PERMIT APPLICATION REVIEW
GREENHOUSE GAS (GHG) EMISSIONS REDUCTION PLAN (ERP)
Covered Source Permit (CSP) No. 0214-01-C
Application for Significant Permit Modification No. 0214-10

Applicant: Kalaeloa Partners, L.P.
Facility: Kalaeloa Cogeneration Plant
Located At: 91-111 Kalaeloa Boulevard, Kapolei, Hawaii 96707

Mailing Address: 91-111 Kalaeloa Boulevard, Kapolei, Hawaii 96707

Responsible Official: Mr. Jeff Walsh, MBA
General Manager
Kalaeloa Partners, L.P.
(808) 682-5288

Greenhouse Gas (GHG) Emissions Reduction Plan (ERP)
Prepared by: G.E. Power, Power Services
91-111 Kalaeloa Boulevard, Kapolei, Hawaii 96707

Contact: Mr. Michael Rossio
Plant Manager
GE Power, Power Services
(808) 682-5344

Proposed Project

The Standard Industrial Classification (SIC) Code is 4911 - Electric Services

Kalaeloa Partners, L.P (KPLP) submitted an application for significant modification to CSP No. 0214-01-C for the Kalaeloa Cogeneration Plant (KCP) to incorporate GHG emission caps established by KPLP in its GHG emissions reduction plan. In summary, the KPLP's GHG emission reduction plan is proposing to:

1. Establish a total combined cap on carbon dioxide equivalent (CO_2e) emissions emitted by the KCP and partnering facilities of 6,371,392 metric tons (7,023,258 short tons) per calendar year (CY) pursuant to Hawaii Administrative Rule (HAR) §11-60.1-204(b) and (c) and §11-60.1-204(d)(6)(A);
2. Establish an individual facility-wide cap of 1,094,813 short tons per CY (993,198 metric tons per CY) pursuant to HAR §11-60.1-204(b) and (c) and §11-60.1-204(d)(6)(A);
3. Add provisions that enable the transfer of GHG emissions allowances between partnering facilities, and vice versa that will allow individual facility-wide caps on CO_2e emissions to be exceeded as long as the total combined cap among partnering facilities is met; and
4. Use CY 2009 as an alternate baseline year to CY 2010 in accordance with HAR §11-60.1-204(d)(1) for establishing KCP's GHG emissions baseline rate.

In addition to the above requested permit revisions, KPLP is also requesting a minor modification to Attachment II, Special Condition No. C.1.c.iii, to increase the amount of specification used oil fired by the combustion turbines from 10,000 gallons per year to 20,000 gallons per year. This modification is considered a minor modification since it:

(1) Does not increase the emissions of any air pollutant above the permitted emission limits;
(2) Does not result in or increase the emissions of any air pollutant not limited by permit to levels equal to or above:

    (a) Five hundred (500) pounds per year of a hazardous air pollutant (HAP), except lead;
    (b) Three hundred (300) pounds per year of lead;
    (c) Twenty-five percent (25%) of significant amounts of emission as defined in Section 11-60.1-1, paragraph (1) in the definition of "significant"; or
    (d) Two (2) tons per year of each regulated air pollutant not already identified above.

(3) Does not violate any applicable requirement;
(4) Does not involve significant changes to existing monitoring requirements or any relaxation or significant change to existing reporting or recordkeeping requirements in the permit. Any change to the existing monitoring, reporting, or recordkeeping requirements that reduces the enforceability of the permit is considered a significant change;
(5) Does not require or change a case-by-case determination of an emission limitation or other standard, a source-specific determination for temporary sources of ambient impacts, or a visibility or increment analysis;
(6) Does not seek to establish or change a permit term or condition for which there is no corresponding underlying applicable requirement, and that the source has assumed to avoid an applicable requirement to which the source would otherwise be subject. Such terms and conditions include:

    (a) A federally enforceable emissions cap assumed to avoid classification as a modification pursuant to any provision of Title I of the Act or subchapter 7; and
    (b) An alternative emissions limit approved pursuant to regulations promulgated pursuant to Section 112(i)(5) of the Act or Subchapter 9.

(7) Is not a modification pursuant to any provision of Title I of the Act.

Department of Health's (DOH) approval

Implementation of KPLP's GHG emissions reduction plan in accordance with HAR §11-60.1-204 and §11-60.1-205, respectively, requires the DOH's approval for the following proposals:

1. Establish "*facility-wide GHG emissions cap*"[1] and associated provisions pursuant to HAR §11-60.1-204(b) and §11-60.1-205;
2. Establish a control strategy involving partnering with other facilities pursuant to HAR §11-60.1-204(d)(6)(A) and §11-60.1-205(b)(5)(D)(iii); and
3. Use an alternate baseline year pursuant to HAR §11-60.1-204(d)(1) and §11-60.1-205(b)(5)(D)(i).

[1]**Facility-wide GHG emissions cap is defined in HAR §11-60.1-202 as a permit emissions limitation, applicable to a covered source. It may also be defined as an approved combined GHG emissions cap applicable to multiple covered source permits used as a control strategy to leverage emission reductions among partnering facilities as described in HAR §11-60.1-204(d)(6)(A). The entire source's annual non-biogenic greenhouse gas, and biogenic nitrous oxide and methane emissions will be subject to the permit emissions limitation.**

Permitted Equipment Subject to GHG Emissions Cap

The following permitted equipment is subject to GHG emission reductions specified in Subchapter 11 of the Hawaii Administrative Rules (HAR):

Unit No.	Equipment Description
CT1	Combustion Turbine Generator with evaporative cooling module, max production rated at 900 MMBtu/hr, 86 Megawatts (MW) at 76°F, manufactured by ABB, type GT11N with GT 11NM upgrade (refer to 2004 CSP modification application review no. 0214-05), typical fuel Low Sulfur Fuel Oil (LSFO) No. 6, diesel during start-up and shutdown.
CT2	Combustion Turbine Generator with evaporative cooling module, max production rated at 900 MMBtu/hr, 86 MW at 76°F, manufactured by ABB, type GT 11N with GT 11 NM upgrade (refer to 2004 CSP modification application review no. 0214-05), typical fuel LSFO no. 6, diesel during start-up and shutdown.

Permitted Equipment Not Subject to GHG Emissions Cap

Unit No.	Equipment Description [a]
HRSG1	Heat Recovery Steam Generator (HRSG), manufactured by Deltak with a condensate preheater installed in the stack breach (duct) of HRSG1, uses exhaust heat from CT1.
HRSG2	Heat Recovery Steam Generator (HRSG), manufactured by Deltak with a condensate preheater installed in the stack breach (duct) of HRSG2, uses exhaust heat from CT2.
STG1	Steam Turbine Generator, 51.5 MW, manufactured by ABB, type KT, uses steam from heat recovery boilers HRSG1 and HRSG2.
C1	Cooling Tower, 4-cell, mechanical forced draft, maximum design cooling capacity 383 million BTU per hour. Maximum water flow per cell of 523,530 gallons per hour.

[a] **Mandatory GHG reporting pursuant to 40 CFR §98.2(a)(3) applies only to "stationary fuel combustion sources" as defined in 40 CFR §98.30**

Background

KCP is a 223.5 megawatt combined cycle electrical generating facility consisting of two (2) combustion turbines (CTs), two (2) heat recovery steam generators, and a single steam turbine generator, which supplies approximately twenty percent (20%) of Oahu's annual electrical energy needs and approximately nine percent (90%) of steam demand for the neighboring refinery. Fuel combusted in the turbines causes a shaft to spin and generates electricity. Steam is generated using the hot exhaust gas from each turbine in the associated heat recovery turbine. After passing through the heat recovery turbine, exhaust gases are released to the atmosphere. Steam from the heat recovery steam generators is expanded in the steam turbine to generate additional electricity. Steam from the steam turbine generator is either condensed and reused in the facility or sold to the neighboring refinery. Optionally, the steam turbine may be bypassed by routing the steam directly to the refinery.

The operating efficiency of the combustion turbines was improved by a prior modification for installing an evaporative cooling unit for each of the two (2) turbines. The cooling units reduce the temperature thereby increases moisture content of the inlet air, which allows for an increased fuel consumption rate and power output, however, Attachment II Special Condition C.1.c.iv of CSP No. 0214-01-C restricts each CT from exceeding a maximum fuel heat input of 900 MMBtu/hr based on the fuel’s lower heating value (LLHV). *[Source: Refer to the Permit Modification Review for application no. 0214-02].*

The power output of the combustion turbines was previously upgraded from 74.6 MW to 86 MW by replacing the internal blades of each turbine with aerodynamically improved blade design. This modification increased efficiency and power output of the combustion turbines with no increase in fuel consumption or emissions. *[Source: Refer to the Permit Modification Review for application no. 0214-05].* This prior modification will be reviewed and addressed separately in the permit application review for the renewal of CSP No. 0243-01-C.

Other minor modifications were previously made, which resulted in no significant increase in emissions.

Plant operation can vary considerably depending how plants are dispatched by Hawaiian Electric Company (HECO) Management System. Either one or both CT’s may operate at a range of 45 to 75 MW. As a minimum, one unit is always in continuous operation unless there is a shutdown due to malfunction or maintenance. The cogeneration plant is designed for base-loaded operation and does not provide peak loading of the combustion turbines.

For meeting the GHG emission reductions, KPLP is proposing to partner KCP with ten (10) HECO facilities and two (2) other independent power producers (IPPs) to allow flexibility in dispatching units to generate power.

Permits issued to the Hawaiian Electric Companies will reference GHG emission caps specified in CSP No. 0548-01-C for Campbell Industrial Park Generating Station as the main permit for specifying each individual partnering facility and total combined GHG emissions limits.
This will enable the modification of a single permit if the GHG emission caps need to be revised and reduce the burden of modifying all Hawaiian Electric Companies’ permits had the caps been incorporated separately into each facility’s permit.

The IPPs will be issued a separate permit specifying individual and total combine GHG emission caps established for the partnering facilities. Any GHG emission cap revision will require each IPP to submit a significant permit modification since emission caps will be incorporated separately into each facility's permit.

An opportunity for public comment on the draft GHG Emissions Reduction Plan and draft permit amendment for the KCP will be provided in accordance with HAR §11-60.1-205.

Air Pollution Control and Monitoring Devices

Nitrogen oxide (NO_X) emissions from the combustion turbines are controlled through the use of water injection at a mass steam to fuel ratio of 1.3 to 1.0, on a one-hour (1-hour) average. Pursuant to the PSD permit conditions, this ratio must be maintained at all times, except for the two (2) hours following start-up and one (1) hour preceding shutdown. The one-hour (1-hour) steam to fuel ratio is monitored by a continuous emissions monitoring system (CEMS).

Emissions of NOx and carbon monoxide (CO) are also monitored with a CEMS. Sulfur dioxide (SO_2) emissions are monitored by using fuel consumption data and the sulfur content of the fuel used. Fuel sulfur content and heat content data are measured and recorded for each new delivery of fuel. Emissions of CO_2e are computed using the Tier 3 method in accordance with 40 CFR Part 98, Subpart C, §98.33, using fuel consumption and fuel sampling data.

Annual stack emissions tests are performed to demonstrate compliance with permit limits for NOx, volatile organic compounds (VOCs), CO, SO_2 and particulate matter at sixty percent (60%), eighty percent (80%), and full capacity.

Particulate emissions from the cooling tower are controlled through the design of the cooling tower which includes a drift eliminator.

Applicable Requirements

State Requirements:

Hawaii Administrative Rules (HAR)
Title 11, Chapter 60.1 Air Pollution Control
Subchapter 1 General Requirements
HAR 11-60.1-1 Definitions
Subchapter 2 General Prohibitions
HAR 11-60.1-31 Applicability
HAR 11-60.1-32 Visible Emissions
HAR 11-60.1-33 Fugitive Dust
HAR 11-60.1-38 Sulfur Oxides from Fuel Combustion
HAR 11-60.1-39 Storage of Volatile Organic Compounds
Subchapter 5 Covered Sources
HAR 11-60.1-81 Definitions
HAR 11-60.1-104 Applications for Significant Modification

Subchapter 6 Fees for Covered Sources, Noncovered Sources, and Agricultural Burning
HAR 11-60.1-111 Definitions
HAR 11-60.1-112 General Fee Provisions for Covered Sources
HAR 11-60.1-113 Application Fees for Covered Sources
HAR 11-60.1-114 Annual Fees for Covered Sources Subchapter 6, revised due dates
HAR 11-60.1-115 Basis of Annual Fees for Covered Sources
Subchapter 8 Standards of Performance for Stationary Sources
Subchapter 11 Greenhouse Gas Emissions

Greenhouse Gas Emissions, Subchapter 11 HAR §11-60.1-204

1. Applicability to Subchapter 11 pursuant to HAR §11-60.1-204(a)

   HAR §11-60.1-204 **is applicable** to the KCP since this facility is a permitted covered source with potential carbon dioxide equivalent (CO_2e) emissions (biogenic plus non-biogenic) equal to or above 100,000 short tons per year.

2. Baseline Emission Rate and Cap

   a. DOH's Approval*:*
   Subsequent to public review and comment, the DOH approval is required for the following:

   i. Proposed total combined cap on CO_2e emissions emitted by the KCP and partnering facilities listed in Table 1 pursuant to HAR §11-60.1-204(d)(6)(A);
   ii. Proposed individual facility-wide cap for the KCP as shown in Table 1; and
   iii. Proposed alternate baseline year to CY 2010 pursuant to HAR §11-60.1-204(d)(1).

   The combined emissions limit was determined by multiplying the total combined baseline GHG emissions (less any biogenic CO_2 emissions) for the partnering facilities by 0.84 (i.e. 1.00-0.16). The total combined GHG baseline and GHG emission caps proposed for the partnering facilities are as follows:

Table 1
GHG ERP Baseline and Proposed CO_2e Facility Emission Caps

Plant	CSP Permit No.	Emissions (Short Tons)				Percent (%) Reduction[c]
		Baseline CO_2e	Baseline Biogenic CO_2	Baseline CO_2e Less Biogenic CO_2	CSP CO_2e Caps	
AES	0087-02-C	1,681,605	0	1,681,605	1,691,605	-0.6%
Hamakua	0243-01-C	182,975	0	182,975	153,699	16.0%
Kalaeloa	0214-01-C	1,094,813	0	1,094,813	1,094,813	0.0%
HECO CIP	0548-01-C	19,179	4,233	14,946	53,740	-259.6%
HECO Honolulu[a]	0238-01-C	133,609	0	133,609	0	100.0%
HECO Kahe	0240-01-C	2,776,073	0	2,776,073	2,133,752	23.1%
HECO Waiau	0239-01-C	1,074,359	0	1,074,359	808,286	24.8%
HELCO Hill	0234-01-C	222,784	0	222,784	172,456	22.6%
HELCO Keahole[b]	0007-01-C	191,387	0	191,387	242,208	-26.6%
HELCO Puna	0235-01-C	99,691	0	99,691	31,747	68.2%
HELCO Shipman	0236-01-C	10,192	0	10,192	0	100.0% Plant closed
MECO Kahului	0232-01-C	230,839	0	230,839	154,633	33.0%
MECO Maalaea[b]	0067-01-C	620,654	1,142	619,512	459,864	25.8%
MECO Palaau	0031-04-C	28,236	0	28,236	26,454	6.3%
Combined		**8,366,396**	**5,375**	**8,361,022**	**7,023,258**	**16.0%**

[a] **The HECO Honolulu Generating Station is currently deactivated (not operating but could restart if necessary)**

[b] **These facilities had two (2) operating permits that were combined into a single permit**

[c] **Negative (-) numbers represent an increase instead of a reduction from the baseline emissions**

Partnering facilities are using CY 2010 as the baseline year to establish their caps, except KPLP is proposing to use CY 2009 as an alternate baseline year.

b. *DOH's Methodology for Conducting Assessment*.
The Tier 1 method described in 40 Code of Federal Regulations (CFR) Part 98, §98.33 is used to illustrate in Enclosure 2, the facility's relative GHG emission levels over a time period that extends beyond the five-year period ending 2010 as prescribed by HAR §11-60.1-204(d)(1). The Tier 1 computation method determine mass emissions from the volume of fuel (excluding used oil) combusted per year using company records, with the default high heat values (HHV) and emission factors from Tables C-1 and C-2 of 40 CFR Part 98. The Tier 1 method is the least accurate method since it utilizes fuel specific default emission factors and HHV. However, relative GHG emissions over a longer time span can be evaluated for trends as shown in Figure 2-2 of Enclosure 2 since fuel consumption data is available. The global warming potentials used to compute CO_2e emissions are based on 40 CFR Part 98, Subpart A, Table A-1 (79 FR 73779, Dec 11, 2014). Biogenic emissions (if any) are factored out of the emission calculations. Pursuant to 40 CFR Part 98, Subpart C, the mass emissions of carbon dioxide (CO_2), methane (CH_4), and nitrous oxide (N_2O) shall be determined for each type of fuel, including specification used oil.

c. *Specification Used Oil Impact*.
The combustion of used oil was not included in the DOH's Tier 1 computation of relative emission rates due to lack of available data for the entire time span of CYs being reviewed. Omitting used oil from the computation of GHG emissions is considered to have negligible impact on overall emissions as Table 2 illustrates the delta (Δ) expressed in percentage terms between emissions from used oil and total emissions.

Table 2

Percent of GHG Emissions Attributed to the Combustion of Used Oil							
	2009	2010	2011	2012	2013	2014	2015
Used Oil (MT)	18	NA	11.60	6.00	0.00	4.90	4.08
Total (MT)	993,198	NA	979,629	900,579	960,263	913,292	947,580
Δ (%)	0.0018%	NA	0.0012%	0.0007%	0.0000%	0.0005%	0.0004%

Refer to Enclosure 2A, Tables 2A-1 for details
NA = Not available

d. *Alternate Baseline Year*.
Pursuant to HAR §11-60.1-204(d)(1)(A), an alternate baseline year or period may be proposed when CY 2010 GHG emissions rate is deemed unrepresentative of normal operations. Except for extreme cases, an alternate baseline are those yearly emissions that are most representative of normal operations during the five-year (5-year) period ending 2010 (i.e., CY 2006 to 2010).

An assessment was conducted from DOH's estimates extracted from Table 2-2 of Enclosure 2 and summarized in Table 3. The DOH's estimates are based on the Tier 1 methodology. The following table compares KCP's average CO_2e emissions rate during the five-year (5-year) period ending 2010 (CY 2006-2010) with the emissions rate for each of the five (5) years for this time period.

Table 3

DOH Alternate Baseline Year Assessment					
CY	2006	2007	2008	2009	2010
CO_2e Emissions (MT) [b]	955,637	1,090,542	969,060	993,180	956,660
$Ave_{2006-2010}$ Emissions	993,016	993,016	993,016	993,016	993,016
Δ [a]	-3.76%	9.82%	-2.41%	0.02%	-3.66%

[a] Δ = (CO_2e Emissions – Average $_{2006-2010}$ Emissions) x 100 ÷ Average $_{2006-2010}$ Emissions
[b] Extracted from DOH emissions estimates in Table 2-2 of Enclosure 2 using Tier 1 methodology Emissions from specification used oil not included

Based on the comparison in Table 3, the DOH considers CY 2009 emissions rate to be the most representative because it has the smallest delta (Δ) in percentage terms from the five-year (5-year) average and is also the most recent alternate CY within the five-year (5-year) period ending 2010. This is consistent with acceptable methods for determining an alternate baseline year in accordance with:

i. HAR §11-60.1-204(d)(1)(A)(i), based on the most recent representative year during the five-year (5-year) period ending 2010; and
ii. HAR §11-60.1-204(d)(1)(A)(iii), based on the average facility-wide GHG emissions (less biogenic CO_2) for the five-year (5-year) period ending in 2010.

HAR §11-60.1-204(d)(1)(A) also requires the facility to clearly document why calendar year 2010 is not representative in addition to why the proposed alternate CY is determined to be a more suitable representation of normal operations based on trends, existing equipment and controls, scheduled maintenance, operational practices, and any other relevant information. KPLP's GHG ERP states that KCP's CY 2010 was deemed unrepresentative of normal operations due to a major overhaul of the facility's steam turbine and its associated generator. CY 2009 represents a realistic year of operation because the plant completed a steam turbine generator major overhaul in CY 2010.

Based on DOH's assessment, KPLP proposal to use CY 2009 as KCP's alternate baseline year complies with HAR §11-60.1-204(d)(1).

e. *Using Tier 1 Methodology to Calculate CY 2009 Baseline Emissions.*
EPA's GHG mandatory emissions reporting required by 40 CFR Part 98 did not apply in CY 2009, and therefore KCP's CY 2009 GHG emissions were calculated using a Tier 1 methodology. The Tier 1 methodology is not allowed by 40 CFR Part 98, Subpart C §98.33(b) where emission units exceed a maximum heat input capacity of 250 mmBtu/hr and therefore, the KCP changed from Tier 1 to using the Tier 3 methodology for their mandatory GHG reporting from CY 2011. Also, fuel sampling data needed for the Tier 3 methodology was not performed in 2009, which precludes the KCP from recalculating their CY 2009 GHG emissions using the Tier 3 methodology.

A comparison of GHG emissions calculated using the Tier 1 and Tier 3 methodologies for CY 2011 to 2015 and averaged over five (5) years shows a delta (Δ) of less than one percent (1%) are shown in Table 4. Tier 3 data for CY 2016 and 2017 is not officially available since CY 2016 and 2017 were reported in FLIGHT using a calculation methodology with continuous emissions monitoring (CEMS) data to determine emissions.

Table 4
Tier 1 to Tier 3 Emissions (Metric Tons) Comparison[b]

Method	2011	2012	2013	2014	2015	AVE 2011 to 2015	AVE 2013 to 2015
CO_2e Emissions $_{Tier\ 1}$	979,629	900,579	960,263	913,292	947,580	940,268	940,378
CO_2e Emissions $_{Tier\ 3}$	992,376	913,639	961,976	915,443	952,059	947,099	943,159
Δ (%) [a]	1.28%	1.43%	0.18%	0.24%	0.47%	0.72%	0.29%

[a] **Δ = (CO2e Emissions $_{Tier\ 3}$– CO2e Emissions $_{Tier\ 1}$) x 100 ÷ CO2e Emissions $_{Tier\ 3}$**
[b] **Refer to enclosure 2A for the detailed computations and assumptions**

DOH considers the expected delta (Δ) from KCP's CY 2009 GHG baseline emission with the Tier 1 methodology to have little impact when used as a benchmark for measuring future emission reductions. In addition, the impact is much smaller when combining the baseline emissions rate with partnering facilities for establishing a combined emissions limit.

f. *DOH's Assessment of Proposed Emissions Caps.*
Pursuant to HAR §11-60.1-204(d)(6)(A), KPLP is proposing to combine the KCP facility-wide GHG emissions cap with other partnering facilities to leverage emission reductions in meeting their combined GHG emissions cap. By integrating heat recovery systems in its design, KCP has the potential to operate at higher efficiencies and is capable of producing the same energy output at reduced fuel consumption rates as compared to less efficient plants. The higher efficiency of the KCP offers partnering facilities the ability to reduce the overall total combined GHG emission rates and achieve a combined sixteen percent (16%) emission reduction by CY 2020.

HAR §11-60.1-204(d)(6)(A) also requires each partnering facility to comply with its own adjusted (individual) GHG facility-wide emissions cap. Therefore, KPLP is proposing an individual cap of 1,094,813 short tons with a zero percent (0%) GHG emissions reduction.

KCP is an independent power producer, whose power demand is dispatched from HECO in accordance with a purchase power agreement that is approved by the Hawaii Public Utility Commission. Hence, KCP does not have direct control over their power output and KCP's high utilization rate is driven by multiple considerations that includes operating cost and plant efficiency. The KCP is more efficient than other plants on Oahu and consumes low cost fuel oil No. 6. Also, the KCP's ability to rapidly start, load up, and load down provides grid stability that supports the growth of renewable sources. Figure 2-2 of Enclosure 2 illustrates KCP's relative GHG emission rates by CYs that extends beyond the five-year period ending 2010, indicating continued demand from HECO for power generation from the KCP.

KCP's higher efficiency reduces overall fuel consumption, which also reduces overall GHG emissions. Therefore, KPLP's proposed combined cap with a sixteen percent (16%) emissions reduction and individual facility-wide GHG emissions cap with zero emissions reduction is characteristic of leveraging reductions in the overall GHG emissions rate for KCP and its partnering facilities.

3. GHG control assessment (Refer to the "Non-Applicable Requirements")

4. Proposed Control Strategy

   KPLP has determined that a combined facility-wide GHG emissions reduction of sixteen percent (16%) is achievable by 2020 when partnering with other facilities listed in Enclosure 1 pursuant to HAR §11-60.1-204(d)(6)(A) using a combined GHG emissions rate as a baseline. Therefore, KPLP is proposing a sixteen percent (16%) combined facility-wide reduction in GHG emissions by partnering to curtail or retire the operations of less efficient source units. A comparison of technically feasible control measures in Table 6, indicates partnering with other facilities is expected to have the least economic and schedule impact, without compromising partnering facilities to effectively meet a sixteen percent (16%) overall facility-wide emissions reduction goal.

   The proposed combined emissions cap will be made part of the permit pursuant to HAR §11-60.1-204(d)(6)(C) and is required to be achieved by the year 2020 and maintained thereafter. Each facility may exceed its individual cap as long as the total combined sixteen percent (16%) GHG reduction from the combined baseline is met.

   The associated monitoring, recordkeeping, and reporting provisions will also be made a part of the permit. Calculation methodologies in 40 CFR Part 98 Subpart C, §98.33 will be used to determine GHG emissions.

Federal Requirements

The following 40 CFR Part 60, New Source Performance Standards (NSPS), **are applicable**:

40 CFR Part 60 Subpart A, General Requirements
40 CFR Part 60 Subpart GG, Standards of Performance for Stationary Gas Turbines

Mandatory Greenhouse Gas Reporting, 40 CFR Part 98, **is applicable** to this facility because:

1. The facility does not meet the requirements of either paragraph (a)(1) or (a)(2) of Subpart A, §98.2;
2. The aggregate maximum rated heat input capacity of the stationary fuel combustion units at the facility is 30 MMBtu/hr or greater; and
3. The total CO_2e emissions from stationary fuel combustion sources at the HEP are greater than 25,000 metric tons per year.

Best Available Control Technology (BACT):

The initial BACT analysis performed as part of **PSD is still valid**. A BACT analysis is required for new or modified sources that have the potential to emit or increase emissions above significant amounts as defined in HAR 11-60.1-1. Since this is not a new source nor are any modifications proposed that have the potential to cause a significant increase in air emissions, a **BACT analysis is not required**.

Major Source/ Synthetic Minor Applicability:

The facility's classification as a major source **remains unchanged** from the previous permit application review.

Compliance Assurance Monitoring (CAM), 40 CFR Part 64:

The purpose of CAM is to provide a reasonable assurance that compliance is being achieved with large emissions units that rely on air pollution control device equipment to meet an emissions limit or standard. Pursuant to 40 CFR Part 64, for CAM to be applicable, the emissions unit must: (1) be located at a major source; (2) be subject to an emissions limit or standard; (3) use a control device to achieve compliance; (4) have potential pre-control emissions that are one hundred percent (100%) of the major source level; and (5) not otherwise be exempt from CAM.

This source **is not subject to CAM.** Although the combustion turbine generators rely on a water injection system to achieve compliance with the NOx standard required by 40 CFR 60, Subpart GG, and have potential pre-control emissions greater than the major source level for NOx, CAM is not applicable because a continuous emission monitoring system (CEMS) is used to determine compliance with the NOx emissions standard. As such, the combustion turbine generators are exempt from CAM for NOx.

Non-Applicable Requirements:

State Requirements

Hawaii Administrative Rules (HAR)
Title 11, Chapter 60.1 Air Pollution Control
- Subchapter 3 Open Burning
- Subchapter 4 Noncovered Sources
- Subchapter 7 Prevention of Significant Deterioration Review
- Subchapter 9 Hazardous Air Pollution Sources
  - HAR 11-60.1-180 National Emission Standards for Hazardous Air Pollutants

GHG Control Assessment Subchapter 11 HAR §11-60.1-204(d)(2):

KPLP is proposing to combine their facility-wide GHG emissions cap among partnering facilities and meet a combined GHG emissions cap and sixteen percent (16%) GHG emissions reduction. In accordance with HAR §11-60.1-202, a facility-wide GHG emissions cap may also be defined in multiple covered source permits to identify partnering facilities with an approved combined GHG emissions cap as described in HAR §11-60.1-204(d)(6)(A). Therefore, KPLP is not required to conduct a GHG control assessment, however, an assessment was included in KPLP's GHG emissions reduction plan as follows:

1. Identify all available control measures and eliminate all technically infeasible options.

   Pursuant to HAR §11-60.1-204(d)(3) and §11-60.1-204(d)(4), respectively, all available control measures applicable to KCP are listed in Table 5 and each available control measure evaluated to determine whether it is technically infeasible.

Table 5
Assessment of All Control Measures

GHG Control Option	Feasibility and Benefit
Carbon Capture and Storage (CCS)	Not technically feasible since not currently commercially available for combustion turbine exhaust treatment.
Fuel Switching or Co-Fired Fuels	Technically feasible – refer to Table 6.
Energy Efficiency Upgrades and Combustion Improvements	Since start-up of KCP, a number of efficiency improvement upgrades were accomplished on the combustion turbine generators, which included the installation of evaporative cooling units and replacing the internal turbine blades with aerodynamically improved blade design. KCP follows a long-term strategic maintenance schedule in keeping with recommendations of the original equipment manufacturer.
Restrictive Operations or Equipment Retirement	KCP is the most efficient power plant on Oahu. Restricting KCP's operation could adversely impact the overall GHG emissions since the operation of other less efficient plants may be needed to make up any shortages in the production of electricity. In addition, operations at lower loads increases the cost per kilowatt-hour.
Outstanding regulatory mandates, emission standards, and binding agreements	No other regulatory mandates are outstanding that would lead to any reductions in GHG emissions.
Other GHG reduction initiatives that may affect the facility's GHG emissions	KCP is proposing a combined facility-wide GHG emissions cap to leverage emission reductions among partnering facilities as a control strategy and listed this as an available control measure in Table 6. Otherwise, KPLP has not been able to identify any other GHG reduction initiatives that would apply.

2. List technically feasible control options and identify the effectiveness and cost of each control measure.

   Pursuant to HAR §11-60.1-204(d)(5), KPLP's evaluation of technically feasible control measures are listed and summarized in Table 6. KPLP used LSFO No. 6 pricing based on the U.S. Energy Information Administration 2020 estimates for residual oil of $72 per barrel (bbl) plus $8 per bbl transportation cost. KCP's power output for CY 2009 is 1,451,424 MWH as provided in Table 1 of KPLP's GHG ERP. For cost comparison of available control measures, KPLP assumes an annual fuel consumption rate that is equivalent to two (2) million barrels of LSFO No. 6.

Table 6
Effectiveness and Cost of Control Measures

Available Control Measure→	Co-fire w/ 16% Biofuel	Fuel Switching	Fuel Switching	Restrictive Operation	Partnering
Fuel Type→	Biodiesel	LNG	Propane	LSFO No. 6	LSFO No. 6
Control Effectiveness	16%	29.9%	16%	16%	16%
Required Implementation Schedule	1 month	1 year	1 year	Immediate	Immediate
GHG Reductions (metric tons)	158,912	283,658	158,912	151,790	Per Partnership Goals
Cost per metric ton of CO_2e removed ($/MT)	$182	$116	$293	$138	$0

Refer to Enclosure 6, Table 6-1 for details of KPLP's evaluation

Table 6 illustrates both the effectiveness, and the schedule and cost impact, of each technically feasible control measure. An independent assessment by DOH (included as Enclosure 6, Table 6-2) using updated and expanded data sources, shows different absolute values but conclusively agrees with KPLP's proposed control strategy of partnering as the most cost-effective available control measure.

3. Discussion of control effectiveness, implementation schedule, and expected GHG CO_2e emissions reductions.

   The following summarizes KPLP's discussion of technically feasible control measures:

   a. As a proposed control strategy, KPLP plans to partner with other facilities to meet a combined facility-wide GHG emissions reduction of sixteen percent (16%) achievable by 2020 when partnering with other facilities. Table 6 indicates partnering is expected to have zero impact to KCP's cost and schedule, with expectations to effectively meet a sixteen percent (16%) combined facility-wide emissions reduction goal.

   b. Fuel switching to liquified natural gas (LNG) is listed in Table 6 as second best to partnering with an expected cost impact of $116 per metric ton of CO_2e removed, control effectiveness of better than twenty-nine percent (29%) GHG emissions reduction, and to reduce emissions of other criteria pollutants, such as NOx, CO, SO_2, lead (Pb), and particulates. Fuel switching to natural gas, however, may increase emissions of N_2O, CH_4, and VOC. A ten million-dollar ($10,000,000) investment is required to install new dual fuel (liquid and gaseous) burners, which is amortized over four (4) years and included in the cost impact of Table 6. A lead time of one (1) year is needed from time of contracting a firm source of fuel, however, the acquisition and transportation of natural gas are currently non-existent and may impact implementation of this control measure.

c. Restrictive operation is listed in Table 6 as third best to partnering with an expected cost impact of $138 per metric ton of CO_2e removed and control effectiveness of sixteen percent (16%) GHG emissions reduction. A sixteen percent (16%) GHG emission reduction goal is achievable using this control measure at the expense of losing KCP's high efficiency to leverage increases in the overall efficiency and reduce emissions on a larger scale through partnering. In addition, restrictive operation imposed on KCP decreases plant efficiency and therefore degrades the plant's ability to maintain a higher power output relative to fuel consumption levels which is proportional to GHG emissions.

d. Co-firing with sixteen percent (16%) blend of biofuel is listed in Table 6 as fourth best to partnering with an expected cost impact of $182 per metric ton of CO_2e removed, control effectiveness of sixteen percent (16%) GHG emissions reduction, and to reduce emissions of other criteria pollutants, such as NOx and SO_2. Co-firing with biofuel is not expected to increase other secondary emissions, however, some impact may result from production of biofuels. KCP can utilize biofuel or blends with the existing equipment and one (1) month lead time from contracting a firm source of fuel.

e. Fuel switching to propane is listed in Table 6 as fifth best to partnering with an expected cost impact of $293 per metric ton of CO_2e removed, control effectiveness of sixteen percent (16%) GHG emissions reduction, and to reduce emissions of other criteria pollutants, such as NOx, CO, SO_2, Pb, and particulates. Fuel switching to propane, however, may increase emissions of N_2O, CH_4, and VOC. A ten million-dollar ($10,000,000) investment is required to install new dual fuel (liquid and gaseous) burners, which is amortized over four (4) years and included in the cost impact of Table 6. A lead time of one (1) year is needed from time of contracting a firm source of fuel. The acquisition and transportation of propane may impact implementation of this control measure.

f. Furthermore, according to the "PSD and Title V Permitting Guidance for Greenhouse Gases" (March 2011 edition), a BACT analysis need not necessarily include inherently lower polluting processes that would fundamentally redefine the nature of the source proposed by the permit applicant. The EPA guidance further states that BACT should generally not be applied to regulate the applicant's purpose or objective for the proposed facility and any decision to exclude an option on "redefining the source" grounds must be explained and documented in the permit record, especially where such an option has been identified as significant in public comments. KCP's dual objectives are to burn fuel oil No. 6 received from an adjacent refinery to generate power and return steam back to the refinery to supply half the power it needs to function. Hence, fuel switching will redefine the operations of KCP.

The proposed partnering of the KCP with other power generation facilities offers economic and environmental advantages to the overall partnership. The KCP possess design elements such as the heat recovery steam generators, evaporative cooling unit, and aerodynamically improved combustion turbine blade design, that increases overall efficiency of the partnership. This provides the partnering facilities with the potential to consume less fuel for the same level of power produced thereby reducing GHG emissions.

Federal Requirements

40 CFR Part 52.21 – Prevention of Significant Deterioration (PSD) of Air Quality. PSD **is not applicable** to the modification to incorporate the GHG emission cap because it does not make the facility a new major stationary source nor does it propose any major modifications to a major stationary source as defined in 40 CFR 52.21. A PSD major modification is defined as a major stationary source that will result in a significant emissions increase and a significant net emission increase of any regulated NSR pollutant as defined in 40 CFR §52.21. Since there are no significant emission increases for this project, PSD is not triggered.

40 CFR Part 60, Subpart Da and Dc – NSPS for Steam Generating Units **is not applicable** to the combined cycle gas turbines based on §60.40Da and §60.40c, respectively. No supplemental fuel combustion (i.e. no duct burner) is required for the heat recovery steam generators since steam is generated using the hot exhaust gas from each combustion turbine.

40 CFR Part 60, Subpart Db - Standards of Performance for New Stationary Sources (NSPS) – Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units **is not applicable** since a modification or reconstruction is not triggered due to the proposed change. Under 40 CFR §60.14(a), an existing facility which does not result in an increase in the emission rate to the atmosphere of any pollutant is not considered a modification under the NSPS.

40 CFR Part 60, Subpart Kb, NSPS – Standards of Performance for Volatile Organic Liquid Storage Vessels **is not applicable** to the storage tanks identified in Table 3A-2 of Enclosure 3A based on 40 CFR §60.110b.

40 CFR Part 60, Subpart KKKK – NSPS for stationary combustion turbines **is not applicable** to the combine cycle gas turbines based on §60.4305 because both stationary combustion turbines were last modified prior to February 18, 2005.

40 CFR Part 61, National Emission Standards for Hazardous Air Pollutants (NESHAP) **is not applicable** because there are no standards in 40 CFR Part 61 applicable to this facility.

40 CFR Part 63, Subpart YYYY NESHAP for stationary combustion turbines **is not applicable** because this facility is not a major source of HAP emissions as determined in §63.6085.

40 CFR Part 63, Subpart ZZZZ - NESHAP **is not applicable** to emergency stationary reciprocating internal combustion engine (RICE) (or diesel engine generator (DEG)) at an area source of HAP that complies with §63.6585(f). However, the emergency stationary RICE (or DEG) must meet the definition in §63.6675, which includes operating according to the provisions specified in §63.6640(f).

40 CFR Part 279 Standards for Management of Used Oil **is not applicable** because used oil burned for energy recovery is not expected to exceed allowable levels specified in §279.11 and is a non-hazardous waste under §279.10(b)(1).

Air Emissions Reporting Requirements (AERR)

40 CFR Part 51, Subpart A – AERR, is based on the emissions of criteria air pollutants from point sources (as defined in 40 CFR Part 51, Subpart A), which exceeds the AERR thresholds as shown in Table 8-5 titled “Total Facility Emissions and Threshold” under the Project Emissions section. Since the facility-wide emission levels of one or more air pollutant(s) still exceeds the reporting threshold(s), the AERR (previously referred to as “CERR” in the 2008 CSP review for application No. 0214-06) and DOH In-house Annual Emissions Reporting requirements **remain unchanged** from the previous permit application review and annual emissions reporting for the facility **is still required** for in-house recordkeeping purposes.

Insignificant Activities

No additional insignificant activities were proposed with the application for permit modification.

Table 7
List of Insignificant Activities

Unit Number	Description[a]	Capacity (gallons)	Justification
Tank No. 1	LSFO Storage Tank	1,050,000 gallons	HAR 11-60.1-82(f)(7) [0.02 tpy VOC emissions]
Tank No. 2	LSFO Storage Tank	1,050,000 gallons	HAR 11-60.1-82(f)(7) [0.02 tpy VOC emissions]
---------	Diesel Fuel Storage Tank	52,920 gallons	HAR 11-60.1-82(f)(7) [1.13 tpy VOC emissions]
---------	Additive Storage Tank[b]	13,020 gallons	HAR 11-60.1-82(f)(1)
---------	Diesel Fire Pump Storage Tank	500 gallons	HAR 11-60.1-82(f)(1)
---------	Fuel System Pumps, (15)	-----------	HAR 11-60.1-82(f)(7) [1.25 tpy VOC emissions]
---------	Fuel System Valves, (350)	-----------	HAR 11-60.1-82(f)(7) [0.31 tpy VOC emissions]
---------	Fuel System Flanges, (297)	-----------	HAR 11-60.1-82(f)(7) [0.26 tpy VOC emissions]
---------	Emergency Diesel Engine Generator[c]	209 bhp	HAR 11-60.1-82(f)(5)
---------	Diesel Engine for Emergency Fire Pump[c]	121 bhp	HAR 11-60.1-82(g)(6)

[a]Mandatory GHG reporting pursuant to 40 CFR §98.2(a)(3) applies only to "stationary fuel combustion sources" as defined in 40 CFR §98.30

[b]The 13,020 gallon tank is no longer being used as a "bio-fuel tank" and returned to service as an "additive storage tank" as clarified in Mr. Michael Rossio's April 3, 2018's email

[c]40 CFR §98.30 excludes emergency generators and equipment as defined in 40 CFR §98.6 from mandatory GHG reporting and monitoring

Alternate Operating Scenarios

The application for a significant modification did not propose any alternate operating scenarios.

Project Emissions

The modification to incorporate GHG emissions caps will not cause an increase in maximum potential emissions from the existing permit limits. Table 8-1 compares current emissions with emissions from the prior permit renewal application review No. 0214-06 and the impact or change in emissions are discussed as follows:

1. NO_x and SO_2 emissions from the CTGs have not change and differences in emissions are due to an apparent transcription error between pollutants, which does not impact the permit limits.
2. The total and single highest HAP increased to 16.03 tpy and 6.93 tpy, respectively. However, the increase does not exceed the thresholds in Table 8-5 nor does it change the facility's designation as a major source of HAPs. The emissions of nickel from the CTGs when firing LSFO No. 6 was not included in the 2008 permit application review No. 0214-06, however, nickel emissions of 9.15 tpy were estimated in the initial permit application review No. 0214-01 based on a subsequent source test result since there are no emission factors in AP-42 for residual oil fired CTGs. For the 2018 permit application review, the nickel emissions were computed on a worst-case basis using the highest nickel content of 16.61 ppm over the last six (6) years. This is the absolute maximum nickel emissions possible since some of the nickel is consumed in the process and does not become an air emission. Refer to Footnote (7) of Table 3-1 in Enclosure 3 for detailed data, calculations, and assumptions.
3. Increasing the consumption limit of specification used oil from 10,000 to 20,000 gallons per year as proposed by KPLP will have negligible impact on total facility wide emissions as summarized in Table 8-2. Refer to Footnote (9) of Table 3-1 in Enclosure 3 for detailed calculations and assumptions. The maximum potential emissions of pollutants from consuming 20,000 gallons were estimated on a worst-case basis using the limits for specification used oil from 40 CFR §279.11 and a maximum fuel consumption rate of 6,300 gal/hr (or 49,264 lbs/hr). It is assumed that the specific gravity of specification used oil is the same as LSFO No. 6. KPLP further states that the total annual fuel consumption is restricted to 106,747,200 gallons per year and therefore, an increase in consumption of specification used oil will be offset by the decrease in consumption of LSFO or diesel fuel. In addition, review of KCP's 2017 fuel delivery data documented in TestAmerica Laboratories, Inc. analytical report dated 2/2/2 017 confirms that contents of constituents associated with pollutants are much less than the limits specified in 40 CFR §279.11.
4. Emissions from emergency DEGs, which are insignificant equipment, are used to evaluate whether these activities combined with emissions from the permitted equipment exceed major source and PSD levels. Table 8-3 summarizes the net increase in emissions from both DEGs in accordance with EPA's memorandum dated September 6, 1995. Refer to Enclosure 4 for detailed emission calculations and assumptions for each DEG. PSD is still valid for the emergency DEGs since both equipment were included as insignificant sources for the initial PSD review. Emissions of NO_x, SO_2, CO and PM were initially above the respective major source thresholds as estimated in the initial application review (No. 0214-01) and therefore net emissions increases from the emergency DEGs will not impact the facility's status as a major source for these pollutants. Net increase in emissions of Lead (Pb), HAPs, and VOCs from the emergency DEGs combined with the permitted equipment will not exceed the respective thresholds as shown in Table 8-5.

5. Assessment of GHG emissions are summarized in Table 8-4 Maximum potential GHG emissions were not included in prior permit application reviews since GHGs were not previously subject to regulation. A total annual combined fuel consumption limit on LSFO No. 6, Diesel, and Specification Used Oil of 106,747,200 gallons per year, is used to compute the maximum mass based GHG emissions expected at this facility in Enclosure 5. The Tier 3 method, Equation C-4 from 40 CFR Subpart C, §98.33(a)(3) with carbon content (CC) data for CY 2014 and CY 2015 on a weighted average basis is used for computing the GHG mass-based emissions since §98.33(b) restricts KCP from using Tier 1 and Tier 2 methods. GHG emissions from the emergency DEG and fuel storage tanks are not included since 40 CFR Part 98, Subpart A, §98.2(a)(3) states that reporting of GHG emissions must be from *stationary fuel combustion sources* only. 40 CFR Part 98, Subpart C, §98.30 defines *stationary fuel combustion sources* as devices that combust fuel for producing useful energy but specifically excludes emergency equipment. The CO_2e emissions were determined by multiplying the mass-based emissions developed in Enclosure 5 by each associated global warming potential (GWP). The GWP for each GHG is provided in 40 CFR Part 98, Table A-1.

Table 8-1
Changes in Annual Emissions

Air Pollutants	2008 Permit Application Review No. 0214-06 Emission Rates			2018 Permit Application Review No. 0214-10 Emissions Rates	
	Hourly (lb/hr)	Total (tpy)		Hourly (lb/hr)	Total (tpy)
NOx - (CT1 & CT2)	488	4,134		483[c]	4,092
SO_2 - (CT1 & CT2)	483	4,096		488[c]	4,134
CO - (CT1 & CT2)	35	296		35[c]	297
PM_{10} - (CT1 & CT2)	80	678		80	678
VOCs - (CT1 & CT2)	3.6	30		3.6	30
Lead (Pb) - (CT1 & CT2)	0.052	0.442		0.052	0.442
HAPs (Total) - (CT1 & CT2)		9.18			16.03
HAP (Single Highest[b])		2.59			6.93
PM Cooling Towers		8.0			8.0
VOCs - Tanks & Eqpt		4.1			6.5

[a] Refer to Table 3-1 of Enclosure 3 for details
[b] Nickel is the single highest HAP
[c] Subject to an existing permit emission limit

Table 8-2
Spec Used Oil Change In Emission Rates (TPY)

Pollutants	Emission Rates per CT		Emission Rates Total		Δ in Emission Rates
	10,000 gal	20,000 gal	10,000 gal	20,000 gal	10,000 to 20,000 gal
	(a)	**(b)**	**(c)=(a) x 2**	**(d)=(b) x 2**	**(e) = (d) - (c)**
Sulfur Dioxide	1.95E-01	3.91E-01	3.91E-01	7.82E-01	3.91E-01
Arsenic	9.77E-05	1.95E-04	1.95E-04	3.91E-04	1.95E-04
Cadmium	3.91E-05	7.82E-05	7.82E-05	1.56E-04	7.82E-05
Chromium	1.95E-04	3.91E-04	3.91E-04	7.82E-04	3.91E-04
Lead (Pb)	1.95E-03	3.91E-03	3.91E-03	7.82E-03	3.91E-03
Halogens[b]	1.95E-02	3.91E-02	3.91E-02	7.82E-02	3.91E-02
PCBs	3.91E-05	7.82E-05	7.82E-05	1.56E-04	7.82E-05

Refer to Footnote (9) of Table 3-1 in Enclosure 3 for detailed calculations and assumptions

Table 8-3
Emergency Diesel Engine Generators[a]

Pollutant	207 bhp DEG Emissions	121 bhp Fire Pump DEG Emissions	Emissions
	(tpy)	(tpy)	(tpy)
	(a)	**(b)**	**(c)=(a) + (b) [b]**
NO_x	1.6	9.38E-01	2.6
SO_2	6.84E-04	3.96E-04	1.08E-03
CO	3.49E-01	2.02E-01	5.51E-01
PM	1.20E-01	6.93E-02	1.89E-01
PM_{10}	1.15E-01	6.66E-02	1.82E-01
$PM_{2.5}$	1.08E-01	6.24E-02	1.70E-01
VOC	1.31E-01	7.61E-02	2.07E-01
Pb	0.00E+00	0.00E+00	0.00E+00
HAP (Highest)[b]	1.55E-04	9.08E-05	1.55E-04
HAP (Total)	3.95E-04	2.31E-04	6.27E-04
CO_2e	22	13	34

[a]Refer to Enclosure 4 for details
[b]The higher value selected for HAP (Highest)

Table 8-4
GHG Emissions (Excluding DEGs)

Description →	GHG Mass-Based Emissions[a]	GWP	CO_2e Based Emissions	
Source or Derivation →	Enclosure 5	40CFRS98 Table A-1	(a)*(b)	(a)*(b)/1.10231[b]
Unit of Measure →	(tpy)	None	(tpy)	(metric tons/yr)
GHG Pollutant ↓	**(a)**	**(b)**	**(c)**	**(d)**
Carbon Dioxide (CO_2)	1,330,271	1	1,330,271	1,206,803
Methane (CH_4)	53	25	1324	1201
Nitrous Oxide (N_2O)	11	298	3,156	2,863
		CO_2e Emissions =	1,334,751	1,210,867

[a] **Refer to Enclosure 5 for details**

[b] **1 metric-ton is equivalent to 1.10231131 U.S. tons**

The following table summarizes the facility-wide total project emissions relative to the monitoring and reporting thresholds:

Table 8-5
Total Facility Emissions Relative To Control Thresholds (TPY)

Pollutant	Combustion Turbines	Emergency DEGs	Combined Emissions	AERR		Major Source		DOH (In-House) Reporting	
				Thresholds (Type B Sources)	Applies	Threshold	Applies	Threshold	Applies
NO_x	4092	2.6	4,095	100	Yes	100	Yes	25	Yes
SO_2	4134	1.08E-03	4,134	100	Yes	100	Yes	25	Yes
CO	297	5.51E-01	297	1,000	No	100	Yes	250	Yes
PM	678	1.89E-01	678	100	Yes	100	Yes	25	Yes
$PM_{2.5}$	678	1.70E-01	678	100	Yes		NA		NA
PM_{10}	678	1.82E-01	678	100	Yes		NA	25	Yes
Pb (Actual)	4.42E-01	0.00E+00	4.42E-01	0.5	No	100	No	5	No
HAPs (Total)	16	3.20E-01	16		NA	25	No	5	Yes
HAP (Highest)	7	6.17E-02	7		NA	10	No		NA
VOC[a]	30	2.07E-01	31	100	No	100	No	25	Yes

[a]Excludes fugitive emissions

KPLP is proposing an individual CO_2e emissions cap of 1,094,813 tpy (993,198 metric tons) for the KCP. While this individual limit may be exceeded, CSP No. 0214-01-C imposes operational restrictions that limit the facility's CO_2e emissions to an estimated 1,208,028 (tpy). In addition, the proposed total combined GHG emissions limit is expected to reduce overall GHG emissions among partnering facilities by sixteen percent (16%) from the total combined baseline level by the start of 2020.

Ambient Air Quality Assessment

An ambient air quality assessment was not required for the significant modification to incorporate the GHG emission caps because there are no increases in emission rates from previously modeled levels. Air quality assessment is not required for the increase in specification used oil since it is a minor modification.

Significant Permit Conditions

1. Each partnering facility shall not emit or cause to be emitted carbon dioxide equivalent (CO_2e) emissions in excess of the following individual caps except as specified in Attachment II – GHG Special Condition No. C.1.c.iv of CSP No. 0214-01-C for Kalaeloa Cogeneration Plant. This CO_2e emissions limit will be specified in Attachment II – GHG, Special Condition No. C.1.a of CSP No. 0214-01-C for Kalaeloa Cogeneration Plant.

Generating Station	CSP Permit No.	CO_2e Emission Cap	
		Metric Tons per Calendar Year[a]	Short Tons per Calendar Year
AES Coal-Fired Cogeneration Plant	0087-02-C	1,534,598	1,691,605
Hamakua Energy, LLC Cogeneration Plant	0243-01-C	139,433	153,699
Kalaeloa Partners, L.P. Cogeneration Plant	0214-01-C	993,198	1,094,813
HECO Campbell Industrial Park Generating Station	0548-01-C	48,752	53,740
HECO Honolulu Generating Station	0238-01-C	0	0
HECO Kahe Generating Station	0240-01-C	1,935,707	2,133,752
HECO Waiau Generating Station	0239-01-C	733,265	808,286
HELCO Kanoelehua-Hill Generating Station	0234-01-C	156,449	172,456
HELCO Keahole Generating Station	0007-01-C	219,727	242,208
HELCO Puna Generating Station	0235-01-C	28,800	31,747
MECO Kahului Generating Station	0232-01-C	140,281	154,633
MECO Maalaea Generating Station	0067-01-C	417,182	459,864
MECO Palaau Generating Station	0031-04-C	23,999	26,454

[a] **1 Metric Tons = (0.90718474) x (Short Tons)**

Reason: Required by HAR §11-60.1-204(d)(6)(A).

2. All partnering facilities shall not emit or cause to be emitted total combined CO_2e emissions in excess of 6,371,392 metric-tons (7,023,258 short tons) per calendar year. This total combined CO_2e emissions limit will be specified in Attachment II – GHG Special Condition No. C.1.b of CSP No. 0214-01-C for Kalaeloa Cogeneration Plant.

   Reason: Required by HAR §11-60.1-204(d)(6)(A).

3. For purposes of the CO_2e emission limits in Attachment II – GHG, Special Condition Nos. C.1.a and C.1.b:

   a. The CO_2e emissions shall have the same meaning as that specified in HAR §11-60.1-1;
   b. In accordance with HAR §11-60.1-204(d)(6)(B), biogenic CO_2 emissions will not be included when determining compliance with the emissions limit;
   c. The permittee shall be in compliance with the emissions limits by the end of 2019 and each CY thereafter;
   d. The permittee may exceed the emissions cap specified in Attachment II – GHG, Special Condition No. C.1.a, if the GHG emissions limit specified in Attachment II – GHG, Special Condition No. C.1.b, is met; and

e. At no time shall the permittee exceed Attachment II – GHG, Special Condition Nos. C.1.a and C.1.b simultaneously over a calendar year. For incidences when Attachment II – GHG Special Condition Nos. C.1.a and C.1.b of this permit are exceeded simultaneously, emissions in excess of the total combined cap shall be allocated according to the following equation for compliance purposes:

$$X = XG \frac{(A - C)}{\sum_{A_i > C_i}(A_i - C_i)}$$

Where:

X = Adjusted portion in metric tons or short tons of GHG emissions that are in excess of total combined cap specified in Attachment II – GHG, Special Condition No. C.1.b. The equation applies to all affected facilities that do not meet the individual and total combined GHG emission caps specified in Attachment II – GHG, Special Condition Nos. C.1.a and C.1.b, respectively.

XG = Total combined actual GHG emissions from affected facilities minus total combined GHG emissions cap. The total combined emissions cap shall be sixteen percent (16%) below the total combined baseline emission level less biogenic CO_2 emissions.

A = Actual GHG emissions from the affected facility.

C = GHG emissions cap for the affected facility.

$\sum_{Ai>ci}(Ai - Ci)$ = The sum of the difference between the actual emissions and cap emissions for all facilities that did not achieve the individual facility-wide GHG emissions cap.

Reason: Required by HAR §11-60.1-3, §11-60.1-90, §11-60.1-204.

4. By **August 29, 2019**, and **within 60 days** following the end of each semi-annual calendar period (January 1 – June 30 and July 1 – December 31) thereafter**, Kalaeloa Cogeneration Plant** shall submit written reports to the Department for monitoring CO_2e emissions to verify compliance with:

   a. The individual GHG emissions cap and allocating excess emissions pursuant to Attachment II – GHG Special Condition No. C.1.c.v; and
   b. The total combined GHG emissions limit and allocating excess emissions pursuant to Attachment II – GHG Special Condition No. C.1.c.v.

   Reason: Required by HAR §11-60.1-3, §11-60.1-11, §11-60.1-90.

5. Attachment II, Special Condition C.1.c.iii, is hereby modified to the following:

   iii. The total combined specification used oil fired in the combustion turbines shall not exceed 20,000 gallons as calculated on a rolling twelve-month (12-month) basis.

   Reason: Requested by the permittee.

Conclusion and Recommendation

KPLP applied for significant permit modification to incorporate the proposed GHG emissions limits and significant permit conditions. These permit additions are required for implementing GHG reduction measures proposed in the GHG ERP for KCP pursuant to HAR §11-60.1-204.

KPLP is proposing to partner the KCP with facilities listed in Enclosure 1, as the primary control strategy, to achieve a combined sixteen percent (16%) reduction below the total combined CO_2e baseline emissions by:

1. Establishing a total combined limit of 6,371,392 metric tons (7,023,258 short tons) of CO_2e emissions per CY; and
2. Establishing a facility wide individual GHG emissions cap of 993,198 metric tons (1,094,813 short tons) per CY.

The proposed partnering allows facilities to leverage emission reductions by utilizing KCP's efficiency to reduce overall GHG emissions.

KCP is also proposing to use CY 2009 as an alternate GHG emissions baseline year as a benchmark to measure the effectiveness of their proposed control strategy. The alternate baseline was evaluated by use of acceptable methods in HAR §11-60.1-204(d)(1)(A) and determined to be more representative of normal operations. KPLP further stated that CY 2009 is more representative because KCP underwent a major overhaul in CY 2010.

KPLP's GHG emissions reduction plan was reviewed and determined to be in compliance with HAR §11-60.1-204. KPLP's proposed baseline emission rate and emission caps were evaluated using KCP's past fuel consumption data and determined to be reasonably representative as documented in Enclosures 2 and 2A.

As specified in HAR §11-60.1-204(g), once a facility-wide GHG emission cap is established and incorporated in the covered source permit, the GHG ERP shall become part of the permit application process for renewals and any required modifications.

Recommend issuance of the significant modification to the CSP subject to thirty-day (30-day) public review and comment period in accordance with HAR §11-60.1-205, forty-five day (45-day) Environmental Protection Agency review period, and incorporation of the significant permit conditions.

Review by: Dale Hamamoto
February 7, 2019

ENCLOSURE 1: GHG PARTNERING FACILITIES

Table 1

Generating Station	CSP Permit No.	CO_2e Emission Caps	
		Metric tons per calendar year[a]	Short tons per calendar year
AES Coal-Fired Cogeneration Plant	0087-02-C	1,534,598	1,691,605
Hamakua Energy, LLC Cogeneration Plant	0243-01-C	139,433	153,699
Kalaeloa Partners, L.P. Cogeneration Plant	0214-01-C	993,198	1,094,813
HECO Campbell Industrial Park Generating Station	0548-01-C	48,752	53,740
HECO Kahe Generating Station	0240-01-C	1,935,707	2,133,752
HECO Honolulu Generating Station[b]	0238-01-C	0	0
HECO Waiau Generating Station	0239-01-C	733,265	808,286
HELCO Kanoelehua-Hill Generating Station	0234-01-C	156,449	172,456
HELCO Keahole Generating Station[c]	0007-01-C	219,727	242,208
HELCO Puna Generating Station	0235-01-C	28,800	31,747
MECO Kahului Generating Station	0232-01-C	140,281	154,633
MECO Maalaea Generating Station[c]	0067-01-C	417,182	459,864
MECO Palaau Generating Station	0031-04-C	23,999	26,454
Partnership Total		6,371,392	7,023,258

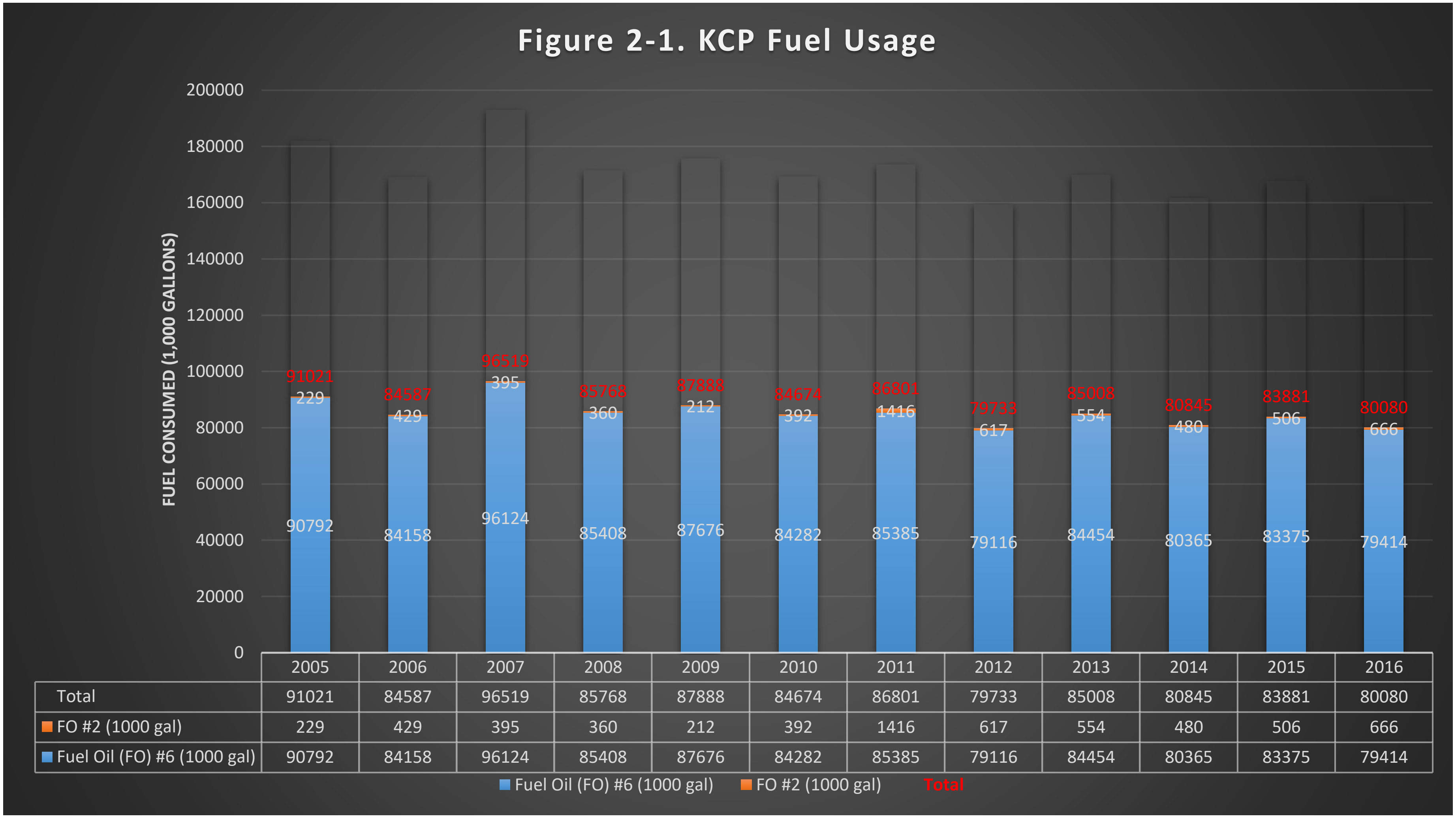
[a] **1 Metric Tons = (0.90718474) x (Short Tons)**

[b] **The HECO Honolulu Generating Station is currently deactivated (not operating but could restart if necessary).**

[c] **These facilities had two operating permits that were combined into a single permit.**

[d] **CSP No. 0236-01-C is not included as a partnering facility since its permit is closed, however, it's 2010 baseline emissions are included in calculating the partnership total baseline and emissions cap pursuant with HAR§11-60.1-204(d)(1).**

ENCLOSURE 2



	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
Total	91021	84587	96519	85768	87888	84674	86801	79733	85008	80845	83881	80080
FO #2 (1000 gal)	229	429	395	360	212	392	1416	617	554	480	506	666
Fuel Oil (FO) #6 (1000 gal)	90792	84158	96124	85408	87676	84282	85385	79116	84454	80365	83375	79414

ENCLOSURE 2 (Continued)

Table 2-1

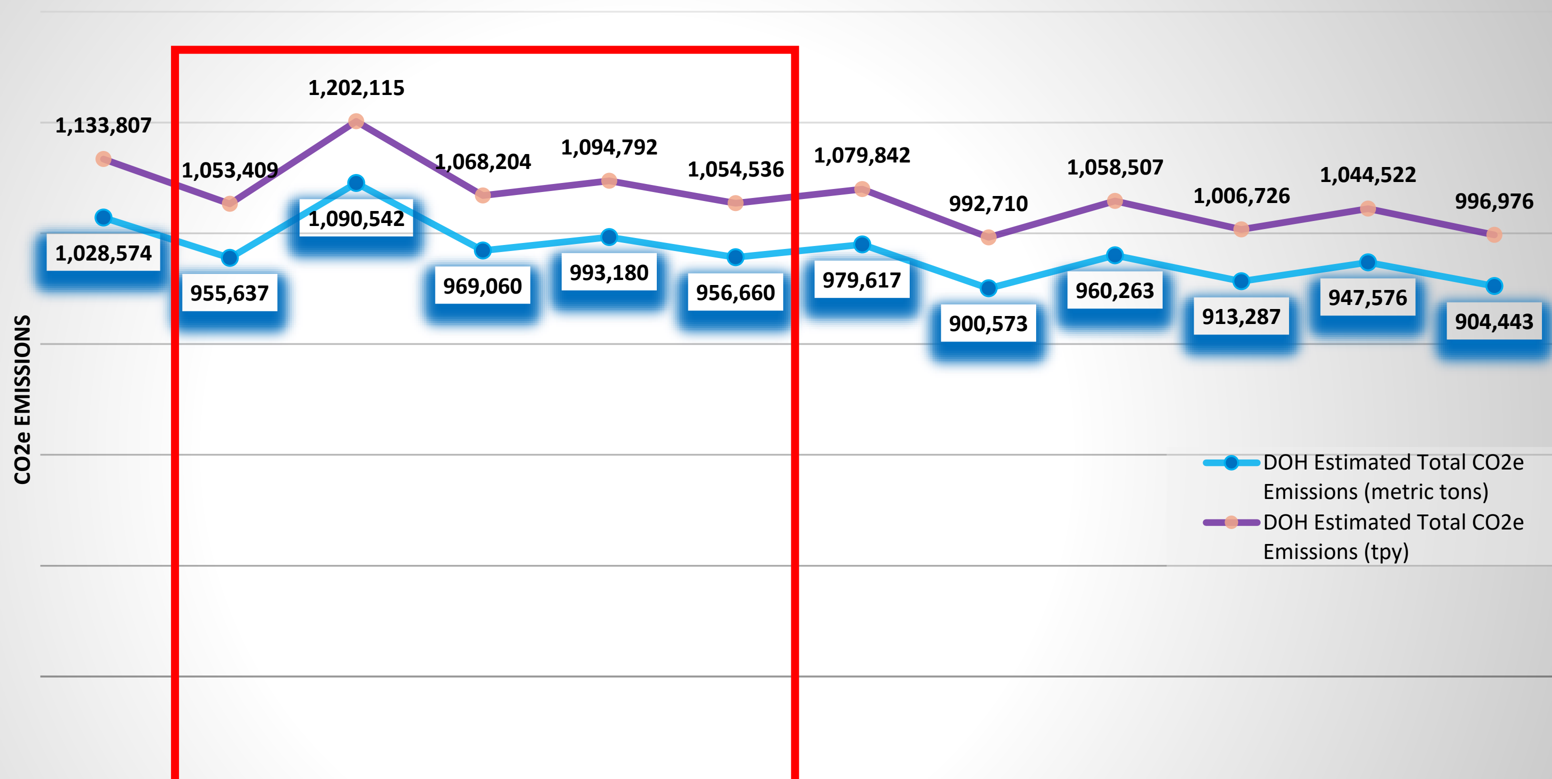
Ref	Source or Derivation	Calendar Year→	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
COMPILE FUEL CONSUMPTION DATA														
(a)	See Data Source	Fuel Oil (FO) #6 (1000 gal)	90792	84158	96124	85408	87676.1	84282	85385	79116	84454	80365	83375	79414
(b)	See Data Source	FO #2 (1000 gal)	229	429	395	360	211.968	392	1416	617	554	480	506	666
	(a)+(b)	**Total**	**91021**	**84587**	**96519**	**85768**	**87888.068**	**84674**	**86801**	**79733**	**85008**	**80845**	**83881**	**80080**
		DATA SOURCE→	CAB Emission Inventory Fuel Data - 2005 to 2010 spreadsheets [a]						SLEIS					
COMPILE EMISSION FACTORS (EF) & GLOBAL WARMING POTENTIAL (GWP) FOR DETERMINING CO_2e EMISSIONS														
(c)	40CFRS98 Table C-1 [78 FR 71950, Nov. 29, 2013]	Heat Value FO#6 (mmBtu/gal)	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15
(d)		Heat Value FO#2 (mmBtu/gal)	0.138	0.138	0.138	0.138	0.138	0.138	0.138	0.138	0.138	0.138	0.138	0.138
(e)		CO_2 EF FO#6 (Kg/mmBtu)	75.10	75.10	75.10	75.10	75.10	75.10	75.10	75.10	75.10	75.10	75.10	75.10
(f)		CO_2 EF FO#2 (Kg/mmBtu)	73.96	73.96	73.96	73.96	73.96	73.96	73.96	73.96	73.96	73.96	73.96	73.96
(g)	40CFRS98 Table C-2 [78 FR 71952, Nov. 29, 2013]	CH_4 EF (Kg/mmBtu)	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003
(h)		N_2O EF (Kg/mmBtu)	0.0006	0.0006	0.0006	0.0006	0.0006	0.0006	0.0006	0.0006	0.0006	0.0006	0.0006	0.0006
(i)	40CFRS98 Table A-1 [79 FR 73779, Dec. 11, 2014]	GWP CO_2	1	1	1	1	1	1	1	1	1	1	1	1
(j)		GWP CH_4	25	25	25	25	25	25	25	25	25	25	25	25
(k)		GWP N_2O	298	298	298	298	298	298	298	298	298	298	298	298
CALCULATE FUEL CONSUMPTION IN MMBTU														
(l)	(a)*(c)*10^3	FO # 6 Consumed (MMBtu)	13,618,800	12,623,700	14,418,600	12,811,200	13,151,415	12,642,300	12,807,735	11,867,400	12,668,061	12,054,750	12,506,250	11,912,100
(m)	(b)*(d)*10^3	FO # 2 Consumed (MMBtu)	31,602	59,202	54,510	49,680	29,252	54,096	195,456	85,146	76,484	66,240	69,828	91,908
(n)	(l)+(m)	Total (MMBtu)	13,650,402	12,682,902	14,473,110	12,860,880	13,180,667	12,696,396	13,003,191	11,952,546	12,744,545	12,120,990	12,576,078	12,004,008
CALCULATE MASS BASED EMISSIONS (TIER 1 METHOD)														
(o)	(e)*(l) + (f)*(m)	CO_2 Mass Emissions (Kg)	1,025,109,164	952,418,450	1,086,868,420	965,795,453	989,834,714	953,437,670	976,316,846	897,539,138	957,028,119	910,210,835	944,383,854	901,396,226
(p)	(g)*(n)*(j)	CH_4 Mass Emissions (Kg)	40,951	38,049	43,419	38,583	39,542	38,089	39,010	35,858	38,234	36,363	37,728	36,012
(q)	(h)*(n)*(k)	N_2O Mass Emissions (Kg)	8,190	7,610	8,684	7,717	7,908	7,618	7,802	7,172	7,647	7,273	7,546	7,202
CALCULATE CO_2e EMISSIONS (TIER 1 METHOD)														
(r)	(l)*(i) + (p)*(j) + (q)*(k)	CO_2e Emissions (Kg)	1,028,573,636	955,637,370	1,090,541,695	969,059,544	993,179,967	956,660,015	979,617,056	900,572,694	960,262,684	913,287,143	947,575,662	904,442,843
(s)	(r)/10^3	**CO_2e Emissions (MT)**	1,028,574	**955,637**	**1,090,542**	**969,060**	**993,180**	**956,660**	979,617	900,573	960,263	913,287	947,576	904,443

[a] **Calendar year 2006 data is based on the annual fee report.**

[b] **The fuel consumption data in CY 2009 monitoring report confirms KCP's proposed alternate GHG emissions baseline,**

Data Source: CAB estimates based on reported fuel consumption

Figure 2-2. Total KPLP CO_2e Emission Estimates



	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
DOH Estimated Total CO2e Emissions (metric tons)	1,028,574	955,637	1,090,542	969,060	993,180	956,660	979,617	900,573	960,263	913,287	947,576	904,443
DOH Estimated Total CO2e Emissions (tpy)	1,133,807	1,053,409	1,202,115	1,068,204	1,094,792	1,054,536	1,079,842	992,710	1,058,507	1,006,726	1,044,522	996,976

ENCLOSURE 2 (Continued)

Table 2-2

	TOTAL COMBINED CO_2e FACILITY-WIDE EMISSIONS														
	Ref	Source or Derivation	Calendar Year→ / Description ↓	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
DOH TIER 1 [d]	(a)	Ref (s) in Table 2-1 of Enclosure 2	DOH Estimated Total CO_2e Emissions (Tier 1, metric tons)	1,028,574	955,637	1,090,542	969,060	993,180	956,660	979,617	900,573	960,263	913,287	947,576	904,443
	(b)	(a)/0.90718474 [a]	DOH Estimated Total CO_2e Emissions (Tier 1 no used oil, tpy)	1,133,807	1,053,410	1,202,116	1,068,205	1,094,794	1,054,537	1,079,842	992,710	1,058,507	1,006,726	1,044,522	996,976
	(c)	FLIGHT	Biogenic Emissions					0	223	0	0	0	0	0	1
	(d)	(b)-(c)	DOH Estimated Non-biogenic Emissions (Tier 1, tpy)					1,094,794	956,437						
KPLP PROPOSAL	(e)	Table 1, Main Text	KPLP Proposed Baseline Emissions (Tier 1 with used oil, tpy)[b]					1,094,813							
	(f)	(e)*0.90718474	KPLP Proposed Baseline Emissions (Tier 1, with used oil, metric tons) [b]					993,198							
	(g)	KPLP GHG ERP	KPLP Baseline Biogenic Emissions (tpy)					0							
	(h)	Table 1, Main Text	KPLP Proposed CO_2e Emissions Cap (Tier 1 with used oil, tpy)[c]					1,094,813							
	(i)	KPLP GHG ERP	KPLP Proposed CO_2e Emissions Cap (metric-tons)[c]					993,198							
	(j)	(e)-(h)	KPLP Proposed Reduction in CO_2e Emissions (tpy)					0							
	(k)	(d)-(j)	DOH Estimated 2020 Minimum CO_2e Emissions Cap (tpy)[c]					1,094,794							
	(l)	(k)-(h)	Amount KPLP Proposed Cap is Lower or Higher (-) than DOH estimates (tpy)					-19.9							
	(m)	(l)/(k)	Percent KPLP Proposed Cap is Lower or Higher (-) than DOH estimates (%)					-0.0018%							
COMBINED PARTNERS	(n)	HECO GHG ERP	Proposed Total Combined Baseline Less Biogenic Emissions (tpy)					8,361,022							
	(o)	(1.00-0.16)*(n)	Calculated Total Combined Emissions Limit (tpy)					7,023,258							
	(p)	HECO GHG ERP	Proposed Partnership Total Combined CO_2e Emissions Limit (tpy)					7,023,258							
	(q)	(p)*0.90718474	Partnering Facilities Proposed Total Combined Emissions Limit Recalculated to Metric Tons					6,371,392							

Included as Table 3 of the main text

DOH Alternate Baseline Assessment (CO_2e Emissions Rate in metric tons)					
CY	2006	2007	2008	2009	2010
CO_2e	955,637	1,090,542	969,060	993,180	956,660
$Ave_{2006-2010}$	993,016	993,016	993,016	993,016	993,016
Δ (%)	-3.76%	9.82%	-2.41%	0.02%	-3.66%

FOOTNOTES

[a] 1 metric-ton = 0.90718474 * short tons

[b] KPLP proposed alternate CY 2009 baseline emissions, which includes emissions from firing specification used oil are shown in Table 2-3.

[c] Minimum Facility-Wide GHG Emissions Cap pursuant to HAR §11-60.1-204(c)

[d] Tier 1 computation method is used to illustrate relative emissions due to the availability of data over a longer duration. Specification used oil and biodiesel fuel consumption data are not available over the entire duration and therefore are not included in DOH estimates. This represents a delta (Δ) of less that one percent (1%) of total GHG emissions (refer to Enclosure 2A, Table 2A-1, Ref (u)).

ENCLOSURE 2 (Continued)

Table 2-3
KPLP Proposed 2009 GHG Baseline Emissions Estimate Using Tier 1 Method[b]

	Convert	Fuel Used	Standard HHV	CO_2 EF	CO_2 Emissions	CH_4 EF	CH_4 Emissions	N_2O EF	N_2O Emissions
	(MT/kg)	**(gals)**	**(mmbtu/ gal)**	**(kg/ mmbtu)**	**(MT)**	**(kg/ mmbtu)**	**(MT)**	**(kg/ mmbtu)**	**(MT)**
LSFO	0.001	87,676,100	0.15	75.1	987,671	0.003	39	0.0006	7.891
Diesel	0.001	211,968	0.138	73.96	2,163	0.003	0	0.0006	0.018
Used Oil	0.001	1,680	0.144	74.27	18	0.003	0	0.0006	0.000
Bio-diesel	0.001	0	0.128	73.84	0	0.003	0	0.0006	0.000
Breakdown of KPLP'S 2009 GHG Mass Based Emissions					989,853		40		7.909
GWP from 40CFR§98 Table A-1					1		25		298
Breakdown of KPLP'S 2009 CO_2e Based Emissions					989,853		989		2,357
Total Combined KPLP's 2009 CO_2e Baseline Emissions Estimate (MT) =									993,198
Total Combined KPLP's 2009 CO_2e Baseline Emissions Estimate (Short Ton)[a] =									1,094,813

[a] **1 metric ton (MT) = 0.90718474 x 1 short ton**

[b] **Data and computations extracted from KPLP's (Michael Rossio) September 5, 2018 email.**

Difference Between KPLP & DOH 2009 Baseline Estimates	
KPLP's 2009 GHG Baseline Emissions Estimate (MT) =	993,198
DOH 2009 GHG Baseline Emissions Estimate (MT) =	993,180
Δ Between KPLP & DOH estimates (MT)	18
Δ Between KPLP & DOH estimates (%)	0.0018%

ENCLOSURE 2A TIER 1 COMPARISON TO TIER 3

Purpose: This enclosure contains the details for calculating KCP's GHG emissions using both the Tier 1 and Tier 3 methods. The results from the detailed computations of this enclosure can be used to examine the potential impact when using a baseline developed from using the Tier 1 method as a benchmark for gaging future GHG emissions developed from using the Tier 3 method.

Background: KCP's proposed alternate CY 2009 baseline GHG emissions rate was calculated using the Tier 1 method in accordance with 40 CFR §98.33. The Tier 1 method is the least accurate method in 40 CFR §98.33 since fuel specific default emission factors and HHV are used in the computations. From CY 2011, KCP started reporting GHG emissions rate using the Tier 3 method pursuant to the new mandatory reporting requirements to EPA's Facility Level Information on Greenhouse Gases (GHG) Tool (FLIGHT) in accordance with 40 CFR §98.33. Tier 3 method uses the annual average carbon content of the liquid fuel with the ratio of carbon dioxide to carbon molecular weights.

Evaluation: Table 2A-1 is DOH's detailed computations of KCP GHG emissions using the Tier 1 method, (Equation C-1) in 40 CFR §98.33, with the following expression:

$$CO_2 = 1 \text{ x } 10^{-3} \text{ x Fuel x HHV x EF}$$

Where,

CO_2 =	Annual CO_2 mass emissions for the specific fuel type (metric tons).
Fuel =	Mass or volume of fuel combusted per year, from the State and Local Emissions Inventory System (SLEIS) (express volume in gallons for liquid fuel).
HHV =	Default high heat value of the fuel, from 40 CFR Part 98, Table C1 (expressed in mmbtu per gal)
EF =	Fuel specific default CO_2 emission factor, from 40 CFR Part 98, Table C1 (expressed in kg CO_2/mmbtu).
1×10^{-3} =	Conversion factor from kilograms to metric tons.

The emissions from firing specification used oil is included for this evaluation for consistency when comparing to GHG emissions developed from the Tier 3 method as reported in FLIGHT. Data for CY 2011 to 2015 were selected because Tier 3 and specification used oil data are available during this time period. It should be noted that SLEIS does not contain KCP's consumption rate data for specification used oil.

Table 2A-2 summarizes KCP GHG emissions using Tier 3 method as reported in FLIGHT.

In both tables, the mass-based emissions were computed as CO_2e emissions using global warming potentials from 40 CFR Part 98, Table A-1. The final comparison between GHG emissions using Tier 1 and Tier 3 methods are summarized in Table 4 of the main body of this review.

ENCLOSURE 2A (Continued)

Table 2A-1 GHG Emission Using Tier 1 (Including Specification Used Oil)

Ref	Source or Derivation	Calendar Year→	2011	2012	2013	2014	2015
COMPILE FUEL CONSUMPTION DATA							
(a)	SLEIS	Fuel Oil (FO) #6 (1000 gal)	85385	79116	84454	80365	83375
(b)	SLEIS	FO #2 (1000 gal)	1416	617	554	480	506
	(a)+(b)	**Total**	**86801**	**79733**	**85008**	**80845**	**83881**
(b1)	FLIGHT (e-Grit) [a]	CT1 Emissions from Used Oil (metric tons)	5.80	3.00	0.00	2.90	2.40
(b2)		CT2 Emissions from Used Oil (metric tons)	5.80	3.00	0.00	2.90	2.40
(b3)		CT1 Used Oil Consumed (1000 gal)	Not Reported in FLIGHT			0.240	0.200
(b4)		CT2 Used Oil Consumed (1000 gal)				0.240	0.200
(b5)	(b3)+(b4)	CT1 & CT2 Used Oil Consumed (1000 gal)	NA	NA	NA	0.480	0.400
COMPILE EMISSION FACTORS (EF) & GLOBAL WARMING POTENTIAL (GWP) FOR DETERMINING CO_2e EMISSIONS							
(c)	40CFRS98 Table C-1 [78 FR 71950, Nov. 29, 2013]	Heat Value FO#6 (mmBtu/gal)	0.15	0.15	0.15	0.15	0.15
(d)		Heat Value FO#2 (mmBtu/gal)	0.138	0.138	0.138	0.138	0.138
(e)		CO_2 EF FO#6 (Kg/mmBtu)	75.10	75.10	75.10	75.10	75.10
(f)		CO_2 EF FO#2 (Kg/mmBtu)	73.96	73.96	73.96	73.96	73.96
(f1)		Heat Value Used Oil (mmBtu/gal)	0.138	0.138	0.138	0.138	0.138
(f2)		CO_2 EF Used Oil (Kg/mmBtu)	74.00	74.00	74.00	74.00	74.00
(g)	40CFRS98 Table C-2 [78 FR 71952, Nov. 29, 2013]	CH_4 EF (Kg/mmBtu)	0.003	0.003	0.003	0.003	0.003
(h)		N_2O EF (Kg/mmBtu)	0.0006	0.0006	0.0006	0.0006	0.0006
(i)	40CFRS98 Table A-1 [79 FR 73779, Dec. 11, 2014]	GWP CO_2	1	1	1	1	1
(j)		GWP CH_4	25	25	25	25	25
(k)		GWP N_2O	298	298	298	298	298
CALCULATE FUEL CONSUMPTION IN MMBTU							
(l)	(a)*(c)*10^3	FO # 6 Consumed (mmbtu)	12,807,735	11,867,400	12,668,061	12,054,750	12,506,250
(m)	(b)*(d)*10^3	FO # 2 Consumed (mmbtu)	195,456	85,146	76,484	66,240	69,828
(m1)	(b5)*(f1)*10^3	Used Oil Consumed (mmbtu)				66.240	55.200
(n)	(l)+(m)	Total (mmbtu)	13,003,191	11,952,546	12,744,545	12,120,990	12,576,078
CALCULATE MASS BASED EMISSIONS (TIER 1 METHOD)							
(o)	(e)*(l) + (f)*(m)	CO_2 Mass Emissions (Kg)	976,316,846	897,539,138	957,028,119	910,210,835	944,383,854
(p)	(g)*(n)*(j)	CH_4 Mass Emissions (Kg)	39,010	35,858	38,234	36,363	37,728
(q)	(h)*(n)*(k)	N_2O Mass Emissions (Kg)	7,802	7,172	7,647	7,273	7,546
CALCULATE CO_2e EMISSIONS (TIER 1 METHOD) & PERCENT IMPACT ATTRIBUTED TO USED OIL							
(r)	(o)*(i) + (o1)*(i) + (p)*(j) + (q)*(k)	CO_2e Emissions (Kg)	979,617,068	900,572,700	960,262,684	913,287,148	947,575,667
(r1)	See notes [a & b]	CO_2e Emissions (MT) from used oil	11.60	6.00	0.00	4.90	4.08
(s)	(r)/10^3	CO_2e Emissions (MT) w/o used oil	979,617	900,573	960,263	913,287	947,576
(t)	**(r1)+(s)**	**CO_2e Emissions (MT) w/ used oil**	**979,629**	**900,579**	**960,263**	**913,292**	**947,580**
(u)	(r1)/(t)	Percent of GHG emissions attributed to the combustion of used oil	0.0012%	0.0007%	0.0000%	0.0005%	0.0004%

[a] **For CY 2011 to 2013, Tier 3 emissions data for specification used oil were taken directly from FLIGHT to compute CO_2e emissions using the following:**

$$(r1) = (b1) + (b2)$$

For CY 2014 and 2015, the fuel consumption rate of specification used oil from FLIGHT with the HHV and emissions factor from 40 CFR98 Table C-1 were used to compute CO_2e emissions in metric tons (MT) using the following:

$$(r1) = (f2)*(i)*(m1) * 10^{-3}$$

[b] **Used oil emissions and consumption data in CY 2009 and 2016 not available in FLIGHT.**

ENCLOSURE 2A (Continued)

Table 2A-2 GHG Emission Using Tier 3 (Including Specification Used Oil)

Emission Type	Emission Unit	Fuel Type	Ref	Source or Derivation ↓	Calendar Year →	2011	2012	2013	2014	2015	2016
					Calculation Method →	Tier 3 (C-4)	Tier 3 (C-4)	Tier 3 (C-4)	Tier 3 (C-4)	Tier 3 (C-4)	CEMS
					Pollutant ↓						
Mass Based CO_2	Unit CT1	FO No. 2		FLIGHT (e-Grit)	Biogenic Carbon dioxide (MT)	0.00	0.00	0.00	0.00	0.00	0.00
			a		Methane (MT)	0.41	0.00	0.00	0.10	0.13	0.13
			b		Nitrous Oxide (MT)	0.08	0.00	0.00	0.02	0.03	0.03
			c		Carbon Dioxide (MT)	10,313	954	3,321	2,547	3,116	0
		FO No. 6			Biogenic Carbon dioxide (MT)	0.00	0.00	0.00	0.00	0.00	0.00
			d		Methane (MT)	20.00	17.00	19.00	18.40	18.88	16.62
			e		Nitrous Oxide (MT)	4.00	3.00	4.00	3.68	3.78	3.33
			f		Carbon Dioxide (MT)	511,277	426,834	491,148	468,011	479,733	402,610
		Used Oil	g		Methane (MT)	0.00	0.00	0.00	0.00	0.00	0.00
			h		Nitrous Oxide (MT)	0.00	0.00	0.00	0.00	0.00	0.00
			i		Carbon Dioxide (MT)	5.80	3.00	0.00	2.90	2.40	0.00
	Unit CT2	FO No. 2			Biogenic Carbon dioxide (MT)	0.00	0.00	0.00	0.00	0.00	0.00
			j		Methane (MT)	0.13	0.00	0.00	0.09	0.08	0.15
			k		Nitrous Oxide (MT)	0.03	0.00	0.00	0.02	0.02	0.03
			l		Carbon Dioxide (MT)	3,226.50	1,316.00	2,065.00	2,284.40	2,051.50	0
		FO No. 6			Biogenic Carbon dioxide (MT)	0.00	0.00	0.00	0.00	0.00	0.00
			m		Methane (MT)	18.16	19.00	18.00	17.29	18.26	18.51
			n		Nitrous Oxide (MT)	3.63	4.00	4.00	3.46	3.65	3.70
			o		Carbon Dioxide (MT)	464,274	481,543	462,133	439,559	463,994	440,619
		Used Oil	p		Methane (MT)	0.00	0.00	0.00	0.00	0.00	0.00
			q		Nitrous Oxide (MT)	0.00	0.00	0.00	0.00	0.00	0.00
			r		Carbon Dioxide (MT)	5.80	3.00	0.00	2.90	2.40	0.00
CO_2e	Combined Units	Combined Fuel Types			Biogenic Carbon dioxide (MT)	0	0	0	0	0	0.00
			s	25*(SUMIF Pollutant =	Methane (MT))	968	900	925	897	934	885.25
			t	298*(SUMIF Pollutant=	Nitrous Oxide (MT))	2,307	2,086	2,384	2,139	2,226	2,110.14
			u	SUMIF Pollutant =	Carbon Dioxide (MT)	989,102	910,653	958,667	912,407	948,899	843,229
			v	$\Sigma_{s \text{ to } u}$	Total CO_2e Non-biogenic Emissions (MT)	992,376	913,639	961,976	915,443	952,059	846,224

ENCLOSURE 3 PROJECT EMISSIONS

Table 3-1 Changes in Annual Emissions

Air Pollutant (CAS #)	2008 Permit Application Review No. 0214-06			2018 Permit Application Review No. 0214-10			
	Hourly Rate[(1)]	Annual (tpy[(2)]) per CT	Total (tpy[(2)])	Hourly Rate (lbs/hr)[(6)]	(hrs)[(2)]	Annual (tpy) per CT	Total (tpy)
NOx (CT1 & CT2)	488	2,067	4,134	483	8,472	2,046	4,092
SO_2 (CT1 and CT2)	483	2,048	4,096	488	8,472	2,067	4,134
CO (CT1 and CT2)	35	148	296	35	8,472	148	297
PM_{10} (CT1 and CT2)	80	339	678	80	8,472	339	678
VOC (CT1 and CT2)	3.6	15	30	3.6	8,472	15	30
Antimony (172) (CT1 & CT2)	15.02	0.28	0.56	0.03304	8,472	0.140	0.28
Arsenic (173) (CT1 & CT2)	3.78	0.035	0.07	0.00832	8,472	0.035	0.07
Benzene (15) (CT1 & CT2)	0.61	0.006	0.01	0.00134	8,472	0.006	0.01
Beryllium (174) (CT1 & CT2)	0.13	0.001	0.002	0.00029	8,472	0.001	0.002
Cadmium (175) (CT1 & CT2)	3.4	0.032	0.064	0.00748	8,472	0.032	0.063
Chlorine (33) (CT1 & CT2)[(11)]	6.6	0.061	0.122	0.01452	8,472	0.062	0.123
Chromium (176) (CT1 & CT2)	19.20	0.179	0.358	0.04224	8,472	0.179	0.358
Cobalt (177) (CT1 & CT2)	17.22	0.161	0.322	0.03788	8,472	0.160	0.321
Ethylbenzene (76) (CT1 & CT2)	0.18	0.002	0.004	0.0004	8,472	0.002	0.003
Formaldehyde (86) (CT1 & CT2)	94.39	0.881	1.762	0.20766	8,472	0.880	1.759
Lead (181) (CT1 & CT2)	23.7	0.221	0.442	0.05214	8,473	0.221	0.442
Manganese (182) (CT1 & CT2)	138.92	1.296	2.592	0.3219	8,472	1.364	2.727
Mercury (183) (CT1 & CT2)	4.43	0.041	0.082	0.00975	8,472	0.041	0.083
Napthalene (118) (CT1 & CT2)	3.23	0.030	0.060	0.00711	8,472	0.030	0.060
Nickel (185) (CT1 & CT2)[(7)]				0.818	8,472	3.466	6.93
Toluene (151) (CT1 & CT2)	17.73	0.165	0.330	0.03901	8,472	0.165	0.330
o-Xylene (169) (CT1 & CT2)	0.31	0.003	0.006	0.00068	8,472	0.003	0.006
POM (186) (CT1 & CT2)	3.72	0.035	0.070	0.00818	8,472	0.035	0.069
Phosphorous (133) (CT1 & CT2)	122.58	1.144	2.288	0.26968	8,472	1.142	2.285
Selenium (188) (CT1 & CT2)	2.17	0.02	0.040	0.0117	8,472	0.050	0.099
VOC (LSFO Storage Tank T1)	1.258[(3)]	0.02	0.02	0.005	8760	NA	0.02
VOC (LSFO Storage Tank T2)	1.258[(3)]	0.02	0.02	0.005	8760		0.02
VOC (Diesel Storage Tank)[(4)]	27.1[(3)]	2.01	2.01	0.258	8760		1.13
VOC (Fuel Additive Tank)[(10)]	0.8[(3)]	0.21	0.21	0.8	8760		3.50
VOC (Fuel Pumps)	0.0190	1.25	1.25	Refer to Table 3A-1			1.25
VOC (Valves)	0.0002	0.31	0.31				0.31
VOC (Flanges)	0.0002	0.26	0.26				0.26
PM_{10} (Cooling Tower)	0.0009[(5)]	8.0	8.0	Refer to note [(8)]			8

ENCLOSURE 3 (Continued)

Table 3-1 (Continued)

Footnotes:

(1) **The HAP hourly emission rates were expressed in grams per hour in the 2008 Permit Application Review No. 0214-06. All other hourly emissions rate for source units are expressed in lbs per hour. For the CTs, the emissions rate are based at > 80% of full load except CO which is based on 60% - 80% of full load.**

(2) **Based on 8,472 maximum annual operating hours after factoring out 288 hours down time for inspection and maintenance. *(Source: section 4.2 of permit renewal application no. 0214-09)*.**

annual operating hours =	**8760**	**-**	**288**	**=**	**8472**	**(hours)**
			Inspect and Maintain			

(3) **Annual throughput, thousand barrels.**

(4) **Horizontal cylinder tanks (12 feet diameter x 50 feet long).**

(5) **lbs/1000 gal-water.**

(6) **A conversion factor of 0.0022 lbs/gram was used in converting the emissions rate to lbs/hr for rates specified in grams/hr.**

(7) **Maximum potential hourly emissions rate for nickel (Ni) computed on a worst-case basis using KCP's highest nickel content of 16.61 ppm based on data over the last six years provided in Mr. Michael Armistead's July 31, 2018 email and API Gravity of 19.507, provided in KCP's 2017 fuel delivery data. This is the absolute maximum nickel emissions possible since some of the nickel is consumed in the process and does not become an air emission.**

KCP's Fuel Delivery Data		
CY	**Ni (PPM)**	
2012	14.88	
2013	16.61	
2014	7.29	
2015	12.32	
2016	12.57	
2017	13.49	
Ave	12.86	Ave content (PPM) for 6 yrs, CY 2012 to 2017
Ave<2014>	13.97	Ave content (PPM) for CY 2012 to 2017 without CY 2014
Maximum	16.61	

Specific Gravity (SG) @ 60°F = 141.5/(API gravity +131.5)

API Gravity =	19.507	SG =	0.937

ENCLOSURE 3 (Continued)

Table 3-1 Footnotes (Continued)

Fuel Density	Water (lbs/gal)	Specific Gravity (none)	LSFO No. 6 (lbs/gal)
	8.345	0.937	7.820

Fuel Consumption Limit (gal/yr)	Annual Operating Hours per CT (hrs/yr)	Fuel Rate per CT (gal /hr)
106,747,200	8,472	6,300

Fuel Consumption Rate	Fuel Rate (gal/hr)	Density (lbs/gal)	Fuel Rate (lbs/hr)
	6,300	7.820	49,264

Emission Rate (lbs/hr) for Nickel (Ni) = Fuel Rate x Nickel Content (ppm) x 10^{-6}

Fuel Rate (lbs/hr)	Ni Content (ppm)	Conversion (none)	Emission Rate (lbs/hr)
49,264	16.61	0.000001	0.818

(8) **PM_{10} emissions for the cooling tower are based on past recommendations from Mr. Ron Myers at the EPA, Research Triangle Park as documented in permit application review no. 0214-01 and computed as follows:**

PM_{10} emissions = DE X TDS X CW

Where,	DE =	Drift Eliminator Factor		=	0.00001	@ 99.999% Control	
	TDS =	Total Dissolved Solids		=	10,332	(ppmwt)	
	CW=	Circulating Water Volume =			523,530	(gal/hr-cell)	
Determine weight fraction	TDS =	10,332	(ppmwt)	X	0.000001	=	0.010332
Compute CW by weight	CW_{Wt} =	523,530	(gal/hr-cell)	X	8.345	(lbs/gal) =	4,368,858
PM_{10} emissions (lbs/hr-cell) =	0.00001	X	0.010332	X	4,368,858	=	0.45139
PM_{10} emissions (tpy) =	0.45139	X	8472 / 2000	X	4 Cells	=	8

(9) **Based on a fuel consumption rate of 49,264 lbs/hr per CT as computed in Footnote (7) and taking the ratio of quantity of specification used oil consumed (i.e. 10,000 or 20,000 gallons per CT) to the annual limit of total fuel consumed of 106,747,200 gallons, maximum potential emissions of pollutants were estimated on a worst case basis using the limits for specification used oil specified in 40 CFR §279.11. The following calculations demonstrates the impact of increasing the quantity of specification used oil fired to 20,000 gallons:**

ENCLOSURE 3 (Continued)

Table 3-1 Footnotes (Continued)

SPEC USED OIL FUEL RATES
(Assume the specific gravity of used oil is the same as LSFO)

Fuel Rate per CT	Annual Usage of Used Oil	Total Fuel Consumption Limit	Ave Fuel Rate of Used Oil per CT	Ave Fuel Rate of LSFO/Diesel per CT
(lbs/hr)	(gal/yr)	(gal/yr)	(lbs/hr)	(lbs/hrs)
(a)	(b)	(c)	(d)=(a)x(b)/(c)	(e)=(a)-(d)
49,264	10,000	106,747,200	4.61	49,259
49,264	20,000	106,747,200	9.23	49,254

SPEC USED OIL EMISSION RATES PER CT (10,000 gal limit per yr)
Emission Rates of Pollutants (lbs/hr) = Ave Fuel Rate x Content (ppm) x 10^{-6}

Pollutants	Ave Fuel Rate	Content	Ave Emission Rate	
	(lbs/hr)	(ppm)	(lbs/hr)	(tpy)
	(a)	(b)	(c)	(d)=(c)x8472/2000
Sulfur[a]	4.61	5,000	2.31E-02	
Sulfur Dioxide[a]			4.61E-02	1.95E-01
Arsenic	4.61	5	2.31E-05	9.77E-05
Cadmium	4.61	2	9.23E-06	3.91E-05
Chromium	4.61	10	4.61E-05	1.95E-04
Lead (Pb)	4.61	100	4.61E-04	1.95E-03
Halogens[b]	4.61	1,000	4.61E-03	1.95E-02
PCBs	4.61	2	9.23E-06	3.91E-05

SPEC USED OIL EMISSION RATES PER CT (20,000 gal limit per yr)
Emissions of Pollutants (lbs/hr) (c) = Ave Fuel Rate x Content (ppm) x 10^{-6}

Pollutants	Ave Fuel Rate	Content	Ave Emission Rate	
	(lbs/hr)	(ppm)	(lbs/hr)	(tpy)
	(a)	(b)	(c)=(a)x(b)x10^{-6}	(d)=(c)x8472/2000
Sulfur	9.23	5000	4.62E-02	
Sulfur Dioxide[a]			9.23E-02	3.91E-01
Arsenic	9.23	5	4.61E-05	1.95E-04
Cadmium	9.23	2	1.85E-05	7.82E-05
Chromium	9.23	10	9.23E-05	3.91E-04
Lead (Pb)	9.23	100	9.23E-04	3.91E-03
Halogens[b]	9.23	1,000	9.23E-03	3.91E-02
PCBs	9.23	2	1.85E-05	7.82E-05

[a] The average emission rate for SO_2 is twice that of sulfur emission rate based on a mass balance ratio of the molecular weights (i.e. $MW_{SO2} \div MW_S$ = 64/32=2).

[b] Added to chlorine in its entirety

Table 3-1 Footnotes (Continued)

(10)

The 13,020 gallon tank is no longer being used as a "bio-fuel tank" and returned to service as an "additive storage tank" as clarified in Mr. Michael Rossio's April 3, 2018's email.

(11) **Emissions of halogens from the consumption of specification used oil was included entirely with the emissions of chlorine since no other elements within the halogen group are listed as a hazardous air pollutant.**

ENCLOSURE 3A TANKS AND MISC

Table 3A-1 VOC Emissions from Pumps, Valves, and Flanges				
Component →	Pumps	Valves	Flanges	Total
Number	15	350	297	
Emission factor (lb/hr-component) [a]	0.019	0.0002	0.0002	
Annual emissions (tpy) [b]	1.25	0.31	0.26	1.82

Footnotes:

[a] **Emission factors from the 1998 permit application review no. 0214-01.**

[b] **Emissions = No. of Components x Emission factor x 8760 hrs ÷ 2000 lbs/tons**

ENCLOSURE 3A (Continued)

Table 3A-2 Subpart Kb Applicability Determination of Storage Vessels

Tank No.	Tank Description	Tank Content	Tank Capacity (gallons)	Tank Capacity[a] (m^3)	Max P_{VA}[b] of fuel (psi)	40CFR Subpart Kb, §60.110b Applicability[c]					
						≥ July 23, 1984	Capacity ≥ 75 m^3	Capacity < 151 m^3	Max P_{VA}≥ 2.18[d] psi	Max P_{VA}≥ 0.508[d] psi	Subpart Kb Applies
(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
1	LSFO storage tank	LSFO	1,050,000	3975	0.00019	Yes	Yes	No	NA	No	No
2	LSFO storage tank	LSFO	1,050,000	3975	0.00019	Yes	Yes	No	NA	No	No
	Diesel fuel storage tank	Fuel Oil No. 2	52,920	200	0.022	Yes	Yes	No	NA	No	No
	Fuel additive tank	Additives	13,020	49		Yes	No				No

Footnotes:

[a] **AP-42 Appendix A (9/85 Reformatted 1/95), MISCELLANEOUS DATA AND CONVERSION FACTORS, used as reference for the following conversions:**

1 gallon = 0.0037854 m^3

[b] **Max P_{VA} = Maximum true vapor pressure as defined in 40 CFR Kb §60.111b and determined from AP42 Section 7.1 (11/06). The worst case vapor pressure taken at 100°F from Table 7.1-2 of AP 42 Section 7.1.**

[c] **40CFR Subpart Kb, §60.110b Applicability:**

(a) Subpart Kb applies to each storage vessel with a capacity greater than or equal to 75 cubic meters (m^3) that is used to store volatile organic liquids (VOL) for which construction, reconstruction, or modification is commenced after July 23, 1984.

(b) Subpart Kb does not apply to storage vessels with:

(1) a capacity greater than or equal to 151 m^3 storing a liquid with a maximum true vapor pressure less than 3.5 kilopascals (kPa); or

(2) a capacity greater than or equal to 75 m^3 but less than 151 m^3 storing a liquid with a maximum true vapor pressure less than 15.0 kPa.

ENCLOSURE 3A (Continued)

Table 3-4 Footnotes (Continued)

[d] The equivalent true vapor pressures (P_{VA}) when converting the units from kPa to psi are shown below:

1 kilo Pascal (kPa) = 0.145038 (psi)

Source of Threshold	P_{VA}	
	kPa	psi
40CFR Kb, §60.110b(b)(1)	3.5	0.508
40CFR Kb, §60.110b(b)(2)	15	2.18

ENCLOSURE 4 EMERGENCY DIESEL ENGINE GENERATOR

Table 4-1

207 bhp Emergency DEG (Fired with fuel oil No. 2)				
Pollutant	Emission Factors (EF) [a]	Emission Rate (ER) [b]	Annual Emissions [c]	Annual Emissions
	(lb/hp-hr)	(lbs/hr)	(lbs/yr)	(tpy)
	(a)	(b)=(a)*207	(c)=500*(b)	(d)=(c)/2000
NO_x	3.10E-02	6.48E+00	3239.5	1.6
SO_2 [d]	1.31E-05	2.74E-03	1.4	6.84E-04
CO	6.68E-03	1.40E+00	698.1	3.49E-01
PM [e]	2.29E-03	4.79E-01	239.5	1.20E-01
PM_{10}	2.20E-03	4.60E-01	229.9	1.15E-01
$PM_{2.5}$ [e]	2.06E-03	4.31E-01	215.5	1.08E-01
TOC [f]	2.51E-03	5.25E-01	262.7	1.31E-01
Pb	0.00E+00	0.00E+00	0.00E+00	0.00E+00
HAP (Highest)	Refer to Sub-Table 4-1.1			1.55E-04
HAP (Total)				3.95E-04
CO_2e	Refer to Sub-Table 4-1.3			22

Table 4-2

121 bhp DEG for the Emergency Fire Pump (Fired with fuel oil No. 2)				
Pollutant	Emission Factors (EF) [a]	Emission Rate (ER) [b]	Annual Emissions [c]	Annual Emissions
	(lb/hp-hr)	(lbs/hr)	(lbs/yr)	(tpy)
	(a)	(b)=(a)*121	(c)=500*(b)	(d)=(c)/2000
NO_x	3.10E-02	3.7510	1876	9.38E-01
SO_2 [d]	1.31E-05	1.58E-03	1	3.96E-04
CO	6.68E-03	8.08E-01	404	2.02E-01
PM [e]	2.29E-03	2.77E-01	139	6.93E-02
PM_{10}	2.20E-03	2.66E-01	133	6.66E-02
$PM_{2.5}$ [e]	2.06E-03	2.50E-01	125	6.24E-02
TOC [f]	2.51E-03	3.04E-01	152	7.61E-02
Pb	0.00E+00	0.00E+00	0.00	0.00E+00
HAP (Highest)	Refer to Sub-Table 4-2.1			9.08E-05
HAP (Total)				2.31E-04
CO_2e	Refer to Sub-Table 4-2.3			13

Footnotes to Tables 4-1 & 4-2:

[a] **EFs are from AP-42 Section 3.3 (10/96), unless otherwise specified.**

[b] **ER (lb/hr) = EF (lb/hp-hr) x *[DEG Power Rating]* (bhp)**

[c] **The 500 maximum annual operating hours is the default assumption used in calculating the potential to emit (PTE) for emergency generators.**

[Source: EPS's memorandum dated September 6, 1995 disseminated from the Office of Air Quality Planning and Standards (MD-10). Refer to inter-office email dated November 19, 2015.]

[d] **The SO_2 EF is determined from the following factors from AP42, Appendix A and low sulfur fuel oil (0.5% maximum sulfur content).**

(e)	**137,000 btu/gal**	**Page A-5 of AP42**	**Heating Value**
(f)	**7.05 lbs/gal**	**Page A-7 of AP42**	**Density of distillate oil**
(g)	**1.341 hp/kW**	**Page A-15 of AP42**	**Conversion factor**
(h)	**3,413 btu/kW-hr**	**Page A-30 of AP42**	**Conversion factor**
(i)=	**(h)*(f)/(g)*(e)**	**0.130971276**	**lbs/hp-hr**

Using a relative atomic mass ratio of 2 for sulfur dioxide to sulfur, the following mass balance calculations is used to determined the EF for SO_2 emissions:

Calculate SO_2 Emission Factor

Total Rate (lbs/hp-hr)	Relative Atomic Mass	Sulfur Content (% wt)	EF (lbs/hp-hr)
(i)	**(j)**	**(k)**	**(a)=(i)*(j)*(k)/100**
0.130971276	**2**	**0.5%**	**1.31E-05**

[e] **It is assumed that 96% and 90% of the total particulate is PM_{10} and $PM_{2.5}$ respectively, based on AP-42 Appendix B.2, Table B.2-2 (9/90 reformatted 1/95) for gasoline and diesel fired internal combustion engines.**

PM =	**$PM_{10} \div (0.96)$**	**=**	**0.002292**	**(lb/hp-hr)**
$PM_{2.5}$ =	**PM x (0.90)**	**=**	**0.0020625**	**(lb/hp-hr)**

[f] **EFs for total organic compounds (TOCs) from Table 3.3-1 of AP-42 Section 3.3 (10/96) include volatile organic compounds (VOCs).**

Total TOC	2.51E-03
Exhaust	2.47E-03
Evaporative	0
Crackcase	4.41E-05
Refueling	0

Sub-Table 4-1.1

HAP (Speciated organic compounds)

207 bhp Emergency DEG (Fired with fuel oil No. 2)				
Organic Compound	Emission Factor[a] (Fuel Input)	Maximum Heat Input Rate [b]	Annual Emissions [c]	Annual Emissions
	(lb/MMBtu)	(MMBtu/hr)	(lbs/yr)	(tpy)
	(a)	(b)	(c)=500*(a)*(b)	(d)=(c)/2000
Acenaphthene	1.42E-06	5.26E-01	3.74E-04	1.87E-07
Acenaphthylene	2.92E-05	5.26E-01	7.68E-03	3.84E-06
Acetaldehyde	7.67E-04	5.26E-01	2.02E-01	1.01E-04
Acrolein	9.25E-05	5.26E-01	2.43E-02	1.22E-05
Anthracene	1.87E-06	5.26E-01	4.92E-04	2.46E-07
Benzene	9.33E-04	5.26E-01	2.46E-01	1.23E-04
Benzo(a)anthracene	1.68E-06	5.26E-01	4.42E-04	2.21E-07
Benzo(b)fluoranthene	9.91E-08	5.26E-01	2.61E-05	1.30E-08
Benzo(k)fluoranthene	1.55E-07	5.26E-01	4.08E-05	2.04E-08
Benzo(g,h,l)perylene	4.89E-07	5.26E-01	1.29E-04	6.43E-08
Benzo(a)pyrene	1.88E-07	5.26E-01	4.95E-05	2.47E-08
1,3 Butadiene	3.91E-05	5.26E-01	1.03E-02	5.14E-06
Chrysene	3.53E-07	5.26E-01	9.29E-05	4.64E-08
Dibenz(a,h)anthracene	5.83E-07	5.26E-01	1.53E-04	7.67E-08
Fluoranthene	7.61E-06	5.26E-01	2.00E-03	1.00E-06
Fluorene	2.92E-05	5.26E-01	7.68E-03	3.84E-06
Formaldehyde	1.18E-03	5.26E-01	3.11E-01	1.55E-04
Indeno(1,2,3-cd)pyrene	3.75E-07	5.26E-01	9.87E-05	4.93E-08
Naphthalene	8.48E-05	5.26E-01	2.23E-02	1.12E-05
Phenanthrene	2.94E-05	5.26E-01	7.74E-03	3.87E-06
Pyrene	4.78E-06	5.26E-01	1.26E-03	6.29E-07
Toluene	4.09E-04	5.26E-01	1.08E-01	5.38E-05
Xylenes	2.85E-04	5.26E-01	7.50E-02	3.75E-05
			HAP (Highest)	1.55E-04
			HAP (Total)	3.95E-04

Table 4-1.2

CO_2 Mass-Based Emissions

207 bhp Emergency DEG (Fired with fuel oil No. 2)					
Pollutant	Maximum Heat Input Rate [b]	Emission Factor [d]	Emission Rate [e]	GHG Mass-Based Emissions	
	(MMBtu/hr)	(kg/MMBtu)	(metric-ton/hr)	(metric-ton/yr)	(tpy)
	(a)	**(b)**	**(c) =(a)*(b)*10^{-3}**	**(d)=(c)*500 [e]**	**(e)**
CO_2	5.26E-01	73.96	3.89E-02	19	21
CH_4	5.26E-01	3.00E-03	1.58E-06	7.89E-04	8.70E-04
N_2O	5.26E-01	6.00E-04	3.16E-07	1.58E-04	1.74E-04

Sub-Table 4-1.3

CO_2e (GHG) Emissions

207 bhp Emergency DEG (Fired with fuel oil No. 2)				
GHG	ΣGHG Mass-Based Emissions	Global Warming Potential (GWP)	CO_2e Emissions	
	Col (d) of Sub-Table 4-1.2	40CFRS98 Table A-1	note [f]	(a)*(b)
	(metric-tons)	None	(tpy)	(metric tons/yr)
	(a)	(b)	(c)	(d)
CO_2	19	1	21	19
CH_4	7.89E-04	25	2.18E-02	1.97E-02
N_2O	1.58E-04	298	5.19E-02	4.71E-02
	Total CO_2e Emissions =		22	20

Sub-Table 4-2-1

HAP (Speciated organic compounds)

121 bhp DEG for the Emergency Fire Pump (Fired with fuel oil No. 2)				
Organic Compound	Emission Factor[a] (Fuel Input)	Maximum Heat Input Rate [b]	Annual Emissions [c]	Annual Emissions
	(lb/MMBtu)	(MMBtu/hr)	(lbs/yr)	(tpy)
	(a)	**(b)=(a)*121**	**(c)=500*(b)**	**(d)=(c)/2000**
Acenaphthene	1.42E-06	3.08E-01	2.18E-04	1.09E-07
Acenaphthylene	2.92E-05	3.08E-01	4.49E-03	2.25E-06
Acetaldehyde	7.67E-04	3.08E-01	1.18E-01	5.90E-05
Acrolein	9.25E-05	3.08E-01	1.42E-02	7.11E-06
Anthracene	1.87E-06	3.08E-01	2.88E-04	1.44E-07
Benzene	9.33E-04	3.08E-01	1.44E-01	7.18E-05
Benzo(a)anthracene	1.68E-06	3.08E-01	2.58E-04	1.29E-07
Benzo(b)fluoranthene	9.91E-08	3.08E-01	1.52E-05	7.62E-09
Benzo(k)fluoranthene	1.55E-07	3.08E-01	2.38E-05	1.19E-08
Benzo(g,h,l)perylene	4.89E-07	3.08E-01	7.52E-05	3.76E-08
Benzo(a)pyrene	1.88E-07	3.08E-01	2.89E-05	1.45E-08
1,3 Butadiene	3.91E-05	3.08E-01	6.01E-03	3.01E-06
Chrysene	3.53E-07	3.08E-01	5.43E-05	2.71E-08
Dibenz(a,h)anthracene	5.83E-07	3.08E-01	8.97E-05	4.48E-08
Fluoranthene	7.61E-06	3.08E-01	1.17E-03	5.85E-07
Fluorene	2.92E-05	3.08E-01	4.49E-03	2.25E-06

ENCLOSURE 4 (Continued)

121 bhp DEG for the Emergency Fire Pump (Fired with fuel oil No. 2)				
Organic Compound	Emission Factor[a] (Fuel Input)	Maximum Heat Input Rate [b]	Annual Emissions [c]	Annual Emissions
	(lb/MMBtu)	(MMBtu/hr)	(lbs/yr)	(tpy)
	(a)	**(b)=(a)*121**	**(c)=500*(b)**	**(d)=(c)/2000**
Formaldehyde	1.18E-03	3.08E-01	1.82E-01	9.08E-05
Indeno(1,2,3-cd)pyrene	3.75E-07	3.08E-01	5.77E-05	2.88E-08
Naphthalene	8.48E-05	3.08E-01	1.30E-02	6.52E-06
Phenanthrene	2.94E-05	3.08E-01	4.52E-03	2.26E-06
Pyrene	4.78E-06	3.08E-01	7.35E-04	3.68E-07
Toluene	4.09E-04	3.08E-01	6.29E-02	3.15E-05
Xylenes	2.85E-04	3.08E-01	4.38E-02	2.19E-05
			HAP (Highest)	9.08E-05
			HAP (Total)	2.31E-04

Sub-Table 4-2.2
CO_2 Mass-Based Emissions

121 bhp DEG for the Emergency Fire Pump (Fired with fuel oil No. 2)					
Pollutant	Maximum Heat Input Rate [b]	Emission Factor [b]	Emission Rate [e]	GHG Mass-Based Emissions	
	(MMBtu/hr)	(kg/MMBtu)	(metric-ton/hr)	(metric-ton/yr)	(tpy)
	(a)	**(b)**	**(c) =(a)*(b)*10^{-3}**	**(d)=(c)*500 [e]**	**(e)**
CO_2	3.08E-01	73.96	0.023	11	13
CH_4	3.08E-01	3.00E-03	9.23E-07	4.61E-04	5.09E-04
N_2O	3.08E-01	6.00E-04	1.85E-07	9.23E-05	1.02E-04

Sub-Table 4-2.3
CO_2e (GHG) Emissions

121 bhp DEG for the Emergency Fire Pump (Fired with fuel oil No. 2)				
GHG	ΣGHG Mass-Based Emissions	Global Warming Potential (GWP)	CO_2e Emissions	
	Col (d) of Sub-Table 4-2.2	40CFRS98 Table A-1	note [f]	(a)*(b)
	(metric-tons)	None	(tpy)	(metric tons/yr)
	(a)	(b)	(c)	(d)
CO_2	11	1	13	11
CH_4	4.61E-04	25	0	1.15E-02
N_2O	9.23E-05	298	0	2.75E-02
	Total CO_2e Emissions =		13	11

Footnotes to Sub-Tables:

[a] **Emission factors are from AP-42 Section 3.3 (10/96).**

[b] **Maximum heat input rate is computed from the DEG mechanical brake hp (bhp) rating as follows:**

DEG bhp Rating	Conversion Factor *Source: AP-42, App A (01-95)*		Max Heat Input Rate	Units
207	2542.50	(btu/bhp-hr)	526,298	(Btu/hr)
121	2542.50	(btu/bhp-hr)	307,643	(Btu/hr)

[c] **The 500 maximum annual operating hours is the default assumption used in calculating the potential to emit (PTE) for emergency DEGs.**

[d] **CO_2, CH_4, and N_2O emission rates are from 40CFRS98, Tables C-1 & C-2.**

[e] **A factor of $1x10^{-3}$ metric-ton/kg is applied to convert emission units from kg to metric-tons.**

[f] **1 tpy = 1.10231131 metric-ton**

ENCLOSURE 5 GHG PTE CALCULATIONS

Source Units	Carbon Dioxide (CO_2)	Methane (CH_4)		Nitrous Oxide (N_2O)	
	Mass-Based Emissions [a] (tpy)	EF [c] (kg/MMBtu)	Mass-Based Emissions [c] (tpy)	EF [c] (kg/MMBtu)	Mass-Based Emissions [c] (tpy)
CT 1 and CT 2	1,330,271	0.003	53.0	0.0006	11
Subtotals of Mass-Based GHG Emissions	**1,330,271**		**53**		**11**

[a] **CO_2 mass-based emissions are computed with the Tier 3 method, Equation C-4 from 40 CFR SUBPART C, §98.33(a)(3) modified as follows:**

$$CO_2 = (44/12) \times Fuel \times CC \times 0.001 \times 1.10231131$$

Where,

CO_2	**=**	**1,330,271**	**=**	**Annual CO_2 mass emissions from the combustion of the specific liquid fuel (equation modified to convert emission unit from metric tons to short tons).**
Fuel	**=**	**106,747,200**	**=**	**Annual volume of the liquid fuel combusted (gallons/yr) or worst case, the fuel consumption limit of 106,747,200 (gal/yr).**
CC	**=**	**3.083**	**=**	**Annual average carbon content of 3.083 (kg C per gallon of fuel). A weighted average of values reported in FLIGHT for CY 2014 and 2015 are used. Refer to Footnote[b].**
44/12	**=**	**3.667**	**=**	**Ratio of molecular weights, CO_2 to carbon.**
0.001	**=**	**0.001**	**=**	**Conversion factor from kg to metric tons.**
1.10231131	**=**	**1.10231131**	**=**	**Conversion factor to change emission units from metric tons to short tons.**

Footnotes: (Continued)

b

An estimate of KCP's annual average carbon content (CC) is computed in accordance with 40CFR§98.35 using values reported in FLIGHT for CY 2014 and CY 2015 combined on a weighted average basis using Equation C-2b (expressed below) in 40CFR§98.33 for carbon content as specified for Tier 3 computations.

$$(CC)_{annual} = \frac{\sum_{i=1}^{n} (CC)_i \times (Fuel)_i}{\sum_{i=1}^{n} (Fuel)_i}$$

Where,

$(CC)_{annual}$ = Weighted annual average carbon content value of the fuel (mmBtu per mass or volume).

$(CC)_i$ = Measured carbon content value of the fuel, for month “i” (which may be the arithmetic average of multiple determinations), or, if applicable, an appropriate substitute data value (mmBtu per mass or volume).

$(Fuel)_i$ = Mass or volume of the fuel combusted during month “i,” from company records (express volume in gallons for liquid fuel).

				2014	2015	Sum 2014 & 2015
	CT 1	(gal/yr)	FO No. 6	41,450,136	42,382,956	Reported in FLIGHT
		(gal/yr)	FO No. 2	251,454	305,054	
	CT 2	(gal/yr)	FO No. 6	38,930,224	40,992,446	
		(gal/yr)	FO No. 2	225,568	200,829	
(1)	$(Fuel)_{CY}$	(gal/yr)	Combined	80,857,382	83,881,285	164,738,667
(2)	$(CC)_{CY}$	(kg C per gal)	Combined	3.07935	3.087	Reported in FLIGHT
(3)	Product of (1) x (2)		Combined	248,988,179	258,941,527	507,929,706
(4)	$(CC)_{annual}$ [(3) ÷ (1)]	(kg C per gal)	Combined			3.083

Carbon content data is not available in FLIGHT for this facility in CY 2016 and CY 2017.

Footnotes: (Continued)

[c] **CH_4 and N_2O mass-based emissions are computed from using Equation C-8 of 40 CFR SUBPART C, §98.33(c) modified as follows:**

$$CH_4 \text{ or } N_2O = 1 \times 10^{-3} \times Fuel \times HHV \times EF \times 1.10231131$$

$$CH_4 \text{ or } N_2O = EF \times 17650.2969$$

Where,	CH_4 or N_2O	=			Annual CH_4 or N_2O emissions from the combustion of a particular type of fuel (equation modified to convert emission unit from metric tons to short tons).
(1)	Fuel	=	106,747,200	=	Annual volume of the liquid fuel combusted (gallons). The fuel consumption limit of 106,747,200 (gal/yr) is used.
(2)	HHV	=	0.15	=	A high heat value (HHV) of 0.15 MMBtu/gal for LSFO No. 6 from TABLE C1 to 40 CFR SUBPART C OF PART 98 is selected because it is the worst-case condition, since KCP's 2017 fuel delivery data reports a HHV of 148.4 MM Btu/Kgal (0.1484 MMBtu/gal) calculated on a weighted average basis.
	EF	=			Fuel specific default emission factor for CH_4 or N_2O, from Table C2 of this subpart (kg CH_4 or N_2O per mmBtu).
(3)	1×10^{-3}	=	0.001	=	Conversion factor from kilograms to metric tons.
(4)	1.10231131	=	1.10231131	=	Conversion factor to change emission units from metric tons to short tons.
(1)x(2)x(3)x(4)		=	17650.2969		

ENCLOSURE 6 EFFECTIVENESS AND COST OF CONTROL MEASURES

1. KPLP's detailed evaluation on the effectiveness and cost of technically feasible control measures are in Table 6-1.

Table 6-1 KPLP's Evaluation

	Source or Derivation	Available Control Measure→	Co-fire w/ 16% Biofuel	Fuel Switching		Restrictive Operation	Partnering
Ref		Fuel Type→	Biodiesel[b]	LNG[c]	Propane[c]	FO#6[d]	FO#6
(a)	KPLP GHG ERP	KPLP Proposed Baseline Emissions (MT)	993,198	993,198	993,198	993,198	993,198
(b)		Power Output (MWH)	1,451,424	1,451,424	1,451,424	1,219,196	1,451,424
(c)		Annual Fuel Consumption Rate (Equivalent bbls of FO No. 6)	2,000,000	2,000,000	2,000,000	2,000,000	2,000,000
(d)		% Emissions Reduction	-16%	-29.9%	-16%	-16%	0%
(e)		Increased fuel cost per equivalent bbl of FO No. 6	$90.00	$16.00	$22.00	$11.20	$0
(f)		Amortized plant modification cost	$0	$2,500,000	$2,500,000	$0	$0
(g)	See Notes **a,b,c & d**	Increased total cost ($/yr)	$28,800,000	$34,500,000	$46,500,000	$22,400,000	$0
(h)	**(g)÷(b)**	Increased cost ($/MWH)	$20.00	$24.00	$32.00	$15.00	$0
(i)	**(a)x(d)**	Emissions Reduction (MT)	-158,912	-283,658	-158,912	-158,912	0
(k)	**(g)÷(-(i))**	Cost per metric ton of CO_2e removed ($/MT)	$182	$116	$293	$138	$0

[a] Cost of fuel oil No. 6 assumed at $80/bbl (based on the EIA 2020 estimates of $72/bbl plus $8 per bbl transportation cost). KPLP assumes an annual fuel consumption rate that is equivalent to 2 million barrels for cost comparison.

[b] Increased fuel cost, (g) = (c) x 16% x (e) + (f), when co-firing with a sixteen percent (16%) blend of biofuel

Where,

16% = Fraction of biodiesel blended with fuel oil No. 6

(e) = $170 - $80, or $90/equiv bbl increase in biodiesel cost over fuel oil No. 6.

(f) = $0, no plant modifications required.

[c] Increased fuel cost (g)= (c) x (e) + (f), when fuel switching

Where,

(e) = $96 - $80, or $16/equiv bbl cost increase when switching from fuel oil No. 6 to LNG.

$102 - $80, or $22/equiv bbl cost increase when switching from fuel oil No. 6 to propane.

$88 - $80, or $8/equiv bbl cost increase when switching from fuel oil No. 6 to diesel.

(f) = $10,000,000÷4 years, or $2,500,000/yr, plant modification amortized over 4 years for LNG

$10,000,000÷4 years, or $2,500,000/yr, plant modification amortized over 4 years for propane

$0, no plant modifications required.

[d] Increased fuel cost (g)= (c) x (e) + (f), when restricting operations

Where,

(e) = 14% x $80, or $11.20/bbl cost increase when curtailing to restrict operations by 16%.

(f) = $0, no plant modifications required.

ENCLOSURE 6 (Continued)

2. DOH's detailed evaluation on the effectiveness and cost of technically feasible control measures are in Table 6-2.

Table 6-2 DOH's Evaluation

Ref	Source or Derivation	Available Control Measure→ / Fuel Type→		Existing[a] FO No.6	Co-fire w/ 16% Biofuel Biodiesel[b,c]	Fuel Switching Natural Gas[d]	Fuel Switching Propane[e]	Fuel Switching Naphtha[f]	Fuel Switching Diesel[g]	Restrictive Operation FO No. 6[h]	Partnering FO No. 6
		HHV (unit)		mmBtu/gal	mmBtu/gal	mmBtu/scf	mmBtu/scf	mmBtu/gal	mmBtu/gal		
(a)	40 CFR §98 Table C-1 & C-2	HHV (value)		0.150	0.146	0.001026	0.002516	0.125	0.138		
(b)		CO_2 EF (Kg/mmBtu)		75.10	74.898	53.06	61.46	68.02	73.96		
(c)		CH_4 EF (Kg/mmBtu)		0.003	0.00270	0.001	0.003	0.003	0.003		
(d)		N_2O EF (Kg/mmBtu)		0.0006	0.00052	0.0001	0.0006	0.0006	0.0006		
(e)	40 CFR §98 Table A-1	GWP CO_2		1	1	1	1	1	1		
(f)		GWP CH_4		25	25	25	25	25	25		
(g)		GWP N_2O		298	298	298	298	298	298		
(h)	40CFR §98.2(b)(4)	CO_2e (from CO_2) (Kg/mmBtu)	(b)*(e)	75.10	74.8984	53.06	61.46	68.02	73.96		
(i)		CO_2e (from CH_4) (Kg/mmBtu)	(c)*(f)	0.075	0.067	0.025	0.075	0.075	0.075		
(j)		CO_2e (from N_2O) (Kg/mmBtu)	(d)*(g)	0.179	0.155	0.030	0.179	0.179	0.179		
(k)		CO_2 Biogenic (Kg/mmBtu)		0	11.984	0	0	0	0		
(l)	HAR §11-60.1-204(c)	CO_2e (total Kg/mmBtu)	(h)+(i)+(j)-(k)	75.4	63.1	53.1	61.7	68.3	74.2		
(m)	DOH Estimates	% Emissions Reduction	((l)-75.4)/75.4		-16.21%	-29.51%	-18.10%	-9.40%	-1.51%	-16.00%	
(o)	40 CFR §98.33	Estimation Method Used		Tier 1	Tier 1 [a]	Tier 1	Tier 1	Tier 1	Tier 1	KPLP GHG ERP	
(p)	KPLP GHG ERP	KPLP Proposed Baseline Emissions (MT)		1,094,794	993,198	993,198	993,198	993,198	993,198	993,198	993,198
(r)		Power Output (MWH)			1,451,424	1,451,424	1,451,424	1,451,425	1,451,424	1,219,196	1,451,424
(s)		Annual Fuel Consumption			2,000,000	2,000,000	2,000,000	2,000,000	2,000,000	2,000,000	2,000,000
(t)		Amortized plant modification cost			$0	$2,500,000	$2,500,000	$0	$0	$0	$0
(u)	DOH Estimates	Increased fuel cost ($) per equivalent bbl of FO No. 6	**Notes [c to h]**		$10.16	$19.78	$9.93		$26.99	$11.20	
(v)		Increased total cost ($/yr)	(s)*(u)+(t)		$20,329,600	$42,060,000	$22,350,000		$53,978,261	$22,400,000	$0
(w)		Increased cost ($/MWH)	(v)/(r)		$14.01	$28.98	$15.40		$37.19	$18.37	$0
(x)		Emissions Reduction (MT)	(m)*(p)		-161,017	-293,120	-179,782		-15,026	-158,912	0
(y)		Cost per metric ton of CO_2e removed ($/MT)	(v)/(x)		$126.26	$143.49	$124.32		$3,592.39	$140.96	$0

[a] FO No. 6 cost per barrel (bbl) as reported in September 2018 DBEDT Monthly Energy Trend Highlights = $83.00 (per bbl)

[b] Composite rates for HHV and emission rates based on a 16% blend of biofuel with FO No. 6.

	Proportion	HHV (mmbtu/gal)		CO_2 EF (Kg/mmBtu)		CH_4 EF (Kg/mmBtu)		N_2O EF (Kg/mmBtu)	
FO No. 6	**0.84**	**0.15**	**0.126**	**75.1**	**63.084**	**0.003**	**0.00252**	**0.0006**	**0.00050**
Biodiesel	**0.16**	**0.128**	**0.02048**	**73.84**	**11.8144**	**0.0011**	**0.000176**	**0.00011**	**0.00002**
Composite Rate			**0.146**		**74.898**		**0.00270**		**0.00052**

ENCLOSURE 6 (Continued)

Table 6-2 DOH's Evaluation (Continued)

[c] 16% blend of biodiesel with FO No. 6, increase in equivalent fuel cost determined as follows:

Fuel Type	Breakdown	Fuel Cost ($/bbl)		Source
FO No. 6	0.84	$83.00	$69.72	Refer to footnote [b]
Biodiesel	0.16	$146.53	$23.44	Based on September 2018 DBEDT Monthly Energy Trend Highlights
Composite Rate			$93.16	

Increased fuel cost when co-firing with a 16% biodiesel blend = $93.16 - $83.00 = $10.16 ($/Eqv bbl of FO No. 6)

[d] Natural Gas, increase in equivalent fuel cost to FO No. 6 determined as follows:

Item	Data	Units	Source
Cost of Natural Gas =	$17.13	($/10^3 cu ft)	2 yr ave city price from www.eia.gov for HI
Natural Gas Thermal Eqv=	1,050	(btu/cu ft)	AP 42 Appendix A (01-95)
FO No. 6 Thermal Eqv=	6.3	(mmbtu/bbl)	AP 42 Appendix A (01-95)

Natural Gas Thermal Equiv = 1,050 (btu/cu ft) x (10^3 cu ft/10^3 cu ft) x 10^{-6} (mmbtu/btu) = 1.05 (mmbtu/10^3 cu ft)

Cost of Natural Gas = $17.13 (/10^3 cu ft) ÷ 1.05 (mmbtu/10^3 cu ft) = $16.31 ($/mmbtu)

Equivalent Cost of Natural Gas = $16.31 (/mmbtu) x 6.3 (mmbtu/bbl) = $102.78 ($/Eqv bbl of FO No. 6)

Increased fuel cost when fuel switching to LNG = $102.78 - $83.00 = $19.78 ($/Eqv bbl of FO No. 6)

[e] Propane, increase in equivalent fuel cost determined as follows:

Item	Data	Units	Source
Cost of propane =	$14.75	($/mmbtu)	2015 industrial pricing from www.eia.gov for HI
FO No. 6 Thermal Eqv=	6.3	(mmbtu/bbl)	AP 42 Appendix A (01-95)

Equivalent cost of propane = $14.75 (/mmbtu) x 6.3 (mmbtu/bbl) = $92.93 ($/Eqv bbl of FO No. 6)

Increased fuel cost when fuel switching to propane = $92.93 - $83.00 = $9.93

[f] Naphtha, increase in equivalent fuel cost determined as follows:

Item	Data	Units	Source
Cost of Naphtha =	$11.50	($/mmbtu)	HECO's email dated 9/08/18
FO No. 6 Thermal Eqv=	6.3	(mmbtu/bbl)	AP 42 Appendix A (01-95)

Equivalent cost of Naphtha = $11.50 x 6.3 = $72.45 ($/Eqv bbl of FO No. 6)

Increased fuel cost when fuel switching to LPG = $72.45 - $83.00 = -$10.55

ENCLOSURE 6 (Continued)

Table 6-2 DOH's Evaluation (Continued)

[g] Diesel, increase in equivalent fuel cost determined as follows:

Item	Data	Units	Source
Cost of diesel =	$101.19	($/bbl)	2015 industrial pricing from www.eia.gov for HI
FO No. 6 Thermal Eqv=	6.3	(mmbtu/bbl)	AP 42 Appendix A (01-95)
HHVof Diesel	0.138	(mmbtu/gal)	40CFRS98Table C-1
HHV of FO No. 6	0.150	(mmbtu/gal)	40CFRS98Table C-1

Equivalent cost of diesel =	$101.19	x	0.150	÷	0.138	=	$109.99
							($/Eqv bbl of FO No. 6)
Increased fuel cost when fuel switching to diesel =			$109.99	-	$83.00	=	$26.99

[h] Refer to footnote [d] of KPLP's Effectivenee and Cost Evaluation.