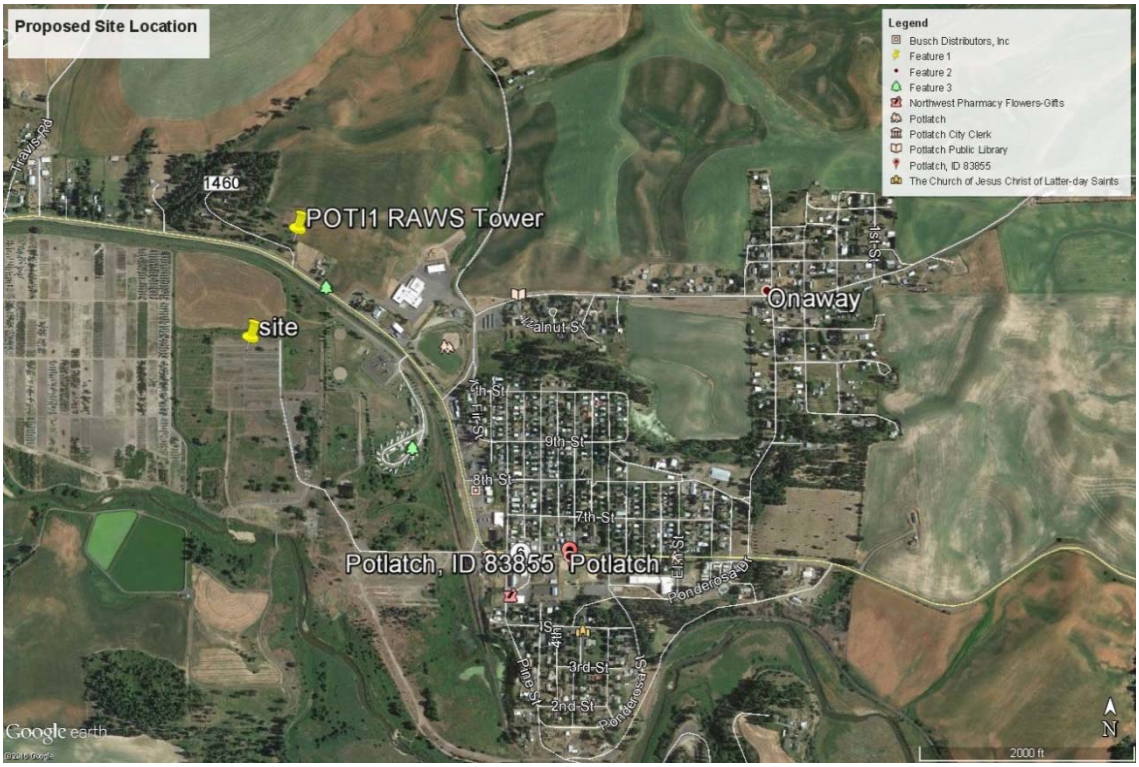
Department of Environmental Quality

Analysyt 3/ Air Quality Modeler

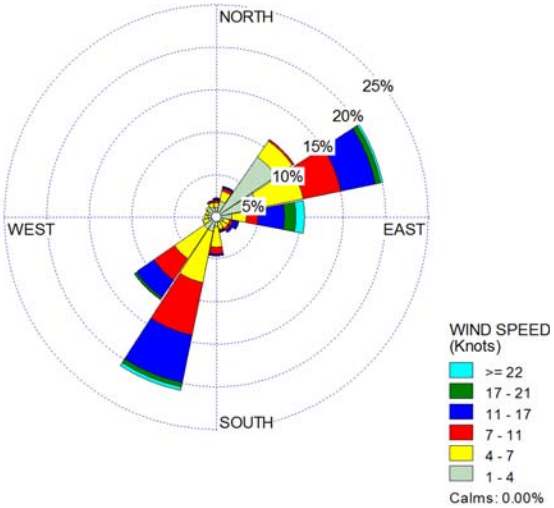
Thomas.swain@deq.idaho.gov

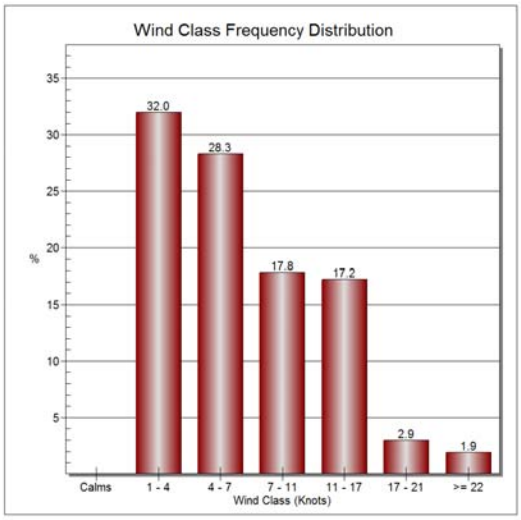
208 373 0220

Figure 1 Proposed Site Location and RAWS Tower location

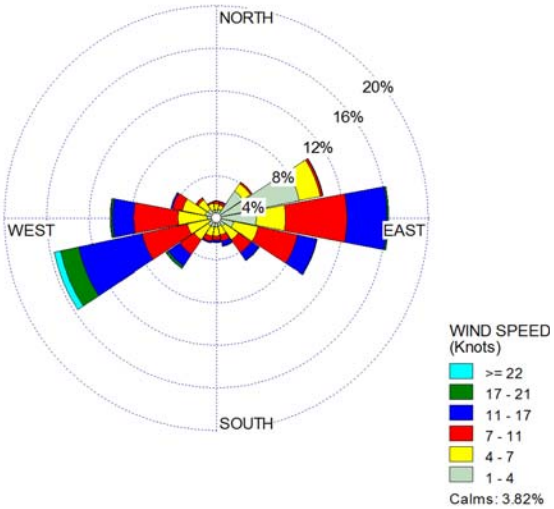


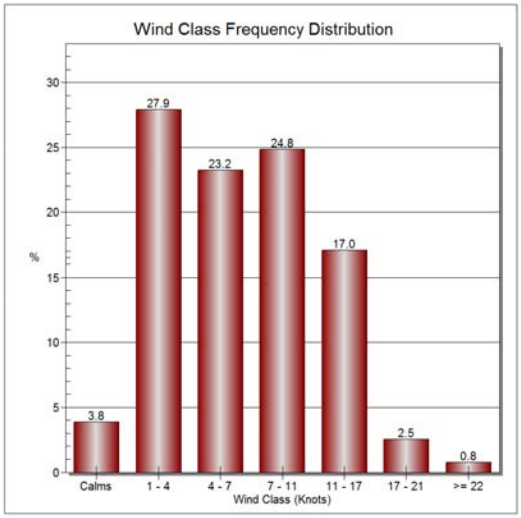
POTLATCH RAWS data 2015



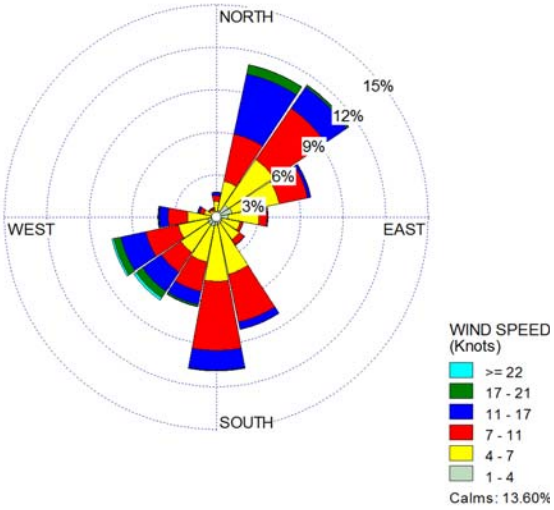


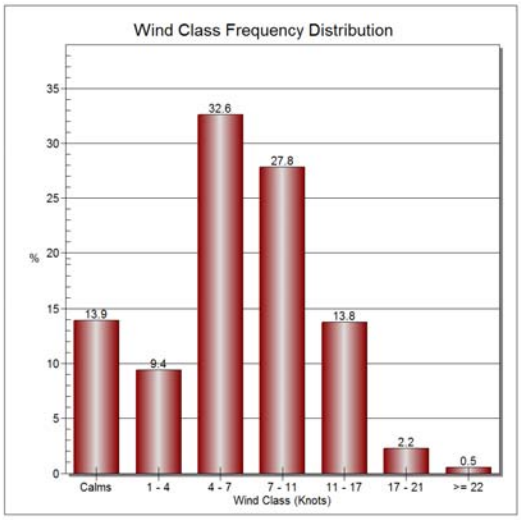
Pullman/Moscow



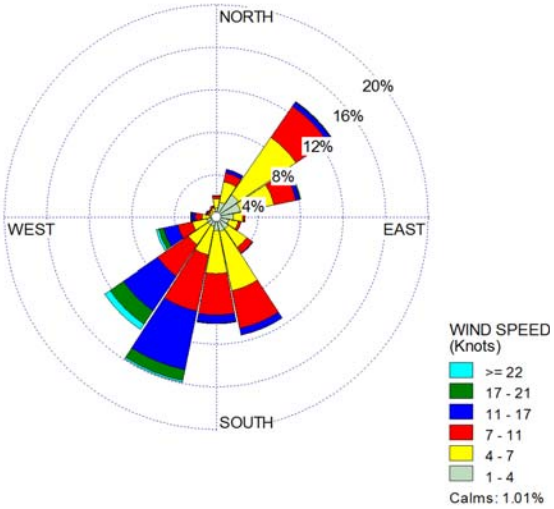


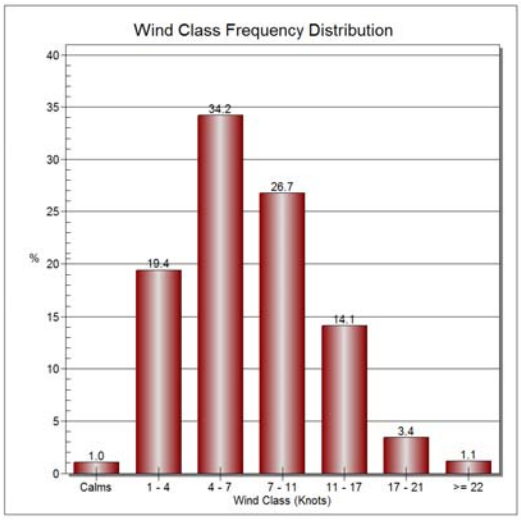
Couer D' Alene



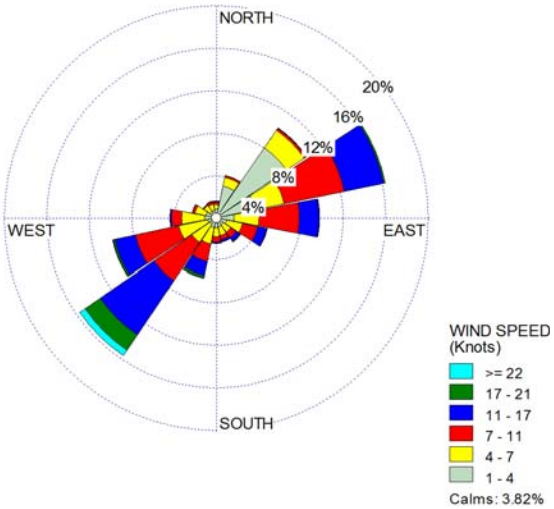


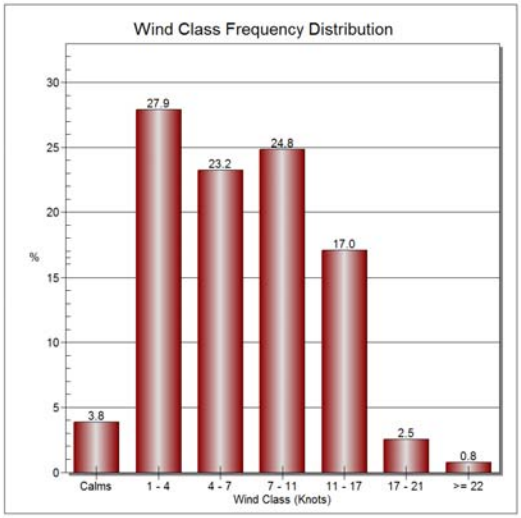
Spokane





Shifted Pullman one sector/ "Pullman/Potlatch"





APPENDIX G: MODELING INPUT AND OUTPUT FILES

APPENDIX F: IDEQ FORM FRA

IDAHO DEPARTMENT OF ENVIRONMENTAL QUALITY
AIR QUALITY DIVISION
1410 N. Hilton, Boise, ID 83706
For assistance, call the
Air Permit Hotline – 1-877-5PERMIT

Preapplication Meeting Information Form FRA (Federal Requirements Applicability) - Regulatory Review

In each box in the table below, CTRL+click on the blue underlined text for instructions and information.

IDENTIFICATION	
1. Company Name:	2. Facility Name:
Centennial Renewable Energy	Potlach Facility
3. Brief Project Description:	CRE is proposing to construct and operate a Greenfield wood pellet production facility near Potlach, Idaho. The facility will produce a proprietary product known as SteamEx Pellets with technology from the Andritz Corporation. The final product will utilize short fiber wood waste from regional mills as feedstock.

APPLICABILITY DETERMINATION	
4. List all applicable subparts of the New Source Performance Standards (NSPS) (40 CFR part 60). List all non-applicable subparts of the NSPS which may appear to apply to the facility but do not. Examples of NSPS-affected emissions units include internal combustion engines, boilers, turbines, etc. Applicant must thoroughly review the list of affected emissions units.	List of all applicable subpart(s): Subpart Db List of all non-applicable subpart(s) which may appear to apply but do not: ☐ Not Applicable
5. List applicable subpart(s) of the National Emission Standards for Hazardous Air Pollutants (NESHAPs) (40 CFR part 61 and 40 CFR part 63). List all non-applicable subparts of the NESHAP which may appear to apply to the facility but do not. Examples of affected emission units include solvent cleaning operations, industrial cooling towers, paint stripping and miscellaneous surface coating. Reference EPA's webpage on NESHAPs for more information.	List of all applicable subpart(s): Subpart DDDDD List of all non-applicable subpart(s) which may appear to apply but do not: ☐ Not Applicable
6. For each subpart identified above, conduct a complete regulatory analysis using the instructions and referencing the example on the following pages. **Note** - Regulatory reviews must be submitted with sufficient detail so that DEQ can verify applicability and document in legal terms why the regulation does or does not apply. Regulatory reviews submitted with insufficient detail will be determined incomplete.	☑ A detailed regulatory review is provided (Follow instructions and example). ☐ DEQ has already been provided a detailed regulatory review. Give a reference to the document including the date.

Subpart DDDDD—National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters

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SOURCE: 76 FR 15664, Mar. 21, 2011, unless otherwise noted.

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WHAT THIS SUBPART COVERS

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§63.7480 What is the purpose of this subpart?

This subpart establishes national emission limitations and work practice standards for hazardous air pollutants (HAP) emitted from industrial, commercial, and institutional boilers and process heaters located at major sources of HAP. This subpart also establishes requirements to demonstrate initial and continuous compliance with the emission limitations and work practice standards.

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§63.7485 Am I subject to this subpart?

You are subject to this subpart if you own or operate an industrial, commercial, or institutional boiler or process heater as defined in §63.7575 that is located at, or is part of, a major source of HAP, except as specified in §63.7491. For purposes of this subpart, a major source of HAP is as defined in §63.2, except that for oil and natural gas production facilities, a major source of HAP is as defined in §63.7575.

The Fluidized Bed Combustor at the proposed CRE Potlach facility is subject to this subpart because it is an industrial boiler and the CRE facility will be a major source of HAPs.

[78 FR 7162, Jan. 31, 2013]

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§63.7490 What is the affected source of this subpart?

(a) This subpart applies to new, reconstructed, and existing affected sources as described in paragraphs (a)(1) and (2) of this section.

(1) The affected source of this subpart is the collection at a major source of all existing industrial, commercial, and institutional boilers and process heaters within a subcategory as defined in §63.7575.

(2) The affected source of this subpart is each new or reconstructed industrial, commercial, or institutional boiler or process heater, as defined in §63.7575, located at a major source.

The FBC will be a new industrial boiler; construction will commence after June 4, 2010.

(b) A boiler or process heater is new if you commence construction of the boiler or process heater after June 4, 2010, and you meet the applicability criteria at the time you commence construction.

(c) A boiler or process heater is reconstructed if you meet the reconstruction criteria as defined in §63.2, you commence reconstruction after June 4, 2010, and you meet the applicability criteria at the time you commence reconstruction.

(d) A boiler or process heater is existing if it is not new or reconstructed.

(e) An existing electric utility steam generating unit (EGU) that meets the applicability requirements of this subpart after the effective date of this final rule due to a change (e.g., fuel switch) is considered to be an existing source under this subpart.

[76 FR 15664, Mar. 21, 2011, as amended at 78 FR 7162, Jan. 31, 2013]

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§63.7491 Are any boilers or process heaters not subject to this subpart?

The types of boilers and process heaters listed in paragraphs (a) through (n) of this section are not subject to this subpart.

(a) An electric utility steam generating unit (EGU) covered by subpart UUUUU of this part or a natural gas-fired EGU as defined in subpart UUUUU of this part firing at least 85 percent natural gas on an annual heat input basis.

(b) A recovery boiler or furnace covered by subpart MM of this part.

(c) A boiler or process heater that is used specifically for research and development, including test steam boilers used to provide steam for testing the propulsion systems on military vessels. This does not include units that provide heat or steam to a process at a research and development facility.

(d) A hot water heater as defined in this subpart.

(e) A refining kettle covered by subpart X of this part.

(f) An ethylene cracking furnace covered by subpart YY of this part.

(g) Blast furnace stoves as described in EPA-453/R-01-005 (incorporated by reference, see §63.14).

(h) Any boiler or process heater that is part of the affected source subject to another subpart of this part, such as boilers and process heaters used as control devices to comply with subparts JJJ, OOO, PPP, and U of this part.

(i) Any boiler or process heater that is used as a control device to comply with another subpart of this part, or part 60, part 61, or part 65 of this chapter provided that at least 50 percent of the average annual heat input during any 3 consecutive calendar years to the boiler or process heater is provided by regulated gas streams that are subject to another standard.

(j) Temporary boilers and process heaters as defined in this subpart.

(k) Blast furnace gas fuel-fired boilers and process heaters as defined in this subpart.

(l) Any boiler or process heater specifically listed as an affected source in any standard(s) established under section 129 of the Clean Air Act.

(m) A unit that burns hazardous waste covered by Subpart EEE of this part. A unit that is exempt from Subpart EEE as specified in §63.1200(b) is not covered by Subpart EEE.

(n) Residential boilers as defined in this subpart.

[76 FR 15664, Mar. 21, 2011, as amended at 78 FR 7162, Jan. 31, 2013; 80 FR 72806, Nov. 20, 2015]

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§63.7495 When do I have to comply with this subpart?

(a) If you have a new or reconstructed boiler or process heater, you must comply with this subpart by April 1, 2013, or upon startup of your boiler or process heater, whichever is later.

CRE will comply with subpart upon startup of the FBC.

(b) If you have an existing boiler or process heater, you must comply with this subpart no later than January 31, 2016, except as provided in §63.6(i).

(c) If you have an area source that increases its emissions or its potential to emit such that it becomes a major source of HAP, paragraphs (c)(1) and (2) of this section apply to you.

(1) Any new or reconstructed boiler or process heater at the existing source must be in compliance with this subpart upon startup.

(2) Any existing boiler or process heater at the existing source must be in compliance with this subpart within 3 years after the source becomes a major source.

(d) You must meet the notification requirements in §63.7545 according to the schedule in §63.7545 and in subpart A of this part. Some of the notifications must be submitted before you are required to comply with the emission limits and work practice standards in this subpart.

CRE will comply with the notification requirements, including but not limited to Initial Notification and notification of stack testing, as highlighted and indicated in the specific sections below.

(e) If you own or operate an industrial, commercial, or institutional boiler or process heater and would be subject to this subpart except for the exemption in §63.7491(l) for commercial and industrial solid waste incineration units covered by part 60, subpart CCCC or subpart DDDD, and you cease combusting solid waste, you must be in compliance with this subpart and are no longer subject to part 60,

subparts CCCC or DDDD beginning on the effective date of the switch as identified under the provisions of §60.2145(a)(2) and (3) or §60.2710(a)(2) and (3).

(f) If you own or operate an existing EGU that becomes subject to this subpart after January 31, 2016, you must be in compliance with the applicable existing source provisions of this subpart on the effective date such unit becomes subject to this subpart.

(g) If you own or operate an existing industrial, commercial, or institutional boiler or process heater and would be subject to this subpart except for a exemption in §63.7491(i) that becomes subject to this subpart after January 31, 2013, you must be in compliance with the applicable existing source provisions of this subpart within 3 years after such unit becomes subject to this subpart.

(h) If you own or operate an existing industrial, commercial, or institutional boiler or process heater and have switched fuels or made a physical change to the boiler or process heater that resulted in the applicability of a different subcategory after the compliance date of this subpart, you must be in compliance with the applicable existing source provisions of this subpart on the effective date of the fuel switch or physical change.

(i) If you own or operate a new industrial, commercial, or institutional boiler or process heater and have switched fuels or made a physical change to the boiler or process heater that resulted in the applicability of a different subcategory, you must be in compliance with the applicable new source provisions of this subpart on the effective date of the fuel switch or physical change.

[76 FR 15664, Mar. 21, 2011, as amended at 78 FR 7162, Jan. 31, 2013; 80 FR 72807, Nov. 20, 2015]

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EMISSION LIMITATIONS AND WORK PRACTICE STANDARDS

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§63.7499 What are the subcategories of boilers and process heaters?

The subcategories of boilers and process heaters, as defined in §63.7575 are:

(a) Pulverized coal/solid fossil fuel units.

(b) Stokers designed to burn coal/solid fossil fuel.

(c) Fluidized bed units designed to burn coal/solid fossil fuel.

(d) Stokers/sloped grate/other units designed to burn kiln dried biomass/bio-based solid.

(e) Fluidized bed units designed to burn biomass/bio-based solid.

The CRE FBC belongs to this subcategory.

(f) Suspension burners designed to burn biomass/bio-based solid.

(g) Fuel cells designed to burn biomass/bio-based solid.

(h) Hybrid suspension/grate burners designed to burn wet biomass/bio-based solid.

(i) Stokers/sloped grate/other units designed to burn wet biomass/bio-based solid.

(j) Dutch ovens/pile burners designed to burn biomass/bio-based solid.

(k) Units designed to burn liquid fuel that are non-continental units.

(l) Units designed to burn gas 1 fuels.

(m) Units designed to burn gas 2 (other) gases.

(n) Metal process furnaces.

(o) Limited-use boilers and process heaters.

(p) Units designed to burn solid fuel.

(q) Units designed to burn liquid fuel.

(r) Units designed to burn coal/solid fossil fuel.

(s) Fluidized bed units with an integrated fluidized bed heat exchanger designed to burn coal/solid fossil fuel.

(t) Units designed to burn heavy liquid fuel.

(u) Units designed to burn light liquid fuel.

[76 FR 15664, Mar. 21, 2011, as amended at 78 FR 7163, Jan. 31, 2013]

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§63.7500 What emission limitations, work practice standards, and operating limits must I meet?

(a) You must meet the requirements in paragraphs (a)(1) through (3) of this section, except as provided in paragraphs (b), through (e) of this section. You must meet these requirements at all times the affected unit is operating, except as provided in paragraph (f) of this section.

(1) You must meet each emission limit and work practice standard in Tables 1 through 3, and 11 through 13 to this subpart that applies to your boiler or process heater, for each boiler or process heater at your source, except as provided under §63.7522. The output-based emission limits, in units of pounds per million Btu of steam output, in Tables 1 or 2 to this subpart are an alternative applicable only to boilers and process heaters that generate either steam, cogenerate steam with electricity, or both. The output-based emission limits, in units of pounds per megawatt-hour, in Tables 1 or 2 to this subpart are an alternative applicable only to boilers that generate only electricity. Boilers that perform multiple functions (cogeneration and electricity generation) or supply steam to common headers would calculate a total steam energy output using equation 21 of §63.7575 to demonstrate compliance with the output-based emission limits, in units of pounds per million Btu of steam output, in Tables 1 or 2 to this subpart. If you operate a new boiler or process heater, you can choose to comply with alternative limits as discussed in paragraphs (a)(1)(i) through (iii) of this section, but on or after January 31, 2016, you must comply with the emission limits in Table 1 to this subpart.

CRE will meet the applicable emission limits and work practices in Tables 1 and 3. Tables 2 and 11 through 13 are not applicable to the CRE FBC which will be constructed in 2016.

(i) If your boiler or process heater commenced construction or reconstruction after June 4, 2010 and before May 20, 2011, you may comply with the emission limits in Table 1 or 11 to this subpart until January 31, 2016.

(ii) If your boiler or process heater commenced construction or reconstruction on or after May 20, 2011 and before December 23, 2011, you may comply with the emission limits in Table 1 or 12 to this subpart until January 31, 2016.

(iii) If your boiler or process heater commenced construction or reconstruction on or after December 23, 2011 and before April 1, 2013, you may comply with the emission limits in Table 1 or 13 to this subpart until January 31, 2016.

(2) You must meet each operating limit in Table 4 to this subpart that applies to your boiler or process heater. If you use a control device or combination of control devices not covered in Table 4 to this subpart, or you wish to establish and monitor an alternative operating limit or an alternative monitoring parameter, you must apply to the EPA Administrator for approval of alternative monitoring under §63.8(f).

(3) At all times, you must operate and maintain any affected source (as defined in §63.7490), including associated air pollution control equipment and monitoring equipment, in a manner consistent with safety and good air pollution control practices for minimizing emissions. Determination of whether such operation and maintenance procedures are being used will be based on information available to the Administrator that may include, but is not limited to, monitoring results, review of operation and maintenance procedures, review of operation and maintenance records, and inspection of the source.

(b) As provided in §63.6(g), EPA may approve use of an alternative to the work practice standards in this section.

(c) Limited-use boilers and process heaters must complete a tune-up every 5 years as specified in §63.7540. They are not subject to the emission limits in Tables 1 and 2 or 11 through 13 to this subpart, the annual tune-up, or the energy assessment requirements in Table 3 to this subpart, or the operating limits in Table 4 to this subpart.

(d) Boilers and process heaters with a heat input capacity of less than or equal to 5 million Btu per hour in the units designed to burn gas 2 (other) fuels subcategory or units designed to burn light liquid fuels subcategory must complete a tune-up every 5 years as specified in §63.7540.

(e) Boilers and process heaters in the units designed to burn gas 1 fuels subcategory with a heat input capacity of less than or equal to 5 million Btu per hour must complete a tune-up every 5 years as specified in §63.7540. Boilers and process heaters in the units designed to burn gas 1 fuels subcategory with a heat input capacity greater than 5 million Btu per hour and less than 10 million Btu per hour must complete a tune-up every 2 years as specified in §63.7540. Boilers and process heaters in the units designed to burn gas 1 fuels subcategory are not subject to the emission limits in Tables 1 and 2 or 11 through 13 to this subpart, or the operating limits in Table 4 to this subpart.

(f) These standards apply at all times the affected unit is operating, except during periods of startup and shutdown during which time you must comply only with items 5 and 6 of Table 3 to this subpart.

Table 1 to Subpart DDDDD of Part 63—Emission Limits for New or Reconstructed Boilers and Process Heaters

If your boiler or process heater is in this subcategory . . .	For the following pollutants . . .	The emissions must not exceed the following emission limits, except during startup and shutdown . . .	Or the emissions must not exceed the following alternative output-based limits, except during startup and shutdown . . .	Using this specified sampling volume or test run duration . . .
1. Units in all subcategories designed to burn solid fuel.	a. HCl	2.2E-02 lb per MMBtu of heat input	2.5E-02 lb per MMBtu of steam output or 0.28 lb per MWh	For M26A, collect a minimum of 1 dscm per run; for M26 collect a minimum of 120 liters per run.
	b. Mercury	8.0E-07[a] lb per MMBtu of heat input	8.7E-07[a] lb per MMBtu of steam output or 1.1E-05[a] lb per MWh	For M29, collect a minimum of 4 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784[b]collect a minimum of 4 dscm.
9. Fluidized bed units designed to burn biomass/bio-based solids	a. CO (or CEMS)	230 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (310 ppm by volume on a dry basis corrected to 3 percent oxygen,[d]30-day rolling average)	2.2E-01 lb per MMBtu of steam output or 2.6 lb per MWh; 3-run average	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	9.8E-03 lb per MMBtu of heat input; or (8.3E-05[a] lb per MMBtu of heat input)	1.2E-02 lb per MMBtu of steam output or 0.14 lb per MWh; or (1.1E-04[a] lb per MMBtu of steam output or 1.2E-03[a] lb per MWh)	Collect a minimum of 3 dscm per run.

FBC emissions were calculated using conservative emission factors from AP-42 Section 1.6 Wood Residue Combustion in Boilers, Tables 1.6-1, 1.6-2, and 1.6-3. Actual emissions from the CRE FBC and compliance with the emission limits in Table 1 of this subpart will be confirmed based on the initial source test.

Table 3 to Subpart DDDDD of Part 63—Work Practice Standards

If your unit is . . .	You must meet the following . . .
3. A new or existing boiler or process heater without a continuous oxygen trim system and with heat input capacity of 10 million Btu per hour or greater	Conduct a tune-up of the boiler or process heater annually as specified in §63.7540. Units in either the Gas 1 or Metal Process Furnace subcategories will conduct this tune-up as a work practice for all regulated emissions under this subpart. Units in all other subcategories will conduct this tune-up as a work practice for dioxins/furans.

5. An existing or new boiler or process heater subject to emission limits in Table 1 or 2 or 11 through 13 to this subpart during startup	a. You must operate all CMS during startup. b. For startup of a boiler or process heater, you must use one or a combination of the following clean fuels: Natural gas, synthetic natural gas, propane, other Gas 1 fuels, distillate oil, syngas, ultra-low sulfur diesel, fuel oil-soaked rags, kerosene, hydrogen, paper, cardboard, refinery gas, liquefied petroleum gas, clean dry biomass, and any fuels meeting the appropriate HCl, mercury and TSM emission standards by fuel analysis. c. You have the option of complying using either of the following work practice standards. (1) If you choose to comply using definition (1) of "startup" in §63.7575, once you start firing fuels that are not clean fuels, you must vent emissions to the main stack(s) and engage all of the applicable control devices except limestone injection in fluidized bed combustion (FBC) boilers, dry scrubber, fabric filter, and selective catalytic reduction (SCR). You must start your limestone injection in FBC boilers, dry scrubber, fabric filter, and SCR systems as expeditiously as possible. Startup ends when steam or heat is supplied for any purpose, OR (2) If you choose to comply using definition (2) of "startup" in §63.7575, once you start to feed fuels that are not clean fuels, you must vent emissions to the main stack(s) and engage all of the applicable control devices so as to comply with the emission limits within 4 hours of start of supplying useful thermal energy. You must engage and operate PM control within one hour of first feeding fuels that are not clean fuels[a]. You must start all applicable control devices as expeditiously as possible, but, in any case, when necessary to comply with other standards applicable to the source by a permit limit or a rule other than this subpart that require operation of the control devices. You must develop and implement a written startup and shutdown plan, as specified in §63.7505(e). d. You must comply with all applicable emission limits at all times except during startup and shutdown periods at which time you must meet this work practice. You must collect monitoring data during periods of startup, as specified in §63.7535(b). You must keep records during periods of startup. You must provide reports concerning activities and periods of startup, as specified in §63.7555.
6. An existing or new boiler or process heater subject to emission limits in Tables 1 or 2 or 11 through 13 to this subpart during shutdown	You must operate all CMS during shutdown. While firing fuels that are not clean fuels during shutdown, you must vent emissions to the main stack(s) and operate all applicable control devices, except limestone injection in FBC boilers, dry scrubber, fabric filter, and SCR but, in any case, when necessary to comply with other standards applicable to the source that require operation of the control device. If, in addition to the fuel used prior to initiation of shutdown, another fuel must be used to support the shutdown process, that additional fuel must be one or a combination of the following clean fuels: Natural gas, synthetic natural gas, propane, other Gas 1 fuels, distillate oil, syngas, ultra-low sulfur diesel, refinery gas, and liquefied petroleum gas. You must comply with all applicable emissions limits at all times except for startup or shutdown periods conforming with this work practice. You must collect monitoring data during periods of shutdown, as specified in §63.7535(b). You must keep records during periods of shutdown. You must provide reports concerning activities and periods of shutdown, as specified in §63.7555.

CRE will comply with this subpart by conducting a tuneup of the boiler annually. The FBC will only be fired on clean fuels, and will comply with all applicable startup and shutdown requirements. Records will be kept of all periods of startup and shutdown.

Table 4 to Subpart DDDDD of Part 63—Operating Limits for Boilers and Process Heaters

When complying with a Table 1, 2, 11, 12, or 13 numerical emission limit using . . .	You must meet these operating limits . . .
7. Performance testing	For boilers and process heaters that demonstrate compliance with a performance test, maintain the 30-day rolling average operating load of each unit such that it does not exceed 110 percent of the highest hourly average operating load recorded during the performance test.

CRE will demonstrate compliance with the emissions limits in Table 1 through performance testing. The 30-day rolling average operating load of each unit such that it does not exceed 110 percent of the highest hourly average operating load recorded during the performance test.

[76 FR 15664, Mar. 21, 2011, as amended at 78 FR 7163, Jan. 31, 2013; 80 FR 72807, Nov. 20, 2015]

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§63.7501 [Reserved]

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GENERAL COMPLIANCE REQUIREMENTS

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§63.7505 What are my general requirements for complying with this subpart?

(a) You must be in compliance with the emission limits, work practice standards, and operating limits in this subpart. These emission and operating limits apply to you at all times the affected unit is operating except for the periods noted in §63.7500(f).

(b) [Reserved]

(c) You must demonstrate compliance with all applicable emission limits using performance stack testing, fuel analysis, or continuous monitoring systems (CMS), including a continuous emission monitoring system (CEMS), or particulate matter continuous parameter monitoring system (PM CPMS), where applicable. You may demonstrate compliance with the applicable emission limit for hydrogen chloride (HCl), mercury, or total selected metals (TSM) using fuel analysis if the emission rate calculated according to §63.7530(c) is less than the applicable emission limit. (For gaseous fuels, you may not use fuel analyses to comply with the TSM alternative standard or the HCl standard.) Otherwise, you must demonstrate compliance for HCl, mercury, or TSM using performance stack testing, if subject to an applicable emission limit listed in Tables 1, 2, or 11 through 13 to this subpart.

CRE will demonstrate compliance with all applicable emission limits using performance stack testing.

(d) If you demonstrate compliance with any applicable emission limit through performance testing and subsequent compliance with operating limits through the use of CPMS, or with a CEMS or COMS, you must develop a site-specific monitoring plan according to the requirements in paragraphs (d)(1) through (4) of this section for the use of any CEMS, COMS, or CPMS. This requirement also applies to you if you petition the EPA Administrator for alternative monitoring parameters under §63.8(f).

(1) For each CMS required in this section (including CEMS, COMS, or CPMS), you must develop, and submit to the Administrator for approval upon request, a site-specific monitoring plan that addresses design, data collection, and the quality assurance and quality control elements outlined in §63.8(d) and the elements described in paragraphs (d)(1)(i) through (iii) of this section. You must submit this site-specific monitoring plan, if requested, at least 60 days before your initial performance evaluation of your CMS. This requirement to develop and submit a site specific monitoring plan does not apply to affected sources with existing CEMS or COMS operated according to the performance specifications under appendix B to part 60 of this chapter and that meet the requirements of §63.7525. Using the process described in §63.8(f)(4), you may request approval of alternative monitoring system quality assurance and quality control procedures in place of those specified in this paragraph and, if approved, include the alternatives in your site-specific monitoring plan.

(i) Installation of the CMS sampling probe or other interface at a measurement location relative to each affected process unit such that the measurement is representative of control of the exhaust emissions (e.g., on or downstream of the last control device);

(ii) Performance and equipment specifications for the sample interface, the pollutant concentration or parametric signal analyzer, and the data collection and reduction systems; and

(iii) Performance evaluation procedures and acceptance criteria (e.g., calibrations, accuracy audits, analytical drift).

(2) In your site-specific monitoring plan, you must also address paragraphs (d)(2)(i) through (iii) of this section.

(i) Ongoing operation and maintenance procedures in accordance with the general requirements of §63.8(c)(1)(ii), (c)(3), and (c)(4)(ii);

(ii) Ongoing data quality assurance procedures in accordance with the general requirements of §63.8(d); and

(iii) Ongoing recordkeeping and reporting procedures in accordance with the general requirements of §63.10(c) (as applicable in Table 10 to this subpart), (e)(1), and (e)(2)(i).

(3) You must conduct a performance evaluation of each CMS in accordance with your site-specific monitoring plan.

(4) You must operate and maintain the CMS in continuous operation according to the site-specific monitoring plan.

(e) If you have an applicable emission limit, and you choose to comply using definition (2) of “startup” in §63.7575, you must develop and implement a written startup and shutdown plan (SSP) according to the requirements in Table 3 to this subpart. The SSP must be maintained onsite and available upon request for public inspection.

[76 FR 15664, Mar. 21, 2011, as amended at 78 FR 7164, Jan. 31, 2013; 80 FR 72807, Nov. 20, 2015]

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TESTING, FUEL ANALYSES, AND INITIAL COMPLIANCE REQUIREMENTS

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§63.7510 What are my initial compliance requirements and by what date must I conduct them?

(a) For each boiler or process heater that is required or that you elect to demonstrate compliance with any of the applicable emission limits in Tables 1 or 2 or 11 through 13 of this subpart through performance (stack) testing, your initial compliance requirements include all the following:

(1) Conduct performance tests according to §63.7520 and Table 5 to this subpart.

(2) Conduct a fuel analysis for each type of fuel burned in your boiler or process heater according to §63.7521 and Table 6 to this subpart, except as specified in paragraphs (a)(2)(i) through (iii) of this section.

(i) For each boiler or process heater that burns a single type of fuel, you are not required to conduct a fuel analysis for each type of fuel burned in your boiler or process heater according to §63.7521 and Table 6 to this subpart. For purposes of this subpart, units that use a supplemental fuel only for startup, unit shutdown, and transient flame stability purposes still qualify as units that burn a single type of fuel, and the supplemental fuel is not subject to the fuel analysis requirements under §63.7521 and Table 6 to this subpart.

(ii) When natural gas, refinery gas, or other gas 1 fuels are co-fired with other fuels, you are not required to conduct a fuel analysis of those Gas 1 fuels according to §63.7521 and Table 6 to this subpart. If gaseous fuels other than natural gas, refinery gas, or other gas 1 fuels are co-fired with other fuels and those non-Gas 1 gaseous fuels are subject to another subpart of this part, part 60, part 61, or part 65, you are not required to conduct a fuel analysis of those non-Gas 1 fuels according to §63.7521 and Table 6 to this subpart.

(iii) You are not required to conduct a chlorine fuel analysis for any gaseous fuels. You must conduct a fuel analysis for mercury on gaseous fuels unless the fuel is exempted in paragraphs (a)(2)(i) and (ii) of this section.

(3) Establish operating limits according to §63.7530 and Table 7 to this subpart.

(4) Conduct CMS performance evaluations according to §63.7525.

(b) For each boiler or process heater that you elect to demonstrate compliance with the applicable emission limits in Tables 1 or 2 or 11 through 13 to this subpart for HCl, mercury, or TSM through fuel analysis, your initial compliance requirement is to conduct a fuel analysis for each type of fuel burned in your boiler or process heater according to §63.7521 and Table 6 to this subpart and establish operating limits according to §63.7530 and Table 8 to this subpart. The fuels described in paragraph (a)(2)(i) and (ii) of this section are exempt from these fuel analysis and operating limit requirements. The fuels described in paragraph (a)(2)(ii) of this section are exempt from the chloride fuel analysis and operating limit requirements. Boilers and process heaters that use a CEMS for mercury or HCl are exempt from the performance testing and operating limit requirements specified in paragraph (a) of this section for the HAP for which CEMS are used.

(c) If your boiler or process heater is subject to a carbon monoxide (CO) limit, your initial compliance demonstration for CO is to conduct a performance test for CO according to Table 5 to this subpart or

conduct a performance evaluation of your continuous CO monitor, if applicable, according to §63.7525(a). Boilers and process heaters that use a CO CEMS to comply with the applicable alternative CO CEMS emission standard listed in Tables 1, 2, or 11 through 13 to this subpart, as specified in §63.7525(a), are exempt from the initial CO performance testing and oxygen concentration operating limit requirements specified in paragraph (a) of this section.

(d) If your boiler or process heater is subject to a PM limit, your initial compliance demonstration for PM is to conduct a performance test in accordance with §63.7520 and Table 5 to this subpart.

(e) For existing affected sources (as defined in §63.7490), you must complete the initial compliance demonstrations, as specified in paragraphs (a) through (d) of this section, no later than 180 days after the compliance date that is specified for your source in §63.7495 and according to the applicable provisions in §63.7(a)(2) as cited in Table 10 to this subpart, except as specified in paragraph (j) of this section. You must complete an initial tune-up by following the procedures described in §63.7540(a)(10)(i) through (vi) no later than the compliance date specified in §63.7495, except as specified in paragraph (j) of this section. You must complete the one-time energy assessment specified in Table 3 to this subpart no later than the compliance date specified in §63.7495.

(f) For new or reconstructed affected sources (as defined in §63.7490), you must complete the initial compliance demonstration with the emission limits no later than July 30, 2013 or within 180 days after startup of the source, whichever is later. If you are demonstrating compliance with an emission limit in Tables 11 through 13 to this subpart that is less stringent (that is, higher) than the applicable emission limit in Table 1 to this subpart, you must demonstrate compliance with the applicable emission limit in Table 1 no later than July 29, 2016.

(g) For new or reconstructed affected sources (as defined in §63.7490), you must demonstrate initial compliance with the applicable work practice standards in Table 3 to this subpart within the applicable annual, biennial, or 5-year schedule as specified in §63.7515(d) following the initial compliance date specified in §63.7495(a). Thereafter, you are required to complete the applicable annual, biennial, or 5-year tune-up as specified in §63.7515(d).

CRE will demonstrate compliance with the above highlighted sections by conducting performance tests according to §63.7520 and Table 5 to this subpart. The FBC burns a single type of fuel, and is therefore not required to conduct a fuel analysis. The FBC is subject a carbon monoxide (CO) limit, therefore the initial compliance demonstration for CO will be a performance test for CO according to Table 5 to this subpart. The FBC is subject to a PM limit; therefore the initial compliance demonstration for PM will be a performance test in accordance with §63.7520 and Table 5 to this subpart. CRE will complete the initial compliance demonstration with the emission limits within 180 days after startup of the FBC. CRE demonstrate initial compliance with the applicable work practice standards in Table 3 to this subpart within the annual schedule as specified in §63.7515(d) following the initial compliance date. Thereafter, CRE will complete the applicable annual tune-up as specified in §63.7515(d).

(h) For affected sources (as defined in §63.7490) that ceased burning solid waste consistent with §63.7495(e) and for which the initial compliance date has passed, you must demonstrate compliance within 60 days of the effective date of the waste-to-fuel switch. If you have not conducted your compliance demonstration for this subpart within the previous 12 months, you must complete all compliance demonstrations for this subpart before you commence or recommence combustion of solid waste.

(i) For an existing EGU that becomes subject after January 31, 2016, you must demonstrate compliance within 180 days after becoming an affected source.

(j) For existing affected sources (as defined in §63.7490) that have not operated between the effective date of the rule and the compliance date that is specified for your source in §63.7495, you must

complete the initial compliance demonstration, if subject to the emission limits in Table 2 to this subpart, as specified in paragraphs (a) through (d) of this section, no later than 180 days after the re-start of the affected source and according to the applicable provisions in §63.7(a)(2) as cited in Table 10 to this subpart. You must complete an initial tune-up by following the procedures described in §63.7540(a)(10)(i) through (vi) no later than 30 days after the re-start of the affected source and, if applicable, complete the one-time energy assessment specified in Table 3 to this subpart, no later than the compliance date specified in §63.7495.

(k) For affected sources, as defined in §63.7490, that switch subcategories consistent with §63.7545(h) after the initial compliance date, you must demonstrate compliance within 60 days of the effective date of the switch, unless you had previously conducted your compliance demonstration for this subcategory within the previous 12 months.

[78 FR 7164, Jan. 31, 2013, as amended at 80 FR 72808, Nov. 20, 2015]

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§63.7515 When must I conduct subsequent performance tests, fuel analyses, or tune-ups?

(a) You must conduct all applicable performance tests according to §63.7520 on an annual basis, except as specified in paragraphs (b) through (e), (g), and (h) of this section. Annual performance tests must be completed no more than 13 months after the previous performance test, except as specified in paragraphs (b) through (e), (g), and (h) of this section.

CRE will conduct all applicable performance tests according to §63.7520 on an annual basis. The annual performance tests must be completed no more than 13 months after the previous performance test. CRE will conduct an annual performance tune-up according to §63.7540(a)(10). The annual tune-up will be no more than 13 months after the previous tune-up and the first annual tune-up will be no later than 13 months, after the initial startup of the FBC. The results of performance tests will be reported within 60 days after the completion of the performance tests. This report will verify that the operating limits for the FBC have not changed, or will provide documentation of revised operating limits established according to §63.7530 and Table 7 to this subpart, as applicable. The reports for all subsequent performance tests will include all applicable information required in §63.7550

(b) If your performance tests for a given pollutant for at least 2 consecutive years show that your emissions are at or below 75 percent of the emission limit (or, in limited instances as specified in Tables 1 and 2 or 11 through 13 to this subpart, at or below the emission limit) for the pollutant, and if there are no changes in the operation of the individual boiler or process heater or air pollution control equipment that could increase emissions, you may choose to conduct performance tests for the pollutant every third year. Each such performance test must be conducted no more than 37 months after the previous performance test. If you elect to demonstrate compliance using emission averaging under §63.7522, you must continue to conduct performance tests annually. The requirement to test at maximum chloride input level is waived unless the stack test is conducted for HCl. The requirement to test at maximum mercury input level is waived unless the stack test is conducted for mercury. The requirement to test at maximum TSM input level is waived unless the stack test is conducted for TSM.

(c) If a performance test shows emissions exceeded the emission limit or 75 percent of the emission limit (as specified in Tables 1 and 2 or 11 through 13 to this subpart) for a pollutant, you must conduct annual performance tests for that pollutant until all performance tests over a consecutive 2-year period meet the required level (at or below 75 percent of the emission limit, as specified in Tables 1 and 2 or 11 through 13 to this subpart).

(d) If you are required to meet an applicable tune-up work practice standard, you must conduct an annual, biennial, or 5-year performance tune-up according to §63.7540(a)(10), (11), or (12), respectively. Each annual tune-up specified in §63.7540(a)(10) must be no more than 13 months after the previous tune-up. Each biennial tune-up specified in §63.7540(a)(11) must be conducted no more than 25 months after the previous tune-up. Each 5-year tune-up specified in §63.7540(a)(12) must be conducted no more than 61 months after the previous tune-up. For a new or reconstructed affected source (as defined in §63.7490), the first annual, biennial, or 5-year tune-up must be no later than 13 months, 25 months, or 61 months, respectively, after April 1, 2013 or the initial startup of the new or reconstructed affected source, whichever is later.

(e) If you demonstrate compliance with the mercury, HCl, or TSM based on fuel analysis, you must conduct a monthly fuel analysis according to §63.7521 for each type of fuel burned that is subject to an emission limit in Tables 1, 2, or 11 through 13 to this subpart. You may comply with this monthly requirement by completing the fuel analysis any time within the calendar month as long as the analysis is separated from the previous analysis by at least 14 calendar days. If you burn a new type of fuel, you must conduct a fuel analysis before burning the new type of fuel in your boiler or process heater. You must still meet all applicable continuous compliance requirements in §63.7540. If each of 12 consecutive monthly fuel analyses demonstrates 75 percent or less of the compliance level, you may decrease the fuel analysis frequency to quarterly for that fuel. If any quarterly sample exceeds 75 percent of the compliance level or you begin burning a new type of fuel, you must return to monthly monitoring for that fuel, until 12 months of fuel analyses are again less than 75 percent of the compliance level. If sampling is conducted on one day per month, samples should be no less than 14 days apart, but if multiple samples are taken per month, the 14-day restriction does not apply.

(f) You must report the results of performance tests and the associated fuel analyses within 60 days after the completion of the performance tests. This report must also verify that the operating limits for each boiler or process heater have not changed or provide documentation of revised operating limits established according to §63.7530 and Table 7 to this subpart, as applicable. The reports for all subsequent performance tests must include all applicable information required in §63.7550.

(g) For affected sources (as defined in §63.7490) that have not operated since the previous compliance demonstration and more than one year has passed since the previous compliance demonstration, you must complete the subsequent compliance demonstration, if subject to the emission limits in Tables 1, 2, or 11 through 13 to this subpart, no later than 180 days after the re-start of the affected source and according to the applicable provisions in §63.7(a)(2) as cited in Table 10 to this subpart. You must complete a subsequent tune-up by following the procedures described in §63.7540(a)(10)(i) through (vi) and the schedule described in §63.7540(a)(13) for units that are not operating at the time of their scheduled tune-up.

(h) If your affected boiler or process heater is in the unit designed to burn light liquid subcategory and you combust ultra-low sulfur liquid fuel, you do not need to conduct further performance tests (stack tests or fuel analyses) if the pollutants measured during the initial compliance performance tests meet the emission limits in Tables 1 or 2 of this subpart providing you demonstrate ongoing compliance with the emissions limits by monitoring and recording the type of fuel combusted on a monthly basis. If you intend to use a fuel other than ultra-low sulfur liquid fuel, natural gas, refinery gas, or other gas 1 fuel, you must conduct new performance tests within 60 days of burning the new fuel type.

(i) If you operate a CO CEMS that meets the Performance Specifications outlined in §63.7525(a)(3) of this subpart to demonstrate compliance with the applicable alternative CO CEMS emission standard listed in Tables 1, 2, or 11 through 13 to this subpart, you are not required to conduct CO performance tests and are not subject to the oxygen concentration operating limit requirement specified in §63.7510(a).

[78 FR 7165, Jan. 31, 2013, as amended at 80 FR 72808, Nov. 20, 2015]

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§63.7520 What stack tests and procedures must I use?

(a) You must conduct all performance tests according to §63.7(c), (d), (f), and (h). You must also develop a site-specific stack test plan according to the requirements in §63.7(c). You shall conduct all performance tests under such conditions as the Administrator specifies to you based on the representative performance of each boiler or process heater for the period being tested. Upon request, you shall make available to the Administrator such records as may be necessary to determine the conditions of the performance tests.

(b) You must conduct each performance test according to the requirements in Table 5 to this subpart.

(c) You must conduct each performance test under the specific conditions listed in Tables 5 and 7 to this subpart. You must conduct performance tests at representative operating load conditions while burning the type of fuel or mixture of fuels that has the highest content of chlorine and mercury, and TSM if you are opting to comply with the TSM alternative standard and you must demonstrate initial compliance and establish your operating limits based on these performance tests. These requirements could result in the need to conduct more than one performance test. Following each performance test and until the next performance test, you must comply with the operating limit for operating load conditions specified in Table 4 to this subpart.

(d) You must conduct a minimum of three separate test runs for each performance test required in this section, as specified in §63.7(e)(3). Each test run must comply with the minimum applicable sampling times or volumes specified in Tables 1 and 2 or 11 through 13 to this subpart.

(e) To determine compliance with the emission limits, you must use the F-Factor methodology and equations in sections 12.2 and 12.3 of EPA Method 19 at 40 CFR part 60, appendix A-7 of this chapter to convert the measured particulate matter (PM) concentrations, the measured HCl concentrations, the measured mercury concentrations, and the measured TSM concentrations that result from the performance test to pounds per million Btu heat input emission rates.

(f) Except for a 30-day rolling average based on CEMS (or sorbent trap monitoring system) data, if measurement results for any pollutant are reported as below the method detection level (e.g., laboratory analytical results for one or more sample components are below the method defined analytical detection level), you must use the method detection level as the measured emissions level for that pollutant in calculating compliance. The measured result for a multiple component analysis (e.g., analytical values for multiple Method 29 fractions both for individual HAP metals and for total HAP metals) may include a combination of method detection level data and analytical data reported above the method detection level.

Stack testing will be conducted by a certified stack testing company and will be performed in accordance with the procedures and requirements outlined above.

[76 FR 15664, Mar. 21, 2011, as amended at 78 FR 7166, Jan. 31, 2013]

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§63.7521 What fuel analyses, fuel specification, and procedures must I use?

The FBC burns a single type of fuel, and is therefore not required to conduct a fuel analysis.

(a) For solid and liquid fuels, you must conduct fuel analyses for chloride and mercury according to the procedures in paragraphs (b) through (e) of this section and Table 6 to this subpart, as applicable. For solid fuels and liquid fuels, you must also conduct fuel analyses for TSM if you are opting to comply with the TSM alternative standard. For gas 2 (other) fuels, you must conduct fuel analyses for mercury according to the procedures in paragraphs (b) through (e) of this section and Table 6 to this subpart, as applicable. (For gaseous fuels, you may not use fuel analyses to comply with the TSM alternative standard or the HCl standard.) For purposes of complying with this section, a fuel gas system that consists of multiple gaseous fuels collected and mixed with each other is considered a single fuel type and sampling and analysis is only required on the combined fuel gas system that will feed the boiler or process heater. Sampling and analysis of the individual gaseous streams prior to combining is not required. You are not required to conduct fuel analyses for fuels used for only startup, unit shutdown, and transient flame stability purposes. You are required to conduct fuel analyses only for fuels and units that are subject to emission limits for mercury, HCl, or TSM in Tables 1 and 2 or 11 through 13 to this subpart. Gaseous and liquid fuels are exempt from the sampling requirements in paragraphs (c) and (d) of this section.

(b) You must develop a site-specific fuel monitoring plan according to the following procedures and requirements in paragraphs (b)(1) and (2) of this section, if you are required to conduct fuel analyses as specified in §63.7510.

(1) If you intend to use an alternative analytical method other than those required by Table 6 to this subpart, you must submit the fuel analysis plan to the Administrator for review and approval no later than 60 days before the date that you intend to conduct the initial compliance demonstration described in §63.7510.

(2) You must include the information contained in paragraphs (b)(2)(i) through (vi) of this section in your fuel analysis plan.

(i) The identification of all fuel types anticipated to be burned in each boiler or process heater.

(ii) For each anticipated fuel type, the notification of whether you or a fuel supplier will be conducting the fuel analysis.

(iii) For each anticipated fuel type, a detailed description of the sample location and specific procedures to be used for collecting and preparing the composite samples if your procedures are different from paragraph (c) or (d) of this section. Samples should be collected at a location that most accurately represents the fuel type, where possible, at a point prior to mixing with other dissimilar fuel types.

(iv) For each anticipated fuel type, the analytical methods from Table 6, with the expected minimum detection levels, to be used for the measurement of chlorine or mercury.

(v) If you request to use an alternative analytical method other than those required by Table 6 to this subpart, you must also include a detailed description of the methods and procedures that you are proposing to use. Methods in Table 6 shall be used until the requested alternative is approved.

(vi) If you will be using fuel analysis from a fuel supplier in lieu of site-specific sampling and analysis, the fuel supplier must use the analytical methods required by Table 6 to this subpart.

(c) You must obtain composite fuel samples for each fuel type according to the procedures in paragraph (c)(1) or (2) of this section, or the methods listed in Table 6 to this subpart, or use an automated sampling mechanism that provides representative composite fuel samples for each fuel type that includes both coarse and fine material. At a minimum, for demonstrating initial compliance by fuel analysis, you must obtain three composite samples. For monthly fuel analyses, at a minimum, you must

obtain a single composite sample. For fuel analyses as part of a performance stack test, as specified in §63.7510(a), you must obtain a composite fuel sample during each performance test run.

(1) If sampling from a belt (or screw) feeder, collect fuel samples according to paragraphs (c)(1)(i) and (ii) of this section.

(i) Stop the belt and withdraw a 6-inch wide sample from the full cross-section of the stopped belt to obtain a minimum two pounds of sample. You must collect all the material (fines and coarse) in the full cross-section. You must transfer the sample to a clean plastic bag.

(ii) Each composite sample will consist of a minimum of three samples collected at approximately equal one-hour intervals during the testing period for sampling during performance stack testing.

(2) If sampling from a fuel pile or truck, you must collect fuel samples according to paragraphs (c)(2)(i) through (iii) of this section.

(i) For each composite sample, you must select a minimum of five sampling locations uniformly spaced over the surface of the pile.

(ii) At each sampling site, you must dig into the pile to a uniform depth of approximately 18 inches. You must insert a clean shovel into the hole and withdraw a sample, making sure that large pieces do not fall off during sampling; use the same shovel to collect all samples.

(iii) You must transfer all samples to a clean plastic bag for further processing.

(d) You must prepare each composite sample according to the procedures in paragraphs (d)(1) through (7) of this section.

(1) You must thoroughly mix and pour the entire composite sample over a clean plastic sheet.

(2) You must break large sample pieces (e.g., larger than 3 inches) into smaller sizes.

(3) You must make a pie shape with the entire composite sample and subdivide it into four equal parts.

(4) You must separate one of the quarter samples as the first subset.

(5) If this subset is too large for grinding, you must repeat the procedure in paragraph (d)(3) of this section with the quarter sample and obtain a one-quarter subset from this sample.

(6) You must grind the sample in a mill.

(7) You must use the procedure in paragraph (d)(3) of this section to obtain a one-quarter subsample for analysis. If the quarter sample is too large, subdivide it further using the same procedure.

(e) You must determine the concentration of pollutants in the fuel (mercury and/or chlorine and/or TSM) in units of pounds per million Btu of each composite sample for each fuel type according to the procedures in Table 6 to this subpart, for use in Equations 7, 8, and 9 of this subpart.

(f) To demonstrate that a gaseous fuel other than natural gas or refinery gas qualifies as an other gas 1 fuel, as defined in §63.7575, you must conduct a fuel specification analyses for mercury according to the procedures in paragraphs (g) through (i) of this section and Table 6 to this subpart, as applicable,

except as specified in paragraph (f)(1) through (4) of this section, or as an alternative where fuel specification analysis is not practical, you must measure mercury concentration in the exhaust gas when firing only the gaseous fuel to be demonstrated as an other gas 1 fuel in the boiler or process heater according to the procedures in Table 6 to this subpart.

(1) You are not required to conduct the fuel specification analyses in paragraphs (g) through (i) of this section for natural gas or refinery gas.

(2) You are not required to conduct the fuel specification analyses in paragraphs (g) through (i) of this section for gaseous fuels that are subject to another subpart of this part, part 60, part 61, or part 65.

(3) You are not required to conduct the fuel specification analyses in paragraphs (g) through (i) of this section on gaseous fuels for units that are complying with the limits for units designed to burn gas 2 (other) fuels.

(4) You are not required to conduct the fuel specification analyses in paragraphs (g) through (i) of this section for gas streams directly derived from natural gas at natural gas production sites or natural gas plants.

(g) You must develop a site-specific fuel analysis plan for other gas 1 fuels according to the following procedures and requirements in paragraphs (g)(1) and (2) of this section.

(1) If you intend to use an alternative analytical method other than those required by Table 6 to this subpart, you must submit the fuel analysis plan to the Administrator for review and approval no later than 60 days before the date that you intend to conduct the initial compliance demonstration described in §63.7510.

(2) You must include the information contained in paragraphs (g)(2)(i) through (vi) of this section in your fuel analysis plan.

(i) The identification of all gaseous fuel types other than those exempted from fuel specification analysis under (f)(1) through (3) of this section anticipated to be burned in each boiler or process heater.

(ii) For each anticipated fuel type, the identification of whether you or a fuel supplier will be conducting the fuel specification analysis.

(iii) For each anticipated fuel type, a detailed description of the sample location and specific procedures to be used for collecting and preparing the samples if your procedures are different from the sampling methods contained in Table 6 to this subpart. Samples should be collected at a location that most accurately represents the fuel type, where possible, at a point prior to mixing with other dissimilar fuel types. If multiple boilers or process heaters are fueled by a common fuel stream it is permissible to conduct a single gas specification at the common point of gas distribution.

(iv) For each anticipated fuel type, the analytical methods from Table 6 to this subpart, with the expected minimum detection levels, to be used for the measurement of mercury.

(v) If you request to use an alternative analytical method other than those required by Table 6 to this subpart, you must also include a detailed description of the methods and procedures that you are proposing to use. Methods in Table 6 to this subpart shall be used until the requested alternative is approved.

(vi) If you will be using fuel analysis from a fuel supplier in lieu of site-specific sampling and analysis, the fuel supplier must use the analytical methods required by Table 6 to this subpart. When using a fuel

supplier's fuel analysis, the owner or operator is not required to submit the information in §63.7521(g)(2)(iii).

(h) You must obtain a single fuel sample for each fuel type for fuel specification of gaseous fuels.

(i) You must determine the concentration in the fuel of mercury, in units of microgram per cubic meter, dry basis, of each sample for each other gas 1 fuel type according to the procedures in Table 6 to this subpart.

[78 FR 7167, Jan. 31, 2013, as amended at 80 FR 72808, Nov. 20, 2015]

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§63.7522 Can I use emissions averaging to comply with this subpart?

The FBC burns a single type of fuel and will be the only boiler at the CRE facility, and is therefore not proposing to use emissions averaging.

(a) As an alternative to meeting the requirements of §63.7500 for PM (or TSM), HCl, or mercury on a boiler or process heater-specific basis, if you have more than one existing boiler or process heater in any subcategories located at your facility, you may demonstrate compliance by emissions averaging, if your averaged emissions are not more than 90 percent of the applicable emission limit, according to the procedures in this section. You may not include new boilers or process heaters in an emissions average.

(b) For a group of two or more existing boilers or process heaters in the same subcategory that each vent to a separate stack, you may average PM (or TSM), HCl, or mercury emissions among existing units to demonstrate compliance with the limits in Table 2 to this subpart as specified in paragraph (b)(1) through (3) of this section, if you satisfy the requirements in paragraphs (c) through (g) of this section.

(1) You may average units using a CEMS or PM CPMS for demonstrating compliance.

(2) For mercury and HCl, averaging is allowed as follows:

(i) You may average among units in any of the solid fuel subcategories.

(ii) You may average among units in any of the liquid fuel subcategories.

(iii) You may average among units in a subcategory of units designed to burn gas 2 (other) fuels.

(iv) You may not average across the units designed to burn liquid, units designed to burn solid fuel, and units designed to burn gas 2 (other) subcategories.

(3) For PM (or TSM), averaging is only allowed between units within each of the following subcategories and you may not average across subcategories:

(i) Units designed to burn coal/solid fossil fuel.

(ii) Stokers/sloped grate/other units designed to burn kiln dried biomass/bio-based solids.

(iii) Stokers/sloped grate/other units designed to burn wet biomass/bio-based solids.

(iv) Fluidized bed units designed to burn biomass/bio-based solid.

(v) Suspension burners designed to burn biomass/bio-based solid.

(vi) Dutch ovens/pile burners designed to burn biomass/bio-based solid.

(vii) Fuel Cells designed to burn biomass/bio-based solid.

(viii) Hybrid suspension/grate burners designed to burn wet biomass/bio-based solid.

(ix) Units designed to burn heavy liquid fuel.

(x) Units designed to burn light liquid fuel.

(xi) Units designed to burn liquid fuel that are non-continental units.

(xii) Units designed to burn gas 2 (other) gases.

(c) For each existing boiler or process heater in the averaging group, the emission rate achieved during the initial compliance test for the HAP being averaged must not exceed the emission level that was being achieved on April 1, 2013 or the control technology employed during the initial compliance test must not be less effective for the HAP being averaged than the control technology employed on April 1, 2013.

(d) The averaged emissions rate from the existing boilers and process heaters participating in the emissions averaging option must not exceed 90 percent of the limits in Table 2 to this subpart at all times the affected units are subject to numeric emission limits following the compliance date specified in §63.7495.

(e) You must demonstrate initial compliance according to paragraph (e)(1) or (2) of this section using the maximum rated heat input capacity or maximum steam generation capacity of each unit and the results of the initial performance tests or fuel analysis.

(1) You must use Equation 1a or 1b or 1c of this section to demonstrate that the PM (or TSM), HCl, or mercury emissions from all existing units participating in the emissions averaging option for that pollutant do not exceed the emission limits in Table 2 to this subpart. Use Equation 1a if you are complying with the emission limits on a heat input basis, use Equation 1b if you are complying with the emission limits on a steam generation (output) basis, and use Equation 1c if you are complying with the emission limits on a electric generation (output) basis.

$$AveWeightedEmissions = 1.1 \times \sum_{i=1}^{n} (Er \times Hm) \div \sum_{i=1}^{n} Hm \qquad \text{(Eq.1a)}$$

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Where:

AveWeightedEmissions = Average weighted emissions for PM (or TSM), HCl, or mercury, in units of pounds per million Btu of heat input.

Er = Emission rate (as determined during the initial compliance demonstration) of PM (or TSM), HCl, or mercury from unit, i, in units of pounds per million Btu of heat input. Determine the emission rate for PM (or TSM), HCl, or mercury by performance testing according to Table 5 to this subpart, or by fuel analysis for HCl or mercury or TSM using the applicable equation in §63.7530(c).

Hm = Maximum rated heat input capacity of unit, i, in units of million Btu per hour.

n = Number of units participating in the emissions averaging option.

1.1 = Required discount factor.

$$AveWeightedEmissions = 1.1 \times \sum_{i=1}^{n} (Er \times So) \div \sum_{i=1}^{n} So \qquad \text{(Eq. 1b)}$$

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Where:

AveWeightedEmissions = Average weighted emissions for PM (or TSM), HCl, or mercury, in units of pounds per million Btu of steam output.

Er = Emission rate (as determined during the initial compliance demonstration) of PM (or TSM), HCl, or mercury from unit, i, in units of pounds per million Btu of steam output. Determine the emission rate for PM (or TSM), HCl, or mercury by performance testing according to Table 5 to this subpart, or by fuel analysis for HCl or mercury or TSM using the applicable equation in §63.7530(c). If you are taking credit for energy conservation measures from a unit according to §63.7533, use the adjusted emission level for that unit, Eadj, determined according to §63.7533 for that unit.

So = Maximum steam output capacity of unit, i, in units of million Btu per hour, as defined in §63.7575.

n = Number of units participating in the emissions averaging option.

1.1 = Required discount factor.

$$AveWeightedEmissions = 1.1 \times \sum_{i=1}^{n} (Er \times Eo) \div \sum_{i=1}^{n} Eo \qquad \text{(Eq. 1c)}$$

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Where:

AveWeightedEmissions = Average weighted emissions for PM (or TSM), HCl, or mercury, in units of pounds per megawatt hour.

Er = Emission rate (as determined during the initial compliance demonstration) of PM (or TSM), HCl, or mercury from unit, i, in units of pounds per megawatt hour. Determine the emission rate for PM (or TSM), HCl, or mercury by performance testing according to Table 5 to this subpart, or by fuel analysis for HCl or mercury or TSM using the applicable equation in §63.7530(c). If you are taking credit for energy conservation measures from a unit according to §63.7533, use the adjusted emission level for that unit, Eadj, determined according to §63.7533 for that unit.

Eo = Maximum electric generating output capacity of unit, i, in units of megawatt hour, as defined in §63.7575.

n = Number of units participating in the emissions averaging option.

1.1 = Required discount factor.

(2) If you are not capable of determining the maximum rated heat input capacity of one or more boilers that generate steam, you may use Equation 2 of this section as an alternative to using Equation 1a of this section to demonstrate that the PM (or TSM), HCl, or mercury emissions from all existing units participating in the emissions averaging option do not exceed the emission limits for that pollutant in Table 2 to this subpart that are in pounds per million Btu of heat input.

$$AveWeightedEmissions = 1.1 \times \sum_{i=1}^{n} (Er \times Sm \times Cfi) \div \sum_{i=1}^{n} (Sm \times Cfi) \qquad \text{(Eq. 2)}$$

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Where:

AveWeightedEmissions = Average weighted emission level for PM (or TSM), HCl, or mercury, in units of pounds per million Btu of heat input.

Er = Emission rate (as determined during the most recent compliance demonstration) of PM (or TSM), HCl, or mercury from unit, i, in units of pounds per million Btu of heat input. Determine the emission rate for PM (or TSM), HCl, or mercury by performance testing according to Table 5 to this subpart, or by fuel analysis for HCl or mercury or TSM using the applicable equation in §63.7530(c).

Sm = Maximum steam generation capacity by unit, i, in units of pounds per hour.

Cfi = Conversion factor, calculated from the most recent compliance test, in units of million Btu of heat input per pounds of steam generated for unit, i.

1.1 = Required discount factor.

(f) After the initial compliance demonstration described in paragraph (e) of this section, you must demonstrate compliance on a monthly basis determined at the end of every month (12 times per year) according to paragraphs (f)(1) through (3) of this section. The first monthly period begins on the compliance date specified in §63.7495. If the affected source elects to collect monthly data for up the 11 months preceding the first monthly period, these additional data points can be used to compute the 12-month rolling average in paragraph (f)(3) of this section.

(1) For each calendar month, you must use Equation 3a or 3b or 3c of this section to calculate the average weighted emission rate for that month. Use Equation 3a and the actual heat input for the month for each existing unit participating in the emissions averaging option if you are complying with emission limits on a heat input basis. Use Equation 3b and the actual steam generation for the month if you are complying with the emission limits on a steam generation (output) basis. Use Equation 3c and the actual electrical generation for the month if you are complying with the emission limits on an electrical generation (output) basis.

$$AveWeightedEmissions = 1.1 \times \sum_{i=1}^{n} (Er \times Hb) \div \sum_{i=1}^{n} Hb \qquad \text{(Eq. 3a)}$$

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Where:

AveWeightedEmissions = Average weighted emission level for PM (or TSM), HCl, or mercury, in units of pounds per million Btu of heat input, for that calendar month.

Er = Emission rate (as determined during the most recent compliance demonstration) of PM (or TSM), HCl, or mercury from unit, i, in units of pounds per million Btu of heat input. Determine the emission rate for PM (or TSM), HCl, or mercury by performance testing according to Table 5 to this subpart, or by fuel analysis for HCl or mercury or TSM according to Table 6 to this subpart.

Hb = The heat input for that calendar month to unit, i, in units of million Btu.

n = Number of units participating in the emissions averaging option.

1.1 = Required discount factor.

$$AveWeightedEmissions = 1.1 \times \sum_{i=1}^{n} (Er \times So) \div \sum_{i=1}^{n} So \qquad \text{(Eq. 3b)}$$

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Where:

AveWeightedEmissions = Average weighted emission level for PM (or TSM), HCl, or mercury, in units of pounds per million Btu of steam output, for that calendar month.

Er = Emission rate (as determined during the most recent compliance demonstration) of PM (or TSM), HCl, or mercury from unit, i, in units of pounds per million Btu of steam output. Determine the emission rate for PM (or TSM), HCl, or mercury by performance testing according to Table 5 to this subpart, or by fuel analysis for HCl or mercury or TSM according to Table 6 to this subpart. If you are taking credit for energy conservation measures from a unit according to §63.7533, use the adjusted emission level for that unit, E_{adj}, determined according to §63.7533 for that unit.

So = The steam output for that calendar month from unit, i, in units of million Btu, as defined in §63.7575.

n = Number of units participating in the emissions averaging option.

1.1 = Required discount factor.

$$AveWeightedEmissions = 1.1 \times \sum_{i=1}^{n} (Er \times Eo) \div \sum_{i=1}^{n} Eo \quad \text{(Eq. 3c)}$$

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Where:

AveWeightedEmissions = Average weighted emission level for PM (or TSM), HCl, or mercury, in units of pounds per megawatt hour, for that calendar month.

Er = Emission rate (as determined during the most recent compliance demonstration) of PM (or TSM), HCl, or mercury from unit, i, in units of pounds per megawatt hour. Determine the emission rate for PM (or TSM), HCl, or mercury by performance testing according to Table 5 to this subpart, or by fuel analysis for HCl or mercury or TSM according to Table 6 to this subpart. If you are taking credit for energy conservation measures from a unit according to §63.7533, use the adjusted emission level for that unit, E_{adi}, determined according to §63.7533 for that unit.

Eo = The electric generating output for that calendar month from unit, i, in units of megawatt hour, as defined in §63.7575.

n = Number of units participating in the emissions averaging option.

1.1 = Required discount factor.

(2) If you are not capable of monitoring heat input, you may use Equation 4 of this section as an alternative to using Equation 3a of this section to calculate the average weighted emission rate using the actual steam generation from the boilers participating in the emissions averaging option.

$$AveWeightedEmissions = 1.1 \times \sum_{i=1}^{n} (Er \times Sa \times Cfi) \div \sum_{i=1}^{n} (Sa \times Cfi) \quad \text{(Eq. 4)}$$

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Where:

AveWeightedEmissions = average weighted emission level for PM (or TSM), HCl, or mercury, in units of pounds per million Btu of heat input for that calendar month.

Er = Emission rate (as determined during the most recent compliance demonstration of PM (or TSM), HCl, or mercury from unit, i, in units of pounds per million Btu of heat input. Determine the emission rate for PM (or TSM),

HCl, or mercury by performance testing according to Table 5 to this subpart, or by fuel analysis for HCl or mercury or TSM according to Table 6 to this subpart.

Sa = Actual steam generation for that calendar month by boiler, i, in units of pounds.

Cfi = Conversion factor, as calculated during the most recent compliance test, in units of million Btu of heat input per pounds of steam generated for boiler, i.

1.1 = Required discount factor.

(3) Until 12 monthly weighted average emission rates have been accumulated, calculate and report only the average weighted emission rate determined under paragraph (f)(1) or (2) of this section for each calendar month. After 12 monthly weighted average emission rates have been accumulated, for each subsequent calendar month, use Equation 5 of this section to calculate the 12-month rolling average of the monthly weighted average emission rates for the current calendar month and the previous 11 calendar months.

$$Eavg = \sum_{i=1}^{n} ERi \div 12 \quad \text{(Eq. 5)}$$

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Where:

Eavg = 12-month rolling average emission rate, (pounds per million Btu heat input)

ERi = Monthly weighted average, for calendar month "i" (pounds per million Btu heat input), as calculated by paragraph (f)(1) or (2) of this section.

(g) You must develop, and submit upon request to the applicable Administrator for review and approval, an implementation plan for emission averaging according to the following procedures and requirements in paragraphs (g)(1) through (4) of this section.

(1) If requested, you must submit the implementation plan no later than 180 days before the date that the facility intends to demonstrate compliance using the emission averaging option.

(2) You must include the information contained in paragraphs (g)(2)(i) through (vii) of this section in your implementation plan for all emission sources included in an emissions average:

(i) The identification of all existing boilers and process heaters in the averaging group, including for each either the applicable HAP emission level or the control technology installed as of January 31, 2013 and the date on which you are requesting emission averaging to commence;

(ii) The process parameter (heat input or steam generated) that will be monitored for each averaging group;

(iii) The specific control technology or pollution prevention measure to be used for each emission boiler or process heater in the averaging group and the date of its installation or application. If the pollution prevention measure reduces or eliminates emissions from multiple boilers or process heaters, the owner or operator must identify each boiler or process heater;

(iv) The test plan for the measurement of PM (or TSM), HCl, or mercury emissions in accordance with the requirements in §63.7520;

(v) The operating parameters to be monitored for each control system or device consistent with §63.7500 and Table 4, and a description of how the operating limits will be determined;

(vi) If you request to monitor an alternative operating parameter pursuant to §63.7525, you must also include:

(A) A description of the parameter(s) to be monitored and an explanation of the criteria used to select the parameter(s); and

(B) A description of the methods and procedures that will be used to demonstrate that the parameter indicates proper operation of the control device; the frequency and content of monitoring, reporting, and recordkeeping requirements; and a demonstration, to the satisfaction of the Administrator, that the proposed monitoring frequency is sufficient to represent control device operating conditions; and

(vii) A demonstration that compliance with each of the applicable emission limit(s) will be achieved under representative operating load conditions. Following each compliance demonstration and until the next compliance demonstration, you must comply with the operating limit for operating load conditions specified in Table 4 to this subpart.

(3) If submitted upon request, the Administrator shall review and approve or disapprove the plan according to the following criteria:

(i) Whether the content of the plan includes all of the information specified in paragraph (g)(2) of this section; and

(ii) Whether the plan presents sufficient information to determine that compliance will be achieved and maintained.

(4) The applicable Administrator shall not approve an emission averaging implementation plan containing any of the following provisions:

(i) Any averaging between emissions of differing pollutants or between differing sources; or

(ii) The inclusion of any emission source other than an existing unit in the same subcategories.

(h) For a group of two or more existing affected units, each of which vents through a single common stack, you may average PM (or TSM), HCl, or mercury emissions to demonstrate compliance with the limits for that pollutant in Table 2 to this subpart if you satisfy the requirements in paragraph (i) or (j) of this section.

(i) For a group of two or more existing units in the same subcategory, each of which vents through a common emissions control system to a common stack, that does not receive emissions from units in other subcategories or categories, you may treat such averaging group as a single existing unit for purposes of this subpart and comply with the requirements of this subpart as if the group were a single unit.

(j) For all other groups of units subject to the common stack requirements of paragraph (h) of this section, including situations where the exhaust of affected units are each individually controlled and then sent to a common stack, the owner or operator may elect to:

(1) Conduct performance tests according to procedures specified in §63.7520 in the common stack if affected units from other subcategories vent to the common stack. The emission limits that the group must comply with are determined by the use of Equation 6 of this section.

$$En = \sum_{i=1}^{n} (ELi \times Hi) \div \sum_{i=1}^{n} Hi \qquad \text{(Eq. 6)}$$

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Where:

En = HAP emission limit, pounds per million British thermal units (lb/MMBtu) or parts per million (ppm).

Eli = Appropriate emission limit from Table 2 to this subpart for unit i, in units of lb/MMBtu or ppm.

Hi = Heat input from unit i, MMBtu.

(2) Conduct performance tests according to procedures specified in §63.7520 in the common stack. If affected units and non-affected units vent to the common stack, the non-affected units must be shut down or vented to a different stack during the performance test unless the facility determines to demonstrate compliance with the non-affected units venting to the stack; and

(3) Meet the applicable operating limit specified in §63.7540 and Table 8 to this subpart for each emissions control system (except that, if each unit venting to the common stack has an applicable opacity operating limit, then a single continuous opacity monitoring system may be located in the common stack instead of in each duct to the common stack).

(k) The common stack of a group of two or more existing boilers or process heaters in the same subcategories subject to paragraph (h) of this section may be treated as a separate stack for purposes of paragraph (b) of this section and included in an emissions averaging group subject to paragraph (b) of this section.

[76 FR 15664, Mar. 21, 2011, as amended at 78 FR 7168, Jan. 31, 2013; 80 FR 72809, Nov. 20, 2015]

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§63.7525 What are my monitoring, installation, operation, and maintenance requirements?

(a) If your boiler or process heater is subject to a CO emission limit in Tables 1, 2, or 11 through 13 to this subpart, you must install, operate, and maintain an oxygen analyzer system, as defined in §63.7575, or install, certify, operate and maintain continuous emission monitoring systems for CO and oxygen (or carbon dioxide (CO_2)) according to the procedures in paragraphs (a)(1) through (6) of this section.

The FBC is subject to a CO emissions limit in Table 1 and will install, operate and maintain an oxygen analyzer system.

(1) Install the CO CEMS and oxygen (or CO_2) analyzer by the compliance date specified in §63.7495. The CO and oxygen (or CO_2) levels shall be monitored at the same location at the outlet of the boiler or process heater. An owner or operator may request an alternative test method under §63.7 of this chapter, in order that compliance with the CO emissions limit be determined using CO_2 as a diluent correction in place of oxygen at 3 percent. EPA Method 19 F-factors and EPA Method 19 equations must be used to generate the appropriate CO_2 correction percentage for the fuel type burned in the unit, and must also take into account that the 3 percent oxygen correction is to be done on a dry basis. The alternative test method request must account for any CO_2 being added to, or removed from, the emissions gas stream as a result of limestone injection, scrubber media, etc.

(2) To demonstrate compliance with the applicable alternative CO CEMS emission standard listed in Tables 1, 2, or 11 through 13 to this subpart, you must install, certify, operate, and maintain a CO CEMS and an oxygen analyzer according to the applicable procedures under Performance Specification 4, 4A, or 4B at 40 CFR part 60, appendix B; part 75 of this chapter (if an CO_2 analyzer is used); the site-specific monitoring plan developed according to §63.7505(d); and the requirements in §63.7540(a)(8) and paragraph (a) of this section. Any boiler or process heater that has a CO CEMS that is compliant with Performance Specification 4, 4A, or 4B at 40 CFR part 60, appendix B, a site-specific monitoring plan developed according to §63.7505(d), and the requirements in §63.7540(a)(8) and paragraph (a) of this section must use the CO CEMS to comply with the applicable alternative CO CEMS emission standard listed in Tables 1, 2, or 11 through 13 to this subpart.

(i) You must conduct a performance evaluation of each CO CEMS according to the requirements in §63.8(e) and according to Performance Specification 4, 4A, or 4B at 40 CFR part 60, appendix B.

(ii) During each relative accuracy test run of the CO CEMS, you must be collect emission data for CO concurrently (or within a 30- to 60-minute period) by both the CO CEMS and by Method 10, 10A, or 10B at 40 CFR part 60, appendix A-4. The relative accuracy testing must be at representative operating conditions.

(iii) You must follow the quality assurance procedures (e.g., quarterly accuracy determinations and daily calibration drift tests) of Procedure 1 of appendix F to part 60. The measurement span value of the CO CEMS must be two times the applicable CO emission limit, expressed as a concentration.

(iv) Any CO CEMS that does not comply with §63.7525(a) cannot be used to meet any requirement in this subpart to demonstrate compliance with a CO emission limit listed in Tables 1, 2, or 11 through 13 to this subpart.

(v) For a new unit, complete the initial performance evaluation no later than July 30, 2013, or 180 days after the date of initial startup, whichever is later. For an existing unit, complete the initial performance evaluation no later than July 29, 2016.

(vi) When CO_2 is used to correct CO emissions and CO_2 is measured on a wet basis, correct for moisture as follows: Install, operate, maintain, and quality assure a continuous moisture monitoring system for measuring and recording the moisture content of the flue gases, in order to correct the measured hourly volumetric flow rates for moisture when calculating CO concentrations. The following continuous moisture monitoring systems are acceptable: A continuous moisture sensor; an oxygen analyzer (or analyzers) capable of measuring O_2 both on a wet basis and on a dry basis; or a stack temperature sensor and a moisture look-up table, *i.e.,* a psychrometric chart (for saturated gas streams following wet scrubbers or other demonstrably saturated gas streams, only). The moisture monitoring system shall include as a component the automated data acquisition and handling system (DAHS) for recording and reporting both the raw data (*e.g.,* hourly average wet-and dry basis O_2 values) and the hourly average values of the stack gas moisture content derived from those data. When a moisture look-up table is used, the moisture monitoring system shall be represented as a single component, the certified DAHS, in the monitoring plan for the unit or common stack.

(3) Complete a minimum of one cycle of CO and oxygen (or CO_2) CEMS operation (sampling, analyzing, and data recording) for each successive 15-minute period. Collect CO and oxygen (or CO_2) data concurrently. Collect at least four CO and oxygen (or CO_2) CEMS data values representing the four 15-minute periods in an hour, or at least two 15-minute data values during an hour when CEMS calibration, quality assurance, or maintenance activities are being performed.

(4) Reduce the CO CEMS data as specified in §63.8(g)(2).

(5) Calculate one-hour arithmetic averages, corrected to 3 percent oxygen (or corrected to an CO_2 percentage determined to be equivalent to 3 percent oxygen) from each hour of CO CEMS data in parts per million CO concentration. The one-hour arithmetic averages required shall be used to calculate the 30-day or 10-day rolling average emissions. Use Equation 19-19 in section 12.4.1 of Method 19 of 40 CFR part 60, appendix A-7 for calculating the average CO concentration from the hourly values.

(6) For purposes of collecting CO data, operate the CO CEMS as specified in §63.7535(b). You must use all the data collected during all periods in calculating data averages and assessing compliance, except that you must exclude certain data as specified in §63.7535(c). Periods when CO data are unavailable may constitute monitoring deviations as specified in §63.7535(d).

(7) Operate an oxygen trim system with the oxygen level set no lower than the lowest hourly average oxygen concentration measured during the most recent CO performance test as the operating limit for oxygen according to Table 7 to this subpart.

(b) If your boiler or process heater is in the unit designed to burn coal/solid fossil fuel subcategory or the unit designed to burn heavy liquid subcategory and has an average annual heat input rate greater than 250 MMBtu per hour from solid fossil fuel and/or heavy liquid, and you demonstrate compliance with the PM limit instead of the alternative TSM limit, you must install, maintain, and operate a PM CPMS monitoring emissions discharged to the atmosphere and record the output of the system as specified in paragraphs (b)(1) through (4) of this section. As an alternative to use of a PM CPMS to demonstrate compliance with the PM limit, you may choose to use a PM CEMS. If you choose to use a PM CEMS to demonstrate compliance with the PM limit instead of the alternative TSM limit, you must install, certify, maintain, and operate a PM CEMS monitoring emissions discharged to the atmosphere and record the output of the system as specified in paragraph (b)(5) through (8) of this section. For other boilers or process heaters, you may elect to use a PM CPMS or PM CEMS operated in accordance with this section in lieu of using other CMS for monitoring PM compliance (*e.g.,* bag leak detectors, ESP secondary power, and PM scrubber pressure). Owners of boilers and process heaters who elect to comply with the alternative TSM limit are not required to install a PM CPMS.

(1) Install, operate, and maintain your PM CPMS according to the procedures in your approved site-specific monitoring plan developed in accordance with §63.7505(d), the requirements in §63.7540(a)(9), and paragraphs (b)(1)(i) through (iii) of this section.

(i) The operating principle of the PM CPMS must be based on in-stack or extractive light scatter, light scintillation, beta attenuation, or mass accumulation detection of PM in the exhaust gas or representative exhaust gas sample. The reportable measurement output from the PM CPMS must be expressed as milliamps.

(ii) The PM CPMS must have a cycle time (i.e., period required to complete sampling, measurement, and reporting for each measurement) no longer than 60 minutes.

(iii) The PM CPMS must have a documented detection limit of 0.5 milligram per actual cubic meter, or less.

(2) For a new unit, complete the initial performance evaluation no later than July 30, 2013, or 180 days after the date of initial startup, whichever is later. For an existing unit, complete the initial performance evaluation no later than July 29, 2016.

(3) Collect PM CPMS hourly average output data for all boiler or process heater operating hours except as indicated in §63.7535(a) through (d). Express the PM CPMS output as milliamps.

(4) Calculate the arithmetic 30-day rolling average of all of the hourly average PM CPMS output data collected during all boiler or process heater operating hours (milliamps).

(5) Install, certify, operate, and maintain your PM CEMS according to the procedures in your approved site-specific monitoring plan developed in accordance with §63.7505(d), the requirements in §63.7540(a)(9), and paragraphs (b)(5)(i) through (iv) of this section.

(i) You shall conduct a performance evaluation of the PM CEMS according to the applicable requirements of §60.8(e), and Performance Specification 11 at 40 CFR part 60, appendix B of this chapter.

(ii) During each PM correlation testing run of the CEMS required by Performance Specification 11 at 40 CFR part 60, appendix B of this chapter, you shall collect PM and oxygen (or carbon dioxide) data concurrently (or within a 30-to 60-minute period) by both the CEMS and conducting performance tests using Method 5 at 40 CFR part 60, appendix A-3 or Method 17 at 40 CFR part 60, appendix A-6 of this chapter.

(iii) You shall perform quarterly accuracy determinations and daily calibration drift tests in accordance with Procedure 2 at 40 CFR part 60, appendix F of this chapter. You must perform Relative Response Audits annually and perform Response Correlation Audits every 3 years.

(iv) Within 60 days after the date of completing each CEMS relative accuracy test audit or performance test conducted to demonstrate compliance with this subpart, you must submit the relative accuracy test audit data and performance test data to the EPA by successfully submitting the data electronically into the EPA's Central Data Exchange by using the Electronic Reporting Tool (see *http://www.epa.gov/ttn/chief/ert/erttool.html/*).

(6) For a new unit, complete the initial performance evaluation no later than July 30, 2013, or 180 days after the date of initial startup, whichever is later. For an existing unit, complete the initial performance evaluation no later than July 29, 2016.

(7) Collect PM CEMS hourly average output data for all boiler or process heater operating hours except as indicated in §63.7535(a) through (d).

(8) Calculate the arithmetic 30-day rolling average of all of the hourly average PM CEMS output data collected during all boiler or process heater operating hours.

(c) If you have an applicable opacity operating limit in this rule, and are not otherwise required or elect to install and operate a PM CPMS, PM CEMS, or a bag leak detection system, you must install, operate, certify and maintain each COMS according to the procedures in paragraphs (c)(1) through (7) of this section by the compliance date specified in §63.7495.

The FBC does not have an applicable opacity operating limit in this rule.

(1) Each COMS must be installed, operated, and maintained according to Performance Specification 1 at appendix B to part 60 of this chapter.

(2) You must conduct a performance evaluation of each COMS according to the requirements in §63.8(e) and according to Performance Specification 1 at appendix B to part 60 of this chapter.

(3) As specified in §63.8(c)(4)(i), each COMS must complete a minimum of one cycle of sampling and analyzing for each successive 10-second period and one cycle of data recording for each successive 6-minute period.

(4) The COMS data must be reduced as specified in §63.8(g)(2).

(5) You must include in your site-specific monitoring plan procedures and acceptance criteria for operating and maintaining each COMS according to the requirements in §63.8(d). At a minimum, the monitoring plan must include a daily calibration drift assessment, a quarterly performance audit, and an annual zero alignment audit of each COMS.

(6) You must operate and maintain each COMS according to the requirements in the monitoring plan and the requirements of §63.8(e). You must identify periods the COMS is out of control including any periods that the COMS fails to pass a daily calibration drift assessment, a quarterly performance audit, or an annual zero alignment audit. Any 6-minute period for which the monitoring system is out of control and data are not available for a required calculation constitutes a deviation from the monitoring requirements.

(7) You must determine and record all the 6-minute averages (and daily block averages as applicable) collected for periods during which the COMS is not out of control.

(d) If you have an operating limit that requires the use of a CMS other than a PM CPMS or COMS, you must install, operate, and maintain each CMS according to the procedures in paragraphs (d)(1) through (5) of this section by the compliance date specified in §63.7495.

The FBC does not have an operating limit that requires the use of a CMS other than a PM CPMS or COMS.

(1) The CPMS must complete a minimum of one cycle of operation every 15-minutes. You must have a minimum of four successive cycles of operation, one representing each of the four 15-minute periods in an hour, to have a valid hour of data.

(2) You must operate the monitoring system as specified in §63.7535(b), and comply with the data calculation requirements specified in §63.7535(c).

(3) Any 15-minute period for which the monitoring system is out-of-control and data are not available for a required calculation constitutes a deviation from the monitoring requirements. Other situations that constitute a monitoring deviation are specified in §63.7535(d).

(4) You must determine the 30-day rolling average of all recorded readings, except as provided in §63.7535(c).

(5) You must record the results of each inspection, calibration, and validation check.

(e) If you have an operating limit that requires the use of a flow monitoring system, you must meet the requirements in paragraphs (d) and (e)(1) through (4) of this section.

The FBC does not have an operating limit that requires the use of a flow monitoring system.

(1) You must install the flow sensor and other necessary equipment in a position that provides a representative flow.

(2) You must use a flow sensor with a measurement sensitivity of no greater than 2 percent of the design flow rate.

(3) You must minimize, consistent with good engineering practices, the effects of swirling flow or abnormal velocity distributions due to upstream and downstream disturbances.

(4) You must conduct a flow monitoring system performance evaluation in accordance with your monitoring plan at the time of each performance test but no less frequently than annually.

(f) If you have an operating limit that requires the use of a pressure monitoring system, you must meet the requirements in paragraphs (d) and (f)(1) through (6) of this section.

The FBC does not have an operating limit that requires the use of a pressure monitoring system.

(1) Install the pressure sensor(s) in a position that provides a representative measurement of the pressure (*e.g.*, PM scrubber pressure drop).

(2) Minimize or eliminate pulsating pressure, vibration, and internal and external corrosion consistent with good engineering practices.

(3) Use a pressure sensor with a minimum tolerance of 1.27 centimeters of water or a minimum tolerance of 1 percent of the pressure monitoring system operating range, whichever is less.

(4) Perform checks at least once each process operating day to ensure pressure measurements are not obstructed (*e.g.*, check for pressure tap pluggage daily).

(5) Conduct a performance evaluation of the pressure monitoring system in accordance with your monitoring plan at the time of each performance test but no less frequently than annually.

(6) If at any time the measured pressure exceeds the manufacturer's specified maximum operating pressure range, conduct a performance evaluation of the pressure monitoring system in accordance with your monitoring plan and confirm that the pressure monitoring system continues to meet the performance requirements in you monitoring plan. Alternatively, install and verify the operation of a new pressure sensor.

(g) If you have an operating limit that requires a pH monitoring system, you must meet the requirements in paragraphs (d) and (g)(1) through (4) of this section.

The FBC does not have an operating limit that requires the use of a pH monitoring system.

(1) Install the pH sensor in a position that provides a representative measurement of scrubber effluent pH.

(2) Ensure the sample is properly mixed and representative of the fluid to be measured.

(3) Calibrate the pH monitoring system in accordance with your monitoring plan and according to the manufacturer's instructions. Clean the pH probe at least once each process operating day. Maintain on-site documentation that your calibration frequency is sufficient to maintain the specified accuracy of your device.

(4) Conduct a performance evaluation (including a two-point calibration with one of the two buffer solutions having a pH within 1 of the pH of the operating limit) of the pH monitoring system in accordance with your monitoring plan at the time of each performance test but no less frequently than annually.

(h) If you have an operating limit that requires a secondary electric power monitoring system for an electrostatic precipitator (ESP) operated with a wet scrubber, you must meet the requirements in paragraphs (h)(1) and (2) of this section.

The FBC does not have an operating limit that requires secondary electric power monitoring system for an electrostatic precipitator (ESP) operated with a wet scrubber.

(1) Install sensors to measure (secondary) voltage and current to the precipitator collection plates.

(2) Conduct a performance evaluation of the electric power monitoring system in accordance with your monitoring plan at the time of each performance test but no less frequently than annually.

(i) If you have an operating limit that requires the use of a monitoring system to measure sorbent injection rate (e.g., weigh belt, weigh hopper, or hopper flow measurement device), you must meet the requirements in paragraphs (d) and (i)(1) through (2) of this section.

The FBC does not have an operating limit that requires the use of a monitoring system to measure sorbent injection rate.

(1) Install the system in a position(s) that provides a representative measurement of the total sorbent injection rate.

(2) Conduct a performance evaluation of the sorbent injection rate monitoring system in accordance with your monitoring plan at the time of each performance test but no less frequently than annually.

(j) If you are not required to use a PM CPMS and elect to use a fabric filter bag leak detection system to comply with the requirements of this subpart, you must install, calibrate, maintain, and continuously operate the bag leak detection system as specified in paragraphs (j)(1) through (6) of this section.

The FBC is not required to use a PM CPMS and does not elect to use a fabric filter bag leak detection system.

(1) You must install a bag leak detection sensor(s) in a position(s) that will be representative of the relative or absolute PM loadings for each exhaust stack, roof vent, or compartment (e.g., for a positive pressure fabric filter) of the fabric filter.

(2) Conduct a performance evaluation of the bag leak detection system in accordance with your monitoring plan and consistent with the guidance provided in EPA-454/R-98-015 (incorporated by reference, see §63.14).

(3) Use a bag leak detection system certified by the manufacturer to be capable of detecting PM emissions at concentrations of 10 milligrams per actual cubic meter or less.

(4) Use a bag leak detection system equipped with a device to record continuously the output signal from the sensor.

(5) Use a bag leak detection system equipped with a system that will alert plant operating personnel when an increase in relative PM emissions over a preset level is detected. The alert must easily recognizable (e.g., heard or seen) by plant operating personnel.

(6) Where multiple bag leak detectors are required, the system's instrumentation and alert may be shared among detectors.

(k) For each unit that meets the definition of limited-use boiler or process heater, you must keep fuel use records for the days the boiler or process heater was operating.

The unit is not a limited-use boiler.

(l) For each unit for which you decide to demonstrate compliance with the mercury or HCl emissions limits in Tables 1 or 2 or 11 through 13 of this subpart by use of a CEMS for mercury or HCl, you must install, certify, maintain, and operate a CEMS measuring emissions discharged to the atmosphere and record the output of the system as specified in paragraphs (l)(1) through (8) of this section. For HCl, this option for an affected unit takes effect on the date a final performance specification for a HCl CEMS is published in the FEDERAL REGISTER or the date of approval of a site-specific monitoring plan.

CRE will demonstrate compliance through stack testing.

(1) Notify the Administrator one month before starting use of the CEMS, and notify the Administrator one month before stopping use of the CEMS.

(2) Each CEMS shall be installed, certified, operated, and maintained according to the requirements in §63.7540(a)(14) for a mercury CEMS and §63.7540(a)(15) for a HCl CEMS.

(3) For a new unit, you must complete the initial performance evaluation of the CEMS by the latest of the dates specified in paragraph (l)(3)(i) through (iii) of this section.

(i) No later than July 30, 2013.

(ii) No later 180 days after the date of initial startup.

(iii) No later 180 days after notifying the Administrator before starting to use the CEMS in place of performance testing or fuel analysis to demonstrate compliance.

(4) For an existing unit, you must complete the initial performance evaluation by the latter of the two dates specified in paragraph (l)(4)(i) and (ii) of this section.

(i) No later than July 29, 2016.

(ii) No later 180 days after notifying the Administrator before starting to use the CEMS in place of performance testing or fuel analysis to demonstrate compliance.

(5) Compliance with the applicable emissions limit shall be determined based on the 30-day rolling average of the hourly arithmetic average emissions rates using the continuous monitoring system outlet data. The 30-day rolling arithmetic average emission rate (lb/MMBtu) shall be calculated using the equations in EPA Reference Method 19 at 40 CFR part 60, appendix A-7, but substituting the mercury or HCl concentration for the pollutant concentrations normally used in Method 19.

(6) Collect CEMS hourly averages for all operating hours on a 30-day rolling average basis. Collect at least four CMS data values representing the four 15-minute periods in an hour, or at least two 15-minute data values during an hour when CMS calibration, quality assurance, or maintenance activities are being performed.

(7) The one-hour arithmetic averages required shall be expressed in lb/MMBtu and shall be used to calculate the boiler 30-day and 10-day rolling average emissions.

(8) You are allowed to substitute the use of the PM, mercury or HCl CEMS for the applicable fuel analysis, annual performance test, and operating limits specified in Table 4 to this subpart to demonstrate compliance with the PM, mercury or HCl emissions limit, and if you are using an acid gas wet scrubber or dry sorbent injection control technology to comply with the HCl emission limit, you are allowed to

substitute the use of a sulfur dioxide (SO_2) CEMS for the applicable fuel analysis, annual performance test, and operating limits specified in Table 4 to this subpart to demonstrate compliance with HCl emissions limit.

(m) If your unit is subject to a HCl emission limit in Tables 1, 2, or 11 through 13 of this subpart and you have an acid gas wet scrubber or dry sorbent injection control technology and you elect to use an SO_2 CEMS to demonstrate continuous compliance with the HCl emission limit, you must install the monitor at the outlet of the boiler or process heater, downstream of all emission control devices, and you must install, certify, operate, and maintain the CEMS according to either part 60 or part 75 of this chapter.

The FBC will not have an acid gas wet scrubber or dry sorbent injection control technology.

(1) The SO_2 CEMS must be installed by the compliance date specified in §63.7495.

(2) For on-going quality assurance (QA), the SO_2 CEMS must meet either the applicable daily and quarterly requirements in Procedure 1 of appendix F of part 60 or the applicable daily, quarterly, and semiannual or annual requirements in sections 2.1 through 2.3 of appendix B to part 75 of this chapter, with the following addition: You must perform the linearity checks required in section 2.2 of appendix B to part 75 of this chapter if the SO_2 CEMS has a span value of 30 ppm or less.

(3) For a new unit, the initial performance evaluation shall be completed no later than July 30, 2013, or 180 days after the date of initial startup, whichever is later. For an existing unit, the initial performance evaluation shall be completed no later than July 29, 2016.

(4) For purposes of collecting SO_2 data, you must operate the SO_2 CEMS as specified in §63.7535(b). You must use all the data collected during all periods in calculating data averages and assessing compliance, except that you must exclude certain data as specified in §63.7535(c). Periods when SO_2 data are unavailable may constitute monitoring deviations as specified in §63.7535(d).

(5) Collect CEMS hourly averages for all operating hours on a 30-day rolling average basis.

(6) Use only unadjusted, quality-assured SO_2 concentration values in the emissions calculations; do not apply bias adjustment factors to the part 75 SO_2 data and do not use part 75 substitute data values.

[76 FR 15664, Mar. 21, 2011, as amended at 78 FR 7171, Jan. 31, 2013; 80 FR 72810, Nov. 20, 2015]

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§63.7530 How do I demonstrate initial compliance with the emission limitations, fuel specifications and work practice standards?

Compliance will be demonstrated through initial and subsequent stack tests; the FBC burns a single fuel type, therefore fuel analysis is not required. CRE is not required to install a CMS. Site specific operating limits will be established during the stack tests in accordance with the requirements of this section. CRE will meet the work practice standard according to Table 3 of this subpart. During startup and shutdown, you must only follow the work practice standards according to items 5 and 6 of Table 3 of this subpart. CRE will submit the Notification of Compliance Status containing the results of the initial compliance demonstration according to the requirements in §63.7545(e).

(a) You must demonstrate initial compliance with each emission limit that applies to you by conducting initial performance tests and fuel analyses and establishing operating limits, as applicable, according to §63.7520, paragraphs (b) and (c) of this section, and Tables 5 and 7 to this subpart. The

requirement to conduct a fuel analysis is not applicable for units that burn a single type of fuel, as specified by §63.7510(a)(2). If applicable, you must also install, operate, and maintain all applicable CMS (including CEMS, COMS, and CPMS) according to §63.7525.

(b) If you demonstrate compliance through performance stack testing, you must establish each site-specific operating limit in Table 4 to this subpart that applies to you according to the requirements in §63.7520, Table 7 to this subpart, and paragraph (b)(4) of this section, as applicable. You must also conduct fuel analyses according to §63.7521 and establish maximum fuel pollutant input levels according to paragraphs (b)(1) through (3) of this section, as applicable, and as specified in §63.7510(a)(2). (Note that §63.7510(a)(2) exempts certain fuels from the fuel analysis requirements.) However, if you switch fuel(s) and cannot show that the new fuel(s) does (do) not increase the chlorine, mercury, or TSM input into the unit through the results of fuel analysis, then you must repeat the performance test to demonstrate compliance while burning the new fuel(s).

(1) You must establish the maximum chlorine fuel input (Clinput) during the initial fuel analysis according to the procedures in paragraphs (b)(1)(i) through (iii) of this section.

(i) You must determine the fuel type or fuel mixture that you could burn in your boiler or process heater that has the highest content of chlorine.

(ii) During the fuel analysis for hydrogen chloride, you must determine the fraction of the total heat input for each fuel type burned (Qi) based on the fuel mixture that has the highest content of chlorine, and the average chlorine concentration of each fuel type burned (Ci).

(iii) You must establish a maximum chlorine input level using Equation 7 of this section.

$$Clinput = \sum_{i=1}^{n} (Ci \times Qi) \quad \text{(Eq. 7)}$$

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Where:

Clinput = Maximum amount of chlorine entering the boiler or process heater through fuels burned in units of pounds per million Btu.

Ci = Arithmetic average concentration of chlorine in fuel type, i, analyzed according to §63.7521, in units of pounds per million Btu.

Qi = Fraction of total heat input from fuel type, i, based on the fuel mixture that has the highest content of chlorine during the initial compliance test. If you do not burn multiple fuel types during the performance testing, it is not necessary to determine the value of this term. Insert a value of “1” for Qi. For continuous compliance demonstration, the actual fraction of the fuel burned during the month should be used.

n = Number of different fuel types burned in your boiler or process heater for the mixture that has the highest content of chlorine.

(2) You must establish the maximum mercury fuel input level (Mercuryinput) during the initial fuel analysis using the procedures in paragraphs (b)(2)(i) through (iii) of this section.

(i) You must determine the fuel type or fuel mixture that you could burn in your boiler or process heater that has the highest content of mercury.

(ii) During the compliance demonstration for mercury, you must determine the fraction of total heat input for each fuel burned (Qi) based on the fuel mixture that has the highest content of mercury, and the average mercury concentration of each fuel type burned (HGi).

(iii) You must establish a maximum mercury input level using Equation 8 of this section.

$$Mercuryinput = \sum_{i=1}^{n} (HGi \times Qi) \qquad \text{(Eq. 8)}$$

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Where:

Mercuryinput = Maximum amount of mercury entering the boiler or process heater through fuels burned in units of pounds per million Btu.

HGi = Arithmetic average concentration of mercury in fuel type, i, analyzed according to §63.7521, in units of pounds per million Btu.

Qi = Fraction of total heat input from fuel type, i, based on the fuel mixture that has the highest mercury content during the initial compliance test. If you do not burn multiple fuel types during the performance test, it is not necessary to determine the value of this term. Insert a value of "1" for Qi. For continuous compliance demonstration, the actual fraction of the fuel burned during the month should be used.

n = Number of different fuel types burned in your boiler or process heater for the mixture that has the highest content of mercury.

(3) If you opt to comply with the alternative TSM limit, you must establish the maximum TSM fuel input (TSMinput) for solid or liquid fuels during the initial fuel analysis according to the procedures in paragraphs (b)(3)(i) through (iii) of this section.

(i) You must determine the fuel type or fuel mixture that you could burn in your boiler or process heater that has the highest content of TSM.

(ii) During the fuel analysis for TSM, you must determine the fraction of the total heat input for each fuel type burned (Qi) based on the fuel mixture that has the highest content of TSM, and the average TSM concentration of each fuel type burned (TSMi).

(iii) You must establish a maximum TSM input level using Equation 9 of this section.

$$TSMinput = \sum_{i=1}^{n} (TSMi \times Qi) \qquad \text{(Eq. 9)}$$

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Where:

TSMinput = Maximum amount of TSM entering the boiler or process heater through fuels burned in units of pounds per million Btu.

TSMi = Arithmetic average concentration of TSM in fuel type, i, analyzed according to §63.7521, in units of pounds per million Btu.

Qi = Fraction of total heat input from fuel type, i, based on the fuel mixture that has the highest content of TSM during the initial compliance test. If you do not burn multiple fuel types during the performance testing, it is not

necessary to determine the value of this term. Insert a value of "1" for Qi. For continuous compliance demonstration, the actual fraction of the fuel burned during the month should be used.

n = Number of different fuel types burned in your boiler or process heater for the mixture that has the highest content of TSM.

(4) You must establish parameter operating limits according to paragraphs (b)(4)(i) through (ix) of this section. As indicated in Table 4 to this subpart, you are not required to establish and comply with the operating parameter limits when you are using a CEMS to monitor and demonstrate compliance with the applicable emission limit for that control device parameter.

(i) For a wet acid gas scrubber, you must establish the minimum scrubber effluent pH and liquid flow rate as defined in §63.7575, as your operating limits during the performance test during which you demonstrate compliance with your applicable limit. If you use a wet scrubber and you conduct separate performance tests for HCl and mercury emissions, you must establish one set of minimum scrubber effluent pH, liquid flow rate, and pressure drop operating limits. The minimum scrubber effluent pH operating limit must be established during the HCl performance test. If you conduct multiple performance tests, you must set the minimum liquid flow rate operating limit at the higher of the minimum values established during the performance tests.

(ii) For any particulate control device (e.g., ESP, particulate wet scrubber, fabric filter) for which you use a PM CPMS, you must establish your PM CPMS operating limit and determine compliance with it according to paragraphs (b)(4)(ii)(A) through (F) of this section.

(A) Determine your operating limit as the average PM CPMS output value recorded during the most recent performance test run demonstrating compliance with the filterable PM emission limit or at the PM CPMS output value corresponding to 75 percent of the emission limit if your PM performance test demonstrates compliance below 75 percent of the emission limit. You must verify an existing or establish a new operating limit after each repeated performance test. You must repeat the performance test annually and reassess and adjust the site-specific operating limit in accordance with the results of the performance test.

(*1*) Your PM CPMS must provide a 4-20 milliamp output and the establishment of its relationship to manual reference method measurements must be determined in units of milliamps.

(*2*) Your PM CPMS operating range must be capable of reading PM concentrations from zero to a level equivalent to at least two times your allowable emission limit. If your PM CPMS is an auto-ranging instrument capable of multiple scales, the primary range of the instrument must be capable of reading PM concentration from zero to a level equivalent to two times your allowable emission limit.

(*3*) During the initial performance test or any such subsequent performance test that demonstrates compliance with the PM limit, record and average all milliamp output values from the PM CPMS for the periods corresponding to the compliance test runs (e.g., average all your PM CPMS output values for three corresponding 2-hour Method 5I test runs).

(B) If the average of your three PM performance test runs are below 75 percent of your PM emission limit, you must calculate an operating limit by establishing a relationship of PM CPMS signal to PM concentration using the PM CPMS instrument zero, the average PM CPMS values corresponding to the three compliance test runs, and the average PM concentration from the Method 5 or performance test with the procedures in paragraphs (b)(4)(ii)(B)(*1*) through (*4*) of this section.

(*1*) Determine your instrument zero output with one of the following procedures:

(*i*) Zero point data for *in-situ* instruments should be obtained by removing the instrument from the stack and monitoring ambient air on a test bench.

(*ii*) Zero point data for *extractive* instruments should be obtained by removing the extractive probe from the stack and drawing in clean ambient air.

(*iii*) The zero point may also be established by performing manual reference method measurements when the flue gas is free of PM emissions or contains very low PM concentrations (e.g., when your process is not operating, but the fans are operating or your source is combusting only natural gas) and plotting these with the compliance data to find the zero intercept.

(*iv*) If none of the steps in paragraphs (b)(4)(ii)(B)(*1*)(*i*) through (*iii*) of this section are possible, you must use a zero output value provided by the manufacturer.

(*2*) Determine your PM CPMS instrument average in milliamps, and the average of your corresponding three PM compliance test runs, using equation 10.

$$\bar{x} = \frac{1}{n}\sum_{i=1}^{n} X_i, \bar{y} = \frac{1}{n}\sum_{i=1}^{n} Y_i \qquad \text{(Eq. 10)}$$

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Where:

X_i = the PM CPMS data points for the three runs constituting the performance test,

Y_i = the PM concentration value for the three runs constituting the performance test, and

n = the number of data points.

(*3*) With your instrument zero expressed in milliamps, your three run average PM CPMS milliamp value, and your three run average PM concentration from your three compliance tests, determine a relationship of lb/MMBtu per milliamp with equation 11.

$$R = \frac{Y_i}{(X_i - z)} \qquad \text{(Eq. 11)}$$

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Where:

R = the relative lb/MMBtu per milliamp for your PM CPMS,

Y_i = the three run average lb/MMBtu PM concentration,

X_i = the three run average milliamp output from you PM CPMS, and

z = the milliamp equivalent of your instrument zero determined from (B)(i).

(*4*) Determine your source specific 30-day rolling average operating limit using the lb/MMBtu per milliamp value from Equation 11 in equation 12, below. This sets your operating limit at the PM CPMS output value corresponding to 75 percent of your emission limit.

$$O_l = z + \frac{0.75(L)}{R} \qquad \text{(Eq. 12)}$$

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Where:

O_l = the operating limit for your PM CPMS on a 30-day rolling average, in milliamps.

L = your source emission limit expressed in lb/MMBtu,

z = your instrument zero in milliamps, determined from (B)(i), and

R = the relative lb/MMBtu per milliamp for your PM CPMS, from Equation 11.

(C) If the average of your three PM compliance test runs is at or above 75 percent of your PM emission limit you must determine your 30-day rolling average operating limit by averaging the PM CPMS milliamp output corresponding to your three PM performance test runs that demonstrate compliance with the emission limit using equation 13 and you must submit all compliance test and PM CPMS data according to the reporting requirements in paragraph (b)(4)(ii)(F) of this section.

$$O_h = \frac{1}{n}\sum_{i=1}^{n} X_i \qquad \text{(Eq. 13)}$$

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Where:

X_i = the PM CPMS data points for all runs i,

n = the number of data points, and

O_h = your site specific operating limit, in milliamps.

(D) To determine continuous compliance, you must record the PM CPMS output data for all periods when the process is operating and the PM CPMS is not out-of-control. You must demonstrate continuous compliance by using all quality-assured hourly average data collected by the PM CPMS for all operating hours to calculate the arithmetic average operating parameter in units of the operating limit (milliamps) on a 30-day rolling average basis, updated at the end of each new operating hour. Use Equation 14 to determine the 30-day rolling average.

$$30-\text{day} = \frac{\sum_{i=1}^{n} Hpvi}{n} \qquad \text{(Eq. 14)}$$

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Where:

30-day = 30-day average.

Hpvi = is the hourly parameter value for hour i

n = is the number of valid hourly parameter values collected over the previous 30 operating days.

(E) Use EPA Method 5 of appendix A to part 60 of this chapter to determine PM emissions. For each performance test, conduct three separate runs under the conditions that exist when the affected source is operating at the highest load or capacity level reasonably expected to occur. Conduct each test

run to collect a minimum sample volume specified in Tables 1, 2, or 11 through 13 to this subpart, as applicable, for determining compliance with a new source limit or an existing source limit. Calculate the average of the results from three runs to determine compliance. You need not determine the PM collected in the impingers ("back half") of the Method 5 particulate sampling train to demonstrate compliance with the PM standards of this subpart. This shall not preclude the permitting authority from requiring a determination of the "back half" for other purposes.

(F) For PM performance test reports used to set a PM CPMS operating limit, the electronic submission of the test report must also include the make and model of the PM CPMS instrument, serial number of the instrument, analytical principle of the instrument (*e.g.* beta attenuation), span of the instruments primary analytical range, milliamp value equivalent to the instrument zero output, technique by which this zero value was determined, and the average milliamp signals corresponding to each PM compliance test run.

(iii) For a particulate wet scrubber, you must establish the minimum pressure drop and liquid flow rate as defined in §63.7575, as your operating limits during the three-run performance test during which you demonstrate compliance with your applicable limit. If you use a wet scrubber and you conduct separate performance tests for PM and TSM emissions, you must establish one set of minimum scrubber liquid flow rate and pressure drop operating limits. The minimum scrubber effluent pH operating limit must be established during the HCl performance test. If you conduct multiple performance tests, you must set the minimum liquid flow rate and pressure drop operating limits at the higher of the minimum values established during the performance tests.

(iv) For an electrostatic precipitator (ESP) operated with a wet scrubber, you must establish the minimum total secondary electric power input, as defined in §63.7575, as your operating limit during the three-run performance test during which you demonstrate compliance with your applicable limit. (These operating limits do not apply to ESP that are operated as dry controls without a wet scrubber.)

(v) For a dry scrubber, you must establish the minimum sorbent injection rate for each sorbent, as defined in §63.7575, as your operating limit during the three-run performance test during which you demonstrate compliance with your applicable limit.

(vi) For activated carbon injection, you must establish the minimum activated carbon injection rate, as defined in §63.7575, as your operating limit during the three-run performance test during which you demonstrate compliance with your applicable limit.

(vii) The operating limit for boilers or process heaters with fabric filters that demonstrate continuous compliance through bag leak detection systems is that a bag leak detection system be installed according to the requirements in §63.7525, and that each fabric filter must be operated such that the bag leak detection system alert is not activated more than 5 percent of the operating time during a 6-month period.

(viii) For a minimum oxygen level, if you conduct multiple performance tests, you must set the minimum oxygen level at the lower of the minimum values established during the performance tests.

(ix) The operating limit for boilers or process heaters that demonstrate continuous compliance with the HCl emission limit using a SO_2 CEMS is to install and operate the SO_2 according to the requirements in §63.7525(m) establish a maximum SO_2 emission rate equal to the highest hourly average SO_2 measurement during the most recent three-run performance test for HCl.

(c) If you elect to demonstrate compliance with an applicable emission limit through fuel analysis, you must conduct fuel analyses according to §63.7521 and follow the procedures in paragraphs (c)(1) through (5) of this section.

(1) If you burn more than one fuel type, you must determine the fuel mixture you could burn in your boiler or process heater that would result in the maximum emission rates of the pollutants that you elect to demonstrate compliance through fuel analysis.

(2) You must determine the 90th percentile confidence level fuel pollutant concentration of the composite samples analyzed for each fuel type using the one-sided t-statistic test described in Equation 15 of this section.

$$P90 = mean + (SD \times t) \quad \text{(Eq. 15)}$$

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Where:

P90 = 90th percentile confidence level pollutant concentration, in pounds per million Btu.

Mean = Arithmetic average of the fuel pollutant concentration in the fuel samples analyzed according to §63.7521, in units of pounds per million Btu.

SD = Standard deviation of the mean of pollutant concentration in the fuel samples analyzed according to §63.7521, in units of pounds per million Btu. SD is calculated as the sample standard deviation divided by the square root of the number of samples.

t = t distribution critical value for 90th percentile ($t_{0.1}$) probability for the appropriate degrees of freedom (number of samples minus one) as obtained from a t-Distribution Critical Value Table.

(3) To demonstrate compliance with the applicable emission limit for HCl, the HCl emission rate that you calculate for your boiler or process heater using Equation 16 of this section must not exceed the applicable emission limit for HCl.

$$HCl = \sum_{i=1}^{n} (Ci90 \times Qi \times 1.028) \quad \text{(Eq. 16)}$$

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Where:

HCl = HCl emission rate from the boiler or process heater in units of pounds per million Btu.

Ci90 = 90th percentile confidence level concentration of chlorine in fuel type, i, in units of pounds per million Btu as calculated according to Equation 15 of this section.

Qi = Fraction of total heat input from fuel type, i, based on the fuel mixture that has the highest content of chlorine. If you do not burn multiple fuel types, it is not necessary to determine the value of this term. Insert a value of “1” for Qi. For continuous compliance demonstration, the actual fraction of the fuel burned during the month should be used.

n = Number of different fuel types burned in your boiler or process heater for the mixture that has the highest content of chlorine.

1.028 = Molecular weight ratio of HCl to chlorine.

(4) To demonstrate compliance with the applicable emission limit for mercury, the mercury emission rate that you calculate for your boiler or process heater using Equation 17 of this section must not exceed the applicable emission limit for mercury.

$$Mercury = \sum_{i=1}^{n} (Hgi90 \times Qi) \qquad \text{(Eq. 17)}$$

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Where:

Mercury = Mercury emission rate from the boiler or process heater in units of pounds per million Btu.

Hgi90 = 90th percentile confidence level concentration of mercury in fuel, i, in units of pounds per million Btu as calculated according to Equation 15 of this section.

Qi = Fraction of total heat input from fuel type, i, based on the fuel mixture that has the highest mercury content. If you do not burn multiple fuel types, it is not necessary to determine the value of this term. Insert a value of "1" for Qi. For continuous compliance demonstration, the actual fraction of the fuel burned during the month should be used.

n = Number of different fuel types burned in your boiler or process heater for the mixture that has the highest mercury content.

(5) To demonstrate compliance with the applicable emission limit for TSM for solid or liquid fuels, the TSM emission rate that you calculate for your boiler or process heater from solid fuels using Equation 18 of this section must not exceed the applicable emission limit for TSM.

$$Metals = \sum_{i=1}^{n} (TSM90i \times Qi) \qquad \text{(Eq. 18)}$$

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Where:

Metals = TSM emission rate from the boiler or process heater in units of pounds per million Btu.

TSMi90 = 90th percentile confidence level concentration of TSM in fuel, i, in units of pounds per million Btu as calculated according to Equation 15 of this section.

Qi = Fraction of total heat input from fuel type, i, based on the fuel mixture that has the highest TSM content. If you do not burn multiple fuel types, it is not necessary to determine the value of this term. Insert a value of "1" for Qi. For continuous compliance demonstration, the actual fraction of the fuel burned during the month should be used.

n = Number of different fuel types burned in your boiler or process heater for the mixture that has the highest TSM content.

(d)[Reserved]

(e) You must include with the Notification of Compliance Status a signed certification that either the energy assessment was completed according to Table 3 to this subpart, and that the assessment is an accurate depiction of your facility at the time of the assessment, or that the maximum number of on-site technical hours specified in the definition of energy assessment applicable to the facility has been expended.

(f) You must submit the Notification of Compliance Status containing the results of the initial compliance demonstration according to the requirements in §63.7545(e).

(g) If you elect to demonstrate that a gaseous fuel meets the specifications of another gas 1 fuel as defined in §63.7575, you must conduct an initial fuel specification analyses according to §63.7521(f) through (i) and according to the frequency listed in §63.7540(c) and maintain records of the results of the testing as outlined in §63.7555(g). For samples where the initial mercury specification has not been exceeded, you will include a signed certification with the Notification of Compliance Status that the initial fuel specification test meets the gas specification outlined in the definition of other gas 1 fuels.

(h) If you own or operate a unit subject to emission limits in Tables 1 or 2 or 11 through 13 to this subpart, you must meet the work practice standard according to Table 3 of this subpart. During startup and shutdown, you must only follow the work practice standards according to items 5 and 6 of Table 3 of this subpart.

(i) If you opt to comply with the alternative SO_2 CEMS operating limit in Tables 4 and 8 to this subpart, you may do so only if your affected boiler or process heater:

(1) Has a system using wet scrubber or dry sorbent injection and SO_2 CEMS installed on the unit; and

(2) At all times, you operate the wet scrubber or dry sorbent injection for acid gas control on the unit consistent with §63.7500(a)(3); and

(3) You establish a unit-specific maximum SO_2 operating limit by collecting the maximum hourly SO_2 emission rate on the SO_2 CEMS during the paired 3-run test for HCl. The maximum SO_2 operating limit is equal to the highest hourly average SO_2 concentration measured during the HCl performance test.

[76 FR 15664, Mar. 21, 2011, as amended at 78 FR 7174, Jan. 31, 2013; 80 FR 72811, Nov. 20, 2015]

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§63.7533 Can I use efficiency credits earned from implementation of energy conservation measures to comply with this subpart?

The FBC will be a new unit and not subject to energy assessment requirements.

(a) If you elect to comply with the alternative equivalent output-based emission limits, instead of the heat input-based limits listed in Table 2 to this subpart, and you want to take credit for implementing energy conservation measures identified in an energy assessment, you may demonstrate compliance using efficiency credits according to the procedures in this section. You may use this compliance approach for an existing affected boiler for demonstrating initial compliance according to §63.7522(e) and for demonstrating monthly compliance according to §63.7522(f). Owners or operators using this compliance approach must establish an emissions benchmark, calculate and document the efficiency credits, develop an Implementation Plan, comply with the general reporting requirements, and apply the efficiency credit according to the procedures in paragraphs (b) through (f) of this section. You cannot use this compliance approach for a new or reconstructed affected boiler. Additional guidance from the Department of Energy on efficiency credits is available at:*http://www.epa.gov/ttn/atw/boiler/boilerpg.html.*

(b) For each existing affected boiler for which you intend to apply emissions credits, establish a benchmark from which emission reduction credits may be generated by determining the actual annual fuel heat input to the affected boiler before initiation of an energy conservation activity to reduce energy demand (*i.e.,* fuel usage) according to paragraphs (b)(1) through (4) of this section. The benchmark shall be expressed in trillion Btu per year heat input.

(1) The benchmark from which efficiency credits may be generated shall be determined by using the most representative, accurate, and reliable process available for the source. The benchmark shall be established for a one-year period before the date that an energy demand reduction occurs, unless it can be demonstrated that a different time period is more representative of historical operations.

(2) Determine the starting point from which to measure progress. Inventory all fuel purchased and generated on-site (off-gases, residues) in physical units (MMBtu, million cubic feet, etc.).

(3) Document all uses of energy from the affected boiler. Use the most recent data available.

(4) Collect non-energy related facility and operational data to normalize, if necessary, the benchmark to current operations, such as building size, operating hours, etc. If possible, use actual data that are current and timely rather than estimated data.

(c) Efficiency credits can be generated if the energy conservation measures were implemented after January 1, 2008 and if sufficient information is available to determine the appropriate value of credits.

(1) The following emission points cannot be used to generate efficiency credits:

(i) Energy conservation measures implemented on or before January 1, 2008, unless the level of energy demand reduction is increased after January 1, 2008, in which case credit will be allowed only for change in demand reduction achieved after January 1, 2008.

(ii) Efficiency credits on shut-down boilers. Boilers that are shut down cannot be used to generate credits unless the facility provides documentation linking the permanent shutdown to energy conservation measures identified in the energy assessment. In this case, the bench established for the affected boiler to which the credits from the shutdown will be applied must be revised to include the benchmark established for the shutdown boiler.

(2) For all points included in calculating emissions credits, the owner or operator shall:

(i) Calculate annual credits for all energy demand points. Use Equation 19 to calculate credits. Energy conservation measures that meet the criteria of paragraph (c)(1) of this section shall not be included, except as specified in paragraph (c)(1)(i) of this section.

(3) Credits are generated by the difference between the benchmark that is established for each affected boiler, and the actual energy demand reductions from energy conservation measures implemented after January 1, 2008. Credits shall be calculated using Equation 19 of this section as follows:

(i) The overall equation for calculating credits is:

$$ECredits = \left(\sum_{i=1}^{n} EIS_{actual} \right) \div EI_{baseline} \quad \text{(Eq. 19)}$$

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Where:

ECredits = Energy Input Savings for all energy conservation measures implemented for an affected boiler, expressed as a decimal fraction of the baseline energy input.

$EIS_{iactual}$ = Energy Input Savings for each energy conservation measure, i, implemented for an affected boiler, million Btu per year.

$EI_{baseline}$ = Energy Input baseline for the affected boiler, million Btu per year.

n = Number of energy conservation measures included in the efficiency credit for the affected boiler.

(ii) [Reserved]

(d) The owner or operator shall develop, and submit for approval upon request by the Administrator, an Implementation Plan containing all of the information required in this paragraph for all boilers to be included in an efficiency credit approach. The Implementation Plan shall identify all existing affected boilers to be included in applying the efficiency credits. The Implementation Plan shall include a description of the energy conservation measures implemented and the energy savings generated from each measure and an explanation of the criteria used for determining that savings. If requested, you must submit the implementation plan for efficiency credits to the Administrator for review and approval no later than 180 days before the date on which the facility intends to demonstrate compliance using the efficiency credit approach.

(e) The emissions rate as calculated using Equation 20 of this section from each existing boiler participating in the efficiency credit option must be in compliance with the limits in Table 2 to this subpart at all times the affected unit is subject to numeric emission limits, following the compliance date specified in §63.7495.

(f) You must use Equation 20 of this section to demonstrate initial compliance by demonstrating that the emissions from the affected boiler participating in the efficiency credit compliance approach do not exceed the emission limits in Table 2 to this subpart.

$$E_{adj} = E_m \times (1 - ECredits) \quad \text{(Eq. 20)}$$

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Where:

E_{adj} = Emission level adjusted by applying the efficiency credits earned, lb per million Btu steam output (or lb per MWh) for the affected boiler.

E_m = Emissions measured during the performance test, lb per million Btu steam output (or lb per MWh) for the affected boiler.

ECredits = Efficiency credits from Equation 19 for the affected boiler.

(g) As part of each compliance report submitted as required under §63.7550, you must include documentation that the energy conservation measures implemented continue to generate the credit for use in demonstrating compliance with the emission limits.

[76 FR 15664, Mar. 21, 2011, as amended at 78 FR 7178, Jan. 31, 2013; 80 FR 72812, Nov. 20, 2015]

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CONTINUOUS COMPLIANCE REQUIREMENTS

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§63.7535 Is there a minimum amount of monitoring data I must obtain?

CRE will not conduct any continuous monitoring.

(a) You must monitor and collect data according to this section and the site-specific monitoring plan required by §63.7505(d).

(b) You must operate the monitoring system and collect data at all required intervals at all times that each boiler or process heater is operating and compliance is required, except for periods of monitoring system malfunctions or out of control periods (see §63.8(c)(7) of this part), and required monitoring system quality assurance or control activities, including, as applicable, calibration checks, required zero and span adjustments, and scheduled CMS maintenance as defined in your site-specific monitoring plan. A monitoring system malfunction is any sudden, infrequent, not reasonably preventable failure of the monitoring system to provide valid data. Monitoring system failures that are caused in part by poor maintenance or careless operation are not malfunctions. You are required to complete monitoring system repairs in response to monitoring system malfunctions or out-of-control periods and to return the monitoring system to operation as expeditiously as practicable.

(c) You may not use data recorded during periods of startup and shutdown, monitoring system malfunctions or out-of-control periods, repairs associated with monitoring system malfunctions or out-of-control periods, or required monitoring system quality assurance or control activities in data averages and calculations used to report emissions or operating levels. You must record and make available upon request results of CMS performance audits and dates and duration of periods when the CMS is out of control to completion of the corrective actions necessary to return the CMS to operation consistent with your site-specific monitoring plan. You must use all the data collected during all other periods in assessing compliance and the operation of the control device and associated control system.

(d) Except for periods of monitoring system malfunctions, repairs associated with monitoring system malfunctions, and required monitoring system quality assurance or quality control activities (including, as applicable, system accuracy audits, calibration checks, and required zero and span adjustments), failure to collect required data is a deviation of the monitoring requirements. In calculating monitoring results, do not use any data collected during periods of startup and shutdown, when the monitoring system is out of control as specified in your site-specific monitoring plan, while conducting repairs associated with periods when the monitoring system is out of control, or while conducting required monitoring system quality assurance or quality control activities. You must calculate monitoring results using all other monitoring data collected while the process is operating. You must report all periods when the monitoring system is out of control in your semi-annual report.

[76 FR 15664, Mar. 21, 2011, as amended at 78 FR 7179, Jan. 31, 2013; 80 FR 72812, Nov. 20, 2015]

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§63.7540 How do I demonstrate continuous compliance with the emission limitations, fuel specifications and work practice standards?

(a) You must demonstrate continuous compliance with each emission limit in Tables 1 and 2 or 11 through 13 to this subpart, the work practice standards in Table 3 to this subpart, and the operating limits in Table 4 to this subpart that applies to you according to the methods specified in Table 8 to this subpart and paragraphs (a)(1) through (19) of this section.

Operating limits will be confirmed or reestablished during performance tests. Records of the type and amount of all fuels burned in in the FBC during the reporting period will be kept to demonstrate compliance with the requirements of this section and this Subpart. CRE does not

plan to burn any type of fuel other than the hogged fuel specified for use in the FBC. CRE will conduct an annual tune-up of the boiler or process heater to demonstrate continuous compliance.

(1) Following the date on which the initial compliance demonstration is completed or is required to be completed under §§63.7 and 63.7510, whichever date comes first, operation above the established maximum or below the established minimum operating limits shall constitute a deviation of established operating limits listed in Table 4 of this subpart except during performance tests conducted to determine compliance with the emission limits or to establish new operating limits. Operating limits must be confirmed or reestablished during performance tests.

(2) As specified in §63.7555(d), you must keep records of the type and amount of all fuels burned in each boiler or process heater during the reporting period to demonstrate that all fuel types and mixtures of fuels burned would result in either of the following:

(i) Equal to or lower emissions of HCl, mercury, and TSM than the applicable emission limit for each pollutant, if you demonstrate compliance through fuel analysis.

(ii) Equal to or lower fuel input of chlorine, mercury, and TSM than the maximum values calculated during the last performance test, if you demonstrate compliance through performance testing.

(3) If you demonstrate compliance with an applicable HCl emission limit through fuel analysis for a solid or liquid fuel and you plan to burn a new type of solid or liquid fuel, you must recalculate the HCl emission rate using Equation 16 of §63.7530 according to paragraphs (a)(3)(i) through (iii) of this section. You are not required to conduct fuel analyses for the fuels described in §63.7510(a)(2)(i) through (iii). You may exclude the fuels described in §63.7510(a)(2)(i) through (iii) when recalculating the HCl emission rate.

(i) You must determine the chlorine concentration for any new fuel type in units of pounds per million Btu, based on supplier data or your own fuel analysis, according to the provisions in your site-specific fuel analysis plan developed according to §63.7521(b).

(ii) You must determine the new mixture of fuels that will have the highest content of chlorine.

(iii) Recalculate the HCl emission rate from your boiler or process heater under these new conditions using Equation 16 of §63.7530. The recalculated HCl emission rate must be less than the applicable emission limit.

(4) If you demonstrate compliance with an applicable HCl emission limit through performance testing and you plan to burn a new type of fuel or a new mixture of fuels, you must recalculate the maximum chlorine input using Equation 7 of §63.7530. If the results of recalculating the maximum chlorine input using Equation 7 of §63.7530 are greater than the maximum chlorine input level established during the previous performance test, then you must conduct a new performance test within 60 days of burning the new fuel type or fuel mixture according to the procedures in §63.7520 to demonstrate that the HCl emissions do not exceed the emission limit. You must also establish new operating limits based on this performance test according to the procedures in §63.7530(b). In recalculating the maximum chlorine input and establishing the new operating limits, you are not required to conduct fuel analyses for and include the fuels described in §63.7510(a)(2)(i) through (iii).

(5) If you demonstrate compliance with an applicable mercury emission limit through fuel analysis, and you plan to burn a new type of fuel, you must recalculate the mercury emission rate using Equation 17 of §63.7530 according to the procedures specified in paragraphs (a)(5)(i) through (iii) of this section. You are not required to conduct fuel analyses for the fuels described in §63.7510(a)(2)(i) through (iii). You may exclude the fuels described in §63.7510(a)(2)(i) through (iii) when recalculating the mercury emission rate.

(i) You must determine the mercury concentration for any new fuel type in units of pounds per million Btu, based on supplier data or your own fuel analysis, according to the provisions in your site-specific fuel analysis plan developed according to §63.7521(b).

(ii) You must determine the new mixture of fuels that will have the highest content of mercury.

(iii) Recalculate the mercury emission rate from your boiler or process heater under these new conditions using Equation 17 of §63.7530. The recalculated mercury emission rate must be less than the applicable emission limit.

(6) If you demonstrate compliance with an applicable mercury emission limit through performance testing, and you plan to burn a new type of fuel or a new mixture of fuels, you must recalculate the maximum mercury input using Equation 8 of §63.7530. If the results of recalculating the maximum mercury input using Equation 8 of §63.7530 are higher than the maximum mercury input level established during the previous performance test, then you must conduct a new performance test within 60 days of burning the new fuel type or fuel mixture according to the procedures in §63.7520 to demonstrate that the mercury emissions do not exceed the emission limit. You must also establish new operating limits based on this performance test according to the procedures in §63.7530(b). You are not required to conduct fuel analyses for the fuels described in §63.7510(a)(2)(i) through (iii). You may exclude the fuels described in §63.7510(a)(2)(i) through (iii) when recalculating the mercury emission rate.

(7) If your unit is controlled with a fabric filter, and you demonstrate continuous compliance using a bag leak detection system, you must initiate corrective action within 1 hour of a bag leak detection system alert and complete corrective actions as soon as practical, and operate and maintain the fabric filter system such that the periods which would cause an alert are no more than 5 percent of the operating time during a 6-month period. You must also keep records of the date, time, and duration of each alert, the time corrective action was initiated and completed, and a brief description of the cause of the alert and the corrective action taken. You must also record the percent of the operating time during each 6-month period that the conditions exist for an alert. In calculating this operating time percentage, if inspection of the fabric filter demonstrates that no corrective action is required, no alert time is counted. If corrective action is required, each alert shall be counted as a minimum of 1 hour. If you take longer than 1 hour to initiate corrective action, the alert time shall be counted as the actual amount of time taken to initiate corrective action.

(8) To demonstrate compliance with the applicable alternative CO CEMS emission limit listed in Tables 1, 2, or 11 through 13 to this subpart, you must meet the requirements in paragraphs (a)(8)(i) through (iv) of this section.

(i) Continuously monitor CO according to §§63.7525(a) and 63.7535.

(ii) Maintain a CO emission level below or at your applicable alternative CO CEMS-based standard in Tables 1 or 2 or 11 through 13 to this subpart at all times the affected unit is subject to numeric emission limits.

(iii) Keep records of CO levels according to §63.7555(b).

(iv) You must record and make available upon request results of CO CEMS performance audits, dates and duration of periods when the CO CEMS is out of control to completion of the corrective actions necessary to return the CO CEMS to operation consistent with your site-specific monitoring plan.

(9) The owner or operator of a boiler or process heater using a PM CPMS or a PM CEMS to meet requirements of this subpart shall install, certify, operate, and maintain the PM CPMS or PM CEMS in accordance with your site-specific monitoring plan as required in §63.7505(d).

(10) If your boiler or process heater has a heat input capacity of 10 million Btu per hour or greater, you must conduct an annual tune-up of the boiler or process heater to demonstrate continuous compliance as specified in paragraphs (a)(10)(i) through (vi) of this section. You must conduct the tune-up while burning the type of fuel (or fuels in case of units that routinely burn a mixture) that provided the majority of the heat input to the boiler or process heater over the 12 months prior to the tune-up. This frequency does not apply to limited-use boilers and process heaters, as defined in §63.7575, or units with continuous oxygen trim systems that maintain an optimum air to fuel ratio.

(i) As applicable, inspect the burner, and clean or replace any components of the burner as necessary (you may perform the burner inspection any time prior to the tune-up or delay the burner inspection until the next scheduled unit shutdown). Units that produce electricity for sale may delay the burner inspection until the first outage, not to exceed 36 months from the previous inspection. At units where entry into a piece of process equipment or into a storage vessel is required to complete the tune-up inspections, inspections are required only during planned entries into the storage vessel or process equipment;

(ii) Inspect the flame pattern, as applicable, and adjust the burner as necessary to optimize the flame pattern. The adjustment should be consistent with the manufacturer's specifications, if available;

(iii) Inspect the system controlling the air-to-fuel ratio, as applicable, and ensure that it is correctly calibrated and functioning properly (you may delay the inspection until the next scheduled unit shutdown). Units that produce electricity for sale may delay the inspection until the first outage, not to exceed 36 months from the previous inspection;

(iv) Optimize total emissions of CO. This optimization should be consistent with the manufacturer's specifications, if available, and with any NO_x requirement to which the unit is subject;

(v) Measure the concentrations in the effluent stream of CO in parts per million, by volume, and oxygen in volume percent, before and after the adjustments are made (measurements may be either on a dry or wet basis, as long as it is the same basis before and after the adjustments are made). Measurements may be taken using a portable CO analyzer; and

(vi) Maintain on-site and submit, if requested by the Administrator, a report containing the information in paragraphs (a)(10)(vi)(A) through (C) of this section,

(A) The concentrations of CO in the effluent stream in parts per million by volume, and oxygen in volume percent, measured at high fire or typical operating load, before and after the tune-up of the boiler or process heater;

(B) A description of any corrective actions taken as a part of the tune-up; and

(C) The type and amount of fuel used over the 12 months prior to the tune-up, but only if the unit was physically and legally capable of using more than one type of fuel during that period. Units sharing a fuel meter may estimate the fuel used by each unit.

(11) If your boiler or process heater has a heat input capacity of less than 10 million Btu per hour (except as specified in paragraph (a)(12) of this section), you must conduct a biennial tune-up of the boiler or process heater as specified in paragraphs (a)(10)(i) through (vi) of this section to demonstrate continuous compliance.

(12) If your boiler or process heater has a continuous oxygen trim system that maintains an optimum air to fuel ratio, or a heat input capacity of less than or equal to 5 million Btu per hour and the unit is in the units designed to burn gas 1; units designed to burn gas 2 (other); or units designed to burn light liquid

subcategories, or meets the definition of limited-use boiler or process heater in §63.7575, you must conduct a tune-up of the boiler or process heater every 5 years as specified in paragraphs (a)(10)(i) through (vi) of this section to demonstrate continuous compliance. You may delay the burner inspection specified in paragraph (a)(10)(i) of this section until the next scheduled or unscheduled unit shutdown, but you must inspect each burner at least once every 72 months. If an oxygen trim system is utilized on a unit without emission standards to reduce the tune-up frequency to once every 5 years, set the oxygen level no lower than the oxygen concentration measured during the most recent tune-up.

(13) If the unit is not operating on the required date for a tune-up, the tune-up must be conducted within 30 calendar days of startup.

(14) If you are using a CEMS measuring mercury emissions to meet requirements of this subpart you must install, certify, operate, and maintain the mercury CEMS as specified in paragraphs (a)(14)(i) and (ii) of this section.

(i) Operate the mercury CEMS in accordance with performance specification 12A of 40 CFR part 60, appendix B or operate a sorbent trap based integrated monitor in accordance with performance specification 12B of 40 CFR part 60, appendix B. The duration of the performance test must be 30 operating days if you specified a 30 operating day basis in §63.7545(e)(2)(iii) for mercury CEMS or it must be 720 hours if you specified a 720 hour basis in §63.7545(e)(2)(iii) for mercury CEMS. For each day in which the unit operates, you must obtain hourly mercury concentration data, and stack gas volumetric flow rate data.

(ii) If you are using a mercury CEMS, you must install, operate, calibrate, and maintain an instrument for continuously measuring and recording the mercury mass emissions rate to the atmosphere according to the requirements of performance specifications 6 and 12A of 40 CFR part 60, appendix B, and quality assurance procedure 6 of 40 CFR part 60, appendix F.

(15) If you are using a CEMS to measure HCl emissions to meet requirements of this subpart, you must install, certify, operate, and maintain the HCl CEMS as specified in paragraphs (a)(15)(i) and (ii) of this section. This option for an affected unit takes effect on the date a final performance specification for an HCl CEMS is published in the FEDERAL REGISTER or the date of approval of a site-specific monitoring plan.

(i) Operate the continuous emissions monitoring system in accordance with the applicable performance specification in 40 CFR part 60, appendix B. The duration of the performance test must be 30 operating days if you specified a 30 operating day basis in §63.7545(e)(2)(iii) for HCl CEMS or it must be 720 hours if you specified a 720 hour basis in §63.7545(e)(2)(iii) for HCl CEMS. For each day in which the unit operates, you must obtain hourly HCl concentration data, and stack gas volumetric flow rate data.

(ii) If you are using a HCl CEMS, you must install, operate, calibrate, and maintain an instrument for continuously measuring and recording the HCl mass emissions rate to the atmosphere according to the requirements of the applicable performance specification of 40 CFR part 60, appendix B, and the quality assurance procedures of 40 CFR part 60, appendix F.

(16) If you demonstrate compliance with an applicable TSM emission limit through performance testing, and you plan to burn a new type of fuel or a new mixture of fuels, you must recalculate the maximum TSM input using Equation 9 of §63.7530. If the results of recalculating the maximum TSM input using Equation 9 of §63.7530 are higher than the maximum total selected input level established during the previous performance test, then you must conduct a new performance test within 60 days of burning the new fuel type or fuel mixture according to the procedures in §63.7520 to demonstrate that the TSM emissions do not exceed the emission limit. You must also establish new operating limits based on this performance test according to the procedures in §63.7530(b). You are not required to conduct fuel

analyses for the fuels described in §63.7510(a)(2)(i) through (iii). You may exclude the fuels described in §63.7510(a)(2)(i) through (iii) when recalculating the TSM emission rate.

(17) If you demonstrate compliance with an applicable TSM emission limit through fuel analysis for solid or liquid fuels, and you plan to burn a new type of fuel, you must recalculate the TSM emission rate using Equation 18 of §63.7530 according to the procedures specified in paragraphs (a)(5)(i) through (iii) of this section. You are not required to conduct fuel analyses for the fuels described in §63.7510(a)(2)(i) through (iii). You may exclude the fuels described in §63.7510(a)(2)(i) through (iii) when recalculating the TSM emission rate.

(i) You must determine the TSM concentration for any new fuel type in units of pounds per million Btu, based on supplier data or your own fuel analysis, according to the provisions in your site-specific fuel analysis plan developed according to §63.7521(b).

(ii) You must determine the new mixture of fuels that will have the highest content of TSM.

(iii) Recalculate the TSM emission rate from your boiler or process heater under these new conditions using Equation 18 of §63.7530. The recalculated TSM emission rate must be less than the applicable emission limit.

(18) If you demonstrate continuous PM emissions compliance with a PM CPMS you will use a PM CPMS to establish a site-specific operating limit corresponding to the results of the performance test demonstrating compliance with the PM limit. You will conduct your performance test using the test method criteria in Table 5 of this subpart. You will use the PM CPMS to demonstrate continuous compliance with this operating limit. You must repeat the performance test annually and reassess and adjust the site-specific operating limit in accordance with the results of the performance test.

(i) To determine continuous compliance, you must record the PM CPMS output data for all periods when the process is operating and the PM CPMS is not out-of-control. You must demonstrate continuous compliance by using all quality-assured hourly average data collected by the PM CPMS for all operating hours to calculate the arithmetic average operating parameter in units of the operating limit (milliamps) on a 30-day rolling average basis.

(ii) For any deviation of the 30-day rolling PM CPMS average value from the established operating parameter limit, you must:

(A) Within 48 hours of the deviation, visually inspect the air pollution control device (APCD);

(B) If inspection of the APCD identifies the cause of the deviation, take corrective action as soon as possible and return the PM CPMS measurement to within the established value; and

(C) Within 30 days of the deviation or at the time of the annual compliance test, whichever comes first, conduct a PM emissions compliance test to determine compliance with the PM emissions limit and to verify or re-establish the CPMS operating limit. You are not required to conduct additional testing for any deviations that occur between the time of the original deviation and the PM emissions compliance test required under this paragraph.

(iii) PM CPMS deviations from the operating limit leading to more than four required performance tests in a 12-month operating period constitute a separate violation of this subpart.

(19) If you choose to comply with the PM filterable emissions limit by using PM CEMS you must install, certify, operate, and maintain a PM CEMS and record the output of the PM CEMS as specified in paragraphs (a)(19)(i) through (vii) of this section. The compliance limit will be expressed as a 30-day

rolling average of the numerical emissions limit value applicable for your unit in Tables 1 or 2 or 11 through 13 of this subpart.

(i) Install and certify your PM CEMS according to the procedures and requirements in Performance Specification 11—Specifications and Test Procedures for Particulate Matter Continuous Emission Monitoring Systems at Stationary Sources in Appendix B to part 60 of this chapter, using test criteria outlined in Table V of this rule. The reportable measurement output from the PM CEMS must be expressed in units of the applicable emissions limit (e.g., lb/MMBtu, lb/MWh).

(ii) Operate and maintain your PM CEMS according to the procedures and requirements in Procedure 2— Quality Assurance Requirements for Particulate Matter Continuous Emission Monitoring Systems at Stationary Sources in Appendix F to part 60 of this chapter.

(A) You must conduct the relative response audit (RRA) for your PM CEMS at least once annually.

(B) You must conduct the relative correlation audit (RCA) for your PM CEMS at least once every 3 years.

(iii) Collect PM CEMS hourly average output data for all boiler operating hours except as indicated in paragraph (v) of this section.

(iv) Calculate the arithmetic 30-day rolling average of all of the hourly average PM CEMS output data collected during all nonexempt boiler or process heater operating hours.

(v) You must collect data using the PM CEMS at all times the unit is operating and at the intervals specified this paragraph (a), except for periods of monitoring system malfunctions, repairs associated with monitoring system malfunctions, and required monitoring system quality assurance or quality control activities.

(vi) You must use all the data collected during all boiler or process heater operating hours in assessing the compliance with your operating limit except:

(A) Any data collected during monitoring system malfunctions, repairs associated with monitoring system malfunctions, or required monitoring system quality assurance or control activities conducted during monitoring system malfunctions in calculations and report any such periods in your annual deviation report;

(B) Any data collected during periods when the monitoring system is out of control as specified in your site-specific monitoring plan, repairs associated with periods when the monitoring system is out of control, or required monitoring system quality assurance or control activities conducted during out of control periods in calculations used to report emissions or operating levels and report any such periods in your annual deviation report;

(C) Any data recorded during periods of startup or shutdown.

(vii) You must record and make available upon request results of PM CEMS system performance audits, dates and duration of periods when the PM CEMS is out of control to completion of the corrective actions necessary to return the PM CEMS to operation consistent with your site-specific monitoring plan.

(b) You must report each instance in which you did not meet each emission limit and operating limit in Tables 1 through 4 or 11 through 13 to this subpart that apply to you. These instances are deviations from the emission limits or operating limits, respectively, in this subpart. These deviations must be reported according to the requirements in §63.7550.

(c) If you elected to demonstrate that the unit meets the specification for mercury for the unit designed to burn gas 1 subcategory, you must follow the sampling frequency specified in paragraphs (c)(1) through (4) of this section and conduct this sampling according to the procedures in §63.7521(f) through (i).

(1) If the initial mercury constituents in the gaseous fuels are measured to be equal to or less than half of the mercury specification as defined in §63.7575, you do not need to conduct further sampling.

(2) If the initial mercury constituents are greater than half but equal to or less than 75 percent of the mercury specification as defined in §63.7575, you will conduct semi-annual sampling. If 6 consecutive semi-annual fuel analyses demonstrate 50 percent or less of the mercury specification, you do not need to conduct further sampling. If any semi-annual sample exceeds 75 percent of the mercury specification, you must return to monthly sampling for that fuel, until 12 months of fuel analyses again are less than 75 percent of the compliance level.

(3) If the initial mercury constituents are greater than 75 percent of the mercury specification as defined in §63.7575, you will conduct monthly sampling. If 12 consecutive monthly fuel analyses demonstrate 75 percent or less of the mercury specification, you may decrease the fuel analysis frequency to semi-annual for that fuel.

(4) If the initial sample exceeds the mercury specification as defined in §63.7575, each affected boiler or process heater combusting this fuel is not part of the unit designed to burn gas 1 subcategory and must be in compliance with the emission and operating limits for the appropriate subcategory. You may elect to conduct additional monthly sampling while complying with these emissions and operating limits to demonstrate that the fuel qualifies as another gas 1 fuel. If 12 consecutive monthly fuel analyses samples are at or below the mercury specification as defined in §63.7575, each affected boiler or process heater combusting the fuel can elect to switch back into the unit designed to burn gas 1 subcategory until the mercury specification is exceeded.

(d) For startup and shutdown, you must meet the work practice standards according to items 5 and 6 of Table 3 of this subpart.

[78 FR 7179, Jan. 31, 2013, as amended at 80 FR 72813, Nov. 20, 2015]

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§63.7541 How do I demonstrate continuous compliance under the emissions averaging provision?

CRE will not use the emissions averaging provision.

(a) Following the compliance date, the owner or operator must demonstrate compliance with this subpart on a continuous basis by meeting the requirements of paragraphs (a)(1) through (5) of this section.

(1) For each calendar month, demonstrate compliance with the average weighted emissions limit for the existing units participating in the emissions averaging option as determined in §63.7522(f) and (g).

(2) You must maintain the applicable opacity limit according to paragraphs (a)(2)(i) and (ii) of this section.

(i) For each existing unit participating in the emissions averaging option that is equipped with a dry control system and not vented to a common stack, maintain opacity at or below the applicable limit.

(ii) For each group of units participating in the emissions averaging option where each unit in the group is equipped with a dry control system and vented to a common stack that does not receive emissions from non-affected units, maintain opacity at or below the applicable limit at the common stack.

(3) For each existing unit participating in the emissions averaging option that is equipped with a wet scrubber, maintain the 30-day rolling average parameter values at or above the operating limits established during the most recent performance test.

(4) For each existing unit participating in the emissions averaging option that has an approved alternative operating parameter, maintain the 30-day rolling average parameter values consistent with the approved monitoring plan.

(5) For each existing unit participating in the emissions averaging option venting to a common stack configuration containing affected units from other subcategories, maintain the appropriate operating limit for each unit as specified in Table 4 to this subpart that applies.

(b) Any instance where the owner or operator fails to comply with the continuous monitoring requirements in paragraphs (a)(1) through (5) of this section is a deviation.

[76 FR 15664, Mar. 21, 2011, as amended at 78 FR 7182, Jan. 31, 2013]

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NOTIFICATION, REPORTS, AND RECORDS

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§63.7545 What notifications must I submit and when?

(a) You must submit to the Administrator all of the notifications in §§63.7(b) and (c), 63.8(e), (f)(4) and (6), and 63.9(b) through (h) that apply to you by the dates specified.

CRE will submit the required notifications as specified and in accordance with the requirements in this section.

(b) As specified in §63.9(b)(2), if you startup your affected source before January 31, 2013, you must submit an Initial Notification not later than 120 days after January 31, 2013.

(c) As specified in §63.9(b)(4) and (5), if you startup your new or reconstructed affected source on or after January 31, 2013, you must submit an Initial Notification not later than 15 days after the actual date of startup of the affected source.

(d) If you are required to conduct a performance test you must submit a Notification of Intent to conduct a performance test at least 60 days before the performance test is scheduled to begin.

(e) If you are required to conduct an initial compliance demonstration as specified in §63.7530, you must submit a Notification of Compliance Status according to §63.9(h)(2)(ii). For the initial compliance demonstration for each boiler or process heater, you must submit the Notification of Compliance Status, including all performance test results and fuel analyses, before the close of business on the 60th day following the completion of all performance test and/or other initial compliance demonstrations for all boiler or process heaters at the facility according to §63.10(d)(2). The Notification of Compliance Status report must contain all the information specified in paragraphs (e)(1) through (8) of this section, as

applicable. If you are not required to conduct an initial compliance demonstration as specified in §63.7530(a), the Notification of Compliance Status must only contain the information specified in paragraphs (e)(1) and (8) of this section and must be submitted within 60 days of the compliance date specified at §63.7495(b).

(1) A description of the affected unit(s) including identification of which subcategories the unit is in, the design heat input capacity of the unit, a description of the add-on controls used on the unit to comply with this subpart, description of the fuel(s) burned, including whether the fuel(s) were a secondary material determined by you or the EPA through a petition process to be a non-waste under §241.3 of this chapter, whether the fuel(s) were a secondary material processed from discarded non-hazardous secondary materials within the meaning of §241.3 of this chapter, and justification for the selection of fuel(s) burned during the compliance demonstration.

(2) Summary of the results of all performance tests and fuel analyses, and calculations conducted to demonstrate initial compliance including all established operating limits, and including:

(i) Identification of whether you are complying with the PM emission limit or the alternative TSM emission limit.

(ii) Identification of whether you are complying with the output-based emission limits or the heat input-based (i.e., lb/MMBtu or ppm) emission limits,

(iii) Identification of whether you are complying the arithmetic mean of all valid hours of data from the previous 30 operating days or of the previous 720 hours. This identification shall be specified separately for each operating parameter.

(3) A summary of the maximum CO emission levels recorded during the performance test to show that you have met any applicable emission standard in Tables 1, 2, or 11 through 13 to this subpart, if you are not using a CO CEMS to demonstrate compliance.

(4) Identification of whether you plan to demonstrate compliance with each applicable emission limit through performance testing, a CEMS, or fuel analysis.

(5) Identification of whether you plan to demonstrate compliance by emissions averaging and identification of whether you plan to demonstrate compliance by using efficiency credits through energy conservation:

(i) If you plan to demonstrate compliance by emission averaging, report the emission level that was being achieved or the control technology employed on January 31, 2013.

(ii) [Reserved]

(6) A signed certification that you have met all applicable emission limits and work practice standards.

(7) If you had a deviation from any emission limit, work practice standard, or operating limit, you must also submit a description of the deviation, the duration of the deviation, and the corrective action taken in the Notification of Compliance Status report.

(8) In addition to the information required in §63.9(h)(2), your notification of compliance status must include the following certification(s) of compliance, as applicable, and signed by a responsible official:

(i) “This facility completed the required initial tune-up for all of the boilers and process heaters covered by 40 CFR part 63 subpart DDDDD at this site according to the procedures in §63.7540(a)(10)(i) through (vi).”

(ii) “This facility has had an energy assessment performed according to §63.7530(e).”

(iii) Except for units that burn only natural gas, refinery gas, or other gas 1 fuel, or units that qualify for a statutory exemption as provided in section 129(g)(1) of the Clean Air Act, include the following: “No secondary materials that are solid waste were combusted in any affected unit.”

(f) If you operate a unit designed to burn natural gas, refinery gas, or other gas 1 fuels that is subject to this subpart, and you intend to use a fuel other than natural gas, refinery gas, gaseous fuel subject to another subpart of this part, part 60, 61, or 65, or other gas 1 fuel to fire the affected unit during a period of natural gas curtailment or supply interruption, as defined in §63.7575, you must submit a notification of alternative fuel use within 48 hours of the declaration of each period of natural gas curtailment or supply interruption, as defined in §63.7575. The notification must include the information specified in paragraphs (f)(1) through (5) of this section.

(1) Company name and address.

(2) Identification of the affected unit.

(3) Reason you are unable to use natural gas or equivalent fuel, including the date when the natural gas curtailment was declared or the natural gas supply interruption began.

(4) Type of alternative fuel that you intend to use.

(5) Dates when the alternative fuel use is expected to begin and end.

(g) If you intend to commence or recommence combustion of solid waste, you must provide 30 days prior notice of the date upon which you will commence or recommence combustion of solid waste. The notification must identify:

(1) The name of the owner or operator of the affected source, as defined in §63.7490, the location of the source, the boiler(s) or process heater(s) that will commence burning solid waste, and the date of the notice.

(2) The currently applicable subcategories under this subpart.

(3) The date on which you became subject to the currently applicable emission limits.

(4) The date upon which you will commence combusting solid waste.

(h) If you have switched fuels or made a physical change to the boiler or process heater and the fuel switch or physical change resulted in the applicability of a different subcategory, you must provide notice of the date upon which you switched fuels or made the physical change within 30 days of the switch/change. The notification must identify:

(1) The name of the owner or operator of the affected source, as defined in §63.7490, the location of the source, the boiler(s) and process heater(s) that have switched fuels, were physically changed, and the date of the notice.

(2) The currently applicable subcategory under this subpart.

(3) The date upon which the fuel switch or physical change occurred.

[76 FR 15664, Mar. 21, 2011, as amended at 78 FR 7183, Jan. 31, 2013; 80 FR 72814, Nov. 20, 2015]

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§63.7550 What reports must I submit and when?

(a) You must submit each report in Table 9 to this subpart that applies to you.

CRE will comply with the reporting requirements and frequency specified in Table 9. When submitting the annual compliance report, the first compliance report will cover the period beginning on the compliance date and ending on December 31 within 1 year after the compliance date.

(b) Unless the EPA Administrator has approved a different schedule for submission of reports under §63.10(a), you must submit each report, according to paragraph (h) of this section, by the date in Table 9 to this subpart and according to the requirements in paragraphs (b)(1) through (4) of this section. For units that are subject only to a requirement to conduct subsequent annual, biennial, or 5-year tune-up according to §63.7540(a)(10), (11), or (12), respectively, and not subject to emission limits or Table 4 operating limits, you may submit only an annual, biennial, or 5-year compliance report, as applicable, as specified in paragraphs (b)(1) through (4) of this section, instead of a semi-annual compliance report.

(1) The first semi-annual compliance report must cover the period beginning on the compliance date that is specified for each boiler or process heater in §63.7495 and ending on June 30 or December 31, whichever date is the first date that occurs at least 180 days after the compliance date that is specified for your source in §63.7495. If submitting an annual, biennial, or 5-year compliance report, the first compliance report must cover the period beginning on the compliance date that is specified for each boiler or process heater in §63.7495 and ending on December 31 within 1, 2, or 5 years, as applicable, after the compliance date that is specified for your source in §63.7495.

(2) The first semi-annual compliance report must be postmarked or submitted no later than July 31 or January 31, whichever date is the first date following the end of the first calendar half after the compliance date that is specified for each boiler or process heater in §63.7495. The first annual, biennial, or 5-year compliance report must be postmarked or submitted no later than January 31.

(3) Each subsequent semi-annual compliance report must cover the semiannual reporting period from January 1 through June 30 or the semiannual reporting period from July 1 through December 31. Annual, biennial, and 5-year compliance reports must cover the applicable 1-, 2-, or 5-year periods from January 1 to December 31.

(4) Each subsequent semi-annual compliance report must be postmarked or submitted no later than July 31 or January 31, whichever date is the first date following the end of the semiannual reporting period. Annual, biennial, and 5-year compliance reports must be postmarked or submitted no later than January 31.

(5) For each affected source that is subject to permitting regulations pursuant to part 70 or part 71 of this chapter, and if the permitting authority has established dates for submitting semiannual reports pursuant to 70.6(a)(3)(iii)(A) or 71.6(a)(3)(iii)(A), you may submit the first and subsequent compliance reports according to the dates the permitting authority has established in the permit instead of according to the dates in paragraphs (b)(1) through (4) of this section.

(c) A compliance report must contain the following information depending on how the facility chooses to comply with the limits set in this rule.

(1) If the facility is subject to the requirements of a tune up you must submit a compliance report with the information in paragraphs (c)(5)(i) through (iii) of this section, (xiv) and (xvii) of this section, and paragraph (c)(5)(iv) of this section for limited-use boiler or process heater.

(2) If you are complying with the fuel analysis you must submit a compliance report with the information in paragraphs (c)(5)(i) through (iii), (vi), (x), (xi), (xiii), (xv), (xvii), (xviii) and paragraph (d) of this section.

(3) If you are complying with the applicable emissions limit with performance testing you must submit a compliance report with the information in (c)(5)(i) through (iii), (vi), (vii), (viii), (ix), (xi), (xiii), (xv), (xvii), (xviii) and paragraph (d) of this section.

(4) If you are complying with an emissions limit using a CMS the compliance report must contain the information required in paragraphs (c)(5)(i) through (iii), (v), (vi), (xi) through (xiii), (xv) through (xviii), and paragraph (e) of this section.

(5)(i) Company and Facility name and address.

(ii) Process unit information, emissions limitations, and operating parameter limitations.

(iii) Date of report and beginning and ending dates of the reporting period.

(iv) The total operating time during the reporting period.

(v) If you use a CMS, including CEMS, COMS, or CPMS, you must include the monitoring equipment manufacturer(s) and model numbers and the date of the last CMS certification or audit.

(vi) The total fuel use by each individual boiler or process heater subject to an emission limit within the reporting period, including, but not limited to, a description of the fuel, whether the fuel has received a non-waste determination by the EPA or your basis for concluding that the fuel is not a waste, and the total fuel usage amount with units of measure.

(vii) If you are conducting performance tests once every 3 years consistent with §63.7515(b) or (c), the date of the last 2 performance tests and a statement as to whether there have been any operational changes since the last performance test that could increase emissions.

(viii) A statement indicating that you burned no new types of fuel in an individual boiler or process heater subject to an emission limit. Or, if you did burn a new type of fuel and are subject to a HCl emission limit, you must submit the calculation of chlorine input, using Equation 7 of §63.7530, that demonstrates that your source is still within its maximum chlorine input level established during the previous performance testing (for sources that demonstrate compliance through performance testing) or you must submit the calculation of HCl emission rate using Equation 16 of §63.7530 that demonstrates that your source is still meeting the emission limit for HCl emissions (for boilers or process heaters that demonstrate compliance through fuel analysis). If you burned a new type of fuel and are subject to a mercury emission limit, you must submit the calculation of mercury input, using Equation 8 of §63.7530, that demonstrates that your source is still within its maximum mercury input level established during the previous performance testing (for sources that demonstrate compliance through performance testing), or you must submit the calculation of mercury emission rate using Equation 17 of §63.7530 that demonstrates that your source is still meeting the emission limit for mercury emissions (for boilers or process heaters that demonstrate compliance through fuel analysis). If you burned a new type of fuel and

are subject to a TSM emission limit, you must submit the calculation of TSM input, using Equation 9 of §63.7530, that demonstrates that your source is still within its maximum TSM input level established during the previous performance testing (for sources that demonstrate compliance through performance testing), or you must submit the calculation of TSM emission rate, using Equation 18 of §63.7530, that demonstrates that your source is still meeting the emission limit for TSM emissions (for boilers or process heaters that demonstrate compliance through fuel analysis).

(ix) If you wish to burn a new type of fuel in an individual boiler or process heater subject to an emission limit and you cannot demonstrate compliance with the maximum chlorine input operating limit using Equation 7 of §63.7530 or the maximum mercury input operating limit using Equation 8 of §63.7530, or the maximum TSM input operating limit using Equation 9 of §63.7530 you must include in the compliance report a statement indicating the intent to conduct a new performance test within 60 days of starting to burn the new fuel.

(x) A summary of any monthly fuel analyses conducted to demonstrate compliance according to §§63.7521 and 63.7530 for individual boilers or process heaters subject to emission limits, and any fuel specification analyses conducted according to §§63.7521(f) and 63.7530(g).

(xi) If there are no deviations from any emission limits or operating limits in this subpart that apply to you, a statement that there were no deviations from the emission limits or operating limits during the reporting period.

(xii) If there were no deviations from the monitoring requirements including no periods during which the CMSs, including CEMS, COMS, and CPMS, were out of control as specified in §63.8(c)(7), a statement that there were no deviations and no periods during which the CMS were out of control during the reporting period.

(xiii) If a malfunction occurred during the reporting period, the report must include the number, duration, and a brief description for each type of malfunction which occurred during the reporting period and which caused or may have caused any applicable emission limitation to be exceeded. The report must also include a description of actions taken by you during a malfunction of a boiler, process heater, or associated air pollution control device or CMS to minimize emissions in accordance with §63.7500(a)(3), including actions taken to correct the malfunction.

(xiv) Include the date of the most recent tune-up for each unit subject to only the requirement to conduct an annual, biennial, or 5-year tune-up according to §63.7540(a)(10), (11), or (12) respectively. Include the date of the most recent burner inspection if it was not done annually, biennially, or on a 5-year period and was delayed until the next scheduled or unscheduled unit shutdown.

(xv) If you plan to demonstrate compliance by emission averaging, certify the emission level achieved or the control technology employed is no less stringent than the level or control technology contained in the notification of compliance status in §63.7545(e)(5)(i).

(xvi) For each reporting period, the compliance reports must include all of the calculated 30 day rolling average values for CEMS (CO, HCl, SO_2, and mercury), 10 day rolling average values for CO CEMS when the limit is expressed as a 10 day instead of 30 day rolling average, and the PM CPMS data.

(xvii) Statement by a responsible official with that official's name, title, and signature, certifying the truth, accuracy, and completeness of the content of the report.

(xviii) For each instance of startup or shutdown include the information required to be monitored, collected, or recorded according to the requirements of §63.7555(d).

(d) For each deviation from an emission limit or operating limit in this subpart that occurs at an individual boiler or process heater where you are not using a CMS to comply with that emission limit or operating limit, or from the work practice standards for periods if startup and shutdown, the compliance report must additionally contain the information required in paragraphs (d)(1) through (3) of this section.

(1) A description of the deviation and which emission limit, operating limit, or work practice standard from which you deviated.

(2) Information on the number, duration, and cause of deviations (including unknown cause), as applicable, and the corrective action taken.

(3) If the deviation occurred during an annual performance test, provide the date the annual performance test was completed.

(e) For each deviation from an emission limit, operating limit, and monitoring requirement in this subpart occurring at an individual boiler or process heater where you are using a CMS to comply with that emission limit or operating limit, the compliance report must additionally contain the information required in paragraphs (e)(1) through (9) of this section. This includes any deviations from your site-specific monitoring plan as required in §63.7505(d).

(1) The date and time that each deviation started and stopped and description of the nature of the deviation (i.e., what you deviated from).

(2) The date and time that each CMS was inoperative, except for zero (low-level) and high-level checks.

(3) The date, time, and duration that each CMS was out of control, including the information in §63.8(c)(8).

(4) The date and time that each deviation started and stopped.

(5) A summary of the total duration of the deviation during the reporting period and the total duration as a percent of the total source operating time during that reporting period.

(6) A characterization of the total duration of the deviations during the reporting period into those that are due to control equipment problems, process problems, other known causes, and other unknown causes.

(7) A summary of the total duration of CMS's downtime during the reporting period and the total duration of CMS downtime as a percent of the total source operating time during that reporting period.

(8) A brief description of the source for which there was a deviation.

(9) A description of any changes in CMSs, processes, or controls since the last reporting period for the source for which there was a deviation.

(f)-(g) [Reserved]

(h) You must submit the reports according to the procedures specified in paragraphs (h)(1) through (3) of this section.

(1) Within 60 days after the date of completing each performance test (as defined in §63.2) required by this subpart, you must submit the results of the performance tests, including any fuel analyses, following the procedure specified in either paragraph (h)(1)(i) or (ii) of this section.

(i) For data collected using test methods supported by the EPA's Electronic Reporting Tool (ERT) as listed on the EPA's ERT Web site (*http://www.epa.gov/ttn/chief/ert/index.html*), you must submit the results of the performance test to the EPA via the Compliance and Emissions Data Reporting Interface (CEDRI). (CEDRI can be accessed through the EPA's Central Data Exchange (CDX) (*https://cdx.epa.gov/*).) Performance test data must be submitted in a file format generated through use of the EPA's ERT or an electronic file format consistent with the extensible markup language (XML) schema listed on the EPA's ERT Web site. If you claim that some of the performance test information being submitted is confidential business information (CBI), you must submit a complete file generated through the use of the EPA's ERT or an alternate electronic file consistent with the XML schema listed on the EPA's ERT Web site, including information claimed to be CBI, on a compact disc, flash drive, or other commonly used electronic storage media to the EPA. The electronic media must be clearly marked as CBI and mailed to U.S. EPA/OAPQS/CORE CBI Office, Attention: Group Leader, Measurement Policy Group, MD C404-02, 4930 Old Page Rd., Durham, NC 27703. The same ERT or alternate file with the CBI omitted must be submitted to the EPA via the EPA's CDX as described earlier in this paragraph.

(ii) For data collected using test methods that are not supported by the EPA's ERT as listed on the EPA's ERT Web site at the time of the test, you must submit the results of the performance test to the Administrator at the appropriate address listed in §63.13.

(2) Within 60 days after the date of completing each CEMS performance evaluation (as defined in 63.2), you must submit the results of the performance evaluation following the procedure specified in either paragraph (h)(2)(i) or (ii) of this section.

(i) For performance evaluations of continuous monitoring systems measuring relative accuracy test audit (RATA) pollutants that are supported by the EPA's ERT as listed on the EPA's ERT Web site at the time of the evaluation, you must submit the results of the performance evaluation to the EPA via the CEDRI. (CEDRI can be accessed through the EPA's CDX.) Performance evaluation data must be submitted in a file format generated through the use of the EPA's ERT or an alternate file format consistent with the XML schema listed on the EPA's ERT Web site. If you claim that some of the performance evaluation information being transmitted is CBI, you must submit a complete file generated through the use of the EPA's ERT or an alternate electronic file consistent with the XML schema listed on the EPA's ERT Web site, including information claimed to be CBI, on a compact disc, flash drive, or other commonly used electronic storage media to the EPA. The electronic media must be clearly marked as CBI and mailed to U.S. EPA/OAPQS/CORE CBI Office, Attention: Group Leader, Measurement Policy Group, MD C404-02, 4930 Old Page Rd., Durham, NC 27703. The same ERT or alternate file with the CBI omitted must be submitted to the EPA via the EPA's CDX as described earlier in this paragraph.

(ii) For any performance evaluations of continuous monitoring systems measuring RATA pollutants that are not supported by the EPA's ERT as listed on the ERT Web site at the time of the evaluation, you must submit the results of the performance evaluation to the Administrator at the appropriate address listed in §63.13.

(3) You must submit all reports required by Table 9 of this subpart electronically to the EPA via the CEDRI. (CEDRI can be accessed through the EPA's CDX.) You must use the appropriate electronic report in CEDRI for this subpart. Instead of using the electronic report in CEDRI for this subpart, you may submit an alternate electronic file consistent with the XML schema listed on the CEDRI Web site (*http://www.epa.gov/ttn/chief/cedri/index.html*), once the XML schema is available. If the reporting form specific to this subpart is not available in CEDRI at the time that the report is due, you must submit the report to the Administrator at the appropriate address listed in §63.13. You must begin submitting reports via CEDRI no later than 90 days after the form becomes available in CEDRI.

[78 FR 7183, Jan. 31, 2013, as amended at 80 FR 72814, Nov. 20, 2015]

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§63.7555 What records must I keep?

CRE will maintain records as highlighted below, as applicable.

(a) You must keep records according to paragraphs (a)(1) and (2) of this section.

(1) A copy of each notification and report that you submitted to comply with this subpart, including all documentation supporting any Initial Notification or Notification of Compliance Status or semiannual compliance report that you submitted, according to the requirements in §63.10(b)(2)(xiv).

(2) Records of performance tests, fuel analyses, or other compliance demonstrations and performance evaluations as required in §63.10(b)(2)(viii).

(3) For units in the limited use subcategory, you must keep a copy of the federally enforceable permit that limits the annual capacity factor to less than or equal to 10 percent and fuel use records for the days the boiler or process heater was operating.

(b) For each CEMS, COMS, and continuous monitoring system you must keep records according to paragraphs (b)(1) through (5) of this section.

(1) Records described in §63.10(b)(2)(vii) through (xi).

(2) Monitoring data for continuous opacity monitoring system during a performance evaluation as required in §63.6(h)(7)(i) and (ii).

(3) Previous (*i.e.,* superseded) versions of the performance evaluation plan as required in §63.8(d)(3).

(4) Request for alternatives to relative accuracy test for CEMS as required in §63.8(f)(6)(i).

(5) Records of the date and time that each deviation started and stopped.

(c) You must keep the records required in Table 8 to this subpart including records of all monitoring data and calculated averages for applicable operating limits, such as opacity, pressure drop, pH, and operating load, to show continuous compliance with each emission limit and operating limit that applies to you.

(d) For each boiler or process heater subject to an emission limit in Tables 1, 2, or 11 through 13 to this subpart, you must also keep the applicable records in paragraphs (d)(1) through (11) of this section.

(1) You must keep records of monthly fuel use by each boiler or process heater, including the type(s) of fuel and amount(s) used.

(2) If you combust non-hazardous secondary materials that have been determined not to be solid waste pursuant to §241.3(b)(1) and (2) of this chapter, you must keep a record that documents how the secondary material meets each of the legitimacy criteria under §241.3(d)(1) of this chapter. If you combust a fuel that has been processed from a discarded non-hazardous secondary material pursuant to §241.3(b)(4) of this chapter, you must keep records as to how the operations that produced the fuel

satisfy the definition of processing in §241.2 of this chapter. If the fuel received a non-waste determination pursuant to the petition process submitted under §241.3(c) of this chapter, you must keep a record that documents how the fuel satisfies the requirements of the petition process. For operating units that combust non-hazardous secondary materials as fuel per §241.4 of this chapter, you must keep records documenting that the material is listed as a non-waste under §241.4(a) of this chapter. Units exempt from the incinerator standards under section 129(g)(1) of the Clean Air Act because they are qualifying facilities burning a homogeneous waste stream do not need to maintain the records described in this paragraph (d)(2).

(3) A copy of all calculations and supporting documentation of maximum chlorine fuel input, using Equation 7 of §63.7530, that were done to demonstrate continuous compliance with the HCl emission limit, for sources that demonstrate compliance through performance testing. For sources that demonstrate compliance through fuel analysis, a copy of all calculations and supporting documentation of HCl emission rates, using Equation 16 of §63.7530, that were done to demonstrate compliance with the HCl emission limit. Supporting documentation should include results of any fuel analyses and basis for the estimates of maximum chlorine fuel input or HCl emission rates. You can use the results from one fuel analysis for multiple boilers and process heaters provided they are all burning the same fuel type. However, you must calculate chlorine fuel input, or HCl emission rate, for each boiler and process heater.

(4) A copy of all calculations and supporting documentation of maximum mercury fuel input, using Equation 8 of §63.7530, that were done to demonstrate continuous compliance with the mercury emission limit for sources that demonstrate compliance through performance testing. For sources that demonstrate compliance through fuel analysis, a copy of all calculations and supporting documentation of mercury emission rates, using Equation 17 of §63.7530, that were done to demonstrate compliance with the mercury emission limit. Supporting documentation should include results of any fuel analyses and basis for the estimates of maximum mercury fuel input or mercury emission rates. You can use the results from one fuel analysis for multiple boilers and process heaters provided they are all burning the same fuel type. However, you must calculate mercury fuel input, or mercury emission rates, for each boiler and process heater.

(5) If, consistent with §63.7515(b), you choose to stack test less frequently than annually, you must keep a record that documents that your emissions in the previous stack test(s) were less than 75 percent of the applicable emission limit (or, in specific instances noted in Tables 1 and 2 or 11 through 13 to this subpart, less than the applicable emission limit), and document that there was no change in source operations including fuel composition and operation of air pollution control equipment that would cause emissions of the relevant pollutant to increase within the past year.

(6) Records of the occurrence and duration of each malfunction of the boiler or process heater, or of the associated air pollution control and monitoring equipment.

(7) Records of actions taken during periods of malfunction to minimize emissions in accordance with the general duty to minimize emissions in §63.7500(a)(3), including corrective actions to restore the malfunctioning boiler or process heater, air pollution control, or monitoring equipment to its normal or usual manner of operation.

(8) A copy of all calculations and supporting documentation of maximum TSM fuel input, using Equation 9 of §63.7530, that were done to demonstrate continuous compliance with the TSM emission limit for sources that demonstrate compliance through performance testing. For sources that demonstrate compliance through fuel analysis, a copy of all calculations and supporting documentation of TSM emission rates, using Equation 18 of §63.7530, that were done to demonstrate compliance with the TSM emission limit. Supporting documentation should include results of any fuel analyses and basis for the estimates of maximum TSM fuel input or TSM emission rates. You can use the results from one fuel analysis for multiple boilers and process heaters provided they are all burning the same fuel type. However, you must calculate TSM fuel input, or TSM emission rates, for each boiler and process heater.

(9) You must maintain records of the calendar date, time, occurrence and duration of each startup and shutdown.

(10) You must maintain records of the type(s) and amount(s) of fuels used during each startup and shutdown.

(11) For each startup period, for units selecting paragraph (2) of the definition of “startup” in §63.7575 you must maintain records of the time that clean fuel combustion begins; the time when you start feeding fuels that are not clean fuels; the time when useful thermal energy is first supplied; and the time when the PM controls are engaged.

(12) If you choose to rely on paragraph (2) of the definition of “startup” in §63.7575, for each startup period, you must maintain records of the hourly steam temperature, hourly steam pressure, hourly steam flow, hourly flue gas temperature, and all hourly average CMS data (*e.g.,* CEMS, PM CPMS, COMS, ESP total secondary electric power input, scrubber pressure drop, scrubber liquid flow rate) collected during each startup period to confirm that the control devices are engaged. In addition, if compliance with the PM emission limit is demonstrated using a PM control device, you must maintain records as specified in paragraphs (d)(12)(i) through (iii) of this section.

(i) For a boiler or process heater with an electrostatic precipitator, record the number of fields in service, as well as each field's secondary voltage and secondary current during each hour of startup.

(ii) For a boiler or process heater with a fabric filter, record the number of compartments in service, as well as the differential pressure across the baghouse during each hour of startup.

(iii) For a boiler or process heater with a wet scrubber needed for filterable PM control, record the scrubber's liquid flow rate and the pressure drop during each hour of startup.

(13) If you choose to use paragraph (2) of the definition of “startup” in §63.7575 and you find that you are unable to safely engage and operate your PM control(s) within 1 hour of first firing of non-clean fuels, you may choose to rely on paragraph (1) of definition of “startup” in §63.7575 or you may submit to the delegated permitting authority a request for a variance with the PM controls requirement, as described below.

(i) The request shall provide evidence of a documented manufacturer-identified safety issue.

(ii) The request shall provide information to document that the PM control device is adequately designed and sized to meet the applicable PM emission limit.

(iii) In addition, the request shall contain documentation that:

(A) The unit is using clean fuels to the maximum extent possible to bring the unit and PM control device up to the temperature necessary to alleviate or prevent the identified safety issues prior to the combustion of primary fuel;

(B) The unit has explicitly followed the manufacturer's procedures to alleviate or prevent the identified safety issue; and

(C) Identifies with specificity the details of the manufacturer's statement of concern.

(iv) You must comply with all other work practice requirements, including but not limited to data collection, recordkeeping, and reporting requirements.

(e) If you elect to average emissions consistent with §63.7522, you must additionally keep a copy of the emission averaging implementation plan required in §63.7522(g), all calculations required under §63.7522, including monthly records of heat input or steam generation, as applicable, and monitoring records consistent with §63.7541.

(f) If you elect to use efficiency credits from energy conservation measures to demonstrate compliance according to §63.7533, you must keep a copy of the Implementation Plan required in §63.7533(d) and copies of all data and calculations used to establish credits according to §63.7533(b), (c), and (f).

(g) If you elected to demonstrate that the unit meets the specification for mercury for the unit designed to burn gas 1 subcategory, you must maintain monthly records (or at the frequency required by §63.7540(c)) of the calculations and results of the fuel specification for mercury in Table 6.

(h) If you operate a unit in the unit designed to burn gas 1 subcategory that is subject to this subpart, and you use an alternative fuel other than natural gas, refinery gas, gaseous fuel subject to another subpart under this part, other gas 1 fuel, or gaseous fuel subject to another subpart of this part or part 60, 61, or 65, you must keep records of the total hours per calendar year that alternative fuel is burned and the total hours per calendar year that the unit operated during periods of gas curtailment or gas supply emergencies.

[76 FR 15664, Mar. 21, 2011, as amended at 78 FR 7185, Jan. 31, 2013; 80 FR 72816, Nov. 20, 2015]

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§63.7560 In what form and how long must I keep my records?

CRE will comply with the requirements in this section by keeping records in a form suitable and readily available for expeditious review for the time periods specified in this section.

(a) Your records must be in a form suitable and readily available for expeditious review, according to §63.10(b)(1).

(b) As specified in §63.10(b)(1), you must keep each record for 5 years following the date of each occurrence, measurement, maintenance, corrective action, report, or record.

(c) You must keep each record on site, or they must be accessible from on site (for example, through a computer network), for at least 2 years after the date of each occurrence, measurement, maintenance, corrective action, report, or record, according to §63.10(b)(1). You can keep the records off site for the remaining 3 years.

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OTHER REQUIREMENTS AND INFORMATION

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§63.7565 What parts of the General Provisions apply to me?

Table 10 to this subpart shows which parts of the General Provisions in §§63.1 through 63.15 apply to you.

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§63.7570 Who implements and enforces this subpart?

(a) This subpart can be implemented and enforced by the EPA, or an Administrator such as your state, local, or tribal agency. If the EPA Administrator has delegated authority to your state, local, or tribal agency, then that agency (as well as the EPA) has the authority to implement and enforce this subpart. You should contact your EPA Regional Office to find out if this subpart is delegated to your state, local, or tribal agency.

(b) In delegating implementation and enforcement authority of this subpart to a state, local, or tribal agency under 40 CFR part 63, subpart E, the authorities listed in paragraphs (b)(1) through (4) of this section are retained by the EPA Administrator and are not transferred to the state, local, or tribal agency, however, the EPA retains oversight of this subpart and can take enforcement actions, as appropriate.

(1) Approval of alternatives to the emission limits and work practice standards in §63.7500(a) and (b) under §63.6(g), except as specified in §63.7555(d)(13).

(2) Approval of major change to test methods in Table 5 to this subpart under §63.7(e)(2)(ii) and (f) and as defined in §63.90, and alternative analytical methods requested under §63.7521(b)(2).

(3) Approval of major change to monitoring under §63.8(f) and as defined in §63.90, and approval of alternative operating parameters under §§63.7500(a)(2) and 63.7522(g)(2).

(4) Approval of major change to recordkeeping and reporting under §63.10(e) and as defined in §63.90.

[76 FR 15664, Mar. 21, 2011, as amended at 78 FR 7186, Jan. 31, 2013; 80 FR 72817, Nov. 20, 2015]

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§63.7575 What definitions apply to this subpart?

Terms used in this subpart are defined in the Clean Air Act, in §63.2 (the General Provisions), and in this section as follows:

10-day rolling average means the arithmetic mean of the previous 240 hours of valid operating data. Valid data excludes hours during startup and shutdown, data collected during periods when the monitoring system is out of control as specified in your site-specific monitoring plan, while conducting repairs associated with periods when the monitoring system is out of control, or while conducting required monitoring system quality assurance or quality control activities, and periods when this unit is not operating. The 240 hours should be consecutive, but not necessarily continuous if operations were intermittent.

30-day rolling average means the arithmetic mean of the previous 720 hours of valid CO CEMS data. The 720 hours should be consecutive, but not necessarily continuous if operations were intermittent. For parameters other than CO, 30-day rolling average means either the arithmetic mean of all valid hours of data from 30 successive operating days or the arithmetic mean of the previous 720 hours of valid operating data. Valid data excludes hours during startup and shutdown, data collected during periods when the monitoring system is out of control as specified in your site-specific monitoring plan, while conducting repairs associated with periods when the monitoring system is out of control, or while conducting required monitoring system quality assurance or quality control activities, and periods when this unit is not operating.

Annual capacity factor means the ratio between the actual heat input to a boiler or process heater from the fuels burned during a calendar year and the potential heat input to the boiler or process heater had it been operated for 8,760 hours during a year at the maximum steady state design heat input capacity.

Annual heat input means the heat input for the 12 months preceding the compliance demonstration.

Average annual heat input rate means total heat input divided by the hours of operation for the 12 months preceding the compliance demonstration.

Bag leak detection system means a group of instruments that are capable of monitoring particulate matter loadings in the exhaust of a fabric filter (*i.e.,* baghouse) in order to detect bag failures. A bag leak detection system includes, but is not limited to, an instrument that operates on electrodynamic, triboelectric, light scattering, light transmittance, or other principle to monitor relative particulate matter loadings.

Benchmark means the fuel heat input for a boiler or process heater for the one-year period before the date that an energy demand reduction occurs, unless it can be demonstrated that a different time period is more representative of historical operations.

Biodiesel means a mono-alkyl ester derived from biomass and conforming to ASTM D6751-11b, Standard Specification for Biodiesel Fuel Blend Stock (B100) for Middle Distillate Fuels (incorporated by reference, see §63.14).

Biomass or bio-based solid fuel means any biomass-based solid fuel that is not a solid waste. This includes, but is not limited to, wood residue; wood products (*e.g.,* trees, tree stumps, tree limbs, bark, lumber, sawdust, sander dust, chips, scraps, slabs, millings, and shavings); animal manure, including litter and other bedding materials; vegetative agricultural and silvicultural materials, such as logging residues (slash), nut and grain hulls and chaff (*e.g.,* almond, walnut, peanut, rice, and wheat), bagasse, orchard prunings, corn stalks, coffee bean hulls and grounds. This definition of biomass is not intended to suggest that these materials are or are not solid waste.

Blast furnace gas fuel-fired boiler or process heater means an industrial/commercial/institutional boiler or process heater that receives 90 percent or more of its total annual gas volume from blast furnace gas.

Boiler means an enclosed device using controlled flame combustion and having the primary purpose of recovering thermal energy in the form of steam or hot water. Controlled flame combustion refers to a steady-state, or near steady-state, process wherein fuel and/or oxidizer feed rates are controlled. A device combusting solid waste, as defined in §241.3 of this chapter, is not a boiler unless the device is exempt from the definition of a solid waste incineration unit as provided in section 129(g)(1) of the Clean Air Act. Waste heat boilers are excluded from this definition.

Boiler system means the boiler and associated components, such as, the feed water system, the combustion air system, the fuel system (including burners), blowdown system, combustion control systems, steam systems, and condensate return systems.

Calendar year means the period between January 1 and December 31, inclusive, for a given year.

Clean dry biomass means any biomass-based solid fuel that have not been painted, pigment-stained, or pressure treated, does not contain contaminants at concentrations not normally associated with virgin biomass materials and has a moisture content of less than 20 percent and is not a solid waste.

Coal means all solid fuels classifiable as anthracite, bituminous, sub-bituminous, or lignite by ASTM D388 (incorporated by reference, see §63.14), coal refuse, and petroleum coke. For the purposes of this subpart, this definition of "coal" includes synthetic fuels derived from coal, including but not limited to, solvent-refined coal, coal-oil mixtures, and coal-water mixtures. Coal derived gases are excluded from this definition.

Coal refuse means any by-product of coal mining or coal cleaning operations with an ash content greater than 50 percent (by weight) and a heating value less than 13,900 kilojoules per kilogram (6,000 Btu per pound) on a dry basis.

Commercial/institutional boiler means a boiler used in commercial establishments or institutional establishments such as medical centers, nursing homes, research centers, institutions of higher education, elementary and secondary schools, libraries, religious establishments, governmental buildings, hotels, restaurants, and laundries to provide electricity, steam, and/or hot water.

Common stack means the exhaust of emissions from two or more affected units through a single flue. Affected units with a common stack may each have separate air pollution control systems located before the common stack, or may have a single air pollution control system located after the exhausts come together in a single flue.

Cost-effective energy conservation measure means a measure that is implemented to improve the energy efficiency of the boiler or facility that has a payback (return of investment) period of 2 years or less.

Daily block average means the arithmetic mean of all valid emission concentrations or parameter levels recorded when a unit is operating measured over the 24-hour period from 12 a.m. (midnight) to 12 a.m. (midnight), except for periods of startup and shutdown or downtime.

Deviation. (1) *Deviation* means any instance in which an affected source subject to this subpart, or an owner or operator of such a source:

(i) Fails to meet any applicable requirement or obligation established by this subpart including, but not limited to, any emission limit, operating limit, or work practice standard; or

(ii) Fails to meet any term or condition that is adopted to implement an applicable requirement in this subpart and that is included in the operating permit for any affected source required to obtain such a permit.

(2) A deviation is not always a violation.

Dioxins/furans means tetra- through octa-chlorinated dibenzo-p-dioxins and dibenzofurans.

Distillate oil means fuel oils that contain 0.05 weight percent nitrogen or less and comply with the specifications for fuel oil numbers 1 and 2, as defined by the American Society of Testing and Materials in ASTM D396 (incorporated by reference, see §63.14) or diesel fuel oil numbers 1 and 2, as defined by the American Society for Testing and Materials in ASTM D975 (incorporated by reference, see §63.14), kerosene, and biodiesel as defined by the American Society of Testing and Materials in ASTM D6751-11b (incorporated by reference, see §60.14).

Dry scrubber means an add-on air pollution control system that injects dry alkaline sorbent (dry injection) or sprays an alkaline sorbent (spray dryer) to react with and neutralize acid gas in the exhaust stream forming a dry powder material. Sorbent injection systems used as control devices in fluidized bed boilers and process heaters are included in this definition. A dry scrubber is a dry control system.

Dutch oven means a unit having a refractory-walled cell connected to a conventional boiler setting. Fuel materials are introduced through an opening in the roof of the dutch oven and burn in a pile on its floor. Fluidized bed boilers are not part of the dutch oven design category.

Efficiency credit means emission reductions above those required by this subpart. Efficiency credits generated may be used to comply with the emissions limits. Credits may come from pollution prevention projects that result in reduced fuel use by affected units. Boilers that are shut down cannot be used to generate credits unless the facility provides documentation linking the permanent shutdown to implementation of the energy conservation measures identified in the energy assessment.

Electric utility steam generating unit (EGU) means a fossil fuel-fired combustion unit of more than 25 megawatts electric (MWe) that serves a generator that produces electricity for sale. A fossil fuel-fired unit that cogenerates steam and electricity and supplies more than one-third of its potential electric output capacity and more than 25 MWe output to any utility power distribution system for sale is considered an electric utility steam generating unit. To be "capable of combusting" fossil fuels, an EGU would need to have these fuels allowed in their operating permits and have the appropriate fuel handling facilities on-site or otherwise available (e.g., coal handling equipment, including coal storage area, belts and conveyers, pulverizers, etc.; oil storage facilities). In addition, fossil fuel-fired EGU means any EGU that fired fossil fuel for more than 10.0 percent of the average annual heat input in any 3 consecutive calendar years or for more than 15.0 percent of the annual heat input during any one calendar year after April 16, 2012.

Electrostatic precipitator (ESP) means an add-on air pollution control device used to capture particulate matter by charging the particles using an electrostatic field, collecting the particles using a grounded collecting surface, and transporting the particles into a hopper. An electrostatic precipitator is usually a dry control system.

Energy assessment means the following for the emission units covered by this subpart:

(1) The energy assessment for facilities with affected boilers and process heaters with a combined heat input capacity of less than 0.3 trillion Btu (TBtu) per year will be 8 on-site technical labor hours in length maximum, but may be longer at the discretion of the owner or operator of the affected source. The boiler system(s), process heater(s), and any on-site energy use system(s) accounting for at least 50 percent of the affected boiler(s) energy (*e.g.,* steam, hot water, process heat, or electricity) production, as applicable, will be evaluated to identify energy savings opportunities, within the limit of performing an 8-hour on-site energy assessment.

(2) The energy assessment for facilities with affected boilers and process heaters with a combined heat input capacity of 0.3 to 1.0 TBtu/year will be 24 on-site technical labor hours in length maximum, but may be longer at the discretion of the owner or operator of the affected source. The boiler system(s), process heater(s), and any on-site energy use system(s) accounting for at least 33 percent of the energy (*e.g.,* steam, hot water, process heat, or electricity) production, as applicable, will be evaluated to identify energy savings opportunities, within the limit of performing a 24-hour on-site energy assessment.

(3) The energy assessment for facilities with affected boilers and process heaters with a combined heat input capacity greater than 1.0 TBtu/year will be up to 24 on-site technical labor hours in length for the first TBtu/yr plus 8 on-site technical labor hours for every additional 1.0 TBtu/yr not to exceed 160 on-site technical hours, but may be longer at the discretion of the owner or operator of the affected source. The boiler system(s), process heater(s), and any on-site energy use system(s) accounting for at least 20 percent of the energy (*e.g.,* steam, process heat, hot water, or electricity) production, as applicable, will be evaluated to identify energy savings opportunities.

(4) The on-site energy use systems serving as the basis for the percent of affected boiler(s) and process heater(s) energy production in paragraphs (1), (2), and (3) of this definition may be segmented

by production area or energy use area as most logical and applicable to the specific facility being assessed (*e.g.,* product X manufacturing area; product Y drying area; Building Z).

Energy management practices means the set of practices and procedures designed to manage energy use that are demonstrated by the facility's energy policies, a facility energy manager and other staffing responsibilities, energy performance measurement and tracking methods, an energy saving goal, action plans, operating procedures, internal reporting requirements, and periodic review intervals used at the facility.

Energy management program means a program that includes a set of practices and procedures designed to manage energy use that are demonstrated by the facility's energy policies, a facility energy manager and other staffing responsibilities, energy performance measurement and tracking methods, an energy saving goal, action plans, operating procedures, internal reporting requirements, and periodic review intervals used at the facility. Facilities may establish their program through energy management systems compatible with ISO 50001.

Energy use system includes the following systems located on-site that use energy (steam, hot water, or electricity) provided by the affected boiler or process heater: process heating; compressed air systems; machine drive (motors, pumps, fans); process cooling; facility heating, ventilation, and air-conditioning systems; hot water systems; building envelop; and lighting; or other systems that use steam, hot water, process heat, or electricity provided by the affected boiler or process heater. Energy use systems are only those systems using energy clearly produced by affected boilers and process heaters.

Equivalent means the following only as this term is used in Table 6 to this subpart:

(1) An equivalent sample collection procedure means a published voluntary consensus standard or practice (VCS) or EPA method that includes collection of a minimum of three composite fuel samples, with each composite consisting of a minimum of three increments collected at approximately equal intervals over the test period.

(2) An equivalent sample compositing procedure means a published VCS or EPA method to systematically mix and obtain a representative subsample (part) of the composite sample.

(3) An equivalent sample preparation procedure means a published VCS or EPA method that: Clearly states that the standard, practice or method is appropriate for the pollutant and the fuel matrix; or is cited as an appropriate sample preparation standard, practice or method for the pollutant in the chosen VCS or EPA determinative or analytical method.

(4) An equivalent procedure for determining heat content means a published VCS or EPA method to obtain gross calorific (or higher heating) value.

(5) An equivalent procedure for determining fuel moisture content means a published VCS or EPA method to obtain moisture content. If the sample analysis plan calls for determining metals (especially the mercury, selenium, or arsenic) using an aliquot of the dried sample, then the drying temperature must be modified to prevent vaporizing these metals. On the other hand, if metals analysis is done on an “as received” basis, a separate aliquot can be dried to determine moisture content and the metals concentration mathematically adjusted to a dry basis.

(6) An equivalent pollutant (mercury, HCl) determinative or analytical procedure means a published VCS or EPA method that clearly states that the standard, practice, or method is appropriate for the pollutant and the fuel matrix and has a published detection limit equal or lower than the methods listed in Table 6 to this subpart for the same purpose.

Fabric filter means an add-on air pollution control device used to capture particulate matter by filtering gas streams through filter media, also known as a baghouse. A fabric filter is a dry control system.

Federally enforceable means all limitations and conditions that are enforceable by the EPA Administrator, including, but not limited to, the requirements of 40 CFR parts 60, 61, 63, and 65, requirements within any applicable state implementation plan, and any permit requirements established under 40 CFR 52.21 or under 40 CFR 51.18 and 40 CFR 51.24.

Fluidized bed boiler means a boiler utilizing a fluidized bed combustion process that is not a pulverized coal boiler.

Fluidized bed boiler with an integrated fluidized bed heat exchanger means a boiler utilizing a fluidized bed combustion where the entire tube surface area is located outside of the furnace section at the exit of the cyclone section and exposed to the flue gas stream for conductive heat transfer. This design applies only to boilers in the unit designed to burn coal/solid fossil fuel subcategory that fire coal refuse.

Fluidized bed combustion means a process where a fuel is burned in a bed of granulated particles, which are maintained in a mobile suspension by the forward flow of air and combustion products.

Fossil fuel means natural gas, oil, coal, and any form of solid, liquid, or gaseous fuel derived from such material.

Fuel cell means a boiler type in which the fuel is dropped onto suspended fixed grates and is fired in a pile. The refractory-lined fuel cell uses combustion air preheating and positioning of secondary and tertiary air injection ports to improve boiler efficiency. Fluidized bed, dutch oven, pile burner, hybrid suspension grate, and suspension burners are not part of the fuel cell subcategory.

Fuel type means each category of fuels that share a common name or classification. Examples include, but are not limited to, bituminous coal, sub-bituminous coal, lignite, anthracite, biomass, distillate oil, residual oil. Individual fuel types received from different suppliers are not considered new fuel types.

Gaseous fuel includes, but is not limited to, natural gas, process gas, landfill gas, coal derived gas, refinery gas, and biogas. Blast furnace gas and process gases that are regulated under another subpart of this part, or part 60, part 61, or part 65 of this chapter, are exempted from this definition.

Heat input means heat derived from combustion of fuel in a boiler or process heater and does not include the heat input from preheated combustion air, recirculated flue gases, returned condensate, or exhaust gases from other sources such as gas turbines, internal combustion engines, kilns, etc.

Heavy liquid includes residual oil and any other liquid fuel not classified as a light liquid.

Hourly average means the arithmetic average of at least four CMS data values representing the four 15-minute periods in an hour, or at least two 15-minute data values during an hour when CMS calibration, quality assurance, or maintenance activities are being performed.

Hot water heater means a closed vessel with a capacity of no more than 120 U.S. gallons in which water is heated by combustion of gaseous, liquid, or biomass/bio-based solid fuel and is withdrawn for use external to the vessel. Hot water boilers (i.e., not generating steam) combusting gaseous, liquid, or biomass fuel with a heat input capacity of less than 1.6 million Btu per hour are included in this definition. The 120 U.S. gallon capacity threshold to be considered a hot water heater is independent of the 1.6 MMBtu/hr heat input capacity threshold for hot water boilers. Hot water heater also means a tankless unit that provides on demand hot water.

Hybrid suspension grate boiler means a boiler designed with air distributors to spread the fuel material over the entire width and depth of the boiler combustion zone. The biomass fuel combusted in these units exceeds a moisture content of 40 percent on an as-fired annual heat input basis as demonstrated by monthly fuel analysis. The drying and much of the combustion of the fuel takes place in suspension, and the combustion is completed on the grate or floor of the boiler. Fluidized bed, dutch oven, and pile burner designs are not part of the hybrid suspension grate boiler design category.

Industrial boiler means a boiler used in manufacturing, processing, mining, and refining or any other industry to provide steam, hot water, and/or electricity.

Light liquid includes distillate oil, biodiesel, or vegetable oil.

Limited-use boiler or process heater means any boiler or process heater that burns any amount of solid, liquid, or gaseous fuels and has a federally enforceable annual capacity factor of no more than 10 percent.

Liquid fuel includes, but is not limited to, light liquid, heavy liquid, any form of liquid fuel derived from petroleum, used oil, liquid biofuels, biodiesel, and vegetable oil.

Load fraction means the actual heat input of a boiler or process heater divided by heat input during the performance test that established the minimum sorbent injection rate or minimum activated carbon injection rate, expressed as a fraction (*e.g.,* for 50 percent load the load fraction is 0.5). For boilers and process heaters that co-fire natural gas or refinery gas with a solid or liquid fuel, the load fraction is determined by the actual heat input of the solid or liquid fuel divided by heat input of the solid or liquid fuel fired during the performance test (*e.g.,* if the performance test was conducted at 100 percent solid fuel firing, for 100 percent load firing 50 percent solid fuel and 50 percent natural gas the load fraction is 0.5).

Major source for oil and natural gas production facilities, as used in this subpart, shall have the same meaning as in §63.2, except that:

(1) Emissions from any oil or gas exploration or production well (with its associated equipment, as defined in this section), and emissions from any pipeline compressor station or pump station shall not be aggregated with emissions from other similar units to determine whether such emission points or stations are major sources, even when emission points are in a contiguous area or under common control;

(2) Emissions from processes, operations, or equipment that are not part of the same facility, as defined in this section, shall not be aggregated; and

(3) For facilities that are production field facilities, only HAP emissions from glycol dehydration units and storage vessels with the potential for flash emissions shall be aggregated for a major source determination. For facilities that are not production field facilities, HAP emissions from all HAP emission units shall be aggregated for a major source determination.

Metal process furnaces are a subcategory of process heaters, as defined in this subpart, which include natural gas-fired annealing furnaces, preheat furnaces, reheat furnaces, aging furnaces, heat treat furnaces, and homogenizing furnaces.

Million Btu (MMBtu) means one million British thermal units.

Minimum activated carbon injection rate means load fraction multiplied by the lowest hourly average activated carbon injection rate measured according to Table 7 to this subpart during the most recent performance test demonstrating compliance with the applicable emission limit.

Minimum oxygen level means the lowest hourly average oxygen level measured according to Table 7 to this subpart during the most recent performance test demonstrating compliance with the applicable emission limit.

Minimum pressure drop means the lowest hourly average pressure drop measured according to Table 7 to this subpart during the most recent performance test demonstrating compliance with the applicable emission limit.

Minimum scrubber effluent pH means the lowest hourly average sorbent liquid pH measured at the inlet to the wet scrubber according to Table 7 to this subpart during the most recent performance test demonstrating compliance with the applicable hydrogen chloride emission limit.

Minimum scrubber liquid flow rate means the lowest hourly average liquid flow rate (e.g., to the PM scrubber or to the acid gas scrubber) measured according to Table 7 to this subpart during the most recent performance stack test demonstrating compliance with the applicable emission limit.

Minimum scrubber pressure drop means the lowest hourly average scrubber pressure drop measured according to Table 7 to this subpart during the most recent performance test demonstrating compliance with the applicable emission limit.

Minimum sorbent injection rate means:

(1) The load fraction multiplied by the lowest hourly average sorbent injection rate for each sorbent measured according to Table 7 to this subpart during the most recent performance test demonstrating compliance with the applicable emission limits; or

(2) For fluidized bed combustion not using an acid gas wet scrubber or dry sorbent injection control technology to comply with the HCl emission limit, the lowest average ratio of sorbent to sulfur measured during the most recent performance test.

Minimum total secondary electric power means the lowest hourly average total secondary electric power determined from the values of secondary voltage and secondary current to the electrostatic precipitator measured according to Table 7 to this subpart during the most recent performance test demonstrating compliance with the applicable emission limits.

Natural gas means:

(1) A naturally occurring mixture of hydrocarbon and nonhydrocarbon gases found in geologic formations beneath the earth's surface, of which the principal constituent is methane; or

(2) Liquefied petroleum gas, as defined in ASTM D1835 (incorporated by reference, see §63.14); or

(3) A mixture of hydrocarbons that maintains a gaseous state at ISO conditions. Additionally, natural gas must either be composed of at least 70 percent methane by volume or have a gross calorific value between 35 and 41 megajoules (MJ) per dry standard cubic meter (950 and 1,100 Btu per dry standard cubic foot); or

(4) Propane or propane derived synthetic natural gas. Propane means a colorless gas derived from petroleum and natural gas, with the molecular structure C_3H_8.

Opacity means the degree to which emissions reduce the transmission of light and obscure the view of an object in the background.

Operating day means a 24-hour period between 12 midnight and the following midnight during which any fuel is combusted at any time in the boiler or process heater unit. It is not necessary for fuel to be combusted for the entire 24-hour period. For calculating rolling average emissions, an operating day does not include the hours of operation during startup or shutdown.

Other combustor means a unit designed to burn solid fuel that is not classified as a dutch oven, fluidized bed, fuel cell, hybrid suspension grate boiler, pulverized coal boiler, stoker, sloped grate, or suspension boiler as defined in this subpart.

Other gas 1 fuel means a gaseous fuel that is not natural gas or refinery gas and does not exceed a maximum concentration of 40 micrograms/cubic meters of mercury.

Oxygen analyzer system means all equipment required to determine the oxygen content of a gas stream and used to monitor oxygen in the boiler or process heater flue gas, boiler or process heater, firebox, or other appropriate location. This definition includes oxygen trim systems. The source owner or operator must install, calibrate, maintain, and operate the oxygen analyzer system in accordance with the manufacturer's recommendations.

Oxygen trim system means a system of monitors that is used to maintain excess air at the desired level in a combustion device over its operating load range. A typical system consists of a flue gas oxygen and/or CO monitor that automatically provides a feedback signal to the combustion air controller or draft controller.

Particulate matter (PM) means any finely divided solid or liquid material, other than uncombined water, as measured by the test methods specified under this subpart, or an approved alternative method.

Period of gas curtailment or supply interruption means a period of time during which the supply of gaseous fuel to an affected boiler or process heater is restricted or halted for reasons beyond the control of the facility. The act of entering into a contractual agreement with a supplier of natural gas established for curtailment purposes does not constitute a reason that is under the control of a facility for the purposes of this definition. An increase in the cost or unit price of natural gas due to normal market fluctuations not during periods of supplier delivery restriction does not constitute a period of natural gas curtailment or supply interruption. On-site gaseous fuel system emergencies or equipment failures qualify as periods of supply interruption when the emergency or failure is beyond the control of the facility.

Pile burner means a boiler design incorporating a design where the anticipated biomass fuel has a high relative moisture content. Grates serve to support the fuel, and underfire air flowing up through the grates provides oxygen for combustion, cools the grates, promotes turbulence in the fuel bed, and fires the fuel. The most common form of pile burning is the dutch oven.

Process heater means an enclosed device using controlled flame, and the unit's primary purpose is to transfer heat indirectly to a process material (liquid, gas, or solid) or to a heat transfer material (e.g., glycol or a mixture of glycol and water) for use in a process unit, instead of generating steam. Process heaters are devices in which the combustion gases do not come into direct contact with process materials. A device combusting solid waste, as defined in §241.3 of this chapter, is not a process heater unless the device is exempt from the definition of a solid waste incineration unit as provided in section 129(g)(1) of the Clean Air Act. Process heaters do not include units used for comfort heat or space heat, food preparation for on-site consumption, or autoclaves. Waste heat process heaters are excluded from this definition.

Pulverized coal boiler means a boiler in which pulverized coal or other solid fossil fuel is introduced into an air stream that carries the coal to the combustion chamber of the boiler where it is fired in suspension.

Qualified energy assessor means:

(1) Someone who has demonstrated capabilities to evaluate energy savings opportunities for steam generation and major energy using systems, including, but not limited to:

(i) Boiler combustion management.

(ii) Boiler thermal energy recovery, including

(A) Conventional feed water economizer,

(B) Conventional combustion air preheater, and

(C) Condensing economizer.

(iii) Boiler blowdown thermal energy recovery.

(iv) Primary energy resource selection, including

(A) Fuel (primary energy source) switching, and

(B) Applied steam energy versus direct-fired energy versus electricity.

(v) Insulation issues.

(vi) Steam trap and steam leak management.

(vi) Condensate recovery.

(viii) Steam end-use management.

(2) Capabilities and knowledge includes, but is not limited to:

(i) Background, experience, and recognized abilities to perform the assessment activities, data analysis, and report preparation.

(ii) Familiarity with operating and maintenance practices for steam or process heating systems.

(iii) Additional potential steam system improvement opportunities including improving steam turbine operations and reducing steam demand.

(iv) Additional process heating system opportunities including effective utilization of waste heat and use of proper process heating methods.

(v) Boiler-steam turbine cogeneration systems.

(vi) Industry specific steam end-use systems.

Refinery gas means any gas that is generated at a petroleum refinery and is combusted. Refinery gas includes natural gas when the natural gas is combined and combusted in any proportion with a gas

generated at a refinery. Refinery gas includes gases generated from other facilities when that gas is combined and combusted in any proportion with gas generated at a refinery.

Regulated gas stream means an offgas stream that is routed to a boiler or process heater for the purpose of achieving compliance with a standard under another subpart of this part or part 60, part 61, or part 65 of this chapter.

Residential boiler means a boiler used to provide heat and/or hot water and/or as part of a residential combined heat and power system. This definition includes boilers located at an institutional facility (e.g., university campus, military base, church grounds) or commercial/industrial facility (e.g., farm) used primarily to provide heat and/or hot water for:

(1) A dwelling containing four or fewer families; or

(2) A single unit residence dwelling that has since been converted or subdivided into condominiums or apartments.

Residual oil means crude oil, fuel oil that does not comply with the specifications under the definition of distillate oil, and all fuel oil numbers 4, 5, and 6, as defined by the American Society of Testing and Materials in ASTM D396-10 (incorporated by reference, *see* §63.14(b)).

Responsible official means responsible official as defined in §70.2.

Rolling average means the average of all data collected during the applicable averaging period. For demonstration of compliance with a CO CEMS-based emission limit based on CO concentration a 30-day (10-day) rolling average is comprised of the average of all the hourly average concentrations over the previous 720 (240) operating hours calculated each operating day. To demonstrate compliance on a 30-day rolling average basis for parameters other than CO, you must indicate the basis of the 30-day rolling average period you are using for compliance, as discussed in §63.7545(e)(2)(iii). If you indicate the 30 operating day basis, you must calculate a new average value each operating day and shall include the measured hourly values for the preceding 30 operating days. If you select the 720 operating hours basis, you must average of all the hourly average concentrations over the previous 720 operating hours calculated each operating day.

Secondary material means the material as defined in §241.2 of this chapter.

Shutdown means the period in which cessation of operation of a boiler or process heater is initiated for any purpose. Shutdown begins when the boiler or process heater no longer supplies useful thermal energy (such as heat or steam) for heating, cooling, or process purposes and/or generates electricity or when no fuel is being fed to the boiler or process heater, whichever is earlier. Shutdown ends when the boiler or process heater no longer supplies useful thermal energy (such as steam or heat) for heating, cooling, or process purposes and/or generates electricity, and no fuel is being combusted in the boiler or process heater.

Sloped grate means a unit where the solid fuel is fed to the top of the grate from where it slides downwards; while sliding the fuel first dries and then ignites and burns. The ash is deposited at the bottom of the grate. Fluidized bed, dutch oven, pile burner, hybrid suspension grate, suspension burners, and fuel cells are not considered to be a sloped grate design.

Solid fossil fuel includes, but is not limited to, coal, coke, petroleum coke, and tire derived fuel.

Solid fuel means any solid fossil fuel or biomass or bio-based solid fuel.

Startup means:

(1) Either the first-ever firing of fuel in a boiler or process heater for the purpose of supplying useful thermal energy for heating and/or producing electricity, or for any other purpose, or the firing of fuel in a boiler after a shutdown event for any purpose. Startup ends when any of the useful thermal energy from the boiler or process heater is supplied for heating, and/or producing electricity, or for any other purpose, or

(2) The period in which operation of a boiler or process heater is initiated for any purpose. Startup begins with either the first-ever firing of fuel in a boiler or process heater for the purpose of supplying useful thermal energy (such as steam or heat) for heating, cooling or process purposes, or producing electricity, or the firing of fuel in a boiler or process heater for any purpose after a shutdown event. Startup ends four hours after when the boiler or process heater supplies useful thermal energy (such as heat or steam) for heating, cooling, or process purposes, or generates electricity, whichever is earlier.

Steam output means:

(1) For a boiler that produces steam for process or heating only (no power generation), the energy content in terms of MMBtu of the boiler steam output,

(2) For a boiler that cogenerates process steam and electricity (also known as combined heat and power), the total energy output, which is the sum of the energy content of the steam exiting the turbine and sent to process in MMBtu and the energy of the electricity generated converted to MMBtu at a rate of 10,000 Btu per kilowatt-hour generated (10 MMBtu per megawatt-hour), and

(3) For a boiler that generates only electricity, the alternate output-based emission limits would be the appropriate emission limit from Table 1 or 2 of this subpart in units of pounds per million Btu heat input (lb per MWh).

(4) For a boiler that performs multiple functions and produces steam to be used for any combination of paragraphs (1), (2), and (3) of this definition that includes electricity generation of paragraph (3) of this definition, the total energy output, in terms of MMBtu of steam output, is the sum of the energy content of steam sent directly to the process and/or used for heating (S_1), the energy content of turbine steam sent to process plus energy in electricity according to paragraph (2) of this definition (S_2), and the energy content of electricity generated by a electricity only turbine as paragraph (3) of this definition ($MW_{(3)}$) and would be calculated using Equation 21 of this section. In the case of boilers supplying steam to one or more common heaters, S_1, S_2, and $MW_{(3)}$ for each boiler would be calculated based on the its (steam energy) contribution (fraction of total steam energy) to the common heater.

$$SO_M = S_1 + S_2 + (MW_{(3)} \; x \; CFn) \qquad \text{(Eq. 21)}$$

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Where:

SO_M = Total steam output for multi-function boiler, MMBtu

S_1 = Energy content of steam sent directly to the process and/or used for heating, MMBtu

S_2 = Energy content of turbine steam sent to the process plus energy in electricity according to (2) above, MMBtu

$MW_{(3)}$ = Electricity generated according to paragraph (3) of this definition, MWh

CFn = Conversion factor for the appropriate subcategory for converting electricity generated according to paragraph (3) of this definition to equivalent steam energy, MMBtu/MWh

CFn for emission limits for boilers in the unit designed to burn solid fuel subcategory = 10.8

CFn PM and CO emission limits for boilers in one of the subcategories of units designed to burn coal = 11.7

CFn PM and CO emission limits for boilers in one of the subcategories of units designed to burn biomass = 12.1

CFn for emission limits for boilers in one of the subcategories of units designed to burn liquid fuel = 11.2

CFn for emission limits for boilers in the unit designed to burn gas 2 (other) subcategory = 6.2

Stoker means a unit consisting of a mechanically operated fuel feeding mechanism, a stationary or moving grate to support the burning of fuel and admit under-grate air to the fuel, an overfire air system to complete combustion, and an ash discharge system. This definition of stoker includes air swept stokers. There are two general types of stokers: Underfeed and overfeed. Overfeed stokers include mass feed and spreader stokers. Fluidized bed, dutch oven, pile burner, hybrid suspension grate, suspension burners, and fuel cells are not considered to be a stoker design.

Stoker/sloped grate/other unit designed to burn kiln dried biomass means the unit is in the units designed to burn biomass/bio-based solid subcategory that is either a stoker, sloped grate, or other combustor design and is not in the stoker/sloped grate/other units designed to burn wet biomass subcategory.

Stoker/sloped grate/other unit designed to burn wet biomass means the unit is in the units designed to burn biomass/bio-based solid subcategory that is either a stoker, sloped grate, or other combustor design and any of the biomass/bio-based solid fuel combusted in the unit exceeds 20 percent moisture on an annual heat input basis.

Suspension burner means a unit designed to fire dry biomass/biobased solid particles in suspension that are conveyed in an airstream to the furnace like pulverized coal. The combustion of the fuel material is completed on a grate or floor below. The biomass/biobased fuel combusted in the unit shall not exceed 20 percent moisture on an annual heat input basis. Fluidized bed, dutch oven, pile burner, and hybrid suspension grate units are not part of the suspension burner subcategory.

Temporary boiler means any gaseous or liquid fuel boiler or process heater that is designed to, and is capable of, being carried or moved from one location to another by means of, for example, wheels, skids, carrying handles, dollies, trailers, or platforms. A boiler or process heater is not a temporary boiler or process heater if any one of the following conditions exists:

(1) The equipment is attached to a foundation.

(2) The boiler or process heater or a replacement remains at a location within the facility and performs the same or similar function for more than 12 consecutive months, unless the regulatory agency approves an extension. An extension may be granted by the regulating agency upon petition by the owner or operator of a unit specifying the basis for such a request. Any temporary boiler or process heater that replaces a temporary boiler or process heater at a location and performs the same or similar function will be included in calculating the consecutive time period.

(3) The equipment is located at a seasonal facility and operates during the full annual operating period of the seasonal facility, remains at the facility for at least 2 years, and operates at that facility for at least 3 months each year.

(4) The equipment is moved from one location to another within the facility but continues to perform the same or similar function and serve the same electricity, process heat, steam, and/or hot water system in an attempt to circumvent the residence time requirements of this definition.

Total selected metals (TSM) means the sum of the following metallic hazardous air pollutants: arsenic, beryllium, cadmium, chromium, lead, manganese, nickel and selenium.

Traditional fuel means the fuel as defined in §241.2 of this chapter.

Tune-up means adjustments made to a boiler or process heater in accordance with the procedures outlined in §63.7540(a)(10).

Ultra low sulfur liquid fuel means a distillate oil that has less than or equal to 15 ppm sulfur.

Unit designed to burn biomass/bio-based solid subcategory includes any boiler or process heater that burns at least 10 percent biomass or bio-based solids on an annual heat input basis in combination with solid fossil fuels, liquid fuels, or gaseous fuels.

Unit designed to burn coal/solid fossil fuel subcategory includes any boiler or process heater that burns any coal or other solid fossil fuel alone or at least 10 percent coal or other solid fossil fuel on an annual heat input basis in combination with liquid fuels, gaseous fuels, or less than 10 percent biomass and bio-based solids on an annual heat input basis.

Unit designed to burn gas 1 subcategory includes any boiler or process heater that burns only natural gas, refinery gas, and/or other gas 1 fuels. Gaseous fuel boilers and process heaters that burn liquid fuel for periodic testing of liquid fuel, maintenance, or operator training, not to exceed a combined total of 48 hours during any calendar year, are included in this definition. Gaseous fuel boilers and process heaters that burn liquid fuel during periods of gas curtailment or gas supply interruptions of any duration are also included in this definition.

Unit designed to burn gas 2 (other) subcategory includes any boiler or process heater that is not in the unit designed to burn gas 1 subcategory and burns any gaseous fuels either alone or in combination with less than 10 percent coal/solid fossil fuel, and less than 10 percent biomass/bio-based solid fuel on an annual heat input basis, and no liquid fuels. Gaseous fuel boilers and process heaters that are not in the unit designed to burn gas 1 subcategory and that burn liquid fuel for periodic testing of liquid fuel, maintenance, or operator training, not to exceed a combined total of 48 hours during any calendar year, are included in this definition. Gaseous fuel boilers and process heaters that are not in the unit designed to burn gas 1 subcategory and that burn liquid fuel during periods of gas curtailment or gas supply interruption of any duration are also included in this definition.

Unit designed to burn heavy liquid subcategory means a unit in the unit designed to burn liquid subcategory where at least 10 percent of the heat input from liquid fuels on an annual heat input basis comes from heavy liquids.

Unit designed to burn light liquid subcategory means a unit in the unit designed to burn liquid subcategory that is not part of the unit designed to burn heavy liquid subcategory.

Unit designed to burn liquid subcategory includes any boiler or process heater that burns any liquid fuel, but less than 10 percent coal/solid fossil fuel and less than 10 percent biomass/bio-based solid fuel on an annual heat input basis, either alone or in combination with gaseous fuels. Units in the unit design to burn gas 1 or unit designed to burn gas 2 (other) subcategories that burn liquid fuel for periodic testing of liquid fuel, maintenance, or operator training, not to exceed a combined total of 48 hours during any calendar year are not included in this definition. Units in the unit design to burn gas 1 or unit designed to burn gas 2 (other) subcategories during periods of gas curtailment or gas supply interruption of any duration are also not included in this definition.

Unit designed to burn liquid fuel that is a non-continental unit means an industrial, commercial, or institutional boiler or process heater meeting the definition of the unit designed to burn liquid subcategory located in the State of Hawaii, the Virgin Islands, Guam, American Samoa, the Commonwealth of Puerto Rico, or the Northern Mariana Islands.

Unit designed to burn solid fuel subcategory means any boiler or process heater that burns only solid fuels or at least 10 percent solid fuel on an annual heat input basis in combination with liquid fuels or gaseous fuels.

Useful thermal energy means energy (*i.e.,* steam, hot water, or process heat) that meets the minimum operating temperature, flow, and/or pressure required by any energy use system that uses energy provided by the affected boiler or process heater.

Vegetable oil means oils extracted from vegetation.

Voluntary Consensus Standards or VCS mean technical standards (*e.g.,* materials specifications, test methods, sampling procedures, business practices) developed or adopted by one or more voluntary consensus bodies. EPA/Office of Air Quality Planning and Standards, by precedent, has only used VCS that are written in English. Examples of VCS bodies are: American Society of Testing and Materials (ASTM 100 Barr Harbor Drive, P.O. Box CB700, West Conshohocken, Pennsylvania 19428-B2959, (800) 262-1373, *http://www.astm.org*), American Society of Mechanical Engineers (ASME ASME, Three Park Avenue, New York, NY 10016-5990, (800) 843-2763, *http://www.asme.org*), International Standards Organization (ISO 1, ch. de la Voie-Creuse, Case postale 56, CH-1211 Geneva 20, Switzerland, + 41 22 749 01 11, *http://www.iso.org/iso/home.htm*), Standards Australia (AS Level 10, The Exchange Centre, 20 Bridge Street, Sydney, GPO Box 476, Sydney NSW 2001, + 61 2 9237 6171 *http://www.stadards.org.au*), British Standards Institution (BSI, 389 Chiswick High Road, London, W4 4AL, United Kingdom, + 44 (0)20 8996 9001,*http://www.bsigroup.com*), Canadian Standards Association (CSA 5060 Spectrum Way, Suite 100, Mississauga, Ontario L4W 5N6, Canada, 800-463-6727, *http://www.csa.ca*), European Committee for Standardization (CEN CENELEC Management Centre Avenue Marnix 17 B-1000 Brussels, Belgium + 32 2 550 08 11, *http://www.cen.eu/cen*), and German Engineering Standards (VDI VDI Guidelines Department, P.O. Box 10 11 39 40002, Duesseldorf, Germany, + 49 211 6214-230, *http://www.vdi.eu*). The types of standards that are not considered VCS are standards developed by: The United States, *e.g.,* California (CARB) and Texas (TCEQ); industry groups, such as American Petroleum Institute (API), Gas Processors Association (GPA), and Gas Research Institute (GRI); and other branches of the U.S. government, *e.g.,*Department of Defense (DOD) and Department of Transportation (DOT). This does not preclude EPA from using standards developed by groups that are not VCS bodies within their rule. When this occurs, EPA has done searches and reviews for VCS equivalent to these non-EPA methods.

Waste heat boiler means a device that recovers normally unused energy (i.e., hot exhaust gas) and converts it to usable heat. Waste heat boilers are also referred to as heat recovery steam generators. Waste heat boilers are heat exchangers generating steam from incoming hot exhaust gas from an industrial (e.g., thermal oxidizer, kiln, furnace) or power (e.g., combustion turbine, engine) equipment. Duct burners are sometimes used to increase the temperature of the incoming hot exhaust gas.

Waste heat process heater means an enclosed device that recovers normally unused energy (i.e., hot exhaust gas) and converts it to usable heat. Waste heat process heaters are also referred to as recuperative process heaters. This definition includes both fired and unfired waste heat process heaters.

Wet scrubber means any add-on air pollution control device that mixes an aqueous stream or slurry with the exhaust gases from a boiler or process heater to control emissions of particulate matter or to absorb and neutralize acid gases, such as hydrogen chloride. A wet scrubber creates an aqueous stream or slurry as a byproduct of the emissions control process.

Work practice standard means any design, equipment, work practice, or operational standard, or combination thereof, that is promulgated pursuant to section 112(h) of the Clean Air Act.

[78 FR 15664, Mar. 21, 2011, as amended at 78 FR 7163, Jan. 31, 2013; 80 FR 72817, Nov. 20, 2015]

Subpart Db—Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units

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SOURCE: 72 FR 32742, June 13, 2007, unless otherwise noted.

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§60.40b Applicability and delegation of authority.

(a) The affected facility to which this subpart applies is each steam generating unit that commences construction, modification, or reconstruction after June 19, 1984, and that has a heat input capacity from fuels combusted in the steam generating unit of greater than 29 megawatts (MW) (100 million British thermal units per hour (MMBtu/hr)).

The Fluidized Bed Combustor at the proposed CRE Potlach facility is subject to this subpart because it generates steam, will be constructed after June 19, 1984 and has a heat input capacity of 200 MMBtu/hr.

(b) Any affected facility meeting the applicability requirements under paragraph (a) of this section and commencing construction, modification, or reconstruction after June 19, 1984, but on or before June 19, 1986, is subject to the following standards:

(1) Coal-fired affected facilities having a heat input capacity between 29 and 73 MW (100 and 250 MMBtu/hr), inclusive, are subject to the particulate matter (PM) and nitrogen oxides (NO_x) standards under this subpart.

(2) Coal-fired affected facilities having a heat input capacity greater than 73 MW (250 MMBtu/hr) and meeting the applicability requirements under subpart D (Standards of performance for fossil-fuel-fired steam generators; §60.40) are subject to the PM and NO_x standards under this subpart and to the sulfur dioxide (SO_2) standards under subpart D (§60.43).

(3) Oil-fired affected facilities having a heat input capacity between 29 and 73 MW (100 and 250 MMBtu/hr), inclusive, are subject to the NO_x standards under this subpart.

(4) Oil-fired affected facilities having a heat input capacity greater than 73 MW (250 MMBtu/hr) and meeting the applicability requirements under subpart D (Standards of performance for fossil-fuel-fired steam generators; §60.40) are also subject to the NO_x standards under this subpart and the PM and SO_2 standards under subpart D (§60.42 and §60.43).

(c) Affected facilities that also meet the applicability requirements under subpart J or subpart Ja of this part are subject to the PM and NO_x standards under this subpart and the SO_2 standards under subpart J or subpart Ja of this part, as applicable.

(d) Affected facilities that also meet the applicability requirements under subpart E (Standards of performance for incinerators; §60.50) are subject to the NO_x and PM standards under this subpart.

(e) Steam generating units meeting the applicability requirements under subpart Da (Standards of performance for electric utility steam generating units; §60.40Da) are not subject to this subpart.

(f) Any change to an existing steam generating unit for the sole purpose of combusting gases containing total reduced sulfur (TRS) as defined under §60.281 is not considered a modification under §60.14 and the steam generating unit is not subject to this subpart.

(g) In delegating implementation and enforcement authority to a State under section 111(c) of the Clean Air Act, the following authorities shall be retained by the Administrator and not transferred to a State.

(1) Section 60.44b(f).

(2) Section 60.44b(g).

(3) Section 60.49b(a)(4).

(h) Any affected facility that meets the applicability requirements and is subject to subpart Ea, subpart Eb, subpart AAAA, or subpart CCCC of this part is not subject to this subpart.

(i) Affected facilities (*i.e.,* heat recovery steam generators) that are associated with stationary combustion turbines and that meet the applicability requirements of subpart KKKK of this part are not subject to this subpart. This subpart will continue to apply to all other affected facilities (*i.e.* heat recovery steam generators with duct burners) that are capable of combusting more than 29 MW (100 MMBtu/h) heat input of fossil fuel. If the affected facility (*i.e.* heat recovery steam generator) is subject to this subpart, only emissions resulting from combustion of fuels in the steam generating unit are subject to this subpart. (The stationary combustion turbine emissions are subject to subpart GG or KKKK, as applicable, of this part.)

(j) Any affected facility meeting the applicability requirements under paragraph (a) of this section and commencing construction, modification, or reconstruction after June 19, 1986 is not subject to subpart D (Standards of Performance for Fossil-Fuel-Fired Steam Generators, §60.40).

The FBC meets the applicability requirements under paragraph (a) and will be constructed after June 19, 1986.

(k) Any affected facility that meets the applicability requirements and is subject to an EPA approved State or Federal section 111(d)/129 plan implementing subpart Cb or subpart BBBB of this part is not covered by this subpart.

(l) Affected facilities that also meet the applicability requirements under subpart BB of this part (Standards of Performance for Kraft Pulp Mills) are subject to the SO_2 and NO_x standards under this subpart and the PM standards under subpart BB.

(m) Temporary boilers are not subject to this subpart.

[72 FR 32742, June 13, 2007, as amended at 74 FR 5084, Jan. 28, 2009; 77 FR 9459, Feb. 16, 2012]

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§60.41b Definitions.

As used in this subpart, all terms not defined herein shall have the meaning given them in the Clean Air Act and in subpart A of this part.

CRE has read and understands these definitions and used them in providing this regulatory analysis.

Annual capacity factor means the ratio between the actual heat input to a steam generating unit from the fuels listed in §60.42b(a), §60.43b(a), or §60.44b(a), as applicable, during a calendar year and the potential heat input to the steam generating unit had it been operated for 8,760 hours during a calendar year at the maximum steady state design heat input capacity. In the case of steam generating units that are rented or leased, the actual heat input shall be determined based on the combined heat input from all operations of the affected facility in a calendar year.

Byproduct/waste means any liquid or gaseous substance produced at chemical manufacturing plants, petroleum refineries, or pulp and paper mills (except natural gas, distillate oil, or residual oil) and combusted in a steam generating unit for heat recovery or for disposal. Gaseous substances with carbon dioxide (CO_2) levels greater than 50 percent or carbon monoxide levels greater than 10 percent are not byproduct/waste for the purpose of this subpart.

Chemical manufacturing plants mean industrial plants that are classified by the Department of Commerce under Standard Industrial Classification (SIC) Code 28.

Coal means all solid fuels classified as anthracite, bituminous, subbituminous, or lignite by the American Society of Testing and Materials in ASTM D388 (incorporated by reference, see §60.17), coal refuse, and petroleum coke. Coal-derived synthetic fuels, including but not limited to solvent refined coal, gasified coal not meeting the definition of natural gas, coal-oil mixtures, coke oven gas, and coal-water mixtures, are also included in this definition for the purposes of this subpart.

Coal refuse means any byproduct of coal mining or coal cleaning operations with an ash content greater than 50 percent, by weight, and a heating value less than 13,900 kJ/kg (6,000 Btu/lb) on a dry basis.

Cogeneration, also known as combined heat and power, means a facility that simultaneously produces both electric (or mechanical) and useful thermal energy from the same primary energy source.

Coke oven gas means the volatile constituents generated in the gaseous exhaust during the carbonization of bituminous coal to form coke.

Combined cycle system means a system in which a separate source, such as a gas turbine, internal combustion engine, kiln, etc., provides exhaust gas to a steam generating unit.

Conventional technology means wet flue gas desulfurization (FGD) technology, dry FGD technology, atmospheric fluidized bed combustion technology, and oil hydrodesulfurization technology.

Distillate oil means fuel oils that contain 0.05 weight percent nitrogen or less and comply with the specifications for fuel oil numbers 1 and 2, as defined by the American Society of Testing and Materials in ASTM D396 (incorporated by reference, see §60.17), diesel fuel oil numbers 1 and 2, as defined by the

American Society for Testing and Materials in ASTM D975 (incorporated by reference, see §60.17), kerosine, as defined by the American Society of Testing and Materials in ASTM D3699 (incorporated by reference, see §60.17), biodiesel as defined by the American Society of Testing and Materials in ASTM D6751 (incorporated by reference, see §60.17), or biodiesel blends as defined by the American Society of Testing and Materials in ASTM D7467 (incorporated by reference, see §60.17).

Dry flue gas desulfurization technology means a SO_2 control system that is located downstream of the steam generating unit and removes sulfur oxides from the combustion gases of the steam generating unit by contacting the combustion gases with an alkaline reagent and water, whether introduced separately or as a premixed slurry or solution and forming a dry powder material. This definition includes devices where the dry powder material is subsequently converted to another form. Alkaline slurries or solutions used in dry flue gas desulfurization technology include but are not limited to lime and sodium.

Duct burner means a device that combusts fuel and that is placed in the exhaust duct from another source, such as a stationary gas turbine, internal combustion engine, kiln, etc., to allow the firing of additional fuel to heat the exhaust gases before the exhaust gases enter a steam generating unit.

Emerging technology means any SO_2 control system that is not defined as a conventional technology under this section, and for which the owner or operator of the facility has applied to the Administrator and received approval to operate as an emerging technology under §60.49b(a)(4).

Federally enforceable means all limitations and conditions that are enforceable by the Administrator, including the requirements of 40 CFR parts 60 and 61, requirements within any applicable State Implementation Plan, and any permit requirements established under 40 CFR 52.21 or under 40 CFR 51.18 and 51.24.

Fluidized bed combustion technology means combustion of fuel in a bed or series of beds (including but not limited to bubbling bed units and circulating bed units) of limestone aggregate (or other sorbent materials) in which these materials are forced upward by the flow of combustion air and the gaseous products of combustion.

Fuel pretreatment means a process that removes a portion of the sulfur in a fuel before combustion of the fuel in a steam generating unit.

Full capacity means operation of the steam generating unit at 90 percent or more of the maximum steady-state design heat input capacity.

Gaseous fuel means any fuel that is a gas at ISO conditions. This includes, but is not limited to, natural gas and gasified coal (including coke oven gas).

Gross output means the gross useful work performed by the steam generated. For units generating only electricity, the gross useful work performed is the gross electrical output from the turbine/generator set. For cogeneration units, the gross useful work performed is the gross electrical or mechanical output plus 75 percent of the useful thermal output measured relative to ISO conditions that is not used to generate additional electrical or mechanical output or to enhance the performance of the unit (*i.e.*, steam delivered to an industrial process).

Heat input means heat derived from combustion of fuel in a steam generating unit and does not include the heat derived from preheated combustion air, recirculated flue gases, or exhaust gases from other sources, such as gas turbines, internal combustion engines, kilns, etc.

Heat release rate means the steam generating unit design heat input capacity (in MW or Btu/hr) divided by the furnace volume (in cubic meters or cubic feet); the furnace volume is that volume bounded

by the front furnace wall where the burner is located, the furnace side waterwall, and extending to the level just below or in front of the first row of convection pass tubes.

Heat transfer medium means any material that is used to transfer heat from one point to another point.

High heat release rate means a heat release rate greater than 730,000 J/sec-m^3 (70,000 Btu/hr-ft^3).

ISO Conditions means a temperature of 288 Kelvin, a relative humidity of 60 percent, and a pressure of 101.3 kilopascals.

Lignite means a type of coal classified as lignite A or lignite B by the American Society of Testing and Materials in ASTM D388 (incorporated by reference, see §60.17).

Low heat release rate means a heat release rate of 730,000 J/sec-m^3 (70,000 Btu/hr-ft^3) or less.

Mass-feed stoker steam generating unit means a steam generating unit where solid fuel is introduced directly into a retort or is fed directly onto a grate where it is combusted.

Maximum heat input capacity means the ability of a steam generating unit to combust a stated maximum amount of fuel on a steady state basis, as determined by the physical design and characteristics of the steam generating unit.

Municipal-type solid waste means refuse, more than 50 percent of which is waste consisting of a mixture of paper, wood, yard wastes, food wastes, plastics, leather, rubber, and other combustible materials, and noncombustible materials such as glass and rock.

Natural gas means:

(1) A naturally occurring mixture of hydrocarbon and nonhydrocarbon gases found in geologic formations beneath the earth's surface, of which the principal constituent is methane; or

(2) Liquefied petroleum gas, as defined by the American Society for Testing and Materials in ASTM D1835 (incorporated by reference, see §60.17); or

(3) A mixture of hydrocarbons that maintains a gaseous state at ISO conditions. Additionally, natural gas must either be composed of at least 70 percent methane by volume or have a gross calorific value between 34 and 43 megajoules (MJ) per dry standard cubic meter (910 and 1,150 Btu per dry standard cubic foot).

Noncontinental area means the State of Hawaii, the Virgin Islands, Guam, American Samoa, the Commonwealth of Puerto Rico, or the Northern Mariana Islands.

Oil means crude oil or petroleum or a liquid fuel derived from crude oil or petroleum, including distillate and residual oil.

Petroleum refinery means industrial plants as classified by the Department of Commerce under Standard Industrial Classification (SIC) Code 29.

Potential sulfur dioxide emission rate means the theoretical SO_2 emissions (nanograms per joule (ng/J) or lb/MMBtu heat input) that would result from combusting fuel in an uncleaned state and without using emission control systems. For gasified coal or oil that is desulfurized prior to combustion,

the *Potential sulfur dioxide emission rate* is the theoretical SO_2 emissions (ng/J or lb/MMBtu heat input) that would result from combusting fuel in a cleaned state without using any post combustion emission control systems.

Process heater means a device that is primarily used to heat a material to initiate or promote a chemical reaction in which the material participates as a reactant or catalyst.

Pulp and paper mills means industrial plants that are classified by the Department of Commerce under North American Industry Classification System (NAICS) Code 322 or Standard Industrial Classification (SIC) Code 26.

Pulverized coal-fired steam generating unit means a steam generating unit in which pulverized coal is introduced into an air stream that carries the coal to the combustion chamber of the steam generating unit where it is fired in suspension. This includes both conventional pulverized coal-fired and micropulverized coal-fired steam generating units. Residual oil means crude oil, fuel oil numbers 1 and 2 that have a nitrogen content greater than 0.05 weight percent, and all fuel oil numbers 4, 5 and 6, as defined by the American Society of Testing and Materials in ASTM D396 (incorporated by reference, see §60.17).

Spreader stoker steam generating unit means a steam generating unit in which solid fuel is introduced to the combustion zone by a mechanism that throws the fuel onto a grate from above. Combustion takes place both in suspension and on the grate.

Steam generating unit means a device that combusts any fuel or byproduct/waste and produces steam or heats water or heats any heat transfer medium. This term includes any municipal-type solid waste incinerator with a heat recovery steam generating unit or any steam generating unit that combusts fuel and is part of a cogeneration system or a combined cycle system. This term does not include process heaters as they are defined in this subpart.

Steam generating unit operating day means a 24-hour period between 12:00 midnight and the following midnight during which any fuel is combusted at any time in the steam generating unit. It is not necessary for fuel to be combusted continuously for the entire 24-hour period.

Temporary boiler means any gaseous or liquid fuel-fired steam generating unit that is designed to, and is capable of, being carried or moved from one location to another by means of, for example, wheels, skids, carrying handles, dollies, trailers, or platforms. A steam generating unit is not a temporary boiler if any one of the following conditions exists:

(1) The equipment is attached to a foundation.

(2) The steam generating unit or a replacement remains at a location for more than 180 consecutive days. Any temporary boiler that replaces a temporary boiler at a location and performs the same or similar function will be included in calculating the consecutive time period.

(3) The equipment is located at a seasonal facility and operates during the full annual operating period of the seasonal facility, remains at the facility for at least 2 years, and operates at that facility for at least 3 months each year.

(4) The equipment is moved from one location to another in an attempt to circumvent the residence time requirements of this definition.

Very low sulfur oil means for units constructed, reconstructed, or modified on or before February 28, 2005, oil that contains no more than 0.5 weight percent sulfur or that, when combusted without

SO_2 emission control, has a SO_2emission rate equal to or less than 215 ng/J (0.5 lb/MMBtu) heat input. For units constructed, reconstructed, or modified after February 28, 2005 and not located in a noncontinental area, *very low sulfur oil* means oil that contains no more than 0.30 weight percent sulfur or that, when combusted without SO_2 emission control, has a SO_2 emission rate equal to or less than 140 ng/J (0.32 lb/MMBtu) heat input. For units constructed, reconstructed, or modified after February 28, 2005 and located in a noncontinental area, *very low sulfur oil* means oil that contains no more than 0.5 weight percent sulfur or that, when combusted without SO_2 emission control, has a SO_2 emission rate equal to or less than 215 ng/J (0.50 lb/MMBtu) heat input.

Wet flue gas desulfurization technology means a SO_2 control system that is located downstream of the steam generating unit and removes sulfur oxides from the combustion gases of the steam generating unit by contacting the combustion gas with an alkaline slurry or solution and forming a liquid material. This definition applies to devices where the aqueous liquid material product of this contact is subsequently converted to other forms. Alkaline reagents used in wet flue gas desulfurization technology include, but are not limited to, lime, limestone, and sodium.

Wet scrubber system means any emission control device that mixes an aqueous stream or slurry with the exhaust gases from a steam generating unit to control emissions of PM or SO_2.

Wood means wood, wood residue, bark, or any derivative fuel or residue thereof, in any form, including, but not limited to, sawdust, sanderdust, wood chips, scraps, slabs, millings, shavings, and processed pellets made from wood or other forest residues.

[72 FR 32742, June 13, 2007, as amended at 74 FR 5084, Jan. 28, 2009; 77 FR 9459, Feb. 16, 2012]

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§60.42b Standard for sulfur dioxide (SO_2).

The CRE FBC does not combust coal or oil, either alone or in combination with any other fuel; therefore there are no requirements under this section.

(a) Except as provided in paragraphs (b), (c), (d), or (j) of this section, on and after the date on which the performance test is completed or required to be completed under §60.8, whichever comes first, no owner or operator of an affected facility that commenced construction, reconstruction, or modification on or before February 28, 2005, that combusts coal or oil shall cause to be discharged into the atmosphere any gases that contain SO_2 in excess of 87 ng/J (0.20 lb/MMBtu) or 10 percent (0.10) of the potential SO_2 emission rate (90 percent reduction) and the emission limit determined according to the following formula:

$$E_s = \frac{(K_a H_a + K_b H_b)}{(H_a + H_b)}$$

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Where:

E_s = SO_2 emission limit, in ng/J or lb/MMBtu heat input;

K_a = 520 ng/J (or 1.2 lb/MMBtu);

K_b = 340 ng/J (or 0.80 lb/MMBtu);

H_a = Heat input from the combustion of coal, in J (MMBtu); and

H_b = Heat input from the combustion of oil, in J (MMBtu).

For facilities complying with the percent reduction standard, only the heat input supplied to the affected facility from the combustion of coal and oil is counted in this paragraph. No credit is provided for the heat input to the affected facility from the combustion of natural gas, wood, municipal-type solid waste, or other fuels or heat derived from exhaust gases from other sources, such as gas turbines, internal combustion engines, kilns, etc.

(b) On and after the date on which the performance test is completed or required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that commenced construction, reconstruction, or modification on or before February 28, 2005, that combusts coal refuse alone in a fluidized bed combustion steam generating unit shall cause to be discharged into the atmosphere any gases that contain SO_2 in excess of 87 ng/J (0.20 lb/MMBtu) or 20 percent (0.20) of the potential SO_2 emission rate (80 percent reduction) and 520 ng/J (1.2 lb/MMBtu) heat input. If coal or oil is fired with coal refuse, the affected facility is subject to paragraph (a) or (d) of this section, as applicable. For facilities complying with the percent reduction standard, only the heat input supplied to the affected facility from the combustion of coal and oil is counted in this paragraph. No credit is provided for the heat input to the affected facility from the combustion of natural gas, wood, municipal-type solid waste, or other fuels or heat derived from exhaust gases from other sources, such as gas turbines, internal combustion engines, kilns, etc.

(c) On and after the date on which the performance test is completed or is required to be completed under §60.8, whichever comes first, no owner or operator of an affected facility that combusts coal or oil, either alone or in combination with any other fuel, and that uses an emerging technology for the control of SO_2 emissions, shall cause to be discharged into the atmosphere any gases that contain SO_2 in excess of 50 percent of the potential SO_2 emission rate (50 percent reduction) and that contain SO_2 in excess of the emission limit determined according to the following formula:

$$E_s = \frac{(K_c H_c + K_d H_d)}{(H_c + H_d)}$$

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Where:

E_s = SO2 emission limit, in ng/J or lb/MM Btu heat input;

K_c = 260 ng/J (or 0.60 lb/MMBtu);

K_d = 170 ng/J (or 0.40 lb/MMBtu);

H_c = Heat input from the combustion of coal, in J (MMBtu); and

H_d = Heat input from the combustion of oil, in J (MMBtu).

For facilities complying with the percent reduction standard, only the heat input supplied to the affected facility from the combustion of coal and oil is counted in this paragraph. No credit is provided for the heat input to the affected facility from the combustion of natural gas, wood, municipal-type solid waste, or other fuels, or from the heat input derived from exhaust gases from other sources, such as gas turbines, internal combustion engines, kilns, etc.

(d) On and after the date on which the performance test is completed or required to be completed under §60.8, whichever comes first, no owner or operator of an affected facility that commenced construction, reconstruction, or modification on or before February 28, 2005 and listed in paragraphs (d)(1), (2), (3), or (4) of this section shall cause to be discharged into the atmosphere any gases that

contain SO_2 in excess of 520 ng/J (1.2 lb/MMBtu) heat input if the affected facility combusts coal, or 215 ng/J (0.5 lb/MMBtu) heat input if the affected facility combusts oil other than very low sulfur oil. Percent reduction requirements are not applicable to affected facilities under paragraphs (d)(1), (2), (3) or (4) of this section. For facilities complying with paragraphs (d)(1), (2), or (3) of this section, only the heat input supplied to the affected facility from the combustion of coal and oil is counted in this paragraph. No credit is provided for the heat input to the affected facility from the combustion of natural gas, wood, municipal-type solid waste, or other fuels or heat derived from exhaust gases from other sources, such as gas turbines, internal combustion engines, kilns, etc.

(1) Affected facilities that have an annual capacity factor for coal and oil of 30 percent (0.30) or less and are subject to a federally enforceable permit limiting the operation of the affected facility to an annual capacity factor for coal and oil of 30 percent (0.30) or less;

(2) Affected facilities located in a noncontinental area; or

(3) Affected facilities combusting coal or oil, alone or in combination with any fuel, in a duct burner as part of a combined cycle system where 30 percent (0.30) or less of the heat entering the steam generating unit is from combustion of coal and oil in the duct burner and 70 percent (0.70) or more of the heat entering the steam generating unit is from the exhaust gases entering the duct burner; or

(4) The affected facility burns coke oven gas alone or in combination with natural gas or very low sulfur distillate oil.

(e) Except as provided in paragraph (f) of this section, compliance with the emission limits, fuel oil sulfur limits, and/or percent reduction requirements under this section are determined on a 30-day rolling average basis.

(f) Except as provided in paragraph (j)(2) of this section, compliance with the emission limits or fuel oil sulfur limits under this section is determined on a 24-hour average basis for affected facilities that (1) have a federally enforceable permit limiting the annual capacity factor for oil to 10 percent or less, (2) combust only very low sulfur oil, and (3) do not combust any other fuel.

(g) Except as provided in paragraph (i) of this section and §60.45b(a), the SO_2 emission limits and percent reduction requirements under this section apply at all times, including periods of startup, shutdown, and malfunction.

(h) Reductions in the potential SO_2 emission rate through fuel pretreatment are not credited toward the percent reduction requirement under paragraph (c) of this section unless:

(1) Fuel pretreatment results in a 50 percent or greater reduction in potential SO_2 emissions and

(2) Emissions from the pretreated fuel (without combustion or post-combustion SO_2 control) are equal to or less than the emission limits specified in paragraph (c) of this section.

(i) An affected facility subject to paragraph (a), (b), or (c) of this section may combust very low sulfur oil or natural gas when the SO_2 control system is not being operated because of malfunction or maintenance of the SO_2 control system.

(j) Percent reduction requirements are not applicable to affected facilities combusting only very low sulfur oil. The owner or operator of an affected facility combusting very low sulfur oil shall demonstrate that the oil meets the definition of very low sulfur oil by: (1) Following the performance testing procedures as described in §60.45b(c) or §60.45b(d), and following the monitoring procedures as described in

§60.47b(a) or §60.47b(b) to determine SO_2 emission rate or fuel oil sulfur content; or (2) maintaining fuel records as described in §60.49b(r).

(k)(1) Except as provided in paragraphs (k)(2), (k)(3), and (k)(4) of this section, on and after the date on which the initial performance test is completed or is required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that commences construction, reconstruction, or modification after February 28, 2005, and that combusts coal, oil, natural gas, a mixture of these fuels, or a mixture of these fuels with any other fuels shall cause to be discharged into the atmosphere any gases that contain SO_2 in excess of 87 ng/J (0.20 lb/MMBtu) heat input or 8 percent (0.08) of the potential SO_2 emission rate (92 percent reduction) and 520 ng/J (1.2 lb/MMBtu) heat input. For facilities complying with the percent reduction standard and paragraph (k)(3) of this section, only the heat input supplied to the affected facility from the combustion of coal and oil is counted in paragraph (k) of this section. No credit is provided for the heat input to the affected facility from the combustion of natural gas, wood, municipal-type solid waste, or other fuels or heat derived from exhaust gases from other sources, such as gas turbines, internal combustion engines, kilns, etc.

(2) Units firing only very low sulfur oil, gaseous fuel, a mixture of these fuels, or a mixture of these fuels with any other fuels with a potential SO_2 emission rate of 140 ng/J (0.32 lb/MMBtu) heat input or less are exempt from the SO_2 emissions limit in paragraph (k)(1) of this section.

(3) Units that are located in a noncontinental area and that combust coal, oil, or natural gas shall not discharge any gases that contain SO_2 in excess of 520 ng/J (1.2 lb/MMBtu) heat input if the affected facility combusts coal, or 215 ng/J (0.50 lb/MMBtu) heat input if the affected facility combusts oil or natural gas.

(4) As an alternative to meeting the requirements under paragraph (k)(1) of this section, modified facilities that combust coal or a mixture of coal with other fuels shall not cause to be discharged into the atmosphere any gases that contain SO_2 in excess of 87 ng/J (0.20 lb/MMBtu) heat input or 10 percent (0.10) of the potential SO_2 emission rate (90 percent reduction) and 520 ng/J (1.2 lb/MMBtu) heat input.

[72 FR 32742, June 13, 2007, as amended at 74 FR 5084, Jan. 28, 2009; 76 FR 3523, Jan. 20, 2011]

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§60.43b Standard for particulate matter (PM).

(a) On and after the date on which the initial performance test is completed or is required to be completed under §60.8, whichever comes first, no owner or operator of an affected facility that commenced construction, reconstruction, or modification on or before February 28, 2005 that combusts coal or combusts mixtures of coal with other fuels, shall cause to be discharged into the atmosphere from that affected facility any gases that contain PM in excess of the following emission limits:

(1) 22 ng/J (0.051 lb/MMBtu) heat input, (i) If the affected facility combusts only coal, or

(ii) If the affected facility combusts coal and other fuels and has an annual capacity factor for the other fuels of 10 percent (0.10) or less.

(2) 43 ng/J (0.10 lb/MMBtu) heat input if the affected facility combusts coal and other fuels and has an annual capacity factor for the other fuels greater than 10 percent (0.10) and is subject to a federally enforceable requirement limiting operation of the affected facility to an annual capacity factor greater than 10 percent (0.10) for fuels other than coal.

(3) 86 ng/J (0.20 lb/MMBtu) heat input if the affected facility combusts coal or coal and other fuels and

(i) Has an annual capacity factor for coal or coal and other fuels of 30 percent (0.30) or less,

(ii) Has a maximum heat input capacity of 73 MW (250 MMBtu/hr) or less,

(iii) Has a federally enforceable requirement limiting operation of the affected facility to an annual capacity factor of 30 percent (0.30) or less for coal or coal and other solid fuels, and

(iv) Construction of the affected facility commenced after June 19, 1984, and before November 25, 1986.

(4) An affected facility burning coke oven gas alone or in combination with other fuels not subject to a PM standard under §60.43b and not using a post-combustion technology (except a wet scrubber) for reducing PM or SO_2 emissions is not subject to the PM limits under §60.43b(a).

(b) On and after the date on which the performance test is completed or required to be completed under §60.8, whichever comes first, no owner or operator of an affected facility that commenced construction, reconstruction, or modification on or before February 28, 2005, and that combusts oil (or mixtures of oil with other fuels) and uses a conventional or emerging technology to reduce SO_2 emissions shall cause to be discharged into the atmosphere from that affected facility any gases that contain PM in excess of 43 ng/J (0.10 lb/MMBtu) heat input.

(c) On and after the date on which the initial performance test is completed or is required to be completed under §60.8, whichever comes first, no owner or operator of an affected facility that commenced construction, reconstruction, or modification on or before February 28, 2005, and that combusts wood, or wood with other fuels, except coal, shall cause to be discharged from that affected facility any gases that contain PM in excess of the following emission limits:

(1) 43 ng/J (0.10 lb/MMBtu) heat input if the affected facility has an annual capacity factor greater than 30 percent (0.30) for wood.

(2) 86 ng/J (0.20 lb/MMBtu) heat input if (i) The affected facility has an annual capacity factor of 30 percent (0.30) or less for wood;

(ii) Is subject to a federally enforceable requirement limiting operation of the affected facility to an annual capacity factor of 30 percent (0.30) or less for wood; and

(iii) Has a maximum heat input capacity of 73 MW (250 MMBtu/hr) or less.

(d) On and after the date on which the initial performance test is completed or is required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that combusts municipal-type solid waste or mixtures of municipal-type solid waste with other fuels, shall cause to be discharged into the atmosphere from that affected facility any gases that contain PM in excess of the following emission limits:

(1) 43 ng/J (0.10 lb/MMBtu) heat input;

(i) If the affected facility combusts only municipal-type solid waste; or

(ii) If the affected facility combusts municipal-type solid waste and other fuels and has an annual capacity factor for the other fuels of 10 percent (0.10) or less.

(2) 86 ng/J (0.20 lb/MMBtu) heat input if the affected facility combusts municipal-type solid waste or municipal-type solid waste and other fuels; and

(i) Has an annual capacity factor for municipal-type solid waste and other fuels of 30 percent (0.30) or less;

(ii) Has a maximum heat input capacity of 73 MW (250 MMBtu/hr) or less;

(iii) Has a federally enforceable requirement limiting operation of the affected facility to an annual capacity factor of 30 percent (0.30) or less for municipal-type solid waste, or municipal-type solid waste and other fuels; and

(iv) Construction of the affected facility commenced after June 19, 1984, but on or before November 25, 1986.

(e) For the purposes of this section, the annual capacity factor is determined by dividing the actual heat input to the steam generating unit during the calendar year from the combustion of coal, wood, or municipal-type solid waste, and other fuels, as applicable, by the potential heat input to the steam generating unit if the steam generating unit had been operated for 8,760 hours at the maximum heat input capacity.

(f) On and after the date on which the initial performance test is completed or is required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that combusts coal, oil, wood, or mixtures of these fuels with any other fuels shall cause to be discharged into the atmosphere any gases that exhibit greater than 20 percent opacity (6-minute average), except for one 6-minute period per hour of not more than 27 percent opacity. An owner or operator of an affected facility that elects to install, calibrate, maintain, and operate a continuous emissions monitoring system (CEMS) for measuring PM emissions according to the requirements of this subpart and is subject to a federally enforceable PM limit of 0.030 lb/MMBtu or less is exempt from the opacity standard specified in this paragraph.

CRE will conduct periodic opacity monitoring to ensure compliance with the opacity limits listed in this section.

(g) The PM and opacity standards apply at all times, except during periods of startup, shutdown, or malfunction.

CRE will comply with the PM and opacity standards at all times except during periods of startup, shutdown or malfunction.

(h)(1) Except as provided in paragraphs (h)(2), (h)(3), (h)(4), (h)(5), and (h)(6) of this section, on and after the date on which the initial performance test is completed or is required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that commenced construction, reconstruction, or modification after February 28, 2005, and that combusts coal, oil, wood, a mixture of these fuels, or a mixture of these fuels with any other fuels shall cause to be discharged into the atmosphere from that affected facility any gases that contain PM in excess of 13 ng/J (0.030 lb/MMBtu) heat input,

CRE will comply with the requirements in paragraph (h)(3)

(2) As an alternative to meeting the requirements of paragraph (h)(1) of this section, the owner or operator of an affected facility for which modification commenced after February 28, 2005, may elect to meet the requirements of this paragraph. On and after the date on which the initial performance test is

completed or required to be completed under §60.8, no owner or operator of an affected facility that commences modification after February 28, 2005 shall cause to be discharged into the atmosphere from that affected facility any gases that contain PM in excess of both:

(i) 22 ng/J (0.051 lb/MMBtu) heat input derived from the combustion of coal, oil, wood, a mixture of these fuels, or a mixture of these fuels with any other fuels; and

(ii) 0.2 percent of the combustion concentration (99.8 percent reduction) when combusting coal, oil, wood, a mixture of these fuels, or a mixture of these fuels with any other fuels.

(3) On and after the date on which the initial performance test is completed or is required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that commences modification after February 28, 2005, and that combusts over 30 percent wood (by heat input) on an annual basis and has a maximum heat input capacity of 73 MW (250 MMBtu/h) or less shall cause to be discharged into the atmosphere from that affected facility any gases that contain PM in excess of 43 ng/J (0.10 lb/MMBtu) heat input.

The CRE FBC has a maximum heat input capacity of 200 MMBtu/hr. PM emissions will be controlled by a baghouse; PM emissions from the baghouse will be a maximum of 3.12 lb/hr, which equates to 0.016 lb/MMBtu.

(4) On and after the date on which the initial performance test is completed or is required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that commences modification after February 28, 2005, and that combusts over 30 percent wood (by heat input) on an annual basis and has a maximum heat input capacity greater than 73 MW (250 MMBtu/h) shall cause to be discharged into the atmosphere from that affected facility any gases that contain PM in excess of 37 ng/J (0.085 lb/MMBtu) heat input.

(5) On and after the date on which the initial performance test is completed or is required to be completed under §60.8, whichever date comes first, an owner or operator of an affected facility not located in a noncontinental area that commences construction, reconstruction, or modification after February 28, 2005, and that combusts only oil that contains no more than 0.30 weight percent sulfur, coke oven gas, a mixture of these fuels, or either fuel (or a mixture of these fuels) in combination with other fuels not subject to a PM standard in §60.43b and not using a post-combustion technology (except a wet scrubber) to reduce SO_2 or PM emissions is not subject to the PM limits in (h)(1) of this section.

(6) On and after the date on which the initial performance test is completed or is required to be completed under §60.8, whichever date comes first, an owner or operator of an affected facility located in a noncontinental area that commences construction, reconstruction, or modification after February 28, 2005, and that combusts only oil that contains no more than 0.5 weight percent sulfur, coke oven gas, a mixture of these fuels, or either fuel (or a mixture of these fuels) in combination with other fuels not subject to a PM standard in §60.43b and not using a post-combustion technology (except a wet scrubber) to reduce SO_2 or PM emissions is not subject to the PM limits in (h)(1) of this section.

[72 FR 32742, June 13, 2007, as amended at 74 FR 5084, Jan. 28, 2009; 77 FR 9459, Feb. 16, 2012]

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§60.44b Standard for nitrogen oxides (NO_x).

The CRE FBC does not combust coal or oil, either alone or in combination with any other fuel and does not combust byproduct/waste with either natural gas or oil; therefore there are no requirements under this section.

(a) Except as provided under paragraphs (k) and (l) of this section, on and after the date on which the initial performance test is completed or is required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that is subject to the provisions of this section and that combusts only coal, oil, or natural gas shall cause to be discharged into the atmosphere from that affected facility any gases that contain NO_x (expressed as NO_2) in excess of the following emission limits:

Fuel/steam generating unit type	Nitrogen oxide emission limits (expressed as NO_2) heat input	
	ng/J	lb/MMBTU
(1) Natural gas and distillate oil, except (4):		
(i) Low heat release rate	43	0.10
(ii) High heat release rate	86	0.20
(2) Residual oil:		
(i) Low heat release rate	130	0.30
(ii) High heat release rate	170	0.40
(3) Coal:		
(i) Mass-feed stoker	210	0.50
(ii) Spreader stoker and fluidized bed combustion	260	0.60
(iii) Pulverized coal	300	0.70
(iv) Lignite, except (v)	260	0.60
(v) Lignite mined in North Dakota, South Dakota, or Montana and combusted in a slag tap furnace	340	0.80
(vi) Coal-derived synthetic fuels	210	0.50
(4) Duct burner used in a combined cycle system:		
(i) Natural gas and distillate oil	86	0.20
(ii) Residual oil	170	0.40

(b) Except as provided under paragraphs (k) and (l) of this section, on and after the date on which the initial performance test is completed or is required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that simultaneously combusts mixtures of only coal, oil, or natural gas shall cause to be discharged into the atmosphere from that affected facility any gases that contain NO_x in excess of a limit determined by the use of the following formula:

$$E_n = \frac{(EL_{go}H_{go}) + (EL_{ro}H_{ro}) + (EL_cH_c)}{(H_{go} + H_{ro} + H_c)}$$

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Where:

E_n = NO_x emission limit (expressed as NO_2), ng/J (lb/MMBtu);

EL_{go} = Appropriate emission limit from paragraph (a)(1) for combustion of natural gas or distillate oil, ng/J (lb/MMBtu);

H_{go} = Heat input from combustion of natural gas or distillate oil, J (MMBtu);

EL_{ro} = Appropriate emission limit from paragraph (a)(2) for combustion of residual oil, ng/J (lb/MMBtu);

H_{ro} = Heat input from combustion of residual oil, J (MMBtu);

EL_c = Appropriate emission limit from paragraph (a)(3) for combustion of coal, ng/J (lb/MMBtu); and

H_c = Heat input from combustion of coal, J (MMBtu).

(c) Except as provided under paragraph (d) and (l) of this section, on and after the date on which the initial performance test is completed or is required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that simultaneously combusts coal or oil, natural gas (or any combination of the three), and wood, or any other fuel shall cause to be discharged into the atmosphere any gases that contain NO_x in excess of the emission limit for the coal, oil, natural gas (or any combination of the three), combusted in the affected facility, as determined pursuant to paragraph (a) or (b) of this section. This standard does not apply to an affected facility that is subject to and in compliance with a federally enforceable requirement that limits operation of the affected facility to an annual capacity factor of 10 percent (0.10) or less for coal, oil, natural gas (or any combination of the three).

(d) On and after the date on which the initial performance test is completed or is required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that simultaneously combusts natural gas and/or distillate oil with a potential SO_2 emissions rate of 26 ng/J (0.060 lb/MMBtu) or less with wood, municipal-type solid waste, or other solid fuel, except coal, shall cause to be discharged into the atmosphere from that affected facility any gases that contain NO_x in excess of 130 ng/J (0.30 lb/MMBtu) heat input unless the affected facility has an annual capacity factor for natural gas, distillate oil, or a mixture of these fuels of 10 percent (0.10) or less and is subject to a federally enforceable requirement that limits operation of the affected facility to an annual capacity factor of 10 percent (0.10) or less for natural gas, distillate oil, or a mixture of these fuels.

(e) Except as provided under paragraph (l) of this section, on and after the date on which the initial performance test is completed or is required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that simultaneously combusts only coal, oil, or natural gas with byproduct/waste shall cause to be discharged into the atmosphere any gases that contain NO_x in excess of the emission limit determined by the following formula unless the affected facility has an annual capacity factor for coal, oil, and natural gas of 10 percent (0.10) or less and is subject to a federally enforceable requirement that limits operation of the affected facility to an annual capacity factor of 10 percent (0.10) or less:

(f) Any owner or operator of an affected facility that combusts byproduct/waste with either natural gas or oil may petition the Administrator within 180 days of the initial startup of the affected facility to establish a NO_x emission limit that shall apply specifically to that affected facility when the byproduct/waste is combusted. The petition shall include sufficient and appropriate data, as determined

by the Administrator, such as NO_x emissions from the affected facility, waste composition (including nitrogen content), and combustion conditions to allow the Administrator to confirm that the affected facility is unable to comply with the emission limits in paragraph (e) of this section and to determine the appropriate emission limit for the affected facility.

(1) Any owner or operator of an affected facility petitioning for a facility-specific NO_x emission limit under this section shall:

(i) Demonstrate compliance with the emission limits for natural gas and distillate oil in paragraph (a)(1) of this section or for residual oil in paragraph (a)(2) or (l)(1) of this section, as appropriate, by conducting a 30-day performance test as provided in §60.46b(e). During the performance test only natural gas, distillate oil, or residual oil shall be combusted in the affected facility; and

(ii) Demonstrate that the affected facility is unable to comply with the emission limits for natural gas and distillate oil in paragraph (a)(1) of this section or for residual oil in paragraph (a)(2) or (l)(1) of this section, as appropriate, when gaseous or liquid byproduct/waste is combusted in the affected facility under the same conditions and using the same technological system of emission reduction applied when demonstrating compliance under paragraph (f)(1)(i) of this section.

(2) The NO_x emission limits for natural gas or distillate oil in paragraph (a)(1) of this section or for residual oil in paragraph (a)(2) or (l)(1) of this section, as appropriate, shall be applicable to the affected facility until and unless the petition is approved by the Administrator. If the petition is approved by the Administrator, a facility-specific NO_x emission limit will be established at the NO_x emission level achievable when the affected facility is combusting oil or natural gas and byproduct/waste in a manner that the Administrator determines to be consistent with minimizing NO_x emissions. In lieu of amending this subpart, a letter will be sent to the facility describing the facility-specific NO_x limit. The facility shall use the compliance procedures detailed in the letter and make the letter available to the public. If the Administrator determines it is appropriate, the conditions and requirements of the letter can be reviewed and changed at any point.

(g) Any owner or operator of an affected facility that combusts hazardous waste (as defined by 40 CFR part 261 or 40 CFR part 761) with natural gas or oil may petition the Administrator within 180 days of the initial startup of the affected facility for a waiver from compliance with the NO_x emission limit that applies specifically to that affected facility. The petition must include sufficient and appropriate data, as determined by the Administrator, on NO_x emissions from the affected facility, waste destruction efficiencies, waste composition (including nitrogen content), the quantity of specific wastes to be combusted and combustion conditions to allow the Administrator to determine if the affected facility is able to comply with the NO_x emission limits required by this section. The owner or operator of the affected facility shall demonstrate that when hazardous waste is combusted in the affected facility, thermal destruction efficiency requirements for hazardous waste specified in an applicable federally enforceable requirement preclude compliance with the NO_x emission limits of this section. The NO_x emission limits for natural gas or distillate oil in paragraph (a)(1) of this section or for residual oil in paragraph (a)(2) or (l)(1) of this section, as appropriate, are applicable to the affected facility until and unless the petition is approved by the Administrator. (See 40 CFR 761.70 for regulations applicable to the incineration of materials containing polychlorinated biphenyls (PCB's).) In lieu of amending this subpart, a letter will be sent to the facility describing the facility-specific NO_x limit. The facility shall use the compliance procedures detailed in the letter and make the letter available to the public. If the Administrator determines it is appropriate, the conditions and requirements of the letter can be reviewed and changed at any point.

(h) For purposes of paragraph (i) of this section, the NO_x standards under this section apply at all times including periods of startup, shutdown, or malfunction.

(i) Except as provided under paragraph (j) of this section, compliance with the emission limits under this section is determined on a 30-day rolling average basis.

(j) Compliance with the emission limits under this section is determined on a 24-hour average basis for the initial performance test and on a 3-hour average basis for subsequent performance tests for any affected facilities that:

(1) Combust, alone or in combination, only natural gas, distillate oil, or residual oil with a nitrogen content of 0.30 weight percent or less;

(2) Have a combined annual capacity factor of 10 percent or less for natural gas, distillate oil, and residual oil with a nitrogen content of 0.30 weight percent or less; and

(3) Are subject to a federally enforceable requirement limiting operation of the affected facility to the firing of natural gas, distillate oil, and/or residual oil with a nitrogen content of 0.30 weight percent or less and limiting operation of the affected facility to a combined annual capacity factor of 10 percent or less for natural gas, distillate oil, and residual oil with a nitrogen content of 0.30 weight percent or less.

(k) Affected facilities that meet the criteria described in paragraphs (j)(1), (2), and (3) of this section, and that have a heat input capacity of 73 MW (250 MMBtu/hr) or less, are not subject to the NO_x emission limits under this section.

(l) On and after the date on which the initial performance test is completed or is required to be completed under 60.8, whichever date is first, no owner or operator of an affected facility that commenced construction after July 9, 1997 shall cause to be discharged into the atmosphere from that affected facility any gases that contain NOx (expressed as NO2) in excess of the following limits:

(1) 86 ng/J (0.20 lb/MMBtu) heat input if the affected facility combusts coal, oil, or natural gas (or any combination of the three), alone or with any other fuels. The affected facility is not subject to this limit if it is subject to and in compliance with a federally enforceable requirement that limits operation of the facility to an annual capacity factor of 10 percent (0.10) or less for coal, oil, and natural gas (or any combination of the three); or

(2) If the affected facility has a low heat release rate and combusts natural gas or distillate oil in excess of 30 percent of the heat input on a 30-day rolling average from the combustion of all fuels, a limit determined by use of the following formula:

$$E_n = \frac{(0.10 \times H_{go}) + (0.20 \times H_r)}{(H_{go} + H_r)}$$

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Where:

E_n = NO_x emission limit, (lb/MMBtu);

H_{go} = 30-day heat input from combustion of natural gas or distillate oil; and

H_r = 30-day heat input from combustion of any other fuel.

(3) After February 27, 2006, units where more than 10 percent of total annual output is electrical or mechanical may comply with an optional limit of 270 ng/J (2.1 lb/MWh) gross energy output, based on a 30-day rolling average. Units complying with this output-based limit must demonstrate compliance

according to the procedures of §60.48Da(i) of subpart Da of this part, and must monitor emissions according to §60.49Da(c), (k), through (n) of subpart Da of this part.

[72 FR 32742, June 13, 2007, as amended at 74 FR 5086, Jan. 28, 2009; 77 FR 9459, Feb. 16, 2012]

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§60.45b Compliance and performance test methods and procedures for sulfur dioxide.

The CRE facility is not subject to SO2 emissions standards listed in this subpart.

(a) The SO_2 emission standards in §60.42b apply at all times. Facilities burning coke oven gas alone or in combination with any other gaseous fuels or distillate oil are allowed to exceed the limit 30 operating days per calendar year for SO_2 control system maintenance.

(b) In conducting the performance tests required under §60.8, the owner or operator shall use the methods and procedures in appendix A (including fuel certification and sampling) of this part or the methods and procedures as specified in this section, except as provided in §60.8(b). Section 60.8(f) does not apply to this section. The 30-day notice required in §60.8(d) applies only to the initial performance test unless otherwise specified by the Administrator.

(c) The owner or operator of an affected facility shall conduct performance tests to determine compliance with the percent of potential SO_2 emission rate (% P_s) and the SO_2 emission rate (E_s) pursuant to §60.42b following the procedures listed below, except as provided under paragraph (d) and (k) of this section.

(1) The initial performance test shall be conducted over 30 consecutive operating days of the steam generating unit. Compliance with the SO_2 standards shall be determined using a 30-day average. The first operating day included in the initial performance test shall be scheduled within 30 days after achieving the maximum production rate at which the affected facility will be operated, but not later than 180 days after initial startup of the facility.

(2) If only coal, only oil, or a mixture of coal and oil is combusted, the following procedures are used:

(i) The procedures in Method 19 of appendix A-7 of this part are used to determine the hourly SO_2 emission rate (E_{ho}) and the 30-day average emission rate (E_{ao}). The hourly averages used to compute the 30-day averages are obtained from the CEMS of §60.47b(a) or (b).

(ii) The percent of potential SO_2 emission rate (%P_s) emitted to the atmosphere is computed using the following formula:

$$\%P_s = 100\left(1 - \frac{\%R_g}{100}\right)\left(1 - \frac{\%R_f}{100}\right)$$

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Where:

%P_s = Potential SO_2 emission rate, percent;

%R_g = SO_2 removal efficiency of the control device as determined by Method 19 of appendix A of this part, in percent; and

$\%R_f$ = SO_2 removal efficiency of fuel pretreatment as determined by Method 19 of appendix A of this part, in percent.

(3) If coal or oil is combusted with other fuels, the same procedures required in paragraph (c)(2) of this section are used, except as provided in the following:

(i) An adjusted hourly SO_2 emission rate ($E_{ho}°$) is used in Equation 19-19 of Method 19 of appendix A of this part to compute an adjusted 30-day average emission rate ($E_{ao}°$). The Eho° is computed using the following formula:

$$E_{ho}^{\circ} = \frac{E_{ho} - E_w(1 - X_k)}{X_k}$$

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Where:

$E_{ho}°$ = Adjusted hourly SO_2 emission rate, ng/J (lb/MMBtu);

E_{ho} = Hourly SO_2 emission rate, ng/J (lb/MMBtu);

E_w = SO_2 concentration in fuels other than coal and oil combusted in the affected facility, as determined by the fuel sampling and analysis procedures in Method 19 of appendix A of this part, ng/J (lb/MMBtu). The value E_w for each fuel lot is used for each hourly average during the time that the lot is being combusted; and

X_k = Fraction of total heat input from fuel combustion derived from coal, oil, or coal and oil, as determined by applicable procedures in Method 19 of appendix A of this part.

(ii) To compute the percent of potential SO_2 emission rate ($\%P_s$), an adjusted $\%R_g$ ($\%R_g°$) is computed from the adjusted $E_{ao}°$ from paragraph (b)(3)(i) of this section and an adjusted average SO_2 inlet rate ($E_{ai}°$) using the following formula:

$$\%R_g^{\circ} = 100\left(1.0 - \frac{E_{ao}^{\circ}}{E_{ai}^{\circ}}\right)$$

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To compute $E_{ai}°$, an adjusted hourly SO_2 inlet rate ($E_{hi}°$) is used. The $E_{hi}°$ is computed using the following formula:

$$E_{hi}^{\circ} = \frac{E_{hi} - E_w(1 - X_k)}{X_k}$$

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Where:

$E_{hi}°$ = Adjusted hourly SO_2 inlet rate, ng/J (lb/MMBtu); and

E_{hi} = Hourly SO_2 inlet rate, ng/J (lb/MMBtu).

(4) The owner or operator of an affected facility subject to paragraph (c)(3) of this section does not have to measure parameters E_w or X_k if the owner or operator elects to assume that X_k = 1.0. Owners or operators of affected facilities who assume X_k = 1.0 shall:

(i) Determine $\%P_s$ following the procedures in paragraph (c)(2) of this section; and

(ii) Sulfur dioxide emissions (E_s) are considered to be in compliance with SO_2 emission limits under §60.42b.

(5) The owner or operator of an affected facility that qualifies under the provisions of §60.42b(d) does not have to measure parameters E_w or X_k in paragraph (c)(3) of this section if the owner or operator of the affected facility elects to measure SO_2 emission rates of the coal or oil following the fuel sampling and analysis procedures in Method 19 of appendix A-7 of this part.

(d) Except as provided in paragraph (j) of this section, the owner or operator of an affected facility that combusts only very low sulfur oil, natural gas, or a mixture of these fuels, has an annual capacity factor for oil of 10 percent (0.10) or less, and is subject to a federally enforceable requirement limiting operation of the affected facility to an annual capacity factor for oil of 10 percent (0.10) or less shall:

(1) Conduct the initial performance test over 24 consecutive steam generating unit operating hours at full load;

(2) Determine compliance with the standards after the initial performance test based on the arithmetic average of the hourly emissions data during each steam generating unit operating day if a CEMS is used, or based on a daily average if Method 6B of appendix A of this part or fuel sampling and analysis procedures under Method 19 of appendix A of this part are used.

(e) The owner or operator of an affected facility subject to §60.42b(d)(1) shall demonstrate the maximum design capacity of the steam generating unit by operating the facility at maximum capacity for 24 hours. This demonstration will be made during the initial performance test and a subsequent demonstration may be requested at any other time. If the 24-hour average firing rate for the affected facility is less than the maximum design capacity provided by the manufacturer of the affected facility, the 24-hour average firing rate shall be used to determine the capacity utilization rate for the affected facility, otherwise the maximum design capacity provided by the manufacturer is used.

(f) For the initial performance test required under §60.8, compliance with the SO_2 emission limits and percent reduction requirements under §60.42b is based on the average emission rates and the average percent reduction for $SO_2$for the first 30 consecutive steam generating unit operating days, except as provided under paragraph (d) of this section. The initial performance test is the only test for which at least 30 days prior notice is required unless otherwise specified by the Administrator. The initial performance test is to be scheduled so that the first steam generating unit operating day of the 30 successive steam generating unit operating days is completed within 30 days after achieving the maximum production rate at which the affected facility will be operated, but not later than 180 days after initial startup of the facility. The boiler load during the 30-day period does not have to be the maximum design load, but must be representative of future operating conditions and include at least one 24-hour period at full load.

(g) After the initial performance test required under §60.8, compliance with the SO_2 emission limits and percent reduction requirements under §60.42b is based on the average emission rates and the average percent reduction for $SO_2$for 30 successive steam generating unit operating days, except as provided under paragraph (d). A separate performance test is completed at the end of each steam generating unit operating day after the initial performance test, and a new 30-day average emission rate and percent reduction for SO_2 are calculated to show compliance with the standard.

(h) Except as provided under paragraph (i) of this section, the owner or operator of an affected facility shall use all valid SO_2 emissions data in calculating $\%P_s$ and E_{ho} under paragraph (c), of this section whether or not the minimum emissions data requirements under §60.46b are achieved. All valid

emissions data, including valid SO_2 emission data collected during periods of startup, shutdown and malfunction, shall be used in calculating $\%P_s$ and E_{ho} pursuant to paragraph (c) of this section.

(i) During periods of malfunction or maintenance of the SO_2 control systems when oil is combusted as provided under §60.42b(i), emission data are not used to calculate $\%P_s$ or E_s under §60.42b(a), (b) or (c), however, the emissions data are used to determine compliance with the emission limit under §60.42b(i).

(j) The owner or operator of an affected facility that only combusts very low sulfur oil, natural gas, or a mixture of these fuels with any other fuels not subject to an SO_2 standard is not subject to the compliance and performance testing requirements of this section if the owner or operator obtains fuel receipts as described in §60.49b(r).

(k) The owner or operator of an affected facility seeking to demonstrate compliance in §§60.42b(d)(4), 60.42b(j), 60.42b(k)(2), and 60.42b(k)(3) (when not burning coal) shall follow the applicable procedures in §60.49b(r).

[72 FR 32742, June 13, 2007, as amended at 74 FR 5086, Jan. 28, 2009]

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§60.46b Compliance and performance test methods and procedures for particulate matter and nitrogen oxides.

(a) The PM emission standards and opacity limits under §60.43b apply at all times except during periods of startup, shutdown, or malfunction. The NO_x emission standards under §60.44b apply at all times.

CRE will comply with the PM emission standards and opacity limits under 60.43b at all times except during startup, shutdown and malfunction. The facility is not subject to NOx emission standards listed in this subpart.

(b) Compliance with the PM emission standards under §60.43b shall be determined through performance testing as described in paragraph (d) of this section, except as provided in paragraph (i) of this section.

(c) Compliance with the NO_x emission standards under §60.44b shall be determined through performance testing under paragraph (e) or (f), or under paragraphs (g) and (h) of this section, as applicable.

(d) To determine compliance with the PM emission limits and opacity limits under §60.43b, the owner or operator of an affected facility shall conduct an initial performance test as required under §60.8, and shall conduct subsequent performance tests as requested by the Administrator, using the following procedures and reference methods:

CRE will conduct initial and subsequent performance tests using Method 5. The exhaust temperature from the FBC baghouse will be approximately 350 F, therefore Method 17 is not an appropriate method. The baghouse is not equipped with a wet FGD system, therefore Method 5B will not be used. Method 9 will be used to determine stack opacity.

(1) Method 3A or 3B of appendix A-2 of this part is used for gas analysis when applying Method 5 of appendix A-3 of this part or Method 17 of appendix A-6 of this part.

(2) Method 5, 5B, or 17 of appendix A of this part shall be used to measure the concentration of PM as follows:

(i) Method 5 of appendix A of this part shall be used at affected facilities without wet flue gas desulfurization (FGD) systems; and

(ii) Method 17 of appendix A-6 of this part may be used at facilities with or without wet scrubber systems provided the stack gas temperature does not exceed a temperature of 160 °C (320 °F). The procedures of sections 8.1 and 11.1 of Method 5B of appendix A-3 of this part may be used in Method 17 of appendix A-6 of this part only if it is used after a wet FGD system. Do not use Method 17 of appendix A-6 of this part after wet FGD systems if the effluent is saturated or laden with water droplets.

(iii) Method 5B of appendix A of this part is to be used only after wet FGD systems.

(3) Method 1 of appendix A of this part is used to select the sampling site and the number of traverse sampling points. The sampling time for each run is at least 120 minutes and the minimum sampling volume is 1.7 dscm (60 dscf) except that smaller sampling times or volumes may be approved by the Administrator when necessitated by process variables or other factors.

(4) For Method 5 of appendix A of this part, the temperature of the sample gas in the probe and filter holder is monitored and is maintained at 160±14 °C (320±25 °F).

(5) For determination of PM emissions, the oxygen (O_2) or CO_2 sample is obtained simultaneously with each run of Method 5, 5B, or 17 of appendix A of this part by traversing the duct at the same sampling location.

(6) For each run using Method 5, 5B, or 17 of appendix A of this part, the emission rate expressed in ng/J heat input is determined using:

(i) The O_2 or CO_2 measurements and PM measurements obtained under this section;

(ii) The dry basis F factor; and

(iii) The dry basis emission rate calculation procedure contained in Method 19 of appendix A of this part.

(7) Method 9 of appendix A of this part is used for determining the opacity of stack emissions.

(e) To determine compliance with the emission limits for NO_x required under §60.44b, the owner or operator of an affected facility shall conduct the performance test as required under §60.8 using the continuous system for monitoring NO_x under §60.48(b).

(1) For the initial compliance test, NO_x from the steam generating unit are monitored for 30 successive steam generating unit operating days and the 30-day average emission rate is used to determine compliance with the NO_xemission standards under §60.44b. The 30-day average emission rate is calculated as the average of all hourly emissions data recorded by the monitoring system during the 30-day test period.

(2) Following the date on which the initial performance test is completed or is required to be completed in §60.8, whichever date comes first, the owner or operator of an affected facility which combusts coal (except as specified under §60.46b(e)(4)) or which combusts residual oil having a nitrogen content greater than 0.30 weight percent shall determine compliance with the NO_x emission standards in §60.44b on a continuous basis through the use of a 30-day rolling average emission rate. A new 30-day

rolling average emission rate is calculated for each steam generating unit operating day as the average of all of the hourly NO_x emission data for the preceding 30 steam generating unit operating days.

(3) Following the date on which the initial performance test is completed or is required to be completed under §60.8, whichever date comes first, the owner or operator of an affected facility that has a heat input capacity greater than 73 MW (250 MMBtu/hr) and that combusts natural gas, distillate oil, or residual oil having a nitrogen content of 0.30 weight percent or less shall determine compliance with the NO_x standards under §60.44b on a continuous basis through the use of a 30-day rolling average emission rate. A new 30-day rolling average emission rate is calculated each steam generating unit operating day as the average of all of the hourly NO_x emission data for the preceding 30 steam generating unit operating days.

(4) Following the date on which the initial performance test is completed or required to be completed under §60.8, whichever date comes first, the owner or operator of an affected facility that has a heat input capacity of 73 MW (250 MMBtu/hr) or less and that combusts natural gas, distillate oil, gasified coal, or residual oil having a nitrogen content of 0.30 weight percent or less shall upon request determine compliance with the NO_x standards in §60.44b through the use of a 30-day performance test. During periods when performance tests are not requested, NO_x emissions data collected pursuant to §60.48b(g)(1) or §60.48b(g)(2) are used to calculate a 30-day rolling average emission rate on a daily basis and used to prepare excess emission reports, but will not be used to determine compliance with the NO_x emission standards. A new 30-day rolling average emission rate is calculated each steam generating unit operating day as the average of all of the hourly NO_x emission data for the preceding 30 steam generating unit operating days.

(5) If the owner or operator of an affected facility that combusts residual oil does not sample and analyze the residual oil for nitrogen content, as specified in §60.49b(e), the requirements of §60.48b(g)(1) apply and the provisions of §60.48b(g)(2) are inapplicable.

(f) To determine compliance with the emissions limits for NO_x required by §60.44b(a)(4) or §60.44b(l) for duct burners used in combined cycle systems, either of the procedures described in paragraph (f)(1) or (2) of this section may be used:

(1) The owner or operator of an affected facility shall conduct the performance test required under §60.8 as follows:

(i) The emissions rate (E) of NO_x shall be computed using Equation 1 in this section:

$$E = E_{sg} + \left(\frac{H_g}{H_b}\right)\left(E_{sg} - E_g\right) \qquad \text{(Eq.1)}$$

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Where:

E = Emissions rate of NO_x from the duct burner, ng/J (lb/MMBtu) heat input;

E_{sg} = Combined effluent emissions rate, in ng/J (lb/MMBtu) heat input using appropriate F factor as described in Method 19 of appendix A of this part;

H_g = Heat input rate to the combustion turbine, in J/hr (MMBtu/hr);

H_b = Heat input rate to the duct burner, in J/hr (MMBtu/hr); and

E_a = Emissions rate from the combustion turbine, in ng/J (lb/MMBtu) heat input calculated using appropriate F factor as described in Method 19 of appendix A of this part.

(ii) Method 7E of appendix A of this part or Method 320 of appendix A of part 63 shall be used to determine the NO_x concentrations. Method 3A or 3B of appendix A of this part shall be used to determine O_2 concentration.

(iii) The owner or operator shall identify and demonstrate to the Administrator's satisfaction suitable methods to determine the average hourly heat input rate to the combustion turbine and the average hourly heat input rate to the affected duct burner.

(iv) Compliance with the emissions limits under §60.44b(a)(4) or §60.44b(l) is determined by the three-run average (nominal 1-hour runs) for the initial and subsequent performance tests; or

(2) The owner or operator of an affected facility may elect to determine compliance on a 30-day rolling average basis by using the CEMS specified under §60.48b for measuring NO_x and O_2 and meet the requirements of §60.48b. The sampling site shall be located at the outlet from the steam generating unit. The NO_x emissions rate at the outlet from the steam generating unit shall constitute the NO_x emissions rate from the duct burner of the combined cycle system.

(g) The owner or operator of an affected facility described in §60.44b(j) or §60.44b(k) shall demonstrate the maximum heat input capacity of the steam generating unit by operating the facility at maximum capacity for 24 hours. The owner or operator of an affected facility shall determine the maximum heat input capacity using the heat loss method or the heat input method described in sections 5 and 7.3 of the ASME *Power Test Codes* 4.1 (incorporated by reference, see §60.17). This demonstration of maximum heat input capacity shall be made during the initial performance test for affected facilities that meet the criteria of §60.44b(j). It shall be made within 60 days after achieving the maximum production rate at which the affected facility will be operated, but not later than 180 days after initial start-up of each facility, for affected facilities meeting the criteria of §60.44b(k). Subsequent demonstrations may be required by the Administrator at any other time. If this demonstration indicates that the maximum heat input capacity of the affected facility is less than that stated by the manufacturer of the affected facility, the maximum heat input capacity determined during this demonstration shall be used to determine the capacity utilization rate for the affected facility. Otherwise, the maximum heat input capacity provided by the manufacturer is used.

(h) The owner or operator of an affected facility described in §60.44b(j) that has a heat input capacity greater than 73 MW (250 MMBtu/hr) shall:

(1) Conduct an initial performance test as required under §60.8 over a minimum of 24 consecutive steam generating unit operating hours at maximum heat input capacity to demonstrate compliance with the NO_x emission standards under §60.44b using Method 7, 7A, or 7E of appendix A of this part, Method 320 of appendix A of part 63 of this chapter, or other approved reference methods; and

(2) Conduct subsequent performance tests once per calendar year or every 400 hours of operation (whichever comes first) to demonstrate compliance with the NO_x emission standards under §60.44b over a minimum of 3 consecutive steam generating unit operating hours at maximum heat input capacity using Method 7, 7A, or 7E of appendix A of this part, Method 320 of appendix A of part 63, or other approved reference methods.

(i) The owner or operator of an affected facility seeking to demonstrate compliance with the PM limit in paragraphs §60.43b(a)(4) or §60.43b(h)(5) shall follow the applicable procedures in §60.49b(r).

(j) In place of PM testing with Method 5 or 5B of appendix A-3 of this part, or Method 17 of appendix A-6 of this part, an owner or operator may elect to install, calibrate, maintain, and operate a CEMS for

monitoring PM emissions discharged to the atmosphere and record the output of the system. The owner or operator of an affected facility who elects to continuously monitor PM emissions instead of conducting performance testing using Method 5 or 5B of appendix A-3 of this part or Method 17 of appendix A-6 of this part shall comply with the requirements specified in paragraphs (j)(1) through (j)(14) of this section.

(1) Notify the Administrator one month before starting use of the system.

(2) Notify the Administrator one month before stopping use of the system.

(3) The monitor shall be installed, evaluated, and operated in accordance with §60.13 of subpart A of this part.

(4) The initial performance evaluation shall be completed no later than 180 days after the date of initial startup of the affected facility, as specified under §60.8 of subpart A of this part or within 180 days of notification to the Administrator of use of the CEMS if the owner or operator was previously determining compliance by Method 5, 5B, or 17 of appendix A of this part performance tests, whichever is later.

(5) The owner or operator of an affected facility shall conduct an initial performance test for PM emissions as required under §60.8 of subpart A of this part. Compliance with the PM emission limit shall be determined by using the CEMS specified in paragraph (j) of this section to measure PM and calculating a 24-hour block arithmetic average emission concentration using EPA Reference Method 19 of appendix A of this part, section 4.1.

(6) Compliance with the PM emission limit shall be determined based on the 24-hour daily (block) average of the hourly arithmetic average emission concentrations using CEMS outlet data.

(7) At a minimum, valid CEMS hourly averages shall be obtained as specified in paragraphs (j)(7)(i) of this section for 75 percent of the total operating hours per 30-day rolling average.

(i) At least two data points per hour shall be used to calculate each 1-hour arithmetic average.

(ii) [Reserved]

(8) The 1-hour arithmetic averages required under paragraph (j)(7) of this section shall be expressed in ng/J or lb/MMBtu heat input and shall be used to calculate the boiler operating day daily arithmetic average emission concentrations. The 1-hour arithmetic averages shall be calculated using the data points required under §60.13(e)(2) of subpart A of this part.

(9) All valid CEMS data shall be used in calculating average emission concentrations even if the minimum CEMS data requirements of paragraph (j)(7) of this section are not met.

(10) The CEMS shall be operated according to Performance Specification 11 in appendix B of this part.

(11) During the correlation testing runs of the CEMS required by Performance Specification 11 in appendix B of this part, PM and O_2 (or CO_2) data shall be collected concurrently (or within a 30-to 60-minute period) by both the continuous emission monitors and performance tests conducted using the following test methods.

(i) For PM, Method 5 or 5B of appendix A-3 of this part or Method 17 of appendix A-6 of this part shall be used; and

(ii) For O_2 (or CO_2), Method 3A or 3B of appendix A-2 of this part, as applicable shall be used.

(12) Quarterly accuracy determinations and daily calibration drift tests shall be performed in accordance with procedure 2 in appendix F of this part. Relative Response Audit's must be performed annually and Response Correlation Audits must be performed every 3 years.

(13) When PM emissions data are not obtained because of CEMS breakdowns, repairs, calibration checks, and zero and span adjustments, emissions data shall be obtained by using other monitoring systems as approved by the Administrator or EPA Reference Method 19 of appendix A of this part to provide, as necessary, valid emissions data for a minimum of 75 percent of total operating hours per 30-day rolling average.

(14) As of January 1, 2012, and within 90 days after the date of completing each performance test, as defined in §60.8, conducted to demonstrate compliance with this subpart, you must submit relative accuracy test audit (*i.e.,* reference method) data and performance test (*i.e.,* compliance test) data, except opacity data, electronically to EPA's Central Data Exchange (CDX) by using the Electronic Reporting Tool (ERT) (see *http://www.epa.gov/ttn/chief/ert/ert_tool.html/*) or other compatible electronic spreadsheet. Only data collected using test methods compatible with ERT are subject to this requirement to be submitted electronically into EPA's WebFIRE database.

[72 FR 32742, June 13, 2007, as amended at 74 FR 5086, Jan. 28, 2009; 76 FR 3523, Jan. 20, 2011; 77 FR 9460, Feb. 16, 2012; 79 FR 11249, Feb. 27, 2014]

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§60.47b Emission monitoring for sulfur dioxide.

The CRE facility is not subject to SO2 emissions standards listed in this subpart.

(a) Except as provided in paragraphs (b) and (f) of this section, the owner or operator of an affected facility subject to the SO_2 standards in §60.42b shall install, calibrate, maintain, and operate CEMS for measuring SO_2 concentrations and either O_2 or CO_2 concentrations and shall record the output of the systems. For units complying with the percent reduction standard, the SO_2 and either O_2 or CO_2 concentrations shall both be monitored at the inlet and outlet of the SO_2 control device. If the owner or operator has installed and certified SO_2 and O_2 or CO_2 CEMS according to the requirements of §75.20(c)(1) of this chapter and appendix A to part 75 of this chapter, and is continuing to meet the ongoing quality assurance requirements of §75.21 of this chapter and appendix B to part 75 of this chapter, those CEMS may be used to meet the requirements of this section, provided that:

(1) When relative accuracy testing is conducted, SO_2 concentration data and CO_2 (or O_2) data are collected simultaneously; and

(2) In addition to meeting the applicable SO_2 and CO_2 (or O_2) relative accuracy specifications in Figure 2 of appendix B to part 75 of this chapter, the relative accuracy (RA) standard in section 13.2 of Performance Specification 2 in appendix B to this part is met when the RA is calculated on a lb/MMBtu basis; and

(3) The reporting requirements of §60.49b are met. SO_2 and CO_2 (or O_2) data used to meet the requirements of §60.49b shall not include substitute data values derived from the missing data procedures in subpart D of part 75 of this chapter, nor shall the SO_2 data have been bias adjusted according to the procedures of part 75 of this chapter.

(b) As an alternative to operating CEMS as required under paragraph (a) of this section, an owner or operator may elect to determine the average SO_2 emissions and percent reduction by:

(1) Collecting coal or oil samples in an as-fired condition at the inlet to the steam generating unit and analyzing them for sulfur and heat content according to Method 19 of appendix A of this part. Method 19 of appendix A of this part provides procedures for converting these measurements into the format to be used in calculating the average SO_2 input rate, or

(2) Measuring SO_2 according to Method 6B of appendix A of this part at the inlet or outlet to the SO_2 control system. An initial stratification test is required to verify the adequacy of the sampling location for Method 6B of appendix A of this part. The stratification test shall consist of three paired runs of a suitable SO_2 and CO_2 measurement train operated at the candidate location and a second similar train operated according to the procedures in Section 3.2 and the applicable procedures in Section 7 of Performance Specification 2. Method 6B of appendix A of this part, Method 6A of appendix A of this part, or a combination of Methods 6 and 3 or 3B of appendix A of this part or Methods 6C or Method 320 of appendix A of part 63 of this chapter and 3A of appendix A of this part are suitable measurement techniques. If Method 6B of appendix A of this part is used for the second train, sampling time and timer operation may be adjusted for the stratification test as long as an adequate sample volume is collected; however, both sampling trains are to be operated similarly. For the location to be adequate for Method 6B of appendix A of this part, 24-hour tests, the mean of the absolute difference between the three paired runs must be less than 10 percent.

(3) A daily SO_2 emission rate, E_D, shall be determined using the procedure described in Method 6A of appendix A of this part, section 7.6.2 (Equation 6A-8) and stated in ng/J (lb/MMBtu) heat input.

(4) The mean 30-day emission rate is calculated using the daily measured values in ng/J (lb/MMBtu) for 30 successive steam generating unit operating days using equation 19-20 of Method 19 of appendix A of this part.

(c) The owner or operator of an affected facility shall obtain emission data for at least 75 percent of the operating hours in at least 22 out of 30 successive boiler operating days. If this minimum data requirement is not met with a single monitoring system, the owner or operator of the affected facility shall supplement the emission data with data collected with other monitoring systems as approved by the Administrator or the reference methods and procedures as described in paragraph (b) of this section.

(d) The 1-hour average SO_2 emission rates measured by the CEMS required by paragraph (a) of this section and required under §60.13(h) is expressed in ng/J or lb/MMBtu heat input and is used to calculate the average emission rates under §60.42(b). Each 1-hour average SO_2 emission rate must be based on 30 or more minutes of steam generating unit operation. The hourly averages shall be calculated according to §60.13(h)(2). Hourly SO_2 emission rates are not calculated if the affected facility is operated less than 30 minutes in a given clock hour and are not counted toward determination of a steam generating unit operating day.

(e) The procedures under §60.13 shall be followed for installation, evaluation, and operation of the CEMS.

(1) Except as provided for in paragraph (e)(4) of this section, all CEMS shall be operated in accordance with the applicable procedures under Performance Specifications 1, 2, and 3 of appendix B of this part.

(2) Except as provided for in paragraph (e)(4) of this section, quarterly accuracy determinations and daily calibration drift tests shall be performed in accordance with Procedure 1 of appendix F of this part.

(3) For affected facilities combusting coal or oil, alone or in combination with other fuels, the span value of the SO_2CEMS at the inlet to the SO_2 control device is 125 percent of the maximum estimated hourly potential SO_2 emissions of the fuel combusted, and the span value of the CEMS at the outlet to the SO_2 control device is 50 percent of the maximum estimated hourly potential SO_2 emissions of the fuel

combusted. Alternatively, SO_2 span values determined according to section 2.1.1 in appendix A to part 75 of this chapter may be used.

(4) As an alternative to meeting the requirements of requirements of paragraphs (e)(1) and (e)(2) of this section, the owner or operator may elect to implement the following alternative data accuracy assessment procedures:

(i) For all required CO_2 and O_2 monitors and for SO_2 and NO_x monitors with span values greater than or equal to 100 ppm, the daily calibration error test and calibration adjustment procedures described in sections 2.1.1 and 2.1.3 of appendix B to part 75 of this chapter may be followed instead of the CD assessment procedures in Procedure 1, section 4.1 of appendix F to this part.

(ii) For all required CO_2 and O_2 monitors and for SO_2 and NO_x monitors with span values greater than 30 ppm, quarterly linearity checks may be performed in accordance with section 2.2.1 of appendix B to part 75 of this chapter, instead of performing the cylinder gas audits (CGAs) described in Procedure 1, section 5.1.2 of appendix F to this part. If this option is selected: The frequency of the linearity checks shall be as specified in section 2.2.1 of appendix B to part 75 of this chapter; the applicable linearity specifications in section 3.2 of appendix A to part 75 of this chapter shall be met; the data validation and out-of-control criteria in section 2.2.3 of appendix B to part 75 of this chapter shall be followed instead of the excessive audit inaccuracy and out-of-control criteria in Procedure 1, section 5.2 of appendix F to this part; and the grace period provisions in section 2.2.4 of appendix B to part 75 of this chapter shall apply. For the purposes of data validation under this subpart, the cylinder gas audits described in Procedure 1, section 5.1.2 of appendix F to this part shall be performed for SO_2 and NO_x span values less than or equal to 30 ppm; and

(iii) For SO_2, CO_2, and O_2 monitoring systems and for NO_x emission rate monitoring systems, RATAs may be performed in accordance with section 2.3 of appendix B to part 75 of this chapter instead of following the procedures described in Procedure 1, section 5.1.1 of appendix F to this part. If this option is selected: The frequency of each RATA shall be as specified in section 2.3.1 of appendix B to part 75 of this chapter; the applicable relative accuracy specifications shown in Figure 2 in appendix B to part 75 of this chapter shall be met; the data validation and out-of-control criteria in section 2.3.2 of appendix B to part 75 of this chapter shall be followed instead of the excessive audit inaccuracy and out-of-control criteria in Procedure 1, section 5.2 of appendix F to this part; and the grace period provisions in section 2.3.3 of appendix B to part 75 of this chapter shall apply. For the purposes of data validation under this subpart, the relative accuracy specification in section 13.2 of Performance Specification 2 in appendix B to this part shall be met on a lb/MMBtu basis for SO_2 (regardless of the SO_2 emission level during the RATA), and for NO_x when the average NO_x emission rate measured by the reference method during the RATA is less than 0.100 lb/MMBtu.

(f) The owner or operator of an affected facility that combusts very low sulfur oil or is demonstrating compliance under §60.45b(k) is not subject to the emission monitoring requirements under paragraph (a) of this section if the owner or operator maintains fuel records as described in §60.49b(r).

[72 FR 32742, June 13, 2007, as amended at 74 FR 5087, Jan. 28, 2009; 79 FR 11249, Feb. 27, 2014]

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§60.48b Emission monitoring for particulate matter and nitrogen oxides.

(a) Except as provided in paragraph (j) of this section, the owner or operator of an affected facility subject to the opacity standard under §60.43b shall install, calibrate, maintain, and operate a continuous opacity monitoring systems (COMS) for measuring the opacity of emissions discharged to the atmosphere and record the output of the system. The owner or operator of an affected facility subject to an opacity standard under §60.43b and meeting the conditions under paragraphs (j)(1), (2), (3), (4), (5),

or (6) of this section who elects not to use a COMS shall conduct a performance test using Method 9 of appendix A-4 of this part and the procedures in §60.11 to demonstrate compliance with the applicable limit in §60.43b by April 29, 2011, within 45 days of stopping use of an existing COMS, or within 180 days after initial startup of the facility, whichever is later, and shall comply with either paragraphs (a)(1), (a)(2), or (a)(3) of this section. The observation period for Method 9 of appendix A-4 of this part performance tests may be reduced from 3 hours to 60 minutes if all 6-minute averages are less than 10 percent and all individual 15-second observations are less than or equal to 20 percent during the initial 60 minutes of observation.

CRE is subject to an opacity standard under 60.43b and will install, calibrate, maintain and operate a COMS for measuring the opacity of emissions.

(1) Except as provided in paragraph (a)(2) and (a)(3) of this section, the owner or operator shall conduct subsequent Method 9 of appendix A-4 of this part performance tests using the procedures in paragraph (a) of this section according to the applicable schedule in paragraphs (a)(1)(i) through (a)(1)(iv) of this section, as determined by the most recent Method 9 of appendix A-4 of this part performance test results.

(i) If no visible emissions are observed, a subsequent Method 9 of appendix A-4 of this part performance test must be completed within 12 calendar months from the date that the most recent performance test was conducted or within 45 days of the next day that fuel with an opacity standard is combusted, whichever is later;

(ii) If visible emissions are observed but the maximum 6-minute average opacity is less than or equal to 5 percent, a subsequent Method 9 of appendix A-4 of this part performance test must be completed within 6 calendar months from the date that the most recent performance test was conducted or within 45 days of the next day that fuel with an opacity standard is combusted, whichever is later;

(iii) If the maximum 6-minute average opacity is greater than 5 percent but less than or equal to 10 percent, a subsequent Method 9 of appendix A-4 of this part performance test must be completed within 3 calendar months from the date that the most recent performance test was conducted or within 45 days of the next day that fuel with an opacity standard is combusted, whichever is later; or

(iv) If the maximum 6-minute average opacity is greater than 10 percent, a subsequent Method 9 of appendix A-4 of this part performance test must be completed within 45 calendar days from the date that the most recent performance test was conducted.

(2) If the maximum 6-minute opacity is less than 10 percent during the most recent Method 9 of appendix A-4 of this part performance test, the owner or operator may, as an alternative to performing subsequent Method 9 of appendix A-4 of this part performance tests, elect to perform subsequent monitoring using Method 22 of appendix A-7 of this part according to the procedures specified in paragraphs (a)(2)(i) and (ii) of this section.

(i) The owner or operator shall conduct 10 minute observations (during normal operation) each operating day the affected facility fires fuel for which an opacity standard is applicable using Method 22 of appendix A-7 of this part and demonstrate that the sum of the occurrences of any visible emissions is not in excess of 5 percent of the observation period (*i.e.*, 30 seconds per 10 minute period). If the sum of the occurrence of any visible emissions is greater than 30 seconds during the initial 10 minute observation, immediately conduct a 30 minute observation. If the sum of the occurrence of visible emissions is greater than 5 percent of the observation period (*i.e.,* 90 seconds per 30 minute period), the owner or operator shall either document and adjust the operation of the facility and demonstrate within 24 hours that the sum of the occurrence of visible emissions is equal to or less than 5 percent during a 30 minute observation (*i.e.,* 90 seconds) or conduct a new Method 9 of appendix A-4 of this part performance test

using the procedures in paragraph (a) of this section within 45 calendar days according to the requirements in §60.46d(d)(7).

(ii) If no visible emissions are observed for 10 operating days during which an opacity standard is applicable, observations can be reduced to once every 7 operating days during which an opacity standard is applicable. If any visible emissions are observed, daily observations shall be resumed.

(3) If the maximum 6-minute opacity is less than 10 percent during the most recent Method 9 of appendix A-4 of this part performance test, the owner or operator may, as an alternative to performing subsequent Method 9 of appendix A-4 performance tests, elect to perform subsequent monitoring using a digital opacity compliance system according to a site-specific monitoring plan approved by the Administrator. The observations shall be similar, but not necessarily identical, to the requirements in paragraph (a)(2) of this section. For reference purposes in preparing the monitoring plan, see OAQPS "Determination of Visible Emission Opacity from Stationary Sources Using Computer-Based Photographic Analysis Systems." This document is available from the U.S. Environmental Protection Agency (U.S. EPA); Office of Air Quality and Planning Standards; Sector Policies and Programs Division; Measurement Policy Group (D243-02), Research Triangle Park, NC 27711. This document is also available on the Technology Transfer Network (TTN) under Emission Measurement Center Preliminary Methods.

(b) Except as provided under paragraphs (g), (h), and (i) of this section, the owner or operator of an affected facility subject to a NO_x standard under §60.44b shall comply with either paragraphs (b)(1) or (b)(2) of this section.

(1) Install, calibrate, maintain, and operate CEMS for measuring NO_x and O_2 (or CO_2) emissions discharged to the atmosphere, and shall record the output of the system; or

(2) If the owner or operator has installed a NO_x emission rate CEMS to meet the requirements of part 75 of this chapter and is continuing to meet the ongoing requirements of part 75 of this chapter, that CEMS may be used to meet the requirements of this section, except that the owner or operator shall also meet the requirements of §60.49b. Data reported to meet the requirements of §60.49b shall not include data substituted using the missing data procedures in subpart D of part 75 of this chapter, nor shall the data have been bias adjusted according to the procedures of part 75 of this chapter.

(c) The CEMS required under paragraph (b) of this section shall be operated and data recorded during all periods of operation of the affected facility except for CEMS breakdowns and repairs. Data is recorded during calibration checks, and zero and span adjustments.

(d) The 1-hour average NO_x emission rates measured by the continuous NO_x monitor required by paragraph (b) of this section and required under §60.13(h) shall be expressed in ng/J or lb/MMBtu heat input and shall be used to calculate the average emission rates under §60.44b. The 1-hour averages shall be calculated using the data points required under §60.13(h)(2).

(e) The procedures under §60.13 shall be followed for installation, evaluation, and operation of the continuous monitoring systems.

(1) For affected facilities combusting coal, wood or municipal-type solid waste, the span value for a COMS shall be between 60 and 80 percent.

(2) For affected facilities combusting coal, oil, or natural gas, the span value for NO_x is determined using one of the following procedures:

(i) Except as provided under paragraph (e)(2)(ii) of this section, NO_x span values shall be determined as follows:

Fuel	Span values for NO_x (ppm)
Natural gas	500.
Oil	500.
Coal	1,000.
Mixtures	500 (x + y) + 1,000z.

Where:

x = Fraction of total heat input derived from natural gas;

y = Fraction of total heat input derived from oil; and

z = Fraction of total heat input derived from coal.

(ii) As an alternative to meeting the requirements of paragraph (e)(2)(i) of this section, the owner or operator of an affected facility may elect to use the NO_x span values determined according to section 2.1.2 in appendix A to part 75 of this chapter.

(3) All span values computed under paragraph (e)(2)(i) of this section for combusting mixtures of regulated fuels are rounded to the nearest 500 ppm. Span values computed under paragraph (e)(2)(ii) of this section shall be rounded off according to section 2.1.2 in appendix A to part 75 of this chapter.

(f) When NO_x emission data are not obtained because of CEMS breakdowns, repairs, calibration checks and zero and span adjustments, emission data will be obtained by using standby monitoring systems, Method 7 of appendix A of this part, Method 7A of appendix A of this part, or other approved reference methods to provide emission data for a minimum of 75 percent of the operating hours in each steam generating unit operating day, in at least 22 out of 30 successive steam generating unit operating days.

(g) The owner or operator of an affected facility that has a heat input capacity of 73 MW (250 MMBtu/hr) or less, and that has an annual capacity factor for residual oil having a nitrogen content of 0.30 weight percent or less, natural gas, distillate oil, gasified coal, or any mixture of these fuels, greater than 10 percent (0.10) shall:

(1) Comply with the provisions of paragraphs (b), (c), (d), (e)(2), (e)(3), and (f) of this section; or

(2) Monitor steam generating unit operating conditions and predict NO_x emission rates as specified in a plan submitted pursuant to §60.49b(c).

(h) The owner or operator of a duct burner, as described in §60.41b, that is subject to the NO_x standards in §60.44b(a)(4), §60.44b(e), or §60.44b(l) is not required to install or operate a continuous emissions monitoring system to measure NO_x emissions.

(i) The owner or operator of an affected facility described in §60.44b(j) or §60.44b(k) is not required to install or operate a CEMS for measuring NO_x emissions.

(j) The owner or operator of an affected facility that meets the conditions in either paragraph (j)(1), (2), (3), (4), (5), (6), or (7) of this section is not required to install or operate a COMS if:

(1) The affected facility uses a PM CEMS to monitor PM emissions; or

(2) The affected facility burns only liquid (excluding residual oil) or gaseous fuels with potential SO_2 emissions rates of 26 ng/J (0.060 lb/MMBtu) or less and does not use a post-combustion technology to reduce SO_2 or PM emissions. The owner or operator must maintain fuel records of the sulfur content of the fuels burned, as described under §60.49b(r); or

(3) The affected facility burns coke oven gas alone or in combination with fuels meeting the criteria in paragraph (j)(2) of this section and does not use a post-combustion technology to reduce SO_2 or PM emissions; or

(4) The affected facility does not use post-combustion technology (except a wet scrubber) for reducing PM, SO_2, or carbon monoxide (CO) emissions, burns only gaseous fuels or fuel oils that contain less than or equal to 0.30 weight percent sulfur, and is operated such that emissions of CO to the atmosphere from the affected facility are maintained at levels less than or equal to 0.15 lb/MMBtu on a steam generating unit operating day average basis. Owners and operators of affected facilities electing to comply with this paragraph must demonstrate compliance according to the procedures specified in paragraphs (j)(4)(i) through (iv) of this section; or

(i) You must monitor CO emissions using a CEMS according to the procedures specified in paragraphs (j)(4)(i)(A) through (D) of this section.

(A) The CO CEMS must be installed, certified, maintained, and operated according to the provisions in §60.58b(i)(3) of subpart Eb of this part.

(B) Each 1-hour CO emissions average is calculated using the data points generated by the CO CEMS expressed in parts per million by volume corrected to 3 percent oxygen (dry basis).

(C) At a minimum, valid 1-hour CO emissions averages must be obtained for at least 90 percent of the operating hours on a 30-day rolling average basis. The 1-hour averages are calculated using the data points required in §60.13(h)(2).

(D) Quarterly accuracy determinations and daily calibration drift tests for the CO CEMS must be performed in accordance with procedure 1 in appendix F of this part.

(ii) You must calculate the 1-hour average CO emissions levels for each steam generating unit operating day by multiplying the average hourly CO output concentration measured by the CO CEMS times the corresponding average hourly flue gas flow rate and divided by the corresponding average hourly heat input to the affected source. The 24-hour average CO emission level is determined by calculating the arithmetic average of the hourly CO emission levels computed for each steam generating unit operating day.

(iii) You must evaluate the preceding 24-hour average CO emission level each steam generating unit operating day excluding periods of affected source startup, shutdown, or malfunction. If the 24-hour average CO emission level is greater than 0.15 lb/MMBtu, you must initiate investigation of the relevant equipment and control systems within 24 hours of the first discovery of the high emission incident and, take the appropriate corrective action as soon as practicable to adjust control settings or repair equipment to reduce the 24-hour average CO emission level to 0.15 lb/MMBtu or less.

(iv) You must record the CO measurements and calculations performed according to paragraph (j)(4) of this section and any corrective actions taken. The record of corrective action taken must include the date and time during which the 24-hour average CO emission level was greater than 0.15 lb/MMBtu, and the date, time, and description of the corrective action.

(5) The affected facility uses a bag leak detection system to monitor the performance of a fabric filter (baghouse) according to the most current requirements in section §60.48Da of this part; or

(6) The affected facility uses an ESP as the primary PM control device and uses an ESP predictive model to monitor the performance of the ESP developed in accordance and operated according to the most current requirements in section §60.48Da of this part; or

(7) The affected facility burns only gaseous fuels or fuel oils that contain less than or equal to 0.30 weight percent sulfur and operates according to a written site-specific monitoring plan approved by the permitting authority. This monitoring plan must include procedures and criteria for establishing and monitoring specific parameters for the affected facility indicative of compliance with the opacity standard.

(k) Owners or operators complying with the PM emission limit by using a PM CEMS must calibrate, maintain, operate, and record the output of the system for PM emissions discharged to the atmosphere as specified in §60.46b(j). The CEMS specified in paragraph §60.46b(j) shall be operated and data recorded during all periods of operation of the affected facility except for CEMS breakdowns and repairs. Data is recorded during calibration checks, and zero and span adjustments.

(l) An owner or operator of an affected facility that is subject to an opacity standard under §60.43b(f) is not required to operate a COMS provided that the unit burns only gaseous fuels and/or liquid fuels (excluding residue oil) with a potential SO_2 emissions rate no greater than 26 ng/J (0.060 lb/MMBtu), and the unit operates according to a written site-specific monitoring plan approved by the permitting authority is not required to operate a COMS. This monitoring plan must include procedures and criteria for establishing and monitoring specific parameters for the affected facility indicative of compliance with the opacity standard. For testing performed as part of this site-specific monitoring plan, the permitting authority may require as an alternative to the notification and reporting requirements specified in §§60.8 and 60.11 that the owner or operator submit any deviations with the excess emissions report required under §60.49b(h).

[72 FR 32742, June 13, 2007, as amended at 74 FR 5087, Jan. 28, 2009; 76 FR 3523, Jan. 20, 2011; 77 FR 9460, Feb. 16, 2012]

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§60.49b Reporting and recordkeeping requirements.

(a) The owner or operator of each affected facility shall submit notification of the date of initial startup, as provided by §60.7. This notification shall include:

(1) The design heat input capacity of the affected facility and identification of the fuels to be combusted in the affected facility;

(2) If applicable, a copy of any federally enforceable requirement that limits the annual capacity factor for any fuel or mixture of fuels under §60.42b(d)(1), §60.43b(a)(2), (a)(3)(iii), (c)(2)(ii), (d)(2)(iii), §60.44b(c), (d), (e), (i), (j), (k), §60.45b(d), (g), §60.46b(h), or §60.48b(i);

(3) The annual capacity factor at which the owner or operator anticipates operating the facility based on all fuels fired and based on each individual fuel fired; and

(4) Notification that an emerging technology will be used for controlling emissions of SO_2. The Administrator will examine the description of the emerging technology and will determine whether the technology qualifies as an emerging technology. In making this determination, the Administrator may require the owner or operator of the affected facility to submit additional information concerning the

control device. The affected facility is subject to the provisions of §60.42b(a) unless and until this determination is made by the Administrator.

CRE will comply with the requirements of 60.49b (a)(1)-(3). The facility will not use emerging technology for control of SO2.

(b) The owner or operator of each affected facility subject to the SO_2, PM, and/or NO_x emission limits under §§60.42b, 60.43b, and 60.44b shall submit to the Administrator the performance test data from the initial performance test and the performance evaluation of the CEMS using the applicable performance specifications in appendix B of this part. The owner or operator of each affected facility described in §60.44b(j) or §60.44b(k) shall submit to the Administrator the maximum heat input capacity data from the demonstration of the maximum heat input capacity of the affected facility.

CRE will submit the performance test data from the initial performance test.

(c) The owner or operator of each affected facility subject to the NO_x standard in §60.44b who seeks to demonstrate compliance with those standards through the monitoring of steam generating unit operating conditions in the provisions of §60.48b(g)(2) shall submit to the Administrator for approval a plan that identifies the operating conditions to be monitored in §60.48b(g)(2) and the records to be maintained in §60.49b(g). This plan shall be submitted to the Administrator for approval within 360 days of the initial startup of the affected facility. An affected facility burning coke oven gas alone or in combination with other gaseous fuels or distillate oil shall submit this plan to the Administrator for approval within 360 days of the initial startup of the affected facility or by November 30, 2009, whichever date comes later. If the plan is approved, the owner or operator shall maintain records of predicted nitrogen oxide emission rates and the monitored operating conditions, including steam generating unit load, identified in the plan. The plan shall:

(1) Identify the specific operating conditions to be monitored and the relationship between these operating conditions and NO_x emission rates (*i.e.*, ng/J or lbs/MMBtu heat input). Steam generating unit operating conditions include, but are not limited to, the degree of staged combustion (*i.e.*, the ratio of primary air to secondary and/or tertiary air) and the level of excess air (*i.e.*, flue gas O_2 level);

(2) Include the data and information that the owner or operator used to identify the relationship between NO_x emission rates and these operating conditions; and

(3) Identify how these operating conditions, including steam generating unit load, will be monitored under §60.48b(g) on an hourly basis by the owner or operator during the period of operation of the affected facility; the quality assurance procedures or practices that will be employed to ensure that the data generated by monitoring these operating conditions will be representative and accurate; and the type and format of the records of these operating conditions, including steam generating unit load, that will be maintained by the owner or operator under §60.49b(g).

(d) Except as provided in paragraph (d)(2) of this section, the owner or operator of an affected facility shall record and maintain records as specified in paragraph (d)(1) of this section.

(1) The owner or operator of an affected facility shall record and maintain records of the amounts of each fuel combusted during each day and calculate the annual capacity factor individually for coal, distillate oil, residual oil, natural gas, wood, and municipal-type solid waste for the reporting period. The annual capacity factor is determined on a 12-month rolling average basis with a new annual capacity factor calculated at the end of each calendar month.

(2) As an alternative to meeting the requirements of paragraph (d)(1) of this section, the owner or operator of an affected facility that is subject to a federally enforceable permit restricting fuel use to a single fuel such that the facility is not required to continuously monitor any emissions (excluding opacity)

or parameters indicative of emissions may elect to record and maintain records of the amount of each fuel combusted during each calendar month.

CRE will combust only wood and is not required to continuously monitor any emissions (excluding opacity) and will record and maintain records of the amount of wood combusted during each calendar month.

(e) For an affected facility that combusts residual oil and meets the criteria under §60.46b(e)(4), §60.44b(j), or (k), the owner or operator shall maintain records of the nitrogen content of the residual oil combusted in the affected facility and calculate the average fuel nitrogen content for the reporting period. The nitrogen content shall be determined using ASTM Method D4629 (incorporated by reference, see §60.17), or fuel suppliers. If residual oil blends are being combusted, fuel nitrogen specifications may be prorated based on the ratio of residual oils of different nitrogen content in the fuel blend.

(f) For an affected facility subject to the opacity standard in §60.43b, the owner or operator shall maintain records of opacity. In addition, an owner or operator that elects to monitor emissions according to the requirements in §60.48b(a) shall maintain records according to the requirements specified in paragraphs (f)(1) through (3) of this section, as applicable to the visible emissions monitoring method used.

CRE will maintain records of opacity and will maintain records according to the requirements specified in paragraph (f)(3) of this sections.

(1) For each performance test conducted using Method 9 of appendix A-4 of this part, the owner or operator shall keep the records including the information specified in paragraphs (f)(1)(i) through (iii) of this section.

(i) Dates and time intervals of all opacity observation periods;

(ii) Name, affiliation, and copy of current visible emission reading certification for each visible emission observer participating in the performance test; and

(iii) Copies of all visible emission observer opacity field data sheets;

(2) For each performance test conducted using Method 22 of appendix A-4 of this part, the owner or operator shall keep the records including the information specified in paragraphs (f)(2)(i) through (iv) of this section.

(i) Dates and time intervals of all visible emissions observation periods;

(ii) Name and affiliation for each visible emission observer participating in the performance test;

(iii) Copies of all visible emission observer opacity field data sheets; and

(iv) Documentation of any adjustments made and the time the adjustments were completed to the affected facility operation by the owner or operator to demonstrate compliance with the applicable monitoring requirements.

(3) For each digital opacity compliance system, the owner or operator shall maintain records and submit reports according to the requirements specified in the site-specific monitoring plan approved by the Administrator.

(g) Except as provided under paragraph (p) of this section, the owner or operator of an affected facility subject to the NO_x standards under §60.44b shall maintain records of the following information for each steam generating unit operating day:

(1) Calendar date;

(2) The average hourly NO_x emission rates (expressed as NO_2) (ng/J or lb/MMBtu heat input) measured or predicted;

(3) The 30-day average NO_x emission rates (ng/J or lb/MMBtu heat input) calculated at the end of each steam generating unit operating day from the measured or predicted hourly nitrogen oxide emission rates for the preceding 30 steam generating unit operating days;

(4) Identification of the steam generating unit operating days when the calculated 30-day average NO_x emission rates are in excess of the NO_x emissions standards under §60.44b, with the reasons for such excess emissions as well as a description of corrective actions taken;

(5) Identification of the steam generating unit operating days for which pollutant data have not been obtained, including reasons for not obtaining sufficient data and a description of corrective actions taken;

(6) Identification of the times when emission data have been excluded from the calculation of average emission rates and the reasons for excluding data;

(7) Identification of "F" factor used for calculations, method of determination, and type of fuel combusted;

(8) Identification of the times when the pollutant concentration exceeded full span of the CEMS;

(9) Description of any modifications to the CEMS that could affect the ability of the CEMS to comply with Performance Specification 2 or 3; and

(10) Results of daily CEMS drift tests and quarterly accuracy assessments as required under appendix F, Procedure 1 of this part.

(h) The owner or operator of any affected facility in any category listed in paragraphs (h)(1) or (2) of this section is required to submit excess emission reports for any excess emissions that occurred during the reporting period.

(1) Any affected facility subject to the opacity standards in §60.43b(f) or to the operating parameter monitoring requirements in §60.13(i)(1).

The CRE facility is subject to the opacity standards in 60.43b(f) and will submit excess emission reports.

(2) Any affected facility that is subject to the NO_x standard of §60.44b, and that:

(i) Combusts natural gas, distillate oil, gasified coal, or residual oil with a nitrogen content of 0.3 weight percent or less; or

(ii) Has a heat input capacity of 73 MW (250 MMBtu/hr) or less and is required to monitor NO_x emissions on a continuous basis under §60.48b(g)(1) or steam generating unit operating conditions under §60.48b(g)(2).

(3) For the purpose of §60.43b, excess emissions are defined as all 6-minute periods during which the average opacity exceeds the opacity standards under §60.43b(f).

(4) For purposes of §60.48b(g)(1), excess emissions are defined as any calculated 30-day rolling average NO_xemission rate, as determined under §60.46b(e), that exceeds the applicable emission limits in §60.44b.

(i) The owner or operator of any affected facility subject to the continuous monitoring requirements for NO_x under §60.48(b) shall submit reports containing the information recorded under paragraph (g) of this section.

(j) The owner or operator of any affected facility subject to the SO_2 standards under §60.42b shall submit reports.

(k) For each affected facility subject to the compliance and performance testing requirements of §60.45b and the reporting requirement in paragraph (j) of this section, the following information shall be reported to the Administrator:

(1) Calendar dates covered in the reporting period;

(2) Each 30-day average SO_2 emission rate (ng/J or lb/MMBtu heat input) measured during the reporting period, ending with the last 30-day period; reasons for noncompliance with the emission standards; and a description of corrective actions taken; For an exceedance due to maintenance of the SO_2 control system covered in paragraph 60.45b(a), the report shall identify the days on which the maintenance was performed and a description of the maintenance;

(3) Each 30-day average percent reduction in SO_2 emissions calculated during the reporting period, ending with the last 30-day period; reasons for noncompliance with the emission standards; and a description of corrective actions taken;

(4) Identification of the steam generating unit operating days that coal or oil was combusted and for which SO_2 or diluent (O_2 or CO_2) data have not been obtained by an approved method for at least 75 percent of the operating hours in the steam generating unit operating day; justification for not obtaining sufficient data; and description of corrective action taken;

(5) Identification of the times when emissions data have been excluded from the calculation of average emission rates; justification for excluding data; and description of corrective action taken if data have been excluded for periods other than those during which coal or oil were not combusted in the steam generating unit;

(6) Identification of “F” factor used for calculations, method of determination, and type of fuel combusted;

(7) Identification of times when hourly averages have been obtained based on manual sampling methods;

(8) Identification of the times when the pollutant concentration exceeded full span of the CEMS;

(9) Description of any modifications to the CEMS that could affect the ability of the CEMS to comply with Performance Specification 2 or 3;

(10) Results of daily CEMS drift tests and quarterly accuracy assessments as required under appendix F, Procedure 1 of this part; and

(11) The annual capacity factor of each fired as provided under paragraph (d) of this section.

(l) For each affected facility subject to the compliance and performance testing requirements of §60.45b(d) and the reporting requirements of paragraph (j) of this section, the following information shall be reported to the Administrator:

(1) Calendar dates when the facility was in operation during the reporting period;

(2) The 24-hour average SO_2 emission rate measured for each steam generating unit operating day during the reporting period that coal or oil was combusted, ending in the last 24-hour period in the quarter; reasons for noncompliance with the emission standards; and a description of corrective actions taken;

(3) Identification of the steam generating unit operating days that coal or oil was combusted for which $S0_2$ or diluent (O_2 or CO_2) data have not been obtained by an approved method for at least 75 percent of the operating hours; justification for not obtaining sufficient data; and description of corrective action taken;

(4) Identification of the times when emissions data have been excluded from the calculation of average emission rates; justification for excluding data; and description of corrective action taken if data have been excluded for periods other than those during which coal or oil were not combusted in the steam generating unit;

(5) Identification of "F" factor used for calculations, method of determination, and type of fuel combusted;

(6) Identification of times when hourly averages have been obtained based on manual sampling methods;

(7) Identification of the times when the pollutant concentration exceeded full span of the CEMS;

(8) Description of any modifications to the CEMS that could affect the ability of the CEMS to comply with Performance Specification 2 or 3; and

(9) Results of daily CEMS drift tests and quarterly accuracy assessments as required under Procedure 1 of appendix F 1 of this part. If the owner or operator elects to implement the alternative data assessment procedures described in §§60.47b(e)(4)(i) through (e)(4)(iii), each data assessment report shall include a summary of the results of all of the RATAs, linearity checks, CGAs, and calibration error or drift assessments required by §§60.47b(e)(4)(i) through (e)(4)(iii).

(m) For each affected facility subject to the SO_2 standards in §60.42(b) for which the minimum amount of data required in §60.47b(c) were not obtained during the reporting period, the following information is reported to the Administrator in addition to that required under paragraph (k) of this section:

(1) The number of hourly averages available for outlet emission rates and inlet emission rates;

(2) The standard deviation of hourly averages for outlet emission rates and inlet emission rates, as determined in Method 19 of appendix A of this part, section 7;

(3) The lower confidence limit for the mean outlet emission rate and the upper confidence limit for the mean inlet emission rate, as calculated in Method 19 of appendix A of this part, section 7; and

(4) The ratio of the lower confidence limit for the mean outlet emission rate and the allowable emission rate, as determined in Method 19 of appendix A of this part, section 7.

(n) If a percent removal efficiency by fuel pretreatment (*i.e.*, $\%R_f$) is used to determine the overall percent reduction (*i.e.*, $\%R_o$) under §60.45b, the owner or operator of the affected facility shall submit a signed statement with the report.

(1) Indicating what removal efficiency by fuel pretreatment (*i.e.*, $\%R_f$) was credited during the reporting period;

(2) Listing the quantity, heat content, and date each pre-treated fuel shipment was received during the reporting period, the name and location of the fuel pretreatment facility; and the total quantity and total heat content of all fuels received at the affected facility during the reporting period;

(3) Documenting the transport of the fuel from the fuel pretreatment facility to the steam generating unit; and

(4) Including a signed statement from the owner or operator of the fuel pretreatment facility certifying that the percent removal efficiency achieved by fuel pretreatment was determined in accordance with the provisions of Method 19 of appendix A of this part and listing the heat content and sulfur content of each fuel before and after fuel pretreatment.

(o) All records required under this section shall be maintained by the owner or operator of the affected facility for a period of 2 years following the date of such record.

CRE will maintain all records required by this Subpart for 2 years.

(p) The owner or operator of an affected facility described in §60.44b(j) or (k) shall maintain records of the following information for each steam generating unit operating day:

(1) Calendar date;

(2) The number of hours of operation; and

(3) A record of the hourly steam load.

(q) The owner or operator of an affected facility described in §60.44b(j) or §60.44b(k) shall submit to the Administrator a report containing:

(1) The annual capacity factor over the previous 12 months;

(2) The average fuel nitrogen content during the reporting period, if residual oil was fired; and

(3) If the affected facility meets the criteria described in §60.44b(j), the results of any NO_x emission tests required during the reporting period, the hours of operation during the reporting period, and the hours of operation since the last NO_x emission test.

(r) The owner or operator of an affected facility who elects to use the fuel based compliance alternatives in §60.42b or §60.43b shall either:

(1) The owner or operator of an affected facility who elects to demonstrate that the affected facility combusts only very low sulfur oil, natural gas, wood, a mixture of these fuels, or any of these fuels (or a

mixture of these fuels) in combination with other fuels that are known to contain an insignificant amount of sulfur in §60.42b(j) or §60.42b(k) shall obtain and maintain at the affected facility fuel receipts (such as a current, valid purchase contract, tariff sheet, or transportation contract) from the fuel supplier that certify that the oil meets the definition of distillate oil and gaseous fuel meets the definition of natural gas as defined in §60.41b and the applicable sulfur limit. For the purposes of this section, the distillate oil need not meet the fuel nitrogen content specification in the definition of distillate oil. Reports shall be submitted to the Administrator certifying that only very low sulfur oil meeting this definition, natural gas, wood, and/or other fuels that are known to contain insignificant amounts of sulfur were combusted in the affected facility during the reporting period; or

(2) The owner or operator of an affected facility who elects to demonstrate compliance based on fuel analysis in §60.42b or §60.43b shall develop and submit a site-specific fuel analysis plan to the Administrator for review and approval no later than 60 days before the date you intend to demonstrate compliance. Each fuel analysis plan shall include a minimum initial requirement of weekly testing and each analysis report shall contain, at a minimum, the following information:

(i) The potential sulfur emissions rate of the representative fuel mixture in ng/J heat input;

(ii) The method used to determine the potential sulfur emissions rate of each constituent of the mixture. For distillate oil and natural gas a fuel receipt or tariff sheet is acceptable;

(iii) The ratio of different fuels in the mixture; and

(iv) The owner or operator can petition the Administrator to approve monthly or quarterly sampling in place of weekly sampling.

(s) Facility specific NO_x standard for Cytec Industries Fortier Plant's C.AOG incinerator located in Westwego, Louisiana:

(1) *Definitions.*

Oxidation zone is defined as the portion of the C.AOG incinerator that extends from the inlet of the oxidizing zone combustion air to the outlet gas stack.

Reducing zone is defined as the portion of the C.AOG incinerator that extends from the burner section to the inlet of the oxidizing zone combustion air.

Total inlet air is defined as the total amount of air introduced into the C.AOG incinerator for combustion of natural gas and chemical by-product waste and is equal to the sum of the air flow into the reducing zone and the air flow into the oxidation zone.

(2) *Standard for nitrogen oxides.* (i) When fossil fuel alone is combusted, the NO_x emission limit for fossil fuel in §60.44b(a) applies.

(ii) When natural gas and chemical by-product waste are simultaneously combusted, the NO_x emission limit is 289 ng/J (0.67 lb/MMBtu) and a maximum of 81 percent of the total inlet air provided for combustion shall be provided to the reducing zone of the C.AOG incinerator.

(3) *Emission monitoring.* (i) The percent of total inlet air provided to the reducing zone shall be determined at least every 15 minutes by measuring the air flow of all the air entering the reducing zone and the air flow of all the air entering the oxidation zone, and compliance with the percentage of total inlet air that is provided to the reducing zone shall be determined on a 3-hour average basis.

(ii) The NO_x emission limit shall be determined by the compliance and performance test methods and procedures for NO_x in §60.46b(i).

(iii) The monitoring of the NO_x emission limit shall be performed in accordance with §60.48b.

(4) *Reporting and recordkeeping requirements.* (i) The owner or operator of the C.AOG incinerator shall submit a report on any excursions from the limits required by paragraph (a)(2) of this section to the Administrator with the quarterly report required by paragraph (i) of this section.

(ii) The owner or operator of the C.AOG incinerator shall keep records of the monitoring required by paragraph (a)(3) of this section for a period of 2 years following the date of such record.

(iii) The owner of operator of the C.AOG incinerator shall perform all the applicable reporting and recordkeeping requirements of this section.

(t) Facility-specific NO_x standard for Rohm and Haas Kentucky Incorporated's Boiler No. 100 located in Louisville, Kentucky:

(1) *Definitions.*

Air ratio control damper is defined as the part of the low NO_x burner that is adjusted to control the split of total combustion air delivered to the reducing and oxidation portions of the combustion flame.

Flue gas recirculation line is defined as the part of Boiler No. 100 that recirculates a portion of the boiler flue gas back into the combustion air.

(2) *Standard for nitrogen oxides.* (i) When fossil fuel alone is combusted, the NO_x emission limit for fossil fuel in §60.44b(a) applies.

(ii) When fossil fuel and chemical by-product waste are simultaneously combusted, the NO_x emission limit is 473 ng/J (1.1 lb/MMBtu), and the air ratio control damper tee handle shall be at a minimum of 5 inches (12.7 centimeters) out of the boiler, and the flue gas recirculation line shall be operated at a minimum of 10 percent open as indicated by its valve opening position indicator.

(3) *Emission monitoring for nitrogen oxides.* (i) The air ratio control damper tee handle setting and the flue gas recirculation line valve opening position indicator setting shall be recorded during each 8-hour operating shift.

(ii) The NO_x emission limit shall be determined by the compliance and performance test methods and procedures for NO_x in §60.46b.

(iii) The monitoring of the NO_x emission limit shall be performed in accordance with §60.48b.

(4) *Reporting and recordkeeping requirements.* (i) The owner or operator of Boiler No. 100 shall submit a report on any excursions from the limits required by paragraph (b)(2) of this section to the Administrator with the quarterly report required by §60.49b(i).

(ii) The owner or operator of Boiler No. 100 shall keep records of the monitoring required by paragraph (b)(3) of this section for a period of 2 years following the date of such record.

(iii) The owner of operator of Boiler No. 100 shall perform all the applicable reporting and recordkeeping requirements of §60.49b.

(u) *Site-specific standard for Merck & Co., Inc.'s Stonewall Plant in Elkton, Virginia.* (1) This paragraph (u) applies only to the pharmaceutical manufacturing facility, commonly referred to as the Stonewall Plant, located at Route 340 South, in Elkton, Virginia ("site") and only to the natural gas-fired boilers installed as part of the powerhouse conversion required pursuant to 40 CFR 52.2454(g). The requirements of this paragraph shall apply, and the requirements of §§60.40b through 60.49b(t) shall not apply, to the natural gas-fired boilers installed pursuant to 40 CFR 52.2454(g).

(i) The site shall equip the natural gas-fired boilers with low NO_x technology.

(ii) The site shall install, calibrate, maintain, and operate a continuous monitoring and recording system for measuring NO_x emissions discharged to the atmosphere and opacity using a continuous emissions monitoring system or a predictive emissions monitoring system.

(iii) Within 180 days of the completion of the powerhouse conversion, as required by 40 CFR 52.2454, the site shall perform a performance test to quantify criteria pollutant emissions.

(2) [Reserved]

(v) The owner or operator of an affected facility may submit electronic quarterly reports for SO_2 and/or NO_x and/or opacity in lieu of submitting the written reports required under paragraphs (h), (i), (j), (k) or (l) of this section. The format of each quarterly electronic report shall be coordinated with the permitting authority. The electronic report(s) shall be submitted no later than 30 days after the end of the calendar quarter and shall be accompanied by a certification statement from the owner or operator, indicating whether compliance with the applicable emission standards and minimum data requirements of this subpart was achieved during the reporting period. Before submitting reports in the electronic format, the owner or operator shall coordinate with the permitting authority to obtain their agreement to submit reports in this alternative format.

(w) The reporting period for the reports required under this subpart is each 6 month period. All reports shall be submitted to the Administrator and shall be postmarked by the 30th day following the end of the reporting period.

CRE will submit required reports to the administrator postmarked by the 30th day following the end of the reporting period.

(x) Facility-specific NO_x standard for Weyerhaeuser Company's No. 2 Power Boiler located in New Bern, North Carolina:

(1) *Standard for nitrogen oxides.* (i) When fossil fuel alone is combusted, the NO_x emission limit for fossil fuel in §60.44b(a) applies.

(ii) When fossil fuel and chemical by-product waste are simultaneously combusted, the NO_x emission limit is 215 ng/J (0.5 lb/MMBtu).

(2) *Emission monitoring for nitrogen oxides.* (i) The NO_x emissions shall be determined by the compliance and performance test methods and procedures for NO_x in §60.46b.

(ii) The monitoring of the NO_x emissions shall be performed in accordance with §60.48b.

(3) *Reporting and recordkeeping requirements.* (i) The owner or operator of the No. 2 Power Boiler shall submit a report on any excursions from the limits required by paragraph (x)(2) of this section to the Administrator with the quarterly report required by §60.49b(i).

(ii) The owner or operator of the No. 2 Power Boiler shall keep records of the monitoring required by paragraph (x)(3) of this section for a period of 2 years following the date of such record.

(iii) The owner or operator of the No. 2 Power Boiler shall perform all the applicable reporting and recordkeeping requirements of §60.49b.

(y) Facility-specific NO_x standard for INEOS USA's AOGI located in Lima, Ohio:

(1) *Standard for NO_x*. (i) When fossil fuel alone is combusted, the NO_x emission limit for fossil fuel in §60.44b(a) applies.

(ii) When fossil fuel and chemical byproduct/waste are simultaneously combusted, the NO_x emission limit is 645 ng/J (1.5 lb/MMBtu).

(2) *Emission monitoring for NO_x*. (i) The NO_x emissions shall be determined by the compliance and performance test methods and procedures for NO_x in §60.46b.

(ii) The monitoring of the NO_x emissions shall be performed in accordance with §60.48b.

(3) *Reporting and recordkeeping requirements.* (i) The owner or operator of the AOGI shall submit a report on any excursions from the limits required by paragraph (y)(2) of this section to the Administrator with the quarterly report required by paragraph (i) of this section.

(ii) The owner or operator of the AOGI shall keep records of the monitoring required by paragraph (y)(3) of this section for a period of 2 years following the date of such record.

(iii) The owner or operator of the AOGI shall perform all the applicable reporting and recordkeeping requirements of this section.

[72 FR 32742, June 13, 2007, as amended at 74 FR 5089, Jan. 28, 2009; 77 FR 9461, Feb. 16, 2012]

APPENDIX G: PROCESS WEIGHT CALCULATIONS

CRE Potlach Facility - Process Weight Calculations

E = Emission Limit = $0.045(PW)^{0.60}$, if PW is less than 9,250 lb/hr. E = $1.10(PW)^{0.25}$, if PW is greater than 9,250 lb/hr.

Emission Unit No.	System Description	Requested Process Rate (ton/hr)	Requested Process Rate (lb/hr)	PM Emission Rate (lb/hr)	Process Weight Rate Limitations - E (lb/hr)	In Compliance? (Y/N)
HF1	Truck Unloading to Hog Fuel Tipper	36	72,765	0.055	18.07	Yes
HF2	Hog Fuel Pile to Hopper #4/Screw Feeder #4 via Front Loader	12	23,153	0.017	13.57	Yes
HF3	Fuel Screen #1 and transfers (in from Hopper #4, out to Bucket Elevator #1)	12	23,153	0.145	13.57	Yes
HF4	Bucket Elevator #1 to Surge Bin #2	12	23,153	0.017	13.57	Yes
HF5	Surge Bin #2 to Pnuematic System #5	12	23,153	0.000	13.57	Yes
HF6	Pneumatic System #5 to Combustor	12	23,153	0.000	13.57	Yes
FS1	Truck Unloading to Feedstock Tipper #1	94	187,425	0.186	22.89	Yes
FS2	Feedstock Pile to Hopper #1, 2 or 3 via Front Loader	33	65,599	0.065	17.60	Yes
FS3	Hopper #1, 2 or 3 to Conveyor #1	33	65,599	0.065	17.60	Yes
FS4	Conveyor #1 to Feed Screw #1	16	32,810	0.032	14.80	Yes
FS5	Conveyor #1 to Feed Screw #2	16	32,810	0.032	14.80	Yes
FS6	Green Hammer Mill #1 and transfers (in from Feed Screw #1, out to Green Cyclone #1)	16	32,810	0.058	14.80	Yes
FS7	Green Hammer Mill #2 and transfers (in from Feed Screw #2, out to Green Cyclone #2)	16	32,810	0.058	14.80	Yes
FS8	Green Cyclone #1 to Conveyor #2	16	32,810	0.032	14.80	Yes
FS9	Green Cyclone #2 to Conveyor #2	16	32,810	0.032	14.80	Yes
FS10	Conveyor #2 to Conveyor #3 (Inside Tower 1)	33	65,599	0.049	17.60	Yes
FS11	Conveyor #3 to Steam Ex Preheat Bin	33	65,599	0.000	17.60	Yes
FS12	SteamEx Preheat Bin to Conveyor #4	33	65,599	0.000	17.60	Yes
FS13	Conveyor #4 to Belt Dryer	33	65,599	0.000	17.60	Yes
FS14	Belt Dryer to Conveyor #5	33	65,599	0.000	17.60	Yes
FS15	Conveyor #5 to Feed Screw #3	33	65,599	0.091	17.60	Yes
FS16	Feed Screw #3 to Dry Hammer Mill	33	65,599	0.091	17.60	Yes
FS17	Dry Hammer Mill to Dry Cyclone #1	33	65,599	0.001	17.60	Yes
FS18	Dry Cyclone #1 to Pneumatic System #1	33	65,599	0.000	17.60	Yes
FS19	Pnuematic System #1 to Surge Bin #1	33	65,599	0.000	17.60	Yes
FS20	Surge Bin #1 to Conveyor #6	33	65,599	0.091	17.60	Yes
FS21	Conveyor #6 to Conveyor #7	16	32,810	0.000	14.80	Yes
FS22	Conveyor #7 to Mill Feed Bin #1 and #2	16	32,810	0.000	14.80	Yes
FS23	Mill Feed Bin #1 and #2 to Mill Feed Screws #1, 2, 3 and 4	16	32,810	0.000	14.80	Yes
FS24	Mill Feed Screws #1, 2, 3, and 4 to Conditioning Screws #1, 2, 3 and 4	16	32,810	0.000	14.80	Yes
FS25	Pellet Mills #1, 2, 3 and 4 and transfers (in from Conditioning Screws #1-4 and out to Co	16	32,810	0.000	14.80	Yes
FS26	Conveyor #9 to Pellet Cooler #1	16	32,810	0.000	14.80	Yes
FS27	Pellet Cooler #1 to Conveyor #11	16	32,810	0.000	14.80	Yes
FS28	Pellet Cooler #1 to Multiclone #1	0	772	0.000	0.24	Yes
FS29	Pellet Screen #1 and transfers (in from Conveyor #11, out to Pneumatic System #3)	16	32,810	0.000	14.80	Yes
FS30	Multiclone #1 to Pneumatic System #2	0	772	0.000	0.24	Yes
FS31	Conveyor #6 to Conveyor #8	16	32,810	0.000	14.80	Yes
FS32	Conveyor #8 to Mill Feed Bin #3 and #4	16	32,810	0.000	14.80	Yes
FS33	Mill Feed Bin #3 and #4 to Mill Feed Screws #5, 6, 7 and 8	16	32,810	0.000	14.80	Yes
FS34	Mill Feed Screws #5, 6, 7, and 8 to Conditioning Screws #5, 6, 7 and 8	16	32,810	0.000	14.80	Yes
FS35	Pellet Mills #5, 6, 7 and 8 and transfers (in from Conditioning Screws #5-8 and out to Co	16	32,810	0.000	14.80	Yes
FS36	Conveyor #10 to Pellet Cooler #2	16	32,810	0.000	14.80	Yes
FS37	Pellet Cooler #2 to Conveyor #12	16	32,810	0.000	14.80	Yes
FS38	Pellet Cooler #2 to Multiclone #2	0	772	0.000	0.24	Yes
FS39	Pellet Screen #2 and transfers (in from Conveyor #12, out to Pneumatic System #3)	16	32,810	0.000	14.80	Yes
FS40	Multiclone #2 to Pneumatic System #2	0	772	0.000	0.24	Yes
FS41	Pneumatic System #2 to Surge Bin #1	0	772	0.000	0.24	Yes
FS42	Pnuematic System #3 to Pellet Product Stockpile	33	65,599	0.094	17.60	Yes
FS43	Pellet Product Stockpile to Hopper #5 via Front Loader	336	672,525	0.968	31.50	Yes
FS44	Hopper #5 to Conveyor #13	336	672,525	0.968	31.50	Yes
FS45	Shipping Screens and transfers (in from Conveyor #13, out to Conveyor #14)	336	672,525	4.203	31.50	Yes
FS46	Shipping Screen to Pneumatic System #4	5	9,220	0.000	1.08	Yes
FS47	Conveyor #14 to Filling Spout	336	672,525	0.968	31.50	Yes
FS48	Filling Spout to Rail Car	336	672,525	0.968	31.50	Yes
FS49	Pneumatic System #4 to Surge Bin #1	5	9,220	0.000	1.08	Yes
	Hog Fuel Piles	11	22,831	0.155	13.52	Yes
	Pellet Pile	25	50,342	11.714	16.48	Yes
	Feedstock Piles	25	50,342	0.585	16.48	Yes
	Wood Dryer	33	65,599	7.654	17.60	Yes