SAN JOAQUIN SOLAR 1 & 2 HYBRID PROJECT
12-AFC-08

Supplemental Information
In Response To Cure Data Request Set #2

August 13, 2009

URS

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San Diego, CA 92108-4314
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URS Project No.27658033

Data Request 3: Please provide a copy of the grading and drainage plan.

Response: Please see Objections To Data Requests Of California Unions For Reliable Energy, Set 2, dated August 3, 2009.

Data Request 4: Please provide a process flow diagram for biomass handling including maximum equipment throughput.

Response: Please see the attached figure. (Attachment DR-4)

Data Request 5: Please provide a description of the biomass receiving and unloading area including, *e.g.*, mechanical or electronic drive-on scales or conveyor belt scales, the hydraulic truck lifts, etc.

Response: After receiving the biomass from the trucks, the Dump Receiving Hoppers are emptied by inclined Transfer Conveyors, which convey the material to the feed points on the single Collecting Conveyor. The Collecting Conveyor moves the biomass at 128,000lbs/hr during which the material is weighed before dropping into a Screener. The Screener filters out the larger pieces (overs), which fall into the Hogger. In the Hogger, large pieces are re-sized and reintroduced into the process. The pieces that pass through the Screener (accepts) are transferred on an Inclined Conveyor up to the Positioning Conveyor. The Positioning Conveyor creates a fuel storage pile that is approximately 1,740,000 ft3, with dimensions 420’ long, 140’ wide and 70’ high. A Reclaimer Conveyor will collect biomass from the storage pile at 92,000 lbs/hr transferring it from the pile to the Reclaimer Transfer Conveyor. The Transfer Conveyor conveys biomass to the Bucket Elevator Feed Conveyor. The Bucket Elevator Feed Conveyor will discharge into the inlet of the Bucket Elevator Lift. The Bucket Elevator will lift biomass to the top of a 90’ tall and 30’ diameter silo having a one-day storage capacity per boiler. A Cross-over Conveyor is located above the Storage Silos and fills the two silos. At the base of each silo, a Screw Conveyor transfers the biomass onto its respective Metering Bin Feed Conveyor at 46,000 lbs/hr. Each Metering Bin Conveyor, at a 6 ft elevation, carries the material up to an elevation of 45 ft where it discharges the biomass into each Fluid Bed Combustor Metering Hoppers.

Data Request 6: Please provide a schematic drawing showing the biomass handling and storage facility layout including all conveyors, fuel aggregators, and installed emission controls.

Response: Please see the attached figure. (Attachment DR-4)

Data Request 7: Please provide a description of the biomass inspection and cleaning procedures for removal of foreign materials such as metals, stone, and dirt, *e.g.*, with magnets, non-ferrous metal detectors, trommel screens, etc.

Response: A magnet to remove metal will be installed over the conveyor that feeds the biomass screen. A small transverse belt that is part of the magnet assembly will discharge the collected metal to a nearby bin. The bin will periodically be manually emptied.

Data Request 8: Please provide a description of the automatic conveyor, *e.g.*, bucket, belt, screw, chain/drag, oscillating, pneumatic, etc.

Response: The current design of the conveyor system in the biomass handling includes belt conveyors and a bucket elevator.

Data Request 9: Please provide a description of biomass “pre-sizing” by “fuel aggregators” including a discussion of the typical particle sizes of biomass waste products for loading into the fluidized bed combustors and a description of the fuel aggregators including their type (hammer mill, knife hog, etc.), type of screens (scalping disk oscillating, shaker deck, etc.), power supply, loading and unloading, maximum rated throughput, etc.

Response: Please see Objections To Data Requests Of California Unions For Reliable Energy, Set 2, dated August 3, 2009.

Data Request 10: Please provide a description and schematic drawing of the proposed fluidized bed combustion technology, including pressure seals, maximum throughput, etc.

Response: A description of the fluidized bed technology is attached. (Attachment DR-10) A schematic drawing of the fluidized bed combustion technology was included in the AFC as Figure 3.4-5.

Data Request 11: Please discuss the type of fluidized bed combustor (in-bed or over-bed feed system), feeder type (spreader, air swept, gravity), fuel requirements (particle size, moisture content, ash content), operating characteristics (residence time, fly ash production), advantages, and disadvantages of fluidized bed combustion technology.

Response: Attached are two papers from the biomass facilities equipment supplier regarding this issue. (Attachment DR-10 and DR-11)

Data Request 12: Please calculate annual average fly ash production for the Project's two biomass combustion facilities and document your assumptions, or document your assumption in Attachment AQ-1, p. 44 to the Applicant's 3rd Response to CEC Data Request Set #1 that a total of 30,459 tons of fly ash would be produced each year.

Response: Fly ash production cannot be calculated, but it can be estimated. According to the biomass equipment manufacturer, the hourly fly ash production is expected to be approximately 5% of the fuel feed rate. Therefore, the approximate annual average of fly ash production, assuming a 75% capacity factor is estimated to be 30,459 tons: (46,360 lb/hr feed * 8760 hr/yr*0.75*4 boilers/2000 (lb/tons)*0.05 equals 30,459 tons/year of fly ash.)

Biomass Fuel Analysis of 50/50 Blend of Agricultural Pruning and Urban Wood	
Fuel, % Btu (LHV)	
ag pruning	57.00%
waste waste	43.00%
Fuel, TPY	
ag pruning	101,527
waste waste	101,527
B.D.Blend Analysis	
Carbon, %	49.63
Hydrogen, %	5.67
Sulfur, %	0.07
Oxygen, %	39.18
Nitrogen, %	0.86
Chlorine, %	0.06
Ash/Other, %	**4.54**
As Fired, Moisture %	19.25
Flowrate lb/ hr	46,360

LHV = lower heating value
TPY = tons per year, based on 100 % capacity of one boiler
Lb/hr = pounds per hour of biomass feed, based on 100% capacity of one boiler.

Data Request 13: Please provide fly ash analyses from biomass combustion at similar facilities. When providing percentages, please indicate whether the values are based on "as combusted" or "bone dry."

Response: Please see Objections To Data Requests Of California Unions For Reliable Energy, Set 2, dated August 3, 2009.

Data Request 14: Please state whether fly ash generated by the Project would be disposed of at a landfill. The response should identify the amount of fly ash that would be disposed of in this manner and the receiving landfills.

Response: Fly ash generated from the Project site is not anticipated to be disposed of at a landfill. Potential uses for the ash were presented in response number 145 in the Complete Response to CEC Data Request Set #1, dated July 15, 2009.

Data Request 15: Please provide estimates for the maximum daily and annual average on-site electricity demand for the Project's electric-powered equipment and facility operations including the reverse osmosis water treatment facility, the "fuel aggregators," conveyors, baghouses, pumps, fans, motors, controls, lighting, heating, ventilation, air conditioning, etc.

Response: The maximum daily on-site electricity demand (parasitic load) is estimated to be 9,240 KW. The average daily demand is estimated at 8,494 KW. Also, please see Objections To Data Requests Of California Unions For Reliable Energy, Set 2, dated August 3, 2009.

Data Request 16: Please provide maximum emissions estimates for operating at 100 percent load and using 100 percent municipal green waste and using the anticipated fuel mix of 50 percent municipal green waste and 50 percent agricultural wood waste.

Response: The summary of maximum emissions estimates for operating at 100 percent load and using 100 percent municipal green waste and using the anticipated fuel mix of 50 percent municipal green waste and 50 percent agricultural wood waste are presented in following Table DR-16a and Table DR-16b, respectively. The detailed emission estimations and the vendor supporting data are all provided in the Attachment DR-16. In addition, the emissions of 100% load using 100% wood waste in the AFC have been revised and they can be found in the CEC's Data Request Set 1 Responses (DR135 and Attachment AQ-2).

Table DR-16a
Summary for Maximum Daily and Annual Emission Estimations Based on 100% Load, 100% Municipal Green Waste (per Boiler)

	Daily Emissions (lb/day)	Annual Emissions (tons/year) [1]
NO_X	160.7	12.13
SO_x	144.4	11.91
CO	156.3	20.13
PM_{10}	172.3	23.61
$PM_{2.5}$	172.3	23.61
VOC	26.4	3.62

1. Annual emission are based on 2 cold start events and 75% operating capacity.

Table DR-16b
Summary for Maximum Daily and Annual Emission Estimations Based on 100% Load, 50% Urban Waste 50% Ag Waste(per Boiler)

	Daily Emissions (lb/day)	Annual Emissions (tons/year) [1]
NO_X	160.2	12.03
SO_x	145.6	12.14
CO	158.5	20.59
PM_{10}	166.6	22.82
$PM_{2.5}$	166.6	22.82
VOC	24.7	3.39

1. Annual emission are based on 2 cold start events and 75% operating capacity.

Data Request 17: Please provide estimates for breathing losses of ammonia from the Project's four 20-gallon storage tanks.

Response: Breathing losses in tanks occur as a result of diurnal temperature variations. The SJS ammonia storage tanks will be designed to withstand pressure changes associated with diurnal temperature variations, and thus there will be no breathing losses associated with the four ammonia 20,000 gallon storage tanks.

Data Request 18: Please provide a discussion of the disposal of solids and removal of the evaporation ponds. Please indicate whether solids would be removed occasionally or only at the end of the Project's operational life. Please quantify the amount of solids expected.

Response: Removal of solids from the pond will occur on a routine basis (e.g. biannually). The amount of solids to be disposed of is unknown at this time.

Data Request 19: Please provide an estimate of the chemical composition of the dewatered residues in the evaporation ponds in mg/kg for each constituent.

Response: Please see Objections To Data Requests Of California Unions For Reliable Energy, Set 2, dated August 3, 2009.

Data Request 20: Please discuss and estimate the quantity of the annual expected mirror breakage at the Project's solar fields.

Response: The annual 3,000 mirrors replaced at SEGS that is referenced in the data request background is for all nine SEGS facilities (354 MW total). Improvement in mirror technology since the construction of SEGS will result in reduced mirror breakage at SJS 1&2. The estimated annual mirror breakage expected during operation of SJS 1&2 is 0.2%.

Data Request 21: Please provide information regarding the estimated frequency of herbicide application at the solar field, the annual quantity of herbicide(s) used, the active ingredient content in the formulation(s), the type of application, and the amount of active ingredient applied per application.

Response: This information has been provided in the Response to CEC Data Request Set #1, docketed July 15, 2009 in the responses to requests nos. 90, 93, 96 and 97. As stated in DR 96, "At this time the use of herbicides has not been determined for the project". However, as stated in response to DR 93 "Only herbicides approved by the State of California will be used within the project site." Response to Data Request 93 and 96 of CEC Data Request Set #1 discusses the frequency of application and the types of herbicides that may be used.

Data Request 22: Please indicate whether professional pesticide applicators or Project personnel would apply the herbicide(s) at the Project site. If the latter, please discuss any pesticide application training Project personnel would receive.

Response: According to response to Data Request 93 of CEC Data Request Set #1, prior to application of herbicide, the required permits from state and local authorities will be obtained, and personnel accordingly trained. Herbicides will be applied in accordance with applicable laws, regulations, and permit stipulations

Data Request 23: Please discuss best management practices for herbicide applications to ensure protection of groundwater and biological resources and indicate how these would be implemented at the Project.

Response: As stated in response to DR 93 "Only herbicides approved by the State of California will be used within the project site." Additional best management practices will be described in the final industrial SWPPP. Herbicides will be applied in accordance with applicable laws, regulations, and permit stipulations.

Data Request 24: Please provide a discussion of the persistence of herbicides that may be used for brush and weed control at the Project's solar fields.

Response: Response to Data Request 96 and 97 of CEC Data Request Set #1 discusses the persistence of herbicides to be used for the Project. It is not anticipated that there will be a significant buildup of herbicides that will not be degraded by the soil over the life of the Project.

Data Request 25: Please identify what type of pile foundations (cast-in-hole piles or driven piles) will be used for the Project's structures that support heavy equipment, e.g., the steam turbines or boilers.

Response: Foundations for the solar field will be drilled and poured piles. No driven piles will be used. For the power block, according to the initial geotechnical report, pile foundations will not be needed.

Data Request 26: If driven piles will be used to support the Project's heavily loaded structures, please identify the type of pile driver (impact, vibratory) that will be used to construct the supporting piles.

Response: Per response to request #25, above, this request is not applicable.

Data Request 27: Please identify the construction month during which pile drivers will be used.

Response: Per response to request #25, above, this request is not applicable.

Data Request 28: Please identify the number of hours per day pile driving would be conducted and the daily schedule for pile driving

Response: Per response to request #25, above, this request is not applicable.

Data Request 29: Please provide a discussion and quantitative analysis of potential noise impacts from pile driving.

Response: Per response to request #25, above, this request is not applicable.

Data Request 30: Please state the number of acres within the Project site that are subject to a Williamson Act contract and their corresponding assessor parcel numbers.

Response: 468.88 acres are currently under Williamson Act contract. The remaining 171.12 acres of the project site are not under a Williamson Act contract. The three assessor parcel numbers relevant to Williamson Act Cancellation are: APN 085-030-55s, APN 085-030-57s, APN 085-030-58s

Data Request 31: Please state the number of Williamson Act contracts that apply to the Project site.

Response: One Agriculture Land Conservation Contract applies – No. 3219

Data Request 32: Please provide a copy of all applicable Williamson Act contracts

Response: See Attachment DR-32.

Data Request 33: Please state whether a notice of non-renewal was filed with the County of Fresno and the date of filing

Response: Yes, a Notice of Non-Renewal was filed. See answer to Request #34 below.

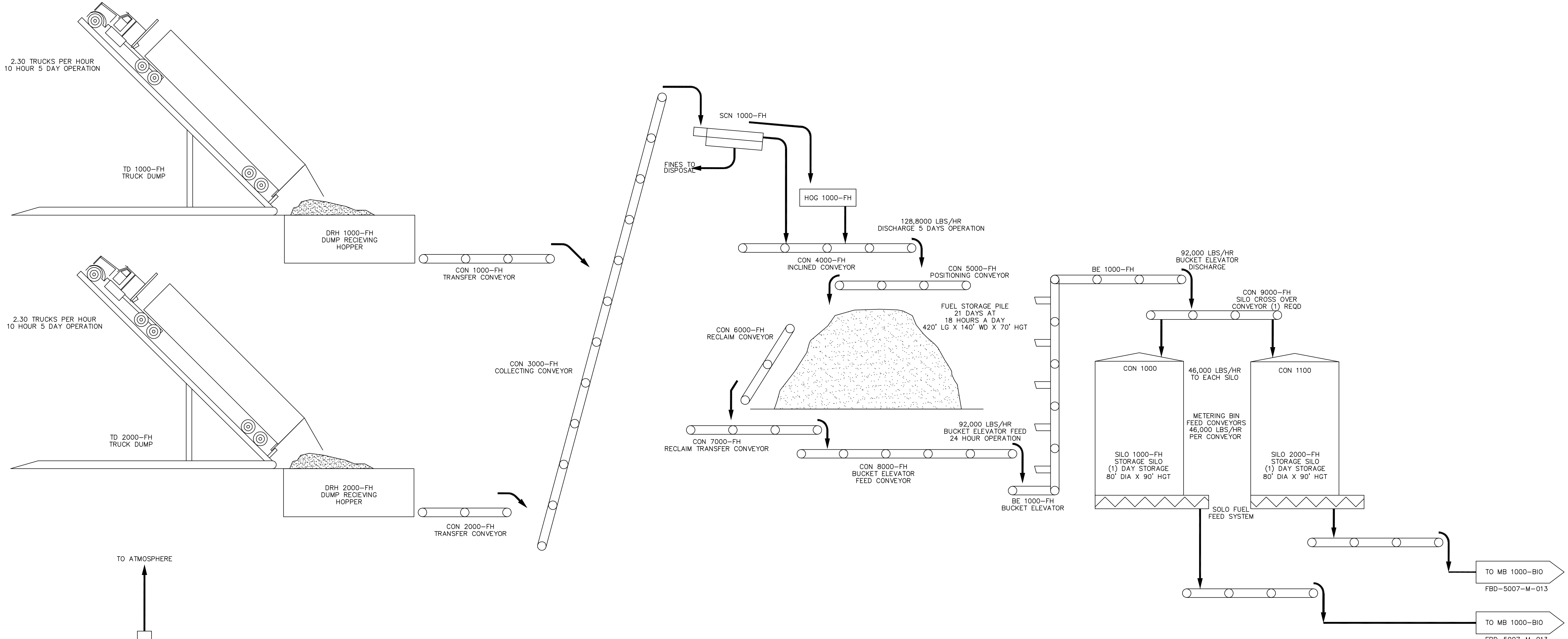
Data Request 34: If a notice of non-renewal has been filed, please indicate whether and when it was recorded.

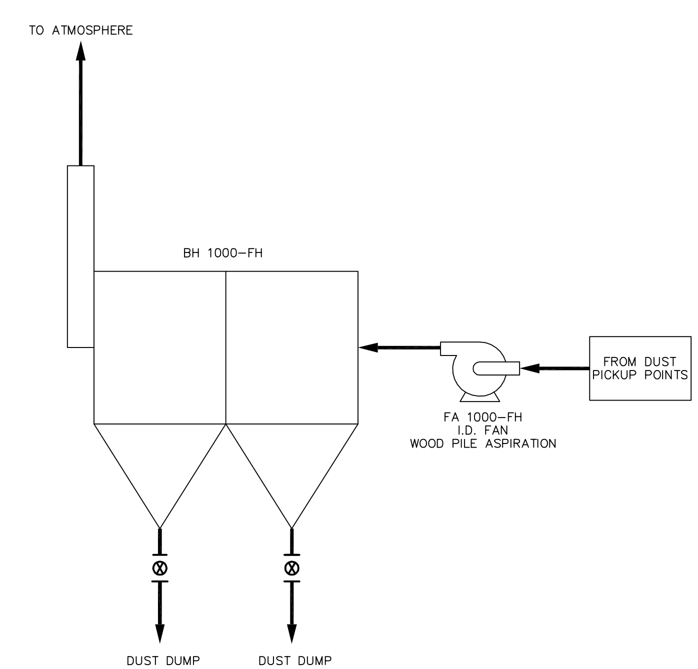
Response: The notice of non-renewal was recorded on April 14, 2009 by Fresno County.

Data Request 35: Please rank alternative Project locations and state which would be the preferred Project site alternative in the event that Fresno County denies cancellation of the subject Williamson Act contracts.

Response: Please see Objections To Data Requests Of California Unions For Reliable Energy, Set 2, dated August 3, 2009.

ATTACHMENT DR-4





REV	DATE	DRWN BY	CHKD BY	APVD BY	DESCRIPTION
A	12/01/08	KRS	GAG	DCG	ISSUED FOR FEL 2 REPORT

REVISIONS

Ford, Bacon & Davis
A Limited Liability Company

SPINNAKER
SAN JOAQUIN, CA

FLOW DIAGRAM
FUEL HANDLING

FB&D JOB NUMBER: Z5007
SCALE: NONE
DATE: 10–21–08
DRAWN BY: K. SCRUGGS

FBD–5007–M–012

REV.
A

ATTACHMENT DR-10

FLUIDIZED BED COMBUSTION
PROCESS DESCRIPTION

Fluidization is a term used to describe a phenomena that is created by passing an air stream vertically upward through a mass of solid particles. The upward velocity creates a lifting, or buoyancy effect on the particles and results in the suspension of those particles within the air. As the air velocities are increased above a minimum fluidization velocity, the particles are no longer held to normal solid-to-solid contact and they begin to float and travel within the air stream. The fluidized media exhibits the physical characteristics of a fluid and resembles a pot of water in a rolling boil. The result is that the physical properties of the mixture become very homogenous; all concentrations are evenly distributed throughout the fluidized bed and temperatures are uniform throughout.

Due to the fluid bed's inherent benefits, the technology has been utilized more frequently in the combustion of solid fuels in the past twenty-five years. The fluidization effect of the bed media results in a constant surface cleaning of the burning fuel particle. Any ash and char that is created from the combustion of that fuel, as it is slowly being burned, will be scraped off by the etching effect of the sand. This allows a new surface to be exposed to the combustion air and results in much faster and very complete thermal conversion of the fuel particle.

In the fluid bed process, the bed media serves three major purposes:

- It acts as a thermal storage medium to hold the heat within the system;
- It provides the ignition source for fuel that is fed into the unit; and
- It cleans the surface of the fuel particle exposing it to combustion air.

These properties allow the fluid bed to burn much higher moisture content fuels because the bed media retains sufficient heat storage capacity to first evaporate the moisture from the fuel particles prior to combustion. This in itself is a sufficient advantage over many of the conventional combustion systems, which are limited in their ability to handle wet fuels because of the tendency of the high moisture content to extinguish the fire.

The typical philosophy for the operation of the EPI fluid bed is to use an externally fired air preheating system to initially heat the bed media up to the ignition temperature of the fuel. By having the bed media at these temperatures and then introducing a small quantity of fuel, ignition can be established, and more fuel added, to increase the combustion temperatures and overall system output. As the temperatures are increased, more air and fuel are added and the system is brought up to full operating and stable condition without further use of supplemental fuel.

As fuel is fed into the fluid bed combustor, depending upon the fuel particle size and characteristics, a certain portion of its energy will be released directly into the bed, with the remainder being released as combustion is completed in the vapor space or overbed region of the combustor.

The design objective of the fluid bed combustion process is to optimize the temperature profile throughout the system. Temperatures within the bed are maintained hot enough to continually ignite the new fuel being introduced, and temperatures in the vapor space are sustained below the ash fusion temperature of the particular fuel. The fluidized bed section of the combustion chamber is typically maintained in the range of 1400 to 1700°F (760 to 927°C) and the vapor space temperatures are generally limited to a range of 1600 to 1800°F (871 to 982°C).

Most of the temperature control comes from using excess air flows to dilute the combustion temperatures throughout the vessel. However, in some situations where fuel economy is important, such as with power plant operations, the amount of excess air to be used can be minimized so that excess fuel is not consumed just for heating this added air. Under these conditions, a certain portion of the heat release from combustion is removed directly from the fluid bed through the use of in-vessel steam generating tubes placed in the bed and vapor space. This heat transfer surface cools the vessel with the forced circulation flow of saturated water from the boiler steam drum. As water is pumped through these tubes, it extracts heat directly from the vessel and steam is generated. The heat that is removed from the vessel results in lower operating temperatures and allows the system to maintain the desired temperature without utilizing excess air. For the same reason that the combustion efficiency of a fuel particle is extremely high within the fluid bed, the heat transfer rate from the bed to in-vessel steam generating tubes is also very rapid. Heat transfer coefficients within the bed are typically up to ten times greater than in a standard convective type boiler. Consequently, a considerable amount of energy can be recovered from the system and the amount of boiler surface can be minimized. This allows for economy of boiler surface design and optimization of overall fuel consumption efficiency.

Due to the continued cleaning and exposure of fuel surface to oxygen for combustion and also the uniform temperatures and concentrations of fuel and air within the system, the overall combustion efficiencies are extremely high in fluid bed combustors. In fact, in many cases the carbon burn-out percentages within the combustor are in excess of 99% efficiency.

As opposed to conventional grate combustors, the EPI fluid bed combustor produces no bottom ash. EPI has developed a proprietary bed cleaning system to continuously remove tramp material from the bottom of the fluid bed. Bed media along with any tramp material is drawn down through the static portion of the fluid bed. The bed media is screened of tramp metal and rocks, and reinjected back into the fluid bed boiler vessel. This cleaning and recycling operation occurs continuously and without interruption to the operations of the combustion system.

The versatility of the fluid bed, with its extended residence time and low operating temperatures, minimizes the production of most emissions and allows for the application of various abatement techniques to further reduce various pollutants. Emissions related to the products of incomplete combustion (PIC) such as; carbon monoxide (CO), volatile organic compounds (VOC), total hydrocarbons (THC), dioxins and furans (PCDD and PCDF), are greatly minimized due to the high efficiencies of combustion associated with the fluid bed.

More recently, fluid beds have been the combustion system of choice due to their ability to control acid gas emissions. By utilizing a sorbent material such as limestone in the fluid bed, a chemical reaction occurs under normal combustion operating temperatures, whereby the calcium oxide generated on calcination of the limestone reacts with the sulfur from the fuel to form a stable calcium sulfate (gypsum) product. This material becomes part of the ash particulate stream and can be removed from the system with the normal particulate gas clean-up devices. Consequently, the sulfuric acid gas can be minimized, if not totally eliminated, in a manner that is very cost competitive to both wet and dry acid gas scrubbers. The unreacted calcium oxide (CaO) that is carried out of the combustor as particulate also assists in the abatement of hydrochloric (HCl) acid gases in the cooler zones downstream of the combustor.

EPI has developed a selective non-catalytic reduction (SNCR) system for the abatement of NOx to be used specifically with it's fluid bed combustion systems. The operating temperature profile, coupled with the efficiencies of combustion associated with the fluid bed, provide optimum conditions for use of SNCR to reduce emissions of NOx. EPI fluidized bed combustion systems typically achieve NOx reductions in excess of 80%, with minimal amounts of ammonia slip.

EPI's fluid bed technology has continually met this country's most stringent emissions constraints, including six (6) facilities in non-attainment areas of California. EPI's fluid bed technology has also been considered LAER (lowest achievable emission rate) for both CO and VOC, and BACT (best available control technology) for NOx when coupled with SNCR for NOx abatement.

ATTACHMENT DR-11

1.SECTION
FLUIDIZED BED TECHNOLOGY

a. Introduction

The following document was prepared by Energy Products of Idaho (EPI) for coal combustion in small fluidized bed systems. Over the past twenty seven years, EPI has provided 78 medium to small sized fluidized bed systems throughout the world.

b. Discussion

The success of many power plant projects is dependent on the fuel flexibility of the combustion equipment. A plant designed for a single fuel may run profitably for many years and then suddenly find that the fuel costs and/or emissions constraints have increased to the point that the plant is no longer profitable. Fuel flexibility is the key to a long term successful project.

Fluidized bed technology has provided more fuel flexibility than any other combustion technology available today. Fluidized bed combustion and gasification systems are located throughout the world in the industries of fossil fuel, wood products, paper, power generation, agriculture, food processing, and municipalities recovering energy from wastes such as municipal garbage and sludge, paper, paper sludge, coal, plastic, manure, biomass, wood, and numerous other materials. The fluidized bed is suitable for burning a wide range of materials containing varying moisture contents while generating the lowest possible emissions.

i. Fluidized Bed Combustion Process Description

Fluidization is a term used to describe a phenomenon that passing an air stream vertically upward through a mass of solid particles. The upward velocity creates a lifting, or buoyancy effect on the particles and results in the suspension of those particles within the air. As the air velocities are increased above a minimum fluidization velocity, the particles are no longer held to normal solid-to-solid contact and they begin to float and travel within the air stream. The fluidized media exhibits the physical characteristics of a fluid and resembles a pot of water in a rolling boil. The result is that the physical properties of the mixture become very homogenous; all concentrations are evenly distributed throughout the fluidized bed and temperatures are uniform throughout.

Due to the fluidized bed's inherent benefits, the technology has been utilized in the combustion of solid fuels over the past twenty-five years. The fluidization effect of the bed media results in a constant surface cleaning of the burning fuel particle. Any ash and char created from the combustion of that fuel, as it is slowly being burned, will be scraped off by the etching effect of the sand. This allows a new surface to be exposed to the combustion air and results in much faster and very complete thermal conversion of the fuel particle.

In the fluid bed process, the bed media serves three major purposes:

- It acts as a thermal storage medium to hold the heat within the system;
- It provides the ignition source for fuel fed into the unit; and
- It cleans the surface of the fuel particle exposing it to combustion air.

These properties allow the fluidized bed to burn much higher moisture content fuels because the bed media retains sufficient heat storage capacity to evaporate the moisture from the fuel particles prior to combustion. This in itself is a sufficient advantage over many conventional combustion systems that are limited in their ability to handle wet fuels because of the tendency of the high moisture content to extinguish the fire.

Fluidized bed technology is well suited for burning coal and wood wastes, either separately or in combination. Coal and/or wood wastes are fed into the system through overbed feeders. Pulverization of the coal is not necessary due to the scrubbing action of the sand and the thermal inertia of the bed. Coal is sized to 3/4" to 1/2" and wood is sized to a 3-inch minus for handling considerations. Once in the system, the combustion process begins. The fine portions of the combined fuel stream begin burning as they are projected across the active bed. The lighter particles may completely burn in the vapor space while the larger particles fall onto the fluidized bed. Most of the larger fuel particles are thermally oxidized in the active fluidized bed region. Coal and large wood particles take longer to ignite than the fine particles. These heavier fuel particles overcome the updraft from the fluidizing air and become part of the active bed. The bed is maintained at a temperature of about 1500° F. At this temperature ignition of coal and wood is relatively quick. As the fuel burns, the ash is liberated as small particles that get carried out of the bed. This process limits the formation of clinkers normally formed at higher combustion temperatures. Sorbents such as limestone can be added to the bed to capture sulfur in the coal before it becomes SO_2, an acid gas emission. This process is described in more detail later in the paper.

ii. Fluidized Bed Operating Philosophy

The typical philosophy for the operation of the EPI fluidized bed is to use an externally fired air preheating system to initially heat the bed media up to the ignition temperature of the fuel. By having the bed media at these temperatures and then introducing a small quantity of fuel, ignition can be established, and more fuel added, to increase the combustion temperatures and overall system output. As the temperatures are increased, more air and fuel are added and the system is brought up to full operating and stable condition without further use of supplemental fuel.

As fuel is fed into the fluidized bed combustor, depending upon the fuel particle size, moisture content and other characteristics, a certain portion of its energy will be released directly into the bed, with the remainder being released as combustion is completed in the vapor space or overbed region of the combustor.

The design objective of the fluid bed combustion process is to optimize the temperature profile throughout the system. This optimum temperature minimizes the production of NO_x while maximizing the capture of sulfur. Temperatures within the bed are maintained hot enough to continually ignite the new fuel being introduced, and temperatures in the vapor space are sustained below the ash fusion temperature of the particular fuel. The fluidized bed section of the combustion chamber is typically maintained in the range of 1400 to 1700°F (760 to 927°C) and the vapor space temperatures are generally limited to a range of 1600 to 1800°F (871 to 982°C).

Temperature control in the combustor is achieved by diluting the combustion temperatures throughout the vessel with excess air, recycled flue gas or by direct removal of a portion of the heat with inbed and/or vapor space heat transfer surface. When fuel economy is important, such as with most power plant operations, the amount of excess air can be minimized to insure maximum boiler efficiency. Under these conditions, a certain portion of the heat release from combustion is removed directly from the fluid bed through the use of in-vessel steam generating tubes placed in the bed and vapor space. This heat transfer surface cools the vessel with the natural circulation flow of saturated water from the boiler steam drum. Water circulates through these tubes and extracts heat directly from the vessel to generate steam. The removed from the vessel results in lower operating temperatures and allows the system to maintain the desired temperature without increasing excess air. For the same reason that the combustion efficiency of a fuel particle is extremely high within the fluid bed, the heat transfer rate from the bed to in-vessel steam generating tubes is also very rapid. The heat transfer coefficient within the bed is typically ten times greater than in a standard convective type boiler. Consequently, a considerable amount of energy can be recovered from the system with a minimal amount of boiler surface. This allows for economy of boiler surface design and optimization of overall fuel consumption efficiency.

iii. Combustion Efficiency and Emissions

Due to the continued cleaning and exposure of fuel surface to oxygen for combustion and the uniform temperatures and concentrations of fuel and air within the system, the overall combustion efficiencies are extremely high in fluid bed combustors. In fact, in many cases the carbon burnout percentages within the combustor are in excess of 99%. Because of the enhanced combustion efficiency of the fluidized bed, it can operate at lower temperatures than other combustion technologies. Lower temperatures produce less NO_x and less potential to form slag on the combustor and boiler surfaces.

The versatility of the fluid bed, with its extended residence time and low operating temperatures, minimizes the production of most emissions and allows for the application of various abatement techniques to further reduce various pollutants. The products of incomplete combustion (PIC) such as; carbon monoxide (CO), volatile organic compounds (VOC), total hydrocarbons (THC), dioxins and furans (PCDD and PCDF), are minimized due to the high combustion efficiency of the fluidized bed.

Fluidized beds have been the combustion system of choice due to their ability to control acid gas emissions. By utilizing an inexpensive calcium-based sorbent material such as limestone in the fluid bed, a chemical reaction occurs under normal combustion operating temperatures whereby the calcium oxide generated on calcination of the limestone reacts with the oxidized sulfur from the fuel to form a stable calcium sulfate (gypsum) product. This material becomes part of the ash particulate stream and is removed from the system with the normal particulate gas cleanup devices. Consequently, the sulfuric acid gas is minimized in a manner that is very cost competitive to both wet and dry acid gas scrubbers. The unreacted calcium oxide (CaO) that is carried out of the combustor as particulate also assists in the abatement of hydrochloric (HCl) acid gases in the cooler zones downstream of the heat transfer equipment.

Production of nitrogen oxides (NO_x) is inherently low in fluidized bed systems due to the reduced operating temperatures of the combustor. Typically the vapor space temperatures are maintained at levels well below the temperature where air borne nitrogen converts to NO_x. At these reduced temperatures, the fuel bound nitrogen is the source of most of the NO_x produced. Given the wide range of fuels that these systems handle, many times the most cost effective fuel contains the highest amounts of nitrogen. To control the NO_x produced by the fuel bound nitrogen, selective non-catalytic reduction (SNCR) for NO_x abatement is an ideal solution. The operating temperature profile, coupled with the efficiencies of combustion associated with the fluidized bed, provide optimum conditions for use of SNCR to reduce emissions of NO_x. These systems utilize ammonia (aqueous, anhydrous or urea) as a reacting agent to abate NO_x. Due to the simplicity of the design, these systems are relatively inexpensive yet have a dramatic impact on NO_x abatement. Fluidized bed combustion systems typically achieve NO_x reductions in excess of 80%.

Fluidized bed technology has continually met the worlds most stringent emissions constraints. It has also been considered LAER (lowest achievable emission rate) for CO and VOCs, and BACT (best available control technology) for NO_x especially when coupled with SNCR.

iv. Other Benefits of Fluidized Bed Systems

Fluidized bed systems are well known for their benefits in combustion efficiency and low air emissions. There are other advantages to fluidized bed systems that are not so well published.

(1) Low Carbon Fly Ash - No Bottom Ash

As opposed to conventional grate, stoker or cyclone combustors, the fluidized bed combustion technology achieves complete carbon burnout. No black mucky carbon-rich gluck that oozes out of the bottom of the system. This is a benefit in that all of the combustible material stays in the system until it is completely burned up resulting in a very high combustion efficiency with no bottom ash. The ash in fluidized bed systems becomes fly ash. As the ash disintegrates into small particles, it is carried out as nearly carbon free fly ash and is captured in downstream particulate capture equipment.

(2) **Favorable Ash Properties**

The high combustion efficiency of a fluid bed results in a reduced amount of residual materials material as fine ash when compared to grate or stoker technology. From a landfill or ash usability perspective, this ash is easier to landfill and is more desirable for alternative uses. Low combustion temperatures in the fluidized bed minimize the formation of toxic materials that might go into the ash. Ash samples from EPI systems have consistently tested nontoxic, and in many instances the ash is being sold as input for other products such as cement. The low combustion temperature assures that there is no reactive silica in the ash.

(3) **Bed Recycle System**

The accumulation of large non-combustible materials in fluidized bed systems can present an operations problem if the system does not have a good online bed cleaning and re-injection system. Some fluidized bed systems simply drain the bed media out of the system periodically and replace it with new media. This technique increases operating costs both for new media replacement and for landfill costs of used contaminated media. A better method of solving the tramp accumulation problem is with an online bed cleaning and re-injection system.

Bed media along with any tramp material is drawn down through the static portion of the fluid bed. The bed media is screened of tramp metal and rocks, and reinjected back into the fluid bed boiler vessel. This cleaning and recycling operation occurs continuously and without interruption to the operations of the combustion system and has expanded the fuel versatility of fluidized bed systems.

This innovative system enables fluidized bed systems to operate on fuels with significant quantities of 4-inch minus noncombustible tramp material (contaminants such as rocks, metal etc.). In grate style systems, tramp material and ash slag can cause significant problems requiring a shutdown to correct. Without a bed cleaning system, fluidized bed systems can build tramp to the point that fluidization is no longer possible allowing clinkers to form. Online bed cleaning has dramatically increased the online availability of fluidized bed systems while reducing operating costs.

(4) **Operating Flexibility**

Fluidized bed systems have demonstrated the ability to operate under a wide range of load conditions. The thermal "flywheel" effect of the bed material allows swings in moisture and heating content of the fuel to be absorbed by the system without negative impact. Conversely, the low fuel inventory present in the unit makes it very responsive to varying loads. The fluidized bed also maintains efficiency during system turn-down. The operating flexibility demonstrated by many existing systems has proven quite valuable for prospective plant owners. This flexibility allows them to take advantage of utility incentive programs for generation that follows electric demand.

(5) **Low Operating Costs**

The lack of moving parts in a fluid bed reduces maintenance costs and down time. Fluidized bed systems have achieved operating availabilities above 98% and have kept operating costs relatively low given the difficult fuels they are burning.

(6) **Environmentally Sound Energy Production from Waste**

Fluidized bed combustion is an environmentally favorable, proven technology for disposal of solid wastes and generation of energy. The combination of the industries vast experience in developing solutions for a wide variety of applications, with the favorable characteristics of fluidized bed combustion make fluidized bed technology the leader in providing environmentally sound waste disposal solutions.

c. **Bubbling Fluidized Bed (BFB) vs. Circulating Fluidized Bed (CFB)**

There are two distinct types of fluidized bed technologies, circulating fluidized bed, CFB and bubbling fluidized bed, BFB. The prime difference between the two is the gas velocities maintained in the furnace. For a CFB the gas velocities are typically around 15-30 feet per second. At these velocities, all of the bed media along with most of the fuel is carried out of the furnace with the flue gas. Most of this material is removed from the gas in a cyclone and returned to the furnace, hence the term circulating fluid bed. A BFB operates at velocities typically below 10-20 feet per second and maintains a distinct layer of fluidized sand in the lower region of the furnace. Circulating fluidized bed technology has been primarily used for the combustion of coal in large utility sized boilers, while bubbling fluidized bed has dominated the smaller scale biomass combustion market. Both technologies have distinct characteristics described in the following sections.

i. Bed Media and Operating Velocities

A CFB is designed to recirculate the bed material through the furnace and cyclone system to maintain the heat transfer configuration. Usually, in coal-fired applications, the bed media consists of coal ash and/or limestone, introduced to control the sulfur emissions. For a wood fired system, the limestone consumption is not sufficient to generate and maintain the bed inventory necessary for operation. An additional increment of limestone is required, or an inert bed material, such as sand, is necessary. At the high velocities of operation in the CFB, selection of a bed media can become a significant factor contributing to excessive erosion and wear of the refractory and furnace tubes in the combustor or the cyclone.

In BFB designs, an inert bed media is used to maintain necessary bed depth. This inventory is eventually contaminated by ash and sand coming in with the fuel, and eventually the composition of the media is an equilibrium mixture of bed material, limestone, and fuel ash. The operating velocities in the bubbling bed are typically around 6-8 fps as compared with 20-30 fps for the CFB. At the lower velocities, erosion and wear on the inner vessel walls and inbed tubes are minimal. The particle sizing for the bed material in the BFB unit is around 8-20 mesh, whereas the particle sizing for the CFB is usually 20-mesh and finer.

ii. Excess Air and Temperature Control

The BFB design often incorporates a fixed quantity of steaming/heat transfer surface area in the bed and vapor region to remove a portion of the fuel energy directly from the furnace. This enables the incoming air to maintain the combustion temperatures around the targeted 1700°F. In a CFB, the boiler surface is incorporated into the walls of the combustor and cyclone. The rate of heat transfer to these walls is controlled by increasing or decreasing the volume of bed media being recirculated through the unit. A higher circulation rate increases the effective heat transfer rate to these wall tubes and results in an increased removal of energy from the furnace. In both instances, the combustor design is set to maintain excess air levels of 40% or greater.

Although both units may be operated at approximately the same excess air levels, the increased height of the CFB plus the significant density of bed media in the circulating gases results in a noticeable increase in the draft requirements of the forced draft fan. This results in a direct increase in fan horsepower requirements for the CFB.

iii. **Refractory vs. Membrane Wall Construction**

Some BFB systems utilize refractory walls in the combustion chamber with widely spaced vapor tubes offset from the refractory. CFB's use a membrane wall furnace with refractory coating covering most of the lower chamber. The combustion process is similar. A portion of the combustion air is introduced as fluidizing or underfire air and the balance is introduced as staged overfire air. The major differences between the two configurations are in the installation arrangement, the capital cost, the cost of installation and the maintenance cost. Due to the increased velocities, the CFB has a smaller footprint than a BFB, typically 50% of the plan area of the furnace. The height of the combustor, however, is often more than twice that of a bubbling bed. The roof of a typical BFB is combustor is typically 55 feet above grade, and the CFB height is often more than 110 feet high. Not only does this equate to significant costs for support steel and footings, it also translates to major dollars for buildings, access, and other appurtenances. The BFB design typically incorporates factory installed refractory and insulation in the combustion chamber. Panel assemblies create relatively easy field installation. The field labor to erect such a unit is minimized. Most CFB boilers are field erected systems that cannot easily be factory assembled. Construction costs, especially for skilled boiler laborers, are significant.

Maintenance on the steam generating tubes in the BFB combustion chamber is minimal. The tubes are easily accessible, in the event any repair or replacement is necessary. It is much more complicated to repair or replace a portion of a water wall in a CFB that is partially covered with refractory.

iv. **Boiler System**

Bubbling fluidized bed systems typically utilize a modular, vertical tube, bottom supported, waste-heat style boiler in addition to the inbed and vapor tube surfaces in the combustion chamber. This provides several advantages over the field erected boilers of a CFB. The BFB boiler and superheater modules are factory assembled and are bottom supported. This greatly reduces field erection time cost over a top supported field erected system. The boiler tubes are arranged vertically which enhances cleanability and ash deentrainment.

The design incorporates a screen tube section ahead of the superheater to reduce flue gas temperatures into the superheater. This design is extremely efficient and effective and is a significant cost savings over the radiant wall cooling section included in some CFB designs.

All of the above considerations create a very significant cost advantage, for equipment and installation, for the bubbling fluidized bed design.

v. **Operating Horsepower**

Depending on the fuel mix, bubbling bed systems can have a significant advantage in horsepower over CFBs. Typically a BFB offers up to a 30% savings in forced draft and induced draft fan horsepower. The reason for this is that the CFB requires more horsepower to circulate the sand up out of the bed and through a cyclone that returns the sand to the bed. In a BFB the sand always remains in the bed area.

vi. **Experience**

Fluidized bed combustion systems have been successfully utilized for nearly every type of conventional and alternative fuel. These systems have been utilized for coal in many locations around the world and since the early 1970's they started appearing in biomass applications where emissions were starting to be a concern. Both BFB and CFB designs offer an efficient method of converting dirty fuels into clean usable energy.

ATTACHMENT DR-16

San Joaquin Solar 1 and 2 Project

Responses for CURE Data Request #16

Estimation Estimations for Each Biomass Boiler

based on 100% Load, 100% Municipal Green Waste

The maximum hourly potential to emit from each boiler will occur when the unit is operating under startup mode at either the 7th or 8th hour. On the 7th hour, biomass is also introduced into the boiler. On the 8th hour, the startup natural gas burners are

Maximum One Startup Event Emissions (8-hour duration)						
	NO_X (lbs/event)	CO (lbs/event)	VOC (lbs/event)	PM_{10} (lbs/event)	$PM_{2.5}$ (lbs/event)	SO_x (lbs/event)
Mass Emission Rate (per boiler)	102.10	58.50	5.74	23.18	23.18	86.84

Maximum Hourly Startup Emissions (1-hour duration)						
	NO_X (lb/hr)	CO (lb/hr)	VOC (lb/hr)	PM_{10} (lb/hr)	$PM_{2.5}$ (lb/hr)	SO_x (lb/hr)
Mass Emission Rate (per boiler)	37.62	15.50	3.72	13.95	13.95	46.50

Maximum Normal Hourly Emissions based on 100% Load, 100% Municipal Green Waste							
	NO_X (lb/hr)	CO (lb/hr)	VOC (lb/hr)	PM_{10} (lb/hr)	$PM_{2.5}$ (lb/hr)	SO_x (lb/hr)	NH_3 (lb/hr)
Mass Emission Rate (per boiler)	3.66	6.11	1.10	7.180	7.180	3.60	1.06
ppmvd @ 15% O_2 limits	6	18.0	2.0			5	5

The maximum daily emissions occur when each boiler operates with 1 startup for 8 hours and the remainder at 100% load for every criteria pollutants except for PM10, PM2.5, and VOC. The maximum daily emissions for PM10, PM2.5, and VOC occur when each boiler is in normal operation. The results for each boiler is summarized in the table below:

Maximum Daily Emissions				
	Startup Emissions Rate (lb/day)	Emissions Rate based on 100% Load, 100% Municipal Green Waste (lb/day)		Daily Emissions Limitation (lb/day)
Formula	*lb / 1 event/day*	*lb/hr x (24 hour/day – 1 event/day x 8 hr/event)*		*Startup + 100% Load*
NO_X	102.10	3.63 lb/hr x (24 hr – 1 x 8 hr)/day =	58.56 lb/day	160.66
SO_x	86.84	3.67 lb/hr x (24 hr – 1 x 8 hr)/day =	57.60 lb/day	144.44
CO	58.50	6.25 lb/hr x (24 hr – 1 x 8 hr)/day =	97.76 lb/day	156.26
Formula		*lb/hr x (24 hour/day)*		*100% Load*
PM_{10}		6.940 lb/hr x 24 hr / day =	172.32 lb/day	172.32
$PM_{2.5}$		6.940 lb/hr x 24 hr / day =	172.32 lb/day	172.32
VOC		1.03 lb/hr x 24 hr / day =	26.40 lb/day	26.40

The maximum annual emissions occur when each boiler operates with 2 startups and 6570 hours per year at 100% load. The results for each boiler are summarized in the table

Maximum Annual Emissions				
	Startup Emissions Rate (lb/year)	Emissions Rate @ 100% Load, 50% Urban Waste 50% Ag Waste (lb/year)		Annual Emissions Limitation (tons/year) (per boiler)
Formula	*lb/hr x 2 events/yr x 7 hr/event*	*lb/hr x 6570 hour/yr*		*Startup + 100% Load*
NO_X	204.20	3.63 lb/hr x 6570 hr/yr =	24,046.20 lb/yr	12.13
SO_x	173.68	3.67 lb/hr x 6570 hr/yr =	23,652.00 lb/yr	11.91
CO	117.00	6.25 lb/hr x 6570 hr/yr =	40,142.70 lb/yr	20.13
PM_{10}	46.36	6.940 lb/hr x 6570 hr/yr =	47,172.60 lb/yr	23.61
$PM_{2.5}$	46.36	6.940 lb/hr x 6570 hr/yr =	47,172.60 lb/yr	23.61
VOC	11.48	1.03 lb/hr x 6570 hr/yr =	7,227.00 lb/yr	3.62

SUMMARY

The daily and annual PE2 for each boiler is summarized in the table below:

Summary for Daily and Annual Emission Estimations based on 100% Load, 100% Municipal Green Waste		
	Daily Emissions (lb/day)	Annual Emissions (tons/year)
NO_X	160.7	12.13
SO_x	144.4	11.91
CO	156.3	20.13
PM_{10}	172.3	23.61
$PM_{2.5}$	172.3	23.61
VOC	26.4	3.62

Supporting Vendor Emission Data from EPI (100% municipal green waste)

EMISSIONS AT STACK

EPI Reference Number	1587	Performed by:	mlm
Customer	Spinnaker - Steam cycle -004-C	Date:	27-May-09
Project Name	San Juaquin, ca	Revision:	4B
ag prun		Filename:	stm 4 30 09 Rev B
emissions per boiler		Page	1a

Flue Gas @ ID Fan Outlet							
	Mass Flow	424,730	lbs/hr		O2	8.54	% vol.(dry)
	Vol. Flow	126,727	acfm	126727	CO2	12.04	% vol.(dry)
	Temp.	230	deg. F		N2	79.41	% vol.(dry)
	Dry MW	30.28	moles/lb		density	0.056	lb/ft3
	Wet MW	28.14	moles/lb				
	Std. Vol.	97,341	scfm		Moisture	11.19	% by wt.
	Std. Dry Vol.	80,318	sdcfm		Moisture	17.49	% by vol.

Flue Gas @ Stack				%of Total
	Mass Flow	424,730	lbs/hr	100.00%
	Vol. Flow	126,727	acfm	100.00%
	Temp.	230	deg. F	
	Std. Vol.	97,341	scfm	100.00%
	Std. Dry Vol.	80,318	sdcfm	100.00%

capacity factor 75.00%

Emissions @ Stack

		Potential Unabated Emissions			Abated Emissions @ Stack			
Pollutant	mole. wt.	ppmdv	lbs/hr	lbs/MBtu	ppmdv	lbs/hr	lbs/MBtu	Ton/yr
CO	28.01				18	6.11	0.020	20.06
SO2	64.07	45	36.03	0.120	5	3.60	0.012	11.84
NOx	46.01	213	122.17	0.408	6	3.66	0.012	12.04
HCl	36.47	32	14.41	0.048	3	1.44	0.005	4.73
VOC	44.09				2	1.10	0.004	3.61
NH3	17.03				5	1.06	0.004	

Particulate -Front Half Catch

	Potential From FBI	Loading To Cleanup	Abated @ Stack
gr/SDCF	2.18	0.52	0.005
lbs/hr	1,501	359	3.59
lbs/day	36,026	8,615	86.16
tons/yr	4,931	1,179	11.79
lbs/MMBTU	5.015	1.199	0.0120

San Joaquin Solar 1 and 2 Project
Responses for CURE Data Request #16
Estimation Estimations for Each Biomass Boiler
based on 100% Load, 50% Urban Waste 50% Ag Waste

The maximum hourly potential to emit from each boiler will occur when the unit is operating under startup mode at either the 7th or 8th hour. On the 7th hour, biomass is also introduced into the boiler. On the 8th hour, the startup natural gas burners are no longer needed and the boiler is fired exclusively on biomass.

Maximum One Startup Event Emissions (8-hour duration)						
	NO_X (lbs/event)	CO (lbs/event)	VOC (lbs/event)	PM_{10} (lbs/event)	$PM_{2.5}$ (lbs/event)	SO_x (lbs/event)
Mass Emission Rate (per boiler)	102.10	58.50	5.74	23.18	23.18	86.84

Maximum Hourly Startup Emissions (1-hour duration)						
	NO_X (lb/hr)	CO (lb/hr)	VOC (lb/hr)	PM_{10} (lb/hr)	$PM_{2.5}$ (lb/hr)	SO_x (lb/hr)
Mass Emission Rate (per boiler)	37.62	15.50	3.72	13.95	13.95	46.50

Maximum Normal Hourly Emissions based on 100% Load, 50% Urban Waste 50% Ag Waste							
	NO_X (lb/hr)	CO (lb/hr)	VOC (lb/hr)	PM_{10} (lb/hr)	$PM_{2.5}$ (lb/hr)	SO_x (lb/hr)	NH_3 (lb/hr)
Mass Emission Rate (per boiler)	3.63	6.25	1.03	6.940	6.940	3.67	1.00
ppmvd @ 15% O_2 limits	7	19.0	2.0			5	5

The maximum daily emissions occur when each boiler operates with 1 startup for 8 hours and the remainder at 100% load for every criteria pollutants except for PM10, PM2.5, and VOC. The maximum daily emissions for PM10, PM2.5, and VOC occur when each boiler is in normal operation. The results for each boiler is summarized in the table below:

Maximum Daily Emissions					
	Startup Emissions Rate (lb/day)	Emissions Rate @ 100% Load, 50% Urban Waste 50% Ag Waste (lb/day)			Daily Emissions Limitation (lb/day)
Formula	*lb / 1 event/day*	*lb/hr x (24 hour/day – 1 event/day x 8 hr/event)*			*Startup + 100% Load*
NO_X	102.10	3.63 lb/hr x (24 hr – 1 x 8 hr)/day =	58.08	lb/day	160.18
SO_x	86.84	3.67 lb/hr x (24 hr – 1 x 8 hr)/day =	58.72	lb/day	145.56
CO	58.50	6.25 lb/hr x (24 hr – 1 x 8 hr)/day =	100.00	lb/day	158.50
Formula		*lb/hr x (24 hour/day)*			*100% Load*
PM_{10}		6.940 lb/hr x 24 hr / day =	166.56	lb/day	166.56
$PM_{2.5}$		6.940 lb/hr x 24 hr / day =	166.56	lb/day	166.56
VOC		1.03 lb/hr x 24 hr / day =	24.72	lb/day	24.72

The maximum annual emissions occur when each boiler operates with 2 startups and 6570 hours per year at 100% load. The results for each boiler are summarized in the table below:

Maximum Annual Emissions					
	Startup Emissions Rate (lb/year)	Emissions Rate based on 100% Load, 50% Urban Waste 50% Ag Waste (lb/day)			Annual Emissions Limitation (tons/year) (per boiler)
Formula	*lb/hr x 2 events/yr x 7 hr/event*	*lb/hr x 6570 hour/yr*			*Startup + 100% Load*
NO_X	204.20	3.63 lb/hr x 6570 hr/yr =	23,849.10	lb/yr	12.03
SO_x	173.68	3.67 lb/hr x 6570 hr/yr =	24,111.90	lb/yr	12.14
CO	117.00	6.25 lb/hr x 6570 hr/yr =	41,062.50	lb/yr	20.59
PM_{10}	46.36	6.940 lb/hr x 6570 hr/yr =	45,595.80	lb/yr	22.82
$PM_{2.5}$	46.36	6.940 lb/hr x 6570 hr/yr =	45,595.80	lb/yr	22.82
VOC	11.48	1.03 lb/hr x 6570 hr/yr =	6,767.10	lb/yr	3.39

SUMMARY
The daily and annual emissions for each combustor for SJS1&2 are summarized in the table below:

Summary for Daily and Annual Emission Estimations based on 100% Load, 50% Urban Waste 50% Ag Waste		
	Daily Emissions (lb/day)	Annual Emissions (tons/year)
NO_X	160.2	12.03
SO_x	145.6	12.14
CO	158.5	20.59
PM_{10}	166.6	22.82
$PM_{2.5}$	166.6	22.82
VOC	24.7	3.39

Supporting Vendor Emission Data from EPI (50% fuel blend)

EMISSIONS AT STACK

EPI Reference Number	1587	Performed by:	mlm
Customer	Spinnaker - Steam cycle -004-C	Date:	27-May-09
Project Name	San Juaquin, ca	Revision:	4B
50/50		Filename:	stm 4 30 09 Rev B
emissions per boiler		Page	1a

Flue Gas @ ID Fan Outlet							
	Mass Flow	408,457	lbs/hr		O2	7.40	% vol.(dry)
	Vol. Flow	122,567	acfm	122567	CO2	13.12	% vol.(dry)
	Temp.	230	deg. F		N2	79.46	% vol.(dry)
	Dry MW	30.41	moles/lb		density	0.056	lb/ft3
	Wet MW	27.98	moles/lb				
	Std. Vol.	94,145	scfm		Moisture	12.63	% by wt.
	Std. Dry Vol.	75,669	sdcfm		Moisture	19.63	% by vol.

Flue Gas @ Stack				%of Total
	Mass Flow	408,457	lbs/hr	100.00%
	Vol. Flow	122,567	acfm	100.00%
	Temp.	230	deg. F	
	Std. Vol.	94,145	scfm	100.00%
	Std. Dry Vol.	75,669	sdcfm	100.00%

capacity factor 75.00%

Emissions @ Stack		Potential Unabated Emissions			Abated Emissions @ Stack			
Pollutant	mole. wt.	ppmdv	lbs/hr	lbs/MBtu	ppmdv	lbs/hr	lbs/MBtu	Ton/yr
CO	28.01				19	6.25	0.021	20.52
SO2	64.07	72	54.36	0.179	5	3.67	0.012	12.05
NOx	46.01	234	126.27	0.416	7	3.63	0.012	11.93
HCl	36.47	55	23.43	0.077	3	1.41	0.005	4.62
VOC	44.09				2	1.03	0.003	3.40
NH3	17.03				5	1.00	0.003	

Particulate -Front Half Catch

	Potential From FBI	Loading To Cleanup	Abated @ Stack
gr/SDCF	3.05	0.76	0.005
lbs/hr	1,981	495	3.47
lbs/day	47,533	11,883	83.20
tons/yr	6,506	1,627	11.39
lbs/MMBTU	6.518	1.629	0.0114

ATTACHMENT DR-32

3219 11963 BOOK 5863 PAGE 434

Recording Requested by
County Board of Supervisors

When recorded, return to the
Fresno County Planning Dept.
4499 E. Kings Canyon Road
Fresno, California 93702

RECORDED IN OFFICIAL RECORDS OF
FRESNO COUNTY, CALIFORNIA
AT ___ MIN. PAST ___ M

FEB 17 1971

J. L. BROWN, County Recorder
FEE $

SPACE ABOVE THIS LINE FOR RECORDER'S USE

SHORT FORM LAND CONSERVATION CONTRACT

Incorporating Board of Supervisors Resolution by reference.

THIS LAND CONSERVATION CONTRACT, MADE AND EXECUTED THIS 2nd day of January, 19 71, by and between Standard Oil Company of California, a corporation

hereinafter referred to as 'Owner' and the COUNTY OF FRESNO, a political subdivision of the State of California, hereinafter referred to as 'County,'

W I T N E S S E T H :

WHEREAS, Owner possesses certain real property situate in the County of Fresno, State of California, hereinafter referred to as 'the Subject Property,' and more particularly described in Exhibit 'A' attached hereto and by this reference incorporated herein; and

WHEREAS, the Subject Property is now devoted to agricultural uses and uses compatible thereto; and

WHEREAS, the Subject Property is located in an 'agricultural preserve' heretofore established by the County, and designated as the Westside #103

;

NOW, THEREFORE, both Owner and County, in consideration of the mutual promises, covenants and conditions to which reference is made herein and the substantial public benefits to be derived therefrom, do hereby agree as follows:

FIRST: The Subject Property shall be subject to all restrictions and conditions adopted by resolution by the Board of Supervisors of Fresno County, California on December 1, 1970 and recorded December 4, 1970 as Instrument Number 84793, Book 5841, Pages 570 through 577 of the Official Records of Fresno County, California, and IT IS MUTUALLY AGREED THAT the conditions and restrictions set forth in said resolution are adopted and incorporated herein and made a part hereof as fully as though set forth herein at length and that Owner will observe and perform said provisions.

SECOND: The minimum acreage for new parcels described in Paragraph Seven of the Board of Supervisors' Resolution shall be 40 acres.

THIRD: This Contract shall be effective as of the first day of March, 1971.

IN WITNESS WHEREOF, the Owner and County have executed this Contract the day and year first above written.

COUNTY OF FRESNO

By John Vantuyl
Chairman of the Board of Supervisors

ATTEST:

J. L. Brown, County Clerk and Ex Officio
Clerk of the Board of Supervisors

By [signature]
Deputy

OWNERS

STANDARD OIL COMPANY OF CALIFORNIA

By [signature]
Contract Agent

By J. Bowman
Assistant Secretary

State of California
City and County of San Francisco } ss

BOOK 5863 PAGE 435

On February 1, 1971, before me, Edmond Lee Kelly, a Notary Public in and for said City and County and State, residing therein, duly commissioned and sworn, personally appeared A. T. SMITH and J. P. BOWMAN known to me to be CONTRACT AGENT and ASSISTANT SECRETARY, respectively, of STANDARD OIL COMPANY OF CALIFORNIA the Corporation described in and that executed the within instrument, and also known to me to be the persons who executed it on behalf of the said Corporation therein named, and they acknowledged to me that such Corporation executed the same.

IN WITNESS WHEREOF, I have hereunto set my hand and affixed my Official Seal, at my office in the City and County and State aforesaid the day and year in this certificate above written.

EDMOND LEE KELLY
NOTARY PUBLIC - CALIFORNIA
CITY AND COUNTY OF SAN FRANCISCO
My Commission Expires January 22, 1972

Edmond Lee Kelly 19
Notary Public in and for said City and County of San Francisco, State of California

APN 85-020-08, 21, 31
85-030-56 & other property
85-060-11, 14,27
85-070-01, 05, 10
85-100-16 & other property
85-320-04.

SCHEDULE A

EXHIBIT "A"

NO. 258287

The assurances referred to on the face page are:

That, according to the Company's property records relative to the following described real property (but without examination of those Company records maintained and indexed by name):

The South half and the Northwest quarter of Section 3, all of Section 5, the South half of Section 7, all of Section 9, the North half of Section 11, all of Section 15, the South half; the Northeast quarter; that portion of the Northwest quarter lying northeast of the Westside Freeway and that portion of the South half of the South half of the Northwest quarter lying southwest of the Westside Freeway, in Section 17; the East half; the East half of the Northwest quarter and the Southwest quarter of Section 19, the Northwest quarter; (see * below)

The last recorded instrument purporting to transfer title to said real property is:

STANDARD OIL COMPANY OF CALIFORNIA
a corporation

Documentary Transfer Tax $

If information was requested by reference to a street address, no guarantee is made that said real property is the same as said address.

(description continued)

*The North half of the Southwest quarter; the Southwest quarter of the Southwest quarter; the West half of the Southeast quarter of the Southwest quarter; the Northwest quarter of the Southwest quarter of the Northeast quarter; the West half of the Northwest quarter of the Northeast quarter and the Northeast quarter of the Northwest quarter of the Northeast quarter of Section 13, all of Sections 21 and 23, ~~and the South half and the Northeast quarter of Section 33~~, all in Township 21 South, Range 16 East, Mount Diablo Base and Meridian, according to the United States Government Township Plat approved by the Surveyor GEneral on May 14, 1883.

EXCEPTING from the South half of Section 3, the Southwest quarter of the Southwest quarter of the Southwest quarter, as conveyed to Walter I. Gray, Jr., by deed dated October 8, 1968, recorded November 14, 1968 in Book 5674 Page 164 of Official Records, Document No. 81047.

BEFORE THE ENERGY RESOURCES CONSERVATION AND DEVELOPMENT COMMISSION OF THE STATE OF CALIFORNIA
1516 NINTH STREET, SACRAMENTO, CA 95814
1-800-822-6228 – WWW.ENERGY.CA.GOV

APPLICATION FOR CERTIFICATION FOR THE *SAN JOAQUIN SOLAR UNITS 1 AND 2* *LICENSING PROJECT*

Docket No. 08-AFC-12

PROOF OF SERVICE
(Revised 7/23/2009)

APPLICANT

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Declaration of Service

I, Anne Runnalls, declare that on August 13, 2009, I served and filed copies of the attached Response to CURE Data Request Set #2. The original document, filed with the Docket Unit, is accompanied by a copy of the most recent Proof of Service list, located on the web page for this project at: **[http://www.energy.ca.gov/sitingcases/sjsolar/index.html].** The document has been sent to both the other parties in this proceeding (as shown on the Proof of Service list) and to the Commission's Docket Unit, in the following manner:

(C*heck all that Apply*)

For service to all other parties:

__X___sent electronically to all email addresses on the Proof of Service list;

_____by personal delivery or by depositing in the United States mail at ____________________ with first-class postage thereon fully prepaid and addressed as provided on the Proof of Service list above to those addresses NOT marked "email preferred."

AND

For filing with the Energy Commission:

__X___sending an original paper copy and one electronic copy, mailed and emailed respectively, to the address below (preferred method);

OR

_____depositing in the mail an original and 12 paper copies, as follows:

CALIFORNIA ENERGY COMMISSION
Attn: Docket No. 08-AFC-12
1516 Ninth Street, MS-4
Sacramento, CA 95814-5512

docket@energy.state.ca.us

I declare under penalty of perjury that the foregoing is true and correct.

Anne Runnalls