PROPOSED

COVERED SOURCE PERMIT APPLICATION REVIEW 0638-01-C

Initial Application No. 0638-02

APPLICANT:	Honua Power, LLC
LOCATION:	Tax Map Key 9-1-1-31:32 Kapolei, HI 96707 UTM Coordinates (NAD 83, zone 4) 593,290 m East, 2,355,739 m North
MAILING ADDRESS:	500 Ala Moana Blvd, Suite 7-220 Honolulu, HI 96813
RESPONSIBLE OFFICIAL:	Mr. Tim Mobley President/CEO 808-550-2877
SIC CODE:	4939 (Combination utilities, not elsewhere classified)

PROPOSED PROJECT:

The subject application is for an initial permit for a new facility. The applicant is requesting approval to construct and operate a 230 ton per day gasification plant in the Campbell Industrial Park area. The gasification plant also includes an 82,635 lb/hr steam boiler fired by synthetic gas produced by the facility. The boiler will also be permitted to use liquefied petroleum gas (LPG) as an allowable fuel. The steam generated by the boiler is supplied to a turbine generator set for the production of electricity. The maximum production rate of the generator is 6.64 MW/hr. The equipment is to operated on a continuous basis (8,760 hours per year). A 1,000 kW black-start diesel engine generator (DEG) is also to be permitted to operate 500 hours per year. The types of waste to be gasified includes construction and demolition waste, with the exception of shredded tires. The applicant will not gasify shredded tires, and will be restricted from gasifying tires via permit condition.

Proposed Process:

The process begins with the receipt of feedstock from off-site suppliers. The suppliers prepare the feedstock material to standards required for gasification as specified by the facility. Feedstock is received by truck 6 days per week. Trucks offload the feedstock into a live-bottom receiving pit, for transport via a screw conveyor to the appropriate storage silo. The receiving pit area will use a baghouse system to control fugitive emissions generated during the receiving process. The dust captured by the baghouse is discharged back into the receiving pit to be used as feedstock.

The gasification process begins by loading feedstock from the silos onto an enclosed delivery conveyor. Each silo discharges at a set rate to achieve the desired mix and quantity of feedstock material delivered to the gasifier. The delivery conveyor transports the feedstock to the feed hopper for the gasifier where it is mixed, then transported by a screw conveyor to the gasifier. All conveying equipment is enclosed to minimize fugitive emissions.

The properly mixed feedstock enters the up-flow gasifier and is converted to synthesis gas (syngas) by using a thermo-chemical process that uses controlled amounts of heat and air to

break down hydrocarbons. The gasifier usually operates in the range of 1400°F to 1600°F. The syngas is used to fire a boiler to superheat steam.

After exiting the gasifier, the syngas enters a high temperature cyclone to remove particulate matter. The syngas then flows from the cyclone to the combustion tube. The combustion tube allows for the controlled addition of air to the syngas while remaining in an chemically reducing reaction, minimizing NO_x emissions. The temperature of the combustion tube is controlled at 2200°F to 2400°F.

The syngas then flows to a low NO_x, staged combustion burner for combustion. After the combustion process is complete, the flue gas is directed to the Selective Non Catalytic Reduction (SNCR) chamber. In the SNCR chamber, urea is atomized into the flue gas stream flows to further control NO_x emissions. The gas at the inlet to the SNCR chamber is maintained between 1650°F and 2100°F to insure the gas is in the optimal range to control NO_x emissions.

The hot gases enter the boiler after exiting the SNCR chamber. The boiler produces high pressure, superheated steam (650 psig, 700°F). Steam is produced at a rate of 82,000 pounds per hour, and supplies a turbine generator set that will produce 6,642 kW per hour of electricity.

Upon exiting the boiler at 350°F, the exhaust gas is injected with a sorbent (sodium bicarbonate) to control acid gases and activated carbon to control hydrocarbons and heavy metals. The exhaust gas then enters a baghouse to remove solids. The exhaust gas is then drawn from the system using an induced draft fan to an exhaust vent, where the gas is discharged to the atmosphere.

AIR POLLUTION CONTROL DEVICES:

The application states that the following control devices will be installed at the facility to control air pollutant emissions:

The receiving area, char removal area, feedstock silos and the boiler will use baghouses to limit particulate matter emissions. In addition, particulate matter emissions from the boiler will also be controlled with the use of a cyclone. The application also states that all conveyors will be enclosed and thus will not have any air emissions.

NO_x emissions originate from the boiler and are controlled using a combustion tube to partially combust flue gas, reducing bound nitrogen to diatomic nitrogen (N_2) instead of nitrogen oxides (NO_x), low NO_x burners, flue gas recirculation, and urea injection (SNCR). Monitoring and recording of NO_x emissions will be done with a continuous emissions monitoring system (CEMS). The urea injection system pump will is equipped with a pressure sensor monitor urea injection SNCR system will be monitored

SO_2 emission control consists of sodium bicarbonate injection and baghouse collection. SO_2 emissions will be monitored and recorded with a CEMS to determine the proper sorbent injection rate.

CO and VOC emission control achieved by proper combustion conditions

HCl emissions are controlled by same control equipment as SO_2. The amount of sorbent required over and above the amount needed for proper SO_2 control will be based upon the highest HCl emission level obtained in the initial performance test. HCl emissions are not

monitored directly due to the fact the HCl is more reactive than SO_2. However, the permittee has agreed to a permit condition that regulates HCl emissions by using SO_2 emissions as a surrogate. If there is an exceedance of SO_2 emissions, it will also be considered an exceedance of the HCl emission rate also.

HAPs will be controlled by using proper combustion, carbon injection and baghouses. The quantity of carbon required will be determined from the results of the initial performance test.

Compliance Assurance Monitoring (CAM)
Applicability of the CAM Rule (40 CFR, Part 64) is determined on a pollutant specific basis for each affected emission unit. Each determination is based upon a series of evaluation criteria. In order for a source to be subject to CAM, each source must:

- Be located at a major stationary source per Title V of the Clean Air Act Amendments of 1990;
- Be subject to federally enforceable applicable requirements;
- Have pre-control device potential emissions that exceed applicable major source thresholds;
- Be fitted with an "active" air pollution control device; and
- Not be subject to certain regulations that specifically exempt it from CAM.

Emission units are any part or activity of a stationary source that emits or has the potential to emit any air pollutant. The facility is not a major covered source and thus is not subject to CAM.

APPLICABLE REQUIREMENTS:

Hawaii Administrative Rules (HAR)
- Chapter 11-59, Ambient Air Quality Standards
- Chapter 11-60.1, Air Pollution Control
  - Subchapter 1, General Requirements
  - Subchapter 2, General Prohibitions
    - 11-60.1-31 Applicability
    - 11-60.1-32 Visible Emissions
    - 11-60.1-33 Fugitive Dust
    - 11-60.1-38 Sulfur Oxides from fuel combustion
  - Subchapter 5, Covered Sources
  - Subchapter 6, Fees for Covered Sources, Noncovered Sources, and Agricultural Burning
    - 11-60.1-111 Definitions
    - 11-60.1-112 General fee provisions for covered sources
    - 11-60.1-113 Application fees for covered sources
    - 11-60.1-114 Annual fees for covered sources
  - Subchapter 7, Prevention of Significant Deterioration Review
  - Subchapter 8, Standards of Performance for Stationary Sources
  - Subchapter 9, Hazardous Air Pollutant Sources
  - Subchapter 10, Field Citations

NSPS:
The facility is subject to the following New Source Performance Standards (NSPS):

1. 40 CFR Part 60 Subpart A, *General Requirements*
2. 40 CFR Part 60 Subpart Dc, *Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units.*
3. 40 CFR Part 60 Subpart IIII, *Standards of Performance for Stationary Compression Ignition Internal Combustion Engines*
4. 40 CFR Part 63, Subpart ZZZZ, *National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines.*

Discussion:

40 CFR 60 Subpart Dc is an applicable requirement for the boiler because it is a steam generating unit, construction will commence after June 9, 1989 and has a maximum heat input capacity (22.9 MMBtu/hr) of between 100 MMBtu/hr and greater than or equal to 10 MMBtu/hr. The facility is required under this subpart to comply with visible emission (20%) and particulate matter emission limits. The particulate matter emission rate was calculated as shown in the following table:

Boiler Capacity =	82,365	lb/hr steam
1 lb/hr steam =	0.0014	MMBtu/hr
Boiler Capacity =	115.311	MMbtu/hr
PM emission limit =	0.03	lb/MMbtu

Pursuant to the calculations, a particulate matter emission limit of 3.48 pounds per hour will be added as a permit condition

40 CFR 63 Subpart ZZZZ is an applicable requirement for the black-start diesel engine generator because it is a stationary reciprocating internal combustion engine (RICE) located at an area source of HAPs. However, pursuant to §63.6590, a new or reconstructed stationary RICE located at an area source will satisfy the requirements of this subpart by meeting the requirements of 40 CFR subpart IIII for compression ignition engines. No further requirements for such engines are required by 40 CFR 63 Subpart ZZZZ.

Since 40 CFR 60 Subpart IIII is an applicable requirement for the black-start diesel engine generator pursuant to 40 CFR 63 Subpart ZZZZ, §63.6590, the applicable requirements are as follows:

Pursuant to §60.4204(b), “owners and operators of 2007 model year and later non-emergency stationary compression-ignition internal combustion engine (CI ICE) with a displacement of of less than 30 liters per cylinder must comply with the emission standards for new CI engines in §60.4201 for their 2007 model year and later stationary CI ICE, as applicable.”

§60.4201(a) states: “Stationary CI internal combustion engine manufacturers must certify their 2007 model year and later non-emergency stationary CI ICE with a maximum engine power less than or equal to 2,237 kilowatt (KW) (3,000 horsepower (HP)) and a displacement of less than 10 liters per cylinder to the certification emission standards for new nonroad CI engines in

40 CFR 89.112, 40 CFR 89.113, 40 CFR 1039.101, 40 CFR 1039.102, 40 CFR 1039.104, 40 CFR 1039.105, 40 CFR 1039.107, and 40 CFR 1039.115, as applicable, for all pollutants, for the same model year and maximum engine power.

However, pursuant to §60.4211:

(a) If you are an owner or operator and must comply with the emission standards specified in this subpart, you must operate and maintain the stationary CI internal combustion engine and control device according to the manufacturer's written instructions or procedures developed by the owner or operator that are approved by the engine manufacturer. In addition, owners and operators may only change those settings that are permitted by the manufacturer. You must also meet the requirements of 40 CFR parts 89, 94 and/or 1068, as they apply to you.

(c) If you are an owner or operator of a 2007 model year and later stationary CI internal combustion engine and must comply with the emission standards specified in §60.4204(b) or §60.4205(b), or if you are an owner or operator of a CI fire pump engine that is manufactured during or after the model year that applies to your fire pump engine power rating in table 3 to this subpart and must comply with the emission standards specified in §60.4205(c), you must comply by purchasing an engine certified to the emission standards in §60.4204(b), or §60.4205(b) or (c), as applicable, for the same model year and maximum (or in the case of fire pumps, NFPA nameplate) engine power. The engine must be installed and configured according to the manufacturer's specifications.

Since the black-start generator is subject to the emission standards specified in §60.4204(b), conditions will be added to the permit to require that the engine purchased must be certified to the emission standards in §60.4204(b), and that the engine be installed and configured according to the manufacturers specifications.

Non-applicable Requirements

40 CFR 60 Subpart EEEE, *Standards of Performance for Other Solid Waste Incineration Units for Which Construction is Commenced After December 9, 2004 or for Which Modification is Commenced on or After June 16, 2006*

Exemption determination:
Pursuant to 40 CFR §60.2885, other solid waste incineration units are either very small municipal waste combustors or institutional waste incineration units as defined in §60.2977.

Pursuant to §60.2977, the following definitions are used for this subpart:

Institutional waste incineration unit means any combustion unit that combusts institutional waste (as defined in this subpart) and is a distinct operating unit of the institutional facility that generated the waste. Institutional waste incineration units include field-erected, modular, cyclonic burn barrel, and custom built incineration units operating with starved or excess air, and any air curtain incinerator that is a distinct operating unit of the institutional facility that generated the institutional waste (except those air curtain incinerators listed in §60.2888(b)).

Institutional waste means solid waste (as defined in this subpart) that is combusted at any institutional facility using controlled flame combustion in an enclosed, distinct operating unit: whose design does not provide for energy recovery (as defined in this subpart); operated without energy recovery (as defined in this subpart); or operated with only waste heat recovery

(as defined in this subpart). Institutional waste also means solid waste (as defined in this subpart) combusted on site in an air curtain incinerator that is a distinct operating unit of any institutional facility.

Very small municipal waste combustion unit means any municipal waste combustion unit that has the capacity to combust less than 35 tons per day of municipal solid waste or refuse-derived fuel, as determined by the calculations in §60.2975.

The waste used by Honua is combusted using controlled flame combustion in an enclosed, distinct operating unit, but the design includes both energy recovery and waste heat recovery. Therefore, the waste combusted by Honua is not "industrial waste." If the waste isn't "industrial waste" then the unit in question is not a "industrial waste incineration unit" because is doesn't process industrial waste. Also, the capacity of the unit is greater than 35 tons per day, so it is not a "very small municipal waste combustion unit.

Since the unit is not a "very small municipal waste combustion unit" or an "industrial waste "industrial waste incineration unit," it is not classified as an "other solid waste incineration unit."

Subpart AAAA—Standards of Performance for Small Municipal Waste Combustion Units for Which Construction is Commenced After August 30, 1999 or for Which Modification or Reconstruction is Commenced After June 6, 2001

Exemption determination:
If the unit is assumed to be a "municipal waste combustion unit," then Subpart AAAA is an applicable requirement pursuant to 40 CFR §60.1010. The section states that subpart AAAA is an applicable requirement it the municipal waste combustion unit is new, and has a capacity to combust between 35 and 250 tons of fuel per day.

The proposed unit has a capacity (250 tons/day) between 35 and 250 tons per day, but is not classified as a "municipal waste combustion unit." However pursuant to §60.1465, the following definitions apply:

Municipal solid waste or municipal-type solid waste means household, commercial/retail, or institutional waste. Household waste includes material discarded by residential dwellings, hotels, motels, and other similar permanent or temporary housing. Commercial/retail waste includes material discarded by stores, offices, restaurants, warehouses, nonmanufacturing activities at industrial facilities, and other similar establishments or facilities. Institutional waste includes materials discarded by schools, by hospitals (nonmedical), by nonmanufacturing activities at prisons and government facilities, and other similar establishments or facilities. Household, commercial/retail, and institutional waste does include yard waste and refuse-derived fuel. Household, commercial/retail, and institutional waste does not include used oil; sewage sludge; wood pallets; construction, renovation, and demolition wastes (which include railroad ties and telephone poles); clean wood; industrial process or manufacturing wastes; medical waste; or motor vehicles (including motor vehicle parts or vehicle fluff).

Since construction, renovation and demolition wastes and medical waste are not classified as municipal solid waste, the facility is not subject to the requirements.

Subpart Ec—Standards of Performance for Hospital/Medical/Infectious Waste Incinerators for Which Construction is Commenced After June 20, 1996

The unit is subject to the standard since medical waste is to be processed and pursuant to the definition in 40 CFR §60.51c, which states:

Hospital/medical/infectious waste incinerator or *HMIWI* or *HMIWI unit* means any device that combusts any amount of hospital waste and/or medical/infectious waste.

While the unit is considered to be a HMIWI unit pursuant to the definition, it is also classified as a pyrolysis unit, which is defined in §60.51c as:

Pyrolysis means the endothermic gasification of hospital waste and/or medical/infectious waste using external energy.

Pursuant to §60.50c(f), any pyrolysis unit is not subject to this subpart. Therefore, the equipment is exempt from the requirements of 40 CFR part 60 subpart Ec.

CONSOLIDATED EMISSIONS REPORTING RULE (CERR):
Consolidated Emissions Reporting Rule (CERR) is not an applicable requirement because annual emissions from the facility do not exceed the minimum than reporting levels for a Type B source pursuant to 40, CFR 51, Subpart A (see following table)

CERR Reporting Requirements

Pollutant	Facility Emissions (tpy)	CERR Triggering Levels (tpy)		Internal Reporting Threshold (tpy)
		1-yr Reporting Cycle (Type A Sources)	3-yr Reporting Cycle (Type B Sources)	
VOC	1.71	≥ 250	≥ 100	≥ 25
PM_{10}	25.14	≥ 250	≥ 100	≥ 25
$PM_{2.5}$	10.75	≥ 250	≥ 100	≥ 25
NO_x	79.06	≥ 2,500	≥ 100	≥ 25
SO_x	40.94	≥ 2,500	≥ 100	≥ 25
CO	42.94	≥ 2,500	≥ 1,000	≥ 250
HAPs (total)	11.04	n/a	n/a	≥ 5

PREVENTION OF SIGNIFICANT DETERIORATION (PSD):
PSD applies to new stationary sources in an attainment area which emit or have the potential to emit 250 TPY (or 100 TPY for 28 named source categories) of any regulated pollutant, to a major stationary source making a major modification involving a significant net emissions increase (e.g., 15 tons per year PM_{10} [HAR 11-60.1-1]), or to a non-major source undergoing a modification that is major by itself. The proposed facility does not have a pollutant that exceeds 100 tons per year, 10 tons of any individual HAP or 25 tons total HAPs, so PSD does not apply

BEST AVAILABLE CONTROL TECHNOLOGY (BACT):
Pursuant to HAR §11-60.1-81(14), the application of BACT is required for all pollutants that have the potential to emit or increase emissions above significant amounts considering any limitations, enforceable by the director, on the covered source to emit a pollutant.

To determine what constitutes a significant amount, refer to the definition of "significant" listed in HAR §11-60.1-1. Pursuant to the definition, a "significant: amount is a rate of emissions that would equal or exceed an of the following pollutant and emission rates:

Pollutant	Significant Level (tpy)	Calculated Emissions (tpy)
Carbon Monoxide	100	42.94
Nitrogen Oxides	40	79.06
Sulfur dioxide	40	40.94
Particulate matter	A total of 25 tpy(PM) or 15 tpy (PM_{10})	25.14 (PM_{10})
Ozone	40 of VOC	1.71
Lead	0.6	2.06
Asbestos	0.007	0
Beryllium	0.0004	0
Mercury	0.1	2.61E-03
Vinyl Chloride	1	0
Fluorides	3	0
Sulfuric acid mist	7	0
Total reduced sulfur	10	0
Reduced sulfur compounds	10	0

For the proposed project, the applicant has provided a BACT determination for NO_x and SO_2 and lead. An BACT analysis was not submitted for particulate matter since PM emissions are being controlled with baghouses, and baghouses are considered as BACT for particulate matter.

To determine BACT for NO_x and SO_2, a top-down analysis was performed. A top-down BACT analysis evaluates the technical feasibility of available emission control technologies, beginning with the control technologies which result in the greatest emission reductions. The technically feasible alternatives are then examined for economic feasibility by comparing the costs of the alternatives to the base case. The control technologies considered include all potentially applicable technologies available today, including emerging technologies, to determine technical feasibility for installation. BACT requirements specify that each control alternative is to be reviewed in the context of environmental , energy and economic impacts.

The BACT for lead was determined to be a baghouse. No other lead control was addressed by the applicant.

<u>NO_x BACT</u>

Identification of alternative NO_x control technologies.

<u>LNB (low NO_x burners)</u> – control NO_x formation by using staged combustion. LNB designed to reduce turbulence, delay fuel/air mixing, and establish fuel-rich zones for initial combustion. The reduced amount of O_2 in the initial combustion zone inhibits fuel NO_x formation, and the unburned fuel gases mix with excess air it the final combustion zone, reducing temperatures and the formation of thermal NO_x. NO_x removal efficiency varies from 25-85%.

<u>FGR (flue gas recirculation)</u> – recycles a portion of cooled flue gas back into the primary combustion zone. Thermal NO_x formulation is reduced by reducing the peak flame temperature and lowering the O_2 concentration in the primary flame zone. FGR is often combined with LNB for NO_x reduction of 60-99%.

OFA (over fire air) – uses conventional burners to introduce fuel and sub-stoichiometric amounts of combustion (primary) air. The remainder of the combustion air (secondary air) is introduced about 1/3 of the distance down the firebox through over fire air ports. Staging the combustion in this manner results in a lower temperature flame and lower thermal NO_x formation. The sub-stoichiometric with less O_2 and the reduced fuel/air mixing in the combustion region reduces the formation of fuel NO_x. Removal efficiency estimated at 30-60%.

BOOS (burners out of service) – a retrofit NO_x control for existing fireboxes. Fuel flow is diverted from selected burners to the remaining firing burners while air flow is unchanged. This effectively stages combustion, reducing the formation of both fuel and thermal NO_x.

Reburn – Reburn, or staged fuel injection, involves passing the primary combustion zone products through a secondary flame or fuel-rich combustion process. A portion of the fuel is diverted to create the secondary flame or fuel-rich zone downstream of the primary burner. NO_x removal efficiency estimated at 30-60%.

SNCR (selective non-catalytic reduction) – injects urea or ammonia into combustion flue gases. The injection is typically multi-level and automatically controlled to account for boiler load changes and changing gas feed conditions. Flue gas recirculation can be incorporated into the combustion system to maintain the combustion chamber in the required temperature zone for optimum SNCR reaction. Removal efficiency between 25-70%.

SCR (selective catalytic reduction) – injects urea or ammonia into combustion flue gases for mixing prior to passing through a catalyst bed. The flue gases flow into the catalyst bed in the temperature range of 500°F to 750°F. The injection process is automatically controlled to adjust injection rates in response to changing load and gas feed conditions. Efficiency is estimated at 60-90%.

RSCR (regenerative selective catalytic reduction) – This process reheats the post-baghouse flue gas with burners coupled with cycling beds of ceramic heat exchangers. NO_x reduction takes place on a conventional SCR catalyst. Either anhydrous or aqueous ammonia is typically used.

After identifying the possible NO_x control technologies, the technical feasibility for each control device is determined. The applicant states that all options are feasible with the exception of BOOS, since BOOS is used to retrofit existing boilers, not for installation on a new boiler.

The applicant also states that while feasible, both SCR and RCSR have not been used on the this type of plant. In addition, SCR is not feasible since the SCR catalyst would be poisoned by the presence of metals in the flue gas prior to the baghouse. A ranking of the technically feasible alternatives is listed in the following table:

Control Alternative	NO_x removal efficiency
Low NO_x burners (LNB) with FGR	60-90%
RSCR	60-75%
SNCR	25-70%
Reburn	35-60%

NO_x BACT selection:
It has been determined that a combination of LNB-FGR-SNCR will be used as BACT for NO_x. RSCR was rejected as an alternative because both the average cost effectiveness and energy impacts are more than three times that of the selected method, and the incremental cost effectiveness if $88,000 for ton of NO_x removed. Refer to the following table for a summary of the economic, energy and environmental impacts of technically feasible NO_x control systems.

Control Alternative	LNB-RSCR	CT-LNB-FGR-SNCR	Uncontrolled
NO_x emissions (TPY)	40	74	338
NO_x emissions removed	298	264	0
lb/hr	9.1	17.0	77.2
Removal efficiency (%)	88.2	78.0	n/a
Installed capital cost addition[1] ($)	4,099,805	2,031,508	0
Total addition annualized cost[2] ($)	3,800,153	1,019,491	0
Average cost effectiveness[3] ($/T)	12,750	3,866	0
Incremental cost effectiveness[4] ($/T)	80,898	3,866	0
Energy impact (MMBtu/yr)	43,247	13,434	
Environmental impact (toxics)	Y	Y	
Environmental impact (other)	N	N	

Notes:
1. Installed capital cost addition relative to uncontrolled baseline.
2. Total additional annualized cost (capital, direct, indirect) of purchasing, installing and operating the control alternative.
3. Average cost effectiveness over baseline is equal to annualized cost divided by the difference in emissions between the control alternative and the uncontrolled baseline.
4. Incremental cost effectiveness is the same as the average cost effectiveness except that the control alternative is considered relative to the next most stringent alternative rather than the uncontrolled baseline.

SO_2 BACT Determination

Identification of SO_2 control technologies:

Wet Scrubber – Wet scrubber systems employ alkaline slurries as the SO_2 absorbent and typically contain lime (calcium oxide) or limestone although a more effective (but more expensive) sodium-based alkali such as sodium hydroxide, carbonate, or bicarbonate may also be used. Flue gas is ducted into a chamber where the aqueous alkaline slurry is injected into the flue gas. Smaller systems can enhanced by the presence of various shaped packing materials or plates/trays in the chamber which increase mixing of gas and slurry. Removal efficiencies range from 80-98%.

Semi-Dry Systems (Spray Dryers) This approach uses a calcium or sodium based alkaline slurry, which is injected into the flue gas at a higher concentration than in a wet scrubber slurry. The aqueous solution is injected through rotary atomizers or dual-fluid nozzles to create a fine droplet spray. Water from the slurry evaporates as it mixes with the flue gas, while the remaining water in the solid sorbent enhances the reaction with the SO_2, and a dry waste product is created which can be collected by a baghouse or electrostatic precipitator. Typical control efficiency is 80-90%.

Dry Systems: Dry systems pneumatically inject dry sorbent directly into the furnace, economizer or downstream ductwork. Injection of water downstream of the sorbent injection enhances SO_2 collection. Calcium based sorbents achieve 50-60% removal, while sodium based sorbents can reach 80% removal.

After identifying the possible control options, the technical feasibility of the options is determined. The applicant states that all technologies are technically feasible, although size limitations may make it problematic to use a wet or semi-dry system. A ranking of the feasible alternatives is presented in the following table:

Control Alternative	SO_2 Removal Efficiency
Wet Scrubber	80-98%
Semi-dry System	80-90%
Dry System	80-90%

SO_2 BACT Selection

A dry scrubber system was selected as BACT for SO_2. A dry scrubber system was selected since it is the most cost effective means of SO_2 removal. The following table presents a summary of the economic, energy, and environmental impacts of the technically feasible SO_2 control systems. The use of a wet scrubber for SO_2 control will cause a 3-fold increase in cost effectiveness and increase energy consumption. Use of a wet scrubbing system will also consume 8.78 million gallons of potable water, of which 2.52 million gallons would contain collected sulfates and chlorides and require proper disposal. The additional space requirements for a wet scrubber would also be an issue due to the size of the property.

Control Alternative	Wet Scrubber (polishing)[5]	Wet Scrubber (Total Control)	Semi-Dry Scrubber	Dry Scrubber	Uncontrolled
SO_2 emissions (TPY)	3.9	25.8	67	77	516
SO_2 emissions removed (T/yr)	74	490	449	439	0
SO_2 emissions removed (lb/hr)	0.88	5.89	15.3	17.7	117.9
Removal efficiency (%)	95	95	87	85	
Installed capital cost addition[1] ($)	4,505,902	4,521,707	4,060,462	296,672	
Total addition annualized cost[2] ($)	856,812	1,042,692	946,218	260,891	
Average cost effectiveness[3] ($/T)	11,646.79	2,125.91	2,106.61	594.50	
Incremental cost effectiveness[4] ($/T)	8,100	2,336	66,371	595	
Energy impact (MMBtu/yr)	8,621	8,620	1,810	0	
Environmental impact (toxics)	N	N	N	N	
Environmental impact (other)	Y	Y	N	N	

Notes:

1. Installed capital cost addition relative to uncontrolled baseline.
2. Total additional annualized cost (capital, direct, indirect) of purchasing, installing and operating the control alternative.
3. Average cost effectiveness over baseline is equal to annualized cost divided by the difference in emissions between the control alternative and the uncontrolled baseline.
4. Incremental cost effectiveness is the same as the average cost effectiveness except that the control alternative is considered relative to the next most stringent alternative rather than the uncontrolled baseline.
5. SO_2 "polishing" after dry scrubber and baghouse (BH) since carbon injection and BH are system requirements.

INSIGNIFICANT ACTIVITIES

Insignificant activities at the facility consist of a rental diesel engine generator to be used during annual maintenance. Since the specifics of the rental DEG are not known, the rental DEG will be handled as an alternate operating scenario. In order for the operating scenario to be approved, the permittee will be required to submit emission calculations that verify the emissions of the actual DEG used are insignificant, and that the DEG emissions have been certified by the manufacturer pursuant to Federal New Source Performance Standards.

PROPOSED

EMISSION CALCULATIONS

Emissions from the facility originate from the following sources

- Gasifier-Boiler Combustion Unit
- Black Start Diesel Engine Generator
- Baghouses servicing the receiving area

To calculate emissions from the gasifier-boiler, emission factors were derived by using data from a source performance test on a similar but smaller gasification unit and adding a safety factor of twenty percent. The factors derived and used to determine the gasifier-boiler emissions were as follows:

Pollutant	Emission Rate (lb/hr)	Reference
PM	0.1	40 CFR §60.43c(e)(1)[A]
PM_{10}	3.82E-02	Source Performance Test
SO_2	9.16E-02	Source Performance Test
NO_x	1.72E-01	Source Performance Test
As	1.11E-03	Source Performance Test
Pb	4.76E-03	Source Performance Test
Cd	1.83E-05	Source Performance Test
Cr	4.87E-06	Source Performance Test
Hg	6.03E-06	Source Performance Test
HCl	1.96E-02	Source Performance Test
Total Dioxins	4.89E-09	Source Performance Test
Dioxin TEQ	8.69E-11	Source Performance Test
Total PCB	6.08E-08	Source Performance Test

[A] emissions limit of 0.03 lb/MMBtu converted to lb/hr.

It should be noted that the particulate matter emission limit is required pursuant to 40 CFR §60.43c(e)(1). Although the emission limit for PM_{10} is greater than the emission limit for particulate matter, the particulate matter emission limit remains due to the fact that demonstrating compliance with the PM_{10} emissions limit will not guarantee compliance with the PM emission limit.

Due to the fact that non-standard emission factors were used in determining project emissions, The aforementioned emission factors will be incorporated into the covered source permit as emission limits. Compliance with the emission limits will be demonstrated by conducting annual performance testing on the gasifier-boiler unit, and with the monitoring of NO_x and SO_2l with a continuous emissions monitoring system (CEMS). It should also be noted that the permittee has agreed to a permit condition which states that an exceedance of SO_2 limit is also an exceedance or HCl emission limit

Since the permittee is requesting approval to use propane as a backup fuel, the gram per second pollutant emission rates for syngas and propane are compared to determine the worst-case emissions scenario. A comparison of the emission rate is shown in the following table:

Fuel rate	546.4	gallons per hour
Hours of Operation	8760	hours per year
Sulfur Content	15	grains per hundred cubic feet (as

Pollutant	Emission Factor (lb/kgal)	Emission Rate (lb/hr)	Emission Rate (g/s)
NOx	13	7.10	0.90
SO2	1.5	0.82	0.10
CO	7.5	4.10	0.52

The comparison of emission rates shows that all of the emission rates when firing syngas are higher than when firing propane. Therefore, to determine worst-case emissions and compliance with ambient air quality standards, it is assumed that boiler will be fired entirely by syngas. Emissions from the gasifier-boiler are shown in the following table:

Gasifier – Boiler Emissions

Process Rate =	230	tons/day
	9.5833	tons/hour
	83,950	tons/year

Pollutant	Emission Rate (lb/ton)	Uncontrolled Emissions (tpy)	Control Efficiency (%)	Controlled Emissions (tpy)	Controlled Emission Rate (lb/hr)
PM_{10}	13.16	552.39	97	16.57	3.78
$PM_{2.5}$	7.50	314.81	97	9.44	2.16
SO_2	6.75	283.33	86	39.67	9.06
NO_x	8.05	337.90	78	74.34	16.97
As	0.11	4.62	90	0.46	0.11
Pb	0.66	27.70	92.6	2.05	0.47
Cd	0.0019	0.08	90	0.008	0.0018
Cr	0.0419	1.76	99.88	0.002	0.0005
Hg	0.00062	0.03	90	0.00300	0.00068
HCl	3.11	130.54	93.5	8.49	1.94
Total Dioxins	3.36E-06	0.00014	98.5	0.0000021	0.0000005
Dioxin TEQ	6.40E-08	0.0000027	98.6	0.0000000	0.0000000
Total PCB	2.51E-06	0.000105	75	0.0000263	0.0000060
CO[1]	N/A	N/A	0	42.05	9.6
VOC	4.06E-02	1.70	0	1.70	0.39

Notes:
CO emission rate converted from 100 ppm emission rate guaranteed by vendor.

Emissions from the black start DEG were determined using AP-42, section 3.4, "Large Stationary Diesel and All Stationary Dual-Fuel Engines," with the exception of NO_x, CO, VOC, and PM emission factors, which were obtained from manufacturer's information. The black start DEG emissions are as follows:

Black-start Diesel Engine Generator Emissions

Engine Horsepower	1,474	hp
Max. Fuel Rate	72	gal/hr
Operating Hours	500	hr/yr
Fuel Heating Value	140,000	BTU/gal
Maximum Heat Input	0.74	MMBtu/hr

Pollutant	Emission Factor[A] (lb/MMBtu)	Emissions			
		(lb/hr)	(g/s)	Max (tpy)	Limited (tpy)
SO_2	0.51	5.14	0.6477	22.52	1.29
NO_x	1.8611	18.76	2.3637	82.18	4.69
CO	0.3343	3.37	0.4248	14.76	0.84
TOC	0.004	0.04	0.005	0.18	0.01
PM_{10}	0.0099	0.1	0.0126	0.44	0.03
HAPs					
Benzene	7.76E-04	7.82E-03	9.86E-04	3.43E-02	1.96E-03
Toluene	2.81E-04	2.83E-03	3.57E-04	1.24E-02	7.08E-04
Xylenes	1.93E-04	1.95E-03	2.45E-04	8.52E-03	4.88E-04
Propylene	2.79E-05	2.81E-02	3.54E-03	1.23E-01	7.03E-03
Formaldehyde	7.89E-05	7.95E-04	1.00E-04	3.48E-03	1.99E-04
Acetaldehyde	2.52E-05	2.54E-04	3.20E-05	1.11E-03	6.35E-05
Acrolein	7.88E-06	7.94E-05	1.00E-05	3.48E-04	1.99E-05
			Total HAPS	0.18	0.01

Baghouse emissions were calculated using airflow and emission specifications provided by the baghouse manufacturer. Baghouses are located at the feedstock receiving area, char removal area, construction and demolition (C & D) feedstock silo, tire feedstock silo, and char silo. Emissions are summarized in the following table, Refer to attachments for detailed baghouse emission calculations.

Area	Emissions (tpy)	
	PM_{10}	$PM_{2.5}$
Receiving	7.5	1.12
Char Removal	1.02	0.15
C & D Feedstock	1.74E-02	2.61E-03
Tire Feedstock	6.87E-04	1.03E-04
Char Silo	1.41E-03	2.11E-04
Total	8.54	1.27

The total emissions from the facility is as follows:

Pollutant	Emissions (TPY)			
	Gasifier	Blackstart DEG	Baghouses	Total
PM10	16.58	0.03	8.54	25.14
PM25	9.44	0.02	1.28	10.75
SO2	39.65	1.29	no data	40.94
NOx	74.37	4.69	no data	79.06
CO	42.10	0.84	no data	42.94
TOC	1.70	0.01	no data	1.71
HAPs				
As	0.46	no data	no data	0.46
Pb	2.06	no data	no data	2.06
Cd	0.01	no data	no data	0.01
Hg	2.61E-03	no data	no data	2.61E-03
HCl	8.49	no data	no data	8.49
Dioxin	2.12E-06	no data	no data	2.12E-06
BENZENE	no data	1.96E-03	no data	1.96E-03
TOLUENE	no data	7.08E-04	no data	7.08E-04
XYLENES	no data	4.86E-04	no data	4.86E-04
PROPYLENE	no data	7.03E-03	no data	7.03E-03
FORMALDEHYDE	no data	1.99E-04	no data	1.99E-04
ACETALDEHYDE	no data	6.35E-05	no data	6.35E-05
ACROLEIN	no data	1.99E-05	no data	1.99E-05
			Total HAPs	11.04

AIR QUALITY ASSESSMENT:
An ambient air quality assessment was performed to demonstrate that the facility is in compliance with State and Federal ambient air quality standards (AAQS).

To demonstrate compliance with State and Federal AAQS, the EPA-approved AERMOD modeling program was used. Two separate sets of runs were done to account for the different fuels that are allowed for use in the boiler. The first set of modeling runs assumes the boiler is fired with syngas, while the second set of runs assumes the boiler is fired with propane. In both sets of modeling runs the diesel engine generator is fired with diesel fuel.

The stack parameters used in both sets of runs are identical and are as follows:

Air Modeling Source Parameters							
Source ID	Location			Stack Parameters			
	Elevation (m)	East (m)	North (m)	Height (1) (m)	Temperature (K)	Diameter(2) (m)	Exit Velocity (2) (m/sec)
BH	2	593,290	2,355,739	24.384	450	1.220	18.02
GEN1	2	593,231	2,355,702	22.860	752	0.254	75.72

Meteorological data for one year was obtained from the AES Barbers Point facility, and USGS DEM data for the Ewa quadrangle was used. A total of 1,296 receptors spaced at thirty meter intervals around the plant was used. The program used the following emission rates:

AirMod Emission Rate Parameters – Boiler w/Syngas (g/s)						
Source	**SO_2**	**NO_x[1]**	**CO**	**PM_{10}**	**$PM_{2.5}$**	**Pb**
BH	1.407	2.4431	1.211	0.047	0.273	0.08
GEN1	0.0641	0.1046	0.099	0.01524	0.014	N/A
[1] Annual NO_x emission rate of 2.4431 (500/8760)= 0.1394 used in model, due to 500 hour annual limit						

The predicted air impacts as determined by AirMod are:

AMBIENT AIR QUALITY IMPACT ANALYSIS

Pollutant	Averaging Period	CONCENTRATION, µg/m³ (ppm)				% of std.
		Conc.	Background [b]	Total	Std[2]	
NO_x	1-hr	92.3 (0.0491)	56.4 (0.030)	148.7 (0.0791)	188 (0.1)	79.10
	Annual	3.83 (0.002)	8 (0.0043)	11.83 (0.0063)	70 (0.0372)	16.90
SO_2	1-hr	7.8 (0.003)	17 (0.0065)	24.8 (0.0095)	75 (0.0287)	33.07
	3-Hour	18.02 (0.0069)	24 (0.0092)	42.02 (0.0161)	1,300 (0.0498)	3.23
	24-Hour	8.30 (0.0032)	13 (0.005)	21.3 (0.0082)	365 (0.1398)	5.84
	Annual	1.99 (0.0008)	3 (0.0011)	4.99 (0.0019)	80 (0.0307)	6.24
PM_{10}[a,]	24-Hour	3.33	61	64.33	150	42.89
	Annual	0.768	18	18.768	50	37.54
PM_{25}	24-Hour	1.96	21	22.96	65	35.32
	Annual	0.463	4.9	5.363	15	35.75
CO	1-hour	25.57 (22.33)	2,517 (2,198)	2,542.57 (2,221)	10,000 (8,734)	25.40
	8-hour	13.41 (11.71)	801 (700)	814.41 (711.3)	5,000 (4,367)	16.29
Pb	Rolling 3-month	0.13	N/A	0.13	0.15	86.67
HCl	8-hr	3.3	N/A	3.3	70	4.71
	Annual	0.35	N/A	0.36	16.7	2.16
Hg	8-hr	1.03E-03	N/A	1.03E-03	0.24	0.43
	Annual	1.06E-04	N/A	1.06E-04	1	0.01
As	8-hr	0.2	N/A	0.2	5	4.00
	Annual	0.02	N/A	0.02	1.19	1.68
Cd	8-hr	3.13E-03	N/A	3.13E-03	0.025	12.52
	Annual	3.23E-04	N/A	3.23E-04	5.95E-03	5.43

[a] assumes all particulate is PM_{10}
[b] Background levels obtained from Kapolei monitoring station, 2008.

Ambient levels for lead were determined by obtaining the monthly lead concentrations, then sorting by receptor, date and monthly concentrations to identify the highest rolling 3-month average.

The one hour NO_x ambient air concentration was determined by running AERMOD with the ozone limiting method enabled. To identify the highest of the 8th highest NO_2 value, 1-hour NO_x concentrations were determined for each hour at each receptor. The values were then sorted by receptor and NO_2 value to determine the highest of the 8th highest NO_x value.

Compliance with the one hour SO_2 ambient air concentration is attained when the 3-year average of the 99th-percentile of the annual distribution of the daily maximum 1-hour concentrations does not exceed 75 parts per billion (ppb) at each monitor within an area.. This is done by determining the fourth highest modeled concentration at each receptor and using the highest value. The values obtained for the 1-hour NO_x and SO_2 concentrations, along with the location of each receptor is shown in the following table:

Pollutant	Receptor location (m, NAD-83)	Concentration (µg/m^3)	Conversion Factor (µg/m^3 to ppb)	Concentration, ppb
NO_x (1-hour)	595,035 E, 2,355,665 N	92.4	0.5319	49.1
SO_2 (1-hour)	593,045 E, 2,355,685 N	20.36	0.3823	7.8

To demonstrate that non-carcinogenic HAP emissions will not result in, or contribute to, any significant ambient air concentrations as defined in HAR §11-60.1-179(c), the modeled ambient air concentration for each HAP is compared to 1/100 of its threshold limit value-time weighted average (TLV-TWA) for 8-hour ambient concentrations and 1/420 of its TLV-TWA for annual ambient air concentrations. The results, exhibited in the previous table, demonstrate that each HAP does not exceed the 8-hour or annual standard when compared to their individual adjusted TLV-TWA.

To determine if carcinogenic HAP emissions result in or contribute to any significant ambient air concentration, modeled carcinogenic HAP ambient air concentrations were compared to EPA Region 9 Regional Screening Levels (RSL) for Residential Air. RSL's are chemical concentrations that correspond to fixed levels of risk, and are extremely conservative. EPA Region 9 RSL's are chemical concentrations in air that correspond to a one in a million cancer risk or a non-carcinogenic hazard quotient of 1. The PRG's are used to screen out chemicals which are at such low levels that adverse health effects would not be expected even in the most sensitive individuals if they were exposed for a lifetime. Exceeding a screening level does not automatically indicate that a chemical is present at levels that may pose a health risk.

As shown in the following table, no carcinogenic HAP exceeded the residential RSL's for air. The cancer risk from exposure to air emissions from the facility is 1.20×10^{-7}. This does not exceed Hawaii Administrative Rules cancer risk level of 1×10^{-5} for air and is less than EPA's acceptable cancer risk range of 10^{-4} to 10^{-6}. These results indicate that exposure to emissions from the facility should not pose a significant health risk even from long-term exposure. For detailed calculations, refer to the attached emission calculations.

Risk Summary Analysis	
Risk Estimate	**Allowable Limit**
1.20E-07	1.00E-06

PROPOSED

CONCLUSION:
The operation of the facility does not violate State or Federal Ambient Air Quality Standards. Recommend approval of permit subject to 30 day public comment period and EPA 45-day review.

Kevin Kihara
October 20, 2010