May 17, 2023

Frank Schubert
Combined Solar Technologies, Inc.
PO Box 583
Tracy, CA 95378

Re: Notice of Preliminary Decision - Authority to Construct
Facility Number: N-10188
Project Number: N-1223107

Dear Mr. Schubert:

Enclosed for your review and comment is the District's analysis of Combined Solar Technologies, Inc.'s application for an Authority to Construct for the installation of walnut shell receiving and conveying equipment, a 65.6 MMBtu/hr (heat input) walnut-shell fired boiler, a steam turbine and electrical generator, a cooling tower, and trona or hydrated lime receiving and storage operation, at 9251 W Arbor Ave, in Tracy, California.

The notice of preliminary decision for this project has been posted on the District's website (www.valleyair.org). After addressing all comments made during the 30-day public notice period, the District intends to issue the Authority to Construct. Please submit your written comments on this project within the 30-day public comment period, as specified in the enclosed public notice.

Thank you for your cooperation in this matter. If you have any questions regarding this matter, please contact Mr. Jag Kahlon of Permit Services at (209) 557-6452.

Sincerely,

Brian Clements
Director of Permit Services

BC:JK

Enclosures

cc: Courtney Graham, CARB (w/ enclosure) via email

San Joaquin Valley Air Pollution Control District

Authority to Construct Application Review

5 MW Electric Generation Plant

Facility Name:	Combined Solar Technologies	Date:	May 16, 2023
Mailing Address:	P.O. Box 583 Tracy, CA 95378	Engineer:	Jag Kahlon
		Lead Engineer:	James Harader
Contact Person:	Frank R. Schubert		
Telephone:	(831) 224-2513		
Fax:	N/A		
E-Mail:	therub9@aol.com		
Application #(s):	N-10188-1-0 and '-4-0		
Project #:	N-1223107		
Deemed Complete:	October 24, 2022		

I. Proposal

N-10188-1-0: Walnut shell receiving and unloading operation

Combustion Solar Technologies, Inc. (referred to hereafter as "CST") has proposed to receive walnut shells in enclosed trailers from nearby walnut processing facilities. The incoming trailers will be staged on-site, and will be backed into enclosed slips prior to unload the material on an as-needed basis. The material will be slowly metered into the hoppers that are connected to a conveying system that feeds the proposed boiler.

N-10188-2-0: 65.6 MMBtu/hr Walnut Shell-Fired Boiler

CST has proposed to install a 65.6 MMBtu/hr (heat input) stoker grate walnut shell fired Zozen Boiler Co Ltd., Model ZZ-25/4.29/400-M boiler with an economizer to recover sensible heat from the exhaust to pre-heat boiler water. This boiler will provide steam to a steam turbine that is connected to 5 MW electric generator. The boiler will be equipped with a urea injection system (selective non-catalytic reduction system (SNCR)), a dry sorbent injection system, a cyclone, a baghouse and a selective catalytic reduction (SCR) system to reduce emissions. The exhaust from the boiler will be discharged through a stack. The stack will be equipped with continous emissions monitoring system (CEMS) to monitor NOx, SOx, CO, and CO2 or O2 concentrations in the exhaust.

N-10188-3-0: Cooling Tower

CST has proposed to install a cooling tower to remove heat from the low quality steam/condensate stream coming from the steam turbine. This cooling tower will be equipped with high efficiency drift eliminator designed to reduce water carryover to 0.0005% of the circulating water rate. The proposed circulating water rate is 6,538 gpm.

N-10188-4-0: Dry sorbent receiving and storage operation
CST has proposed to receive dry sorbent (trona or hydrated lime) via trucks and to conveying equipment that will load the sorbent into a silo. The laden air from the silo will be discharged through a dust collection system.

Tracy Renewable Energy, LLC (N-8887) and Combined Solar Technologies, Inc. (N-10188) are under common ownership, are located adjacent to each other, and share the same first two digits of the SIC code (49). Therefore, these companies are treated as a single Stationary Source under District Rule 2201.

Facility N-8887 was recently issued ATCs to limit facility-wide NOx emissions to 19,999 lb/rolling 12-months. These proposed units in this project, for Facility N-10188 (same stationary source), will be subject to the existing facility-wide NOx limit. Therefore, ATC's N-8887-21-1, '-22-1, and '-23-1 will be required to be converted into Permits to Operate prior to or concurrently with the ATCs issued in this project.

The draft ATC permits related to this project are included in **Appendix A** of this document.

II. Applicable Rules

Rule 2201	New and Modified Stationary Source Review Rule (8/15/19)
Rule 2410	Prevention of Significant Deterioration (6/16/11)
Rule 2520	Federally Mandated Operating Permits (8/15/19)
Rule 4001	New Source Performance Standards (4/14/99)
Rule 4002	National Emissions Standards for Hazardous Air Pollutants (5/20/04)
Rule 4101	Visible Emissions (2/17/05)
Rule 4102	Nuisance (12/17/92)
Rule 4201	Particulate Matter Concentration (12/17/92)
Rule 4202	Particulate Matter - Emission Rate (12/17/92)
Rule 4301	Fuel Burning Equipment (12/17/92)
Rule 4352	Solid Fuel Fired Boilers, Steam Generators, and Process Heaters (12/16/21)
Rule 4801	Sulfur Compounds (12/17/92)
Rule 7012	Hexavalent Chromium – Cooling Towers (12/17/92)
CH&SC 41700	Health Risk Assessment
CH&SC 42301.6	School Notice

Public Resources Code 21000-21177: California Environmental Quality Act (CEQA)
California Code of Regulations, Title 14, Division 6, Chapter 3, Sections 15000-15387: CEQA Guidelines

III. Project Location

The proposed equipment will be located at 9251 W Arbor Ave in Tracy, California. The equipment will not be located within 1,000 feet of the outer boundary of a K-12 school. Therefore, the public notification requirement of California Health and Safety Code 42301.6 is not applicable to this project.

IV. Process Description

N-10188-1-0: Walnut shell receiving and unloading operation

Walnut shells will be received by truck trailers from nearby walnut processing facilities. These trailers will be docked and walnuts will be slowly unloaded into the hoppers, from where the material is conveyed into the boiler. Use of fully enclosed trailers and slow unloading will reduce particulate matter emissions. The technique is expected to result in less fugitive dust emissions compared to dumping of the material onto the ground and then using front-end loaders to load the hoppers.

N-10188-2-0: 65.6 MMBtu/hr Walnut Shell-Fired Boiler

The boiler will be a stoker-type unit, meaning that fuel is burned on a grate as opposed to being burned in suspension or in a fluidized bed. The boiler will be equipped with a vibrating grate, upon which fuel from the charging hopper is spread using a number of distribution devices. The vibrating grate will consist of a series of grate elements in a horizontal arrangement. Half of the horizontal grate elements will be fixed and half oscillate to move fuel along the grate toward the ash discharge side of the grate. Combustion air will be injected into the combustion chamber through ports located under each grate section, while over fire air enters the combustion chamber through additional ports spaced around the combustion chamber and arranged to ensure optimal mixing and complete combustion. Bottom ash, essentially all unburned fuel residue that is too massive to become entrained in the flue gas as fly ash, will be removed from the stoker grate at the opposite end from the fuel charging hopper. The boiler will supply steam to the steam turbine, which is connected to an electrical generator to produce electric power.

N-10188-3-0: Cooling Tower

A cooling tower will be used to remove heat from low quality steam/condensate from the steam turbine. The cooling tower is a 2-cell tower, each cell will be equipped with high efficiency drift eliminator designed to reduce water carryover to 0.0005% of the circulating water rate. The proposed cooling tower will have water circulation rate of 6,538 gpm.

N-10188-4-0: Dry sorbent receiving and storage operation

CST has proposed to receive dry sorbent (trona or hydrated lime) via trucks using a conveying system to transfer the material into a silo. The laden air from the silo will be discharged through a dust collection system.

V. Equipment Listing

N-10188-1-0: WALNUT SHELL RECEIVING AND HANDLING OPERATION

N-10188-2-0: 65.6 MMBTU/HR ZOZEN BOILER CO LTD., MODEL ZZ-25/4.29/400-M, STOKER-TYPE WALNUT-SHELL FUEL FIRED BOILER WITH UREA INJECTION SYSTEM, A CYCLONE, A BAGHOUSE FILTER SYSTEM, AND A SELECTIVE CATALYTIC REDUCTION SYSTEM

N-10188-3-0: 6,538 GALLONS PER MINUTE MARLEY FIELD COOLING TOWER SERVED BY HIGH EFFICIENCY DRIFT ELIMINATORS

N-10188-4-0: DRY SORBENT RECEIVING AND STORAGE OPERATION WITH ONE 1,300 CUBIC FOOT (APPROX. DIMENSIONS 26 FEET TALL, 8 FEET DIAMETER) SILO SERVED BY A DUST COLLECTION SYSTEM

VI. Emission Control Technology Evaluation

N-10188-1-0: Walnut shell receiving and unloading operation

CST has proposed to use enclosed conveyors to transfer walnut shells from hoppers to the boilers.

Walnut shells will be received via truck trailers. The shells will not be received and stored on the ground; rather the trailers will be docked and the shells will be slowly metered into the bins. From the bins, material will be conveyed to the boilers using an enclosed conveying system. This practice is expected to significantly reduce particulate matter emissions from material handling activities at this plant, compared to a typical plant that receives and stores shells on the ground.

N-10188-2-0: 65.6 MMBtu/hr walnut shell fired boiler

The boiler will result in emissions of NO_x, SO_x, PM_{10}, CO, VOC, while ammonia injection will result in ammonia “slip” emissions.

Any operation that combusts fuel has the potential to result in NO_x emissions, which can come from the oxidation of fuel-bound nitrogen (“fuel NOx”) or from the oxidation of nitrogen in the combustion air at high temperature (“thermal NO_x”). Fuel NO_x is largely, although not directly, proportional to the fuel nitrogen content, and therefore essentially fixed in the design phase. Thermal NO_x is a function of several variables, including peak combustion temperature, the residence time at peak temperature, nitrogen concentration, and oxygen concentration or flame stoichiometry.

CST has proposed to use urea injection system (SNCR) and an add-on SCR system to reduce NOx emissions from the unit. In the SNCR, the combustion units acts as the reactor chamber. The reagent (urea solution) is generally injected within the boiler superheater and reheater radiant and convective regions, where the combustion gas temperature is at the required temperature range (1600°F to 2100°F). In general, the injection system is designed to promote mixing of the reagent with the flue gas. The number and location of urea injection is determined by the temperature profiles and flow patterns within the combustion unit. SNCR system typically reduces 30% to 50% NOx[1]. The SCR is an add-on control that will further reduce NOx emissions. In the SCR, flue gas (480°F to 800°F, with fluctuations of ±200°F) containing NOx will be react with reagent such as ammonia or urea in the presence of a catalyst to reduce up to 90% of NOx

[1] https://www3.epa.gov/ttncatc1/dir1/fsncr.pdfgo

emissions[2]. The SCR system is expected to release some unreacted ammonia called “ammonia slip” in the exhaust gases.

SO_x emissions from fuel combustion will be the result of fuel-bound sulfur being oxidized in the combustion process. CST has proposed to use dry sorbent injection (DSI) system using trona or hydrated lime sorbent. A properly engineered DSI system will reduce up to 80% of SOx emissions.

PM_{10} emissions from the boilers will be reduced with the use of a cyclone and a baghouse that can withstand high temperatures. The baghouse is expected to reduce at least 99% of particulate matter emissions.

CO and VOC emissions from the boilers will primarily the result from incomplete combustion. However, highly efficient combustion that minimizes CO and VOC emissions also tends to maximize NO_x emissions. CST is expected to use good combustion practices to reduce the formation of both CO and VOC emissions. No add-on controls are proposed to reduce CO or VOC emissions.

<u>N-10188-3-0: Cooling Tower</u>
The cooling tower is a source of PM10 emissions. PM10 emissions are due to the total dissolved solids (TDS), mostly salts, in the cooling water. In the cooling process, some of the cooling water (and TDS) escapes the cooling tower. This is referred to as drift. Some portion of the drift dries in the air before settling to ground, and its TDS content can thereby become airborne PM. The applicant has conservatively assumed that all TDS in the drift will remain suspended in the air and will dry to become airborne PM10 emissions.

Cooling water drift will be controlled using drift eliminators in each of the 2 cooling tower cells. These drift eliminators act as a coalescer for the evolved cooling water to collect on and drop back into the process stream. The proposed drift eliminators have a drift rate of 0.0005% (i.e. 0.0005% of the cooling water circulated is emitted into the atmosphere).

<u>N-10188-4-0: Dry sorbent receiving and storage operation</u>
The laden air from the silo will be discharged through a dust collection system. The system is expected to reduce at least 99% of the particulate matter emissions.

VII. General Calculations

A. Assumptions

- Assumptions will be stated as they are made during the analysis.

[2] https://www3.epa.gov/ttncatc1/dir1/fscr.pdf

B. Emission Factors

1. Pre-Project Emission Factors (EF1)

EF1 is not available since the proposed units are new emission units.

2. Post-Project Emission Factors (EF2)

N-10188-1-0: Walnut shell receiving and unloading operation
As stated previously, enclosed trailers will be backed into an enclosed slip prior to unloading the material into the enclosed hoppers, and conveying the material to the boilers.

An uncontrolled emission factor of 0.0011 lb-PM_{10}/ton of material from EPA's AP-42 Table 11.19.2-2 for a conveyor transfer point will be adjusted using the density of walnut shells and the density of aggregate material. The walnut shell density is 40-45 lb/ft^3 whereas the aggregate material density is 102 lb/ft^3. After applying the density adjustments, the uncontrolled emissions from each transfer point is 0.0005 lb-PM_{10}/ton of material (0.0011 x 45/102).

EF2 = 0.0005 lb-PM_{10}/ton of material

N-10188-2-0: 65.6 MMBtu/hr walnut shell fired boiler

Pollutant	EF2 lb/MMBtu	Source
NOx Startup & shutdown	0.0289	Proposed by the applicant
NOx Steady state	0.0179 14 ppmvd NOx @ 3% O_2[3] 0.235 lb/MW-hr	Proposed by the applicant
SOx	0.035 (block 24-hr average) 0.02 (rolling 30-day average)	Proposed by the Applicant
PM_{10}	0.0036 (0.047 lb/MW-hr)	Proposed by the Applicant
CO Startup & shutdown	0.3575	Proposed by the Applicant
CO Steady state	0.071 89 ppmvd CO @ 3% O_2[4]	Per application
VOC Startup & shutdown	0.0186	Proposed by the Applicant
VOC Steady state	0.0036	Proposed by the Applicant
NH_3	0.0129	Per application

[3](X x 10^{-6} x 9,240 dscf/MMBtu x 46 lb-NOx/lb-mole x (20.95/(20.95-3)) x 1/379.5 dscf/lb-mole = 0.0179 lb-NOx/MMBtu; X = 14 ppmvd NOx @ 3% O_2

[4] [4](X x 10^{-6} x 9,240 dscf/MMBtu x 28 lb-CO/lb-mole x (20.95/(20.95-3)) x 1/379.5 dscf/lb-mole = 0.071 lb-CO/MMBtu; X = 89 ppmvd CO @ 3% O_2

Note that bottom ash from the boiler grate will drop into a water trough from where it will conveyed via chain conveyor onto a stockpile. Water saturated ash will be loaded into the truck and shipped to a nearby disposal facility. Moisture content in the bottom ash will be above 6% (by wt.). Due to moist material handling, the bottom ash handling & truck loading system is considered to be an insignificant source of particulate matter emissions.

N-10188-3-0: Cooling tower

PM_{10} emissions from the cooling tower can be quantified using the drift of the circulating water flow rate, drift rate of 0.0005% (typical for high efficiency drift eliminators), the maximum concentration of total dissolved solids (TDS) in the water, 1,000 ppmw, and the density of water.

EF2 = (5×10^{-6} gal-drift/gal-water)($1{,}000 \times 10^{-6}$ lb-TDS/lb-drift)(8.34 lb/gal of drift water)(1 lb-PM_{10}/lb-TDS)
= 4.17×10^{-5} lb-PM_{10}/1,000 gal of water circulation

N-10188-4-0: Dry sorbent receiving and storage operation

Trona or hydrated lime will be received via truck and loading into a silo using a conveying system.

The transfer of sorbent most closely resembles ‘cement supplement unloading to elevated silo’. Therefore, a controlled emission factor of 0.0049 lb-PM_{10}/ton of material from EPA’s AP-42 Table 11.12-2 (6/06) can be used.

EF2 = 0.0049 lb-PM_{10}/ton of material

C. Calculations

1. Pre-Project Potential to Emit (PE1)

Since the proposed emission units are new emissions units, PE1 is zero for each pollutant.

2. Post-Project Potential to Emit (PE2)

N-10188-1-0: Walnut shell receiving and unloading operation

PE2 (lb/hr) = EF2 (lb-PM_{10}/ton of material) x 4 tons/hr
PE2 (lb/day) = EF2 (lb-PM_{10}/ton of material) x 96 tons/day
PE2 (lb/yr) = EF2 (lb-PM_{10}/ton of material) x 33,600 tons/yr

Operation	EF2 (lb-PM_{10}/ton of material)	PE2 (lb/hr)	PE2 (lb/day)	PE2 (lb/yr)
Transfer (metering) of walnut shells from trailers to hoppers	0.0005	0.002	0.1	17
Hoppers to an elevators	0.0005	0.002	0.1	17
Enclosed elevators to enclosed conveyors that delivers material to the boiler	0.0005	0.002	0.1	17
Total:		0.006	0.3	51

N-10188-2-0: 65.6 MMBtu/hr walnut shell fired boiler

Per applicant, the maximum startup duration will be 12 hr/day, 24 hr/year, and the maximum shutdown duration will be 12 hr/day and 24 hr/year. The applicant wants to operate the boiler up to 350 days/yr, which equates to 8,400 hr/year.

NOx, CO and VOC

Startup/Shutdown

$PE2_{daily}$ = EF2 (lb/MMBtu) x 65.6 MMBtu/hr x 12 hr/day

$PE2_{annual}$ = EF2 (lb/MMBtu) x 65.6 MMBtu/hr x 24 hr/yr

Steady-state

$PE2_{daily}$ = EF2 (lb/MMBtu) x 65.6 MMBtu/hr x 24 hr/day

$PE2_{annual}$ = EF2 (lb/MMBtu) x 65.6 MMBtu/hr x (8,400 – 24 – 24) hr/yr

SOx

Startup/Shutdown/Steady-state

$PE2_{daily}$ = $EF2_{\text{Block 24-hr avg}}$ (lb/MMBtu) x 65.6 MMBtu/hr x 24 hr/day

$PE2_{annual}$ = $EF2_{\text{Rolling 30-day avg}}$ (lb/MMBtu) x 65.6 MMBtu/hr x 8,400 hr/yr

PM_{10} and NH_3

Startup/Shutdown/Steady-state

$PE2_{daily}$ = EF2 (lb/MMBtu) x 65.6 MMBtu/hr x 24 hr/day

$PE2_{annual}$ = EF2 (lb/MMBtu) x 65.6 MMBtu/hr x 8,400 hr/yr

Pollutant	Event	EF2 (lb/MMBtu)	PE2 (lb/day)	PE2 (lb/yr)
NOx	Startup (12-hr)	0.0289	22.8	46
	Steady-state (24 hr)	0.0179	28.2	9,807
	Shutdown (12 hr)	0.0289	22.8	46
		Total:	**45.6***	**9,899**
SOx	Startup, steady-state, or shutdown	0.035	55.1	--
		0.02	--	11,021
		Total:	**55.1**	**11,021**
PM_{10}	Startup, steady-state, or shutdown	0.0036	**5.7**	**1,984**
CO	Startup (12 hr)	0.3575	281.4	563
	Steady-state (24 hr)	0.071	55.9	38,900
	Shutdown (12 hr)	0.3575	281.4	563
		Total:	**562.8***	**40,026**
VOC	Startup (12 hr)	0.0186	14.6	29
	Steady-state (24 hr)	0.0036	5.7	1,972
	Shutdown (12 hr)	0.0186	14.6	29
		Total:	**29.2***	**2,030**
NH_3	Startup, steady-state, or shutdown	0.0129	**20.3**	**7,108**

* Worst-case daily emissions occur when 12 hours of startup and 12 hours of shutdown are assumed.

<u>Commissioning period:</u>
CST has proposed to conduct commissioning activities, including but not limited to, all testing, adjustment, tuning, and calibration activities recommended by the equipment manufacturers and the construction contractor to ensure safe and reliable steady state operation of the boiler and associated equipment. During the commissioning activities, the applicant has proposed to limit the daily emissions rate of each pollutant (NOx, SOx, PM_{10}, CO, VOC and NH_3) to the maximum emissions estimated in the table above.

NOx, SOx, and CO emissions during commissioning period will be measured using the CEMS systems. PM10, VOC and NH3 emissions will be estimated using EFs obtained during the initial source testing, heat input rate to the boiler, and hours of operation during the commissioning period. The emissions occurred during commissioning period are required to be counted toward annual emission limits.

<u>N-10188-3-0: Cooling tower</u>
PE2 = (4.17×10^{-5} lb-PM_{10}/1,000 gal of water circulation)(6,538 gal/min)(60 min/hr)(24 hr/day)
= 0.4 lb-PM_{10}/day

Using a worst-case operating scenario of 365 days/year, the annual emissions are:

PE2 (lb/yr) = 0.4 lb-PM_{10}/day x 365 days/yr
= 146 lb-PM_{10}/yr

N-10188-4-0: Dry sorbent receiving and storage operation
CST will receive a truck load (25 tons) of dry sorbent material during a given day. Thus,

PE2 (lb/day) = EF2 (lb-PM_{10}/ton of material) x 25 tons/day

Using a worst-case operating scenario 365 days/year, the annual emissions are:

PE2 (lb/yr) = EF2 (lb-PM_{10}/ton of material) x 25 tons/day x 365 days/yr

Operation	EF2 (lb-PM_{10}/ton of material)	PE2 (lb/day)	PE2 (lb/yr)
Receive trona or hydrated lime sorbents	0.0049	0.1	45

3. Pre-Project Stationary Source Potential to Emit (SSPE1)

Pursuant to District Rule 2201, the SSPE1 is the Potential to Emit (PE) from all units with valid Authorities to Construct (ATC) or Permits to Operate (PTO) at the Stationary Source and the quantity of Emission Reduction Credits (ERC) which have been banked since September 19, 1991 for Actual Emissions Reductions (AER) that have occurred at the source, and which have not been used on-site. As stated previously, facility N-8887 and N-10188, are same stationary source.

SSPE1 (lb/year)						
Permit Unit	NO_X	SO_X	PM_{10}	CO	VOC	NH3
N-8887-19-0	19,999	0	876	0	0	--
N-8887-21-1		0	5	47	5	--
N-8887-22-1		11,021	1,984	40,026	2,030	7,108
N-8887-23-1		11,021	1,984	40,026	2,030	7,108
N-8887-24-0		0	15	0	0	--
N-8887-25-0		0	869 (861+8)	0	700	--
N-8887-26-0		0	0	0	0	--
N-8887-27-0		0	102	0	0	--
N-8887-28-0		0	45	0	0	0
SSPE1	**19,999**	**22,042**	**5,880**	**80,099**	**4,765**	**14,216**

4. Post-Project Stationary Source Potential to Emit (SSPE2)

Pursuant to District Rule 2201, the SSPE2 is the PE from all units with valid ATCs or PTOs at the Stationary Source and the quantity of ERCs which have been banked since September 19, 1991 for AER that have occurred at the source, and which have not been used on-site. The applicant has proposed to establish facility-wide NOx emissions of 19,999 pounds per year (12-month rolling basis) for both facility N-8887 and N-10188.

SSPE2 (lb/year)						
Permit Unit	**NO_X**	**SO_X**	**PM_{10}**	**CO**	**VOC**	**NH3**
N-8887-19-0	19,999	0	876	0	0	--
N-8887-21-1		0	5	47	5	--
N-8887-22-1		11,021	1,984	40,026	2,030	7,108
N-8887-23-1		11,021	1,984	40,026	2,030	7,108
N-8887-24-0		0	15	0	0	--
N-8887-25-0		0	869	0	700	--
N-8887-26-0		0	0	0	0	--
N-8887-27-0		0	102	0	0	--
N-8887-28-0		0	45	0	0	0
N-10188-1-0		0	51	0	0	0
N-10188-2-0		11,021	1,984	40,026	2,030	7,108
N-10188-3-0		0	146	0	0	0
N-10188-4-0		0	45	0	0	0
SSPE2	**19,999**	**33,063**	**8,106**	**120,125**	**6,795**	**21,324**

5. Major Source Determination

Rule 2201 Major Source Determination:

Pursuant to District Rule 2201, a Major Source is a stationary source with a SSPE2 equal to or exceeding one or more of the following threshold values. For the purposes of determining major source status the following shall not be included:

- any ERCs associated with the stationary source
- Emissions from non-road IC engines (i.e. IC engines at a particular site at the facility for less than 12 months), pursuant to the Clean Air Act, Title 3, Section 302, US Codes 7602(j) and (z)
- Fugitive emissions, except for the specific source categories specified in 40 CFR 70.2

Rule 2201 Major Source Determination (lb/year)						
	NO_X	**SO_X**	**PM_{10}**	**$*PM_{2.5}$**	**CO**	**VOC**
SSPE1	19,999	22,042	5,880	5,880	80,099	4,765
SSPE2	19,999	33,063	8,106	8,106	120,125	6,795
Major Source Threshold	20,000	140,000	140,000	140,000	200,000	20,000
Becoming Major Source?	No	No	No	No	No	No

*$PM_{2.5}$ assumed to be equal to PM_{10}

As seen in the table above, the facility is not a Major Source for any pollutant, nor is it becoming a Major Source for any pollutant after the proposed project.

Rule 2410 Major Source Determination:

The facility or the equipment evaluated under this project is not listed as one of the categories specified in 40 CFR 52.21 (b)(1)(iii). Therefore the PSD Major Source threshold is 250 tpy for any regulated NSR pollutant.

PSD Major Source Determination (tons/year)						
	NO_2	VOC	SO_2	CO	PM	PM_{10}
Estimated Facility PE before Project Increase	10.0	2.4	11.0	40.0	2.9	2.9
PSD Major Source Thresholds	250	250	250	250	250	250
PSD Major Source?	No	No	No	No	No	No

As shown above, the facility is not an existing PSD major source for any regulated NSR pollutant expected to be emitted at this facility.

6. Baseline Emissions (BE)

The BE calculation (in lb/year) is performed pollutant-by-pollutant for each unit within the project to calculate the QNEC, and if applicable, to determine the amount of offsets required.

Pursuant to District Rule 2201, BE = PE1 for:

- Any unit located at a non-Major Source,
- Any Highly-Utilized Emissions Unit, located at a Major Source,
- Any Fully-Offset Emissions Unit, located at a Major Source, or
- Any Clean Emissions Unit, located at a Major Source.

otherwise,

BE = Historic Actual Emissions (HAE), calculated pursuant to District Rule 2201.

<u>N-10188-1-0 through ‘-4-0:</u>

Since the emission units in this project are new emission units, BE is zero for each pollutant.

7. SB 288 Major Modification

40 CFR Part 51.165 defines a SB 288 Major Modification as any physical change in or change in the method of operation of a major stationary source that would result in a significant net emissions increase of any pollutant subject to regulation under the Act.

As seen in table in Section VII.C.5 above, this facility is not a Major Source for any pollutant; consequently, the proposed project cannot trigger SB-288 Major Modification.

8. Federal Major Modification / New Major Source

Federal Major Modification

District Rule 2201 states that a Federal Major Modification is the same as a "Major Modification" as defined in 40 CFR 51.165 and part D of Title I of the CAA.

As defined in 40 CFR 51.165, Section (a)(1)(v) and part D of Title I of the CAA, a Federal Major Modification is any physical change in or change in the method of operation of a major stationary source that would result in a significant net emissions increase of any pollutant subject to regulation under the Act. The significant net emission increase threshold for each criteria pollutant is included in Rule 2201.

As seen in table in Section VII.C.5 above, this facility is not a Major Source for any pollutant; consequently, the proposed project cannot trigger Federal Modification.

New Major Source

As seen in section VII.C.5 above, this facility is not becoming a Major Source as a result of this project, therefore, this facility is not a New Major Source pursuant to 40 CFR 51.165 a(1)(iv)(A)(3).

9. Rule 2410 – Prevention of Significant Deterioration (PSD) Applicability Determination

Rule 2410 applies to any pollutant regulated under the Clean Air Act, except those for which the District has been classified nonattainment. The pollutants which must be addressed in the PSD applicability determination for sources located in the SJV and which are emitted in this project are: (See 52.21 (b) (23) definition of significant)

- NO2 (as a primary pollutant)
- SO2 (as a primary pollutant)
- CO
- PM
- PM10

I. Project Emissions Increase - New Major Source Determination

The post-project potentials to emit from all new and modified units are compared to the PSD major source thresholds to determine if the project constitutes a new major source subject to PSD requirements.

The facility or the equipment evaluated under this project is not listed as one of the categories specified in 40 CFR 52.21 (b)(1)(iii). The PSD Major Source threshold is 250 tpy for any regulated NSR pollutant.

PSD Major Source Determination: Potential to Emit (tons/year)						
	NO_2	VOC	SO_2	CO	PM	PM_{10}
Total PE from New and Modified Units	4.9	1.0	5.5	20.0	1.1	1.1
PSD Major Source threshold	250	250	250	250	250	250
New PSD Major Source?	No	No	No	No	No	No

As shown in the table above, the potential to emit for the project, by itself, does not exceed any PSD major source threshold. Therefore Rule 2410 is not applicable and no further analysis is required.

10. Quarterly Net Emissions Change (QNEC)

The QNEC is calculated solely to establish emissions that are used to complete the District's PAS emissions profile screen. Detailed QNEC calculations are included in **Appendix E.**

VIII. Compliance Determination

Rule 1080 Stack Monitoring

This rule grants the APCO the authority to request the installation, use, maintenance, and inspection of continuous emissions monitors, and specifies performance standards for the equipment and administrative requirements for recordkeeping, reporting, and notification.

CST has proposed to monitor NOx, SOx, CO, and O2 or CO2 concentrations from the boiler using continuous emissions monitoring system (CEMS). The following conditions will be included in the boiler permit:

- The owner or operator shall install, certify, maintain, operate and quality-assure a Continuous Emissions Monitoring System (CEMS) which continuously measures and records the exhaust gas NOx, SOx, CO and O2 or CO2 concentrations for each boiler.

CEMS shall monitor emissions during all types of operation, including during startup and shutdown periods, provided the CEMS passes the relative accuracy requirement specified herein during startups and shutdowns periods. If relative accuracy of CEMS cannot be demonstrated during startup or shutdown periods, CEMS results during startup and shutdown events shall be replaced with startup emission rates obtained during initial source testing. [District Rules 1080, 2201 and 4352]

- Each CEMS shall complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each 15-minute quadrant of the hour or shall meet equivalent specifications established by mutual agreement of the District, the CARB and the EPA. [District Rules 1080, 2201, and 4352]

- Each CEMS shall meet the requirements in 40 CFR 60, Appendix F Procedure 1 for CEMS and Part 60, Appendix B Performance Specification 6 (PS6), or shall meet equivalent specifications established by mutual agreement of the District, the CARB, and the EPA. [District Rules 1080, 2201 and 4352]

- In accordance with 40 CFR Part 60, Appendix F, NOx, SOx, CO and O2 or CO2 monitors must be audited at least once each calendar quarter, by conducting cylinder gas audits (CGA) or relative accuracy audits (RAA). CGA or RAA may be conducted three of four calendar quarters, but no more than three calendar quarters in succession. Audit reports shall be submitted along with quarterly compliance reports to the District. [District Rules 1080, 2201 and 4352]

- The owner/operator shall perform a RATA for NOx, SOx, CO and O2 or CO2 (as specified in 40 CFR Part 60, Appendix F) and flow rate sensor at least once every four calendar quarters. The permittee shall comply with the applicable requirements for quality assurance testing and maintenance of the CEMS equipment in accordance with the procedures and guidance specified in 40 CFR Part 60, Appendix F for CEMS equipment. [District Rules 1080, 2201, and 4352]

- APCO or an authorized representative shall be allowed to inspect, as determined to be necessary, the required monitoring devices to ensure that such devices are functioning properly. [District Rule 1080]

- The CEMS data shall be reduced to hourly averages as specified in 40 CFR 60.13(h), or by other methods deemed equivalent by mutual agreement with the District, the CARB, and the EPA. [District Rules 1080, 2201 and 4352]

- Upon written notice from the District, the owner or operator shall provide a summary of the data obtained from the CEMS. This summary shall be in the form and the manner prescribed by the District. [District Rules 1080 and 2201]

- The facility shall install and maintain equipment, facilities, and systems compatible with the District's CEMS data polling software system and shall make CEMS data available to the District's automated polling system on a daily basis. [District Rules 1080, 2201 and 4352]

- Upon notice by the District that the facility's CEMS is not providing polling data, the facility may continue to operate without providing automated data for a maximum of 30 days per calendar year provided the CEMS data is sent to the District by a District-approved alternative method. [District Rule 1080]

- The permittee shall maintain the following records for CEMS equipment: (1) Date, time and duration of any malfunction; (2) Date of performance testing; (3) Date of evaluations, calibrations, checks, and adjustments; and (4) Date and time period for which CEMS was inoperative. [District Rules 1080, 2201 and 4352]

- The owner or operator shall maintain records of NOx, SOx and CO emissions and submit a written report each calendar quarter to the District containing the following information for each operating day: (1) Calendar date; (2) NOx (expressed as NO2), SOx and CO emission rate (lb/hr) measured at the exhaust of each boiler; (3) NOx (expressed as NO2), SOx and CO emissions rate factor (lb/MMBtu, over a block 24-hour average basis), (4) Total daily NOx, SOx and CO emission rates (lb/day) calculated at the end of each operating day from the measured total hourly NOx, SOx and CO emission rates; (5) The 30-day rolling average SOx emission rate (lb/MMBtu); (6) The total monthly NOx, SOx and CO emission rates (lb/month) calculated at the end of each month using total daily NOx, SOx and CO emissions rates; (7) The total annual NOx, SOx and CO emission rates (lb/year, on a rolling 12-month basis) calculated at the end of each month using total monthly NOx emission rate; (8) Identification of the operating days when NOx, SOx and CO emission rates are in excess of the permitted levels, with the reasons for such excess emissions as well as a description of corrective actions taken; (9) Identification of the operating days for which pollutant data have not been obtained, including reasons for not obtaining sufficient data and a description of corrective actions taken; (10) Identification of the times when emission data have been excluded from the calculation of average emission rates and the reasons for excluding such data; (11) Identification of each parameter used in calculations; (12) Identification of the times when the pollutant concentration exceeded full span of the CEMS; (13) Description of any modifications to the CEMS that could affect the ability of the CEMS to comply with Performance Specification 6; (14) Results of daily CEMS drift tests and quarterly accuracy assessments as required under Appendix F, Procedure 1 of Part 60; and (15) A negative declaration when no excess emissions occurred. The report is due on the 30th day following the end of the calendar quarter. [District Rules 1080, 2201 and 4352]

- The owner or operator may submit electronic quarterly reports in lieu of submitting the written reports. The format of each quarterly electronic report shall be coordinated with the District. 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 permit was achieved during the reporting period. Before submitting reports in the electronic format, the owner or operator shall coordinate with the

District to obtain their agreement to submit reports in this alternative format. [District Rules 1080, 2201 and 4352]

Compliance is expected with this rule.

Rule 2201 New and Modified Stationary Source Review Rule

A. Best Available Control Technology (BACT)

1. BACT Applicability

Pursuant to District Rule 2201, Section 4.1, BACT requirements are triggered on a pollutant-by-pollutant basis and on an emissions unit-by-emissions unit basis. Unless specifically exempted by Rule 2201, BACT shall be required for the following actions*:

a. Any new emissions unit with a potential to emit exceeding two pounds per day,
b. The relocation from one Stationary Source to another of an existing emissions unit with a potential to emit exceeding two pounds per day,
c. Modifications to an existing emissions unit with a valid Permit to Operate resulting in an Adjusted Increase in Permitted Emissions (AIPE) exceeding two pounds per day, and/or
d. Any new or modified emissions unit, in a stationary source project, which results in an SB 288 Major Modification or a Federal Major Modification, as defined by the rule.

*Except for CO emissions from a new or modified emissions unit at a Stationary Source with an SSPE2 of less than 200,000 pounds per year of CO.

a. New emissions units – PE > 2 lb/day

N-10188-1-0: Walnut shell receiving and unloading operation
Per section VII.C.2 above, PE2 is not greater than 2 lb/day for PM_{10} emissions for any source operation. Thus, BACT is not triggered for PM_{10} emissions.

N-10188-2-0: 65.6 MMBtu/hr walnut shell fired boiler
Per section VII.C.2 above, PE2 is greater than 2 lb/day for NOx, SOx, PM_{10}, CO and VOC emissions. The facility's total CO emissions do not exceed 200,000 lb/yr. Thus, BACT is triggered for NOx, SOx, PM_{10} and VOC emissions.

N-10188-3-0: Cooling tower
Per section VII.C.2 above, PE2 is not greater than 2 lb/day for PM_{10} emissions for this operation. Thus, BACT is not triggered for PM_{10} emissions.

N-10188-4-0: Dry sorbent receiving and storage operation
Per section VII.C.2 above, PE2 is not greater than 2 lb/day for PM_{10} emissions for this operation. Thus, BACT is not triggered for PM_{10} emissions.

b. Relocation of emissions units – PE > 2 lb/day

None of the emissions units are being relocated from one stationary source to another; therefore BACT is not triggered.

c. Modification of emissions units – AIPE > 2 lb/day

None of the emission units are being modified emissions in this project. Therefore BACT is not triggered.

d. SB 288/Federal Major Modification

As discussed in Sections VII.C.7 and VII.C.8 above, this project does not constitute an SB 288 and/or Federal Major Modification for any pollutant. Therefore BACT is not triggered for any pollutant.

2. Top-Down BACT Analysis

Per Permit Services Policies and Procedures for BACT, a Top-Down BACT analysis shall be performed as a part of the application review for each application subject to the BACT requirements pursuant to the District Rule 2201.

<u>N-10188-2-0: 65.6 MMBtu/hr walnut shell fired boiler</u>
A project specific BACT analysis is conducted to address BACT for NOx, SOx, PM10 and VOC emissions. Pursuant to the Top-Down BACT Analysis (see **Appendix B**), BACT has been satisfied with the following:

NOx:
CST has proposed to achieve NOx emissions of 0.0179 lb/MMBtu during steady state and 0.0289 lb/MMBtu during startup using urea injection system and a selective catalytic reduction system. Thus, this proposal meets BACT requirements.

SOx:
The applicant has proposed to achieve SOx emissions of 0.035 lb/MMBtu (block 24-hour average) and 0.02 lb/MMBtu (rolling 30-day average) during startup, steady state and shutdown periods through use of a dry sorbent injection system using Trona or hydrated lime sorbent. Thus, this proposal meets BACT requirements.

PM_{10}:
The applicant has proposed to achieve PM10 emissions of 0.0036 lb/MMBtu during startup, steady-state and shutdown periods through the use of a cyclone and high temperature baghouse. Thus, this proposal meets BACT requirements.

VOC:
The applicant has proposed to achieve 0.0036 lb/MMBtu during steady-state state period Thus, this proposal meets BACT requirements.

B. Offsets

1. Offset Applicability

Pursuant to District Rule 2201, Section 4.5, offset requirements shall be triggered on a pollutant by pollutant basis and shall be required if the SSPE2 equals or exceeds the offset threshold levels in Table 4-1 of Rule 2201.

The SSPE2 is compared to the offset thresholds in the following table.

Offset Determination (lb/year)					
	NO_X	SO_X	PM_{10}	CO	VOC
SSPE2	19,999	33,063	8,106	120,125	6,795
Offset Thresholds	20,000	54,750	29,200	200,000	20,000
Offsets Triggered?	No	No	No	No	No

2. Quantity of District Offsets Required

As seen the table above, the SSPE2 is not greater than the offset thresholds for any pollutant. Therefore offset are not triggered and no further calculations are required for this project.

C. Public Notification

1. Applicability

Pursuant to District Rule 2201, Section 5.4, public noticing is required for:

a. New Major Sources, Federal Major Modifications, and SB 288 Major Modifications,
b. Any new emissions unit with a Potential to Emit greater than 100 pounds during any one day for any one pollutant,
c. Any project which results in the offset thresholds being surpassed,
d. Any project with an SSIPE of greater than 20,000 lb/year for any pollutant, and/or
e. Any project which results in a Title V significant permit modification

a. New Major Sources, Federal Major Modifications, and SB 288 Major Modifications

Per sections VII.C.7 and VII.C.8 above, this project does not constitute an SB 288 or a Federal Major Modification, or a New Major Source. Consequently, public noticing is not required under this section.

b. PE > 100 lb/day

Applications which include a new emissions unit with a PE greater than 100 pounds during any one day for any pollutant will trigger public noticing requirements.

As seen in Section VII.C.2 above, the potential CO emissions from unit N-10188-2-0 are greater than 100 lb/day, therefore public notice is required.

c. Offset Threshold

Public notification is required if the pre-project Stationary Source Potential to Emit (SSPE1) is increased to a level exceeding the offset threshold levels. The following table compares the SSPE1 with the SSPE2 in order to determine if any offset thresholds have been surpassed with this project.

Offset Thresholds				
Pollutant	**SSPE1 (lb/year)**	**SSPE2 (lb/year)**	**Offset Threshold**	**Public Notice Required?**
NO_X	19,999	19,999	20,000 lb/year	No
SO_X	22,042	33,063	54,750 lb/year	No
PM_{10}	5,880	8,106	29,200 lb/year	No
CO	80,099	120,125	200,000 lb/year	No
VOC	4,765	6,795	20,000 lb/year	No

As seen in the table above, offset threshold did not surpass for any pollutant due to this project. Thus, public notice for offset purposes is not required.

d. SSIPE > 20,000 lb/year

Public notification is required for any permitting action that results in a SSIPE of more than 20,000 lb/year of any affected pollutant. According to District policy, the SSIPE = SSPE2 – SSPE1. The SSIPE is compared to the SSIPE Public Notice thresholds in the following table.

SSIPE Public Notice Thresholds					
Pollutant	**SSPE2 (lb/year)**	**SSPE1 (lb/year)**	**SSIPE (lb/year)**	**SSIPE Public Notice Threshold**	**Public Notice Required?**
NO_x	19,999	19,999	0	20,000 lb/year	No
SO_x	33,063	22,042	11,021	20,000 lb/year	No
PM_{10}	8,106	5,880	2,096	20,000 lb/year	No
CO	120,125	80,099	40,026	20,000 lb/year	Yes
VOC	6,795	4,765	2,030	20,000 lb/year	No
NH_3	21,324	14,216	7,108	20,000 lb/year	No

As seen in the table above, the SSIPE for CO is greater than 20,000 lb/year; therefore public noticing for SSIPE purposes is required.

e. Title V Significant Permit Modification

Since this facility does not have a Title V operating permit, the proposed project cannot be a Title V significant Modification. Consequently, public noticing is not required.

2. Public Notice Action

As discussed above, public noticing is required for this project. Public notice documents will be submitted to the California Air Resources Board (CARB) and a public notice will be electronically published on the District's website prior to the issuance of the ATCs under this project.

D. Daily Emission Limits (DELs)

DELs and other enforceable conditions are required by Rule 2201 to restrict a unit's maximum daily emissions, to a level at or below the emissions associated with the maximum design capacity. The DEL must be contained in the latest ATC and contained in or enforced by the latest PTO and enforceable, in a practicable manner, on a daily basis. DELs are also required to enforce the applicability of BACT.

Proposed Rule 2201 (DEL) Conditions:

N-10188-1-0: Walnut shell receiving and unloading operation

- PM_{10} emissions from walnut shell receiving and transferring operations shall not exceed 0.00152 pounds per ton of material processed. [District Rule 2201]
- The amount of walnut shells received shall not exceed any of the following limits: 96 tons/day and 33,600 tons/year. [District Rule 2201]

N-10188-2-0: 65.6 MMBtu/hr walnut shell fired boiler
The following condition will be included in the permit:

- Only walnut shells shall be used as fuel in this boiler. [District Rules 2201 and 4102]

Startup/shutdown:

- Upon completing commissioning period, the startup period for the boiler shall not exceed any of the following limits: 12 hours during any one day and 24 hours per calendar year. [District Rules 2201 and 4352]

- Upon completing commissioning period, the shutdown period for the boiler shall not exceed any of the following limits: 12 hours during any one day and 24 hours per calendar year. [District Rules 2201 and 4352]

- Upon completing commissioning period, during periods of startup and shutdown, emissions from this boiler shall not exceed any of the following limits: 0.0289 lb-NOx/MMBtu (expressed as NO2), 0.3575 lb-CO/MMBtu, and 0.0186 lb-VOC/MMBtu (expressed as CH4), all emission limits averaged over the entire startup or shutdown period. [District Rule 2201]

Steady-state:

- Upon completing commissioning period, except during periods of startup and shutdown, emissions from this boiler shall not exceed any of the following limits: 0.0179 lb-NOx/MMBtu (expressed as NO2) over a block 24-hour average basis, 0.071 lb-CO/MMBtu over a block 24-hour average basis, 0.0036 lb-VOC/MMBtu (expressed as CH4) over a 30-minute period. [District Rules 2201 and 4352]

Startup/steady state/shutdown:

- Upon completing commissioning period, during periods of startup, shutdown or steady state, emissions from this boiler shall not exceed any of the following limits: 0.035 lb-SOx/MMBtu (expressed as SO2) on a bock 24-hour average basis and 0.02 lb-SOx/MMBtu (expressed as SO2) on a rolling 30-day average basis, and 0.0036 lb-PM10/MMBtu (both filterable and condensable). [District Rules 2201 and 4352]

- Upon completing commissioning period, during periods of startup, shutdown or steady state, ammonia (NH3) slip emissions associated with boiler's NOx control system shall not exceed 0.0129 lb/MMBtu. [District Rule 2201]

Commissioning Period:

- Commissioning activities are defined as, but not limited to, all testing, adjustment, tuning, and calibration activities recommended by the equipment manufacturers and the construction contractor to ensure safe and reliable steady state operation of the boiler and associated system. [District Rule 2201]

- Commissioning period shall commence when all mechanical, electrical, and control systems are installed and individual system startup has been completed, or when the boiler is first fired, whichever occurs first. The commissioning period shall terminate when the boiler has completed initial source testing, completed final boiler tuning, and is available for commercial operation. [District Rule 2201]

- During the commissioning period, the emission rates from the boiler system shall not exceed any of the following limits: NOx (as NO2) - 45.6 lb/day; VOC (as CH4) –29.2 lb/day; CO –562.8 lb/day; PM10 5.7 lb/day; SOx (as SO2) - 55.1 lb/day or NH3 (from SCR system) –20.3 lb/day. [District Rule 2201]

- During commissioning period, NOx, CO and SOx emissions rate shall be monitored and recorded using installed and calibrated CEMS. [District Rule 2201]

- Commissioning period PM_{10}, VOC and NH3 emissions rate shall be estimated using emission factors (lb/MMBtu) from the initial source testing, actual fuel heat input rate (MMBtu/hr), and hour of operation (hr/day). [District Rule 2201]

- The total annual mass emissions of NOx, SOx, PM10, CO, VOC and NH3 emissions that are emitted during the commissioning period shall accrue towards the annual emission limits. [District Rule 2201]

Note that records of date, type of commissioning activity, heat input rate to the boiler, hours of operation, and hourly, daily and up-to-date annual mass emission rates are required for each pollutant during commissioning period.

In addition, the following condition will ensure on-going compliance with the annual emission rates:

- The combined total NOx emissions from the emission units at facilities N-8887 and N-10188 shall not exceed 19,999 pounds during any consecutive 12-month period. [District Rule 2201]

- Emissions from this boiler shall not exceed any of the following limits: 9,899 lb-NOx/year (expressed as NO2), 11,021 lb-SOx/year (expressed as SO2), 1,984 lb-PM10/year, 40,026 lb-CO/year, 2,030 lb-VOC/year (expressed as CH4) and 7,108 lb-NH3/year. These limits are on a 12 consecutive month rolling basis. Compliance with NOx, CO and SOx limits shall be determined from CEMS data. Compliance with PM10, VOC and NH3 limits shall be calculated using emission factors (the most recent source test results), actual heat input to the boiler, and actual operating time. [District Rule 2201]

- During all types of operation, ammonia injection into the SCR system shall occur once the minimum temperature established during the initial source testing at the catalyst face has been reached to ensure NOx emission reductions can occur with a reasonable level of ammonia slip. The minimum temperature established during the initial testing shall be administratively included in the permit to operate. The established temperature may be modified administratively as necessary following any replacement of the SCR catalyst material. [District Rule 2201]

- The SCR system shall be equipped with a continuous temperature monitoring system to measure and record the temperature at the catalyst face. [District Rule 2201]

N-10188-3-0: Cooling tower

- PM_{10} emissions shall not exceed 0.4 pounds in any one day. [District Rule 2201]

N-10188-4-0: Dry sorbent receiving and storage operation

- Only trona or hydrated lime shall be received as a dry sorbent material. [District Rules 4102 and 2201]

- PM_{10} emissions from dry sorbent material receiving and storage shall not exceed 0.0049 pounds per ton of material processed. [District Rule 2201]

- No more than 25 tons of dry sorbent material shall be received in any one day. [District Rule 2201]

E. Compliance Assurance

1. Source Testing

N-10188-1-0: Walnut shell receiving and unloading operation
The potential emission are estimated using generally accepted emission factors; therefore, source testing is not required for this operation.

N-10188-2-0: 65.6 MMBtu/hr walnut shell fired boiler
District Policy APR-1705 requires that the cogeneration and resource recovery facilities utilizing external combustion boilers or turbines must be tested upon initial start-up and annually thereafter. NOx, PM_{10} and CO shall be tested for all units, SOx shall be tested for units fired on liquid or solid fuel, and VOC shall be tested for units fired on waste gas which contains VOCs. Note that the District has historically required to also test VOC emissions from solid fuel-fired boilers.

Startup/shutdown:
To verify compliance with the proposed NOx, CO and VOC startup/shutdown emissions rates, the proposed boiler is required to be tested within 60 days of initial startup.

Steady state:
To verify compliance with the proposed steady-state NOx, CO, PM_{10}, SOx and VOC emissions, the proposed boiler is required to be tested within 60 days of initial startup and at least once every 12-months thereafter.

N-10188-3-0: Cooling tower
The applicant will be required to perform a blowdown water sample analysis by independent laboratory within 60 days of initial startup and quarterly thereafter. This sample analysis along with water circulation rate, drift rate of 0.0005%, and operating time will be required to be used to demonstrate compliance with the permitted emission limits.

N-10188-4-0: Dry sorbent receiving and storage operation
District Policy APR-1705 requires that non-combustion equipment served by a baghouse or dust collector with expected PM_{10} emissions of 30 pounds per day or greater must be tested upon initial start-up. Units with PM_{10} emissions in excess of 70 pounds per day should also be tested on annual basis.

Per section VII.C.2 above, the potential PM_{10} emissions from this operation are below 30 pounds per day. Thus, source testing is not required for this operation.

2. Monitoring

N-10188-1-0: Walnut shell receiving and unloading operation
No monitoring is required to demonstrate compliance with Rule 2201.

N-10188-2-0: 65.6 MMBtu/hr walnut shell fired boiler
NOx, SOx, and CO:
The applicant has proposed to use a CEMS to measure and record NOx, SOx, CO and O2 concentrations. The proposed CEMS system must comply with all applicable requirements from 40 CFR Part 60 for CEMS.

PM_{10}:
The applicant has proposed to install, operate and maintain a differential pressure gauge that would continuously monitor the pressure difference across the bags. This monitoring scheme will ensure that baghouse operates within the pressure range suggested by the manufacturer.

VOC:
No monitoring is required for VOC emissions.

N-10188-3-0: Cooling tower
The owner or operator will be required to monitor water re-circulation rate (gallons/day). The circulation rate is required to be used with quarterly total dissolved solids (ppm) to verify compliance with the daily emission limit.

N-10188-4-0: Dry sorbent receiving and storage operation
The owner or operator is required to monitor differential pressure across the filter during loading the silos to ensure that the pressure stays within the established differential pressure range readings. In addition, the operator will also be required to thoroughly inspect the filter media annually for tears, scuffs, abrasions, holes, or any evidence of particulate matter leaks, and replace the media as needed.

3. Recordkeeping

Recordkeeping is required to demonstrate compliance with the offset, public notification and daily emission limit requirements of Rule 2201. The following condition(s) are listed on the permit to operate:

N-10188-1-0: Walnut shell receiving and unloading operation
The owner or operator will be required to keep records of date, amount of walnut shells received (dry-tons/day), and cumulative total amount of walnut shells received up-to-date in a year (dry-tons/yr).

N-10188-2-0: 65.6 MMBtu/hr (each) walnut shell fired boiler (boiler #1)
The owner or operator will be required to keep the following records: boiler startup time, boiler shutdown time, duration of each startup period, duration of each shutdown period, hourly, daily, monthly, and annual records of emissions of NOx, SOx, PM_{10}, CO and VOC and NH3 emissions rates, SCR temperature records, baghouse pressure differential reading records, baghouse filter media changeout records, amount of fuel used, HHV of the fuel, and all CEMS records.

N-10188-3-0: Cooling tower
The owner or operator will be required to maintain records of quarterly blowdown water sample analysis showing total dissolved solids content, daily water circulation rate, total operating time (hours/day) and daily PM_{10} emissions. Each of these records is required to be kept for a period of at least 5 years from the date of such record.

N-10188-4-0: Dry sorbent receiving and storage operation
The owner or operator will be required to keep records of date, name of the material, and amount of material loaded in the silo (tons/day). In addition, differential pressure records will also be required.

4. Reporting

N-10188-1-0: Walnut shell receiving and unloading operation
N-10188-3-0: Cooling tower
N-10188-4-0: Dry sorbent receiving and storage operation
For the above permit units, no reporting is required to demonstrate compliance with Rule 2201.

N-10188-2-0: 65.6 MMBtu/hr (each) walnut shell fired boiler
The owner or operator will be required to submit source test reports within 60-days after conducting each source test.

F. Ambient Air Quality Analysis (AAQA)

Section 4.14 of District Rule 2201 requires that an AAQA be conducted for the purpose of determining whether a new or modified Stationary Source will cause or make worse a violation of an air quality standard. The District's Technical Services Division conducted the required analysis. Refer to **Appendix D** of this document for the AAQA summary sheet.

The proposed location is in an attainment area for NO_X, CO, and SO_X. As shown by the AAQA summary sheet the proposed equipment will not cause a violation of an air quality standard for NO_X, CO, or SO_X.

The proposed location is in a non-attainment area for the state's PM_{10} as well as federal and state $PM_{2.5}$ thresholds. As shown by the AAQA summary sheet the proposed equipment will not cause a violation of an air quality standard for PM_{10} and $PM_{2.5}$.

Compliance is expected with this rule.

Rule 2410 Prevention of Significant Deterioration

As shown in Section VII.C.9 above, this project does not result in a new PSD major source or PSD major modification. No further discussion is required.

Rule 2520 Federally Mandated Operating Permits

Since this facility's potential emissions do not exceed any major source thresholds of Rule 2201, this facility is not a major source, and Rule 2520 does not apply.

Rule 4001 New Source Performance Standards (NSPS)

This rule incorporates NSPS from Part 60, Chapter 1, Title 40, Code of Federal Regulations (CFR); and applies to all new sources of air pollution and modifications of existing sources of air pollution listed in 40 CFR Part 60. The following subpart(s) apply to the walnut shell fired boilers:

<u>40 CFR Part 60 Subpart Dc – Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units</u>

§ 60.40c Applicability and delegation of authority

(a) The affected facility to which this subpart applies is each steam generating unit for which construction, modification, or reconstruction is commenced after June 9, 1989 and that has a maximum design heat input capacity of 29 megawatts (MW) (100 million British thermal units per hour (MMBtu/h)) or less, but greater than or equal to 2.9 MW (10 MMBtu/h)

Heat input rate to the each boiler will be 65 MMBtu/hr and each will be constructed after the cut-off date of June 9, 1989. Thus, these units are subject to requirements of this subpart.

§ 60.42c Standard for sulfur dioxide (SO_2)

There are no SO2 emission standards for wood fired boilers.

§ 60.43c Standard for particulate matter (PM)

(c) On and after the date on which the initial 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 combusts coal, wood, or oil and has a heat input capacity of 8.7 MW (30 MMBtu/h) or greater shall cause to be discharged into the atmosphere from that affected facility 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. Owners and operators of an affected facility that elect to install, calibrate, maintain, and operate a continuous emissions monitoring system (CEMS) for measuring PM emissions according to the requirements of this subpart and are subject to a federally enforceable PM limit of 0.030 lb/MMBtu or less are exempt from the opacity standard specified in this paragraph (c).

The following condition(s) will be included in the boiler permit:

- Except during periods of startup, shutdown, or malfunction, exhaust discharge from this unit shall not exhibit greater than 20 percent opacity (6-minute average), with an exception of one 6-minute period per hour of not more than 27 percent opacity. [40 CFR 60.43c(c) and 40 CFR 60.43c(d)]

(d) The PM and opacity standards under this section apply at all times, except during periods of startup, shutdown, or malfunction.

The above requirement is incorporated in the permit requirements in sections (c) & (d). Thus, compliance is expected.

(e)(1) 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, wood, a mixture of these fuels, or a mixture of these fuels with any other fuels and has a heat input capacity of 8.7 MW (30 MMBtu/h) or greater 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, except as provided in paragraphs (e)(2), (e)(3), and (e)(4) of this section.

Each boiler will be constructed after the cut-off date and will use walnut shells. Heat input rate to each unit will be 65 MMBtu/hr. The following condition(s) will be included in the boiler permit:

- Except during periods of startup, shutdown, or malfunction, PM emissions from this boiler shall not exceed 0.030 lb/MMBtu. [40 CFR 60.43c(e)(1) and 40 CFR 60.43c(d)]

§ 60.44c Compliance and performance test methods and procedures for sulfur dioxide

Since there are no SO2 emissions standard for wood fired boilers, no performance test discussion is necessary.

§ 60.45c Compliance and performance test methods and procedures for particulate matter

(a) The owner or operator of an affected facility subject to the PM and/or opacity standards under § 60.43c shall conduct an initial performance test as required under § 60.8, and shall conduct subsequent performance tests as requested by the Administrator, to determine compliance with the standards using the following procedures and reference methods, except as specified in paragraph (c) of this section.

(1) Method 1 of appendix A of this part shall be used to select the sampling site and the number of traverse sampling points.

(2) Method 3A or 3B of appendix A-2 of this part shall be used for gas analysis when applying Method 5 or 5B of appendix A-3 of this part or 17 of appendix A-6 of this part.

(3) 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 may be used only at affected facilities without wet scrubber systems.

(ii) Method 17 of appendix A of this part may be used at affected 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 of this part may be used in Method 17 of appendix A of this part only if Method 17 of appendix A of this part is used in conjunction with a wet scrubber system. Method 17 of appendix A of this part shall not be used in conjunction with a wet scrubber system if the effluent is saturated or laden with water droplets.

(iii) Method 5B of appendix A of this part may be used in conjunction with a wet scrubber system.

(4) The sampling time for each run shall be at least 120 minutes and the minimum sampling volume shall be 1.7 dry standard cubic meters (dscm) [60 dry standard cubic feet (dscf)] except that smaller sampling times or volumes may be approved by the Administrator when necessitated by process variables or other factors.

(5) For Method 5 or 5B of appendix A of this part, the temperature of the sample gas in the probe and filter holder shall be monitored and maintained at 160 ±14 °C (320±25 °F).

(6) For determination of PM emissions, an oxygen (O2) or carbon dioxide (CO2) measurement shall be 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.

(7) For each run using Method 5, 5B, or 17 of appendix A of this part, the emission rates expressed in ng/J (lb/MMBtu) heat input shall be determined using:

(i) The O2 or CO2 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.

(8) Method 9 of appendix A-4 of this part shall be used for determining the opacity of stack emissions.

The following condition(s) will be included in the boiler permit:

- EPA Method 1 of Appendix A of 40 CFR Part 60 shall be used to select the sampling site and the number of traverse sampling points. [40 CFR 60.45c(a)(1)]

- EPA Method 3A or 3B of Appendix A-2 of 40 CFR Part 60 shall be used for gas analysis when applying Method 5 of Appendix A-3 of 40 CFR Part 60 or EPA Method 17 of Appendix A-6 of 40 CFR Part 60. [40 CFR 60.45c(a)(2)]

- PM emissions shall be determined EPA Method 5, or 17 of Appendix A of 40 CFR Part 60 provided the stack gas temperature does not exceed a temperature of 160 °C (320 °F). [40 CFR 60.45c(a)(3)]

- Each PM testing run shall be at least 120 minutes and the minimum sampling volume shall be 1.7 dry standard cubic meters (dscm) [60 dry standard cubic feet (dscf)] except that smaller sampling times or volumes may be approved by the District when necessitated by process variables or other factors. [40 CFR 60.45c(a)(4)]

- For Method 5 of Appendix A in 40 CFR Part 60, the temperature of the sample gas in the probe and filter holder shall be monitored and maintained at 160 ±14 °C (320±25 °F). [40 CFR 60.45c(a)(5)]

- For determination of PM emissions, an oxygen (O2) or carbon dioxide (CO2) measurement shall be obtained simultaneously with each run of Method 5, or 17 of Appendix A of 40 CFR Part 60 by traversing the duct at the same sampling location. [40 CFR 60.45c(a)(6)]

- For each testing run using Method 5 or 17 of Appendix A of 40 CFR Part 60, the emission rates expressed in ng/J (lb/MMBtu) heat input shall be determined using: (i) The O2 or CO2 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 40 CFR Part 60. [40 CFR 60.45c(a)(7)]

- EPA Method 9 of Appendix A-4 and the procedure in section 60.11 of 40 CFR Part 60 shall be used for determining the opacity of stack emissions. [40 CFR 60.45c(a)(8) and 40 CFR 60.47c(a)]]

§ 60.46c Emission monitoring for sulfur dioxide

Since there are no SO2 emissions standard for wood fired boilers, no emissions monitoring discussion is necessary.

§ 60.47c Emission monitoring for particulate matter

(a) Except as provided in paragraphs (c), (d), (e), and (f) of this section, the owner or operator of an affected facility combusting coal, oil, or wood that is subject to the opacity standards under § 60.43c shall install, calibrate, maintain, and operate a continuous opacity monitoring system (COMS) for measuring the opacity of the 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 in § 60.43c(c) that is not required to use a COMS due to paragraphs (c), (d), (e), or (f) of this section that 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 § 60.43c 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.

(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 § 60.45c(a)(8).

(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.

(f) An owner or operator of an affected facility that is subject to an opacity standard in § 60.43c(c) is not required to operate a COMS provided that the affected facility meets the conditions in either paragraphs (f)(1), (2), or (3) of this section.

(1) The affected facility uses a fabric filter (baghouse) as the primary PM control device and, the owner or operator operates a bag leak detection system to monitor the performance of the fabric filter according to the requirements in section § 60.48Da of this part.

(2) The affected facility uses an ESP as the primary PM control device, and the owner or operator uses an ESP predictive model to monitor the performance of the ESP developed in accordance and operated according to the requirements in section § 60.48Da of this part.

(3) The affected facility burns only gaseous fuels and/or fuel oils that contain no greater than 0.5 weight percent sulfur, and the owner or operator operates the unit 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. 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 § 60.48c(c).

CST is not proposing to use continuous opacity monitoring system (COMS) for the boilers. Each boiler will be served by it's own fabric filter baghouse to reduce PM emissions. CST will be required to operate a bag leak detection system to monitor the performance of the fabric filter according to the requirements in section 40 CFR 60.48Da(o)(4) of 40 CFR Part 60.

- The owner or operator shall install, operate and maintain a bag leak detection system to monitor the performance of the fabric filter baghouse according to the requirements in 40 CFR 60.48Da(o)(4) of 40 CFR Part 60. [40 CFR 60.47c(a)]

- 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. [40 CFR 60.47c(a)]

- If no visible emissions are observed during the Method 9 test, a subsequent Method 9 test shall 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. [40 CFR 60.47c(a)(1)(i)]

- If visible emissions are observed during the Method 9 test but the maximum 6-minute average opacity is less than or equal to 5 percent, a subsequent Method 9 test shall be conducted 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. [40 CFR 60.47c(a)(1)(ii)]

- If the maximum 6-minute average opacity is greater than 5 percent but less than or equal to 10 percent during the Method 9 test, a subsequent Method 9 shall be conducted 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. [40 CFR 60.47c(a)(1)(iii)]

- If the maximum 6-minute average opacity is greater than 10 percent during the Method 9 test, a subsequent Method 9 test shall be conducted within 45 calendar days from the date that the most recent performance test was conducted. [40 CFR 60.47c(a)(1)(iv)]

- If the maximum 6-minute opacity is less than 10 percent during the Method 9 test, the owner or operator may, as an alternative to performing subsequent Method 9 test, elect to perform subsequent monitoring using Method 22 of Appendix A-7 of 40 CFR Part 60 according to the procedures specified in paragraphs 40 CFR 60.47c(a)(2)(i) and (ii). [40 CFR 60.47c(a)(2)]

- If the maximum 6-minute opacity is less than 10 percent during the Method 9 test, the owner or operator may, as an alternative to performing subsequent Method 9 test , elect to perform subsequent monitoring using a digital opacity compliance system according to a site-specific monitoring plan approved by the District. The observations shall be similar, but not necessarily identical, to the requirements in paragraph 40 CFR 60.47c(a)(2). 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. [40 CFR 60.47c(a)(3)]

§ 60.48c Reporting and recordkeeping requirements

(a) The owner or operator of each affected facility shall submit notification of the date of construction or reconstruction and actual startup, as provided by § 60.7 of this part. This notification shall include:

(1) The design heat input capacity of the affected facility and identification of 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 § 60.42c, or § 60.43c.

(3) The annual capacity factor at which the owner or operator anticipates operating the affected facility based on all fuels fired and based on each individual fuel fired.

(4) Notification if an emerging technology will be used for controlling SO2 emissions. The Administrator will examine the description of the control device 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 § 60.42c(a) or (b)(1), unless and until this determination is made by the Administrator.

CST is not proposing the use of any emerging technology to reduce SO2 emissions. Therefore, no notification is required under item (a)(4).

The following condition will be included in the boiler permits:

- The owner or operator shall submit notification of the date of construction and actual startup. This notification shall also include design heat input capacity and anticipated annual capacity factor. [40 CFR 60.48c(a)]

(c) In addition to the applicable requirements in § 60.7, the owner or operator of an affected facility subject to the opacity limits in § 60.43c(c) shall submit excess emission reports for any excess emissions from the affected facility that occur during the reporting period and maintain records according to the requirements specified in paragraphs (c)(1) through (3) of this section, as applicable to the visible emissions monitoring method used.

(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 (c)(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 (c)(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.

The following condition will be included in the boiler permit:

- The owner or operator shall submit excess emission reports, every 6-month period, for any excess emissions from the affected facility that occur during the reporting period and maintain records according to the requirements, as applicable to the visible emissions monitoring method used: (1) For each performance test conducted using Method 9, the owner or operator shall keep the records of (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, the owner or operator shall keep the records including the information of (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 District. All reports shall be submitted to the Administrator and shall be postmarked by the 30th day following the end of the reporting period. [40 CFR 60.48c(c) and 40 CFR 60.48c(j)]

(g)(1) Except as provided under paragraphs (g)(2) and (g)(3) of this section, the owner or operator of each affected facility shall record and maintain records of the amount of each fuel combusted during each operating day.

(2) As an alternative to meeting the requirements of paragraph (g)(1) of this section, the owner or operator of an affected facility that combusts only natural gas, wood, fuels using fuel certification in § 60.48c(f) to demonstrate compliance with the SO2 standard, fuels not subject to an emissions standard (excluding opacity), or a mixture of these fuels may elect to record and maintain records of the amount of each fuel combusted during each calendar month.

(3) As an alternative to meeting the requirements of paragraph (g)(1) of this section, the owner or operator of an affected facility or multiple affected facilities located on a contiguous property unit where the only fuels combusted in any steam generating unit (including steam generating units not subject to this subpart) at that property are natural gas, wood, distillate oil meeting the most current requirements in § 60.42C to use fuel certification to demonstrate compliance with the SO2 standard, and/or fuels, excluding coal and residual oil, not subject to an emissions standard (excluding opacity) may elect to record and maintain records of the total amount of each steam generating unit fuel delivered to that property during each calendar month.

CST will be required to maintain records of the amount of each fuel combusted during each operating day (tons/day). The following condition will be included in the boiler permit:

- The owner or operator shall keep records of the date and the amount of each fuel combusted during each operating day. [40 CFR 60.48c(g)(1)]

(h) The owner or operator of each affected facility subject to a federally enforceable requirement limiting the annual capacity factor for any fuel or mixture of fuels under § 60.42c or § 60.43c shall calculate the annual capacity factor individually for each fuel combusted.

The annual capacity factor is determined on a 12-month rolling average basis with a new annual capacity factor calculated at the end of the calendar month.

The boiler permit will not include any restriction on the annual capacity factor. As, such no capacity factor calculations or records are required.

(i) All records required under this section shall be maintained by the owner or operator of the affected facility for a period of two years following the date of such record.

The following condition will be included in the boiler permit:

- The owner or operator shall retain all records on site for a period of five year following the date of such record. These records shall be made available to the District, CARB and EPA upon request. [District Rules 1070, 2201, and 4352, 40 CFR 60.48c(i)]

(j) The reporting period for the reports required under this subpart is each six-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.

The reporting and submittal requirements above are included in a permit condition discussed under section 40 CFR 60.48c(c). Therefore, compliance is expected with this section.

Compliance is expected with this regulation.

Rule 4002 National Emission Standards for Hazardous Air Pollutants (NESHAPs)

This rule incorporates NESHAPs from Part 61, Chapter I, Subchapter C, Title 40, CFR and the NESHAPs from Part 63, Chapter I, Subchapter C, Title 40, CFR; and applies to all sources of hazardous air pollution listed in 40 CFR Part 61 or 40 CFR Part 63.

The following subparts are reviewed:

<u>40 CFR Part 63 Subpart DDDDD - National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters</u>

§ 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.

Per worksheet in **Appendix D** of this document, potential HAP emissions are below the threshold of 10 tons/yr for single HAP and 25 tons/yr for combined HAP. Therefore, this facility is not a major source of HAP emissions; consequently, the proposed boiler is not subject to the requirements of this subpart.

40 CFR Part 63 Subpart JJJJJJ - National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers Area Sources

Per phone conversation on November 3, 2021, between District staff and Mario Zuniga of EPA Region 9, the District has not been delegated to enforce the requirements of this subpart for area sources. As such, no further discussion is required. Note that EPA retains the authority to enforce the requirements of this subpart at this time, and requires owners or operator to comply all applicable requirements in this subpart.

Rule 4101 Visible Emissions

Section 5.0, indicates that no air contaminant shall be discharged into the atmosphere for a period or periods aggregating more than three minutes in any one hour, which is dark or darker than Ringlemann 1 or equivalent to 20% opacity. The following condition will be included in the permits:

- No air contaminant shall be discharged into the atmosphere for a period or periods aggregating more than three minutes in any one hour which is as dark as, or darker than, Ringelmann 1 or 20% opacity. [District Rule 4101]

Compliance is expected with this Rule.

Rule 4102 Nuisance

Rule 4102 prohibits discharge of air contaminants which could cause injury, detriment, nuisance or annoyance to the public. Public nuisance conditions are not expected as a result of these operations, provided the equipment is well maintained. Therefore, compliance with this rule is expected.

California Health & Safety Code 41700 (Health Risk Assessment)

District Policy APR 1905 – *Risk Management Policy for Permitting New and Modified Sources* specifies that for an increase in emissions associated with a proposed new source or modification, the District perform an analysis to determine the possible impact to the nearest resident or worksite.

District policy APR 1905 also specifies that the increase in emissions associated with a proposed new source or modification of an existing source shall not result in an increase in cancer risk greater than the District's significance level (20 in a million) and shall not result in acute and/or chronic risk indices greater than 1.

According to the Technical Services Memo for this project, the total facility prioritization score including this project was greater than one. Therefore, an HRA was required to determine the short-term acute and long-term chronic exposure from this project.

The risk management review results are summarized below:

Health Risk Assessment Summary						
Units	**Prioritization Score**	**Acute Hazard Index**	**Chronic Hazard Index**	**Maximum Individual Cancer Risk**	**T-BACT Required**	**Special Permit Requirements**
1-0	0.00	0.00	0.00	3.27E-09	No	No
2-0	49.87	0.19	0.04	5.33E-07	No	No
3-0[1]	N/A[1]	N/A[1]	N/A[1]	N/A[1]	No	No
4-0	0.00	N/A[2]	0.00	N/A[2]	No	No
Project Totals	49.90	0.19	0.04	5.36E-07		
Facility Totals	>1	0.19	0.04	5.36E-07		

Notes:
1. Review of the SDS for the proposed products to be used for Unit 3 determined that there are no Toxic Air Contaminants (TACs) associated with operation of Unit 3. Therefore, no further analysis of this unit for RMR purposes was necessary.
2. Maximum individual cancer risk and acute hazard index were not calculated for Unit 4-0 since there is no risk factor or the risk factor is so low that it has been determined to be insignificant for this type of unit.

Discussion of T-BACT

BACT for toxic emission control (T-BACT) is required if the cancer risk exceeds one in one million. As demonstrated above, T-BACT is not required for this project because the HRA indicates that the risk is not above the District's thresholds for triggering T-BACT requirements.

The cumulative acute and chronic indices for this facility, including this project, are below 1.0; and the cumulative cancer risk for this facility, including this project, is less than 20 in a million. In addition, the cancer risk for each unit in this project is less than 1.0 in a million. In accordance with the District's Risk Management Policy, the project is approved without Toxic Best Available Control Technology (T-BACT).

See **Appendix C**: Health Risk Assessment Summary

The following permit conditions are required to ensure compliance with the assumptions made for the risk management review:

<u>N-10188-2-0</u>

- The exhaust stack shall vent vertically upward. The vertical exhaust flow shall not be impeded by a rain cap (flapper ok), roof overhang, or any other obstruction. [District Rule 4102]

- Only walnut shells shall be used as fuel in this boiler. [District Rules 2201 and 4102]

In accordance with District policy APR 1905, no further analysis is required, and compliance with District Rule 4102 requirements is expected.

Rule 4201 Particulate Matter Concentration

Section 3.0 prohibits discharge of dust, fumes, or total particulate matter into the atmosphere from any single source operation in excess of 0.1 grain per dry standard cubic foot.

N-10188-1-0: Walnut shell receiving and unloading operation
PM emissions from these operations are not vented through a discharge stack; therefore, these operations are not subject to the requirements of this rule.

N-10188-2-0: 65.6 MMBtu/hr walnut shell fired boiler
F-factor (CO_2 basis) = 1,830 dscf/MMBtu (Wood)

$$\text{PM}\left(\frac{\text{gr}}{\text{dscf}}\right)=\frac{\left(0.0036\ \frac{\text{lb-PM}}{\text{MMBtu}}\right)\left(7{,}000\,\frac{\text{gr-PM}}{\text{lb-PM}}\right)}{\left(1{,}830\,\frac{\text{ft}^3}{\text{MMBtu}}\right)\left(\frac{100\%}{12\%}\right)}=0.0\ \frac{\text{gr-PM}}{\text{dscf}}<0.1\ \frac{\text{gr-PM}}{\text{dscf}}$$

N-10188-3-0: Cooling tower
Per applicant, exhaust flow rate would be 198,000 acfm @ 118°F. The moisture content of the exhaust stream is assumed to be 25%. Therefore, the exhaust particulate matter emission concentration at 60°F is:

$$\text{PM}\left(\frac{\text{gr}}{\text{dscf}}\right)=\frac{\left(0.0164\ \frac{\text{lb-PM}}{\text{hr}}\right)\left(7{,}000\,\frac{\text{gr-PM}}{\text{lb-PM}}\right)}{\left(198{,}000\,\frac{\text{ft}^3}{\text{min}}\right)\left(\frac{459.6+60}{459.6+118}\right)(1-0.25)\left(60\ \frac{\text{min}}{\text{hr}}\right)}=0.0\ \frac{\text{gr-PM}}{\text{dscf}}<0.1\ \frac{\text{gr-PM}}{\text{dscf}}$$

N-10188-4-0: Dry sorbent receiving and storage operation
PM emissions = 0.061 lb-PM/hr (per section VII.C.2 above)
Exhaust flow rate = 340 scfm (similar bin dispensing system under project N-1103242)

$$\text{PM}\left(\frac{\text{gr}}{\text{dscf}}\right)=\frac{\left(0.061\ \frac{\text{lb-PM}}{\text{hr}}\right)\left(7{,}000\,\frac{\text{gr-PM}}{\text{lb-PM}}\right)\left(\frac{\text{hr}}{60\ \text{min}}\right)}{\left(340\,\frac{\text{ft}^3}{\text{min}}\right)}=0.0\ \frac{\text{gr-PM}}{\text{dscf}}<0.1\ \frac{\text{gr-PM}}{\text{dscf}}$$

Compliance is expected with this Rule.

Rule 4301 Fuel Burning Equipment

The requirements of section 5.0 are as follows:

- Combustion contaminates (TSP) - Not to exceed 0.1 gr/dscf @ 12% CO_2 and 10 lb/hr.
- SO_x emissions - Not to exceed 200 /hr
- NO_x emissions - Not to exceed 140 lb/hr

<u>N-10188-2-0: 65.6 MMBtu/hr walnut shell fired boiler</u>
Per section VII.C.2 of this document,

NOx = 1.896 lb/hr
SOx = 3.214 lb/hr
PM = 0.236 lb/hr

PM grain loading is calculated below:

F-factor (CO2 basis) = 1,830 dscf/MMBtu (Wood)

$$\mathrm{PM}\left(\frac{\mathrm{gr}}{\mathrm{dscf}}\right)=\frac{\left(0.0036\ \frac{\text{lb-PM}}{\text{MMBtu}}\right)\left(7{,}000\,\frac{\text{gr-PM}}{\text{lb-PM}}\right)}{\left(1{,}830\,\frac{\mathrm{ft}^3}{\mathrm{min}}\right)\left(\frac{100\%}{12\%}\right)}=0.0\ \frac{\text{gr-PM}}{\text{dscf}}<0.1\ \frac{\text{gr-PM}}{\text{dscf}}$$

Since the potential emissions from each boiler are below the threshold for each pollutant, compliance is expected with this rule.

<u>N-10188-1-0: Walnut shell receiving and unloading operation</u>
<u>N-10188-4-0: Dry sorbent receiving and storage operation</u>
The operations under above permits do not involve any fuel burning equipment; therefore, these operations are not subject to the requirements of this rule.

Rule 4202 Particulate Matter - Emission Rate

Section 4.0 of this rule, a person shall not discharge into the atmosphere PM emissions in excess of the maximum allowable limit (E_{Max}), in lb/hr, determined by the following equations:

E_{Max} = 3.59 $P^{0.62}$, for Process weight (P) less than or equal to 30 tons/hr
E_{Max} = 17.31 $P^{0.16}$, for Process weight (P) greater than 30 tons/hr

<u>N-10188-1-0: Walnut shell receiving and unloading operation</u>
Processing Rate: 4 tons/hr (per applicant)

E_{Max} = 3.59 (4 tons/hr)$^{0.62}$
= 8.5 lb-PM/hr

$E_{Proposed}$ = 0.012 lb-PM/hr

The proposed emission rate ($E_{Proposed}$) is less than the maximum allowable emission rate (E_{Max}); therefore, compliance is expected with this rule.

N-10188-2-0: 65.6 MMBtu/hr (each) walnut shell fired boiler
Processing Rate: 4 tons/hr (per applicant)

E_{Max} = 3.59 (4 tons/hr)$^{0.62}$
= 8.5 lb-PM/hr

$E_{Proposed}$ = 0.236 lb-PM/hr

N-10188-3-0: Cooling tower
The process weight of water being recirculated through this unit would be 1,636 tons/hour[5].

E_{Max} = 17.31 (1,636 tons/hr)$^{0.16}$
= 56.6 lb-PM/hr

$E_{Proposed}$ = 0.0164 lb-PM/hr

N-10188-4-0: Dry sorbent receiving and storage operation
Processing Rate: 12.5 tons/hr (per applicant)

E_{Max} = 3.59 (12.5 tons/hr)$^{0.62}$
= 17.2 lb-PM/hr

$E_{Proposed}$ = 0.1 lb-PM/hr

The proposed emission rate ($E_{Proposed}$) is less than the maximum allowable emission rate (E_{Max}); therefore, compliance is expected with this rule.

Rule 4352 Solid Fuel Fired Boilers, Steam Generators, and Process Heaters

Section 2.0 – Applicability

Section 2.0 states that this rule applies to any boiler steam generator or process heater fired on solid fuel. Heat may be supplied by liquid or gaseous fuel for start-ups, shutdowns, and during other flame stabilization periods, as deemed necessary by the owner/operator.

CST has proposed to install a 65.6 MMBtu/hr solid fuel fired boiler. Therefore, this unit is subject to the requirements of this rule.

[5](6,538 gal/min)(8.34 lb/gal)(60 min/hr)(ton/2,000 lb) = 1,636 tons/hr

<u>Section 4.0 – Requirements</u>

Section 4.1 lists NOx, SOx, PM_{10} and CO limits for "municipal solid waste", "biomass", and "all others" fuel type units.

The proposed boilers will use walnut shells. Walnut shell is not considered "biomass" fuel per section 3.11 of Rule 2201. Thus, these units fall in "all others" category.

Per Table 1, until December 31, 2023, "all others" fuel type units are required to operate each unit at or below the following limits:

NOx: 65 ppmvd @ 3% O2
CO: 400 ppmvd @ 3% O2

The applicant has proposed to limit NOx and CO emissions to 0.0179 lb/MMBtu and 0.071 lb/MMBtu, respectively during steady state operation. These values equivalent to 14 ppmvd NOx @ 3% O_2[6] and 89 ppmvd CO @ 3% O_2[7]. Since the equated values are below the rule limits, compliance is expected.

Per Table 2, on and after January 1, 2024, "all others" fuel type units are required to operate each unit at or below the following limits:

NOx: 65 ppmvd @ 3% O2
CO: 400 ppmvd @ 3% O2
PM_{10}: 0.03 lb/MMBtu
SOx: 0.035 lb/MMBtu (block 24-hour average) and 0.02 lb/MMBtu (rolling 30-day average)

The applicant has proposed to limit NOx and CO emissions to 0.0179 lb/MMBtu and 0.071 lb/MMBtu, respectively during steady state operation. These values are equivalent to 14 ppmvd NOx @ 3% O2 and 89 ppmvd CO @ 3% O2 . Since the equated values are well below the rule limits, compliance is expected.

The applicant has proposed to limit PM_{10} and SOx emissions equal to the limits in this rule. Thus, compliance is expected.

The following conditions ensure on-going compliance:

- Upon completing commissioning period, except during periods of startup and shutdown, emissions from this boiler shall not exceed any of the following limits: 0.0179 lb-NOx/MMBtu (expressed as NO2) over a block 24-hour average basis, 0.071 lb-CO/MMBtu over a block

[6](X x 10^{-6} x 9,240 dscf/MMBtu x 46 lb-NOx/lb-mole x (20.95/(20.95-3)) x 1/379.5 dscf/lb-mole = 0.0179 lb-NOx/MMBtu; X = 13.7 ppmvd NOx @ 3% O_2

[7] [7](X x 10^{-6} x 9,240 dscf/MMBtu x 28 lb-CO/lb-mole x (20.95/(20.95-3)) x 1/379.5 dscf/lb-mole = 0.071 lb-CO/MMBtu; X = 89.2 ppmvd CO @ 3% O_2

24-hour average basis, 0.0036 lb-VOC/MMBtu (expressed as CH_4) over a 30-minute period. [District Rules 2201 and 4352]

- Upon completing commissioning period, during periods of startup, shutdown or steady state, emissions from this boiler shall not exceed any of the following limits: 0.035 lb-SOx/MMBtu (expressed as SO_2) on a bock 24-hour average basis and 0.02 lb-SOx/MMBtu (expressed as SO_2) on a rolling 30-day average basis, and 0.0036 lb-PM10/MMBtu (both filterable and condensable). [District Rules 2201 and 4352]

Section 4.2 states a violation of the emission limits as measured by the test methods listed in Section 5.3 shall constitute a violation of this rule.

Section 4.3 lists start-up and shutdown provisions. The applicable emission limits of Section 4.1 shall not apply during start-up or shutdown provided an operator complies with the requirements specified below.

4.3.1 The duration of each shut down shall not exceed 12 hours, except as provided in Section 4.3.4.

4.3.2 Except as provided in Section 4.3.4, the duration of each start-up shall not exceed 96 hours. If curing of the refractory is required after a modification to the unit is made, the duration of start-up shall not exceed 192 hours, except as provided in Section 4.3.4.

4.3.3 The emission control system shall be in operation and emissions shall be minimized insofar as technologically feasible during start-up or shutdown.

4.3.4 Notwithstanding the requirements of Section 4.3.1 or Section 4.3.2, the APCO, ARB, and EPA may approve a longer start-up or shutdown duration, if an operator submits an application for a Permit to Operate which provides a justification for the requested additional duration.

CST has proposed to limit startup and shutdown period well below the limits mentioned above section. Thus, compliance is expected. The following conditions will ensure on-going compliance with these sections:

- Upon completing commissioning period, startup period shall not exceed any of the following limits: 12 hours during any one day and 24 hours per calendar year. [District Rules 2201 and 4352]

- Upon completing commissioning period, shutdown period shall not exceed any of the following limits: 12 hours during any one day and 24 hours per calendar year. [District Rules 2201 and 4352]

- The emission control system shall be in operation and emissions shall be minimized insofar as technologically feasible during start-up or shutdown. [District Rule 4352]

Section 4.4 includes monitoring provisions. The owner/operator of any unit using ammonia injection as a NOx control technique, shall operate a Continuous Emissions Monitoring system (CEM) to monitor and record NOx concentrations, SOx concentrations, CO_2 or O_2 concentrations, as well as the NOx and SOx emission rates. Continuous Emission Monitoring systems shall be operated, maintained, and calibrated pursuant to the requirements of 40 CFR 60.7 (c) and 60.13. CEMs must also satisfy the Performance Specifications of 40 CFR 60 Appendix B and the Relative Accuracy Test Audit of Appendix F.

CST will inject ammonia in SCR system. CST has proposed to install CEMS to monitor and records NOx, SOx, CO_2 or O_2 concentrations as well as NOx and SOx emission rates. Thus, compliance is expected with this section. Refer to discussion under Rule 1080 (above) for the requirements that will enforce on-going compliance with this section.

Section 5.0 – Administrative Requirements

Section 5.1 includes recordkeeping. The subsections are as follows:

Section 5.1.1 states that except for municipal solid waste (MSW) fired units; the owner/operator of any unit subject to the requirements of this rule shall maintain, on a monthly basis, an operating log for each unit that includes the following information:

5.1.1.1 Type and quantity of fuel used.

5.1.1.2 The higher heating value (HHV) of each fuel as determined by Section 5.3, EPA Method 19, or as certified by a third party fuel supplier.

Section 5.1.2 states that the records required by Section 5.1.1 shall be retained on site for a period of five years, and shall be made available to the APCO, ARB, and EPA upon request.

The following conditions in the boiler permit will ensure on-going compliance with the above section:

- The owner or operator shall keep monthly records of the type, quantity, and the HHV of the fuel used in this boiler. [District Rule 4352]
- HHV in the fuel used in this boiler shall be conducted using ASTM 5865-10, EPA Method 19, ASTM D2015 or ASTM D3588 or District-approved equivalent method. [District Rules 1081, 2201 and 4352]
- The owner or operator shall retain all records on site for a period of five year following the date of such record. These records shall be made available to the District, CARB and EPA upon request. [District Rules 1070, 2201, and 4352, 40 CFR 60.48c(i)]

Section 5.2 lists compliance source testing provisions. The subsections are as follows:

Section 5.2.1 states that each unit subject to the requirements of this rule shall be tested at least once every 12 months, to determine compliance with the applicable short term emission limit (i.e. the applicable emission limit with the shortest averaging period) requirements of Section 4.0.

Section 5.2.2 states that all emission measurements shall be made with the unit operating either at conditions representative of normal operations or conditions specified in the Permit to Operate.

Section 5.2.3 states that no compliance determination shall be established within two hours after a period in which fuel flow to the unit is zero, or is shut off for 30 minutes or longer.

The following conditions in the boiler permit ensure on-going compliance with the above sections:

- Source testing to measure steady state NOx, CO, PM10, SOx, VOC, and NH3 emissions shall be conducted within 60 days of initial startup and at least once 12 months thereafter. [District Rules 2201 and 4352]

- All emission measurements shall be made with the unit operating either at conditions representative of normal operations or conditions specified in the Permit to Operate. [District Rules 2201 and 4352]

- No compliance determination shall be established within two hours after a period in which fuel flow to the unit is zero, or is shut off for 30 minutes or longer. [District Rules 2201 and 4352]

Section 5.3 lists various test methods. The following conditions in the boiler permit ensure on-going compliance with this section.

- NOx emissions for source test purposes shall be determined using EPA Methods 7E and 19 or CARB Method 100 and EPA Method 19. [District Rules 1081 and 4352]

- CO emissions for source test purposes shall be determined using EPA Method 10, EPA Method 3A or CARB Method 100. [District Rules 1081 and 4352]

- PM10 emissions for source test purposes shall be determined using EPA Methods 201A, 202, and 19. [District Rules 1081 and 4352]

- In lieu of performing a source test for PM10, the results of the total particulate test may be used for compliance with the PM10 emission limit provided the results include both the filterable and condensable (back half) particulates, and that all particulate matter is assumed to be PM10. If this option is exercised, source testing shall be conducted using

CARB Method 5 or EPA Method 5 (including condensable (back half) particulates). [District Rule 1081]

- Stack gas oxygen shall be determined using EPA Method 3 or 3A or CARB Method 100. [District Rules 1081 and 4352]
- SOx emissions for source test purposes shall be determined using EPA Method 6, EPA Method 6C, EPA Method 8 or CARB Method 100. [District Rules 1081 and 4352]
- Stack gas velocity shall be determined using EPA Method 2. [District Rules 1081 and 4352]
- Stack gas moisture content shall be determined using EPA Method 4. [District Rules 1081 and 4352]

Section 6.0 – Compliance Schedule

The operator is required to obtain ATC by June 1, 2022 such that any non-compliant unit have ample time to comply with the NOx, PM_{10} and SOx limits that become effective on January 1, 2024..

The proposed boiler in this project is a new unit. This unit is expected to operate in compliance with the requirements of this rule.

Compliance is expected with this rule.

Rule 4801 Sulfur Compounds

Section 3.1 states that a person shall not discharge into the atmosphere sulfur compounds, which would exist as a liquid or gas at standard conditions, exceeding a concentration of two-tenths (0.2) percent by volume calculated as sulfur dioxide (SO_2) at the point of discharge on a dry basis averaged over 15 consecutive minutes.

N-10188-2-0: 65.6 MMBtu/hr walnut shell fired boiler

For the proposed wood fuel combustion at a reference state of 60 °F, the Rule 4801 limit of 2,000 ppmvd is equivalent to:

$$\frac{(2{,}000\ \text{ppmvd})\left(9{,}240\ \frac{\text{dscf}}{\text{MMBtu}}\right)\left(64\,\frac{\text{lb-SOx}}{\text{lb-mol}}\right)}{\left(379.5\,\frac{\text{dscf}}{\text{lb-mol}}\right)(10^6)} = 3.117\ \frac{\text{lb-SOx}}{\text{MMBtu}}$$

CST has proposed to comply with 0.035 lb-SOx/MMBtu on a block 24-hour average basis. Since the proposed limit is below the 3.117 lb-SOx/MMBtu rule limit, compliance is expected with this rule.

<u>N-10188-1-0: Walnut shell receiving and unloading operation</u>
<u>N-10188-3-0: Cooling tower</u>
<u>N-10188-4-0: Dry sorbent receiving and storage operation</u>
The operations under above permits do not involve any fuel burning equipment; therefore, these operations are not subject to the requirements of this rule.

California Health & Safety Code 42301.6 (School Notice)

The District has verified that this site is not located within 1,000 feet of a school. Therefore, pursuant to California Health and Safety Code 42301.6, a school notice is not required.

California Environmental Quality Act (CEQA)

CEQA requires each public agency to adopt objectives, criteria, and specific procedures consistent with CEQA Statutes and the CEQA Guidelines for administering its responsibilities under CEQA, including the orderly evaluation of projects and preparation of environmental documents. The District adopted its *Environmental Review Guidelines* (ERG) in 2001. The basic purposes of CEQA are to:

- Inform governmental decision-makers and the public about the potential, significant environmental effects of proposed activities;
- Identify the ways that environmental damage can be avoided or significantly reduced;
- Prevent significant, avoidable damage to the environment by requiring changes in projects through the use of alternatives or mitigation measures when the governmental agency finds the changes to be feasible; and
- Disclose to the public the reasons why a governmental agency approved the project in the manner the agency chose if significant environmental effects are involved.

District CEQA Findings

The City of Tracy (City) is the public agency having principal responsibility for approving the project. As such, the City served as the Lead Agency (CCR §15367). In approving the project, the Lead Agency prepared and adopted a Mitigated Negative Declaration. The Lead agency filed a Notice of Determination, stating that the environmental document was adopted pursuant to the provisions of CEQA and concluding that the project would not have a significant effect on the environment.

Pursuant to CEQA Guidelines §15250, the District is a Responsible Agency for the Project via its Permits Rule (Rule 2010) and New Source Review Rule (Rule 2201), (CEQA Guidelines §15381). As a Responsible Agency the District complies with CEQA by considering the environmental document prepared by the Lead Agency, and by reaching its own conclusion on whether and how to approve the project (CCR §15096).

The District has considered the Lead Agency's environmental document. Furthermore, the District has conducted an engineering evaluation of the project, this document, which demonstrates that Stationary Source emissions from the project would be below the District's thresholds of significance for criteria pollutants. Thus, the District finds that through a combination of project design elements, compliance with applicable District rules and regulations, and compliance with District air permit conditions, project specific stationary source emissions will have a less than significant impact on air quality. The District does not have authority over any of the other project impacts and has, therefore, determined that no additional findings are required (CEQA Guidelines §15096(h)).

Indemnification Agreement/Letter of Credit Determination

According to District Policy APR 2010 (CEQA Implementation Policy), when the District is the Lead or Responsible Agency for CEQA purposes, an indemnification agreement and/or a letter of credit may be required. The decision to require an indemnity agreement and/or a letter of credit is based on a case-by-case analysis of a particular project's potential for litigation risk, which in turn may be based on a project's potential to generate public concern, its potential for significant impacts, and the project proponent's ability to pay for the costs of litigation without a letter of credit, among other factors.

The criteria pollutant emissions and toxic air contaminant emissions associated with the proposed project are not significant, and there is minimal potential for public concern for this particular type of facility/operation. Therefore, an Indemnification Agreement and/or a Letter of Credit will not be required for this project in the absence of expressed public concern.

IX. Recommendation

Compliance with all applicable rules and regulations is expected. Pending a successful NSR Public Noticing period, issue ATCs N-10188-1-0 through '-4-0 subject to the permit conditions on the attached draft ATCs in **Appendix A**.

X. Billing Information

Annual Permit Fees			
Permit Number	**Fee Schedule**	**Fee Description**	**Annual Fee**
N-10188-1-0	3020-01A	<25 hp, electric hp	$107
N-10188-2-0	3020-02H	65 MMBtu/hr boiler	$1,238
N-10188-3-0	3020-01	345 hp, total electric hp	$495
N-10188-4-0	3020-01A	<25 hp, electric hp	$107

Appendixes

A: Draft ATCs
B: BACT Analysis
C: HRA Summary
D: HAP Calculations
E: Quarterly Net Emissions Change

Appendix A
Draft ATCs

San Joaquin Valley
Air Pollution Control District

AUTHORITY TO CONSTRUCT

PERMIT NO: N-10188-1-0 **ISSUANCE DATE:** DRAFT

LEGAL OWNER OR OPERATOR: COMBINED SOLAR TECHNOLOGIES, INC.
MAILING ADDRESS: PO BOX 583
TRACY, CA 95304

LOCATION: 9251 W ARBOR AVE
TRACY, CA 95304

EQUIPMENT DESCRIPTION:
WALNUT SHELL RECEIVING AND HANDLING OPERATION

CONDITIONS

1. {98} No air contaminant shall be released into the atmosphere which causes a public nuisance. [District Rule 4102]
2. {14} Particulate matter emissions shall not exceed 0.1 grains/dscf in concentration. [District Rule 4201]
3. {15} No air contaminant shall be discharged into the atmosphere for a period or periods aggregating more than three minutes in any one hour which is as dark as, or darker than, Ringelmann 1 or 20% opacity. [District Rule 4101]
4. Walnut shells shall be received via truck trailers and shall never be dumped onto the ground or stockpiled onto the ground; rather the trailers shall be docked and metered slowly into the bins for conveying the material to the boiler(s) using enclosed conveying system. [District Rule 2201 and 4102]
5. PM10 emissions from walnut shell receiving and transferring operations shall not exceed 0.00152 pounds per ton of material processed. [District Rule 2201]
6. The amount of walnut shells received shall not exceed any of the following limits: 96 tons/day and 33,600 tons/year. . [District Rule 2201]
7. The owner or operator shall keep records of the following items: (a) Date, (b) Amount of walnut shells received (tons/day)and (c) An up-to-date record of the total amount of walnut shells received (tons) during a given year. [District Rule 2201]
8. All records shall be maintained and retained on-site for a period of at least 5 years and shall be made available for District inspection upon request. [District Rule 1070]

YOU MUST NOTIFY THE DISTRICT COMPLIANCE DIVISION AT (209) 557-6400 WHEN CONSTRUCTION IS COMPLETED AND PRIOR TO OPERATING THE EQUIPMENT OR MODIFICATIONS AUTHORIZED BY THIS AUTHORITY TO CONSTRUCT. This is NOT a PERMIT TO OPERATE. Approval or denial of a PERMIT TO OPERATE will be made after an inspection to verify that the equipment has been constructed in accordance with the approved plans, specifications and conditions of this Authority to Construct, and to determine if the equipment can be operated in compliance with all Rules and Regulations of the San Joaquin Valley Unified Air Pollution Control District. Unless construction has commenced pursuant to Rule 2050, this Authority to Construct shall expire and application shall be cancelled two years from the date of issuance. The applicant is responsible for complying with all laws, ordinances and regulations of all other governmental agencies which may pertain to the above equipment.

Samir Sheikh, Executive Director / APCO

DRAFT

Brian Clements, Director of Permit Services
N-10188-1-0 : May 17 2023 8:48AM -- KAHLONJ : Joint Inspection NOT Required

San Joaquin Valley
Air Pollution Control District

AUTHORITY TO CONSTRUCT

DRAFT

PERMIT NO: N-10188-2-0 **ISSUANCE DATE:** DRAFT

LEGAL OWNER OR OPERATOR: COMBINED SOLAR TECHNOLOGIES, INC.
MAILING ADDRESS: PO BOX 583
TRACY, CA 95304

LOCATION: 9251 W ARBOR AVE
TRACY, CA 95304

EQUIPMENT DESCRIPTION:
65.6 MMBTU/HR ZOZEN BOILER CO LTD., MODEL ZZ-25/4.29/400-M, STOKER-TYPE WALNUT-SHELL FUEL FIRED BOILER WITH UREA INJECTION SYSTEM, A CYCLONE, A BAGHOUSE FILTER SYSTEM, AND A SELECTIVE CATALYTIC REDUCTION SYSTEM

CONDITIONS

1. The combined total NOx emissions from the emission units at facilities N-8887 and N-10188 shall not exceed 19,999 pounds during any consecutive 12-month period. [District Rule 2201]
2. {98} No air contaminant shall be released into the atmosphere which causes a public nuisance. [District Rule 4102]
3. The owner or operator shall notify the District of any breakdown condition as soon as reasonably possible, but no later than one hour after its detection, unless the owner or operator demonstrates to the District's satisfaction that the longer reporting period was necessary. [District Rule 1100]
4. The District shall be notified in writing within ten days following the correction of any breakdown condition. The breakdown notification shall include a description of the equipment malfunction or failure, the date and cause of the initial failure, the estimated emissions in excess of those allowed, and the methods utilized to restore normal operations. [District Rule 1100]
5. {14} Particulate matter emissions shall not exceed 0.1 grains/dscf in concentration. [District Rule 4201]
6. {15} No air contaminant shall be discharged into the atmosphere for a period or periods aggregating more than three minutes in any one hour which is as dark as, or darker than, Ringelmann 1 or 20% opacity. [District Rule 4101]
7. The exhaust stack shall vent vertically upward. The vertical exhaust flow shall not be impeded by a rain cap (flapper ok), roof overhang, or any other obstruction. [District Rule 4102]

CONDITIONS CONTINUE ON NEXT PAGE

YOU <u>MUST</u> NOTIFY THE DISTRICT COMPLIANCE DIVISION AT (209) 557-6400 WHEN CONSTRUCTION IS COMPLETED AND PRIOR TO OPERATING THE EQUIPMENT OR MODIFICATIONS AUTHORIZED BY THIS AUTHORITY TO CONSTRUCT. This is NOT a PERMIT TO OPERATE. Approval or denial of a PERMIT TO OPERATE will be made after an inspection to verify that the equipment has been constructed in accordance with the approved plans, specifications and conditions of this Authority to Construct, and to determine if the equipment can be operated in compliance with all Rules and Regulations of the San Joaquin Valley Unified Air Pollution Control District. Unless construction has commenced pursuant to Rule 2050, this Authority to Construct shall expire and application shall be cancelled two years from the date of issuance. The applicant is responsible for complying with all laws, ordinances and regulations of all other governmental agencies which may pertain to the above equipment.

Samir Sheikh, Executive Director / APCO

DRAFT

Brian Clements, Director of Permit Services

N-10188-2-0 : May 17 2023 8:48AM -- KAHLONJ : Joint Inspection NOT Required

8. During all types of operation, ammonia injection into the SCR system shall occur once the minimum temperature established during the initial source testing at the catalyst face has been reached to ensure NOx emission reductions can occur with a reasonable level of ammonia slip. The minimum temperature established during the initial testing shall be administratively included in the permit to operate. The established temperature may be modified administratively as necessary following any replacement of the SCR catalyst material. [District Rule 2201]
9. The SCR system shall be equipped with a continuous temperature monitoring system to measure and record the temperature at the catalyst face. [District Rule 2201]
10. The baghouse shall be maintained and operated according to manufacturer's specifications. [District Rule 2201]
11. The baghouse cleaning frequency and duration shall be adjusted to optimize the control efficiency. [District Rule 2201]
12. The baghouse shall be equipped with a pressure differential gauge to indicate the pressure drop across the filters. The gauge shall be maintained in good working condition at all times and shall be located in an easily accessible location. [District Rule 2201]
13. The differential pressure gauge reading range shall be established per manufacturer's recommendation at time of start up inspection. [District Rule 2201]
14. Material removed from the baghouse shall be disposed of in a manner preventing entrainment into the atmosphere. [District Rule 2201]
15. Replacement bags numbering at least 10% of the total number of bags in the baghouse shall be maintained on the premises. [District Rule 2201]
16. Differential operating pressure shall be monitored and recorded continuously each day this boiler operates. [District Rule 2201]
17. The baghouse shall be thoroughly inspected annually for tears, scuffs, abrasions, holes, or any evidence of particulate matter breakthrough and shall be replaced as needed. [District Rule 2201]
18. Commissioning activities are defined as, but not limited to, all testing, adjustment, tuning, and calibration activities recommended by the equipment manufacturers and the construction contractor to ensure safe and reliable steady state operation of the boiler and associated system. [District Rule 2201]
19. Commissioning period shall commence when all mechanical, electrical, and control systems are installed and individual system startup has been completed, or when the boiler is first fired, whichever occurs first. The commissioning period shall terminate when the boiler has completed initial source testing, completed final boiler tuning, and is available for commercial operation. [District Rule 2201]
20. During the commissioning period, the emission rates from the boiler system shall not exceed any of the following limits: NOx (as NO2) - 45.6 lb/day; VOC (as CH4) - 29.2 lb/day; CO - 562.8 lb/day; PM10 - 5.7 lb/day; SOx (as SO2) - 55.1 lb/day or NH3 (from SCR system) - 20.3 lb/day. [District Rule 2201]
21. During commissioning period, NOx, CO and SOx emissions rate shall be monitored and recorded using installed and calibrated CEMS. [District Rule 2201]
22. Commissioning period PM10, VOC and NH3 emissions rate shall be estimated using emission factors (lb/MMBtu) from the initial source testing, actual fuel heat input rate (MMBtu/hr), and hours of operation (hr/day). [District Rule 2201]
23. The total annual mass emissions of NOx, SOx, PM10, CO, VOC and NH3 emissions that are emitted during the commissioning period shall accrue towards the annual emission limits. [District Rule 2201]
24. For commissioning period, the owner or operator shall keep records of following items: (1) Date, (2) Type of commissioning activities performed, (3) Heat input rate to the boiler (MMBtu/hr), (4) Hours of boiler operation (hours), and (5) Daily and annual mass emissions of NOx, SOx, PM10, CO, VOC and NH3. [District Rule 2201]
25. During start-up or shutdown, the emissions control system shall be in operation, and emissions shall be minimized insofar as technologically possible. [District Rule 2201]

CONDITIONS CONTINUE ON NEXT PAGE

26. Startup is defined as the period of time beginning when the unit is heated to the operating temperature and pressure from a shutdown status or hot standby condition. [District Rule 2201]

27. Shutdown is defined as the period of time during which a unit is taken from operational to non-operational status by allowing it to cool down from its operating temperature and pressure to an ambient temperature, or to a hot standby condition. [District Rule 2201]

28. Only walnut shells shall be used as fuel in this boiler. [District Rules 2201 and 4102]

29. Upon completing commissioning period, the startup period shall not exceed any of the following limits: 12 hours during any one day and 24 hours per calendar year. [District Rules 2201 and 4352]

30. Upon completing commissioning period, the shutdown period shall not exceed any of the following limits: 12 hours during any one day and 24 hours per calendar year. [District Rules 2201 and 4352]

31. The emission control system shall be in operation and emissions shall be minimized insofar as technologically feasible during start-up or shutdown. [District Rule 4352]

32. Upon completing commissioning period, during periods of startup and shutdown, emissions from this boiler shall not exceed any of the following limits: 0.0289 lb-NOx/MMBtu (expressed as NO2), 0.3575 lb-CO/MMBtu, and 0.0186 lb-VOC/MMBtu (expressed as CH4), all emission limits averaged over the entire startup or shutdown period. [District Rule 2201]

33. Upon completing commissioning period, except during periods of startup and shutdown, emissions from this boiler shall not exceed any of the following limits: 0.0179 lb-NOx/MMBtu (expressed as NO2) over a block 24-hour average basis, 0.071 lb-CO/MMBtu over a block 24-hour average basis, 0.0036 lb-VOC/MMBtu (expressed as CH4) over a 30-minute period. [District Rules 2201 and 4352]

34. Upon completing commissioning period, during periods of startup, shutdown or steady state, emissions from this boiler shall not exceed any of the following limits: 0.035 lb-SOx/MMBtu (expressed as SO2) on a bock 24-hour average basis and 0.02 lb-SOx/MMBtu (expressed as SO2) on a rolling 30-day average basis, and 0.0036 lb-PM10/MMBtu (both filterable and condensable). [District Rules 2201 and 4352]

35. Upon completing commissioning period, during periods of startup, shutdown or steady state, ammonia (NH3) slip emissions associated with boiler's NOx control system shall not exceed 0.0129 lb/MMBtu. [District Rule 2201]

36. Emissions from this boiler shall not exceed any of the following limits: 9,899 lb-NOx/year (expressed as NO2), 11,021 lb-SOx/year (expressed as SO2), 1,984 lb-PM10/year, 40,026 lb-CO/year, 2,030 lb-VOC/year (expressed as CH4) and 7,108 lb-NH3/year. These limits are on a 12 consecutive month rolling basis. Compliance with NOx, CO and SOx limits shall be determined from CEMS data. Compliance with PM10, VOC and NH3 limits shall be determined by calculating emissions using emission factors (the most recent source test results), actual heat input to the boiler, and actual operating time. [District Rule 2201]

37. The exhaust stack shall be equipped with permanent provisions to allow collection of stack gas samples consistent with EPA test methods and shall be equipped with safe permanent provisions to sample stack gases with a portable NOx, SOx, CO, and O2 analyzer during District inspections. The sampling ports shall be located in accordance with the CARB regulation titled California Air Resources Board Air Monitoring Quality Assurance Volume VI, Standard Operating Procedures for Stationary Emission Monitoring and Testing. [District Rule 1081]

38. Source testing shall be conducted using the methods and procedures approved by the District. The District must be notified at least 30 days prior to any compliance source test, and a source test plan must be submitted for approval at least 15 days prior to testing. [District Rule 1081]

39. Source testing to measure startup and shutdown NOx, CO and VOC emissions shall be conducted within 60 days of initial startup. CEMS relative accuracy for NOx, SOx and CO shall be determined during startup and shutdown source testing in accordance with 40 CFR 60, Appendix F (Relative Accuracy Audit). [District Rule 2201]

40. Source testing to measure steady state NOx, CO, PM10, SOx, VOC, and NH3 emissions shall be conducted within 60 days of initial startup and at least once 12 months thereafter. [District Rules 2201 and 4352]

41. All emission measurements shall be made with the unit operating either at conditions representative of normal operations or conditions specified in the Permit to Operate. [District Rules 2201 and 4352]

CONDITIONS CONTINUE ON NEXT PAGE

42. No compliance determination shall be established within two hours after a period in which fuel flow to the unit is zero, or is shut off for 30 minutes or longer. [District Rules 2201 and 4352]

43. NOx emissions for source test purposes shall be determined using EPA Methods 7E and 19 or CARB Method 100 and EPA Method 19. [District Rules 1081 and 4352]

44. CO emissions for source test purposes shall be determined using EPA Method 10, EPA Method 3A or CARB Method 100. [District Rules 1081 and 4352]

45. PM10 emissions for source test purposes shall be determined using EPA Methods 201A, 202, and 19. [District Rules 1081 and 4352]

46. In lieu of performing a source test for PM10, the results of the total particulate test may be used for compliance with the PM10 emission limit provided the results include both the filterable and condensable (back half) particulates, and that all particulate matter is assumed to be PM10. If this option is exercised, source testing shall be conducted using CARB Method 5 or EPA Method 5 (including condensable (back half) particulates). [District Rule 1081]

47. Stack gas oxygen shall be determined using EPA Method 3 or 3A or CARB Method 100. [District Rules 1081 and 4352]

48. SOx emissions for source test purposes shall be determined using EPA Method 6, EPA Method 6C, EPA Method 8 or CARB Method 100. [District Rules 1081 and 4352]

49. VOC emissions for source test purposes shall be determined using EPA Method 18, 25A, or 25B, or ARB Method 100. [District Rule 1081]

50. Stack gas velocity shall be determined using EPA Method 2. [District Rules 1081 and 4352]

51. Stack gas moisture content shall be determined using EPA Method 4. [District Rules 1081 and 4352]

52. Source testing for ammonia slip shall be conducted utilizing BAAQMD Method ST-1B. [District Rule 1081]

53. Testing to determine the higher heating value (HHV) of the fuel used in this boiler shall be conducted at least once every 12 months. [District Rules 1081 and 2201]

54. HHV in the fuel used in this boiler shall be conducted using ASTM 5865-10, EPA Method 19, ASTM D2015 or ASTM D3588 or District-approved equivalent method. [District Rules 1081, 2201 and 4352]

55. The owner or operator shall install, certify, maintain, operate and quality-assure a Continuous Emissions Monitoring System (CEMS) which continuously measures and records the exhaust gas NOx, SOx, CO and O2 or CO2 concentrations for each boiler. CEMS shall monitor emissions during all types of operation, including during startup and shutdown periods, provided the CEMS passes the relative accuracy requirement specified herein during startups and shutdowns periods. If relative accuracy of CEMS cannot be demonstrated during startup or shutdown periods, CEMS results during startup and shutdown events shall be replaced with startup emission rates obtained during initial source testing. [District Rules 1080, 2201 and 4352]

56. Each CEMS shall complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each 15-minute quadrant of the hour or shall meet equivalent specifications established by mutual agreement of the District, the CARB and the EPA. [District Rules 1080, 2201 and 4352]

57. Each CEMS shall meet the requirements in 40 CFR 60, Appendix F Procedure 1 for CEMS and Part 60, Appendix B Performance Specification 6 (PS6), or shall meet equivalent specifications established by mutual agreement of the District, the CARB, and the EPA. [District Rules 1080 and 2201]

58. In accordance with 40 CFR Part 60, Appendix F, NOx, SOx, CO and O2 or CO2 monitors must be audited at least once each calendar quarter, by conducting cylinder gas audits (CGA) or relative accuracy audits (RAA). CGA or RAA may be conducted three of four calendar quarters, but no more than three calendar quarters in succession. Audit reports shall be submitted along with quarterly compliance reports to the District. [District Rules 1080, 2201 and 4352]

59. The owner/operator shall perform a RATA for NOx, SOx, CO and O2 or CO2 (as specified in 40 CFR Part 60, Appendix F) and flow rate sensor at least once every four calendar quarters. The permittee shall comply with the applicable requirements for quality assurance testing and maintenance of the CEMS equipment in accordance with the procedures and guidance specified in 40 CFR Part 60, Appendix F for CEMS equipment. [District Rules 1080, 2201 and 4352]

CONDITIONS CONTINUE ON NEXT PAGE

60. APCO or an authorized representative shall be allowed to inspect, as determined to be necessary, the required monitoring devices to ensure that such devices are functioning properly. [District Rule 1080]

61. The CEMS data shall be reduced to hourly averages as specified in 40 CFR 60.13(h), or by other methods deemed equivalent by mutual agreement with the District, the CARB, and the EPA. [District Rules 1080, 2201 and 4352]

62. Upon written notice from the District, the owner or operator shall provide a summary of the data obtained from the CEMS. This summary shall be in the form and the manner prescribed by the District. [District Rules 1080 and 2201]

63. The facility shall install and maintain equipment, facilities, and systems compatible with the District's CEMS data polling software system and shall make CEMS data available to the District's automated polling system on a daily basis [District Rules 1080, 2201 and 4352]

64. Upon notice by the District that the facility's CEMS is not providing polling data, the facility may continue to operate without providing automated data for a maximum of 30 days per calendar year provided the CEMS data is sent to the District by a District-approved alternative method. [District Rule 1080]

65. The owner or operator shall maintain the following records for CEMS equipment: (1) Date, time and duration of any malfunction; (2) Date of performance testing; (3) Date of evaluations, calibrations, checks, and adjustments; and (4) Date and time period for which CEMS was inoperative. [District Rules 1080, 2201 and 4352]

66. The owner or operator shall maintain records of NOx, SOx and CO emissions and submit a written report each calendar quarter to the District containing the following information for each operating day: (1) Calendar date; (2) NOx (expressed as NO2), SOx and CO emission rate (lb/hr) measured at the exhaust of each boiler; (3) NOx (expressed as NO2), SOx and CO emissions rate factor (lb/MMBtu, over a block 24-hour average basis), (4) Total daily NOx, SOx and CO emission rates (lb/day) calculated at the end of each operating day from the measured total hourly NOx, SOx and CO emission rates; (5) The 30-day rolling average SOx emission rate (lb/MMBtu); (6) The total monthly NOx, SOx and CO emission rates (lb/month) calculated at the end of each month using total daily NOx, SOx and CO emissions rates; (7) The total annual NOx, SOx and CO emission rates (lb/year, on a rolling 12-month basis) calculated at the end of each month using total monthly NOx emission rate; (8) Identification of the operating days when NOx, SOx and CO emission rates are in excess of the permitted levels, with the reasons for such excess emissions as well as a description of corrective actions taken; (9) Identification of the operating days for which pollutant data have not been obtained, including reasons for not obtaining sufficient data and a description of corrective actions taken; (10) Identification of the times when emission data have been excluded from the calculation of average emission rates and the reasons for excluding such data; (11) Identification of each parameter used in calculations; (12) Identification of the times when the pollutant concentration exceeded full span of the CEMS; (13) Description of any modifications to the CEMS that could affect the ability of the CEMS to comply with Performance Specification 6; (14) Results of daily CEMS drift tests and quarterly accuracy assessments as required under Appendix F, Procedure 1 of Part 60; and (15) A negative declaration when no excess emissions occurred. The report is due on the 30th day following the end of the calendar quarter. [District Rules 1080, 2201 and 4352]

67. The owner or operator may submit electronic quarterly reports in lieu of submitting the written reports. The format of each quarterly electronic report shall be coordinated with the District. 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 permit was achieved during the reporting period. Before submitting reports in the electronic format, the owner or operator shall coordinate with the District to obtain their agreement to submit reports in this alternative format. [District Rules 1080, 2201 and 4352]

68. The owner or operator shall maintain an operating log that includes, on a daily basis: (1) Actual local startup and shutdown time, (2) Total hours of operation, (3) Duration of each start-up, (4) Duration of each shutdown, (5) Total duration of all startups occurred in a given calendar year, (6) Total duration of all shutdowns occurred in a given calendar year, (7) SCR face temperature records, (8) Baghouse differential pressure records, (9) Quantity of the fuel combusted in this boiler. [District Rule 2201]

69. The owner or operator shall maintain records of monthly and annual (12-month rolling basis) PM10, VOC and NH3 emissions. [District Rule 2201]

CONDITIONS CONTINUE ON NEXT PAGE

70. The owner or operator shall keep records of all maintenance of the baghouse, including all change outs of bags or filter media. These records shall include identification of the equipment, date of inspection, any corrective action taken, and identification of the personnel performing the inspection. [District Rule 2201]

71. The owner or operator shall keep monthly records of the type, quantity, and the HHV of the fuel used in this boiler. [District Rule 4352]

72. Except during periods of startup, shutdown, or malfunction, PM emissions from this boiler shall not exceed 0.030 lb/MMBtu. [40 CFR 60.43c(e)(1) and 40 CFR 60.43c(d)]

73. EPA Method 1 of Appendix A of 40 CFR Part 60 shall be used to select the sampling site and the number of traverse sampling points. [40 CFR 60.45c(a)(1)]

74. EPA Method 3A or 3B of Appendix A-2 of 40 CFR Part 60 shall be used for gas analysis when applying Method 5 of Appendix A-3 of 40 CFR Part 60 or EPA Method 17 of Appendix A-6 of 40 CFR Part 60. [40 CFR 60.45c(a)(2)]

75. PM emissions shall be determined EPA Method 5, or 17 of Appendix A of 40 CFR Part 60 provided the stack gas temperature does not exceed a temperature of 160 °C (320 °F). [40 CFR 60.45c(a)(3)]

76. Each PM testing run shall be at least 120 minutes and the minimum sampling volume shall be 1.7 dry standard cubic meters (dscm) [60 dry standard cubic feet (dscf)] except that smaller sampling times or volumes may be approved by the District when necessitated by process variables or other factors. [40 CFR 60.45c(a)(4)]

77. For Method 5 of Appendix A in 40 CFR Part 60, the temperature of the sample gas in the probe and filter holder shall be monitored and maintained at 160 ±14 °C (320±25 °F). [40 CFR 60.45c(a)(5)]

78. For determination of PM emissions, an oxygen (O2) or carbon dioxide (CO2) measurement shall be obtained simultaneously with each run of Method 5, or 17 of Appendix A of 40 CFR Part 60 by traversing the duct at the same sampling location. [40 CFR 60.45c(a)(6)]

79. For each testing run using Method 5 or 17 of Appendix A of 40 CFR Part 60, the emission rates expressed in ng/J (lb/MMBtu) heat input shall be determined using: (i) The O2 or CO2 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 40 CFR Part 60. [40 CFR 60.45c(a)(7)]

80. Except during periods of startup, shutdown, or malfunction, exhaust discharge from this unit shall not exhibit greater than 20 percent opacity (6-minute average), with an exception of one 6-minute period per hour of not more than 27 percent opacity. [40 CFR 60.43c(c) and 40 CFR 60.43c(d)]

81. EPA Method 9 of Appendix A-4 and the procedure in section 60.11 of 40 CFR Part 60 shall be used for determining the opacity of stack emissions. [40 CFR 60.45c(a)(8) and 40 CFR 60.47c(a)]

82. The owner or operator shall install, operate and maintain a bag leak detection system to monitor the performance of the fabric filter baghouse according to the requirements in 40 CFR 60.48Da(o)(4) of 40 CFR Part 60. [40 CFR 60.47c(a)]

83. 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. [40 CFR 60.47c(a)]

84. During the latest Method 9 test, if no visible emissions are observed, a subsequent Method 9 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. [40 CFR 60.47c(a)(1)(i)]

85. During the latest Method 9 test, if visible emissions are observed but the maximum 6-minute average opacity is less than or equal to 5 percent, a subsequent Method 9 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. [40 CFR 60.47c(a)(1)(ii)]

86. During the latest Method 9 test, if the maximum 6-minute average opacity is greater than 5 percent but less than or equal to 10 percent, a subsequent Method 9 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. [40 CFR 60.47c(a)(1)(iii)]

CONDITIONS CONTINUE ON NEXT PAGE

87. During the latest Method 9 test, if the maximum 6-minute average opacity is greater than 10 percent, a subsequent Method 9 must be completed within 45 calendar days from the date that the most recent performance test was conducted. [40 CFR 60.47c(a)(1)(iv)]

88. During the latest Method 9 test, if the maximum 6-minute opacity is less than 10 percent, the owner or operator may, as an alternative to performing subsequent Method 9, elect to perform subsequent monitoring using Method 22 of Appendix A-7 of 40 CFR Part 60 according to the procedures specified in paragraphs 40 CFR 60.47c(a)(2)(i) and (ii). [40 CFR 60.47c(a)(2)]

89. During the latest Method 9 test, if the maximum 6-minute opacity is less than 10 percent, the owner or operator may, as an alternative to performing subsequent Method 9 of, elect to perform subsequent monitoring using a digital opacity compliance system according to a site-specific monitoring plan approved by the District. The observations shall be similar, but not necessarily identical, to the requirements in paragraph 40 CFR 60.47c(a)(2). 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. [40 CFR 60.47c(a)(3)]

90. The owner or operator shall submit notification of the date of construction and actual startup. This notification shall also include design heat input capacity and anticipated annual capacity factor. [40 CFR 60.48c(a)]

91. The owner or operator shall submit excess emission reports, every 6-month period, for any excess emissions from the affected facility that occur during the reporting period and maintain records according to the requirements, as applicable to the visible emissions monitoring method used: (1) For each performance test conducted using Method 9, the owner or operator shall keep the records of (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, the owner or operator shall keep the records including the information of (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 District. All reports shall be submitted to the Administrator and shall be postmarked by the 30th day following the end of the reporting period. [40 CFR 60.48c(c) and 40 CFR 60.48c(j)]

92. The owner or operator shall keep records of the date and the amount of each fuel combusted during each operating day. [40 CFR 60.48c(g)(1)]

93. The owner shall keep records of monthly NOx emitted from each unit at facilities N-8887 and N-10188. These records shall be used to determine the total NOx emissions at the end of each month to demonstrate compliance with NOx limit for each 12-consecutive month period. [District Rule 2201]

94. The owner or operator shall retain all records on site for a period of five year following the date of such record. These records shall be made available to the District, CARB and EPA upon request. [District Rules 1070, 2201, and 4352, 40 CFR 60.48c(i)]

San Joaquin Valley
Air Pollution Control District

AUTHORITY TO CONSTRUCT

PERMIT NO: N-10188-3-0 **ISSUANCE DATE:** DRAFT

LEGAL OWNER OR OPERATOR: COMBINED SOLAR TECHNOLOGIES, INC.
MAILING ADDRESS: PO BOX 583
TRACY, CA 95304

LOCATION: 9251 W ARBOR AVE
TRACY, CA 95304

EQUIPMENT DESCRIPTION:
6,538 GALLONS PER MINUTE MARLEY FIELD COOLING TOWER SERVED BY HIGH EFFICIENCY DRIFT ELIMINATORS

CONDITIONS

1. The owner or operator shall notify the District of any breakdown condition as soon as reasonably possible, but no later than one hour after its detection, unless the owner or operator demonstrates to the District's satisfaction that the longer reporting period was necessary. [District Rule 1100]
2. The District shall be notified in writing within ten days following the correction of any breakdown condition. The breakdown notification shall include a description of the equipment malfunction or failure, the date and cause of the initial failure, the estimated emissions in excess of those allowed, and the methods utilized to restore normal operations. [District Rule 1100]
3. {98} No air contaminant shall be released into the atmosphere which causes a public nuisance. [District Rule 4102]
4. {14} Particulate matter emissions shall not exceed 0.1 grains/dscf in concentration. [District Rule 4201]
5. {15} No air contaminant shall be discharged into the atmosphere for a period or periods aggregating more than three minutes in any one hour which is as dark as, or darker than, Ringelmann 1 or 20% opacity. [District Rule 4101]
6. No hexavalent chromium containing compounds shall be added to cooling tower circulating water. [District Rule 7012]
7. The drift rate shall not exceed 0.0005%. [District Rule 2201]
8. PM10 emissions shall not exceed 0.4 pounds in any one day. [District Rule 2201]

CONDITIONS CONTINUE ON NEXT PAGE

YOU <u>MUST</u> NOTIFY THE DISTRICT COMPLIANCE DIVISION AT (209) 557-6400 WHEN CONSTRUCTION IS COMPLETED AND PRIOR TO OPERATING THE EQUIPMENT OR MODIFICATIONS AUTHORIZED BY THIS AUTHORITY TO CONSTRUCT. This is NOT a PERMIT TO OPERATE. Approval or denial of a PERMIT TO OPERATE will be made after an inspection to verify that the equipment has been constructed in accordance with the approved plans, specifications and conditions of this Authority to Construct, and to determine if the equipment can be operated in compliance with all Rules and Regulations of the San Joaquin Valley Unified Air Pollution Control District. Unless construction has commenced pursuant to Rule 2050, this Authority to Construct shall expire and application shall be cancelled two years from the date of issuance. The applicant is responsible for complying with all laws, ordinances and regulations of all other governmental agencies which may pertain to the above equipment.

Samir Sheikh, Executive Director / APCO

Brian Clements, Director of Permit Services

9. Compliance with the PM10 emission limit (lb/day) shall be demonstrated by using the following equation: Water Recirculation Rate (gal/day) x 8.34 lb/gal x Total Dissolved Solids Concentration in the blowdown water (ppm x 10E-06) x Design Drift Rate (%). [District Rule 2201]
10. Compliance with PM10 emission limit shall be determined by blowdown water sample analysis by independent laboratory within 60 days of the initial startup and at least once quarterly thereafter. [District Rule 2201]
11. The owner or operator shall monitor and record water recirculation rate (gal/day) at least once daily when the equipment is in operation. [District Rule 2201]
12. The owner or operator shall keep records of the date and PM10 emissions (lb/day). [District Rule 2201]
13. {3246} All records shall be maintained and retained on-site for a period of at least 5 years and shall be made available for District inspection upon request. [District Rule 1070]

San Joaquin Valley
Air Pollution Control District

AUTHORITY TO CONSTRUCT

PERMIT NO: N-10188-4-0 **ISSUANCE DATE:** DRAFT

LEGAL OWNER OR OPERATOR: COMBINED SOLAR TECHNOLOGIES, INC.
MAILING ADDRESS: PO BOX 583
TRACY, CA 95304

LOCATION: 9251 W ARBOR AVE
TRACY, CA 95304

EQUIPMENT DESCRIPTION:
DRY SORBENT RECEIVING AND STORAGE OPERATION WITH ONE 1,300 CUBIC FOOT (APPROX. DIMENSIONS 26 FEET TALL, 8 FEET DIAMETER) SILO SERVED BY A DUST COLLECTION SYSTEM

CONDITIONS

1. {98} No air contaminant shall be released into the atmosphere which causes a public nuisance. [District Rule 4102]
2. {14} Particulate matter emissions shall not exceed 0.1 grains/dscf in concentration. [District Rule 4201]
3. {15} No air contaminant shall be discharged into the atmosphere for a period or periods aggregating more than three minutes in any one hour which is as dark as, or darker than, Ringelmann 1 or 20% opacity. [District Rule 4101]
4. Visible emissions from the bin vent filter or dust collector serving the storage silo shall not equal or exceed 5% opacity for a period or periods aggregating more than three minutes in any one hour. [District Rule 2201]
5. The bin vent filter or dust collector shall be maintained and operated according to manufacturer's specifications. [District Rule 2201]
6. The bin vent filter or dust collector cleaning frequency and duration shall be adjusted to optimize the control efficiency. [District Rule 2201]
7. The bin vent filter or dust collector system shall be equipped with a pressure differential gauge to indicate the pressure drop across the filters. The gauge shall be maintained in good working condition at all times and shall be located in an easily accessible location. [District Rule 2201]
8. The differential pressure gauge reading range shall be established per manufacturer's recommendation at time of start up inspection. [District Rule 2201]

CONDITIONS CONTINUE ON NEXT PAGE

YOU <u>MUST</u> NOTIFY THE DISTRICT COMPLIANCE DIVISION AT (209) 557-6400 WHEN CONSTRUCTION IS COMPLETED AND PRIOR TO OPERATING THE EQUIPMENT OR MODIFICATIONS AUTHORIZED BY THIS AUTHORITY TO CONSTRUCT. This is NOT a PERMIT TO OPERATE. Approval or denial of a PERMIT TO OPERATE will be made after an inspection to verify that the equipment has been constructed in accordance with the approved plans, specifications and conditions of this Authority to Construct, and to determine if the equipment can be operated in compliance with all Rules and Regulations of the San Joaquin Valley Unified Air Pollution Control District. Unless construction has commenced pursuant to Rule 2050, this Authority to Construct shall expire and application shall be cancelled two years from the date of issuance. The applicant is responsible for complying with all laws, ordinances and regulations of all other governmental agencies which may pertain to the above equipment.

Samir Sheikh, Executive Director / APCO

Brian Clements, Director of Permit Services

N-10188-4-0 : May 17 2023 8:48AM -- KAHLONJ : Joint Inspection NOT Required

9. Material removed from the bin vent filter or dust collector system shall be disposed of in a manner preventing entrainment into the atmosphere. [District Rule 2201]

10. Replacement bags numbering at least 10% of the total number of bags in the bin vent filter or dust collector shall be maintained on the premises. [District Rule 2201]

11. Only trona or hydrated lime shall be received as a dry sorbent material. [District Rules 4102 and 2201]

12. PM10 emissions from dry sorbent material receiving and storage operation shall not exceed 0.0049 pounds per ton of material processed. [District Rule 2201]

13. No more than 25 tons of dry sorbent material shall be received in any one day. [District Rule 2201]

14. The owner or operator shall keep records of the following items: (a) Date, (b) Name of the material, (c) Quantity of the material received (tons/day) and (d) An up-to-date record of the total quantity of the materials received (tons) during a given year. [District Rule 2201]

15. Differential operating pressure shall be monitored and recorded on each day the operator loads the silo. [District Rule 2201]

16. Bin vent filter or dust collector shall be thoroughly inspected annually for tears, scuffs, abrasions, holes, or any evidence of particulate matter breakthrough and shall be replaced as needed. [District Rule 2201]

17. Records of all maintenance of the bin vent filter or dust collector system, including all change outs of bags or filter media, shall be maintained. These records shall include identification of the equipment, date of inspection, any corrective action taken, and identification of the personnel performing the inspection. [District Rule 2201]

18. All records shall be maintained and retained on-site for a period of at least 5 years and shall be made available for District inspection upon request. [District Rule 1070]

Appendix B
BACT Analysis

Top-Down BACT Analysis

N-10188-2-0

As noted previously, the proposed walnut-shell fired boiler triggered BACT for NOx, SOx, PM10 and VOC emissions. A project specific BACT analysis will be conducted for this proposal. The following databases were searched to determine existing limits for various pollutants that are achieved or are technically feasible for the proposed unit.

BACT Clearinghouse Survey:

The following BACT clearinghouses were consulted:

- EPA RACT/BACT/LAER clearinghouse
- CARB BACT clearinghouse
- South Coast AQMD BACT clearinghouse
- Bay Area AQMD BACT clearinghouse
- Ventura County APCD BACT clearinghouse
- Sacramento Metro AQMD BACT clearinghouse
- San Diego APCD BACT clearinghouse
- Yolo-Solano AQMD BACT clearinghouse
- Placer County AQMD BACT clearinghouse
- San Joaquin Valley APCD BACT clearinghouse

EPA RACT/BACT/LAER clearinghouse

EPA's RBLC database was searched. Most of this search was conducted in April 2019, under project N-1180873. The District did not expect that any new facilities came on-line since 2019. Therefore, no additional search is necessary.

The highlighted emission limits are stringent than the emission limits for a typical solid fuel-fired boiler. However, as discussed below, most of these facilities were never installed (VT-0037, VT-0039, CT-0156, GA-0141, GA-0132, NH-0018, TX-0553, NH-0015) or are no longer operating (KS-0034, TX-0555).

RBLC ID	Facility Name	Fuel Type	Heat input rate	NOx	SOx	PM_{10}	CO	VOC
KS-0034 (no longer operating)	Abengoa Bioenergy Biomass of Kansas	Different types of biomass	500 MMBtu/hr	0.3000 lb/MMBtu	0.2100 lb/MMBtu	0.0320 lb/MMBtu	260 ppmv@ 3% O2	0.0050 lb/MMBtu
CA-1225	Sierra Pacific Industries	Biomass (stoker boiler)	468 MMBtu/hr	0.1300 lb/MMBtu	N/A	0.0200 lb/MMBtu 3-hour block avg	0.2300 lb/MMBtu	N/A
OR-0051	Seneca Sustainable Energy, LLC	Biomass	352.8 MMBtu/hr	N/A	N/A	0.01 lb/MMBtu	N/A	N/A
VT-0039 (facility never built)	North Springfield Sustainable Energy Project, LLC	Wood (bubbling fluidized bed design and SCR)	464 MMBtu/hr	0.0300 lb/MMBtu on 12-month rolling avg; 0.06 lb/MMBtu on 1-hour*	0.02 lb/MMBtu	0.0190 lb/MMBtu hourly avg	0.075 lb/MMBtu on 24-hour*	N/A
VT-0037 (facility never built)	Beaver Wood Energy Fair Haven, LLC	Wood	482 MMBtu/hr	0.0300 lb/MMBtu on 12-month rolling average; 0.0600 lb/MMBtu hourly avg 0.3300 lb/MMBtu 8-hour average – startup limit	0.02 lb/MMBtu hourly average	0.0190 lb/MMBtu hourly average; 0.012 lb/MMBtu hourly average filterable PM10	0.075 lb/MMBtu on 24-hr rolling average	0.0050 lb/MMBtu Hourly average
CT-0162	Plainfield Renewable Energy, LLC	Wood	523.10 MMBtu/hr	0.075 lb/MMBtu	0.035 lb/MMBtu; 15.4 ppmvd @ 7% O2 3-hour block	0.038 lb/MMBtu	0.105 lb/MMBtu	0.012 lb/MMBtu
GA-0141 (facility never built)	Warren County Biomass Energy Facility	Biomass Wood	100 MW	0.1 lb/MMBtu	0.01 lb/MMBtu 30 day rolling average	0.01 lb/MMBtu filterable PM10 30 hour Avg; 0.018 lb/MMBtu (total) 3 hour Avg	0.0800 lb/MMBtu 30 day rolling avg	N/A
NH-0018 (facility never built)	Berlin Biopower	Wood	1,013 MMBtu/hr	0.0600 lb/MMBtu 30-day rolling	0.012 lb/MMBtu	0.0100 lb/MMBtu, filterable PM	0.075 lb/MMBtu calendar day	N/A
CT-0156 (facility never built)	Montville Power LLC	Clean wood	600 MMBtu/hr	0.0600 lb/MMBtu 24-hour block	0.025 lb/MMBtu 3-hour block	0.026 lb/MMBtu	0.1 lb/MMBtu 8-hour block	0.01 lb/MMBtu
TX-0553 (facility never built)	Lindale Renewable Energy	Biomass (stoker grate boiler)	54 to 73 ton/hr	0.15 lb/MMBtu rolling 30-day average	0.0250 lb/MMBtu rolling 30-day average	0.0200 lb/MMBtu, filterable rolling 30-day avg	0.31 lb/MMBtu rolling 30-day average	N/A
TX-0555 (no longer operating)	Lufkin Generating Plant	Wood	693 MMBtu/hr	0.075 lb/MMBtu	0.025 lb/MMBtu 30-day rolling avg	0.025 lb/MMBtu PM total, 30 day rolling average	0.075 lb/MMBtu rolling 30-day average	0.01 lb/MMBtu rolling 30-day average
NH-0015 (facility never built)	Concord Steam Corporation	Wood (stoker boiler)	32.62 tons/hr	0.0600 lb/MMBtu on 30-day rolling average	N/A	N/A	N/A	N/A
GA-0132 (facility never built)	Yellow Pine Energy Company LLC	Biomass	1,529 MMBtu/hr	0.1000 lb/MMBtu	N/A	0.018 lb/MMBtu, total PM; 0.0100 lb/MMBtu PM10 (filterable)	0.149 lb/MMBtu 30 day rolling average	0.0200 lb/MMBtu

*Does not apply during startup; N/A – Data not available

Abengoa Bioenergy Biomass of Kansas (KS-0034):
Staff at Kansas state confirmed that this facility is no longer operating.

Further, the boiler is permitted to use wheat straw, milo (sorghum) stubble, corn stover, switchgrass, other opportunity feedstocks that are available, enzymatic hydrolysis residuals (including lignin-rich stillage cake and thin stillage syrup), particulate collected during biomass grinding operation, wastewater treatment sludge and biogas. These fuels are significantly different than the locally available biomass fuels from agricultural such as orchard prunings or trimmings (primarily) and urban wood waste.

Sierra Pacific Industries (CA-1225)
The boiler at Sierra Pacific Industries uses bark, sawdust and other low-grade byproducts of the sawmill manufacturing process, as the primary fuel. There is limited variation among wood species processed at sawmills. Therefore, the fuel is expected to burn cleaner as the boiler controls can be fine-tuned to achieve optimum combustion; this results in lesser overall emissions, in particular, CO and PM_{10} emissions from the boiler compared to the some of the boiler in the valley (PM10 emission limit comparison made with permits at DTE Stockton). The boiler in the San Joaquin Valley primarily uses locally available biomass fuels from agricultural such as orchard prunings or trimmings (primarily) and urban wood waste. Due to difference in fuel types, PM_{10} emissions limit of the boiler at Sierra Pacific Industries cannot be implied to the boilers in the valley.

Seneca Sustainable Energy, LLC (OR-0051)
The boiler uses sawmill bark, sawdust, shavings and forest biomass “logging residuals or slash” from Seneca Jones Timber Company, as the primary fuel. There is limited variation among wood species processed at sawmills. Therefore, the fuel will likely burn cleaner and results lesser PM_{10} emissions from the boiler compared to the boiler in the San Joaquin Valley (PM10 emission limit comparison made with permits at DTE Stockton). The boiler in the San Joaquin Valley primarily uses locally available biomass fuels from agricultural such as orchard prunings or trimmings (primarily) and urban wood waste. Due to difference in fuel types, PM_{10} emissions limit of the boiler at Seneca Sustainable Energy is not representative of the emissions from the boiler in the valley.

North Springfield Sustainable Energy Project, LLC (VT-0039)
Per Vermont’s Department of Environmental Conservation website (https://dec.vermont.gov/air-quality/permits/issued-permits), this facility has not commenced construction and their approval to construct has been expired on 10/19/2014. Therefore, the limits for the boiler cannot be used to establish the limits for the biomass fired boiler in the San Joaquin Valley. Also, note that the permit (AP-11-038) for North Springfield boiler states that the boiler will use green natural wood chip as primary fuel.

Beaver Wood Energy Fair Haven, LLC (VT-0037)
Per Vermont's Department of Environmental Conservation website (https://dec.vermont.gov/air-quality/permits/issued-permits), this facility has not commenced construction and their approval to construct has been expired on 8/2/2016. Therefore, the limits for the boiler cannot be implied to the boiler in the San Joaquin Valley. Also, note that the permit (AP-11-015b) for Beaver Wood boiler states that the boiler will use green wood chip fuel consisting of forest residue chips, bark and mill waste (clean untreated wood fragments) as primary fuel.

Plainfield Renewable Energy, LLC (CT-0162)
The biomass fired boiler is a fluidized bed staged gasification process with a close-coupled electric generating boiler, and uses biomass from forest management residues (pine, oak, etc.), land clearing debris, waste wood from industries, construction and demolition waste. Along with the other emission limits, the unit is permitted to achieve 0.035 lb-SOx/MMBtu (15.4 ppmvd SOx @ 7% O2). Source test conducted on March 26, 2014 indicate that they have successfully complied with SOx emission limit. Further, CEMS data indicate that SO_2 during normal operation (after switching from diesel to biomass) stay below the permitted limit.

Generally, sulfur dioxide emissions are associated with the sulfur content in biomass fuel charged in the boiler. The fuel charged in the boiler at Plainfield Renewable Energy is from forest management residues (pine, oak, etc.) different than the locally available biomass fuels from agricultural such as orchard prunings or trimmings (primarily) and urban wood waste. Therefore, SOx emissions of the unit at Plainfield Renewable Energy cannot be used to establish the limits for the boilers in the San Joaquin Valley.

Montville Power LLC (CT-0156)
District staff contacted the regulatory agency, and was told that this biomass plant was never constructed.

Warren County Biomass Energy Facility (GA-0141)
Yellow Pine Energy Company LLC (GA-0132)
For both facilities, District staff contacted the regulatory agency, and was told that these biomass plants were never built.

Berlin Biopower (NH-0018)
This facility was never built and their permit was cancelled March 9, 2012.

Lindale Renewable Energy (TX-0553)
District staff contacted TCEQ, and was told that this plant was never constructed.

Lufkin Generating Plant (TX-0555)
District staff contacted TCEQ, and was told that this plant is not operating since 2015.

Concord Steam Corporation (NH-0015)
Online search shows that this facility was never constructed.

CARB BACT clearinghouse
CARB's BACT Clearinghouse - CARB's BACT Guidelines Tool was searched (https://ww2.arb.ca.gov/our-work/programs/technology-clearinghouse/clearinghouse-tools/bact-guidelines-tool). A relevant guideline in the Bay Area AQMD was found and will be discussed under the Air District's BACT clearinghouse section.

Agency	BACT Guideline #	Last Update	Title
Bay Area AQMD	17.9.1	8/5/1991	Boiler – Wood Fired

South Coast AQMD BACT clearinghouse
The existing determinations under "Part B: Section I – SCAQMD LAER/BACT" were reviewed (http://www.aqmd.gov/home/permits/bact/guidelines/i---scaqmd-laer-bact). No relevant BACT determination was found.

The existing determinations under "Part B: Section II – Other LAER/BACT" were reviewed (http://www.aqmd.gov/home/permits/bact/guidelines/ii---other-laer-bact). No relevant BACT determination was found.

The existing determinations under "Part B: Section III – Other Technologies" were reviewed (http://www.aqmd.gov/home/permits/bact/guidelines/iii---other-technologies). No relevant BACT determination was found.

The draft LAER Part B, Section I and III Draft Proposals were also reviewed (http://www.aqmd.gov/docs/default-source/bact/proposed_updates_bact_partb_draft_2-2-18.pdf?sfvrsn=6). No relevant BACT determination was found.

Further, the draft Major Source, Part D Draft Proposals were also reviewed (http://www.aqmd.gov/docs/default-source/bact/proposed_updates_bact_guidelines_partd_draft_2-2-18.pdf?sfvrsn=6). No relevant BACT guideline was found.

Bay Area AQMD BACT clearinghouse
The BACT guidelines available on BAAQMD website were reviewed (http://www.baaqmd.gov/permits/permitting-manuals/bact-tbact-workbook). BACT guideline document 17.9.1 (8/05/91) – Boiler wood-fired, lists the following achieved-in-practice (AIP) and technologically feasible options:

Fuel Type	Rating	NOx	SOx	PM_{10}	CO	VOC
Wood	All	AIP: 0.08 lb/MMBtu (selective non-catalytic reduction, ammonia injection) Tech. feasible: N/S* (SCR + combustion modifications)	AIP: 0.027 lb/MMBtu (limestone injection with baghouse) Tech. feasible: N/S* (dry scrubber with baghouse)	AIP: ≤0.01 gr/dscf (multiclone and baghouse) Tech. feasible: ≤ 0.002 gr/dscf @ 12% CO_2 (multiclone and baghouse)	AIP: 0.038 lb/MMBtu (Good combustion practice) Tech. feasible: N/S* (catalytic oxidation)	AIP: 0.027 lb/MMBtu (Good Combustion Practice) Tech. feasible: n/d

*N/S = No standard established

<u>Ventura County APCD BACT Clearinghouse</u>

Ventura County APCD conducts project specific BACT analysis under each project (http://www.vcapcd.org) by considering BACT established in other air districts. No relevant BACT guideline was found.

<u>Sacramento Metro AQMD BACT clearinghouse</u>

SMAQMD BACT clearinghouse was reviewed (https://www.airquality.org/businesses/permits-registration-programs/best-available-control-technology-(bact)). No relevant BACT guideline was found.

<u>San Diego APCD BACT clearinghouse</u>

SDCAPCD website was searched (https://www.sdapcd.org/content/sdapcd/permits.html). No relevant BACT guideline was found.

<u>Yolo-Solano AQMD BACT clearinghouse</u>

Yolo-Solano AQMD website (https://www.ysaqmd.org/) was searched. No relevant BACT guideline was found.

<u>Placer County AQMD BACT clearinghouse</u>

Placer County AQMD website (https://www.placerair.org/1569/Air-Pollution-Control) was searched. No relevant BACT guideline was found.

San Joaquin Valley APCD BACT clearinghouse
The BACT clearinghouse contains two rescinded BACT guidelines.

BACT Guideline 1.3.2 (currently rescinded) applied to biomass-fired fluidized bubbling bed combustor and listed the following emission limits as Achieved-in-Practice controls:

BACT Guideline 1.3.2 (Rescinded)					
Operation	**Heat Input**	**NOx**	**SOx**	**PM_{10}**	**VOC**
Biomass-fired Bubbling Bed Combustor	All	0.10 lb/MMBtu	23 ppmvd @ 3% O_2	0.045 lb/MMBtu	0.02 lb/MMBtu
	Control Technology	NH_3 injection and NG as auxiliary fuel	limestone injection & NG as auxiliary fuel	Baghouse	NG as auxiliary fuel

BACT Guideline 1.1.8 (currently rescinded) applied to biomass-fired boilers with grate systems and only listed CO AIP BACT of 400 ppmvd @ 3% O_2.

BACT Guideline 1.1.8 (Rescinded)		
Operation	**Heat Input**	**CO**
Biomass-fired grate systems	All	400 ppmvd @ 3% O2
		Good combustion practices

Survey of Federal, State and Local Rules and Regulations

The following rules were consulted:

- New Source Performance Standard
- CARB (no applicable rules)
- South Coast AQMD Rules
- Bay Area AQMD Rules
- Ventura County APCD Rules
- Sacramento Metro AQMD Rules
- San Diego APCD Rules
- Yolo-Solano AQMD Rules
- Placer County AQMD Rules
- San Joaquin Valley APCD Rules

40 CFR Part 60 Subpart Db – Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units

Type of boiler	NOx or SOx	PM	Opacity
Wood fired boiler (>100 MMBtu/hr)	No standard	0.1 lb-PM/MMBtu with annual capacity factor >30% for wood 0.2 lb/MMBtu with annual capacity factor 30% or less for wood and unit's max. heat input rating is 250 MMBtu/hr or less, except during startup, shutdown and malfunction (Source: 40 CFR 60.43b(c)(1), (c)(2) and 40 CFR 60.43b(g))	20% (6-min average) with an exception of one 6-min period per hour of not more than 27% opacity (Source: 40 CFR 60.43b(f) and 40 CFR 60.43b(g))

40 CFR Part 60 Subpart Dc – Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units

Type of boiler	NOx or SOx	PM	Opacity
Wood fired (30 MMBtu/hr or more)	No standard	0.030 lb-PM/MMBtu, except during startup, shutdown and malfunction (Source: 40 CFR 60.43c(e)(1) and 40 CFR 60.43c(d))	20% (6-min average) with an exception of one 6-min period per hour of not more than 27% opacity (Source: 40 CFR 60.43c(c) and 40 CFR 60.43c(d))

CARB (no applicable rules)
CARB's website includes rules from local air district related to stationary sources.

South Coast AQMD Rules
SCAQMD Rule 1146, Emissions of Oxides of Nitrogen from Industrial, Institutional, and Commercial Boilers, Steam Generators, and Process Heaters (Last amended December 4, 2020)

This rule applies to boilers using liquid and/or gaseous (including landfill and digester gas) and/or solid fossil fuels. This rule is not applicable to biomass-fired boilers. As such, no further discussion is required.

Bay Area AQMD Rules
BAAQMD Regulation 9 Rule 7 (May 4, 2011) was reviewed. This rule limits NOx emissions to 40 ppmvd @ 3% O2 for non-gaseous fuels. Per Final Draft Staff Report Rule 4352 (11/15/2011), BAAQMD does not have any solid fuel fired boilers. Furthermore, it is not clear if the BAAQMD rule limit is intended for solid fuel fired boilers similar to the unit under this project. Therefore, this limit is not deemed achieved-in-practice limit for solid fuel fired units. Also note that this rule exempts boilers used by public electric utilities or

qualifying small power production facilities, as defined in Section 228.5 of the Public Utilities Code, to generate electricity.

Ventura County APCD Rules
VCAPCD Rule 74.15 (11/8/94) was reviewed. This rule primarily applies to natural gas-fired boilers.

Sacramento Metro AQMD Rules
Sac Metro AQMD Rule 411 (August 23, 2007) was reviewed. When using biomass fuel, the rule requires to achieve 70 ppmvd NOx @ 12% CO_2 (equates to 99 ppmvd @ 3% O2) and 400 ppmvd CO @ 12% CO_2 (equates to 565 ppmvd CO @ 3% O2). Note that there has only been one biomass fired unit subject to the rule and it has been shutdown since 1996.

San Diego County APCD Rules
Rule 69 was reviewed and the rule definition includes solid fuel fired boilers. However, the rule exempts electrical generating steam boilers with a maximum heat input capacity of less than 100 MMBtu/hr; therefore, this rule will not be considered further. In addition, Rule 69.2 was reviewed, but this rule is only for gas or liquid fuel-fired units; therefore, this rule will not be considered further.

Yolo-Solano AQMD Rules
Regulation II, Rule 2.43 was reviewed. This rule requires to achieve 90 ppm NOx @ 3% O_2 (block 24-hour average) and 400 ppm CO @ 3% O_2 (block 24-hour average).

Placer County AQMD Rules
Rule 233 was reviewed. This rule applies to biomass boilers rated at less than 500 MMBtu/hr. NOx and CO limits are summarized below:

Type of boiler	NOx	CO
Circulating fluidized bed (<500 MMBtu/hr)	*115 ppmv @ 12% CO_2 (3-hour rolling average)	***400 ppmv @ 12% CO_2 (3-hour rolling average)
	**68 ppmv @ 12% CO_2 (24-hour block average)	
Stoker (<500 MMBtu/hr)	*115 ppmv @ 12% CO_2 (3-hour rolling average)	****1,000 ppmv @ 12% CO_2 (3-hour rolling average)
	**68 ppmv @ 12% CO_2 (24-hour block average)	

*115 ppmv @ 12% CO_2 equates to 163 ppmv@ 3% O_2; **68 ppmv @ 12% CO_2 equates to 63 ppmvd @ 3% O_2; ***400 ppmv @ 12% CO_2 equates to 565 ppmvd @ 3% O_2; ****1,000 ppmv @ 12% CO_2 equates to 1,414 ppmv @ 3% O_2

San Joaquin Valley APCD Rules
District Rule 4352 applies to solid fuel fired boilers, steam generators, and process heaters. Rule 4352 currently requires the following emission limits for the biomass fired units:

Table 1 - NOx Emission Limit (Emission Limit effective until December 31, 2023)		
Fuel Type	**NOx Limit**	**CO Limit**
Biomass	90 ppmv corrected to 3% O_2	400 ppmv corrected to 3% O_2

Table 2 – NOx, PM_{10}, and SOx Emission Limits (Emission Limits effective on and after January 1, 2024)				
Fuel Type	**NOx Limit**	**CO Limit**	**PM_{10} Limit**	**SOx Limit**
Biomass	65 ppmv corrected to 3% O_2[A]	400 ppmv corrected to 3% O_2[A]	0.03 lb/MMBtu	0.02 lb/MMBtu [B] 0.035 lb/MMBtu [A]

[A] Block 24-hour average
[B] Rolling 30-day average

Alternative technologies to generate electrical power from wood combustion:

Gasification (pyrolysis) and combustion in IC engine powering a generator:
Wood can be gasified to release various organic gases (a.k.a. syn gases). These syn gases are polished to remove impurities and then used to power internal combustion engines coupled with electric generator to produce electric power. North Fork Community Power (District facility ID: C-8980) is in the process of constructing two 1 MW each electric generation units using this technology. NOx and PM10 emissions from the North Fork Community power project are estimated to be 0.647 lb/MW-hr and 0.12 lb/MW-hr.

The proposed boiler+steam turbine operation will achieve NOx and PM10 emissions of 0.235 lb/MW-hr and 0.047 lb/MW-hr, respectively. Since the proposed technology achieves much lower emissions per unit of power generation, the use of an IC engine powered by pyrolyzed syn gas will not be considered as an alternative to the equipment proposed for this project.

Fuel Cells:
In theory, syn gas from gasification can be used as fuel for solid oxide fuel cell (SOFC) technology to generate power. However, the potential presence of tars in syn gases could adversely impact the performance and useful life of the SOFC technology[8]. An online search revealed no commercial installation that uses wood gasified syn gas in fuel cells to generate electric power. Due to reliability concern and unavailability of the commercial installation, use of this technology is considered infeasible at this time for this project.

[8] https://www.sciencedirect.com/science/article/abs/pii/S0306261921000581

Survey of Source Tests for Biomass-Fired Boilers in the SJVAPCD:

The District permit database was searched to identify biomass fired boilers with active permits in the San Joaquin Valley. Results from two latest source tests for various pollutants are summarized in the table in this section.

Facility Name	Permit #	Equipment Description	Boiler Type	Control Technology	Permit Limits					Test Date	Source Tested Values				
					NOx	SOx	PM10	CO	VOC		NOx	SOx	PM10	CO	VOC
CES DELANO BECCS PLANT	S-75-6-33	400 MMBTU/HR (32 MW) EPI FLUIDIZED BED, BIOMASS-FUELED BOILER (UNIT #1) WITH NH_3, LIMESTONE, SODIUM BICARBONATE, AND SAND INJECTION, WITH BOILER EXHAUST VENTED TO FABRIC FILTER; AND FOUR 10 MMBTU/HR PORTABLE NATURAL GAS-FIRED REFRACTORY CURING HEATERS	Fluidized bed	baghouse, sodium bicarbonate injection, ammonia injection	0.1 lb/MMBtu	18.8 ppmvd @ 3% O_2 (13.2 lb/hr) (Calc. 0.033 lb/MMBtu)	0.010 gr/dscf@12% O_2 (filterable), 15.98 lb/hr (total) (Calc. 0.04 lb/MMBtu)	181 ppmvd @ 3% O_2 and 56 lb/hr (Calc. 0.152 lb/MMBtu)**	0.02 lb/MMBtu and 8 lb/hr	4/23/2015	0.087 lb/MMBtu	0.8 ppmv @ 3% O_2 (calc. 0.00156 lb/MMBtu)	0.0202 lb/MMBtu; 0.00868 gr-PM10 (cond + filter)/dscf @ 12% CO_2; 0.00692 gr-PM10 (cond+filter)/dscf;	5.5 ppmv @ 3% O_2 (calc. 0.0047 lb/MMBtu)	0.02 lb/MMBtu; <0.645 ppmvd as CH_4
										4/15/2014	0.0849 lb/MMBtu; 61.9 ppmvd @ 3% O_2	0.52 ppmv@ 3% O_2 (0.00098 lb/MMBtu)	0.00774 lb/MMBtu; 0.00326 gr/dscf @ 12% CO_2 (cond+filter); 0.00258 gr-PM10 /MMBtu (cond+filter)	14.9 ppmvd @ 3% O_2 (0.0125 lb/MMBtu)	0.00138 lb/MMBtu
	S-75-11-29	315 MMBTU/HR EPI FLUIDIZED BUBBLING BED, BIOMASS-FUELED BOILER (UNIT #2) WITH NH_3, LIMESTONE, SAND AND SODIUM BICARBONATE ($NAHCO_3$) INJECTION, WITH BOILER EXHAUST VENTED TO SIX COMPARTMENT FABRIC FILTER DUST COLLECTOR; AND FOUR 10 MMBTU/HR THERMAL SOLUTIONS INCORPORATED MODEL NO. TSI-10 PORTABLE NATURAL GAS-FIRED REFRACTORY CURING HEATERS	Fluidized bed	baghouse, sodium bicarbonate injection, ammonia injection	0.1 lb/MMBtu	23 ppmvd @ 3% O_2 and 12.09 lb/hr (Calc. 0.038 lb/MMBtu)	0.045 lb/MMBtu (filterable) and 14.08 lb/hr (total)	183 ppmvd @ 3% O_2 and 44.10 lb/hr (Calc. 0.156 lb/MMBtu)**	0.020 lb/MMBtu and 6.3 lb/hr	4/21/2015	0.092 lb/MMBtu	3.4 ppmvd @ 3% O_2 (calc. 0.0067 lb/MMBtu)	0.0378 lb/MMBtu; 0.0159 gr-PM10 (cond+filter)/dscf @ 12% CO_2; 0.0128 gr-PM (cond+filter)/dscf	6.7 ppmvd @ 3% O_2 (cal. 0.0058 lb/MMBtu)	0.020 lb/MMBtu
										4/16/2014	0.0903 lb/MMBtu 64.5 ppmvd @ 3% O_2	2.01 ppmvd @ 3% O_2; 0.00392 lb/MMBtu	0.0295 lb-PM10/MMBtu (filter+cond); 0.0122 gr/dscf @ 12% Co_2 (cond+filter); 0.00907 gr/dscf (filter+cond)	31.2 ppmvd @ 3% O_2 (0.0266 lb/MMBtu)	0.00159 lb/MMBtu
DTE STOCKTON, LLC	N-645-36-7	54 MW (GROSS) ELECTRICAL GENERATING STATION WITH A 780 MMBTU/HR STOKER BOILER EQUIPPED WITH A 100 MMBTU/HR NATURAL GAS-FIRED STARTUP BURNER, MULTICLONE AND ELECTROSTATIC PRECIPITATOR, TRONA INJECTION AND WET SCRUBBER, AND SELECTIVE CATALYTIC REDUCTION	Stoker	cyclone and ESP, trona injection, SCR system, HCl scrubber	0.065 lb/MMBtu	0.054 lb/MMBtu	0.0214 lb/MMBtu	0.09 lb/MMBtu (Calc. 114 ppmvd @ 3% O_2)	0.009 lb/MMBtu	4/20/2022	0.048 lb/MMBtu	0.0007 lb/MMBtu	0.001 lb-PM/MMBtu	0.059 lb/MMBtu	0.0006 lb/MMBtu
										5/11/21-5/12/21	0.048 lb/MMBtu	0.001 lb/MMBtu	0.001 lb-PM10/MMBtu	0.055 lb/MMBtu	0.001 lb/MMBtu
CES MENDOTA BECCS PLANT	C-825-5-20	30 MW POWER PRODUCTION FACILITY WITH A 317 MMBTU/HR BIOMASS AND NATURAL GAS-FIRED GOTAVERKEN CIRCULATING FLUIDIZED BED BOILER CONTROLLED WITH A MODULAR SIX-COMPARTMENT BAGHOUSE AND THERMAL DE-NOX SYSTEM AND WITH A CYCLONE, A SUPERHEATER, A STEAM DRUM, AN ECONOMIZER, AN AIR HEATER, A SAND SILO AND A LIMESTONE SILO EACH CONTROLLED WITH A DCE DALAMATIC MODEL # DLM-V20/10W BIN VENT FILTER, AN ENCLOSED ASH SILO, AND BOTTOM SAND DISCHARGE UNITS	Fluidized bed	baghouse, limestone injection, thermal de-NOx system	27.8 lb/hr	10.3 lb/hr (Calc. 0.032 lb/MMBtu)	7.62 lb/hr (filterable), 14.3 lb/hr (total) (Calc. 0.045 lb/MMBtu)	38.7 lb/hr (Calc. 0.122 lb/MMBtu)	9.7 lb/hr (calc. 0.03 lb/MMBtu)	6/17/2014	21.4 lb/hr	1.4 lb/hr	3.8 lb-PM10/hr; 0.004 gr-PM/dscf	0.8 lb/hr	0.2 lb/hr
										6/18/2013	0.0610 lb/MMBtu; 20.6 lb/hr	0.00023 lb/MMBtu; 0.08 lb/hr	0.0102 lb-PM/MMBtu; 0.00738 lb-PM (filterable)/MMBtu; 3.52 lb-PM10/hr; 0.0039 gr-PM/dscf	0.00565 lb/MMBtu; 1.9 lb/hr	0.00327 lb/MMBtu; 1.11 lb/hr
RIO BRAVO FRESNO	C-1820-1-31	352 MMBTU/HR CIRCULATING FLUIDIZED-BED BIOMASS COMBUSTOR USED TO PRODUCE STEAM FOR ELECTRICAL POWER GENERATION (28.5 MW), WITH ONE COOLING TOWER, ONE AIR PREHEATER, ONE BARETUBE ECONOMIZER, AND TWO 900 AND ONE 700 HP FANS	Fluidized bed	ESP, limestone injection, ammonia injection	0.08 lb/MMBtu	10.0 lb/hr (Calc. 0.028 lb/MMBtu)	5.8 lb/hr (filterable), 17.4 lb/hr (condensable) (Calc. 0.066 lb/MMBtu)	400 ppmv @ 3% O_2 (Calc. 0.318 lb/MMBtu)	10.4 lb/hr (Calc. 0.03 lb/MMBtu)	11/2/22-11/3/22	0.074 lb/MMBtu; 57.1 ppmvd @ 3% O_2	0.004 lb/MMBtu;1.32 lb/hr; 2.06 ppmv @ 3% O_2	0.028 lb/MMBtu; 7.69 lb-PM/hr; 0.0055 gr-PM(F1/2)/dscf; 0.0067 gr-PM(F1/2)/dscf @ 12% CO_2	0.5 ppm @ 3% O_2; 0.0004 lb/MMBtu	0.69 lb/hr; 2.38 ppmv dry
										11/2/21-11/4/21	0.068 lb/MMBtu; 52.8 ppmvd@3% O_2	0.68 lb/hr; 0.002 lb/MMBtu	0.022 lb/MMBtu, 2.98 lb-PM/hr; 0.0018 gr/dscf (F1/2)	2.4 ppmv @ 3% O_2; 0.0019 lb/MMBtu	0.13 lb/hr; ND <0.5 ppm dry
MERCED POWER, LLC	N-4607-8-9	185 MMBTU/HR ENERGY PRODUCTS OF IDAHO BIOMASS-FIRED BUBBLING FLUIDIZED BED COMBUSTOR WITH ONE 15 MMBTU/HR PROPANE-FIRED AUXILIARY BURNER POWERING A 13 MW STEAM TURBINE GENERATOR, SERVED BY A SELECTIVE NON-CATALYTIC REDUCTION SYSTEM WITH AN AUTOMATED AMMONIA INJECTION SYSTEM, A LIMESTONE/SODIUM BICARBONATE INJECTION SYSTEM, AND A GENERAL ELECTRIC BAGHOUSE	Fluidized bed	baghouse, SNCR system, limestone or sodium bicarbonate injection	0.08 lb/MMBtu	0.035 lb/MMBtu	0.04-PM10/MMBtu	51 ppmvd @ 12% CO_2 (0.057 lb/MMBtu) (Calc. 72 ppmvd @ 3% O_2)	0.005 lb/MMBtu	6/21/22-6/22/22	0.068 lb/MMBtu	0.002 lb/MMBtu	0.0052 lb/MMBtu; 0.002 gr/dscf	0.012 lb/MMBtu; 10.52 ppm@ 12%CO_2	0.0001 lb/MMBtu
										6/14/21-6/18/21	0.057 lb/MMBtu	0.004 lb/MMBtu	0.0012 gr/dscf; 0.0038 lb/MMBtu	0.011 lb/MMBtu; 10.2 ppmv@ 12% CO_2	0.0 lb/MMBtu
AMPERSAND CHOWCHILLA BIOMASS LLC	C-6923-3-16	185 MMBTU/HR ENERGY PRODUCTS OF IDAHO (EPI) BIOMASS-FIRED FLUIDIZED BUBBLING BED COMBUSTOR WITH ONE 10 MMBTU/HR NATURAL GAS-FIRED PREHEAT BURNER POWERING A 12.5 MW STEAM TURBINE GENERATOR, SERVED BY A SELECTIVE NON-CATALYTIC REDUCTION (SNCR) SYSTEM WITH AN AUTOMATED AMMONIA INJECTION SYSTEM, A LIMESTONE/SODIUM BICARBONATE INJECTION SYSTEM, A MULTICLONE, AND A PULSE JET BAGHOUSE	Fluidized bed	baghouse, SNCR system, limestone or sodium bicarbonate injection	0.08 lb/MMBtu	0.04 lb/MMBtu	0.04 lb/MMBtu	51 ppmvd @ 12% CO_2 (0.057 lb/MMBtu) (Calc. 72 ppmvd @ 3% O_2)	0.005 lb/MMBtu	6/6/22-6/7/22	0.066 lb/MMBtu	0.002 lb/MMBtu	0.009 lb-PM10/MMBtu; 0.0042 gr-PM/dscf	2.3 ppmv @ 3% O_2; 0.003 lb/MMBtu	0.0004 lb/MMBtu
										5/10/2021	0.066 lb/MMBtu	0.003 lb/MMBtu	0.01 lb-PM10/MMBtu; 0.006 gr-PM/dscf	17.1 ppmv @ 12% O_2; 0.019 lb/MMBtu	0.0003 lb/MMBtu

List of Control Options:

Based on the search of *BACT Clearinghouse Survey, Survey of Federal, State and Local Rules and Regulations, Survey of Source Tests for Biomass-Fired Boilers in the SJVAPCD, and Alternative to Wood Combustion* discussed above, the following emission control options are developed:

NOx:

- There is only one currently operating boiler (DTE Stockton, N-645) which is equipped with an add-on selective catalytic reduction (SCR system) to reduce NOx emissions. This boiler has been demonstrated to achieve steady state NOx emissions of 0.048 lb-NOx/MMBtu (equivalent to 50 ppmvd @ 3% O2).

  In addition, the District received a proposal from a company to install a biomass-fired boiler using starved-air combustion technology[9], where combustion air is introduced in a controlled manner in various zones of the combustion process. This technology reduces formation of thermal NOx, which in combination with an SCR system, are expected to achieve less than 20 ppmvd NOx @ 3% O2. Therefore, at this time, a NOx level of 20 ppmvd @ 3% O2 with the use of starved-air combustion technology and SCR technology (or equivalent control) is considered most stringent level of emissions proposed for a project prior to the receipt of this project.

SOx:

- All boilers in the San Joaquin Valley use sorbent (i.e., calcium carbonate (limestone), trona, sodium carbonate) injection system that injects powder form of sorbent in the exhaust stream. The sorbent reacts with the sulfur dioxide and acid gases in the exhaust and neutralize them into sodium sulfite or calcium sulfite (particulate matter). The particulate matter is then captured either in a downstream emission control such as baghouse, or electrostatic precipitator.

  Source testing results indicate SOx emissions from biomass fired boilers varied from 0.0007 to 0.0067 lb-SOx/MMBtu averaging around 0.0025 lb-SOx/MMBtu for all source tested values. SOx emissions vary significantly from one installation to another. Emission variations are also significant among boilers at the same site. For example, two boilers at CES Delano BECCS Plant (S-75) - unit 1 was tested at 0.8 ppm SOx @ 3% O2 and unit 2 was tested at 3.4 ppmv SOx @ 3% O2 in 2015, indicating, 425% more SO_2 emissions from unit 2 than unit 1. The lowest permitted SOx limit is 0.028 lb/MMBtu calculated from the permitted hourly emissions for a boiler under permit C-1820-1. Furthermore, Rule 4352 establishes SOx limits of 0.02 lb/MMBtu on a rolling 30-day average and 0.035 lb/MMBtu based on block 24-hour average basis, which is considered to be achieved in practice emissions standards for SOx emissions.

[9] Refer to USEPA's AP-42 Chapter 2.1 (Refuse Combustion) and Chapter 2.3 (Medical Waste Incineration) for more details on starved air combustion technology

Further, as noted in project N-1204246, an emission standard of 0.001 lb-SO2/MMBtu using flue gas desulfurization using wet scrubber or semi-dry absorber capable of achieving 98%[10] control efficiency is considered a technologically feasible options for biomass fired boilers.

PM_{10}:

- Solid fuel-fired boilers are commonly equipped with either a baghouse or electrostatic precipitator controls to reduce filterable particulate matter emissions.

  Source testing results indicate PM_{10} emissions from biomass fired boilers varied from 0.001 to 0.0378 lb/MMBtu averaging around 0.01312 lb/MMBtu for all source tested values. PM_{10} emissions also vary significantly from one installation to another. Emission variations are also significant among boilers at the same site. For example, two boilers at CES Delano BECCS Plant (S-75) - unit 1 tested at 0.0202 lb/MMBtu versus unit 2 tested at 0.0378 lb/MMBtu in 2015, indicating 87% more PM_{10} emissions from unit 2 than unit 1.

  Further, the lowest permitted PM_{10} limit is 0.0214 lb/MMBtu for a boiler under permit N-645-36 (stoker grate boiler with a electrostatic precipitator), and 0.040 lb/MMBtu calculated from the permitted hourly emissions for a boiler under permit S-75-6 (Fluidized bed boiler with a baghouse). District Rule 4352 limits PM_{10} emissions to 0.03 lb/MMBtu.

  Therefore, a PM_{10} emission limit of 0.0214 lb/MMBtu is considered to be the most stringent limit achieved by permitted units.

VOC:

- None of the biomass fired boiler uses add-on control to reduce VOC emissions.

  VOC emissions from the biomass fired boilers varied from 0.0001 to 0.02 lb/MMBtu averaging around 0.0044 lb/MMBtu for all source tested values. VOC emission variations are also significant for a boiler tested in different years. For instance, unit 1 at CES Delano BECCS Plant (S-75) tested at 0.02 lb/MMBtu in 2015 and 0.00138 lb/MMBtu in 2014. VOC emissions were 14.5 times more in 2015 compared to that of 2014. Further, the lowest permitted VOC emissions limit is 0.005 lb/MMBtu under permit N-4607-8 & C-6923-3 (Fluidized bed boilers).

  Therefore, a VOC emission limit of 0.005 lb/MMBtu for is considered to be the most stringent limit achieved by permitted units.

[10] (0.02 ÷(1-0.60))*(1-0.98) = 0.001 lb/MMBtu

Based on the above discussion, the following table summarizes emissions standards and technologies that the District would consider as part of a BACT analysis for this class and category of source.

Pollutant	Emission Standards Considered for BACT Analysis
NOx	1. 20 ppmvd @ 3% O2 (0.026 lb/MMBtu) with boiler design using starved-air technology and selective catalytic reduction system, or equivalent controls (Technologically Feasible) 2. 50 ppmvd @ 3% O2 (0.048 lb/MMBtu) with use of selective catalytic reduction system or equivalent controls (Achieved in Practice)
SOx	1. 0.001 lb/MMBtu with use of wet scrubber or equivalent controls (Technologically Feasible) 2. 0.035 lb/MMBtu on a block 24-hour basis and 0.020 lb/MMBtu on a rolling 30-day average basis with use of sorbent injection system or equivalent controls (Achieved in Practice)
PM_{10}	0.0214 lb/MMBtu with use of baghouse, ESP or equivalent controls (Achieved in Practice)
VOC	0.005 lb/MMBtu (Achieved in Practice)

NOx:

Step 1: Identify All Possible Control Technologies

- 20 ppmvd @ 3% O2 (0.026 lb/MMBtu) with boiler design using starved-air technology and selective catalytic reduction system, or equivalent controls

- 50 ppmvd @ 3% O2 (0.048 lb/MMBtu) using selective catalytic reduction system

Step 2: Eliminate Technologically Infeasible Options

All control options listed in step 1 are technologically feasible.

Step 3: Rank Remaining Control Technologies by Control Effectiveness

1. 20 ppmvd @ 3% O2 (0.026 lb/MMBtu) with boiler design using starved-air technology and selective catalytic reduction system, or equivalent controls

2. 37 ppmvd @ 3% O2 (0.048 lb/MMBtu) using selective catalytic reduction system

Step 4: Cost Effectiveness Analysis

The applicant has proposed to comply with the most stringent emission limit listed in Step 3. As such, cost effectiveness analysis is not required.

Step 5: Select BACT

The applicant has proposed to achieve 14 ppmvd @ 3% O2 (0.0179 lb-NOx/MMBtu, 0.235 lb-NOx/MW-hr) during steady state operation using urea injection system and a selective catalytic reduction system. Thus, this proposal complies with the BACT requirements for NOx emissions.

Note that use of gasification technology with internal combustion engines to produce electric power results in NOx emissions of 0.647 lb/MW-hr, significantly higher than the 0.235 lb-NOx/MW-hr proposed by CST. As such, the use of alternative technology is not considered for this project.

SOx:

Step 1: Identify All Possible Control Technologies

- 0.001 lb/MMBtu[11] on a block 24-hour average (Flue gas desulfurization using wet scrubber or semi-dry absorber capable of achieving 98% control efficiency, or equal, and natural gas auxiliary fuel) – Technologically Feasible

- 0.035 lb/MMBtu on a block 24-hour average and 0.02 lb/MMBtu on a rolling 30-day average basis – Achieved in Practice

Step 2: Eliminate Technologically Infeasible Options

All control options listed in step 1 are technologically feasible.

Step 3: Rank Remaining Control Technologies by Control Effectiveness

1. 0.001 lb/MMBtu on a block 24-hour average – Technologically Feasible

2. 0.035 lb/MMBtu on a block 24-hour average and 0.02 lb/MMBtu on a rolling 30-day average basis - Achieved-in-Practice

Step 4: Cost Effectiveness Analysis

Option 1: 0.001 lb/MMBtu on a block 24-hour average (Wet SOx scrubber, Spray Dry Absorber)
Per cost effectiveness worksheets (see pages below), cost of reduction ($/ton) for installing wet scrubbers to achieve this level is $156,407/ton of SOx reduced, and the cost of reduction for installing spray dry absorbers to achieve this level is $206,144/ton of SOx reduced. Since the cost of reduction for each technology exceeds the $19,000/ton of SOx reduction threshold, the use of these technologies is not cost effective and will not be required for this project.

Option 2: 0.035 lb/MMBtu on a block 24-hour average and 0.02 lb/MMBtu on a rolling 30-day average basis
The applicant has proposed to comply with this option. Therefore, cost effectiveness analysis is not required.

Step 5: Select BACT

The applicant has proposed to comply with 0.035 lb/MMBtu on a block 24-hour average and 0.02 lb/MMBtu on a rolling 30-day average basis with the use dry sorbent injection system. Thus, this proposal complies with the BACT requirements for SOx emissions.

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[11] (0.02 ÷(1-0.60))*(1-0.98) = 0.001 lb/MMBtu

Wet SOx Scrubber Cost

Plant: Combined Solar Technologies			
Combustor Rating	CR	65.6	MMBtu/hr
MW Rating		4.4	MW
Current SOx limit	EF_C	0.02	lb/MMBtu
Current SOx Control Efficiency		60%	EPA Cost Manual Section 5
Wet Scrubber SOx Control Efficiency		98%	EPA Cost Manual Section 5
Controlled Limit (Wet Scrubber)	EF_{SDA}	0.001	lb/MMbtu
Operating Schedule	OP	8400	hr/year
Item		Method of Calculation	Cost
Direct Capital Costs			
*Total Purchased Equipment Costs (includes freight, sales tax, installation)		$900/kw	$3,989,189.19
Total Direct Capital Costs	A		$3,989,189.19
Indirect Capital Costs			
Facilities	B	Included above	$0.00
Engineering	C	Included above	$0.00
ProcessContingency	D	Included above	$0.00
Total Indirect Capital Costs	E	Included above	$0.00
Project Contingency	F	Included above	$0.00
Total Capital Costs	G	A+B+C+D+E+F	$3,989,189.19
Annualized Capital costs (10 years @ 4%)	**H**	0.123 * G	$490,670.27
Direct Annual Costs			
Operating Costs			
Operator	I	0.5 hr/shift, $25/hr, 2 shifts/day, 350 days/yr	$8,750.00
Supervisor	J	0.15 * I	$1,312.50
Maintenance Costs			
Labor	K	0.5 hr/shift, $25/hr, 2 shifts/day, 350 days/yr	$8,750.00
Material	L	1.0 * K	$8,750.00
Utility Costs			
Reagent Costs	M = RC		$724.07
Electricity Costs	N = EC		$99,639.02
Waste Disposal Costs	O = DC		$1,311.28
Water Costs	P = WC		$17,303.07
Total Direct Annual Costs	Q	I+J+K+L+M+N+O+P	$146,539.94
Indirect Annual Costs			
Overhead	R	0.6 * (I+J+K+L)	$16,537.50
Administrative	S	0.02 * A	$79,783.78
Insurance	T	0.01 * A	$39,891.89
Property Tax	U	0.01 * A	$39,891.89
Total Indirect Annual Costs	V	R+S+T+U	$176,105.07
Total Annualized Cost	**W**	**H+Q+V**	$813,315.28
Potential to Emit SOx (current system)	$PE_C = EF_C \times CR \times OP \times 1/2000$	5.5104	tons/year
Potential to Emit (Wet Scrubber)	$PE_{SDA} = EF_{SDA} \times CR \times OP \times 1/2000$	0.27552	tons/year
Emission Reductions	ER = PEc - PEsDA	**5.2**	**Tons/year**
Cost/ton of Emissions Reduced	**W/ER**	**$156,407.00**	**$/ton**

Utility Costs			
Reagent Cost (Wet Scrubber)			
Limestone Usage	0.00287328	tons/hr	EPA Cost Manual Secton 5 Eqn 1.09
Limestone Usage	24.135552	tons/year	
Cost/ton Limestone	30	$/ton	EPA Cost Manual Section 5
Cost/year (RC)	724.06656		
Electricity Cost (Wet Scrubber)			
Increased Fan Power Required (P)	74.04362017	kW	EPA Cost Manual Section 5 Eqn 1.12
Annual Electricty Required	621966.4094		
**Electricty Cost/KW	0.1602		
Cost/year (EC)	99639.01879		
Waste Disposal Cost (Wet Scrubber)			
Waste Generation Rate	0.00520351	tons/hr	EPA Cost Manual Eqn 1.11
Waste/year	43.71	tons/yr	
Cost/ton	30	$/ton	EPA Cost Manual Section 5
Cost/year (DC)	1311.28	$/year	
Water Makeup Cost (wet scrubber)			
Makeup Water Consumption Rate	0.490449872	1000 gal/hour	EPA Eqn 1.10
annual Makeup water Required	4119.778925	1000 gal/year	
Cost/gallon	0.0042	$/gal	EPA Cost Manual Section 5
Cost/year (WC)	17303.07148	$/year	

Notes:

*EPA Cost Manual Section 5 (April 2021)

**https://www.eia.gov/electricity/data/browser/#/topic/7?agg=0,1&geo=000000000004&endsec=vg&freq=M&start=200101&end=202010&ctype=linechart&ltype=pin&rtype=s&maptype=0&rse=0&pin=

Spray Drying Absorber (Dry Scrubber) Cost

Plant: Combined Solar Technologies			
Combustor Rating	CR	65.6	MMBtu/hr
MW Rating		4.4	MW
Current SOx limit	EF_C	0.02	lb/MMBtu
Current SOx Control Efficiency		60%	EPA Cost Manual Section 5
SDA SOx Control Efficiency		98%	EPA Cost Manual Section 5
Controlled Limit (Spray dry absorber)	EF_{SDA}	0.001	lb/MMbtu
Operating Schedule	OP	8400	hr/year
Item		Method of Calculation	Cost
Direct Capital Costs			
Total Purchased Equipment Costs (includes freight, sales tax, installation)		$1000/kw	$4,432,432.43
Total Direct Capital Costs	A		$4,432,432.43
Indirect Capital Costs			
Facilities	B	Included above	$0.00
Engineering	C	Included above	$0.00
ProcessContingency	D	Included above	$0.00
Total Indirect Capital Costs	E	Included above	$0.00
Project Contingency	F	Included above	$0.00
Total Capital Costs	G	A+B+C+D+E+F	$4,432,432.43
Annualized Capital costs (10 years @ 4%)	**H**	0.123 * G	$721,156.76
Direct Annual Costs			
Operating Costs			
Operator	I	0.5 hr/shift, $25/hr, 2 shifts/day, 350 days/yr	$8,750.00
Supervisor	J	0.15 * I	$1,312.50
Maintenance Costs			
Labor	K	0.5 hr/shift, $25/hr, 2 shifts/day, 350 days/yr	$8,750.00
Material	L	1.0 * K	$8,750.00
Utility Costs			
Reagent Costs	M = RC		$556.01
Electricity Costs	N = EC		$114,788.36
Waste Disposal Costs	O = DC		$1,290.75
Water Costs	P = WC		$12,761.37
Total Direct Annual Costs	Q	I+J+K+L+M+N+O+P	$156,958.98
Indirect Annual Costs			
Overhead	R	0.6 * (I+J+K+L)	$16,537.50
Administrative	S	0.02 * A	$88,648.65
Insurance	T	0.01 * A	$44,324.32
Property Tax	U	0.01 * A	$44,324.32
Total Indirect Annual Costs	V	R+S+T+U	$193,834.80
Total Annualized Cost	**W**	**H+Q+V**	$1,071,950.53
Potential to Emit SOx (current system)	$PE_C = EF_C \times CR \times OP \times 1/2000$	5.5104	tons/year
Potential to Emit (SDA)	$PE_{SDA} = EF_{SDA} \times CR \times OP \times 1/2000$	0.27552	tons/year
Emission Reductions	ER = PEc - PEsDA	**5.2**	**Tons/year**
Cost/ton of Emissions Reduced	**W/ER**	**$206,144.00**	**$/ton**
Notes:			
*EPA Cost Manual Section 5 (April 2021)			

**https://www.eia.gov/electricity/data/browser/#/topic/7?agg=0,1&geo=000000000004&endsec=vg&freq=M&start=200101&end=202010&ctype=linechart&ltype=pin&rtype=s&maptype=0&rse=0&pin=

Utility Costs			
Reagent Cost (SDA)			
Limestone Usage	0.002206376	tons/hr	EPA Cost Manual Secton 5 Eqn 1.33
Limestone Usage	18.53355538	tons/year	
Cost/ton Limestone	30	$/ton	EPA Cost Manual Section 5
Cost/year (RC)	556.0066613		
Electricity Cost (SDA)			
Increased Fan Power Required (P)	85.30137691	kW	EPA Cost Manual Section 5 Eqn 1.36
Annual Electricty Required	716531.566		
**Electricty Cost/KW	0.1602		
Cost/year (EC)	114788.3569		
Waste Disposal Cost (SDA)			
Waste Generation Rate	0.005122012	tons/hr	EPA Cost Manual Eqn 1.35
Waste/year	43.02	tons/yr	
Cost/ton	30	$/ton	EPA Cost Manual Section 5
Cost/year (DC)	1290.75	$/year	
Water Makeup Cost (SDA)			
Makeup Water Consumption Rate	0.361716743	1000 gal/hour	EPA Eqn 1.34
annual Makeup water Required	3038.420643	1000 gal/year	
Cost/gallon	0.0042	$/gal	EPA Cost Manual Section 5
Cost/year (WC)	12761.3667	$/year	

PM_{10}:

Step 1: Identify All Possible Control Technologies

- 0.0214 lb/MMBtu, 30-minute average (multiclone and electrostatic precipitator or baghouse, or equal, and natural gas auxiliary fuel) – Achieved in Practice

Step 2: Eliminate Technologically Infeasible Options

All control options listed in step 1 are technologically feasible.

Step 3: Rank Remaining Control Technologies by Control Effectiveness

1. 0.0214 lb/MMBtu, 30-minute average (multiclone and electrostatic precipitator or baghouse, or equal, and natural gas auxiliary fuel)

Step 4: Cost Effectiveness Analysis

The option identified in step 3 above is achieved in practice. Therefore, cost effectiveness analysis is not required.

Step 5: Select BACT

CST has proposed to limit PM_{10} emissions to 0.0036 lb/MMBtu (0.047 lb-PM_{10}/MW-hr) from the boiler, well below the 0.0214 lb/MMBtu noted above. Thus, this proposal complies with the BACT requirements for PM_{10} emissions.

Note that use of gasification technology with internal combustion engines to produce electric power results in PM_{10} emissions of 0.12 lb/MW-hr, significantly higher than the 0.047 lb-PM_{10}/MW-hr proposed by CST. As such, the use of alternative technology is not considered for this project.

VOC:

Step 1: Identify All Possible Control Technologies

- 0.005 lb/MMBtu

Step 2: Eliminate Technologically Infeasible Options

All control options listed in step 1 are technologically feasible.

Step 3: Rank Remaining Control Technologies by Control Effectiveness

1. 0.005 lb/MMBtu

Step 4: Cost Effectiveness Analysis

The option identified in step 3 above is achieved in practice. Therefore, cost effectiveness analysis is not required.

Step 5: Select BACT

CST has proposed to limit VOC emissions to 0.0036 lb/MMBtu from the boiler. Thus, this proposal complies with the BACT requirements for VOC emissions.

Appendix C
HRA Summary

San Joaquin Valley Air Pollution Control District
Risk Management Review and Ambient Air Quality Analysis

To:	Jag S Kahlon – Permit Services
From:	Michael Scott – Technical Services
Date:	January 9, 2023
Facility Name:	Combined Solar Technologies, Inc.
Location:	9251 W Arbor Avenue, Tracy, CA
Application #(s):	N-10188-1-0, -2-0, -3-0, -4-0
Project #:	N-1223107

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1. Summary

1.1 Risk Management Review (RMR)

Units	Prioritization Score	Acute Hazard Index	Chronic Hazard Index	Maximum Individual Cancer Risk	T-BACT Required	Special Permit Requirements
1-0	0.00	0.00	0.00	3.27E-09	No	No
2-0	49.87	0.19	0.04	5.33E-07	No	No
3-0[1]	N/A[1]	N/A[1]	N/A[1]	N/A[1]	No	No
4-0	0.00	N/A[2]	0.00	N/A[2]	No	No
Project Totals	49.90	0.19	0.04	5.36E-07		
Facility Totals	>1	0.19	0.04	5.36E-07		

Notes:
1. Review of the SDS for the proposed products to be used for Unit 3 determined that there are no Toxic Air Contaminants (TACs) associated with operation of Unit 3. Therefore, no further analysis of this unit for RMR purposes was necessary.
2. Maximum individual cancer risk and acute hazard index were not calculated for Unit 4-0 since there is no risk factor or the risk factor is so low that it has been determined to be insignificant for this type of unit.

1.2 Ambient Air Quality Analysis (AAQA)

Pollutant	Air Quality Standard (State/Federal)				
	1 Hour	3 Hours	8 Hours	24 Hours	Annual
CO	Pass		Pass		
NO_x	Pass				Pass
SO_x	Pass	Pass		Pass	Pass
PM10				Pass[3]	Pass[3]
PM2.5				Pass[4]	Pass[4]

Notes:
1. Results were taken from the attached AAQA Report.
2. The criteria pollutants are below EPA's level of significance as found in 40 CFR Part 51.165 (b)(2) unless otherwise noted below.
3. Modeled PM10 concentrations were below the District SIL for non-fugitive sources of 5 μg/m^3 for the 24-hour average concentration and 1 μg/m^3 for the annual concentration.
4. Modeled PM2.5 concentrations were below the District SIL for non-fugitive sources of 1.2 μg/m^3 for the 24-hour average concentration and 0.2 μg/m^3 for the annual concentration.

To ensure that human health risks will not exceed District allowable levels; the following shall be included as requirements for:

Unit # 3-0

1. The exhaust stack shall vent vertically upward. The vertical exhaust flow shall not be impeded by a rain cap (flapper ok), roof overhang, or any other obstruction.
2. The boiler shall only be operated to combust walnut shells.

2. Project Description

Technical Services received a request to perform a Risk Management Review (RMR) and Ambient Air Quality Analysis (AAQA) for the following:

- Unit -1-0: WALNUT SHELL RECEIVING AND HANDLING OPERATION
- Unit -2-0: 65.6 MMBTU/HR ZOZEN BOILER CO LTD., MODEL ZZ-25/4.29/400-M, STOKER-TYPE WALNUT-SHELL FUEL FIRED BOILER WITH UREA INJECTION SYSTEM, A CYCLONE, A BAGHOUSE FILTER SYSTEM, AND A SELECTIVE CATALYTIC REDUCTION SYSTEM
- Unit -3-0: 6,538 GALLONS PER MINUTE MARLEY FIELD COOLING TOWER SERVED BY HIGH EFFICIENCY DRIFT ELIMINATORS
- Unit -4-0: TRONA OR HYDRATED LIME RECEIVING AND STORAGE OPERATION WITH ONE 1,300 CUBIC FOOT (APPROX. DIMENSIONS 26 FEET TALL, 8 FEET DIAMETER) SILO SERVED BY A DUST COLLECTION OR BIN VENT FILTRATION SYSTEM

3. RMR Report

3.1 Analysis

The District performed an analysis pursuant to the District's Risk Management Policy for Permitting New and Modified Sources (APR 1905, May 28, 2015) to determine the possible cancer and non-cancer health impact to the nearest resident or worksite. This policy requires that an assessment be performed on a unit by unit basis, project basis, and on a facility-wide basis. If a preliminary prioritization analysis demonstrates that:

- A unit's prioritization score is less than the District's significance threshold and;
- The project's prioritization score is less than the District's significance threshold and;
- The facility's total prioritization score is less than the District's significance threshold

Then, generally no further analysis is required.

The District's significant prioritization score threshold is defined as being equal to or greater than 1.0. If a preliminary analysis demonstrates that either the units', the project's or the facility's total prioritization score is greater than the District threshold, a screening or a refined assessment is required.

If a refined assessment is greater than one in a million but less than 20 in a million for carcinogenic impacts (cancer risk) and less than 1.0 for the acute and chronic hazard indices (non-carcinogenic) on a unit by unit basis, project basis and on a facility-wide basis the proposed application is considered less than significant. For units that exceed a cancer risk of one in a million, Toxic Best Available Control Technology (TBACT) must be implemented.

Toxic emissions for this project were calculated using the following methods:

- Particulate matter emissions from this proposed operation were provided by the Permit Engineer. These emissions were speciated into toxic air contaminants using emission factors derived from a 1997 soil profile "Composite of three almond orchards" in EPA's Speciation program from Central Valley CA Almond Growers test data.
- Toxic emissions from this proposed unit were calculated using District approved emission factors based on the 2003 AP-42 chapter 1 section 6 Wood Residue Combustion in Boilers. Dioxin and Furan emission were removed as the wood combusted is limited to only utilize walnut shells.

These emissions were input into the San Joaquin Valley APCD's Hazard Assessment and Reporting Program (SHARP). In accordance with the District's Risk Management Policy, risks from the proposed unit's toxic emissions were prioritized using the procedure in the 2016 CAPCOA Facility Prioritization Guidelines. The prioritization score for this proposed facility was greater than 1.0 (see RMR Summary Table). Therefore, a refined health risk assessment was required.

The AERMOD model was used, with the parameters outlined below and meteorological data for 2013-2017 from Stockton (rural dispersion coefficient selected) to determine the dispersion factors (i.e., the predicted concentration or X divided by the normalized source strength or Q) for a receptor grid. These dispersion factors were input into the SHARP Program, which then used the Air Dispersion Modeling and Risk Tool (ADMRT) of the Hot Spots Analysis and Reporting Program Version 2 (HARP 2) to calculate the chronic and acute hazard indices and the carcinogenic risk for the project.

The following parameters were used for the review:

Source Process Rates					
Unit ID	**Process ID**	**Process Material**	**Process Units**	**Hourly Process Rate**	**Annual Process Rate**
1-0	1	PM_{10}	Lbs	0.012	102
2-0	1	PM_{10}	Lbs	0.236	1,984
2-0	2	VOC	Lbs	1.22	2,030
4-0	1	PM_{10}	Lbs	0.061	45

Point Source Parameters						
Unit ID	**Unit Description**	**Release Height (m)**	**Temp. (°K)**	**Exit Velocity (m/sec)**	**Stack Diameter (m)**	**Vertical/ Horizontal/ Capped**
2-0	Biomass-Fired Boiler	24.38	422	8.08	1.52	Vertical
4-0	Dry Sorbent Injection System	7.93	294	19.79	0.10	Horizontal

Volume Source Parameters					
Unit ID	Unit Description	Release Height (m)	Side Length (m)	Initial Lateral Dimension (m)	Initial Vertical Dimension (m)
1-0	Walnut Shell Loading (Drop 1)	1.22	0.76	0.18	1.00
1-0	Walnut Shell Loading (Drop 2)	0.00	0.76	0.18	1.00
1-0	Walnut Shell Loading (Drop 3)	7.16	0.76	0.18	1.00

4. AAQA Report

The District modeled the impact of the proposed project on the National Ambient Air Quality Standard (NAAQS) and/or California Ambient Air Quality Standard (CAAQS) in accordance with District Policy APR-1925 (Policy for District Rule 2201 AAQA Modeling) and EPA's Guideline for Air Quality Modeling (Appendix W of 40 CFR Part 51). The District uses a progressive three level approach to perform AAQAs. The first level (Level 1) uses a very conservative approach. If this analysis indicates a likely exceedance of an AAQS or Significant Impact Level (SIL), the analysis proceeds to the second level (Level 2) which implements a more refined approach. For the 1-hour NO_2 standard, there is also a third level that can be implemented if the Level 2 analysis indicates a likely exceedance of an AAQS or SIL.

The modeling analyses predicts the maximum air quality impacts using the appropriate emissions for each standard's averaging period. Required model inputs for a refined AAQA include background ambient air quality data, land characteristics, meteorological inputs, a receptor grid, and source parameters including emissions. These inputs are described in the sections that follow.

Ambient air concentrations of criteria pollutants are recorded at monitoring stations throughout the San Joaquin Valley. Monitoring stations may not measure all necessary pollutants, so background data may need to be collected from multiple sources. The following stations were used for this evaluation:

Monitoring Stations				
Pollutant	Station Name	County	City	Measurement Year
CO	HAZELTON-HD, STOCKTON	San Joaquin	Stockton	2018
NOx	HAZELTON-HD, STOCKTON	San Joaquin	Stockton	2018
PM10	TRACY AIRPORT	San Joaquin	Tracy	2018
PM2.5	HAZELTON-HD, STOCKTON	San Joaquin	Stockton	2018
SOx	Fresno - Garland	Fresno	Fresno	2018

Technical Services performed modeling for directly emitted criteria pollutants with the emission rates below:

Emission Rates (lbs/hour)						
Unit ID	Process	NOx	SOx	CO	PM10	PM2.5
1-0	1	0	0	0	0.01	0
2-0	1	1.90	2.30	23.45	0.24	0.24
3-0	1	0	0	0	0.02	0.01
4-0	1	0	0	0	0.06	0.02

Emission Rates (lbs/year)						
Unit ID	Process	NOx	SOx	CO	PM10	PM2.5
1-0	1	0	0	0	102	28.8
2-0	1	9,899	11,021	40,026	1,984	1,984
3-0	1	0	0	0	146	89
4-0	1	0	0	0	45	16.9

The AERMOD model was used to determine if emissions from the project would cause or contribute to an exceedance of any state of federal air quality standard. The parameters outlined below and meteorological data for 2013-2017 from Stockton (rural dispersion coefficient selected) were used for the analysis:

The following parameters were used for the review:

Point Source Parameters						
Unit ID	Unit Description	Release Height (m)	Temp. (°K)	Exit Velocity (m/sec)	Stack Diameter (m)	Vertical/ Horizontal/ Capped
2-0	Biomass-Fired Boiler	24.38	422	8.08	1.52	Vertical
4-0	Dry Sorbent Injection System	7.93	294	19.79	0.10	Horizontal

Volume Source Parameters					
Unit ID	Unit Description	Release Height (m)	Side Length (m)	Initial Lateral Dimension (m)	Initial Vertical Dimension (m)
1-0	Walnut Shell Loading (Drop 1)	1.22	0.76	0.18	1.00
1-0	Walnut Shell Loading (Drop 2)	0.00	0.76	0.18	1.00
1-0	Walnut Shell Loading (Drop 3)	7.16	0.76	0.18	1.00

5. Conclusion

5.1 RMR

The cumulative acute and chronic indices for this facility, including this project, are below 1.0; and the cumulative cancer risk for this facility, including this project, is less than 20 in a million. In addition, the cancer risk for each unit in this project is less than 1.0 in a million. **In accordance with the District's Risk Management Policy, the project is approved without Toxic Best Available Control Technology (T-BACT).**

These conclusions are based on the data provided by the applicant and the project engineer. Therefore, this analysis is valid only as long as the proposed data and parameters do not change.

5.2 AAQA

The emissions from the proposed equipment will not cause or contribute significantly to a violation of the State and National AAQS.

6. Attachments

A. Modeling request from the project engineer

B. Additional information from the applicant/project engineer

C. Prioritization score w/ toxic emissions summary

D. Facility Summary

E. AAQA results

Appendix D
HAP Calculations

Tracy Renewable Energy LLC (N-8887) Combined Solar Technologies, Inc. (N-10188)
HAP Emissions Summary

Substances	N-8887-19-0 Cooling tower	N-8887-21-0 Fire-pump emergency engine	N-8887-22-0 Walnut shell-fired boiler	N-8887-23-0 Walnut shell-fired boiler	N-8887-24-0 Potato receiveing, storage and handling operations	N-8887-25-0 Potato drying and storage operations	N-8887-26-0 Dried potato loadout operation	N-8887-27-0 Walnut shell receiving and unloading operation	N-8887-28-0 Trona or hydrated lime receiving and storage operation	N-10188-1-0 Walnut shell receiving and unloading operation	N-10188-2-0 Walnut shell-fired boiler	N-10188-3-0 Cooling tower	N-10188-4-0 Trona or hydrated lime receiving and storage operation	Total, all permit units (lb/yr)	HAP?	HAP, Total of all permit units (lb/yr)
1,3 Butadiene	--	4.82E-03	--	--	--	--	--	--	--	--	--	--	--	0.00	Y	0.00
Acenaphthene	--	--	4.03E-01	4.03E-01	--	--	--	--	--	--	4.03E-01	--	--	1.21		
Acenaphthylene	--	--	3.18E+00	3.18E+00	--	--	--	--	--	--	3.18E+00	--	--	9.55		
Acetaldehyde	--	6.59E-03	--	--	--	--	--	--	--	--	--	--	--	0.01	Y	0.01
Aluminum	--	--	--	--	--	--	--	9.77E+00	--	9.77E+00	--	--	--	19.54		
Ammonia	--	--	--	--	--	--	--	2.02E-01	--	2.02E-01	--	--	--	0.40		
Anthracene	--	--	4.03E-01	4.03E-01	--	--	--	--	--	--	4.03E-01	--	--	1.21		
Antimony	--	--	--	--	--	--	--	1.04E-02	--	1.04E-02	--	--	--	0.02	Y	0.02
Arsenic	--	3.85E-03	5.28E-01	5.28E-01	--	--	--	5.10E-04	--	5.10E-04	5.28E-01	--	--	1.59	Y	1.59
Barium	--	--	--	--	--	--	--	8.93E-02	--	8.93E-02	--	--	--	0.18		
Benzene	--	2.16E-02	2.59E+01	2.59E+01	--	--	--	--	--	--	2.59E+01	--	--	77.64	Y	77.64
Benzo(a)anthracene	--	--	4.03E-01	4.03E-01	--	--	--	--	--	--	4.03E-01	--	--	1.21		
Benzo(a)pyrene	--	--	4.03E-01	4.03E-01	--	--	--	--	--	--	4.03E-01	--	--	1.21		
Benzo(b)fluoranthene	--	--	4.03E-01	4.03E-01	--	--	--	--	--	--	4.03E-01	--	--	1.21		
Benzo[g,h,i] perylene	--	--	4.03E-01	4.03E-01	--	--	--	--	--	--	4.03E-01	--	--	1.21		
Benzo[k] Fluoranthene	--	--	4.03E-01	4.03E-01	--	--	--	--	--	--	4.03E-01	--	--	1.21		
Beryllium	--	5.30E-05	7.26E-02	7.26E-02	--	--	--	--	--	--	7.26E-02	--	--	0.22	Y	0.22
Bromine Atom	--	--	--	--	--	--	--	1.12E-03	--	1.12E-03	--	--	--	0.00		
Cadmium	--	1.28E-03	2.98E+00	2.98E+00	--	--	--	3.06E-04	--	3.06E-04	2.98E+00	--	--	8.94	Y	8.94
Carbon Tetrachloride	--	5.58E-03	--	--	--	--	--	--	--	--	--	--	--	0.01	Y	0.01
Chlorobenzene	--	4.80E-03	--	--	--	--	--	--	--	--	--	--	--	0.00	Y	0.00
Chloroform	--	4.63E-03	--	--	--	--	--	--	--	--	--	--	--	0.00	Y	0.00
Chromium	--	2.57E-03	9.68E-02	9.68E-02	--	--	--	1.22E-03	--	1.22E-03	9.68E-02	--	--	0.30	Y	0.30
Chrysene	--	--	4.03E-01	4.03E-01	--	--	--	--	--	--	4.03E-01	--	--	1.21		
Cobalt	--	--	--	--	--	--	--	8.16E-04	--	8.16E-04	--	--	--	0.00	Y	0.00
Copper	--	--	2.07E+00	2.07E+00	--	--	--	1.72E-02	--	1.72E-02	2.07E+00	--	--	6.23		
Dibenz(A,H)Anthracene	--	--	4.03E-01	4.03E-01	--	--	--	--	--	--	4.03E-01	--	--	1.21		
Dioxin 4D	--	--	1.50E-05	1.50E-05	--	--	--	--	--	--	1.50E-05	--	--	0.00		
Dioxin 5D 12378	--	--	3.70E-05	3.70E-05	--	--	--	--	--	--	3.70E-05	--	--	0.00		
Dioxin 6D 123478	--	--	4.10E-05	4.10E-05	--	--	--	--	--	--	4.10E-05	--	--	0.00		
Dioxin 6D 123678	--	--	4.27E-05	4.27E-05	--	--	--	--	--	--	4.27E-05	--	--	0.00		
Dioxin 6D 123789	--	--	3.86E-05	3.86E-05	--	--	--	--	--	--	3.86E-05	--	--	0.00		
Dioxin 7D	--	--	2.83E-04	2.83E-04	--	--	--	--	--	--	2.83E-04	--	--	0.00		
Dioxin 8D	--	--	1.95E-03	1.95E-03	--	--	--	--	--	--	1.95E-03	--	--	0.01		
Ethylene Dichloride	--	3.52E-03	--	--	--	--	--	--	--	--	--	--	--	0.00	Y	0.00
Fluoranthene	--	--	1.61E+00	1.61E+00	--	--	--	--	--	--	1.61E+00	--	--	4.83		
Fluorene	--	--	4.03E-01	4.03E-01	--	--	--	--	--	--	4.03E-01	--	--	1.21		
Formaldehyde	--	1.74E-01	7.86E+02	7.86E+02	--	--	--	--	--	--	7.86E+02	--	--	2358.89	Y	2358.89
Furan 4F	--	--	1.08E-04	1.08E-04	--	--	--	--	--	--	1.08E-04	--	--	0.00		
Furan 5F 12378	--	--	1.04E-04	1.04E-04	--	--	--	--	--	--	1.04E-04	--	--	0.00		
Furan 5F 23478	--	--	1.51E-04	1.51E-04	--	--	--	--	--	--	1.51E-04	--	--	0.00		
Furan 6F 123478	--	--	5.14E-05	5.14E-05	--	--	--	--	--	--	5.14E-05	--	--	0.00		
Furan 6F 123678	--	--	5.24E-05	5.24E-05	--	--	--	--	--	--	5.24E-05	--	--	0.00		
Furan 6F 123789	--	--	2.19E-04	2.19E-04	--	--	--	--	--	--	2.19E-04	--	--	0.00		
Furan 6F 234678	--	--	5.88E-05	5.88E-05	--	--	--	--	--	--	5.88E-05	--	--	0.00		
Furan 7F 1234678	--	--	2.46E-04	2.46E-04	--	--	--	--	--	--	2.46E-04	--	--	0.00		
Furan 7F 1234789	--	--	2.50E-05	2.50E-05	--	--	--	--	--	--	2.50E-05	--	--	0.00		
Furan 8F	--	--	1.76E-04	1.76E-04	--	--	--	--	--	--	1.76E-04	--	--	0.00		
Hexavalent Chromium	--	1.29E-04	1.44E+00	1.44E+00	--	--	--	6.12E-05	--	6.12E-05	1.44E+00	--	--	4.31	Y	4.31
Hydrochloric acid	--	--	2.42E+03	2.42E+03	--	--	--	--	--	--	2.42E+03	--	--	7267.68	Y	7267.68
Indeno [1,2,3-cd] pyrene	--	--	4.03E-01	4.03E-01	--	--	--	--	--	--	4.03E-01	--	--	1.21		
Lead	--	3.85E-03	2.20E+00	2.20E+00	--	--	--	6.32E-03	--	6.32E-03	2.20E+00	--	--	6.61	Y	6.61
Manganese	--	1.36E-01	9.61E+00	9.61E+00	--	--	--	1.06E-01	--	1.06E-01	9.61E+00	--	--	29.18	Y	29.18
Mercury	--	2.07E-04	6.45E+00	6.45E+00	--	--	--	1.33E-03	--	1.33E-03	6.45E+00	--	--	19.36	Y	19.36
Methylene Chloride	--	4.94E-03	--	--	--	--	--	--	--	--	--	--	--	0.00	Y	0.00
Naphthalene	--	2.64E-02	2.41E+02	2.41E+02	--	--	--	--	--	--	2.41E+02	--	--	722.76	Y	722.76
Nickel	--	8.98E-03	1.51E+00	1.51E+00	--	--	--	1.22E-03	--	1.22E-03	1.51E+00	--	--	4.55	Y	4.55
PAHs	--	2.71E-02	--	--	--	--	--	--	--	--	--	--	--	0.03	Y	0.03
p-Dichlorobenzene	--	5.33E-03	--	--	--	--	--	--	--	--	--	--	--	0.01	Y	0.01
Perchloroethylene	--	6.02E-03	--	--	--	--	--	--	--	--	--	--	--	0.01	Y	0.01
Phenanthrene	--	--	3.80E+00	3.80E+00	--	--	--	--	--	--	3.80E+00	--	--	11.39		
Phosphorus	--	--	--	--	--	--	--	1.60E-01	--	1.60E-01	--	--	--	0.32	Y	0.32
Pyrene	--	--	1.66E+00	1.66E+00	--	--	--	--	--	--	1.66E+00	--	--	4.97		
Selenium	--	1.28E-02	6.38E-01	6.38E-01	--	--	--	3.06E-04	--	3.06E-04	6.38E-01	--	--	1.93	Y	1.93
Silver	--	--	--	--	--	--	--	3.06E-04	--	3.06E-04	--	--	--	0.00		
Sulfate	--	--	--	--	--	--	--	1.03E+00	--	1.03E+00	--	--	--	2.06		
Total Dioxin:4D	--	--	7.26E-03	7.26E-03	--	--	--	--	--	--	7.26E-03	--	--	0.02		
Total Dioxin:5D	--	--	1.97E-03	1.97E-03	--	--	--	--	--	--	1.97E-03	--	--	0.01		
Total Dioxin:6D	--	--	8.53E-04	8.53E-04	--	--	--	--	--	--	8.53E-04	--	--	0.00		
Total Dioxin:7D	--	--	6.08E-04	6.08E-04	--	--	--	--	--	--	6.08E-04	--	--	0.00		
Total Furan:4F	--	--	1.04E-02	1.04E-02	--	--	--	--	--	--	1.04E-02	--	--	0.03		
Total Furan:5F	--	--	2.88E-03	2.88E-03	--	--	--	--	--	--	2.88E-03	--	--	0.01		
Total Furan:6F	--	--	9.58E-04	9.58E-04	--	--	--	--	--	--	9.58E-04	--	--	0.00		
Total Furan:7F	--	--	3.29E-04	3.29E-04	--	--	--	--	--	--	3.29E-04	--	--	0.00		
Trichloroethylene	--	4.78E-03	--	--	--	--	--	--	--	--	--	--	--	0.00		
Vanadium	--	--	--	--	--	--	--	4.28E-03	--	4.28E-03	--	--	--	0.01		
Vinyl Chloride	--	1.13E-02	1.82E+01	1.82E+01	--	--	--	--	--	--	1.82E+01	--	--	54.75	Y	54.75
Vinylidene Chloride	--	3.52E-03	--	--	--	--	--	--	--	--	--	--	--	0.00	Y	0.00
Zinc	--	--	1.13E+01	1.13E+01	--	--	--	1.61E-01	--	1.61E-01	1.13E+01	--	--	34.19		
										--	--	--	--		**Total:**	**10559 lb/yr**
																5.3 tons/yr

N-8887-19-0

Cooling Tower

Per project N-1204246, proposed chemicals used in the cooling tower does not contain any HAPs.

N-8887-21
Emergency Fire-Pump Engine

Substances	CAS#	*PE (lb/hr)	*PE (lb/yr)
1,3 Butadiene	106990	4.80E-05	4.82E-03
Acetaldehyde	75070	6.58E-05	6.59E-03
Arsenic	7440382	3.84E-05	3.85E-03
Benzene	71432	2.15E-04	2.16E-02
Beryllium	7440417	5.29E-07	5.30E-05
Cadmium	7440439	1.28E-05	1.28E-03
Carbon Tetrachloride	56235	5.56E-05	5.58E-03
Chlorobenzene	108907	4.79E-05	4.80E-03
Chloroform	67663	4.62E-05	4.63E-03
Chromium	7440473	2.57E-05	2.57E-03
Ethylene Dichloride	107062	3.51E-05	3.52E-03
Formaldehyde	50000	1.74E-03	1.74E-01
Hexavalent Chromium	18540299	1.28E-06	1.29E-04
Lead	7439921	3.84E-05	3.85E-03
Manganese	7439965	1.36E-03	1.36E-01
Mercury	7439976	2.07E-06	2.07E-04
Methylene Chloride	75092	4.93E-05	4.94E-03
Naphthalene	91203	2.63E-04	2.64E-02
Nickel	7440020	8.95E-05	8.98E-03
p-Dichlorobenzene	106467	5.32E-05	5.33E-03
PAHs	1151	2.70E-04	2.71E-02
Perchloroethylene	127184	6.01E-05	6.02E-03
Selenium	7782492	1.28E-04	1.28E-02
Trichloroethylene	79016	4.77E-05	4.78E-03
Vinyl Chloride	75014	1.13E-04	1.13E-02
Vinylidene Chloride	75354	3.51E-05	3.52E-03

*PE values are derived using the worksheet for diesel-fuel internal combustion engines available at: https://www.valleyair.org/busind/pto/emission_factors/emission_factors_idx.htm; Fuel use rate - 12.57 gal/hr and 1,257 gal/yr (non-emergency use)

N-8887-22-0

Walnut Shell-Fired Boiler

Substances	CAS#	PE* (lb/hr)	PE* (lb/yr)
Acenaphthene	83329	4.80E-05	4.03E-01
Acenaphthylene	208968	3.79E-04	3.18E+00
Anthracene	120127	4.80E-05	4.03E-01
Arsenic	7440382	6.28E-05	5.28E-01
Benzene	71432	3.08E-03	2.59E+01
Benzo(a)anthracene	56553	4.80E-05	4.03E-01
Benzo(a)pyrene	50328	4.80E-05	4.03E-01
Benzo(b)fluoranthene	205992	4.80E-05	4.03E-01
Benzo[g,h,i] perylene	191242	4.80E-05	4.03E-01
Benzo[k] Fluoranthene	207089	4.80E-05	4.03E-01
Beryllium	7440417	8.64E-06	7.26E-02
Cadmium	7440439	3.55E-04	2.98E+00
Chromium	7440473	1.15E-05	9.68E-02
Chrysene	218019	4.80E-05	4.03E-01
Copper	7440508	2.46E-04	2.07E+00
Dibenz(A,H)Anthracene	53703	4.80E-05	4.03E-01
Dioxin 4D	1746016	1.78E-09	1.50E-05
Dioxin 5D 12378	40321764	4.40E-09	3.70E-05
Dioxin 6D 123478	39227286	4.88E-09	4.10E-05
Dioxin 6D 123678	57653857	5.08E-09	4.27E-05
Dioxin 6D 123789	19408743	4.60E-09	3.86E-05
Dioxin 7D	35822469	3.36E-08	2.83E-04
Dioxin 8D	3268879	2.32E-07	1.95E-03
Fluoranthene	206440	1.92E-04	1.61E+00
Fluorene	86737	4.80E-05	4.03E-01
Formaldehyde	50000	9.36E-02	7.86E+02
Furan 4F	51207319	1.28E-08	1.08E-04
Furan 5F 12378	57117416	1.24E-08	1.04E-04
Furan 5F 23478	57117314	1.79E-08	1.51E-04
Furan 6F 123478	70648269	6.12E-09	5.14E-05
Furan 6F 123678	57117449	6.24E-09	5.24E-05
Furan 6F 123789	72918219	2.60E-08	2.19E-04
Furan 6F 234678	60851345	7.00E-09	5.88E-05
Furan 7F 1234678	67562394	2.93E-08	2.46E-04
Furan 7F 1234789	55673897	2.97E-09	2.50E-05
Furan 8F	39001020	2.10E-08	1.76E-04
Hexavalent Chromium	18540299	1.71E-04	1.44E+00
Hydrochloric acid	7647010	2.88E-01	2.42E+03
Indeno [1,2,3-cd] pyrene	193395	4.80E-05	4.03E-01
Lead	7439921	2.62E-04	2.20E+00
Manganese	7439965	1.14E-03	9.61E+00
Mercury	7439976	7.68E-04	6.45E+00
Naphthalene	91203	2.87E-02	2.41E+02
Nickel	7440020	1.80E-04	1.51E+00
Phenanthrene	85018	4.52E-04	3.80E+00
Pyrene	129000	1.97E-04	1.66E+00
Selenium	7782492	7.60E-05	6.38E-01
Total Dioxin:4D	41903575	8.64E-07	7.26E-03
Total Dioxin:5D	36088229	2.34E-07	1.97E-03
Total Dioxin:6D	34465468	1.02E-07	8.53E-04
Total Dioxin:7D	37871004	7.24E-08	6.08E-04
Total Furan:4F	55722275	1.24E-06	1.04E-02
Total Furan:5F	30402154	3.43E-07	2.88E-03
Total Furan:6F	55684941	1.14E-07	9.58E-04
Total Furan:7F	38998753	3.92E-08	3.29E-04
Vinyl Chloride	75014	2.17E-03	1.82E+01
Zinc	7440666	1.34E-03	1.13E+01
*PE values are taken from HAP worksheets			

N-8887-23-0
Walnut Shell-Fired Boiler

Substances	CAS#	PE* (lb/hr)	PE* (lb/yr)
Acenaphthene	83329	4.80E-05	4.03E-01
Acenaphthylene	208968	3.79E-04	3.18E+00
Anthracene	120127	4.80E-05	4.03E-01
Arsenic	7440382	6.28E-05	5.28E-01
Benzene	71432	3.08E-03	2.59E+01
Benzo(a)anthracene	56553	4.80E-05	4.03E-01
Benzo(a)pyrene	50328	4.80E-05	4.03E-01
Benzo(b)fluoranthene	205992	4.80E-05	4.03E-01
Benzo[g,h,i] perylene	191242	4.80E-05	4.03E-01
Benzo[k] Fluoranthene	207089	4.80E-05	4.03E-01
Beryllium	7440417	8.64E-06	7.26E-02
Cadmium	7440439	3.55E-04	2.98E+00
Chromium	7440473	1.15E-05	9.68E-02
Chrysene	218019	4.80E-05	4.03E-01
Copper	7440508	2.46E-04	2.07E+00
Dibenz(A,H)Anthracene	53703	4.80E-05	4.03E-01
Dioxin 4D	1746016	1.78E-09	1.50E-05
Dioxin 5D 12378	40321764	4.40E-09	3.70E-05
Dioxin 6D 123478	39227286	4.88E-09	4.10E-05
Dioxin 6D 123678	57653857	5.08E-09	4.27E-05
Dioxin 6D 123789	19408743	4.60E-09	3.86E-05
Dioxin 7D	35822469	3.36E-08	2.83E-04
Dioxin 8D	3268879	2.32E-07	1.95E-03
Fluoranthene	206440	1.92E-04	1.61E+00
Fluorene	86737	4.80E-05	4.03E-01
Formaldehyde	50000	9.36E-02	7.86E+02
Furan 4F	51207319	1.28E-08	1.08E-04
Furan 5F 12378	57117416	1.24E-08	1.04E-04
Furan 5F 23478	57117314	1.79E-08	1.51E-04
Furan 6F 123478	70648269	6.12E-09	5.14E-05
Furan 6F 123678	57117449	6.24E-09	5.24E-05
Furan 6F 123789	72918219	2.60E-08	2.19E-04
Furan 6F 234678	60851345	7.00E-09	5.88E-05
Furan 7F 1234678	67562394	2.93E-08	2.46E-04
Furan 7F 1234789	55673897	2.97E-09	2.50E-05
Furan 8F	39001020	2.10E-08	1.76E-04
Hexavalent Chromium	18540299	1.71E-04	1.44E+00
Hydrochloric acid	7647010	2.88E-01	2.42E+03
Indeno [1,2,3-cd] pyrene	193395	4.80E-05	4.03E-01
Lead	7439921	2.62E-04	2.20E+00
Manganese	7439965	1.14E-03	9.61E+00
Mercury	7439976	7.68E-04	6.45E+00
Naphthalene	91203	2.87E-02	2.41E+02
Nickel	7440020	1.80E-04	1.51E+00
Phenanthrene	85018	4.52E-04	3.80E+00
Pyrene	129000	1.97E-04	1.66E+00
Selenium	7782492	7.60E-05	6.38E-01
Total Dioxin:4D	41903575	8.64E-07	7.26E-03
Total Dioxin:5D	36088229	2.34E-07	1.97E-03
Total Dioxin:6D	34465468	1.02E-07	8.53E-04
Total Dioxin:7D	37871004	7.24E-08	6.08E-04
Total Furan:4F	55722275	1.24E-06	1.04E-02
Total Furan:5F	30402154	3.43E-07	2.88E-03
Total Furan:6F	55684941	1.14E-07	9.58E-04
Total Furan:7F	38998753	3.92E-08	3.29E-04
Vinyl Chloride	75014	2.17E-03	1.82E+01
Zinc	7440666	1.34E-03	1.13E+01
*PE values are taken from HAP worksheets			

N-8887-24-0: Potato Receiving, storage and processing operations

N-8887-25-0: Potato drying and storage operations

N-8887-26-0: Dried-potato truck loadout operation

The processes under these permits handle material (potatoes) that does not contain any HAPs.

N-8887-27-0

Walnut shell receiving and unloading operation

Substances	CAS#	*PE (lb/hr)	*PE (lb/yr)
Aluminum	7429905	1.15E-03	9.77E+00
Ammonia	7664417	2.38E-05	2.02E-01
Antimony	7440360	1.22E-06	1.04E-02
Arsenic	7440382	6.00E-08	5.10E-04
Barium	7440393	1.05E-05	8.93E-02
Bromine Atom	7726956	1.32E-07	1.12E-03
Cadmium	7440439	3.60E-08	3.06E-04
Chromium	7440473	1.44E-07	1.22E-03
Cobalt	7440484	9.60E-08	8.16E-04
Copper	7440508	2.03E-06	1.72E-02
Hexavalent Chromium	18540299	7.20E-09	6.12E-05
Lead	7439921	7.44E-07	6.32E-03
Manganese	7439965	1.24E-05	1.06E-01
Mercury	7439976	1.56E-07	1.33E-03
Nickel	7440020	1.44E-07	1.22E-03
Phosphorus	7723140	1.89E-05	1.60E-01
Selenium	7782492	3.60E-08	3.06E-04
Silver	7440224	3.60E-08	3.06E-04
Sulfate	9960	1.21E-04	1.03E+00
Vanadium	7440622	5.04E-07	4.28E-03
Zinc	7440666	1.90E-05	1.61E-01
*PE values are taken from HAP worksheets			

N-8887-28-0: Trona or hydrated lime receiving and storage operation

The processes under this permit handle material that does not contain any TACs or HAPs.

N-10188-1-0
Walnut shell receiving and unloading operation

Substances	CAS#	*PE (lb/hr)	*PE (lb/yr)
Aluminum	7429905	1.15E-03	9.77E+00
Ammonia	7664417	2.38E-05	2.02E-01
Antimony	7440360	1.22E-06	1.04E-02
Arsenic	7440382	6.00E-08	5.10E-04
Barium	7440393	1.05E-05	8.93E-02
Bromine Atom	7726956	1.32E-07	1.12E-03
Cadmium	7440439	3.60E-08	3.06E-04
Chromium	7440473	1.44E-07	1.22E-03
Cobalt	7440484	9.60E-08	8.16E-04
Copper	7440508	2.03E-06	1.72E-02
Hexavalent Chromium	18540299	7.20E-09	6.12E-05
Lead	7439921	7.44E-07	6.32E-03
Manganese	7439965	1.24E-05	1.06E-01
Mercury	7439976	1.56E-07	1.33E-03
Nickel	7440020	1.44E-07	1.22E-03
Phosphorus	7723140	1.89E-05	1.60E-01
Selenium	7782492	3.60E-08	3.06E-04
Silver	7440224	3.60E-08	3.06E-04
Sulfate	9960	1.21E-04	1.03E+00
Vanadium	7440622	5.04E-07	4.28E-03
Zinc	7440666	1.90E-05	1.61E-01
*PE values are taken from HAP worksheets			

N-10188-2-0
Walnut Shell-Fired Boiler

Substances	CAS#	PE* (lb/hr)	PE* (lb/yr)
Acenaphthene	83329	4.80E-05	4.03E-01
Acenaphthylene	208968	3.79E-04	3.18E+00
Anthracene	120127	4.80E-05	4.03E-01
Arsenic	7440382	6.28E-05	5.28E-01
Benzene	71432	3.08E-03	2.59E+01
Benzo(a)anthracene	56553	4.80E-05	4.03E-01
Benzo(a)pyrene	50328	4.80E-05	4.03E-01
Benzo(b)fluoranthene	205992	4.80E-05	4.03E-01
Benzo[g,h,i] perylene	191242	4.80E-05	4.03E-01
Benzo[k] Fluoranthene	207089	4.80E-05	4.03E-01
Beryllium	7440417	8.64E-06	7.26E-02
Cadmium	7440439	3.55E-04	2.98E+00
Chromium	7440473	1.15E-05	9.68E-02
Chrysene	218019	4.80E-05	4.03E-01
Copper	7440508	2.46E-04	2.07E+00
Dibenz(A,H)Anthracene	53703	4.80E-05	4.03E-01
Dioxin 4D	1746016	1.78E-09	1.50E-05
Dioxin 5D 12378	40321764	4.40E-09	3.70E-05
Dioxin 6D 123478	39227286	4.88E-09	4.10E-05
Dioxin 6D 123678	57653857	5.08E-09	4.27E-05
Dioxin 6D 123789	19408743	4.60E-09	3.86E-05
Dioxin 7D	35822469	3.36E-08	2.83E-04
Dioxin 8D	3268879	2.32E-07	1.95E-03
Fluoranthene	206440	1.92E-04	1.61E+00
Fluorene	86737	4.80E-05	4.03E-01
Formaldehyde	50000	9.36E-02	7.86E+02
Furan 4F	51207319	1.28E-08	1.08E-04
Furan 5F 12378	57117416	1.24E-08	1.04E-04
Furan 5F 23478	57117314	1.79E-08	1.51E-04
Furan 6F 123478	70648269	6.12E-09	5.14E-05
Furan 6F 123678	57117449	6.24E-09	5.24E-05
Furan 6F 123789	72918219	2.60E-08	2.19E-04
Furan 6F 234678	60851345	7.00E-09	5.88E-05
Furan 7F 1234678	67562394	2.93E-08	2.46E-04
Furan 7F 1234789	55673897	2.97E-09	2.50E-05
Furan 8F	39001020	2.10E-08	1.76E-04
Hexavalent Chromium	18540299	1.71E-04	1.44E+00
Hydrochloric acid	7647010	2.88E-01	2.42E+03
Indeno [1,2,3-cd] pyrene	193395	4.80E-05	4.03E-01
Lead	7439921	2.62E-04	2.20E+00
Manganese	7439965	1.14E-03	9.61E+00
Mercury	7439976	7.68E-04	6.45E+00
Naphthalene	91203	2.87E-02	2.41E+02
Nickel	7440020	1.80E-04	1.51E+00
Phenanthrene	85018	4.52E-04	3.80E+00
Pyrene	129000	1.97E-04	1.66E+00
Selenium	7782492	7.60E-05	6.38E-01
Total Dioxin:4D	41903575	8.64E-07	7.26E-03
Total Dioxin:5D	36088229	2.34E-07	1.97E-03
Total Dioxin:6D	34465468	1.02E-07	8.53E-04
Total Dioxin:7D	37871004	7.24E-08	6.08E-04
Total Furan:4F	55722275	1.24E-06	1.04E-02
Total Furan:5F	30402154	3.43E-07	2.88E-03
Total Furan:6F	55684941	1.14E-07	9.58E-04
Total Furan:7F	38998753	3.92E-08	3.29E-04
Vinyl Chloride	75014	2.17E-03	1.82E+01
Zinc	7440666	1.34E-03	1.13E+01
*PE values are taken from HAP worksheets			

N-10188-3-0

Cooling Tower

Per RMR memo, proposed chemicals that will be used in the cooling tower does not contain any HAPs.

N-8887-28-0: Trona or hydrated lime receiving and storage operation

The processes under this permit handle material that does not contain any TACs or HAPs.

Appendix E
Quarterly Net Emissions Change

Quarterly Net Emissions Change (QNEC)

The Quarterly Net Emissions Change is used to complete the emission profile screen for the District's PAS database. The QNEC shall be calculated as follows:

QNEC = PE2 - PE1, where:

QNEC = Quarterly Net Emissions Change for each emissions unit, lb/qtr.
PE2 = Post-Project Potential to Emit for each emissions unit, lb/qtr.
PE1 = Pre-Project Potential to Emit for each emissions unit, lb/qtr.

Using the values in Sections VII.C.2 and VII.C.1 in the evaluation above, quarterly PE2 and quarterly PE1 can be calculated as follows:

$PE2_{quarterly} = PE2_{annual} \div 4$ quarters/year
$PE1_{quarterly} = PE1_{annual} \div 4$ quarters/year

N-10188-1-0

QNEC			
Pollutant	**PE2 (lb/qtr)**	**PE1 (lb/qtr)**	**QNEC (lb/qtr)**
NO_X	0	0	0
SO_X	0	0	0
PM_{10}	12.75	0	12.75
CO	0	0	0
VOC	0	0	0

N-10188-2-0

QNEC			
Pollutant	**PE2 (lb/qtr)**	**PE1 (lb/qtr)**	**QNEC (lb/qtr)**
NO_X	2,474.75	0	2,474.75
SO_X	2,755.25	0	2,755.25
PM_{10}	496	0	496
CO	10,006.5	0	10,006.5
VOC	507.5	0	507.5

N-10188-3-0

QNEC			
Pollutant	**PE2 (lb/qtr)**	**PE1 (lb/qtr)**	**QNEC (lb/qtr)**
NO_X	0	0	0
SO_X	0	0	0
PM_{10}	36.5	0	36.5
CO	0	0	0
VOC	0	0	0

N-10188-4-0

QNEC			
Pollutant	**PE2 (lb/qtr)**	**PE1 (lb/qtr)**	**QNEC (lb/qtr)**
NO_X	0	0	0
SO_X	0	0	0
PM_{10}	11.25	0	11.25
CO	0	0	0
VOC	0	0	0