ADMINISTRATIVE RECORD

Hawaii Electric Light Company, Inc.

Application No. 0007-05 for Renewal
Application No. 0070-02 for Renewal
Application Nos. 0007-06, 0007-08, and 0007-09 for Minor Modification
Application No. 0070-03 for Minor Modification

Keahole Generating Station

Located At: 73-4249 Pukiawe Street, Kailua-Kona, Island of Hawaii

CSP No. 0007-01-C

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Public Notice

REQUEST FOR PUBLIC COMMENTS
ON DRAFT AIR PERMIT
REGULATING THE EMISSIONS OF AIR POLLUTANTS

(Docket No. 24-CA-PA-09)

Pursuant to Hawaii Revised Statutes (HRS), Chapter 342B-13 and Hawaii Administrative Rules (HAR), Chapter 11-60.1, the Department of Health, State of Hawaii (DOH), is requesting public comments on the following **DRAFT PERMIT** presently under review for:

> **Covered Source Permit (CSP) No. 0007-01-C**
> Application No. 0007-05 for Renewal
> Application No. 0070-02 for Renewal
> Application Nos. 0007-06, 0007-08, and 0007-09 for Minor Modification
> Application No. 0070-03 for Minor Modification
> Hawaii Electric Light Company, Inc.
> Keahole Generating Station
> Located At: 73-4249 Pukiawe Street, Kailua Kona, Island of Hawaii

The **DRAFT PERMIT** is described as follows:

CSP No. 0007-01-C would grant conditional approval for the continued operation of the existing electrical power generating station. This facility is subject to the following Federal Requirements:

40 Code of Federal Regulations (CFR) Part 60 - Standards of Performance for New Stationary Sources (NSPS)

Subpart A:	General Provisions
Subpart GG:	Standards of Performance for Stationary Gas Turbines (applies to combustion turbine generators, Units CT-2, CT-4, and CT-5)

40 CFR Part 63 - National Emission Standards for Hazardous Air Pollutants for Source Categories (MACT)

Subpart A:	General Provisions
Subpart ZZZZ:	National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines (applies to diesel engine generators, Units D-21, D-22, and D-23, and black start diesel engine generator, Unit BS-1)

40 CFR Part 98 – Mandatory Greenhouse Gas Reporting

The total potential emissions from the Keahole Generating Station are as follows:

Pollutant	Emissions (tpy)
NO_x	1,153.18
CO	542.86
SO_2	1,422.83
PM	305.18
PM_{10}	305.18

$PM_{2.5}$	305.18
VOC	164.44
HAPS	6.52
CO_2e	576,243

The **ADMINISTRATIVE RECORD**, consisting of the **APPLICATION** and non-confidential supporting materials from the applicant, the permit review summary, and the **DRAFT PERMIT**, is available online at: http://health.hawaii.gov/cab/public-notices/ and for public inspection during regular office hours, Monday through Friday, 7:45 a.m. to 4:15 p.m., at the following locations:

Oahu:

State of Hawaii
Clean Air Branch
2827 Waimano Home Road, #130
Pearl City, Hawaii 96782

Hawaii:

- Hawaii District Health Office, Department of Health
  1582 Kamehameha Avenue, Hilo, Hawaii

- Sanitation Branch, Keakealani Building, Department of Health
  79-1020 Haukapila Street, Room 115, Kealakekua, Hawaii

All comments on the draft permit and any request for a public hearing must be in writing, addressed to the Clean Air Branch at the above address on Oahu and must be postmarked or received by **August 13, 2024**.

Any person may request a public hearing by submitting a written request that explains the party's interest and the reasons why a hearing is warranted. The DOH may hold a public hearing if a hearing would aid in DOH's decision. If a public hearing is warranted, a public notice for the hearing will be published at least thirty days in advance of the hearing.

Interested persons may obtain copies of the administrative record or parts thereof by paying **five (5) cents per page copying costs**. Please send written requests to the Clean Air Branch listed above or call Mr. Darin Lum at the Clean Air Branch at (808) 586-4200.

Comments on the draft permit should address, but need not be limited to, the permit conditions and the facility's compliance with federal and state air pollution laws, including: (1) the National and State Ambient Air Quality Standards; and (2) HRS, Chapter 342B and HAR, Chapter 11-60.1.

DOH will make a final decision on the permit after considering all comments and will send notice of the final decision to each person who has submitted comments or requested such notice.

Kenneth S. Fink, MD, MGA, MPH
Director of Health

Draft Permit

DRAFT

Issuance Date

CERTIFIED MAIL
RETURN RECEIPT REQUESTED
(xxxx xxxx xxxx xxxx xxxx)

24-xxxE CAB
File No. 0007

Mr. Ryan Kohatsu
Director, Generation – Hawaii
Hawaii Electric Light Company, Inc.
P.O. Box 1027
Hilo, Hawaii 96721-1027

Dear Mr. Kohatsu:

SUBJECT: Covered Source Permit (CSP) No. 0007-01-C
Application No. 0007-05 for Renewal
Application No. 0070-02 for Renewal
Application Nos. 0007-06, 0007-08, and 0007-09 for Minor Modification
Application No. 0070-03 for Minor Modification
Hawaii Electric Light Company, Inc.
Keahole Generating Station
Two (2) 20 MW Combustion Turbine Generators, Units CT-4 and CT-5 with Two (2) Heat Recovery Steam Generators and One (1) 16 MW Steam Turbine, One (1) 18 MW Combustion Turbine Generator, Unit CT-2, Three (3) 2.5 MW Diesel Engine Generators, and One (1) 500 kW Diesel Engine Generator
Located At: 73-4249 Pukiawe Street, Kailua-Kona, Island of Hawaii
Date of Expiration: DATE

The subject CSP is issued in accordance with Hawaii Administrative Rules (HAR), Title 11, Chapter 60.1. The issuance of this permit is based on the plans and specifications that you submitted as part of your renewal applications dated July 30, 2012, with updated information dated December 3, 2015, and January 8, 2010, with updated information dated February 3, 2011, and minor modification applications dated December 10, 2015, April 17, 2018, October 29, 2019, and December 10, 2015. This permit supersedes, in its entirety, CSP No. 0007-01-C issued on June 27, 2018, and amended on October 22, 2020.

The CSP is issued subject to the conditions/requirements set forth in the following attachments:

Attachment I:	Standard Conditions
Attachment IIA:	Special Conditions for the Combustion Turbine Generators, Units CT-4 and CT-5
Attachment IIB:	Special Conditions for the Combustion Turbine Generator, Unit CT-2
Attachment IIC:	Special Conditions for the Diesel Engine Generators

Attachment II - INSIG: Special Conditions for Insignificant Activities
Attachment II - GHG: Special Conditions - GHG Reduction Requirements
Attachment III: Annual Fee Requirements
Attachment IV: Annual Emissions Reporting Requirements

The forms for the submission of reports and annual emissions are as follows:

Compliance Certification Form
Annual Emissions Report Form: Combustion Turbine Generators and Diesel Engine Generators
Monitoring Report Form: Operating Hours: B lack Start Diesel Engine Generator
Monitoring Report Form: Combustion Turbine Generator Operation
Monitoring Report Form: Combustion Turbine Generator Monthly Operation Below Minimum Operating Load with Water Injection
Monitoring Report Form: Fuel Consumption
Monitoring Report Form: Fuel Certification
Monitoring Report Form: Visible Emission Exceedances
Monitoring Report Form: GHG Emissions
Excess Emission and Monitoring System Performance Summary Report
Excess Emissions and Continuous Monitoring System (CMS) Performance Report and/or Summary Report Form

The following are enclosed for your use in monitoring visible emissions:

Visible Emissions Form Requirements, State of Hawaii
Visible Emissions Form

This permit: (a) shall not in any manner affect the title of the premises upon which the equipment is to be located; (b) does not release the permittee from any liability for any loss due to personal injury or property damage caused by, resulting from or arising out of the design, installation, maintenance, or operation of the equipment; and (c) in no manner implies or suggests that the Department of Health, Clean Air Branch (herein after referred to as Department), or its officers, agents, or employees, assumes any liability, directly or indirectly, for any loss due to personal injury or property damage caused by, resulting from or arising out of the design, installation, maintenance, or operation of the equipment.

If you have any questions regarding this matter, please contact Mr. Darin Lum of the Clean Air Branch at (808) 586-4200.

Sincerely,

JOANNA L. SETO, P.E., CHIEF
Environmental Management Division

DL:tkg
Enclosures

ATTACHMENT I: STANDARD CONDITIONS
COVERED SOURCE PERMIT NO. 0007-01-C

Issuance Date: DATE **Expiration Date: DATE**

This permit is granted in accordance with the HAR, Title 11, Chapter 60.1, Air Pollution Control, and is subject to the following standard conditions:

1. Unless specifically identified, the terms and conditions contained in this permit are consistent with the applicable requirement, including form, on which each term or condition is based.

   (Auth.: HAR §11-60.1-90)

2. This permit, or a copy thereof, shall be maintained at or near the source and shall be made available for inspection upon request. The permit shall not be willfully defaced, altered, forged, counterfeited, or falsified.

   (Auth.: HAR §11-60.1-6; SIP §11-60-11)[2]

3. This permit is not transferable whether by operation of law or otherwise, from person to person, from place to place, or from one piece of equipment to another without the approval of the Department, except as provided in HAR, Section 11-60.1-91.

   (Auth.: HAR §11-60.1-7; SIP §11-60-9)[2]

4. A request for transfer from person to person shall be made on forms furnished by the Department.

   (Auth.: HAR §11-60.1-7)

5. In the event of any changes in control or ownership of the facilities to be constructed or modified, this permit shall be binding on all subsequent owners and operators. The permittee shall notify the succeeding owner and operator of the existence of this permit and its conditions by letter, copies of which will be forwarded to the Department and the U.S. Environmental Protection Agency (EPA), Region 9.

   (Auth.: HAR §11-60.1-5, §11-60.1-7, §11-60.1-94)

6. The facility covered by this permit shall be constructed and operated in accordance with the application, and any information submitted as part of the application, for CSP. There shall be no deviation unless additional or revised plans are submitted to and approved by the Department, and the permit is amended to allow such deviation.

   (Auth.: HAR §11-60.1-2, §11-60.1-4, §11-60.1-82, §11-60.1-84, §11-60.1-90)

7. This permit (a) does not release the permittee from compliance with other applicable statutes of the State of Hawaii, or with applicable local laws, regulations, or ordinances, and (b) shall not constitute, nor be construed to be an approval of the design of the covered source.

   (Auth.: HAR §11-60.1-5, §11-60.1-82)

8. The permittee shall comply with all the terms and conditions of this permit. Any permit noncompliance constitutes a violation of HAR, Chapter 11-60.1 and the Clean Air Act and is grounds for enforcement action; for permit termination, suspension, reopening, or amendment; or for denial of a permit renewal application.

   (Auth.: HAR §11-60.1-3, §11-60.1-10, §11-60.1-19, §11-60.1-90)

9. If any term or condition of this permit becomes invalid as a result of a challenge to a portion of this permit, the other terms and conditions of this permit shall not be affected and shall remain valid.

   (Auth.: HAR §11-60.1-90)

10. The permittee shall not use as a defense in an enforcement action that it would have been necessary to halt or reduce the permitted activity to maintain compliance with the terms and conditions of this permit.

    (Auth.: HAR §11-60.1-90)

11. This permit may be terminated, suspended, reopened, or amended for cause pursuant to HAR, Sections, 11-60.1-10 and 11-60.1-98, and Hawaii Revised Statutes (HRS), Chapter 342B-27, after affording the permittee an opportunity for a hearing in accordance with HRS, Chapter 91.

    (Auth.: HAR §11-60.1-3, §11-60.1-10, §11-60.1-90, §11-60.1-98)

12. The filing of a request by the permittee for the termination, suspension, reopening, or amendment of this permit, or of a notification of planned changes or anticipated noncompliance does not stay any permit condition.

    (Auth.: HAR §11-60.1-90)

13. This permit does not convey any property rights of any sort, or any exclusive privilege.

    (Auth.: HAR §11-60.1-90)

14. The permittee shall notify the Department and U.S. EPA, Region 9, in writing of the following dates:

    a. The **anticipated date of initial start-up** for each emission unit of a new source or significant modification not more than sixty (60) days or less than thirty (30) days prior to such date;
    b. The **actual date of construction commencement** within fifteen (15) days after such date; and
    c. The **actual date of start-up** within fifteen (15) days after such date.

    (Auth.: HAR §11-60.1-90)

15. The permittee shall furnish, in a timely manner, any information or records requested in writing by the Department to determine whether cause exists for terminating, suspending, reopening, or amending this permit, or to determine compliance with this permit. Upon request, the permittee shall also furnish to the Department copies of records required to be kept by the permittee. For information claimed to be confidential, the Director of Health (Director) may require the permittee to furnish such records not only to the Department but also directly to the U.S. EPA, Region 9, along with a claim of confidentiality.

    (Auth.: HAR §11-60.1-14, §11-60.1-90)

16. The permittee shall notify the Department in writing, of the **intent to shut down air pollution control equipment for necessary scheduled maintenance** at least twenty-four (24) hours prior to the planned shutdown. The submittal of this notice shall not be a defense to an enforcement action. The notice shall include the following:

    a. Identification of the specific equipment to be taken out of service, as well as its location and permit number;
    b. The expected length of time that the air pollution control equipment will be out of service;
    c. The nature and quantity of emissions of air pollutants likely to be emitted during the shutdown period;
    d. Measures such as the use of off-shift labor and equipment that will be taken to minimize the length of the shutdown period; and
    e. The reasons why it would be impossible or impractical to shut down the source operation during the maintenance period.

    (Auth.: HAR §11-60.1-15; SIP §11-60-16)[2]

17. **In the event any emission unit, air pollution control equipment, or related equipment malfunctions or breaks down in such a manner as to cause the emission of air pollutants in violation of HAR, Chapter 11-60.1 or this permit**, the permittee shall immediately notify the Department of the malfunction or breakdown, unless the protection

of personnel or public health or safety demands immediate attention to the malfunction or breakdown and makes such notification infeasible. In the latter case, the notice shall be provided as soon as practicable. Within five (5) working days of this initial notification, the permittee shall also submit, in writing, the following information:

a. Identification of each affected emission point and each emission limit exceeded;
b. Magnitude of each excess emission;
c. Time and duration of each excess emission;
d. Identity of the process or control equipment causing the excess emission;
e. Cause and nature of each excess emission;
f. Description of the steps taken to remedy the situation, prevent a recurrence, limit the excessive emissions, and assure that the malfunction or breakdown does not interfere with the attainment and maintenance of the National Ambient Air Quality Standards and State Ambient Air Quality Standards;
g. Documentation that the equipment or process was at all times maintained and operated in a manner consistent with good practice for minimizing emissions; and
h. A statement that the excess emissions are not part of a recurring pattern indicative of inadequate design, operation, or maintenance.

The submittal of these notices shall not be a defense to an enforcement action.

(Auth.: HAR §11-60.1-16; SIP §11-60-16)[2]

18. The permittee may request confidential treatment of any records in accordance with HAR, Section 11-60.1-14.

    (Auth.: HAR §11-60.1-14, §11-60.1-90)

19. This permit shall become invalid with respect to the authorized construction if construction is not commenced as follows:

    a. Within eighteen (18) months after the permit takes effect, is discontinued for a period of eighteen (18) months or more, or is not completed within a reasonable time.
    b. For phased construction projects, each phase shall commence construction within eighteen (18) months of the projected and approved commencement dates in the permit. This provision shall be applicable only if the projected and approved commencement dates of each construction phase are defined in Attachment II, Special Conditions, of this permit.

    (Auth.: HAR §11-60.1-9, §11-60.1-90)

20. The Department may extend the time periods specified in Standard Condition No. 19 upon a satisfactory showing that an extension is justified. Requests for an extension shall be submitted in writing to the Department.

    (Auth.: HAR §11-60.1-9, §11-60.1-90)

21. The permittee shall submit fees in accordance with HAR, Chapter 11-60.1, Subchapter 6.

    (Auth.: HAR §11-60.1-90)

22. All certifications shall be in accordance with HAR, Section 11-60.1-4.

    (Auth.: HAR §11-60.1-4, HAR §11-60.1-90)

23. The permittee shall allow the Director, the Regional Administrator for the U.S. EPA and/or an authorized representative, upon presentation of credentials or other documents required by law:

    a. To enter the premises where a source is located or emission-related activity is conducted, or where records must be kept under the conditions of this permit and inspect at reasonable times all facilities, equipment, including monitoring and air pollution control equipment, practices, operations, or records covered under the terms and conditions of this permit and request copies of records or copy records required by this permit; and
    b. To sample or monitor at reasonable times substances or parameters to ensure compliance with this permit or applicable requirements of HAR, Chapter 11-60.1.

    (Auth.: HAR §11-60.1-11, §11-60.1-90)

24. Within thirty (30) days of **permanent discontinuance of the construction, modification, relocation, or operation of a covered source covered by this permit**, the discontinuance shall be reported in writing to the Department by a responsible official of the source.

    (Auth.: HAR §11-60.1-8; SIP §11-60-10)[2]

25. Each permit renewal application shall be submitted to the Department and the U.S. EPA, Region 9, no less than twelve (12) months and no more than eighteen (18) months prior to the permit expiration date. The Director may allow a permit renewal application to be submitted no less than six (6) months prior to the permit expiration date, if the Director determines that there is reasonable justification.

    (Auth.: HAR §11-60.1-101; 40 CFR §70.5(a)(1)(iii))[1]

26. The terms and conditions included in this permit, including any provision designed to limit a source's potential to emit, are federally enforceable unless such terms, conditions, or requirements are specifically designated as not federally enforceable.

    (Auth.: HAR §11-60.1-93)

27. The compliance plan and compliance certification submittal requirements shall be in accordance with HAR, Sections 11-60.1-85 and 11-60.1-86. As specified in HAR, Section 11-60.1-86, the compliance certification shall be submitted to the Department and the U.S. EPA, Region 9, once per year, or more frequently as set by any applicable requirement.

    (Auth.: HAR §11-60.1-90)

28. **Any document (including reports) required to be submitted by this permit shall be certified as being true, accurate, and complete by a responsible official in accordance with HAR, Sections 11-60.1-1 and 11-60.1-4, and shall be mailed to the following address:**

    State of Hawaii
    Clean Air Branch
    2827 Waimano Home Road, #130
    Pearl City, HI 96782

    Upon request and as required by this permit, all correspondence to the State of Hawaii Department of Health associated with this CSP shall have duplicate copies forwarded to:

    Manager
    Enforcement Division, Air Section
    U.S. Environmental Protection Agency, Region 9
    75 Hawthorne Street, ENF-2-1
    San Francisco, CA 94105

    (Auth.: HAR §11-60.1-4, §11-60.1-90)

29. To determine compliance with submittal deadlines for time-sensitive documents, the postmark date of the document shall be used. If the document was hand-delivered, the date received ("stamped") at the Clean Air Branch shall be used to determine the submittal date.

    (Auth.: HAR §11-60.1-5, §11-60.1-90)

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[1]The citations to the Code of Federal Regulations (CFR) identified under a particular condition, indicate that the permit condition complies with the specified provision(s) of the CFR. Due to the integration of the preconstruction and operating permit requirements, permit conditions may incorporate more stringent requirements than those set forth in the CFR.

[2]The citations to the State Implementation Plan (SIP) identified under a particular condition, indicate that the permit condition complies with the specified provision(s) of the SIP.

ATTACHMENT IIA: SPECIAL CONDITIONS FOR THE COMBUSTION TURBINE GENERATORS, UNITS CT-4 AND CT-5
COVERED SOURCE PERMIT NO. 0007-01-C

Issuance Date: DATE **Expiration Date: DATE**

In addition to the standard conditions of the CSP, the following special conditions shall apply to the permitted facility:

Section A. Equipment Description

1. This attachment encompasses the following equipment and associated appurtenances:

   a. Two (2) 20 MW Nominal (24.66 MW (gross) peak load) General Electric LM2500 combustion turbine generators, Units CT-4 and CT-5; and
   b. One (1) 16 MW steam turbine generator Unit ST-7, including two (2) unfired heat recovery steam generators (HRSG) with two (2) selective catalytic reduction (SCR) units.

   (Auth.: HAR §11-60.1-3, §11-60.1-90)

2. The permittee shall permanently attach an identification tag or name plate on the combustion turbine generators which identifies the model no., serial no., and manufacturer. The identification tag or nameplate shall be permanently attached to the equipment at a conspicuous location.

   (Auth.: HAR §11-60.1-5, §11-60.1-90)

Section B. Applicable Federal Regulations

1. Units CT-4 and CT-5 are subject to the provisions of the following federal standards:

   a. 40 Code of Federal Regulations (CFR) Part 60, Standards of Performance for New Stationary Sources, Subpart A - General Provisions; and
   b. 40 CFR Part 60, Standards of Performance of New Stationary Sources, Subpart GG - Standards of Performance for Stationary Gas Turbines.

   (Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-161; 40 CFR §60.1, §60.330)[1]

2. The permittee shall comply with all applicable requirements of these standards including all emission limits, notification, testing, monitoring, and reporting requirements. The major requirements of these standards are detailed in this attachment.

   (Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-161; 40 CFR §60.1, §60.330)[1]

Section C. Operational and Emission Limitations

1. Startup and Shutdown

   a. Each combustion turbine generator shall not be started up more than eleven (11) times per day. The startup sequence for each combustion turbine generator shall be a twenty (20) minute period starting from the time fuel use at the combustion turbine generator begins. Upon completion of the twenty (20) minute startup sequence, the water injection system shall be operational, and the combustion turbine generator shall be at twenty-five (25) percent of peak load (6.17 MW) or more except as provided in Special Condition No. C.2 of this attachment.

   b. Each combustion turbine generator shall not be started up more than eleven (11) times per day. The shutdown sequence for any combustion turbine generator shall not exceed twenty (20) minutes. A shutdown sequence shall be from the time the combustion turbine controls stop signal is initiated for each combustion turbine generator and the combustion turbine generator is below twenty-five (25) percent of peak load (6.17 MW), until fuel use at the combustion turbine generator ceases.

   (Auth.: HAR §11-60.1-3, §11-60.1-5, §11-60.1-90)

2. Minimum Operational Loads

   The operation of Units CT-2, CT-4, and CT-5, below twenty-five (25) percent of peak load with water injection, shall not exceed a combined total of sixty-six (66) hours in any rolling twelve (12) month period, except during startup and shutdown sequences, and as approved pursuant to Special Condition No. C.7.c of this attachment.

   (Auth.: HAR §11-60.1-3, §11-60.1-5, §11-60.1-90)

3. Air Pollution Equipment

   a. Water Injection

      The permittee shall continuously operate and maintain a water injection system to meet the emission limits specified for nitrogen oxides (NO_x) in Special Condition No. C.5.a of this attachment. Water injection shall be initiated during the startup sequence of each combustion turbine generator and shall be terminated at the beginning of or during the shutdown sequence of each combustion turbine generator.

      For each combustion turbine generator, after completion of the startup sequence and until the beginning of the shutdown sequence, the following water-to-fuel mass ratios, on a one (1) unit operating hour average basis, shall be maintained when the combustion turbine generators are firing fuel oil No. 2 in combined cycle operation at loads less than fifty (50) percent of the peak load (12.33 MW) or in simple cycle operation. When firing an approved alternate fuel, the same water-to-fuel mass ratios or approved fuel specific water-to-fuel mass ratios, on a one (1) unit operating hour average basis, shall be maintained. A unit operating hour shall be as defined in 40 CFR §60.331.

WATER INJECTION SYSTEM
MINIMUM WATER INJECTION RATES BASED ON LOAD

Peak load (%)	Load (MW)	Mass Ratio (lb-water / lb-fuel)
100	24.66	1.04
75 - <100	18.50 - <24.66	0.94
50 - <75	12.33 - <18.50	0.87
<50	<12.33	0.72

For operating hours during which the combustion turbine generator operates at multiple loads where multiple water-to-fuel mass ratios apply, the applicable water-to-fuel mass ratio shall be determined based on the load that corresponded to the lowest minimum water-to-fuel mass ratio.

b. Selective Catalytic Reduction System

The permittee shall continuously operate and maintain a SCR system to meet the emission limits as specified in Special Condition No. C.5.a of this attachment.

The SCR system shall be functional and in operation whenever the combustion turbine generators are in combined cycle operation at loads greater than or equal to fifty (50) percent of the peak load (12.33 MW). The SCR system shall continue to operate until the load is reduced to below fifty (50) percent of the peak load (12.33 MW).

c. The use of an alternative control system other than those specified above is contingent upon receiving the Department's written approval to use such a system and shall not relieve the permittee from the responsibility to meet all emission limitations contained within this CSP.

(Auth.: HAR §11-60.1-3, §11-60.1-5, §11-60.1-90)

4. Fuel Specifications

The combustion turbine generators shall be fired only on fuel oil No. 2 with a maximum sulfur content not to exceed 0.4 percent by weight or an alternate fuel allowed under Special Condition No. C.7.e of this attachment.

(Auth.: HAR §11-60.1-3, §11-60.1-5, §11-60.1-90, §11-60.1-161; 40 CFR §60.333)[1]

5. Maximum Emission Limits

   a. Except during the startup and shutdown sequences, the permittee shall not discharge or cause the discharge into the atmosphere from each of the combustion turbine generators, nitrogen oxides (as NO_2), sulfur dioxide (SO_2), particulate matter (PM)/PM_{10}, carbon monoxide (CO), volatile organic compounds (VOC), and ammonia (NH_3) in excess of the following specified limits:

Combustion Turbine Generator Operating in the Simple Cycle Mode

Compound	Maximum Emission Limit (3-hour Average) (lbs/hr)	(ppmvd @ 15 percent O_2)
Nitrogen Oxides as NO_2	42.3	42
Sulfur Dioxide	110	79
Particulate Matter/PM_{10}	19.7	0.045 (gr/dscf @ 12 percent O_2)
Carbon Monoxide		
100% (24.66 MW) Peak load	26.8	44
75% (18.50 MW) - <100% (24.66 MW) Peak load	56.4	123
50% (12.33 MW) - <75% (18.50 MW) Peak load	181.0	566
<50% (12.33 MW) Peak load	475.6	2,386
Volatile Organic Compounds		
100% (24.66 MW) Peak load	0.8	2.5
75% (18.50 MW) - <100% (24.66 MW) Peak load	2.6	11.8
50% (12.33 MW) - <75% (18.50 MW) Peak load	28.1	178
<50% (12.33 MW) Peak load	297.6	3,025

Combustion Turbine Generator Operating in the Combined Cycle Mode

Compound	Maximum Emission Limit (3-hour Average) (lbs/hr)	(ppmvd @ 15 percent O_2)
Nitrogen Oxides as NO_2		
50% (12.33 MW) - 100% (24.66 MW) Peak load	15.1	15
<50% (12.33 MW) Peak load	42.3	42
Sulfur Dioxide	110	79
Particulate Matter/PM_{10}	19.7	0.045 (gr/dscf @ 12 percent CO_2)
Carbon Monoxide		
100% (24.66 MW) Peak load	26.9	44
75% (18.50 MW) - <100% (24.66 MW) Peak load	50.2	105
50% (12.33 MW) - <75% (18.50 MW) Peak load	170.4	523
<50% (12.33 MW) Peak load	457.4	2,218
Volatile Organic Compounds		
100% (24.66 MW) Peak load	0.8	2.5
75% (18.50 MW) - <100% (24.66 MW) Peak load	2.0	8.6
50% (12.33 MW) - <75% (18.50 MW) Peak load	25.0	156
<50% (12.33 MW) Peak load	271.0	2,662
Ammonia	4.30	10

b. The three-hour (3-hour) averaging period shall begin immediately upon completion of the combustion turbine generator's startup sequence and end immediately prior to the combustion turbine generator's shutdown sequence. For operating periods during which the combustion turbine generator operates at multiple loads where multiple NO_x and CO emissions standards apply, the applicable NO_x and CO emissions limit shall be the average of the applicable standards during each hour. For hours with multiple emissions standards, the applicable limit for that hour is determined based on the load that corresponds with the highest emissions standard in accordance with 40 CFR §60.4380(b)(3).

c. The permittee shall not discharge or cause the discharge into the atmosphere from each of the combustion turbine generators, a rolling four (4) hour average NO_X emission in excess of 109 parts per million by volume (ppmvd) at fifteen (15) percent oxygen (O_2). The four (4) hour averaging period shall include all periods of operation, including startup, shutdown, and malfunction.

d. The Department, with U.S. EPA, Region 9, concurrence, may revise the allowable emission limitation for NO_X, PM, CO, VOC, and NH_3 after reviewing the initial performance test results required under Section F of this attachment. The Department, with U.S. EPA, Region 9, concurrence, may also revise the water-to-fuel ratios or include NH_3-to-NO_x injection rates if findings through operating parameters and performance test results show an optimum operating range which minimizes emissions.

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e. If the NO_x, PM/PM_{10}, CO, VOC, or NH_3 emission limit is revised, the difference between the applicable emission limit set forth above and the revised lower emission limit shall not be allowed as an emission offset for future construction or modification.

(Auth.: HAR §11-60.1-3, §11-60.1-5, §11-60.1-90, §11-60.1-161; 40 CFR §60.332, §60.333, §60.334)[1]

6. Visible Emissions (VE)

For any six (6) minute averaging period, the combustion turbine generators shall not exhibit VE of twenty (20) percent opacity or greater, except as follows: during startup, shutdown, or equipment malfunction, the combustion turbine generators may exhibit VE not greater than sixty (60) percent opacity for a period aggregating not more than six (6) minutes in any sixty (60) minute period. In the event of equipment breakdown, the equipment shall be shut down within one (1) hour if the opacity problem cannot be corrected with the six (6) minute period.

(Auth.: HAR §11-60.1-3, §11-60.1-32, §11-60.1-90; SIP §11-60-24)[2]

7. Alternate Operating Scenarios

The terms and conditions under the following alternate operating scenarios shall meet all applicable requirements including all conditions of this permit. Requests for written approval from the Department to operate under the applicable alternate operating scenario shall be in accordance with Special Condition No. E.3 of this attachment.

a. Temporary Replacement. In the event of a failure or major overhaul of the equipment, the permittee may replace the combustion turbine generators with one of the General Electric LM2500 with the serial numbers listed below. Notification must be provided in accordance with Special Condition No. E.3 of this attachment. Notification and approval is required for temporary replacements with units that are not listed, the replacement unit shall be a General Electric LM2500 with equal or lesser emissions:

   i. 481-688
   ii. 481-692
   iii. 481-651

b. Permanent Replacement. Upon receiving written approval from the Department, the permittee may replace the combustion turbine generators with another General Electric LM2500 if any repair work reasonably warrants the removal (i.e., equipment failure or malfunction, overhaul, or any major equipment problems requiring maintenance for efficient operation) of a combustion turbine generator from its site and the following provisions are adhered to:

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i. The replacement combustion turbine generator is a General Electric LM2500 with one of the following serial numbers:

1) 481-688
2) 481-692
3) 481-651

ii. The permittee may continue using the replacement combustion turbine generator and is not required to return the original combustion turbine generator after it is repaired.

c. The combustion turbine generators may operate below twenty-five (25) percent of peak load (6.17 MW) during:

i. Testing of the heat recovery steam generators and steam turbine;
ii. Steam blows needed to clean the steam tubes prior to initial operation;
iii. Testing of combustion turbine generator controls;
iv. Dry running the Once Through Steam Generator (OTSG) to remove deposits from the OTSG;
v. In isochronous mode with water injection for system restoration; and
vi. Other maintenance and testing as approved by the Department in accordance with Special Condition No. E.3.c of this attachment.

Operation during these periods shall not result in an exceedance of the emission limits at the lower load specified in Special Condition No. C.5.a of this attachment.

d. Combustion Turbine Operation Above Peak Load. The permittee may operate the combustion turbine generators up to 110% peak load to support the electrical grid in situations such as a sudden loss of a unit. The time period of this operation shall not exceed thirty (30) minutes in duration, and shall not result in an exceedance of the emission limits at maximum load specified in Special Condition No. C.5.a of this attachment.
e. Alternate Fuels. Upon receiving written approval from the Department, the permittee may burn an alternate fuel (e.g., but not limited to, biodiesel, renewable diesel, jet fuel, hydrogen, or ethanol). The alternative fuel shall be burned only temporarily and shall not result in an increase in emissions of any air pollutant or in the emission of any air pollutant not previously emitted.
f. Fuel Additives. Upon receiving written approval from the Department, the permittee may use fuel additives to reduce corrosion, control biological growth, and enhance combustion. Additives used during this scenario shall not affect emission estimates.
g. Alternate Means and Methods. Upon receiving written approval from the Department, the permittee may use alternate means and methods to improve combustion and/or reduce emissions.

(Auth.: HAR §11-60.1-3, §11-60.1-90)

8. Fugitive Emissions

   a. Potential sources of fugitive emissions in fuel oil transfer systems shall be inspected and maintained on a regular schedule to control VOC emissions.
   b. The permittee shall provide access to the Department to inspect tank weld, seams, gauge hatches, sampling ports and pressure relief valves.

   (Auth.: HAR §11-60.1-3, §11-60.1-90)

<u>Section D</u>. <u>Monitoring and Recordkeeping</u>

1. The permittee shall operate and maintain the following continuous monitoring systems for each combustion turbine generator to measure and record the following parameters and data. The associated date and time of the monitored data shall also be recorded.

   a. Operating load in MW.
   b. Water-to-fuel ratio. The water-to-fuel monitor/recorder shall be accurate to +/- five (5) percent.
   c. Fuel consumption using a flow metering system.
   d. NO_x, CO, and CO_2 or O_2, concentrations in the stack gases using a Continuous Emissions Monitoring System (CEMS). If CO_2 is measured with the CEMS to adjust the pollutant concentration, the CO_2 correction factor equations listed in 40 CFR §60.4213(d)(3) shall be used to determine compliance with the applicable emissions limit and a diluent cap value for CO_2 may be use in accordance with 40 CFR §60.4350(b). The emissions for NO_x and CO shall be recorded in ppmvd at fifteen (15) percent O_2 and lbs/hr. The system shall meet U.S. EPA performance specifications (40 CFR §60.13 and 40 CFR Part 60, Appendix B and Appendix F).
   e. The permittee shall operate and maintain a transmissometer continuous monitoring system for the measurement and recording of the opacity of stack emissions. The systems shall meet the U.S. EPA monitoring performance standards of 40 CFR §60.13 and 40 CFR Part 60, Appendix B, Performance Specifications.

   (Auth.: HAR §11-60.1-3, §11-60.1-11, §11-60.1-90, §11-60.1-161; 40 CFR §60.334)[1]

2. Ammonia Slip

   Records shall be maintained on the amount of NH_3 slip from the operation of the SCR system. Estimates of NH_3 slip shall be based on the NH_3 emission rates measured during the initial and subsequent annual performance test required by Section F of this attachment. Backup data, calculations, and the resulting NH_3 emissions shall be maintained on a monthly basis.

   (Auth.: HAR §11-60.1-3, §11-60.1-90)

3. Fuel Data

   a. The sulfur content of the fuel fired in the combustion turbine generators shall be determined using one of the following sampling options described in Sections 2.2.3, 2.2.4.1, 2.2.4.2, and 2.2.4.3 of Appendix D to 40 CFR Part 75. The analysis may be performed by the permittee, the supplier, or other qualified third party lab. The analysis shall be performed using one of the following ASTM International (ASTM) methods: D129-00, D2622-05, D4294-03, D1266-98, D5453-05, D1552-01, D5623-19, or D7039-15a, a more current version of these ASTM methods, or other U.S. EPA-approved equivalent methods.
   b. The permittee shall maintain records of the fuel deliveries identifying the delivery dates and the type and amount of fuel received, sampling option and analysis method from Special Condition No. D.3.a of this attachment used, and results of the analysis. Records of the sulfur content of the fuel shall be maintained on a monthly basis.

   (Auth.: HAR §11-60.1-3, §11-60.1-11, §11-60.1-38, §11-60.1-90, §11-60.1-161; 40 CFR §60.17, §60.334)[1]

4. An inspection, maintenance, and repair log shall be maintained for the combustion turbine generators, SCR system, and fuel oil transfer system. Replacement and repairs to the catalyst of the SCR system shall be documented.

   (Auth.: HAR §11-60.1-3, §11-60.1-90)

5. Operation Below 25 Percent of Peak Load with Water Injection

   The permittee shall maintain records of the total time Units CT-2, CT-4, and CT-5 operate below twenty-five (25) percent of peak load with water injection for the purpose of demonstrating compliance with Special Condition No. C.2 of this attachment. Records of the total time Units CT-2, CT-4, and CT-5 operated below twenty-five (25) percent of peak load with water injection, excluding startup and shutdown sequences, and as approved pursuant to Special Condition No. C.7.c of this attachment, shall be maintained on a monthly and rolling twelve (12) month basis using data recorded by the operating load continuous monitoring system.

   (Auth.: HAR §11-60.1-3, §11-60.1-90)

6. Startup and shutdown

   a. The following shall be recorded for each startup sequence:

      i. The date, start and end times, and corresponding load (MW) at the end of each startup sequence.
      ii. Duration (minutes) of the startup sequence.
      iii. The time and operating load (MW) at which water injection was initiated.

b. The following shall be recorded for each shutdown sequence:

i. The date, start and end times, and corresponding load (MW) at which the combustion turbine controls stop signal was initiated.
ii. Duration (minutes) of the shutdown sequence.
iii. The time and operating load (MW) at which water injection was terminated.

(Auth.: HAR §11-60.1-3, §11-60.1-90)

7. Alternate Operating Scenarios

a. The permittee shall contemporaneously with making a change from one operating scenario to another in accordance with Special Condition No. C.7 of this attachment, record in a log at the permitted facility the scenario under which it is operating.
b. The permittee shall maintain all records corresponding to the implementation of an alternate operating scenario specified in Special Condition No. C.7 of this attachment.
c. The reason for operating the combustion turbine generators below twenty-five (25) percent of peak load (6.17 MW) shall be clearly documented, along with the event's date, time, operating load, and resulting three-hour (3-hour) average emission rates.
d. The reason for operating the combustion turbine generators above peak load shall be clearly documented, with the event's date, time, duration, operating load, and resulting three-hour (3-hour) average emission rates.

(Auth.: HAR §11-60.1-3, §11-60.1-90)

8. All records, including support information, shall be maintained for at least five (5) years from the date of the monitoring sample, measurement, test, report, or application. Support information includes all maintenance, inspection, calibration, and repair records, and copies of all reports required by the permit. These records shall be true, accurate, and maintained in a permanent form suitable for inspection and made available to the Department or its representative upon request.

(Auth.: HAR §11-60.1-3, §11-60.1-11, §11-60.1-90)

Section E. Notification and Reporting Requirements

1. Notification and reporting pertaining to the following events shall be done in accordance with Attachment I, Standard Conditions Nos. 16, 17, and 24, respectively:

a. Intent to shut down air pollution control equipment for necessary scheduled maintenance;
b. Emissions of air pollutants in violation of HAR, Chapter 11-60.1 or this permit; and

c. Permanent discontinuance of construction, modification, relocation, or operation of the facility covered by this permit.

(Auth.: HAR §11-60.1-8, §11-60.1-15, §11-60.1-16, §11-60.1-90; SIP §11-60-10, SIP §11-60-16)[2]

2. The permittee shall report **within five (5) working days** any deviations from permit requirements, including those attributable to upset conditions, the probable cause of such deviations and any corrective actions or preventive measures taken. Corrective actions may include a requirement for additional stack testing, or more frequent monitoring, or could trigger implementation of a corrective action plan.

   (Auth.: HAR §11-60.1-3, §11-60.1-15, §11-60.1-16, §11-60.1-90)

3. Alternate Operating Scenarios

   a. Temporary Replacement

      i. Listed Sources – Notification

         Within thirty (30) days after the installation of the temporary replacement unit with one of the General Electric LM2500 units listed in Special Condition No. C.7.a of this attachment, the permittee shall submit in writing to the Department, the reason for the temporary replacement, removal date, the make, model, and serial number of the existing and temporary replacement unit, the estimated return date of the permanent unit, and the emission data of the existing and temporary replacement unit. Within thirty (30) days after the return of the permanent unit, the permittee shall notify the Department of the return date, in writing.

      ii. Sources Not Listed – Request for Approval

         The permittee shall submit a written request and obtain prior approval from the Department for any temporary replacement General Electric LM2500 unit not listed in Special Condition No. C.7.a of this attachment. The request shall include the reason for the temporary replacement, estimated removal and return dates, the make, mode, and serial number of the existing and temporary replacement unit, and the emission data of the existing and temporary replacement unit. Within thirty (30) days after the return of the permanent unit, the permittee shall notify the Department of the return date, in writing.

   b. Permanent Replacement - Request for approval

      The permittee shall submit a written request and obtain prior approval from the Department for any permanent replacement of the combustion turbine generators. The request shall include the reason for the permanent replacement, estimated replacement date, the make, model, and serial number of the existing and permanent

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replacement unit, and the emission data of the existing and permanent replacement unit. The permittee must also submit a demonstration to the Department showing that the equipment change does not trigger PSD under the actual-to-projected-actual applicability test. If approved, within thirty (30) days after the installation of the permanent replacement unit, the permittee shall notify the Department of the permanent replacement date, in writing.

c. Operation Below Twenty-Five (25) Percent Load for Other Maintenance and Testing – Request for Approval

The permittee shall submit a written request a obtain prior approval from the Department to operate below twenty-five (25) percent load for other maintenance and testing as specified in Special Condition No. C.7.c of this attachment.

d. Alternate Fuels – Request for Approval

The permittee shall submit a written request and obtain prior approval from the Department to fire the combustion turbine generators on alternate fuels; the permittee shall at a minimum, provided the Department with information on the type of fuel proposed, reason for using the alternate fuel, emissions data, stack parameters when firing the alternate fuel, the manufacturer's recommended water-to-fuel ratio and minimum operating load for compliance with the emission limits, and the estimated start and end dates for firing the alternate fuel. Within thirty (30) days after discontinuing firing of the alternate fuel, the permittee shall notify the Department of the end date, in writing. The Department may require an ambient air quality impact assessment for firing the alternate fuel and/or provide a conditional approval to impose additional monitoring, testing, recordkeeping, and reporting requirements. The Department may establish minimum water-to-fuel ratio conditions in the permit for firing the combustion turbine generators on alternate fuels.

e. Fuel Additives - Request for Approval

The permittee shall submit a written request and obtain prior approval from the Department to use fuel additives; the permittee shall, at a minimum, provide the Department the specifications of the fuel additive(s), maximum expected emission rates of any criteria or non-criteria pollutant, certification that corresponding emission rates will not exceed permitted rates, and any other related information as requested by the Department. The Department may provide a conditional approval to impose additional monitoring, testing, recordkeeping, and reporting requirements to ensure the use of the fuel additive is in compliance with the applicable requirements.

f. Alternate Means and Methods - Request for Approval

The permittee shall submit a written request and obtain prior approval from the Department to use alternate means and methods to improve combustion and/or reduce emissions. The permittee shall demonstrate that the proposal will not result in the exceedance of the National and State Ambient Air Quality Standards, that emission rates will not exceed the permitted emission limits, and that the proposal will not result in the emissions of air pollutants not previously emitted. The Department may approve, conditionally approve, or deny any request for using alternate means and methods.

(Auth.: HAR §11-60.1-3, §11-60.1-90)

4. **At least thirty (30) days prior** to the following events, the permittee shall notify the Department in writing of:

   a. Conducting a performance specification test on the CEMS. The testing date shall be in accordance with the performance test date identified in 40 CFR §60.13(c).
   b. Conducting a source performance test as required in Section F of this attachment, Testing Requirements.

   (Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-161; 40 CFR §60.8, §60.13)[1]

5. The permittee shall submit reports of excess emissions and monitoring downtime in accordance with 40 CFR §60.7(c) to the Department and U.S. EPA, Region 9, **every semi-annual period**. The report shall include the following, except when the conditions in 40 CFR §60.7(d)(1) are met:

   a. The magnitude of excess emissions computed in accordance with 40 CFR §60.13(h), any conversion factors used, and the date and time of commencement, completion of each time period of excess emissions, and the corresponding operating load of the combustion turbine generators.
   b. Specific identification of each period of excess emissions that occurs during startups, shutdowns, and malfunctions of the combustion turbine generators and the nature and cause of any malfunction (if known), and the corrective action taken, or preventive measures adopted.
   c. The date and time identifying each period during which the continuous monitoring system was inoperative except for zero and span checks and the nature of the system repairs or adjustments.
   d. The report shall state if no excess emissions have occurred. Also, the report shall state if the CEMS operated properly during the period and was not subject to any repairs or adjustments except for zero and span checks.
   e. All reports shall be postmarked by the 30th day following the end of each semi-annual period. The enclosed **Excess Emission and Monitoring System Performance Summary Report** form or an equivalent form shall be used in conjunction to the reporting of excess emissions of NO_x, CO, and opacity.

f. For purposes of this CSP, excess emissions shall be defined as follows:

i. Any three (3) hour period during which the average emissions of NO_x and CO, as measured by the CEMS, exceed the emission limits set forth in Special Condition No. C.5.a of this attachment;

ii. During simple cycle operation and combined cycle operation at loads less than fifty (50) percent of peak load (12.33 MW), any one (1) unit operating hour period during which the average water-to-fuel mass ratio, as measured by the continuous monitoring system, falls below the water-to-fuel mass ratio at the corresponding operating load specified in Special Condition No. C.3.a of this attachment, except when the NO_x CEMS concurrently shows compliance with the NO_x limits set forth in Special Condition No. C.5.a of this attachment. For operating hours during which the combustion turbine generator operates at multiple loads where multiple water-to-fuel mass ratios apply, the applicable water-to-fuel mass ratio shall be determined based on the load that corresponded to the lowest minimum water-to-fuel mass ratio. A period of monitor downtime shall be any unit operating hour in which water is injected into the combustion turbine, but the essential parametric data needed to determine the water-to-fuel ratio are unavailable or invalid. Each report shall include the average water-to-fuel ratio, average fuel consumption, and the combustion turbine load during each excess emission;

iii. Any unit operating period in which the four (4) hour rolling average NO_X emission rate exceeds the applicable emission limits in Special Condition No. C.5.c of this attachment "four (4) hour rolling average NO_X emission rate" is the arithmetic average of the average NO_X emission rate in ppm measured by the continuous emission monitoring equipment for a given hour and the three (3) unit operating hour average NO_X emission rates immediately preceding that unit operating hour. A period of monitor downtime shall be any unit operating hour in which sufficient data are not obtained to validate the hour, for either NO_x concentration or diluent (or both); and

iv. Any opacity measurements, as measured by the transmissometer continuous monitoring system, exceeding the opacity limits and corresponding averaging times set forth in Special Condition No. C.6 of this attachment. During periods of opacity exceedances as measured by the transmissometer continuous monitoring system, VE observations conducted in accordance with 40 CFR Part 60, Appendix A, Method 9 may be considered in determining compliance, however, all exceedances of the opacity limits as measured by the transmissometer continuous monitoring system shall be reported as an excess emission.

g. On and after the date of completion of the source performance test and CEMS certification, excess emissions indicated by the CEMS shall be considered violations of the applicable emission limit for the purposes of the permit with the following exceptions:

i. During the twenty (20) minute start-up period of the combustion turbine generators operating in the simple cycle mode and combined cycle mode, respectively; and

ii. During the twenty (20) minute shutdown period of the combustion turbine generators operating in either the simple cycle mode or combined cycle mode.

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-161; 40 CFR §60.7, §60.13, §60.334)[1]

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6. The permittee shall submit **semi-annually** the following written reports to the Department. The report shall be submitted **within sixty (60) days** *after the end of each semi-annual calendar period (January 1 to June 30 and July 1 to December 31*).

   a. The enclosed forms or equivalent forms shall be used for reporting:

      i. **Monitoring Report Form: Combustion Turbine Generator Operation**
      ii. **Monitoring Report Form: Combustion Turbine Generator Monthly Operation Below Minimum Operating Load with Water Injection**
      iii. **Monitoring Report Form: Fuel Certification**

   b. A summary of the occurrences and duration of any malfunction in the operation of the combustion turbine generators and air pollution control devices. The summary shall be for each semi-annual reporting period and include the corrective actions taken during the reporting period. Malfunctions occurring in previous reporting periods shall be continually listed in the summary until the corrective actions are completed.
   c. Except during the start-up and shutdown sequences, a report detailing all incidences where the air pollution control devices/systems were not in operation when the combustion turbines were operating. The report for each combustion turbine generator shall include the date, time, and duration of each incidence. The report shall list the corrective actions taken and the operational procedures used to minimize emissions during the incident.
   d. Deviations from permit requirements shall be clearly identified and addressed in these reports.

   (Auth.: HAR §11-60.1-3, §11-60.1-5, §11-60.1-90, §11-60.1-161; 40 CFR §60.334)[1]

7. Annual Emissions

   As required by Attachment IV and in conjunction with the requirements of Attachment III, the permittee shall submit **annually** the total tons/year emitted of each regulated air pollutant, including hazardous air pollutants. The reporting of annual emissions is due **within sixty (60) days** following the end of each calendar year. The enclosed form or equivalent form shall be used for reporting:

   Annual Emission Reporting Form: Combustion Turbine Generators and Diesel Engine Generators

   Upon the written request of the permittee, the deadline for reporting the annual emissions may be extended, if the Department determines that reasonable justification exists for the extension.

   (Auth.: HAR §11-60.1-3, §11-60.1-90)

8. Compliance Certification

   a. During the permit term, the permittee shall submit at least **annually** to the Department and U.S. EPA, Region 9, the attached **Compliance Certification Form** pursuant to HAR §11-60.1-86. The permittee shall indicate whether or not compliance is being met with each term or condition of this permit. The compliance certification shall include, at a minimum, the following information:

      i. The identification of each term or condition of the permit that is the basis of the certification;
      ii. The compliance status;
      iii. Whether compliance was continuous or intermittent;
      iv. The methods used for determining the compliance status of the source currently and over the reporting period;
      v. Any additional information indicating the source's compliance status with any applicable enhanced monitoring and compliance certification, including the requirements of Section 114(a)(3) of the Clean Air Act or any applicable monitoring and analysis provisions of Section 504 (b) of the Clean Air Act;
      vi. Brief description of any deviations including identifying as possible exceptions to compliance any periods during which compliance is required and which the excursion or exceedances as defined in 40 CFR Part 64 occurred; and
      vii. Any additional information as required by the Department, including information to determine compliance.

   b. The compliance certification shall be submitted within **sixty (60) days after** the end of each calendar year and shall be signed and dated by a responsible official.
   c. Upon the written request of the permittee, the deadline for submitting the compliance certification may be extended, if the Department determines that reasonable justification exists for the extension.

   (Auth.: HAR §11-60.1-4, §11-60.1-86, §11-60.1-90)

<u>Section F</u>. <u>Testing Requirements</u>

1. The permittee shall conduct or cause to be conducted, performance tests on the combustion turbine generators while operating in simple cycle mode, combined cycle mode at loads less than fifty (50) percent of peak load, and combined cycle mode with SCR at loads equal to and greater than fifty (50) percent peak load **on an annual basis** or at other times specified by the Department to demonstrate compliance with the emission limits in Special Condition No. C.5.a of this attachment.

   (Auth.: HAR §11-60.1-3, §11-60.1-5, §11-60.1-11, §11-60.1-90, §11-60.1-161; 40 CFR §60.8, §60.335)[1]

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2. All performance tests shall be conducted at twenty-five (25), fifty (50), seventy-five (75), and ninety (90) to one hundred (100) percent of the peak load, or highest achievable load. The Department may require the permittee to conduct the performance tests at additional operating loads.

   (Auth.: HAR §11-60.1-3, §11-60.1-5, §11-60.1-11, §11-60.1-90, §11-60.1-161; 40 CFR §60.8, §60.335)[1]

3. The performance tests on the combustion turbine generators operating in the simple cycle and combined cycle modes shall be conducted for SO_2, PM/PM_{10}, and VOC.

   (Auth.: HAR §11-60.1-3, §11-60.1-5, §11-60.1-11, §11-60.1-90, §11-60.1-161; 40 CFR §60.8, §60.335)[1]

4. The performance test on the combustion turbine generators operating in the combined cycle mode with SCR shall be conducted for SO_2, PM/PM_{10}, VOC, and NH_3.

   (Auth.: HAR §11-60.1-3, §11-60.1-5, §11-60.1-11, §11-60.1-90, §11-60.1-161; 40 CFR §60.8, §60.335)[1]

5. The Department may define specific water-to-fuel injection ratios for which the performance tests will be conducted.

   (Auth.: HAR §11-60.1-3, §11-60.1-5, §11-60.1-11, §11-60.1-90)

6. Performance tests for the emissions of SO_2, PM/PM_{10}, VOC, and NH_3 shall be conducted and results reported in accordance with the test methods set forth in 40 CFR Part 60, Appendix A, and 40 CFR §60.8. The following test methods or U.S. EPA-approved equivalent methods, or alternate methods with prior written approval from the Department and the U.S. EPA, shall be used. Method 3A may be used in place of Method 3.

   a. Performance tests for the emissions of SO_2 shall be conducted using 40 CFR Part 60, Methods 1-4 and 6 or 6C, or Method 3A, or Method 20, or Method 19 and fuel analysis. The following test methods shall be used to perform the fuel analysis:

      i. Sulfur content: ASTM D129-00, D2622-05, D4294-03, D1266-98, D5453-05, D1552-01, D5623-19, or D7039-15a, a more current version of these ASTM methods, or other U.S. EPA-approved equivalent methods; and
      ii. Gross Calorific Value (GCV): ASTM D240.

   b. Performance tests for the emissions of VOC shall be conducted using 40 CFR Part 60, Methods 1-4 and 25A or Methods 3A, 25A, and 19. Method 18 may be used to account for the actual methane fraction of the measured VOC emissions.
   c. Performance tests for the emissions of PM/PM_{10} shall be conducted using 40 CFR Part 60, Methods 1-5 or Method 3A.

d. Performance test for the emissions of NH_3 shall be conducted using U.S. EPA Conditional Test Method 027(CTM-027).

(Auth.: HAR §11-60.1-3, §11-60.1-5, §11-60.1-11, §11-60.1-90, §11-60.1-161; 40 CFR §60.8, §60.335)[1]

7. The performance test shall consist of three (3) separate runs using the applicable test method. For the purpose of determining compliance with an applicable regulation, the arithmetic mean of the results from the three (3) runs shall apply.

(Auth.: HAR §11-60.1-3, §11-60.1-5, §11-60.1-11, §11-60.1-90, §11-60.1-161; 40 CFR §60.8)[1]

8. **At least thirty (30) days** prior to performing a test, the permittee shall submit a written performance test plan to the Department and U.S. EPA, Region 9, that describes the test duration, test locations, test methods, source operation and other parameters that may affect test results. Such a plan shall conform to U.S. EPA guidelines including quality assurance procedures. A test plan or quality assurance plan that does not have the approval of the Department may be grounds to invalidate any test and require a retest.

(Auth.: HAR §11-60.1-3, §11-60.1-11, §11-60.1-90, §11-60.1-161; 40 CFR §60.8)[1]

9. The permittee shall provide sampling and testing facilities at its own expense. The Department may monitor the performance tests.

(Auth.: HAR §11-60.1-3, §11-60.1-5, §11-60.1-11, §11-60.1-90)

10. Any deviations from these conditions, test methods, or procedures may be cause for rejection of the test results unless such deviations are approved by the Department before the tests.

(Auth.: HAR §11-60.1-3, §11-60.1-11, §11-60.1-90)

11. **Within sixty (60) days** after completion of the performance test, the permittee shall submit to the Department and U.S. EPA, Region 9, the test report which shall include the operating conditions of the combustion turbine generators at the time of the test, the analysis of the fuel oil, the summarized test results, comparative results with the permit emission limits, and other pertinent field and laboratory data.

(Auth.: HAR §11-60.1-3, §11-60.1-11, §11-60.1-90, §11-60.1-161; 40 CFR §60.8)[1]

12. Upon written request and justification, the Department may waive the requirement for a specific annual performance test. The waiver request is to be submitted prior to the required test and must include documentation justifying such action. Documentation should include, but is not limited to, the results of the prior tests indicating compliance by a wide margin, documentation of continuing compliance, and further that operations of the source have not changed since the previous performance test.

    (Auth.: HAR §11-60.1-3, §11-60.1-90)

Section G. Agency Notification

Any document (including reports) required to be submitted by this CSP shall be done in accordance with Attachment I, Standard Condition No. 28.

(Auth.: HAR §11-60.1-4, §11-60.1-90)

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[1] The citations to the Code of Federal Regulations (CFR) identified under a particular condition, indicate that the permit condition complies with the specified provision(s) of the CFR. Due to the integration of the preconstruction and operating permit requirements, permit conditions may incorporate more stringent requirements than those set forth in the CFR.

[2] The citations to the State Implementation Plan (SIP) identified under a particular condition, indicate that the permit condition complies with the specified provision(s) of the SIP.

ATTACHMENT IIB: SPECIAL CONDITIONS FOR THE COMBUSTION TURBINE GENERATOR, UNIT CT-2
COVERED SOURCE PERMIT NO. 0007-01-C

Issuance Date: DATE **Expiration Date: DATE**

In addition to the standard conditions of the CSP, the following special conditions shall apply to the permitted facility:

Section A. Equipment Description

1. This permit encompasses the following equipment and associated appurtenances:

   One (1) 18 MW (nominal) (18.3 MW peak load) Simple Cycle Combustion Turbine Generator, Model Jupiter GT-35 (Manufactured by Asea Brown Boveri (ABB) and supplied by Solar Turbines) with a maximum design heat input rate of 198 MMBtu/hr, Unit CT-2.

   (Auth.: HAR §11-60.1-3, §11-60.1-90)

2. The permittee shall have installed an identification tag or name plate on the combustion turbine generator which identifies the model no., serial no., and manufacturer. The identification tag or name plate shall be permanently attached to the equipment at a conspicuous location.

   (Auth.: HAR §11-60.1-5, §11-60.1-90)

Section B. Applicable Federal Regulations

1. Unit CT-2 is subject to the provisions of the following federal regulations:

   a. 40 CFR Part 60, Standards of Performance for New Stationary Sources, Subpart A, General Provisions; and
   b. 40 CFR Part 60, Standards of Performance for New Stationary Sources, Subpart GG, Standards of Performance for Stationary Gas Turbines.

   (Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-132, §11-60.1-161; 40 CFR §60.1, §60.330)[1]

2. The permittee shall comply with all applicable provisions of these standards, including all emission limits, notification, testing, monitoring, and reporting requirements. The major requirements of these standards are detailed in the special conditions of this permit.

   (Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-132, §11-60.1-161; 40 CFR §60.1, §60.330)[1]

3. This CSP incorporates conditional requirements from an existing permit issued pursuant to 40 CFR §52.21, Prevention of Significant Deterioration of Air Quality.

   (Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-132; 40 CFR §52.21)[1]

Section C. Operational and Emission Limitations

1. Startup and Shutdown

   a. The startup sequence for the combustion turbine generator shall be a twenty (20) minute period starting from the time fuel use at the combustion turbine generator begins. Upon completion of the twenty (20) minute startup sequence, the water injection system shall be operational, and the combustion turbine generator shall be at twenty-five (25) percent of peak load (4.6 MW) or more except as provided in Special Condition No. C.2 of this attachment.
   b. The shutdown sequence for the combustion turbine generator shall not exceed twenty (20) minutes. A shutdown sequence shall be from the time the combustion turbine controls stop signal is initiated for the combustion turbine generator and the combustion turbine generator is below twenty-five (25) percent of peak load (4.6 MW), until fuel use at the combustion turbine generator ceases.

   (Auth.: HAR §11-60.1-3, §11-60.1-5, §11-60.1-90)

2. Minimum Operational Loads

   The operation of the Units CT-2, CT-4, and CT-5, below twenty-five (25) percent of peak load with water injection, shall not exceed a combined total of sixty-six (66) hours in any rolling twelve (12) month period, except during startup and shutdown sequences, and as approved pursuant to Special Condition No. C.7.b of this attachment.

   (Auth.: HAR §11-60.1-3, §11-60.1-5, §11-60.1-90)

3. Air Pollution Control Equipment

   a. Water Injection

      The permittee shall continuously operate and maintain a water injection system to meet the emission limits as specified for NO_x in Special Condition No. C.5 of this attachment. Water injection shall be initiated during the startup sequence of the combustion turbine generator and shall be terminated at the beginning of or during the shutdown sequence of the combustion turbine generator.

For the combustion turbine generator, after completion of the startup sequence and until the beginning of the shutdown sequence, the following water-to-fuel mass ratios, on a one (1) unit operating hour average basis, shall be maintained when the combustion turbine generator is firing fuel oil No. 2. When firing an approved alternate fuel, the same water-to-fuel mass ratios or approved fuel specific water-to-fuel mass ratios, on a one (1) unit operating hour average basis, shall be maintained. A unit operating hour shall be as defined in 40 CFR §60.331.

WATER INJECTION SYSTEM
MINIMUM WATER INJECTION RATES BASED ON LOAD

Peak load (%)	Load (MW)	Mass Ratio (lb-water / lb-fuel)
100	18.3	1.00
75 - <100	13.7 - <18.3	0.75
50 - <75	9.15 - <13.7	0.55
<50	<9.15	0.3

For operating hours during which the combustion turbine generator operates at multiple loads where multiple water-to-fuel mass ratios apply, the applicable water-to-fuel mass ratio shall be determined based on the load that corresponded to the lowest minimum water-to-fuel mass ratio.

The Department, with U.S. EPA's concurrence, may increase the minimum water injection rates after reviewing the performance test results required in Section F of this attachment.

b. The use of an alternate control system other than those specified above (contingent upon receipt of the Department's written approval to use such a system) shall not relieve the permittee from the responsibility to meet all emission limitations contained within this CSP.

(Auth.: HAR §11-60.1-3, §11-60.1-5, §11-60.1-90)

4. Fuel Usage and Specifications

a. The combustion turbine generator shall be fired only on fuel oil No. 2 with a maximum sulfur content not to exceed 0.4 percent by weight or an alternate fuel allowed under Special Condition No. C.7.d of this attachment.
b. The maximum amount of fuel oil No. 2 or any alternate fuel allowed under Special Condition No. C.7.d of this attachment fired in Unit CT-2 shall not exceed 12,301,254 gallons per any rolling twelve (12) month period.

(Auth.: HAR §11-60.1-3, §11-60.1-5, §11-60.1-90, §11-60.1-161; 40 CFR §60.333)[1]

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5. Maximum Emission Limits

Except for the startup and shutdown sequences, the permittee shall not discharge or cause the discharge into the atmosphere from the combustion turbine generator, NO_x, SO_2, PM/PM_{10}, CO, and VOC in excess of the following specified limits:

MAXIMUM EMISSION LIMITS (3-hour average)

Air Pollutant	lbs/hr	ppmvd @ 15 percent O_2
NO_x (as NO_2)	39	47
SO_2	110	95.4
PM/PM_{10}	20	0.06*
CO	22.4	44.4
VOC	22.4	28.2**

Based on Unit CT-2 operating at ISO atmospheric conditions (59° F, 60% relative humidity and 19.92 in mercury (Hg) pressure).
* gr/dscf @ 12 percent CO_2.
**Using a molecular weight of 44 (propane) for VOC.

The three-hour (3-hour) averaging period shall begin immediately upon completion of the combustion turbine generator's startup sequence and end immediately prior to the combustion turbine generator's shutdown sequence.

The Department, with U.S. EPA's concurrence, may lower the allowable emission limitation for NO_X, PM, CO, and VOC after reviewing the performance test results required in Section F of this attachment.

If the NO_X, PM/PM_{10}, CO, or VOC emission limit is revised, the difference between the applicable emission limit set forth above and the revised lower emission limit shall not be allowed as an emission offset for future construction or modification.

(Auth.: HAR §11-60.1-3, §11-60.1-5, §11-60.1-90, §11-60.1-161; 40 CFR §60.332, §60.333)[1]

6. Visible Emissions (VE)

For any six (6) minute averaging period, the combustion turbine generator shall not exhibit VE of twenty (20) percent opacity or greater, except as follows: during startup, shutdown, or equipment malfunction, the combustion turbine generator may exhibit VE not greater than sixty (60) percent opacity for a period aggregating not more than six (6) minutes in any sixty (60) minute period.

(Auth.: HAR §11-60.1-3, §11-60.1-32, §11-60.1-90; SIP §11-60-24)[2]

7. Alternate Operating Scenarios

   The terms and conditions under the following alternate operating scenarios shall meet all applicable requirements including all conditions of this permit. Requests for written approval to operate under the applicable alternate operating scenario shall be in accordance with Special Condition No. E.3 of this attachment.

   a. Temporary Replacement. Upon receiving approval from the Department, the permittee may replace the combustion turbine generator with an equivalent temporary replacement unit with equal or lesser emissions in the event of a failure or major overhaul of the equipment. The combustion turbine generator shall be repaired and returned to service in a timely manner. The installation and operation of the temporary replacement unit shall not exceed twelve (12) consecutive months,
   b. The combustion turbine generator may operate below twenty-five (25) percent of peak load (4.6 MW) in isochronous mode with water injection for system restoration and for other maintenance and testing as approved by the Department in accordance with Special Condition No. E.3.b of this attachment. Operation during these periods shall not result in an exceedance of the emission limits of Special Condition No. C.5 of this attachment.
   c. Combustion Turbine Operation Above Peak Load. The permittee may operate the combustion turbine generators up to 110% peak load to support the electrical grid in situations such as a sudden loss of a unit. The time period of this operation shall not exceed thirty (30) minutes in duration, and shall not result in an exceedance of the emission limits at maximum load specified in Special Condition No. C.5 of this attachment.
   d. Alternate Fuels. Upon receiving written approval from the Department, the permittee may burn an alternate fuel (e.g., but not limited to, biodiesel, renewable diesel, jet fuel, hydrogen, or ethanol). The alternative fuel shall be burned only temporarily and shall not result in an increase in emissions of any air pollutant or in the emission of any air pollutant not previously emitted.
   e. Fuel Additives. Upon receiving written approval from the Department, the permittee may use fuel additives to reduce corrosion, control biological growth, and enhance combustion. Additives used during this scenario shall not affect emission estimates.
   f. Alternate Means and Methods. Upon receiving written approval from the Department, the permittee may use alternate means and methods to improve combustion and/or reduce emissions.

   (Auth.: HAR §11-60.1-3, §11-60.1-90)

8. Fugitive Emissions

   a. Potential sources of fugitive emissions in fuel oil transfer systems shall be inspected and maintained on a regular schedule to control VOC emissions.
   b. The permittee shall provide access to the Department to inspect tank weld, seams, gauge hatches, sampling ports and pressure relief valves.

   (Auth.: HAR §11-60.1-3, §11-60.1-90)

Section D. Monitoring and Recordkeeping

1. The permittee shall operate and maintain a continuous monitoring system to measure and record the following parameters or data. The associated date and time of the monitored data shall also be recorded.

   a. Operating load in MW;
   b. Water-to-fuel ratio. The water-to-fuel monitor/recorder shall be accurate to ± five (5) percent;
   c. Fuel consumption using a flow metering system; and
   d. NO_x, CO, and CO_2 or O_2 concentrations in the stack gases using a CEMS. The system shall meet U.S. EPA performance specifications (40 CFR §60.13 and 40 CFR Part 60, Appendix B and Appendix F). If CO_2 is measured with the CEMS to adjust the pollutant concentration, the CO_2 correction factor equations listed in 40 CFR §60.4213(d)(3) shall be used to determine compliance with the applicable emissions limit and a diluent cap value for CO_2 may be used in accordance with 40 CFR §60.4350(b). The CEMS shall be on-line and fully operational, upon completion and thereafter of the performance specification test. The emissions for NO_x and CO shall be recorded in ppmvd at fifteen (15) percent O_2 and lbs/hr.

   (Auth.: HAR §11-60.1-3, §11-60.1-11, §11-60.1-90, §11-60.1-161; 40 CFR §60.334)[1]

2. Visible Emissions (VE)

   a. The permittee shall conduct **monthly** (calendar month) VE observations for each equipment for the month the equipment is in operation by a certified reader in accordance with 40 CFR Part 60, Appendix A, Method 9, or U.S. EPA approved equivalent methods, or alternate methods with prior written approval from the Department and the U.S. EPA. For each month, two (2) consecutive six (6) minute observations shall be taken at fifteen (15) second intervals. Records shall be completed and maintained in accordance with the **Visible Emissions Form Requirements**.
   b. The Department may at any time require the permittee to install, operate, and maintain a transmissometer system for the continuous measurement and recording of the opacity of stack emissions if it is determined that the VE are in excess of the applicable standard. The system shall meet U.S. EPA monitoring performance standards (40 CFR §60.13 and 40 CFR Part 60, Appendix B, Performance Specifications).

   (Auth.: HAR §11-60.1-3, §11-60.1-11, §11-60.1-32, §11-60.1-90)

3. Fuel Data

   a. The sulfur content of the fuel fired in the combustion turbine generator shall be determined using one of the following sampling options described in Sections 2.2.3, 2.2.4.1, 2.2.4.2, and 2.2.4.3 of Appendix D to 40 CFR Part 75. The analysis may be performed by the permittee, the supplier, or other qualified third party lab. The analysis shall be performed using one of the following ASTM methods:

D129-00, D2622-05, D4294-03, D1266-98, D5453-05, D1552-01, D5623-19, or D7039-15a, a more current version of these ASTM methods, or other U.S. EPA-approved equivalent methods.

b. The permittee shall maintain records of the fuel deliveries identifying the delivery dates and the type and amount of fuel received, sampling option and analysis method from Special Condition No. D.3.a of this attachment used, and results of the analysis. Records of the sulfur content of the fuel shall be maintained on a monthly basis.

c. Total fuel usage. Records on the total amount (gallons) used by Unit CT-2 shall be maintained on a monthly and rolling twelve (12) month basis.

(Auth.: HAR §11-60.1-3, §11-60.1-11, §11-60.1-38, §11-60.1-90, §11-60.1-161; 40 CFR §60.17, §60.334)[1]

4. An inspection, maintenance, and repair log shall be maintained for the combustion turbine generator and fuel oil transfer system.

(Auth.: HAR §11-60.1-3, §11-60.1-90)

5. Operation Below Twenty-Five (25) Percent of Peak Load with Water Injection

The permittee shall maintain records of the total time Units CT-2, CT-4, and CT-5 operate below twenty-five (25) percent of peak load with water injection for the purpose of demonstrating compliance with Special Condition No. C.2 of this attachment. Records of the total time Units CT-2, CT-4, and CT-5 operated below twenty-five (25) percent of peak load with water injection, excluding startup and shutdown sequences, and as approved pursuant to Special Condition No. C.7.b of this attachment, shall be maintained on a monthly and rolling twelve (12) month basis using data recorded by the operating load continuous monitoring system.

(Auth.: HAR §11-60.1-3, §11-60.1-90)

6. Startup and Shutdown

a. The following shall be recorded for each startup sequence:

i. The date, start and end times, and corresponding load (MW) at the end of each startup sequence.
ii. Duration (minutes) of the startup sequence.
iii. The time and operating load (MW) at which water injection was initiated.

b. The following shall be recorded for each shutdown sequence:

i. The date, start and end times, and corresponding load (MW) at which the combustion turbine controls stop signal was initiated.
ii. Duration (minutes) of the shutdown sequence.
iv. The time and operating load (MW) at which water injection was terminated.

(Auth.: HAR §11-60.1-3, §11-60.1-90)

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7. Alternate Operating Scenarios

   a. The permittee shall contemporaneously with making a change from one operating scenario to another in accordance with Special Condition No. C.7 of this attachment, record in a log at the permitted facility the scenario under which it is operating.
   b. The permittee shall maintain all records corresponding to the implementation of an alternate operating scenario specified in Special Condition No. C.7 of this attachment.
   c. The reason for operating the combustion turbine generator below twenty-five (25) percent of peak load (4.6 MW) shall be clearly documented, along with the event's date, time, operating load, and resulting three-hour (3-hour) average emission rates.
   d. The reason for operating the combustion turbine generator above peak load shall be clearly documented, with the event's date, time, duration, operating load, and resulting three-hour average emission rates.

   (Auth.: HAR §11-60.1-3, §11-60.1-90)

8. All records, including support information, shall be maintained for at least five (5) years from the date of the monitoring sample, measurement, test, report, or application. Support information includes all maintenance, inspection, calibration, and repair records, and copies of all reports required by the permit. These records shall be true, accurate, and maintained in a permanent form suitable for inspection and made available to the Department or its representative upon request.

   (Auth.: HAR §11-60.1-3, §11-60.1-11, §11-60.1-90)

<u>Section E</u>. <u>Notification and Reporting Requirements</u>

1. Notification and reporting pertaining to the following events shall be done in accordance with Attachment I, Standard Conditions 16, 17, and 24, respectively:

   a. Intent to shut down air pollution control equipment for necessary scheduled maintenance;
   b. Emissions of air pollutants in violation of HAR, Chapter 11-60.1 or this permit; and
   c. Permanent discontinuance of construction, modification, relocation, or operation of the facility covered by this permit.

   (Auth.: HAR §11-60.1-8, §11-60.1-15, §11-60.1-16, §11-60.1-90; SIP §11-60-10, SIP §11-60-16)[2]

2. The permittee shall report (in writing) **within five (5) working days** *any deviations from permit requirements,* including those attributable to upset conditions, the probable cause of such deviations and any corrective actions or preventive measures taken. Corrective actions may include a requirement for additional stack testing, or more frequent monitoring, or could trigger implementation of a corrective action plan.

   (Auth.: HAR §11-60.1-3, §11-60.1-15, §11-60.1-16, §11-60.1-90)

3. Alternate Operating Scenarios

a. Temporary Replacement – Request for Approval

The permittee shall submit a written request and obtain prior approval from the Department for a temporary replacement unit. The request shall include the reason for the temporary replacement, estimated removal date, the make, mode, and serial number of the existing and temporary replacement unit, the estimated return date of the permanent unit, the emission data of the existing and temporary replacement unit, and a demonstration that the temporary replacement unit will not result in the exceedance of the National and State Ambient Air Quality Standards. Within thirty (30) days after the return of the permanent unit, the permittee shall notify the Department of the return date, in writing.

b. Operation Below Twenty-Five (25) Percent Load for Other Maintenance and Testing – Request for Approval

The permittee shall submit a written request a obtain prior approval from the Department to operate below twenty-five (25) percent load for other maintenance and testing as specified in Special Condition No. C.7.b of this attachment.

c. Alternate Fuels – Request for Approval

The permittee shall submit a written request and obtain prior approval from the Department to fire the combustion turbine generator on alternate fuels; the permittee shall at a minimum, provided the Department with information on the type of fuel proposed, reason for using the alternate fuel, emissions data, stack parameters when firing the alternate fuel, the manufacturer's recommended water-to-fuel ratio and minimum operating load for compliance with the emission limits, and the estimated start and end dates for firing of the alternate fuel. Within thirty (30) days after discontinuing firing of the alternate fuel, the permittee shall notify the Department of the end date, in writing. The Department may require an ambient air quality impact assessment for firing the alternate fuel and/or provide a conditional approval to impose additional monitoring, testing, recordkeeping, and reporting requirements. The Department may establish minimum water-to-fuel ratio conditions in the permit for firing the combustion turbine generator on alternate fuels.

d. Fuel Additives - Request for Approval

The permittee shall submit a written request and obtain prior approval from the Department to use fuel additives; the permittee shall, at a minimum, provide the Department the specifications of the fuel additive(s), maximum expected emission rates of any criteria or non-criteria pollutant, certification that corresponding emission rates will not exceed permitted rates, and any other related information as requested by the Department. The Department may provide a conditional approval to impose additional monitoring, testing, recordkeeping, and reporting requirements to ensure the use of the fuel additive is in compliance with the applicable requirements.

e. Alternate Means and Methods - Request for Approval

The permittee shall submit a written request and obtain prior approval from the Department to use alternate means and methods to improve combustion and/or reduce emissions. The permittee shall demonstrate that the proposal will not result in the exceedance of the National and State Ambient Air Quality Standards, that emission rates will not exceed the permitted emission limits, and that the proposal will not result in the emissions of air pollutants not previously emitted. The Department may approve, conditionally approve, or deny any request for using alternate means and methods.

(Auth.: HAR §11-60.1-3, §11-60.1-90)

4. **At least thirty (30) days prior** to the following events, the permittee shall notify the Department in writing of:

   a. Conducting a performance specification test on the CEMS. The testing date shall be in accordance with the performance test date identified in 40 CFR §60.13(c).
   b. Conducting a source performance test as required in Section F of this attachment.

   (Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-161; 40 CFR §60.8, §60.13)[1]

5. The permittee shall submit reports of excess emissions and monitoring downtime in accordance with 40 CFR §60.7(c) to the Department and U.S. EPA, Region 9, **every semi-annual period**. The report shall include the following, except when the conditions in 40 CFR §60.7(d)(1) are met:

   a. The magnitude of excess emissions computed in accordance with 40 CFR §60.13(h), any conversion factors used, and the date and time of commencement, completion of each time period of excess emissions, and the corresponding operating load of the combustion turbine generator.
   b. Specific identification of each period of excess emissions that occurs during startups, shutdowns, and malfunctions of the combustion turbine generator and the nature and cause of any malfunction (if known), and the corrective action taken, or preventive measures adopted.
   c. The date and time identifying each period during which the continuous monitoring system was inoperative except for zero and span checks and the nature of the system repairs or adjustments.
   d. The report shall state if no excess emissions have occurred. Also, the report shall state if the CEMS operated properly during the period and was not subject to any repairs or adjustments except for zero and span checks.
   e. All reports shall be postmarked by the 30th day following the end of each semi-annual period. The enclosed **Excess Emission and Monitoring System Performance Summary Report** form or an equivalent form shall be used in conjunction to the reporting of excess emissions of NO_x and CO.

f. For purposes of this CSP, excess emissions shall be defined as follows:

i. Any three (3) hour period during which the average emissions of NO_x and CO, as measured by the CEMS, exceed the emission limits set forth in Special Condition No. C.5 of this attachment;

ii. Any one (1) unit operating hour period during which the average water-to-fuel mass ratio, as measured by the continuous monitoring system, falls below the water-to-fuel mass ratio at the corresponding operating load specified in Special Condition No. C.3.a of this attachment, except when the NO_x CEMS concurrently shows compliance with the NO_x limits set forth in Special Condition No. C.5 of this attachment. For operating hours during which the combustion turbine generator operates at multiple loads where multiple water-to-fuel mass ratios apply, the applicable water-to-fuel mass ratio shall be determined based on the load that corresponded to the lowest minimum water-to-fuel mass ratio; and

g. On and after the date of completion of the source performance test and CEMS certification, excess emissions indicated by the CEMS shall be considered violations of the applicable emission limit for the purposes of the permit with the following exceptions:

i. During the twenty (20) minute start-up period of the combustion turbine generator; and

ii. During the twenty (20) minute shutdown period of the combustion turbine generator.

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.161; 40 CFR §60.7, §60.13, §60.334)[1]

6. The permittee shall submit **semi-annually** the following written reports to the Department. The report shall be submitted **within sixty (60) days** *after the end of each semi-annual calendar period (January 1 to June 30 and July 1 to December 31*).

a. The enclosed forms or equivalent forms shall be used for reporting:

i. **Monitoring Report Form: Combustion Turbine Generator Operation**
ii. **Monitoring Report Form: Combustion Turbine Generator Monthly Operation Below Minimum Operating Load with Water Injection**
iii. **Monitoring Report Form: Fuel Certification**
iv**.** **Monitoring Report Form: Fuel Consumption**
v. **Monitoring Report Form: Visible Emissions Exceedances**

b. A summary of the occurrences and duration of any malfunction in the operation of the combustion turbine generator and air pollution control devices. The summary shall be for each semi-annual reporting period and include the corrective actions taken during the reporting period. Malfunctions occurring in previous reporting periods shall be continually listed in the summary until the corrective actions are completed.

c. Except during the start-up and shutdown sequences, a report detailing all incidences where the air pollution control devices/systems were not in operation when the combustion turbine was operating. The report for the combustion turbine generator shall include the date, time, and duration of each incidence. The report shall list the corrective actions taken and the operational procedures used to minimize emissions during the incident.

d. Deviations from permit requirements shall be clearly identified and addressed in these reports.

(Auth.: HAR §11-60.1-3, §11-60.1-5, §11-60.1-90, §11-60.161; 40 CFR §60.334)[1]

7. Annual Emissions

As required by Attachment IV and in conjunction with the requirements of Attachment III, the permittee shall submit **annually** the total tons/year emitted of each regulated air pollutant, including hazardous air pollutants. The reporting of annual emissions is due **within sixty (60) days** following the end of each calendar year. The enclosed **Annual Emission Reporting Form: Combustion Turbine Generators and Diesel Engine Generators**, or an equivalent form, shall be used in reporting.

Upon the written request of the permittee, the deadline for reporting the annual emissions may be extended, if the Department determines that reasonable justification exists for the extension.

(Auth.: HAR §11-60.1-3, §11-60.1-90)

8. Compliance Certification

a. During the permit term, the permittee shall submit at least **annually** to the Department and U.S. EPA, Region 9, the attached **Compliance Certification Form** pursuant to HAR §11-60.1-86. The permittee shall indicate whether or not compliance is being met with each term or condition of this permit. The compliance certification shall include, at a minimum, the following information:

i. The identification of each term or condition of the permit that is the basis of the certification;
ii. The compliance status;
iii. Whether compliance was continuous or intermittent;
iv. The methods used for determining the compliance status of the source currently and over the reporting period;
v. Any additional information indicating the source's compliance status with any applicable enhanced monitoring and compliance certification, including the requirements of Section 114(a)(3) of the Clean Air Act or any applicable monitoring and analysis provisions of Section 504 (b) of the Clean Air Act;
vi. Brief description of any deviations including identifying as possible exceptions to compliance any periods during which compliance is required and which the excursion or exceedances as defined in 40 CFR Part 64 occurred; and

vii. Any additional information as required by the Department, including information to determine compliance.

b. The compliance certification shall be submitted within **sixty (60) days after** the end of each calendar year and shall be signed and dated by a responsible official.

c. Upon the written request of the permittee, the deadline for submitting the compliance certification may be extended, if the Department determines that reasonable justification exists for the extension.

(Auth.: HAR §11-60.1-4, §11-60.1-86, §11-60.1-90)

Section F. Testing Requirements

1. The permittee shall conduct or cause to be conducted performance tests on the combustion turbine generator in the simple cycle mode. Performance tests on the combustion turbine generator shall be conducted for SO_2, PM/PM_{10}, and VOC. The performance tests for SO_2, PM/PM_{10}, and VOC shall be conducted at one hundred (100) percent of peak load or highest achievable load. Performance tests shall be conducted on an annual basis or at such times as may be specified by the Department. The Department may define specific water-to-fuel injection ratios for which the performance tests will be conducted. For any performance test, a continuous monitoring system shall be in operation to monitor and record the ratio of water-to-fuel fired in the combustion turbine generator.

   (Auth.: HAR §11-60.1-3, §11-60.1-5, §11-60.1-11, §11-60.1-90, §11-60.1-161; 40 CFR §60.8, §60.335)[1]

2. Performance tests for the emissions of SO_2, VOC, and PM/PM_{10} shall be conducted and results reported in accordance with the test methods set forth in 40 CFR Part 60, Appendix A, and 40 CFR §60.8. The following test methods or U.S. EPA-approved equivalent methods, or alternate methods with prior written approval from the Department and the U.S. EPA, shall be used. Method 3A may be used in place of Method 3.

   a. Performance tests for the emissions of SO_2 shall be conducted using 40 CFR Part 60, Methods 1-4 and 6 or 6C, or Method 3A, or Method 20, or Method 19 and fuel analysis. The following test methods shall be used to perform the fuel analysis:

      i. Sulfur content: ASTM D129-00, D2622-05, D4294-03, D1266-98, D5453-05, D1552-01, D5623-19, or D7039-15a, a more current version of these ASTM methods, or other U.S. EPA-approved equivalent methods; and
      ii. Gross Calorific Value (GCV): ASTM D240.

   b. Performance tests for the emissions of VOC shall be conducted using 40 CFR Part 60, Methods 1-4 and 25A or Methods 3A, 25A, and 19. Method 18 may be used to account for the actual methane fraction of the measured VOC emissions.

c. Performance tests for the emissions of PM/PM_{10} shall be conducted using 40 CFR Part 60, Methods 1-5, or Method 3A.

(Auth.: HAR §11-60.1-3, §11-60.1-5, §11-60.1-11, §11-60.1-90, §11-60.1-161; 40 CFR §60.8, §60.335)[1]

3. The performance test shall consist of three (3) separate runs using the applicable test method. For the purpose of determining compliance with an applicable regulation, the arithmetic mean of the results from the three (3) runs shall apply.

   (Auth.: HAR §11-60.1-3, §11-60.1-5, §11-60.1-11, §11-60.1-90, §11-60.1-161; 40 CFR §60.8)[1]

4. **At least thirty (30) days** prior to performing a test, the permittee shall submit a written performance test plan to the Department that describes the test duration, test locations, test methods, source operation and other parameters that may affect test results. Such a plan shall conform to U.S. EPA guidelines including quality assurance procedures. A test plan or quality assurance plan that does not have the approval of the Department may be grounds to invalidate any test and require a retest.

   (Auth.: HAR §11-60.1-3, §11-60.1-11, §11-60.1-90, §11-60.1-161; 40 CFR §60.8)[1]

5. The permittee shall provide sampling and testing facilities at its own expense. The Department may monitor the performance tests.

   (Auth.: HAR §11-60.1-3, §11-60.1-5, §11-60.1-11, §11-60.1-90)

6. Any deviations from these conditions, test methods, or procedures may be cause for rejection of the test results unless such deviations are approved by the Department before the tests.

   (Auth.: HAR §11-60.1-3, §11-60.1-11, §11-60.1-90)

7. **Within sixty (60) days** after completion of the performance test, the permittee shall submit to the Department and U.S. EPA, Region 9, the test report which shall include the operating conditions of the combustion turbine generator at the time of the test, the analysis of the fuel oil, the summarized test results, comparative results with the permit emission limits, and other pertinent field and laboratory data.

   (Auth.: HAR §11-60.1-3, §11-60.1-11, §11-60.1-90, §11-60.1-161; 40 CFR §60.8)[1]

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8. Upon written request and justification, the Department may waive the requirement for a specific annual performance test. The waiver request is to be submitted prior to the required test and must include documentation justifying such action. Documentation should include, but is not limited to, the results of the prior tests indicating compliance by a wide margin, documentation of continuing compliance, and further that operations of the source have not changed since the previous performance test.

   (Auth.: HAR §11-60.1-3, §11-60.1-90)

Section G. Agency Notification

Any document (including reports) required to be submitted by this CSP shall be done in accordance with Attachment I, Standard Condition No. 28.

(Auth.: HAR §11-60.1-4, §11-60.1-90)

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[1] The citations to the Code of Federal Regulations (CFR) identified under a particular condition, indicate that the permit condition complies with the specified provision(s) of the CFR. Due to the integration of the preconstruction and operating permit requirements, permit conditions may incorporate more stringent requirements than those set forth in the CFR.

[2] The citations to the State Implementation Plan (SIP) identified under a particular condition, indicate that the permit condition complies with the specified provision(s) of the SIP.

ATTACHMENT IIC: SPECIAL CONDITIONS FOR THE DIESEL ENGINE GENERATORS COVERED SOURCE PERMIT NO. 0007-01-C

Issuance Date: DATE **Expiration Date: DATE**

In addition to the Standard Conditions of the CSP, the following Special Conditions shall apply to the permitted facility:

Section A. Equipment Description

1. This permit encompasses the following equipment and associated appurtenances:

   a. One (1) 2.5 MW General Motors EMD Model No. 20-645F4B Diesel Engine Generator, Unit D-21;
   b. One (1) 2.5 MW General Motors EMD Model No. 20-645F4B Diesel Engine Generator, Unit D-22;
   c. One (1) 2.5 MW General Motors EMD Model No. 20-645E4 Diesel Engine Generator, Unit D-23; and
   d. One (1) 500 kW Caterpillar Model 3412 Black Start Diesel Engine Generator, Unit BS-1.

   (Auth.: HAR §11-60.1-3, §11-60.1-90)

2. The permittee shall permanently attach an identification tag or nameplate on each equipment, which identifies the model no., serial no., and manufacturer. The identification tag or nameplate shall be attached to the equipment at a conspicuous location.

   (Auth.: HAR §11-60.1-5, §11-60.1-90)

Section B. Applicable Federal Regulations

1. Diesel engine generators, Units D-21, D-22, and D-23, and Black Start Diesel Engine Generator, Unit BS-1, are subject to the provisions of the following federal regulations.

   a. 40 CFR Part 63, National Emission Standards for Hazardous Air Pollutants for Source Categories (Maximum Achievable Control Technologies (MACT) Standards), Subpart A, General Provisions; and
   b. 40 CFR Part 63, National Emission Standards for Hazardous Air Pollutants for Source Categories (Maximum Achievable Control Technologies (MACT) Standards), Subpart ZZZZ, National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines (RICE).

   (Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-174; 40 CFR §63.1, §63.6585)[1]

2. The permittee shall comply with all applicable provisions of these standards, including all emission limits, notification, testing, monitoring, and reporting requirements. The major requirements of these standards are detailed in the special conditions of this permit.

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-174; 40 CFR §63.1, §63.6585)[1]

Section C. Operational and Emission Limitations

1. Operating Hours, black start diesel engine generator, Unit BS-1

   The maximum operating hours of the black start diesel engine generator, Unit BS-1, shall not exceed 300 hours in any rolling twelve (12) month period.

   (Auth.: HAR §11-60.1-3, §11-60.1-5, §11-60.1-90)

2. Fuel Consumption Limit, diesel engine generator, Unit D-21

   The maximum fuel consumption of diesel engine generator, Unit D-21, shall not exceed 70,000 gallons in any rolling twelve (12) month period.

   (Auth.: HAR §11-60.1-3, §11-60.1-5, §11-60.1-90)

3. Fuel Injection Timing Retard

   Diesel engine generators, Units D-21, D-22, and D-23, shall operate with a fuel injection timing retard of four (4) degrees at all loads. The permittee may use an alternate control system upon receiving the Department's written approval to use such a system. The alternate control system shall meet all emission limitations contained within this attachment.

   (Auth.: HAR §11-60.1-3, §11-60.1-5, §11-60.1-90)

4. Fuel Specifications

   a. Black start diesel engine generator, Unit BS-1, shall be fired only on fuel oil No. 2 with a maximum sulfur content not to exceed 0.4 percent by weight, or an alternate fuel allowed under Special Condition No. C.7.b of this attachment.
   b. Diesel engine generators, Units D-21, D-22, and D-23, shall be fired on the following fuels:

      i. Fuel oil No.2 with a maximum sulfur content of 0.0015 percent by weight and a minimum cetane index of 40 or a maximum aromatic content of 35 volume percent;
      ii. Alternate fuels as allowed under Special Condition No. C.7.b of this attachment; or
      iii. Any combination thereof.

   (Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-174; 40 CFR §63.6604)[1]

5. Maximum Emission Limit

Diesel engine generators, Units D-21, D-22, and D-23, shall not discharge into the atmosphere NO_x in excess of the following specified limit:

	Maximum Emission Limit (3-hour Average)[a]	
Compound	(lbs/hr)	(ppmvd @ 15 percent O_2)
NO_x[b]	68.4	600

[a]Emission limit per diesel engine generator.
[b]Measured as nitrogen dioxide (NO_2).

The Department, with U.S. EPA's concurrence, may revise the allowable emission limitation for NO_x after reviewing the annual performance test results required under Section F of this attachment.

If the NO_x emission limit is revised, the difference between the applicable emission limit set forth above and the revised lower emission limit shall not be allowed as an emission offset for future construction or modification.

(Auth.: HAR §11-60.1-3, §11-60.1-5, §11-60.1-90)

6. Visible Emissions (VE)

For any six (6) minute averaging period, the diesel engine generators shall not exhibit VE of twenty (20) percent opacity or greater, except as follows: during startup, shutdown, or equipment malfunction, the diesel engine generators may exhibit VE not greater than sixty (60) percent opacity for a period aggregating not more than six (6) minutes in any sixty (60) minute period.

(Auth.: HAR §11-60.1-3, §11-60.1-32, §11-60.1-90; SIP §11-60-24)[2]

7. Alternate Operating Scenarios

The terms and conditions under the following alternate operating scenarios shall meet all applicable requirements including all conditions of this permit. Requests for written approval from the Department to operate under the applicable alternate operating scenario shall be in accordance with Special Condition No. E.7 of this attachment.

a. Temporary Replacement. In the event of a failure or major overhaul of the equipment, the permittee may replace the diesel engine generators, Units D-21, D-22, and D-23, with one of the General Motors EMD Model No. 20-645 with the serial numbers listed below. Notification must be provided in accordance with Special Condition No. E.7 of

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this attachment. Notification and approval is required for temporary replacements with units that are not listed, the replacement unit shall be a 2.5 MW General Motors EMD Model No. 20-645 with equal or lesser emissions:

i. 74-K3-1540
ii. 71-M1-1092
iii. 71-M1-1045
iv. 74-B1-1078
v. 66-K1-1062
vi. 69-H1-1057
vii. 74-B1-1063
viii. 72-E1-1027
ix. 72-B1-1122
x. 73-G1-1129
xi. 66-K1-1057
xii. 72-E1-1094
xiii. 66-J1-1156

b. Permanent Replacement. Upon receiving written approval from the Department, the permittee may replace the diesel engine generators, Units D-21, D-22, and D-23, with another General Motors EMD Model No. 20-645 if any repair work reasonably warrants the removal (i.e., equipment failure or malfunction, overhaul, or any major equipment problems requiring maintenance for efficient operation) of a diesel engine generator from its site and the following provisions are adhered to:

i. The replacement diesel engine generator is a General Motors EMD Model No. 20-645 with one of the following serial numbers:

1) 74-K3-1540
2) 71-M1-1092
3) 71-M1-1045
4) 74-B1-1078
5) 66-K1-1062
6) 69-H1-1057
7) 74-B1-1063
8) 72-E1-1027
9) 72-B1-1122
10) 73-G1-1129
11) 66-K1-1057
12 72-E1-1094
13) 66-J1-1156

ii. The permittee may continue using the replacement diesel engine generator and is not required to return the original diesel engine generator after it is repaired.

c. Alternate Fuels. Upon receiving written approval from the Department, the permittee may burn an alternate fuel (e.g., but not limited to, biodiesel or renewable diesel). The alternative fuel shall be burned only temporarily and shall not result in an increase in emissions of any air pollutant or in the emission of any air pollutant not previously emitted.
d. Fuel Additives. Upon receiving written approval from the Department, the permittee may use fuel additives to reduce corrosion, control biological growth, enhance combustion, improve lubricity, or other reasons. Additives used during this scenario shall not affect emission estimates.
e. Alternate Means and Methods. Upon receiving written approval from the Department, the permittee may use alternate means and methods to improve combustion and/or reduce emissions.

(Auth.: HAR §11-60.1-3, §11-60.1-90)

8. On and after May 3, 2013, the permittee shall comply with the following requirements for diesel engine generators, Units D-21, D-22, and D-23:

a. Oxidation catalyst systems shall be installed, operated, and maintained;
b. Except during startup, limit concentration of CO in the stationary RICE exhaust to twenty-three (23) ppmvd at fifteen (15) percent O_2 or reduce CO emissions by seventy (70) percent or more;
c. Except during startup, maintain engine exhaust temperature so that the temperature at the oxidation catalyst inlet is greater than or equal to 450 °F and less than or equal to 1350 °F;
d. Except during startup, maintain the oxidation catalyst so that the pressure drop does not change by more than two (2) inches water (H_2O) from the pressure drop across the catalyst measured during the initial performance test;
e. Minimize engine idling during startup and limit startup to less than thirty (30) minutes; and
f. Install, operate, and maintain a closed crankcase ventilation system or a filtration system on the open crankcase ventilation system.

(Auth.: HAR §11-60.1-3; §11-60.1-11, §11-60.1-90, §11-60.1-174; 40 CFR §63.6603, §63.6625)[1]

9. The permittee shall comply with the following requirements for the black start diesel engine generator, Unit BS-1:

a. Change the engine oil and filter every 500 hours of operation or annually, whichever comes first (an oil analysis program as described in 40 CFR §63.6625(i) may be utilized in order to extend the specified oil change requirement;
b. Inspect the engine air cleaner every 1,000 hours of operation or annually, whichever comes first, and replace as necessary; and
c. Inspect all engine hoses and belts every 500 hours of operation or annually, whichever comes first, and replace as necessary.
d. The black start diesel engine generator idling during startup shall be minimized and startup shall not exceed thirty (30) minutes.

(Auth.: HAR §11-60.1-3; §11-60.1-11, §11-60.1-90, §11-60.1-174; 40 CFR §63.6603)[1]

<u>Section D</u>. <u>Monitoring and Recordkeeping Requirements</u>

1. Fuel Data

   a. Black Start Diesel Engine Generator, Unit BS-1

      i. The sulfur content of the fuel fired in the black start diesel engine generator, Unit BS-1, shall be determined for each batch of fuel received using one of the following sampling options described in Sections 2.2.3, 2.2.4.1, 2.2.4.2, and 2.2.4.3 of Appendix D to 40 CFR Part 75. The analysis may be performed by the permittee, the supplier, or other qualified third party lab. The analysis shall be performed using one of the following ASTM Methods: D129-00, D2622-05, D4294-03, D1266-98, D5453-05, D1552-01, D5623-19, or D7039-15a, a more current version of these ASTM methods, or other U.S. EPA-approved equivalent methods. The methods used to analyze the fuel and the results of the analysis shall be maintained.
      ii. The permittee shall maintain records of the fuel deliveries identifying the delivery dates and the type and amount of fuel received. Records of the sulfur content of the fuel shall be maintained on a monthly basis.

   b. Diesel Engine Generators, Units D-21, D-22, and D-23

      i. The sulfur content of the fuel fired in the diesel engine generators, Units D-21, D-22, and D-23, shall be determined by sampling each batch of fuel received. The analysis may be performed by the permittee, the supplier, or other qualified third party lab. The analysis shall be performed using one of the following ASTM Methods: D129-00, D2622-05, D4294-03, D1266-98, D5453-05, D1552-01, D5623-19, or D7039-15a, a more current version of these ASTM methods, or other U.S. EPA-approved equivalent methods. The methods used to analyze the fuel and the results of the analysis shall be maintained.
      ii. The cetane index or aromatic content may be demonstrated by providing the supplier's fuel specification sheet for the type of fuel purchased and received.

   (Auth.: HAR §11-60.1-3, §11-60.1-11, §11-60.1-38, §11-60.1-90)

2. Operating Hours

   The permittee shall operate and maintain a non-resetting hour meter on the black start diesel engine generator, Unit BS-1, to permanently record the total hours that the unit has operated. Monthly records shall be kept of the beginning and ending meter readings and the total hours that Unit BS-1 operated during that month. A monthly summary shall include the total hours Unit BS-1 operated on a monthly and rolling twelve (12) month basis.

   (Auth.: HAR §11-60.1-3, §11-60.1-5, §11-60.1-90)

3. Fuel Consumption, diesel engine generator, Unit D-21

   The permittee shall operate and maintain a non-resetting flow meter system on diesel engine generator, Unit D-21, for the continuous measurement and recording of the fuel consumed by the diesel engine generator. The flow meter reading shall be recorded at the beginning and end of each calendar month. Records on the total gallons of fuel consumed shall be maintained on a monthly and rolling twelve (12) month basis.

   (Auth.: HAR §11-60.1-3, §11-60.1-5, §11-60.1-90)

4. Inspection, Maintenance, and Repair Log

   An inspection, maintenance, and repair log shall be maintained for the diesel engine generators covered under this permit. Replacement of parts and repairs to the diesel engine generators shall be well documented.

   (Auth.: HAR §11-60.1-3, §11-60.1-5, §11-60.1-90)

5. Visible Emissions (VE)

   The permittee shall conduct **monthly** (calendar month) VE observations for each equipment for each month the equipment is in operation by a certified reader in accordance with 40 CFR Part 60, Appendix A, Method 9, or U.S. EPA approved equivalent methods, or alternate methods with prior written approval from the Department and the U.S. EPA. For each month, two (2) consecutive six (6) minute observations shall be taken at fifteen (15) second intervals. Records shall be completed and maintained in accordance with the **Visible Emissions Form Requirements**.

   (Auth.: HAR §11-60.1-3, §11-60.1-11, §11-60.1-32, §11-60.1-90)

6. Alternate Operating Scenarios

   a. The permittee shall contemporaneously with making a change from one operating scenario to another in accordance with Special Condition No. C.7 of this attachment, record in a log at the permitted facility the scenario under which it is operating.
   b. The permittee shall maintain all records corresponding to the implementation of an alternate operating scenario specified in Special Condition No. C.7 of this attachment.

   (Auth.: HAR §11-60.1-3, §11-60.1-90)

7. Not later than May 3, 2013, the permittee shall install, operate, and maintain a continuous parameter monitoring system (CPMS) to monitor and record temperature at the oxidation catalyst inlet on diesel engine generators, Units D-21, D-22, and D-23. The permittee must prepare a site-specific monitoring plan. The CPMS and the site-specific monitoring plan must meet the requirements of 40 CFR §63.6625(b).

   (Auth.: HAR §11-60.1-3, §11-60.1-11, §11-60.1-90, §11-60.1-174; 40 CFR §63.6625, §63.6655)[1]

8. Once the testing required pursuant to Special Condition No. F.3 of this attachment is completed, the permittee shall measure and record the pressure drop across each oxidation catalyst on a monthly basis except during months in which the diesel engine generator does not operate.

   (Auth.: HAR §11-60.1-3, §11-60.1-11, §11-60.1-90, §11-60.1-174; 40 CFR §63.6625, §63.6640, §63.6655)[1]

9. All records, including support information, shall be maintained for at least five (5) years from the date of the monitoring sample, measurement, test, report, or application. Support information includes all maintenance, inspection, calibration, and repair records, and copies of all reports required by the permit. These records shall be true, accurate, and maintained in a permanent form suitable for inspection and made available to the Department or its representative upon request.

   (Auth.: HAR §11-60.1-3, §11-60.1-11, §11-60.1-90)

Section E. Notification and Reporting Requirements

1. Notification and reporting pertaining to the following events shall be done in accordance with Attachment I, Standard Condition Nos. 16, 17, and 24, respectively:

   a. Intent to shut down air pollution control equipment for necessary scheduled maintenance;
   b. Emissions of air pollutants in violation of HAR, Chapter 11-60.1 or this permit; and
   c. Permanent discontinuance of construction, modification, relocation, or operation of the facility covered by this permit.

   (Auth.: HAR §11-60.1-8, §11-60.1-16, §11-60.1-90)

2. The permittee shall report **within five (5) working days** any deviations from the permit requirements, including those attributable to upset conditions, the probable cause of such deviations and any corrective actions or preventive measures taken. Corrective actions may include a requirement for additional stack testing, or more frequent monitoring, or the implementation of a corrective action plan.

   (Auth.: HAR §11-60.1-3, §11-60.1-15, §11-60.1-16, §11-60.1-90)

3. **At least thirty (30) days** or **sixty (60) days** (as applicable) prior to conducting a source performance test, the permittee shall notify the Department in writing of conducting a source performance test as required by Section F of this attachment.

   (Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-161; 40 CFR §60.8, §60.13)[1]

4. The permittee shall submit **semi-annually** the following written reports to the Department. The report shall be submitted **within sixty (60) days** after the end of each semi-annual calendar period (January 1 to June 30 and July 1 to December 31), and shall include the following:

   a. The enclosed forms or equivalent forms shall be used for reporting:

      i. **Monitoring Report Form**: **Operating Hours: Black Start Diesel Engine Generator** for Unit BS-1.
      ii. **Monitoring Report Form: Fuel Consumption** for Unit D-21.
      iii. **Monitoring Report Form: Visible Emission Exceedances** for each diesel engine generator.

   b. A report identifying the type of fuel fired in each of the diesel engine generators during the semi-annual reporting period. The report shall include the maximum sulfur content (percent by weight) of the fuel for the reporting period. Also, the cetane index or aromatic content for diesel engine generators, Units D-21, D-22, and D-23. The enclosed **Monitoring Report Form: Fuel Certification**, or an equivalent form, shall be used for reporting.
   c. Any deviations from the permit requirements shall be clearly identified. At a minimum, a summary of each deviation shall include a description of the deviation, the reason for the deviation, the duration, and the corrective actions taken.

   (Auth.: HAR §11-60.1-3, §11-60.1-5, §11-60.1-90)

   d. The permittee shall submit semi-annual compliance reports to the Department and U.S. EPA, Region 9 required by 40 CFR §63.6650. The enclosed **Excess Emissions and Continuous Monitoring System (CMS) Performance Report and/or Summary Report Form,** or an equivalent form, shall be used for reporting.

   (Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-174; 40 CFR §63.6650, §63.6650(b)(5))[1]

5. Compliance Certification

   a. During the permit term, the permittee shall submit at least **annually** to the Department and U.S. EPA, Region 9, the attached **Compliance Certification Form** pursuant to HAR §11-60.1-86. The permittee shall indicate whether or not compliance is being met with each term or condition of this permit. The compliance certification shall include, at a minimum, the following information:

      i. The identification of each term or condition of the permit that is the basis of the certification;
      ii. The compliance status;
      iii. Whether compliance was continuous or intermittent;
      iv. The methods used for determining the compliance status of the source currently and over the reporting period;

v. Any additional information indicating the source's compliance status with any applicable enhanced monitoring and compliance certification, including the requirements of Section 114(a)(3) of the Clean Air Act or any applicable monitoring and analysis provisions of Section 504 (b) of the Clean Air Act;

vi. Brief description of any deviations including identifying as possible exceptions to compliance any periods during which compliance is required and which the excursion or exceedances as defined in 40 CFR Part 64 occurred; and

vii. Any additional information as required by the Department, including information to determine compliance.

b. The compliance certification shall be submitted within **sixty (60) days after** the end of each calendar year and shall be signed and dated by a responsible official.

c. Upon the written request of the permittee, the deadline for submitting the compliance certification may be extended, if the Department determines that reasonable justification exists for the extension.

(Auth.: HAR §11-60.1-4, §11-60.1-86, §11-60.1-90)

6. Annual Emissions

As required by Attachment IV and in conjunction with the requirements of Attachment III, Annual Fee Requirements, the permittee shall report **annually** the total tons/yr emitted of each regulated air pollutant, including hazardous air pollutants. The reporting of annual emissions is due **within sixty (60) days following** the end of each calendar year. The enclosed **Annual Emission Reporting Form: Combustion Turbine Generators and Diesel Engine Generators,** or an equivalent form, shall be used in reporting.

Upon the written request of the permittee, the deadline for reporting of annual emissions may be extended, if the Department determines that reasonable justification exists for the extension.

(Auth.: HAR §11-60.1-3, §11-60.1-90)

7. Alternate Operating Scenarios

a. Temporary Replacement

i. Listed Sources – Notification

Within thirty (30) days after the installation of the temporary replacement unit with one of the General Motors EMD Model No. 20-645 units listed in Special Condition No. C.7.a of this attachment, the permittee shall submit in writing to the Department, the reason for the temporary replacement, removal date, the make, model, and serial number of the existing and temporary replacement units, the estimated return date of the permanent unit, and the emission data of the existing and temporary replacement unit. Within thirty (30) days after the return of the permanent unit, the permittee shall notify the Department of the return date, in writing.

ii. Sources Not Listed – Request for Approval

The permittee shall submit a written request and obtain prior approval from the Department for any temporary replacement General Motors EMD Model No. 20-645 unit not listed in Special Condition No. C.7.a of this attachment. The request shall include the reason for the temporary replacement, estimated removal and return dates, the make, mode, and serial number of the existing and temporary replacement unit, and the emission data of the existing and temporary replacement unit. Within thirty (30 days after the return of the permanent unit, the permittee shall notify the Department of the return date, in writing.

b. Permanent Replacement - Request for Approval

The permittee shall submit a written request and obtain prior approval from the Department for any permanent replacement of the diesel engine generators, Units D-21, D-22, and D-23. The request shall include the reason for the permanent replacement, estimated replacement date, the make, model, and serial number of the existing and replacement unit, and the emission data of the existing and permanent replacement unit. The permittee must also submit a demonstration to the Department showing that the equipment change does not trigger PSD under the actual-to-projected-actual applicability test. If approved, within thirty (30) days after the installation of the permanent replacement, the permittee shall notify the Department of the permanent replacement date, in writing.

c. Alternate Fuels – Request for Approval

The permittee shall submit a written request and obtain prior approval from the Department to fire the diesel engine generators on alternate fuels; the permittee shall at a minimum, provided the Department with information on the type of fuel proposed, reason for using the alternate fuel, emissions data, stack parameters when firing the alternate fuel, and the estimated start and end dates for firing the alternate fuel. Within thirty (30) days after discontinuing the firing of the alternate fuel, the permittee shall notify the Department of the end date, in writing. The Department may require an ambient air quality impact assessment for firing the alternate fuel and/or provide a conditional approval to impose additional monitoring, testing, recordkeeping, and reporting requirements.

d. Fuel Additives - Request for Approval

The permittee shall submit a written request and obtain prior approval from the Department to use fuel additives; the permittee shall, at a minimum, provide the Department the specifications of the fuel additive(s), maximum expected emission rates of any criteria or non-criteria pollutant, certification that corresponding emission rates will not exceed permitted rates, and any other related information as requested by the Department. The Department may provide a conditional approval to impose additional monitoring, testing, recordkeeping, and reporting requirements to ensure the use of the fuel additive is in compliance with the applicable requirements.

e. Alternate Means and Methods - Request for Approval

The permittee shall submit a written request and obtain prior approval from the Department to use alternate means and methods to improve combustion and/or reduce emissions. The permittee shall demonstrate that the proposal will not result in the exceedance of the National and State Ambient Air Quality Standards, that emission rates will not exceed the permitted emission limits, and that the proposal will not result in the emissions of air pollutants not previously emitted. The Department may approve, conditionally approve, or deny any request for using alternate means and methods.

(Auth.: HAR §11-60.1-3, §11-60.1-90)

Section F. Testing Requirements

1. **On an annual basis** or at such other times as may be specified by the Department, the permittee shall conduct or cause to be conducted performance tests on the diesel engine generators, Units D-21, D-22, and D-23, at maximum load or highest achievable load for NO_x.

   Upon written request and justification, the Department may waive the requirement for the annual NO_x performance test. The waiver request is to be submitted prior to the required test and must include documentation justifying such action. Documentation should include, but is not limited to, the results of the prior tests indicating compliance by a wide margin, documentation of continuing compliance, and further that operations of the source have not changed since the previous performance test.

   (Auth.: HAR §11-60.1-3, §11-60.1-90)

2. Performance tests for the emissions of NO_x shall be conducted and results reported in accordance with the test methods set forth in 40 CFR Part 60, Appendix A, and 40 CFR §60.8. The following test methods or U.S. EPA-approved equivalent methods, or alternate methods with prior written approval from the Department and the U.S. EPA, shall be used. Method 3A may be used in place of Method 3. Performance tests for the emissions of NO_x shall be conducted using 40 CFR Part 60, Methods 1-4 and 7 or 7E or Method 19.

   (Auth.: HAR §11-60.1-3, §11-60.1-5, §11-60.1-11, §11-60.1-90)

3. The permittee shall conduct performance tests on the diesel engine generators, Units D-21, D-22, and D-23, to demonstrate compliance with the requirements of Special Condition No. C.8.b of this attachment no later than October 30, 2013. Performance tests shall be conducted for CO. Subsequent performance tests shall be conducted after every 8,760 hours of operation or three (3) years of operation, whichever comes first, or following the catalyst replacement in accordance with 40 CFR §63.6640(b). Performance tests shall

be conducted under such conditions as the EPA specifies to the permittee based on representative performance (i.e., performance based on normal operating conditions) of the diesel engine generator. Performance tests for emissions of CO shall be conducted and results recorded and reported in accordance with the test methods and procedures set forth in 40 CFR §63.6620.

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-174; 40 CFR §63.7, §63.6612, §63.6615, §63.6620)[1]

4. The performance test shall consist of three (3) separate runs using the applicable test method. For the purpose of determining compliance with an applicable regulation, the arithmetic mean of the results from the three (3) runs shall apply.

   (Auth.: HAR §11-60.1-5, §11-60.1-11, §11-60.1-90)

5. The permittee shall provide sampling and testing facilities at its own expense. The tests shall be conducted at the maximum load or highest achievable load of the diesel engine generators and the Department may monitor the tests.

   (Auth.: HAR §11-60.1-3, §11-60.1-5, §11-60.1-11, §11-60.1-90; SIP §11-60-15)[2]

6. Any deviations from these conditions, test methods, or procedures may be cause for rejection of the test results unless such deviations are approved by the Department before the tests.

   (Auth.: HAR §11-60.1-3, §11-60.1-11, §11-60.1-90)

7. **At least thirty (30) days** prior to performing the performance tests required by Special Condition No. F.1 of this attachment, the permittee shall submit a written performance test plan to the Department that describes the test duration, test locations, test methods, source operation, and other parameters that may affect test results. Such a plan shall conform to U.S. EPA guidelines including quality assurance procedures. A test plan or quality assurance plan that does not have the approval of the Department may be grounds to invalidate any test and require a retest.

   (Auth.: HAR §11-60.1-3, §11-60.1-11, §11-60.1-90)

8. **At least sixty (60) days** prior to performing the performance tests required by Special Condition No. F.3 of this attachment, the permittee shall submit a written performance test plan to the Department and U.S. EPA Region 9, (Attention: Enforcement Division, Air Section), that describes the test duration, test locations, test methods, source operation, and other parameters that may affect test results. Such a plan shall conform to U.S. EPA guidelines including quality assurance procedures. A test plan or quality assurance plan that does not have the approval of the Department may be grounds to invalidate any test and require a retest.

   (Auth.: HAR §11-60.1-3, §11-60.1-11, §11-60.1-90; 40 CFR §63.7, §63.6645, §63.6665)[1]

9. **Within sixty (60) days** after completion of the performance test required by Special Conditions Nos. F.1 and F.3 of this attachment, the permittee shall submit to the Department and U.S. EPA, Region 9, (Attention: Enforcement Division, Air Section), the test report which shall include the operating conditions of the diesel engine generators at the time of the test, the analysis of the fuel, the summarized test results, comparative results with the permit emission limits, and other pertinent field and laboratory data.

   (Auth.: HAR §11-60.1-3, §11-60.1-11, §11-60.1-90; 40 CFR §63.7, §63.6645, §63.6665)[1]

Section G. Agency Notification

Any document (including reports) required to be submitted by this CSP shall be done in accordance with Attachment I, Standard Condition No. 28.

(Auth.: HAR §11-60.1-4, §11-60.1-90)

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[1] The citations to the Code of Federal Regulations (CFR) identified under a particular condition, indicate that the permit condition complies with the specified provision(s) of the CFR. Due to the integration of the pre-construction and operating permit requirements, permit conditions may incorporate more stringent requirements than those set forth in the CFR.

[2] The citations to the State Implementation Plan (SIP) identified under a particular condition, indicate that the permit condition complies with the specified provision(s) of the SIP.

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ATTACHMENT II - INSIG: SPECIAL CONDITIONS FOR INSIGNIFICANT ACTIVITIES
COVERED SOURCE PERMIT NO. 0007-01-C

Issuance Date: DATE **Expiration Date: DATE**

In addition to the Standard Conditions of the CSP, the following Special Conditions shall apply to the permitted facility:

Section A. Equipment Description

This attachment encompasses insignificant activities listed in HAR §11-60.1-82(f) and (g) for which provisions of this permit and HAR, Subchapter 2, General Prohibitions, apply.

(Auth.: HAR §11-60.1-3)

Section B. Operational Limitations

1. The permittee shall take measures to operate applicable insignificant activities in accordance with the provisions of HAR, Subchapter 2 for VE, fugitive dust, incineration, process industries, sulfur oxides from fuel combustion, storage of VOC, VOC water separation, pump and compressor requirements, and waste gas disposal.

   (Auth.: HAR §11-60.1-3, §11-60.1-82, §11-60.1-90)

2. The Department may at any time require the permittee to further abate emissions if an inspection indicates poor or insufficient controls.

   (Auth.: HAR §11-60.1-3, §11-60.1-5, §11-60.1-82, §11-60.1-90)

Section C. Monitoring and Recordkeeping Requirements

1. The Department reserves the right to require monitoring, recordkeeping, or testing of any insignificant activity to determine compliance with the applicable requirements.

   (Auth.: HAR §11-60.1-3, §11-60.1-90)

2. All records, including support information, shall be maintained for at least five (5) years from the date of the monitoring sample, measurement, test, report, or application. Support information includes all maintenance, inspection, calibration, and repair records, and copies of all reports required by the permit. These records shall be true, accurate, and maintained in a permanent form suitable for inspection and made available to the Department or its representative upon request.

   (Auth.: HAR §11-60.1-3, §11-60.1-11, §11-60.1-90)

<u>Section D</u>. <u>Notification and Reporting</u>

Compliance Certification

During the permit term, the permittee shall submit at least **annually** to the Department and U.S. EPA, Region 9, the attached **Compliance Certification Form** pursuant to HAR §11-60.1-86. The permittee shall indicate whether or not compliance is being met with each term or condition of this permit. The compliance certification shall include, at a minimum, the following information:

1. The identification of each term or condition of the permit that is the basis of the certification;
2. The compliance status;
3. Whether compliance was continuous or intermittent;
4. The methods used for determining the compliance status of the source currently and over the reporting period;
5. Any additional information indicating the source's compliance status with any applicable enhanced monitoring and compliance certification including the requirements of Section 114(a)(3) of the Clean Air Act or any applicable monitoring and analysis provisions of Section 504(b) of the Clean Air Act;
6. Brief description of any deviations including identifying as possible exceptions to compliance any periods during which compliance is required and in which the excursion or exceedances as defined in 40 CFR Part 64 occurred; and
7. Any additional information as required by the Department including information to determine compliance.

The compliance certification shall be submitted **within sixty (60) days** after the end of each calendar year, and shall be signed and dated by a responsible official.

Upon written request of the permittee, the deadline for submitting the compliance certification may be extended, if the Department determines that reasonable justification exists for the extension.

In lieu of addressing each emission unit as specified in **Compliance Certification Form**, the permittee may address insignificant activities as a single unit provided compliance is met with all applicable requirements. If compliance is not totally attained, the permittee shall identify the specific insignificant activity and provide the details associated with the noncompliance.

(Auth.: HAR §11-60.1-4, §11-60.1-86, §11-60.1-90)

<u>Section E</u>. <u>Agency Notification</u>

Any document (including reports) required to be submitted by this CSP shall be done in accordance with Attachment I, Standard Condition No. 28.

(Auth.: HAR §11-60.1-4, §11-60.1-90)

ATTACHMENT II - GHG: SPECIAL CONDITIONS
GHG REDUCTION REQUIREMENTS
COVERED SOURCE PERMIT NO. 0007-01-C

Issuance Date: DATE **Expiration Date: DATE**

In addition to the standard conditions of the CSP, the following state enforceable special conditions shall apply to the permitted facility:

Section A. Equipment Description

1. Attachment II - GHG of this permit encompasses the following equipment and associated appurtenances for Keahole Generating Station:

Unit	Description
CT-2	18 MW Asea Brown Boveri Combustion Turbine Generator, Model Jupiter GT-35
CT-4	20 MW General Electric LM2500 Combustion Turbine Generator
CT-5	20 MW General Electric LM2500 Combustion Turbine Generator
D-21	2.5 MW General Motors EMD Model No. 20-645F4B Diesel Engine Generator
D-22	2.5 MW General Motors EMD Model No. 20-645F4B Diesel Engine Generator
D-23	2.5 MW General Motors EMD Model No. 20-645E4 Diesel Engine Generator
BS-1	500 kW Caterpillar Model 3412 Black Start Diesel Engine Generator

(Auth.: HAR §11-60.1-3)

2. The equipment is subject to greenhouse gas (GHG) emission reduction requirements of HAR, Chapter 11-60.1, Subchapter 11 and associated permit conditions based on information from the GHG emission reduction plan and permit application for significant modification. The GHG emission reduction plan shall become a part of the CSP application process for renewals and any required modifications pursuant to HAR, Chapter 11-60.1, Subchapter 5. With each subsequent GHG emission reduction plan submittal, the permittee shall report:

   a. The GHG emission reduction status;
   b. Factors contributing to the emission changes;
   c. Any control measure updates; and
   d. Any new developments or changes that would affect the basis of the facility GHG emissions cap.

   (Auth.: HAR §11-60.1-5, §11-60.1-204(g))

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Section B. GHG Permit Conditions

1. Permit conditions specified in Attachment II – GHG, including provisions to limit maximum potential GHG emissions, are state-only enforceable requirements which are not federally enforceable under the federal Clean Air Act.

   (Auth.: HAR §11-60.1-3, §11-60.1-90, 11-60.1-161; 40 CFR §70.6)[1]

2. The permittee shall comply with all applicable provisions of these conditions, including all emission limits, notification, testing, monitoring, and reporting requirements. The major requirements of these provisions are detailed in the special conditions of this attachment.

   (Auth.: HAR §11-60.1-3, §11-60.1-90, 11-60.1-161)[1]

Section C. GHG Emission Limitations

1. GHG Emission Caps

   a. Keahole Generating Station shall not emit or cause to be emitted carbon dioxide equivalent (CO_2e) emissions in excess of its individual caps specified in Attachment II - GHG, Special Condition No. C.1.a of CSP No. 0548-01-C for Campbell Industrial Park (CIP) Generating Station, except as specified in Attachment II – GHG, Special Condition No. C.1.c.iv of this permit.
   b. All partnering facilities shall not emit or cause to be emitted total combined CO_2e emissions in excess of the combined limits specified in Attachment II – GHG, Special Condition No. C.1.b of CSP No. 0548-01-C for CIP Generating Station.
   c. For purposes of the CO_2e emission limits in Attachment II - GHG, Special Condition Nos. C.1.a and C.1.b of this permit:

      i. The CO_2e emissions shall have the same meaning as that specified in HAR §11-60.1-1;
      ii. In accordance with HAR §11-60.1-204(d)(6)(B), biogenic carbon dioxide (CO_2) emissions shall not be included when determining compliance with the emissions limits;
      iii. The permittee shall be in compliance with the applicable emission limits by the end of 2019 and each calendar year thereafter;
      iv. 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
      v. 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 are exceeded simultaneously, emissions in excess of the total combined cap shall be allocated according to the following equation for compliance purposes:

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

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.
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.

(Auth.: HAR §11-60.1-3, §11-60.1-5, §11-60.1-5, §11-60.1-90, §11-60.1-204)

2. GHG Emission Cap Revisions

   a. The facility-wide GHG emissions cap may be re-evaluated and revised by the Department in accordance with HAR §11-60.1-204(h).
   b. Any revision to the facility-wide GHG emissions caps shall be considered a significant modification subject to the application and review requirements of HAR §11-60.1-104. For each GHG emission cap revision, the Department may impose additional emission limits or requirements, or limit the time-frame allowed for the revised GHG emissions cap.

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-204)

3. Alternate Operating Scenarios

The alternate operating scenario for the PGV facility shutdown due to volcanic activity on the island of Hawaii in 2018, shall remain in effect until an additional net energy generation of 26,883 MWh per month from the PGV facility is reached in any month of the year. The following shall apply to the individual and total combined alternate operating scenario GHG emission cap adjustments starting January 1, 2020, and for any subsequent year until these alternate operating scenarios no longer apply:

   a. Attachment II – GHG, Special Condition No. C.3 no longer applies when,

$$NG_{PGV\text{-}R} \geq NG_{PGV2017}$$

Where,

$NG_{PGV2017}$ =	26,883	Net generating capacity from the PGV facility in calendar year 2017 on an average monthly basis (MWh) preceding its shutdown.
$NG_{PGV\text{-}R}$ =		Net generation from the restored PGV facility (MWh per month).

b. The alternate scenario individual GHG emission cap adjustment for Calendar Year 2019 is 97,524 short tons for Hamakua Energy, LLC, 17,132 short tons for Kanoelehua-Hill Generating Station, 31,213 short tons for Keahole Generating Station, and 39,535 short tons for Puna Generating Station. Starting on January 1, 2020, and for any subsequent year, the alternate scenario GHG emissions individual cap adjustment for each of the foregoing island of Hawaii partnering facilities shall be calculated by adding one-twelfth (1/12) of the 2019 annual adjustment for each facility's individual GHG emissions cap specified in Attachment II – GHG, Special Condition No. C.1.a.ii of CSP No. 0548-01-C for CIP Generating Station per month for the facilities from January 1 of that year. Monthly adjustments to the individual GHG emission caps shall be determined as specified in Attachment II – GHG, Special Condition No. C.3.d until this alternate operating scenario no longer applies as specified in Attachment II – GHG, Special Condition No. C.3.a. A full one-twelfth (1/12) of the annual cap adjustment shall apply per month until the criteria in Attachment II – GHG, Special Condition No. C.3.a are met and not thereafter.

c. The PGV alternate scenario total combined cap adjustment for Calendar Year 2019 is 185,404 short tons. Starting on January 1, 2020, and for any subsequent year, the PGV alternate operating scenario total combined GHG emissions cap adjustment shall be calculated by adding one-twelfth (1/12) of the 2019 annual adjustment of 15,450 short tons to the total combined cap specified in Attachment II – GHG, Special Condition No. C.1.b.ii of CSP No. 0548-01-C for CIP Generating Station per month from January 1 of that year. Monthly adjustments to the total combined GHG emissions cap shall be determined as specified in Attachment II – GHG, Special Condition No. C.3.d until this alternate operating scenario no longer applies as specified in Attachment II – GHG, Special Condition No. C.3.a. A full one-twelfth (1/12) of the annual cap adjustment shall apply per month until the criteria in Attachment II – GHG, Special Condition No. C.3.a are met and not thereafter.

d. Monthly adjustments to the individual and total combined GHG emission caps shall be determined with the following equation:

$$AC = FAC/12$$

Where,

FAC = Full adjustment to CO_2e caps (short tons – refer to table below).
AC = Monthly adjustment to GHG emissions caps.

Generating Station	Full Adjustment to CO_2e Caps (Short Tons)	2020 CO_2e Cap (Short Tons)	FAC/12 (Short Tons)[b]
Hamakua Energy	97,524	153,699	8,127
Kanoelehua-Hill	17,132	172,456	1,428
Keahole	31,213	242,208	2,601
Puna	39,535	31,747	3,295
Combined	185,404	see note[a]	15,450

[a]Total combined CO_2e cap for all partnering facilities is 7,023,257 short tons.
[b]Monthly full CO_2e cap adjustment.

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e. Individual GHG emission cap adjustments, affecting the total combined GHG emissions cap, shall only apply to partnering facilities on the island of Hawaii.
f. The permittee may exceed the adjusted individual GHG emissions cap as determined in Attachment II – GHG, Special Condition No. C.3.b, if the adjusted total combined GHG emission cap as determined in Attachment II – GHG, Special Condition No. C.3.c is met.
g. Alternate operating scenario records shall be maintained in accordance with Attachment II - GHG, Special Condition No. D.3.
h. The terms and conditions under each operating scenario shall meet all applicable requirements, including the special conditions of this permit.

(Auth.: HAR §11-60.1-3, §11-60.1-5, §11-60.1-204(h))

Section D. Monitoring and Recordkeeping Requirements

1. GHG Emissions

For calculating CO_2e emissions to assess fees, determining compliance with the GHG emission caps, and quality assurance/quality control requirements, the permittee shall:

a. Monitor CO_2 mass emissions data for the stationary source combustion units listed in Attachment II – GHG, Special Condition No. A.1 in accordance with the 40 CFR §98.34;
b. Estimate missing data in accordance with the applicable procedures in 40 CFR §98.35;
c. Determine the metric tons of CO_2, methane (CH_4), and nitrous oxide (N_2O) in accordance with 40 CFR §98.33;
d. Calculate the GHG emissions, expressed in metric tons of CO_2e, using Equation A-1 of 40 CFR §98.2;
e. Convert the metric tons of CO_2e emissions to short tons for monitoring and annual emissions reporting as applicable. For the conversion, one (1) short ton is equal to 0.90718474 metric tons; and
f. Report CO_2e emissions to the Department in accordance with Attachment II - GHG Special Condition No. E.4.

(Auth.: HAR §11-60.1-3, §11-60.1-90; §11-60.1-204d(6)(c); 40 CFR §98.2, §98.33, §98.34, §98.35)[1]

2. Records

All records, including support information, shall be maintained for **at least five (5) years** from the date of the monitoring sample, measurement, test, report, or applications. Support information includes all maintenance, inspection, and repair records, and copies of all reports required by this permit. These records shall be true, accurate, and maintained in a permanent form suitable for inspection and be made available to the Department or authorized representative(s) upon request.

(Auth.: HAR §11-60.1-3, §11-60.1-5, §11-60.1-11, §11-60.1-90)

3. Alternate Operating Scenarios

a. The permittee shall contemporaneously with making a change from one operating scenario to another record in a log, the scenario under which it is operating.
b. The permittee shall maintain all records corresponding to the implementation of an alternate operating scenario.

(Auth.: HAR §11-60.1-3, §11-60.1-5, §11-60.1-90)

<u>Section E</u>. <u>Notification and Reporting Requirements</u>

1. Standard Condition Reporting

Notification and reporting pertaining to the following events shall be done in accordance with Attachment I, Standard Condition Nos. 17 and 24, respectively:

a. Emissions of air pollutants in violation of HAR, Chapter 11-60.1 or this permit; and
b. Permanent discontinuance of construction, modification, relocation, or operation of the facility covered by this permit.

(Auth.: HAR §11-60.1-8, §11-60.1-15, §11-60.1-16, §11-60.1-90; SIP §11-60-10, SIP §11-60-16)[2]

2. Deviations

a. Except as specified in Attachment II – GHG, Special Condition No. E.2.b, the permittee shall report in writing **within five (5) working days** any deviations from permit requirements, including those attributed to upset conditions, the probable cause of such deviations, and any corrective actions or preventive measures taken. Corrective actions may include a requirement for testing, or more frequent monitoring, or could trigger implementation of a corrective action plan.

b. The permittee shall report, in writing, deviations from Attachment II – GHG, Special Condition No. C.1.c.v, the probable cause of such deviations, and any corrective actions or preventive measures taken. Corrective actions may include a requirement for testing, more frequent monitoring, or could trigger implementation of a corrective action plan. Reports shall be submitted **within sixty (60) days** following the end of each calendar year.

(Auth.: HAR §11-60.1-3, §11-60.1-15, §11-60.1-16, §11-60.1-90)

3. Compliance Certification

a. During the permit term, the permittee shall submit at least **annually** to the Department and U.S. EPA, Region 9, the attached **Compliance Certification Form** pursuant to HAR, Subsection 11-60.1-86. The permittee shall indicate whether or not compliance is being met with each term or condition of this permit. For making this certification for the partnering facility conditions in Attachment II – GHG, the permittee is relying on information provided by other partners that these partners independently certify. The compliance certification shall include, at a minimum, the following information:

i. The identification of each term or condition of the permit that is the basis of the certification;
ii. The compliance status;
iii. Whether compliance was continuous or intermittent;
iv. The methods used for determining the compliance status of the source currently and over the reporting period;
v. Any additional information indicating the source's compliance status with any applicable enhanced monitoring and compliance certification, including the requirements of Section 114(a)(3) of the Clean Air Act or any applicable monitoring and analysis provisions of Section 504(b) of the Clean Air Act;
vi. Brief description of any deviations including identifying as possible exceptions to compliance any periods during which compliance is required and which the excursion or exceedances as defined in 40 CFR Part 64 occurred; and
vii. Any additional information as required by the Department, including information to determine compliance.

b. The compliance certification shall be submitted within **sixty (60) days after** the end of each calendar year and shall be signed and dated by a responsible official.
c. Upon the written request of the permittee, the deadline for submitting the compliance certification may be extended, if the Department determines that reasonable justification exists for the extension.

(Auth.: HAR §11-60.1-4, §11-60.1-86, §11-60.1-90)

4. Monitoring Reports

   a. The permittee shall complete and submit **semi-annual** monitoring reports to the Department that provide the metric tons and short tons of CO_2e emitted by all partnering facilities, except that biogenic CO_2 shall be excluded from the total CO_2e emissions. All reports shall be submitted **within sixty (60) days after** the end of each semi-annual calendar period (January 1 – June 30 and July 1 – December 31). The following enclosed form, or equivalent form, shall be used for reporting and shall be signed and dated by a responsible official:

      Monitoring Report Form: GHG Emissions

   b. For Calendar Year 2019, the permittee shall report the CO_2e emissions **within sixty (60) days** after the issuance of this permit. The Monitoring Report Form: GHG Emissions, or equivalent form, for the 2019 Calendar Year shall be used for reporting and shall be signed and dated by a responsible official.

   c. For Calendar Year 2020, the permittee shall report the CO_2e emissions **within sixty (60**) **days** after the issuance of this permit or **within sixty (60) days** after the end of the semi-annual calendar period, whichever is later. The Monitoring Report Form: GHG Emissions, or equivalent form, for the 2020 Calendar Year shall be used for reporting and shall be signed and dated by a responsible official.

   d. Upon written request by the permittee, the deadline for submitting the monitoring report may be extended, if the Department determines that reasonable justification exists for the extension.

   (Auth.: HAR §11-60.1-3, §11-60.1-5, §11-60.1-90)

Section F. Agency Notification

Any document (including reports) required to be submitted by this CSP shall be done in accordance with Attachment I, Standard Condition No. 28.

(Auth.: HAR §11-60.1-4, §11-60.1-90)

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[1]The citations to the CFR identified under a particular condition, indicate that the permit condition complies with the specified provision(s) of the CFR. Due to the integration of the preconstruction and operating permit requirements, permit conditions may incorporate more stringent requirements than those set forth in the CFR.

[2]The citations to the State Implementation Plan (SIP) identified under a particular condition, indicate that the permit condition complies with the specified provision(s) of the SIP.

ATTACHMENT III: ANNUAL FEE REQUIREMENTS
COVERED SOURCE PERMIT NO. 0007-01-C

Issuance Date: DATE **Expiration Date: DATE**

The following requirements for the submittal of annual fees are established pursuant to HAR, Title 11, Chapter 60.1, Air Pollution Control. Should HAR, Chapter 60.1 be revised such that the following requirements are in conflict with the provisions of HAR, Chapter 60.1, the permittee shall comply with the provisions of HAR, Chapter 60.1.

1. Annual fees shall be paid in full:

   a. Within **120 days** after the end of each calendar year; and
   b. Within **thirty (30) days** after the permanent discontinuance of the covered source.

2. The annual fees shall be determined and submitted in accordance with HAR, Chapter 11-60.1, Subchapter 6.

3. The annual emissions data for which the annual fees are based shall accompany the submittal of any annual fees and be submitted on forms furnished by the Department.

4. The annual fees and the emission data shall be mailed to:

State of Hawaii
Clean Air Branch
2827 Waimano Home Road, #130
Pearl City, HI 96782

ATTACHMENT IV: ANNUAL EMISSIONS REPORTING REQUIREMENTS
COVERED SOURCE PERMIT NO. 0007-01-C

Issuance Date: DATE **Expiration Date: DATE**

In accordance with the HAR, Title 11, Chapter 60.1, Air Pollution Control, the permittee shall report to the Department the nature and amounts of emissions.

1. Complete the attached forms:

   Annual Emissions Report Form: Combustion Turbine Generators and Diesel Engine Generators

2. The reporting period shall be from January 1 to December 31 of each year. All reports shall be submitted to the Department within **sixty (60) days** after the end of each calendar year and shall be mailed to the following address:

   State of Hawaii
   Clean Air Branch
   2827 Waimano Home Road, #130
   Pearl City, HI 96782

3. The permittee shall retain the information submitted, including all emission calculations. These records shall be in a permanent form suitable for inspection, retained for a minimum of five (5) years, and made available to the Department upon request.

4. Any information submitted to the Department without a request for confidentiality shall be considered public record.

5. In accordance with HAR, Section 11-60.1-14, the permittee may request confidential treatment of specific information, including information concerning secret processes or methods of manufacture, by submitting a written request to the Director and clearly identifying the specific information that is to be accorded confidential treatment.

DRAFT

COMPLIANCE CERTIFICATION FORM
COVERED SOURCE PERMIT NO. 0007-01-C
PAGE 1 OF ___

Issuance Date: DATE | **Expiration Date: DATE**

In accordance with the Hawaii Administrative Rules (HAR), Title 11, Chapter 60.1, Air Pollution Control, the permittee shall report to the Department of Health the following certification at least annually, or more frequently as requested by the Department of Health.

(Make Copies of the Compliance Certification Form for Future Use)

For Period: ______________________________ Date: ____________

Company/Facility Name: ______________________________

Responsible Official (Print): ______________________________

Title: ______________________________

Responsible Official (Signature): ______________________________

I certify that I have knowledge of the facts herein set forth, that the same are true, accurate and complete to the best of my knowledge and belief, and that all information not identified by me as confidential in nature shall be treated by Department of Health as public record. I further state that I will assume responsibility for the construction, modification, or operation of the source in accordance with the HAR, Title 11, Chapter 60.1, Air Pollution Control, and any permit issued thereof.

DRAFT

COMPLIANCE CERTIFICATION FORM
COVERED SOURCE PERMIT NO. 0007-01-C
(CONTINUED, PAGE 2 OF ___)

Issuance Date: DATE **Expiration Date: DATE**

The purpose of this form is to evaluate whether or not the facility was in compliance with the permit terms and conditions during the covered period. If there were any deviations to the permit terms and conditions during the covered period, the deviation(s) shall be certified as *intermittent compliance* for the particular permit term(s) or condition(s). Deviations include failure to monitor, record, report, or collect the minimum data required by the permit to show compliance. In the absence of any deviation, the particular permit term(s) or condition(s) may be certified as *continuous compliance*.

Instructions:
Please certify Sections A, B, and C below for continuous or intermittent compliance. Sections A and B are to be certified as a group of permit conditions. Section C shall be certified individually for each operational and emissions limit condition as listed in the Special Conditions section of the permit (list all applicable equipment for each condition). Any deviations shall also be listed individually and described in Section D. The facility may substitute its own generated form in verbatim for Sections C and D.

A. Attachment I, Standard Conditions

Permit term/condition	Equipment	Compliance
All standard conditions	All Equipment listed in the permit	☐ Continuous ☐ Intermittent

B. Special Conditions - Monitoring, Recordkeeping, Reporting, Testing, and INSIG

Permit term/condition	Equipment	Compliance
All monitoring conditions	All Equipment listed in the permit	☐ Continuous ☐ Intermittent
Permit term/condition All recordkeeping conditions	Equipment All Equipment listed in the permit	Compliance ☐ Continuous ☐ Intermittent
Permit term/condition All reporting conditions	Equipment All Equipment listed in the permit	Compliance ☐ Continuous ☐ Intermittent
Permit term/condition All testing conditions	Equipment All Equipment listed in the permit	Compliance ☐ Continuous ☐ Intermittent
Permit term/condition All INSIG conditions	Equipment All Equipment listed in the permit	Compliance ☐ Continuous ☐ Intermittent

DRAFT

COMPLIANCE CERTIFICATION FORM
COVERED SOURCE PERMIT NO. 0007-01-C
(CONTINUED, PAGE ____ OF ___)

Issuance Date: DATE **Expiration Date: DATE**

C. Special Conditions - Operational and Emissions Limitations

Each permit term/condition shall be identified in chronological order using attachment and section numbers (e.g., Attachment II, B.1, Attachment IIA, Special Condition No. B.1.f, etc.). Each equipment shall be identified using the description stated in Section A of the Special Conditions (e.g., unit no., model no., serial no., etc.). Check all methods (as required by permit) used to determine the compliance status of the respective permit term/condition.

Permit term/condition	Equipment	Method	Compliance
		☐ monitoring ☐ recordkeeping ☐ reporting ☐ testing ☐ none of the above	☐ Continuous ☐ Intermittent
		☐ monitoring ☐ recordkeeping ☐ reporting ☐ testing ☐ none of the above	☐ Continuous ☐ Intermittent
		☐ monitoring ☐ recordkeeping ☐ reporting ☐ testing ☐ none of the above	☐ Continuous ☐ Intermittent
		☐ monitoring ☐ recordkeeping ☐ reporting ☐ testing ☐ none of the above	☐ Continuous ☐ Intermittent
		☐ monitoring ☐ recordkeeping ☐ reporting ☐ testing ☐ none of the above	☐ Continuous ☐ Intermittent
		☐ monitoring ☐ recordkeeping ☐ reporting ☐ testing ☐ none of the above	☐ Continuous ☐ Intermittent
		☐ monitoring ☐ recordkeeping ☐ reporting ☐ testing ☐ none of the above	☐ Continuous ☐ Intermittent

(Make Additional Copies if Needed)

COMPLIANCE CERTIFICATION FORM
COVERED SOURCE PERMIT NO. 0007-01-C
(CONTINUED, PAGE ___ OF ___)

Issuance Date: DATE **Expiration Date: DATE**

D. Deviations

Permit Term/ Condition	Equipment / Brief Summary of Deviation*	Deviation Period time (am/pm) & date (mo/day/yr)	Date of Written Deviation Report to DOH (mo/day/yr)
		Beginning: Ending:	
		Beginning: Ending:	
		Beginning: Ending:	
		Beginning: Ending:	
		Beginning: Ending:	
		Beginning: Ending:	
		Beginning: Ending:	

*Identify as possible exceptions to compliance any periods during which compliance is required and in which an excursion or exceedance as defined under 40 CFR Part 64 occurred.

(Make Additional Copies if Needed)

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ANNUAL EMISSIONS REPORT FORM
COMBUSTION TURBINE GENERATORS AND DIESEL ENGINE GENERATORS
COVERED SOURCE PERMIT NO. 0007-01-C

Issuance Date: DATE **Expiration Date: DATE**

In accordance with the Hawaii Administrative Rules, Title 11, Chapter 60.1, Air Pollution Control, the permittee shall report to the Department of Health the nature and amounts of emissions.

(Make Copies for Future Use)

For Period: ____________________ Date: ____________

Facility Name: HELCO Keahole Generating Station

Equipment Description: ____________________

Serial/Unit ID No.: ____________________

I certify that I have knowledge of the facts herein set forth, that the same are true, accurate and complete to the best of my knowledge and belief, and that all information not identified by me as confidential in nature shall be treated by the Department of Health as public record.

Responsible Official (Print): ____________________

Title: ____________________

Responsible Official (Signature): ____________________

1. Report the Combustion Turbine Generators fuel consumption as follows:

CT-2		
Fuel Type	Fuel Use	Maximum Sulfur Content
	gallons	% by weight
Fuel Oil No. 2		

CT-4		
Fuel Type	Fuel Use	Maximum Sulfur Content
	Gallons	% by weight
Fuel Oil No. 2		

CT-5		
Fuel Type	Fuel Use	Maximum Sulfur Content
	gallons	% by weight
Fuel Oil No. 2		

DRAFT

ANNUAL EMISSIONS REPORT FORM
COMBUSTION TURBINE GENERATORS AND DIESEL ENGINE GENERATORS
COVERED SOURCE PERMIT NO. 0007-01-C
(CONTINUED, PAGE 2 OF 3)

Issuance Date: DATE **Expiration Date: DATE**

2. Report Diesel Engine Generators fuel consumption as follows:

D-21		
Fuel Type	Fuel Use	Maximum Sulfur Content
	gallons	% by weight
Fuel Oil No. 2		

D-22		
Fuel Type	Fuel Use	Maximum Sulfur Content
	gallons	% by weight
Fuel Oil No. 2		

D-23		
Fuel Type	Fuel Use	Maximum Sulfur Content
	gallons	% by weight
Fuel Oil No. 2		

BS-1		
Fuel Type	Fuel Use	Maximum Sulfur Content
	gallons	% by weight
Fuel Oil No. 2		

3. Report the type of air pollution control, pollutant(s) controlled, and control efficiency:

CT-2			
Type of Air Pollution Control	In Use?	Pollutant(s) Controlled	Control Efficiency / % Reduction

DRAFT

ANNUAL EMISSIONS REPORT FORM
COMBUSTION TURBINE GENERATORS AND DIESEL ENGINE GENERATORS
COVERED SOURCE PERMIT NO. 0007-01-C
(CONTINUED, PAGE 3 OF 3)

Issuance Date: DATE **Expiration Date: DATE**

CT-4			
Type of Air Pollution Control	In Use?	Pollutant(s) Controlled	Control Efficiency / % Reduction

CT-5			
Type of Air Pollution Control	In Use?	Pollutant(s) Controlled	Control Efficiency / % Reduction

D-21			
Type of Air Pollution Control	In Use?	Pollutant(s) Controlled	Control Efficiency / % Reduction

D-22			
Type of Air Pollution Control	In Use?	Pollutant(s) Controlled	Control Efficiency / % Reduction

D-23			
Type of Air Pollution Control	In Use?	Pollutant(s) Controlled	Control Efficiency / % Reduction

BS-1			
Type of Air Pollution Control	In Use?	Pollutant(s) Controlled	Control Efficiency / % Reduction

DRAFT

MONITORING REPORT FORM
OPERATING HOURS: BLACK START DIESEL ENGINE GENERATOR
COVERED SOURCE PERMIT NO. 0007-01-C

Issuance Date: DATE **Expiration Date: DATE**

In accordance with the Hawaii Administrative Rules, Title 11, Chapter 60.1, Air Pollution Control, the permittee shall report to the Department of Health the following information **semi-annually:**

(Make Copies for Future Use)

For Period: ______________________________ Date: ______________

Facility Name: HELCO Keahole Generating Station

Equipment Description: 500 kW Caterpillar Model 3412 Black Start Diesel Engine Generator, BS-1

Serial/ID No.: ______________________________

I certify that I have knowledge of the facts herein set forth, that the same are true, accurate and complete to the best of my knowledge and belief, and that all information not identified by me as confidential in nature shall be treated by the Department of Health as public record.

Responsible Official (PRINT): ______________________________

Title: ______________________________

Responsible Official (Signature): ______________________________

BLACK-START DIESEL ENGINE GENERATOR

Month	**Operating Hours** **Monthly Total**	 **Rolling 12-Month Total**	**Notes**
January			
February			
March			
April			
May			
June			
July			
August			
September			
October			
November			
December			
TOTAL			

MONITORING REPORT FORM
COMBUSTION TURBINE GENERATOR OPERATION
COVERED SOURCE PERMIT NO. 0007-01-C
(PAGE 1 OF 2)

Issuance Date: DATE **Expiration Date: DATE**

In accordance with the Hawaii Administrative Rules, Title 11, Chapter 60.1, Air Pollution Control, the permittee shall report to the Department of Health the following information **semi-annually:**

(Make Copies for Future Use)

COMPLETE SEPARATE FORMS FOR EACH COMBUSTION TURBINE GENERATOR

For Period: ______________________________ Date: __________

Facility Name HELCO Keahole Generating Station

Equipment Description: ______________________________

Serial/Unit ID No.:______________________________

I certify that I have knowledge of the facts herein set forth, that the same are true, accurate and complete to the best of my knowledge and belief, and that all information not identified by me as confidential in nature shall be treated by the Department of Health as public record.

Responsible Official (PRINT): ______________________________

Title: ______________________________

Responsible Official (Signature): ______________________________

Use additional sheets if necessary. Indicate in the appropriate table if there were no exceedances during the reporting period.

1. Combustion turbine generator unit no.: ____________
2. Identify the months of operation: ______________
3. Exceedance of Startup and Shutdown durations:

Exceedance		Duration (minutes)		Reason for Exceedance / Final Outcome / Corrective Actions
Date	Time	Startup	Shutdown	

MONITORING REPORT FORM
COMBUSTION TURBINE GENERATOR OPERATION
COVERED SOURCE PERMIT NO. 0007-01-C
(CONTINUED, PAGE 2 OF 2)

Issuance Date: DATE **Expiration Date: DATE**

Combustion Turbine Generator Unit No.: ____________

4. Dates, times and durations when the water injection system was not operated as specified in Attachment IIA, Special Condition No. C.3.a and Attachment IIB, Special Condition No. C.3.a:

Exceedance		Specify Startup, Shutdown or other	Duration (minutes)	Reason for Exceedance Final Outcome / Corrective Actions
Date	Time			

5. Dates, times, and durations when the combustion turbine generators were operated below twenty-five (25) percent of peak load at periods other than during startup, shutdown, or as authorized pursuant to Attachment IIA, Special Condition No. C.2 and Attachment IIB, Special Condition No. C.2, and approved pursuant to Attachment IIA, Special Condition No. C.7 and Attachment IIB, Special Condition No. C.7:

Date	Time	Duration Below 25% of Peak Load (minutes)	Reason for Exceedance / Final Outcome/ Corrective Actions

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MONITORING REPORT FORM
COMBUSTION TURBINE GENERATOR
MONTHLY OPERATION BELOW MINIMUM LOAD WITH WATER INJECTION
COVERED SOURCE PERMIT NO. 0007-01-C

Issuance Date: DATE **Expiration Date: DATE**

In accordance with the Hawaii Administrative Rules, Title 11, Chapter 60.1, Air Pollution Control, the permittee shall report to the Department of Health the following information **semi-annually:**

(Make Copies for Future Use)

For Period: ______________________________ Date: ______________

Facility Name HELCO Keahole Generating Station ______________________

Equipment Description: ______________________________

Serial/Unit ID No.:______________________________

I certify that I have knowledge of the facts herein set forth, that the same are true, accurate and complete to the best of my knowledge and belief, and that all information not identified by me as confidential in nature shall be treated by the Department of Health as public record.

Responsible Official (PRINT): ______________________________

Title: ______________________________

Responsible Official (Signature): ______________________________

Report periods of operation below twenty-five (25) percent of peak load with water injection for Units CT-2, CT-4, and CT-5 excluding startup, shutdown, and as approved pursuant to Attachment IIA, Special Condition No. C.7 and Attachment IIB, Special Condition No. C.7:

Month	CT-2, CT-4, CT-5 Monthly Total (hours)	Rolling 12-Month Total (hours)

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MONITORING REPORT FORM
FUEL CONSUMPTION
COVERED SOURCE PERMIT NO. 0007-01-C

Issuance Date: DATE **Expiration Date: DATE**

In accordance with the Hawaii Administrative Rules, Title 11, Chapter 60.1, Air Pollution Control, the permittee shall report to the Department of Health the following information **semi-annually:**

(Make Copies for Future Use)

For Period: ______________________________ Date: __________

Facility Name: HELCO Keahole Generating Station

Equipment Description: ______________________________

Serial/Unit ID No.: ______________________________

Type of Fuel: ______________

I certify that I have knowledge of the facts herein set forth, that the same are true, accurate and complete to the best of my knowledge and belief, and that all information not identified by me as confidential in nature shall be treated by the Department of Health as public record.

Responsible Official (Print): ______________________________

Title: ______________________________

Responsible Official (Signature): ______________________________

Month	Monthly Fuel Consumption (gallons)	Rolling 12-Month Total (gallons)	Notes
January			
February			
March			
April			
May			
June			
July			
August			
September			
October			
November			
December			

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MONITORING REPORT FORM
FUEL CERTIFICATION
COVERED SOURCE PERMIT NO. 0007-01-C

Issuance Date: DATE **Expiration Date: DATE**

In accordance with the Hawaii Administrative Rules, Title 11, Chapter 60.1, Air Pollution Control, the permittee shall report to the Department of Health the following information **semi-annually:**

(Make Copies for Future Use)

For Period: ______________________________ Date: ______________

Facility Name: HELCO Keahole Generating Station

Equipment Location: ______________________________

I certify that I have knowledge of the facts herein set forth, that the same are true, accurate and complete to the best of my knowledge and belief, and that all information not identified by me as confidential in nature shall be treated by the Department of Health as public record.

Responsible Official (Print): ______________________________

Title: ______________________________

Responsible Official (Signature): ______________________________

Unit No.	Equipment Description	Fuel Fired	Sulfur Content (% by weight)	Minimum Cetane Index	Maximum Aromatic Content (Volume %)

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MONITORING REPORT FORM
VISIBLE EMISSION EXCEEDANCES
COVERED SOURCE PERMIT NO. 0007-01-C

Issuance Date: DATE **Expiration Date: DATE**

In accordance with the Hawaii Administrative Rules, Title 11, Chapter 60.1, Air Pollution Control, the permittee shall report to the Department of Health the following information **semi-annually:**

(Make Copies for Future Use)

For Period: ____ Date: ____________________

Facility Name: HELCO Keahole Generating Station

I certify that I have knowledge of the facts herein set forth, that the same are true, accurate and complete to the best of my knowledge and belief, and that all information not identified by me as confidential in nature shall be treated by the Department of Health as public record.

Responsible Official (PRINT): ____

Title: ____

Responsible Official (Signature): ____

Visible Emission Exceedances:

Report the following on the lines provided below: all date(s) and six (6) minute average opacity reading(s) which the opacity limit was exceeded during the monthly observations; or if there were no exceedances during the monthly observations, then write "no exceedances" in the comment column:

EQUIPMENT	SERIAL/ID NO.	DATE	6 MIN. AVER. (%)	COMMENTS

MONITORING REPORT FORM
GHG EMISSIONS
COVERED SOURCE PERMIT NO. 0007-01-C
(PAGE 1 OF 2)

Issuance Date: DATE **Expiration Date: DATE**

In accordance with the Hawaii Administrative Rules (HAR), Title 11, Chapter 60.1, Air Pollution Control, the permittee shall report to the Department of Health the following information **semi-annually**:

(Make Copies for Future Use)

For Period: ______________________________ Date: ______________

Facility Name: ______________________________

Location: ______________________________

I certify that I have knowledge of the facts herein set forth, that the same are true, accurate and complete to the best of my knowledge and belief, and that all information not identified by me as confidential in nature shall be treated by the Department of Health as public record. In making this certification for the partnering facility conditions in Items 2 and 3 of this form, I am relying on information provided by other partners that these partners independently certify.

Responsible Official (Print): ______________________________

Title: ______________________________

Responsible Official (Signature): ______________________________

1. Report the carbon dioxide equivalent (CO_2e) emitted by Keahole Generating Station during each reporting period for purposes of the facility's individual GHG emissions cap:

Emission Year Reporting For ______________					
Reporting Period	Keahole Generating Station Emissions (Metric Tons of CO_2e)			Keahole Generating Station Emissions (Total CO_2e)	
	CO_2 (Non-biogenic)	CH_4	N_2O	Metric Tons	Short Tons
January 1 – June 30 (1st Semi-annual Period)					
July 1 – December 31 (2nd Semi-annual Period)					
Total Emissions →					

MONITORING REPORT FORM
GHG EMISSIONS
COVERED SOURCE PERMIT NO. 0007-01-C
(CONTINUED, PAGE 2 OF 2)

Issuance Date: DATE **Expiration Date: DATE**

In accordance with the HAR, Title 11, Chapter 60.1, Air Pollution Control, the permittee shall report to the Department of Health the following information **semi-annually**:

2. Report the total combined CO_2e emitted by all partnering facilities during each reporting period for purposes of the total combined GHG emissions cap for these facilities:

Emission Year Reporting For___________________					
Reporting Period	Total Combined Emissions from All Partnering Facilities (Metric Tons of CO_2e)			Total CO_2e	
	CO_2 (Non-biogenic)	CH_4	N_2O	Metric-tons	Short Tons
January 1 – June 30 (1st Semi-annual Period)					
July 1 – December 31 (2nd Semi-annual Period)					
Total Emissions →					

3. For incidences when the individual cap for Keahole Generating Station and total combined cap for all partnering facilities are exceeded, report the emissions in excess of the total combined cap using the following equation:

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

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.
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.

EXCESS EMISSIONS AND MONITORING SYSTEM PERFORMANCE SUMMARY REPORT
COVERED SOURCE PERMIT NO. 0007-01-C
(PAGE 1 OF 2)

Issuance Date: **Expiration Date:**

In accordance with the Hawaii Administrative Rules, Title 11, Chapter 11-60.1, Air Pollution Control, the permittee shall report to the Department of Health the following information **semi-annually**:

(Make Copies for Future Use)

Facility Name: ______________________________

Equipment Location: ______________________________

Equipment Description: ______________________________

Covered Source Permit No.:______________________ Condition No.:______________________

PSD Permit No.: ______________________ Condition No.:______________________

Code of Federal Regulations (CFR): ______________________________

Pollutant Monitored:

From: Date _________ - Time _____________

To: Date _________ - Time _____________

Emission Limit: __________________

Date of Last CEMS Certification/Audit . . . . ______

Total Source Operating Time . . . . ______

EMISSION DATA SUMMARY

1. Duration (Hours/Periods) of Excess Emissions in Reporting Period due to:
   a. Start-Up/Shutdown . . . . ______
   b. Cleaning/Soot Blowing . . . . ______
   c. Control Equipment Failure . . . . ______
   d. Process Problems . . . . ______
   e. Other Known Causes . . . . ______
   f. Unknown Causes . . . . ______
   g. Fuel Problems . . . . ______

   Number of incidents of excess emissions . . . . ______

2. Total Duration of Excess Emissions . . . . ______

3. Total Duration of Excess Emissions
   (% of Total Source Operating Time) . . . . ______

CEMS PERFORMANCE SUMMARY

1. CEMS Downtime (Hours/Periods) in Reporting Period Due to:
   a. Monitor Equipment Malfunctions . . . . ______
   b. Non-Monitor Equipment Malfunctions . . . . ______
   c. Quality Assurance Calibration . . . . ______
   d. Other Known Causes . . . . ______
   e. Unknown Causes . . . . ______

   Number of incidents of monitor downtime. . . . . ______

2. Total CEMS Downtime . . . . ______

3. Total CEMS Downtime
   (% of Total Source Operating Time) . . . . ______

EXCESS EMISSIONS AND MONITORING SYSTEM PERFORMANCE SUMMARY REPORT
COVERED SOURCE PERMIT NO. 0007-01-C
(CONTINUED, PAGE 2 OF 2)

Issuance Date: DATE **Expiration Date: DATE**

CERTIFICATION by Responsible Official

I certify that I have knowledge of the facts herein set forth, that the same are true, accurate and complete to the best of my knowledge and belief, and that all information not identified by me as confidential in nature shall be treated by the Department of Health as public record.

Responsible Official (Print): ______________________________

Title: ______________________________

Responsible Official (Signature): ______________________________

EXCESS EMISSIONS AND CONTINUOUS MONITORING SYSTEM (CMS)
PERFORMANCE REPORT AND/OR SUMMARY REPORT
COVERED SOURCE PERMIT NO. 0007-01-C
(PAGE 1 OF 6)

Issuance Date: DATE **Expiration Date: DATE**

In accordance with the Hawaii Administrative Rules, Title 11, Chapter 11-60.1, Air Pollution Control, the permittee shall report to the Department of Health the following information **semi-annually**:

(Make Copies for Future Use)

SECTION I. GENERAL INFORMATION **[63.6650(c)(1), 63.10(e)(vi)(A)]**

Company Name	Permit No.

Street Address

City	State	ZIP Code

Facility Name

Facility Street Address (If different than Company Address)

City	State	ZIP Code

Report Date and Submittal Reporting Period [63.6650(c)(3), 63.10(e)(3)(vi)(C), 63.10(e)(3)(vi)(M)]

Reporting period beginning date (mm/dd/yyyy)	Reporting period ending date (mm/dd/yyyy)	Summary report date (mm/dd/yyyy)

A. Unit Information

Unit Name

Unit Description [63.6650(e)(9), 63.10(e)(3)(vi)(D)]

B. Excess Emissions and Operating Limitations/Parameters [63.6650(c)(5)]

Have any excess emissions or exceedances of an operating limitation/parameter occurred during this reporting period?

☐ Yes ☐ No

If yes, complete the Excess Emissions and Parameter Monitoring Exceedances table ***for each period*** of excess emissions and/or parameter monitoring exceedances that occurred ***during*** startups, shutdowns, and/or malfunctions, ***or during periods other than*** startups, shutdowns, and/or malfunctions.

Excess Emissions and Continuous Monitoring System (CMS) Performance Report and/or Summary Report (CONTINUED, PAGE 2 OF 6)

C. CMS Performance [63.6650(c)(6)]

Has a CMS been inoperative (except for zero/low-level and high-level checks) or out of control during this reporting period?

☐ Yes ☐ No

If yes, complete the CMS Performance table ***for each period*** a CMS was inoperative or out of control.

SECTION II. CERTIFICATION [63.6650(c)(2), 63.10(e)(3)(vi)(L)]

I certify that I have knowledge of the facts herein set forth, that the same are true, accurate and complete to the best of my knowledge and belief, and that all information not identified by me as confidential in nature shall be treated by the Department of Health as public record.

Name of Responsible Official (Print or Type)	Title	Date (mm/dd/yy)

Signature of Responsible Official

DRAFT

Excess Emissions and Continuous Monitoring System (CMS) Performance Report and/or Summary Report (CONTINUED,PAGE 3 OF 6)

SECTION III. EXCESS EMISSIONS AND CMS PERFORMANCE REPORT

Excess Emissions and Parameter Monitoring Exceedances [63.6650(e)(1), (4); 63.6650(c)(4); 63.10(c)(7), (8), (10), (11)]

Note: Use a separate line for each period of excess emissions and/or parameter monitoring exceedances.

Nature of Event or Problem		Excess Emissions and/or Parameter Monitoring Exceedances Occurred *During*:				Start Date (mm/dd/yyyy)	Completion Date (mm/dd/yyyy)	Nature and Cause of any Malfunction (if known)	Corrective Action Taken or Preventive Measures Adopted
Excess Emissions	Parameter Monitoring Exceedance	Startup	Shutdown	Malfunction	Another Period				
☐	☐	☐	☐	☐	☐				
☐	☐	☐	☐	☐	☐				
☐	☐	☐	☐	☐	☐				
☐	☐	☐	☐	☐	☐				
☐	☐	☐	☐	☐	☐				
☐	☐	☐	☐	☐	☐				
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☐	☐	☐	☐	☐	☐				
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☐	☐	☐	☐	☐	☐				
☐	☐	☐	☐	☐	☐				

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Excess Emissions and Continuous Monitoring System (CMS) Performance Report and/or Summary Report (CONTINUED, PAGE 4 OF 6)

Continuous Monitoring System (CMS) Performance [63.6650(e)(2), (3); 63.10(c)(5), (6), (8), (10), (11), (12); 63.8(c)(8)]

Note: Use a separate line for each period a CMS was inoperative or out of control.

CMS Type	Manufacturer	Start Date (mm/dd/yyyy)	Completion Date (mm/dd/yyyy)	Nature and Cause of Any Malfunction (if known)	Corrective Action Taken or Preventive Measures Adopted	Nature of the Repairs or Adjustments Made to the CMS that was Inoperative or Out of Control

Excess Emissions and Continuous Monitoring System (CMS) Performance Report and/or Summary Report (CONTINUED, PAGE 5 OF 6)

SECTION IV. SUMMARY REPORT: EXCESS EMISSION AND CONTINUOUS MONITORING SYSTEM PERFORMANCE

A. Process Description and Monitoring Equipment Information

Emission and/or operating parameter limitations [63.6650(e)(8), 63.10(e)(3)(vi)(E)]

Monitoring Equipment Information [63.6650(e)(10), (11); 63.10(e)(3)(vi)(F), (G)]

Type	Latest Certification or Audit Date (mm/dd/yyyy)	Manufacturer	Model	Parameter Monitored

B. Emission Data Summary [63.6650(e)(5), (6); 63.10(e)(3)(vi)(I)]

Total duration of excess emissions/parameter exceedances (hours)

Total operating time of affected source during the reporting period (hours) [63.10(c)(13), 63.10(e)(3)(vi)(H)]

Percent of total source operating time during which excess emissions/parameter exceedances occurred (percent)

Summary of causes of excess emissions/parameter exceedances (percent of total duration by cause)

Startup/shutdown	%
Control equipment problems	%
Process problems	%
Other known causes	%
Other unknown causes	%
TOTAL	100%

Excess Emissions and Continuous Monitoring System (CMS) Performance Report and/or Summary Report (CONTINUED, PAGE 6 OF 6)

C. CMS Performance Summary [63.6650(e)(7), 63.10(e)(3)(vi)(J)]

Total duration of CMS downtime (hours)

Total operating time of affected source during the reporting period (hours) [63.10(c)(13), 63.10(e)(3)(vi)(H)]

Percent of total source operating time during which CMS were down (percent)

Summary of causes of CMS downtime (percent of downtime by cause)

Monitoring equipment malfunctions	%
Nonmonitoring equipment malfunctions	%
Quality assurance/quality control calibrations	%
Other known causes	%
Other unknown causes	%
TOTAL	100%

E. CMS, Process, or Control Changes

Have you made any changes in CMS, processes, or controls since the last reporting period?

☐ Yes ☐ No

If you answered yes, please describe the changes below:

Changes in CMS, processes, or controls since the last reporting period [63.6650(e)(12), 63.10(e)(3)(vi)(K)]

VISIBLE EMISSIONS FORM REQUIREMENTS
STATE OF HAWAII
COVERED SOURCE PERMIT NO. 0007-01-C

Issuance Date: DATE **Expiration Date: DATE**

The ***Visible Emissions (VE) Form*** shall be completed **monthly** (*each calendar month*) for each equipment subject to opacity limits by a certified reader in accordance with 40 CFR Part 60, Appendix A, Method 9, or U.S. EPA approved equivalent methods, or alternative methods with prior written approval from the Department and the U.S. EPA. The VE Form shall be completed as follows:

1. Visible emissions observations shall take place during the day only. The opacity shall be noted in five (5) percent increments (e.g., 25%).
2. Orient the sun within a 140-degree sector to your back. Provide a source layout sketch on the VE Form using the symbols as shown.
3. For VE observations of stacks, stand at least three (3) stack heights but not more than a quarter mile from the stack.
4. For VE observations of fugitive emissions from crushing and screening plants, stand at least 4.57 meters (fifteen (15) feet) from the VE source, but not more than a quarter mile from the visible emission source.
5. Two (2) consecutive six (6) minute observations shall be taken at fifteen (15) second intervals for each stack or emission point.
6. The six (6) minute average opacity reading shall be calculated for each observation.
7. If possible, the observations shall be performed as follows:
   a. Read from where the line of sight is at right angles to the wind direction.
   b. The line of sight shall not include more than one (1) plume at a time.
   c. Read at the point in the plume with the greatest opacity (without condensed water vapor), ideally while the plume is no wider than the stack diameter.
   d. Read the plume at fifteen (15) second intervals only. Do not read continuously.
   e. The equipment shall be operating at the maximum permitted capacity.
8. If the equipment was shut-down for that period, briefly explain the reason for shut-down in the comment column.

The permittee shall retain the completed VE Forms for recordkeeping. These records shall be in a permanent form suitable for inspection, retained for a minimum of five (5) years, and made available to the Department, or their representative upon request.

Any required initial and annual performance test performed in accordance with Method 9 by a certified reader shall satisfy the respective equipment's VE monitoring requirements for the month the performance test is performed.

DRAFT

VISIBLE EMISSIONS FORM
STATE OF HAWAII
COVERED SOURCE PERMIT NO. 0007-01-C

Issuance Date: DATE **Expiration Date: DATE**

(Make Copies for Future Use)

Permit No.: 0007-01-C

Company Name: HELCO Keahole Generating Station

Equipment and Fuel: ______________________________________

Site Conditions:

Stack height above ground (ft): ____________________

Stack distance from observer (ft): _________________

Emission color: Black / White

Sky conditions (% cloud cover): __________________

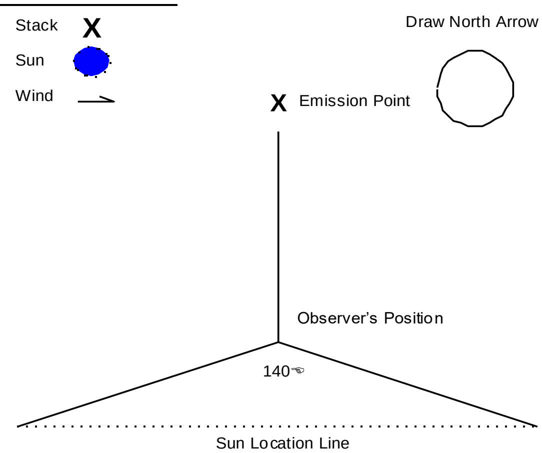
Wind speed (mph): ______________________

Temperature (EF):______________________

Observer Name: ___________________________

Certified?: Yes / No

Observation Date and Time: ________________



SEC. / MIN.	0	15	30	45	COMMENTS
1					
2					
3					
4					
5					
6					
Six (6) Minute Average Opacity Reading (%):					

Observation Date and Start Time: ______________________________

SEC. / MIN.	0	15	30	45	COMMENTS
1					
2					
3					
4					
5					
6					
Six (6) Minute Average Opacity Reading (%):					

Draft Review Summary

Permit Application Review Summary

Application No.:	Application No. 0007-05 for Renewal (CSP No. 0007-01-C) Application No. 0070-02 for Renewal (CSP No. 0070-01-C) Application Nos. 0007-06, 0007-08, and 0007-09 for Minor Modification (CSP No. 0007-01-C) Application No. 0070-03 for Minor Modification (CSP No. 0070-01-C)
Permit No.:	Covered Source Permit (CSP) No. 0007-01-C
Applicant:	Hawaii Electric Light Company, Inc. (HELCO)
Facility Title:	Keahole Generating Station Located At: 73-4249 Pukiawe Street, Kailua Kona, Island of Hawaii UTM: 2,184,955 m N and 811,293 m E, Zone 4, Old Hawaiian
Mailing Address:	Hawaii Electric Light Company, Inc. P.O. Box 1027 Hilo, Hawaii 96721-1027
Responsible Official:	Mr. Ryan Kohatsu
Company:	Hawaii Electric Light Company, Inc.
Title:	Director, Generation – Hawaii
Phone:	(808) 969-0437
Contact:	Karin Kimura (Owner's Agent)
Company:	HECO
Title:	Director, Environmental Department
Phone:	808-543-4500
Contact:	Myrna Tandi
Company:	HECO
Title:	Environmental Scientist
Phone:	808-543-4535

Application Dates:

- Application No. 0007-05 for Renewal dated July 30, 2012, with updated information dated December 3, 2015 (CSP No. 0007-01-C);
- Application No. 0070-02 for Renewal dated January 8, 2010, with updated information dated February 3, 2011 (CSP No. 0070-01-C);
- Application Nos. 0007-06, 0007-08, and 0007-09 for Minor Modification dated December 10, 2015, April 17, 2018, and October 29, 2019 (CSP No. 0007-01-C); and
- Application No. 0070-03 for Minor Modification dated December 10, 2015 (CSP No. 0070-01-C).

Proposed Project:

SICC 4911 (Electrical Power Generation Through Combustion of Fossil Fuels).

HELCO currently operates two (2) 20 MW combustion turbine generators, Units CT-4 and CT-5 with two (2) heat recovery steam generators and one (1) 16 MW steam turbine, one (1) 18 MW combustion turbine generator, Unit CT-2, three (3) 2.5 MW diesel engine generators, Units D-21, D-22, and D-23, and one (1) 500 kW black start diesel engine generator, Unit BS-1 at the Keahole Generating Station. In a previous administrative amendment issued on June 27, 2018, the Department of Health consolidated the terms and conditions of CSP No. 0007-01-C and CSP No. 0070-01-C into a single permit, CSP No. 0007-01-C. Therefore, CSP No. 0070-01-C was closed on June 27, 2018. The purpose of this draft permit is to consolidate all outstanding permit applications (renewals and modifications) for CSP No. 0007-01-C and the former CSP No. 0070-01-C.

<u>Application Nos. 0007-05 and 0070-02 for Renewal</u>
These are renewal applications to renew CSP Nos. 0007-01-C and 0070-01-C for the Keahole Generating Station.

The applicant also submitted the following minor modification applications: Nos. 0007-06, 0007-08, and 0007-09 (CSP No. 0007-01-C) and No. 0070-03 (CSP No. 0070-01-C). These applications are considered to be minor modifications since each modification:

(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) 500 pounds per year of a hazardous air pollutant (HAP), except lead;
    (B) 300 pounds per year of lead;
    (C) Twenty-five (25) percent 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; and

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

Application No. 0007-06 for Minor Modification
In this application, HELCO requests to operate the combustion turbine generators, Units CT-4 and CT-5, below twenty-five (25) percent of peak load with water injection to address system disturbances and frequency issues and to clarify permit conditions regarding startup and minimum water-to-fuel ratios when Units CT-4 and CT-5 operate at multiple loads. The table below shows that the proposed operation below twenty-five (25) percent of peak load is considered a minor modification. In addition, this proposed operation does not trigger New Source Performance Standards (NSPS) Subpart KKKK by modification since there is no increase in the lb/hr emission rates or reconstruction since capital expenditure is not required.

Project Emissions – CT-2, CT-4, CT-5
Operation Below 25% of Peak Load with Water Injection

Pollutant		(lb/hr)	(tpy)	Significant Level (tpy)	Minor Modification Trigger Level (tpy)	Significant Modification Required (yes/no)
CO		475.6	15.69	100	25	no
NO_x		42.3	1.40	40	10	no
SO_2		110.0	3.63	40	10	no
PM		20	0.66	25	6.25	no
PM_{10}		20	0.66	15	3.75	no
$PM_{2.5}$	$PM_{2.5}$	20	0.66	10	2.5	no
	SO_2	110.0	3.63	40	10	no
	NO_x	42.3	1.40	40	10	no
O_3	NO_x	42.3	1.40	40	10	no
	VOC	297.6	9.82	40	10	no
Lead		3.85E-03	1.27E-04	0.6	0.15	no
CO_2e			1,485	40,000	10,000	no

Notes:
1. Project tpy values based on 66 hrs/yr.
2. Minor modification trigger levels from HAR §11-60.1-81.
3. Emission rates for CO, NO_x, VOC, and lead based on Units CT-4 and CT-5 permit emission limits.
4. PM emission rates based on PM limit for Unit CT-2.
5. $PM_{2.5}$ emissions and PM_{10} emissions shall include gaseous emissions from a source or activity which condense to form particulate matter at ambient temperatures (40 CFR §52.21(b)(50)(i)(a) and HAR §11-60.1-1).
6. In addition to the 2.5 tpy minor modification trigger level for direct $PM_{2.5}$ emissions, minor modification trigger levels for $PM_{2.5}$ are also if SO_2 or NO_x emissions exceed 10 tpy based on a significant level of 40 tpy (40 CFR §52.21(b)(23)(i), HAR §11-60.1-1, and HAR §11-60.1-81).
7. The minor modification trigger level for O_3 is if NO_x or VOC emissions exceed 10 tpy based on a significant level of 40 tpy (40 CFR §52.21(b)(23)(i), HAR §11-60.1-1, and HAR §11-60.1-81).

Application No. 0007-08 for Minor Modification
In this application, HELCO requests to install a direct urea injection system at the exit of the combustion turbine generators, Units CT-4 and CT-5, to improve ammonia distribution at the catalyst to continue meeting the nitrogen oxides (NO_x) emissions limits specified in CSP No. 0007-01-C. HELCO has been working with Fuel Tech Inc. to perform modeling and simulations of the proposed system and the results are favorable. No emissions increase is expected from this modification and compliance with the NO_x emissions limits will be continuous.

The proposed changes are to improve the performance and reliability of the NO_x emissions control systems for Units CT-4 and CT-5. The system as currently configured involves feeding a solution of urea in water to a heater that decomposes the urea into ammonia gas. The gas is introduced into the combustion gas stream through an Air Injection Grid ahead of the selective catalytic reduction (SCR) catalyst where ammonia reacts to remove NO_x. This project will modify the system to directly inject urea solution into the combustion gases through specially designed injection nozzles. The injection point will be moved to a location in the ductwork upstream of the SCR reactor. The heat of combustion gases will decompose the urea rather than having to rely on an external heater. The supplier has used Computerized Fluid Dynamics (CFD) modeling to design the direct injection system to assure complete decomposition of urea and uniform dispersion of ammonia across the catalyst. Based on the CFD modeling the supplier has guaranteed that NO_x emissions will be controlled at least as effectively with direct urea injection as the system it replaces.

The new system will improve NO_x control reliability and performance in several important ways. For one, the existing heater creates significant lag between when the process control system adjusts the urea flow and the results of that change appear at the catalyst and the outlet NO_x sensor. HELCO estimates that lag is about three (3) minutes. The new system will have only a few seconds lag. That lag can also create discrepancies between the actual and the calculated ammonia slip. Second, a urea heater failure in the existing system is not detected until the NO_x concentration exiting the SCR reactor starts increasing. With the new system, loss of urea and ammonia flow will be detected immediately so corrective actions can be taken sooner. Finally, the existing system requires a backup urea heater in case the primary one goes down. It takes a lot of time to bring the backup heater up to temperature if it is needed. The new system will keep a urea heater as backup to direct urea injection. Since the heater is a weak link for reliability, HELCO expects that the new system will be more reliable and the backup system will not likely have to be used. Until the direct injection system has been proven in operation, the existing urea heater system will be kept available for operation after which one of the urea heaters may be taken out of service.

In a letter dated May 7, 2018, and pursuant to Hawaii Administrative Rules (HAR) §11-60.1-82(k)(1), the Clean Air Branch (CAB) authorized HELCO to install and operate a direct urea injection system for Units CT-4 and CT-5 as an air pollution control device.

Application No. 0007-09 for Minor Modification
In this application, HELCO requests to remove the fuel-bound nitrogen content requirement for Units CT-2, CT-4, and CT-5 in accordance with NSPS Subpart GG. HELCO has not claimed the optional fuel-bound nitrogen emission allowance under NSPS Subpart GG and does not plan to claim the allowance in the future. No changes are requested for the NO_x emissions limitations and the corresponding monitoring and reporting conditions. Compliance with the NO_x emissions limitation will continue to be monitored and demonstrated using a NO_x continuous emission monitoring system (CEMS). Any excess NO_x emissions will continue to be reported as required by the CSP.

From 40 Code of Federal Regulations (CFR) §60.334(h)(2):

(h) The owner or operator of any stationary gas turbine subject to the provisions of this subpart:
(2) Shall monitor the nitrogen content of the fuel combusted in the turbine, if the owner or operator claims an allowance for fuel-bound nitrogen (i.e., if an F-value greater than zero is being or will be used by the owner or operator to calculate STD in §60.332).

The fuel-bound nitrogen content allowance and associated fuel-bound nitrogen monitoring became optional on July 8, 2004, when EPA published a final rule amending several sections of 40 CFR Part 60, Subpart GG (69 FR 41345). Section II.B of the Federal Register notice states:

The NO_x emission standard in 40 CFR §60.332 includes a NO_x emission allowance for fuel-bound nitrogen. The use of this allowance for fuel-bound nitrogen will be optional upon July 8, 2004. Owners or operators will be able to choose to accept a value of zero for the NO_x emission allowance.

Section II.C of the Federal Register notice also states:

We are amending Subpart GG of 40 CFR Part 60 so that sources are required to monitor the nitrogen content of the fuel being fired in the turbine only if they claim the allowance for fuel-bound nitrogen. For sources that do not seek to use the fuel-bound nitrogen credit, sampling to determine the daily fuel nitrogen concentrations is not required.

The proposed change has previously been requested in the renewal applications dated July 30, 2012, and January 8, 2010.

Application No. 0070-03 for Minor Modification
In this application, HELCO requests to operate the combustion turbine generator, Unit CT-2, below twenty-five (25) percent of peak load with water injection to address system disturbances and frequency issues and to clarify permit conditions regarding startup and minimum water-to-fuel ratios when Unit CT-2 operates at multiple loads. The table on the next page shows that the proposed operation below twenty-five (25) percent of peak load is considered a minor modification. In addition, this proposed operation does not trigger NSPS Subpart KKKK by modification since there is no increase in the lb/hr emission rates or reconstruction since capital expenditure is not required.

Project Emissions – CT-2, CT-4, CT-5
Operation Below 25% of Peak Load with Water Injection

Pollutant		(lb/hr)	(tpy)	Significant Level (tpy)	Minor Modification Trigger Level (tpy)	Significant Modification Required (yes/no)
CO		475.6	15.69	100	25	no
NO_x		42.3	1.40	40	10	no
SO_2		110.0	3.63	40	10	no
PM		20	0.66	25	6.25	no
PM_{10}		20	0.66	15	3.75	no
$PM_{2.5}$	$PM_{2.5}$	20	0.66	10	2.5	no
	SO_2	110.0	3.63	40	10	no
	NO_x	42.3	1.40	40	10	no
O_3	NO_x	42.3	1.40	40	10	no
	VOC	297.6	9.82	40	10	no
Lead		3.85E-03	1.27E-04	0.6	0.15	no
CO_2e			1,485	40,000	10,000	no

Notes:
1. Project tpy values based on 66 hrs/yr.
2. Minor modification trigger levels from HAR §11-60.1-81.
3. Emission rates for CO, NO_x, VOC, and lead based on Units CT-4 and CT-5 permit emission limits.
4. PM emission rates based on PM limit for Unit CT-2.
5. $PM_{2.5}$ emissions and PM_{10} emissions shall include gaseous emissions from a source or activity which condense to form particulate matter at ambient temperatures (40 CFR §52.21(b)(50)(i)(a) and HAR §11-60.1-1).
6. In addition to the 2.5 tpy minor modification trigger level for direct $PM_{2.5}$ emissions, minor modification trigger levels for $PM_{2.5}$ are also if SO_2 or NO_x emissions exceed 10 tpy based on a significant level of 40 tpy (40 CFR §52.21(b)(23)(i), HAR §11-60.1-1, and HAR §11-60.1-81).
7. The minor modification trigger level for O_3 is if NO_x or VOC emissions exceed 10 tpy based on a significant level of 40 tpy (40 CFR §52.21(b)(23)(i), HAR §11-60.1-1, and HAR §11-60.1-81).

Equipment Description:

a. Two (2) 20 MW Nominal (24.66 MW (gross) peak load) General Electric LM2500 combustion turbine generators, Units CT-4 and CT-5;
b. One (1) 16 MW steam turbine generator Unit ST-7, including two (2) unfired heat recovery steam generators (HRSG) with two (2) SCR units;
c. One (1) 18 MW (nominal) (18.3 MW peak load) Simple Cycle Combustion Turbine Generator, Model No. Jupiter GT-35 (Manufactured by Asea Brown Boveri (ABB) and supplied by Solar Turbines) with a maximum design heat input rate of 198 MMBtu/hr, Unit CT-2;
d. One (1) 2.5 MW General Motors EMD Model No. 20-645F4B Diesel Engine Generator, Unit D-21;
e. One (1) 2.5 MW General Motors EMD Model No. 20-645F4B Diesel Engine Generator, Unit D-22;
f. One (1) 2.5 MW General Motors EMD Model No. 20-645E4 Diesel Engine Generator, Unit D-23; and
g. One (1) 500 kW Caterpillar Model No. 3412 Black Start Diesel Engine Generator, Unit BS-1.

Air Pollution Controls:

a. The combustion turbine generators, Units CT-4 and CT-5, use water injection to control NO_X emissions while operating in both simple and combined cycles and a SCR system is used to further reduce the NO_x emissions while operating in combined cycle.
b. The combustion turbine generator, Unit CT-2, uses water injection to control NO_X emissions.
c. The diesel engine generators, Units D-21, D-22, and D-23, use oxidation catalyst systems to control carbon monoxide (CO) emissions, ultralow sulfur diesel to control sulfur dioxide (SO_2) emissions, and fuel injection timing retard to control NO_x emissions.

Applicable Requirements:

Hawaii Administrative Rules (HAR)
Title 11, Chapter 59 - Ambient Air Quality Standards
Title 11, Chapter 60.1 - Air Pollution Control
- Subchapter 1 - General Requirements
- Subchapter 2 - General Prohibition
  - HAR 11-60.1-31: Applicability
  - HAR 11-60.1-32: Visible Emissions
  - HAR 11-60.1-38: Sulfur Oxides from Fuel Combustion
- Subchapter 5 - Covered Sources
- 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
  - HAR 11-60.1-115: Basis of Annual Fees for Covered Sources
- Subchapter 8 - Standards of Performance for Stationary Sources
  - HAR 11-60.1-161: New Source Performance Standards
- Subchapter 9 - Hazardous Air Pollutant Sources
  - HAR 11-60.1-174: Maximum Achievable Control Technology (MACT) Emission Standards
- Subchapter 11 - Greenhouse Gas Emissions

Federal Requirements
40 CFR Part 60 - Standards of Performance for New Stationary Sources (NSPS)

Subpart A	General Provisions
Subpart GG	Standards of Performance for Stationary Gas Turbines (applies to combustion turbine generators, Units CT-4, CT-5, and CT-2)

40 CFR Part 63 - National Emission Standards for Hazardous Air Pollutants for Source Categories (MACT)

Subpart A	General Provisions
Subpart ZZZZ	National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines (applies to diesel engine generators, Units D-21, D-22, and D-23, and black start diesel engine generator, Unit BS-1)

Unit BS-1 is not subject to the ULSD requirement in Subpart ZZZZ. See §63.6604.

40 CFR Part 98 – Mandatory Greenhouse Gas Reporting

Non-Applicable Requirements:

Hawaii Administrative Rules (HAR)
Title 11, Chapter 60.1 - Air Pollution Control
Subchapter 7 - Prevention of Significant Deterioration Review
Subchapter 9 - Hazardous Air Pollutant Sources
HAR §11-60.1-180: National Emission Standards for Hazardous Air Pollutants

Federal Requirements
40 CFR Part 52, §52.21 – Prevention of Significant Deterioration of Air Quality
40 CFR Part 61 - National Emission Standards for Hazardous Air Pollutants (NESHAPS)

Best Available Control Technology (BACT):

A BACT analysis is applicable only to new covered sources and significant modifications to covered sources that have the potential to emit or increase emissions above significant levels as defined in HAR §11-60.1-1. A BACT analysis is not applicable since this is a minor modification and permit renewal with no emission increases for an existing covered source.

Prevention of Significant Deterioration (PSD):

A PSD major modification is defined as a project at an existing major stationary source that will result in a significant emissions increase and a significant net emissions increase of any pollutant subject to regulations approved pursuant to the Clean Air Act as defined in 40 CFR Part 52, §52.21. Since there are no significant emission increases for this modification, PSD is not triggered.

Air Emissions Reporting Requirements (AERR):

40 CFR Part 51, Subpart A – AERR, is based on the emissions of criteria air pollutants from Type A and B point sources (as defined in 40 CFR Part 51, Subpart A), that emit at the AERR triggering levels as shown in the table below:

Pollutant	Type A Triggering Levels[1,2] (tpy)	Type B Triggering Levels[1] (tpy)	Pollutant	In-house Total Facility Triggering Levels[1] (tpy)	Potential Emissions (tpy)
NO_x	≥2500	≥100	NO_x	≥25	1,153.18
SO_2	≥2500	≥100	SO_2	≥25	1,422.83
CO	≥2500	≥1000	CO	≥250	542.86
$PM_{10}/PM_{2.5}$	≥250/250	≥100/100	PM/PM_{10}	≥25/25	$PM/PM_{10}/PM_{2.5}$ = 305.18
VOC	≥250	≥100	VOC	≥25	164.44
Pb		≥0.5 (actual)	Pb	≥5	4.93E-02
			HAPS	≥5	6.52

[1]Based on potential emissions.
[2]Type A sources are a subset of Type B sources and are the larger emitting sources by pollutant.

The Keahole Generating Station exceeds the Type A triggering levels. Therefore, AERR requirements are applicable.

The CAB also requests annual emissions reporting from those facilities that have facility-wide emissions of a single air pollutant exceeding in-house triggering levels or is a covered source. Annual emissions reporting for the facility will be required for in-house recordkeeping purposes since this is a covered source.

Compliance Assurance Monitoring (CAM):

40 CFR Part 64

Applicability of the CAM rule is determined on a pollutant specific basis for each affected emission unit. Each determination is based upon a series of evaluation criteria. In order for a source to be subject to CAM, each source must:

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

Emission units are any part or activity of a stationary source that emits or has the potential to emit any air pollutant.

CAM requirements are applicable to Units CT-2, CT-4, and CT-5. These units have existing monitoring devices including, a flow metering system to measure fuel consumption, a continuous monitoring system to record the water-to-fuel ratio, and a NO_x CEMS. Units CT-2, CT-4, and CT-5 uses water injection to reduce NO_x emissions to comply with NSPS Subpart GG, which was promulgated prior to 1990. Therefore, the CAM requirements have already been met.

Insignificant Activities:

Per HAR §11-60.1-82(f)(1).

1. CT-4 Day Tank (Tank 5) – 13,500 gallon capacity storing No. 2 diesel fuel;
2. CT-5 Day Tank (Tank 6) – 13,500 gallon capacity storing No. 2 diesel fuel;
3. Used Oil North Tank – 1,500 gallon capacity;
4. Used Oil South Tank – 1,500 gallon capacity;
5. Fire Pump Diesel Tank – 350 gallon capacity;
6. EMD Used Oil Tank – 500 gallon capacity;
7. EMD Lube Oil Tank – 500 gallon capacity;
8. EMD Lube Oil (5) Tank – 670 gallon capacity;
9. EMD Lube Oil (6) Tank – 670 gallon capacity;
10. Used Oil Tote – 200 gallon capacity; and
11. Used Oil Tote – 342 gallon capacity.

Per HAR §11-60.1-82(f)(2).

Other than smoke house generators and gasoline fired industrial equipment, fuel burning equipment with a heat input capacity less than one million BTU per hour, or a combination of fuel burning equipment operated simultaneously as a single unit having a total combined heat input capacity of less than one million BTU per hour.

These types of units may be on site occasionally.

Per HAR §11-60.1-82(f)(5).

Standby generators used exclusively to provide electricity, standby sewage pump drives, and other emergency equipment used to protect the health and welfare of personnel and the public, all of which are used only during power outages, emergency equipment maintenance and testing, and which:

(A) Are fired exclusively by natural or synthetic gas; or liquified petroleum gas; or fuel oil No. 1 or No. 2; or diesel fuel oil No. 1D or No. 2D; and
(B) Do not trigger a PSD or covered source review, based on their potential to emit regulated or HAPs.

These types of units may be on site occasionally.

Per HAR §11-60.1-82(f)(6).

Paint spray booths that emit less than two (2) tons per year of any regulated air pollutant, except for paint spray booths subject to any standard or other requirement pursuant to Section 112(d) of the Act.

Per HAR §11-60.1-82(f)(7).

1. Tank 1 – 3,080 bbl capacity storing No. 2 diesel fuel;
2. Tank 2 – 6,290 bbl capacity storing No. 2 diesel fuel;
3. Tank 3 – 617,000 gallon capacity storing No. 2 diesel fuel;
4. Tank 4 – 617,000 gallon capacity storing No. 2 diesel fuel;
5. Tank 7 – 1,475,000 gallon capacity storing No. 2 diesel fuel;
6. Fugitive equipment leaks from valves, flanges, pump seals and any VOC water separators; and
7. Solvents used for maintenance purposes/

Alternate Operating Scenarios:

1. Units CT-4 and CT-5

   a. Temporary Replacement. In the event of a failure or major overhaul of the equipment, the permittee may replace the combustion turbine generators with one of the General Electric LM2500 with the serial numbers listed below. Notification must be provided in accordance with Special Condition No. E.3 of this attachment. Notification and approval is required for temporary replacements with units that are not listed, the replacement unit shall be a General Electric LM2500 with equal or lesser emissions

      i. 481-688;
      ii. 481-692; and
      iii. 481-651.

   b. Permanent Replacement. Upon receiving written approval from the Department, the permittee may replace the combustion turbine generators with another General Electric LM2500 if any repair work reasonably warrants the removal (i.e., equipment failure or malfunction, overhaul, or any major equipment problems requiring maintenance for efficient operation) of a combustion turbine generator from its site and the following provisions are adhered to:

      i. The replacement combustion turbine generator is a General Electric LM2500 with one of the following serial numbers:

         1) 481-688;
         2) 481-692; and
         3) 481-651.

      ii. The permittee may continue using the replacement combustion turbine generator and is not required to return the original combustion turbine generator after it is repaired.

c. The combustion turbine generators may operate below twenty-five (25) percent of peak load (6.17 MW) during:

   i. Testing of the heat recovery steam generators and steam turbine;
   ii. Steam blows needed to clean the steam tubes prior to initial operation;
   iii. Testing of combustion turbine generator controls;
   iv. Dry running the Once Through Steam Generator (OTSG) to remove deposits from the OTSG;
   v. In isochronous mode with water injection for system restoration; and
   vi. Other maintenance and testing as approved by the Department in accordance with Special Condition No. E.3.c of this attachment.

   Operation during these periods shall not result in an exceedance of the emission limits at the lower load specified in Special Condition No. C.5.a of this attachment.

d. Combustion Turbine Operation Above Peak Load. The permittee may operate the combustion turbine generators up to 110% peak load to support the electrical grid in situations such as a sudden loss of a unit. The time period of this operation shall not exceed thirty (30) minutes in duration, and shall not result in an exceedance of the emission limits at maximum load specified in Special Condition No. C.5.a of this attachment.

e. Alternate Fuels. Upon receiving written approval from the Department, the permittee may burn an alternate fuel (e.g., but not limited to, biodiesel, renewable diesel, jet fuel, hydrogen, or ethanol). The alternative fuel shall be burned only temporarily and shall not result in an increase in emissions of any air pollutant or in the emission of any air pollutant not previously emitted.

f. Fuel Additives. Upon receiving written approval from the Department, the permittee may use fuel additives to reduce corrosion, control biological growth, and enhance combustion. Additives used during this scenario shall not affect emission estimates.

g. Alternate Means and Methods. Upon receiving written approval from the Department, the permittee may use alternate means and methods to improve combustion and/or reduce emissions.

2. Unit CT-2

   a. Temporary Replacement. Upon receiving approval from the Department, the permittee may replace the combustion turbine generator with an equivalent temporary replacement unit with equal or lesser emissions in the event of a failure or major overhaul of the equipment. The combustion turbine generator shall be repaired and returned to service in a timely manner. The installation and operation of the temporary replacement unit shall not exceed twelve (12) consecutive months.

   b. The combustion turbine generator may operate below twenty-five (25) percent of peak load (4.6 MW) in isochronous mode with water injection for system restoration and for other maintenance and testing as approved by the Department in accordance with Special Condition No. E.3.b of this attachment. Operation during these periods shall not result in an exceedance of the emission limits of Special Condition No. C.5 of this attachment.

c. Combustion Turbine Operation Above Peak Load. The permittee may operate the combustion turbine generators up to 110% peak load to support the electrical grid in situations such as a sudden loss of a unit. The time period of this operation shall not exceed thirty (30) minutes in duration, and shall not result in an exceedance of the emission limits at maximum load specified in Special Condition No. C.5 of this attachment.

d. Alternate Fuels. Upon receiving written approval from the Department, the permittee may burn an alternate fuel (e.g., but not limited to, biodiesel, renewable diesel, jet fuel, hydrogen, or ethanol). The alternative fuel shall be burned only temporarily and shall not result in an increase in emissions of any air pollutant or in the emission of any air pollutant not previously emitted.

e. Fuel Additives. Upon receiving written approval from the Department, the permittee may use fuel additives to reduce corrosion, control biological growth, and enhance combustion. Additives used during this scenario shall not affect emission estimates.

f. Alternate Means and Methods. Upon receiving written approval from the Department, the permittee may use alternate means and methods to improve combustion and/or reduce emissions.

3. Units D-21, D-22, and D-23

a. Temporary Replacement. In the event of a failure or major overhaul of the equipment, the permittee may replace the diesel engine generators, Units D-21, D-22, and D-23, with one of the General Motors EMD Model No. 20-645 with the serial numbers listed below. Notification must be provided in accordance with Special Condition No. E.7 of this attachment. Notification and approval is required for temporary replacements with units that are not listed, the replacement unit shall be a 2.5 MW General Motors EMD Model No. 20-645 with equal or lesser emissions

i. 74-K3-1540;
ii. 71-M1-1092;
iii. 71-M1-1045;
iv. 74-B1-1078;
v. 66-K1-1062;
vi. 69-H1-1057;
vii. 74-B1-1063;
viii. 72-E1-1027;
ix. 72-B1-1122;
x. 73-G1-1129;
xi. 66-K1-1057;
xii. 72-E1-1094; and
xiii. 66-J1-1156.

b. Permanent Replacement. Upon receiving written approval from the Department, the permittee may replace the diesel engine generators, Units D-21, D-22, and D-23, with another General Motors EMD Model No. 20-645 if any repair work reasonably warrants the removal (i.e., equipment failure or malfunction, overhaul, or any major equipment problems requiring maintenance for efficient operation) of a diesel engine generator from its site and the following provisions are adhered to:

i. The replacement diesel engine generator is a General Motors EMD Model No. 20-645 with one of the following serial numbers:

1) 74-K3-1540;
2) 71-M1-1092;
3) 71-M1-1045;
4) 74-B1-1078;
5) 66-K1-1062;
6) 69-H1-1057;
7) 74-B1-1063;
8) 72-E1-1027;
9) 72-B1-1122;
10) 73-G1-1129;
11) 66-K1-1057;
12 72-E1-1094; and
13) 66-J1-1156.

ii. The permittee may continue using the replacement diesel engine generator and is not required to return the original diesel engine generator after it is repaired.

c. Alternate Fuels. Upon receiving written approval from the Department, the permittee may burn an alternate fuel (e.g., but not limited to, biodiesel or renewable diesel). The alternative fuel shall be burned only temporarily and shall not result in an increase in emissions of any air pollutant or in the emission of any air pollutant not previously emitted.
d. Fuel Additives. Upon receiving written approval from the Department, the permittee may use fuel additives to reduce corrosion, control biological growth, enhance combustion, improve lubricity, or other reasons. Additives used during this scenario shall not affect emission estimates.
e. Alternate Means and Methods. Upon receiving written approval from the Department, the permittee may use alternate means and methods to improve combustion and/or reduce emissions.

Project Emissions:

The emissions from the Keahole Generating Station consists of SO_2, NO_x, CO, particulate matter, volatile organic compounds (VOCs), HAPs, and greenhouse gases (GHGs). A summary of the potential total annual emissions of criteria pollutants and HAPs expected from the Keahole Generating Station are shown on the next page:

SUMMARY OF POTENTIAL POLLUTANT EMISSIONS
(tons/yr)

Sources	SO_2	NO_2	CO	$PM/PM_{10}/PM_{2.5}$	VOC	Total HAPs	CO_2e
Unit CT-4	481.8	185.3	117.4	86.3	3.6	2.16	197,072
Unit CT-5	481.8	185.3	117.4	86.3	3.6	2.16	197,072
Unit CT-2	478.4	169.6	97.4	87.0	97.4	1.55	140,886
Unit D-21	0	11.9	4.1	0.88	1.17	0.013	802
Unit D-22	0.2	299.6	103.1	22.2	29.3	0.32	20,137
Unit D-23	0.2	299.6	103.1	22.2	29.3	0.32	20,137
Unit BS-1	0.43	1.88	0.36	0.30	0.07	0.0022	137
Totals	1,422.83	1,153.18	542.86	305.18	164.44	6.52	576,243

Ambient Air Quality Assessment (AAQA):

An AAQA is not required for the minor modifications or the permit renewals with no emission increases.

Significant Permit Conditions/Changes:

1. Units CT-4 and CT-5

   a. In Attachment IIA, Special Condition No. C.1, clarified the description of startup and shutdown sequences to allow stabilization of the water injection system following initiation of the system.

      Additional revisions to Startup and Shutdown to allow more operational flexibility due to the increased use of renewable energy in the grid:

      - For each combustion turbine for each day, revision from four (4) simple cycle startups at twenty (20) minutes each and four (4) combined cycle startups at ninety (90) minutes each to eleven (11) total startups at twenty (20) minutes.
      - For each combustion turbine for each day, revision from four (4) shutdowns at twenty (20) minutes each to eleven (11) total shutdowns at twenty (20) minutes.

      The revision does not result in an increase in emissions. For each combustion turbine for each day, current (440 minutes) and proposed (440 minutes) startup/shutdown durations remain unchanged.

   b. The permit did not previously allow CT-4 and CT-5 to operate below twenty-five (25) percent of peak load except during equipment start-up, shutdown, maintenance, and testing.

Attachment IIA, Special Condition No. C.2 was added to address system disturbances and frequency issues. The revised condition allows CT-4 and CT-5 (and CT-2) to operate below twenty-five (25) percent of peak load with water injection for a combined maximum of sixty-six (66) hours in any rolling twelve (12) month period. Startup, shutdown, and approved maintenance and testing do not count toward the sixty-six (66) hour limit.

c. In Attachment IIA, Special Condition No. C.3.a, clarified that for operating hours during which Units CT-4 or CT-5 operate at multiple loads where multiple water-to-fuel mass ratios apply, the applicable water-to-fuel mass ratio shall be determined based on the load that corresponded to the lowest minimum water-to-fuel mass ratio.

d. In Attachment IIA, Special Condition No. C.3.b, for the SCR system, the word "fully" was removed from the permit condition to describe the system:

> The selective catalytic reduction system shall be ~~fully~~ functional and in operation whenever the combustion turbine generators are in combined cycle operation at loads greater than or equal to fifty (50) percent of the peak load (12.33 MW).

HECO has explained that ammonia doesn't have to be injected continuously in order for the NO_x control to be fully functional. Urea injection is controlled automatically by a Programmable Logic Controller (PLC) and Human-Machine Interface (HMI) based upon an ammonia demand signal. A metering module is used to control the rate of urea injection into the duct upstream of the catalyst bed for NO_x control. There are instances where ammonia is not injected continuously according to the program logic.

e. In Attachment IIA, Special Condition No. C.4, removed the fuel-bound nitrogen content requirement for Units CT-4 and CT-5 in accordance with the current version of NSPS Subpart GG.

f. In Attachment IIA, Special Condition No. C.5.a, revised the twenty-five (25) percent < fifty (50) percent peak load to < fifty (50) percent (12.33 MW) peak load in the emission tables. This is because of the permit revision which allows a maximum of sixty-six (66) hours of operation below twenty-five (25) percent peak load; therefore, the old twenty-five (25) percent – fifty (50) percent peak load range is no longer relevant and should be replaced with <fifty (50) percent peak load.

g. In Attachment IIA, Special Condition No. C.5.b, clarified that for operating periods during which Units CT-4 or CT-5 operates at multiple loads where multiple NO_x and CO emissions standards apply, the applicable NO_x and CO emissions limit shall be the average of the applicable standards during each hour. For hours with multiple emissions standards, the applicable limit for that hour is determined based on the load that corresponds with the highest emissions standard in accordance with 40 CFR §60.4380(b)(3).

h. In Attachment IIA, Special Condition No. C.5.c, in accordance with the current version of NSPS Subpart GG, the following permit condition was added:

> The permittee shall not discharge or cause the discharge into the atmosphere from each of the combustion turbine generators, a rolling four (4) hour average NO_X emission in excess of one-hundred and nine (109) parts per million by volume (ppmvd) at fifteen (15) percent oxygen (O_2). The four (4) hour averaging period shall include all periods of operation, including startup, shutdown, and malfunction.

i. In Attachment IIA, Special Condition No. C.7, updated the alternate operating scenarios (see Alternate Operating Scenario section). Revisions include:

- Allowing for the temporary replacement of a permitted General Electric LM2500 with one of the General Electric LM2500 listed in the Alternative Operating Scenario condition of the permit. The permittee is not required to obtain approval from the Department of Health prior to temporarily replacing one of the permitted units with a unit listed in the permit. If the temporary unit is not listed in the permit, the permittee must obtain approval prior to the replacement.
- Allowing for the permanent replacement of a permitted General Electric LM2500 with one of the General Electric LM2500 listed in the Alternative Operating Scenario condition of the permit. The request for permanent replacement is required include a demonstration that the equipment change does not trigger PSD under the actual-to-projected actual applicability test.
- Allowing operation below twenty-five (25) percent of peak load for maintenance and testing. Additional approved scenarios are identified. In addition, other maintenance and testing may be allowed upon request and approval. Operation during these periods must comply with emission limits at the lower load.

j. In Attachment IIA, Special Condition No. C.5.a, added "Except during the startup and shutdown sequences." The emission limits in the table are not based on NSPS Subpart GG, but on the manufacturer's guaranteed emission limits. However, Attachment IIA, Special Condition No. C.5.c includes the NSPS Subpart GG limit, which includes periods of startup, shutdown, and malfunction.

k. In Attachment IIA, Special Condition No. D.1, removed the requirement for a NO_x CEMS located at a point between the exit of the combustion turbine generator with water injection and the entrance to the SCR system, the ammonia injection rate in lbs/hr, and the ammonia-to-NO_x ratio, since compliance with the ammonia slip permit limit is demonstrated through the annual source performance test for ammonia.

l. In Attachment IIA, Special Condition No. D.3, in the test analysis for the fuel the following was removed:

   i. Type of fuel;
   ii. Date and time the fuel sample was drawn;
   iii. Date the analyses were performed;
   iv. Name and address of the company or entity that performed the analyses;
   v. Means and methods used to analyze the fuel; and
   vi. Analyses results.

   This is because this additional data is not required by NSPS Subpart GG. Condition does require permittee maintain records of delivery dates, fuel received, sampling option and analysis method used, and results of the analysis.

m. In Attachment IIA, Special Condition No. E.5.f.ii, the definition of excess emissions was clarified:

During simple cycle operation and combined cycle operation at loads less than fifty (50) percent of peak load (12.33 MW), any one (1) unit operating hour period during which the average water-to-fuel mass ratio, as measured by the continuous monitoring system, falls below the water-to-fuel mass ratio at the corresponding operating load specified in Special Condition No. C.3.a of this attachment, except when the NO_x CEMS concurrently shows compliance with the NO_x limits set forth in Special Condition No. C.5.a of this attachment.

This is because the current version of NSPS Subpart GG only specifies that either a water-to-fuel ratio monitor or a NO_x CEMS be used, not both. NSPS Subpart GG specifies a NO_x limit to be met, not a water-to-fuel ratio.

n. In Attachment IIA, Special Condition No. E.5.f.iv, language was added that allows for 40 CFR, Part 60, Appendix A, Method 9 readings to be considered in determining compliance with the opacity limits during periods of opacity exceedances as measured by the transmissometer continuous monitoring system.
o. In Attachment IIA, Section F, updated the performance testing requirements and removed the annual performance testing for NO_x and CO since there are NO_x and CO CEMS that can be used to demonstrate compliance with the NO_x and CO permit limits. Also, the CO_2 source testing requirement was removed since there is a CO_2 CEMS.

2. Unit CT-2

a. In Attachment IIB, Special Condition No. C.1, clarified the description of startup and shutdown sequences to allow stabilization of the water injection system following initiation of the system.
b. The permit did not previously allow CT-2 to operate below twenty-fire (25) percent of peak load except during equipment startup, shutdown, maintenance, and testing.

   Attachment IIB, Special Condition No. C.2 was added to address system disturbances and frequency issues. The revised condition allows the operation of Unit CT-2 below twenty-five (25) percent of peak load with water injection for a combined maximum of sixty-six (66) hours in any rolling twelve-month period and to clarify permit conditions regarding startup and minimum water-to-fuel ratios when Unit CT-2 operates at multiple loads.
c. In Attachment IIB, Special Condition No. C.3.a, clarified that for operating hours during which Unit CT-2 operates at multiple loads where multiple water-to-fuel mass ratios apply, the applicable water-to-fuel mass ratio shall be determined based on the load that corresponded to the lowest minimum water-to-fuel mass ratio.
d. In Attachment IIB, Special Condition No. C.4, removed the fuel-bound nitrogen content requirement for Unit CT-2 in accordance with the current version of NSPS Subpart GG.
e. In Attachment IIB, Special Condition No. C.7, updated the alternate operating scenarios (see Alternate Operating Scenario section). Revisions include:

- The permit previously allowed the permittee to temporary replace the permitted unit with an identical unit in the event of a failure or major overhaul of the permitted unit. The permit is revised to allow the permitted unit to temporarily be replaced with an equivalent unit, not identical to the permitted unit, having equal or lesser emissions, in the event of a failure or major overhaul of the permitted unit. The permittee must request approval for the temporary replacement and must provide a demonstration that the temporary replacement unit will not result in the exceedance of the National and State ambient air quality standards. The installation and operation of the temporary unit shall not exceed twelve (12) consecutive months.
- A condition is added to the permit allowing the permittee to operate below twenty-five (25) percent of peak load in isochronous mode with water injection for system restoration. In addition, other maintenance and testing may be allowed upon request and approval. Operation during these periods must comply with emission limits at the lower load.

f. In Attachment IIB, Special Condition No. E.5.f.ii, the definition of excess emissions was clarified:

> Any one (1) unit operating hour period during which the average water-to-fuel mass ratio, as measured by the continuous monitoring system, falls below the water-to-fuel mass ratio at the corresponding operating load specified in Special Condition No. C.3.a of this attachment, except when the NO_x CEMS concurrently shows compliance with the NO_x limits set forth in Special Condition No. C.5 of this attachment.

This is because the current version of NSPS Subpart GG only specifies that either a water-to-fuel ratio monitor or a NO_x CEMS be used, not both. NSPS Subpart GG specifies a NO_x limit to be met, not a water-to-fuel ratio.

g. In Attachment IIB, Section F, updated the performance testing requirements and removed the annual performance testing for NO_x and CO since there are NO_x and CO CEMS that can be used to demonstrate compliance with the NO_x and CO permit limits.

3. Units D-21, D-22, D-23, and BS-1

a. In Attachment IIC, Special Condition No. B.1, listed 40 CFR Part 63, Subpart ZZZZ as an applicable requirement for Units D-21, D-22, D-23, and BS-1.

b. In Attachment IIC, Special Condition No. C.7, updated the alternate operating scenarios (see Alternate Operating Scenario section). Revisions include:

- Allowing for the temporary replacement of a permitted General Motors EMD Model No. 20-645F4B or 20-645E4 with one of the General Motors EMD Model No. 20-645 listed in the Alternative Operating Scenario condition of the permit in the event of a failure or major overhaul of the permitted equipment. The permittee is not required to obtain approval from the Department of Health prior to temporarily replacing one of the permitted units with a unit listed in the permit. If the temporary unit is not listed in the permit, the permittee must obtain approval prior to the replacement.

- Allowing for the permanent replacement of a permitted General Motors EMD Model No. 20-645F4B or 20-645E4 with one of the General Motors EMD Model No. 20-645 listed in the Alternative Operating Scenario condition of the permit. The request for permanent replacement is required include a demonstration that the equipment change does not trigger PSD under the actual-to-projected actual applicability test.

Proposed Changes Not Approved by the Department

1. The permittee requested that the following language pertaining to the water injection system be added to Attachment IIA, Special Condition No. C.3.a:

   A failure to meet the minimum water to fuel mass ratio shall not be a deviation when the NOx CEMS concurrently shows compliance with the NOx limits set forth in Special Condition No. C.5.a of this attachment.

   The Department is denying this request. A deviation from the required minimum water to fuel ratio still occurs even when compliance with the NOx limit is demonstrated.

2. The permittee requested the following revision to Attachment IIA, Special Condition No. C.3.a:

   For any six (6) minute averaging period, the combustion turbine generators shall not exhibit visible emissions of twenty (20) percent opacity or greater, except as follows: during startup, shutdown, or equipment malfunction, the combustion turbine generators may exhibit visible emissions not greater than sixty (60) percent opacity for a period aggregating not more than six (6) minutes in any sixty (60) minute period.~~ In the event of equipment breakdown, the equipment shall be shut down within one (1) hour if the opacity problem cannot be corrected within the six (6) minute period.~~

   The Department is denying this request, and the language will remain in the permit. This requirement is from the original PSD/Title V permit issued on July 25, 2001.

Conclusion and Recommendations:

Recommend issuance of the renewal and minor modifications of the existing CSP No. 0007-01-C, and the renewal and minor modification of the former CSP No. 0070-01-C, subject to the significant permit conditions/changes above. This permit would supersede CSP No. 0007-01-C issued on June 27, 2018, in its entirety. A thirty (30) day public comment period and forty-five (45) day EPA review period are also required.

Reviewer: Darin Lum
Date: 6/2024

Application
and
Supporting Information

OCT 3 0 2019

POSTMARK
OCT 29 2019

Karin Kimura
Director
Environmental Division

Hawai'i Electric Light
Keahole

October 29, 2019

USPS CERTIFIED MAIL NO. 7018 0680 0000 9728 4725
RETURN RECEIPT REQUESTED

Ms. Marianne Rossio, P.E.
Manager, Clean Air Branch
State of Hawaii Department of Health
2827 Waimano Home Road
Hale Ola Building, Room 130
Pearl City, Hawaii 96782

Dear Ms. Rossio:

Subject: **Application for a Minor Modification to a Covered Source**
Covered Source Permit (CSP) No. 0007-01-C
Keahole Generating Station
Hawai'i Electric Light Company, Inc.

On behalf of Hawai'i Electric Light Company, Inc., Hawaiian Electric Company, Inc. submits an original and one copy of the Application for a Minor Modification to a Covered Source for the Keahole Generating Station CSP No. 0007-01-C.

Hawai'i Electric Light requests to remove the fuel-bound nitrogen content requirement for CT-2, CT-4, and CT-5, in accordance with 40 CFR Part 60 Subpart GG. Additional information regarding this proposed modification is included in Form S-7 and Attachment S-7a.

Certifications in accordance with HAR 11-60.1-4 are included on Forms S-1 and C-1. Also enclosed is a check number 1100115627 in the amount of $200.00 for the minor modification application fee.

If you have any questions regarding this submittal, please contact Myrna Tandi at 543-4535 or myrna.tandi@hawaiianelectric.com.

Sincerely,

Enclosures: (1) Application for a Minor Modification to Covered Source Permit No. 0007-01-C
(2) Application fee (check number 1100115627)

cc w/ Encl.: **USPS CERTIFIED MAIL RETURN RECEIPT REQUESTED**
Mr. Gerardo Rios [Certified Mail No.7018 0680 0000 9728 4732]
Chief, Permits Office, Air Division
U.S. EPA Region 9
75 Hawthorne Street, Mail Code: AIR-3
San Francisco, CA 94105

OCT 30 2019

File / Application No.:____________

S-1: Standard Air Pollution Control Permit Application Form
(Covered Source Permit and Noncovered Source Permit)

State of Hawaii
Department of Health
Environmental Management Division
Clean Air Branch
P. O. Box 3378 • Honolulu, HI 96801-3378 • Phone: (808) 586-4200

1. Company Name: Hawai'i Electric Light Company, Inc. (Hawai'i Electric Light)

2. Facility Name (if different from the Company): Keahole Generating Station

3. Mailing Address: 73-4249 Pukiawe Street

   City: Kailua Kona State: HI Zip Code: 96740

   Phone Number: (808) 935-1711

4. Name of Owner/Owner's Agent: Karin Kimura (Owner's Agent)

   Title: Director, Environmental Division Phone: (808) 543-4500

   Mailing Address: PO Box 2750

   City: Honolulu State: HI Zip Code: 96840-0001

5. Plant Site Manager/Other Contact: Everett Lacro

   Title: Director, Generation – Hawaii Phone: (808) 969-0437

   Mailing Address: P.O. Box 1027

   City: Hilo State: HI Zip Code: 96721-1027

6. Permit Application Basis: (Check appropriate boxes)

   ☐ Initial Permit for a New Source ☐ Initial Permit for an Existing Source

   ☐ Renewal of Existing Permit ☐ General Permit

   ☐ Temporary Source ☐ Transfer of Permit

   ■ Modification to a Covered Source: → Is modification? ☐ Significant ■ Minor ☐ Uncertain

   ☐ Modification to a Noncovered Source

7. If renewal or modification, include existing permit number: CSP Nos. 0007-01-C

8. Does the Proposed Source require a County Special Management Area Permit? ☐ Yes ■ No

9. Type of Source (Check One): ☐ Covered Source ■ Covered & PSD Source

   ☐ Noncovered Source ☐ Uncertain

10. Standard Industrial Classification Code (SICC), if known: 4911

11. Proposed Equipment/Plant Location (e.g. street address): 73-4249 Pukiawe Street

City: Kailua Kona State: HI Zip Code: 96740

UTM Coordinates (meters): East: 811,293 North: 2,184,955

UTM Zone: 4 UTM Horizontal Datum: ■ Old Hawaiian ☐ NAD-27 ☐ NAD-83

12. General Nature of Business: Electrical Generation

13. Date of Planned Commencement of Installation or Modification: Upon approval of the proposed modification.

14. Is *any* of the equipment to be leased to another individual or entity? ☐ Yes ■ No

15. Type of Organization: ■ Corporation ☐ Individual Owner ☐ Partnership

☐ Government Agency (Government Facility Code: ____________)

☐ Other: ____________

Any applicant for a permit who fails to submit any relevant facts or who has submitted incorrect information in any permit application shall, upon becoming aware of such failure or incorrect submittal, promptly submit such supplementary facts or corrected information. In addition, an applicant shall provide additional information as necessary to address any requirements that become applicable to the source after the date it filed a complete application, but prior to the issuance of the noncovered source permit or release of a draft covered source permit. (HAR § 11-60.1-64 & 11-60.1-84)

RESPONSIBLE OFFICIAL (as defined in §11-60.1-1):

Name (Last): Lacro (First): Everett (MI): ____________

Title: Director, Generation – Hawaii Phone: (808) 969-0437

Mailing Address: P.O. Box 1027

City: Hilo State: HI Zip Code: 96721-1027

CERTIFICATION by Responsible Official (pursuant to §11-60.1-4):

I certify that I have knowledge of the facts herein set forth, that the same are true, accurate and complete to the best of my knowledge and belief, and that all information not identified by me as confidential in nature shall be treated by the Department of Health as public record. I further state that I will assume responsibility for the construction, modification, or operation of the source in accordance with the Hawaii Administrative Rules (HAR), Title 11, Chapter 60.1, Air Pollution Control, and any permit issued thereof.

NAME (Print/Type): Everett Lacro

(Signature): Everett A. Lacro Date: 10/22/19

FOR AGENCY USE ONLY:

File/Application No: ____________

Island: ____________

Date Received: ____________

Submit the following documents as part of your application:

A. The ***Emissions Units Table***, filled in as completely as possible. Use separate sheets of paper as needed. General instructions include the following:

1. Identify each **emission point** with a unique number for this plant site, consistent with emission point identification used on the location drawing and previous permits; if known, provide the SICC number. Emission points shall be identified and described in sufficient detail to establish the basis for fees and applicability of requirements of HAR, Chapter 11-60.1. Examples of emission point names are: heater, vent, boiler, tank, baghouse, fugitive, etc. Abbreviations may be used.
   a. For each emission point use as many lines as necessary to list regulated and hazardous air pollutant data. For hazardous air pollutants, also list the Chemical Abstracts Service number (CAS#).
   b. Indicate the emission points that discharge together for any length of time.
   c. The **Equipment Date** is the date of equipment construction, reconstruction, or modification. Provide supporting documentation.

2. State the **maximum emission rates** in terms sufficient to establish compliance with the applicable requirements and standard reference test methods. Provide all supporting emission calculations and assumptions:
   a. Include all regulated and hazardous air pollutants and air pollutants for which the source is major, as defined in HAR §11-60.1-1. Examples of regulated pollutant names are: Carbon Monoxide (CO), Nitrogen Oxides (NO_x), Sulfur Dioxide (SO_2), Volatile Organic Compounds (VOC), particulate matter (PM), and particulate less than 10 microns (PM_{10}). Abbreviations may be used.
   b. Include fugitive emissions.
   c. **Pounds per hour (#/HR)** is the maximum potential emission rate expected by applicant.
   Tons per year is the annual maximum potential emissions expected by the applicant, taking into account the typical operating schedule.

3. Describe ***Stack Source Parameters***:
   a. **Stack Height** is the height above the ground.
   b. **Direction** refers to the exit direction of stack emissions: up, down or horizontal.
   c. **Flow Rate** is the actual, not the calculated, flow rate.

4. Provide any additional information, if applicable, as follows:
   a. If combinations of different fuels are used that cause any of the stack source parameters to differ, complete one row for each possible set of stack parameters and identify each fuel in the **Equipment Description**.
   b. For a rectangular stack, indicate the length and width.
   c. Provide any information on stack parameters or any stack height limitations developed pursuant to Section 123 of the Clean Air Act.

B. A **process flow diagram** identifying all equipment used in the process, including the following:
   1. Identify and describe each emission point.
   2. Identify the locations of safety valves, bypasses, and other such devices which when activated may release air pollutants to the atmosphere.

C. A **facility location map**, drawn to a reasonable scale and showing the following:
   1. The property involved and all structures on it. Identify property/fence lines plainly.
   2. Layout of the facility.
   3. Location and identification of the proposed emissions unit on the property.
   4. Location of the property and equipment with respect to streets and all adjacent property. Show the location of all structures within 325 meters of the applicant's emissions unit. Provide the building dimensions (height, length, and width) of all structures that have heights greater than 40% of the stack height of the emissions unit.

D. Provide a description of any proposed modifications or permit revisions. Include any justification or supporting information for the proposed modifications or permit revisions.

Attachment S-1a
Responses to Emission Unit Table Instructions for Form S-1

A.1. Emission Point Identification and Description	Refer to Form S-1 Emissions Units Tables. The proposed changes do not impact emission point identification and description.
A.2. Maximum Emission Rates	Refer to Forms S-1 Emissions Units Tables and Attachments S-1b, S-1c, S-1d, and S-1e. The proposed changes do not impact maximum emission rates.
A.3. Stack Parameters	Refer to Forms S-1 Emissions Units Tables. The proposed changes do not impact stack parameters.
A.4. Additional Information	None
B. Process Flow Diagram	Refer to Figures S-1.1, S-1.2, S-1.3, and S-1.4.
C. Facility Location Map	Refer to Figure S-1.5.
D. Proposed Revisions	Refer to Attachments S-7 and S-7a.

Figure S-1.1

Process Flow Diagram for CT-2

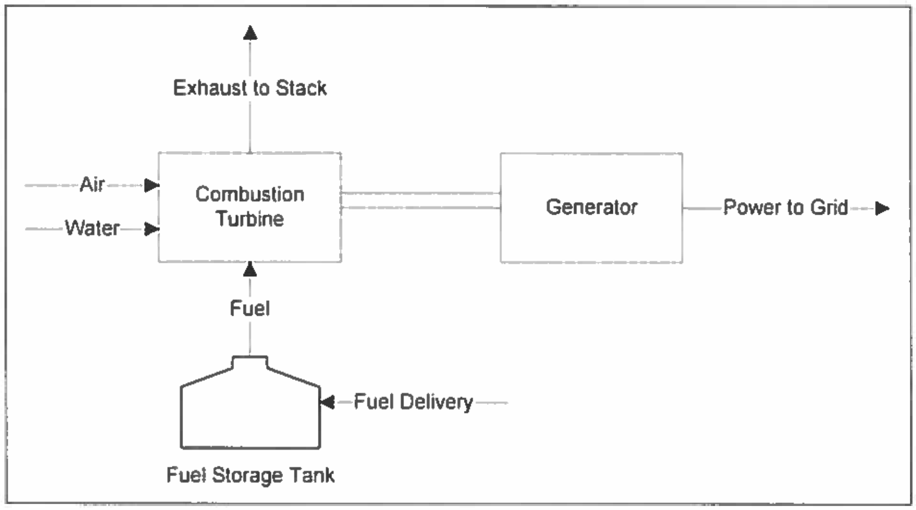


Figure S-1.2

Process Flow Diagram for Units CT-4 and CT-5

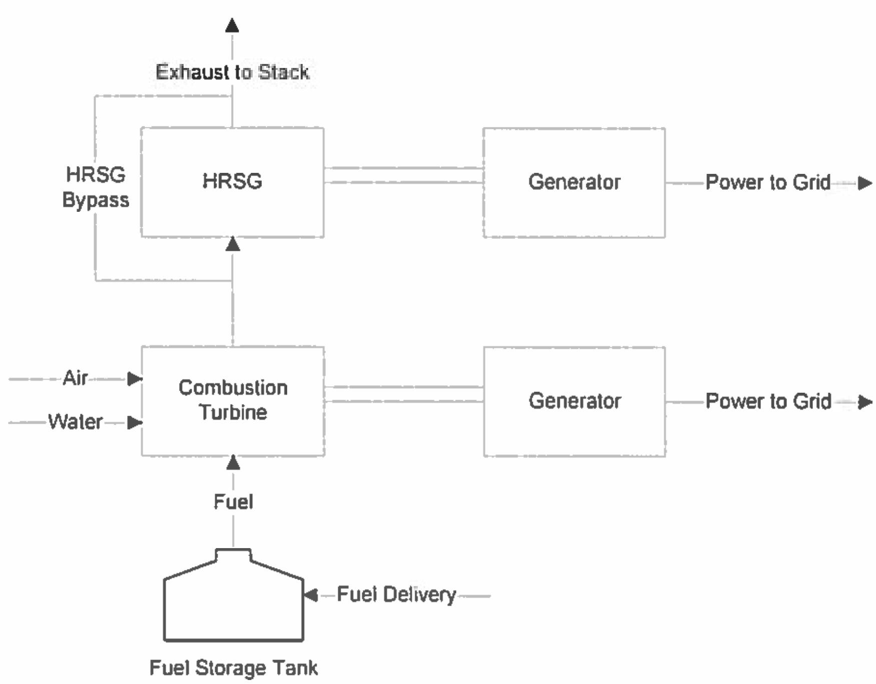


Figure S-1.3

Process Flow Diagram for Units D-21, D-22, and D-23

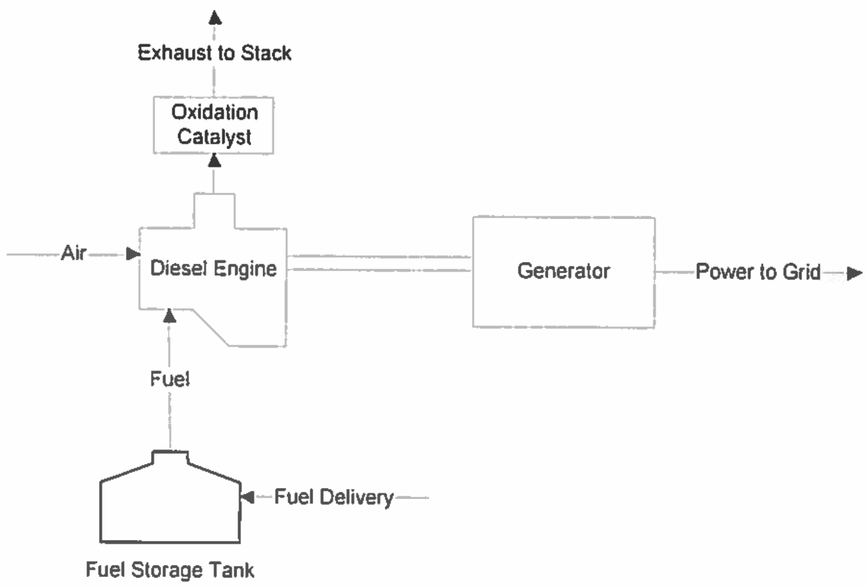


Figure S-1.4

Process Flow Diagram for Unit BS-1

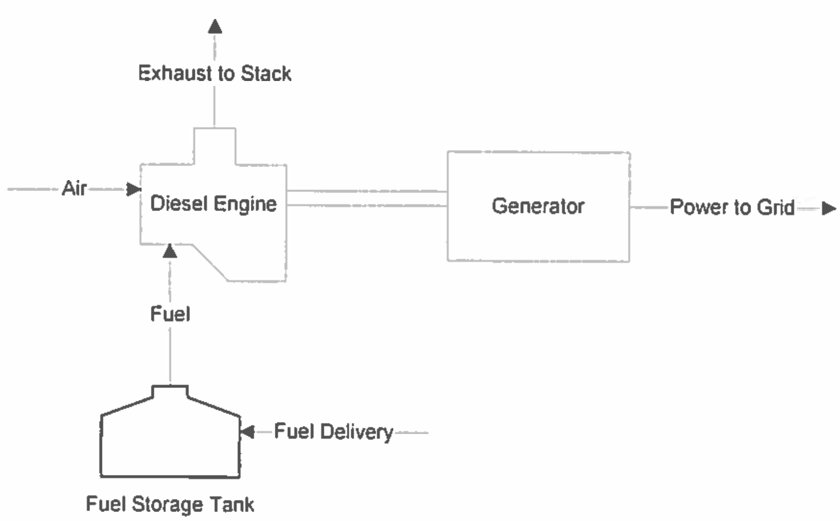
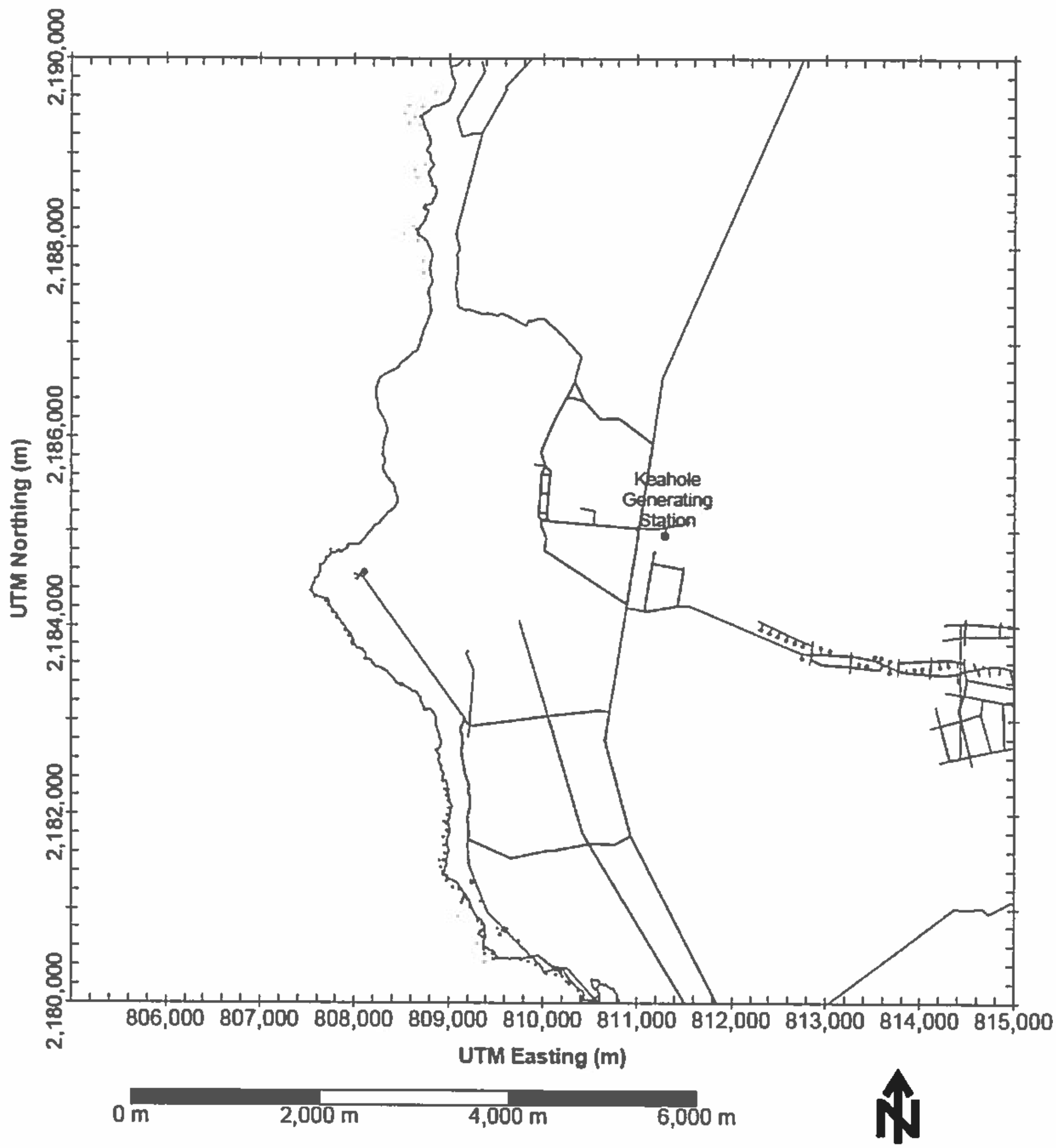


FIGURE S-1.5 LOCATION MAP



Company Name: Hawai'i Electric Light Company, Inc. File No.: ____

Location: Keahole Generating Station

(Make as many copies of this page as necessary) Page 1

EMISSIONS UNITS TABLE

Review of applications and issuance of permits will be expedited by supplying all necessary information on this table.

AIR POLLUTANT DATA: EMISSION POINTS				AIR POLLUTANT	AIR POLLUTANT EMISSION RATE		UTM Zone: 4 Horizontal Datum [a]: Old Hawaiian		STACK SOURCE PARAMETERS						
Stack No.	Unit No.	EQUIPMENT NAME/DESCRIPTION & SICC number	Equipment Date	Regulated/Hazardous Air Pollutant Name & CAS#	#/HR.	Tons/Year	Coordinates (mtrs)		Stack Height (mtrs)	Direction (u/d/h)[b]	Inside Diameter (mtrs)	Velocity (m/s)	Flow Rate (m^3/s)	Temp (°K)	Capped (Y/N)
4 or 5	CT-4 or CT-5	20 MW (Nominal) General Electric LM2500 Combustion Turbine, (SICC 4911), Simple Cyle, Peak Load	7/25/2001	SO_2	110.0	481.8	East	811,293	31.5	U	2.44	38.5	179.9	821	N
							North	2,184,955							
				NO_x	42.3	185.3	East	811,293	31.5	U	2.44	38.5	179.9	821	N
							North	2,184,955							
				CO	26.8	117.4	East	811,293	31.5	U	2.44	38.5	179.9	821	N
							North	2,184,955							
				VOC	0.8	3.5	East	811,293	31.5	U	2.44	38.5	179.9	821	N
							North	2,184,955							
				PM/PM-10	19.7	86.3	East	811,293	31.5	U	2.44	38.5	179.9	821	N
							North	2,184,955							
				H_2SO_4 Mist	14.4	63.2	East	811,293	31.5	U	2.44	38.5	179.9	821	N
							North	2,184,955							
				Pb	See Attachment S-1b		East	811,293	31.5	U	2.44	38.5	179.9	821	N
							North	2,184,955							
				Fluorides	2.77E-03	1.21E-02	East	811,293	31.5	U	2.44	38.5	179.9	821	N
							North	2,184,955							
				CFCs	Not Expected		East	811,293	31.5	U	2.44	38.5	179.9	821	N
							North	2,184,955							
				HAP	See Attachment S-1b		East	811,293	31.5	U	2.44	38.5	179.9	821	N
							North	2,184,955							
				GHG (CO_2e)	See Attachment S-1e		East	811,293	31.5	U	2.44	38.5	179.9	821	N
							North	2,184,955							

[a] Specify UTM Horizontal Datum as Old Hawaiian, NAD-83, or NAD-27

[b] Specify the direction of the stack exhaust as u=upward, d=downward, h=horizontal

Notes: 1. The equipment date is the date that CSP No. 0007-01-C was issued.

2. Stack parameters and SO_2, NO_x, CO, VOC, and PM/PM_{10} emission rates are from the PSD Permit Application for CT-4 and CT-5, dated January 1993.

3. H_2SO_4 emission rate based on 13.12% of the SO2 emission rate (5.57 lb/hr / 42.44 lb/hr). This ratio is derived from the August 19, 1994 SCEC report of Maui Electric Company, Ltd. Maalaea Generating Station's M16 source tests.

4. Emission rate for Fluorides based on Maui Electric Company, Ltd. fuel test results of 0.2 ppm dated April 11, 1985.

Company Name: Hawai'i Electric Light Company, Inc.

Location: Keahole Generating Station

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File No.: ______

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EMISSIONS UNITS TABLE

Review of applications and issuance of permits will be expedited by supplying all necessary information on this table.

AIR POLLUTANT DATA: EMISSION POINTS				AIR POLLUTANT	AIR POLLUTANT EMISSION RATE		UTM Zone: 4 Horizontal Datum [a]: Old Hawaiian		STACK SOURCE PARAMETERS						
Stack No.	Unit No	EQUIPMENT NAME/DESCRIPTION & SICC number	Equipment Date	Regulated/Hazardous Air Pollutant Name & CAS#	#/HR.	Tons/Year	Coordinates (mtrs)		Stack Height (mtrs)	Direction (u/d/h)[b]	Inside Diameter (mtrs)	Velocity (m/s)	Flow Rate (m^3/s)	Temp. (°K)	Capped (Y/N)
4 or 5	CT-4 or CT-5	20 MW (Nominal) General Electric LM2500 Combustion Turbine, (SICC 4911), Simple Cyle, 75% of Peak Load	7/25/2001	SO_2	82.9	363.1	East North	811,293 2,184,955	31.5	U	2.44	38.5	179.9	821	N
				NO_x	42.3	185.3	East North	811,293 2,184,955	31.5	U	2.44	38.5	179.9	821	N
				CO	56.4	247.0	East North	811,293 2,184,955	31.5	U	2.44	38.5	179.9	821	N
				VOC	2.6	11.4	East North	811,293 2,184,955	31.5	U	2.44	38.5	179.9	821	N
				PM/PM-10	19.7	86.3	East North	811,293 2,184,955	31.5	U	2.44	38.5	179.9	821	N

[a] Specify UTM Horizontal Datum as Old Hawaiian, NAD-83, or NAD-27

[b] Specify the direction of the stack exhaust as u=upward, d=downward, h=horizontal

Notes: 1. The equipment date is the date that CSP No. 0007-01-C was issued.

2. Stack parameters and SO_2, NO_x, CO, VOC, and PM/PM_{10} emission rates are from the PSD Permit Application for CT-4 and CT-5, dated January 1993.

Company Name: Hawai'i Electric Light Company, Inc. File No.: ____

Location: Keahole Generating Station

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EMISSIONS UNITS TABLE

Review of applications and issuance of permits will be expedited by supplying all necessary information on this table.

AIR POLLUTANT DATA: EMISSION POINTS				AIR POLLUTANT	AIR POLLUTANT EMISSION RATE		UTM Zone: 4 Horizontal Datum [a]: Old Hawaiian		STACK SOURCE PARAMETERS						
Stack No.	Unit No.	EQUIPMENT NAME/DESCRIPTION & SICC number	Equipment Date	Regulated/Hazardous Air Pollutant Name & CAS#	#/HR.	Tons/Year	Coordinates (mtrs)		Stack Height (mtrs)	Direction (u/d/h)[b]	Inside Diameter (mtrs)	Velocity (m/s)	Flow Rate (m^3/s)	Temp. (°K)	Capped (Y/N)
4 or 5	CT-4 or CT-5	20 MW (Nominal) General Electric LM2500 Combustion Turbine, (SICC 4911), Simple Cyle, 50% of Peak Load	7/25/2001	SO_2	58.0	254.0	East	811,293	31.5	U	2.44	38.5	179.9	821	N
							North	2,184,955							
				NO_x	42.3	185.3	East	811,293	31.5	U	2.44	38.5	179.9	821	N
							North	2,184,955							
				CO	181.0	792.8	East	811,293	31.5	U	2.44	38.5	179.9	821	N
							North	2,184,955							
				VOC	28.1	123.1	East	811,293	31.5	U	2.44	38.5	179.9	821	N
							North	2,184,955							
				PM/PM-10	19.7	86.3	East	811,293	31.5	U	2.44	38.5	179.9	821	N
							North	2,184,955							

[a] Specify UTM Horizontal Datum as Old Hawaiian, NAD-83, or NAD-27

[b] Specify the direction of the stack exhaust as u=upward, d=downward, h=horizontal

Notes: 1. The equipment date is the date that CSP No. 0007-01-C was issued.

2. Stack parameters and SO_2, NO_x, CO, VOC, and PM/PM_{10} emission rates are from the PSD Permit Application for CT-4 and CT-5, dated January 1993.

Company Name: Hawai'i Electric Light Company, Inc.

Location: Keahole Generating Station

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File No.:

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EMISSIONS UNITS TABLE

Review of applications and issuance of permits will be expedited by supplying all necessary information on this table.

AIR POLLUTANT DATA: EMISSION POINTS				AIR POLLUTANT	AIR POLLUTANT EMISSION RATE		UTM Zone: 4 Horizontal Datum [a]: Old Hawaiian		STACK SOURCE PARAMETERS						
Stack No	Unit No	EQUIPMENT NAME/DESCRIPTION & SICC number	Equipment Date	Regulated/Hazardous Air Pollutant Name & CAS#	#/HR	Tons/Year	Coordinates (mtrs)		Stack Height (mtrs)	Direction (u/d/h)[b]	Inside Diameter (mtrs)	Velocity (m/s)	Flow Rate (m^3/s)	Temp. (°K)	Capped (Y/N)
4 or 5	CT-4 or CT-5	20 MW (Nominal) General Electric LM2500 Combustion Turbine, (SICC 4911), Simple Cyle, 25% of Peak Load	7/25/2001	SO_2	39.0	170.8	East	811,293	31.5	U	2.44	38.5	179.9	821	N
							North	2,184,955							
				NO_x	42.3	185.3	East	811,293	31.5	U	2.44	38.5	179.9	821	N
							North	2,184,955							
				CO	475.6	2083.1	East	811,293	31.5	U	2.44	38.5	179.9	821	N
							North	2,184,955							
				VOC	297.6	1303.5	East	811,293	31.5	U	2.44	38.5	179.9	821	N
							North	2,184,955							
				PM/PM-10	19.7	86.3	East	811,293	31.5	U	2.44	38.5	179.9	821	N
							North	2,184,955							

[a] Specify UTM Horizontal Datum as Old Hawaiian, NAD-83, or NAD-27

[b] Specify the direction of the stack exhaust as u=upward, d=downward, h=horizontal

Notes: 1. The equipment date is the date that CSP No. 0007-01-C was issued.

2. Stack parameters and SO_2, NO_x, CO, VOC, and PM/PM_{10} emission rates are from the PSD Permit Application for CT-4 and CT-5, dated January 1993.

Company Name: Hawai'i Electric Light Company, Inc. File No.:

Location: Keahole Generating Station

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EMISSIONS UNITS TABLE

Review of applications and issuance of permits will be expedited by supplying all necessary information on this table.

AIR POLLUTANT DATA: EMISSION POINTS				AIR POLLUTANT	AIR POLLUTANT EMISSION RATE		UTM Zone: 4 Horizontal Datum [a]: Old Hawaiian	STACK SOURCE PARAMETERS							
Stack No.	Unit No.	EQUIPMENT NAME/DESCRIPTION & SICC number	Equipment Date	Regulated/Hazardous Air Pollutant Name & CAS#	#/HR.	Tons/Year	Coordinates (mtrs)	Stack Height (mtrs)	Direction (u/d/h)[b]	Inside Diameter (mtrs)	Velocity (m/s)	Flow Rate (m^3/s)	Temp. (°K)	Capped (Y/N)
4 or 5	CT-4 or CT-5	20 MW (Nominal) General Electric LM2500 Combustion Turbine, (SICC 4911); Combined Cyle, Peak Load	7/25/2001	SO_2	110.0	481.8	East 811,293 North 2,184,955	31.5	U	2.44	38.5	179.9	821	N
				NO_x	15.1	66.1	East 811,293 North 2,184,955	31.5	U	2.44	38.5	179.9	821	N
				CO	26.9	117.8	East 811,293 North 2,184,955	31.5	U	2.44	38.5	179.9	821	N
				VOC	0.8	3.5	East 811,293 North 2,184,955	31.5	U	2.44	38.5	179.9	821	N
				PM/PM-10	19.7	86.3	East 811,293 North 2,184,955	31.5	U	2.44	38.5	179.9	821	N
				H_2SO_4 Mist	14.4	63.2	East 811,293 North 2,184,955	31.5	U	2.44	38.5	179.9	821	N
				Pb	See Attachment S-1b		East 811,293 North 2,184,955	31.5	U	2.44	38.5	179.9	821	N
				Fluorides	2.77E-03	1.21E-02	East 811,293 North 2,184,955	31.5	U	2.44	38.5	179.9	821	N
				TRS	Not Expected		East 811,293 North 2,184,955	31.5	U	2.44	38.5	179.9	821	N
				CFCs	Not Expected		East 811,293 North 2,184,955	31.5	U	2.44	38.5	179.9	821	N
				HAP	See Attachment S-1b		East 811,293 North 2,184,955	31.5	U	2.44	38.5	179.9	821	N
				NH_3	4.3	18.8	East 811,293 North 2,184,955	31.5	U	2.44	38.5	179.9	821	N
				GHG (CO_2-e)	See Attachment S-1e		East 811,293 North 2,184,955	31.5	U	2.44	38.5	179.9	821	N

[a] Specify UTM Horizontal Datum as Old Hawaiian, NAD-83, or NAD-27

[b] Specify the direction of the stack exhaust as u=upward, d=downward, h=horizontal

Notes:
1. The equipment date is the date that CSP No. 0007-01-C was issued.
2. Stack parameters and SO_2, NO_x, CO, VOC, and PM/PM_{10} emission rates are from the PSD Permit Application for CT-4 and CT-5, dated January 1993
3. NO_x emission rate is based on SCR and water injection reducing emissions to 15 ppmvd (15.1 = 42.3 x (15 ppmvd/42 ppmvd)).
4. H_2SO_4 emission rate based on 13.12% of the SO2 emission rate (5.57 lb/hr / 42.44 lb/hr). This ratio is derived from the August 19, 1994 SCEC report of Maui Electric Company, Ltd. Maalaea Generating Station's M16 source tests.
5. Emission rate for Fluorides based on Maui Electric Company, Ltd. fuel tests results of 0.2 ppm dated April 11, 1985.
6. NH_3 emission rate is based on manufacturer's maximum ammonia slip of 10 ppmvd and a peak load flow rate of 559,400 lb/hr at 59 degrees F.

Company Name: Hawai'i Electric Light Company, Inc.

Location: Keahole Generating Station

(Make as many copies of this page as necessary)

File No.:

EMISSIONS UNITS TABLE

Review of applications and issuance of permits will be expedited by supplying all necessary information on this table.

AIR POLLUTANT DATA: EMISSION POINTS				AIR POLLUTANT	AIR POLLUTANT EMISSION RATE		UTM Zone: 4 Horizontal Datum [a]: Old Hawaiian		STACK SOURCE PARAMETERS						
Stack No.	Unit No.	EQUIPMENT NAME/DESCRIPTION & SICC number	Equipment Date	Regulated/Hazardous Air Pollutant Name & CAS#	#/HR.	Tons/Year	Coordinates (mtrs)		Stack Height (mtrs)	Direction (u/d/h)[b]	Inside Diameter (mtrs)	Velocity (m/s)	Flow Rate (m^3/s)	Temp. (°K)	Capped (Y/N)
4 or 5	CT-4 or CT-5	20 MW (Nominal) General Electric LM2500 Combustion Turbine, (SICC 4911). Combined Cyle, 75% of Peak Load	7/25/2001	SO_2	86.0	376.7	East North	811,293 2,184,955	31.5	U	2.44	38.5	179.9	821	N
				NO_x	15.1	66.1	East North	811,293 2,184,955	31.5	U	2.44	38.5	179.9	821	N
				CO	50.2	219.9	East North	811,293 2,184,955	31.5	U	2.44	38.5	179.9	821	N
				VOC	2.0	8.8	East North	811,293 2,184,955	31.5	U	2.44	38.5	179.9	821	N
				PM/PM-10	19.7	86.3	East North	811,293 2,184,955	31.5	U	2.44	38.5	179.9	821	N
				NH_3	4.3	18.8	East North	811,293 2,184,955	31.5	U	2.44	38.5	179.9	821	N

[a] Specify UTM Horizontal Datum as Old Hawaiian, NAD-83, or NAD-27

[b] Specify the direction of the stack exhaust as u=upward, d=downward, h=horizontal

Notes: 1. The equipment date is the date that CSP No. 0007-01-C was issued.

2. Stack parameters and SO_2, NO_x, CO, VOC, and PM/PM_{10} emission rates are from the PSD Permit Application for CT-4 and CT-5, dated January 1993.

3. NO_x emission rate is based on SCR and water injection reducing emissions to 15 ppmvd (15.1 = 42.3 x (15 ppmvd/42 ppmvd)).

4. NH_3 emissions are the worst-case emission rate based on the manufacturer's guaranteed ammonia slip of 10 ppmvd and a 100 percent load flow rate of 559,400 lb/hr at 59 degrees F.

Company Name: Hawai'i Electric Light Company, Inc. File No.: ____________

Location: Keahole Generating Station

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EMISSIONS UNITS TABLE

Review of applications and issuance of permits will be expedited by supplying all necessary information on this table.

AIR POLLUTANT DATA: EMISSION POINTS				AIR POLLUTANT	AIR POLLUTANT EMISSION RATE		UTM Zone: 4 Horizontal Datum [a]: Old Hawaiian		STACK SOURCE PARAMETERS						
Stack No.	Unit No.	EQUIPMENT NAME/DESCRIPTION & SICC number	Equipment Date	Regulated/Hazardous Air Pollutant Name & CAS#	#/HR.	Tons/Year	Coordinates (mtrs)		Stack Height (mtrs)	Direction (u/d/h)[b]	Inside Diameter (mtrs)	Velocity (m/s)	Flow Rate (m^3/s)	Temp. (°K)	Capped (Y/N)
4 or 5	CT-4 or CT-5	20 MW (Nominal) General Electric LM2500 Combustion Turbine, (SICC 4911), Combined Cycle, 50% of Peak Load	7/25/2001	SO_2	59.0	258.4	East	811,293	31.5	U	2.44	14.2	66.4	419	N
							North	2,184,955							
				NO_x	42.3	185.3	East	811,293	31.5	U	2.44	14.2	66.4	419	N
							North	2,184,955							
				CO	170.4	746.4	East	811,293	31.5	U	2.44	14.2	66.4	419	N
							North	2,184,955							
				VOC	25.0	109.5	East	811,293	31.5	U	2.44	14.2	66.4	419	N
							North	2,184,955							
				PM/PM-10	19.7	86.3	East	811,293	31.5	U	2.44	14.2	66.4	419	N
							North	2,184,955							

[a] Specify UTM Horizontal Datum as Old Hawaiian, NAD-83, or NAD-27

[b] Specify the direction of the stack exhaust as u=upward, d=downward, h=horizontal

Notes: 1. The equipment date is the date that CSP No. 0007-01-C was issued.

2. Stack parameters and SO_2, NO_x, CO, VOC, and PM/PM_{10} emission rates are from the PSD Permit Application for CT-4 and CT-5, dated January 1993.

3. NO_x emission rate is based on water injection reducing emissions to 42 ppmvd. SCR is not required for loads less than 50% of peak. Operating the SCR at loads less than 50% of peak will cause ammonium sulfates to form in the catalyst and on the boiler tubes in the heat recovery steam generator.

Company Name: Hawai'i Electric Light Company, Inc. File No.: ______

Location: Keahole Generating Station

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EMISSIONS UNITS TABLE

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AIR POLLUTANT DATA: EMISSION POINTS				AIR POLLUTANT	AIR POLLUTANT EMISSION RATE		UTM Zone: 4 Horizontal Datum [a]: Old Hawaiian		STACK SOURCE PARAMETERS						
Stack No.	Unit No	EQUIPMENT NAME/DESCRIPTION & SICC number	Equipment Date	Regulated/Hazardous Air Pollutant Name & CAS#	#/HR.	Tons/Year	Coordinates (mtrs)		Stack Height (mtrs)	Direction (u/d/h)[b]	Inside Diameter (mtrs)	Velocity (m/s)	Flow Rate (m^3/s)	Temp. (°K)	Capped (Y/N)
4 or 5	CT-4 or CT-5	20 MW (Nominal) General Electric LM2500 Combustion Turbine, (SICC 4911), Combined Cyle, 25% of Peak Load	7/25/2001	SO_2	39.9	174.8	East North	811,293 2,184,955	31.5	U	2.44	10.8	50.5	414	N
				NO_x	42.3	185.3	East North	811,293 2,184,955	31.5	U	2.44	10.8	50.5	414	N
				CO	457.4	2003.4	East North	811,293 2,184,955	31.5	U	2.44	10.8	50.5	414	N
				VOC	271.0	1187.0	East North	811,293 2,184,955	31.5	U	2.44	10.8	50.5	414	N
				PM/PM-10	19.7	86.3	East North	811,293 2,184,955	31.5	U	2.44	10.8	50.5	414	N

[a] Specify UTM Horizontal Datum as Old Hawaiian, NAD-83, or NAD-27

[b] Specify the direction of the stack exhaust as u=upward, d=downward, h=horizontal

Notes: 1. The equipment date is the date that CSP No. 0007-01-C was issued.

2. Stack parameters and SO_2, NO_x, CO, VOC, and PM/PM_{10} emission rates are from the PSD Permit Application for CT-4 and CT-5, dated January 1993.

3. NO_X emission rate is based on water injection reducing emissions to 42 ppmvd. SCR is not required for loads less than 50% of peak. Operating the SCR at loads less than 50% of peak will cause ammonium sulfates to form in the catalyst and on the boiler tubes in the heat recovery steam generator.

Company Name: Hawai'i Electric Light Company, Inc. File No. ______

Location: Keahole Generating Station

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EMISSIONS UNITS TABLE

Review of applications and issuance of permits will be expedited by supplying all necessary information on this table.

AIR POLLUTANT DATA: EMISSION POINTS				AIR POLLUTANT	AIR POLLUTANT EMISSION RATE		UTM Zone: 4 Horizontal Datum [a]: Old Hawaiian		STACK SOURCE PARAMETERS						
Stack No.	Unit No	EQUIPMENT NAME/DESCRIPTION & SICC number	Equipment Date	Regulated/Hazardous Air Pollutant Name & CAS#	#/HR.	Tons/Year	Coordinates (mtrs)		Stack Height (mtrs)	Direction (u/d/h)[b]	Inside Diameter (mtrs)	Velocity (m/s)	Flow Rate (m^3/s)	Temp. (°K)	Capped (Y/N)
2	CT-2	18 MW (Nominal) Jupiter GT-35 Combustion Turbine supplied by Solar Turbines. (SICC 4911)	6/29/1989	SO_2	110.0	478.4	East North	811,250 2,184,848	21.3	U	3.40	19.8	175.0	647	N
				NO_x	39.0	169.6	East North	811,250 2,184,848	21.3	U	3.40	19.8	175.0	647	N
				CO	22.4	97.4	East North	811,250 2,184,848	21.3	U	3.40	19.8	175.0	647	N
				VOC	22.4	97.4	East North	811,250 2,184,848	21.3	U	3.40	19.8	175.0	647	N
				PM/PM-10	20.0	87.0	East North	811,250 2,184,848	21.3	U	3.40	19.8	175.0	647	N
				H_2SO_4 Mist	14.4	62.8	East North	811,250 2,184,848	21.3	U	3.40	19.8	175.0	647	N
				Pb	See Attachment S-1a		East North	811,250 2,184,848	21.3	U	3.40	19.8	175.0	647	N
				Fluorides	1.99E-03	8.67E-03	East North	811,250 2,184,848	21.3	U	3.40	19.8	175.0	647	N
				TRS	Not Expected		East North	811,250 2,184,848	21.3	U	3.40	19.8	175.0	647	N
				CFC	Not Expected		East North	811,250 2,184,848	21.3	U	3.40	19.8	175.0	647	N
				HAP	See Attachment S-1a		East North	811,250 2,184,848	21.3	U	3.40	19.8	175.0	647	N
				GHG (CO_2e)	See Attachment S-1d		East North	811,250 2,184,848	21.3	U	3.40	19.8	175.0	647	N

[a] Specify UTM Horizontal Datum as Old Hawaiian, NAD-83, or NAD-27

[b] Specify the direction of the stack exhaust as u=upward, d=downward, h=horizontal

Notes
1. The equipment date is the date that HI 88-01 was issued.
2. Stack parameters are from the PSD Permit Application for CT-2, dated January 1989.
3. Unit CT-2 'tpy' values are based on 12,301,254 gallon per rolling 12-month period fuel limit, AP-42 no. 2 fuel oil heat content of 140,000 Btu/gal, and unit heat input of 198 MMBtu/hr
4. SO_2, NO_x, CO, VOC, and PM/PM_{10} emission rates were established by HI 88-01
5. NO_x and PM/PM_{10} emission rates were established by CSP No. 0070-01-C, dated January 12, 2006.
6. H_2SO_4 emission rate based on 13.12% of the SO_2 emission rate (5.57 lb/hr / 42.44 lb/hr). This ratio is derived from the August 19, 1994 SCEC report of Maui Electric Company, Ltd. Maalaea Generating Station's M16 source tests.
7. Emission rate for Fluorides based on Maui Electric Company, Ltd. fuel test results of 0.2 ppm dated 04/11/85.

Company Name: Hawai'i Electric Light Company, Inc.

Location: Keahole Generating Station

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EMISSIONS UNITS TABLE

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AIR POLLUTANT DATA: EMISSION POINTS				AIR POLLUTANT	AIR POLLUTANT EMISSION RATE		UTM Zone: 4 Horizontal Datum [a]: Old Hawaiian		STACK SOURCE PARAMETERS						
Stack No.	Unit No.	EQUIPMENT NAME/DESCRIPTION & SICC number	Equipment Date	Regulated/Hazardous Air Pollutant Name & CAS#	#/HR	Tons/Year	Coordinates (mtrs)		Stack Height (mtrs)	Direction (u/d/h) [b]	Inside Diameter (mtrs)	Velocity (m/s)	Flow Rate (m^3/s)	Temp (°K)	Capped (Y/N)
21	D-21	2.5 MW (Nominal) General Motors EMD Model 20-645F4B Diesel Engine Generator (SICC 4911)	1974	SO_2	0.04	0.0	East North	811,255 2,184,884	12.2	U	0.90	18.3	11.6	677	N
				NO_x	68.4	11.9	East North	811,255 2,184,884	12.2	U	0.90	18.3	11.6	677	N
				CO	23.6	4.1	East North	811,255 2,184,884	12.2	U	0.90	18.3	11.6	677	N
				VOC	6.69	1.17	East North	811,255 2,184,884	12.2	U	0.90	18.3	11.6	677	N
				PM/PM-10	5.06	0.88	East North	811,255 2,184,884	12.2	U	0.90	18.3	11.6	677	N
				H_2SO_4 Mist	0.01	0.00	East North	811,255 2,184,884	12.2	U	0.90	18.3	11.6	677	N
				Pb	See Attachment S-1b		East North	811,255 2,184,884	12.2	U	0.90	18.3	11.6	677	N
				Fluorides	2.83E-04	4.94E-05	East North	811,255 2,184,884	12.2	U	0.90	18.3	11.6	677	N
				TRS	Not Expected		East North	811,255 2,184,884	12.2	U	0.90	18.3	11.6	677	N
				CFCs	Not Expected		East North	811,255 2,184,884	12.2	U	0.90	18.3	11.6	677	N
				HAP	See Attachment S-1b		East North	811,255 2,184,884	12.2	U	0.90	18.3	11.6	677	N
				GHG (CO_2e)	See Attachment S-1e		East North	811,255 2,184,884	12.2	U	0.90	18.3	11.6	677	N

[a] Specify UTM Horizontal Datum as Old Hawaiian, NAD-83, or NAD-27

[b] Specify the direction of the stack exhaust as u=upward, d=downward, h=horizontal

Notes: 1. NO_x, CO, VOC, and PM/PM_{10} emission rates are based on an evaluation of AP-42 calculations and stack test data. Emission rate for CO includes a 70% reduction in accordance with 40 CFR Part 63 Subpart ZZZZ.

2. SO_2 emission rate based on mass balance with maximum fuel sulfur content of 0.0015 percent and assuming conversion of all sulfur to SO_2.

3. H_2SO_4 emission rate based on 13.83% of the SO_2 emission rate (0.73 lb/hr / 5.28 lb/hr). This ratio is derived from the August 19, 1994 SCEC report of Maui Electric Company, Ltd. Maalaea Generating Station M3 source tests.

4. Emission rate for Fluorides based on Maui Electric Company, Ltd. fuel test results of 0.2 ppm dated April 11, 1985.

5. Unit D-21 'tpy' values are based on 70,000 gal/yr fuel limit, AP-42 no. 2 fuel oil heat content of 140,000 Btu/gal, and unit heat input of 28.1 MMBtu/hr.

Company Name: Hawai'i Electric Light Company, Inc. File No.: ________

Location: Keahole Generating Station

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EMISSIONS UNITS TABLE

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AIR POLLUTANT DATA: EMISSION POINTS				AIR POLLUTANT	AIR POLLUTANT EMISSION RATE		UTM Zone: 4 Horizontal Datum [a]: Old Hawaiian		STACK SOURCE PARAMETERS						
Stack No	Unit No	EQUIPMENT NAME/DESCRIPTION & SICC number	Equipment Date	Regulated/Hazardous Air Pollutant Name & CAS#	#/HR	Tons/Year	Coordinates (mtrs) East	Coordinates (mtrs) North	Stack Height (mtrs)	Direction (u/d/h)[b]	Inside Diameter (mtrs)	Velocity (m/s)	Flow Rate (m^3/s)	Temp. (°K)	Capped (Y/N)
22	D-22	2.5 MW (Nominal) General Motors EMD Model 20-645F4B Diesel Engine Generator (SICC 4911)	1966	SO_2	0.04	0.2	811,253	2,184,874	12.2	U	0.90	18.3	11.6	877	N
				NO_x	68.4	299.6	811,253	2,184,874	12.2	U	0.90	18.3	11.6	877	N
				CO	23.6	103.1	811,253	2,184,874	12.2	U	0.90	18.3	11.6	877	N
				VOC	6.69	29.30	811,253	2,184,874	12.2	U	0.90	18.3	11.6	877	N
				PM/PM-10	5.06	22.16	811,253	2,184,874	12.2	U	0.90	18.3	11.6	877	N
				H_2SO_4 Mist	0.01	0.03	811,253	2,184,874	12.2	U	0.90	18.3	11.6	877	N
				Pb	See Attachment S-1a		811,253	2,184,874	12.2	U	0.90	18.3	11.6	877	N
				Fluorides	2.83E-04	1.24E-03	811,253	2,184,874	12.2	U	0.90	18.3	11.6	877	N
				TRS	Not Expected		811,253	2,184,874	12.2	U	0.90	18.3	11.6	877	N
				CFCs	Not Expected		811,253	2,184,874	12.2	U	0.90	18.3	11.6	877	N
				HAP	See Attachment S-1a		811,253	2,184,874	12.2	U	0.90	18.3	11.6	877	N
				GHG (CO_2e)	See Attachment S-1e		811,253	2,184,874	12.2	U	0.90	18.3	11.6	877	N

[a] Specify UTM Horizontal Datum as Old Hawaiian, NAD-83, or NAD-27

[b] Specify the direction of the stack exhaust as u=upward, d=downward, h=horizontal

Notes:
1. NO_x, CO, VOC, and PM/PM_{10} emission rates are based on an evaluation of AP-42 calculations and stack test data. Emission rate for CO includes a 70% reduction in accordance with 40 CFR Part 63 Subpart ZZZZ.
2. SO_2 emission rate based on mass balance with maximum fuel sulfur content of 0.0015 percent and assuming conversion of all sulfur to SO_2.
3. H_2SO_4 emission rate based on 13.83% of the SO_2 emission rate (0.73 lb/hr / 5.28 lb/hr). This ratio is derived from the August 19, 1994 SCEC report of Maui Electric Company, Ltd. Maalaea Generating Station M3 source tests.
4. Emission rate for Fluorides based on Maui Electric Company, Ltd. fuel test results of 0.2 ppm dated April 11, 1985.

Company Name: Hawai'i Electric Light Company, Inc. File No.:
Location: Keahole Generating Station
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EMISSIONS UNITS TABLE

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AIR POLLUTANT DATA: EMISSION POINTS				AIR POLLUTANT	AIR POLLUTANT EMISSION RATE		UTM Zone: 4 Horizontal Datum [a]: Old Hawaiian		STACK SOURCE PARAMETERS						
Stack No.	Unit No	EQUIPMENT NAME/DESCRIPTION & SICC number	Equipment Date	Regulated/Hazardous Air Pollutant Name & CAS#	#/HR.	Tons/Year	Coordinates (mtrs)		Stack Height (mtrs)	Direction (u/d/h)[b]	Inside Diameter (mtrs)	Velocity (m/s)	Flow Rate (m^3/s)	Temp. (°K)	Capped (Y/N)
23	D-23	2.5 MW (Nominal) General Motors EMD Model 20-645F4B Diesel Engine Generator (SICC 4911)	1969	SO_2	0.04	0.2	East	811,251	12.2	U	0.90	18.3	11.6	677	N
							North	2,184,869							
				NO_x	68.4	299.6	East	811,251	12.2	U	0.90	18.3	11.6	677	N
							North	2,184,869							
				CO	23.6	103.1	East	811,251	12.2	U	0.90	18.3	11.6	677	N
							North	2,184,869							
				VOC	6.69	29.3	East	811,251	12.2	U	0.90	18.3	11.6	677	N
							North	2,184,869							
				PM/PM-10	5.06	22.2	East	811,251	12.2	U	0.90	18.3	11.6	677	N
							North	2,184,869							
				H_2SO_4 Mist	0.01	0.0	East	811,251	12.2	U	0.90	18.3	11.6	677	N
							North	2,184,869							
				Pb	See Attachment S-1a		East	811,251	12.2	U	0.90	18.3	11.6	677	N
							North	2,184,869							
				Fluorides	2.83E-04	1.24E-03	East	811,251	12.2	U	0.90	18.3	11.6	677	N
							North	2,184,869							
				TRS	Not Expected		East	811,251	12.2	U	0.90	18.3	11.6	677	N
							North	2,184,869							
				CFCs	Not Expected		East	811,251	12.2	U	0.90	18.3	11.6	677	N
							North	2,184,869							
				HAP	See Attachment S-1a		East	811,251	12.2	U	0.90	18.3	11.6	677	N
							North	2,184,869							
				GHG (CO_2e)	See Attachment S-1e		East	811,251	12.2	U	0.90	18.3	11.6	677	N
							North	2,184,869							

[a] Specify UTM Horizontal Datum as Old Hawaiian, NAD-83, or NAD-27

[b] Specify the direction of the stack exhaust as u=upward, d=downward, h=horizontal

Notes: 1. NO_x, CO, VOC, and PM/PM_{10} emission rates are based on an evaluation of AP-42 calculations and stack test data. Emission rate for CO includes a 70% reduction in accordance with 40 CFR Part 63 Subpart ZZZZ.

2. SO_2 emission rate based on mass balance with maximum fuel sulfur content of 0.0015 percent and assuming conversion of all sulfur to SO_2.

3. H_2SO_4 emission rate based on 13.83% of the SO_2 emission rate (0.73 lb/hr / 5.28 lb/hr). This ratio is derived from the August 19, 1994 SCEC report of Maui Electric Company, Ltd. Maalaea Generating Station M3 source tests.

4. Emission rate for Fluorides based on Maui Electric Company, Ltd. fuel test results of 0.2 ppm dated April 11, 1985.

Company Name: Hawai'i Electric Light Company, Inc.

File No.: ________

Location: Keahole Generating Station

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AIR POLLUTANT DATA: EMISSION POINTS				AIR POLLUTANT	AIR POLLUTANT EMISSION RATE		UTM Zone: 4 Horizontal Datum [a]: Old Hawaiian		STACK SOURCE PARAMETERS						
Stack No.	Unit No.	EQUIPMENT NAME/DESCRIPTION & SICC number	Equipment Date	Regulated/Hazardous Air Pollutant Name & CAS#	#/HR.	Tons/Year	Coordinates (mtrs)		Stack Height (mtrs)	Direction (u/d/h)[b]	Inside Diameter (mtrs)	Velocity (m/s)	Flow Rate (m^3/s)	Temp. (°K)	Capped (Y/N)
1	BS-1	500 kW Caterpillar Model 3412 Blackstart Diesel Engine Generator (SICC 4911)	Nov. 4, 1991	SO_2	2.86	0.43	East North	811,250 2,184,848	21.3	U	0.20	62.2	2.0	894	N
				NO_x	12.50	1.88	East North	811,250 2,184,848	21.3	U	0.20	62.2	2.0	894	N
				CO	2.38	0.36	East North	811,250 2,184,848	21.3	U	0.20	62.2	2.0	894	N
				VOC	0.46	0.07	East North	811,250 2,184,848	21.3	U	0.20	62.2	2.0	894	N
				PM/PM-10	1.98	0.30	East North	811,250 2,184,848	21.3	U	0.20	62.2	2.0	894	N
				H_2SO_4 Mist	0.40	0.06	East North	811,250 2,184,848	21.3	U	0.20	62.2	2.0	894	N
				Pb	See Attachment S-1a		East North	811,250 2,184,848	21.3	U	0.20	62.2	2.0	894	N
				Fluorides	5.61E-05	8.41E-06	East North	811,250 2,184,848	21.3	U	0.20	62.2	2.0	894	N
				TRS	Not Expected		East North	811,250 2,184,848	21.3	U	0.20	62.2	2.0	894	N
				CFCs	Not Expected		East North	811,250 2,184,848	21.3	U	0.20	62.2	2.0	894	N
				HAP	See Attachment S-1a		East North	811,250 2,184,848	21.3	U	0.20	62.2	2.0	894	N
				GHG (CO_2e)	See Attachment S-1e		East North	811,250 2,184,848	21.3	U	0.20	62.2	2.0	894	N

[a] Specify UTM Horizontal Datum as Old Hawaiian, NAD-83, or NAD-27

[b] Specify the direction of the stack exhaust as u=upward, d=downward, h=horizontal

Notes: 1. Equipment date is the date that PTO No. P-936-1287 was issued.

2. SO_2, NO_x, CO, and PM/PM_{10} emission rates are from ATC application dated Jan. 30, 1981. VOC emissions are based on AP-42, Section 3.4, dated 10/96.

3. BS-1 is limited to 300 hours per year.

4. H_2SO_4 emission rate based on 13.83% of the SO_2 emission rate (0.73 lb/hr / 5.28 lb/hr). This ratio is derived from the August 19, 1994 SCEC report of Maui Electric Company, Ltd. Maalaea Generating Station M3 source tests.

5. Emission rate for Fluorides based on Maui Electric Company, Ltd. fuel test results of 0.2 ppm dated April 11, 1985.

Attachment S-1b
Air Toxic Emissions for CT-4 or CT-5

SECTION 112 HAZARDOUS AIR POLLUTANTS

CAS Number	Pollutant[1]	Source of Emission Factor	Emission Factor (lb/MMBtu)	Heat Input (MMBtu/hr)	Emissions (lb/hr)	Emissions (tpy)
75-07-0	Acetaldehyde	AP-42, Section 3.4, Table 3.4-3	2.52E-05	275	6.93E-03	3.04E-02
60-35-5	Acetamide			275		
75-05-8	Acetonitrile			275		
98-86-2	Acetophenone			275		
53-96-3	2-Acetylaminofluorene			275		
107-02-8	Acrolein	AP-42, Section 3.4, Table 3.4-3	7.88E-06	275	2.17E-03	9.49E-03
79-06-1	Acrylamide			275		
79-10-7	Acrylic acid			275		
107-13-1	Acrylonitrile			275		
107-05-1	Allyl chloride			275		
92-67-1	4-Aminobiphenyl			275		
62-53-3	Aniline			275		
90-04-0	o-Anisidine			275		
1332-21-4	Asbestos			275		
71-43-2	Benzene (including benzene from gasoline)	AP-42, Section 3.1, Table 3.1-4	5.50E-05	275	1.51E-02	6.61E-02
92-87-5	Benzidine			275		
98-07-7	Benzotrichloride			275		
100-44-7	Benzyl chloride			275		
92-52-4	Biphenyl			275		
117-81-7	Bis(2-ethylhexyl)phthalate (DEHP)			275		
542-88-1	Bis(chloromethyl) ether			275		
75-25-2	Bromoform			275		
106-99-0	1,3-Butadiene	AP-42, Section 3.1, Table 3.1-4	1.60E-05	275	4.40E-03	1.93E-02
156-62-7	Calcium cyanamide			275		
105-60-2	Caprolactam (Removed 06/18/96, See 61FR30816)			275		
133-06-2	Captan			275		
63-25-2	Carbaryl			275		
75-15-0	Carbon disulfide			275		
56-23-5	Carbon tetrachloride			275		
463-58-1	Carbonyl sulfide			275		
120-80-9	Catechol			275		
133-90-4	Chloramben			275		
57-74-9	Chlordane			275		
7782-50-5	Chlorine			275		
79-11-8	Chloroacetic acid			275		
532-27-4	2-Chloroacetophenone			275		
108-90-7	Chlorobenzene			275		
510-15-6	Chlorobenzilate			275		
67-66-3	Chloroform			275		
107-30-2	Chloromethyl methyl ether			275		
126-99-8	Chloroprene			275		
1319-77-3	Cresol/Cresylic acid(mixed isomers)			275		
95-48-7	o-Cresol			275		
108-39-4	m-Cresol			275		
106-44-5	p-Cresol			275		
98-82-8	Cumene			275		
94-75-7	2,4-D salts and esters			275		
72-55-9	DDE(1,1-dichloro-2,2-bis(p-chlorophenyl) ethylene)			275		
334-88-3	Diazomethane			275		
132-64-9	Dibenzofuran			275		
96-12-8	1,2-Dibromo-3-chloropropane			275		
84-74-2	Dibutyl phthalate			275		
106-46-7	1,4-Dichlorobenzene			275		
91-94-1	Dichlorobenzidine			275		
111-44-4	Dichloroethyl ether(Bis[2-chloroethyl]ether)			275		
542-75-6	1,3-Dichloropropene			275		
62-73-7	Dichlorvos			275		
111-42-2	Diethanolamine			275		
64-67-5	Diethyl sulfate			275		
119-90-4	3,3'-Dimethoxybenzidine			275		
60-11-7	4-Dimethylaminoazobenzene			275		
121-69-7	N,N-Dimethylaniline			275		
119-93-7	3,3'-Dimethylbenzidine			275		
79-44-7	Dimethylcarbamoyl chloride			275		
68-12-2	N,N-Dimethylformamide			275		
57-14-7	1,1-Dimethylhydrazine			275		
131-11-3	Dimethyl phthalate			275		
77-78-1	Dimethyl sulfate			275		
534-52-1	4,6-Dinitro-o-cresol (including salts)			275		
51-28-5	2,4-Dinitrophenol			275		
121-14-2	2,4-Dinitrotoluene			275		
123-91-1	1,4-Dioxane (1,4-Diethyleneoxide)			275		
122-66-7	1,2-Diphenylhydrazine			275		
106-89-8	Epichlorohydrin (l-Chloro-2,3-epoxypropane)			275		
106-88-7	1,2-Epoxybutane			275		

Attachment S-1b
Air Toxic Emissions for CT-4 or CT-5

SECTION 112 HAZARDOUS AIR POLLUTANTS

CAS Number	Pollutant[1]	Source of Emission Factor	Emission Factor (lb/MMBtu)	Heat Input (MMBtu/hr)	Emissions (lb/hr)	Emissions (tpy)
140-88-5	Ethyl acrylate			275		
100-41-4	Ethylbenzene			275		
51-79-6	Ethyl carbamate (Urethane)			275		
75-00-3	Ethyl chloride (Chloroethane)			275		
106-93-4	Ethylene dibromide (Dibromoethane)			275		
107-06-2	Ethylene dichloride (1,2-Dichloroethane)			275		
107-21-1	Ethylene glycol			275		
151-56-4	Ethyleneimine (Aziridine)			275		
75-21-8	Ethylene oxide			275		
96-45-7	Ethylene thiourea			275		
75-34-3	Ethylidene dichloride (1,1-Dichloroethane)			275		
50-00-0	Formaldehyde	AP-42, Section 3.1, Table 3.1-4	2.80E-04	275	7.70E-02	3.37E-01
76-44-8	Heptachlor			275		
118-74-1	Hexachlorobenzene			275		
87-68-3	Hexachlorobutadiene			275		
77-47-4	Hexachlorocyclopentadiene			275		
67-72-1	Hexachloroethane			275		
822-06-0	Hexamethylene diisocyanate			275		
680-31-9	Hexamethylphosphoramide			275		
110-54-3	Hexane			275		
302-01-2	Hydrazine			275		
7647-01-0	Hydrochloric acid (Hydrogen chloride (gas only))			275		
7664-39-3	Hydrogen fluoride (Hydrofluoric acid)			275		
123-31-9	Hydroquinone			275		
78-59-1	Isophorone			275		
58-89-9	Lindane (all isomers)			275		
108-31-6	Maleic anhydride			275		
67-56-1	Methanol			275		
72-43-5	Methoxychlor			275		
74-83-9	Methyl bromide (Bromomethane)			275		
74-87-3	Methyl chloride(Chloromethane)			275		
71-55-6	Methyl chloroform(1,1,1-Trichloroethane)			275		
78-93-3	Methyl ethyl ketone (2-Butanone) (Removed 12/19/05, See 70FR75047)			275		
60-34-4	Methylhydrazine			275		
74-88-4	Methyl iodide (Iodomethane)			275		
108-10-1	Methyl isobutyl ketone(Hexone)			275		
624-83-9	Methyl isocyanate			275		
80-62-6	Methyl methacrylate			275		
1634-04-4	Methyl tert-butyl ether			275		
101-14-4	4,4'-Methylenebis(2-chloroaniline)			275		
75-09-2	Methylene chloride(Dichloromethane)			275		
101-68-8	4,4'-Methylenediphenyl diisocyanate(MDI)			275		
101-77-9	4,4'-Methylenedianiline			275		
91-20-3	Naphthalene	AP-42, Section 3.1, Table 3.1-4	3.50E-05	275	9.63E-03	4.22E-02
98-95-3	Nitrobenzene			275		
92-93-3	4-Nitrobiphenyl			275		
100-02-7	4-Nitrophenol			275		
79-46-9	2-Nitropropane			275		
684-93-5	N-Nitroso-N-methylurea			275		
62-75-9	N-Nitrosodimethylamine			275		
59-89-2	N-Nitrosomorpholine			275		
56-38-2	Parathion			275		
82-68-8	Pentachloronitrobenzene(Quintobenzene)			275		
87-86-5	Pentachlorophenol			275		
108-95-2	Phenol			275		
106-50-3	p-Phenylenediamine			275		
75-44-5	Phosgene			275		
7803-51-2	Phosphine			275		
7723-14-0	Phosphorus			275		
85-44-9	Phthalic anhydride			275		
1336-36-3	Polychlorinated biphenyls(Aroclors)			275		
1120-71-4	1,3-Propane sultone			275		
57-57-8	beta-Propiolactone			275		
123-38-6	Propionaldehyde			275		
114-26-1	Propoxur (Baygon)			275		
78-87-5	Propylene dichloride (1,2-Dichloropropane)			275		
75-56-9	Propylene oxide			275		
75-55-8	1,2-Propylenimine (2-Methylaziridine)			275		
91-22-5	Quinoline			275		
106-51-4	Quinone(p-Benzoquinone)			275		
100-42-5	Styrene			275		
96-09-3	Styrene oxide			275		
1746-01-6	2,3,7,8-Tetrachlorodibenzo-p-dioxin			275		
79-34-5	1,1,2,2-Tetrachloroethane			275		
127-18-4	Tetrachloroethylene(Perchloroethylene)			275		

Attachment S-1b
Air Toxic Emissions for CT-4 or CT-5

SECTION 112 HAZARDOUS AIR POLLUTANTS

CAS Number	Pollutant[1]	Source of Emission Factor	Emission Factor (lb/MMBtu)	Heat Input (MMBtu/hr)	Emissions (lb/hr)	Emissions (tpy)
7550-45-0	Titanium tetrachloride			275		
108-88-3	Toluene	AP-42, Section 3.4, Table 3.4-3	2.81E-04	275	7.73E-02	3.38E-01
95-80-7	Toluene-2,4-diamine			275		
584-84-9	2,4-Toluene diisocyanate			275		
95-53-4	o-Toluidine			275		
8001-35-2	Toxaphene (chlorinated camphene)			275		
120-82-1	1,2,4-Trichlorobenzene			275		
79-00-5	1,1,2-Trichloroethane			275		
79-01-6	Trichloroethylene			275		
95-95-4	2,4,5-Trichlorophenol			275		
88-06-2	2,4,6-Trichlorophenol			275		
121-44-8	Triethylamine			275		
1582-09-8	Trifluralin			275		
540-84-1	2,2,4-Trimethylpentane			275		
108-05-4	Vinyl acetate			275		
593-60-2	Vinyl bromide			275		
75-01-4	Vinyl chloride			275		
75-35-4	Vinylidene chloride (1,1-Dichloroethylene)			275		
1330-20-7	Xylene (mixed isomers)	AP-42, Section 3.4, Table 3.4-3	1.93E-04	275	5.31E-02	2.32E-01
95-47-6	o-Xylene			275		
108-38-3	m-Xylene			275		
106-42-3	p-Xylene			275		
	Antimony Compounds			275		
	Arsenic Compounds (inorganic including arsine)	AP-42, Section 3.1, Table 3.1-5	1.10E-05	275	3.03E-03	1.33E-02
	Beryllium Compounds	AP-42, Section 3.1, Table 3.1-5	3.10E-07	275	8.53E-05	3.73E-04
	Cadmium Compounds	AP-42, Section 3.1, Table 3.1-5	4.80E-06	275	1.32E-03	5.78E-03
	Chromium Compounds	AP-42, Section 3.1, Table 3.1-5	1.10E-05	275	3.03E-03	1.32E-02
	Cobalt Compounds			275		
	Coke Oven Emissions			275		
	Cyanide Compounds[2]			275		
	Glycol ethers[3]			275		
	Lead Compounds	AP-42, Section 3.1, Table 3.1-5	1.40E-05	275	3.85E-03	1.69E-02
	Manganese Compounds	AP-42, Section 3.1, Table 3.1-5	7.90E-04	275	2.17E-01	9.52E-01
	Mercury Compounds	AP-42, Section 3.1, Table 3.1-5	1.20E-06	275	3.30E-04	1.45E-03
	Fine mineral fibers[4]			275		
	Nickel Compounds	AP-42, Section 3.1, Table 3.1-5	4.60E-06	275	1.27E-03	5.54E-03
	Polycyclic Organic Matter[5]	AP-42, Section 3.1, Table 3.1-4	4.00E-05	275	1.10E-02	4.82E-02
	Radionuclides (including radon)[6]			275		
	Selenium Compounds	AP-42, Section 3.1, Table 3.1-5	2.50E-05	275	6.88E-03	3.01E-02
	Total				4.94E-01	2.16

Notes:

1. For all listings above which contain the word "compounds" and for glycol ethers, the following applies. Unless otherwise specified, these listings are defined as including any unique chemical substance that contains the named chemical (i.e., antimony, arsenic, etc.) as part of that chemical's infrastructure.
2. X'CN where X = H' or any other group where a formal dissociation may occur. For example, KCN or Ca(CN)2
3. Includes mono- and di- ethers of ethylene glycol, diethylene glycol, and triethylene glycol, R-(OCH2CH2)n-OR'

where n = 1, 2, or 3

R = alkyl or aryl groups

R' = R, H, or groups which, when removed, yield glycol ethers with the structure: R-(OCH2CH)n-OH. Polymers are excluded from the glycol category

4. Includes mineral fiber emissions from facilities manufacturing or processing glass, rock, or slag fibers (or other mineral derived fibers) of average diameter 1 micrometer or less
5. Includes organic compounds with more than one benzene ring, and which have a boiling point greater than or equal to 100°C
6. A type of atom which spontaneously undergoes radioactive decay

Attachment S-1b
Air Toxic Emissions for CT-2

SECTION 112 HAZARDOUS AIR POLLUTANTS

CAS Number	Pollutant[1]	Source of Emission Factor	Emission Factor (lb/MMBtu)	Heat Input (MMBtu/hr)	Heat Input (MMBtu/yr)	Emissions (lb/hr)	Emissions (tpy)
75-07-0	Acetaldehyde	AP-42, Section 3.4, Table 3.4-3	2.52E-05	198	1,722,176	4.99E-03	2.17E-02
60-35-5	Acetamide			198	1,722,176		
75-05-8	Acetonitrile			198	1,722,176		
98-86-2	Acetophenone			198	1,722,176		
53-96-3	2-Acetylaminofluorene			198	1,722,176		
107-02-8	Acrolein	AP-42, Section 3.4, Table 3.4-3	7.88E-06	198	1,722,176	1.56E-03	6.79E-03
79-06-1	Acrylamide			198	1,722,176		
79-10-7	Acrylic acid			198	1,722,176		
107-13-1	Acrylonitrile			198	1,722,176		
107-05-1	Allyl chloride			198	1,722,176		
92-67-1	4-Aminobiphenyl			198	1,722,176		
62-53-3	Aniline			198	1,722,176		
90-04-0	o-Anisidine			198	1,722,176		
1332-21-4	Asbestos			198	1,722,176		
71-43-2	Benzene (including benzene from gasoline)	AP-42, Section 3.1, Table 3.1-4	5.50E-05	198	1,722,176	1.09E-02	4.74E-02
92-87-5	Benzidine			198	1,722,176		
98-07-7	Benzotrichloride			198	1,722,176		
100-44-7	Benzyl chloride			198	1,722,176		
92-52-4	Biphenyl			198	1,722,176		
117-81-7	Bis(2-ethylhexyl)phthalate (DEHP)			198	1,722,176		
542-88-1	Bis(chloromethyl) ether			198	1,722,176		
75-25-2	Bromoform			198	1,722,176		
106-99-0	1,3-Butadiene	AP-42, Section 3.1, Table 3.1-4	1.60E-05	198	1,722,176	3.17E-03	1.38E-02
156-62-7	Calcium cyanamide			198	1,722,176		
105-60-2	Caprolactam (Removed 06/18/96, See 61FR30816)			198	1,722,176		
133-06-2	Captan			198	1,722,176		
63-25-2	Carbaryl			198	1,722,176		
75-15-0	Carbon disulfide			198	1,722,176		
56-23-5	Carbon tetrachloride			198	1,722,176		
463-58-1	Carbonyl sulfide			198	1,722,176		
120-80-9	Catechol			198	1,722,176		
133-90-4	Chloramben			198	1,722,176		
57-74-9	Chlordane			198	1,722,176		
7782-50-5	Chlorine			198	1,722,176		
79-11-8	Chloroacetic acid			198	1,722,176		
532-27-4	2-Chloroacetophenone			198	1,722,176		
108-90-7	Chlorobenzene			198	1,722,176		
510-15-6	Chlorobenzilate			198	1,722,176		
67-66-3	Chloroform			198	1,722,176		
107-30-2	Chloromethyl methyl ether			198	1,722,176		
126-99-8	Chloroprene			198	1,722,176		
1319-77-3	Cresol/Cresylic acid(mixed isomers)			198	1,722,176		
95-48-7	o-Cresol			198	1,722,176		
108-39-4	m-Cresol			198	1,722,176		
106-44-5	p-Cresol			198	1,722,176		
98-82-8	Cumene			198	1,722,176		
94-75-7	2,4-D salts and esters			198	1,722,176		
72-55-9	DDE(1,1-dichloro-2,2-bis(p-chlorophenyl) ethylene)			198	1,722,176		
334-88-3	Diazomethane			198	1,722,176		
132-64-9	Dibenzofuran			198	1,722,176		
96-12-8	1,2-Dibromo-3-chloropropane			198	1,722,176		
84-74-2	Dibutyl phthalate			198	1,722,176		
106-46-7	1,4-Dichlorobenzene			198	1,722,176		
91-94-1	Dichlorobenzidine			198	1,722,176		
111-44-4	Dichloroethyl ether(Bis[2-chloroethyl]ether)			198	1,722,176		
542-75-6	1,3-Dichloropropene			198	1,722,176		
62-73-7	Dichlorvos			198	1,722,176		
111-42-2	Diethanolamine			198	1,722,176		
64-67-5	Diethyl sulfate			198	1,722,176		
119-90-4	3,3'-Dimethoxybenzidine			198	1,722,176		
60-11-7	4-Dimethylaminoazobenzene			198	1,722,176		
121-69-7	N,N-Dimethylaniline			198	1,722,176		
119-93-7	3,3'-Dimethylbenzidine			198	1,722,176		
79-44-7	Dimethylcarbamoyl chloride			198	1,722,176		
68-12-2	N,N-Dimethylformamide			198	1,722,176		
57-14-7	1,1-Dimethylhydrazine			198	1,722,176		
131-11-3	Dimethyl phthalate			198	1,722,176		
77-78-1	Dimethyl sulfate			198	1,722,176		
534-52-1	4,6-Dinitro-o-cresol (including salts)			198	1,722,176		
51-28-5	2,4-Dinitrophenol			198	1,722,176		
121-14-2	2,4-Dinitrotoluene			198	1,722,176		
123-91-1	1,4-Dioxane (1,4-Diethyleneoxide)			198	1,722,176		
122-66-7	1,2-Diphenylhydrazine			198	1,722,176		
106-89-8	Epichlorohydrin (l-Chloro-2,3-epoxypropane)			198	1,722,176		
106-88-7	1,2-Epoxybutane			198	1,722,176		

Attachment S-1b
Air Toxic Emissions for CT-2

SECTION 112 HAZARDOUS AIR POLLUTANTS

CAS Number	Pollutant[1]	Source of Emission Factor	Emission Factor (lb/MMBtu)	Heat Input (MMBtu/hr)	Heat Input (MMBtu/yr)	Emissions (lb/hr)	Emissions (tpy)
140-88-5	Ethyl acrylate			198	1,722,176		
100-41-4	Ethylbenzene			198	1,722,176		
51-79-6	Ethyl carbamate (Urethane)			198	1,722,176		
75-00-3	Ethyl chloride (Chloroethane)			198	1,722,176		
106-93-4	Ethylene dibromide (Dibromoethane)			198	1,722,176		
107-06-2	Ethylene dichloride (1,2-Dichloroethane)			198	1,722,176		
107-21-1	Ethylene glycol			198	1,722,176		
151-56-4	Ethyleneimine (Aziridine)			198	1,722,176		
75-21-8	Ethylene oxide			198	1,722,176		
96-45-7	Ethylene thiourea			198	1,722,176		
75-34-3	Ethylidene dichloride (1,1-Dichloroethane)			198	1,722,176		
50-00-0	Formaldehyde	AP-42, Section 3.1, Table 3.1-4	2.80E-04	198	1,722,176	5.54E-02	2.41E-01
76-44-8	Heptachlor			198	1,722,176		
118-74-1	Hexachlorobenzene			198	1,722,176		
87-68-3	Hexachlorobutadiene			198	1,722,176		
77-47-4	Hexachlorocyclopentadiene			198	1,722,176		
67-72-1	Hexachloroethane			198	1,722,176		
822-06-0	Hexamethylene diisocyanate			198	1,722,176		
680-31-9	Hexamethylphosphoramide			198	1,722,176		
110-54-3	Hexane			198	1,722,176		
302-01-2	Hydrazine			198	1,722,176		
7647-01-0	Hydrochloric acid (Hydrogen chloride [gas only])			198	1,722,176		
7664-39-3	Hydrogen fluoride (Hydrofluoric acid)			198	1,722,176		
123-31-9	Hydroquinone			198	1,722,176		
78-59-1	Isophorone			198	1,722,176		
58-89-9	Lindane (all isomers)			198	1,722,176		
108-31-6	Maleic anhydride			198	1,722,176		
67-56-1	Methanol			198	1,722,176		
72-43-5	Methoxychlor			198	1,722,176		
74-83-9	Methyl bromide (Bromomethane)			198	1,722,176		
74-87-3	Methyl chloride(Chloromethane)			198	1,722,176		
71-55-6	Methyl chloroform(1,1,1-Trichloroethane)			198	1,722,176		
78-93-3	Methyl ethyl ketone (2-Butanone) (Removed 12/19/05, See 70FR75047)			198	1,722,176		
60-34-4	Methylhydrazine			198	1,722,176		
74-88-4	Methyl iodide (Iodomethane)			198	1,722,176		
108-10-1	Methyl isobutyl ketone(Hexone)			198	1,722,176		
624-83-9	Methyl isocyanate			198	1,722,176		
80-62-6	Methyl methacrylate			198	1,722,176		
1634-04-4	Methyl tert-butyl ether			198	1,722,176		
101-14-4	4,4'-Methylenebis(2-chloroaniline)			198	1,722,176		
75-09-2	Methylene chloride(Dichloromethane)			198	1,722,176		
101-68-8	4,4'-Methylenediphenyl diisocyanate(MDI)			198	1,722,176		
101-77-9	4,4'-Methylenedianiline			198	1,722,176		
91-20-3	Naphthalene	AP-42, Section 3.1, Table 3.1-4	3.50E-05	198	1,722,176	6.93E-03	3.01E-02
98-95-3	Nitrobenzene			198	1,722,176		
92-93-3	4-Nitrobiphenyl			198	1,722,176		
100-02-7	4-Nitrophenol			198	1,722,176		
79-46-9	2-Nitropropane			198	1,722,176		
684-93-5	N-Nitroso-N-methylurea			198	1,722,176		
62-75-9	N-Nitrosodimethylamine			198	1,722,176		
59-89-2	N-Nitrosomorpholine			198	1,722,176		
56-38-2	Parathion			198	1,722,176		
82-68-8	Pentachloronitrobenzene(Quintobenzene)			198	1,722,176		
87-86-5	Pentachlorophenol			198	1,722,176		
108-95-2	Phenol			198	1,722,176		
106-50-3	p-Phenylenediamine			198	1,722,176		
75-44-5	Phosgene			198	1,722,176		
7803-51-2	Phosphine			198	1,722,176		
7723-14-0	Phosphorus			198	1,722,176		
85-44-9	Phthalic anhydride			198	1,722,176		
1336-36-3	Polychlorinated biphenyls(Aroclors)			198	1,722,176		
1120-71-4	1,3-Propane sultone			198	1,722,176		
57-57-8	beta-Propiolactone			198	1,722,176		
123-38-6	Propionaldehyde			198	1,722,176		
114-26-1	Propoxur (Baygon)			198	1,722,176		
78-87-5	Propylene dichloride (1,2-Dichloropropane)			198	1,722,176		
75-56-9	Propylene oxide			198	1,722,176		
75-55-8	1,2-Propylenimine (2-Methylaziridine)			198	1,722,176		
91-22-5	Quinoline			198	1,722,176		
106-51-4	Quinone(p-Benzoquinone)			198	1,722,176		
100-42-5	Styrene			198	1,722,176		
96-09-3	Styrene oxide			198	1,722,176		
1746-01-6	2,3,7,8-Tetrachlorodibenzo-p-dioxin			198	1,722,176		
79-34-5	1,1,2,2-Tetrachloroethane			198	1,722,176		
127-18-4	Tetrachloroethylene(Perchloroethylene)			198	1,722,176		

Attachment S-1b
Air Toxic Emissions for CT-2

SECTION 112 HAZARDOUS AIR POLLUTANTS

CAS Number	Pollutant[1]	Source of Emission Factor	Emission Factor (lb/MMBtu)	Heat Input (MMBtu/hr)	Heat Input (MMBtu/yr)	Emissions (lb/hr)	Emissions (tpy)
7550-45-0	Titanium tetrachloride			198	1,722,176		
108-88-3	Toluene	AP-42, Section 3.4, Table 3.4-3	2.81E-04	198	1,722,176	5.56E-02	2.42E-01
95-80-7	Toluene-2,4-diamine			198	1,722,176		
584-84-9	2,4-Toluene diisocyanate			198	1,722,176		
95-53-4	o-Toluidine			198	1,722,176		
8001-35-2	Toxaphene (chlorinated camphene)			198	1,722,176		
120-82-1	1,2,4-Trichlorobenzene			198	1,722,176		
79-00-5	1,1,2-Trichloroethane			198	1,722,176		
79-01-6	Trichloroethylene			198	1,722,176		
95-95-4	2,4,5-Trichlorophenol			198	1,722,176		
88-06-2	2,4,6-Trichlorophenol			198	1,722,176		
121-44-8	Triethylamine			198	1,722,176		
1582-09-8	Trifluralin			198	1,722,176		
540-84-1	2,2,4-Trimethylpentane			198	1,722,176		
108-05-4	Vinyl acetate			198	1,722,176		
593-60-2	Vinyl bromide			198	1,722,176		
75-01-4	Vinyl chloride			198	1,722,176		
75-35-4	Vinylidene chloride (1,1-Dichloroethylene)			198	1,722,176		
1330-20-7	Xylene (mixed isomers)	AP-42, Section 3.4, Table 3.4-3	1.93E-04	198	1,722,176	3.82E-02	1.66E-01
95-47-6	o-Xylene			198	1,722,176		
108-38-3	m-Xylene			198	1,722,176		
106-42-3	p-Xylene			198	1,722,176		
	Antimony Compounds			198	1,722,176		
	Arsenic Compounds (inorganic including arsine)	AP-42, Section 3.1, Table 3.1-5	1.10E-05	198	1,722,176	2.18E-03	9.47E-03
	Beryllium Compounds	AP-42, Section 3.1, Table 3.1-5	3.10E-07	198	1,722,176	6.14E-05	2.67E-04
	Cadmium Compounds	AP-42, Section 3.1, Table 3.1-5	4.80E-06	198	1,722,176	9.50E-04	4.13E-03
	Chromium Compounds	AP-42, Section 3.1, Table 3.1-5	1.10E-05	198	1,722,176	2.18E-03	9.47E-03
	Cobalt Compounds			198	1,722,176		
	Coke Oven Emissions			198	1,722,176		
	Cyanide Compounds[2]			198	1,722,176		
	Glycol ethers[3]			198	1,722,176		
	Lead Compounds	AP-42, Section 3.1, Table 3.1-5	1.40E-05	198	1,722,176	2.77E-03	1.21E-02
	Manganese Compounds	AP-42, Section 3.1, Table 3.1-5	7.90E-04	198	1,722,176	1.56E-01	6.80E-01
	Mercury Compounds	AP-42, Section 3.1, Table 3.1-5	1.20E-06	198	1,722,176	2.38E-04	1.03E-03
	Fine mineral fibers[4]			198	1,722,176		
	Nickel Compounds	AP-42, Section 3.1, Table 3.1-5	4.60E-06	198	1,722,176	9.11E-04	3.96E-03
	Polycyclic Organic Matter[5]	AP-42, Section 3.1, Table 3.1-4	4.00E-05	198	1,722,176	7.92E-03	3.44E-02
	Radionuclides (including radon)[6]			198	1,722,176		
	Selenium Compounds	AP-42, Section 3.1, Table 3.1-5	2.50E-05	198	1,722,176	4.95E-03	2.15E-02
	Total					3.55E-01	1.55

Notes:

1 For all listings above which contain the word "compounds" and for glycol ethers, the following applies: Unless otherwise specified, these listings are defined as including any unique chemical substance that contains the named chemical (i.e., antimony, arsenic, etc.) as part of that chemical's infrastructure.

2 X'CN where X = H' or any other group where a formal dissociation may occur. For example, KCN or Ca(CN)2

3 Includes mono- and di- ethers of ethylene glycol, diethylene glycol, and triethylene glycol, R-(OCH2CH2)n-OR'

where n = 1, 2, or 3

R = alkyl or aryl groups

R' = R, H, or groups which, when removed, yield glycol ethers with the structure: R-(OCH2CH)n-OH. Polymers are excluded from the glycol category.

4 Includes mineral fiber emissions from facilities manufacturing or processing glass, rock, or slag fibers (or other mineral derived fibers) of average diameter 1 micrometer or less.

5 Includes organic compounds with more than one benzene ring, and which have a boiling point greater than or equal to 100°C.

6 A type of atom which spontaneously undergoes radioactive decay.

Attachment S-1b
Air Toxic Emissions for D-21

SECTION 112 HAZARDOUS AIR POLLUTANTS

CAS Number	Pollutant[1]	Source of Emission Factor	Emission Factor (lb/MMBtu)	Heat Input (MMBtu/hr)	Heat Input (MMBtu/yr)	Emissions (lb/hr)	Emissions (tpy)
75-07-0	Acetaldehyde	AP-42, Section 3.4, Table 3.4-3	2.52E-05	28.1	9,800	7.08E-04	1.23E-04
60-35-5	Acetamide			28.1	9,800		
75-05-8	Acetonitrile			28.1	9,800		
98-86-2	Acetophenone			28.1	9,800		
53-96-3	2-Acetylaminofluorene			28.1	9,800		
107-02-8	Acrolein	AP-42, Section 3.4, Table 3.4-3	7.88E-06	28.1	9,800	2.21E-04	3.86E-05
79-06-1	Acrylamide			28.1	9,800		
79-10-7	Acrylic acid			28.1	9,800		
107-13-1	Acrylonitrile			28.1	9,800		
107-05-1	Allyl chloride			28.1	9,800		
92-67-1	4-Aminobiphenyl			28.1	9,800		
62-53-3	Aniline			28.1	9,800		
90-04-0	o-Anisidine			28.1	9,800		
1332-21-4	Asbestos			28.1	9,800		
71-43-2	Benzene (including benzene from gasoline)	AP-42, Section 3.4, Table 3.4-3	7.76E-04	28.1	9,800	2.18E-02	3.80E-03
92-87-5	Benzidine			28.1	9,800		
98-07-7	Benzotrichloride			28.1	9,800		
100-44-7	Benzyl chloride			28.1	9,800		
92-52-4	Biphenyl			28.1	9,800		
117-81-7	Bis(2-ethylhexyl)phthalate (DEHP)			28.1	9,800		
542-88-1	Bis(chloromethyl) ether			28.1	9,800		
75-25-2	Bromoform			28.1	9,800		
106-99-0	1,3-Butadiene	AP-42, Section 3.1, Table 3.1-4	1.60E-05	28.1	9,800	4.50E-04	7.84E-05
156-62-7	Calcium cyanamide			28.1	9,800		
105-60-2	Caprolactam (Removed 06/18/96, See 61FR30816)			28.1	9,800		
133-06-2	Captan			28.1	9,800		
63-25-2	Carbaryl			28.1	9,800		
75-15-0	Carbon disulfide			28.1	9,800		
56-23-5	Carbon tetrachloride			28.1	9,800		
463-58-1	Carbonyl sulfide			28.1	9,800		
120-80-9	Catechol			28.1	9,800		
133-90-4	Chloramben			28.1	9,800		
57-74-9	Chlordane			28.1	9,800		
7782-50-5	Chlorine			28.1	9,800		
79-11-8	Chloroacetic acid			28.1	9,800		
532-27-4	2-Chloroacetophenone			28.1	9,800		
108-90-7	Chlorobenzene			28.1	9,800		
510-15-6	Chlorobenzilate			28.1	9,800		
67-66-3	Chloroform			28.1	9,800		
107-30-2	Chloromethyl methyl ether			28.1	9,800		
126-99-8	Chloroprene			28.1	9,800		
1319-77-3	Cresol/Cresylic acid(mixed isomers)			28.1	9,800		
95-48-7	o-Cresol			28.1	9,800		
108-39-4	m-Cresol			28.1	9,800		
106-44-5	p-Cresol			28.1	9,800		
98-82-8	Cumene			28.1	9,800		
94-75-7	2,4-D salts and esters			28.1	9,800		
72-55-9	DDE(1,1-dichloro-2,2-bis(p-chlorophenyl) ethylene)			28.1	9,800		
334-88-3	Diazomethane			28.1	9,800		
132-64-9	Dibenzofuran			28.1	9,800		
96-12-8	1,2-Dibromo-3-chloropropane			28.1	9,800		
84-74-2	Dibutyl phthalate			28.1	9,800		
106-46-7	1,4-Dichlorobenzene			28.1	9,800		
91-94-1	Dichlorobenzidine			28.1	9,800		
111-44-4	Dichloroethyl ether(Bis[2-chloroethyl]ether)			28.1	9,800		
542-75-6	1,3-Dichloropropene			28.1	9,800		
62-73-7	Dichlorvos			28.1	9,800		
111-42-2	Diethanolamine			28.1	9,800		
64-67-5	Diethyl sulfate			28.1	9,800		
119-90-4	3,3'-Dimethoxybenzidine			28.1	9,800		
60-11-7	4-Dimethylaminoazobenzene			28.1	9,800		
121-69-7	N,N-Dimethylaniline			28.1	9,800		
119-93-7	3,3'-Dimethylbenzidine			28.1	9,800		
79-44-7	Dimethylcarbamoyl chloride			28.1	9,800		
68-12-2	N,N-Dimethylformamide			28.1	9,800		
57-14-7	1,1-Dimethylhydrazine			28.1	9,800		
131-11-3	Dimethyl phthalate			28.1	9,800		
77-78-1	Dimethyl sulfate			28.1	9,800		
534-52-1	4,6-Dinitro-o-cresol (including salts)			28.1	9,800		
51-28-5	2,4-Dinitrophenol			28.1	9,800		
121-14-2	2,4-Dinitrotoluene			28.1	9,800		
123-91-1	1,4-Dioxane (1,4-Diethyleneoxide)			28.1	9,800		
122-66-7	1,2-Diphenylhydrazine			28.1	9,800		
106-89-8	Epichlorohydrin (l-Chloro-2,3-epoxypropane)			28.1	9,800		
106-88-7	1,2-Epoxybutane			28.1	9,800		

Attachment S-1b
Air Toxic Emissions for D-21

SECTION 112 HAZARDOUS AIR POLLUTANTS

CAS Number	Pollutant[1]	Source of Emission Factor	Emission Factor (lb/MMBtu)	Heat Input (MMBtu/hr)	Heat Input (MMBtu/yr)	Emissions (lb/hr)	Emissions (tpy)
140-88-5	Ethyl acrylate			28.1	9,800		
100-41-4	Ethylbenzene			28.1	9,800		
51-79-6	Ethyl carbamate (Urethane)			28.1	9,800		
75-00-3	Ethyl chloride (Chloroethane)			28.1	9,800		
106-93-4	Ethylene dibromide (Dibromoethane)			28.1	9,800		
107-06-2	Ethylene dichloride (1,2-Dichloroethane)			28.1	9,800		
107-21-1	Ethylene glycol			28.1	9,800		
151-56-4	Ethyleneimine (Aziridine)			28.1	9,800		
75-21-8	Ethylene oxide			28.1	9,800		
96-45-7	Ethylene thiourea			28.1	9,800		
75-34-3	Ethylidene dichloride (1,1-Dichloroethane)			28.1	9,800		
50-00-0	Formaldehyde	AP-42, Section 3.4, Table 3.4-3	7.89E-05	28.1	9,800	2.22E-03	3.87E-04
76-44-8	Heptachlor			28.1	9,800		
118-74-1	Hexachlorobenzene			28.1	9,800		
87-68-3	Hexachlorobutadiene			28.1	9,800		
77-47-4	Hexachlorocyclopentadiene			28.1	9,800		
67-72-1	Hexachloroethane			28.1	9,800		
822-06-0	Hexamethylene diisocyanate			28.1	9,800		
680-31-9	Hexamethylphosphoramide			28.1	9,800		
110-54-3	Hexane			28.1	9,800		
302-01-2	Hydrazine			28.1	9,800		
7647-01-0	Hydrochloric acid (Hydrogen chloride [gas only])			28.1	9,800		
7664-39-3	Hydrogen fluoride (Hydrofluoric acid)			28.1	9,800		
123-31-9	Hydroquinone			28.1	9,800		
78-59-1	Isophorone			28.1	9,800		
58-89-9	Lindane (all isomers)			28.1	9,800		
108-31-6	Maleic anhydride			28.1	9,800		
67-56-1	Methanol			28.1	9,800		
72-43-5	Methoxychlor			28.1	9,800		
74-83-9	Methyl bromide (Bromomethane)			28.1	9,800		
74-87-3	Methyl chloride(Chloromethane)			28.1	9,800		
71-55-6	Methyl chloroform(1,1,1-Trichloroethane)			28.1	9,800		
78-93-3	Methyl ethyl ketone (2-Butanone) (Removed 12/19/05, See 70FR75047)			28.1	9,800		
60-34-4	Methylhydrazine			28.1	9,800		
74-88-4	Methyl iodide (Iodomethane)			28.1	9,800		
108-10-1	Methyl isobutyl ketone(Hexone)			28.1	9,800		
624-83-9	Methyl isocyanate			28.1	9,800		
80-62-6	Methyl methacrylate			28.1	9,800		
1634-04-4	Methyl tert-butyl ether			28.1	9,800		
101-14-4	4,4'-Methylenebis(2-chloroaniline)			28.1	9,800		
75-09-2	Methylene chloride(Dichloromethane)			28.1	9,800		
101-68-8	4,4'-Methylenediphenyl diisocyanate(MDI)			28.1	9,800		
101-77-9	4,4'-Methylenedianiline			28.1	9,800		
91-20-3	Naphthalene	AP-42, Section 3.4, Table 3.4-4	1.30E-04	28.1	9,800	3.65E-03	6.37E-04
98-95-3	Nitrobenzene			28.1	9,800		
92-93-3	4-Nitrobiphenyl			28.1	9,800		
100-02-7	4-Nitrophenol			28.1	9,800		
79-46-9	2-Nitropropane			28.1	9,800		
684-93-5	N-Nitroso-N-methylurea			28.1	9,800		
62-75-9	N-Nitrosodimethylamine			28.1	9,800		
59-89-2	N-Nitrosomorpholine			28.1	9,800		
56-38-2	Parathion			28.1	9,800		
82-68-8	Pentachloronitrobenzene(Quintobenzene)			28.1	9,800		
87-86-5	Pentachlorophenol			28.1	9,800		
108-95-2	Phenol			28.1	9,800		
106-50-3	p-Phenylenediamine			28.1	9,800		
75-44-5	Phosgene			28.1	9,800		
7803-51-2	Phosphine			28.1	9,800		
7723-14-0	Phosphorus			28.1	9,800		
85-44-9	Phthalic anhydride			28.1	9,800		
1336-36-3	Polychlorinated biphenyls(Aroclors)			28.1	9,800		
1120-71-4	1,3-Propane sultone			28.1	9,800		
57-57-8	beta-Propiolactone			28.1	9,800		
123-38-6	Propionaldehyde			28.1	9,800		
114-26-1	Propoxur (Baygon)			28.1	9,800		
78-87-5	Propylene dichloride (1,2-Dichloropropane)			28.1	9,800		
75-56-9	Propylene oxide			28.1	9,800		
75-55-8	1,2-Propylenimine (2-Methylaziridine)			28.1	9,800		
91-22-5	Quinoline			28.1	9,800		
106-51-4	Quinone(p-Benzoquinone)			28.1	9,800		
100-42-5	Styrene			28.1	9,800		
96-09-3	Styrene oxide			28.1	9,800		
1746-01-6	2,3,7,8-Tetrachlorodibenzo-p-dioxin			28.1	9,800		
79-34-5	1,1,2,2-Tetrachloroethane			28.1	9,800		
127-18-4	Tetrachloroethylene(Perchloroethylene)			28.1	9,800		

Attachment S-1b
Air Toxic Emissions for D-21

SECTION 112 HAZARDOUS AIR POLLUTANTS

CAS Number	Pollutant[1]	Source of Emission Factor	Emission Factor (lb/MMBtu)	Heat Input (MMBtu/hr)	Heat Input (MMBtu/yr)	Emissions (lb/hr)	Emissions (tpy)
7550-45-0	Titanium tetrachloride			28.1	9,800		
108-88-3	Toluene	AP-42, Section 3.4, Table 3.4-3	2.81E-04	28.1	9,800	7.90E-03	1.38E-03
95-80-7	Toluene-2,4-diamine			28.1	9,800		
584-84-9	2,4-Toluene diisocyanate			28.1	9,800		
95-53-4	o-Toluidine			28.1	9,800		
8001-35-2	Toxaphene (chlorinated camphene)			28.1	9,800		
120-82-1	1,2,4-Trichlorobenzene			28.1	9,800		
79-00-5	1,1,2-Trichloroethane			28.1	9,800		
79-01-6	Trichloroethylene			28.1	9,800		
95-95-4	2,4,5-Trichlorophenol			28.1	9,800		
88-06-2	2,4,6-Trichlorophenol			28.1	9,800		
121-44-8	Triethylamine			28.1	9,800		
1582-09-8	Trifluralin			28.1	9,800		
540-84-1	2,2,4-Trimethylpentane			28.1	9,800		
108-05-4	Vinyl acetate			28.1	9,800		
593-60-2	Vinyl bromide			28.1	9,800		
75-01-4	Vinyl chloride			28.1	9,800		
75-35-4	Vinylidene chloride (1,1-Dichloroethylene)			28.1	9,800		
1330-20-7	Xylene (mixed isomers)	AP-42, Section 3.4, Table 3.4-3	1.93E-04	28.1	9,800	5.42E-03	9.46E-04
95-47-6	o-Xylene			28.1	9,800		
108-38-3	m-Xylene			28.1	9,800		
106-42-3	p-Xylene			28.1	9,800		
	Antimony Compounds			28.1	9,800		
	Arsenic Compounds (inorganic including arsine)	AP-42, Section 3.1, Table 3.1-5	1.10E-05	28.1	9,800	3.09E-04	5.39E-05
	Beryllium Compounds	AP-42, Section 3.1, Table 3.1-5	3.10E-07	28.1	9,800	8.71E-06	1.52E-06
	Cadmium Compounds	AP-42, Section 3.1, Table 3.1-5	4.80E-06	28.1	9,800	1.35E-04	2.35E-05
	Chromium Compounds	AP-42, Section 3.1, Table 3.1-5	1.10E-05	28.1	9,800	3.09E-04	5.39E-05
	Cobalt Compounds			28.1	9,800		
	Coke Oven Emissions			28.1	9,800		
	Cyanide Compounds[2]			28.1	9,800		
	Glycol ethers[3]			28.1	9,800		
	Lead Compounds	AP-42, Section 3.1, Table 3.1-5	1.40E-05	28.1	9,800	3.93E-04	6.86E-05
	Manganese Compounds	AP-42, Section 3.1, Table 3.1-5	7.90E-04	28.1	9,800	2.22E-02	3.87E-03
	Mercury Compounds	AP-42, Section 3.1, Table 3.1-5	1.20E-06	28.1	9,800	3.37E-05	5.88E-06
	Fine mineral fibers[4]			28.1	9,800		
	Nickel Compounds	AP-42, Section 3.1, Table 3.1-5	4.60E-06	28.1	9,800	1.29E-04	2.25E-05
	Polycyclic Organic Matter[5]	AP-42, Section 3.4, Table 3.4-4	2.12E-04	28.1	9,800	5.96E-03	1.04E-03
	Radionuclides (including radon)[6]			28.1	9,800		
	Selenium Compounds	AP-42, Section 3.1, Table 3.1-5	2.50E-05	28.1	9,800	7.03E-04	1.23E-04
	Total					**7.26E-02**	**1.27E-02**

Notes:

1. For all listings above which contain the word "compounds" and for glycol ethers, the following applies: Unless otherwise specified, these listings are defined as including any unique chemical substance that contains the named chemical (i.e., antimony, arsenic, etc.) as part of that chemical's infrastructure.
2. X'CN where X = H' or any other group where a formal dissociation may occur. For example, KCN or Ca(CN)2
3. Includes mono- and di- ethers of ethylene glycol, diethylene glycol, and triethylene glycol, R-(OCH2CH2)n-OR'

where: n = 1, 2, or 3

R = alkyl or aryl groups

R' = R, H, or groups which, when removed, yield glycol ethers with the structure: R-(OCH2CH)n-OH. Polymers are excluded from the glycol category.

4. Includes mineral fiber emissions from facilities manufacturing or processing glass, rock, or slag fibers (or other mineral derived fibers) of average diameter 1 micrometer or less
5. Includes organic compounds with more than one benzene ring, and which have a boiling point greater than or equal to 100°C
6. A type of atom which spontaneously undergoes radioactive decay

Attachment S-1b
Air Toxic Emissions for D-22 or D-23

SECTION 112 HAZARDOUS AIR POLLUTANTS

CAS Number	Pollutant[1]	Source of Emission Factor	Emission Factor (lb/MMBtu)	Heat Input (MMBtu/hr)	Emissions (lb/hr)	Emissions (tpy)
75-07-0	Acetaldehyde	AP-42, Section 3.4, Table 3.4-3	2.52E-05	28.1	7.08E-04	3.10E-03
60-35-5	Acetamide			28.1		
75-05-8	Acetonitrile			28.1		
98-86-2	Acetophenone			28.1		
53-96-3	2-Acetylaminofluorene			28.1		
107-02-8	Acrolein	AP-42, Section 3.4, Table 3.4-3	7.88E-06	28.1	2.21E-04	9.70E-04
79-06-1	Acrylamide			28.1		
79-10-7	Acrylic acid			28.1		
107-13-1	Acrylonitrile			28.1		
107-05-1	Allyl chloride			28.1		
92-67-1	4-Aminobiphenyl			28.1		
62-53-3	Aniline			28.1		
90-04-0	o-Anisidine			28.1		
1332-21-4	Asbestos			28.1		
71-43-2	Benzene (including benzene from gasoline)	AP-42, Section 3.4, Table 3.4-3	7.76E-04	28.1	2.18E-02	9.55E-02
92-87-5	Benzidine			28.1		
98-07-7	Benzotrichloride			28.1		
100-44-7	Benzyl chloride			28.1		
92-52-4	Biphenyl			28.1		
117-81-7	Bis(2-ethylhexyl)phthalate (DEHP)			28.1		
542-88-1	Bis(chloromethyl) ether			28.1		
75-25-2	Bromoform			28.1		
106-99-0	1,3-Butadiene	AP-42, Section 3.1, Table 3.1-4	1.60E-05	28.1	4.50E-04	1.97E-03
156-62-7	Calcium cyanamide			28.1		
105-60-2	Caprolactam (Removed 06/18/96. See 61FR30816)			28.1		
133-06-2	Captan			28.1		
63-25-2	Carbaryl			28.1		
75-15-0	Carbon disulfide			28.1		
56-23-5	Carbon tetrachloride			28.1		
463-58-1	Carbonyl sulfide			28.1		
120-80-9	Catechol			28.1		
133-90-4	Chloramben			28.1		
57-74-9	Chlordane			28.1		
7782-50-5	Chlorine			28.1		
79-11-8	Chloroacetic acid			28.1		
532-27-4	2-Chloroacetophenone			28.1		
108-90-7	Chlorobenzene			28.1		
510-15-6	Chlorobenzilate			28.1		
67-66-3	Chloroform			28.1		
107-30-2	Chloromethyl methyl ether			28.1		
126-99-8	Chloroprene			28.1		
1319-77-3	Cresol/Cresylic acid(mixed isomers)			28.1		
95-48-7	o-Cresol			28.1		
108-39-4	m-Cresol			28.1		
106-44-5	p-Cresol			28.1		
98-82-8	Cumene			28.1		
94-75-7	2,4-D salts and esters			28.1		
72-55-9	DDE(1,1-dichloro-2,2-bis(p-chlorophenyl) ethylene)			28.1		
334-88-3	Diazomethane			28.1		
132-64-9	Dibenzofuran			28.1		
96-12-8	1,2-Dibromo-3-chloropropane			28.1		
84-74-2	Dibutyl phthalate			28.1		
106-46-7	1,4-Dichlorobenzene			28.1		
91-94-1	Dichlorobenzidine			28.1		
111-44-4	Dichloroethyl ether(Bis[2-chloroethyl]ether)			28.1		
542-75-6	1,3-Dichloropropene			28.1		
62-73-7	Dichlorvos			28.1		
111-42-2	Diethanolamine			28.1		
64-67-5	Diethyl sulfate			28.1		
119-90-4	3,3'-Dimethoxybenzidine			28.1		
60-11-7	4-Dimethylaminoazobenzene			28.1		
121-69-7	N,N-Dimethylaniline			28.1		
119-93-7	3,3'-Dimethylbenzidine			28.1		
79-44-7	Dimethylcarbamoyl chloride			28.1		
68-12-2	N,N-Dimethylformamide			28.1		
57-14-7	1,1-Dimethylhydrazine			28.1		
131-11-3	Dimethyl phthalate			28.1		
77-78-1	Dimethyl sulfate			28.1		
534-52-1	4,6-Dinitro-o-cresol (including salts)			28.1		
51-28-5	2,4-Dinitrophenol			28.1		
121-14-2	2,4-Dinitrotoluene			28.1		
123-91-1	1,4-Dioxane (1,4-Diethyleneoxide)			28.1		
122-66-7	1,2-Diphenylhydrazine			28.1		
106-89-8	Epichlorohydrin (l-Chloro-2,3-epoxypropane)			28.1		
106-88-7	1,2-Epoxybutane			28.1		
140-88-5	Ethyl acrylate			28.1		
100-41-4	Ethylbenzene			28.1		
51-79-6	Ethyl carbamate (Urethane)			28.1		

Attachment S-1b
Air Toxic Emissions for D-22 or D-23

SECTION 112 HAZARDOUS AIR POLLUTANTS

CAS Number	Pollutant[1]	Source of Emission Factor	Emission Factor (lb/MMBtu)	Heat Input (MMBtu/hr)	Emissions (lb/hr)	Emissions (tpy)
75-00-3	Ethyl chloride (Chloroethane)			28.1		
106-93-4	Ethylene dibromide (Dibromoethane)			28.1		
107-06-2	Ethylene dichloride (1,2-Dichloroethane)			28.1		
107-21-1	Ethylene glycol			28.1		
151-56-4	Ethyleneimine (Aziridine)			28.1		
75-21-8	Ethylene oxide			28.1		
96-45-7	Ethylene thiourea			28.1		
75-34-3	Ethylidene dichloride (1,1-Dichloroethane)			28.1		
50-00-0	Formaldehyde	AP-42, Section 3.4, Table 3.4-3	7.89E-05	28.1	2.22E-03	9.71E-03
76-44-8	Heptachlor			28.1		
118-74-1	Hexachlorobenzene			28.1		
87-68-3	Hexachlorobutadiene			28.1		
77-47-4	Hexachlorocyclopentadiene			28.1		
67-72-1	Hexachloroethane			28.1		
822-06-0	Hexamethylene diisocyanate			28.1		
680-31-9	Hexamethylphosphoramide			28.1		
110-54-3	Hexane			28.1		
302-01-2	Hydrazine			28.1		
7647-01-0	Hydrochloric acid (Hydrogen chloride [gas only])			28.1		
7664-39-3	Hydrogen fluoride (Hydrofluoric acid)			28.1		
123-31-9	Hydroquinone			28.1		
78-59-1	Isophorone			28.1		
58-89-9	Lindane (all isomers)			28.1		
108-31-6	Maleic anhydride			28.1		
67-56-1	Methanol			28.1		
72-43-5	Methoxychlor			28.1		
74-83-9	Methyl bromide (Bromomethane)			28.1		
74-87-3	Methyl chloride(Chloromethane)			28.1		
71-55-6	Methyl chloroform(1,1,1-Trichloroethane)			28.1		
78-93-3	Methyl ethyl ketone (2-Butanone) (Removed 12/19/05, See 70FR75047)			28.1		
60-34-4	Methylhydrazine			28.1		
74-88-4	Methyl iodide (Iodomethane)			28.1		
108-10-1	Methyl isobutyl ketone(Hexone)			28.1		
624-83-9	Methyl isocyanate			28.1		
80-62-6	Methyl methacrylate			28.1		
1634-04-4	Methyl tert-butyl ether			28.1		
101-14-4	4,4'-Methylenebis(2-chloroaniline)			28.1		
75-09-2	Methylene chloride(Dichloromethane)			28.1		
101-68-8	4,4'-Methylenediphenyl diisocyanate(MDI)			28.1		
101-77-9	4,4'-Methylenedianiline			28.1		
91-20-3	Naphthalene	AP-42, Section 3.4, Table 3.4-4	1.30E-04	28.1	3.65E-03	1.60E-02
98-95-3	Nitrobenzene			28.1		
92-93-3	4-Nitrobiphenyl			28.1		
100-02-7	4-Nitrophenol			28.1		
79-46-9	2-Nitropropane			28.1		
684-93-5	N-Nitroso-N-methylurea			28.1		
62-75-9	N-Nitrosodimethylamine			28.1		
59-89-2	N-Nitrosomorpholine			28.1		
56-38-2	Parathion			28.1		
82-68-8	Pentachloronitrobenzene(Quintobenzene)			28.1		
87-86-5	Pentachlorophenol			28.1		
108-95-2	Phenol			28.1		
106-50-3	p-Phenylenediamine			28.1		
75-44-5	Phosgene			28.1		
7803-51-2	Phosphine			28.1		
7723-14-0	Phosphorus			28.1		
85-44-9	Phthalic anhydride			28.1		
1336-36-3	Polychlorinated biphenyls(Aroclors)			28.1		
1120-71-4	1,3-Propane sultone			28.1		
57-57-8	beta-Propiolactone			28.1		
123-38-6	Propionaldehyde			28.1		
114-26-1	Propoxur (Baygon)			28.1		
78-87-5	Propylene dichloride (1,2-Dichloropropane)			28.1		
75-56-9	Propylene oxide			28.1		
75-55-8	1,2-Propylenimine (2-Methylaziridine)			28.1		
91-22-5	Quinoline			28.1		
106-51-4	Quinone(p-Benzoquinone)			28.1		
100-42-5	Styrene			28.1		
96-09-3	Styrene oxide			28.1		
1746-01-6	2,3,7,8-Tetrachlorodibenzo-p-dioxin			28.1		
79-34-5	1,1,2,2-Tetrachloroethane			28.1		
127-18-4	Tetrachloroethylene(Perchloroethylene)			28.1		
7550-45-0	Titanium tetrachloride			28.1		
108-88-3	Toluene	AP-42, Section 3.4, Table 3.4-3	2.81E-04	28.1	7.90E-03	3.46E-02
95-80-7	Toluene-2,4-diamine			28.1		
584-84-9	2,4-Toluene diisocyanate			28.1		
95-53-4	o-Toluidine			28.1		
8001-35-2	Toxaphene (chlorinated camphene)			28.1		

Attachment S-1b
Air Toxic Emissions for D-22 or D-23

SECTION 112 HAZARDOUS AIR POLLUTANTS

CAS Number	Pollutant[1]	Source of Emission Factor	Emission Factor (lb/MMBtu)	Heat Input (MMBtu/hr)	Emissions (lb/hr)	Emissions (tpy)
120-82-1	1,2,4-Trichlorobenzene			28.1		
79-00-5	1,1,2-Trichloroethane			28.1		
79-01-6	Trichloroethylene			28.1		
95-95-4	2,4,5-Trichlorophenol			28.1		
88-06-2	2,4,6-Trichlorophenol			28.1		
121-44-8	Triethylamine			28.1		
1582-09-8	Trifluralin			28.1		
540-84-1	2,2,4-Trimethylpentane			28.1		
108-05-4	Vinyl acetate			28.1		
593-60-2	Vinyl bromide			28.1		
75-01-4	Vinyl chloride			28.1		
75-35-4	Vinylidene chloride (1,1-Dichloroethylene)			28.1		
1330-20-7	Xylene (mixed isomers)	AP-42, Section 3.4, Table 3.4-3	1.93E-04	28.1	5.42E-03	2.38E-02
95-47-6	o-Xylene			28.1		
108-38-3	m-Xylene			28.1		
106-42-3	p-Xylene			28.1		
	Antimony Compounds			28.1		
	Arsenic Compounds (inorganic including arsine)	AP-42, Section 3.1, Table 3.1-5	1.10E-05	28.1	3.09E-04	1.35E-03
	Beryllium Compounds	AP-42, Section 3.1, Table 3.1-5	3.10E-07	28.1	8.71E-06	3.82E-05
	Cadmium Compounds	AP-42, Section 3.1, Table 3.1-5	4.80E-06	28.1	1.35E-04	5.91E-04
	Chromium Compounds	AP-42, Section 3.1, Table 3.1-5	1.10E-05	28.1	3.09E-04	1.35E-03
	Cobalt Compounds			28.1		
	Coke Oven Emissions			28.1		
	Cyanide Compounds[2]			28.1		
	Glycol ethers[3]			28.1		
	Lead Compounds	AP-42, Section 3.1, Table 3.1-5	1.40E-05	28.1	3.93E-04	1.72E-03
	Manganese Compounds	AP-42, Section 3.1, Table 3.1-5	7.90E-04	28.1	2.22E-02	9.72E-02
	Mercury Compounds	AP-42, Section 3.1, Table 3.1-5	1.20E-06	28.1	3.37E-05	1.48E-04
	Fine mineral fibers[4]			28.1		
	Nickel Compounds	AP-42, Section 3.1, Table 3.1-5	4.60E-06	28.1	1.29E-04	5.66E-04
	Polycyclic Organic Matter[5]	AP-42, Section 3.4, Table 3.4-4	2.12E-04	28.1	5.96E-03	2.61E-02
	Radionuclides (including radon)[6]			28.1		
	Selenium Compounds	AP-42, Section 3.1, Table 3.1-5	2.50E-05	28.1	7.03E-04	3.08E-03
	Total				**7.25E-02**	**3.18E-01**

Notes:

1 For all listings above which contain the word "compounds" and for glycol ethers, the following applies: Unless otherwise specified, these listings are defined as including any unique chemical substance that contains the named chemical (i.e., antimony, arsenic, etc.) as part of that chemical's infrastructure

2 X'CN where X = H' or any other group where a formal dissociation may occur. For example, KCN or Ca(CN)2

3 Includes mono- and di- ethers of ethylene glycol, diethylene glycol, and triethylene glycol, R-(OCH2CH2)n-OR'

where: n = 1, 2, or 3

R = alkyl or aryl groups

R' = R, H, or groups which, when removed, yield glycol ethers with the structure R-(OCH2CH)n-OH. Polymers are excluded from the glycol category

4 Includes mineral fiber emissions from facilities manufacturing or processing glass, rock, or slag fibers (or other mineral derived fibers) of average diameter 1 micrometer or less.

5 Includes organic compounds with more than one benzene ring, and which have a boiling point greater than or equal to 100°C

6 A type of atom which spontaneously undergoes radioactive decay

Attachment S-1b
Air Toxic Emissions for BS-1

SECTION 112 HAZARDOUS AIR POLLUTANTS

CAS Number	Pollutant[1]	Source of Emission Factor	Emission Factor (lb/MMBtu)	Heat Input (MMBtu/hr)	Emissions (lb/hr)	Emissions (tpy)
75-07-0	Acetaldehyde	AP-42, Section 3.4, Table 3.4-3	2.52E-05	5.57	1.40E-04	2.11E-05
60-35-5	Acetamide			5.57		
75-05-8	Acetonitrile			5.57		
98-86-2	Acetophenone			5.57		
53-96-3	2-Acetylaminofluorene			5.57		
107-02-8	Acrolein	AP-42, Section 3.4, Table 3.4-3	7.88E-06	5.57	4.39E-05	6.58E-06
79-06-1	Acrylamide			5.57		
79-10-7	Acrylic acid			5.57		
107-13-1	Acrylonitrile			5.57		
107-05-1	Allyl chloride			5.57		
92-67-1	4-Aminobiphenyl			5.57		
62-53-3	Aniline			5.57		
90-04-0	o-Anisidine			5.57		
1332-21-4	Asbestos			5.57		
71-43-2	Benzene (including benzene from gasoline)	AP-42, Section 3.4, Table 3.4-3	7.76E-04	5.57	4.32E-03	6.48E-04
92-87-5	Benzidine			5.57		
98-07-7	Benzotrichloride			5.57		
100-44-7	Benzyl chloride			5.57		
92-52-4	Biphenyl			5.57		
117-81-7	Bis(2-ethylhexyl)phthalate (DEHP)			5.57		
542-88-1	Bis(chloromethyl) ether			5.57		
75-25-2	Bromoform			5.57		
106-99-0	1,3-Butadiene	AP-42, Section 3.1, Table 3.1-4	1.60E-05	5.57	8.91E-05	1.34E-05
156-62-7	Calcium cyanamide			5.57		
105-60-2	Caprolactam (Removed 06/18/96, See 61FR30816)			5.57		
133-06-2	Captan			5.57		
63-25-2	Carbaryl			5.57		
75-15-0	Carbon disulfide			5.57		
56-23-5	Carbon tetrachloride			5.57		
463-58-1	Carbonyl sulfide			5.57		
120-80-9	Catechol			5.57		
133-90-4	Chloramben			5.57		
57-74-9	Chlordane			5.57		
7782-50-5	Chlorine			5.57		
79-11-8	Chloroacetic acid			5.57		
532-27-4	2-Chloroacetophenone			5.57		
108-90-7	Chlorobenzene			5.57		
510-15-6	Chlorobenzilate			5.57		
67-66-3	Chloroform			5.57		
107-30-2	Chloromethyl methyl ether			5.57		
126-99-8	Chloroprene			5.57		
1319-77-3	Cresol/Cresylic acid(mixed isomers)			5.57		
95-48-7	o-Cresol			5.57		
108-39-4	m-Cresol			5.57		
106-44-5	p-Cresol			5.57		
98-82-8	Cumene			5.57		
94-75-7	2,4-D salts and esters			5.57		
72-55-9	DDE(1,1-dichloro-2,2-bis(p-chlorophenyl) ethylene)			5.57		
334-88-3	Diazomethane			5.57		
132-64-9	Dibenzofuran			5.57		
96-12-8	1,2-Dibromo-3-chloropropane			5.57		
84-74-2	Dibutyl phthalate			5.57		
106-46-7	1,4-Dichlorobenzene			5.57		
91-94-1	Dichlorobenzidine			5.57		
111-44-4	Dichloroethyl ether(Bis[2-chloroethyl]ether)			5.57		
542-75-6	1,3-Dichloropropene			5.57		
62-73-7	Dichlorvos			5.57		
111-42-2	Diethanolamine			5.57		
64-67-5	Diethyl sulfate			5.57		
119-90-4	3,3'-Dimethoxybenzidine			5.57		
60-11-7	4-Dimethylaminoazobenzene			5.57		
121-69-7	N,N-Dimethylaniline			5.57		
119-93-7	3,3'-Dimethylbenzidine			5.57		
79-44-7	Dimethylcarbamoyl chloride			5.57		
68-12-2	N,N-Dimethylformamide			5.57		
57-14-7	1,1-Dimethylhydrazine			5.57		
131-11-3	Dimethyl phthalate			5.57		
77-78-1	Dimethyl sulfate			5.57		
534-52-1	4,6-Dinitro-o-cresol (including salts)			5.57		
51-28-5	2,4-Dinitrophenol			5.57		
121-14-2	2,4-Dinitrotoluene			5.57		
123-91-1	1,4-Dioxane (1,4-Diethyleneoxide)			5.57		
122-66-7	1,2-Diphenylhydrazine			5.57		
106-89-8	Epichlorohydrin (l-Chloro-2,3-epoxypropane)			5.57		
106-88-7	1,2-Epoxybutane			5.57		

Attachment S-1b
Air Toxic Emissions for BS-1

SECTION 112 HAZARDOUS AIR POLLUTANTS

CAS Number	Pollutant[1]	Source of Emission Factor	Emission Factor (lb/MMBtu)	Heat Input (MMBtu/hr)	Emissions (lb/hr)	Emissions (tpy)
140-88-5	Ethyl acrylate			5.57		
100-41-4	Ethylbenzene			5.57		
51-79-6	Ethyl carbamate (Urethane)			5.57		
75-00-3	Ethyl chloride (Chloroethane)			5.57		
106-93-4	Ethylene dibromide (Dibromoethane)			5.57		
107-06-2	Ethylene dichloride (1,2-Dichloroethane)			5.57		
107-21-1	Ethylene glycol			5.57		
151-56-4	Ethyleneimine (Aziridine)			5.57		
75-21-8	Ethylene oxide			5.57		
96-45-7	Ethylene thiourea			5.57		
75-34-3	Ethylidene dichloride (1,1-Dichloroethane)			5.57		
50-00-0	Formaldehyde	AP-42, Section 3.4, Table 3.4-3	7.89E-05	5.57	4.39E-04	6.59E-05
76-44-8	Heptachlor			5.57		
118-74-1	Hexachlorobenzene			5.57		
87-68-3	Hexachlorobutadiene			5.57		
77-47-4	Hexachlorocyclopentadiene			5.57		
67-72-1	Hexachloroethane			5.57		
822-06-0	Hexamethylene diisocyanate			5.57		
680-31-9	Hexamethylphosphoramide			5.57		
110-54-3	Hexane			5.57		
302-01-2	Hydrazine			5.57		
7647-01-0	Hydrochloric acid (Hydrogen chloride [gas only])			5.57		
7664-39-3	Hydrogen fluoride (Hydrofluoric acid)			5.57		
123-31-9	Hydroquinone			5.57		
78-59-1	Isophorone			5.57		
58-89-9	Lindane (all isomers)			5.57		
108-31-6	Maleic anhydride			5.57		
67-56-1	Methanol			5.57		
72-43-5	Methoxychlor			5.57		
74-83-9	Methyl bromide (Bromomethane)			5.57		
74-87-3	Methyl chloride(Chloromethane)			5.57		
71-55-6	Methyl chloroform(1,1,1-Trichloroethane)			5.57		
78-93-3	Methyl ethyl ketone (2-Butanone) (Removed 12/19/05, See 70FR75047)			5.57		
60-34-4	Methylhydrazine			5.57		
74-88-4	Methyl iodide (Iodomethane)			5.57		
108-10-1	Methyl isobutyl ketone(Hexone)			5.57		
624-83-9	Methyl isocyanate			5.57		
80-62-6	Methyl methacrylate			5.57		
1634-04-4	Methyl tert-butyl ether			5.57		
101-14-4	4,4'-Methylenebis(2-chloroaniline)			5.57		
75-09-2	Methylene chloride(Dichloromethane)			5.57		
101-68-8	4,4'-Methylenediphenyl diisocyanate(MDI)			5.57		
101-77-9	4,4'-Methylenedianiline			5.57		
91-20-3	Naphthalene	AP-42, Section 3.4, Table 3.4-4	1.30E-04	5.57	7.24E-04	1.09E-04
98-95-3	Nitrobenzene			5.57		
92-93-3	4-Nitrobiphenyl			5.57		
100-02-7	4-Nitrophenol			5.57		
79-46-9	2-Nitropropane			5.57		
684-93-5	N-Nitroso-N-methylurea			5.57		
62-75-9	N-Nitrosodimethylamine			5.57		
59-89-2	N-Nitrosomorpholine			5.57		
56-38-2	Parathion			5.57		
82-68-8	Pentachloronitrobenzene(Quintobenzene)			5.57		
87-86-5	Pentachlorophenol			5.57		
108-95-2	Phenol			5.57		
106-50-3	p-Phenylenediamine			5.57		
75-44-5	Phosgene			5.57		
7803-51-2	Phosphine			5.57		
7723-14-0	Phosphorus			5.57		
85-44-9	Phthalic anhydride			5.57		
1336-36-3	Polychlorinated biphenyls(Aroclors)			5.57		
1120-71-4	1,3-Propane sultone			5.57		
57-57-8	beta-Propiolactone			5.57		
123-38-6	Propionaldehyde			5.57		
114-26-1	Propoxur (Baygon)			5.57		
78-87-5	Propylene dichloride (1,2-Dichloropropane)			5.57		
75-56-9	Propylene oxide			5.57		
75-55-8	1,2-Propylenimine (2-Methylaziridine)			5.57		
91-22-5	Quinoline			5.57		
106-51-4	Quinone(p-Benzoquinone)			5.57		
100-42-5	Styrene			5.57		
96-09-3	Styrene oxide			5.57		
1746-01-6	2,3,7,8-Tetrachlorodibenzo-p-dioxin			5.57		
79-34-5	1,1,2,2-Tetrachloroethane			5.57		
127-18-4	Tetrachloroethylene(Perchloroethylene)			5.57		

Attachment S-1b
Air Toxic Emissions for BS-1

SECTION 112 HAZARDOUS AIR POLLUTANTS

CAS Number	Pollutant[1]	Source of Emission Factor	Emission Factor (lb/MMBtu)	Heat Input (MMBtu/hr)	Emissions (lb/hr)	Emissions (tpy)
7550-45-0	Titanium tetrachloride			5.57		
108-88-3	Toluene	AP-42, Section 3.4, Table 3.4-3	2.81E-04	5.57	1.57E-03	2.35E-04
95-80-7	Toluene-2,4-diamine			5.57		
584-84-9	2,4-Toluene diisocyanate			5.57		
95-53-4	o-Toluidine			5.57		
8001-35-2	Toxaphene (chlorinated camphene)			5.57		
120-82-1	1,2,4-Trichlorobenzene			5.57		
79-00-5	1,1,2-Trichloroethane			5.57		
79-01-6	Trichloroethylene			5.57		
95-95-4	2,4,5-Trichlorophenol			5.57		
88-06-2	2,4,6-Trichlorophenol			5.57		
121-44-8	Triethylamine			5.57		
1582-09-8	Trifluralin			5.57		
540-84-1	2,2,4-Trimethylpentane			5.57		
108-05-4	Vinyl acetate			5.57		
593-60-2	Vinyl bromide			5.57		
75-01-4	Vinyl chloride			5.57		
75-35-4	Vinylidene chloride (1,1-Dichloroethylene)			5.57		
1330-20-7	Xylene (mixed isomers)	AP-42, Section 3.4, Table 3.4-3	1.93E-04	5.57	1.08E-03	1.61E-04
95-47-6	o-Xylene			5.57		
108-38-3	m-Xylene			5.57		
106-42-3	p-Xylene			5.57		
	Antimony Compounds			5.57		
	Arsenic Compounds (inorganic including arsine)	AP-42, Section 3.1, Table 3.1-5	1.10E-05	5.57	6.13E-05	9.19E-06
	Beryllium Compounds	AP-42, Section 3.1, Table 3.1-5	3.10E-07	5.57	1.73E-06	2.59E-07
	Cadmium Compounds	AP-42, Section 3.1, Table 3.1-5	4.80E-06	5.57	2.67E-05	4.01E-06
	Chromium Compounds	AP-42, Section 3.1, Table 3.1-5	1.10E-05	5.57	6.13E-05	9.19E-06
	Cobalt Compounds			5.57		
	Coke Oven Emissions			5.57		
	Cyanide Compounds[2]			5.57		
	Glycol ethers[3]			5.57		
	Lead Compounds	AP-42, Section 3.1, Table 3.1-5	1.40E-05	5.57	7.80E-05	1.17E-05
	Manganese Compounds	AP-42, Section 3.1, Table 3.1-5	7.90E-04	5.57	4.40E-03	6.60E-04
	Mercury Compounds	AP-42, Section 3.1, Table 3.1-5	1.20E-06	5.57	6.68E-06	1.00E-06
	Fine mineral fibers[4]			5.57		
	Nickel Compounds	AP-42, Section 3.1, Table 3.1-5	4.60E-06	5.57	2.56E-05	3.84E-06
	Polycyclic Organic Matter[5]	AP-42, Section 3.4, Table 3.4-4	2.12E-04	5.57	1.18E-03	1.77E-04
	Radionuclides (including radon)[6]			5.57		
	Selenium Compounds	AP-42, Section 3.1, Table 3.1-5	2.50E-05	5.57	1.39E-04	2.09E-05
	Total				1.44E-02	2.16E-03

Notes

1 For all listings above which contain the word "compounds" and for glycol ethers, the following applies: Unless otherwise specified, these listings are defined as including any unique chemical substance that contains the named chemical (i.e., antimony, arsenic, etc.) as part of that chemical's infrastructure

2 X'CN where X = H' or any other group where a formal dissociation may occur. For example, KCN or Ca(CN)2

3 Includes mono- and di- ethers of ethylene glycol, diethylene glycol, and triethylene glycol, R-(OCH2CH2)n-OR'

where n = 1, 2, or 3

R = alkyl or aryl groups

R' = R, H, or groups which, when removed, yield glycol ethers with the structure: R-(OCH2CH)n-OH. Polymers are excluded from the glycol category

4 Includes mineral fiber emissions from facilities manufacturing or processing glass, rock, or slag fibers (or other mineral derived fibers) of average diameter 1 micrometer or less

5 Includes organic compounds with more than one benzene ring, and which have a boiling point greater than or equal to 100°C.

6 A type of atom which spontaneously undergoes radioactive decay

Attachment S-1b
Total Air Toxic Emissions

SECTION 112 HAZARDOUS AIR POLLUTANTS

CAS Number	Pollutant[1]	CT-4 Emissions (tpy)	CT-5 Emissions (tpy)	CT-2 Emissions (tpy)	D-21 Emissions (tpy)	D-22 Emissions (tpy)	D-23 Emissions (tpy)	BS-1 Emissions (tpy)	Total Emissions (tpy)
75-07-0	Acetaldehyde	3.04E-02	3.04E-02	2.17E-02	1.23E-04	3.10E-03	3.10E-03	2.11E-05	8.88E-02
60-35-5	Acetamide								
75-05-8	Acetonitrile								
98-86-2	Acetophenone								
53-96-3	2-Acetylaminofluorene								
107-02-8	Acrolein	9.49E-03	9.49E-03	6.79E-03	3.86E-05	9.70E-04	9.70E-04	6.58E-06	2.78E-02
79-06-1	Acrylamide								
79-10-7	Acrylic acid								
107-13-1	Acrylonitrile								
107-05-1	Allyl chloride								
92-67-1	4-Aminobiphenyl								
62-53-3	Aniline								
90-04-0	o-Anisidine								
1332-21-4	Asbestos								
71-43-2	Benzene (including benzene from gasoline)	6.61E-02	6.61E-02	4.74E-02	3.80E-03	9.55E-02	9.55E-02	6.48E-04	3.75E-01
92-87-5	Benzidine								
98-07-7	Benzotrichloride								
100-44-7	Benzyl chloride								
92-52-4	Biphenyl								
117-81-7	Bis(2-ethylhexyl)phthalate (DEHP)								
542-88-1	Bis(chloromethyl) ether								
75-25-2	Bromoform								
106-99-0	1,3-Butadiene	1.93E-02	1.93E-02	1.38E-02	7.84E-05	1.97E-03	1.97E-03	1.34E-05	5.64E-02
156-62-7	Calcium cyanamide								
105-60-2	Caprolactam (Removed 06/18/96, See 61FR30816								
133-06-2	Captan								
63-25-2	Carbaryl								
75-15-0	Carbon disulfide								
56-23-5	Carbon tetrachloride								
463-58-1	Carbonyl sulfide								
120-80-9	Catechol								
133-90-4	Chloramben								
57-74-9	Chlordane								
7782-50-5	Chlorine								
79-11-8	Chloroacetic acid								
532-27-4	2-Chloroacetophenone								
108-90-7	Chlorobenzene								
510-15-6	Chlorobenzilate								
67-66-3	Chloroform								
107-30-2	Chloromethyl methyl ether								
126-99-8	Chloroprene								
1319-77-3	Cresol/Cresylic acid(mixed isomers)								
95-48-7	o-Cresol								
108-39-4	m-Cresol								
106-44-5	p-Cresol								
98-82-8	Cumene								
94-75-7	2,4-D salts and esters								
72-55-9	DDE(1,1-dichloro-2,2-bis(p-chlorophenyl) ethylene								
334-88-3	Diazomethane								
132-64-9	Dibenzofuran								
96-12-8	1,2-Dibromo-3-chloropropane								
84-74-2	Dibutyl phthalate								
106-46-7	1,4-Dichlorobenzene								
91-94-1	Dichlorobenzidine								
111-44-4	Dichloroethyl ether(Bis[2-chloroethyl]ether)								
542-75-6	1,3-Dichloropropene								
62-73-7	Dichlorvos								
111-42-2	Diethanolamine								
64-67-5	Diethyl sulfate								
119-90-4	3,3'-Dimethoxybenzidine								
60-11-7	4-Dimethylaminoazobenzene								
121-69-7	N,N-Dimethylaniline								
119-93-7	3,3'-Dimethylbenzidine								
79-44-7	Dimethylcarbamoyl chloride								
68-12-2	N,N-Dimethylformamide								
57-14-7	1,1-Dimethylhydrazine								
131-11-3	Dimethyl phthalate								
77-78-1	Dimethyl sulfate								
534-52-1	4,6-Dinitro-o-cresol (including salts)								
51-28-5	2,4-Dinitrophenol								
121-14-2	2,4-Dinitrotoluene								
123-91-1	1,4-Dioxane (1,4-Diethyleneoxide)								
122-66-7	1,2-Diphenylhydrazine								
106-89-8	Epichlorohydrin (l-Chloro-2,3-epoxypropane)								
106-88-7	1,2-Epoxybutane								
140-88-5	Ethyl acrylate								
100-41-4	Ethylbenzene								
51-79-6	Ethyl carbamate (Urethane)								

Attachment S-1b
Total Air Toxic Emissions

SECTION 112 HAZARDOUS AIR POLLUTANTS

CAS Number	Pollutant[1]	CT-4 Emissions (tpy)	CT-5 Emissions (tpy)	CT-2 Emissions (tpy)	D-21 Emissions (tpy)	D-22 Emissions (tpy)	D-23 Emissions (tpy)	BS-1 Emissions (tpy)	Total Emissions (tpy)
75-00-3	Ethyl chloride (Chloroethane)								
106-93-4	Ethylene dibromide (Dibromoethane)								
107-06-2	Ethylene dichloride (1,2-Dichloroethane)								
107-21-1	Ethylene glycol								
151-56-4	Ethyleneimine (Aziridine)								
75-21-8	Ethylene oxide								
96-45-7	Ethylene thiourea								
75-34-3	Ethylidene dichloride (1,1-Dichloroethane)								
50-00-0	Formaldehyde	3.37E-01	3.37E-01	2.41E-01	3.87E-04	9.71E-03	9.71E-03	6.59E-05	9.35E-01
76-44-8	Heptachlor								
118-74-1	Hexachlorobenzene								
87-68-3	Hexachlorobutadiene								
77-47-4	Hexachlorocyclopentadiene								
67-72-1	Hexachloroethane								
822-06-0	Hexamethylene diisocyanate								
680-31-9	Hexamethylphosphoramide								
110-54-3	Hexane								
302-01-2	Hydrazine								
7647-01-0	Hydrochloric acid (Hydrogen chloride [gas only])								
7664-39-3	Hydrogen fluoride (Hydrofluoric acid)								
123-31-9	Hydroquinone								
78-59-1	Isophorone								
58-89-9	Lindane (all isomers)								
108-31-6	Maleic anhydride								
67-56-1	Methanol								
72-43-5	Methoxychlor								
74-83-9	Methyl bromide (Bromomethane)								
74-87-3	Methyl chloride(Chloromethane)								
71-55-6	Methyl chloroform(1,1,1-Trichloroethane)								
78-93-3	Methyl ethyl ketone (2-Butanone) (Removed 12/19								
60-34-4	Methylhydrazine								
74-88-4	Methyl iodide (Iodomethane)								
108-10-1	Methyl isobutyl ketone(Hexone)								
624-83-9	Methyl isocyanate								
80-62-6	Methyl methacrylate								
1634-04-4	Methyl tert-butyl ether								
101-14-4	4,4'-Methylenebis(2-chloroaniline)								
75-09-2	Methylene chloride(Dichloromethane)								
101-68-8	4,4'-Methylenediphenyl diisocyanate(MDI)								
101-77-9	4,4'-Methylenedianiline								
91-20-3	Naphthalene	4.22E-02	4.22E-02	3.01E-02	6.37E-04	1.60E-02	1.60E-02	1.09E-04	1.47E-01
98-95-3	Nitrobenzene								
92-93-3	4-Nitrobiphenyl								
100-02-7	4-Nitrophenol								
79-46-9	2-Nitropropane								
684-93-5	N-Nitroso-N-methylurea								
62-75-9	N-Nitrosodimethylamine								
59-89-2	N-Nitrosomorpholine								
56-38-2	Parathion								
82-68-8	Pentachloronitrobenzene(Quintobenzene)								
87-86-5	Pentachlorophenol								
108-95-2	Phenol								
106-50-3	p-Phenylenediamine								
75-44-5	Phosgene								
7803-51-2	Phosphine								
7723-14-0	Phosphorus								
85-44-9	Phthalic anhydride								
1336-36-3	Polychlorinated biphenyls(Aroclors)								
1120-71-4	1,3-Propane sultone								
57-57-8	beta-Propiolactone								
123-38-6	Propionaldehyde								
114-26-1	Propoxur (Baygon)								
78-87-5	Propylene dichloride (1,2-Dichloropropane)								
75-56-9	Propylene oxide								
75-55-8	1,2-Propylenimine (2-Methylaziridine)								
91-22-5	Quinoline								
106-51-4	Quinone(p-Benzoquinone)								
100-42-5	Styrene								
96-09-3	Styrene oxide								
1746-01-6	2,3,7,8-Tetrachlorodibenzo-p-dioxin								
79-34-5	1,1,2,2-Tetrachloroethane								
127-18-4	Tetrachloroethylene(Perchloroethylene)								
7550-45-0	Titanium tetrachloride								
108-88-3	Toluene	3.38E-01	3.38E-01	2.42E-01	1.38E-03	3.46E-02	3.46E-02	2.35E-04	9.90E-01
95-80-7	Toluene-2,4-diamine								
584-84-9	2,4-Toluene diisocyanate								
95-53-4	o-Toluidine								
8001-35-2	Toxaphene (chlorinated camphene)								

Attachment S-1b
Total Air Toxic Emissions

SECTION 112 HAZARDOUS AIR POLLUTANTS

CAS Number	Pollutant[1]	CT-4 Emissions (tpy)	CT-5 Emissions (tpy)	CT-2 Emissions (tpy)	D-21 Emissions (tpy)	D-22 Emissions (tpy)	D-23 Emissions (tpy)	BS-1 Emissions (tpy)	Total Emissions (tpy)
120-82-1	1,2,4-Trichlorobenzene								
79-00-5	1,1,2-Trichloroethane								
79-01-6	Trichloroethylene								
95-95-4	2,4,5-Trichlorophenol								
88-06-2	2,4,6-Trichlorophenol								
121-44-8	Triethylamine								
1582-09-8	Trifluralin								
540-84-1	2,2,4-Trimethylpentane								
108-05-4	Vinyl acetate								
593-60-2	Vinyl bromide								
75-01-4	Vinyl chloride								
75-35-4	Vinylidene chloride (1,1-Dichloroethylene)								
1330-20-7	Xylene (mixed isomers)	2.32E-01	2.32E-01	1.66E-01	9.46E-04	2.38E-02	2.38E-02	1.61E-04	6.80E-01
95-47-6	o-Xylene								
108-38-3	m-Xylene								
106-42-3	p-Xylene								
	Antimony Compounds								
	Arsenic Compounds (inorganic including arsine)	1.33E-02	1.33E-02	9.47E-03	5.39E-05	1.35E-03	1.35E-03	9.19E-06	3.88E-02
	Beryllium Compounds	3.73E-04	3.73E-04	2.67E-04	1.52E-06	3.82E-05	3.82E-05	2.59E-07	1.09E-03
	Cadmium Compounds	5.78E-03	5.78E-03	4.13E-03	2.35E-05	5.91E-04	5.91E-04	4.01E-06	1.69E-02
	Chromium Compounds	1.32E-02	1.32E-02	9.47E-03	5.39E-05	1.35E-03	1.35E-03	9.19E-06	3.87E-02
	Cobalt Compounds								
	Coke Oven Emissions								
	Cyanide Compounds[2]								
	Glycol ethers[3]								
	Lead Compounds	1.69E-02	1.69E-02	1.21E-02	6.86E-05	1.72E-03	1.72E-03	1.17E-05	4.93E-02
	Manganese Compounds	9.52E-01	9.52E-01	6.80E-01	3.87E-03	9.72E-02	9.72E-02	6.60E-04	2.78E+00
	Mercury Compounds	1.45E-03	1.45E-03	1.03E-03	5.88E-06	1.48E-04	1.48E-04	1.00E-06	4.23E-03
	Fine mineral fibers[4]								
	Nickel Compounds	5.54E-03	5.54E-03	3.96E-03	2.25E-05	5.66E-04	5.66E-04	3.84E-06	1.62E-02
	Polycyclic Organic Matter[5]	4.82E-02	4.82E-02	3.44E-02	1.04E-03	2.61E-02	2.61E-02	1.77E-04	1.84E-01
	Radionuclides (including radon)[6]								
	Selenium Compounds	3.01E-02	3.01E-02	2.15E-02	1.23E-04	3.08E-03	3.08E-03	2.09E-05	8.80E-02
	Total	**2.16**	**2.16**	**1.55**	**0.013**	**0.32**	**0.32**	**0.0022**	**6.52**

Notes:

1 For all listings above which contain the word "compounds" and for glycol ethers, the following applies: Unless otherwise specified, these listings are defined as including any unique chemical substance that contains the named chemical (i.e., antimony, arsenic, etc.) as part of that chemical's infrastructure.

2 X'CN where X = H' or any other group where a formal dissociation may occur. For example, KCN or Ca(CN)2

3 Includes mono- and di- ethers of ethylene glycol, diethylene glycol, and triethylene glycol, R-(OCH2CH2)n-OR'

where n = 1, 2, or 3

R = alkyl or aryl groups

R' = R, H, or groups which, when removed, yield glycol ethers with the structure: R-(OCH2CH)n-OH. Polymers are excluded from the glycol category

4 Includes mineral fiber emissions from facilities manufacturing or processing glass, rock, or slag fibers (or other mineral derived fibers) of average diameter 1 micrometer or less.

5 Includes organic compounds with more than one benzene ring, and which have a boiling point greater than or equal to 100°C

6 A type of atom which spontaneously undergoes radioactive decay

Attachment S-1c
Other Regulated Pollutants

Emissions for Unit CT-4 or CT-5	Emissions (lb/hr)	Emissions (tpy)
Hydrogen Sulfide	neg.	neg.
Halons	neg.	neg.
MWC Acid Gases	neg.	neg.
MWC Metals	neg.	neg.
MWC Organics	neg.	neg.

Emissions for Unit CT-2	Emissions (lb/hr)	Emissions (tpy)
Hydrogen Sulfide	neg.	neg.
Halons	neg.	neg.
MWC Acid Gases	neg.	neg.
MWC Metals	neg.	neg.
MWC Organics	neg.	neg.

Emissions for Unit D-21	Emissions (lb/hr)	Emissions (tpy)
Hydrogen Sulfide	neg.	neg.
Halons	neg.	neg.
MWC Acid Gases	neg.	neg.
MWC Metals	neg.	neg.
MWC Organics	neg.	neg.

Emissions for Unit D-22 or D-23	Emissions (lb/hr)	Emissions (tpy)
Hydrogen Sulfide	neg.	neg.
Halons	neg.	neg.
MWC Acid Gases	neg.	neg.
MWC Metals	neg.	neg.
MWC Organics	neg.	neg.

Emissions for Unit BS-1	Emissions (lb/hr)	Emissions (tpy)
Hydrogen Sulfide	neg.	neg.
Halons	neg.	neg.
MWC Acid Gases	neg.	neg.
MWC Metals	neg.	neg.
MWC Organics	neg.	neg.

Notes:
MWC = Municipal Waste Combustor
neg. = negligible

Attachment S-1d
Pollutant Emission Rate Calculations

Sulfur Dioxide (SO_2)

Unit	Heat Input (MMBtu/hr)	AP-42 Emission Factor[1,2] (lb/MMBtu)	CSP Application Emission Factor[3] (lb/MMBtu)	CSP Application Emission Rate (lb/hr)
CT-2	198	0.404	0.556	110.0
CT-4	275	0.404	0.400	110.0
CT-5	275	0.404	0.400	110.0
D-21	28.1	0.002	0.002	0.04
D-22	28.1	0.002	0.002	0.04
D-23	28.1	0.002	0.002	0.04
BS-1	5.57	0.404	0.513	2.86

1. AP-42 emission factor for CT-4, and CT-5 from Section 3.1, dated April 2000, Table 3.1-2a, using a sulfur content of 0.4%.
2. AP-42 emission factor for D-21, D-22, and D-23 from Section 3.4, dated October 1996, Table 3.4-1, using a sulfur content of 0.0015%.
3. AP-42 emission factor for BS-1 from Section 3.4, dated October 1996, Table 3.4-1, using a sulfur content of 0.4%.

Nitrogen Oxides (NO_X)

Unit	Heat Input (MMBtu/hr)	AP-42 Emission Factor[1,2] (lb/MMBtu)	CSP Application Emission Factor (lb/MMBtu)	CSP Application Emission Rate (lb/hr)
CT-2	198	0.24	0.197	39.0
CT-4	275	0.24	0.154	42.3
CT-5	275	0.24	0.154	42.3
D-21	28.1	3.2	2.434	68.4
D-22	28.1	3.2	2.434	68.4
D-23	28.1	3.2	2.434	68.4
BS-1	5.57	3.2	2.244	12.5

1. AP-42 emission factor for CT-4, and CT-5 from Section 3.1, dated April 2000, Table 3.1-1.
2. AP-42 emission factor for D-21, D-22, D-23, and BS-1 from Section 3.4, dated October 1996, Table 3.4-1.

Attachment S-1d
Pollutant Emission Rate Calculations

Carbon Monoxide (CO)

Unit	Heat Input (MMBtu/hr)	AP-42 Emission Factor[1,2] (lb/MMBtu)	CSP Application Emission Factor (lb/MMBtu)	CSP Application Emission Rate (lb/hr)
CT-2	198	0.076	0.113	22.4
CT-4	275	0.076	0.097	26.8
CT-5	275	0.076	0.097	26.8
D-21	28.1	0.255	0.838	23.6
D-22	28.1	0.255	0.838	23.6
D-23	28.1	0.255	0.838	23.6
BS-1	5.57	0.85	0.427	2.38

1. AP-42 emission factor for CT-4, and CT-5 from Section 3.1, dated April 2000, Tabel 3.1-1.
2. AP-42 emission factor for D-21, D-22, D-23, and BS-1 from Section 3.4, dated October 1996, Table 3.4-1. A 70% reduction is applied to the CO AP-42 emission factor (uncontrolled) to account for the emission reduction required in accordance with 40 CFR Part 63 Subpart ZZZZ.

Particulate Matter (PM/PM_{10})

Unit	Heat Input (MMBtu/hr)	AP-42 Emission Factor[1,2] (lb/MMBtu)	CSP Application Emission Factor (lb/MMBtu)	CSP Application Emission Rate (lb/hr)
CT-2	198	0.012	0.101	20
CT-4	275	0.012	0.072	19.7
CT-5	275	0.012	0.072	19.7
D-21	28.1	0.1	0.180	5.06
D-22	28.1	0.1	0.180	5.06
D-23	28.1	0.1	0.180	5.06
BS-1	5.57	0.1	0.355	1.98

1. AP-42 emission factor for CT-2, CT-4, and CT-5 from Section 3.1, dated April 2000, Tabel 3.1-2a.
2. AP-42 emission factor for D-21, D-22, D-23, and BS-1 from Section 3.4, dated October 1996, Table 3.4-2.

Volatile Organic Compounds (VOC)

Unit	Heat Input (MMBtu/hr)	AP-42 Emission Factor[1,2] (lb/MMBtu)	CSP Application Emission Factor (lb/MMBtu)	CSP Application Emission Rate (lb/hr)
CT-2	198	0.00041	0.113	22.4
CT-4	275	0.00041	0.003	0.80
CT-5	275	0.00041	0.003	0.80
D-21	28.1	0.082	0.238	6.69
D-22	28.1	0.082	0.238	6.69
D-23	28.1	0.082	0.238	6.69
BS-1	5.57	0.082	0.083	0.46

1. AP-42 emission factor for CT-2, CT-4, and CT-5 from Section 3.1, dated April 2000, Tabel 3.1-2a.
2. AP-42 emission factor for D-21, D-22, D-23, and BS-1 from Section 3.4, dated October 1996, Table 3.4-1.

Attachment S-1e
GHG Emissions Calculations

Unit	Heat Input (MMBtu/hr)	Operating Hours (hrs/yr)	Annual Heat Input (MMBtu/yr)	GHG Pollutant[1]	Emission Factor[2] (kg/MMBtu)	Maximum Hourly Emissions (kg/hr)	Annual Emissions (metric tpy)	Global Warming Potential[3]	Total GHG Emissions CO_2e (lb/hr)	Total GHG Emissions CO_2e (metric tpy)	Total GHG Emissions CO_2e (tpy)
				CO_2	73.96	20,339	178,170	1	44,840	178,170	196,398
CT-4	275.0	8,760	2,409,000	N_2O	6.0E-04	0.165	1.445	298	108	431	475
				CH_4	3.0E-03	0.825	7.227	25	45	181	199
								Total CO_2e =	**44,994**	**178,781**	**197,072**
				CO_2	73.96	20,339	178,170	1	44,840	178,170	196,398
CT-5	275.0	8,760	2,409,000	N_2O	6.0E-04	0.165	1.445	298	108	431	475
				CH_4	3.0E-03	0.825	7.227	25	45	181	199
								Total CO_2e =	**44,994**	**178,781**	**197,072**
				CO_2	73.96	14,644	127,372	1	32,285	127,372	140,404
CT-2	198.0	8,698	1,722,176	N_2O	6.0E-04	0.119	1.033	298	78	308	339
				CH_4	3.0E-03	0.594	5.167	25	33	129	142
								Total CO_2e =	**32,395**	**127,809**	**140,886**
				CO_2	73.96	2,078	725	1	4,582	725	799
D-21	28.1	349	9,800	N_2O	6.0E-04	0.017	0.006	298	11	2	2
				CH_4	3.0E-03	0.084	0.029	25	5	1	1
								Total CO_2e =	**4,598**	**727**	**802**
				CO_2	73.96	2,078	18,206	1	4,582	18,206	20,068
D-22	28.1	8,760	246,156	N_2O	6.0E-04	0.017	0.148	298	11	44	49
				CH_4	3.0E-03	0.084	0.738	25	5	18	20
								Total CO_2e =	**4,598**	**18,268**	**20,137**
				CO_2	73.96	2,078	18,206	1	4,582	18,206	20,068
D-23	28.1	8,760	246,156	N_2O	6.0E-04	0.000	0.000	298	0	0	0
				CH_4	3.0E-03	0.000	0.000	25	0	0	0
								Total CO_2e =	**4,582**	**18,206**	**20,068**
				CO_2	73.96	412	124	1	908	124	136
BS-1	5.6	300	1,671	N_2O	6.0E-04	0.003	0.001	298	2	0	0
				CH_4	3.0E-03	0.017	0.005	25	1	0	0
								Total CO_2e =	**911**	**124**	**137**
								Facility Total CO2e =		**522,696**	**576,174**

Notes:
1. Greenhouse Gas (GHG) pollutants from the Mandatory Greenhouse Gas Reporting rule (40 CFR §98.32).
2. Emission factors from the Mandatory Greenhouse Gas Reporting rule (40 CFR Part 98 Subpart C, Tables C-1 and C-2).
3. Global Warming Potentials from the Mandatory Greenhouse Gas Reporting rule (40 CFR Part 98 Subpart A, Table A-1).

4. CT2 annual heat input is based on 292,887 barrels per rolling 12-month period limit, AP-42 no. 2 fuel oil heat content of 140,000 Btu/gal, and unit heat input of 198 MMBtu/hr.

File No.: ________

S-7: Application for a Minor Modification to a Covered Source

In providing the required information, reference the corresponding letters and numbers listed below.

Provide a minimum of **two (2)** sets (1 original and 1 copy) of all application materials to the Hawaii Department of Health. Also, mail **one (1)** set directly to EPA at the following address:

Chief (Attention: AIR-3)
Permits Office, Air Division
U.S. Environmental Protection Agency
Region 9
75 Hawthorne Street
San Francisco, CA 94105

I. In accordance with Hawaii Administrative Rules (HAR) §11-60.1-103, the following information is required:

A. A clear description of all changes.

Hawai'i Electric Light proposes to remove the fuel-bound nitrogen content in fuel requirement for the combustion turbine generators, CT-2, CT-4, and CT-5 from CSP No. 0007-01-C (CSP). 40 CFR Part 60, Standards of Performance of New Stationary Sources (NSPS), Subpart GG - Standards of Performance for Stationary Gas Turbines, which the turbines are subject to, does not require fuel-bound nitrogen monitoring condition if an emission allowance for fuel-bound nitrogen is not claimed.

40 CFR §60.334(h)(2):
(h) The owner or operator of any stationary gas turbine subject to the provisions of this subpart:
(2) Shall monitor the nitrogen content of the fuel combusted in the turbine, if the owner or operator claims an allowance for fuel-bound nitrogen (i.e., if an F-value greater than zero is being or will be used by the owner or operator to calculate STD in §60.332).

The fuel-bound nitrogen allowance and associated fuel-bound nitrogen monitoring became optional on July 8, 2004, when EPA published a final rule amending several sections of 40 CFR part 60, subpart GG (69 FR 41345). Section II.B of the Federal Register notice states:

The NO_X emission standard in 40 CFR 60.332 includes a NO_X emission allowance for fuel-bound nitrogen. The use of this allowance for fuel-bound nitrogen will be optional upon July 8, 2004. Owners or operators will be able to choose to accept a value of zero for the NO_X emission allowance.

Section II.C of the Federal Register notice also states:

We are amending subpart GG of 40 CFR part 60 so that sources are required to monitor the nitrogen content of the fuel being fired in the turbine only if they claim the allowance for fuel-bound nitrogen. For sources that do not seek to use the fuel-bound nitrogen credit, sampling to determine the daily fuel nitrogen concentrations is not required.

Hawai'i Electric Light has not claimed the fuel-bound nitrogen emission allowance under NSPS Subpart GG and does not plan to claim the allowance in the future. Therefore, in accordance with the 40 CFR §60.334, the nitrogen monitoring condition is not required and should be removed from the CSP. No changes are requested for the NO_x emission limitations and the corresponding monitoring and reporting conditions. Compliance with the NO_x emissions limitations will continue to be monitored and demonstrated using the Continuous Emissions Monitoring System (CEMS). Any excess NO_x emissions will continue to be reported as required by the CSP.

The proposed change has previously been requested in the renewal applications dated 12/10/2015, 7/30/2012, and 1/8/2010, which were submitted to the Department of Health.

B. A statement of why the modification is determined to be minor, and a request that minor modification procedures be used.

The proposed modifications meet the criteria of a "minor modification" as defined in HAR § 11-60.1-81. The proposed modifications:

(1) Do not increase the emissions of any air pollutant above the permitted emission limits;

(2) Do not result in or increase the emissions of any air pollutant not limited by permit levels equal to or above: (A) 500 pounds per year of a hazardous air pollutant; (B) 300 pounds of lead; (C) twenty-five percent of significant amounts of emission as defined in section 11-60.1-1, paragraph (1) in the definition of "significant"; or (D) two tons per year of each regulated air pollutant not already identified above (the proposed modification do not result in emissions increase);

(3) Do not violate any applicable requirement;

(4) Do not involve significant changes to existing monitoring requirements or any relaxation or significant change to existing reporting or recordkeeping requirements in the permit.

(5) Do not require or change a case-by-case determination, a source-specific determination for temporary sources for ambient impacts, or a visibility or increment analysis;

(6) Do 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; and

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

C. Cite and describe any new applicable requirements as defined in HAR § 11-60.1-81 that will apply if the minor modification occurs.

No new applicable requirements will apply to the proposed minor modifications.

D. The suggested changes to permit terms or conditions.

Attachment S-7a contains Hawai'i Electric Light's suggested permit changes. Suggested deletions are struck through and suggested additions are underlined.

E. Certification by a responsible official that the proposed modification meets the criteria for minor modification.

Form S-1 contains the Responsible Official's signature certifying that the modifications are minor.

F. All information submitted with the application for the Initial Covered Source Permit or any subsequent application for a Covered Source Permit. The owner or operator may reference information contained in a previous application submittal, provided such referenced information has been certified as being current and still applicable.

References are made herein to pertinent information in previously submitted materials.

G. Other information, as required by any applicable requirement or as requested and deemed necessary by the Director of Health (hereafter, Director) to make a decision on the application.

Not applicable.

II. Submit an application fee according to the Application Fees Schedule in the Instructions for Applying for an Air Pollution Control Permit.

III. An application shall be determined to be complete only when all of the following have been complied with:

A. All information required or requested in number I have been submitted.

B. All documents requiring certification have been certified pursuant to HAR § 11-60.1-4.

C. All applicable fees have been submitted.

D. The Director has certified that the application is complete.

IV. The Director shall not continue to act upon or consider an incomplete application.

A. The applicant shall be notified in writing whether the application is complete. Unless the Director requests additional information or notifies the applicant of incompleteness within thirty days of receipt of an application, the application shall be deemed complete.

B. During the processing of an application that has been determined or deemed complete, if the Director determines that additional information is necessary to evaluate or take final action on the application, the Director may request such information in writing and set a reasonable deadline for a response.

V. Within ninety days of receipt of a complete application for a minor modification, or upon program approval, within fifteen days after the end of the Administrator's forty-five-day review period, whichever is later, the Director in writing shall:

A. Amend the permit to reflect the minor modification as proposed.

B. Deny the minor modification.

C. Determine that the requested modification does not meet the minor modification criteria, and should be reviewed under the significant modification process; or

D. Upon program approval, amend the proposed permit and resubmit the amendment to EPA for reevaluation.

VI. An application for minor modification to a covered source shall be approved only if the Director determines that the minor modification will be in compliance with all applicable requirements.

VII. The Director shall provide a statement that sets forth the legal and factual bases for the proposed permit conditions (including references to the applicable statutory or regulatory provisions) to EPA and any other person requesting it.

VIII. Each application and proposed permit reflecting the minor modification to a covered source shall be subject to EPA oversight in accordance with HAR § 11-60.1-95.

June 27, 2018

CERTIFIED MAIL
RETURN RECEIPT REQUESTED
(7017 0660 0001 0766 1000)

18-436E CAB
File No. 0007

Mr. Norman M. Uchida, P.E.
Manager, Production Department
Hawaii Electric Light Company, Inc.
P.O. Box 1027
Hilo, Hawaii 96721-1027

Dear Mr. Uchida:

SUBJECT: Administrative Permit Amendment
Covered Source Permit (CSP) No. 0007-01-C
Hawaii Electric Light Company, Inc.
Two (2) 20 MW Combustion Turbine Generators, Units CT-4 and CT-5 with Two (2) Heat Recovery Steam Generators and One (1) 16 MW Steam Turbine, One (1) 18 MW Combustion Turbine Generator, Unit CT-2, Three (3) 2.5 MW Diesel Engine Generators, and One (1) 500 kW Diesel Engine Generator
Located At: Keahole Generating Station, Keahole, Hawaii
Date of Expiration: August 6, 2013 (this date is to be revised upon issuance of the renewal for CSP No. 0007-01-C)

The subject CSP is issued in accordance with Hawaii Administrative Rules (HAR), Title 11, Chapter 60.1 and consolidates the terms and conditions of CSP No. 0007-01-C and CSP No. 0070-01-C into a single permit, CSP No. 0007-01-C. This permit supersedes CSP No. 0007-01-C issued on August 7, 2008, and amended on June 23, 2009, and CSP No. 0070-01-C issued on January 12, 2006, and amended on June 15, 2006, and June 23, 2009, in their entireties.

The CSP is issued subject to the conditions/requirements set forth in the following Attachments:

Attachment I:	Standard Conditions
Attachment IIA:	Special Conditions for the Combustion Turbines, Units CT-4 and CT-5
Attachment IIB:	Special Conditions for the Combustion Turbine, Unit CT-2
Attachment IIC:	Special Conditions for the Diesel Engines

Attachment II - INSIG: Special Conditions for Insignificant Activities
Attachment III: Annual Fee Requirements
Attachment IV: Annual Emissions Reporting Requirements

The forms for the submission of reports and annual emissions are as follows:

Annual Emissions Report Form: Combustion Turbines
Annual Emissions Report Form: Ammonia Slip
Annual Emissions Report Form: Diesel Engines
Monitoring Report Form: Operating Hours: Black Start Diesel Engine Generator
Monitoring Report Form: Daily Startup and Shutdown
Monitoring Report Form: Fuel Consumption
Monitoring Report Form: Fuel Certification
Monitoring Report Form: Visible Emission Exceedances
Excess Emission and Monitoring System Performance Summary Report
Visible Emissions Form Requirements
Visible Emissions Form
Compliance Certification Form
The Ringelmann Chart

This permit: (a) shall not in any manner affect the title of the premises upon which the equipment is to be located; (b) does not release the permittee from any liability for any loss due to personal injury or property damage caused by, resulting from or arising out of the design, installation, maintenance, or operation of the equipment; and (c) in no manner implies or suggests that the Department of Health, Clean Air Branch (herein after referred to as Department), or its officers, agents, or employees, assumes any liability, directly or indirectly, for any loss due to personal injury or property damage caused by, resulting from or arising out of the design, installation, maintenance, or operation of the equipment.

If you have any questions regarding this matter, please contact Mr. Darin Lum of the Clean Air Branch at (808) 586-4200.

Sincerely,

JOANNA SETO, P.E., ACTING CHIEF
Environmental Management Division

DL:tkg
Enclosures

ATTACHMENT I: STANDARD CONDITIONS
COVERED SOURCE PERMIT NO. 0007-01-C

Issuance Date: June 27, 2018 **Expiration Date: August 6, 2013 [3]**

This permit is granted in accordance with the Hawaii Administrative Rules (HAR), Title 11, Chapter 60.1, Air Pollution Control, and is subject to the following standard conditions:

1. Unless specifically identified, the terms and conditions contained in this permit are consistent with the applicable requirement, including form, on which each term or condition is based.

   (Auth.: HAR §11-60.1-90)

2. This permit, or a copy thereof, shall be maintained at or near the source and shall be made available for inspection upon request. The permit shall not be willfully defaced, altered, forged, counterfeited, or falsified.

   (Auth.: HAR §11-60.1-6; SIP §11-60-11)[2]

3. This permit is not transferable whether by operation of law or otherwise, from person to person, from place to place, or from one piece of equipment to another without the approval of the Department, except as provided in HAR, Section 11-60.1-91.

   (Auth.: HAR §11-60.1-7; SIP §11-60-9)[2]

4. A request for transfer from person to person shall be made on forms furnished by the Department.

   (Auth.: HAR §11-60.1-7)

5. In the event of any changes in control or ownership of the facilities to be constructed or modified, this permit shall be binding on all subsequent owners and operators. The permittee shall notify the succeeding owner and operator of the existence of this permit and its conditions by letter, copies of which will be forwarded to the Department and the U.S. Environmental Protection Agency (EPA), Region 9.

   (Auth.: HAR §11-60.1-5, §11-60.1-7, §11-60.1-94)

6. The facility covered by this permit shall be constructed and operated in accordance with the application, and any information submitted as part of the application, for CSP. There shall be no deviation unless additional or revised plans are submitted to and approved by the Department, and the permit is amended to allow such deviation.

   (Auth.: HAR §11-60.1-2, §11-60.1-4, §11-60.1-82, §11-60.1-84, §11-60.1-90)

7. This permit (a) does not release the permittee from compliance with other applicable statutes of the State of Hawaii, or with applicable local laws, regulations, or ordinances, and (b) shall not constitute, nor be construed to be an approval of the design of the covered source.

   (Auth.: HAR §11-60.1-5, §11-60.1-82)

8. The permittee shall comply with all the terms and conditions of this permit. Any permit noncompliance constitutes a violation of HAR, Chapter 11-60.1 and the Clean Air Act and is grounds for enforcement action; for permit termination, suspension, reopening, or amendment; or for denial of a permit renewal application.

   (Auth.: HAR §11-60.1-3, §11-60.1-10, §11-60.1-19, §11-60.1-90)

9. If any term or condition of this permit becomes invalid as a result of a challenge to a portion of this permit, the other terms and conditions of this permit shall not be affected and shall remain valid.

   (Auth.: HAR §11-60.1-90)

10. The permittee shall not use as a defense in an enforcement action that it would have been necessary to halt or reduce the permitted activity to maintain compliance with the terms and conditions of this permit.

    (Auth.: HAR §11-60.1-90)

11. This permit may be terminated, suspended, reopened, or amended for cause pursuant to HAR, Sections, 11-60.1-10 and 11-60.1-98, and Hawaii Revised Statutes (HRS), Chapter 342B-27, after affording the permittee an opportunity for a hearing in accordance with HRS, Chapter 91.

    (Auth.: HAR §11-60.1-3, §11-60.1-10, §11-60.1-90, §11-60.1-98)

12. The filing of a request by the permittee for the termination, suspension, reopening, or amendment of this permit, or of a notification of planned changes or anticipated noncompliance does not stay any permit condition.

    (Auth.: HAR §11-60.1-90)

13. This permit does not convey any property rights of any sort, or any exclusive privilege.

    (Auth.: HAR §11-60.1-90)

14. The permittee shall <u>notify</u> the Department and U.S. EPA, Region 9, in writing of the following dates:

a. The **anticipated date of initial start-up** for each emission unit of a new source or significant modification not more than sixty (60) days or less than thirty (30) days prior to such date;
b. The **actual date of construction commencement** within fifteen (15) days after such date; and
c. The **actual date of start-up** within fifteen (15) days after such date.

(Auth.: HAR §11-60.1-90)

15. The permittee shall furnish, in a timely manner, any information or records requested in writing by the Department to determine whether cause exists for terminating, suspending, reopening, or amending this permit, or to determine compliance with this permit. Upon request, the permittee shall also furnish to the Department copies of records required to be kept by the permittee. For information claimed to be confidential, the Director of Health (Director) may require the permittee to furnish such records not only to the Department but also directly to the U.S. EPA, Region 9, along with a claim of confidentiality.

(Auth.: HAR §11-60.1-14, §11-60.1-90)

16. The permittee shall notify the Department in writing, of the **intent to shut down air pollution control equipment for necessary scheduled maintenance** at least twenty-four (24) hours prior to the planned shutdown. The submittal of this notice shall not be a defense to an enforcement action. The notice shall include the following:

a. Identification of the specific equipment to be taken out of service, as well as its location and permit number;
b. The expected length of time that the air pollution control equipment will be out of service;
c. The nature and quantity of emissions of air pollutants likely to be emitted during the shutdown period;
d. Measures such as the use of off-shift labor and equipment that will be taken to minimize the length of the shutdown period; and
e. The reasons why it would be impossible or impractical to shut down the source operation during the maintenance period.

(Auth.: HAR §11-60.1-15; SIP §11-60-16)[2]

17. **Except for emergencies which result in noncompliance with any technology-based emission limitation in accordance with HAR, Section 11-60.1-16.5, in the event any emission unit, air pollution control equipment, or related equipment malfunctions or breaks down in such a manner as to cause the emission of air pollutants in violation of HAR, Chapter 11-60.1 or this permit**, the permittee shall immediately notify the Department of the malfunction or breakdown, unless the protection of personnel or public health or safety demands immediate attention to the malfunction or breakdown and makes such notification infeasible. In the latter case, the notice shall be provided as soon as

practicable. Within five (5) working days of this initial notification, the permittee shall also submit, in writing, the following information:

a. Identification of each affected emission point and each emission limit exceeded;
b. Magnitude of each excess emission;
c. Time and duration of each excess emission;
d. Identity of the process or control equipment causing the excess emission;
e. Cause and nature of each excess emission;
f. Description of the steps taken to remedy the situation, prevent a recurrence, limit the excessive emissions, and assure that the malfunction or breakdown does not interfere with the attainment and maintenance of the National Ambient Air Quality Standards and state ambient air quality standards;
g. Documentation that the equipment or process was at all times maintained and operated in a manner consistent with good practice for minimizing emissions; and
h. A statement that the excess emissions are not part of a recurring pattern indicative of inadequate design, operation, or maintenance.

The submittal of these notices shall not be a defense to an enforcement action.

(Auth.: HAR §11-60.1-16; SIP §11-60-16)[2]

18. The permittee may request confidential treatment of any records in accordance with HAR, Section 11-60.1-14.

    (Auth.: HAR §11-60.1-14, §11-60.1-90)

19. This permit shall become invalid with respect to the authorized construction if construction is not commenced as follows:

    a. Within eighteen (18) months after the permit takes effect, is discontinued for a period of eighteen (18) months or more, or is not completed within a reasonable time.
    b. For phased construction projects, each phase shall commence construction within eighteen (18) months of the projected and approved commencement dates in the permit. This provision shall be applicable only if the projected and approved commencement dates of each construction phase are defined in Attachment II, Special Conditions, of this permit.

    (Auth.: HAR §11-60.1-9, §11-60.1-90)

20. The Department may extend the time periods specified in Standard Condition No. 19 upon a satisfactory showing that an extension is justified. Requests for an extension shall be submitted in writing to the Department.

    (Auth.: HAR §11-60.1-9, §11-60.1-90)

21. The permittee shall submit fees in accordance with HAR, Chapter 11-60.1, Subchapter 6.

    (Auth.: HAR §11-60.1-90)

22. All certifications shall be in accordance with HAR, Section 11-60.1-4.

    (Auth.: HAR §11-60.1-4, HAR §11-60.1-90)

23. The permittee shall allow the Director, the Regional Administrator for the U.S. EPA and/or an authorized representative, upon presentation of credentials or other documents required by law:

    a. To enter the premises where a source is located or emission-related activity is conducted, or where records must be kept under the conditions of this permit and inspect at reasonable times all facilities, equipment, including monitoring and air pollution control equipment, practices, operations, or records covered under the terms and conditions of this permit and request copies of records or copy records required by this permit; and
    b. To sample or monitor at reasonable times substances or parameters to ensure compliance with this permit or applicable requirements of HAR, Chapter 11-60.1.

    (Auth.: HAR §11-60.1-11, §11-60.1-90)

24. Within thirty (30) days of **permanent discontinuance of the construction, modification, relocation, or operation of a covered source covered by this permit**, the discontinuance shall be reported in writing to the Department by a responsible official of the source.

    (Auth.: HAR §11-60.1-8; SIP §11-60-10)[2]

25. Each permit renewal application shall be submitted to the Department and the U.S. EPA, Region 9, no less than twelve (12) months and no more than eighteen (18) months prior to the permit expiration date. The Director may allow a permit renewal application to be submitted no less than six (6) months prior to the permit expiration date, if the Director determines that there is reasonable justification.

    (Auth.: HAR §11-60.1-101, 40 CFR §70.5(a)(1)(iii))[1]

26. The terms and conditions included in this permit, including any provision designed to limit a source's potential to emit, are federally enforceable unless such terms, conditions, or requirements are specifically designated as not federally enforceable.

    (Auth.: HAR §11-60.1-93)

27. The compliance plan and compliance certification submittal requirements shall be in accordance with HAR, Sections 11-60.1-85 and 11-60.1-86. As specified in HAR,

    Section 11-60.1-86, the compliance certification shall be submitted to the Department and the U.S. EPA, Region 9, once per year, or more frequently as set by any applicable requirement.

    (Auth.: HAR §11-60.1-90)

28. **Any document (including reports) required to be submitted by this permit shall be certified as being true, accurate, and complete by a responsible official in accordance with HAR, Sections 11-60.1-1 and 11-60.1-4, and shall be mailed to the following address:**

    State of Hawaii
    Clean Air Branch
    2827 Waimano Home Road #130
    Pearl City, HI 96782

    Upon request and as required by this permit, all correspondence to the State of Hawaii Department associated with this CSP shall have duplicate copies forwarded to:

    Manager
    Enforcement Division, Air Section
    U.S. Environmental Protection Agency, Region 9
    75 Hawthorne Street, ENF-2-1
    San Francisco, CA 94105

    (Auth.: HAR §11-60.1-4, §11-60.1-90)

29. To determine compliance with submittal deadlines for time-sensitive documents, the postmark date of the document shall be used. If the document was hand-delivered, the date received ("stamped") at the Clean Air Branch shall be used to determine the submittal date.

    (Auth.: HAR §11-60.1-5, §11-60.1-90)

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[1]The citations to the Code of Federal Regulations (CFR) identified under a particular condition, indicate that the permit condition complies with the specified provision(s) of the CFR. Due to the integration of the preconstruction and operating permit requirements, permit conditions may incorporate more stringent requirements than those set forth in the CFR.

[2]The citations to the State Implementation Plan (SIP) identified under a particular condition, indicate that the permit condition complies with the specified provision(s) of the SIP.

[3]This date is to be revised upon issuance of the renewal for CSP No. 0007-01-C.

ATTACHMENT IIA: SPECIAL CONDITIONS FOR THE COMBUSTION TURBINES, UNITS CT-4 AND CT-5
COVERED SOURCE PERMIT NO. 0007-01-C

Issuance Date: June 27, 2018 **Expiration Date: August 6, 2013** [3]

In addition to the standard conditions of the Covered Source Permit, the following special conditions shall apply to the permitted facility:

Section A. Equipment Description

1. This attachment encompasses the following equipment and associated appurtenances:

   a. Two (2) 20 MW General Electric LM2500 combustion turbine generators, Units CT-4 and CT-5; and
   b. One (1) 16 MW steam turbine generator Unit ST-7, including two (2) unfired heat recovery steam generators (HRSG) with two (2) selective catalytic reduction (SCR) units.

   (Auth.: HAR §11-60.1-3)

2. The permittee shall permanently attach an identification tag or name plate on the combustion turbines which identifies the model no., serial no., and manufacturer. The identification tag or nameplate shall be permanently attached to the combustion turbines at a conspicuous location.

   (Auth.: HAR §11-60.1-5)

Section B. Applicable Federal Regulations

1. The combustion turbines are subject to the provisions of the following federal standards:

   a. 40 CFR Part 60, Standards of Performance for New Stationary Sources, Subpart A - General Provisions; and
   b. 40 CFR Part 60, Standards of Performance of New Stationary Sources, Subpart GG - Standards of Performance for Stationary Gas Turbines.

   The permittee shall comply with all applicable requirements of these standards including all emission limits, notification, testing, monitoring, and reporting requirements. The major requirements of these standards are detailed in this attachment.

   (Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-161; 40 CFR §60.1, §60.330)[1]

<u>Section C</u>. <u>Operational Limitations</u>

1. Start-up and Shutdown

   a. The "start-up" time shall not exceed twenty (20) minutes for any combustion turbine generator operating in simple cycle and ninety (90) minutes for any combustion turbine generator operating in combined cycle. Except during maintenance (e.g., equipment installations and inspections, and electrical switching work), testing, and emergency power demands due to sudden loss of a power generating unit, each combustion turbine generator shall not be started up more than four times per calendar day. A "start-up" sequence shall be from the time fuel use at the combustion turbine generator begins, until the time the combustion turbine generator is initially brought up to twenty-five (25) percent of peak load at which time the operation of the air pollution control equipment shall commence.
   b. The "shutdown" time for any combustion turbine generator operating in either simple or combined cycle shall not exceed twenty (20) minutes. Except during maintenance (e.g., equipment installations and inspections, and electrical switching work), testing, and emergency power demands due to sudden loss of a power generating unit, each combustion turbine generator shall not be shut down more than four (4) times per calendar day. A "shutdown" sequence shall be considered from the time when the combustion turbine generator is operating below twenty-five (25) percent of peak load, until fuel consumption at the combustion turbine generator ceases.

2. Minimum Operational Loads

   The combustion turbine generators shall not operate below twenty-five (25) percent of peak load, except during equipment start-up, shutdown, maintenance, or testing.

   (Auth.: HAR §11-60.1-3, §11-60.1-5, §p11-60.1-90)

3. Air Pollution Equipment

   The use of an alternative control system other than those specified below is contingent upon receiving the Department's written approval to use such a system and shall not relieve the permittee from the responsibility to meet all emission limitations contained within this CSP.

   a. Combustor Water Injection

      The permittee shall continuously operate and maintain a combustor water injection system to meet the emission limits as specified in Special Condition No. D.1 of this attachment. The combustor water injection system shall be fully operational and commence operation immediately after the start-up sequence of the combustion turbine generators. The combustor water injection system shall continue to operate until the commencement of the shutdown sequence of the combustion turbine generators.

The operation of the combustor water injection system shall be used whenever the combustion turbine generators are operating at twenty-five (25) percent peak load and above. The following water-to-fuel ratio shall be maintained when the combustion turbine generators are in simple cycle operation or in combined cycle operation at loads less than fifty (50) percent of the peak load.

WATER INJECTION SYSTEM MINIMUM WATER-TO-FUEL MASS RATIO BASED ON LOAD

Combustion Turbine Generator Peak load (Percent)	**Ratio** (lb-water/lb-fuel)
100	1.04
75 - <100	0.94
50 - <75	0.87
25 - <50	0.72

b. Selective Catalytic Reduction System

The permittee shall design, install, maintain, and continuously operate a selective catalytic reduction system with ammonia injection to meet the emission limits as specified in Special Condition No. D.1 of this attachment.

The selective catalytic reduction system shall be fully functional and in operation whenever the combustion turbine generators are in combined cycle operation at loads greater than or equal to fifty (50) percent of the peak load. The selective catalytic reduction system shall continue to operate until the load is reduced to below fifty (50) percent of the peak load.

(Auth.: HAR §11-60.1-3, §11-60.1-5, §11-60.1-90, §11-60.1-140)

4. Fuel Specifications

a. Sulfur Content

The combustion turbine generators and diesel engines shall be fired only on fuel oil No. 2 with a maximum sulfur content not to exceed 0.4 percent by weight.

~~b. Nitrogen Content~~

~~The fuel bound nitrogen content of the fuel fired in the combustion turbine generators, units CT-4 and CT-5, shall not exceed 0.015 percent by weight on a rolling twelve (12) month average.~~

Justification *– Hawai'i Electric Light requests to delete the requirement to monitor fuel-bound nitrogen content in fuel because it is not required by NSPS Subpart GG if an emission allowance for fuel-bound nitrogen is not claimed. Please refer to 40 CFR §60.334(h)(2) and 69 FR 41345, July 8, 2004. Hawai'i Electric Light has not claimed the optional fuel-bound nitrogen emission allowance under NSPS Subpart GG and does not plan to claim the allowance in the future. Thus, the nitrogen monitoring condition is not required and should be removed from the CSP. No changes are requested for the* NO_X *emissions limitation and the corresponding monitoring and reporting conditions. Compliance with the* NO_X *emissions limitation will continue to be monitored and demonstrated using Continuous Emissions Monitoring System (CEMS). Any excess* NO_X *emissions will continue to be reported as required by the CSP.*

(Auth.: HAR §11-60.1-3, §11-60.1-5, §11-60.1-90, §11-60.1-140)

5. Alternate Operating Scenarios

Terms and conditions for reasonably anticipated operating scenarios identified by the source in the CSP application and approved by the Department are as follows:

a. Upon receiving written approval from the Department, the permittee may replace any of the combustion turbine generators with a temporary replacement unit in the event of a sudden malfunction or a planned major overhaul. The temporary replacement unit shall comply with all applicable permit conditions.

   A written request shall be submitted to the Department prior to the exchange and at a minimum, the request shall include the following:

   i. the reason for temporary replacement;
   ii. the removal and estimated return dates of the permitted unit;
   iii. the make, model, serial number, and size of the temporary replacement unit; and
   iv. the emissions data of the permitted and temporary replacement unit.

   The Department may require an ambient air quality impact analysis and/or may impose additional requirements on the temporary replacement unit to ensure compliance with the conditions of this permit.

b. The combustion turbine generators may operate below twenty-five (25) percent of peak load during:

   i. Testing of the heat recovery steam generators and steam turbine; and
   ii. Steam blows needed to clean the steam tubes prior to initial operation.

c. In the event of equipment malfunctions, such as the sudden loss of a unit, the combustion turbine generators may operate up to one hundred ten (110) percent of peak load. The time period for operating the combustion turbines above one hundred (100) percent peak load shall be limited to no more than thirty (30) minutes in duration. Under no circumstance shall the emission limits specified in Special Condition No. D.1 of this attachment be exceeded.

d. Upon receiving written approval from the Department, the permittee may burn an alternative fuel provided the permittee demonstrates compliance with all applicable state and federal requirements and applicable conditions of this CSP. The alternative fuel shall be burned only temporarily and shall not result in an increase in emissions of any air pollutant or in the emission of any air pollutant not previously emitted. The permittee shall not be allowed to switch fuels unless all of the following information is provided:

   i. Specific type of fuel provided;
   ii. Consumption rate of the fuel;
   iii. Fuel blending rate;
   iv. Emissions calculations;
   v. Ambient air quality analyses verifying that SAAQS will be met;
   vi. Fuel storage; and
   vii. Plan to monitor and record the fuel analyses and consumption.

e. The permittee may use fuel additives to reduce corrosion, control biological growth, and enhance combustion. Additives used during this scenario shall not affect emission estimates.

f. Upon receiving written approval from the Department, the permittee may use alternate means and methods to improve combustion and/or reduce emissions provided the permittee demonstrate that the following conditions will be met.

   i. The national and state ambient air quality standards will not be violated.
   ii. The emissions and emission rates do not exceed the permitted emission limits.
   iii. The facility shall continue to operate and comply with the conditions of this permit.
   iv. There are no emissions of air pollutants not previously emitted.

   The Department may approve, conditionally approve, or deny any request for using alternate means and methods. Under no circumstance shall an alternate mean and/or method be employed without the prior written approval, or conditional approval, of the Department.

g. The permittee shall, contemporaneously with making a change from one operating scenario to another, record in a log at the permitted facility the scenario under which it is operating and, if required by any applicable requirement or the Department, submit written notification to the Department; and

h. The terms and conditions under each alternative operating scenario shall meet all applicable requirements including all conditions of this permit.

(Auth.: HAR §11-60.1-90)

Section D. Emission Limitations

1. Maximum Emission Limits

   The permittee shall not discharge or cause the discharge into the atmosphere from each of the combustion turbine generator nitrogen oxides (as NO_2), sulfur dioxide (SO_2), particulate matter/PM_{10}, carbon monoxide (CO), volatile organic compounds (VOC), and ammonia in excess of the following specified limits:

Combustion Turbine Generator Operating in the Simple Cycle Mode

Compound	Maximum Emission Limit (3-hour Average) (lbs/hr)	(ppmvd @ 15 percent O_2)
Nitrogen Oxides as NO_2	42.3	42
Sulfur Dioxide	110	79
Particulate Matter/PM_{10}	19.7	0.045 (gr/dscf @ 12 percent O_2)
Carbon Monoxide		
100% Peak load	26.8	44
75% - <100% Peak load	56.4	123
50% - <75% Peak load	181.0	566
25% - <50% Peak load	475.6	2,386
Volatile Organic Compounds		
100% Peak load	0.8	2.5
75% - <100% Peak load	2.6	11.8
50% - <75% Peak load	28.1	178
25% - <50% Peak load	297.6	3,025

Combustion Turbine Generator Operating in the Combined Cycle Mode

Compound	Maximum Emission Limit (3-hour Average) (lbs/hr)	(ppmvd @ 15 percent O_2)
Nitrogen Oxides as NO_2		
50% - 100% Peak load	15.1	15
25% - <50% Peak load	42.3	42
Sulfur Dioxide	110	79
Particulate Matter/PM_{10}	19.7	0.045 (gr/dscf @ 12 percent CO_2)
Carbon Monoxide		
100% Peak load	26.9	44
75% - <100% Peak load	50.2	105
50% - <75% Peak load	170.4	523
25% - <50% Peak load	457.4	2,218
Volatile Organic Compounds		
100% Peak load	0.8	2.5
75% - <100% Peak load	2.0	8.6
50% - <75% Peak load	25.0	156
25% - <50% Peak load	271.0	2,662
Ammonia	4.30	10

The Department, with U.S. EPA, Region 9, concurrence, may revise the allowable emission limitation for nitrogen oxides, particulate matter, carbon monoxide, volatile organic compounds, and ammonia after reviewing the initial performance test results required under Section G of this attachment. The Department, with U.S. EPA, Region 9, concurrence, may also revise the water-to-fuel ratios or include ammonia-to-NO_x injection rates if findings through operating parameters and performance test results show an optimum operating range which minimizes emissions.

If the nitrogen oxides, particulate matter, carbon monoxide, volatile organic compounds, or ammonia emission limit is revised, the difference between the applicable emission limit set forth above and the revised lower emission limit shall not be allowed as an emission offset for future construction or modification.

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-140)

2. For any six (6) minute averaging period, the combustion turbines shall not exhibit visible emissions of twenty (20) percent opacity or greater, except as follows: during startup, shutdown, or equipment breakdown, the combustion turbines may exhibit visible emissions greater than twenty (20) but not exceeding sixty (60) percent opacity for a period aggregating not more than six (6) minutes in any sixty (60) minute period. In the event of equipment breakdown, the equipment shall be shut down within one (1) hour if the opacity problem cannot be corrected within the six (6) minute period.

   (Auth.: HAR §11-60.1-3, §11-60.1-32, §11-60.1-90; SIP §11-60-24)[2]

3. Fugitive Emissions

   a. Potential sources of fugitive emissions in fuel oil transfer systems shall be inspected and maintained on a regular schedule to control VOC emissions.
   b. The permittee shall maintain records of inspections of the fuel oil transfer system as part of the operational log. The permittee shall provide the Department with copies of the log upon request.
   c. The permittee shall provide access to the Department to inspect tank weld, seams, gauge hatches, sampling ports and pressure relief valves.

   (Auth.: HAR §11-60.1-4, §11-60.1-90)

Section E. Monitoring and Recordkeeping

All records, including support information, shall be maintained for at least five (5) years from the date of the monitoring sample, measurement, test, report, or application. Support information includes all calibration and maintenance records and copies of all reports required by the permit.

These records shall be true, accurate, maintained in a permanent form suitable for inspection and made available to the Department or their representative upon request.

1. Continuous Monitoring Systems

   All monitoring systems shall record the date and time that the measured parameters and data were collected.

   a. The permittee shall continuously monitor and record the operating load of the combustion turbines.
   b. The permittee shall operate and maintain a continuous monitoring system to monitor and record the ratio of water-to-fuel being fired in the combustion turbines. The water-to-fuel monitor/recorder shall be accurate to +/- five (5) percent.

c. The permittee shall operate and maintain a total volumetric flow metering system for the continuous measurement and recording of the fuel usage of the combustion turbine generators. The permittee shall maintain records on the total amount of fuel fired in the combustion turbine generators.

d. The permittee shall operate and maintain a Continuous Emissions Monitoring System (CEMS) to measure and record the NO_x, CO, and carbon dioxide (CO_2) or oxygen (O_2) concentrations in the stack gas from the combustion turbines. The emission rates for NO_x and CO shall be recorded in parts per million by volume dry (ppmvd) at fifteen (15) percent O_2 and pounds per hour (lbs/hr). If CO_2 is measured with the CEMS to adjust the pollutant concentration, the CO_2 correction factor equations listed in 40 CFR §60.4213(d)(3) shall be used to determine compliance with the applicable emissions limit.

e. Prior to the startup of the selective catalytic reduction system and thereafter, the permittee shall at its own expense install, operate, and maintain a continuous monitoring system for each combustion turbine to measure and record the following parameters and data.

   i. The ammonia injection rate in lbs/hr and the ammonia-to-NO_x ratio. The ratio shall be based on the pounds per hour of ammonia injected into the SCR to the pounds of NO_x entering the SCR system.

   ii. The NO_x and CO_2 or O_2 concentrations in the exhaust gas stream at a point between the exit of the combustion turbine with water injection and the entrance to the SCR system.

   The emission rates for NO_x shall be recorded in ppmvd at fifteen (15) percent O_2 and in lbs/hr. The continuous emissions monitoring system used for these measurements shall meet the U.S. EPA performance specifications of 40 CFR §60.13, Appendix B, and Appendix F.

f. The permittee shall operate and maintain a transmissometer continuous monitoring system for the measurement and recording of the opacity of stack emissions. The systems shall meet the U.S. EPA monitoring performance standards of 40 CFR §60.13 and 40 CFR Part 60, Appendix B, Performance Specifications.

g. The permittee shall maintain a file of all measurements and monitoring data, performance testing requirements and results, system performance evaluations, calibration checks, adjustments and maintenance as performed, and all other information required by 40 CFR Part 60 recorded in a permanent form suitable for inspection.

(Auth.: HAR §11-60.1-3, §11-60.1-90)

2. Ammonia Slip

   Records shall be maintained on the amount of ammonia slip from the operation of the selective catalytic reduction system. Estimates of ammonia slip shall be based on the ammonia emission rates measured during the initial and subsequent annual performance test required by Section G of this attachment. Back-up data, calculations, and the resulting ammonia emissions shall be maintained on a monthly basis.

   (Auth.: HAR §11-60.1-3, §11-60.1-90)

3. Fuel Specifications

   a. The fuel sulfur content of the fuel fired in the combustion turbines shall be verified by one of the following methods:

      i. A representative sample of each batch of the fuel received shall be analyzed using the most current version of any of the following American Society for Testing and Materials (ASTM) methods: D129, D2622, D4292, D5453, or D1552; or
      ii. A certificate of analysis on the sulfur content (percent by weight) shall be obtained from the fuel supplier for each batch of fuel received.

   ~~b. The fuel bound nitrogen content of the fuel fired in the combustion turbines shall be verified by the following method. A representative sample of each batch of fuel received shall be analyzed for its nitrogen content by weight using the most current version of any of the following ASTM methods: D6366, D4629, or D5762.~~
   c. The permittee shall maintain records of the fuel delivery receipts, the supplier's certificate of analysis showing the sulfur content of the fuel delivered, and all test analysis. At a minimum, the test analysis shall include the following:

      i. Type of fuel;
      ii. Date and time the fuel sample was drawn;
      iii. Date the analyses were performed;
      iv. Name and address of the company or entity that performed the analyses;
      v. Means and methods used to analyze the fuel; and
      vi. Analyses results.

      Records of the sulfur ~~and nitrogen~~ contents of the fuel shall be maintained on a monthly basis.

   Justification *– The changes were requested in the 7/30/2012 renewal application submitted to the Department of Health. The exclusion of the nitrogen content is consistent with the proposed modification in this application. Refer to the proposed modification to Attachment IIA, Special Condition C.4.b and the corresponding justification.*

   (Auth.: HAR §11-60.1-3, §11-60.1-90)

4. An inspection, maintenance, and repair log shall be maintained for the combustion turbines and selective catalytic reduction system. Replacement and repairs to the catalyst of the selective catalytic reduction system shall be documented.

   (Auth.: HAR §11-60.1-3, §11-60.1-90)

Section F. Notification and Reporting Requirements

1. Notification and reporting pertaining to the following events shall be done in accordance with Attachment I, Standard Conditions Nos. 14, 16, 17, and 24, respectively:

   a. *Anticipated date of initial start-up, actual date of construction commencement*, and *actual date of start-up*;
   b. *Intent to shut down air pollution control equipment for necessary scheduled maintenance*;
   c. *Emissions of air pollutants in violation of HAR, Chapter 11-60.1 or this permit (excluding technology-based emission exceedences due to emergencies)*; and
   d. *Permanent discontinuance of construction, modification, relocation, or operation of the facility covered by this permit.*

   (Auth.: HAR §11-60.1-8, §11-60.1-15, §11-60.1-16, §11-60.1-90; SIP §11-60-10, SIP §11-60-16)[2]

2. The permittee shall report **within five (5) working days** any deviations from permit requirements, including those attributable to upset conditions, the probable cause of such deviations and any corrective actions or preventive measures taken. Corrective actions may include a requirement for additional stack testing, or more frequent monitoring, or could trigger implementation of a corrective action plan.

   (Auth.: HAR §11-60.1-3, §11-60.1-15, §11-60.1-16, §11-60.1-90)

3. **Within sixty (60) days** after initial start-up of the selective catalytic reduction system, the permittee shall submit to the Department a quality assurance project plan for the continuous monitoring system conforming to 40 CFR Part 60, Appendix F.

   (Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-161; 40 CFR Part 60 Appendix F)

4. The permittee shall notify the Department in writing **within thirty (30) days** prior to conducting performance specification tests on the continuous monitoring system. The testing date shall be in accordance with the performance test date identified in 40 CFR Part 60 Section 60.13.

   (Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-161; 40 CFR §60.13)

5. The permittee shall submit a written report of all excess emissions, including those associated with the water-to-fuel ratio requirement, to the Department and U.S. EPA, Region 9, **every semi-annual period**. The report shall include the following:

a. The magnitude of excess emissions computed in accordance with 40 CFR §60.13(h), any conversion factors used, and the date and time of commencement, completion of each time period of excess emissions, and the corresponding operating load of the combustion turbine generators.

b. Specific identification of each period of excess emissions that occurs during start-ups, shutdowns, and malfunctions of the combustion turbine generators. The nature and cause of any malfunction (if known), and the corrective action taken, or preventive measures adopted, shall also be reported.
c. The date and time identifying each period during which the continuous monitoring system was inoperative except for zero and span checks. The nature of each system repair or adjustment shall be described.
d. The report shall state if no excess emissions have occurred. Also, the report shall state if the CEMS operated properly during the period and was not subject to any repairs or adjustments except for zero and span checks.
e. All reports shall be postmarked by the 30th day following the end of each semi-annual period. The enclosed **Excess Emission and Monitoring System Performance Summary Report** form, or similar form shall be used in conjunction to the reporting of excess emissions of NO_x, CO, and opacity.
f. For purposes of this CSP, excess emissions shall be defined as follows:

   i. Any three (3) hour period during which the average emissions of NO_x and CO, as measured by the continuous monitoring system, exceed the emission limits set forth in Special Condition No. D.1 of this attachment;
   ii. During simple cycle operation and combined cycle operation at loads less than fifty (50) percent of peak load, any one (1) hour period during which the average water-to-fuel ratio, as measured by the continuous monitoring system, falls below the water-to-fuel ratio at the corresponding operating load specified in Special Condition No. C.3 of this attachment; and
   iii. Any opacity measurements, as measured by the transmissometer continuous monitoring system, exceeding the opacity limits and corresponding averaging times set forth in Special Condition No. D.2 of this attachment.

g. On and after the date of completion of the source performance test and CEMS certification, excess emissions indicated by the continuous emission monitoring system shall be considered violations of the applicable emission limit for the purposes of the permit with the following exceptions:

   i. During the twenty (20) minute and ninety (90) minute start-up period of the combustion turbine generators operating in the simple cycle mode and combined cycle mode, respectively;
   ii. During the twenty (20) minute shutdown period of the combustion turbine generators operating in either the simple cycle mode or combined cycle mode;
   iii. ~~Nitrogen oxide emissions in excess of forty-two (42) ppmvd at fifteen (15) percent~~ ~~O_2 while operating in simple cycle mode and combined cycle mode at loads less~~ ~~than fifty (50) percent of peak load or fifteen (15) ppmvd at fifteen (15) percent O_2~~

~~while operating in combined cycle mode at loads equal to or greater than fifty (50) percent of peak load if it can be shown that the excess emissions resulted from the firing of fuel with a fuel-bound nitrogen content in excess of 0.015 percent by weight. Under no circumstance shall the nitrogen oxide emission limit of 42.3 pounds per hour while operating in simple cycle mode and combined cycle~~

~~mode at loads less than fifty (50) percent of peak load or 15.1 pounds per hour while operating in combined cycle mode at loads equal to or greater than fifty (50) percent of peak load, as specified in Special Condition No. D.1 of this attachment, be exceeded.~~

Justification *– The exception is not needed. Hawai'i Electric Light has not claimed the optional fuel-bound nitrogen emission allowance under NSPS Subpart GG and does not plan to claim the allowance in the future. Refer to the proposed modification to Attachment IIA, Special Condition C.4.b and the corresponding justification.*

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-161; 40 CFR Part §60.13)

6. The permittee shall submit **semi-annually** the following written reports to the Department. The report shall be submitted **within sixty (60) days** after the end of each semi-annual calendar period, and shall include the following:

   a. A monthly summary listing the time and duration of all start-up and shut-down sequences for each combustion turbine. The summary shall include the combustion turbine generator load (MW) at the time the air pollution control devices and systems are initiated and terminated. The enclosed **Monitoring Report Form: Daily Startup and Shutdown**, or similar form, shall be used.
   b. Except for all start-up and shutdown sequences, report all periods where the minimum operating load for each combustion turbine was less than twenty-five (25) percent of the rated capacity. The report shall include the date, time, and duration of each period.
   c. A summary of the occurrences and duration of any malfunction in the operation of the combustion turbine generators and air pollution control devices. The summary shall be for each semi-annual reporting period and include the corrective actions taken during the reporting period. Malfunctions occurring in previous reporting periods shall be continually listed in the summary until the corrective actions are completed.
   d. A report identifying the type of fuel fired in each of the combustion turbines during the semi-annual reporting period. The report shall include the maximum sulfur content (percent by weight) ~~and the average nitrogen content (percent by weight)~~ of the fuel for the reporting period. ~~The report shall identify the means and methods used to verify the sulfur and nitrogen content of each fuel.~~ The enclosed **Monitoring Report Form: Fuel Certification**, or ~~similar~~ equivalent form, shall be used.

Justification *– This requirement is no longer needed. Refer to the proposed modification to Attachment IIA, Special Condition C.4.b and the corresponding justification.*

e. Except during the start-up and shutdown sequences, a report detailing all incidences where the air pollution control devices/systems were not fully operational when the combustion turbines were operating. The report for each combustion turbine shall include the date, time, and duration of each incidence. The report shall list the corrective actions taken and the operational procedures used to minimize emissions during the incident.

(Auth.: HAR §11-60.1-3, §11-60.1-5, §11-60.1-90, §11-60.1-161; 40 CFR §60.334)

7. Annual Emissions

As required by Attachment IV and in conjunction with the requirements of Attachment III, Annual Fee Requirements, the permittee shall submit **annually** the total tons/yr. emitted of each regulated air pollutant, including hazardous air pollutants. The reporting of annual emissions is due **within sixty (60) days** following the end of each calendar year. The enclosed Annual Emissions Forms shall be used.

Upon a written request from the permittee, the deadline for reporting of annual emissions may be extended, if the Department determines that reasonable justification exists for the extension.

(Auth.: HAR §11-60.1-3, §11-60.1-5, §11-60.1-90)

8. Compliance Certification

During the permit term, the permittee shall submit at least **annually** to the Department and U.S. EPA, Region 9, the attached **Compliance Certification Form** pursuant to HAR, §11-60.1-86. The permittee shall indicate whether or not compliance is being met with each term or condition of this permit. The compliance certification shall include, at a minimum, the following information:

a. The identification of each term or condition of the permit that is the basis of the certification;
b. The compliance status;
c. Whether compliance was continuous or intermittent;
d. The methods used for determining the compliance status of the source currently and over the reporting period;
e. Any additional information indicating the source's compliance status with any applicable enhanced monitoring and compliance certification including the requirements of Section 114(a)(3) of the Clean Air Act or any applicable monitoring and analysis provisions of Section 504(b) of the Clean Air Act; and
f. Any additional information as required by the Department including information to determine compliance.

The compliance certification shall be submitted **within ninety (90) days** after the end of each calendar year and shall be signed and dated by a responsible official. Upon a written request from the permittee, the deadline for submitting the compliance certification may be extended, if the Department determines that reasonable justification exists for the extension.

(Auth.: HAR §11-60.1-4, §11-60.1-86, §11-60.1-90)

Section G. Testing Requirements

1. **Within sixty (60) days** after achieving the maximum production rate of the 16 MW steam turbine, but not later than one hundred eighty (180) days after the initial start-up of the 16 MW steam turbine (as defined in 40 CFR §60.2), the permittee shall conduct or cause to be conducted performance tests on the combustion turbine generators operating with SCR in the combined cycle mode.

   (Auth.: HAR §11-60.1-5, §11-60.1-11, §11-60.1-90, §11-60.1-161; 40 CFR §60.335)[1]

2. The permittee shall conduct or cause to be conducted, performance tests on the combustion turbine generators while operating in simple cycle mode, combined cycle mode at loads less than fifty (50) percent of peak load, and combined cycle mode with SCR at loads equal to and greater than fifty (50) percent peak load **on an annual basis** or at other times specified by the Department.

   (Auth.: HAR §11-60.1-5, §11-60.1-11, §11-60.1-90, §11-60.1-161; 40 CFR §60.335)[1]

3. All performance tests shall be conducted at twenty-five (25), fifty (50), seventy-five (75), and one hundred (100) percent of the peak load of the combustion turbine generators. The Department may require the permittee to conduct the performance tests at additional operating loads.

   (Auth.: HAR §11-60.1-5, §11-60.1-11, §11-60.1-90, §11-60.1-161; 40 CFR §60.8, §60.335)[1]

4. The performance tests on the combustion turbines operating in the simple cycle and combined cycle modes shall be conducted for NO_x, SO_2, CO, PM, and VOC.

   (Auth.: HAR §11-60.1-5, §11-60.1-11, §11-60.1-90, §11-60.1-161; 40 CFR §60.335)[1]

5. The performance test on the combustion turbines operating in the combined cycle mode with SCR shall be conducted for NO_x, SO_2, CO, PM, VOC, and ammonia (NH_3).

   A performance test shall also be conducted for CO_2 or O_2 concentrations in the gas stream at a point between the exit of the combustion turbine with water injection and the entrance to the SCR system.

   (Auth.: HAR §11-60.1-5, §11-60.1-11, §11-60.1-90, §11-60.1-161; 40 CFR §60.335)[1]

6. The Department may define specific water-to-fuel injection ratios for which the performance tests will be conducted.

   (Auth.: HAR §11-60.1-5, §11-60.1-11, §11-60.1-90)

7. The Department may waive a specific performance test upon prior written request of the permittee. Such a request would need to be justified on the grounds that prior tests had shown compliance by a wide margin, and that adequate means exist to show continuing compliance.

   (Auth.: HAR §11-60.1-3, §11-60.1-90)

8. Performance tests for the emissions of SO_2, NO_x, CO, VOC, PM, CO_2, and NH_3 shall be conducted and results reported in accordance with the test methods set forth in 40 CFR Part 60, Appendix A, and 40 CFR Part 60.8. The following test methods or U.S. EPA-approved equivalent methods, or alternate methods with prior written approval from the Department, shall be used:

   a. Performance tests for the emissions of SO_2 shall be conducted using the 40 CFR Part 60, Methods 1-4 and 20.
   b. Performance tests for the emissions of NO_x shall be conducted using 40 CFR Part 60, Methods 1-4 and 20.
   c. Performance tests for the emissions of CO shall be conducted using 40 CFR Part 60, Methods 1-4 and 10.
   d. Performance tests for the emissions of VOC shall be conducted using 40 CFR Part 60, Methods 1-4 and 25A.
   e. Performance tests for the emissions of particulate matter shall be conducted using 40 CFR Part 60, Methods 1-5.
   f. Performance tests for the emissions of CO_2 shall be conducted using 40 CFR Part 60, Method 20, Equations 20-2 and 20-5.
   g. Performance test for the emissions of NH_3 shall be conducted using U.S. EPA Conditional Test Method 027(CTM-027).

   (Auth.: HAR §11-60.1-5, §11-60.1-11, §11-60.1-90, §11-60.1-161; SIP §11-60.15; 40 CFR §60.335)[1, 2]

9. The performance test shall consist of three (3) separate runs using the applicable test method. For the purpose of determining compliance with an applicable regulation, the arithmetic mean of the results from the three (3) runs shall apply.

   (Auth.: HAR §11-60.1-5, §11-60.1-11, §11-60.1-90, §11-60.1-161; SIP §11-60.15; 40 CFR §60.8)[1, 2]

10. The permittee shall demonstrate compliance with the NO_x emission limit specified in 40 CFR §60.332 by using the test methods and procedures of 40 CFR §60.335(b).

(Auth.: HAR §11-60.1-5, §11-60.1-11, §11-60.1-90, §11-60.1-161; 40 CFR §60.335)[1]

11. **At least thirty (30) calendar days** prior to performing a test, the permittee shall submit a written performance test plan to the Department and U.S. EPA, Region 9, that describes the test duration, test locations, test methods, source operation and other parameters that may affect test results. Such a plan shall conform to U.S. EPA guidelines including quality assurance procedures. A test plan or quality assurance plan that does not have the approval of the Department may be grounds to invalidate any test and require a retest.

    (Auth.: HAR §11-60.1-5, §11-60.1-11, §11-60.1-90, §11-60.1-161; SIP §11-60.15; 40 CFR §60.8)[1,2]

12. The permittee shall provide sampling and testing facilities at its own expense. The Department may monitor the performance tests.

    (Auth.: HAR §11-60.1-3, §11-60.1-5, §11-60.1-11, §11-60.1-90; SIP §11-60.15)[2]

13. Any deviations from these conditions, test methods, or procedures may be cause for rejection of the test results unless such deviations are approved by the Department before the tests.

    (Auth.: HAR §11-60.1-11, §11-60.1-90; SIP §11-60.15)[2]

14. **Within sixty (60) days** after completion of the performance test, the permittee shall submit to the Department and U.S. EPA, Region 9, the test report which shall include the operating conditions of the combustion turbine generators at the time of the test, the analysis of the fuel, the summarized test results, and other pertinent field and laboratory data.

    (Auth.: HAR §11-60.1-11, §11-60.1-90)

Section H. Agency Notification

Any document (including reports) required to be submitted by this CSP shall be done in accordance with Attachment I, Standard Condition No. 28.

(Auth.: HAR §11-60.1-4, §11-60.1-90)

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[1] The citations to the Code of Federal Regulations (CFR) identified under a particular condition, indicate that the permit condition complies with the specified provision(s) of the CFR. Due to the integration of the preconstruction and operating permit requirements, permit conditions may incorporate more stringent requirements than those set forth in the CFR.

[2] The citations to the State Implementation Plan (SIP) identified under a particular condition, indicate that the permit condition complies with the specified provision(s) of the SIP.

[3] This date is to be revised upon issuance of the renewal for CSP No. 0007-01-C.

ATTACHMENT IIB: SPECIAL CONDITIONS FOR THE COMBUSTION TURBINE, UNIT CT-2
COVERED SOURCE PERMIT NO. 0007-01-C

Issuance Date: June 27, 2018 **Expiration Date: August 6, 2013 [3]**

In addition to the standard conditions of the Covered Source Permit, the following special conditions shall apply to the permitted facility:

Section A. Equipment Description

1. This permit encompasses the following equipment and associated appurtenances:

   One (1) 18 MW (nominal) Simple Cycle Combustion Turbine Generator, Model Jupiter GT-35 (Manufactured by Asea Brown Boveri (ABB) and supplied by Solar Turbines) with a maximum design heat input rate of 198 MMBtu/hr, unit CT-2.

   (Auth.: HAR §11-60.1-3)

2. The permittee shall have installed an identification tag or name plate on Unit CT-2 which identifies the model no., serial no., and manufacturer. The identification tag or name plate shall be permanently attached to the equipment at a conspicuous location.

   (Auth.: HAR §11-60.1-5)

Section B. Applicable Federal Regulations

1. Unit CT-2 is subject to the provisions of the following federal regulations:

   a. 40 CFR Part 60, Standards of Performance for New Stationary Sources, Subpart A, General Provisions; and
   b. 40 CFR Part 60, Standards of Performance for New Stationary Sources, Subpart GG, Standards of Performance for Stationary Gas Turbines.

   The permittee shall comply with all applicable provisions of these standards, including all emission limits, notification, testing, monitoring, and reporting requirements. The major requirements of these standards are detailed in the special conditions of this permit.

   (Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-132, §11-60.1-161; 40 CFR 60.2, 40 CFR 60.330)[1]

2. This CSP incorporates conditional requirements from an existing permit issued pursuant to 40 CFR §52.21, Prevention of Significant Deterioration of Air Quality.

   (Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-132; 40 CFR §52.21)[1]

Section C. Operational Limitations

1. The "start-up" time for Unit CT-2 shall not exceed twenty (20) minutes. A "start-up" sequence shall be from the time fuel use at Unit CT-2 commences, until the time Unit CT-2 is initially brought up to twenty-five (25) percent peak load at which time the operation of the air pollution control equipment shall commence.

   (Auth.: HAR §11-60.1-3, §11-60.1-5, §11-60.1-90)

2. The "shut-down" time for Unit CT-2 shall not exceed twenty (20) minutes. A "shut-down" sequence shall be considered from the time when Unit CT-2 is below twenty-five (25) percent peak load, until fuel use at Unit CT-2 ceases.

   (Auth.: HAR §11-60.1-3, §11-60.1-5, §11-60.1-90)

3. Minimum Operational Loads

   Except during Unit CT-2's "start-up" and "shut-down," maintenance, or testing, Unit CT-2's load shall not be less than twenty-five (25) percent of the rated capacity.

   (Auth.: HAR §11-60.1-3, §11-60.1-5, §11-60.1-90)

4. Air Pollution Control Equipment

   a. The permittee shall continuously operate and maintain a combustor water injection system to meet the emission limits as specified in Special Condition No. C.6 of this attachment.
   b. The operation of the combustor water injection system shall commence operation within twenty (20) minutes of start-up of Unit CT-2, and shall continue to operate within twenty (20) minutes of shutdown of Unit CT-2. The combustor water injection system shall be used whenever Unit CT-2 is operating at twenty-five (25) percent peak load and above, and shall be maintained at a minimum water-to-fuel mass ratio as follows:

WATER INJECTION SYSTEM
MINIMUM WATER INJECTION RATES BASED ON LOAD

Percent Peak load (%)	Load (MW)	Ratio (lb-water / lb-fuel)
100	18.3	1.00
75 - <100	13.7 - <18.3	0.75
50 - <75	9.15 - <13.7	0.55
25 - <50	4.6 - <9.15	0.3

c. The Department, with U.S. EPA's concurrence, may increase the minimum water injection rates after reviewing the performance test results required in Section F of this attachment.

d. The use of an alternate control system other than those specified above (contingent upon receipt of the Department's written approval to use such a system) shall not relieve the permittee from the responsibility to meet all emission limitations contained within this CSP.

(Auth.: HAR §11-60.1-3, §11-60.1-5, §11-60.1-90)

5. Fuel Usage and Specifications

a. Unit CT-2 shall be fired only on fuel oil No. 2 with a maximum sulfur content not to exceed 0.4 percent by weight. The use of fuel additives to control algae, inhibit corrosion or improve fuel combustion may be used in combination with the fuel oil No. 2.

b. The maximum amount of fuel oil No. 2 fired in Unit CT-2 shall not exceed 24,407 barrels per month or 292,887 barrels per any rolling twelve (12) month period.

~~c. The fuel bound nitrogen content of the fuel fired in Unit CT-2 shall not exceed 0.015 percent by weight on a rolling twelve (12) month average.~~

***Justification** – Hawai'i Electric Light requests to delete the requirement to monitor fuel-bound nitrogen content in fuel because it is not required by NSPS Subpart GG if the NO_X emission allowance for fuel-bound nitrogen is not claimed. Please refer to 40 CFR §60.334(h)(2) and 69 FR 41345, July 8, 2004. Hawai'i Electric Light has not claimed the optional fuel-bound nitrogen emission allowance under NSPS Subpart GG and does not plan to claim the allowance in the future. Thus, the nitrogen monitoring condition is not required and should be removed from the CSP. No changes are requested for the NO_X emissions limitation and the corresponding monitoring and reporting conditions. Compliance with the NO_X emissions limitation will continue to be monitored and demonstrated using Continuous Emissions Monitoring System (CEMS). Any excess NO_X emissions will continue to be reported as required by the CSP.*

(Auth.: HAR §11-60.1-3, §11-60.1-5, §11-60.1-90, §11-60.1-161, 40 CFR §60.333)[1]

6. Maximum Emission Limits

Except for Unit CT-2's "start-up" and "shut-down" sequence, the permittee shall not discharge or cause the discharge into the atmosphere from Unit CT-2, nitrogen oxides, sulfur dioxide, particulate matter/PM_{10}, carbon monoxide, and volatile organic compounds in excess of the following specified limits as noted below:

MAXIMUM EMISSION LIMITS (3-hour average)

Air Pollutant	lbs/hr	ppmvd @ 15 percent O_2
Nitrogen Oxides (as NO_2)	39	47
Sulfur Dioxide	110	95.4
Particulate Matter/PM_{10}	20	0.06*
Carbon Monoxide	22.4	44.4
Volatile Organic Compounds	22.4	28.2**

Based on Unit CT-2 operating at ISO atmospheric conditions (59°F, 60% relative humidity and 19.92 in mercury (Hg) pressure).
* gr/dscf @ 12 percent CO_2.
**Using a molecular weight of 44 (propane) for Volatile Organic Compounds (VOC).

For the purposes of the annual performance tests and the continuous monitoring system, emission limits shall be measured on a rolling three (3) hour average.

The Department, with U.S. EPA's concurrence, may lower the allowable emission limitation for nitrogen oxides, particulate matter, carbon monoxide, and volatile organic compounds after reviewing the performance test results required in Section F of this attachment.

If the nitrogen oxides, particulate matter/PM_{10}, carbon monoxide or volatile organic compounds emission limit is revised, the difference between the applicable emission limit set forth above and the revised lower emission limit shall not be allowed as an emission offset for future construction or modification.

(Auth.: HAR §11-60.1-3, §11-60.1-5, §11-60.1-90, §11-60.1-161; 40 CFR §60.332, 40 CFR §60.333)[1]

7. Visible Emissions (VE)

For any six (6) minute averaging period, Unit CT-2 shall not exhibit visible emissions of twenty (20) percent opacity or greater, except as follows: during equipment "start-up" or "shut-down," or equipment breakdown, Unit CT-2 may exhibit emissions greater than twenty (20) percent opacity but not exceeding sixty (60) percent opacity for a period aggregating not more than six (6) minutes in any sixty (60) minutes.

(Auth.: HAR §11-60.1-3, §11-60.1-32, §11-60.1-90; SIP §11-60-24)[2]

8. Alternate Operating Scenarios

   a. Terms and conditions for reasonably anticipated operating scenarios identified by the source in the CSP application and approved by the Department are as follows:

i. Temporary Replacement. Upon receiving written approval from the Department, the permittee may use a temporary replacement unit identical to the permitted equipment in the event of a failure or major overhaul of the permitted equipment. Emissions from the replacement unit shall comply with all applicable requirements of the permitted unit. In requesting for approval, the permittee shall at a minimum provide the Department the reason and estimated time period/dates for temporary replacement, type and size of the temporary unit, emissions data, stack parameters, and measures to be taken in minimizing the time period needed for a temporary unit. The Department may require an ambient air quality assessment of the temporary unit, and/or provide a conditional approval to impose additional monitoring, testing, recordkeeping, and reporting requirements to ensure the temporary unit is in compliance with the applicable requirements of the permitted unit being temporarily replaced.

ii. Alternate Fuels. Upon receiving written approval from the Department, the use of alternative fuels may be allowed provided that all permit conditions are met. The permittee must submit all pertinent documentation (e.g., calculations, specifications, etc.) to the Department to demonstrate compliance with permit conditions.

iii. Emergency load conditions. Certain equipment malfunctions (such as the sudden loss of a unit) may necessitate the operation of Unit CT-2 at loads as high as one hundred ten (110) percent of peak load. The time period of this operation will be limited to no more than thirty (30) minutes in duration. These operations shall not exceed the three (3) hour average maximum emission limits as specified in Special Condition No. C.6 of this attachment.

iv. Unpredictable periods of equipment failure, upsets, or emergency conditions. During any emergency condition, the permittee will operate the subject equipment in such a manner as to minimize emissions. The permittee shall comply with the Emergency Provisions.

v. If approved by the Department, the burning of naphtha or other cleaner burning fuels.

b. The permittee shall, contemporaneously with making a change from one operating scenario to another, record in a log at the permitted facility the scenario under which it is operating and, if required by any applicable requirement or by the Department, submit written notification to the Department.

c. The terms and conditions under each alternative operating scenario shall meet all applicable requirements including all conditions of this permit.

(Auth.: HAR §11-60.1-3, §11-60.1-5, §11-60.1-90)

Section D. Monitoring and Recordkeeping

1. The permittee shall at its own expense continue to operate, calibrate, and maintain a continuous monitoring system and total volumetric flow metering system for Unit CT-2 to

measure and record the following parameters or data. The associated date and time of the monitored data shall also be recorded.

a. Operating load in MW;
b. Water-to-fuel ratio. The water-to-fuel monitor/recorder shall be accurate to ±5 percent;
c. Fuel consumption in gal/hr using a volumetric flow metering system; and
d. NO_x, CO, and CO_2 or O_2 concentrations in the stack gases using a CEMS. The system shall meet U.S. EPA performance specifications (40 CFR Part 60, Section 60.13 and 40 CFR Part 60, Appendix B and Appendix F). If CO_2 is measured with the CEMS to adjust the pollutant concentration, the CO_2 correction factor equations listed in 40 CFR §60.4213(d)(3) shall be used to determine compliance with the applicable emissions limit. The CEMS shall be on-line and fully operational, upon completion and thereafter of the performance specification test. The emissions for NO_x and CO shall be recorded in ppmvd at fifteen (15) percent O_2 and lbs/hr.

(Auth.: HAR §11-60.1-3, §11-60.1-5, §11-60.1-11, §11-60.1-90, §11-60.1-161; SIP §11-60-15; 40 CFR §60.334)[1,2]

2. Visible Emissions (VE)

a. The permittee shall conduct **monthly** *(calendar month)* VE observations for Unit CT-2 in accordance with 40 CFR Part 60, Appendix A, Method 9 or by use of a Ringelmann chart as provided. For each period, two (2) observations shall be taken at fifteen (15) second intervals for six (6) consecutive minutes for Unit CT-2. Records shall be completed and maintained in accordance with the **Visible Emissions Form Requirements.**
b. The permittee shall conduct **annually** *(calendar year)* VE observations for Unit CT-2 by a certified reader in accordance with 40 CFR Part 60, Appendix A, Method 9. For each period, two (2) observations shall be taken at fifteen (15) second intervals for six (6) consecutive minutes for Unit CT-2. Records shall be completed and maintained in accordance with the **Visible Emissions Form Requirements.**
c. Upon written request and justification, the Department may waive the requirements for the **annual** VE observations. The waiver request is to be submitted prior to the required test and must include documentation justifying such action. Documentation should include, but is not limited to, the results of the prior tests indicating compliance by a wide margin, documentation of continuing compliance, and further that operations of the source have not changed since the previous **annual** VE observations.
d. The Department may at any time require the permittee to install, operate, and maintain a transmissometer system for the continuous measurement and recording of the opacity of stack emissions if it is determined that the visible emissions are in excess of the applicable standard. The system shall meet U.S. EPA monitoring performance standards (40 CFR §60.13 and 40 CFR Part 60, Appendix B, Performance Specifications).

(Auth.: HAR §11-60.1-3, §11-60.1-5, §11-60.1-11, §11-60.1-32, §11-60.1-90; SIP §11-60-15, SIP §11-60-24)[2]

3. Daily "start-up" and "shut-down" times. The start and end times of each sequence shall be recorded. In addition, the operating load (MW) at which the air pollution control equipment was initiated and terminated shall be recorded.

   (Auth.: HAR §11-60.1-3, §11-60.1-5, §11-60.1-90)

4. Fuel Data

   a. Sulfur content in the fuel. The sulfur content in the fuel to be fired in Unit CT-2 shall be tested in accordance with the most current ASTM methods. ASTM method D4294-98 is a suitable alternative to Method D129-00 for determining the sulfur content. The fuel sulfur content shall be verified by both of the following methods:

      i. A representative sample of each batch of fuel received shall be analyzed for its sulfur content; and
      ii. A certificate of analysis on the sulfur content shall be obtained for each batch of the fuel delivered by the supplier.

   b. Records of the sulfur content of the fuel shall be maintained on a monthly basis.
   c. Total fuel usage. Records on the total amount (gallons) used by Unit CT-2 shall be maintained on a monthly and rolling twelve (12) month basis.
   ~~d. Nitrogen content in the fuel. The fuel bound nitrogen content of the fuel to be fired in Unit CT-2 shall be verified by taking and analyzing a representative sample of each batch of fuel received to determine the nitrogen content by weight.~~
   ~~e. Records of the nitrogen content of the fuel shall be maintained on a monthly and rolling twelve (12) month basis.~~

   ***Justification** – These requirements are no longer needed. Refer to the proposed modification to Attachment IIB, Special Condition C.5.c and the corresponding justification.*

   (Auth.: HAR §11-60.1-3, §11-60.1-5, §11-60.1-11, §11-60.1-90, §11-60.1-161; SIP §11-60-15; 40 CFR §60.334)[1,2]

5. Performance Test.

   An annual source performance test shall be conducted pursuant to Section F of this attachment. Records of test summaries and results shall be maintained.

   (Auth.: HAR §11-60.1-3, §11-60.1-5, §11-60.1-11, §11-60.1-90, §11-60.1-161; SIP §11-60-15)[2]

6. An inspection, maintenance, and repair log shall be maintained for Unit CT-2.

   (Auth.: HAR §11-60.1-3, §11-60.1-5, §11-60.1-11, §11-60.1-90)

7. The permittee shall maintain a permanent file of all measurements, including continuous monitoring system, monitoring device, and performance testing requirements: all

continuous monitoring system performance evaluations; all continuous monitoring system of monitoring device calibration checks; adjustments and maintenance performed on these systems or devices; and all other information required by 40 CFR Part 60 recorded in a permanent form suitable for inspection. The file shall be retained for at least five (5) years following the date of such measurements, maintenance reports, and records.

(Auth.: HAR §11-60.1-3, §11-60.1-90)

Section E. Notification and Reporting Requirements

1. Notification and reporting pertaining to the following events shall be done in accordance with Attachment I, Standard Conditions 16, 17, and 25, respectively:

   a. Intent to shut down air pollution control equipment for necessary scheduled maintenance;
   b. Emissions of air pollutants in violation of HAR, Chapter 11-60.1 or this permit (excluding technology-based emission exceedances due to emergencies); and
   c. Permanent discontinuance of construction, modification, relocation, or operation of the facility covered by this permit.

   (Auth.: HAR §11-60.1-8, §11-60.1-15, §11-60.1-16, §11-60.1-90; SIP §11-60-10, SIP §11-60-16)[2]

2. The permittee shall report (in writing) **within five (5) working days** *any deviations from permit requirements,* including those attributable to upset conditions, the probable cause of such deviations and any corrective actions or preventive measures taken. Corrective actions may include a requirement for additional stack testing, or more frequent monitoring, or could trigger implementation of a corrective action plan.

   (Auth.: HAR §11-60.1-3, §11-60.1-15, §11-60.1-16, §11-60.1-90)

3. **At least thirty (30) days prior** to the following events, the permittee shall notify the Department in writing of:

   a. Conducting a performance specification test on the CEMs. The testing date shall be in accordance with the performance test date identified in 40 CFR §60.13.
   b. *Conducting a source performance test* as required in Section F of this attachment.

   (Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-161; 40 CFR §60.8, 40 CFR §60.13)[1]

4. Excess Emissions.

   The permittee shall submit an excess emissions and monitoring systems performance report of *all excess emissions, including those associated with the water-to-fuel ratio requirement and implementation of any alternate operating scenarios,* to the Department for **every semi-annual calendar period**. The report shall include the following:

a. The magnitude of excess emissions computed in accordance with 40 CFR §60.13(h), any conversion factors used, and the date and time of commencement and completion of each time period of excess emissions, and the corresponding operating load of Unit CT-2.
b. Specific identification of each period of excess emissions that occurs during "start-ups," "shut-downs," and malfunctions of Unit CT-2. The nature and cause of any malfunction (if known), and the corrective action taken or preventive measures adopted, shall also be reported.
c. The date and time identifying each period during which continuous monitoring system was inoperative except for zero and span checks. The nature of each system repair or adjustment shall be described.
d. The report shall so state if no excess emissions have occurred. Also, the report shall so state if the CEMS operated properly during the period and was not subject to any repairs or adjustments except for zero and span checks.

~~e. For periods of excess emissions as defined in Special Condition No. E.4.g.ii of this attachment, the report shall also include the average water-to-fuel ratio, average fuel consumption, ambient temperature, gas turbine load, and nitrogen content of the fuel during the period of excess emissions.~~

***Justification** – The deletion is requested in the 7/30/2012 renewal application submitted to the Department of Health. The exclusion of the nitrogen content is consistent with the proposed modification in this application. Refer to the proposed modification to Attachment IIB, Special Condition C.5.c and the corresponding justification.*

f. All reports shall be postmarked by the **30th day following the end of each semi-annual calendar period**. The enclosed **Excess Emission and Monitoring System Performance Summary Report** form or an equivalent form approved by the Department shall be used in conjunction to the reporting of excess emissions of NO_x and CO.
g. For purposes of this CSP, excess emissions shall be defined as follows:

    i. Any three (3) hour period during which the average emissions of NO_x and CO, as measured by the continuous monitoring system, exceed the emission limits set forth in Special Condition No. C.6 of this attachment; and
    ii. Any one (1) hour period during which the average water-to-fuel ratio, as measured by the continuous monitoring system, falls below the water-to-fuel ratio at the corresponding operating load specified in Special Condition No. C.4.b of this attachment. When the load is not constant, provided that the above water injection rates at the four different peak load conditions are maintained, and NO_x emissions do not exceed the limits given in Special Condition No. C.6 of this attachment, a mathematical deviation on the one-hour average will not be considered out of compliance.

h. On and after the date of completion of the source performance test and CEMs certification, excess emissions indicated by the continuous emission monitoring system shall be considered violations of the applicable emission limit for the purposes of the permit with the following exceptions:

i. During the twenty (20) minute "start-up" period of Unit CT-2.
ii. During the twenty (20) minute "shut-down" period of Unit CT-2.
~~iii. Nitrogen oxide emissions in excess of forty-seven (47) ppmvd at fifteen (15) percent O_2, if it can be shown that the excess emissions resulted from the firing of fuel with a fuel-bound nitrogen content in excess of 0.015 percent by weight.~~

Justification *– The exception is not needed. Hawai'i Electric Light has not claimed the fuel-bound nitrogen emission allowance under NSPS Subpart GG and does not plan to claim the allowance in the future. Refer to the proposed modification to Attachment IIB, Special Condition C.5.c and the corresponding justification.*

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.161; 40 CFR 60.7, 40 CFR §60.13, 40 CFR §60.334)[1]

5. The permittee shall submit **semi-annually** the following written reports to the Department. The report shall be submitted **within sixty (60) days** *after the end of each semi-annual calendar period (January 1 to June 30 and July 1 to December 31)*, and shall include the following:

   a. Monthly summary showing the daily "start-up" and "shut-down" times and duration sequence for Unit CT-2. Include the associated load (MW) of Unit CT-2 at the start-up and termination of the air pollution control device. Include total operating hours per day and the total operating hours by month for Unit CT-2. The enclosed **Monitoring Report Form: Daily Startup and Shutdown** or an equivalent form approved by the Department shall be used in reporting Unit CT-2's "start-up" and "shut-down" sequence.
   b. A summary report of the occurrence and duration of any malfunction in the operation of Unit CT-2 and air pollution equipment, and the corrective actions taken. The malfunctions reported shall be such as to cause the emission of air pollutants in violation of HAR, Chapter 11-60.1 or this permit.
   ~~c. Receipt dates of fuel deliveries, type of fuel, date batch sample taken, and the analyzed sulfur and nitrogen content in the fuel. Include copies of the supplier's certificate of analysis showing the sulfur content of the fuel delivered.~~ A report identifying the type of fuel fired in the combustion turbine during the semi-annual reporting period. The report shall include the maximum sulfur content (percent by weight) of the fuel for the reporting period. The enclosed Monitoring Report Form: *Fuel Certification*, or an equivalent form, shall be used.

Justification *– The deletion is requested in the 12/10/2015 renewal application submitted to the Department of Health. The exclusion of the nitrogen content is consistent with the proposed modification in this application. Refer to the proposed modification to Attachment IIB, Special Condition C.5.c and the corresponding justification.*

d. Minimum combustion turbine generator load. Except for Unit CT-2's "start-up" and "shut-down" sequence, report all periods of time (date, time and duration) when the minimum operating load for Unit CT-2 is less than twenty-five (25) percent of the rated capacity.
e. Gallons of the fuel fired in Unit CT-2 on a monthly and rolling twelve (12) month basis. The enclosed **Monitoring Report Form: Fuel Consumption** or an equivalent form approved by the Department, shall be used in reporting.
f. Any opacity exceedances as determined by the required VE monitoring. Each exceedance reported shall include the date, six (6) minute average opacity reading, possible reason for exceedance, duration of exceedance, and corrective actions taken. If there were no exceedances, the permittee shall submit in writing a statement indicating that for each equipment there were no exceedances for that semi-annual period. The enclosed **Monitoring Report Form: Visible Emissions Exceedances,** shall be used for reporting.
g. Deviations from permit requirements shall be clearly identified and addressed in these reports.

(Auth.: HAR §11-60.1-3, §11-60.1-5, §11-60.1-32, §11-60.1-90, §11-60.161; 40 CFR §60.334)[1]

6. Compliance Certification

During the permit term, the permittee shall submit at least **annually** to the Department and U.S. EPA, Region 9, the attached **Compliance Certification Form** pursuant to HAR, Subsection 11-60.1-86. The permittee shall indicate whether or not compliance is being met with each term or condition of this permit. The compliance certification shall include, at a minimum, the following information:

a. The identification of each term or condition of the permit that is the basis of the certification;
b. The compliance status;
c. Whether compliance was continuous or intermittent;

d. The methods used for determining the compliance status of the source currently and over the reporting period;
e. Any additional information indicating the source's compliance status with any applicable enhanced monitoring and compliance certification including the requirements of Section 114 (a)(3) of the Clean Air Act or any applicable monitoring and analysis provisions of Section 504(b) of the Clean Air Act; and
f. Any additional information as required by the Department including information to determine compliance.

The compliance certification shall be submitted within **ninety (90) days** after the end of each calendar year and shall be signed and dated by a responsible official. Upon written request of the permittee, the deadline for submitting the compliance certification may be extended, if the Department determines that reasonable justification exists for the extension.

(Auth.: HAR §11-60.1-4, §11-60.1-86, §11-60.1-90)

7. Annual Emissions.

As required by Attachment IV and in conjunction with the requirements of Attachment III, the permittee shall submit **annually** the total tons/year emitted of each regulated air pollutant, including hazardous air pollutants. The reporting of annual emissions is due **within sixty (60) days** following the end of each calendar year. The enclosed **Annual Emission Reporting Form: Gas Turbines** or an equivalent form approved by the Department, shall be used in reporting.

Upon the written request of the permittee, the deadline for reporting the annual emissions may be extended, if the Department determines that reasonable justification exists for the extension.

(Auth.: HAR §11-60.1-3, §11-60.1-90)

Section F. Testing Requirements

1. The permittee shall conduct or cause to be conducted performance tests on Unit CT-2 in the simple cycle mode. Performance tests on Unit CT-2 shall be conducted for NO_x, SO_2, CO, PM/PM_{10}, and VOC. The performance tests for NO_x shall be conducted at twenty-five (25), fifty (50), seventy-five (75), and one hundred (100) percent of peak load of Unit CT-2, or at other operating loads as may be specified by the Department. The performance tests for SO_2, CO, PM/PM_{10}, and VOC shall be conducted at one hundred (100) percent of peak load of Unit CT-2. Performance tests shall be conducted on an annual basis or at such times as may be specified by the Department. The Department may define specific water-to-fuel injection ratios for which the performance tests will be conducted. For any performance test, a continuous monitoring system shall be in operation to monitor and record the ratio of water-to-fuel fired in Unit CT-2.

   Upon written request and justification, the Department may waive the requirement for a specific annual source test. The waiver request is to be submitted prior to the required test and must include documentation justifying such action. Documentation should include, but is not limited to, the results of the prior tests indicating compliance by a wide margin, documentation of continuing compliance, and further that operations of the source have not changed since the previous source test.

   (Auth.: HAR §11-60.1-3, §11-60.1-11, §11-60.1-90, §11-60.1-161; 40 CFR §60.8, 40 CFR §60.335)[1]

2. Performance tests for the emissions of NO_x, SO_2, CO, VOC, and PM/PM_{10} shall be conducted and results reported in accordance with the test methods set forth in 40 CFR Part 60, Appendix A and 40 CFR §60.8. The following test methods or U.S. EPA-

approved equivalent methods with prior written approval from the Department shall be used:

a. Performance tests for the emissions of SO_2 shall be conducted using 40 CFR Part 60, Methods 1-4 and 20.
b. Performance tests for the emissions of NO_x shall be conducted using 40 CFR Part 60, Methods 1-4 and 20.
c. Performance tests for the emissions of CO shall be conducted using 40 CFR Part 60, Methods 1-4 and 10.
d. Performance tests for the emissions of VOC shall be conducted using 40 CFR Part 60, Methods 1-4 and 25A.
e. Performance tests for the emissions of particulate matter shall be conducted using 40 CFR Part 60, Methods 1-5.

(Auth.: HAR §11-60.1-3, §11-60.1-11, §11-60.1-90, §11-60.1-161; SIP §11-60-15; 40 CFR §60.335)[1,2]

3. The performance test shall consist of three (3) separate runs using the applicable test method. For the purpose of determining compliance with an applicable regulation, the arithmetic mean of the results from the three (3) runs shall apply.

(Auth.: HAR §11-60.1-11, §11-60.1-90, §11-60.1-161; SIP §11-60-15; 40 CFR §60.8)[1,2]

4. At least **thirty (30) days** prior to performing a test, the permittee shall submit a written *performance test plan* to the Department that describes the test duration, test locations, test methods, source operation and other parameters that may affect test results. Such a plan shall conform to U.S. EPA guidelines including quality assurance procedures. A test plan or quality assurance plan that does not have the approval of the Department may be grounds to invalidate any test and require a retest.

(Auth.: HAR §11-60.1-3, §11-60.1-11, §11-60.1-90, §11-60.1-161; SIP §11-60-15; 40 CFR §60.8)[1,2]

5. The permittee shall provide sampling and testing facilities at its own expense. The tests shall be conducted at the operating capacities identified in Special Condition No. F.1 of this attachment, and the Department may monitor the tests.

(Auth.: HAR §11-60.1-3, §11-60.1-5, §11-60.1-11, §11-60.1-90)

6. Any deviations from these conditions, test methods, or procedures may be cause for rejection of the test results unless such deviations are approved by the Department before the tests.

(Auth.: HAR §11-60.1-11, §11-60.1-90)

7. **Within sixty (60) days** after completion of the performance test, the permittee shall submit

to the Department and U.S. EPA, Region 9, the test report which shall include the operating conditions of Unit CT-2 at the time of the test, the analysis of the fuel oil, the summarized test results, comparative results with the permit emission limits, and other pertinent field and laboratory data.

(Auth.: HAR §11-60.1-11, §11-60.1-90; SIP §11-60-15; 40 CFR 60.8)[1,2]

Section G. Agency Notification

Any document (including reports) required to be submitted by this CSP shall be done in accordance with Attachment I, Standard Condition No. 28.

(Auth.: HAR §11-60.1-4, §11-60.1-90)

[1]The citations to the Code of Federal Regulations (CFR) identified under a particular condition, indicate that the permit condition complies with the specified provision(s) of the CFR. Due to the integration of the preconstruction and operating permit requirements, permit conditions may incorporate more stringent requirements than those set forth in the CFR.

[2]The citations to the State Implementation Plan (SIP) identified under a particular condition, indicate that the permit condition complies with the specified provision(s) of the SIP.

[3]This date is to be revised upon issuance of the renewal for CSP No. 0007-01-C.

ATTACHMENT IIC: SPECIAL CONDITIONS FOR THE DIESEL ENGINES
COVERED SOURCE PERMIT NO. 0007-01-C

Issuance Date: June 27, 2018 **Expiration Date: August 6, 2013 [3]**

In addition to the Standard Conditions of the Covered Source Permit, the following Special Conditions shall apply to the permitted facility:

Section A. Equipment Description

1. This permit encompasses the following equipment and associated appurtenances:

   a. One (1) 2.5 MW General Motors EMD Model 20-645F4B Diesel Engine Generator, Unit No. D21;
   b. One (1) 2.5 MW General Motors EMD Model 20-645F4B Diesel Engine Generator, Unit No. D22;
   c. One (1) 2.5 MW General Motors EMD Model 20-645E4 Diesel Engine Generator, Unit No. D23; and
   d. One (1) 500 kW Caterpillar Model 3412 Black Start Diesel Engine Generator with an exhaust stack height of seventy (70) feet Unit No. BS-1.

   (Auth.: HAR §11-60.1-3)

2. The permittee shall permanently attach an identification tag or nameplate on each equipment, which identifies the model no., serial no., and manufacturer. The identification tag or nameplate shall be attached to the equipment at a conspicuous location.

   (Auth.: HAR §11-60.1-5)

Section B. Operational and Emission Limitations

1. Operating Hours, Unit BS-1

   The maximum operating hours of the black start diesel engine generator, Unit No. BS-1, shall not exceed three hundred (300) hours in any rolling twelve (12) month period.

   (Auth.: HAR §11-60.1-3, §11-60.1-5, §11-60.1-90)

2. Fuel Consumption Limit, Unit D21

   The maximum fuel consumption of diesel engine generator Unit No. D21 shall not exceed 70,000 gallons per rolling twelve (12) month period.

   (Auth.: HAR §11-60.1-3, §11-60.1-5, §11-60.1-90)

3. Fuel Injection Timing Retard

   Diesel engine generator Unit Nos. D21, D22, and D23 shall operate with a fuel injection timing retard of four (4) degrees at all loads.

   The permittee may use an alternate control system upon receiving the Department's written approval to use such a system. The alternate control system shall meet all emission limitations contained within this attachment.

4. Fuel Specifications

   The diesel engines shall be fired only on fuel oil No. 2 with a maximum sulfur content not to exceed 0.4 percent by weight, or alternative fuel allowed under Special Condition No. B.7.b of this attachment.

5. Maximum Emission Limit

   The diesel engine generators Unit Nos. D21, D22, and D23 shall not discharge into the atmosphere nitrogen oxides in excess of the following specified limit:

	Maximum Emission Limit (3-hour Average) [a]	
Compound	(lbs/hr)	(ppmvd @ 15 percent O_2)
Nitrogen Oxides [b]	68.4	600

[a]Emission limit per generator.
[b]Measured as nitrogen dioxide (NO_2).

The Department, with U.S. EPA's concurrence, may revise the allowable emission limitation for NO_x after reviewing the annual performance test results required under Section E of this attachment.

If the NO_x emission limit is revised, the difference between the applicable emission limit set forth above and the revised lower emission limit shall not be allowed as an emission offset for future construction or modification.

6. Opacity Limits

   For any six (6) minute averaging period, the diesel engine generators shall not exhibit visible emissions of twenty (20) percent or greater, except as follows: during start-up, shutdown, or equipment breakdown, the diesel engine generators may exhibit visible emissions greater than twenty (20) but not exceeding sixty (60) percent opacity for a period aggregating not more than six minutes (6) in any one (1) hour.

7. Alternate Operating Scenarios

Terms and conditions for reasonably anticipated operating scenarios identified by the permittee in the CSP application and approved by the Department are as follows:

a. Upon receiving written approval from the Department, the permittee may replace any of the permitted diesel engine generators with a temporary replacement unit in the event of a sudden malfunction or a planned major overhaul. The temporary replacement unit shall comply with all applicable permit conditions.

   A written request shall be submitted to the Department prior to the exchange and at a minimum, the request shall include the following:

   i. the reason for temporary replacement;
   ii. the removal and estimated return dates of the permitted unit;
   iii. the make, model, serial number, and size of the temporary replacement unit; and
   iv. the emissions data of the permitted and temporary replacement unit.

   The Department may require an ambient air quality impact analysis and/or may impose additional requirements on the temporary replacement unit to ensure compliance with the conditions of this permit.

b. Upon receiving written approval from the Department, the permittee may burn an alternative fuel or fuel additive provided the permittee demonstrates compliance with all applicable State and Federal requirements and applicable conditions of this CSP. The burning of the alternative fuel or fuel additive shall not result in an increase in emissions of any air pollutant or in the emission of any air pollutant not previously emitted. As a minimum, the following information must be included with any request to burn an alternate fuel or fuel additive.

   i. Specific type of fuel or fuel additive;
   ii. Composition and consumption rate of the fuel;
   iii. Fuel blending rate;
   iv. Emissions calculations;
   v. Ambient air quality analyses verifying that SAAQS will be met;
   vi. Fuel storage; and
   vii. Plan to monitor and record the fuel type and consumption.

c. The permittee shall contemporaneously with making a change from one alternate operating scenario to another, record in a log at the permitted facility the scenario under which it is operating and submit written notification to the Department.

d. The terms and conditions under each alternate operating scenario shall meet all applicable requirements, including conditions of this permit.

(Auth.: HAR §11-60.1-3, §11-60.1-5, §11-60.1-16.5, §11-60.1-90)

Section C. Monitoring and Recordkeeping Requirements

All records, including support information, shall be maintained for at least five (5) years from the date of the monitoring, measurement, test, report or application. Support information, including all maintenance, inspection and repair records for the diesel engine generators, shall be true, accurate, and maintained in a permanent form suitable for inspection and made available to the Department or their representative upon request.

1. Sulfur Content

   The sulfur content (% by weight) of the fuel fired in the diesel engines shall be verified by one of the following methods:

   a. A representative sample of each batch of fuel received shall be analyzed using the most current version of the following ASTM methods: D129, D2622, D4292, D5453, or D1552; or
   b. A certificate of analysis on the sulfur content shall be obtained from the fuel supplier for each batch of fuel received.

   (Auth.: HAR §11-60.1-3, §11-60.1-5, §11-60.1-90)

2. Operating Hours

   The permittee shall operate and maintain a non-resetting hour meter on the black start diesel engine generator, Unit No. BS-1, to permanently record the total hours that the unit has operated. Monthly records shall be kept of the beginning and ending meter readings and the total hours that Unit No. BS-1 operated during that month. A monthly summary shall include the total hours Unit No. BS-1 operated on a monthly and rolling twelve (12) month basis.

   (Auth.: HAR §11-60.1-3, §11-60.1-5, §11-60.1-90)

3. Fuel Consumption, Unit No. D21

   The permittee shall operate and maintain a non-resetting volumetric flow meter system on diesel engine generator Unit No. D21 for the continuous measurement and recording of the fuel consumed by the diesel engine generator. The flow meter reading shall be recorded at the beginning and end of each calendar month. Records on the total gallons of fuel consumed shall be maintained on a monthly and rolling twelve (12) month basis.

   (Auth.: HAR §11-60.1-3, §11-60.1-5, §11-60.1-90)

4. Inspection, Maintenance, and Repair Log

   An inspection, maintenance, and repair log shall be maintained for the diesel engines covered under this permit. Replacement of parts and repairs to the diesel engines shall be well documented.

   (Auth.: HAR §11-60.1-3, §11-60.1-5, §11-60.1-90)

5. Visible Emissions (VE)

   a. The permittee shall conduct **monthly** (*calendar month*) VE observations for each equipment subject to opacity limits in accordance with 40 CFR Part 60, Appendix A, Method 9 or by use of a Ringelmann Chart as provided. For each period, two (2) observations shall be taken at fifteen (15) second intervals for six (6) consecutive minutes for each equipment. Records shall be completed and maintained in accordance with the **Visible Emissions Form Requirements.**
   b. The permittee shall conduct **annually** (*calendar year*) VE observations for each equipment subject to opacity limits by a certified reader in accordance with 40 CFR Part 60, Appendix A, Method 9. For each period, two (2) observations shall be taken at fifteen (15) second intervals for six (6) consecutive minutes for each equipment. Records shall be completed and maintained in accordance with the **Visible Emissions Form Requirements.**
   c. Upon written request and justification by the permittee, the Department may waive the requirement for a specific annual VE test. The waiver request is to be submitted prior to the required test and must include documentation justifying such action. Documentation should include, but is not limited to, the continuing compliance, and further that operations of the source have not changed since the previous source test.

   (Auth.: HAR §11-60.1-3, §11-60.1-5, §11-60.1-90)

<u>Section D.</u> <u>Notification and Reporting Requirements</u>

1. Notification and reporting pertaining to the following events shall be done in accordance with Attachment I, Standard Condition Nos. 17 and 24, respectively:

   a. Emissions of air pollutants in violation of HAR, Chapter 11-60.1 or this permit (excluding technology-based emission exceedances due to emergencies); and
   b. Permanent discontinuance of construction, modification, relocation, or operation of the facility covered by this permit.

   (Auth.: HAR §11-60.1-8, §11-60.1-16, §11-60.1-90)

2. The permittee shall report **within five (5) working days** any deviations from the permit requirements, including those attributable to upset conditions, the probable cause of such deviations and any corrective actions or preventive measures taken. Corrective actions

may include a requirement for additional stack testing, or more frequent monitoring, or the implementation of a corrective action plan.

(Auth.: HAR §11-60.1-3, §11-60.1-15, §11-60.1-16, §11-60.1-90)

3. **At least thirty (30) days** prior to conducting a source performance test, the permittee shall notify the Department in writing as required by Section E of this attachment.

   (Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-161; SIP §11-60-15)[2]

4. The permittee shall submit **semi-annually** the following written reports to the Department. The report shall be submitted **within sixty (60) days** after the end of each semi-annual calendar period (January 1 to June 30 and July 1 to December 31), and shall include the following:

   a. Total operating hours of the black start diesel engine generator on a monthly and rolling twelve (12) month basis. The enclosed **Monitoring Report Form: Operating Hours: Black Start Diesel Engine Generator**, or similar form, shall be used.
   b. The total quantity of fuel consumed by diesel engine generator Unit No. D21 on a monthly and rolling twelve (12) month basis. The enclosed **Monitoring Report Form: Fuel Consumption**, or similar form, shall be used.
   c. Any opacity exceedances as determined by the required VE monitoring. Each exceedance reported shall include the date, six (6) minute average opacity reading, possible reason for exceedance, duration of exceedance, and corrective actions taken. If there were no exceedances, the permittee shall submit in writing a statement indicating that for each diesel engine, there were no exceedances for the semi-annual period. The enclosed **Monitoring Report Form: Visible Emission Exceedances**, shall be used.
   d. Analysis of the sulfur content in the fuel for which there were exceedances of the sulfur content limits specified in Special Condition No. B.4 of this attachment. If there were no exceedances, the permittee shall submit in writing a statement indicating that there were no exceedances of the sulfur content limit for that semi-annual period.
   e. Any deviations from the permit requirements shall be clearly identified. At a minimum, a summary of each deviation shall include a description of the deviation, the reason for the deviation, the duration, and the corrective actions taken.

   (Auth.: HAR §11-60.1-3, §11-60.1-5, §11-60.1-90)

5. Compliance Certification

   During the permit term, the permittee shall submit at least **annually** to the Department and U.S. EPA, Region 9, the attached **Compliance Certification Form** pursuant to HAR, §11-60.1-86. The permittee shall indicate whether or not compliance is being met with each term or condition of this permit. The compliance certification shall include, at a minimum, the following information:

   a. The identification of each term or condition of the permit that is the basis of the certification;

b. The compliance status;
c. Whether compliance was continuous or intermittent;
d. The methods used for determining the compliance status of the source currently and over the reporting period;
e. Any additional information indicating the source's compliance status with any applicable enhanced monitoring and compliance certification including the requirements of Section 114(a)(3) of the Clean Air Act or any applicable monitoring and analysis provisions of Section 504(b) of the Clean Air Act; and
f. Any additional information as required by the Department including information to determine compliance.

The compliance certification shall be submitted **within ninety (90) days after** the end of each calendar year and shall be signed and dated by a responsible official.

Upon written request of the permittee, the deadline for submitting the compliance certification may be extended, if the Department determines that reasonable justification exists for the extension.

(Auth.: HAR §11-60.1-4, §11-60.1-86, §11-60.1-90)

6. Annual Emissions

As required by Attachment IV and in conjunction with the requirements of Attachment III, Annual Fee Requirements, the permittee shall report **annually** the total tons/yr emitted of each regulated air pollutant, including hazardous air pollutants. The reporting of annual emissions is due **within sixty (60) days following** the end of each calendar year. The enclosed Annual Emissions Report Forms, shall be used.

Upon the written request of the permittee, the deadline for reporting of annual emissions may be extended, if the Department determines that reasonable justification exists for the extension.

(Auth.: HAR §11-60.1-3, §11-60.1-5, §11-60.1-90)

Section E. Testing Requirements

1. **On an annual basis** or at such other times as may be specified by the Department, the permittee shall conduct or cause to be conducted performance tests on the diesel engine generators Unit Nos. D21, D22, and D23 at maximum load for NO_x.

(Auth.: HAR §11-60.1-3, §11-60.1-90)

2. Performance tests for the emissions of NO_x shall be conducted and results reported in accordance with the test methods set forth in 40 CFR Part 60 Appendix A, and 40 CFR §60.8. The performance tests for the emissions of NO_x shall be

conducted using 40 CFR Part 60 Methods 1-4 and 7 or U.S. EPA-approved equivalent methods, or alternate methods with prior written approval from the Department.

(Auth.: HAR §11-60.1-5, §11-60.1-11, §11-60.1-90)

3. The performance test shall consist of three (3) separate runs using the applicable test method. For the purpose of determining compliance with an applicable regulation, the arithmetic mean of the results from the three (3) runs shall apply.

   (Auth.: HAR §11-60.1-5, §11-60.1-11, §11-60.1-90)

4. The permittee shall provide sampling and testing facilities at its own expense. The tests shall be conducted at the maximum load of the diesel engine generators and the Department may monitor the tests.

   (Auth.: HAR §11-60.1-3, §11-60.1-5, §11-60.1-11, §11-60.1-90; SIP §11-60-15)[2]

5. **At least thirty (30) calendar days** prior to performing a test, the permittee shall submit a written performance test plan to the Department that describes the test duration, test locations, test methods, source operation and other parameters that may affect test results. Such a plan shall conform to U.S. EPA guidelines including quality assurance procedures. A test plan or quality assurance plan that does not have the approval of the Department may be grounds to invalidate any test and require a retest.

   (Auth.: HAR §11-60.1-3, §11-60.1-5, §11-60.1-11, §11-60.1-90)

6. Any deviations from these conditions, test methods, or procedures may be cause for rejection of the test results unless such deviations are approved by the Department before the tests.

   (Auth.: HAR §11-60.1-3, §11-60.1-11, §11-60.1-90)

7. **Within sixty (60) days** after completion of the performance test, the permittee shall submit to the Department and U.S. EPA, Region 9, the test report which shall include the operating conditions of the diesel engine generators at the time of the test, the analysis of the fuel, the summarized test results, comparative results with the permit emission limits, and other pertinent field and laboratory data.

   (Auth.: HAR §11-60.1-3, §11-60.1-11, §11-60.1-90; SIP §11-60-15)[2]

8. The Department may waive a specific performance test upon prior written request of the permittee. Such a request would need to be justified on the grounds that prior tests had shown compliance by a wide margin, and that adequate means exist to show continuing compliance.

   (Auth.: HAR §11-60.1-3, §11-60.1-11, §11-60.1-90)

Section F. Agency Notification

Any document (including reports) required to be submitted by this CSP shall be done in accordance with Attachment I, Standard Condition No. 28.

(Auth.: HAR §11-60.1-4, §11-60.1-90)

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[1] The citations to the Code of Federal Regulations (CFR) identified under a particular condition, indicate that the permit condition complies with the specified provision(s) of the CFR. Due to the integration of the pre-construction and operating permit requirements, permit conditions may incorporate more stringent requirements than those set forth in the CFR.

[2] The citations to the State Implementation Plan (SIP) identified under a particular condition, indicate that the permit condition complies with the specified provision(s) of the SIP.

[3] This date is to be revised upon issuance of the renewal for CSP No. 0007-01-C.

ATTACHMENT II-INSIG: SPECIAL CONDITIONS FOR INSIGNIFICANT ACTIVITIES
COVERED SOURCE PERMIT NO. 0007-01-C

Issuance Date: June 27, 2018 **Expiration Date: August 6, 2013** [1]

In addition to the Standard Conditions of the Covered Source Permit, the following Special Conditions shall apply to the permitted facility:

In addition to the Standard Conditions of the CSP, the following Special Conditions shall apply to the permitted facility:

Section A. Equipment Description

This attachment encompasses insignificant activities listed in HAR, §11-60.1-82(f) and (g) for which provisions of this permit and HAR, Subchapter 2, General Prohibitions apply.

(Auth.: HAR §11-60.1-3)

Section B. Operational Limitations

1. The permittee shall take measures to operate applicable insignificant activities in accordance with the provisions of HAR, Subchapter 2 for visible emissions, fugitive dust, incineration, process industries, sulfur oxides from fuel combustion, storage of volatile organic compounds, volatile organic compound water separation, pump and compressor requirements, and waste gas disposal.

   (Auth.: HAR §11-60.1-3, §11-60.1-82, §11-60.1-90)

2. The Department may at any time require the permittee to further abate emissions if an inspection indicates poor or insufficient controls.

   (Auth.: HAR §11-60.1-3, §11-60.1-5, §11-60.1-82, §11-60.1-90)

Section C. Monitoring and Recordkeeping Requirements

1. The Department reserves the right to require monitoring, recordkeeping, or testing of any insignificant activity to determine compliance with the applicable requirements.

   (Auth.: HAR §11-60.1-3, §11-60.1-90)

2. All records shall be maintained for at least five (5) years from the date of any required monitoring, recordkeeping, testing, or reporting. These records shall be in a permanent form suitable for inspection and made available to the Department or their authorized representative upon request.

   (Auth.: HAR §11-60.1-3, §11-60.1-11, §11-60.1-90)

Section D. Notification and Reporting

Compliance Certification

1. During the permit term, the permittee shall submit at least **annually** to the Department and U.S. EPA, Region 9, the attached **Compliance Certification Form** pursuant to HAR, Subsection 11-60.1-86. The permittee shall indicate whether or not compliance is being met with each term or condition of this permit. The compliance certification shall include, at a minimum, the following information:

   a. The identification of each term or condition of the permit that is the basis of the certification;
   b. The compliance status;
   c. Whether compliance was continuous or intermittent;
   d. The methods used for determining the compliance status of the source currently and over the reporting period;
   e. Any additional information indicating the source's compliance status with any applicable enhanced monitoring and compliance certification including the requirements of Section 114(a)(3) of the Clean Air Act or any applicable monitoring and analysis provisions of Section 504(b) of the Clean Air Act; and
   f. Any additional information as required by the Department including information to determine compliance.

   In lieu of addressing each emission unit as specified in the attached Compliance Certification Form, the permittee may address insignificant activities as a single unit provided compliance is met with all applicable requirements. If compliance is not totally attained, the permittee shall identify the specific insignificant activity and provide the details associated with the noncompliance.

2. The compliance certification shall be submitted **within ninety (90) days** after the end of each calendar year and shall be signed and dated by a responsible official.

3. Upon written request of the permittee, the deadline for submitting the compliance certification may be extended, if the Department determines that reasonable justification exists for the extension.

   (Auth.: HAR §11-60.1-4, §11-60.1-86, §11-60.1-90)

Section E. Agency Notification

Any document (including reports) required to be submitted by this CSP shall be done in accordance with Attachment I, Standard Condition No. 28.

(Auth.: HAR §11-60.1-4, §11-60.1-90)

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[1]This date is to be revised upon issuance of the renewal for CSP No. 0007-01-C.

ATTACHMENT III: ANNUAL FEE REQUIREMENTS
COVERED SOURCE PERMIT NO. 0007-01-C

Issuance Date: June 27, 2018 **Expiration Date: August 6, 2013** [1]

The following requirements for the submittal of annual fees are established pursuant to Hawaii Administrative Rules (HAR), Title 11, Chapter 60.1, Air Pollution Control. Should HAR, Chapter 60.1 be revised such that the following requirements are in conflict with the provisions of HAR, Chapter 60.1, the permittee shall comply with the provisions of HAR, Chapter 60.1.

1. Annual fees shall be paid in full:

   a. Within **one-hundred twenty (120) days** after the end of each calendar year; and
   b. Within **thirty (30) days** after the permanent discontinuance of the covered source.

2. The annual fees shall be determined and submitted in accordance with Hawaii Administrative Rules, Chapter 11-60.1, Subchapter 6.

3. The annual emissions data for which the annual fees are based shall accompany the submittal of any annual fees and be submitted on forms furnished by the Department.

4. The annual fees and the emission data shall be mailed to:

State of Hawaii
Clean Air Branch
2827 Waimano Home Road #130
Pearl City, HI 96782

[1]This date is to be revised upon issuance of the renewal for CSP No. 0007-01-C.

ATTACHMENT IV: ANNUAL EMISSIONS REPORTING REQUIREMENTS
COVERED SOURCE PERMIT NO. 0007-01-C

Issuance Date: June 27, 2018 **Expiration Date: August 6, 2013** [1]

In accordance with the Hawaii Administrative Rules, Title 11, Chapter 60.1, Air Pollution Control, the permittee shall report to the Department the nature and amounts of emissions.

1. Complete the attached forms:

   Annual Emissions Report Form: Combustion Turbines;
   Annual Emissions Report Form: Ammonia Slip; and
   Annual Emissions Report Form: Diesel Engines.

2. The reporting period shall be from January 1 to December 31 of each year. All reports shall be submitted to the Department within **sixty (60) days** after the end of each calendar year and shall be mailed to the following address:

   State of Hawaii
   Clean Air Branch
   2827 Waimano Home Road #130
   Pearl City, HI 96782

3. The permittee shall retain the information submitted, including all emission calculations. These records shall be in a permanent form suitable for inspection, retained for a minimum of five (5) years, and made available to the Department upon request.

4. Any information submitted to the Department without a request for confidentiality shall be considered public record.

5. In accordance with HAR, Section 11-60.1-14, the permittee may request confidential treatment of specific information, including information concerning secret processes or methods of manufacture, by submitting a written request to the Director and clearly identifying the specific information that is to be accorded confidential treatment.

[1]This date is to be revised upon issuance of the renewal for CSP No. 0007-01-C.

ANNUAL EMISSIONS REPORT FORM
COMBUSTION TURBINES
COVERED SOURCE PERMIT NO. 0007-01-C

Issuance Date: June 27, 2018 **Expiration Date:** August 6, 2013
[Expiration date to be revised upon issuance of the permit renewal]

In accordance with the Hawaii Administrative Rules, Title 11, Chapter 60.1, Air Pollution Control, the permittee shall report to the Department of Health the nature and amounts of emissions.

For Period: ______________________ Date: ______________

Facility Name: HELCO Keahole Generating Station

Equipment Description: ______________________

Serial/Unit ID No.: ______________________

Responsible Official (Print): ______________________

Title: ______________________

I certify that I have knowledge of the facts herein set forth, that the same are true, accurate and complete to the best of my knowledge and belief, and that all information not identified by me as confidential in nature shall be treated by the Department of Health as public record.

Responsible Official (Signature): ______________________

Type of Fuel Fired	Fuel Usage (Gallons)	% Sulfur Content by weight	~~% Nitrogen Content by weight~~
Fuel Oil No. 2			

Commented [HECO1]: Hawai'i Electric Light requests to remove Nitrogen content reporting requirement because it is no longer needed. Refer to the proposed modification in Attachment IIA Special Condition C.4.b and the corresponding justification.

Type of Air Pollution Control	In Use?	Pollutant(s) Controlled	Control Efficiency, % Reduction
Water Injection	Yes or No	NO_x	______
SCR	Yes or No	NO_x	______
______	Yes or No	______	______

ANNUAL EMISSIONS REPORT FORM
AMMONIA SLIP
COVERED SOURCE PERMIT NO. 0007-01-C

Issuance Date: June 27, 2018 **Expiration Date: August 6, 2013**
[Expiration date to be revised upon issuance of the permit renewal]

In accordance with the Hawaii Administrative Rules, Title 11, Chapter 60.1, Air Pollution Control, the permittee shall report to the Department of Health the nature and amounts of emissions, semi-annually.

For Period: ______________________ Date: ____________

Facility Name: HELCO Keahole Generating Station

Equipment Description: Selective Catalytic Reduction System

Serial/ID No.: Operating with unit CT-4/CT-5

Responsible Official (Print): ______________________

Title: ______________________

I certify that I have knowledge of the facts herein set forth, that the same are true, accurate and complete to the best of my knowledge and belief, and that all information not identified by me as confidential in nature shall be treated by the Department of Health as public record.

Responsible Official (Signature): ______________________

Month	Ammonia Slip (lbs)	Method Used to Calculate Ammonia Slip
January		
February		
March		
April		
May		
June		
July		
August		
September		
October		
November		
December		
TOTAL		

ANNUAL EMISSIONS REPORT FORM
DIESEL ENGINES
COVERED SOURCE PERMIT NO. 0007-01-C

Issuance Date: June 27, 2018 **Expiration Date: August 6, 2013**
[Expiration date to be revised upon issuance of the permit renewal]
In accordance with the Hawaii Administrative Rules, Title 11, Chapter 60.1, Air Pollution Control, the permittee shall report to the Department of Health the nature and amounts of emissions.

For Period: ________________ Date: ________

Facility Name: HELCO Keahole Generating Station

Equipment Description: 2.5 MW General Motors EMD DEG

Serial/ID No.: ________________

I certify that I have knowledge of the facts herein set forth, that the same are true, accurate and complete to the best of my knowledge and belief, and that all information not identified by me as confidential in nature shall be treated by the Department of Health as public record. I further state that I will assume responsibility for the construction, modification, or operation of the source in accordance with the Hawaii Administrative Rules, Title 11, Chapter 60.1, Air Pollution Control, and any permit issued thereof.

Responsible Official (PRINT): ________________

Title: ________________

Responsible Official (Signature): ________________

2.5 MW kilowatt rating

Unit No./Fuel Fired	Fuel Usage Gallons per year	% Sulfur Content by weight
D21/Fuel Oil No. 2		
D22/Fuel Oil No. 2		
D23/Fuel Oil No. 2		
BS-1/Fuel Oil No. 2		

Type of Air Pollution Control	In Use?	Pollutant(s) Controlled	Control Efficiency, % reduction
	Yes or No		
	Yes or No		
	Yes or No		

MONITORING REPORT FORM
OPERATING HOURS: BLACK START DIESEL ENGINE GENERATOR
COVERED SOURCE PERMIT NO. 0007-01-C

Issuance Date: June 27, 2018 **Expiration Date:** August 6, 2013
[Expiration date to be revised upon issuance of the permit renewal]

In accordance with the Hawaii Administrative Rules, Title 11, Chapter 60.1, Air Pollution Control, the permittee shall report to the Department of Health the following information **semi-annually:**

For Period: ______________________ Date: ______________

Facility Name: HELCO Keahole Generating Station

Equipment Description: 500 kW Caterpillar Model 3412 Black Start Diesel Engine Generator, BS-1

Serial/ID No.: ______________________

I certify that I have knowledge of the facts herein set forth, that the same are true, accurate and complete to the best of my knowledge and belief, and that all information not identified by me as confidential in nature shall be treated by the Department of Health as public record. I further state that I will assume responsibility for the construction, modification, or operation of the source in accordance with the Hawaii Administrative Rules, Title 11, Chapter 60.1, Air Pollution Control, and any permit issued thereof.

Responsible Official (PRINT): ______________________

Title: ______________________

Responsible Official (Signature): ______________________

BLACK-START DIESEL ENGINE GENERATOR

Month	Operating Hours		Notes
	Monthly Total	Rolling 12- Month Total	
January			
February			
March			
April			
May			
June			
July			
August			
September			
October			
November			
December			
TOTAL			

MONITORING REPORT FORM
DAILY STARTUP AND SHUTDOWN
COMBUSTION TURBINE GENERATOR
COVERED SOURCE PERMIT NO. 0007-01-C

Issuance Date: June 27, 2018 **Expiration Date: August 6, 2013**
[Expiration date to be revised upon issuance of the permit renewal]

For Month: ____________________ Year: ____________________

Facility Name HELCO Keahole Generating Station

Equipment Description: ____________________

Serial/Unit ID No.: ____________________

Responsible Official (PRINT): ____________________

Title: ____________________

I certify that I have knowledge of the facts herein set forth, that the same are true, accurate and complete to the best of my knowledge and belief, and that all information not identified by me as confidential in nature shall be treated by the Department of Health as public record.

Responsible Official (Signature): ____________________

Combustion Turbine Generator								
	AStart-up@				AShut-down@			
Day	Start Time	End Time	Duration[1]	Turbine Load at APC[2] Initiation (MW)	Start Time	End Time	Turbine Load at ACP[2] Shutdown (MW)	Turbine Daily Operating Hours
1								
2								
3								
4								
5								
6								
7								
8								
9								
10								
11								

[1]Log duration in AMinutes"

[2]APC = Air Pollution Control

Combustion Turbine Generator								
	AStart-up@				AShut-down@			
Day	Start Time	End Time	Duration[1]	Turbine Load at APC[2] Initiation (MW)	Start Time	End Time	Turbine Load at ACP[2] Shutdown (MW)	Turbine Daily Operating Hours
12								
13								
14								
15								
16								
17								
18								
19								
20								
21								
22								
23								
24								
25								
26								
27								
28								
29								
30								
31								
TOTAL MONTHLY HOURS:								

[1]Log duration in AMinutes"

[2]APC = Air Pollution Control

MONITORING REPORT FORM
FUEL CONSUMPTION
COVERED SOURCE PERMIT NO. 0007-01-C

Issuance Date: June 27, 2018 **Expiration Date:** August 6, 2013
[Expiration date to be revised upon issuance of the permit renewal]

In accordance with the Hawaii Administrative Rules, Title 11, Chapter 60.1, Air Pollution Control, the permittee shall report to the Department of Health the nature and amounts of emissions.

For Period: ____________________ Date: __________

Facility Name: HELCO Keahole Generating Station

Equipment Description: ____________________

Serial/Unit ID No.: ____________________

Type of Fuel: Fuel Oil No. 2 %Sulfur Content by Weight: ____________________

Responsible Official (Print): ____________________

Title: ____________________

I certify that I have knowledge of the facts herein set forth, that the same are true, accurate and complete to the best of my knowledge and belief, and that all information not identified by me as confidential in nature shall be treated by the Department of Health as public record.

Responsible Official (Signature): ____________________

Month	Monthly Fuel Consumption (gallons)	Rolling 12-Month Total (gallons)	Notes
January			
February			
March			
April			
May			
June			
July			
August			
September			
October			
November			
December			

MONITORING REPORT FORM
FUEL CERTIFICATION
COVERED SOURCE PERMIT NO. 0007-01-C

Issuance Date: June 27, 2018 **Expiration Date:** August 6, 2013

(Expiration date to be revised upon issuance of the permit renewal)

In accordance with the Hawaii Administrative Rules, Title 11, Chapter 60.1, Air Pollution Control, the permittee shall report to the Department of Health the nature of fuel used for the permitted equipment.

For Period: ______________________ Date: ______________

Facility Name: Hawaii Electric Light Co.

Equipment Location: Keahole Generating Station

Responsible Official (Print): ______________________

Title: ______________________

I certify that I have knowledge of the facts herein set forth, that the same are true, accurate and complete to the best of my knowledge and belief, and that all information not identified by me as confidential in nature shall be treated by the Department of Health as public record.

Responsible Official (Signature): ______________________

Unit No.	Equipment Description	Fuel Fired	Sulfur Content [1]	~~Nitrogen Content [2]~~
CT-4	20 MW Combustion Turbine	Fuel Oil No. 2		
CT-5	20 MW Combustion Turbine	Fuel Oil No. 2		
D-21	2.5 MW General Motors EMD DEG	Fuel Oil No. 2		
D-22	2.5 MW General Motors EMD DEG	Fuel Oil No. 2		
D-23	2.5 MW General Motors EMD DEG	Fuel Oil No. 2		
BS-1	500 kW Caterpillar Black Start DEG	Fuel Oil No. 2		

1 - Report the maximum sulfur content (% by weight) recorded during the reporting period.

~~2 - Report the average nitrogen content (% by weight) for the reporting period.~~

List means and methods used to determine the sulfur content.

____

____

List means and methods used to determine the nitrogen content.

____

____

Commented [HECO2]: Hawai'i Electric Light requests to remove Nitrogen content reporting requirement because it is no longer needed. Refer to the proposed modification in Attachment IIA Special Condition C.4.b and the corresponding justification.

MONITORING REPORT FORM
VISIBLE EMISSION EXCEEDANCES
COVERED SOURCE PERMIT NO. 0007-01-C

Issuance Date: June 27, 2018 **Expiration Date: August 6, 2013**
[Expiration date to be revised upon issuance of the permit renewal]

In accordance with the Hawaii Administrative Rules, Title 11, Chapter 60.1, Air Pollution Control, the permittee shall report to the Department of Health the following information semi-annually:

For Period: ______________________ Date: ______________

Facility Name: HELCO Keahole Generating Station

I certify that I have knowledge of the facts herein set forth, that the same are true, accurate and complete to the best of my knowledge and belief, and that all information not identified by me as confidential in nature shall be treated by the Department of Health as public record. I further state that I will assume responsibility for the construction, modification, or operation of the source in accordance with the Hawaii Administrative Rules, Title 11, Chapter 60.1, Air Pollution Control, and any permit issued thereof.

Responsible Official (PRINT): ______________________

Title: ______________________

Responsible Official (Signature): ______________________

Visible Emission Exceedances:

Report the following on the lines provided below: all date(s) and six (6) minute average opacity reading(s) which the opacity limit was exceeded during the monthly observations; or if there were no exceedances during the monthly observations, then write no exceedances in the comment column.

EQUIPMENT	SERIAL/ID NO.	DATE	6 MIN. AVER. (%)	COMMENTS

EXCESS EMISSION AND MONITORING SYSTEM PERFORMANCE SUMMARY REPORT

(Make Copies for Future Use)

Facility Name: HELCO Keahole Generating Station

Equipment Location: Keahole Generating Station, Keahole, Hawaii

Equipment Description:______________________________

Serial/Unit ID No.: ______________________________

Covered Source Permit No.: **CSP No. 0007-01-C** Condition No.:______________

PSD Permit No.: __________Condition No.:______________________

Code of Federal Regulations (CFR): ______________________

Pollutant Monitored: __________

From: Date ____________ - Time ____________

To: Date ____________ - Time ____________

Emission Limit: ______________________

Date of Last CEMS Certification/Audit .... _____

Total Source Operating Time .... _____

EMISSION DATA SUMMARY

1. Duration (Hours/Periods) of Excess Emissions in Reporting Period due to:
   a. Start-Up/Shutdown .... _____
   b. Cleaning/Soot Blowing .... _____
   c. Control Equipment Failure .... _____
   d. Process Problems .... _____
   e. Other Known Causes .... _____
   f. Unknown Causes .... _____
   g. Fuel Problems .... _____

   Number of incidents of excess emissions .... _____

2. Total Duration of Excess Emissions .... _____

3. Total Duration of Excess Emissions (% of Total Source Operating Time) .... _____

CEMS PERFORMANCE SUMMARY

1. CEMS Downtime (Hours/Periods) in Reporting Period Due to:
   a. Monitor Equipment Malfunctions .... _____
   b. Non-Monitor Equipment Malfunctions .... _____
   c. Quality Assurance Calibration .... _____
   d. Other Known Causes .... _____
   e. Unknown Causes .... _____

   Number of incidents of monitor downtime........................ _____

2. Total CEMS Downtime .... _____

3. Total CEMS Downtime (% of Total Source Operating Time) .... _____

EXCESS EMISSION AND MONITORING SYSTEM PERFORMANCE SUMMARY REPORT

(PAGE 2 OF 2)

CERTIFICATION by Responsible Official

Responsible Official (Print): ______________________________

Title: ______________________________

I certify that I have knowledge of the facts herein set forth, that the same are true, accurate and complete to the best of my knowledge and belief, and that all information not identified by me as confidential in nature shall be treated by the Department of Health as public record.

Responsible Official (Signature): ______________________________

VISIBLE EMISSIONS FORM REQUIREMENTS
STATE OF HAWAII
COVERED SOURCE PERMIT NO. 0007-01-C

Issuance Date: June 27, 2018 **Expiration Date: August 6, 2013**
[Expiration date to be revised upon issuance of the permit renewal]

The following Visible Emissions (VE) Form shall be completed **monthly** (*each calendar month*) for each equipment subject to opacity limits in accordance with Method 9 or by use of a Ringelmann Chart as provided. At least **annually** (*calendar year*), VE observations shall be conducted for each equipment subject to opacity limits by a certified reader in accordance with Method 9. The VE Form shall be completed as follows:

1. Visible emissions observations shall take place during the day only and shall be compared to the Ringelmann Chart provided. The opacity shall be noted in five (5) percent increments (i.e., 25%).

2. Orient the sun within a one hundred forty (140) degree sector to your back. Provide a source layout sketch on the VE Form using the symbols as shown.

3. Stand at least three (3) stack heights, but not more than a quarter mile from the stack.

4. Two (2) observations shall be taken at fifteen (15) second intervals for six (6) consecutive minutes for each equipment.

5. The six (6) minute average opacity reading shall be calculated for each observation.

6. If possible, the observations shall be performed as follows:

   a. Read from where the line of sight is at right angles to the wind direction.
   b. The line of sight shall not include more than one (1) plume at a time.
   c. Read at the point in the plume with the greatest opacity (without condensed water vapor), ideally while the plume is no wider than the stack diameter.
   d. Read the plume at fifteen (15) second intervals only. Do not read continuously.
   e. The equipment shall be operating at maximum permitted capacity.

7. If the equipment was shut-down for that period, briefly explain the reason for shut-down in the comment column.

The permittee shall retain the completed VE Forms for recordkeeping. These records shall be in a permanent form suitable for inspection, retained for a minimum of five (5) years, and made available to the Department of Health, or their representative upon request.

VISIBLE EMISSIONS FORM
STATE OF HAWAII
COVERED SOURCE PERMIT NO. 0007-01-C

Issuance Date: June 27, 2018 **Expiration Date: August 6, 2013**
[Expiration date to be revised upon issuance of the permit renewal]

Permit No.: 0007-01-C

Company Name: HELCO Keahole Generating Station

Equipment and Fuel: ______________________________

Site Conditions:

Stack height above ground (ft): ______________

Stack distance from observer (ft): ______________

Emission color: black / white

Sky conditions (% cloud cover): ______________

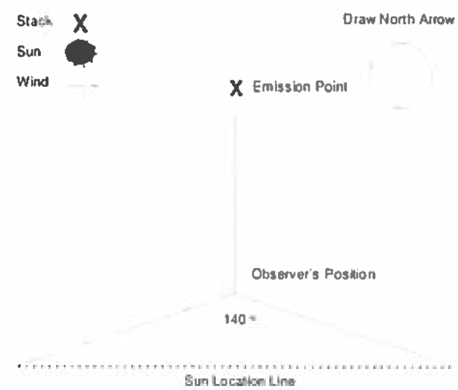
Wind speed (mph): ______________

Temperature (EF): ______________

Observer Name: ______________

Certified?: Yes / No

Observation Date and Time: __



SEC. / MIN.	0	15	30	45	COMMENTS
1					
2					
3					
4					
5					
6					
Six (6) Minute Average Opacity Reading (%):					

Observation Date and Start Time: ______________

SEC. / MIN.	0	15	30	45	COMMENTS
1					
2					
3					
4					
5					
6					
Six (6) Minute Average Opacity Reading (%):					

COMPLIANCE CERTIFICATION FORM
COVERED SOURCE PERMIT NO. 0007-01-C
PAGE 1 OF __

Issuance Date: June 27, 2018 **Expiration Date: August 6, 2013**

[Expiration date to be revised upon issuance of the permit renewal]

In accordance with the Hawaii Administrative Rules, Title 11, Chapter 60.1, Air Pollution Control, the permittee shall report to the Department of Health the following certification at least annually, or more frequently as requested by the Department of Health.

(Make Copies of the Compliance Certification Form for Future Use)

For Period: ______________________________ Date: ______________

Company/Facility Name: ______________________________

Responsible Official (Print): ______________________________

Title: ______________________________

Responsible Official (Signature): ______________________________

I certify that I have knowledge of the facts herein set forth, that the same are true, accurate and complete to the best of my knowledge and belief, and that all information not identified by me as confidential in nature shall be treated by Department of Health as public record. I further state that I will assume responsibility for the construction, modification, or operation of the source in accordance with the Hawaii Administrative Rules, Title 11, Chapter 60.1, Air Pollution Control, and any permit issued thereof.

COMPLIANCE CERTIFICATION FORM
COVERED SOURCE PERMIT NO. 0007-01-C
(CONTINUED, PAGE 2 OF __)

Issuance Date: June 27, 2018 **Expiration Date: August 6, 2013**
[Expiration date to be revised upon issuance of the permit renewal]

The purpose of this form is to evaluate whether or not the facility was in compliance with the permit terms and conditions during the covered period. If there were any deviations to the permit terms and conditions during the covered period, the deviation(s) shall be certified as *intermittent compliance* for the particular permit term(s) or condition(s). Deviations include failure to monitor, record, report, or collect the minimum data required by the permit to show compliance. In the absence of any deviation, the particular permit term(s) or condition(s) may be certified as *continuous compliance.*

Instructions:

Please certify Sections A, B, and C below for continuous or intermittent compliance. Sections A and B are to be certified as a group of permit conditions. Section C shall be certified individually for each operational and emissions limit condition as listed in the Special Conditions section of the permit (list all applicable equipment for each condition). Any deviations shall also be listed individually and described in Section D. The facility may substitute its own generated form in verbatim for Sections C and D.

A. Attachment I, Standard Conditions

Permit term/condition	Equipment(s)	Compliance
All standard conditions	All Equipment(s) listed in the permit	☐ Continuous ☐ Intermittent

B. Special Conditions - Monitoring, Recordkeeping, Reporting, Testing, and INSIG

Permit term/condition	Equipment(s)	Compliance
All monitoring conditions	All Equipment(s) listed in the permit	☐ Continuous ☐ Intermittent
Permit term/condition All recordkeeping conditions	Equipment(s) All Equipment(s) listed in the permit	Compliance ☐ Continuous ☐ Intermittent
Permit term/condition All reporting conditions	Equipment(s) All Equipment(s) listed in the permit	Compliance ☐ Continuous ☐ Intermittent
Permit term/condition All testing conditions	Equipment(s) All Equipment(s) listed in the permit	Compliance ☐ Continuous ☐ Intermittent
Permit term/condition All INSIG conditions	Equipment(s) All Equipment(s) listed in the permit	Compliance ☐ Continuous ☐ Intermittent

COMPLIANCE CERTIFICATION FORM
COVERED SOURCE PERMIT NO. 0007-01-C
(CONTINUED, PAGE __ OF __)

Issuance Date: June 27, 2018 **Expiration Date: August 6, 2013**
[Expiration date to be revised upon issuance of the permit renewal]

C. Special Conditions - Operational and Emissions Limitations

Each permit term/condition shall be identified in chronological order using attachment and section numbers (e.g., Attachment II, B.1, Attachment IIA, Special Condition No. B.1.f, etc.). Each equipment shall be identified using the description stated in Section A of the Special Conditions (e.g., unit no., model no., serial no., etc.). Check all methods (as required by permit) used to determine the compliance status of the respective permit term/condition.

Permit term/condition	Equipment(s)	Method	Compliance
		☐ monitoring ☐ recordkeeping ☐ reporting ☐ testing	☐ Continuous ☐ Intermittent
		☐ monitoring ☐ recordkeeping ☐ reporting ☐ testing	☐ Continuous ☐ Intermittent
		☐ monitoring ☐ recordkeeping ☐ reporting ☐ testing	☐ Continuous ☐ Intermittent
		☐ monitoring ☐ recordkeeping ☐ reporting ☐ testing	☐ Continuous ☐ Intermittent
		☐ monitoring ☐ recordkeeping ☐ reporting ☐ testing	☐ Continuous ☐ Intermittent
		☐ monitoring ☐ recordkeeping ☐ reporting ☐ testing	☐ Continuous ☐ Intermittent
		☐ monitoring ☐ recordkeeping ☐ reporting ☐ testing	☐ Continuous ☐ Intermittent

(Make Additional Copies if Needed)

COMPLIANCE CERTIFICATION FORM
COVERED SOURCE PERMIT NO.
(CONTINUED, PAGE __ OF __)

Issuance Date: June 27, 2018 **Expiration Date: August 6, 2013**
[Expiration date to be revised upon issuance of the permit renewal]

D. Deviations

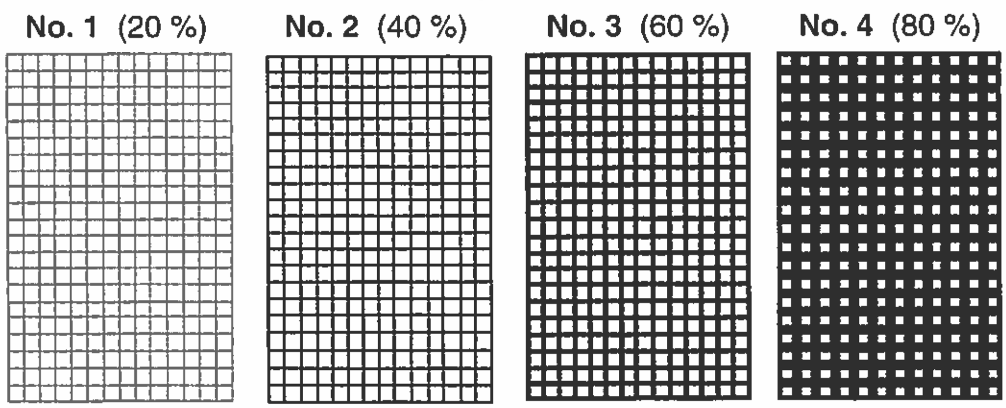
Permit Term/ Condition	Equipment(s) / Brief Summary of Deviation	Deviation Period time (am/pm) & date (mo/day/yr)	Date of Written Deviation Report to DOH (mo/day/yr)
		Beginning: Ending:	
		Beginning: Ending:	
		Beginning: Ending:	
		Beginning: Ending:	
		Beginning: Ending:	
		Beginning: Ending:	
		Beginning: Ending:	

(Make Additional Copies if Needed)

The Ringelmann Chart

In the late 1800's in Paris, France, Professor Maximilian Ringelmann developed the **Ringelmann Chart** to measure the combustion efficiency of coal-fired boilers. The shade of the smoke plume shows how well a boiler is operating - the poorer its combustion efficiency, the more unburned carbon particles in the smoke and the darker the plume.

Professor Ringelmann's chart established four measured shades of gray between white, valued at zero, and black, at five. These specific shades of gray, Ringelmann No. 1 to Ringelmann No. 4, can be accurately reproduced by placing a grid of black lines of a given width and spacing on a white background. Viewed from a distance, the grid lines and background merge into the shades of gray, to be compared to the shade of the smoke plume.



Ringelmann Chart (not to scale)

Regulating Visible Emissions

The Ringelmann Chart became one of the first tools used to measure visible emissions. Introduced into the United States in 1897, it was soon accepted as the standard measure of smoke density and was used by engineers for power plant testing and smokeless combustion studies. In 1910, the Chart was officially adopted as part of the Smoke Ordinance for Boston, Mass.

Many city, state, and federal regulations now set smoke density limits based on the Ringelmann Smoke Chart. Although not originally designed as a regulatory tool to control air pollution, it gives good practical results when used by well-trained observers.

File No.: __________

C-1: Compliance Plan

The Responsible Official shall submit a Compliance Plan as indicated in the Instructions for Applying for an Air Pollution Control Permit and at such other times as requested by the Director of Health (hereafter, Director).

Use separate sheets if necessary.

---

1. Compliance status with respect to all Applicable Requirements:

   Will your facility be in compliance, or is your facility in compliance, with all applicable requirements in effect at the time of your permit application submittal?

   ■ YES { If YES, Complete items a and c below}

   ☐ NO { If NO, complete items a-c below}

   a. Identify all applicable requirement(s) for which compliance is achieved:

      - Refer to CSP No. 0007-01-C issued on August 7, 2008;
      - Administrative Amendments issued on June 23, 2009 and June 27, 2018;
      - The National Ambient Air Quality Standards (NAAQS) and State Ambient Air Quality Standards (SAAQS) are "Applicable requirement[s]" as defined in HAR § 11-60.1-81; and
      - Diesel engine generators, D-21, D-22, and D-23, are subject to 40 CFR Part 63 Subpart ZZZZ, National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines (RICE NESHAP).

      Provide a statement that the source is in compliance and will continue to comply with all such requirements.

      The facility is in compliance and will continue to comply with the applicable requirements identified in 1.a above.

   b. Identify all applicable requirement(s) for which compliance is NOT achieved:

      Not applicable.

      Provide a detailed Schedule of Compliance and a description of how the source will achieve compliance with all such applicable requirements. Use separate sheets of paper, if necessary.

Description of Remedial Action	Expected Date of Completion
Not applicable.	

c. Identify any other applicable requirement(s) with a future date that your source is subject to. These applicable requirements may be in effect AFTER permit issuance:

Applicable Requirement	Effective Date	Currently in Compliance?
HAR Title 11 Chapter 60.1 Subchapter 11 –	June 19, 2014	Yes
Greenhouse Gas Emissions	Compliance Date:	
	Upon issuance of the Permit that	
	is currently under review for approval	
	by DOH that incorporates timely filed	
	Greenhouse Gas Emission	
	Reduction Plan that was submitted	
	in June 30, 2015, and amended in	
	September 2017, February 2018,	
	October 2018, and July 2019.	

If the source is not currently in compliance, submit a Schedule of Compliance and a description of how the source will achieve compliance with all such requirements:

Description of Proposed Action/Steps to Achieve Compliance	Expected Date of Achieving Compliance
Not applicable.	

Provide a statement that the source on a timely basis will meet all these applicable requirements.
The source will meet any future applicable requirements on a timely basis.

If the expected date of achieving compliance will NOT meet the applicable requirement's effective date, provide a more detailed description of all remedial actions and the expected dates of completion.

Description of Remedial Action and Explanation	Expected Date of Completion
Not applicable.	

2. Compliance Progress Reports:

a. If a compliance plan is being submitted to remedy a violation, complete the following information:

Frequency of Submittal: ______________ (less than or equal to 6 months) Beginning Date: ______________

b. Date(s) that the Action described in (1)(b) was achieved:

Remedial Action	Date Achieved
Not applicable.	

c. Narrative description of why any date(s) in (1) (b) was not met, and any preventive or corrective measures taken in the interim:

Not applicable.

RESPONSIBLE OFFICIAL (as defined in HAR §11-60.1-1)

Name (Last): Lacro (First): Everett (MI): ______

Title: Director, Generation – Hawaii Phone: (808) 969-0437

Mailing Address: P.O. Box 1027

City: Hilo State: HI Zip Code: 96721-1027

Certification by Responsible Official (pursuant to HAR §11-60.1-4)

I certify that I have knowledge of the facts herein set forth, that the same are true, accurate and complete to the best of my knowledge and belief, and that all information not identified by me as confidential in nature shall be treated by the Department of Health as public record. I further state that I will assume responsibility for the construction, modification, or operation of the source in accordance with the Hawaii Administrative Rules, Title 11, Chapter 60.1, Air Pollution Control, and any permit issued thereof.

Name (Print/Type): Everett Lacro

(Signature): Everett A Lacro Date: 10/22/19

Facility Name: Keahole Generating Station

Location: 73-4249 Pukiawe Street, Kailua Kona, HI 96740

Permit Number: CSP No. 0007-01-C

FOR AGENCY USE ONLY

File/Application No.: ______

Island: ______

Date Received: ______

APR 18 2018

POSTMARK
APR 17 2018

Anthony H. Koyamatsu, P.E., PMP
Manager
Environmental Department

Hawai'i Electric Light
Keahole

April 17, 2018

RETURN RECEIPT REQUESTED
CERTIFIED MAIL NO. 7015 1660 0000 1839 2900

Ms. Marianne Rossio, P.E.
Manager, Clean Air Branch
State of Hawaii Department of Health
2827 Waimano Home Road
Hale Ola Building, Room 130
Pearl City, Hawaii 96782

Dear Ms. Rossio:

Subject: **Application for a Minor Modification to a Covered Source**
CSP No. 0007-01-C
Keahole Generating Station
Hawai'i Electric Light Company, Inc. (Hawai'i Electric Light)

On behalf of Hawai'i Electric Light, Hawaiian Electric Company, Inc. submits an original and one copy of the Application for a Minor Modification to a Covered Source for Keahole Generating Station CSP No. 0007-01-C.

Hawai'i Electric Light requests to install a direct urea injection system at the exit of the combustion turbine units CT4 and CT5 to improve ammonia distribution at the catalyst to continue meeting the NO_x emissions limit as specified in CSP 0007-01-C Attachment IIA Special Condition D.1. Hawai'i Electric Light has been working with Fuel Tech Inc. to perform modeling and simulations of the proposed system and the results were favorable. No emissions increase is expected from this modification and compliance with NO_x emissions limits specified in CSP No. 0007-01-C Attachment IIA Special Condition D.1 will be continuous.

Certifications in accordance with HAR 11-60.1-4 are included on Forms S-1 and C-1. Also enclosed is a check no. 546387 in the amount of $200.00 for the minor modification application fee.

In accordance with HAR §11-60.1-82(k)(1), Hawai'i Electric Light requests the Department of Health to provide written approval of this proposed modification prior to issuance of the amended CSP in a separate letter dated April 17, 2018. Additional information regarding this proposed modification is included in Form S-7, Attachment S-7a, and Attachment S-7b.

If you have any questions regarding this submittal, please contact Myrna Tandi at 543-4535 or myrna.tandi@hawaiianelectric.com.

Sincerely,

AHKoyamatsu

Enclosures: (1) Application for a Minor Modification to Covered Source Permit No. 0007-01-C, one original and one copy
(2) Application fee (check no. 546387)

cc w/ Encl.: **CERTIFIED MAIL RETURN RECEIPT REQUESTED**
Mr. Gerardo Rios [Article No.7015 1730 0002 0151 9068]
Chief, Permits Office, Air Division
U.S. EPA Region 9
75 Hawthorne Street
Mail Code: AIR-3
San Francisco, CA 94105

File / Application No.:____________

S-1: Standard Air Pollution Control Permit Application Form

(Covered Source Permit and Noncovered Source Permit)

State of Hawaii
Department of Health
Environmental Management Division
Clean Air Branch
P. O. Box 3378 • Honolulu, HI 96801-3378 • Phone: (808) 586-4200

1. Company Name: Hawai'i Electric Light Company, Inc.

2. Facility Name (if different from the Company): Keahole Generating Station

3. Mailing Address: 73-4249 Pukiawe Street

   City: Kailua Kona State: HI Zip Code: 96740

   Phone Number: (808) 935-1711

4. Name of Owner/Owner's Agent: Anthony H. Koyamatsu (Owner's Agent)

   Title: Manager, Environmental Department Phone: (808) 543-4500

   Mailing Address: Hawaiian Electric Company; PO Box 2750

   City: Honolulu State: HI Zip Code: 96840-0001

5. Plant Site Manager/Other Contact: Norman M. Uchida, PE

   Title: Manager, Production Department Phone: (808) 969-0422

   Mailing Address: P.O. Box 1027

   City: Hilo State: HI Zip Code: 96721-1027

6. Permit Application Basis: (Check appropriate boxes)

   ☐ Initial Permit for a New Source ☐ Initial Permit for an Existing Source

   ☐ Renewal of Existing Permit ☐ General Permit

   ☐ Temporary Source ☐ Transfer of Permit

   ■ Modification to a Covered Source: → Is modification? ☐ Significant ■ Minor ☐ Uncertain

   ☐ Modification to a Noncovered Source

7. If renewal or modification, include existing permit number: CSP No. 0007-01-C

8. Does the Proposed Source require a County Special Management Area Permit? ☐ Yes ■ No

9. Type of Source (Check One): ☐ Covered Source ■ Covered & PSD Source

   ☐ Noncovered Source ☐ Uncertain

10. Standard Industrial Classification Code (SICC), if known: 4911

11. Proposed Equipment/Plant Location (e.g. street address): 73-4249 Pukiawe Street

City: Kailua Kona State: HI Zip Code: 96740

UTM Coordinates (meters): East: 811,293 North: 2,184,955

UTM Zone: 4 UTM Horizontal Datum: ■ Old Hawaiian ☐ NAD-27 ☐ NAD-83

12. General Nature of Business: Electrical Generation

13. Date of Planned Commencement of Installation or Modification: Upon approval of modification.

14. Is *any* of the equipment to be leased to another individual or entity? ☐ Yes ■ No

15. Type of Organization: ■ Corporation ☐ Individual Owner ☐ Partnership

☐ Government Agency (Government Facility Code: ____________)

☐ Other: ____________

Any applicant for a permit who fails to submit any relevant facts or who has submitted incorrect information in any permit application shall, upon becoming aware of such failure or incorrect submittal, promptly submit such supplementary facts or corrected information. In addition, an applicant shall provide additional information as necessary to address any requirements that become applicable to the source after the date it filed a complete application, but prior to the issuance of the noncovered source permit or release of a draft covered source permit. (HAR § 11-60.1-64 & 11-60.1-84)

RESPONSIBLE OFFICIAL (as defined in §11-60.1-1):

Name (Last): Uchida (First): Norman (MI): M.

Title: Manager, Production Department Phone: (808) 969-0422

Mailing Address: P.O. Box 1027

City: Hilo State: HI Zip Code: 96721-1027

CERTIFICATION by Responsible Official (pursuant to §11-60.1-4):

I certify that I have knowledge of the facts herein set forth, that the same are true, accurate and complete to the best of my knowledge and belief, and that all information not identified by me as confidential in nature shall be treated by the Department of Health as public record. I further state that I will assume responsibility for the construction, modification, or operation of the source in accordance with the Hawaii Administrative Rules (HAR), Title 11, Chapter 60.1, Air Pollution Control, and any permit issued thereof.

NAME (Print/Type): Norman M. Uchida, PE

(Signature): Norman Uchida Date: 4/13/18

FOR AGENCY USE ONLY:

File/Application No: ____________

Island: ____________

Date Received: ____________

Submit the following documents as part of your application:

A. The ***Emissions Units Table***, filled in as completely as possible. Use separate sheets of paper as needed. General instructions include the following:

1. Identify each **emission point** with a unique number for this plant site, consistent with emission point identification used on the location drawing and previous permits; if known, provide the SICC number. Emission points shall be identified and described in sufficient detail to establish the basis for fees and applicability of requirements of HAR, Chapter 11-60.1. Examples of emission point names are: heater, vent, boiler, tank, baghouse, fugitive, etc. Abbreviations may be used.
   a. For each emission point use as many lines as necessary to list regulated and hazardous air pollutant data. For hazardous air pollutants, also list the Chemical Abstracts Service number (CAS#).
   b. Indicate the emission points that discharge together for any length of time.
   c. The **Equipment Date** is the date of equipment construction, reconstruction, or modification. Provide supporting documentation.

2. State the **maximum emission rates** in terms sufficient to establish compliance with the applicable requirements and standard reference test methods. Provide all supporting emission calculations and assumptions:
   a. Include all regulated and hazardous air pollutants and air pollutants for which the source is major, as defined in HAR §11-60.1-1. Examples of regulated pollutant names are: Carbon Monoxide (CO), Nitrogen Oxides (NO_X), Sulfur Dioxide (SO_2), Volatile Organic Compounds (VOC), particulate matter (PM), and particulate less than 10 microns (PM_{10}). Abbreviations may be used.
   b. Include fugitive emissions.
   c. **Pounds per hour (#/HR)** is the maximum potential emission rate expected by applicant.
   Tons per year is the annual maximum potential emissions expected by the applicant, taking into account the typical operating schedule.

3. Describe ***Stack Source Parameters***:
   a. **Stack Height** is the height above the ground.
   b. **Direction** refers to the exit direction of stack emissions: up, down or horizontal.
   c. **Flow Rate** is the actual, not the calculated, flow rate.

4. Provide any additional information, if applicable, as follows:
   a. If combinations of different fuels are used that cause any of the stack source parameters to differ, complete one row for each possible set of stack parameters and identify each fuel in the **Equipment Description**.
   b. For a rectangular stack, indicate the length and width.
   c. Provide any information on stack parameters or any stack height limitations developed pursuant to Section 123 of the Clean Air Act.

B. A **process flow diagram** identifying all equipment used in the process, including the following:
   1. Identify and describe each emission point.
   2. Identify the locations of safety valves, bypasses, and other such devices which when activated may release air pollutants to the atmosphere.

C. A **facility location map**, drawn to a reasonable scale and showing the following:
   1. The property involved and all structures on it. Identify property/fence lines plainly.
   2. Layout of the facility.
   3. Location and identification of the proposed emissions unit on the property.
   4. Location of the property and equipment with respect to streets and all adjacent property. Show the location of all structures within 325 meters of the applicant's emissions unit. Provide the building dimensions (height, length, and width) of all structures that have heights greater than 40% of the stack height of the emissions unit.

D. Provide a description of any proposed modifications or permit revisions. Include any justification or supporting information for the proposed modifications or permit revisions.

Attachment S-1a
Responses to Emission Unit Table Instructions for Form S-1

A.1. Emission Point Identification and Description	Refer to Form S-1 Emissions Units Tables. The proposed changes do not impact emission point identification and description.
A.2. Maximum Emission Rates	Refer to Form S-1 Emissions Units Tables and Attachments S-1b, S-1c, S-1d, and S-1e. The proposed changes do not impact maximum emission rates.
A.3. Stack Parameters	Refer to Forms S-1 Emissions Units Tables. The proposed changes do not impact stack parameters.
A.4. Additional Information	None
B. Process Flow Diagram	Refer to Figures S-1.1, S-1.2, and S-1.3.
C. Facility Location Map	Refer to Figure S-1.4.
D. Proposed Revisions	See Attachment S-7a.

FIGURE S-1.1

PROCESS FLOW DIAGRAM FOR UNITS CT-4 AND CT-5

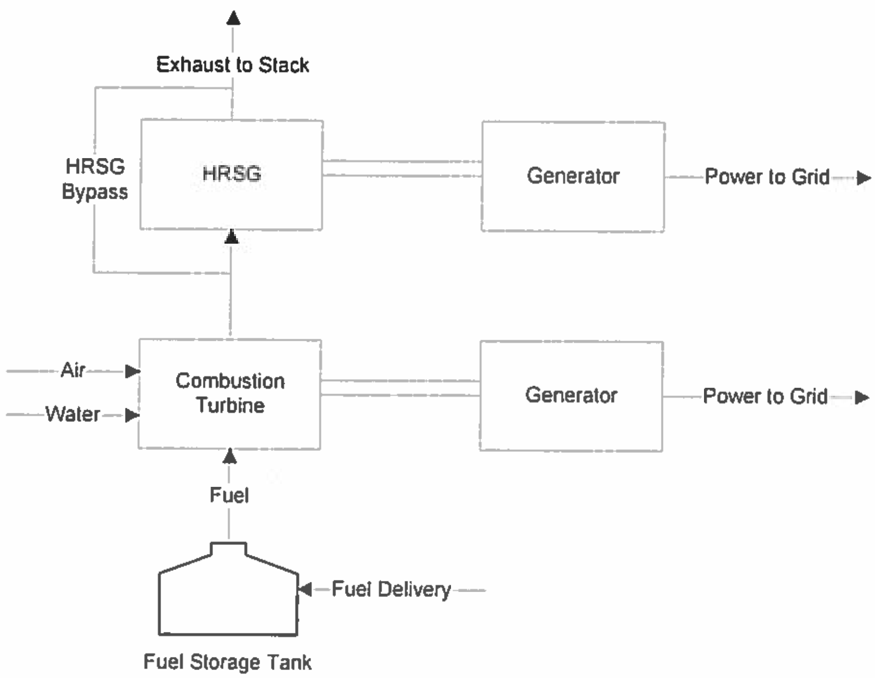


Figure S-1.2

Process Flow Diagram for Units D-21, D-22, and D-23

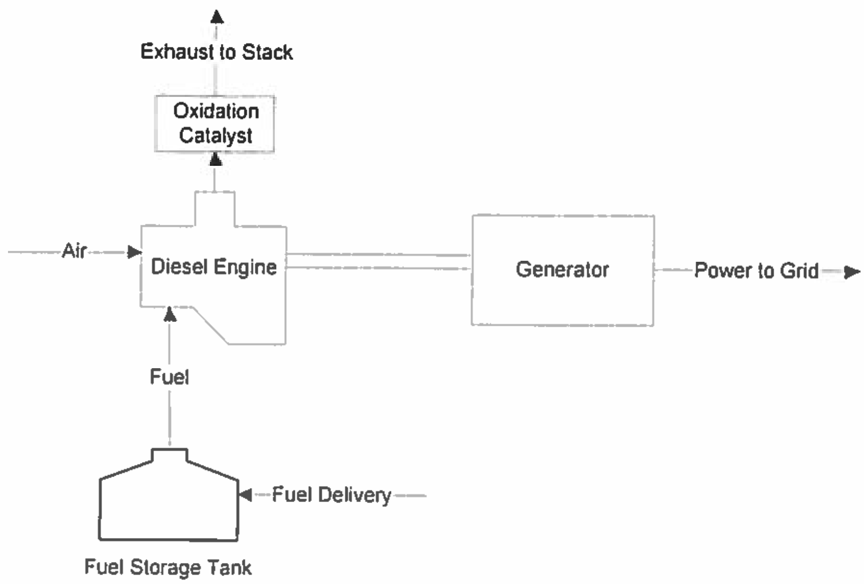


Figure S-1.3

Process Flow Diagram for Unit BS-1

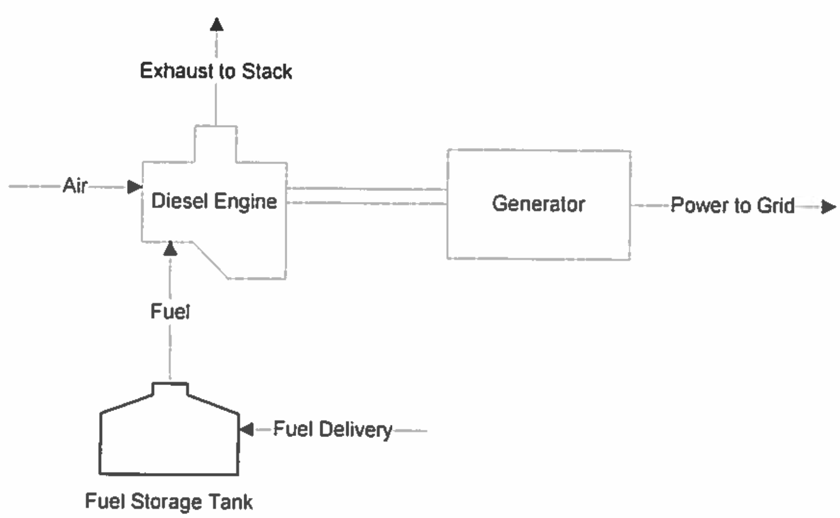
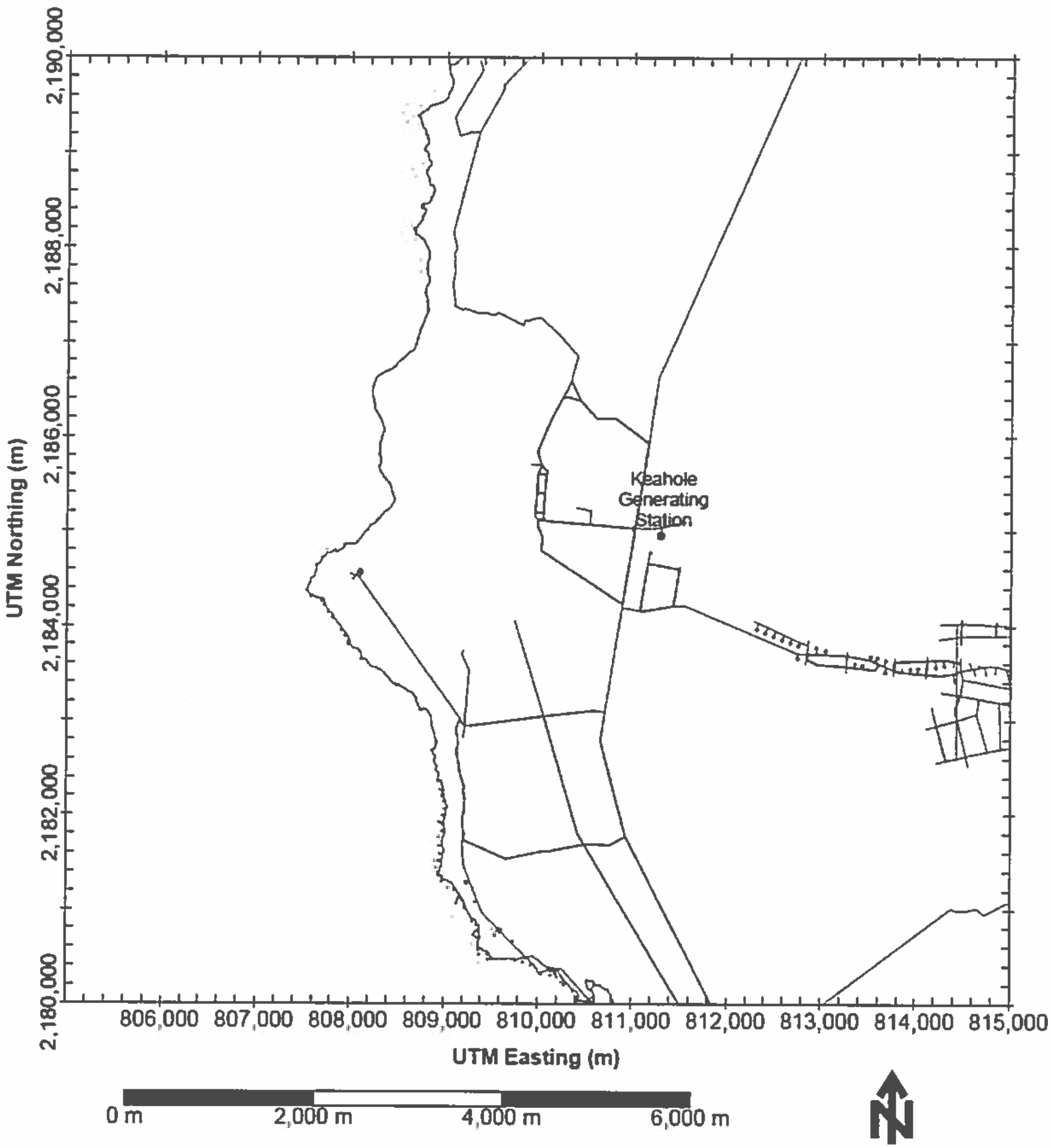


FIGURE S-1.4 LOCATION MAP



Company Name: Hawai'i Electric Light Company, Inc.
Location: Keahole Generating Station
(Make as many copies of this page as necessary)

File No.:

Page 1

EMISSIONS UNITS TABLE

Review of applications and issuance of permits will be expedited by supplying all necessary information on this table.

AIR POLLUTANT DATA: EMISSION POINTS				AIR POLLUTANT	AIR POLLUTANT EMISSION RATE		UTM Zone: 4 Horizontal Datum [a]: Old Hawaiian		STACK SOURCE PARAMETERS						
Stack No.	Unit No.	EQUIPMENT NAME/DESCRIPTION & SICC number	Equipment Date	Regulated/Hazardous Air Pollutant Name & CAS#	#/HR.	Tons/Year	Coordinates (mtrs)		Stack Height (mtrs)	Direction (u/d/h)[b]	Inside Diameter (mtrs)	Velocity (m/s)	Flow Rate (m^3/s)	Temp. (°K)	Capped (Y/N)
4 or 5	CT-4 or CT-5	20 MW (Nominal) General Electric LM2500 Combustion Turbine, (SICC 4911), Simple Cyle, Peak Load	7/25/2001	SO_2	110.0	481.8	East North	811,293 2,184,955	31.5	U	2.44	38.5	179.9	821	N
				NO_x	42.3	185.3	East North	811,293 2,184,955	31.5	U	2.44	38.5	179.9	821	N
				CO	26.8	117.4	East North	811,293 2,184,955	31.5	U	2.44	38.5	179.9	821	N
				VOC	0.8	3.5	East North	811,293 2,184,955	31.5	U	2.44	38.5	179.9	821	N
				PM/PM-10	19.7	86.3	East North	811,293 2,184,955	31.5	U	2.44	38.5	179.9	821	N
				H_2SO_4 Mist	14.4	63.2	East North	811,293 2,184,955	31.5	U	2.44	38.5	179.9	821	N
				Pb	See Attachment S-1b		East North	811,293 2,184,955	31.5	U	2.44	38.5	179.9	821	N
				Fluorides	2.77E-03	1.21E-02	East North	811,293 2,184,955	31.5	U	2.44	38.5	179.9	821	N
				TRS	Not Expected		East North	811,293 2,184,955	31.5	U	2.44	38.5	179.9	821	N
				CFCs	Not Expected		East North	811,293 2,184,955	31.5	U	2.44	38.5	179.9	821	N
				HAP	See Attachment S-1b		East North	811,293 2,184,955	31.5	U	2.44	38.5	179.9	821	N
				GHG (CO_2e)	See Attachment S-1e		East North	811,293 2,184,955	31.5	U	2.44	38.5	179.9	821	N

[a] Specify UTM Horizontal Datum as Old Hawaiian, NAD-83, or NAD-27

[b] Specify the direction of the stack exhaust as u=upward, d=downward, h=horizontal

Notes: 1. The equipment date is the date that CSP No. 0007-01-C was issued.

2. Stack parameters and SO_2, NO_x, CO, VOC, and PM/PM_{10} emission rates are from the PSD Permit Application for CT-4 and CT-5, dated January 1993.

3. H_2SO_4 emission rate based on 13.12% of the SO_2 emission rate (5.57 lb/hr / 42.44 lb/hr). This ratio is derived from the August 19, 1994 SCEC report of Maui Electric Company, Ltd. Maalaea Generating Station's M16 source tests.

4. Emission rate for Fluorides based on Maui Electric Company, Ltd. fuel test results of 0.2 ppm dated April 11, 1985.

Company Name: Hawai'i Electric Light Company, Inc.

Location: Keahole Generating Station

(Make as many copies of this page as necessary)

File No.: ____

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EMISSIONS UNITS TABLE

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AIR POLLUTANT DATA: EMISSION POINTS				AIR POLLUTANT	AIR POLLUTANT EMISSION RATE		UTM Zone: 4 Horizontal Datum [a]: Old Hawaiian		STACK SOURCE PARAMETERS						
Stack No.	Unit No	EQUIPMENT NAME/DESCRIPTION & SICC number	Equipment Date	Regulated/Hazardous Air Pollutant Name & CAS#	#/HR	Tons/Year	Coordinates (mtrs)		Stack Height (mtrs)	Direction (u/d/h) [b]	Inside Diameter (mtrs)	Velocity (m/s)	Flow Rate (m^3/s)	Temp. (°K)	Capped (Y/N)
4 or 5	CT-4 or CT-5	20 MW (Nominal) General Electric LM2500 Combustion Turbine, (SICC 4911), Simple Cyle, 75% of Peak Load	7/25/2001	SO_2	82.9	363.1	East North	811,293 2,184,955	31.5	U	2.44	38.5	179.9	821	N
				NO_x	42.3	185.3	East North	811,293 2,184,955	31.5	U	2.44	38.5	179.9	821	N
				CO	56.4	247.0	East North	811,293 2,184,955	31.5	U	2.44	38.5	179.9	821	N
				VOC	2.6	11.4	East North	811,293 2,184,955	31.5	U	2.44	38.5	179.9	821	N
				PM/PM-10	19.7	86.3	East North	811,293 2,184,955	31.5	U	2.44	38.5	179.9	821	N

[a] Specify UTM Horizontal Datum as Old Hawaiian, NAD-83, or NAD-27

[b] Specify the direction of the stack exhaust as u=upward, d=downward, h=horizontal

Notes: 1. The equipment date is the date that CSP No. 0007-01-C was issued.

2. Stack parameters and SO_2, NO_x, CO, VOC, and PM/PM_{10} emission rates are from the PSD Permit Application for CT-4 and CT-5, dated January 1993.

Company Name: Hawai'i Electric Light Company, Inc.

Location: Keahole Generating Station

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EMISSIONS UNITS TABLE

Review of applications and issuance of permits will be expedited by supplying all necessary information on this table.

AIR POLLUTANT DATA: EMISSION POINTS				AIR POLLUTANT	AIR POLLUTANT EMISSION RATE		UTM Zone: 4 Horizontal Datum [a]: Old Hawaiian		STACK SOURCE PARAMETERS						
Stack No.	Unit No.	EQUIPMENT NAME/DESCRIPTION & SICC number	Equipment Date	Regulated/Hazardous Air Pollutant Name & CAS#	#/HR.	Tons/Year	Coordinates (mtrs)		Stack Height (mtrs)	Direction (u/d/h)[b]	Inside Diameter (mtrs)	Velocity (m/s)	Flow Rate (m^3/s)	Temp. (°K)	Capped (Y/N)
4 or 5	CT-4 or CT-5	20 MW (Nominal) General Electric LM2500 Combustion Turbine, (SICC 4911), Simple Cyle, 50% of Peak Load	7/25/2001	SO_2	58.0	254.0	East	811,293	31.5	U	2.44	38.5	179.9	821	N
							North	2,184,955							
				NO_x	42.3	185.3	East	811,293	31.5	U	2.44	38.5	179.9	821	N
							North	2,184,955							
				CO	181.0	792.8	East	811,293	31.5	U	2.44	38.5	179.9	821	N
							North	2,184,955							
				VOC	28.1	123.1	East	811,293	31.5	U	2.44	38.5	179.9	821	N
							North	2,184,955							
				PM/PM-10	19.7	86.3	East	811,293	31.5	U	2.44	38.5	179.9	821	N
							North	2,184,955							

[a] Specify UTM Horizontal Datum as Old Hawaiian, NAD-83, or NAD-27

[b] Specify the direction of the stack exhaust as u=upward, d=downward, h=horizontal

Notes: 1. The equipment date is the date that CSP No. 0007-01-C was issued.

2. Stack parameters and SO_2, NO_x, CO, VOC, and PM/PM_{10} emission rates are from the PSD Permit Application for CT-4 and CT-5, dated January 1993.

Company Name: Hawai'i Electric Light Company, Inc.

Location: Keahole Generating Station

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AIR POLLUTANT DATA: EMISSION POINTS				AIR POLLUTANT	AIR POLLUTANT EMISSION RATE		UTM Zone: 4 Horizontal Datum [a]: Old Hawaiian		STACK SOURCE PARAMETERS						
Stack No.	Unit No	EQUIPMENT NAME/DESCRIPTION & SICC number	Equipment Date	Regulated/Hazardous Air Pollutant Name & CAS#	#/HR.	Tons/Year	Coordinates (mtrs)		Stack Height (mtrs)	Direction (u/d/h)[b]	Inside Diameter (mtrs)	Velocity (m/s)	Flow Rate (m^3/s)	Temp. (°K)	Capped (Y/N)
4 or 5	CT-4 or CT-5	20 MW (Nominal) General Electric LM2500 Combustion Turbine, (SICC 4911), Simple Cyle, 25% of Peak Load	7/25/2001	SO_2	39.0	170.8	East	811,293	31.5	U	2.44	38.5	179.9	821	N
							North	2,184,955							
				NO_x	42.3	185.3	East	811,293	31.5	U	2.44	38.5	179.9	821	N
							North	2,184,955							
				CO	475.6	2083.1	East	811,293	31.5	U	2.44	38.5	179.9	821	N
							North	2,184,955							
				VOC	297.6	1303.5	East	811,293	31.5	U	2.44	38.5	179.9	821	N
							North	2,184,955							
				PM/PM-10	19.7	86.3	East	811,293	31.5	U	2.44	38.5	179.9	821	N
							North	2,184,955							

[a] Specify UTM Horizontal Datum as Old Hawaiian, NAD-83, or NAD-27

[b] Specify the direction of the stack exhaust as u=upward, d=downward, h=horizontal

Notes: 1. The equipment date is the date that CSP No. 0007-01-C was issued.

2. Stack parameters and SO_2, NO_x, CO, VOC, and PM/PM_{10} emission rates are from the PSD Permit Application for CT-4 and CT-5, dated January 1993.

Company Name: Hawai'i Electric Light Company, Inc.
Location: Keahole Generating Station
(Make as many copies of this page as necessary)

File No. ____

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EMISSIONS UNITS TABLE

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AIR POLLUTANT DATA. EMISSION POINTS				AIR POLLUTANT	AIR POLLUTANT EMISSION RATE		UTM Zone: 4 Horizontal Datum [a]: Old Hawaiian		STACK SOURCE PARAMETERS						
Stack No.	Unit No.	EQUIPMENT NAME/DESCRIPTION & SICC number	Equipment Date	Regulated/Hazardous Air Pollutant Name & CAS#	#/HR.	Tons/Year	Coordinates (mtrs)		Stack Height (mtrs)	Direction (u/d/h)[b]	Inside Diameter (mtrs)	Velocity (m/s)	Flow Rate (m^3/s)	Temp. (°K)	Capped (Y/N)
4 or 5	CT-4 or CT-5	20 MW (Nominal) General Electric LM2500 Combustion Turbine, (SICC 4911), Combined Cyle, Peak Load	7/25/2001	SO_2	110.0	481.8	East	811,293	31.5	U	2.44	38.5	179.9	821	N
							North	2,184,955							
				NO_x	15.1	66.1	East	811,293	31.5	U	2.44	38.5	179.9	821	N
							North	2,184,955							
				CO	26.9	117.8	East	811,293	31.5	U	2.44	38.5	179.9	821	N
							North	2,184,955							
				VOC	0.8	3.5	East	811,293	31.5	U	2.44	38.5	179.9	821	N
							North	2,184,955							
				PM/PM-10	19.7	86.3	East	811,293	31.5	U	2.44	38.5	179.9	821	N
							North	2,184,955							
				H_2SO_4 Mist	14.4	63.2	East	811,293	31.5	U	2.44	38.5	179.9	821	N
							North	2,184,955							
				Pb	See Attachment S-1b		East	811,293	31.5	U	2.44	38.5	179.9	821	N
							North	2,184,955							
				Fluorides	2.77E-03	1.21E-02	East	811,293	31.5	U	2.44	38.5	179.9	821	N
							North	2,184,955							
				TRS	Not Expected		East	811,293	31.5	U	2.44	38.5	179.9	821	N
							North	2,184,955							
				CFCs	Not Expected		East	811,293	31.5	U	2.44	38.5	179.9	821	N
							North	2,184,955							
				HAP	See Attachment S-1b		East	811,293	31.5	U	2.44	38.5	179.9	821	N
							North	2,184,955							
				NH_3	4.3	18.8	East	811,293	31.5	U	2.44	38.5	179.9	821	N
							North	2,184,955							
				GHG (CO_2e)	See Attachment S-1e		East	811,293	31.5	U	2.44	38.5	179.9	821	N
							North	2,184,955							

[a] Specify UTM Horizontal Datum as Old Hawaiian, NAD-83, or NAD-27

[b] Specify the direction of the stack exhaust as u=upward, d=downward, h=horizontal

Notes:
1. The equipment date is the date that CSP No. 0007-01-C was issued.
2. Stack parameters and SO_2, NO_x, CO, VOC, and PM/PM_{10} emission rates are from the PSD Permit Application for CT-4 and CT-5, dated January 1993.
3. NO_x emission rate is based on SCR and water injection reducing emissions to 15 ppmvd (15.1 = 42.3 x (15 ppmvd/42 ppmvd)).
4. H2SO4 emission rate based on 13.12% of the SO2 emission rate (5.57 lb/hr / 42.44 lb/hr). This ratio is derived from the August 19, 1994 SCEC report of Maui Electric Company, Ltd. Maalaea Generating Station's M16 source tests.
5. Emission rate for Fluorides based on Maui Electric Company, Ltd. fuel tests results of 0.2 ppm dated April 11, 1985.
6. NH_3 emission rate is based on manufacturer's maximum ammonia slip of 10 ppmvd and a peak load flow rate of 559,400 lb/hr at 59 degrees F

Company Name: Hawai'i Electric Light Company, Inc.

Location: Keahole Generating Station

(Make as many copies of this page as necessary)

File No.:

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EMISSIONS UNITS TABLE

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AIR POLLUTANT DATA: EMISSION POINTS				AIR POLLUTANT	AIR POLLUTANT EMISSION RATE		UTM Zone: 4 Horizontal Datum [a]: Old Hawaiian		STACK SOURCE PARAMETERS						
Stack No.	Unit No.	EQUIPMENT NAME/DESCRIPTION & SICC number	Equipment Date	Regulated/Hazardous Air Pollutant Name & CAS#	#/HR.	Tons/Year	Coordinates (mtrs)		Stack Height (mtrs)	Direction (u/d/h)[b]	Inside Diameter (mtrs)	Velocity (m/s)	Flow Rate (m^3/s)	Temp. (°K)	Capped (Y/N)
4 or 5	CT-4 or CT-5	20 MW (Nominal) General Electric LM2500 Combustion Turbine, (SICC 4911), Combined Cyle, 75% of Peak Load	7/25/2001	SO_2	86.0	376.7	East	811,293	31.5	U	2.44	38.5	179.9	821	N
							North	2,184,955							
				NO_x	15.1	66.1	East	811,293	31.5	U	2.44	38.5	179.9	821	N
							North	2,184,955							
				CO	50.2	219.9	East	811,293	31.5	U	2.44	38.5	179.9	821	N
							North	2,184,955							
				VOC	2.0	8.8	East	811,293	31.5	U	2.44	38.5	179.9	821	N
							North	2,184,955							
				PM/PM-10	19.7	86.3	East	811,293	31.5	U	2.44	38.5	179.9	821	N
							North	2,184,955							
				NH_3	4.3	18.8	East	811,293	31.5	U	2.44	38.5	179.9	821	N
							North	2,184,955							

[a] Specify UTM Horizontal Datum as Old Hawaiian, NAD-83, or NAD-27

[b] Specify the direction of the stack exhaust as u=upward, d=downward, h=horizontal

Notes:
1. The equipment date is the date that CSP No. 0007-01-C was issued.
2. Stack parameters and SO_2, NO_x, CO, VOC, and PM/PM_{10} emission rates are from the PSD Permit Application for CT-4 and CT-5, dated January 1993.
3. NO_x emission rate is based on SCR and water injection reducing emissions to 15 ppmvd (15.1 = 42.3 x (15 ppmvd/42 ppmvd)).
4. NH_3 emissions are the worst-case emission rate based on the manufacturer's guaranteed ammonia slip of 10 ppmvd and a 100 percent load flow rate of 559,400 lb/hr at 59 degrees F.

Company Name: Hawai'i Electric Light Company, Inc.

Location: Keahole Generating Station

(Make as many copies of this page as necessary)

File No.: ______

EMISSIONS UNITS TABLE

Review of applications and issuance of permits will be expedited by supplying all necessary information on this table.

AIR POLLUTANT DATA: EMISSION POINTS				AIR POLLUTANT	AIR POLLUTANT EMISSION RATE		UTM Zone: 4 Horizontal Datum [a]: Old Hawaiian		STACK SOURCE PARAMETERS						
Stack No	Unit No	EQUIPMENT NAME/DESCRIPTION & SICC number	Equipment Date	Regulated/Hazardous Air Pollutant Name & CAS#	#/HR	Tons/Year	Coordinates (mtrs)		Stack Height (mtrs)	Direction (u/d/h)[b]	Inside Diameter (mtrs)	Velocity (m/s)	Flow Rate (m^3/s)	Temp. (°K)	Capped (Y/N)
4 or 5	CT-4 or CT-5	20 MW (Nominal) General Electric LM2500 Combustion Turbine, (SICC 4911), Combined Cycle, 50% of Peak Load	7/25/2001	SO_2	59.0	258.4	East	811,293	31.5	U	2.44	14.2	66.4	419	N
							North	2,184,955							
				NO_x	42.3	185.3	East	811,293	31.5	U	2.44	14.2	66.4	419	N
							North	2,184,955							
				CO	170.4	746.4	East	811,293	31.5	U	2.44	14.2	66.4	419	N
							North	2,184,955							
				VOC	25.0	109.5	East	811,293	31.5	U	2.44	14.2	66.4	419	N
							North	2,184,955							
				PM/PM-10	19.7	86.3	East	811,293	31.5	U	2.44	14.2	66.4	419	N
							North	2,184,955							

[a] Specify UTM Horizontal Datum as Old Hawaiian, NAD-83, or NAD-27

[b] Specify the direction of the stack exhaust as u=upward, d=downward, h=horizontal

Notes:
1. The equipment date is the date that CSP No. 0007-01-C was issued.
2. Stack parameters and SO_2, NO_x, CO, VOC, and PM/PM_{10} emission rates are from the PSD Permit Application for CT-4 and CT-5, dated January 1993.
3. NO_X emission rate is based on water injection reducing emissions to 42 ppmvd. SCR is not required for loads less than 50% of peak. Operating the SCR at loads less than 50% of peak will cause ammonium sulfates to form in the catalyst and on the boiler tubes in the heat recovery steam generator.

Company Name: Hawai'i Electric Light Company, Inc.

Location: Keahole Generating Station

(Make as many copies of this page as necessary)

File No.:

EMISSIONS UNITS TABLE

Review of applications and issuance of permits will be expedited by supplying all necessary information on this table.

AIR POLLUTANT DATA: EMISSION POINTS				AIR POLLUTANT	AIR POLLUTANT EMISSION RATE		UTM Zone: 4 Horizontal Datum [a]: Old Hawaiian		STACK SOURCE PARAMETERS						
Stack No.	Unit No.	EQUIPMENT NAME/DESCRIPTION & SICC number	Equipment Date	Regulated/Hazardous Air Pollutant Name & CAS#	#/HR.	Tons/Year	Coordinates (mtrs)		Stack Height (mtrs)	Direction (u/d/h)[b]	Inside Diameter (mtrs)	Velocity (m/s)	Flow Rate (m^3/s)	Temp. (°K)	Capped (Y/N)
4 or 5	CT-4 or CT-5	20 MW (Nominal) General Electric LM2500 Combustion Turbine, (SICC 4911), Combined Cyle, 25% of Peak Load	7/25/2001	SO_2	39.9	174.8	East	811,293	31.5	U	2.44	10.8	50.5	414	N
							North	2,184,955							
				NO_x	42.3	185.3	East	811,293	31.5	U	2.44	10.8	50.5	414	N
							North	2,184,955							
				CO	457.4	2003.4	East	811,293	31.5	U	2.44	10.8	50.5	414	N
							North	2,184,955							
				VOC	271.0	1187.0	East	811,293	31.5	U	2.44	10.8	50.5	414	N
							North	2,184,955							
				PM/PM-10	19.7	86.3	East	811,293	31.5	U	2.44	10.8	50.5	414	N
							North	2,184,955							

[a] Specify UTM Horizontal Datum as Old Hawaiian, NAD-83, or NAD-27

[b] Specify the direction of the stack exhaust as u=upward, d=downward, h=horizontal

Notes: 1. The equipment date is the date that CSP No. 0007-01-C was issued.

2. Stack parameters and SO_2, NO_x, CO, VOC, and PM/PM_{10} emission rates are from the PSD Permit Application for CT-4 and CT-5, dated January 1993.

3. NO_X emission rate is based on water injection reducing emissions to 42 ppmvd. SCR is not required for loads less than 50% of peak. Operating the SCR at loads less than 50% of peak will cause ammonium sulfates to form in the catalyst and on the boiler tubes in the heat recovery steam generator.

Company Name: Hawai'i Electric Light Company, Inc.

Location: Keahole Generating Station

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EMISSIONS UNITS TABLE

Review of applications and issuance of permits will be expedited by supplying all necessary information on this table.

AIR POLLUTANT DATA: EMISSION POINTS				AIR POLLUTANT	AIR POLLUTANT EMISSION RATE		UTM Zone: 4 Horizontal Datum [a]: Old Hawaiian		STACK SOURCE PARAMETERS						
Stack No.	Unit No.	EQUIPMENT NAME/DESCRIPTION & SICC number	Equipment Date	Regulated/Hazardous Air Pollutant Name & CAS#	#/HR.	Tons/Year	Coordinates (mtrs)		Stack Height (mtrs)	Direction (u/d/h)[b]	Inside Diameter (mtrs)	Velocity (m/s)	Flow Rate (m^3/s)	Temp. (°K)	Capped (Y/N)
21	D-21	2.5 MW (Nominal) General Motors EMD Model 20-645F4B Diesel Engine Generator (SICC 4911)	1974	SO_2	0.04	0.0	East North	811,255 2,184 884	12.2	U	0.90	18.3	11.6	677	N
				NO_x	68.4	11.9	East North	811,255 2,184,884	12.2	U	0.90	18.3	11.6	677	N
				CO	23.6	4.1	East North	811,255 2,184,884	12.2	U	0.90	18.3	11.6	677	N
				VOC	6.69	1.17	East North	811,255 2,184,884	12.2	U	0.90	18.3	11.6	677	N
				PM/PM-10	5.06	0.88	East North	811,255 2,184,884	12.2	U	0.90	18.3	11.6	677	N
				H_2SO_4 Mist	0.01	0.00	East North	811,255 2,184,884	12.2	U	0.90	18.3	11.6	677	N
				Pb	See Attachment S-1b		East North	811,255 2,184,884	12.2	U	0.90	18.3	11.6	677	N
				Fluorides	2.83E-04	4.94E-05	East North	811,255 2,184,884	12.2	U	0.90	18.3	11.6	677	N
				TRS	Not Expected		East North	811,255 2,184,884	12.2	U	0.90	18.3	11.6	677	N
				CFCs	Not Expected		East North	811,255 2,184,884	12.2	U	0.90	18.3	11.6	677	N
				HAP	See Attachment S-1b		East North	811,255 2,184,884	12.2	U	0.90	18.3	11.6	677	N
				GHG (CO_2e)	See Attachment S-1e		East North	811,255 2,184,884	12.2	U	0.90	18.3	11.6	677	N

[a] Specify UTM Horizontal Datum as Old Hawaiian, NAD-83, or NAD-27

[b] Specify the direction of the stack exhaust as u=upward, d=downward, h=horizontal

Notes:
1. NO_x, CO, VOC, and PM/PM_{10} emission rates are based on an evaluation of AP-42 calculations and stack test data. Emission rate for CO includes a 70% reduction in accordance with 40 CFR Part 63 Subpart ZZZZ.
2. SO_2 emission rate based on mass balance with maximum fuel sulfur content of 0.0015 percent and assuming conversion of all sulfur to SO_2.
3. H_2SO_4 emission rate based on 13.83% of the SO_2 emission rate (0.73 lb/hr / 5.28 lb/hr). This ratio is derived from the August 19, 1994 SCEC report of Maui Electric Company, Ltd. Maalaea Generating Station M3 source tests.
4. Emission rate for Fluorides based on Maui Electric Company, Ltd. fuel test results of 0.2 ppm dated April 11, 1985.
5. Unit D-21 'tpy' values are based on 70,000 gal/yr fuel limit, AP-42 no. 2 fuel oil heat content of 140,000 Btu/gal, and unit heat input of 28.1 MMBtu/hr.

Company Name: Hawai'i Electric Light Company, Inc.
Location: Keahole Generating Station
(Make as many copies of this page as necessary)

File No.: ____________

EMISSIONS UNITS TABLE

Review of applications and issuance of permits will be expedited by supplying all necessary information on this table.

AIR POLLUTANT DATA: EMISSION POINTS				AIR POLLUTANT	AIR POLLUTANT EMISSION RATE		UTM Zone: 4 Horizontal Datum [a]: Old Hawaiian		STACK SOURCE PARAMETERS						
Stack No.	Unit No.	EQUIPMENT NAME/DESCRIPTION & SICC number	Equipment Date	Regulated/Hazardous Air Pollutant Name & CAS#	#/HR	Tons/Year	Coordinates (mtrs)		Stack Height (mtrs)	Direction (u/d/h)[b]	Inside Diameter (mtrs)	Velocity (m/s)	Flow Rate (m^3/s)	Temp. (°K)	Capped (Y/N)
22	D-22	2.5 MW (Nominal) General Motors EMD Model 20-645F4B Diesel Engine Generator (SICC 4911)	1966	SO_2	0.04	0.2	East North	811,253 2,184,874	12.2	U	0.90	18.3	11.6	877	N
				NO_x	68.4	299.6	East North	811,253 2,184,874	12.2	U	0.90	18.3	11.6	877	N
				CO	23.6	103.1	East North	811,253 2,184,874	12.2	U	0.90	18.3	11.6	877	N
				VOC	6.69	29.30	East North	811,253 2,184,874	12.2	U	0.90	18.3	11.6	877	N
				PM/PM-10	5.06	22.16	East North	811,253 2,184,874	12.2	U	0.90	18.3	11.6	877	N
				H_2SO_4 Mist	0.01	0.03	East North	811,253 2,184,874	12.2	U	0.90	18.3	11.6	877	N
				Pb	See Attachment S-1a		East North	811,253 2,184,874	12.2	U	0.90	18.3	11.6	877	N
				Fluorides	2.83E-04	1.24E-03	East North	811,253 2,184,874	12.2	U	0.90	18.3	11.6	877	N
				TRS	Not Expected		East North	811,253 2,184,874	12.2	U	0.90	18.3	11.6	877	N
				CFCs	Not Expected		East North	811,253 2,184,874	12.2	U	0.90	18.3	11.6	877	N
				HAP	See Attachment S-1b		East North	811,253 2,184,874	12.2	U	0.90	18.3	11.6	877	N
				GHG (CO_2e)	See Attachment S-1e		East North	811,253 2,184,874	12.2	U	0.90	18.3	11.6	877	N

[a] Specify UTM Horizontal Datum as Old Hawaiian, NAD-83, or NAD-27

[b] Specify the direction of the stack exhaust as u=upward, d=downward, h=horizontal

Notes:
1. NO_x, CO, VOC, and PM/PM_{10} emission rates are based on an evaluation of AP-42 calculations and stack test data. Emission rate for CO includes a 70% reduction in accordance with 40 CFR Part 63 Subpart ZZZZ.
2. SO_2 emission rate based on mass balance with maximum fuel sulfur content of 0.0015 percent and assuming conversion of all sulfur to SO_2.
3. H_2SO_4 emission rate based on 13.83% of the SO_2 emission rate (0.73 lb/hr / 5.28 lb/hr). This ratio is derived from the August 19, 1994 SCEC report of Maui Electric Company, Ltd. Maalaea Generating Station M3 source tests.
4. Emission rate for Fluorides based on Maui Electric Company, Ltd. fuel test results of 0.2 ppm dated April 11, 1985.

Company Name: Hawai'i Electric Light Company, Inc.

Location: Keahole Generating Station

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EMISSIONS UNITS TABLE

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AIR POLLUTANT DATA: EMISSION POINTS				AIR POLLUTANT	AIR POLLUTANT EMISSION RATE		UTM Zone: 4 Horizontal Datum [a]: Old Hawaiian		STACK SOURCE PARAMETERS						
Stack No.	Unit No.	EQUIPMENT NAME/DESCRIPTION & SICC number	Equipment Date	Regulated/Hazardous Air Pollutant Name & CAS#	#/HR.	Tons/Year	Coordinates (mtrs) East	Coordinates (mtrs) North	Stack Height (mtrs)	Direction (u/d/h)[b]	Inside Diameter (mtrs)	Velocity (m/s)	Flow Rate (m^3/s)	Temp. (°K)	Capped (Y/N)
23	D-23	2.5 MW (Nominal) General Motors EMD Model 20-645F4B Diesel Engine Generator (SICC 4911)	1969	SO_2	0.04	0.2	811,251	2,184,869	12.2	U	0.90	18.3	11.6	677	N
				NO_x	68.4	299.6	811,251	2,184,869	12.2	U	0.90	18.3	11.6	677	N
				CO	23.6	103.1	811,251	2,184,869	12.2	U	0.90	18.3	11.6	677	N
				VOC	6.69	29.3	811,251	2,184,869	12.2	U	0.90	18.3	11.6	677	N
				PM/PM-10	5.06	22.2	811,251	2,184,869	12.2	U	0.90	18.3	11.6	677	N
				H_2SO_4 Mist	0.01	0.0	811,251	2,184,869	12.2	U	0.90	18.3	11.6	677	N
				Pb	See Attachment S-1a		811,251	2,184,869	12.2	U	0.90	18.3	11.6	677	N
				Fluorides	2.83E-04	1.24E-03	811,251	2,184,869	12.2	U	0.90	18.3	11.6	677	N
				TRS	Not Expected		811,251	2,184,869	12.2	U	0.90	18.3	11.6	677	N
				CFCs	Not Expected		811,251	2,184,869	12.2	U	0.90	18.3	11.6	677	N
				HAP	See Attachment S-1b		811,251	2,184,869	12.2	U	0.90	18.3	11.6	677	N
				GHG (CO_2e)	See Attachment S-1e		811,251	2,184,869	12.2	U	0.90	18.3	11.6	677	N

[a] Specify UTM Horizontal Datum as Old Hawaiian, NAD-83, or NAD-27

[b] Specify the direction of the stack exhaust as u=upward, d=downward, h=horizontal

Notes: 1. NO_x, CO, VOC, and PM/PM_{10} emission rates are based on an evaluation of AP-42 calculations and stack test data. Emission rate for CO includes a 70% reduction in accordance with 40 CFR Part 63 Subpart ZZZZ.

2. SO_2 emission rate based on mass balance with maximum fuel sulfur content of 0.0015 percent and assuming conversion of all sulfur to SO_2.

3. H_2SO_4 emission rate based on 13.83% of the SO_2 emission rate (0.73 lb/hr / 5.28 lb/hr). This ratio is derived from the August 19, 1994 SCEC report of Maui Electric Company, Ltd. Maalaea Generating Station M3 source tests.

4. Emission rate for Fluorides based on Maui Electric Company, Ltd. fuel test results of 0.2 ppm dated April 11, 1985.

Company Name: Hawai'i Electric Light Company, Inc.

Location: Keahole Generating Station

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File No.: ________

EMISSIONS UNITS TABLE

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AIR POLLUTANT DATA: EMISSION POINTS				AIR POLLUTANT	AIR POLLUTANT EMISSION RATE		UTM Zone: 4 Horizontal Datum [a]: Old Hawaiian	STACK SOURCE PARAMETERS							
Stack No.	Unit No.	EQUIPMENT NAME/DESCRIPTION & SICC number	Equipment Date	Regulated/Hazardous Air Pollutant Name & CAS#	#/HR	Tons/Year	Coordinates (mtrs)	Stack Height (mtrs)	Direction (u/d/h)[b]	Inside Diameter (mtrs)	Velocity (m/s)	Flow Rate (m^3/s)	Temp (°K)	Capped (Y/N)
1	BS-1	500 kW Caterpillar Model 3412 Blackstart Diesel Engine Generator (SICC 4911)	Nov. 4, 1991	SO_2	2.86	0.43	East 811,250 North 2,184,848	21.3	U	0.20	62.2	2.0	894	N
				NO_x	12.50	1.88	East 811,250 North 2,184,848	21.3	U	0.20	62.2	2.0	894	N
				CO	2.38	0.36	East 811,250 North 2,184,848	21.3	U	0.20	62.2	2.0	894	N
				VOC	0.46	0.07	East 811,250 North 2,184,848	21.3	U	0.20	62.2	2.0	894	N
				PM/PM-10	1.98	0.30	East 811,250 North 2,184,848	21.3	U	0.20	62.2	2.0	894	N
				H_2SO_4 Mist	0.40	0.06	East 811,250 North 2,184,848	21.3	U	0.20	62.2	2.0	894	N
				Pb	See Attachment S-1a		East 811,250 North 2,184,848	21.3	U	0.20	62.2	2.0	894	N
				Fluorides	5.61E-05	8.41E-06	East 811,250 North 2,184,848	21.3	U	0.20	62.2	2.0	894	N
				TRS	Not Expected		East 811,250 North 2,184,848	21.3	U	0.20	62.2	2.0	894	N
				CFCs	Not Expected		East 811,250 North 2,184,848	21.3	U	0.20	62.2	2.0	894	N
				HAP	See Attachment S-1b		East 811,250 North 2,184,848	21.3	U	0.20	62.2	2.0	894	N
				GHG (CO_2e)	See Attachment S-1e		East 811,250 North 2,184,848	21.3	U	0.20	62.2	2.0	894	N

[a] Specify UTM Horizontal Datum as Old Hawaiian, NAD-83, or NAD-27

[b] Specify the direction of the stack exhaust as u=upward, d=downward, h=horizontal

Notes:
1. Equipment date is the date that PTO No. P-936-1287 was issued.
2. SO_2, NO_x, CO, and PM/PM_{10} emission rates are from ATC application dated Jan. 30, 1981. VOC emissions are based on AP-42, Section 3.4, dated 10/96.
3. BS-1 is limited to 300 hours per year.
4. H_2SO_4 emission rate based on 13.83% of the SO_2 emission rate (0.73 lb/hr / 5.28 lb/hr). This ratio is derived from the August 19, 1994 SCEC report of Maui Electric Company, Ltd. Maalaea Generating Station M3 source tests.
5. Emission rate for Fluorides based on Maui Electric Company, Ltd. fuel test results of 0.2 ppm dated April 11, 1985.

Attachment S-1b
Air Toxic Emissions for CT-4 or CT-5

SECTION 112 HAZARDOUS AIR POLLUTANTS

CAS Number	Pollutant[1]	Source of Emission Factor	Emission Factor (lb/MMBtu)	Heat Input (MMBtu/hr)	Emissions (lb/hr)	Emissions (tpy)
75-07-0	Acetaldehyde	AP-42, Section 3.4, Table 3.4-3	2.52E-05	275	6.93E-03	3.04E-02
60-35-5	Acetamide			275		
75-05-8	Acetonitrile			275		
98-86-2	Acetophenone			275		
53-96-3	2-Acetylaminofluorene			275		
107-02-8	Acrolein	AP-42, Section 3.4, Table 3.4-3	7.88E-06	275	2.17E-03	9.49E-03
79-06-1	Acrylamide			275		
79-10-7	Acrylic acid			275		
107-13-1	Acrylonitrile			275		
107-05-1	Allyl chloride			275		
92-67-1	4-Aminobiphenyl			275		
62-53-3	Aniline			275		
90-04-0	o-Anisidine			275		
1332-21-4	Asbestos			275		
71-43-2	Benzene (including benzene from gasoline)	AP-42, Section 3.1, Table 3.1-4	5.50E-05	275	1.51E-02	6.61E-02
92-87-5	Benzidine			275		
98-07-7	Benzotrichloride			275		
100-44-7	Benzyl chloride			275		
92-52-4	Biphenyl			275		
117-81-7	Bis(2-ethylhexyl)phthalate (DEHP)			275		
542-88-1	Bis(chloromethyl) ether			275		
75-25-2	Bromoform			275		
106-99-0	1,3-Butadiene	AP-42, Section 3.1, Table 3.1-4	1.60E-05	275	4.40E-03	1.93E-02
156-62-7	Calcium cyanamide			275		
105-60-2	Caprolactam (Removed 06/18/96, See 61FR30816)			275		
133-06-2	Captan			275		
63-25-2	Carbaryl			275		
75-15-0	Carbon disulfide			275		
56-23-5	Carbon tetrachloride			275		
463-58-1	Carbonyl sulfide			275		
120-80-9	Catechol			275		
133-90-4	Chloramben			275		
57-74-9	Chlordane			275		
7782-50-5	Chlorine			275		
79-11-8	Chloroacetic acid			275		
532-27-4	2-Chloroacetophenone			275		
108-90-7	Chlorobenzene			275		
510-15-6	Chlorobenzilate			275		
67-66-3	Chloroform			275		
107-30-2	Chloromethyl methyl ether			275		
126-99-8	Chloroprene			275		
1319-77-3	Cresol/Cresylic acid(mixed isomers)			275		
95-48-7	o-Cresol			275		
108-39-4	m-Cresol			275		
106-44-5	p-Cresol			275		
98-82-8	Cumene			275		
94-75-7	2,4-D salts and esters			275		
72-55-9	DDE(1,1-dichloro-2,2-bis(p-chlorophenyl) ethylene)			275		
334-88-3	Diazomethane			275		
132-64-9	Dibenzofuran			275		
96-12-8	1,2-Dibromo-3-chloropropane			275		
84-74-2	Dibutyl phthalate			275		
106-46-7	1,4-Dichlorobenzene			275		
91-94-1	Dichlorobenzidine			275		
111-44-4	Dichloroethyl ether(Bis[2-chloroethyl]ether)			275		
542-75-6	1,3-Dichloropropene			275		
62-73-7	Dichlorvos			275		
111-42-2	Diethanolamine			275		
64-67-5	Diethyl sulfate			275		
119-90-4	3,3'-Dimethoxybenzidine			275		
60-11-7	4-Dimethylaminoazobenzene			275		
121-69-7	N,N-Dimethylaniline			275		
119-93-7	3,3'-Dimethylbenzidine			275		
79-44-7	Dimethylcarbamoyl chloride			275		
68-12-2	N,N-Dimethylformamide			275		
57-14-7	1,1-Dimethylhydrazine			275		
131-11-3	Dimethyl phthalate			275		
77-78-1	Dimethyl sulfate			275		
534-52-1	4,6-Dinitro-o-cresol (including salts)			275		
51-28-5	2,4-Dinitrophenol			275		
121-14-2	2,4-Dinitrotoluene			275		
123-91-1	1,4-Dioxane (1,4-Diethyleneoxide)			275		
122-66-7	1,2-Diphenylhydrazine			275		
106-89-8	Epichlorohydrin (l-Chloro-2,3-epoxypropane)			275		
106-88-7	1,2-Epoxybutane			275		

Attachment S-1b
Air Toxic Emissions for CT-4 or CT-5

SECTION 112 HAZARDOUS AIR POLLUTANTS

CAS Number	Pollutant[1]	Source of Emission Factor	Emission Factor (lb/MMBtu)	Heat Input (MMBtu/hr)	Emissions (lb/hr)	Emissions (tpy)
140-88-5	Ethyl acrylate			275		
100-41-4	Ethylbenzene			275		
51-79-6	Ethyl carbamate (Urethane)			275		
75-00-3	Ethyl chloride (Chloroethane)			275		
106-93-4	Ethylene dibromide (Dibromoethane)			275		
107-06-2	Ethylene dichloride (1,2-Dichloroethane)			275		
107-21-1	Ethylene glycol			275		
151-56-4	Ethyleneimine (Aziridine)			275		
75-21-8	Ethylene oxide			275		
96-45-7	Ethylene thiourea			275		
75-34-3	Ethylidene dichloride (1,1-Dichloroethane)			275		
50-00-0	Formaldehyde	AP-42, Section 3.1, Table 3.1-4	2.80E-04	275	7.70E-02	3.37E-01
76-44-8	Heptachlor			275		
118-74-1	Hexachlorobenzene			275		
87-68-3	Hexachlorobutadiene			275		
77-47-4	Hexachlorocyclopentadiene			275		
67-72-1	Hexachloroethane			275		
822-06-0	Hexamethylene diisocyanate			275		
680-31-9	Hexamethylphosphoramide			275		
110-54-3	Hexane			275		
302-01-2	Hydrazine			275		
7647-01-0	Hydrochloric acid (Hydrogen chloride [gas only])			275		
7664-39-3	Hydrogen fluoride (Hydrofluoric acid)			275		
123-31-9	Hydroquinone			275		
78-59-1	Isophorone			275		
58-89-9	Lindane (all isomers)			275		
108-31-6	Maleic anhydride			275		
67-56-1	Methanol			275		
72-43-5	Methoxychlor			275		
74-83-9	Methyl bromide (Bromomethane)			275		
74-87-3	Methyl chloride(Chloromethane)			275		
71-55-6	Methyl chloroform(1,1,1-Trichloroethane)			275		
78-93-3	Methyl ethyl ketone (2-Butanone) (Removed 12/19/05. See 70FR75047)			275		
60-34-4	Methylhydrazine			275		
74-88-4	Methyl iodide (Iodomethane)			275		
108-10-1	Methyl isobutyl ketone(Hexone)			275		
624-83-9	Methyl isocyanate			275		
80-62-6	Methyl methacrylate			275		
1634-04-4	Methyl tert-butyl ether			275		
101-14-4	4,4'-Methylenebis(2-chloroaniline)			275		
75-09-2	Methylene chloride(Dichloromethane)			275		
101-68-8	4,4'-Methylenediphenyl diisocyanate(MDI)			275		
101-77-9	4,4'-Methylenedianiline			275		
91-20-3	Naphthalene	AP-42, Section 3.1, Table 3.1-4	3.50E-05	275	9.63E-03	4.22E-02
98-95-3	Nitrobenzene			275		
92-93-3	4-Nitrobiphenyl			275		
100-02-7	4-Nitrophenol			275		
79-46-9	2-Nitropropane			275		
684-93-5	N-Nitroso-N-methylurea			275		
62-75-9	N-Nitrosodimethylamine			275		
59-89-2	N-Nitrosomorpholine			275		
56-38-2	Parathion			275		
82-68-8	Pentachloronitrobenzene(Quintobenzene)			275		
87-86-5	Pentachlorophenol			275		
108-95-2	Phenol			275		
106-50-3	p-Phenylenediamine			275		
75-44-5	Phosgene			275		
7803-51-2	Phosphine			275		
7723-14-0	Phosphorus			275		
85-44-9	Phthalic anhydride			275		
1336-36-3	Polychlorinated biphenyls(Aroclors)			275		
1120-71-4	1,3-Propane sultone			275		
57-57-8	beta-Propiolactone			275		
123-38-6	Propionaldehyde			275		
114-26-1	Propoxur (Baygon)			275		
78-87-5	Propylene dichloride (1,2-Dichloropropane)			275		
75-56-9	Propylene oxide			275		
75-55-8	1,2-Propylenimine (2-Methylaziridine)			275		
91-22-5	Quinoline			275		
106-51-4	Quinone(p-Benzoquinone)			275		
100-42-5	Styrene			275		
96-09-3	Styrene oxide			275		
1746-01-6	2,3,7,8-Tetrachlorodibenzo-p-dioxin			275		
79-34-5	1,1,2,2-Tetrachloroethane			275		
127-18-4	Tetrachloroethylene(Perchloroethylene)			275		

Attachment S-1b
Air Toxic Emissions for CT-4 or CT-5

SECTION 112 HAZARDOUS AIR POLLUTANTS

CAS Number	Pollutant[1]	Source of Emission Factor	Emission Factor (lb/MMBtu)	Heat Input (MMBtu/hr)	Emissions (lb/hr)	Emissions (tpy)
7550-45-0	Titanium tetrachloride			275		
108-88-3	Toluene	AP-42, Section 3.4, Table 3.4-3	2.81E-04	275	7.73E-02	3.38E-01
95-80-7	Toluene-2,4-diamine			275		
584-84-9	2,4-Toluene diisocyanate			275		
95-53-4	o-Toluidine			275		
8001-35-2	Toxaphene (chlorinated camphene)			275		
120-82-1	1,2,4-Trichlorobenzene			275		
79-00-5	1,1,2-Trichloroethane			275		
79-01-6	Trichloroethylene			275		
95-95-4	2,4,5-Trichlorophenol			275		
88-06-2	2,4,6-Trichlorophenol			275		
121-44-8	Triethylamine			275		
1582-09-8	Trifluralin			275		
540-84-1	2,2,4-Trimethylpentane			275		
108-05-4	Vinyl acetate			275		
593-60-2	Vinyl bromide			275		
75-01-4	Vinyl chloride			275		
75-35-4	Vinylidene chloride (1,1-Dichloroethylene)			275		
1330-20-7	Xylene (mixed isomers)	AP-42, Section 3.4, Table 3.4-3	1.93E-04	275	5.31E-02	2.32E-01
95-47-6	o-Xylene			275		
108-38-3	m-Xylene			275		
106-42-3	p-Xylene			275		
	Antimony Compounds			275		
	Arsenic Compounds (inorganic including arsine)	AP-42, Section 3.1, Table 3.1-5	1.10E-05	275	3.03E-03	1.33E-02
	Beryllium Compounds	AP-42, Section 3.1, Table 3.1-5	3.10E-07	275	8.53E-05	3.73E-04
	Cadmium Compounds	AP-42, Section 3.1, Table 3.1-5	4.80E-06	275	1.32E-03	5.78E-03
	Chromium Compounds	AP-42, Section 3.1, Table 3.1-5	1.10E-05	275	3.03E-03	1.32E-02
	Cobalt Compounds			275		
	Coke Oven Emissions			275		
	Cyanide Compounds[2]			275		
	Glycol ethers[3]			275		
	Lead Compounds	AP-42, Section 3.1, Table 3.1-5	1.40E-05	275	3.85E-03	1.69E-02
	Manganese Compounds	AP-42, Section 3.1, Table 3.1-5	7.90E-04	275	2.17E-01	9.52E-01
	Mercury Compounds	AP-42, Section 3.1, Table 3.1-5	1.20E-06	275	3.30E-04	1.45E-03
	Fine mineral fibers[4]			275		
	Nickel Compounds	AP-42, Section 3.1, Table 3.1-5	4.60E-06	275	1.27E-03	5.54E-03
	Polycyclic Organic Matter[5]	AP-42, Section 3.1, Table 3.1-4	4.00E-05	275	1.10E-02	4.82E-02
	Radionuclides (including radon)[6]			275		
	Selenium Compounds	AP-42, Section 3.1, Table 3.1-5	2.50E-05	275	6.88E-03	3.01E-02
	Total				**4.94E-01**	**2.16**

Notes

1 For all listings above which contain the word "compounds" and for glycol ethers, the following applies: Unless otherwise specified, these listings are defined as including any unique chemical substance that contains the named chemical (i.e., antimony, arsenic, etc.) as part of that chemical's infrastructure

2 X'CN where X = H' or any other group where a formal dissociation may occur. For example, KCN or Ca(CN)2

3 Includes mono- and di- ethers of ethylene glycol, diethylene glycol, and triethylene glycol, R-(OCH2CH2)n-OR'

where: n = 1, 2, or 3

R = alkyl or aryl groups

R' = R, H, or groups which, when removed, yield glycol ethers with the structure: R-(OCH2CH)n-OH. Polymers are excluded from the glycol category

4 Includes mineral fiber emissions from facilities manufacturing or processing glass, rock, or slag fibers (or other mineral derived fibers) of average diameter 1 micrometer or less

5 Includes organic compounds with more than one benzene ring, and which have a boiling point greater than or equal to 100°C

6 A type of atom which spontaneously undergoes radioactive decay

Attachment S-1b
Air Toxic Emissions for D-21

SECTION 112 HAZARDOUS AIR POLLUTANTS

CAS Number	Pollutant[†]	Source of Emission Factor	Emission Factor (lb/MMBtu)	Heat Input (MMBtu/hr)	Heat Input (MMBtu/yr)	Emissions (lb/hr)	Emissions (tpy)
75-07-0	Acetaldehyde	AP-42, Section 3.4, Table 3.4-3	2.52E-05	28.1	9,800	7.08E-04	1.23E-04
60-35-5	Acetamide			28.1	9,800		
75-05-8	Acetonitrile			28.1	9,800		
98-86-2	Acetophenone			28.1	9,800		
53-96-3	2-Acetylaminofluorene			28.1	9,800		
107-02-8	Acrolein	AP-42, Section 3.4, Table 3.4-3	7.88E-06	28.1	9,800	2.21E-04	3.86E-05
79-06-1	Acrylamide			28.1	9,800		
79-10-7	Acrylic acid			28.1	9,800		
107-13-1	Acrylonitrile			28.1	9,800		
107-05-1	Allyl chloride			28.1	9,800		
92-67-1	4-Aminobiphenyl			28.1	9,800		
62-53-3	Aniline			28.1	9,800		
90-04-0	o-Anisidine			28.1	9,800		
1332-21-4	Asbestos			28.1	9,800		
71-43-2	Benzene (including benzene from gasoline)	AP-42, Section 3.4, Table 3.4-3	7.76E-04	28.1	9,800	2.18E-02	3.80E-03
92-87-5	Benzidine			28.1	9,800		
98-07-7	Benzotrichloride			28.1	9,800		
100-44-7	Benzyl chloride			28.1	9,800		
92-52-4	Biphenyl			28.1	9,800		
117-81-7	Bis(2-ethylhexyl)phthalate (DEHP)			28.1	9,800		
542-88-1	Bis(chloromethyl) ether			28.1	9,800		
75-25-2	Bromoform			28.1	9,800		
106-99-0	1,3-Butadiene	AP-42, Section 3.1, Table 3.1-4	1.60E-05	28.1	9,800	4.50E-04	7.84E-05
156-62-7	Calcium cyanamide			28.1	9,800		
105-60-2	Caprolactam (Removed 06/18/96, See 61FR30816)			28.1	9,800		
133-06-2	Captan			28.1	9,800		
63-25-2	Carbaryl			28.1	9,800		
75-15-0	Carbon disulfide			28.1	9,800		
56-23-5	Carbon tetrachloride			28.1	9,800		
463-58-1	Carbonyl sulfide			28.1	9,800		
120-80-9	Catechol			28.1	9,800		
133-90-4	Chloramben			28.1	9,800		
57-74-9	Chlordane			28.1	9,800		
7782-50-5	Chlorine			28.1	9,800		
79-11-8	Chloroacetic acid			28.1	9,800		
532-27-4	2-Chloroacetophenone			28.1	9,800		
108-90-7	Chlorobenzene			28.1	9,800		
510-15-6	Chlorobenzilate			28.1	9,800		
67-66-3	Chloroform			28.1	9,800		
107-30-2	Chloromethyl methyl ether			28.1	9,800		
126-99-8	Chloroprene			28.1	9,800		
1319-77-3	Cresol/Cresylic acid(mixed isomers)			28.1	9,800		
95-48-7	o-Cresol			28.1	9,800		
108-39-4	m-Cresol			28.1	9,800		
106-44-5	p-Cresol			28.1	9,800		
98-82-8	Cumene			28.1	9,800		
94-75-7	2,4-D salts and esters			28.1	9,800		
72-55-9	DDE(1,1-dichloro-2,2-bis(p-chlorophenyl) ethylene)			28.1	9,800		
334-88-3	Diazomethane			28.1	9,800		
132-64-9	Dibenzofuran			28.1	9,800		
96-12-8	1,2-Dibromo-3-chloropropane			28.1	9,800		
84-74-2	Dibutyl phthalate			28.1	9,800		
106-46-7	1,4-Dichlorobenzene			28.1	9,800		
91-94-1	Dichlorobenzidine			28.1	9,800		
111-44-4	Dichloroethyl ether(Bis[2-chloroethyl]ether)			28.1	9,800		
542-75-6	1,3-Dichloropropene			28.1	9,800		
62-73-7	Dichlorvos			28.1	9,800		
111-42-2	Diethanolamine			28.1	9,800		
64-67-5	Diethyl sulfate			28.1	9,800		
119-90-4	3,3'-Dimethoxybenzidine			28.1	9,800		
60-11-7	4-Dimethylaminoazobenzene			28.1	9,800		
121-69-7	N,N-Dimethylaniline			28.1	9,800		
119-93-7	3,3'-Dimethylbenzidine			28.1	9,800		
79-44-7	Dimethylcarbamoyl chloride			28.1	9,800		
68-12-2	N,N-Dimethylformamide			28.1	9,800		
57-14-7	1,1-Dimethylhydrazine			28.1	9,800		
131-11-3	Dimethyl phthalate			28.1	9,800		
77-78-1	Dimethyl sulfate			28.1	9,800		
534-52-1	4,6-Dinitro-o-cresol (including salts)			28.1	9,800		
51-28-5	2,4-Dinitrophenol			28.1	9,800		
121-14-2	2,4-Dinitrotoluene			28.1	9,800		
123-91-1	1,4-Dioxane (1,4-Diethyleneoxide)			28.1	9,800		
122-66-7	1,2-Diphenylhydrazine			28.1	9,800		
106-89-8	Epichlorohydrin (l-Chloro-2,3-epoxypropane)			28.1	9,800		
106-88-7	1,2-Epoxybutane			28.1	9,800		
140-88-5	Ethyl acrylate			28.1	9,800		
100-41-4	Ethylbenzene			28.1	9,800		
51-79-6	Ethyl carbamate (Urethane)			28.1	9,800		
75-00-3	Ethyl chloride (Chloroethane)			28.1	9,800		
106-93-4	Ethylene dibromide (Dibromoethane)			28.1	9,800		
107-06-2	Ethylene dichloride (1,2-Dichloroethane)			28.1	9,800		
107-21-1	Ethylene glycol			28.1	9,800		

Attachment S-1b
Air Toxic Emissions for D-21

SECTION 112 HAZARDOUS AIR POLLUTANTS

CAS Number	Pollutant[1]	Source of Emission Factor	Emission Factor (lb/MMBtu)	Heat Input (MMBtu/hr)	Heat Input (MMBtu/yr)	Emissions (lb/hr)	Emissions (tpy)
151-56-4	Ethyleneimine (Aziridine)			28.1	9,800		
75-21-8	Ethylene oxide			28.1	9,800		
96-45-7	Ethylene thiourea			28.1	9,800		
75-34-3	Ethylidene dichloride (1,1-Dichloroethane)			28.1	9,800		
50-00-0	Formaldehyde	AP-42, Section 3.4, Table 3.4-3	7.89E-05	28.1	9,800	2.22E-03	3.87E-04
76-44-8	Heptachlor			28.1	9,800		
118-74-1	Hexachlorobenzene			28.1	9,800		
87-68-3	Hexachlorobutadiene			28.1	9,800		
77-47-4	Hexachlorocyclopentadiene			28.1	9,800		
67-72-1	Hexachloroethane			28.1	9,800		
822-06-0	Hexamethylene diisocyanate			28.1	9,800		
680-31-9	Hexamethylphosphoramide			28.1	9,800		
110-54-3	Hexane			28.1	9,800		
302-01-2	Hydrazine			28.1	9,800		
7647-01-0	Hydrochloric acid (Hydrogen chloride [gas only])			28.1	9,800		
7664-39-3	Hydrogen fluoride (Hydrofluoric acid)			28.1	9,800		
123-31-9	Hydroquinone			28.1	9,800		
78-59-1	Isophorone			28.1	9,800		
58-89-9	Lindane (all isomers)			28.1	9,800		
108-31-6	Maleic anhydride			28.1	9,800		
67-56-1	Methanol			28.1	9,800		
72-43-5	Methoxychlor			28.1	9,800		
74-83-9	Methyl bromide (Bromomethane)			28.1	9,800		
74-87-3	Methyl chloride(Chloromethane)			28.1	9,800		
71-55-6	Methyl chloroform(1,1,1-Trichloroethane)			28.1	9,800		
78-93-3	Methyl ethyl ketone (2-Butanone) (Removed 12/19/05, See 70FR75047)			28.1	9,800		
60-34-4	Methylhydrazine			28.1	9,800		
74-88-4	Methyl iodide (Iodomethane)			28.1	9,800		
108-10-1	Methyl isobutyl ketone(Hexone)			28.1	9,800		
624-83-9	Methyl isocyanate			28.1	9,800		
80-62-6	Methyl methacrylate			28.1	9,800		
1634-04-4	Methyl tert-butyl ether			28.1	9,800		
101-14-4	4,4'-Methylenebis(2-chloroaniline)			28.1	9,800		
75-09-2	Methylene chloride(Dichloromethane)			28.1	9,800		
101-68-8	4,4'-Methylenediphenyl diisocyanate(MDI)			28.1	9,800		
101-77-9	4,4'-Methylenedianiline			28.1	9,800		
91-20-3	Naphthalene	AP-42, Section 3.4, Table 3.4-4	1.30E-04	28.1	9,800	3.65E-03	6.37E-04
98-95-3	Nitrobenzene			28.1	9,800		
92-93-3	4-Nitrobiphenyl			28.1	9,800		
100-02-7	4-Nitrophenol			28.1	9,800		
79-46-9	2-Nitropropane			28.1	9,800		
684-93-5	N-Nitroso-N-methylurea			28.1	9,800		
62-75-9	N-Nitrosodimethylamine			28.1	9,800		
59-89-2	N-Nitrosomorpholine			28.1	9,800		
56-38-2	Parathion			28.1	9,800		
82-68-8	Pentachloronitrobenzene(Quintobenzene)			28.1	9,800		
87-86-5	Pentachlorophenol			28.1	9,800		
108-95-2	Phenol			28.1	9,800		
106-50-3	p-Phenylenediamine			28.1	9,800		
75-44-5	Phosgene			28.1	9,800		
7803-51-2	Phosphine			28.1	9,800		
7723-14-0	Phosphorus			28.1	9,800		
85-44-9	Phthalic anhydride			28.1	9,800		
1336-36-3	Polychlorinated biphenyls(Aroclors)			28.1	9,800		
1120-71-4	1,3-Propane sultone			28.1	9,800		
57-57-8	beta-Propiolactone			28.1	9,800		
123-38-6	Propionaldehyde			28.1	9,800		
114-26-1	Propoxur (Baygon)			28.1	9,800		
78-87-5	Propylene dichloride (1,2-Dichloropropane)			28.1	9,800		
75-56-9	Propylene oxide			28.1	9,800		
75-55-8	1,2-Propylenimine (2-Methylaziridine)			28.1	9,800		
91-22-5	Quinoline			28.1	9,800		
106-51-4	Quinone(p-Benzoquinone)			28.1	9,800		
100-42-5	Styrene			28.1	9,800		
96-09-3	Styrene oxide			28.1	9,800		
1746-01-6	2,3,7,8-Tetrachlorodibenzo-p-dioxin			28.1	9,800		
79-34-5	1,1,2,2-Tetrachloroethane			28.1	9,800		
127-18-4	Tetrachloroethylene(Perchloroethylene)			28.1	9,800		
7550-45-0	Titanium tetrachloride			28.1	9,800		
108-88-3	Toluene	AP-42, Section 3.4, Table 3.4-3	2.81E-04	28.1	9,800	7.90E-03	1.38E-03
95-80-7	Toluene-2,4-diamine			28.1	9,800		
584-84-9	2,4-Toluene diisocyanate			28.1	9,800		
95-53-4	o-Toluidine			28.1	9,800		
8001-35-2	Toxaphene (chlorinated camphene)			28.1	9,800		
120-82-1	1,2,4-Trichlorobenzene			28.1	9,800		
79-00-5	1,1,2-Trichloroethane			28.1	9,800		
79-01-6	Trichloroethylene			28.1	9,800		
95-95-4	2,4,5-Trichlorophenol			28.1	9,800		
88-06-2	2,4,6-Trichlorophenol			28.1	9,800		
121-44-8	Triethylamine			28.1	9,800		
1582-09-8	Trifluralin			28.1	9,800		
540-84-1	2,2,4-Trimethylpentane			28.1	9,800		

Attachment S-1b
Air Toxic Emissions for D-21

SECTION 112 HAZARDOUS AIR POLLUTANTS

CAS Number	Pollutant[1]	Source of Emission Factor	Emission Factor (lb/MMBtu)	Heat Input (MMBtu/hr)	Heat Input (MMBtu/yr)	Emissions (lb/hr)	Emissions (tpy)
108-05-4	Vinyl acetate			28.1	9,800		
593-60-2	Vinyl bromide			28.1	9,800		
75-01-4	Vinyl chloride			28.1	9,800		
75-35-4	Vinylidene chloride (1,1-Dichloroethylene)			28.1	9,800		
1330-20-7	Xylene (mixed isomers)	AP-42, Section 3.4, Table 3.4-3	1.93E-04	28.1	9,800	5.42E-03	9.46E-04
95-47-6	o-Xylene			28.1	9,800		
108-38-3	m-Xylene			28.1	9,800		
106-42-3	p-Xylene			28.1	9,800		
	Antimony Compounds			28.1	9,800		
	Arsenic Compounds (inorganic including arsine)	AP-42, Section 3.1, Table 3.1-5	1.10E-05	28.1	9,800	3.09E-04	5.39E-05
	Beryllium Compounds	AP-42, Section 3.1, Table 3.1-5	3.10E-07	28.1	9,800	8.71E-06	1.52E-06
	Cadmium Compounds	AP-42, Section 3.1, Table 3.1-5	4.80E-06	28.1	9,800	1.35E-04	2.35E-05
	Chromium Compounds	AP-42, Section 3.1, Table 3.1-5	1.10E-05	28.1	9,800	3.09E-04	5.39E-05
	Cobalt Compounds			28.1	9,800		
	Coke Oven Emissions			28.1	9,800		
	Cyanide Compounds[2]			28.1	9,800		
	Glycol ethers[3]			28.1	9,800		
	Lead Compounds	AP-42, Section 3.1, Table 3.1-5	1.40E-05	28.1	9,800	3.93E-04	6.86E-05
	Manganese Compounds	AP-42, Section 3.1, Table 3.1-5	7.90E-04	28.1	9,800	2.22E-02	3.87E-03
	Mercury Compounds	AP-42, Section 3.1, Table 3.1-5	1.20E-06	28.1	9,800	3.37E-05	5.88E-06
	Fine mineral fibers[4]			28.1	9,800		
	Nickel Compounds	AP-42, Section 3.1, Table 3.1-5	4.60E-06	28.1	9,800	1.29E-04	2.25E-05
	Polycyclic Organic Matter[5]	AP-42, Section 3.4, Table 3.4-4	2.12E-04	28.1	9,800	5.96E-03	1.04E-03
	Radionuclides (including radon)[6]			28.1	9,800		
	Selenium Compounds	AP-42, Section 3.1, Table 3.1-5	2.50E-05	28.1	9,800	7.03E-04	1.23E-04
	Total					**7.26E-02**	**1.27E-02**

Notes:

1. For all listings above which contain the word "compounds" and for glycol ethers, the following applies: Unless otherwise specified, these listings are defined as including any unique chemical substance that contains the named chemical (i.e., antimony, arsenic, etc.) as part of that chemical's infrastructure.
2. X'CN where X = H' or any other group where a formal dissociation may occur. For example, KCN or Ca(CN)2
3. Includes mono- and di- ethers of ethylene glycol, diethylene glycol, and triethylene glycol, R-(OCH2CH2)n-OR'

where: n = 1, 2, or 3

R = alkyl or aryl groups

R' = R, H, or groups which, when removed, yield glycol ethers with the structure: R-(OCH2CH)n-OH. Polymers are excluded from the glycol category.

4. Includes mineral fiber emissions from facilities manufacturing or processing glass, rock, or slag fibers (or other mineral derived fibers) of average diameter 1 micrometer or less.
5. Includes organic compounds with more than one benzene ring, and which have a boiling point greater than or equal to 100°C
6. A type of atom which spontaneously undergoes radioactive decay

Attachment S-1b
Air Toxic Emissions for D-22 or D-23

SECTION 112 HAZARDOUS AIR POLLUTANTS

CAS Number	Pollutant[1]	Source of Emission Factor	Emission Factor (lb/MMBtu)	Heat Input (MMBtu/hr)	Emissions (lb/hr)	Emissions (tpy)
75-07-0	Acetaldehyde	AP-42, Section 3.4, Table 3.4-3	2.52E-05	28.1	7.08E-04	3.10E-03
60-35-5	Acetamide			28.1		
75-05-8	Acetonitrile			28.1		
98-86-2	Acetophenone			28.1		
53-96-3	2-Acetylaminofluorene			28.1		
107-02-8	Acrolein	AP-42, Section 3.4, Table 3.4-3	7.88E-06	28.1	2.21E-04	9.70E-04
79-06-1	Acrylamide			28.1		
79-10-7	Acrylic acid			28.1		
107-13-1	Acrylonitrile			28.1		
107-05-1	Allyl chloride			28.1		
92-67-1	4-Aminobiphenyl			28.1		
62-53-3	Aniline			28.1		
90-04-0	o-Anisidine			28.1		
1332-21-4	Asbestos			28.1		
71-43-2	Benzene (including benzene from gasoline)	AP-42, Section 3.4, Table 3.4-3	7.76E-04	28.1	2.18E-02	9.55E-02
92-87-5	Benzidine			28.1		
98-07-7	Benzotrichloride			28.1		
100-44-7	Benzyl chloride			28.1		
92-52-4	Biphenyl			28.1		
117-81-7	Bis(2-ethylhexyl)phthalate (DEHP)			28.1		
542-88-1	Bis(chloromethyl) ether			28.1		
75-25-2	Bromoform			28.1		
106-99-0	1,3-Butadiene	AP-42, Section 3.1, Table 3.1-4	1.60E-05	28.1	4.50E-04	1.97E-03
156-62-7	Calcium cyanamide			28.1		
105-60-2	Caprolactam (Removed 06/18/96, See 61FR30816)			28.1		
133-06-2	Captan			28.1		
63-25-2	Carbaryl			28.1		
75-15-0	Carbon disulfide			28.1		
56-23-5	Carbon tetrachloride			28.1		
463-58-1	Carbonyl sulfide			28.1		
120-80-9	Catechol			28.1		
133-90-4	Chloramben			28.1		
57-74-9	Chlordane			28.1		
7782-50-5	Chlorine			28.1		
79-11-8	Chloroacetic acid			28.1		
532-27-4	2-Chloroacetophenone			28.1		
108-90-7	Chlorobenzene			28.1		
510-15-6	Chlorobenzilate			28.1		
67-66-3	Chloroform			28.1		
107-30-2	Chloromethyl methyl ether			28.1		
126-99-8	Chloroprene			28.1		
1319-77-3	Cresol/Cresylic acid(mixed isomers)			28.1		
95-48-7	o-Cresol			28.1		
108-39-4	m-Cresol			28.1		
106-44-5	p-Cresol			28.1		
98-82-8	Cumene			28.1		
94-75-7	2,4-D salts and esters			28.1		
72-55-9	DDE(1,1-dichloro-2,2-bis(p-chlorophenyl) ethylene)			28.1		
334-88-3	Diazomethane			28.1		
132-64-9	Dibenzofuran			28.1		
96-12-8	1,2-Dibromo-3-chloropropane			28.1		
84-74-2	Dibutyl phthalate			28.1		
106-46-7	1,4-Dichlorobenzene			28.1		
91-94-1	Dichlorobenzidine			28.1		
111-44-4	Dichloroethyl ether(Bis[2-chloroethyl]ether)			28.1		
542-75-6	1,3-Dichloropropene			28.1		
62-73-7	Dichlorvos			28.1		
111-42-2	Diethanolamine			28.1		
64-67-5	Diethyl sulfate			28.1		
119-90-4	3,3'-Dimethoxybenzidine			28.1		
60-11-7	4-Dimethylaminoazobenzene			28.1		
121-69-7	N,N-Dimethylaniline			28.1		
119-93-7	3,3'-Dimethylbenzidine			28.1		
79-44-7	Dimethylcarbamoyl chloride			28.1		
68-12-2	N,N-Dimethylformamide			28.1		
57-14-7	1,1-Dimethylhydrazine			28.1		
131-11-3	Dimethyl phthalate			28.1		
77-78-1	Dimethyl sulfate			28.1		
534-52-1	4,6-Dinitro-o-cresol (including salts)			28.1		
51-28-5	2,4-Dinitrophenol			28.1		
121-14-2	2,4-Dinitrotoluene			28.1		
123-91-1	1,4-Dioxane (1,4-Diethyleneoxide)			28.1		
122-66-7	1,2-Diphenylhydrazine			28.1		
106-89-8	Epichlorohydrin (l-Chloro-2,3-epoxypropane)			28.1		
106-88-7	1,2-Epoxybutane			28.1		
140-88-5	Ethyl acrylate			28.1		
100-41-4	Ethylbenzene			28.1		
51-79-6	Ethyl carbamate (Urethane)			28.1		
75-00-3	Ethyl chloride (Chloroethane)			28.1		
106-93-4	Ethylene dibromide (Dibromoethane)			28.1		
107-06-2	Ethylene dichloride (1,2-Dichloroethane)			28.1		
107-21-1	Ethylene glycol			28.1		

Attachment S-1b
Air Toxic Emissions for D-22 or D-23

SECTION 112 HAZARDOUS AIR POLLUTANTS

CAS Number	Pollutant[1]	Source of Emission Factor	Emission Factor (lb/MMBtu)	Heat Input (MMBtu/hr)	Emissions (lb/hr)	Emissions (tpy)
151-56-4	Ethyleneimine (Aziridine)			28.1		
75-21-8	Ethylene oxide			28.1		
96-45-7	Ethylene thiourea			28.1		
75-34-3	Ethylidene dichloride (1,1-Dichloroethane)			28.1		
50-00-0	Formaldehyde	AP-42, Section 3.4, Table 3.4-3	7.89E-05	28.1	2.22E-03	9.71E-03
76-44-8	Heptachlor			28.1		
118-74-1	Hexachlorobenzene			28.1		
87-68-3	Hexachlorobutadiene			28.1		
77-47-4	Hexachlorocyclopentadiene			28.1		
67-72-1	Hexachloroethane			28.1		
822-06-0	Hexamethylene diisocyanate			28.1		
680-31-9	Hexamethylphosphoramide			28.1		
110-54-3	Hexane			28.1		
302-01-2	Hydrazine			28.1		
7647-01-0	Hydrochloric acid (Hydrogen chloride [gas only])			28.1		
7664-39-3	Hydrogen fluoride (Hydrofluoric acid)			28.1		
123-31-9	Hydroquinone			28.1		
78-59-1	Isophorone			28.1		
58-89-9	Lindane (all isomers)			28.1		
108-31-6	Maleic anhydride			28.1		
67-56-1	Methanol			28.1		
72-43-5	Methoxychlor			28.1		
74-83-9	Methyl bromide (Bromomethane)			28.1		
74-87-3	Methyl chloride(Chloromethane)			28.1		
71-55-6	Methyl chloroform(1,1,1-Trichloroethane)			28.1		
78-93-3	Methyl ethyl ketone (2-Butanone) (Removed 12/19/05. See 70FR75047)			28.1		
60-34-4	Methylhydrazine			28.1		
74-88-4	Methyl iodide (Iodomethane)			28.1		
108-10-1	Methyl isobutyl ketone(Hexone)			28.1		
624-83-9	Methyl isocyanate			28.1		
80-62-6	Methyl methacrylate			28.1		
1634-04-4	Methyl tert-butyl ether			28.1		
101-14-4	4,4'-Methylenebis(2-chloroaniline)			28.1		
75-09-2	Methylene chloride(Dichloromethane)			28.1		
101-68-8	4,4'-Methylenediphenyl diisocyanate(MDI)			28.1		
101-77-9	4,4'-Methylenedianiline			28.1		
91-20-3	Naphthalene	AP-42, Section 3.4, Table 3.4-4	1.30E-04	28.1	3.65E-03	1.60E-02
98-95-3	Nitrobenzene			28.1		
92-93-3	4-Nitrobiphenyl			28.1		
100-02-7	4-Nitrophenol			28.1		
79-46-9	2-Nitropropane			28.1		
684-93-5	N-Nitroso-N-methylurea			28.1		
62-75-9	N-Nitrosodimethylamine			28.1		
59-89-2	N-Nitrosomorpholine			28.1		
56-38-2	Parathion			28.1		
82-68-8	Pentachloronitrobenzene(Quintobenzene)			28.1		
87-86-5	Pentachlorophenol			28.1		
108-95-2	Phenol			28.1		
106-50-3	p-Phenylenediamine			28.1		
75-44-5	Phosgene			28.1		
7803-51-2	Phosphine			28.1		
7723-14-0	Phosphorus			28.1		
85-44-9	Phthalic anhydride			28.1		
1336-36-3	Polychlorinated biphenyls(Aroclors)			28.1		
1120-71-4	1,3-Propane sultone			28.1		
57-57-8	beta-Propiolactone			28.1		
123-38-6	Propionaldehyde			28.1		
114-26-1	Propoxur (Baygon)			28.1		
78-87-5	Propylene dichloride (1,2-Dichloropropane)			28.1		
75-56-9	Propylene oxide			28.1		
75-55-8	1,2-Propylenimine (2-Methylaziridine)			28.1		
91-22-5	Quinoline			28.1		
106-51-4	Quinone(p-Benzoquinone)			28.1		
100-42-5	Styrene			28.1		
96-09-3	Styrene oxide			28.1		
1746-01-6	2,3,7,8-Tetrachlorodibenzo-p-dioxin			28.1		
79-34-5	1,1,2,2-Tetrachloroethane			28.1		
127-18-4	Tetrachloroethylene(Perchloroethylene)			28.1		
7550-45-0	Titanium tetrachloride			28.1		
108-88-3	Toluene	AP-42, Section 3.4, Table 3.4-3	2.81E-04	28.1	7.90E-03	3.46E-02
95-80-7	Toluene-2,4-diamine			28.1		
584-84-9	2,4-Toluene diisocyanate			28.1		
95-53-4	o-Toluidine			28.1		
8001-35-2	Toxaphene (chlorinated camphene)			28.1		
120-82-1	1,2,4-Trichlorobenzene			28.1		
79-00-5	1,1,2-Trichloroethane			28.1		
79-01-6	Trichloroethylene			28.1		
95-95-4	2,4,5-Trichlorophenol			28.1		
88-06-2	2,4,6-Trichlorophenol			28.1		
121-44-8	Triethylamine			28.1		
1582-09-8	Trifluralin			28.1		
540-84-1	2,2,4-Trimethylpentane			28.1		

Attachment S-1b
Air Toxic Emissions for D-22 or D-23

SECTION 112 HAZARDOUS AIR POLLUTANTS

CAS Number	Pollutant[1]	Source of Emission Factor	Emission Factor (lb/MMBtu)	Heat Input (MMBtu/hr)	Emissions (lb/hr)	Emissions (tpy)
108-05-4	Vinyl acetate			28.1		
593-60-2	Vinyl bromide			28.1		
75-01-4	Vinyl chloride			28.1		
75-35-4	Vinylidene chloride (1,1-Dichloroethylene)			28.1		
1330-20-7	Xylene (mixed isomers)	AP-42, Section 3.4, Table 3.4-3	1.93E-04	28.1	5.42E-03	2.38E-02
95-47-6	o-Xylene			28.1		
108-38-3	m-Xylene			28.1		
106-42-3	p-Xylene			28.1		
	Antimony Compounds			28.1		
	Arsenic Compounds (inorganic including arsine)	AP-42, Section 3.1, Table 3.1-5	1.10E-05	28.1	3.09E-04	1.35E-03
	Beryllium Compounds	AP-42, Section 3.1, Table 3.1-5	3.10E-07	28.1	8.71E-06	3.82E-05
	Cadmium Compounds	AP-42, Section 3.1, Table 3.1-5	4.80E-06	28.1	1.35E-04	5.91E-04
	Chromium Compounds	AP-42, Section 3.1, Table 3.1-5	1.10E-05	28.1	3.09E-04	1.35E-03
	Cobalt Compounds			28.1		
	Coke Oven Emissions			28.1		
	Cyanide Compounds[2]			28.1		
	Glycol ethers[3]			28.1		
	Lead Compounds	AP-42, Section 3.1, Table 3.1-5	1.40E-05	28.1	3.93E-04	1.72E-03
	Manganese Compounds	AP-42, Section 3.1, Table 3.1-5	7.90E-04	28.1	2.22E-02	9.72E-02
	Mercury Compounds	AP-42, Section 3.1, Table 3.1-5	1.20E-06	28.1	3.37E-05	1.48E-04
	Fine mineral fibers[4]			28.1		
	Nickel Compounds	AP-42, Section 3.1, Table 3.1-5	4.60E-06	28.1	1.29E-04	5.66E-04
	Polycyclic Organic Matter[5]	AP-42, Section 3.4, Table 3.4-4	2.12E-04	28.1	5.96E-03	2.61E-02
	Radionuclides (including radon)[6]			28.1		
	Selenium Compounds	AP-42, Section 3.1, Table 3.1-5	2.50E-05	28.1	7.03E-04	3.08E-03
	Total				**7.25E-02**	**3.18E-01**

Notes:

1. For all listings above which contain the word "compounds" and for glycol ethers, the following applies: Unless otherwise specified, these listings are defined as including any unique chemical substance that contains the named chemical (i.e., antimony, arsenic, etc.) as part of that chemical's infrastructure.
2. X'CN where X = H' or any other group where a formal dissociation may occur. For example, KCN or Ca(CN)2.
3. Includes mono- and di- ethers of ethylene glycol, diethylene glycol, and triethylene glycol. R-(OCH2CH2)n-OR'

where n = 1, 2, or 3

R = alkyl or aryl groups

R' = R, H, or groups which, when removed, yield glycol ethers with the structure: R-(OCH2CH)n-OH. Polymers are excluded from the glycol category

4. Includes mineral fiber emissions from facilities manufacturing or processing glass, rock, or slag fibers (or other mineral derived fibers) of average diameter 1 micrometer or less
5. Includes organic compounds with more than one benzene ring, and which have a boiling point greater than or equal to 100°C
6. A type of atom which spontaneously undergoes radioactive decay

Attachment S-1b
Air Toxic Emissions for BS-1

SECTION 112 HAZARDOUS AIR POLLUTANTS

CAS Number	Pollutant[1]	Source of Emission Factor	Emission Factor (lb/MMBtu)	Heat Input (MMBtu/hr)	Emissions (lb/hr)	Emissions (tpy)
75-07-0	Acetaldehyde	AP-42, Section 3.4, Table 3.4-3	2.52E-05	5.57	1.40E-04	2.11E-05
60-35-5	Acetamide			5.57		
75-05-8	Acetonitrile			5.57		
98-86-2	Acetophenone			5.57		
53-96-3	2-Acetylaminofluorene			5.57		
107-02-8	Acrolein	AP-42, Section 3.4, Table 3.4-3	7.88E-06	5.57	4.39E-05	6.58E-06
79-06-1	Acrylamide			5.57		
79-10-7	Acrylic acid			5.57		
107-13-1	Acrylonitrile			5.57		
107-05-1	Allyl chloride			5.57		
92-67-1	4-Aminobiphenyl			5.57		
62-53-3	Aniline			5.57		
90-04-0	o-Anisidine			5.57		
1332-21-4	Asbestos			5.57		
71-43-2	Benzene (including benzene from gasoline)	AP-42, Section 3.4, Table 3.4-3	7.76E-04	5.57	4.32E-03	6.48E-04
92-87-5	Benzidine			5.57		
98-07-7	Benzotrichloride			5.57		
100-44-7	Benzyl chloride			5.57		
92-52-4	Biphenyl			5.57		
117-81-7	Bis(2-ethylhexyl)phthalate (DEHP)			5.57		
542-88-1	Bis(chloromethyl) ether			5.57		
75-25-2	Bromoform			5.57		
106-99-0	1,3-Butadiene	AP-42, Section 3.1, Table 3.1-4	1.60E-05	5.57	8.91E-05	1.34E-05
156-62-7	Calcium cyanamide			5.57		
105-60-2	Caprolactam (Removed 06/18/96, See 61FR30816)			5.57		
133-06-2	Captan			5.57		
63-25-2	Carbaryl			5.57		
75-15-0	Carbon disulfide			5.57		
56-23-5	Carbon tetrachloride			5.57		
463-58-1	Carbonyl sulfide			5.57		
120-80-9	Catechol			5.57		
133-90-4	Chloramben			5.57		
57-74-9	Chlordane			5.57		
7782-50-5	Chlorine			5.57		
79-11-8	Chloroacetic acid			5.57		
532-27-4	2-Chloroacetophenone			5.57		
108-90-7	Chlorobenzene			5.57		
510-15-6	Chlorobenzilate			5.57		
67-66-3	Chloroform			5.57		
107-30-2	Chloromethyl methyl ether			5.57		
126-99-8	Chloroprene			5.57		
1319-77-3	Cresol/Cresylic acid(mixed isomers)			5.57		
95-48-7	o-Cresol			5.57		
108-39-4	m-Cresol			5.57		
106-44-5	p-Cresol			5.57		
98-82-8	Cumene			5.57		
94-75-7	2,4-D salts and esters			5.57		
72-55-9	DDE(1,1-dichloro-2,2-bis(p-chlorophenyl) ethylene)			5.57		
334-88-3	Diazomethane			5.57		
132-64-9	Dibenzofuran			5.57		
96-12-8	1,2-Dibromo-3-chloropropane			5.57		
84-74-2	Dibutyl phthalate			5.57		
106-46-7	1,4-Dichlorobenzene			5.57		
91-94-1	Dichlorobenzidine			5.57		
111-44-4	Dichloroethyl ether(Bis[2-chloroethyl]ether)			5.57		
542-75-6	1,3-Dichloropropene			5.57		
62-73-7	Dichlorvos			5.57		
111-42-2	Diethanolamine			5.57		
64-67-5	Diethyl sulfate			5.57		
119-90-4	3,3'-Dimethoxybenzidine			5.57		
60-11-7	4-Dimethylaminoazobenzene			5.57		
121-69-7	N,N-Dimethylaniline			5.57		
119-93-7	3,3'-Dimethylbenzidine			5.57		
79-44-7	Dimethylcarbamoyl chloride			5.57		
68-12-2	N,N-Dimethylformamide			5.57		
57-14-7	1,1-Dimethylhydrazine			5.57		
131-11-3	Dimethyl phthalate			5.57		
77-78-1	Dimethyl sulfate			5.57		
534-52-1	4,6-Dinitro-o-cresol (including salts)			5.57		
51-28-5	2,4-Dinitrophenol			5.57		
121-14-2	2,4-Dinitrotoluene			5.57		
123-91-1	1,4-Dioxane (1,4-Diethyleneoxide)			5.57		
122-66-7	1,2-Diphenylhydrazine			5.57		
106-89-8	Epichlorohydrin (l-Chloro-2,3-epoxypropane)			5.57		
106-88-7	1,2-Epoxybutane			5.57		
140-88-5	Ethyl acrylate			5.57		
100-41-4	Ethylbenzene			5.57		
51-79-6	Ethyl carbamate (Urethane)			5.57		
75-00-3	Ethyl chloride (Chloroethane)			5.57		
106-93-4	Ethylene dibromide (Dibromoethane)			5.57		
107-06-2	Ethylene dichloride (1,2-Dichloroethane)			5.57		
107-21-1	Ethylene glycol			5.57		

Attachment S-1b
Air Toxic Emissions for BS-1

SECTION 112 HAZARDOUS AIR POLLUTANTS

CAS Number	Pollutant[1]	Source of Emission Factor	Emission Factor (lb/MMBtu)	Heat Input (MMBtu/hr)	Emissions (lb/hr)	Emissions (tpy)
151-56-4	Ethyleneimine (Aziridine)			5.57		
75-21-8	Ethylene oxide			5.57		
96-45-7	Ethylene thiourea			5.57		
75-34-3	Ethylidene dichloride (1,1-Dichloroethane)			5.57		
50-00-0	Formaldehyde	AP-42, Section 3.4, Table 3.4-3	7.89E-05	5.57	4.39E-04	6.59E-05
76-44-8	Heptachlor			5.57		
118-74-1	Hexachlorobenzene			5.57		
87-68-3	Hexachlorobutadiene			5.57		
77-47-4	Hexachlorocyclopentadiene			5.57		
67-72-1	Hexachloroethane			5.57		
822-06-0	Hexamethylene diisocyanate			5.57		
680-31-9	Hexamethylphosphoramide			5.57		
110-54-3	Hexane			5.57		
302-01-2	Hydrazine			5.57		
7647-01-0	Hydrochloric acid (Hydrogen chloride [gas only])			5.57		
7664-39-3	Hydrogen fluoride (Hydrofluoric acid)			5.57		
123-31-9	Hydroquinone			5.57		
78-59-1	Isophorone			5.57		
58-89-9	Lindane (all isomers)			5.57		
108-31-6	Maleic anhydride			5.57		
67-56-1	Methanol			5.57		
72-43-5	Methoxychlor			5.57		
74-83-9	Methyl bromide (Bromomethane)			5.57		
74-87-3	Methyl chloride(Chloromethane)			5.57		
71-55-6	Methyl chloroform(1,1,1-Trichloroethane)			5.57		
78-93-3	Methyl ethyl ketone (2-Butanone) (Removed 12/19/05. See 70FR75047)			5.57		
60-34-4	Methylhydrazine			5.57		
74-88-4	Methyl iodide (Iodomethane)			5.57		
108-10-1	Methyl isobutyl ketone(Hexone)			5.57		
624-83-9	Methyl isocyanate			5.57		
80-62-6	Methyl methacrylate			5.57		
1634-04-4	Methyl tert-butyl ether			5.57		
101-14-4	4,4'-Methylenebis(2-chloroaniline)			5.57		
75-09-2	Methylene chloride(Dichloromethane)			5.57		
101-68-8	4,4'-Methylenediphenyl diisocyanate(MDI)			5.57		
101-77-9	4,4'-Methylenedianiline			5.57		
91-20-3	Naphthalene	AP-42, Section 3.4, Table 3.4-4	1.30E-04	5.57	7.24E-04	1.09E-04
98-95-3	Nitrobenzene			5.57		
92-93-3	4-Nitrobiphenyl			5.57		
100-02-7	4-Nitrophenol			5.57		
79-46-9	2-Nitropropane			5.57		
684-93-5	N-Nitroso-N-methylurea			5.57		
62-75-9	N-Nitrosodimethylamine			5.57		
59-89-2	N-Nitrosomorpholine			5.57		
56-38-2	Parathion			5.57		
82-68-8	Pentachloronitrobenzene(Quintobenzene)			5.57		
87-86-5	Pentachlorophenol			5.57		
108-95-2	Phenol			5.57		
106-50-3	p-Phenylenediamine			5.57		
75-44-5	Phosgene			5.57		
7803-51-2	Phosphine			5.57		
7723-14-0	Phosphorus			5.57		
85-44-9	Phthalic anhydride			5.57		
1336-36-3	Polychlorinated biphenyls(Aroclors)			5.57		
1120-71-4	1,3-Propane sultone			5.57		
57-57-8	beta-Propiolactone			5.57		
123-38-6	Propionaldehyde			5.57		
114-26-1	Propoxur (Baygon)			5.57		
78-87-5	Propylene dichloride (1,2-Dichloropropane)			5.57		
75-56-9	Propylene oxide			5.57		
75-55-8	1,2-Propylenimine (2-Methylaziridine)			5.57		
91-22-5	Quinoline			5.57		
106-51-4	Quinone(p-Benzoquinone)			5.57		
100-42-5	Styrene			5.57		
96-09-3	Styrene oxide			5.57		
1746-01-6	2,3,7,8-Tetrachlorodibenzo-p-dioxin			5.57		
79-34-5	1,1,2,2-Tetrachloroethane			5.57		
127-18-4	Tetrachloroethylene(Perchloroethylene)			5.57		
7550-45-0	Titanium tetrachloride			5.57		
108-88-3	Toluene	AP-42, Section 3.4, Table 3.4-3	2.81E-04	5.57	1.57E-03	2.35E-04
95-80-7	Toluene-2,4-diamine			5.57		
584-84-9	2,4-Toluene diisocyanate			5.57		
95-53-4	o-Toluidine			5.57		
8001-35-2	Toxaphene (chlorinated camphene)			5.57		
120-82-1	1,2,4-Trichlorobenzene			5.57		
79-00-5	1,1,2-Trichloroethane			5.57		
79-01-6	Trichloroethylene			5.57		
95-95-4	2,4,5-Trichlorophenol			5.57		
88-06-2	2,4,6-Trichlorophenol			5.57		
121-44-8	Triethylamine			5.57		
1582-09-8	Trifluralin			5.57		
540-84-1	2,2,4-Trimethylpentane			5.57		

Attachment S-1b
Air Toxic Emissions for BS-1

SECTION 112 HAZARDOUS AIR POLLUTANTS

CAS Number	Pollutant[1]	Source of Emission Factor	Emission Factor (lb/MMBtu)	Heat Input (MMBtu/hr)	Emissions (lb/hr)	Emissions (tpy)
108-05-4	Vinyl acetate			5.57		
593-60-2	Vinyl bromide			5.57		
75-01-4	Vinyl chloride			5.57		
75-35-4	Vinylidene chloride (1,1-Dichloroethylene)			5.57		
1330-20-7	Xylene (mixed isomers)	AP-42, Section 3.4, Table 3.4-3	1.93E-04	5.57	1.08E-03	1.61E-04
95-47-6	o-Xylene			5.57		
108-38-3	m-Xylene			5.57		
106-42-3	p-Xylene			5.57		
	Antimony Compounds			5.57		
	Arsenic Compounds (inorganic including arsine)	AP-42, Section 3.1, Table 3.1-5	1.10E-05	5.57	6.13E-05	9.19E-06
	Beryllium Compounds	AP-42, Section 3.1, Table 3.1-5	3.10E-07	5.57	1.73E-06	2.59E-07
	Cadmium Compounds	AP-42, Section 3.1, Table 3.1-5	4.80E-06	5.57	2.67E-05	4.01E-06
	Chromium Compounds	AP-42, Section 3.1, Table 3.1-5	1.10E-05	5.57	6.13E-05	9.19E-06
	Cobalt Compounds			5.57		
	Coke Oven Emissions			5.57		
	Cyanide Compounds[2]			5.57		
	Glycol ethers[3]			5.57		
	Lead Compounds	AP-42, Section 3.1, Table 3.1-5	1.40E-05	5.57	7.80E-05	1.17E-05
	Manganese Compounds	AP-42, Section 3.1, Table 3.1-5	7.90E-04	5.57	4.40E-03	6.60E-04
	Mercury Compounds	AP-42, Section 3.1, Table 3.1-5	1.20E-06	5.57	6.68E-06	1.00E-06
	Fine mineral fibers[4]			5.57		
	Nickel Compounds	AP-42, Section 3.1, Table 3.1-5	4.60E-06	5.57	2.56E-05	3.84E-06
	Polycyclic Organic Matter[5]	AP-42, Section 3.4, Table 3.4-4	2.12E-04	5.57	1.18E-03	1.77E-04
	Radionuclides (including radon)[6]			5.57		
	Selenium Compounds	AP-42, Section 3.1, Table 3.1-5	2.50E-05	5.57	1.39E-04	2.09E-05
	Total				**1.44E-02**	**2.16E-03**

Notes:

1. For all listings above which contain the word "compounds" and for glycol ethers, the following applies: Unless otherwise specified, these listings are defined as including any unique chemical substance that contains the named chemical (i.e., antimony, arsenic, etc.) as part of that chemical's infrastructure.
2. X'CN where X = H' or any other group where a formal dissociation may occur. For example, KCN or Ca(CN)2.
3. Includes mono- and di- ethers of ethylene glycol, diethylene glycol, and triethylene glycol, R-(OCH2CH2)n-OR'

where: n = 1, 2, or 3
R = alkyl or aryl groups
R' = R, H, or groups which, when removed, yield glycol ethers with the structure: R-(OCH2CH)n-OH. Polymers are excluded from the glycol category.

4. Includes mineral fiber emissions from facilities manufacturing or processing glass, rock, or slag fibers (or other mineral derived fibers) of average diameter 1 micrometer or less.
5. Includes organic compounds with more than one benzene ring, and which have a boiling point greater than or equal to 100°C.
6. A type of atom which spontaneously undergoes radioactive decay.

Attachment S-1b
Total Air Toxic Emissions

SECTION 112 HAZARDOUS AIR POLLUTANTS

CAS Number	Pollutant[1]	CT-4 Emissions (tpy)	CT-5 Emissions (tpy)	D-21 Emissions (tpy)	D-22 Emissions (tpy)	D-23 Emissions (tpy)	BS-1 Emissions (tpy)	Total Emissions (tpy)
75-07-0	Acetaldehyde	3.04E-02	3.04E-02	1.23E-04	3.10E-03	3.10E-03	2.11E-05	6.71E-02
60-35-5	Acetamide							
75-05-8	Acetonitrile							
98-86-2	Acetophenone							
53-96-3	2-Acetylaminofluorene							
107-02-8	Acrolein	9.49E-03	9.49E-03	3.86E-05	9.70E-04	9.70E-04	6.58E-06	2.10E-02
79-06-1	Acrylamide							
79-10-7	Acrylic acid							
107-13-1	Acrylonitrile							
107-05-1	Allyl chloride							
92-67-1	4-Aminobiphenyl							
62-53-3	Aniline							
90-04-0	o-Anisidine							
1332-21-4	Asbestos							
71-43-2	Benzene (including benzene from gasoline)	6.61E-02	6.61E-02	3.80E-03	9.55E-02	9.55E-02	6.48E-04	3.28E-01
92-87-5	Benzidine							
98-07-7	Benzotrichloride							
100-44-7	Benzyl chloride							
92-52-4	Biphenyl							
117-81-7	Bis(2-ethylhexyl)phthalate (DEHP)							
542-88-1	Bis(chloromethyl) ether							
75-25-2	Bromoform							
106-99-0	1,3-Butadiene	1.93E-02	1.93E-02	7.84E-05	1.97E-03	1.97E-03	1.34E-05	4.26E-02
156-62-7	Calcium cyanamide							
105-60-2	Caprolactam (Removed 06/18/96. See 61FR30816)							
133-06-2	Captan							
63-25-2	Carbaryl							
75-15-0	Carbon disulfide							
56-23-5	Carbon tetrachloride							
463-58-1	Carbonyl sulfide							
120-80-9	Catechol							
133-90-4	Chloramben							
57-74-9	Chlordane							
7782-50-5	Chlorine							
79-11-8	Chloroacetic acid							
532-27-4	2-Chloroacetophenone							
108-90-7	Chlorobenzene							
510-15-6	Chlorobenzilate							
67-66-3	Chloroform							
107-30-2	Chloromethyl methyl ether							
126-99-8	Chloroprene							
1319-77-3	Cresol/Cresylic acid(mixed isomers)							
95-48-7	o-Cresol							
108-39-4	m-Cresol							
106-44-5	p-Cresol							
98-82-8	Cumene							
94-75-7	2,4-D salts and esters							
72-55-9	DDE(1,1-dichloro-2,2-bis(p-chlorophenyl) ethylene)							
334-88-3	Diazomethane							
132-64-9	Dibenzofuran							
96-12-8	1,2-Dibromo-3-chloropropane							
84-74-2	Dibutyl phthalate							
106-46-7	1,4-Dichlorobenzene							
91-94-1	Dichlorobenzidine							
111-44-4	Dichloroethyl ether(Bis[2-chloroethyl]ether)							
542-75-6	1,3-Dichloropropene							
62-73-7	Dichlorvos							
111-42-2	Diethanolamine							
64-67-5	Diethyl sulfate							
119-90-4	3,3'-Dimethoxybenzidine							
60-11-7	4-Dimethylaminoazobenzene							
121-69-7	N,N-Dimethylaniline							
119-93-7	3,3'-Dimethylbenzidine							
79-44-7	Dimethylcarbamoyl chloride							
68-12-2	N,N-Dimethylformamide							
57-14-7	1,1-Dimethylhydrazine							
131-11-3	Dimethyl phthalate							
77-78-1	Dimethyl sulfate							
534-52-1	4,6-Dinitro-o-cresol (including salts)							
51-28-5	2,4-Dinitrophenol							
121-14-2	2,4-Dinitrotoluene							
123-91-1	1,4-Dioxane (1,4-Diethyleneoxide)							
122-66-7	1,2-Diphenylhydrazine							
106-89-8	Epichlorohydrin (l-Chloro-2,3-epoxypropane)							
106-88-7	1,2-Epoxybutane							
140-88-5	Ethyl acrylate							
100-41-4	Ethylbenzene							
51-79-6	Ethyl carbamate (Urethane)							
75-00-3	Ethyl chloride (Chloroethane)							
106-93-4	Ethylene dibromide (Dibromoethane)							
107-06-2	Ethylene dichloride (1,2-Dichloroethane)							
107-21-1	Ethylene glycol							

Attachment S-1b
Total Air Toxic Emissions

SECTION 112 HAZARDOUS AIR POLLUTANTS

CAS Number	Pollutant[1]	CT-4 Emissions (tpy)	CT-5 Emissions (tpy)	D-21 Emissions (tpy)	D-22 Emissions (tpy)	D-23 Emissions (tpy)	BS-1 Emissions (tpy)	Total Emissions (tpy)
151-56-4	Ethyleneimine (Aziridine)							
75-21-8	Ethylene oxide							
96-45-7	Ethylene thiourea							
75-34-3	Ethylidene dichloride (1,1-Dichloroethane)							
50-00-0	Formaldehyde	3 37E-01	3.37E-01	3 87E-04	9.71E-03	9.71E-03	6 59E-05	6 94E-01
76-44-8	Heptachlor							
118-74-1	Hexachlorobenzene							
87-68-3	Hexachlorobutadiene							
77-47-4	Hexachlorocyclopentadiene							
67-72-1	Hexachloroethane							
822-06-0	Hexamethylene diisocyanate							
680-31-9	Hexamethylphosphoramide							
110-54-3	Hexane							
302-01-2	Hydrazine							
7647-01-0	Hydrochloric acid (Hydrogen chloride [gas only])							
7664-39-3	Hydrogen fluoride (Hydrofluoric acid)							
123-31-9	Hydroquinone							
78-59-1	Isophorone							
58-89-9	Lindane (all isomers)							
108-31-6	Maleic anhydride							
67-56-1	Methanol							
72-43-5	Methoxychlor							
74-83-9	Methyl bromide (Bromomethane)							
74-87-3	Methyl chloride(Chloromethane)							
71-55-6	Methyl chloroform(1,1,1-Trichloroethane)							
78-93-3	Methyl ethyl ketone (2-Butanone) (Removed 12/19/05. See							
60-34-4	Methylhydrazine							
74-88-4	Methyl iodide (Iodomethane)							
108-10-1	Methyl isobutyl ketone(Hexone)							
624-83-9	Methyl isocyanate							
80-62-6	Methyl methacrylate							
1634-04-4	Methyl tert-butyl ether							
101-14-4	4,4'-Methylenebis(2-chloroaniline)							
75-09-2	Methylene chloride(Dichloromethane)							
101-68-8	4,4'-Methylenediphenyl diisocyanate(MDI)							
101-77-9	4,4'-Methylenedianiline							
91-20-3	Naphthalene	4.22E-02	4.22E-02	6.37E-04	1 60E-02	1.60E-02	1.09E-04	1 17E-01
98-95-3	Nitrobenzene							
92-93-3	4-Nitrobiphenyl							
100-02-7	4-Nitrophenol							
79-46-9	2-Nitropropane							
684-93-5	N-Nitroso-N-methylurea							
62-75-9	N-Nitrosodimethylamine							
59-89-2	N-Nitrosomorpholine							
56-38-2	Parathion							
82-68-8	Pentachloronitrobenzene(Quintobenzene)							
87-86-5	Pentachlorophenol							
108-95-2	Phenol							
106-50-3	p-Phenylenediamine							
75-44-5	Phosgene							
7803-51-2	Phosphine							
7723-14-0	Phosphorus							
85-44-9	Phthalic anhydride							
1336-36-3	Polychlorinated biphenyls(Aroclors)							
1120-71-4	1,3-Propane sultone							
57-57-8	beta-Propiolactone							
123-38-6	Propionaldehyde							
114-26-1	Propoxur (Baygon)							
78-87-5	Propylene dichloride (1,2-Dichloropropane)							
75-56-9	Propylene oxide							
75-55-8	1,2-Propylenimine (2-Methylaziridine)							
91-22-5	Quinoline							
106-51-4	Quinone(p-Benzoquinone)							
100-42-5	Styrene							
96-09-3	Styrene oxide							
1746-01-6	2,3,7,8-Tetrachlorodibenzo-p-dioxin							
79-34-5	1,1,2,2-Tetrachloroethane							
127-18-4	Tetrachloroethylene(Perchloroethylene)							
7550-45-0	Titanium tetrachloride							
108-88-3	Toluene	3 38E-01	3.38E-01	1.38E-03	3 46E-02	3.46E-02	2.35E-04	7.48E-01
95-80-7	Toluene-2,4-diamine							
584-84-9	2,4-Toluene diisocyanate							
95-53-4	o-Toluidine							
8001-35-2	Toxaphene (chlorinated camphene)							
120-82-1	1,2,4-Trichlorobenzene							
79-00-5	1,1,2-Trichloroethane							
79-01-6	Trichloroethylene							
95-95-4	2,4,5-Trichlorophenol							
88-06-2	2,4,6-Trichlorophenol							
121-44-8	Triethylamine							
1582-09-8	Trifluralin							
540-84-1	2,2,4-Trimethylpentane							

Attachment S-1b
Total Air Toxic Emissions

SECTION 112 HAZARDOUS AIR POLLUTANTS

CAS Number	Pollutant[1]	CT-4 Emissions (tpy)	CT-5 Emissions (tpy)	D-21 Emissions (tpy)	D-22 Emissions (tpy)	D-23 Emissions (tpy)	BS-1 Emissions (tpy)	Total Emissions (tpy)
108-05-4	Vinyl acetate							
593-60-2	Vinyl bromide							
75-01-4	Vinyl chloride							
75-35-4	Vinylidene chloride (1,1-Dichloroethylene)							
1330-20-7	Xylene (mixed isomers)	2.32E-01	2.32E-01	9.46E-04	2.38E-02	2.38E-02	1.61E-04	5.14E-01
95-47-6	o-Xylene							
108-38-3	m-Xylene							
106-42-3	p-Xylene							
	Antimony Compounds							
	Arsenic Compounds (inorganic including arsine)	1.33E-02	1.33E-02	5.39E-05	1.35E-03	1.35E-03	9.19E-06	2.93E-02
	Beryllium Compounds	3.73E-04	3.73E-04	1.52E-06	3.82E-05	3.82E-05	2.59E-07	8.25E-04
	Cadmium Compounds	5.78E-03	5.78E-03	2.35E-05	5.91E-04	5.91E-04	4.01E-06	1.28E-02
	Chromium Compounds	1.32E-02	1.32E-02	5.39E-05	1.35E-03	1.35E-03	9.19E-06	2.93E-02
	Cobalt Compounds							
	Coke Oven Emissions							
	Cyanide Compounds[2]							
	Glycol ethers[3]							
	Lead Compounds	1.69E-02	1.69E-02	6.86E-05	1.72E-03	1.72E-03	1.17E-05	3.73E-02
	Manganese Compounds	9.52E-01	9.52E-01	3.87E-03	9.72E-02	9.72E-02	6.60E-04	2.10E+00
	Mercury Compounds	1.45E-03	1.45E-03	5.88E-06	1.48E-04	1.48E-04	1.00E-06	3.19E-03
	Fine mineral fibers[4]							
	Nickel Compounds	5.54E-03	5.54E-03	2.25E-05	5.66E-04	5.66E-04	3.84E-06	1.22E-02
	Polycyclic Organic Matter[5]	4.82E-02	4.82E-02	1.04E-03	2.61E-02	2.61E-02	1.77E-04	1.50E-01
	Radionuclides (including radon)[6]							
	Selenium Compounds	3.01E-02	3.01E-02	1.23E-04	3.08E-03	3.08E-03	2.09E-05	6.65E-02
	Total	**2.16**	**2.16**	**0.013**	**0.32**	**0.32**	**0.0022**	**4.97**

Notes.

1 For all listings above which contain the word "compounds" and for glycol ethers, the following applies. Unless otherwise specified, these listings are defined as including any unique chemical substance that contains the named chemical (i.e., antimony, arsenic, etc.) as part of that chemical's infrastructure

2. X'CN where X = H' or any other group where a formal dissociation may occur. For example, KCN or Ca(CN)2

3 Includes mono- and di- ethers of ethylene glycol, diethylene glycol, and triethylene glycol, R-(OCH2CH2)n-OR'

where n = 1, 2, or 3

R = alkyl or aryl groups

R' = R, H, or groups which, when removed, yield glycol ethers with the structure: R-(OCH2CH)n-OH. Polymers are excluded from the glycol category

4 Includes mineral fiber emissions from facilities manufacturing or processing glass, rock, or slag fibers (or other mineral derived fibers) of average diameter 1 micrometer or less.

5 Includes organic compounds with more than one benzene ring, and which have a boiling point greater than or equal to 100°C

6 A type of atom which spontaneously undergoes radioactive decay

Attachment S-1c
Other Regulated Pollutants

Emissions for Unit CT-4 or CT-5	Emissions (lb/hr)	Emissions (tpy)
Beryllium	See Attachment S-1b	
Mercury	See Attachment S-1b	
Asbestos	neg.	neg.
Hydrogen Sulfide	neg.	neg.
Halons	neg.	neg.
MWC Acid Gases	neg.	neg.
MWC Metals	neg.	neg.
MWC Organics	neg.	neg.

Emissions for Unit D-21	Emissions (lb/hr)	Emissions (tpy)
Beryllium	See Attachment S-1b	
Mercury	See Attachment S-1b	
Asbestos	neg.	neg.
Hydrogen Sulfide	neg.	neg.
Halons	neg.	neg.
MWC Acid Gases	neg.	neg.
MWC Metals	neg.	neg.
MWC Organics	neg.	neg.

Emissions for Unit D-22 or D-23	Emissions (lb/hr)	Emissions (tpy)
Beryllium	See Attachment S-1b	
Mercury	See Attachment S-1b	
Asbestos	neg.	neg.
Hydrogen Sulfide	neg.	neg.
Halons	neg.	neg.
MWC Acid Gases	neg.	neg.
MWC Metals	neg.	neg.
MWC Organics	neg.	neg.

Emissions for Unit BS-1	Emissions (lb/hr)	Emissions (tpy)
Beryllium	See Attachment S-1b	
Mercury	See Attachment S-1b	
Asbestos	neg.	neg.
Hydrogen Sulfide	neg.	neg.
Halons	neg.	neg.
MWC Acid Gases	neg.	neg.
MWC Metals	neg.	neg.
MWC Organics	neg.	neg.

Notes:
MWC = Municipal Waste Combustor
neg. = negligible

Attachment S-1d
Pollutant Emission Rate Calculations

Sulfur Dioxide (SO_2)

Unit	Heat Input (MMBtu/hr)	AP-42 Emission Factor[1,2] (lb/MMBtu)	CSP Application Emission Factor[3] (lb/MMBtu)	CSP Application Emission Rate (lb/hr)
CT-4	275	0.404	0.000	0.0
CT-5	275	0.404	0.000	0.0
D-21	28.1	0.002	0.000	0.00
D-22	28.1	0.002	0.000	0.00
D-23	28.1	0.002	0.000	0.00
BS-1	5.57	0.404	0.000	0.00

1. AP-42 emission factor for CT-4, and CT-5 from Section 3.1, dated April 2000, Table 3.1-2a, using a sulfur content of 0.4%.
2. AP-42 emission factor for D-21, D-22, and D-23 from Section 3.4, dated October 1996, Table 3.4-1, using a sulfur content of 0.0015%.
3. AP-42 emission factor for BS-1 from Section 3.4, dated October 1996, Table 3.4-1, using a sulfur content of 0.4%.

Nitrogen Oxides (NO_X)

Unit	Heat Input (MMBtu/hr)	AP-42 Emission Factor[1,2] (lb/MMBtu)	CSP Application Emission Factor (lb/MMBtu)	CSP Application Emission Rate (lb/hr)
CT-4	275	0.24	0.000	0.0
CT-5	275	0.24	0.000	0.0
D-21	28.1	3.2	0.000	0.0
D-22	28.1	3.2	0.000	0.0
D-23	28.1	3.2	0.000	0.0
BS-1	5.57	3.2	0.000	0.0

1. AP-42 emission factor for CT-4, and CT-5 from Section 3.1, dated April 2000, Table 3.1-1.
2. AP-42 emission factor for D-21, D-22, D-23, and BS-1 from Section 3.4, dated October 1996, Table 3.4-1.

Carbon Monoxide (CO)

Unit	Heat Input (MMBtu/hr)	AP-42 Emission Factor[1,2] (lb/MMBtu)	CSP Application Emission Factor (lb/MMBtu)	CSP Application Emission Rate (lb/hr)
CT-4	275	0.076	0.000	0.0
CT-5	275	0.076	0.000	0.0
D-21	28.1	0.255	0.000	0.0
D-22	28.1	0.255	0.000	0.0
D-23	28.1	0.255	0.000	0.0
BS-1	5.57	0.85	0.000	0.00

1. AP-42 emission factor for CT-4, and CT-5 from Section 3.1, dated April 2000, Table 3.1-1.
2. AP-42 emission factor for D-21, D-22, D-23, and BS-1 from Section 3.4, dated October 1996, Table 3.4-1. A

Attachment S-1d
Pollutant Emission Rate Calculations

Particulate Matter (PM/PM_{10})

Unit	Heat Input (MMBtu/hr)	AP-42 Emission Factor[1,2] (lb/MMBtu)	CSP Application Emission Factor (lb/MMBtu)	CSP Application Emission Rate (lb/hr)
CT-4	275	0.012	0.000	0.0
CT-5	275	0.012	0.000	0.0
D-21	28.1	0.1	0.000	0.00
D-22	28.1	0.1	0.000	0.00
D-23	28.1	0.1	0.000	0.00
BS-1	5.57	0.1	0.000	0.00

1. AP-42 emission factor for CT-2, CT-4, and CT-5 from Section 3.1, dated April 2000, Table 3.1-2a.
2. AP-42 emission factor for D-21, D-22, D-23, and BS-1 from Section 3.4, dated October 1996, Table 3.4-2.

Volatile Organic Compounds (VOC)

Unit	Heat Input (MMBtu/hr)	AP-42 Emission Factor[1,2] (lb/MMBtu)	CSP Application Emission Factor (lb/MMBtu)	CSP Application Emission Rate (lb/hr)
CT-4	275	0.00041	0.000	0.00
CT-5	275	0.00041	0.000	0.00
D-21	28.1	0.082	0.000	0.00
D-22	28.1	0.082	0.000	0.00
D-23	28.1	0.082	0.000	0.00
BS-1	5.57	0.082	0.000	0.00

1. AP-42 emission factor for CT-2, CT-4, and CT-5 from Section 3.1, dated April 2000, Table 3.1-2a.
2. AP-42 emission factor for D-21, D-22, D-23, and BS-1 from Section 3.4, dated October 1996, Table 3.4-1.

Attachment S-1e
GHG Emissions Calculations

Unit	Heat Input (MMBtu/hr)	Operating Hours (hrs/yr)	Annual Heat Input (MMBtu/yr)	GHG Pollutant[1]	Emission Factor[2] (kg/MMBtu)	Maximum Hourly Emissions (kg/hr)	Annual Emissions (metric tpy)	Global Warming Potential[3]	Total GHG Emissions CO_2e (lb/hr)	Total GHG Emissions CO_2e (metric tpy)	Total GHG Emissions CO_2e (tpy)
CT-4	275.0	8,760	2,409,000	CO_2	73.96	20,339	178,170	1	44,840	178,170	196,398
				N_2O	6.0E-04	0.165	1.445	298	108	431	475
				CH_4	3.0E-03	0.825	7.227	25	45	181	199
								Total CO_2e =	**44,994**	**178,781**	**197,072**
CT-5	275.0	8,760	2,409,000	CO_2	73.96	20,339	178,170	1	44,840	178,170	196,398
				N_2O	6.0E-04	0.165	1.445	298	108	431	475
				CH_4	3.0E-03	0.825	7.227	25	45	181	199
								Total CO_2e =	**44,994**	**178,781**	**197,072**
D-21	28.1	349	9,800	CO_2	73.96	2,078	725	1	4,582	725	799
				N_2O	6.0E-04	0.017	0.006	298	11	2	2
				CH_4	3.0E-03	0.084	0.029	25	5	1	1
								Total CO_2e =	**4,598**	**727**	**802**
D-22	28.1	8,760	246,156	CO_2	73.96	2,078	18,206	1	4,582	18,206	20,068
				N_2O	6.0E-04	0.017	0.148	298	11	44	49
				CH_4	3.0E-03	0.084	0.738	25	5	18	20
								Total CO_2e =	**4,598**	**18,268**	**20,137**
D-23	28.1	8,760	246,156	CO_2	73.96	2,078	18,206	1	4,582	18,206	20,068
				N_2O	6.0E-04	0.000	0.000	298	0	0	0
				CH_4	3.0E-03	0.000	0.000	25	0	0	0
								Total CO_2e =	**4,582**	**18,206**	**20,068**
BS-1	5.6	300	1,671	CO_2	73.96	412	124	1	908	124	136
				N_2O	6.0E-04	0.003	0.001	298	2	0	0
				CH_4	3.0E-03	0.017	0.005	25	1	0	0
								Total CO_2e =	**911**	**124**	**137**
								Facility Total CO2e =		**394,887**	**435,289**

Notes:
1. Greenhouse Gas (GHG) pollutants from the Mandatory Greenhouse Gas Reporting rule (40 CFR §98.32).
2. Emission factors from the Mandatory Greenhouse Gas Reporting rule (40 CFR Part 98 Subpart C, Tables C-1 and C-2).
3. Global Warming Potentials from the Mandatory Greenhouse Gas Reporting rule (40 CFR Part 98 Subpart A, Table A-1).

File No.: ________

S-7: Application for a Minor Modification to a Covered Source

In providing the required information, reference the corresponding letters and numbers listed below.

Provide a minimum of **two (2)** sets (1 original and 1 copy) of all application materials to the Hawaii Department of Health. Also, mail **one (1)** set directly to EPA at the following address:

Chief (Attention: AIR-3)
Permits Office, Air Division
U.S. Environmental Protection Agency
Region 9
75 Hawthorne Street
San Francisco, CA 94105

I. In accordance with Hawaii Administrative Rules (HAR) §11-60.1-103, the following information is required:

A. A clear description of all changes.

The proposed changes are to improve the performance and reliability of the NOx emissions control systems for CT4 and CT5. The system as currently configured involves feeding a solution of urea in water to a heater that decomposes the urea into ammonia gas. The gas is introduced into the combustion gas stream through an Air Injection Grid ahead of the selective catalytic reduction (SCR) catalyst where ammonia reacts to remove NOx. This project will modify the system to directly inject urea solution into the combustion gases through specially designed injection nozzles. The injection point will be moved to a location in the ductwork upstream of the SCR reactor. The heat of combustion gases will decompose the urea rather than having to rely on an external heater. The supplier has used Computerized Fluid Dynamics (CFD) modeling to design the direct injection system to assure complete decomposition of urea and uniform dispersion of ammonia across the catalyst. The urea injection rate will be controlled by the same process control system as is used now, which relies on measurements of NOx concentrations entering and leaving the SCR reactor. Based on the CFD modeling the supplier has guaranteed that NOx emissions will be controlled at least as effectively with direct urea injection as the system it replaces.

The new system will improve NOx control reliability and performance in several important ways. For one, the existing heater creates significant lag between when the process control system adjusts the urea flow and the results of that change appear at the catalyst and the outlet NOx sensor. We estimate that lag is about 3 minutes. The new system will have only a few seconds lag. That lag can also create discrepancies between the actual and the calculated ammonia slip. Second, a urea heater failure in the existing system is not detected until the NOx concentration exiting the SCR reactor starts increasing. With the new system, loss of urea and ammonia flow will be detected immediately so corrective actions can be taken sooner. Finally, the existing system requires a backup urea heater in case the primary one goes down. It takes a lot of time to bring the backup heater up to temperature if it is needed. The new system will keep a urea heater as backup to direct urea injection. Since the heater is a weak link for reliability, Hawai'i Electric Light expects that the new system will be more reliable and the backup system will not likely have to be used.

Until the direct injection system has been proven in operation, the existing urea heater system will be kept available for operation after which one of the urea heaters may be taken out of service.

B. A statement of why the modification is determined to be minor, and a request that minor modification procedures be used.

The proposed modifications meet the criteria in the definition of "minor modification" as defined in HAR § 11-60.1-81. The proposed modifications:

(1) Do not increase the emissions of any air pollutant above the permitted emission limits;

(2) Do not result in or increase the emissions of any air pollutant not limited by permit levels equal to or above: (A) 500 pounds per year of a hazardous air pollutant; (B) 300 pounds of lead; (C) twenty-five percent of significant amounts of emission as defined in section 11-60.1-1, paragraph (1) in the definition of "significant"; or (D) two tons per year of each regulated air pollutant not already identified above (the proposed modification do not result in emissions increase);

(3) Do not violate any applicable requirement;

(4) Do not involve significant changes to existing monitoring requirements or any relaxation or significant change to existing reporting or recordkeeping requirements in the permit.

(5) Do not require or change a case-by-case determination, a source-specific determination for temporary sources for ambient impacts, or a visibility or increment analysis;

(6) Do 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; and

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

C. Cite and describe any new applicable requirements as defined in HAR § 11-60.1-81 that will apply if the minor modification occurs.

No new applicable requirements will apply to the proposed minor modifications.

D. The suggested changes to permit terms or conditions.

Attachment S-7a contains Hawai'i Electric Light's suggested permit changes. Suggested deletions are struck through and suggested additions are underlined.

E. Certification by a responsible official that the proposed modification meets the criteria for minor modification.

Form S-1 contains the responsible official's signature certifying that the modifications are minor.

F. All information submitted with the application for the Initial Covered Source Permit or any subsequent application for a Covered Source Permit. The owner or operator may reference information contained in a previous application submittal, provided such referenced information has been certified as being current and still applicable.

References are made herein to pertinent information in previously submitted materials.

G. Other information, as required by any applicable requirement or as requested and deemed necessary by the Director of Health (hereafter, Director) to make a decision on the application.

Not applicable.

II. Submit an application fee according to the Application Fees Schedule in the Instructions for Applying for an Air Pollution Control Permit.

III. An application shall be determined to be complete only when all of the following have been complied with:

A. All information required or requested in number I have been submitted.

B. All documents requiring certification have been certified pursuant to HAR § 11-60.1-4.

C. All applicable fees have been submitted.

D. The Director has certified that the application is complete.

IV. The Director shall not continue to act upon or consider an incomplete application.

A. The applicant shall be notified in writing whether the application is complete. Unless the Director requests additional information or notifies the applicant of incompleteness within thirty days of receipt of an application, the application shall be deemed complete.

B. During the processing of an application that has been determined or deemed complete, if the Director determines that additional information is necessary to evaluate or take final action on the application, the Director may request such information in writing and set a reasonable deadline for a response.

V. Within ninety days of receipt of a complete application for a minor modification, or upon program approval, within fifteen days after the end of the Administrator's forty-five-day review period, whichever is later, the Director in writing shall:

A. Amend the permit to reflect the minor modification as proposed.

B. Deny the minor modification.

C. Determine that the requested modification does not meet the minor modification criteria, and should be reviewed under the significant modification process; or

D. Upon program approval, amend the proposed permit and resubmit the amendment to EPA for reevaluation.

VI. An application for minor modification to a covered source shall be approved only if the Director determines that the minor modification will be in compliance with all applicable requirements.

VII. The Director shall provide a statement that sets forth the legal and factual bases for the proposed permit conditions (including references to the applicable statutory or regulatory provisions) to EPA and any other person requesting it.

VIII. Each application and proposed permit reflecting the minor modification to a covered source shall be subject to EPA oversight in accordance with HAR § 11-60.1-95.

Attachment S-7a

Requested Changes to CSP No. 0007-01-C

Proposed change to Attachment IIA, Special Condition No. C.3.b:

b. Selective Catalytic Reduction System

The permittee shall design, install, maintain, and continuously operate a selective catalytic reduction system ~~with ammonia injection~~ to meet the emission limits as specified in Attachment II, Special Condition D.1. of this Covered Source Permit.

The selective catalytic reduction system shall be ~~fully~~ functional and in operation whenever the combustion turbine generators are in combined cycle operation at loads greater than or equal to 50 percent of the peakload. The selective catalytic reduction system shall continue to operate until the load is reduced to below 50 percent of the peakload.

Justification – The deletion of "ammonia injection" is requested to include the proposed urea direct injection system. The deletion of "fully" is requested as the term is unnecessary.

Attachment S-7b
Manufacturer Literature
Keahole Generating Station
Direct Urea Injection Flow Model
Fuel Tech Inc.

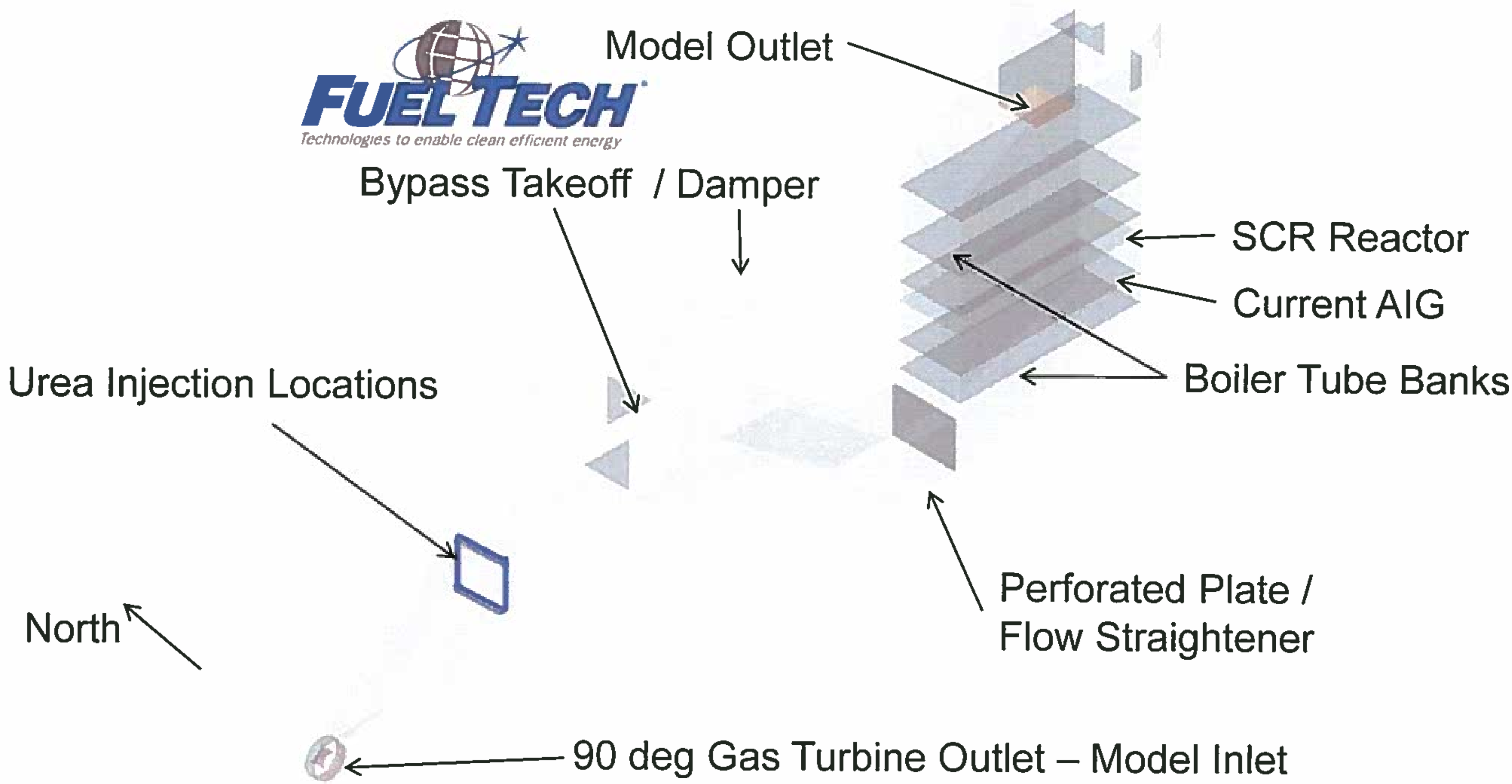
September 28, 2017

HELCO Keahole Plant OTSG Flow Model Rev1; Direct Urea Injection

PRESENTED TO: HELCO
FTI PROJECT: 1231M
CONFIDENTIAL

FUEL TECH
Technologies to enable clean efficient energy

U4 GEOMETRY – AS BUILT ELEVATION VIEW



INTRODUCTION

- Hawai'i Electric Light Company (HELCO) Keahole Power Plant has been experiencing problems with their urea supply system to the SCR.
- HELCO has contracted Fuel Tech (FTI) to evaluate the feasibility of direct liquid injection of urea at the exit of the gas turbine.
- FTI performed CFD modeling on full load and minimum load to determine how the droplets behaved and determine the NH_3 distributions at the catalyst.

MODELING GOALS

- Determine if the droplets are impacting any surfaces in the duct.
  - Initial optimization was performed to determine the number of injectors and injector placement in the duct.
- Determine the NH_3 distribution at the catalyst inlet.
- Predict feasibility of urea injection based on this step and continuing optimization.

FLOW CONDITIONS TESTED

Process Conditions Full Load (100% +STG, backend temp control)	
Flue Gas Flow Rate	602,880 lb/hr
Gas Turbine Exit Temperature	1005F
SCR Inlet Temperature	872F
Urea Injection (40% soln)	75 lb/hr

Process Conditions 50% Load (50% + STG, backend temp control)	
Flue Gas Flow Rate	418,490 lb/hr
Gas Turbine Exit Temperature	882F
SCR Inlet Temperature	804F
Urea Injection (40% soln)	30 lb/hr

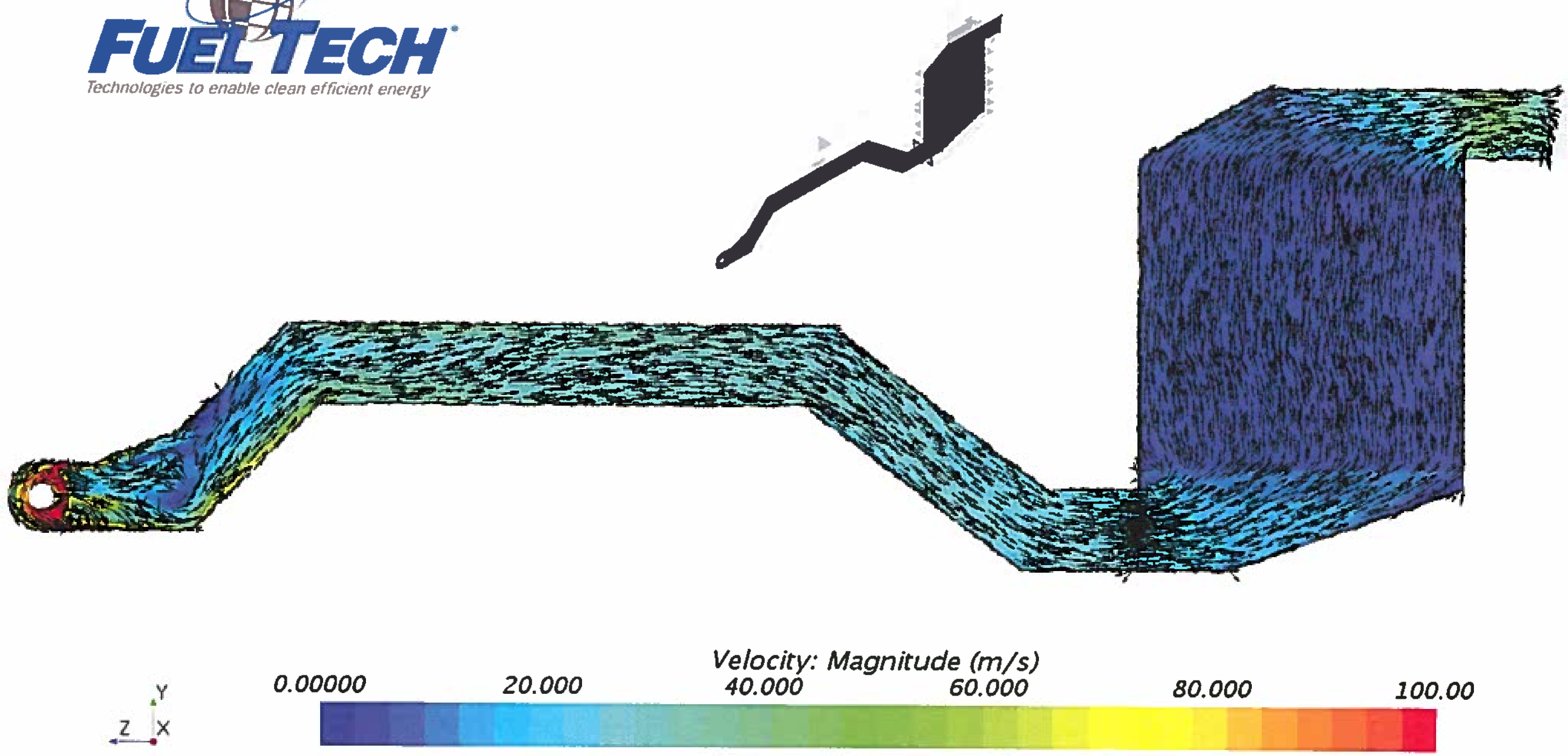
FULL LOAD WITH UREA INJECTION SIMULATION RESULTS

SUMMARY OF FULL LOAD

- Velocity coming out of the turbine was assumed to be uniform based on the mass and the ideal gas law. It also has been given a swirl condition.
- The flow in the duct is relatively straight at the injection location.
- No droplet impacting the duct walls.

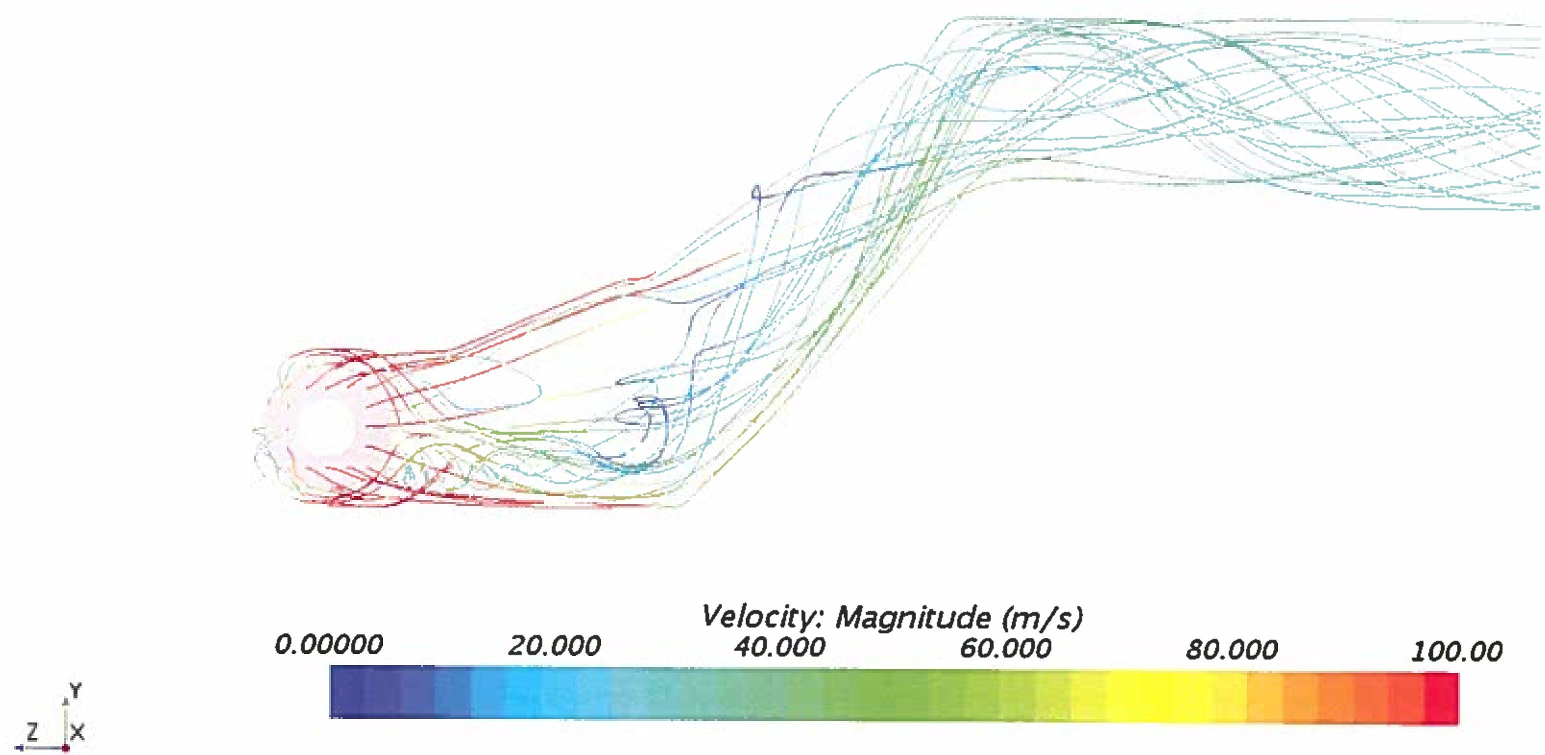
VELOCITY CROSS SECTION AT GAS TURBINE EXIT

Technologies to enable clean efficient energy

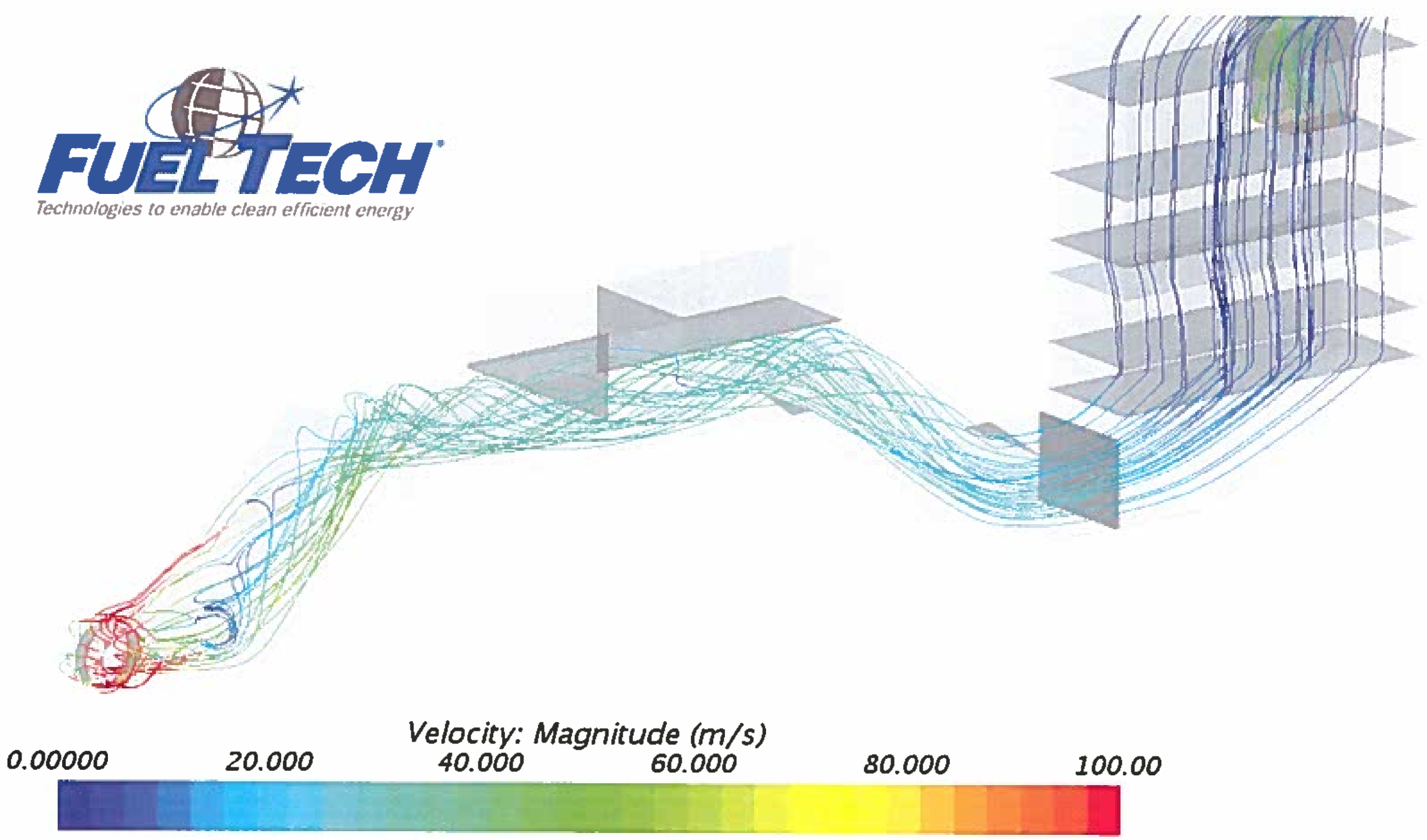


VELOCITY STREAMLINES AT GAS TURBINE EXIT

FUEL TECH
Technologies to enable clean efficient energy



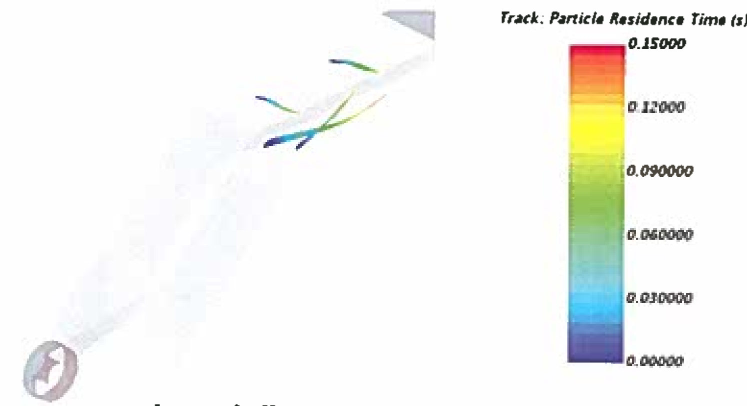
VELOCITY STREAMLINES AT GAS TURBINE EXIT



FULL LOAD SIDE ONLY UREA INJECTION

Relatively straight flow allows for good injection with no impact on internal surfaces

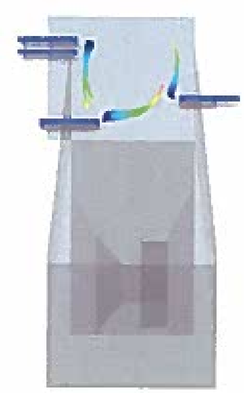
Plan View



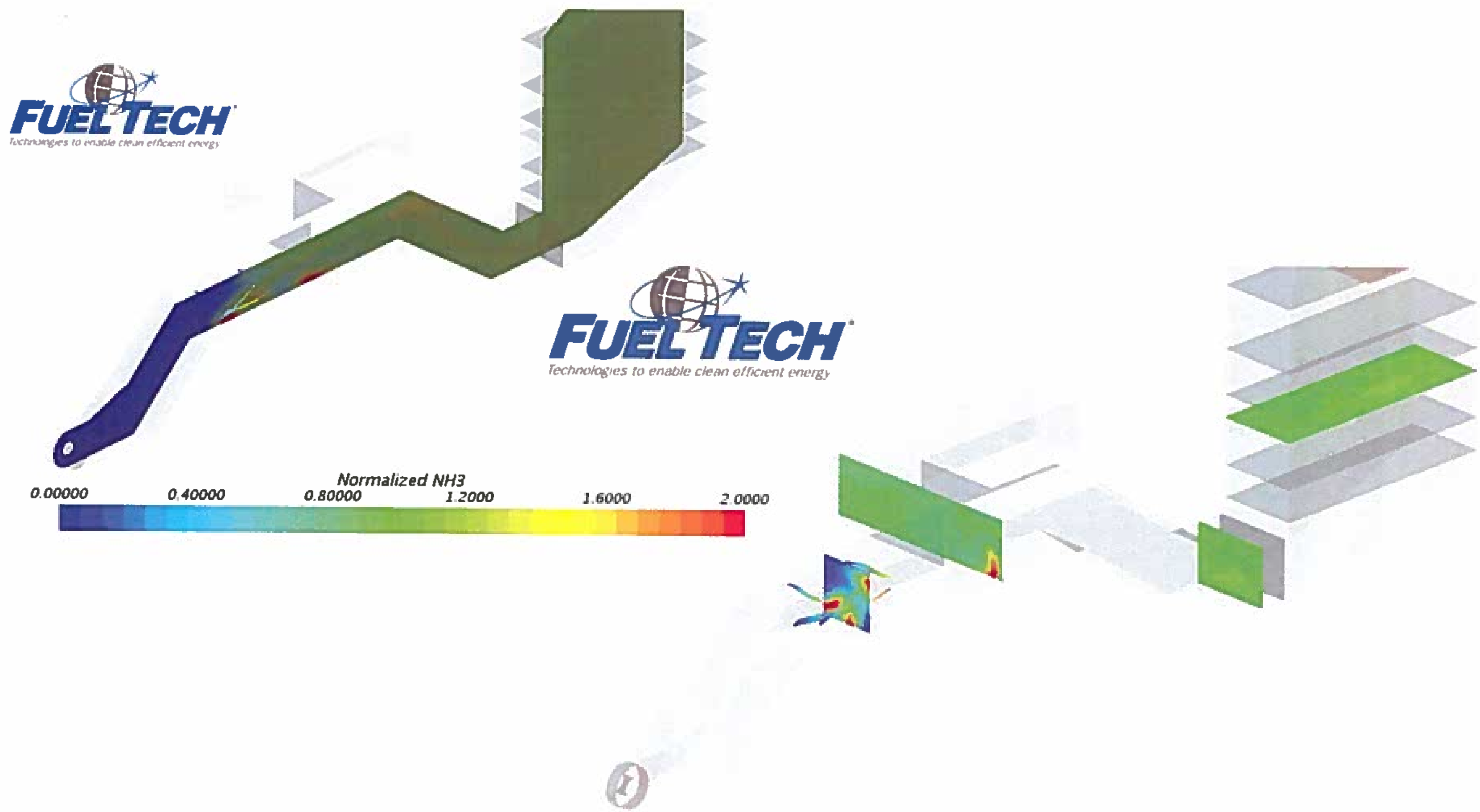
Iso View

Elevation View Looking North

Side View Looking East

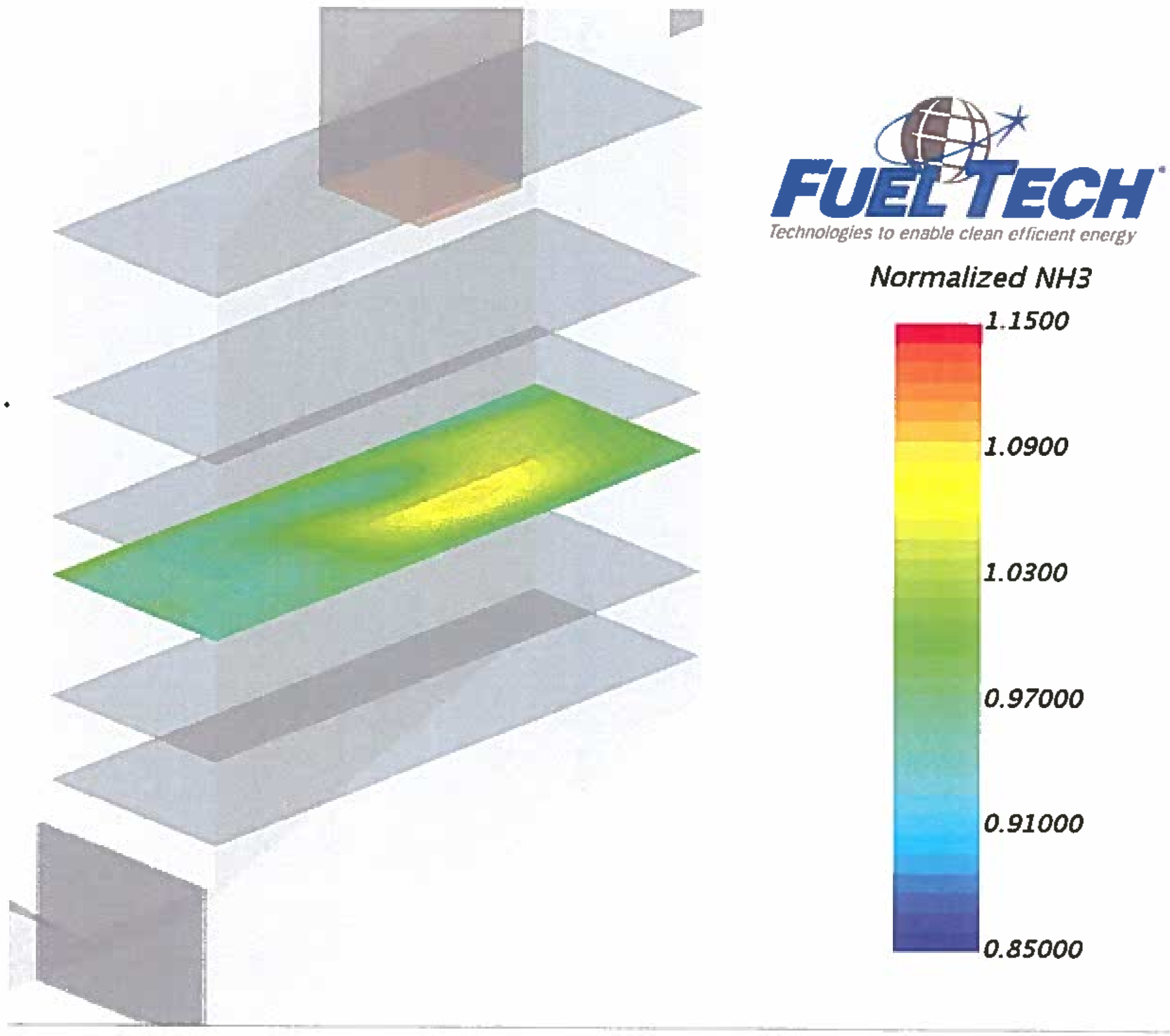


FULL LOAD
NH_3 CROSS SECTION-ISOMETRIC



FULL LOAD
NH_3 CATALYST INLET

NH_3 Distribution
RMSE = 5%
100% w/in +/-15% of the avg.



RESULTS SUMMARY

Normalized Ammonia Distribution	Full Load Side Only	50% Load Side Only
Ammonia % w/in 15% of average	100%	100%
Ammonia RMSE	5%	5%

NH_3 Distribution Goals
RMSE = <10%
100% w/in +/-15% of the average

RESULTS SUMMARY

- Injecting with 4 injectors in the locations shown produced a very good result and will meet or exceed the current arrangement with the Ammonia Injection Grid.

File No.: ________

C-1: Compliance Plan

The Responsible Official shall submit a Compliance Plan as indicated in the Instructions for Applying for an Air Pollution Control Permit and at such other times as requested by the Director of Health (hereafter, Director).

Use separate sheets if necessary.

---

1. Compliance status with respect to all Applicable Requirements:

   Will your facility be in compliance, or is your facility in compliance, with all applicable requirements in effect at the time of your permit application submittal?

   ■ YES { If YES, Complete items a and c below}

   ☐ NO { If NO, complete items a-c below}

   a. Identify all applicable requirement(s) for which compliance is achieved:
      - Refer to CSP No. 0007-01-C issued on August 7, 2008 and the June 23, 2009 Administrative Amendment for all applicable requirements.
      - The National Ambient Air Quality Standards (NAAQS) and State Ambient Air Quality Standards (SAAQS) are "Applicable requirement[s]" as defined in HAR § 11-60.1-81.
      - Diesel engine generators, D-21, D-22, and D-23, are subject to 40 CFR Part 63 Subpart ZZZZ, National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines (RICE NESHAP).

      Provide a statement that the source is in compliance and will continue to comply with all such requirements.

      The facility is in compliance and will continue to comply with the applicable requirements identified in CSP No. 0007-01-C issued on August 7, 2008, the June 23, 2009 Administrative Amendment, and applicable RICE NESHAP.

      The NAAQS and SAAQS are "Applicable requirement[s]" as defined in HAR § 11-60.1-81.

   b. Identify all applicable requirement(s) for which compliance is NOT achieved:

      Not applicable.

      Provide a detailed Schedule of Compliance and a description of how the source will achieve compliance with all such applicable requirements. Use separate sheets of paper, if necessary.

Description of Remedial Action	Expected Date of Completion
Not applicable.	

c. Identify any other applicable requirement(s) with a future date that your source is subject to. These applicable requirements may be in effect AFTER permit issuance:

Applicable Requirement	Effective Date	Currently in Compliance?
HAR Title 11 Chapter 60.1 Subchapter 11 – Greenhouse Gas Emissions	June 19, 2014 Compliance Date: December 31, 2019	Yes

If the source is not currently in compliance, submit a Schedule of Compliance and a description of how the source will achieve compliance with all such requirements:

Description of Proposed Action/Steps to Achieve Compliance	Expected Date of Achieving Compliance
Not applicable.	

Provide a statement that the source on a timely basis will meet all these applicable requirements.

The source will meet any future applicable requirements on a timely basis.

If the expected date of achieving compliance will NOT meet the applicable requirement's effective date, provide a more detailed description of all remedial actions and the expected dates of completion.

Description of Remedial Action and Explanation	Expected Date of Completion
Not applicable.	

2. Compliance Progress Reports:

   a. If a compliance plan is being submitted to remedy a violation, complete the following information:

   Frequency of Submittal: ______________________ Beginning Date: ______________________
   (less than or equal to 6 months)

b. Date(s) that the Action described in (1)(b) was achieved:

Remedial Action	Date Achieved
Not applicable.	

c. Narrative description of why any date(s) in (1) (b) was not met, and any preventive or corrective measures taken in the interim:

Not applicable.

RESPONSIBLE OFFICIAL (as defined in HAR §11-60.1-1)

Name (Last): Uchida (First): Norman (MI): M.

Title: Manager, Production Department Phone: (808) 969-0422

Mailing Address: P.O. Box 1027

City: Hilo State: HI Zip Code: 96721-1027

Certification by Responsible Official (pursuant to HAR §11-60.1-4)

I certify that I have knowledge of the facts herein set forth, that the same are true, accurate and complete to the best of my knowledge and belief, and that all information not identified by me as confidential in nature shall be treated by the Department of Health as public record. I further state that I will assume responsibility for the construction, modification, or operation of the source in accordance with the Hawaii Administrative Rules, Title 11, Chapter 60.1, Air Pollution Control, and any permit issued thereof.

Name (Print/Type): Norman M. Uchida, PE

(Signature): Norman Uchida Date: 4/13/18

Facility Name: Keahole Generating Station

Location: 73-4249 Pukiawe Street, Kailua Kona, HI 96740

Permit Number: CSP No. 0007-01-C

FOR AGENCY USE ONLY

File/Application No.: ________

Island: ________

Date Received: ________

HAND DELIVERED
DEC 10 2015

Brenner Munger, Ph.D., P.E.
Manager
Environmental Department

Hawai'i Electric Light
Keahole

December 10, 2015

HAND DELIVERY

Mr. Nolan Hirai, P.E.
Manager, Clean Air Branch
State of Hawaii Department of Health
919 Ala Moana Blvd., Room 203
Honolulu, Hawaii 96814

Dear Mr. Hirai:

Subject: **Application for a Minor Modification to a Covered Source**
CSP No. 0070-01-C
Keahole Generating Station
Hawai'i Electric Light Company, Inc.

Hawaiian Electric Company, Inc., on behalf of Hawai'i Electric Light Company, Inc. (Hawai'i Electric Light), submits an original and one copy of the Application for a Minor Modification to a Covered Source for the above reference Covered Source Permit (CSP).

In this application, Hawai'i Electric Light requests to operate the combustion turbine generator, CT-2, below minimum load with water injection to address system disturbances and frequency issues and to clarify permit conditions regarding startup and minimum water-to-fuel ratios when CT-2 operates at multiple loads.

This modification is related to the minor modification application submitted for the Keahole Generating Station combustion turbine generators, CT-4 and CT-5, under a separate cover letter dated December 10, 2015.

The enclosed minor modification application includes Forms S-1, S-7, and C-1. Certifications in accordance with HAR 11-60.1-4 are included on the enclosed Forms S-1 and C-1. Also enclosed is a check (number 534892) in the amount of $200.00 for the application fee for a minor modification.

If you have any questions regarding this submittal, please contact Karin Kimura at 543-4522 or karin.kimura@hawaiianelectric.com.

Sincerely,

Brenner Munger

tp

Enclosures: (1) Application for a Minor Modification to a Covered Source
(2) Check No. 534892

cc w/ Encl: **CERTIFIED MAIL RETURN RECEIPT REQUESTED**
Mr. Gerardo Rios [Article No.7014 1200 0002 3428 9148]
Chief, Permits Office
Air Division
U.S. EPA Region 9
75 Hawthorne Street
Mail Code: AIR-3
San Francisco, CA 94105

HAND DELIVERED

~~DEC 1 0 2015~~

File / Application No.:____________

S-1: Standard Air Pollution Control Permit Application Form

(Covered Source Permit and Noncovered Source Permit)

State of Hawaii
Department of Health
Environmental Management Division
Clean Air Branch
P. O. Box 3378 • Honolulu, HI 96801-3378 • Phone: (808) 586-4200

1. Company Name: Hawaii Electric Light Company, Inc. (Hawai'I Electric Light)

2. Facility Name (if different from the Company): Keahole Generating Station

3. Mailing Address: 73-4249 Pukiawe Street

   City: Kailua Kona State: HI Zip Code: 96740

   Phone Number: (808) 935-1711

4. Name of Owner/Owner's Agent: Brenner Munger (Owner's Agent)

   Title: Manager, Environmental Department Phone: (808) 543-4500

   Mailing Address: Hawaiian Electric Company; PO Box 2750

   City: Honolulu State: HI Zip Code: 96840-0001

5. Plant Site Manager/Other Contact: Norman Uchida

   Title: Interim Manager, Technical, Maintenance and Special Projects Phone: (808) 969-0422

   Mailing Address: P.O. Box 1027

   City: Hilo State: HI Zip Code: 96721-1027

6. Permit Application Basis: (Check appropriate boxes)

   ☐ Initial Permit for a New Source ☐ Initial Permit for an Existing Source

   ☐ Renewal of Existing Permit ☐ General Permit

   ☐ Temporary Source ☐ Transfer of Permit

   ■ Modification to a Covered Source: ➔ Is modification? ☐ Significant ■ Minor ☐ Uncertain

   ☐ Modification to a Noncovered Source

7. If renewal or modification, include existing permit number: CSP No. 0070-01-C

8. Does the Proposed Source require a County Special Management Area Permit? ☐ Yes ■ No

9. Type of Source (Check One): ☐ Covered Source ■ Covered & PSD Source

   ☐ Noncovered Source ☐ Uncertain

10. Standard Industrial Classification Code (SICC), if known: 4911

11. Proposed Equipment/Plant Location (e.g. street address): 73-4249 Pukiawe Street

City: Kailua Kona State: HI Zip Code: 96740

UTM Coordinates (meters): East: 811,293 North: 2,184,955

UTM Zone: 4 UTM Horizontal Datum: ■ Old Hawaiian ☐ NAD-27 ☐ NAD-83

12. General Nature of Business: Electrical Generation

13. Date of Planned Commencement of Installation or Modification: Upon approval of modification.

14. Is *any* of the equipment to be leased to another individual or entity? ☐ Yes ■ No

15. Type of Organization: ■ Corporation ☐ Individual Owner ☐ Partnership

☐ Government Agency (Government Facility Code: ______)

☐ Other: ______

Any applicant for a permit who fails to submit any relevant facts or who has submitted incorrect information in any permit application shall, upon becoming aware of such failure or incorrect submittal, promptly submit such supplementary facts or corrected information. In addition, an applicant shall provide additional information as necessary to address any requirements that become applicable to the source after the date it filed a complete application, but prior to the issuance of the noncovered source permit or release of a draft covered source permit. (HAR § 11-60.1-64 & 11-60.1-84)

RESPONSIBLE OFFICIAL (as defined in §11-60.1-1):

Name (Last): Uchida (First): Norman (MI): M.

Title: Interim Manager, Technical, Maintenance and Special Projects Phone: (808) 969-0422

Mailing Address: P.O. Box 1027

City: Hilo State: HI Zip Code: 96721-1027

CERTIFICATION by Responsible Official (pursuant to §11-60.1-4):

I certify that I have knowledge of the facts herein set forth, that the same are true, accurate and complete to the best of my knowledge and belief, and that all information not identified by me as confidential in nature shall be treated by the Department of Health as public record. I further state that I will assume responsibility for the construction, modification, or operation of the source in accordance with the Hawaii Administrative Rules (HAR), Title 11, Chapter 60.1, Air Pollution Control, and any permit issued thereof.

NAME (Print/Type): Norman M. Uchida

(Signature): Norman Uchida Date: 12/8/15

FOR AGENCY USE ONLY:

File/Application No: ______

Island: ______

Date Received: ______

Submit the following documents as part of your application:

A. The ***Emissions Units Table***, filled in as completely as possible. Use separate sheets of paper as needed. General instructions include the following:

1. Identify each **emission point** with a unique number for this plant site, consistent with emission point identification used on the location drawing and previous permits; if known, provide the SICC number. Emission points shall be identified and described in sufficient detail to establish the basis for **fees** and applicability of requirements of HAR, Chapter 11-60.1. Examples of emission point names are: heater, vent, boiler, tank, baghouse, fugitive, etc. Abbreviations may be used.
   a. For each emission point use as many lines as necessary to list regulated and hazardous air pollutant data. For hazardous air pollutants, also list the Chemical Abstracts Service number (CAS#).
   b. Indicate the emission points that discharge together for any length of time.
   c. The **Equipment Date** is the date of equipment construction, reconstruction, or modification. Provide supporting documentation.

2. State the **maximum emission rates** in terms sufficient to establish compliance with the applicable requirements and standard reference test methods. Provide all supporting emission calculations and assumptions:
   a. Include all regulated and hazardous air pollutants and air pollutants for which the source is major, as defined in HAR §11-60.1-1. Examples of regulated pollutant names are: Carbon Monoxide (CO), Nitrogen Oxides (NO_X), Sulfur Dioxide (SO_2), Volatile Organic Compounds (VOC), particulate matter (PM), and particulate less than 10 microns (PM_{10}). Abbreviations may be used.
   b. Include fugitive emissions.
   c. **Pounds per hour (#/HR)** is the maximum potential emission rate expected by applicant.
   Tons per year is the annual maximum potential emissions expected by the applicant, taking into account the typical operating schedule.

3. Describe ***Stack Source Parameters***:
   a. **Stack Height** is the height above the ground.
   b. **Direction** refers to the exit direction of stack emissions: up, down or horizontal.
   c. **Flow Rate** is the actual, not the calculated, flow rate.

4. Provide any additional information, if applicable, as follows:
   a. If combinations of different fuels are used that cause any of the stack source parameters to differ, complete one row for each possible set of stack parameters and identify each fuel in the **Equipment Description.**
   b. For a rectangular stack, indicate the length and width.
   c. Provide any information on stack parameters or any stack height limitations developed pursuant to Section 123 of the Clean Air Act.

B. A **process flow diagram** identifying all equipment used in the process, including the following:
   1. Identify and describe each emission point.
   2. Identify the locations of safety valves, bypasses, and other such devices which when activated may release air pollutants to the atmosphere.

C. A **facility location map**, drawn to a reasonable scale and showing the following:
   1. The property involved and all structures on it. Identify property/fence lines plainly.
   2. Layout of the facility.
   3. Location and identification of the proposed emissions unit on the property.
   4. Location of the property and equipment with respect to streets and all adjacent property. Show the location of all structures within 325 meters of the applicant's emissions unit. Provide the building dimensions (height, length, and width) of all structures that have heights greater than 40% of the stack height of the emissions unit.

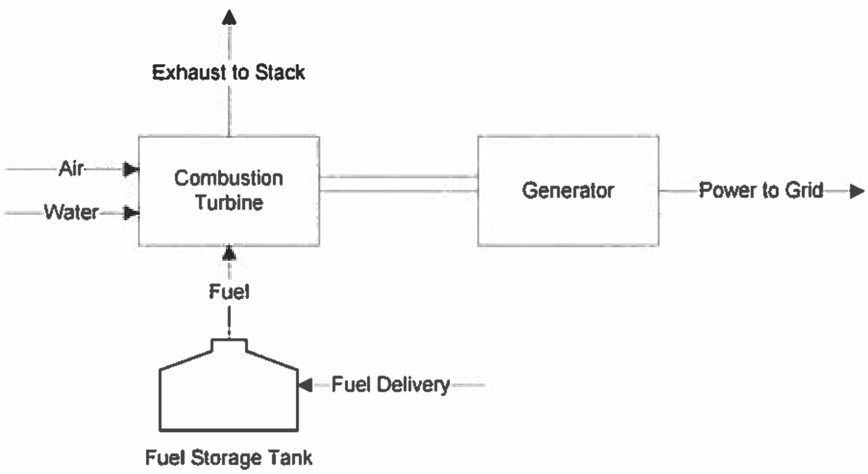
D. Provide a description of any proposed modifications or permit revisions. Include any justification or supporting information for the proposed modifications or permit revisions.

Attachment S-1a
Responses to Emission Unit Table Instructions for Form S-1

A.1. Emission Point Identification and Description	
A.2. Maximum Emission Rates	
A.3. Stack Parameters	
A.4. Additional Information	
B. Process Flow Diagram	Refer to Figure S-1.1.
C. Facility Location Map	
D. Proposed Revisions	Refer to Form S-7.

FIGURE S-1.1

PROCESS FLOW DIAGRAM FOR UNITS CT-2



File No.: ________

S-7: Application for a Minor Modification to a Covered Source

In providing the required information, reference the corresponding letters and numbers listed below.

Provide a minimum of **two (2)** sets (1 original and 1 copy) of all application materials to the Hawaii Department of Health. Also, mail **one (1)** set directly to EPA at the following address:

Chief (Attention: AIR-3)
Permits Office, Air Division
U.S. Environmental Protection Agency
Region 9
75 Hawthorne Street
San Francisco, CA 94105

I. In accordance with Hawaii Administrative Rules (HAR) §11-60.1-104, the following information is required:

A. A clear description of all changes.

Hawai'i Electric Light proposes modifications to CSP No. 0070-01-C for combustion turbine generator, CT-2 which are included in Attachment S-7a. These proposed modifications are related to modifications proposed to CSP No. 0007-01-C for combustion turbine generators, CT-4 and CT-5 submitted to the Department under a separate cover letter and minor modification application.

B. A statement of why the modification is determined to be minor, and a request that minor modification procedures be used.

The proposed modifications for units, CT-2, CT-4, and CT-5 meet the criteria in the definition of "minor modification" as defined in HAR § 11-60.1-81. The proposed modifications:

(1) Do not increase the emissions of any air pollutant above the permitted emission limits;

(2) Do not result in or increase the emissions of any air pollutant not limited by permit levels equal to or above: (A) 500 pounds per year of a hazardous air pollutant; (B) 300 pounds of lead; (C) twenty-five percent of significant amounts of emission as defined in section 11-60.1-1, paragraph (1) in the definition of "significant"; or (D) two tons per year of each regulated air pollutant not already identified above (refer to Attachment S-7a for emissions calculations);

(3) Do not violate any applicable requirement;

(4) Do not involve significant changes to existing monitoring requirements or any relaxation or significant change to existing reporting or recordkeeping requirements in the permit.

(5) Do not require or change a case-by-case determination, a source-specific determination for temporary sources for ambient impacts, or a visibility or increment analysis;

(6) Do 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; and

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

C. Cite and describe any new applicable requirements as defined in HAR § 11-60.1-81 that will apply if the minor modification occurs.

No new applicable requirements will apply to the proposed minor modifications.

D. The suggested changes to permit terms or conditions.

Not applicable.

E. Certification by a responsible official that the proposed modification meets the criteria for minor modification.

Form S-1 contains the responsible official's signature certifying that the modifications are minor.

F. All information submitted with the application for the Initial Covered Source Permit or any subsequent application for a Covered Source Permit. The owner or operator may reference information contained in a previous application submittal, provided such referenced information has been certified as being current and still applicable.

References are made herein to pertinent information in previously submitted materials.

G. Other information, as required by any applicable requirement or as requested and deemed necessary by the Director of Health (hereafter, Director) to make a decision on the application.

Not applicable.

II. Submit an application fee according to the Application Fees Schedule in the Instructions for Applying for an Air Pollution Control Permit.

III. An application shall be determined to be complete only when all of the following have been complied with:

A. All information required or requested in number I have been submitted.

B. All documents requiring certification have been certified pursuant to HAR § 11-60.1-4.

C. All applicable fees have been submitted.

D. The Director has certified that the application is complete.

IV. The Director shall not continue to act upon or consider an incomplete application.

A. The applicant shall be notified in writing whether the application is complete. Unless the Director requests additional information or notifies the applicant of incompleteness within thirty days of receipt of an application, the application shall be deemed complete.

B. During the processing of an application that has been determined or deemed complete, if the Director determines that additional information is necessary to evaluate or take final action on the application, the Director may request such information in writing and set a reasonable deadline for a response.

V. Within ninety days of receipt of a complete application for a minor modification, or upon program approval, within fifteen days after the end of the Administrator's forty-five-day review period, whichever is later, the Director in writing shall:

A. Amend the permit to reflect the minor modification as proposed.

B. Deny the minor modification.

C. Determine that the requested modification does not meet the minor modification criteria, and should be reviewed under the significant modification process; or

D. Upon program approval, amend the proposed permit and resubmit the amendment to EPA for reevaluation.

VI. An application for minor modification to a covered source shall be approved only if the Director determines that the minor modification will be in compliance with all applicable requirements.

VII. The Director shall provide a statement that sets forth the legal and factual bases for the proposed permit conditions (including references to the applicable statutory or regulatory provisions) to EPA and any other person requesting it.

VIII. Each application and proposed permit reflecting the minor modification to a covered source shall be subject to EPA oversight in accordance with HAR § 11-60.1-95.

Attachment S-7a

Requested Changes to CSP No. 0070-01-C

Proposed change to Attachment II, Special Condition No. A.1.:

This permit encompasses the following equipment and associated appurtenances:

Unit No.	Description
CT-2	One (1) 18 MW (nominal) (18.3 MW peak load) Simple Cycle Combustion Turbine Generator, model Jupiter GT-35 (manufactured by Asea Brown Boveri (ABB) and supplied by Solar Turbines) with a maximum design heat input rate of 198 MMBtu/hr.

Justification – The requested change updates the equipment description to include the maximum peak load rating for the combustion turbine generator.

Proposed change to Attachment II, Special Condition No. C.1.:

The ~~"start-up"~~ startup sequence ~~time~~ for ~~Unit~~ CT-2 shall ~~not exceed~~ be a twenty (20) minutes period starting at the time fuel use at CT-2 begins. ~~A "start-up" sequence shall be from the time fuel use at Unit CT-2 commences, until the time Unit CT-2 is initially brought up to~~ Upon completion of the twenty (20) minute startup sequence, CT-2 shall be at 25~~%~~ percent of peak load (4.6 MW) or more and the water injection system shall be operational except as provided in Attachment II, Special Condition No. C.3. ~~at which time the operation of the air pollution control equipment shall commence.~~

Justification –The requested changes are needed to clarify peak load and the description of the startup sequence to allow stabilization of the water injection system following initiation of the system.

Proposed change to Attachment II, Special Condition No. C.2.:

The ~~"shut-down" time~~ shutdown sequence for ~~Unit~~ CT-2 shall not exceed twenty (20) minutes. A ~~"shut-down"~~ shutdown sequence shall be ~~considered~~ from the time ~~when Unit CT-2~~ the combustion turbine controls stop signal is initiated for the combustion turbine generator and the combustion turbine generator is below 25~~%~~ percent of peak load (4.6 MW) until fuel use at ~~Unit CT-2~~ combustion turbine generator ceases.

Justification – The requested change is needed to clarify peak load and the description of the shutdown sequence..

Proposed change to Attachment II, Special Condition No. C.3. Minimum Operational Loads:

~~Except during Unit CT-2's "start-up" and "shut-down," maintenance, or testing., Unit CT-2's load shall not be less than 25% of the rated capacity~~. The operation of the combustion turbine generators, CT-2, CT-4, and CT-5, below 25 percent of peak load with water injection shall not exceed a combined total of 66 hours in any rolling 12 month period, except during startup and shutdown sequences, maintenance, testing, and as approved pursuant to Attachment IIA, Special Condition C.8.a.

Justification – The requested change is needed to clarify peak load and allow the operation of CT-2 below 25 percent of peak load with water injection to address system frequency issues.

Based on the emission limits for CT-2, CT-4, and CT-5 as specified in CSP Nos. 0070-01-C and 0007-01-C and source performance test data, load reduction has the following impacts on the CT emission factors:

- The SO_2 emission factor is directly proportional to fuel sulfur content. Thus, the SO_2 emission factor remains constant.
- The lead, fluorides, and H_2SO_4 emission factors are dependent on fuel type. Thus, these emission factors remain constant.
- The NO_X emission factor decreases with decreasing load.
- The CO, VOC, PM, PM_{10}, and $PM_{2.5}$ emission factors increase with decreasing load.

Since SO_2, NO_X, lead, fluorides, and H_2SO_4 emissions decrease with decreasing load, emission rates below 25% of peak load (6.165 MW) are not needed. Worst-case emissions will occur when the CTs are operating at peak load. Thus, project SO_2, NO_X, lead, fluorides, and H_2SO_4 emissions are based on CT-2, CT-4, and CT-5 operating at peak load. Since emission rates for NO_X, lead and fluorides are higher for CT-4 and CT-5 at peak load than CT-2 at peak load, project emission rates for NO_X, lead, and fluorides are based on CT-4 and CT-5 emission rates.

Based on comparison of the permitted emission rates for CO, VOC, and PM/PM_{10} and source test data for CT-2, CT-4, and CT-5, the permitted emission rates for these pollutants at 25% of peak load are conservative; refer to Figures 4 through 16. Thus, project CO, VOC, and PM/PM_{10} are based on the CTs operating at 25% of peak load and $PM_{2.5}$ emissions are based on PM/PM_{10} emissions. Since emission rates for CO and VOC are higher for CT-4 and CT-5 at 25% of peak load than CT-2 at 25% of peak load, emission rates for CO and VOC are based on CT-4 and CT-5 emission rates.

Table 1 summarizes the project emissions based on a maximum operation of 66 hours per rolling 12-month period at loads less than 25% of peak load with water injection and shows that the project qualifies as a minor modification because the project emissions are below levels specified in HAR §11-60.1-81. GHG emission calculations are provided in Table 2.

Based on the project emissions calculations, the proposed modification will not trigger 40 CFR Subpart KKKK – Standards of Performance for Stationary Combustion Turbines (NSPS Subpart KKKK) based on the following reasons:

- Operation below 25% of peak load with water injection will not increase the SO_2 or NO_X emission rates. Both SO_2 and NO_X emission rates decrease with decreasing load.
- Operation of the combustion turbine generators below 25% of peak load with water injection will not require any capital expenditure. The combustion turbine generators are already capable of operating below 25% of peak load with water injection; i.e., components of the combustion turbine generators will not require replacement as part of this proposed modification. Thus, this proposed modification will not be considered reconstruction as provided in 40 CFR §60.15.

Table 1 – Project Emissions Calculations

Pollutant		CT2, CT4, CT5 Operation Below 25% of Peak Load with Water Injection Project Emissions[1] (lb/hr per CT)	(tpy total)	Significant Level[2] (tpy)	Significant Modification Required (Yes/No)
CO [3]		475.6	15.69	25	No
NO_X [3]		42.3	1.40	10	No
SO_2		110.0	3.63	10	No
PM [4]		22.4	0.74	6.25	No
PM_{10} [4]		22.4	0.74	3.75	No
$PM_{2.5}$ [4, 5, 6]	$PM_{2.5}$	22.4	0.74	2.5	No
	SO_2	110	3.63	10	
	NO_X	42.3	1.40	10	
O_3 [7]	NO_X	42.3	1.40	10	No
	VOC[3]	297.60	9.82	10	
Lead[3]		3.85E-03	1.27E-04	0.15	No
Fluorides[3]		2.77E-03	9.14E-05	2	No
Sulfuric Acid Mist (H_2SO_4)		14.4	0.475	2	No
CO_2e			1,485	10,000	No

Notes:

1. Project tpy values based on 66 hrs/yr.
2. Minor modification significant levels from HAR §11-60.1-81.
3. Emission rates for CO, NO_X, VOC, lead, and fluorides based on CT4 and CT5 emission rates.
4. PM emission rate based on PM limit for CT2.
5. $PM_{2.5}$ emissions and PM_{10} emissions shall include gaseous emissions from a source or activity which condense to form particulate matter at ambient temperatures (40 CFR §52.21(b)(50)(i)(a) and HAR §11-60.1-1).
6. In addition to the 2.5 tpy significant level for direct $PM_{2.5}$ emissions, the project is significant for $PM_{2.5}$ if SO_2 or NO_X emissions exceed 10 tpy (HAR §11-60.1-1 and §11-60.1-81).
7. The project is significant for O_3 if NO_X or VOC emissions exceed 40 tpy (40 CFR §52.21(b)(23)(i) and HAR §11-60.1-1).

Table 2 – GHG Emissions Calculations

Units	Heat Input (MMBtu/yr)	GHG Pollutant[1]	Emission Factor[2] (kg/MMBtu)	Global Warming Potential[3]	GHG Emissions CO_2e (tpy)
CT2, CT3, or CT5	18,150	CO_2	73.96	1	1,479.7
		N_2O	6.0E-04	298	3.58E+00
		CH_4	3.0E-03	25	1.50E+00
				Total CO_2e =	**1,484.8**

Notes:

1. Greenhouse Gas (GHG) pollutants from the Mandatory Greenhouse Gas Reporting rule (40 CFR §98.32).
2. Emission factors from the Mandatory Greenhouse Gas Reporting rule (40 CFR §98, Tables C-1 and C-2).
3. Global Warming Potentials from the Mandatory Greenhouse Gas Reporting rule (40 CFR §98, Table A-1).
4. Project tpy values based on 66 hrs/yr and heat input at peak load for CT4 or CT5; CT2 heat input at peak load is less than heat input of CT4 and CT5 at peak load.

Figure 1 – Relationship Between NO_X Emission Factor and Load (CT4, CT5)

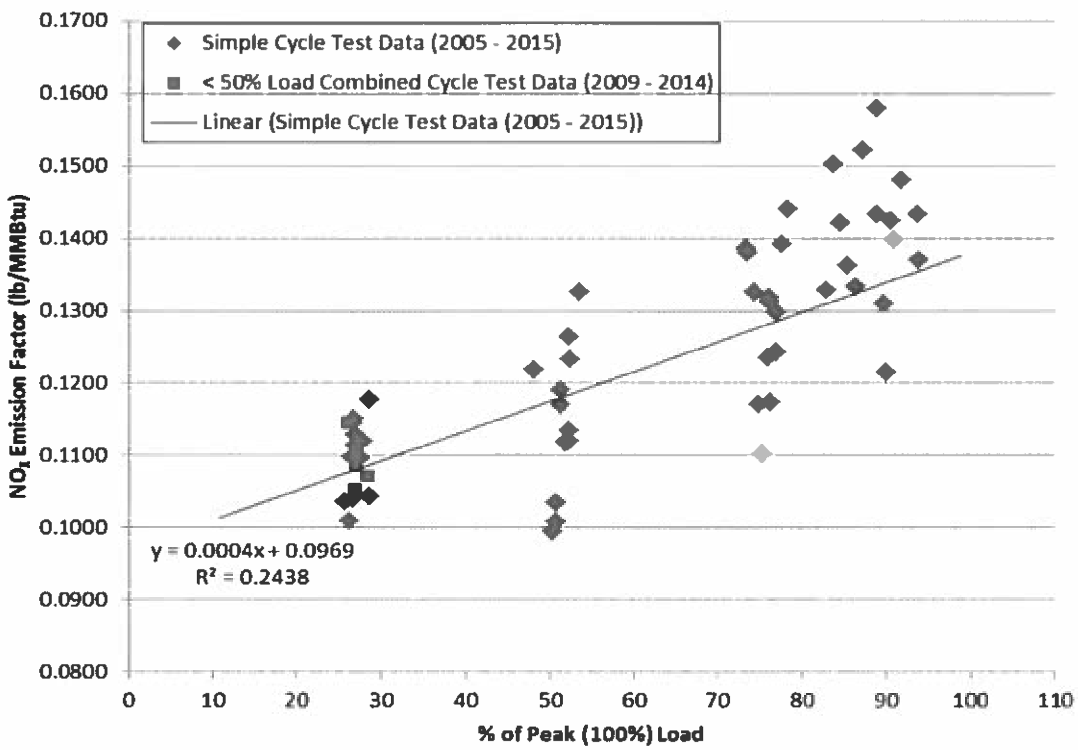


Figure 2 – Comparison of NO_X Source Test Data and NO_X Emission Limits (CT4, CT5)

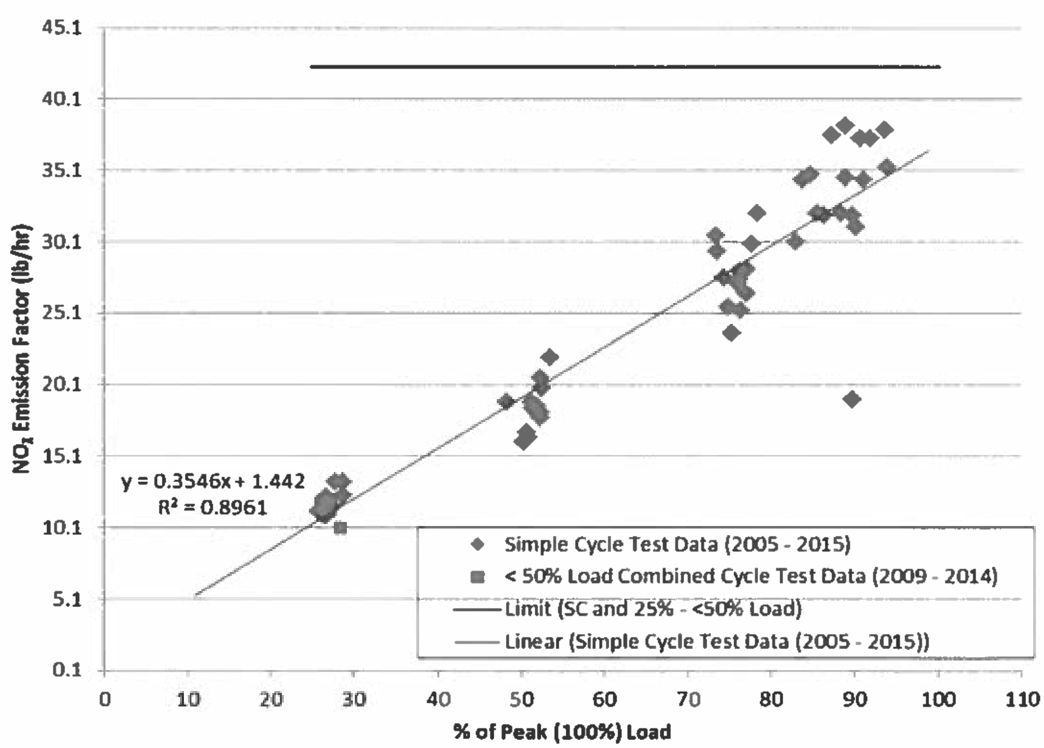


Figure 3 – Relationship Between NO_X Emission Factor and Load (CT2)

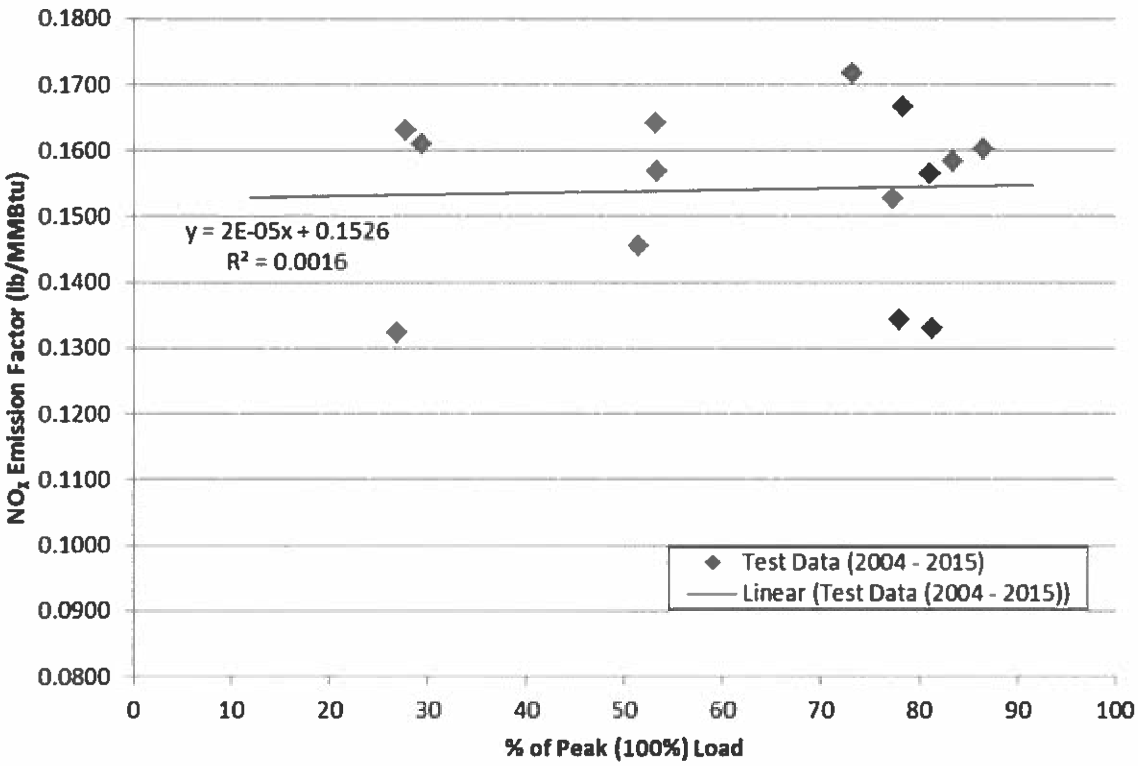


Figure 4 – Comparison of NO_X Source Test Data and NO_X Emission Limits (CT2)

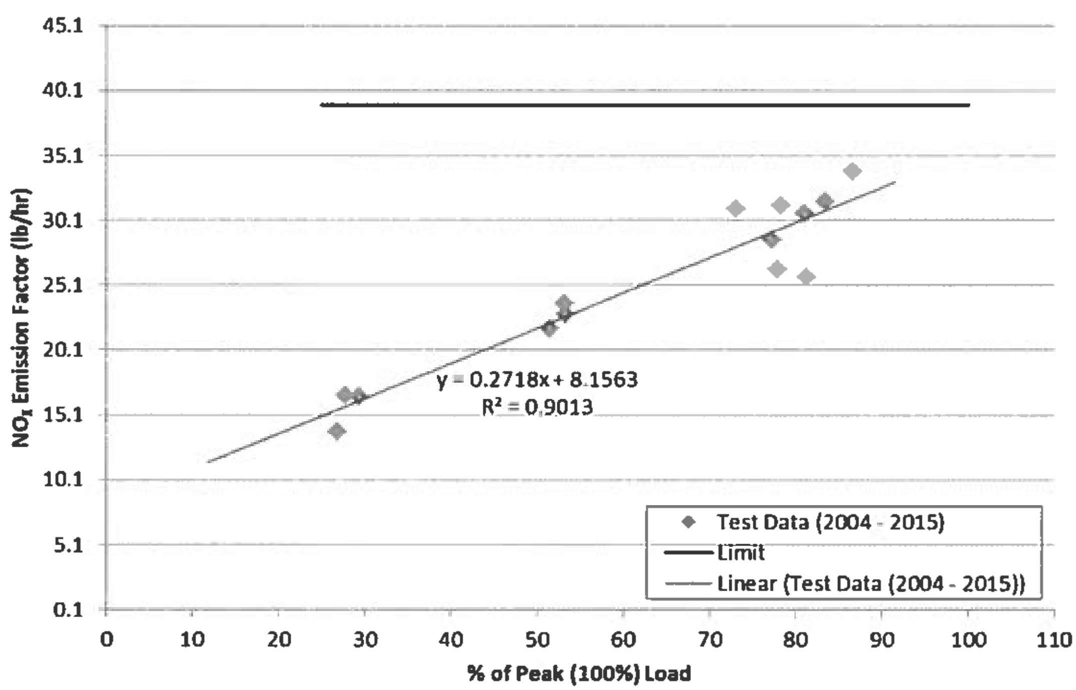


Figure 5 – Relationship Between CO Emission Factor and Load (CT4, CT5)

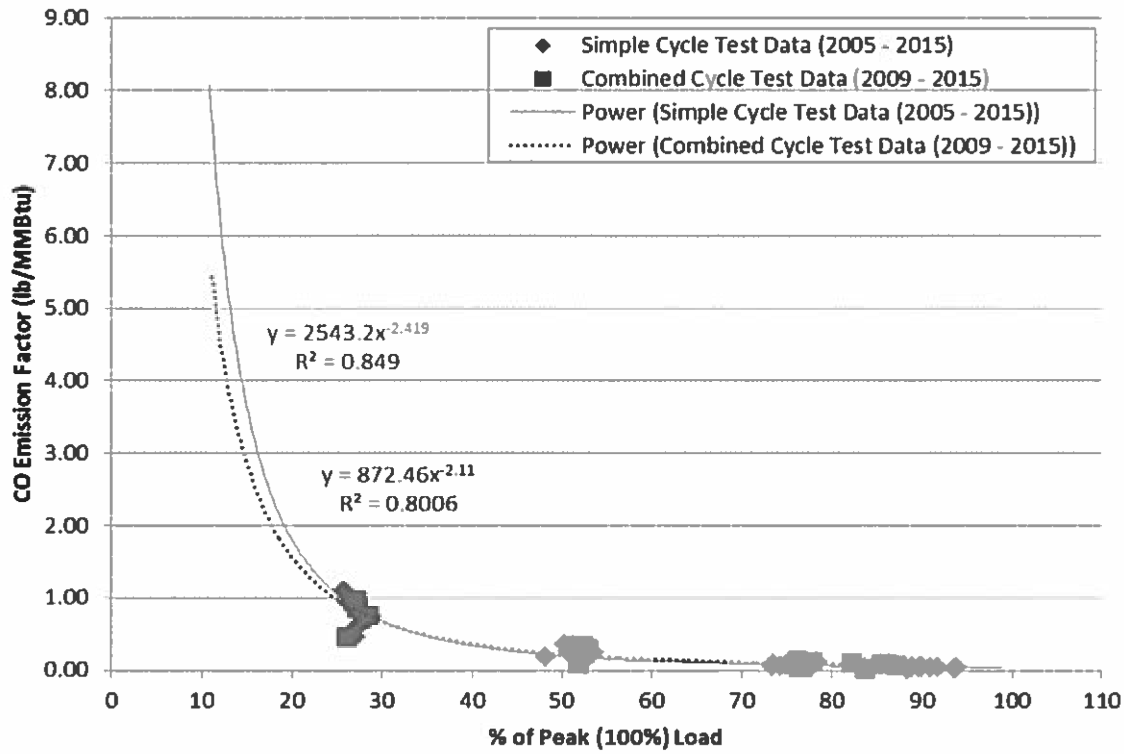


Figure 6 – Comparison of CO Source Test Data and CO Emission Limits (CT4, CT5)

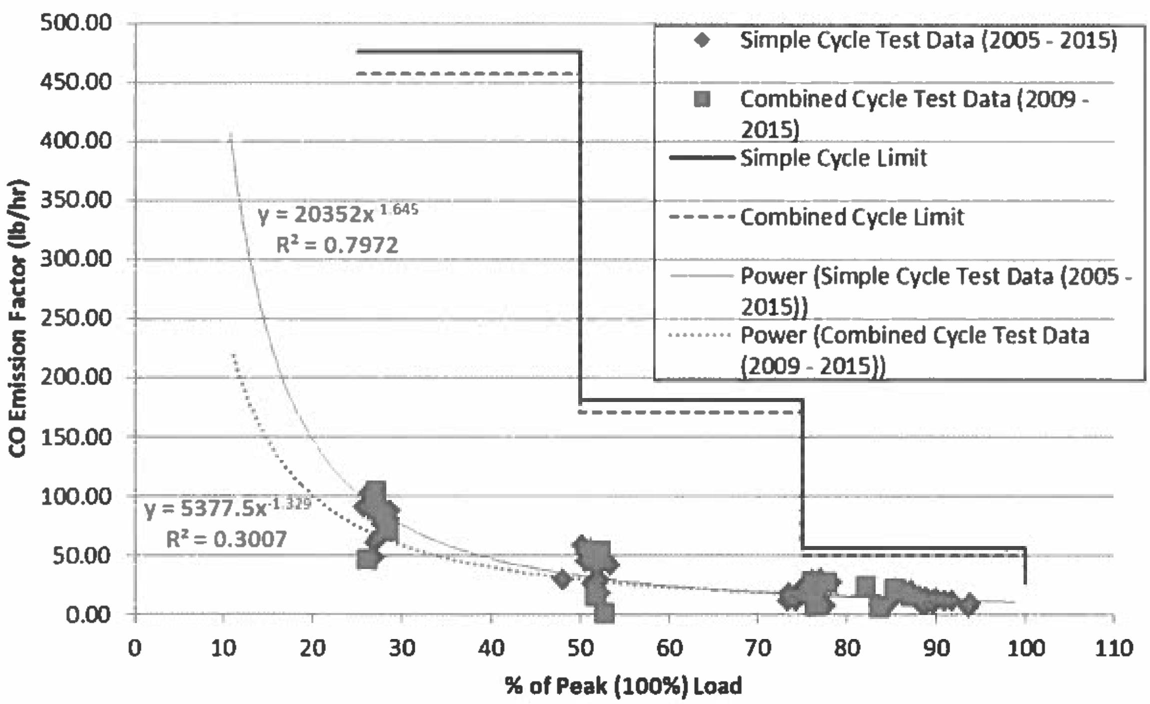


Figure 7 – Relationship Between CO Emission Factor and Load (CT2)

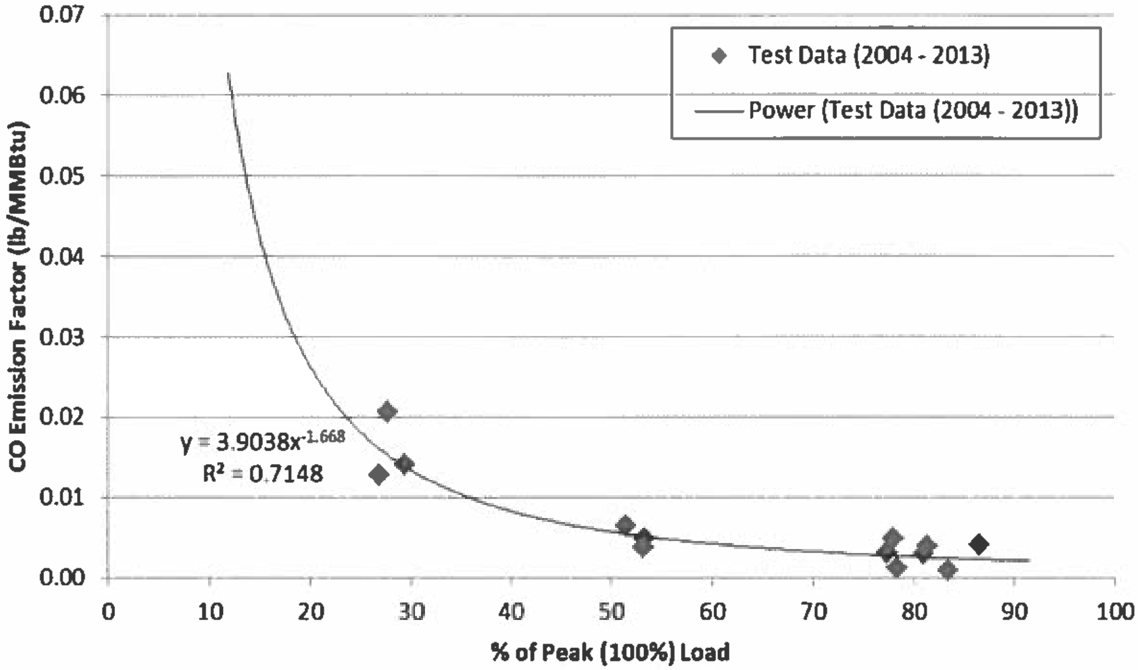


Figure 8 – Comparison of CO Source Test Data and CO Emission Limits (CT2)

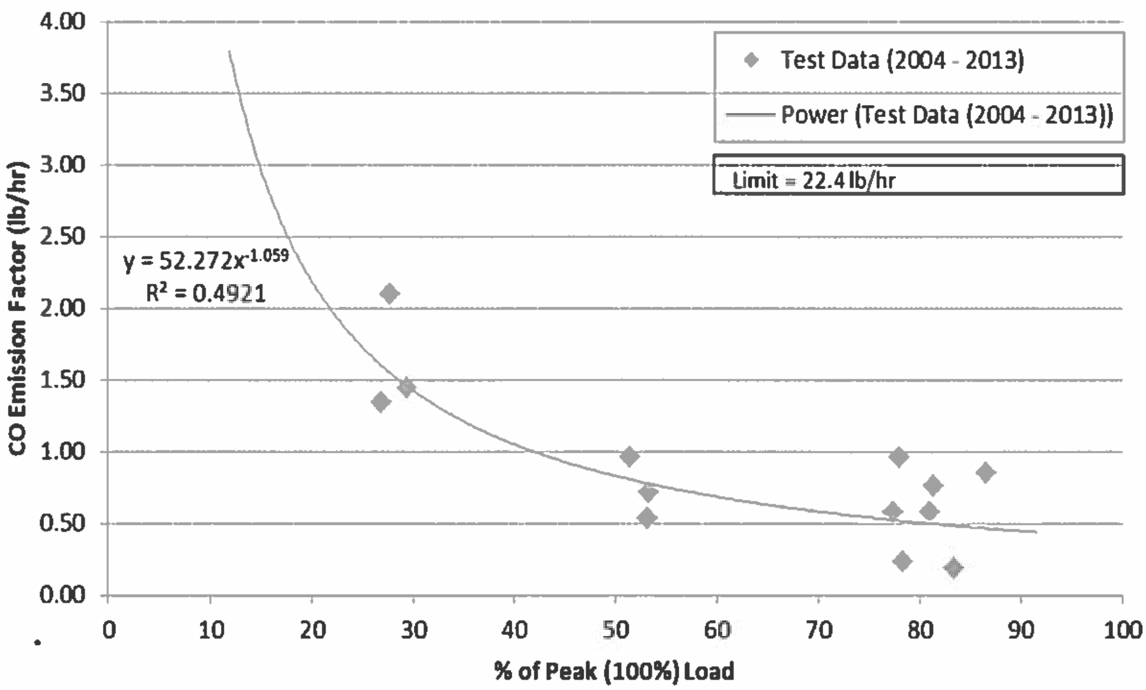


Figure 9 – Relationship Between VOC Emission Factor and Load (CT4, CT5)

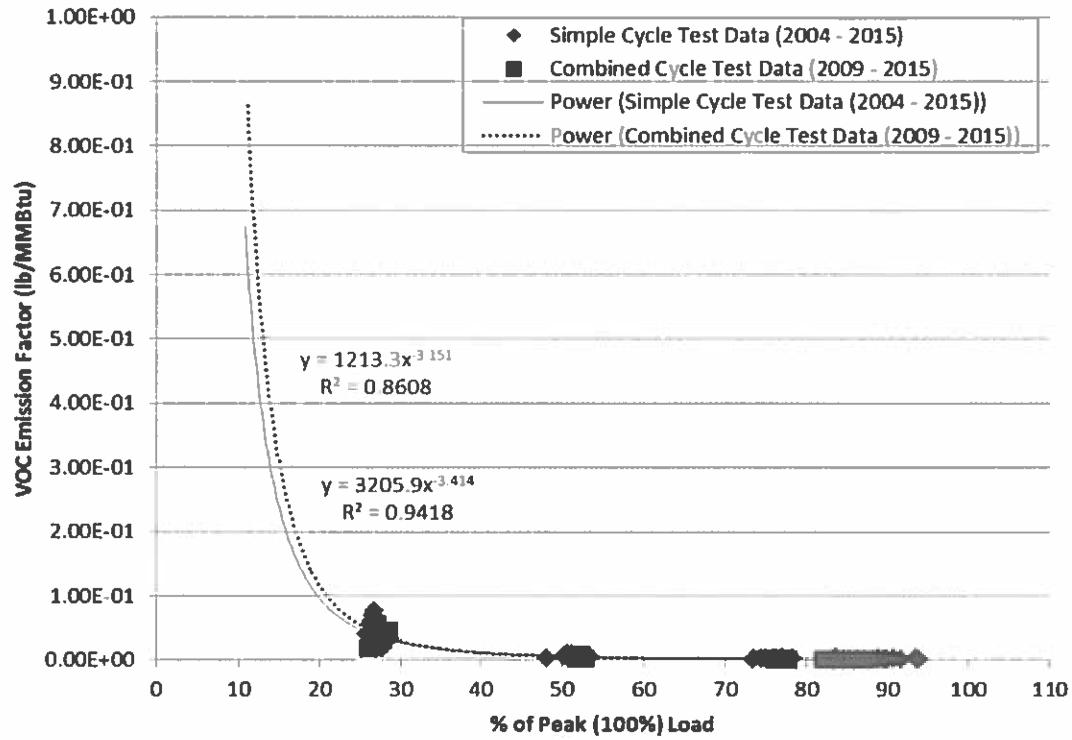


Figure 10 – Comparison of VOC Source Test Data and VOC Emission Limits (CT4, CT5)

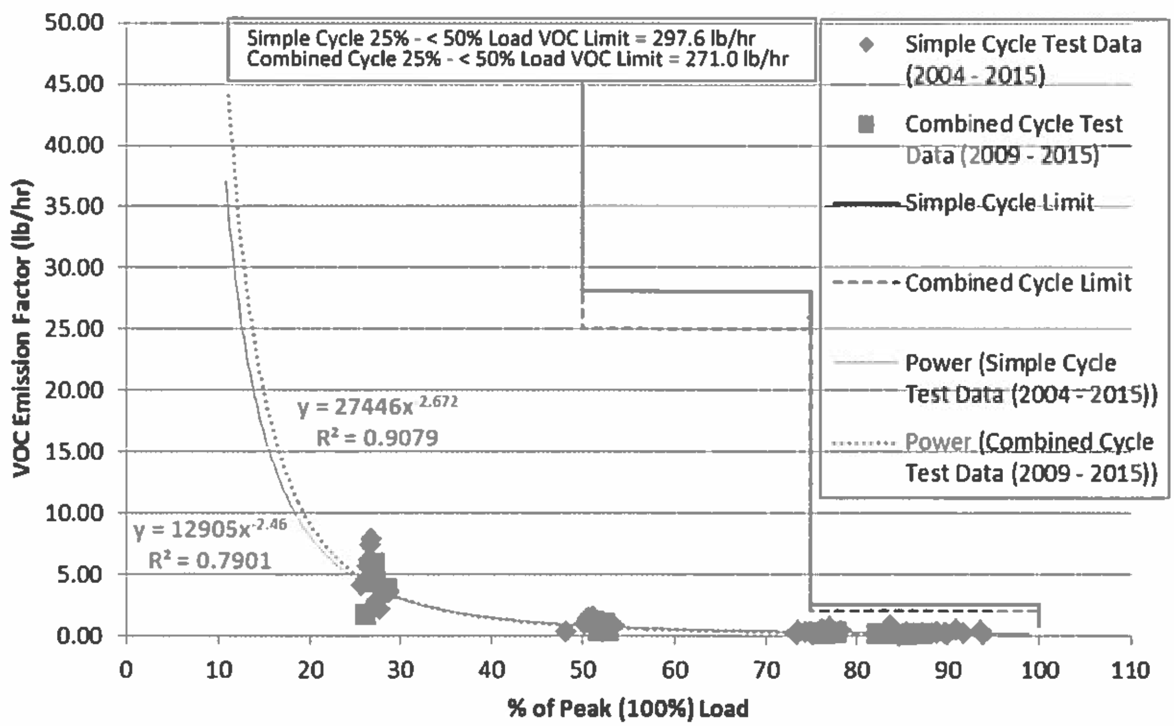


Figure 11 – Relationship Between VOC Emission Factor and Load (CT2)

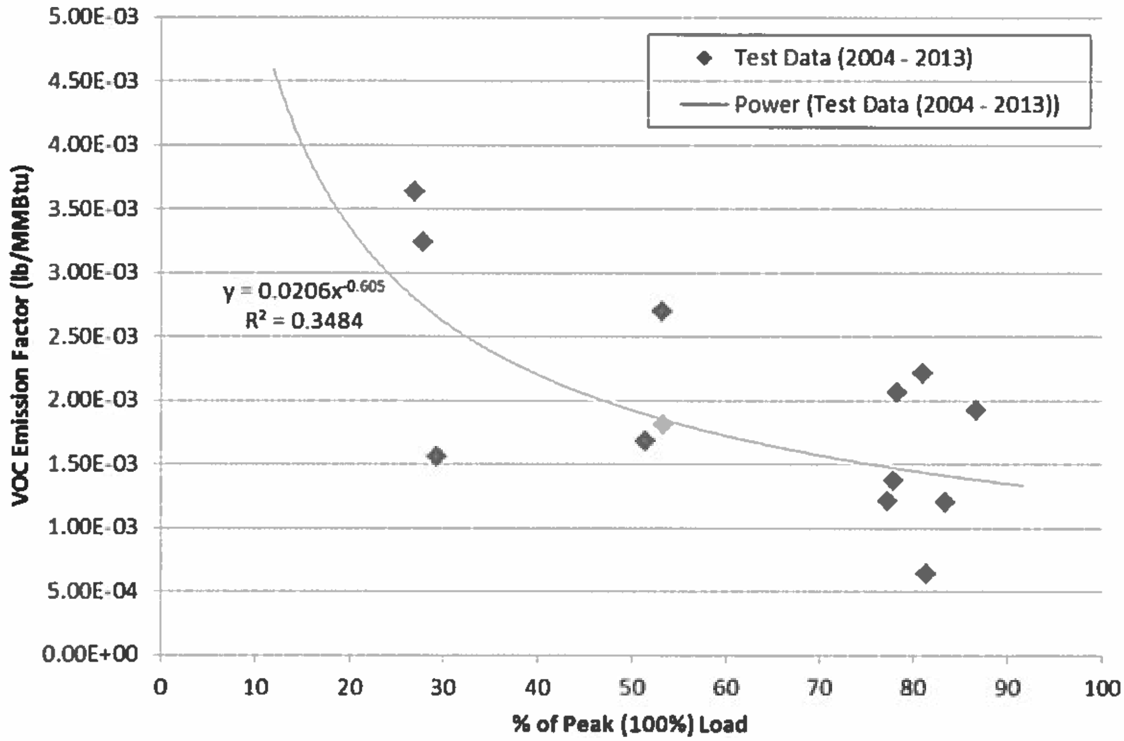


Figure 12 – Comparison of VOC Source Test Data and VOC Emission Limits (CT2)

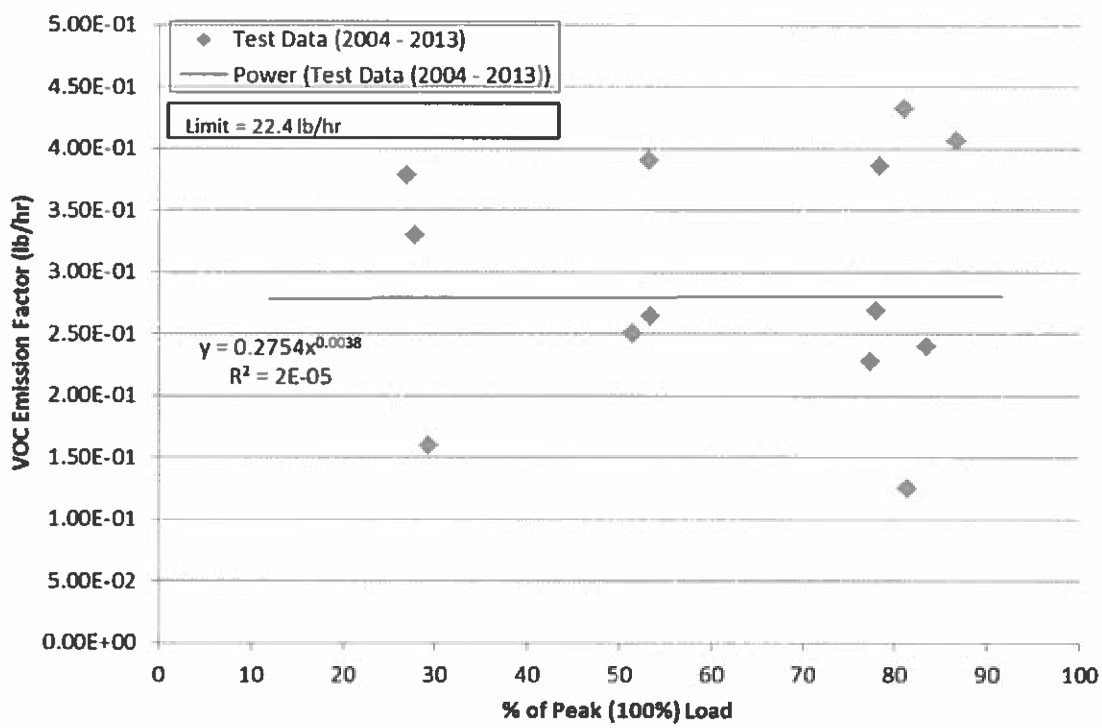


Figure 13 – Relationship Between PM Emission Factor and Load (CT4, CT5)

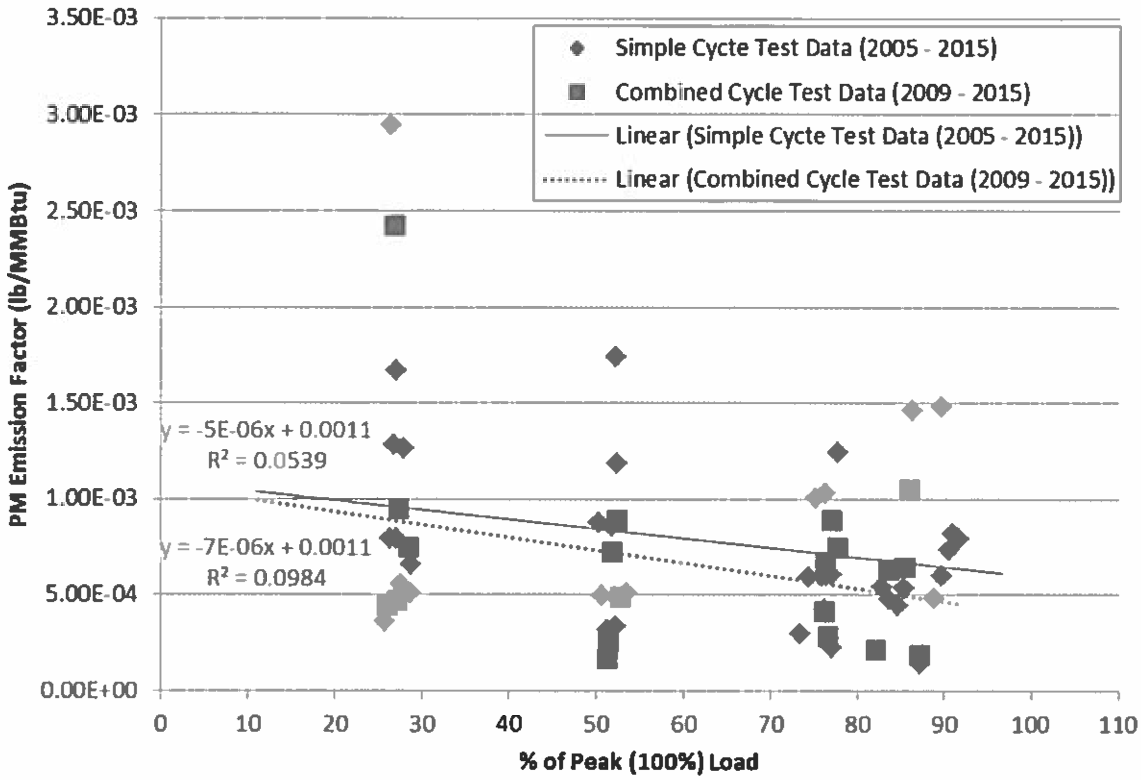


Figure 14 – Comparison of PM Source Test Data and PM Emission Limits (CT4, CT5)

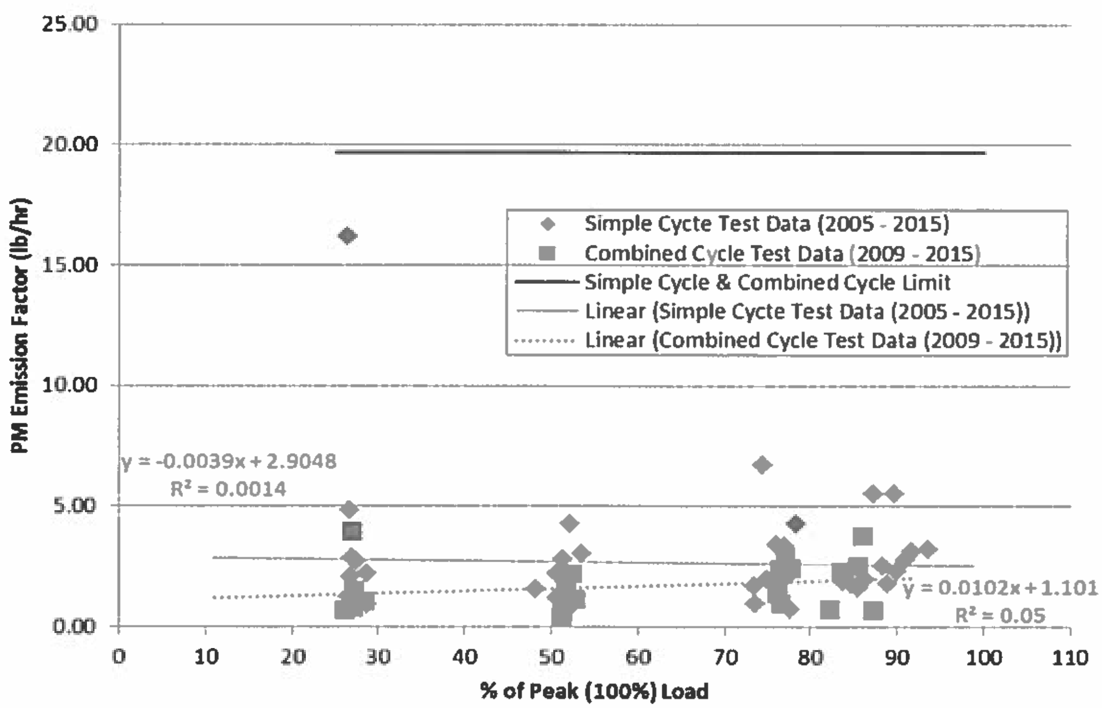


Figure 15 – Relationship Between PM Emission Factor and Load (CT2)

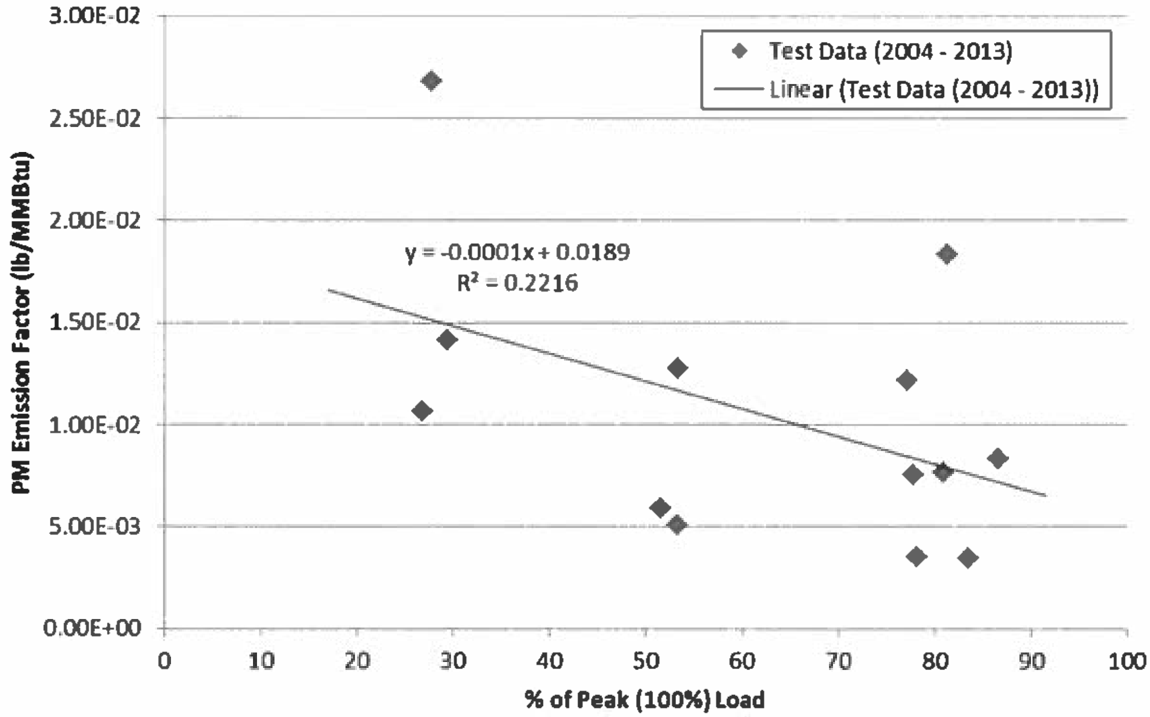
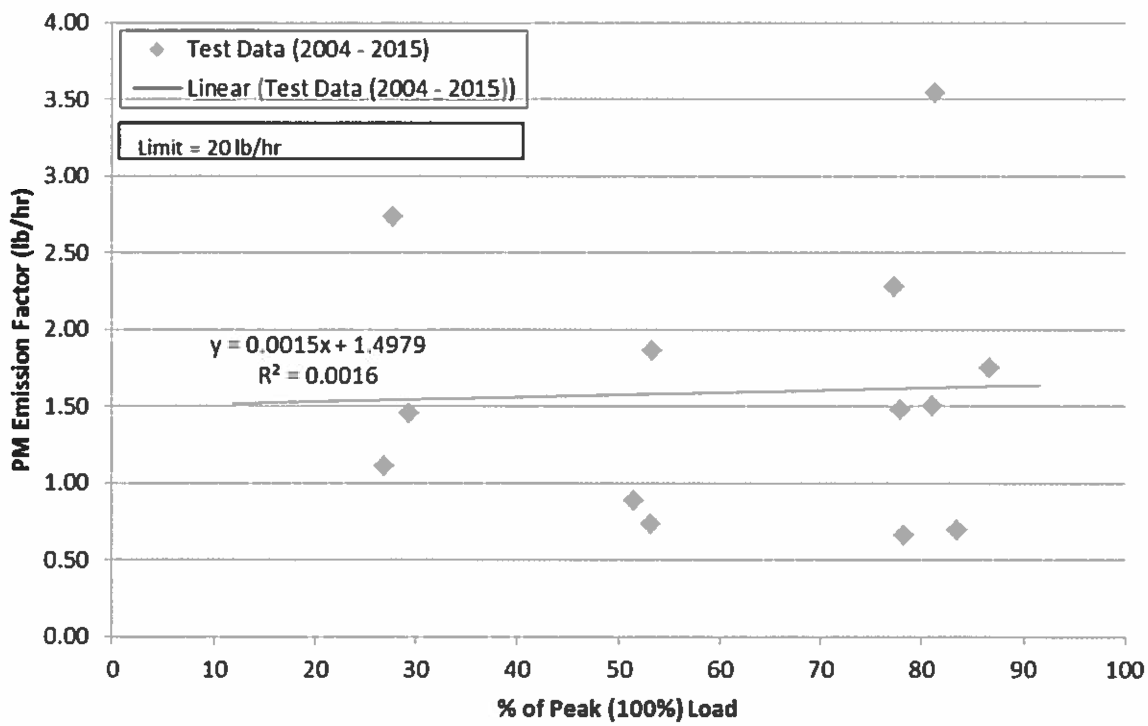


Figure 16 – Comparison of PM Source Test Data and PM Emission Limits (CT2)



Proposed change to Attachment II, Special Condition No. C.4. Air Pollution Control Equipment:

a. The permittee shall continuously operate and maintain ~~a combustor~~ water injection system to meet the emission limits as specified for nitrogen oxides (NO_X) in Attachment II, Special Condition C.6.a. ~~of this Covered Source Permit.~~ Water injection shall be initiated during the startup sequence of the combustion turbine generator and may be terminated at the beginning of or during the shutdown sequence of the combustion turbine generator.

b. ~~The operation of the combustor water injection system shall commence operation within twenty (20) minutes of start-up of Unit CT-2, and shall continue to operate within twenty (20) minutes of shutdown of Unit CT-2. The combustor water injection system shall be used whenever Unit CT-2 is operating at 25% peakload and above, and shall be maintained at a minimum water-to-fuel mass ratio as follows:~~ After completion of the startup sequence of the combustion turbine generator and until the beginning of the shutdown sequence of the combustion turbine generator, the following water-to-fuel mass ratio, on a one (1) hour average basis, shall be maintained when the combustion turbine generator is firing fuel oil No. 2:

WATER INJECTION SYSTEM
MINIMUM WATER INJECTION RATES BASED ON LOAD

Percent Peak load	Load (MW)	Ratio (lb-water/lb-fuel)
100	18.3	1.00
75 - < 100	13.7 - < 18.3	0.75
50 - < 75	9.15 - < 13.7	0.55
~~25-~~ < 50	~~4.6-~~ < 9.15	0.3

For operating periods during which the combustion turbine generator operates at multiple loads where multiple water-to-fuel mass ratios apply, the applicable water-to-fuel mass ratio shall be determined based on the load that corresponded to the lowest minimum water-to-fuel mass ratio.

c. [No changes proposed]

d. [No changes proposed]

Justification – The requested changes are to: 1) clarify the method of determining the applicable minimum water-to-fuel mass ratio for operating hours during which multiple minimum water-to-fuel mass ratios apply; and 2) revise the water injection system table to address operation of the combustion turbine generator below 25 percent of peak load with water injection.

Proposed change to Attachment II, Special Condition No. C.6.:

Maximum Emission Limits

a. Except for Unit CT-2's ~~"start-up"~~ startup and ~~"shut-down"~~ shutdown sequences, the permittee shall not discharge or cause the discharge into the atmosphere from Unit CT-2, nitrogen oxides, sulfur dioxide, particulate matter/PM_{10}, carbon monoxide, and volatile organic compounds in excess of the following specified limits ~~as noted below~~:

[No changes proposed for emission limits table]

~~For the purposes of the annual performance tests and the continuous monitoring system, emissions limits shall be measured on a rolling three (3) hour average.~~ The three-hour averaging period shall begin immediately upon completion of the combustion turbine generator's startup sequence and end immediately prior to the combustion turbine generator's shutdown sequence.

b. The Department of Health, with U.S. EPA's concurrence, may lower the allowable emission limitation for nitrogen oxides, sulfur dioxide, particulate matter/PM_{10}, carbon monoxide, volatile organic compounds after reviewing the performance test results required in Attachment II, Section F, Testing Requirements.

c. If the nitrogen oxides, sulfur dioxide, particulate matter/PM_{10}, carbon monoxide or volatile organic compounds emission limit is revised, the difference between the applicable emission limit set forth above and the revised lower emission limit shall not be allowed as an emission offset for future construction or modification.

Justification – The requested change is needed for clarification regarding the three-hour averaging period.

Proposed change to Attachment II, Special Condition No. C.8.a. Alternate Operating Scenarios: Add alternate scenario.

vi. The permittee may operate the combustion turbine generator below 25 percent of peak load in isochronous mode with water injection for system restoration.

Justification – The requested change is needed to allow the combustion turbine generator to operate below 25 percent of peak load in isochronous mode with water injection when the combustion turbine generator is started in isochronous mode as a black start unit or for system failure mode.

Proposed change to Attachment II, Special Condition No. D.3.:

~~Daily "start-up" and "shut-down" times. The start and end times of each sequence shall be recorded. In addition, the operating load (MW) at which the air pollution control equipment was initiated and terminated shall be recorded.~~.

Startup and shutdown

a. The following shall be recorded for each startup sequence:

   i. The date, start and end times, and corresponding load (MW) at the end of each twenty (20) minute startup sequence.

   ii. Duration (minutes) of the startup sequence.

   iii. The operating load (MW) at which water injection was initiated.

b. The following shall be recorded for each shutdown sequence:

   i. The date, start and end times, and corresponding load (MW) at which the combustion turbine controls stop signal was initiated.

   ii. Duration (minutes) of the shutdown sequence.

   iii. The operating load (MW) at which water injection was terminated.

Justification – The requested change is needed to add monitoring and recordkeeping requirements for the operation of CT-2 below 25 percent of peak load with water injection to address system frequency issues and for consistency with proposed changes to CSP No. 0007-01-C.

Proposed change to Attachment II, Section D: Add monitoring and recordkeeping conditions.

8. Operation Below 25 Percent of Peak Load with Water Injection. The permittee shall maintain records of the total time the combustion turbine generators operate below 25 percent of peak load with water injection. Records of the total time CT-2, CT-4, and CT-5 operated below 25 percent of peak load with water injection, excluding startup and shutdown sequences, maintenance, testing, and as approved pursuant to Special Condition C.8 of this Attachment, shall be maintained on a monthly and rolling twelve (12) month basis using data recorded by the CEMS.

Justification – The requested changes are needed to monitoring and recordkeeping requirements for operation of CT-2 below 25 percent of peak load with water injection to address system frequency issues.

Proposed change to Attachment II, Special Condition No. E.5.:

The permittee shall submit semi-annually the following written reports to the Department of Health. The report shall be submitted within sixty (60) days after the end of each semi-annual calendar period (January 1 to June 30 and July 1 to December 31), and shall include the following:

a. ~~Monthly~~ A summary ~~showing the daily "start-up"~~ identifying all dates, times and durations when the startup and ~~"shut-down" times~~ shutdown ~~and duration~~ sequence for ~~Unit CT-2~~ the combustion turbine generator exceeded twenty (20) minutes. ~~Include the associated load (MW) of Unit CT-2 at the start-up startup and termination of the air pollution control device. Include total operating hours per day and the total operating hours by month for Unit CT-2.~~ The enclosed Monitoring Report Form: ~~Daily "Start-up" and "Shut-down"~~ Combustion Turbine Generator Operation or an equivalent form ~~approved by the Department of Health~~ shall be used. ~~in reporting Unit CT-2's "start-up" and "shut-down" sequence.~~

b. [No changes proposed]

c. [No changes proposed]

d. Minimum ~~combustion turbine generator load~~ Operating Loads. ~~Except for Unit CT-2's "start-up" and "shut-down" sequences, report all periods of time (date, time and duration using data recorded by the CEMS) when the minimum operating load for Unit CT-2 is less than 25% of the rated capacity.~~

   i. All periods when the operating load for the combustion turbine generators was below 25 percent of peak load (4.6 MW) except for all startup and shutdown sequences and as authorized pursuant to Special Condition C.2. of this Attachment. The report shall include the date, time and duration of each period using data recorded by the CEMS. The enclosed Monitoring Report Form: Combustion Turbine Generator Operation or an equivalent form shall be used.

ii. A monthly summary and rolling twelve (12) month total of the hours of operation of the combustion turbine generators, CT-2, CT-4, and CT-5, below 25 percent of peak load with water injection, excluding startup and shutdown sequences, maintenance, testing, and as approved pursuant to Special Condition C.8 of this Attachment. The report shall be based on data recorded by the CEMS. The enclosed Monitoring Report Form: Combustion Turbine Generator Monthly Operation Below Minimum Load with Water Injection or equivalent form shall be used.

e. [No changes proposed]

f. [No changes proposed]

g. [No changes proposed]

Justification – The requested changes are needed for reporting operation of CT-2 below 25 percent of peak load with water injection to address system frequency issues.

Proposed change to Attachment II, Special Condition No. F.1:

The permittee shall conduct or cause to be conducted performance tests on Unit CT-2 in the simple cycle mode. Performance test on Unit CT-2 shall be conducted for nitrogen oxides (NO_X), sulfur dioxide (SO_2), carbon monoxide (CO), particulate matter (PM/PM_{10}), and volatile organic compounds (VOC). The performance tests for NO_X shall be conducted at 25, 50, 75, and 100 or highest achievable percent of peak load of Unit CT-2, or at other operating loads as may be specified by the Department of Health. The performance tests for SO_2, CO, PM/PM_{10} and VOC shall be conducted at 100 percent of peak load, or highest achievable load ~~of Unit CT-2~~. Performance tests shall be conducted on an annual basis or at such times as may be specified by the Department of Health. The Department of Health may define specific water-to-fuel injection ratios for which the performance tests will be conducted. For any performance test, a continuous monitoring system shall be in operation to monitor and record the ratio of water-to-fuel in Unit CT-2.

Justification – The requested change is needed for consistency with NSPS subpart GG and to clarify that testing is allowed at highest achievable load if 90-to-100 percent of peak load cannot be physically achieved.

MONITORING REPORT FORM
COMBUSTION TURBINE GENERATOR
COVERED SOURCE PERMIT NO. 0070-01-C
(PAGE 1 OF 2)

Issuance Date: ____________ **Expiration Date:** ____________

In accordance with the HAR, Title 11, Chapter 60.1, Air Pollution Control, the permittee shall report to the Department of Health the following information semi-annually:

(Make Copies for Future Use)

For Reporting Period: ________________________ Date: ____________

Company Name: ________________________________

Facility Name: ________________________________

Equipment Location: ________________________________

Equipment Description: ________________________________

Serial/ID No.: ________________________________

I certify that I have knowledge of the facts herein set forth, that the same are true, accurate, and complete to the best of my knowledge and belief, and that all information not identified by me as confidential in nature shall be treated by the Department of Health as public record.

Responsible Official (Print): ________________________________

Title: ________________________________

Responsible Official (Signature): ________________________________

Use additional sheets if necessary. Indicate in the appropriate table if there were no exceedances during the reporting period.

1. Combustion turbine generator unit no.: ____________
2. Identify the months of operation: ____________
3. Exceedence of Startup and Shutdown durations:

Exceedence		**Duration (minutes)**		**Reason for Exceedence/ Final Outcome/ Corrective Actions**
Date	**Time**	**Startup**	**Shutdown**	

MONITORING REPORT FORM
COMBUSTION TURBINE GENERATOR
COVERED SOURCE PERMIT NO. 0070-01-C
(PAGE 2 OF 2)

Issuance Date: ______________ **Expiration Date:** ______________

Combustion Turbine Generator Unit No.: ____________

4. Dates, times and durations when the water injection system was not operated as specified in Special Condition No. C.3.:

Exceedence		Specify Startup, Shutdown or other	Duration (minutes)	Reason for Exceedence Final Outcome/ Corrective Actions
Date	Time			

5. Dates, times, and durations when the combustion turbine generators were operated below 25% of peak load at periods other than during startup, shutdown, or as authorized pursuant to Special Condition C.2. and approved pursuant to Special Condition C.5.:

Date	Time	Duration Below 25% of Peak Load (minutes)	Reason for Exceedence / Final Outcome/ Corrective Actions

MONITORING REPORT FORM
COMBUSTION TURBINE GENERATOR
MONTHLY OPERATION BELOW MINIMUM LOAD WITH WATER INJECTION
COVERED SOURCE PERMIT NO. 0070-01-C

Issuance Date: ______________ **Expiration Date:** ______________

In accordance with the HAR, Title 11, Chapter 60.1, Air Pollution Control, the permittee shall report to the Department of Health the following information semi-annually:

(Make Copies for Future Use)

For Reporting Period: ______________________________ Date: ______________

Company Name: ______________________________

Facility Name: ______________________________

Equipment Location: ______________________________

Equipment Description: ______________________________

Serial/ID Nos.: ______________________________

I certify that I have knowledge of the facts herein set forth, that the same are true, accurate, and complete to the best of my knowledge and belief, and that all information not identified by me as confidential in nature shall be treated by the Department of Health as public record.

Responsible Official (Print): ______________________________

Title: ______________________________

Responsible Official (Signature): ______________________________

Report periods of operation below 25% of peak load with water injection for Units CT-2, CT-4, and CT-5 excluding startup, shutdown, maintenance, testing, and as approved pursuant to Special Condition C.5.

Month	CT-2, CT-4, CT-5 Monthly Total (hours)	Rolling 12-Month Total (hours)

File No.: ________

C-1: Compliance Plan

The Responsible Official shall submit a Compliance Plan as indicated in the Instructions for Applying for an Air Pollution Control Permit and at such other times as requested by the Director of Health (hereafter, Director).

Use separate sheets if necessary.

---

1. Compliance status with respect to all Applicable Requirements:

   Will your facility be in compliance, or is your facility in compliance, with all applicable requirements in effect at the time of your permit application submittal?

   ■ YES { If YES, Complete items a and c below}

   ☐ NO { If NO, complete items a-c below}

   a. Identify all applicable requirement(s) for which compliance is achieved:

   Refer to CSP No. 0070-01-C issued on January 12, 2006 and the June 23, 2009 Administrative Amendment for all applicable requirements. The National Ambient Air Quality Standards (NAAQS) and State Ambient Air Quality Standards (SAAQS) are "Applicable requirement[s]" as defined in HAR § 11-60.1-81.

   Provide a statement that the source is in compliance and will continue to comply with all such requirements.

   The facility is in compliance and will continue to comply with the applicable requirements identified in CSP No. 0070-01-C issued on January 12, 2006 and the June 23, 2009 Administrative Amendment. The NAAQS and SAAQS are "Applicable requirement[s]" as defined in HAR § 11-60.1-81.

   b. Identify all applicable requirement(s) for which compliance is NOT achieved:

   Provide a detailed Schedule of Compliance and a description of how the source will achieve compliance with all such applicable requirements. Use separate sheets of paper, if necessary.

Description of Remedial Action	Expected Date of Completion

c. Identify any other applicable requirement(s) with a future date that your source is subject to. These applicable requirements may be in effect AFTER permit issuance:

Applicable Requirement	Effective Date	Currently in Compliance? Yes

If the source is not currently in compliance, submit a Schedule of Compliance and a description of how the source will achieve compliance with all such requirements:

Description of Proposed Action/Steps to Achieve Compliance	Expected Date of Achieving Compliance

Provide a statement that the source on a timely basis will meet all these applicable requirements.

____

____

____

____

____

If the expected date of achieving compliance will NOT meet the applicable requirement's effective date, provide a more detailed description of all remedial actions and the expected dates of completion.

Description of Remedial Action and Explanation	Expected Date of Completion

2. Compliance Progress Reports:

a. If a compliance plan is being submitted to remedy a violation, complete the following information:

Frequency of Submittal: ____________________ Beginning Date: ____________________
(less than or equal to 6 months)

b. Date(s) that the Action described in (1)(b) was achieved:

Remedial Action	Date Achieved

c. Narrative description of why any date(s) in (1) (b) was not met, and any preventive or corrective measures taken in the interim:

RESPONSIBLE OFFICIAL (as defined in HAR §11-60.1-1)

Name (Last): Uchida (First): Norman (MI): M.

Title: Interim Manager, Technical, Maintenance and Special Projects Phone: (808) 969-0422

Mailing Address: P.O. Box 1027

City: Hilo State: HI Zip Code: 96721-1027

Certification by Responsible Official (pursuant to HAR §11-60.1-4)

I certify that I have knowledge of the facts herein set forth, that the same are true, accurate and complete to the best of my knowledge and belief, and that all information not identified by me as confidential in nature shall be treated by the Department of Health as public record. I further state that I will assume responsibility for the construction, modification, or operation of the source in accordance with the Hawaii Administrative Rules, Title 11, Chapter 60.1, Air Pollution Control, and any permit issued thereof.

Name (Print/Type): Norman M. Uchida

(Signature): Norman Uchida Date: 12/8/15

Facility Name: Keahole Generating Station

Location: 73-4249 Pukiawe Street, Kailua Kona, HI 96740

Permit Number: CSP No. 0007-01-C

FOR AGENCY USE ONLY

File/Application No.:

Island:

Date Received:

HAND DELIVERED
DEC 10 2015

Brenner Munger, Ph.D., P.E.
Manager
Environmental Department

Hawai'i Electric Light
Keahole

December 10, 2015

HAND DELIVERY

Mr. Nolan Hirai, P.E.
Manager, Clean Air Branch
State of Hawaii Department of Health
919 Ala Moana Blvd., Room 203
Honolulu, Hawaii 96814

Dear Mr. Hirai:

Subject: **Application for a Minor Modification to a Covered Source**
CSP No. 0007-01-C
Keahole Generating Station
Hawai'i Electric Light Company, Inc.

Hawaiian Electric Company, Inc., on behalf of Hawai'i Electric Light Company, Inc. (Hawai'i Electric Light), submits an original and one copy of the Application for a Minor Modification to a Covered Source for the above reference Covered Source Permit (CSP).

In this application, Hawai'i Electric Light requests to operate the combustion turbine generators, CT-4 and CT-5, below minimum load with water injection to address system disturbances and frequency issues and to clarify permit conditions regarding startup and minimum water-to-fuel ratios when CT-4 and CT-5 operate at multiple loads.

This modification is related to the minor modification application submitted for the Keahole Generating Station combustion turbine generator, CT-2, under a separate cover letter dated December 10, 2015.

The enclosed minor modification application includes Forms S-1, S-7, and C-1. Certifications in accordance with HAR 11-60.1-4 are included on the enclosed Forms S-1 and C-1. Also enclosed is a check (number 534302) in the amount of $200.00 for the application fee for a minor modification.

If you have any questions regarding this submittal, please contact Karin Kimura at 543-4522 or karin.kimura@hawaiianelectric.com.

Sincerely,

Brenner Munger

bp

Enclosures: (1) Application for a Minor Modification to a Covered Source
(2) Check No. 534302

cc w/ Encl: **CERTIFIED MAIL RETURN RECEIPT REQUESTED**
Mr. Gerardo Rios [Article No.7014 1200 0002 3428 9148]
Chief, Permits Office
Air Division
U.S. EPA Region 9
75 Hawthorne Street
Mail Code: AIR-3
San Francisco, CA 94105

HAND DELIVERED
DEC 10 2015

File / Application No.:____________

S-1: Standard Air Pollution Control Permit Application Form

(Covered Source Permit and Noncovered Source Permit)

State of Hawaii
Department of Health
Environmental Management Division
Clean Air Branch
P. O. Box 3378 • Honolulu, HI 96801-3378 • Phone: (808) 586-4200

1. Company Name: Hawaii Electric Light Company, Inc. (Hawai'I Electric Light)

2. Facility Name (if different from the Company): Keahole Generating Station

3. Mailing Address: 73-4249 Pukiawe Street

   City: Kailua Kona State: HI Zip Code: 96740

   Phone Number: (808) 935-1711

4. Name of Owner/Owner's Agent: Brenner Munger (Owner's Agent)

   Title: Manager, Environmental Department Phone: (808) 543-4500

   Mailing Address: Hawaiian Electric Company; PO Box 2750

   City: Honolulu State: HI Zip Code: 96840-0001

5. Plant Site Manager/Other Contact: Norman Uchida

   Title: Interim Manager, Technical, Maintenance and Special Projects Phone: (808) 969-0422

   Mailing Address: P.O. Box 1027

   City: Hilo State: HI Zip Code: 96721

6. Permit Application Basis: (Check appropriate boxes)

   ☐ Initial Permit for a New Source ☐ Initial Permit for an Existing Source

   ☐ Renewal of Existing Permit ☐ General Permit

   ☐ Temporary Source ☐ Transfer of Permit

   ■ Modification to a Covered Source: → Is modification? ☐ Significant ■ Minor ☐ Uncertain

   ☐ Modification to a Noncovered Source

7. If renewal or modification, include existing permit number: CSP No. 0007-01-C

8. Does the Proposed Source require a County Special Management Area Permit? ☐ Yes ■ No

9. Type of Source (Check One): ☐ Covered Source ■ Covered & PSD Source

   ☐ Noncovered Source ☐ Uncertain

10. Standard Industrial Classification Code (SICC), if known: 4911

11. Proposed Equipment/Plant Location (e.g. street address): 73-4249 Pukiawe Street

City: Kailua Kona State: HI Zip Code: 96740

UTM Coordinates (meters): East: 811,293 North: 2,184,955

UTM Zone: 4 UTM Horizontal Datum: ■ Old Hawaiian ☐ NAD-27 ☐ NAD-83

12. General Nature of Business: Electrical Generation

13. Date of Planned Commencement of Installation or Modification: Upon approval of modification.

14. Is *any* of the equipment to be leased to another individual or entity? ☐ Yes ■ No

15. Type of Organization: ■ Corporation ☐ Individual Owner ☐ Partnership

☐ Government Agency (Government Facility Code: ____________)

☐ Other: ____________

Any applicant for a permit who fails to submit any relevant facts or who has submitted incorrect information in any permit application shall, upon becoming aware of such failure or incorrect submittal, promptly submit such supplementary facts or corrected information. In addition, an applicant shall provide additional information as necessary to address any requirements that become applicable to the source after the date it filed a complete application, but prior to the issuance of the noncovered source permit or release of a draft covered source permit. (HAR § 11-60.1-64 & 11-60.1-84)

RESPONSIBLE OFFICIAL (as defined in §11-60.1-1):

Name (Last): Uchida (First): Norman (MI): M.

Title: Interim Manager, Technical, Maintenance and Special Projects Phone: (808) 969-0422

Mailing Address: P.O. Box 1027

City: Hilo State: HI Zip Code: 96721-1027

CERTIFICATION by Responsible Official (pursuant to §11-60.1-4):

I certify that I have knowledge of the facts herein set forth, that the same are true, accurate and complete to the best of my knowledge and belief, and that all information not identified by me as confidential in nature shall be treated by the Department of Health as public record. I further state that I will assume responsibility for the construction, modification, or operation of the source in accordance with the Hawaii Administrative Rules (HAR), Title 11, Chapter 60.1, Air Pollution Control, and any permit issued thereof.

NAME (Print/Type): Norman M. Uchida

(Signature): Norman Uchida Date: 12/8/15

FOR AGENCY USE ONLY:

File/Application No: ____________

Island: ____________

Date Received: ____________

Submit the following documents as part of your application:

A. The ***Emissions Units Table***, filled in as completely as possible. Use separate sheets of paper as needed. General instructions include the following:

1. Identify each **emission point** with a unique number for this plant site, consistent with emission point identification used on the location drawing and previous permits; if known, provide the SICC number. Emission points shall be identified and described in sufficient detail to establish the basis for **fees** and applicability of requirements of HAR, Chapter 11-60.1. Examples of emission point names are: heater, vent, boiler, tank, baghouse, fugitive, etc. Abbreviations may be used.
   a. For each emission point use as many lines as necessary to list regulated and hazardous air pollutant data. For hazardous air pollutants, also list the Chemical Abstracts Service number (CAS#).
   b. Indicate the emission points that discharge together for any length of time.
   c. The **Equipment Date** is the date of equipment construction, reconstruction, or modification. Provide supporting documentation.

2. State the **maximum emission rates** in terms sufficient to establish compliance with the applicable requirements and standard reference test methods. Provide all supporting emission calculations and assumptions:
   a. Include all regulated and hazardous air pollutants and air pollutants for which the source is major, as defined in HAR §11-60.1-1. Examples of regulated pollutant names are: Carbon Monoxide (CO), Nitrogen Oxides (NO_X), Sulfur Dioxide (SO_2), Volatile Organic Compounds (VOC), particulate matter (PM), and particulate less than 10 microns (PM_{10}). Abbreviations may be used.
   b. Include fugitive emissions.
   c. **Pounds per hour (#/HR)** is the maximum potential emission rate expected by applicant.
   Tons per year is the annual maximum potential emissions expected by the applicant, taking into account the typical operating schedule.

3. Describe ***Stack Source Parameters***:
   a. **Stack Height** is the height above the ground.
   b. **Direction** refers to the exit direction of stack emissions: up, down or horizontal.
   c. **Flow Rate** is the actual, not the calculated, flow rate.

4. Provide any additional information, if applicable, as follows:
   a. If combinations of different fuels are used that cause any of the stack source parameters to differ, complete one row for each possible set of stack parameters and identify each fuel in the **Equipment Description**.
   b. For a rectangular stack, indicate the length and width.
   c. Provide any information on stack parameters or any stack height limitations developed pursuant to Section 123 of the Clean Air Act.

B. A **process flow diagram** identifying all equipment used in the process, including the following:
   1. Identify and describe each emission point.
   2. Identify the locations of safety valves, bypasses, and other such devices which when activated may release air pollutants to the atmosphere.

C. A **facility location map**, drawn to a reasonable scale and showing the following:
   1. The property involved and all structures on it. Identify property/fence lines plainly.
   2. Layout of the facility.
   3. Location and identification of the proposed emissions unit on the property.
   4. Location of the property and equipment with respect to streets and all adjacent property. Show the location of all structures within 325 meters of the applicant's emissions unit. Provide the building dimensions (height, length, and width) of all structures that have heights greater than 40% of the stack height of the emissions unit.

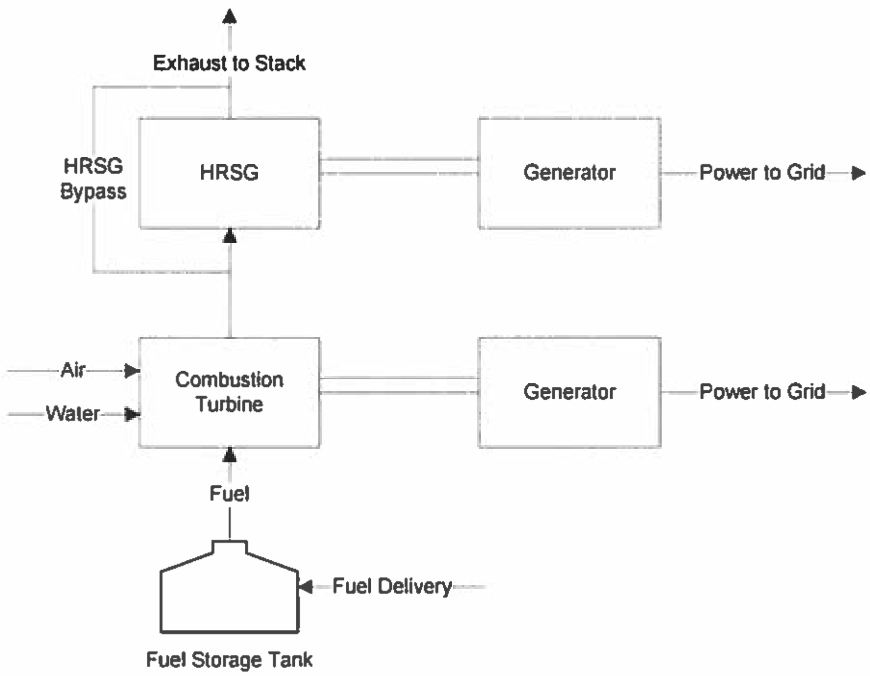
D. Provide a description of any proposed modifications or permit revisions. Include any justification or supporting information for the proposed modifications or permit revisions.

Attachment S-1a
Responses to Emission Unit Table Instructions for Form S-1

A.1. Emission Point Identification and Description	
A.2. Maximum Emission Rates	
A.3. Stack Parameters	
A.4. Additional Information	
B. Process Flow Diagram	Refer to Figure S-1.1.
C. Facility Location Map	
D. Proposed Revisions	Refer to Form S-7.

FIGURE S-1.1

PROCESS FLOW DIAGRAM FOR UNITS CT-4 AND CT-5



File No.: ________

S-7: Application for a Minor Modification to a Covered Source

In providing the required information, reference the corresponding letters and numbers listed below.

Provide a minimum of **two (2)** sets (1 original and 1 copy) of all application materials to the Hawaii Department of Health. Also, mail **one (1)** set directly to EPA at the following address:

Chief (Attention: AIR-3)
Permits Office, Air Division
U.S. Environmental Protection Agency
Region 9
75 Hawthorne Street
San Francisco, CA 94105

I. In accordance with Hawaii Administrative Rules (HAR) §11-60.1-104, the following information is required:

A. A clear description of all changes.

Hawai'i Electric Light proposes modifications to CSP No. 0007-01-C for combustion turbine generators, CT-4 and CT-5 which are included in Attachment S-7a. These proposed modifications are related to modifications proposed to CSP No. 0070-01-C for combustion turbine generator, CT-2 submitted to the Department under a separate cover letter and minor modification application.

B. A statement of why the modification is determined to be minor, and a request that minor modification procedures be used.

The proposed modifications for units, CT-2, CT-4, and CT-5 meet the criteria in the definition of "minor modification" as defined in HAR § 11-60.1-81. The proposed modifications:

(1) Do not increase the emissions of any air pollutant above the permitted emission limits;

(2) Do not result in or increase the emissions of any air pollutant not limited by permit levels equal to or above: (A) 500 pounds per year of a hazardous air pollutant; (B) 300 pounds of lead; (C) twenty-five percent of significant amounts of emission as defined in section 11-60.1-1, paragraph (1) in the definition of "significant"; or (D) two tons per year of each regulated air pollutant not already identified above (refer to Attachment S-7a for emissions calculations);

(3) Do not violate any applicable requirement;

(4) Do not involve significant changes to existing monitoring requirements or any relaxation or significant change to existing reporting or recordkeeping requirements in the permit.

(5) Do not require or change a case-by-case determination, a source-specific determination for temporary sources for ambient impacts, or a visibility or increment analysis;

(6) Do 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; and

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

C. Cite and describe any new applicable requirements as defined in HAR § 11-60.1-81 that will apply if the minor modification occurs.

No new applicable requirements will apply to the proposed minor modifications.

D. The suggested changes to permit terms or conditions.

Not applicable.

E. Certification by a responsible official that the proposed modification meets the criteria for minor modification.

Form S-1 contains the responsible official's signature certifying that the modifications are minor.

F. All information submitted with the application for the Initial Covered Source Permit or any subsequent application for a Covered Source Permit. The owner or operator may reference information contained in a previous application submittal, provided such referenced information has been certified as being current and still applicable.

References are made herein to pertinent information in previously submitted materials.

G. Other information, as required by any applicable requirement or as requested and deemed necessary by the Director of Health (hereafter, Director) to make a decision on the application.

Not applicable.

II. Submit an application fee according to the Application Fees Schedule in the Instructions for Applying for an Air Pollution Control Permit.

III. An application shall be determined to be complete only when all of the following have been complied with:

A. All information required or requested in number I have been submitted.

B. All documents requiring certification have been certified pursuant to HAR § 11-60.1-4.

C. All applicable fees have been submitted.

D. The Director has certified that the application is complete.

IV. The Director shall not continue to act upon or consider an incomplete application.

A. The applicant shall be notified in writing whether the application is complete. Unless the Director requests additional information or notifies the applicant of incompleteness within thirty days of receipt of an application, the application shall be deemed complete.

B. During the processing of an application that has been determined or deemed complete, if the Director determines that additional information is necessary to evaluate or take final action on the application, the Director may request such information in writing and set a reasonable deadline for a response.

V. Within ninety days of receipt of a complete application for a minor modification, or upon program approval, within fifteen days after the end of the Administrator's forty-five-day review period, whichever is later, the Director in writing shall:

A. Amend the permit to reflect the minor modification as proposed.

B. Deny the minor modification.

C. Determine that the requested modification does not meet the minor modification criteria, and should be reviewed under the significant modification process; or

D. Upon program approval, amend the proposed permit and resubmit the amendment to EPA for reevaluation.

VI. An application for minor modification to a covered source shall be approved only if the Director determines that the minor modification will be in compliance with all applicable requirements.

VII. The Director shall provide a statement that sets forth the legal and factual bases for the proposed permit conditions (including references to the applicable statutory or regulatory provisions) to EPA and any other person requesting it.

VIII. Each application and proposed permit reflecting the minor modification to a covered source shall be subject to EPA oversight in accordance with HAR § 11-60.1-95.

Attachment S-7a

Requested Changes to CSP No. 0007-01-C

Proposed change to Attachment IIA, Special Condition No. A.1.a Equipment Description:

Two (2) 20 MW Nominal (24.66 MW Peak Load) General Electric LM2500 combustion turbine generators, units CT-4 and CT-5; and

Justification – The requested change is to update the equipment list with the peak load rating for CT-4 and CT-5.

Proposed change to Attachment IIA, Special Condition No. C.1. Startup and Shutdown:

~~Start-up~~ Startup and Shutdown

a. ~~The "start up" time shall not exceed twenty (20) minutes for any combustion turbine generator operating in simple cycle and ninety (90) minutes for any combustion turbine generator operating in combined cycle. Except during maintenance (e.g., equipment installations and inspections, and electrical switching work), testing, and emergency power demands due to sudden loss of a power generating unit, each combustion turbine generator shall not be started up more than four times per calendar day. A "start-up" sequence shall be from the time fuel use at the combustion turbine generator begins, until the time the combustion turbine generator is initially brought up to 25 percent of peak load at which time the operation of the air pollution control equipment shall commence.~~

   The startup sequence for each combustion turbine generator shall be a twenty (20) minute period in simple or combined cycle mode starting from the time fuel use at the combustion turbine generator begins. Upon completion of the twenty (20) minute startup sequence, the combustion turbine generator shall be at 25 percent of peak load (6.17 MW) or more and the water injection system shall be operational except as provided in Attachment IIA, Special Condition No. C.2.

b. The "shutdown~~" time~~ sequence for any combustion turbine generator ~~operating in either simple cycle or combined cycle~~ shall not exceed twenty (20) minutes in simple or combined cycle mode. ~~Except during maintenance (e.g., equipment installations and inspections, and electrical switching work), testing, and emergency power demands due to sudden loss of a power generating unit, each combustion turbine generator shall not be shut down more than four (4) times per calendar day.~~ A "shutdown" sequence shall be ~~considered~~ from the time ~~when~~ the combustion turbine controls stop signal is initiated for each combustion turbine generator and the combustion turbine generator is ~~operating~~ below 25 percent of peak load (6.17 MW), until fuel ~~consumption~~ use at the combustion turbine generator ceases.

Justification – The requested changes are needed to: 1) clarify peak load; 2) clarify the description of startup and shutdown sequences to allow stabilization of the water injection system following initiation of the system; and 3) remove the limit of the number of startups per day because startup periods for both simple and combined cycle modes are limited to 20 minutes.

Proposed change to Attachment IIA, Special Condition No. C.2. Minimum Operational Loads:

> ~~The combustion turbine generators shall not operate below 25 percent of peak load except during equipment start-up, shutdown, maintenance, or testing.~~ <u>The operation of the combustion turbine generators, CT-2, CT-4, and CT-5, below 25 percent of peak load with water injection shall not exceed a combined total of 66 hours in any rolling 12 month period, except during startup and shutdown sequences, maintenance, testing, and as approved pursuant to Attachment IIA, Special Condition C.5.b.</u>

Justification – The requested change is needed to clarify peak load and allow the operation of CT-4 and CT-5 below 25 percent of peak load with water injection to address system frequency issues.

Based on the emission limits for CT-4, CT-5, and CT-2 as specified in CSP Nos. 0007-01-C and 0070-01-C and source performance test data, load reduction has the following impacts on the CT emission factors:

- The SO_2 emission factor is directly proportional to fuel sulfur content. Thus, the SO_2 emission factor remains constant.
- The lead, fluorides, and H_2SO_4 emission factors are dependent on fuel type. Thus, these emission factors remain constant.
- The NO_X emission factor decreases with decreasing load.
- The CO, VOC, PM, PM_{10}, and $PM_{2.5}$ emission factors increase with decreasing load.

Since SO_2, NO_X, lead, fluorides, and H_2SO_4 emissions decrease with decreasing load, emission rates below 25% of peak load (6.165 MW) are not needed. Worst-case emissions will occur when the CTs are operating at peak load. Thus, project SO_2, NO_X, lead, fluorides, and H_2SO_4 emissions are based on CT-2, CT-4, and CT-5 operating at peak load. Since emission rates for NO_X, lead and fluorides are higher for CT-4 and CT-5 at peak load than CT-2 at peak load, project emission rates for NO_X, lead, and fluorides are based on CT-4 and CT-5 emission rates.

Based on comparison of the permitted emission rates for CO, VOC, and PM/PM_{10} and source test data for CT-2, CT-4, and CT-5, the permitted emission rates for these pollutants at 25% of peak load are conservative; refer to Figures 4 through 16. Thus, project CO, VOC, and PM/PM_{10} are based on the CTs operating at 25% of peak load and $PM_{2.5}$ emissions are based on PM/PM_{10} emissions. Since emission rates for CO and VOC are higher for CT-4 and CT-5 at 25% of peak load than CT-2 at 25% of peak load, emission rates for CO and VOC are based on CT-4 and CT-5 emission rates.

Table 1 summarizes the project emissions based on a maximum operation of 66 hours per rolling 12-month period at loads less than 25% of peak load with water injection and shows that the project qualifies as a minor modification because the project emissions are below levels specified in HAR §11-60.1-81. GHG emission calculations are provided in Table 2.

Based on the project emissions calculations, the proposed modification will not trigger 40 CFR Subpart KKKK – Standards of Performance for Stationary Combustion Turbines (NSPS Subpart KKKK) based on the following reasons:

- Operation below 25% of peak load with water injection will not increase the SO_2 or NO_X emission rates. Both SO_2 and NO_X emission rates decrease with decreasing load.
- Operation of the combustion turbine generators below 25% of peak load with water injection will not require any capital expenditure. The combustion turbine generators are already capable of operating below 25% of peak load with water injection; i.e., components of the combustion turbine generators will not require replacement as part of this proposed modification. Thus, this proposed modification will not be considered reconstruction as provided in 40 CFR §60.15.

Table 1 – Project Emissions Calculations

Pollutant		CT2, CT4, CT5 Operation Below 25% of Peak Load with Water Injection Project Emissions[1] (lb/hr per CT)	(tpy total)	Significant Level[2] (tpy)	Significant Modification Required (Yes/No)
CO [3]		475.6	15.69	25	No
NO_X [3]		42.3	1.40	10	No
SO_2		110.0	3.63	10	No
PM [4]		22.4	0.74	6.25	No
PM_{10} [4]		22.4	0.74	3.75	No
$PM_{2.5}$ [4, 5, 6]	$PM_{2.5}$	22.4	0.74	2.5	No
	SO_2	110	3.63	10	
	NO_X	42.3	1.40	10	
O_3 [7]	NO_X	42.3	1.40	10	No
	VOC[3]	297.60	9.82	10	
Lead[3]		3.85E-03	1.27E-04	0.15	No
Fluorides[3]		2.77E-03	9.14E-05	2	No
Sulfuric Acid Mist (H_2SO_4)		14.4	0.475	2	No
CO_2e			1,485	10,000	No

Notes:

1. Project tpy values based on 66 hrs/yr.
2. Minor modification significant levels from HAR §11-60.1-81.
3. Emission rates for CO, NO_X, VOC, lead, and fluorides based on CT4 and CT5 emission rates.
4. PM emission rate based on PM limit for CT2.
5. $PM_{2.5}$ emissions and PM_{10} emissions shall include gaseous emissions from a source or activity which condense to form particulate matter at ambient temperatures (40 CFR §52.21(b)(50)(i)(a) and HAR §11-60.1-1).
6. In addition to the 2.5 tpy significant level for direct $PM_{2.5}$ emissions, the project is significant for $PM_{2.5}$ if SO_2 or NO_X emissions exceed 10 tpy (HAR §11-60.1-1 and §11-60.1-81).
7. The project is significant for O_3 if NO_X or VOC emissions exceed 40 tpy (40 CFR §52.21(b)(23)(i) and HAR §11-60.1-1).

Table 2 – GHG Emissions Calculations

Units	Heat Input (MMBtu/yr)	GHG Pollutant[1]	Emission Factor[2] (kg/MMBtu)	Global Warming Potential[3]	GHG Emissions CO_2e (tpy)
CT2, CT3, or CT5	18,150	CO_2	73.96	1	1,479.7
		N_2O	6.0E-04	298	3.58E+00
		CH_4	3.0E-03	25	1.50E+00
				Total CO_2e =	1,484.8

Notes:

1. Greenhouse Gas (GHG) pollutants from the Mandatory Greenhouse Gas Reporting rule (40 CFR §98.32).
2. Emission factors from the Mandatory Greenhouse Gas Reporting rule (40 CFR §98, Tables C-1 and C-2).
3. Global Warming Potentials from the Mandatory Greenhouse Gas Reporting rule (40 CFR §98, Table A-1).
4. Project tpy values based on 66 hrs/yr and heat input at peak load for CT4 or CT5; CT2 heat input at peak load is less than heat input of CT4 and CT5 at peak load.

Figure 1 – Relationship Between NO_X Emission Factor and Load (CT4, CT5)

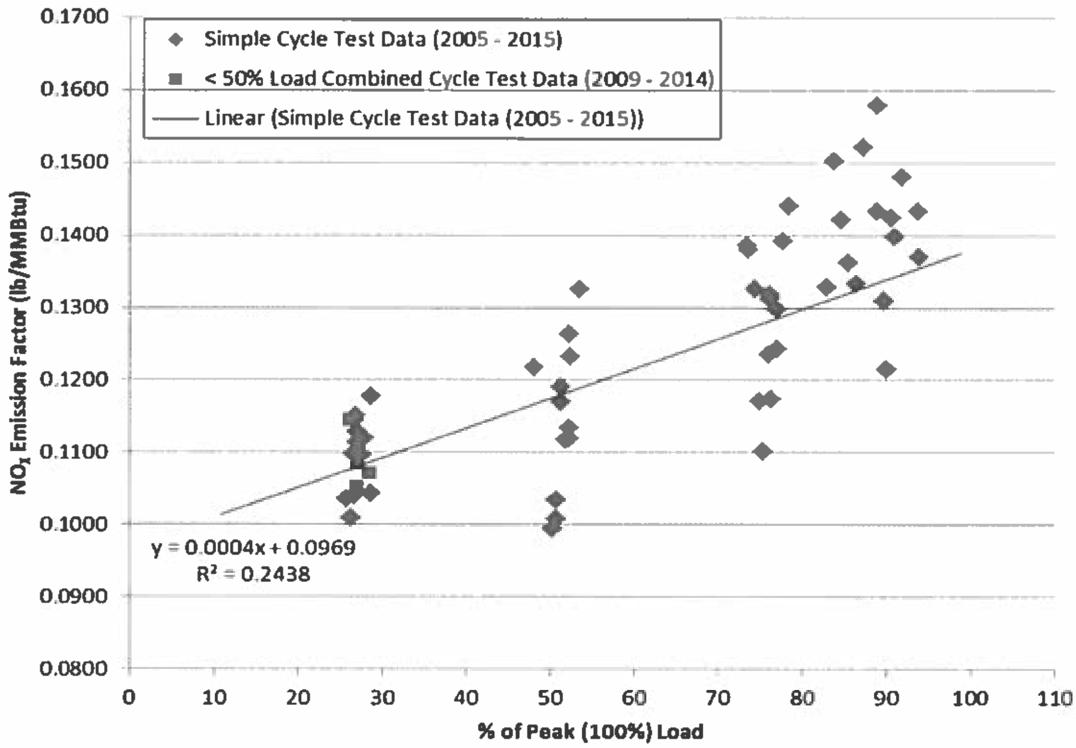


Figure 2 – Comparison of NO_X Source Test Data and NO_X Emission Limits (CT4, CT5)

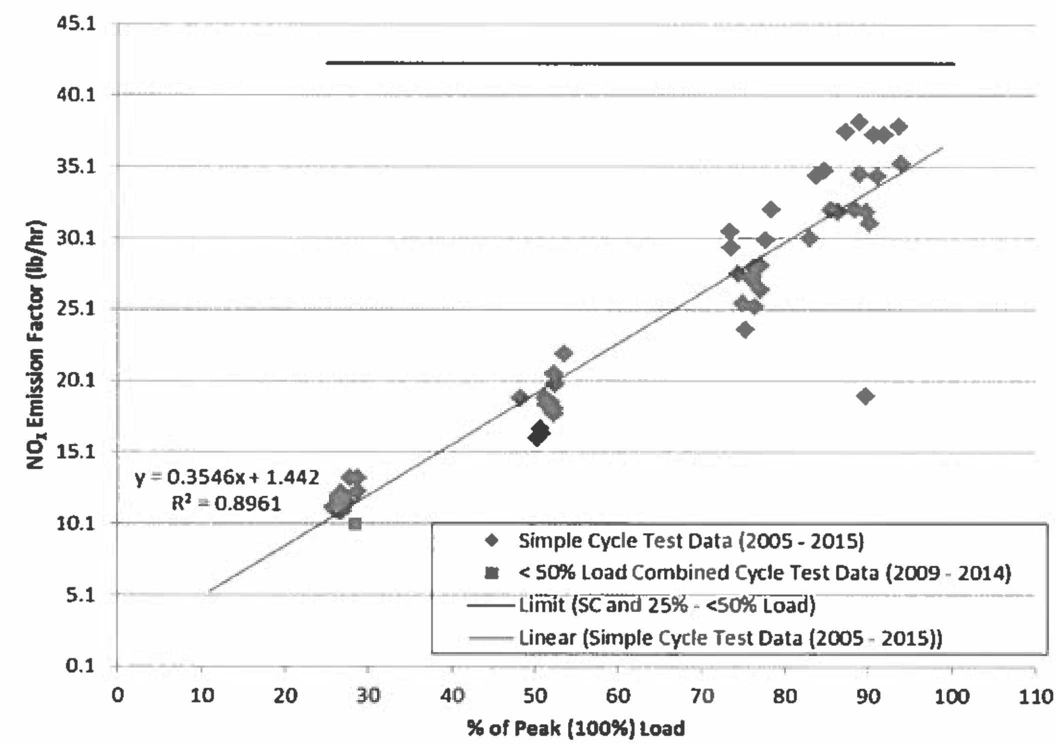


Figure 3 – Relationship Between NO_X Emission Factor and Load (CT2)

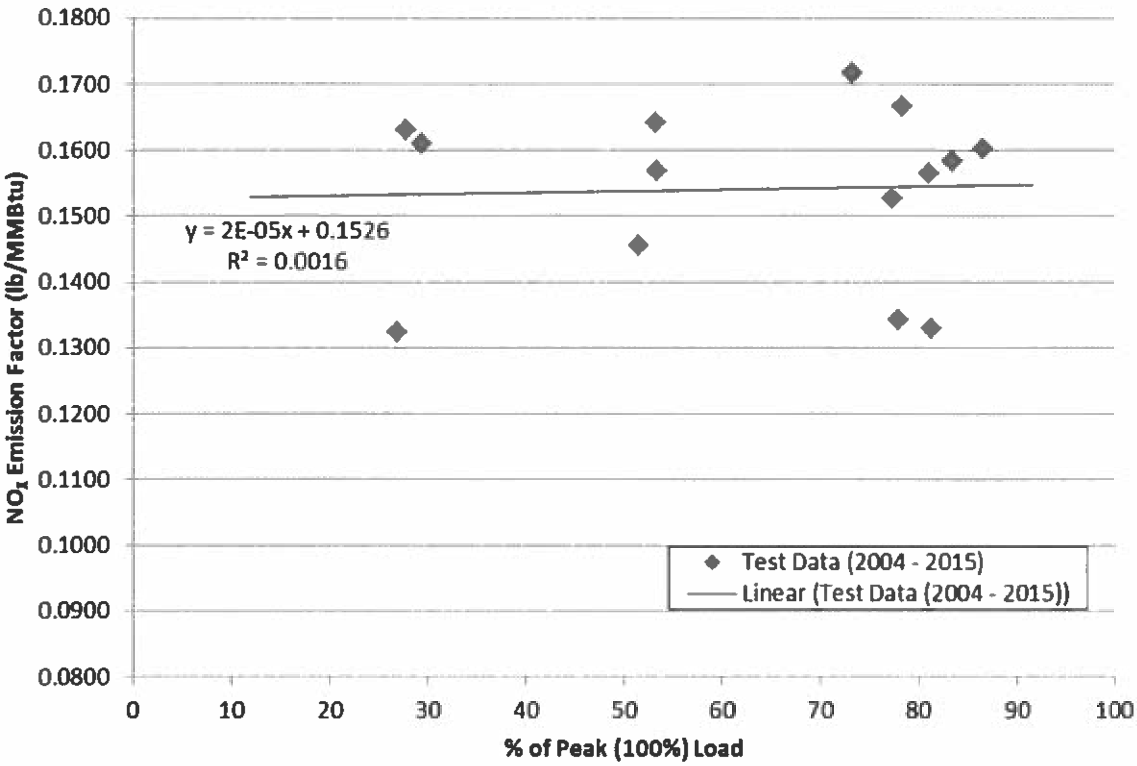


Figure 4 – Comparison of NO_X Source Test Data and NO_X Emission Limits (CT2)

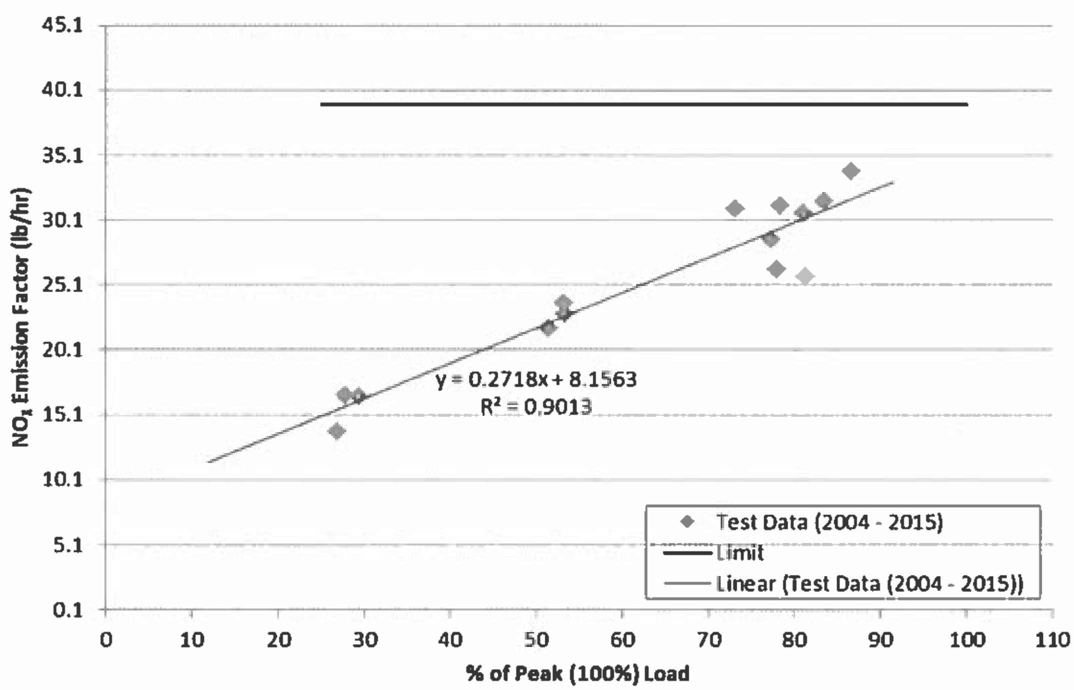


Figure 5 – Relationship Between CO Emission Factor and Load (CT4, CT5)

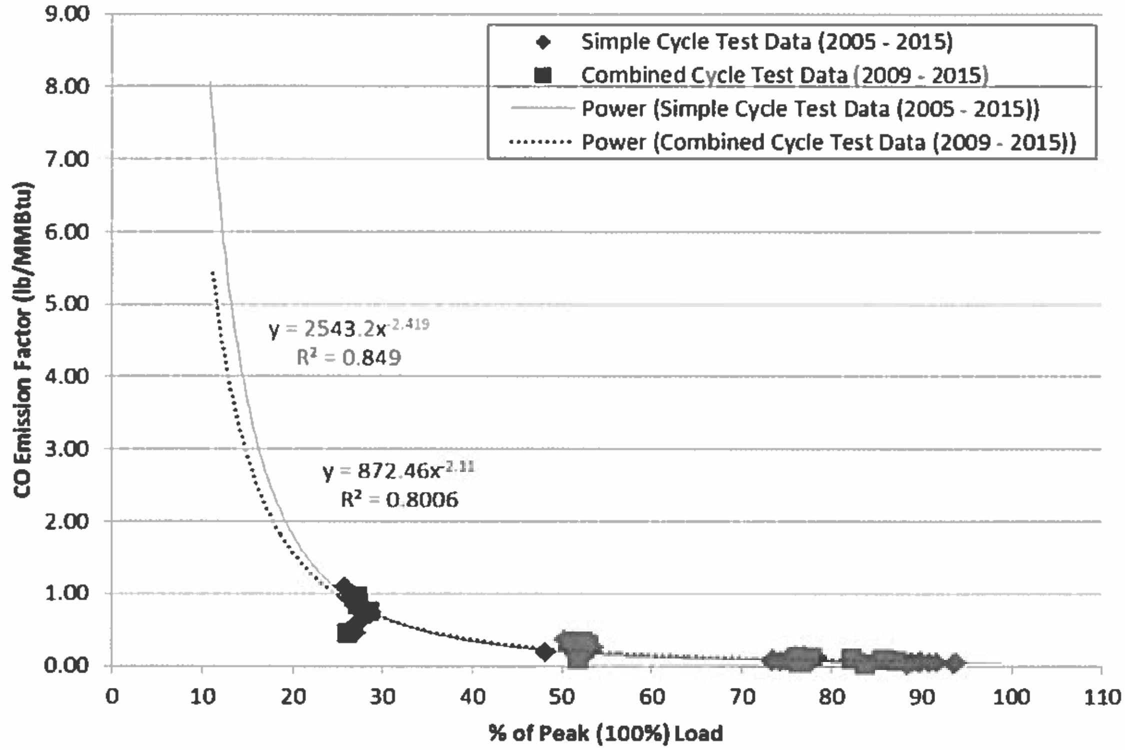


Figure 6 – Comparison of CO Source Test Data and CO Emission Limits (CT4, CT5)

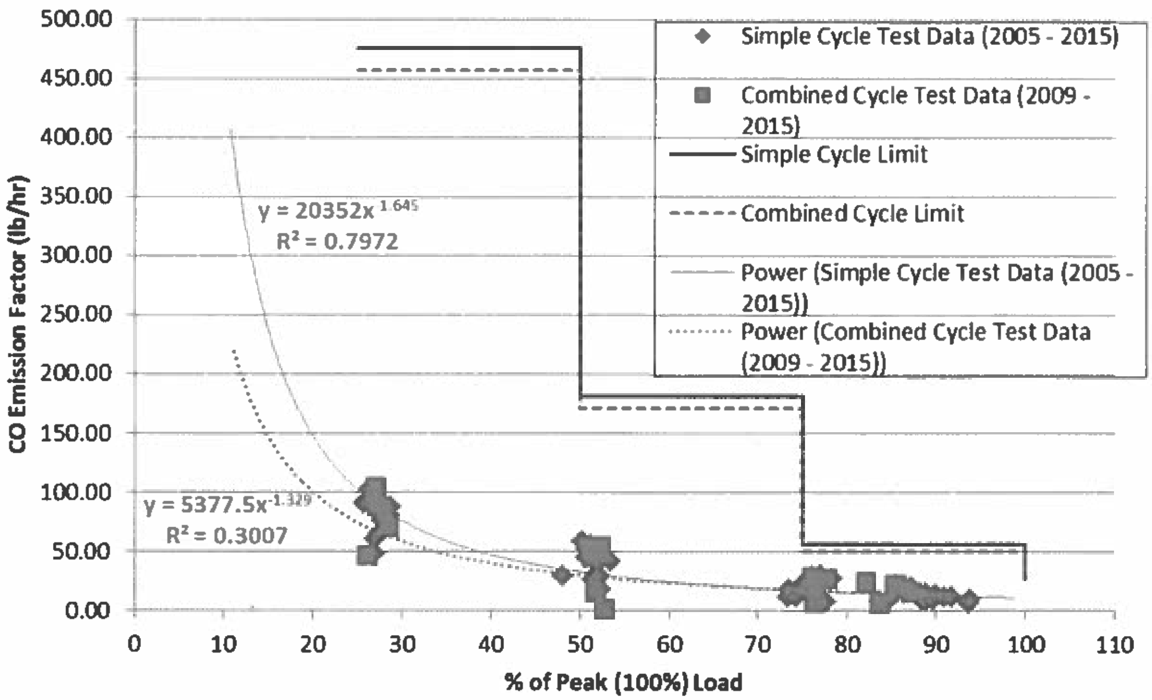


Figure 7 – Relationship Between CO Emission Factor and Load (CT2)

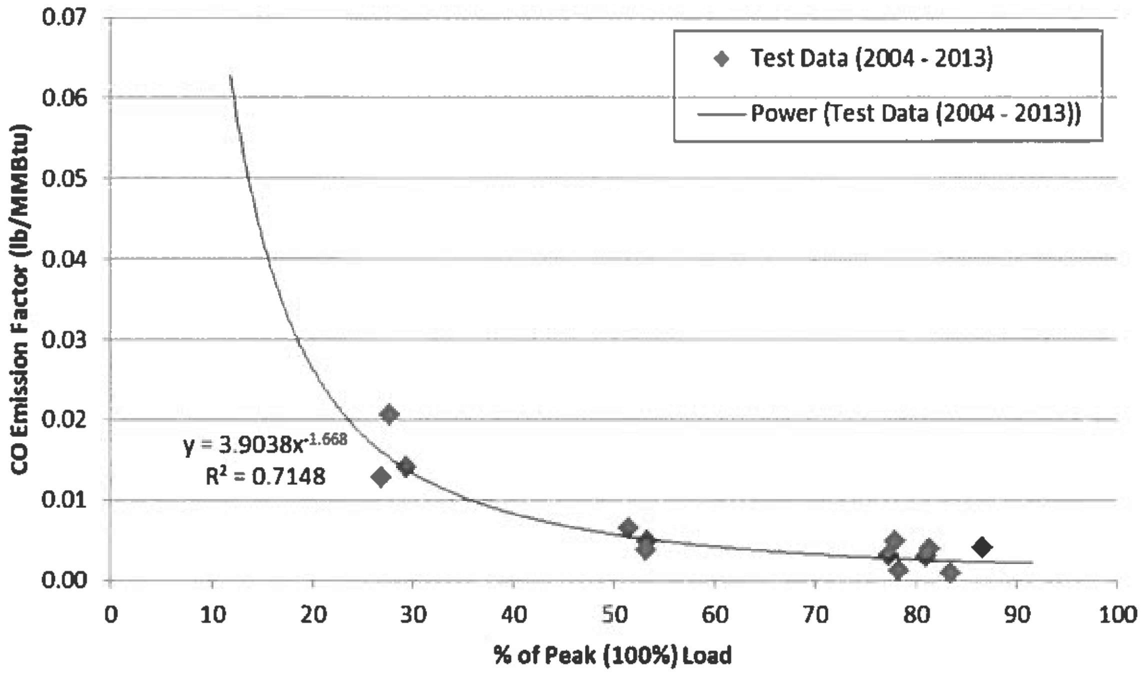


Figure 8 – Comparison of CO Source Test Data and CO Emission Limits (CT2)

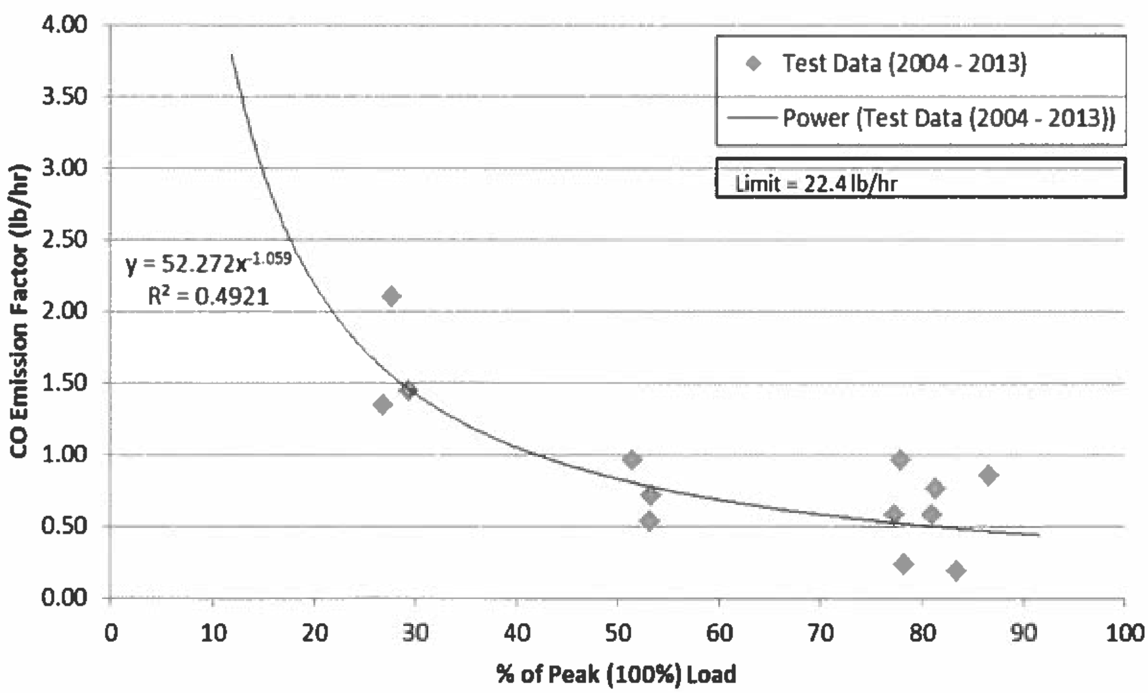


Figure 9 – Relationship Between VOC Emission Factor and Load (CT4, CT5)

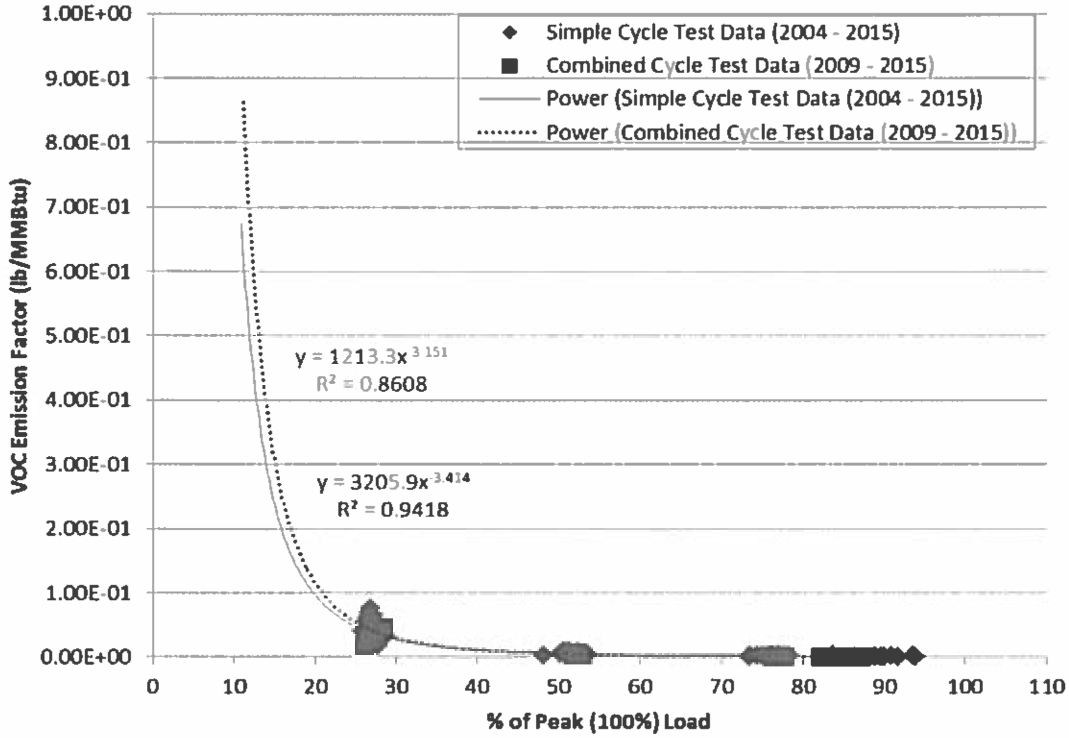


Figure 10 – Comparison of VOC Source Test Data and VOC Emission Limits (CT4, CT5)

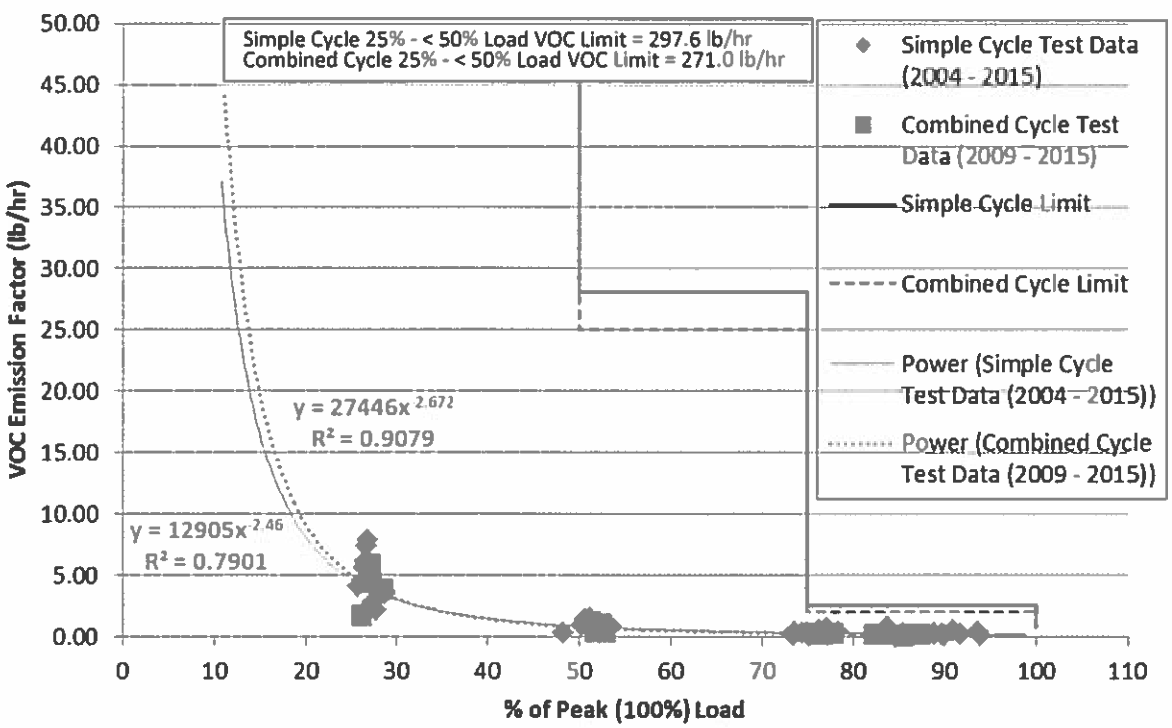


Figure 11 – Relationship Between VOC Emission Factor and Load (CT2)

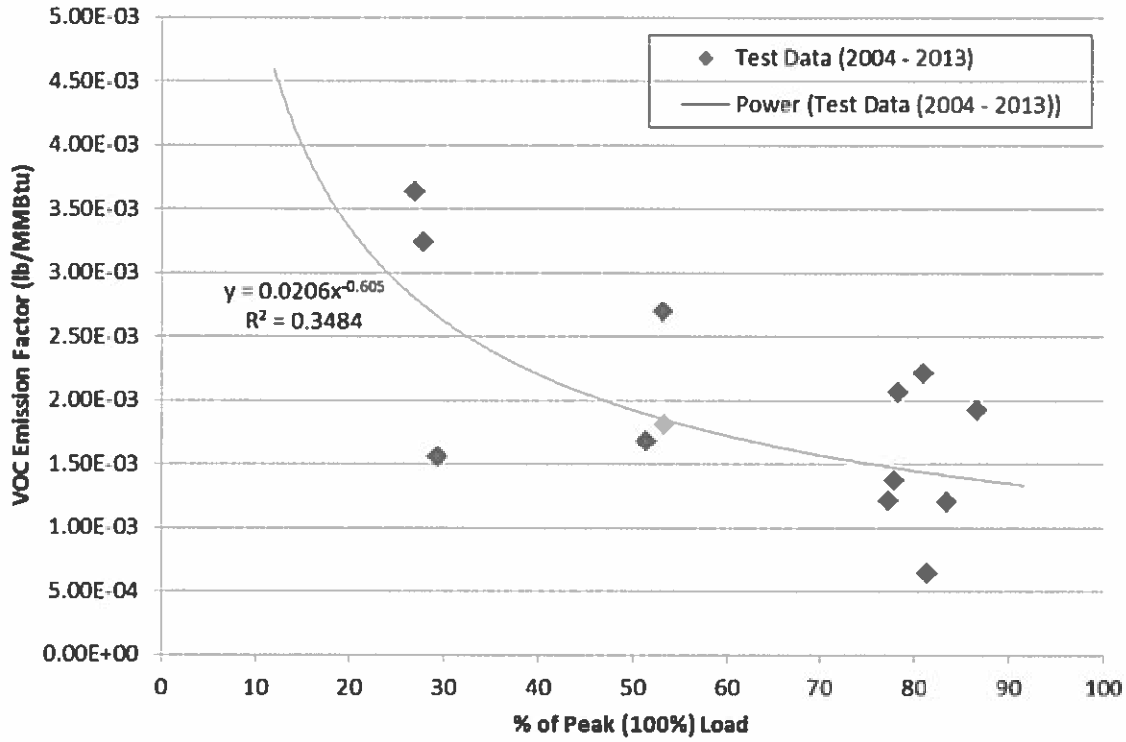


Figure 12 – Comparison of VOC Source Test Data and VOC Emission Limits (CT2)

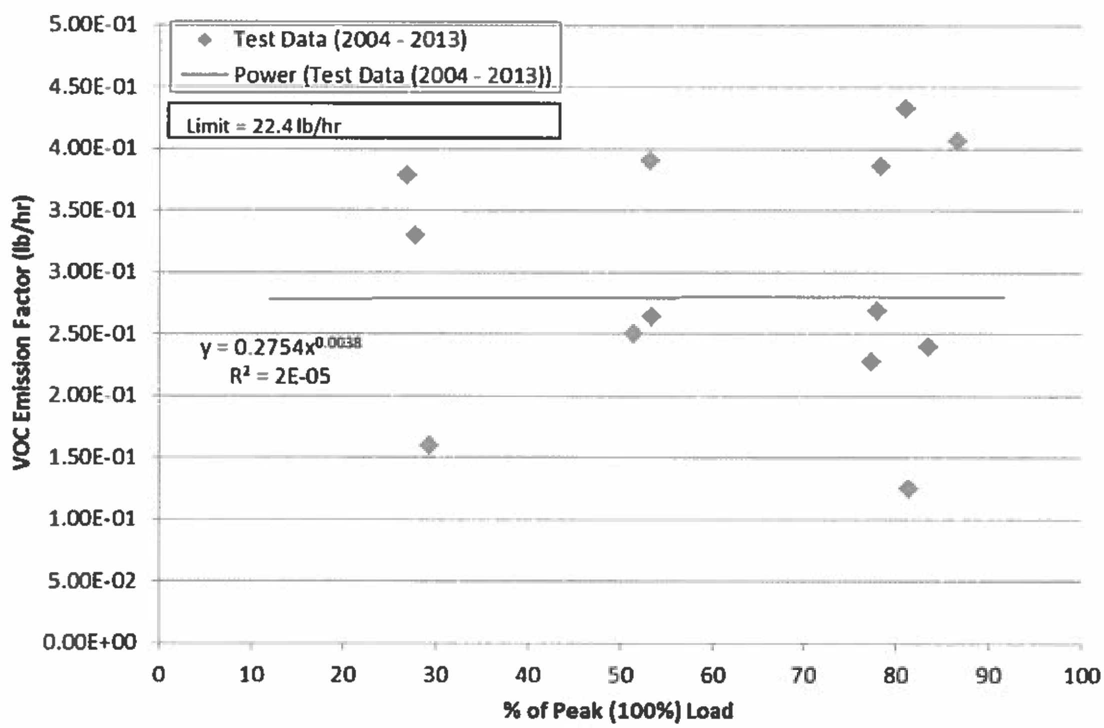


Figure 13 – Relationship Between PM Emission Factor and Load (CT4, CT5)

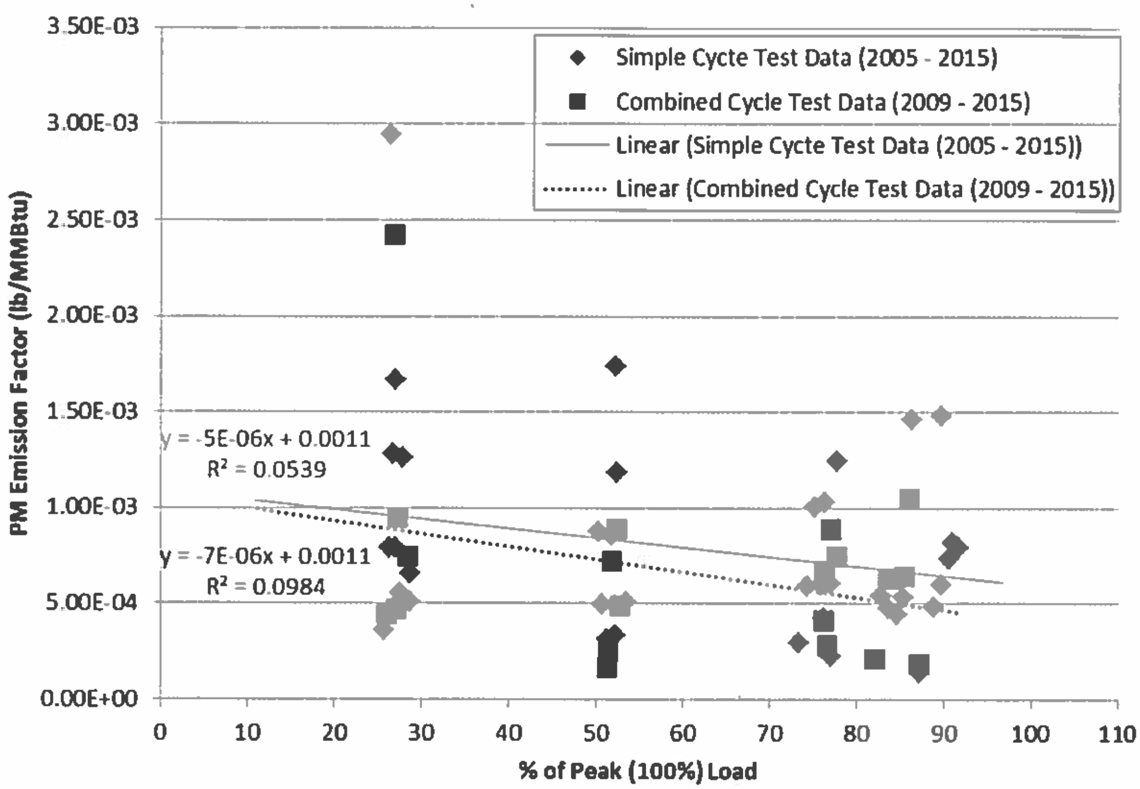


Figure 14 – Comparison of PM Source Test Data and PM Emission Limits (CT4, CT5)

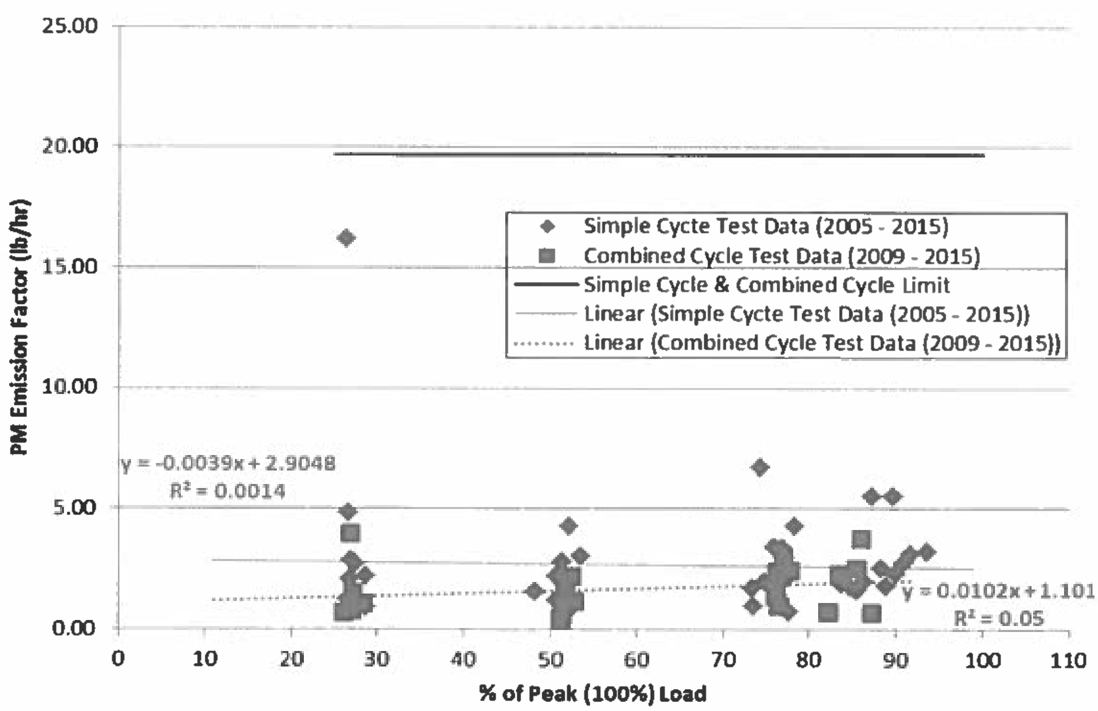


Figure 15 – Relationship Between PM Emission Factor and Load (CT2)

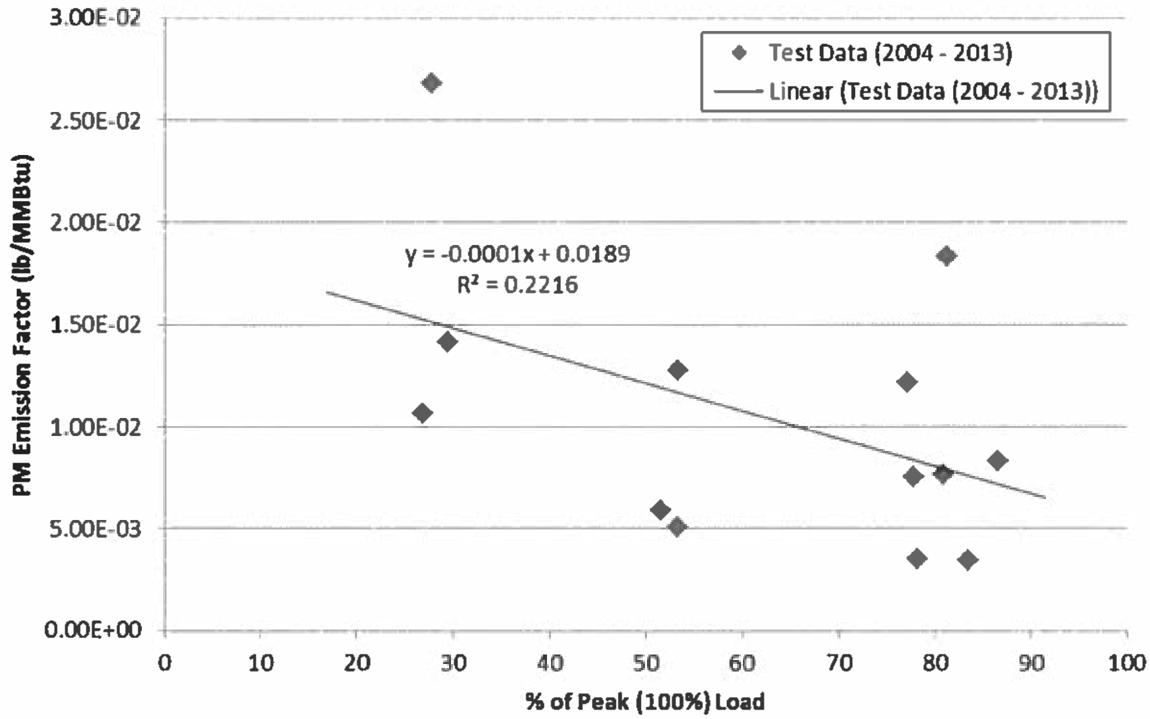
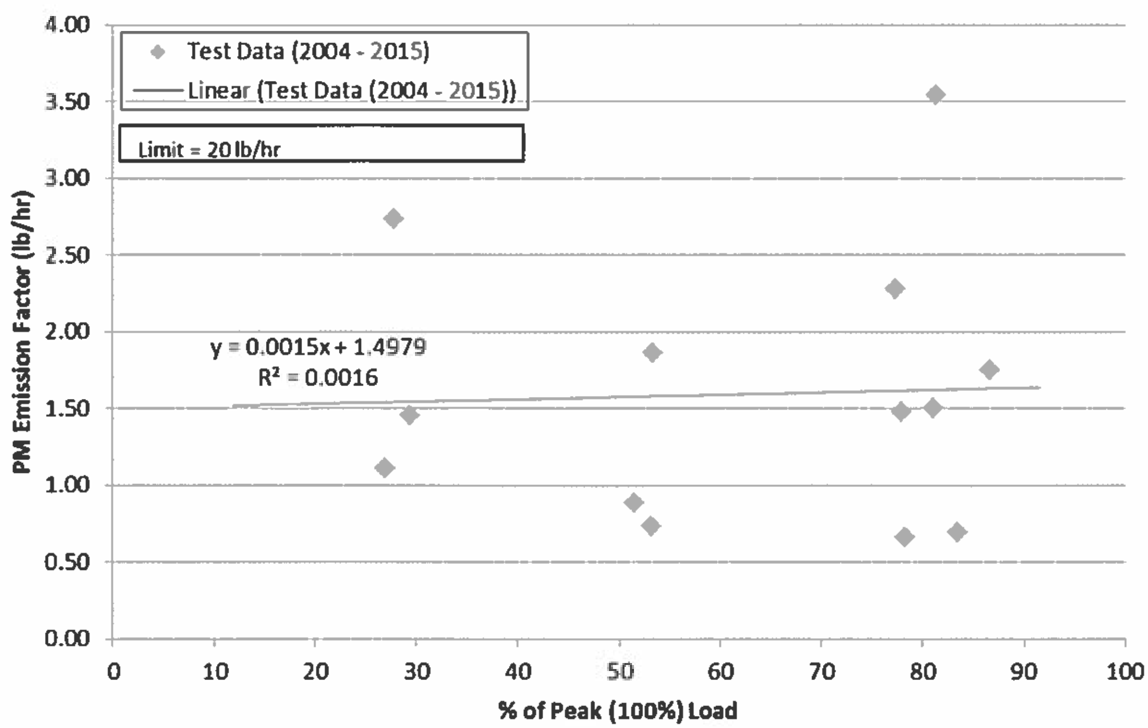


Figure 16 – Comparison of PM Source Test Data and PM Emission Limits (CT2)



Proposed change to Attachment IIA, Special Condition No. C.3. Air Pollution Equipment:

~~The use of an alternative control system other than those specified below is contingent upon receiving the Department of Health's written approval to use such a system and shall not relieve the permittee from the responsibility to meet all emission limitations contained within this Covered Source Permit.~~

a. ~~Combustor~~ Water Injection

i. The permittee shall continuously operate and maintain a ~~combustor~~ water injection system to meet the emission limits ~~as~~ specified for nitrogen oxides (NO_X) in Attachment IIA, Special Condition D.1.a.~~. of this Covered Source Permit~~. Water injection shall be initiated during the startup sequence of each combustion turbine generator and may be terminated at the beginning of or during the shutdown sequence of each combustion turbine generator. ~~The combustor water injection system shall be fully operational and commence operation immediately after the start-up sequence of the combustion turbine generators. The combustor water injection system shall continue to operate until the commencement of the shutdown sequence of the combustion turbine generators.~~

ii. ~~The operation of the combustor water injection system shall be used whenever the combustion turbine generators are operating at 25 percent peak load and above.~~ For each combustion turbine generator, after completion of the startup sequence and until the beginning of the shutdown sequence, ~~T~~the following water-to-fuel mass ratios, on a one (1) average hour basis, shall be maintained when the combustion turbine generators are firing fuel oil No. 2 in simple cycle operation or in combined cycle operation at loads less than 50 percent of peak load (12.33 MW).

WATER INJECTION SYSTEM
MINIMUM WATER-TO-FUEL MASS RATIO BASED ON LOAD

Combustion Turbine Generator Peak L~~l~~oad (Percent)	**Ratio** (lb-water/lb-fuel)
100 (24.66 MW)	1.04
75 - < 100 (18.50 MW - < 24.66 MW)	0.94
50 - < 75 (12.33 MW - < 18.50 MW)	0.87
~~25-~~ < 50 (< 12.33 MW)	0.72

For operating periods during which the combustion turbine generator operates at multiple loads where multiple water-to-fuel mass ratios apply, the applicable water-to-fuel mass ratio shall be determined based on the load that corresponded to the lowest minimum water-to-fuel mass ratio.

Justification – The requested changes are needed to: 1) clarify the method of determining the applicable minimum water-to-fuel mass ratio for operating hours during which multiple minimum water-to-fuel mass ratios apply; 2) clarify peak load; and 3) revise the water injection system table to address operation of the combustion turbine generators below 25 percent of peak load with water injection.

Proposed change to Attachment IIA, Special Condition No. C.5. Alternate Operating Scenarios: Add alternate operating scenario.

i. The permittee may operate the combustion turbine generator below 25 percent of peak load in isochronous mode with water injection for system restoration.

Justification – The requested change is needed to allow the combustion turbine generator to operate below 25 percent of peak load in isochronous mode with water injection when the combustion turbine generator is started in isochronous mode as a black start unit or for system failure mode.

Proposed change to Attachment IIA, Special Condition No. D.1. Maximum Emission Limits:

a. Except during the startup and shutdown sequences, ~~T~~the permittee shall not discharge or cause the discharge into the atmosphere from the combustion turbine generator nitrogen oxides, sulfur dioxide, particulate matter/PM_{10}, carbon monoxide, volatile organic compounds, and ammonia in excess of the following specified limits:

Combustion Turbine Generator Operating in Simple Cycle Mode

Compound	**Maximum Emission Limit (3-hour Average)**	
	(lbs/hr)	(ppmvd @ 15 percent O_2)
Nitrogen Oxides as NO_2	42.3	42
Sulfur Dioxide	110	79
Particulate Matter/PM_{10}	19.7	0.045 (g/dscf @ 12 percent O_2)
Carbon Monoxide		
100% Peak load (24.66 MW)	26.8	44
75% (18.50 MW) - < 100% (24.66 MW) Peak load	56.4	123
50% (12.33 MW) - < 75% (18.50 MW) Peak load	181.0	566
~~25% (6.17 MW) -~~ < 50% (12.33 MW) Peak load	475.6	2,386
Volatile Organic Compounds		
100% Peak load (24.66 MW)	0.8	2.5
75% (18.50 MW) - < 100% (24.66 MW) Peak load	2.6	11.8
50% (12.33 MW) - < 75% (18.50 MW) Peak load	18.1	178
~~25% (6.17 MW) -~~ < 50% (12.33 MW) Peak load	297.6	3,025

Combustion Turbine Generator Operating in Combined Cycle Mode

Compound	Maximum Emission Limit (3-hour Average)	
	(lbs/hr)	(ppmvd @ 15 percent O_2)
Nitrogen Oxides as NO_2		
50% (12.33 MW) - 100% (24.66 MW) Peak_load	15.1	15
~~25% (6.17 MW) -~~ < 50% (12.33 MW) Peak_load	42.3	42
Sulfur Dioxide	110	79
Particulate Matter/PM_{10}	19.7	0.045 (g/dscf @ 12 percent O_2)
Carbon Monoxide		
100% Peak_load (24.66 MW)	26.9	44
75% (18.50 MW) - < 100% (24.66 MW) Peak_load	50.2	105
50% (12.33 MW) - < 75% (18.50 MW) Peak_load	170.4	523
~~25% (6.17 MW) -~~ < 50% (12.33 MW) Peak_load	457.4	2,218
Volatile Organic Compounds		
100% Peak_load (24.66 MW)	0.8	2.5
75% (18.50 MW) - < 100% (24.66 MW) Peak_load	2.0	8.6
50% (12.33 MW) - < 75% (18.50 MW) Peak_load	25.0	156
~~25% (6.17 MW) -~~ < 50% (12.33 MW) Peak_load	271.0	2,662
Ammonia	4.30	10

b. The three-hour averaging period shall begin immediately upon completion of the combustion turbine generator's startup sequence and end immediately prior to the combustion turbine generator's shutdown sequence. For operating periods during which the combustion turbine generator operates at multiple loads where multiple NO_X and CO emission standards apply, the applicable NO_X and CO emissions limit shall be determined in accordance with 40 CFR § 60.4380(b)(3).

c. The Department of Health, with U.S. EPA Region 9 concurrence, may revise the allowable emission limitation for nitrogen oxides, particulate matter, carbon monoxide, volatile organic compounds, and ammonia after reviewing the initial performance test results required under Attachment IIA, Section G of this Covered Source Permit. The Department of Health, with U.S. EPA Region 9 concurrence, may also revise the water-to-fuel ratios or include ammonia-to-NO_X injection rates if findings through operating parameters and performance test results show an optimum operating range which minimizes emissions.

d. If the nitrogen oxides, particulate matter, carbon monoxide, volatile organic compounds, or ammonia emission limit is revised, the difference between the applicable emission limit set forth above and the revised lower emission limit shall not be allowed as an emission offset for future construction or modification.

Justification – The requested changes are needed to: 1) revise the emission limits table to clarify peak load; 2) clarify the method of determining the applicable emission limit for operating periods during which multiple emission standards apply; 3) clarify the three-hour averaging period; and 4) revise the emission limits tables to address operation of CT-4 and CT-5 below 25 percent of peak load with water injection to address system frequency issues.

Proposed change to Attachment IIA, Section E.: Add monitoring and recordkeeping conditions.

4. Operation Below 25 Percent of Peak Load with Water Injection. The permittee shall maintain records of the total time the combustion turbine generators operate below 25 percent of peak load with water injection. Records of the total time CT-2, CT-4, and CT-5 operated below 25 percent of peak load with water injection, excluding startup and shutdown sequences, and maintenance, testing, and as approved pursuant to Special Condition C.5. of this Attachment, shall be maintained on a monthly and rolling twelve (12) month basis using data recorded by the CEMS.

5. Startup and shutdown.

   a. The following shall be recorded for each startup sequence:

      i. The date, start and end times, and corresponding load (MW) at the end of each twenty (20) minute startup sequence.

      ii. Duration (minutes) of the startup sequence.

      iii. The operating load (MW) at which water injection was initiated.

   b. The following shall be recorded for each shutdown sequence:

      i. The date, start and end times, and corresponding load (MW) at which the combustion turbine controls stop signal was initiated.

      ii. Duration (minutes) of the shutdown sequence.

      iii. The operating load (MW) at which water injection was terminated.

Justification – The requested changes are needed to add monitoring and recordkeeping requirements for operation of CT-4 and CT-5 below 25 percent of peak load with water injection to address system frequency issues.

Proposed change to Attachment IIA, Special Condition Nos. F.6.a and b:

The permittee shall submit **semi-annually** the following written reports to the Department of Health. The report shall be submitted **within sixty (60) days** after the end of each semi-annual calendar period, and shall include the following:

a. A ~~monthly~~ summary ~~listing the time and duration of all~~ ~~start-up~~ identifying all dates, times and durations when the ~~and~~ ~~shut-down~~ shutdown sequences for ~~each~~ the combustion turbine generators exceeded twenty (20) minutes. ~~The summary shall include the combustion turbine generator load (MW) at the time the air pollution control devices and systems are initiated and terminated.~~ The enclosed **Monitoring Report Form: ~~*Daily Start-up*~~ *Combustion Turbine Generator Operation* ~~and Shut-down~~** or ~~similar~~ equivalent form, shall be used.

b. Minimum Operating Loads~~Except for all start-up and shutdown sequences report all periods where the minimum operating load for each combustion turbine was less than 25 percent of the rated capacity. The report shall include the date, time, and duration of each period.~~

   i. All periods when the operating load for the combustion turbine generators was below 25 percent of peak load (4.6 MW) except for all startup and shutdown sequences and as authorized pursuant to Special Condition C.2. of this Attachment. The report shall include the date, time and duration of each period using data recorded by the CEMS. The enclosed Monitoring Report Form: Combustion Turbine Generator Operation or an equivalent form shall be used.

   ii. A monthly summary and rolling 12-month combined total of the hours of operation of the combustion turbine generators, CT-2, CT-4, and CT-5, below 25 percent of peak load (6.17 MW) with water injection excluding startup and shutdown sequences, maintenance, testing, and as approved pursuant to Special Condition C.5. of this Attachment. The report shall be based on data recorded by the CEMS. The enclosed Monitoring Report Form: Monthly Combustion Turbine Generator Operation Below Minimum Operating Load with Water Injection or equivalent form shall be completed for each reporting period.

Justification – The requested changes are needed for reporting operation of CT-4 and CT-5 below 25 percent of peak load with water injection to address system frequency issues.

Proposed change to Attachment IIA, Special Condition No. G.3.:

All performance tests shall be conducted at 25, 50, 75, and 90-to-100 percent of peak load, or highest achievable load ~~of the combustion turbine generators~~. The Department of Health may require the permittee to conduct the performance tests at additional operating loads.

Justification – The requested change is needed for consistency with NSPS subpart GG and to clarify that testing is allowed at highest achievable load if 90-to-100 percent of peak load cannot be physically achieved.

MONITORING REPORT FORM
COMBUSTION TURBINE GENERATOR
COVERED SOURCE PERMIT NO. 0007-01-C
(PAGE 1 OF 2)

Issuance Date: ____________ **Expiration Date:** ______________

In accordance with the HAR, Title 11, Chapter 60.1, Air Pollution Control, the permittee shall report to the Department of Health the following information semi-annually:

(Make Copies for Future Use)

COMPLETE SEPARATE FORMS FOR EACH COMBUSTION TURBINE GENERATOR

For Reporting Period: ______________________________ Date: ______________

Company Name: ____

Facility Name: ____

Equipment Location: ____

Equipment Description: ____

Serial/ID No.: ____

I certify that I have knowledge of the facts herein set forth, that the same are true, accurate, and complete to the best of my knowledge and belief, and that all information not identified by me as confidential in nature shall be treated by the Department of Health as public record.

Responsible Official (Print): ____________________________________

Title: ____

Responsible Official (Signature): _________________________________

Use additional sheets if necessary. Indicate in the appropriate table if there were no exceedances during the reporting period.

1. Combustion turbine generator unit no.: ____________
2. Identify the months of operation: ________________
3. Exceedence of Startup and Shutdown durations:

Exceedence		**Duration (minutes)**		**Reason for Exceedence/ Final Outcome/ Corrective Actions**
Date	**Time**	**Startup**	**Shutdown**	

MONITORING REPORT FORM COMBUSTION TURBINE GENERATOR COVERED SOURCE PERMIT NO. 0007-01-C (PAGE 2 OF 2)	
Issuance Date: ____________	**Expiration Date:** ____________

Combustion Turbine Generator Unit No.: ____________

4. Dates, times and durations when the water injection system was not operated as specified in Special Condition No. C.3.:

Exceedence		Specify Startup, Shutdown or other	Duration (minutes)	Reason for Exceedence Final Outcome/ Corrective Actions
Date	Time			

5. Dates, times, and durations when the combustion turbine generators were operated below 25% of peak load at periods other than during startup, shutdown, or as authorized pursuant to Special Condition C.2. and approved pursuant to Special Condition C.5.:

Date	Time	Duration Below 25% of Peak Load (minutes)	Reason for Exceedence / Final Outcome/ Corrective Actions

MONITORING REPORT FORM
COMBUSTION TURBINE GENERATOR
MONTHLY OPERATION BELOW MINIMUM LOAD WITH WATER INJECTION
COVERED SOURCE PERMIT NO. 0007-01-C

Issuance Date: ____________ **Expiration Date:** ______________

In accordance with the HAR, Title 11, Chapter 60.1, Air Pollution Control, the permittee shall report to the Department of Health the following information semi-annually:

(Make Copies for Future Use)

For Reporting Period: ________________________________ Date: ________________

Company Name: ____

Facility Name: ____

Equipment Location: ____

Equipment Description: ____

Serial/ID Nos.: ____

I certify that I have knowledge of the facts herein set forth, that the same are true, accurate, and complete to the best of my knowledge and belief, and that all information not identified by me as confidential in nature shall be treated by the Department of Health as public record.

Responsible Official (Print): ____

Title: ____

Responsible Official (Signature): ____

Report periods of operation below 25% of peak load with water injection for Units CT-2, CT-4, and CT-5 excluding startup, shutdown, maintenance, testing, and as approved pursuant to Special Condition C.5.

Month	CT-2, CT-4, CT-5 Monthly Total (hours)	Rolling 12-Month Total (hours)

File No.: ________

C-1: Compliance Plan

The Responsible Official shall submit a Compliance Plan as indicated in the Instructions for Applying for an Air Pollution Control Permit and at such other times as requested by the Director of Health (hereafter, Director).

Use separate sheets if necessary.

---

1. Compliance status with respect to all Applicable Requirements:

   Will your facility be in compliance, or is your facility in compliance, with all applicable requirements in effect at the time of your permit application submittal?

   ■ YES { If YES, Complete items a and c below}

   ☐ NO { If NO, complete items a-c below}

   a. Identify all applicable requirement(s) for which compliance is achieved:

      Refer to CSP No. 0007-01-C issued on August 7, 2008 and the June 23, 2009 Administrative Amendment for all applicable requirements. The National Ambient Air Quality Standards (NAAQS) and State Ambient Air Quality Standards (SAAQS) are "Applicable requirement[s]" as defined in HAR § 11-60.1-81.

      Provide a statement that the source is in compliance and will continue to comply with all such requirements.

      The facility is in compliance and will continue to comply with the applicable requirements identified in CSP No. 0007-01-C issued on August 7, 2008 and the June 23, 2009 Administrative Amendment. The NAAQS and SAAQS are "Applicable requirement[s]" as defined in HAR § 11-60.1-81.

   b. Identify all applicable requirement(s) for which compliance is NOT achieved:

      Provide a detailed Schedule of Compliance and a description of how the source will achieve compliance with all such applicable requirements. Use separate sheets of paper, if necessary.

Description of Remedial Action	Expected Date of Completion

c. Identify any other applicable requirement(s) with a future date that your source is subject to. These applicable requirements may be in effect AFTER permit issuance:

Applicable Requirement	Effective Date	Currently in Compliance? Yes

If the source is not currently in compliance, submit a Schedule of Compliance and a description of how the source will achieve compliance with all such requirements:

Description of Proposed Action/Steps to Achieve Compliance	Expected Date of Achieving Compliance

Provide a statement that the source on a timely basis will meet all these applicable requirements.

If the expected date of achieving compliance will NOT meet the applicable requirement's effective date, provide a more detailed description of all remedial actions and the expected dates of completion.

Description of Remedial Action and Explanation	Expected Date of Completion

2. Compliance Progress Reports:

a. If a compliance plan is being submitted to remedy a violation, complete the following information:

Frequency of Submittal: ______________________ Beginning Date: ______________________
(less than or equal to 6 months)

b. Date(s) that the Action described in (1)(b) was achieved:

Remedial Action	Date Achieved

c. Narrative description of why any date(s) in (1) (b) was not met, and any preventive or corrective measures taken in the interim:

RESPONSIBLE OFFICIAL (as defined in HAR §11-60.1-1)

Name (Last): Uchida (First): Norman (MI): M.

Title: Interim Manager, Technical, Maintenance and Special Projects Phone: (808) 969-0422

Mailing Address: P.O. Box 1027

City: Hilo State: HI Zip Code: 96721-1027

Certification by Responsible Official (pursuant to HAR §11-60.1-4)

I certify that I have knowledge of the facts herein set forth, that the same are true, accurate and complete to the best of my knowledge and belief, and that all information not identified by me as confidential in nature shall be treated by the Department of Health as public record. I further state that I will assume responsibility for the construction, modification, or operation of the source in accordance with the Hawaii Administrative Rules, Title 11, Chapter 60.1, Air Pollution Control, and any permit issued thereof.

Name (Print/Type): Norman M. Uchida

(Signature): Norman Uchida Date: 12/8/15

Facility Name: Keahole Generating Station

Location: 73-4249 Pukiawe Street, Kailua Kona, HI 96740

Permit Number: CSP No. 0007-01-C

FOR AGENCY USE ONLY

File/Application No.:

Island:

Date Received:

DEC 1 1 2015
POSTMARK
DEC - 9 2015

Brenner Munger, Ph.D., P.E.
Manager
Environmental Department

Hawai'i Electric Light
Keahole

December 8, 2015

CERTIFIED MAIL NO. 7014 1820 0001 1515 0787
RETURN RECEIPT REQUESTED

Mr. Nolan Hirai, P.E.
Manager, Clean Air Branch
State of Hawaii Department of Health
919 Ala Moana Blvd., Room 203
Honolulu, Hawaii 96814

Dear Mr. Hirai:

Subject: **Application for a Covered Source Permit (CSP) Renewal**
CSP No. 0007-01-C
Keahole Generating Station
Hawai'i Electric Light Company, Inc.

On behalf of Hawai'i Electric Light Company, Inc. (Hawai'i Electric Light), Hawaiian Electric Company, Inc. submitted revisions to the CSP renewal application under a cover letter dated December 3, 2015. However, the cover letter (attached for reference) incorrectly stated that an Application for a Minor Modification to a Covered Source was being submitted.

Hawaiian Electric would like to clarify that the December 3, 2015 submittal includes revisions to the CSP renewal application submitted to the Department on July 30, 2012 and not an application for a minor modification.

We apologize for any confusion this may have caused. If you have any questions regarding this submittal and the December 3, 2015 submittal, please contact Karin Kimura at 543-4522 or karin.kimura@hawaiianelectric.com.

Sincerely,

Denise E. Mills

Denise E. Mills
Principal Environmental Scientist
FOR Brenner Munger

Attachment

cc w/ Att: **CERTIFIED MAIL RETURN RECEIPT REQUESTED**
Mr. Gerardo Rios [Article No. 7014 1200 0002 3428 9131]
Chief, Permits Office
Air Division
U.S. EPA Region 9
75 Hawthorne Street
Mail Code: AIR-3
San Francisco, CA 94105

2p

HAND DELIVERED
DEC - 7 2015
COPY

Brenner Munger, Ph.D., P.E.
Manager
Environmental Department

Hawai'i Electric Light
Keahole

December 3, 2015

HAND DELIVERY

Mr. Nolan Hirai, P.E.
Manager, Clean Air Branch
State of Hawaii Department of Health
919 Ala Moana Blvd., Room 203
Honolulu, Hawaii 96814

Dear Mr. Hirai:

Subject: **Application for a Covered Source Permit (CSP) Renewal**
CSP No. 0007-01-C
Keahole Generating Station
Hawai'i Electric Light Company, Inc.

On behalf of Hawai'i Electric Light Company, Inc. (Hawai'i Electric Light), Hawaiian Electric Company, Inc. submits an original and one copy of the Application for a Minor Modification to a Covered Source for Hawai'i Electric Light's Keahole Generating Station CSP No. 0007-01-C.

Hawai'i Electric Light requests to replace the existing Miratech V-CAT Diesel Oxidation Catalyst (DOC) in units D-21, D-22, and D-23 with an alternative DOC that will also comply with the applicable 40 CFR Part 63 Subpart ZZZZ National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines (RICE NESHAP) carbon monoxide (CO) reduction requirement or CO emission limit.

The original CSP renewal application was submitted to the Department on July 30, 2012 to incorporate the applicable RICE NESHAP requirements into the CSP and for approval to install the Miratech V-CAT DOC in units D-21, D-22, and D-23.

On July 30, 2012, Hawai'i Electric Light also submitted a request to the Department for approval to install the Miratech V-CAT DOC on units D-21, D-22, and D-23 to comply with the RICE NESHAP. On August 3, 2012 and in accordance with HAR §11-60.1-82(k)(1), the Department approved the installation of the Miratech V-CAT DOC prior to issuance of the amended CSP.

The following revised forms are enclosed:

- Form S-1 Standard Air Pollution Control Permit Application Form
- Form S-3 Application for a Covered Source Renewal

The enclosed revised CSP application materials are direct replacements for the forms and attachments in the application submitted to the Department on July 30, 2012.

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DEC - 7 2015

Brenner Munger, Ph.D., P.E.
Manager
Environmental Department

Hawai'i Electric Light
Keahole

December 3, 2015

HAND DELIVERY

Mr. Nolan Hirai, P.E.
Manager, Clean Air Branch
State of Hawaii Department of Health
919 Ala Moana Blvd., Room 203
Honolulu, Hawaii 96814

Dear Mr. Hirai:

Subject: **Request to Install and Operate Air Pollution Control Equipment**
CSP No. 0007-01-C
Keahole Generating Station
Hawai'i Electric Light Company, Inc.

Hawai'i Electric Light Company, Inc. (Hawai'i Electric Light) requests to replace the existing Miratech V-CAT Diesel Oxidation Catalyst (DOC) in units D-21, D-22, and D-23 with an alternative DOC that will also comply with the applicable 40 CFR Part 63 Subpart ZZZZ National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines (RICE NESHAP) carbon monoxide (CO) reduction requirement or CO emission limit.

In accordance with HAR § 11-60.1-82(k)(1), Hawai'i Electric Light requests the Department to provide written approval for installation of the alternative DOC prior to issuance of the amended CSP.

The original CSP renewal application was submitted to the Department on July 30, 2012 which included a request to incorporate the applicable RICE NESHAP requirements into the CSP and for approval to install the Miratech V-CAT DOC in units D-21, D-22, and D-23.

On July 30, 2012, Hawai'i Electric Light also submitted a request to the Department for approval to install the Miratech V-CAT DOC on units D-21, D-22, and D-23 prior to the issuance of the amended CSP to comply with the RICE NESHAP. On August 3, 2012 and in accordance with HAR §11-60.1-82(k)(1), the Department approved the installation of the Miratech V-CAT DOC.

Additional information regarding the proposed modification to replace the Miratech V-CAT DOC with an alternative DOC is included in the enclosed revised CSP application materials dated December 3, 2015 which were submitted to the Department under a separate cover letter.

If you have any questions regarding this submittal, please contact Karin Kimura at 543-4522 or karin.kimura@hawaiianelectric.com.

Sincerely,

Brenner Munger

Enclosure: Revised Application for a Covered Source Renewal Materials

cc w/ Encl: **CERTIFIED MAIL RETURN RECEIPT REQUESTED**
Mr. Gerardo Rios [Article No. 7014 1200 0002 3428 8769]
Chief, Permits Office
Air Division
U.S. EPA Region 9
75 Hawthorne Street
Mail Code: AIR-3
San Francisco, CA 94105

HAND DELIVERED
DEC - 7 2015

Brenner Munger, Ph.D., P.E.
Manager
Environmental Department

Hawai'i Electric Light
Keahole

December 3, 2015

HAND DELIVERY

Mr. Nolan Hirai, P.E.
Manager, Clean Air Branch
State of Hawaii Department of Health
919 Ala Moana Blvd., Room 203
Honolulu, Hawaii 96814

Dear Mr. Hirai:

Subject: **Application for a Covered Source Permit (CSP) Renewal**
CSP No. 0007-01-C
Keahole Generating Station
Hawai'i Electric Light Company, Inc.

On behalf of Hawai'i Electric Light Company, Inc. (Hawai'i Electric Light), Hawaiian Electric Company, Inc. submits an original and one copy of the Application for a Minor Modification to a Covered Source for Hawai'i Electric Light's Keahole Generating Station CSP No. 0007-01-C.

Hawai'i Electric Light requests to replace the existing Miratech V-CAT Diesel Oxidation Catalyst (DOC) in units D-21, D-22, and D-23 with an alternative DOC that will also comply with the applicable 40 CFR Part 63 Subpart ZZZZ National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines (RICE NESHAP) carbon monoxide (CO) reduction requirement or CO emission limit.

The original CSP renewal application was submitted to the Department on July 30, 2012 to incorporate the applicable RICE NESHAP requirements into the CSP and for approval to install the Miratech V-CAT DOC in units D-21, D-22, and D-23.

On July 30, 2012, Hawai'i Electric Light also submitted a request to the Department for approval to install the Miratech V-CAT DOC on units D-21, D-22, and D-23 to comply with the RICE NESHAP. On August 3, 2012 and in accordance with HAR §11-60.1-82(k)(1), the Department approved the installation of the Miratech V-CAT DOC prior to issuance of the amended CSP.

The following revised forms are enclosed:

- Form S-1 Standard Air Pollution Control Permit Application Form
- Form S-3 Application for a Covered Source Renewal

The enclosed revised CSP application materials are direct replacements for the forms and attachments in the application submitted to the Department on July 30, 2012.

If you have any questions regarding this submittal, please contact Karin Kimura at 543-4522 or karin.kimura@hawaiianelectric.com.

Sincerely,

Brennon Munger

Enclosures: (1) Form S-1 Standard Air Pollution Control Permit Application Form
(2) Form S-3 Application for a Covered Source Renewal

cc w/ Encl: **CERTIFIED MAIL RETURN RECEIPT REQUESTED**
Mr. Gerardo Rios [Article No. 7014 1200 0002 3428 8769]
Chief, Permits Office
Air Division
U.S. EPA Region 9
75 Hawthorne Street
Mail Code: AIR-3
San Francisco, CA 94105

File / Application No.:____________

S-1: Standard Air Pollution Control Permit Application Form

(Covered Source Permit and Noncovered Source Permit)

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DEC - 7 2015

State of Hawaii
Department of Health
Environmental Management Division
Clean Air Branch
P. O. Box 3378 • Honolulu, HI 96801-3378 • Phone: (808) 586-4200

1. Company Name: Hawaii Electric Light Company, Inc. (Hawai'I Electric Light)
2. Facility Name (if different from the Company): Keahole Generating Station
3. Mailing Address: 73-4249 Pukiawe Street

   City: Kailua Kona State: HI Zip Code: 96740

   Phone Number: (808) 935-1711
4. Name of Owner/Owner's Agent: Brenner Munger (Owner's Agent)

   Title: Manager, Environmental Department Phone: (808) 543-4500

   Mailing Address: Hawaiian Electric Company; PO Box 2750

   City: Honolulu State: HI Zip Code: 96840-0001
5. Plant Site Manager/Other Contact: Norman Uchida

   Title: Interim Manager, Technical, Maintenance and Special Projects Phone: (808) 969-0422

   Mailing Address: P.O. Box 1027

   City: Hilo State: HI Zip Code: 96721
6. Permit Application Basis: (Check appropriate boxes)

   ☐ Initial Permit for a New Source ☐ Initial Permit for an Existing Source

   ■ Renewal of Existing Permit ☐ General Permit

   ☐ Temporary Source ☐ Transfer of Permit

   ☐ Modification to a Covered Source: ➔ Is modification? ☐ Significant ☐ Minor ☐ Uncertain

   ☐ Modification to a Noncovered Source
7. If renewal or modification, include existing permit number: CSP No. 0007-01-C
8. Does the Proposed Source require a County Special Management Area Permit? ☐ Yes ■ No
9. Type of Source (Check One): ☐ Covered Source ■ Covered & PSD Source

   ☐ Noncovered Source ☐ Uncertain
10. Standard Industrial Classification Code (SICC), if known: 4911

11. Proposed Equipment/Plant Location (e.g. street address): 73-4249 Pukiawe Street

City: Kailua Kona State: HI Zip Code: 96740

UTM Coordinates (meters): East: 811,293 North: 2,184,955

UTM Zone: 4 UTM Horizontal Datum: ■ Old Hawaiian ☐ NAD-27 ☐ NAD-83

12. General Nature of Business: Electrical Generation

13. Date of Planned Commencement of Installation or Modification: Upon approval of modification.

14. Is *any* of the equipment to be leased to another individual or entity? ☐ Yes ■ No

15. Type of Organization: ■ Corporation ☐ Individual Owner ☐ Partnership

☐ Government Agency (Government Facility Code: __________)

☐ Other: __________

Any applicant for a permit who fails to submit any relevant facts or who has submitted incorrect information in any permit application shall, upon becoming aware of such failure or incorrect submittal, promptly submit such supplementary facts or corrected information. In addition, an applicant shall provide additional information as necessary to address any requirements that become applicable to the source after the date it filed a complete application, but prior to the issuance of the noncovered source permit or release of a draft covered source permit. (HAR § 11-60.1-64 & 11-60.1-84)

RESPONSIBLE OFFICIAL (as defined in §11-60.1-1):

Name (Last): Uchida (First): Norman (MI): M.

Title: Interim Manager, Technical, Maintenance and Special Projects Phone: (808) 969-0422

Mailing Address: P.O. Box 1027

City: Hilo State: HI Zip Code: 96721-1027

CERTIFICATION by Responsible Official (pursuant to §11-60.1-4):

I certify that I have knowledge of the facts herein set forth, that the same are true, accurate and complete to the best of my knowledge and belief, and that all information not identified by me as confidential in nature shall be treated by the Department of Health as public record. I further state that I will assume responsibility for the construction, modification, or operation of the source in accordance with the Hawaii Administrative Rules (HAR), Title 11, Chapter 60.1, Air Pollution Control, and any permit issued thereof.

NAME (Print/Type): Norman M. Uchida

(Signature): Norman Uchida Date: 11/24/15

FOR AGENCY USE ONLY:

File/Application No: __________

Island: __________

Date Received: __________

Submit the following documents as part of your application:

A. The ***Emissions Units Table***, filled in as completely as possible. Use separate sheets of paper as needed. General instructions include the following:

1. Identify each **emission point** with a unique number for this plant site, consistent with emission point identification used on the location drawing and previous permits; if known, provide the SICC number. Emission points shall be identified and described in sufficient detail to establish the basis for fees and applicability of requirements of HAR, Chapter 11-60.1. Examples of emission point names are: heater, vent, boiler, tank, baghouse, fugitive, etc. Abbreviations may be used.
   a. For each emission point use as many lines as necessary to list regulated and hazardous air pollutant data. For hazardous air pollutants, also list the Chemical Abstracts Service number (CAS#).
   b. Indicate the emission points that discharge together for any length of time.
   c. The **Equipment Date** is the date of equipment construction, reconstruction, or modification. Provide supporting documentation.

2. State the **maximum emission rates** in terms sufficient to establish compliance with the applicable requirements and standard reference test methods. Provide all supporting emission calculations and assumptions:
   a. Include all regulated and hazardous air pollutants and air pollutants for which the source is major, as defined in HAR §11-60.1-1. Examples of regulated pollutant names are: Carbon Monoxide (CO), Nitrogen Oxides (NO_X), Sulfur Dioxide (SO_2), Volatile Organic Compounds (VOC), particulate matter (PM), and particulate less than 10 microns (PM_{10}). Abbreviations may be used.
   b. Include fugitive emissions.
   c. **Pounds per hour (#/HR)** is the maximum potential emission rate expected by applicant.
      Tons per year is the annual maximum potential emissions expected by the applicant, taking into account the typical operating schedule.

3. Describe ***Stack Source Parameters***:
   a. **Stack Height** is the height above the ground.
   b. **Direction** refers to the exit direction of stack emissions: up, down or horizontal.
   c. **Flow Rate** is the actual, not the calculated, flow rate.

4. Provide any additional information, if applicable, as follows:
   a. If combinations of different fuels are used that cause any of the stack source parameters to differ, complete one row for each possible set of stack parameters and identify each fuel in the **Equipment Description**.
   b. For a rectangular stack, indicate the length and width.
   c. Provide any information on stack parameters or any stack height limitations developed pursuant to Section 123 of the Clean Air Act.

B. A **process flow diagram** identifying all equipment used in the process, including the following:
   1. Identify and describe each emission point.
   2. Identify the locations of safety valves, bypasses, and other such devices which when activated may release air pollutants to the atmosphere.

C. A **facility location map**, drawn to a reasonable scale and showing the following:
   1. The property involved and all structures on it. Identify property/fence lines plainly.
   2. Layout of the facility.
   3. Location and identification of the proposed emissions unit on the property.
   4. Location of the property and equipment with respect to streets and all adjacent property. Show the location of all structures within 325 meters of the applicant's emissions unit. Provide the building dimensions (height, length, and width) of all structures that have heights greater than 40% of the stack height of the emissions unit.

D. Provide a description of any proposed modifications or permit revisions. Include any justification or supporting information for the proposed modifications or permit revisions.

File No.: ________

S-3: Application for a Covered Source Permit Renewal

Each application for permit renewal shall be submitted to the Director of Health, (hereafter, Director) a minimum of **twelve months** prior to the date of permit expiration. In providing the required information, please reference the corresponding letters and numbers listed below.

Provide a minimum of **two (2)** sets (1 original and 1 copy) of all application materials to the Hawaii Department of Health. Also, mail **one (1)** set directly to EPA at the following address:

Chief (Attention: AIR-3)
Permits Office, Air Division
U.S. Environmental Protection Agency
Region 9
75 Hawthorne Street
San Francisco, CA 94105

I. In accordance with Hawaii Administrative Rules (HAR) §11-60.1-101, the following information is required:

A. Statement certifying that no changes have been made in the design or operation of the source as proposed in the initial and any subsequent Covered Source Permit applications. If changes have occurred or are being proposed, the applicant shall provide a description of those changes such as work practices, operations, equipment design, and monitoring procedures, including the affected applicable requirements associated with the changes and the corresponding information to determine the applicability of all applicable requirements.

The source continues to operate as proposed in the initial and subsequent covered source permit applications.

Diesel engine generators, D-21, D-22, and D-23, are subject to 40 CFR Part 63 Subpart ZZZZ, National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines (RICE NESHAP). These units are subject to the applicable emissions and operating limitations for existing non-emergency compression ignition (CI) stationary RICE with a site rating of greater than 500 brake HP located at area sources of HAP emissions and to the fuel requirements applicable to existing non-emergency CI stationary RICE with a site rating of more than 300 brake HP with a displacement of less than 30 liters per cylinder. To comply with these applicable RICE NESHAP requirements, Hawai'i Electric Light proposes the following modifications for D-21, D-22, and D-23.

a. Installation of Diesel Oxidation Catalyst (DOC) on units D-21, D-22, and D-23. The DOC will reduce CO emissions by at least 70 percent or limit CO emissions to 23 ppmvd at 15 percent O_2

b. Use of diesel fuel with a maximum sulfur content of 0.0015 percent by weight and a minimum Cetane index of 40 or a maximum aromatic content of 35 volume percent.

Units D-21, D-22, and D-23 are equipped with a lube oil separator that conforms with 40 CFR § 63.6625(g). Refer to manufacturer literature in Attachment S-3a. These EMD 645 units are turbo charged units.

Hawai'i Electric Light requests incorporation of the applicable RICE NESHAP operational and emission limitations, monitoring and recordkeeping, notification and reporting, and testing requirements into CSP No. 0007-01-C.

As part of the renewal process, Hawai'i Electric Light proposes permit condition changes. Attachments S-3c and S-3d lists the proposed changes to CSP Nos. 0007-01-C and 0070-01-C, respectively. Proposed additions are underlined and proposed deletions are struck through. The renewal application also seeks to merge CSP No. 0070-1-C into CSP No. 0007-01-C.

B. Equipment Specifications:

1. Maximum design capacity. See table below.

2. Fuel type. No. 2 diesel fuel with a maximum sulfur content of 0.4 percent by weight for units CT-2, CT-4, CT-5, and BS-1. No. 2 diesel with a maximum sulfur content of 0.4 percent by weight sulfur content for units D-21, D-22, and D-23 through May 2, 2013 and beginning May 3, 2013, No. 2 diesel with a maximum sulfur content of 0.0015 percent by weight and a minimum Cetane index of 40 or a maximum aromatic content of 35 volume percent.

3. Fuel use. See table below.

Maximum Capacity and Fuel Use Per Unit

Unit ID	Manufacturer	Model Number	Serial Number	Capacity (Nominal)	Fuel Flow Rate
D-21	General Motors	20-645F4B	74-B1-1078	2.5 MW	28.1 MMBtu/hr
D-22	General Motors	20-645F4B	66-K1-1062	2.5 MW	28.1 MMBtu/hr
D-23	General Motors	20-645E4	69-H1-1057	2.5 MW	28.1 MMBtu/hr
BS-1	Caterpillar	3412	81Z07275	500 kW	5.57 MMBtu/hr
CT-2	Jupiter	GT-35	JF88702	18 MW	198 MMBtu/hr
CT-4	General Electric	LM2500	481-688	20 MW	275 MMBtu/hr
CT-5	General Electric	LM2500	481-692	20 MW	275 MMBtu/hr
ST-7				16 MW	NA

4. Production capacity. Not applicable.

5. Production rates. Not applicable.

6. Raw materials. Not applicable.

7. Provide any manufacturer's literature. See Attachment S-3a for manufacturer's literature.

C. Provide detailed descriptions of all processes and products defined by Standard Industrial Classification Code (SICC). Also, provide any reasonably anticipated alternative operating scenarios, associated processes, and products, by SICC.

Electrical power generation through combustion of fossil fuels (SICC 4911) is the only product or process.

Several types of alternative operating scenarios apply to the generating station as described below:

a. Use of a temporary replacement unit in the event of a failure or major overhaul of an installed unit. In the event that the projected down time of the unit increases the likelihood of an interruption in electrical service, the down unit would be replaced with an equivalent unit. Emissions from the replacement unit will comply with the original unit's permitted emission limits. Proposed changes to add a permanent replacement AOS are in Attachment S-3c.

b. CT-4 and CT-5 may operate below 25% of peak load during testing of the heat recovery steam generators and steam turbine and steam blows needed to clean the steam tubes prior to initial operation.

c. Should less expensive fuels become available, or the supply of No. 2 diesel become limited, HELCO may use alternative fuels with prior approval from the Department of Health.

d. In the event of emergency load conditions such as the sudden loss of a unit, CT-2, CT-4 and CT-5 may operate up to 110 percent of peak load for up to 30 minutes. Such operation will not exceed the permitted 3-hour average emission rates.

e. Fuel additives to reduce corrosion, control biological growth, and enhance combustion may be used in CT-4 and CT-5.

f. Hawai'i Electric Light, with the approval from the Department of Health, may use alternate means and methods to improve combustion and/or reduce emissions for CT-4 and CT-5.

1. Identify and describe in detail all air pollution control equipment and compliance monitoring devices or activities, and to the extent of available information, an estimate of emissions before and after controls. Provide all calculations and assumptions.

   Fuel injection timing retard (FITR) is used on D-21, D-22, and D-23 to control NO_X emissions. Water injection is used on CT-2 reduce NO_X emissions to 47 ppmvd at 15 percent O_2, with a fuel-bound nitrogen content of 0.015 percent or less. When CT-4 and CT-5 are operating in combined cycle mode at loads less than 50% of peak load and simple cycle mode, water injection is used on CT-4 and CT-5 to reduce NO_X emissions to 42 ppmvd at 15 percent O_2, with a fuel-bound nitrogen content of 0.0015 percent of less. When CT-4 and CT-5 are operating in combined cycle mode at 50% or more of peak load, water injection in combination with selective catalytic reduction (SCR) is used to reduce NO_X emissions to 15 ppmvd at 15 percent O_2, with a fuel-bound nitrogen content of 0.015 percent or less. The design of the SCR system will limit ammonia slip to 10 ppmvd at 15 percent O_2. SO_2 emissions are controlled by limiting the fuel sulfur content to 0.4 percent by weight for CT-2, CT-4, CT-5, and BS-1 and 0.0015 percent by weight for D-21, D-22, and D-23. Emissions of PM, PM_{10}, CO, and VOC are controlled by combustion design and good combustion practices. CO emissions for D-21, D-22, and D-23 will be controlled by a DOC. The DOC will reduce CO emissions by at least 70 percent or limit CO emissions to 23 ppmvd at 15 percenct O_2. Emissions of hazardous air pollutants are controlled by the use of No. 2 fuel oil and combustion system design. Refer to Attachment S-1d for emission rate calculations.

   Compliance monitoring devices and activities are discussed in Form C-2.

2. List all ***insignificant*** activities in accordance with HAR §11-60.1-82.

   Refer to Attachment S-3b for a list of insignificant activities.

D. Maximum Operating Schedule (to the extent needed to determine or regulate emissions):

1. Total hours per day, per week, and/or per month.

   The planned operation of units D-22, D-23, CT-2, CT-4, and CT-5 is up to 24 hours per day, seven days per week. Units BS-1 and D-21 will operate as needed. Depending on future dispatch requirements, the plant may cycle off-line daily, or operate at reduced loads. While expected operating levels are less than continuous, there may be times when the units must be run continuously for extended periods of time. Thus, this application does not propose any annual operating limits for units D-22, D-23, CT-4, and CT-5. Fuel consumption is limited on a rolling 12-month basis to 12,301,254 gallons (292,887 barrels) in CT-2 and 70,000 gallons in D-21.

2. Total hours per year.

   Units D-22, D-23, CT-4, and CT-5 will operate 8760 hours per year. Fuel consumption is limited on a rolling 12-month basis to 12,301,254 gallons (292,887 barrels) in CT-2 and 70,000 gallons in D-21. Operation of BS-1 is limited to 300 hours on a rolling 12-month basis.

3. If operation is seasonal or irregular, describe. Refer to D.1 and 2 above.

E. Cite and describe all applicable requirements as defined in HAR §11-60.1-81, including the following:

1. Description of or reference to any applicable test methods for determining compliance with each applicable requirement. Refer to Form C-2.

2. Explanation of all proposed exemptions from any applicable requirements.

   Refer to Forms C-1 and C-2.

F. Identify and describe current operational limitations or work practices that affect emissions of any regulated or hazardous air pollutant. Provide all calculations and assumptions.

Fuel injection timing retard (FITR) is used on units D-21, D-22, and D-23 to control NO_X emissions. Water injection is used on CT-2 reduce NO_X emissions to 47 ppmvd at 15 percent O_2, with a fuel-bound nitrogen content of 0.015 percent or less. When CT-4 and CT-5 are operating in combined cycle mode at loads less than 50% of peak load and simple cycle mode, water injection is used on CT-4 and CT-5 to reduce NO_X emissions to 42 ppmvd at 15 percent O_2, with a fuel-bound nitrogen content of 0.015 percent of less. When CT-4 and CT-4 are operating in combined cycle mode at 50% or more of peak load, water injection in combination with selective catalytic reduction (SCR) is used to reduce NO_X emissions to 15 ppmvd at 15 percent O_2, with a fuel-bound nitrogen content of 0.015 percent or less. The design of the SCR system will limit ammonia slip to 10 ppmvd at 15 percent O_2. Sulfur dioxide emissions are controlled by limiting the fuel sulfur content to 0.4 percent by weight for CT-2, CT-4, CT-5, and BS-1 and 0.0015 percent by weight for D-21, D-22, and D-23. CO emissions beginning on or before May 3, 2013 will be controlled by a DOC. The DOC will reduce CO emissions by at least 70% or limit CO emissions to 23 ppmvd at 15 percent O_2. Emissions of PM, PM_{10}, and VOC are controlled by combustion design and good combustion practices. Emissions of hazardous air pollutants are controlled by the use of No. 2 fuel oil and combustion system design.

G. For ***new*** covered sources and ***significant*** modifications which increase the emissions of any air pollutant or result in the emission of any air pollutant not previously emitted, an assessment of the ambient air quality impact of the covered source or significant modification, with the inclusion of any available background air quality data. The assessment shall include all supporting data, calculations and assumptions, and a comparison with the NAAQS and SAAQS.

Not applicable. The facility is an existing covered source and is undergoing a renewal of an existing permit as defined by the covered source rules.

H. For ***new*** covered sources and ***significant*** modifications subject to the requirements of subchapter 7 of HAR Chapter 11-60.1, all analyses, assessments, monitoring, and other application requirements of subchapter 7.

Not applicable. The facility is an existing covered source and is not undergoing any modification or increase in emissions as defined in Subchapter 7.

I. Provide detailed information to define permit terms and conditions for any proposed ***emissions trading*** within the facility in accordance with HAR §11-60.1-96.

No emissions trading is proposed.

J. Provide the following for Compliance purposes:
1. A Compliance Plan, Form C-1.
2. A Compliance Certification, Form C-2.

II. Submit an application fee according to the Application Fee Schedule in the <u>Instructions for Applying for an Air Pollution Control Permit</u>.

III. Provide other information as follows:

A. As required by any applicable requirement or as requested and deemed necessary by the Director to make a decision on the application.

B. As may be necessary to implement and enforce other applicable requirements of the Clean Air Act or of HAR Chapter 11-60.1 or to determine the applicability of such requirements.

IV. The Director reserves the right to request the following information:

A. An assessment of the ambient air quality impact of the source or modification. The assessment shall include all supporting data, calculations and assumptions, and a comparison with the National Ambient Air Quality Standards and State Ambient Air Quality Standards.

B. A risk assessment of the air quality related impacts caused by the covered source or significant modification to the surrounding environment.

C. Results of source emissions testing, ambient air quality monitoring, or both.

D. Information on other available control technologies.

V. An application shall be determined to be complete only when all of the following have been complied with:

A. All information required or requested in numbers **I, III, and IV** has been submitted.

B. All documents requiring certification have been certified pursuant to HAR §11-60.1-4.

C. All applicable fees have been submitted.

D. The Director has certified that the application is complete.

VI. The Director shall not continue to act upon or consider an incomplete application.

A. The applicant shall be notified in writing whether the application is complete. Unless the Director requests additional information or notifies the applicant of incompleteness within sixty days of receipt of an application, the application shall be deemed complete.

B. During the processing of an application that has been determined or deemed complete, if the Director determines that additional information is necessary to evaluate or take final action on the application, the Director may request such information in writing and set a reasonable deadline for a response. As set forth in HAR §11-60.1-82, the covered source's ability to operate and the validity of the Covered Source Permit shall continue beyond the permit expiration date until the final permit is issued or denied, provided the applicant submits all additional information within the reasonable deadline specified by the Director.

VII. After receipt of a complete application, the Director, in writing, shall approve, conditionally approve, or deny an application:

A. Within twelve months, ***except*** for applications for renewal for coverage under a covered source general permit. If the application for renewal has not been approved or denied within twelve months, the Covered Source Permit and all its terms and conditions shall remain in effect and not expire until the application for renewal has been approved or denied and provided the applicant has submitted any additional information within the reasonable deadline specified by the Director.

B. Within six months for applications for renewal requesting coverage under a covered source general permit. If the application for renewal has not been approved or denied within six months, the coverage under the covered source general permit and all its terms and conditions shall remain in effect and not expire until the application for renewal has been approved or denied and provided the applicant has submitted any additional information within the reasonable deadline specified by the Director.

VIII. A Covered Source Permit renewal application shall be approved only if the Director determines that the operation of the covered source will be in compliance with all applicable requirements.

IX. The Director shall provide for public notice, including the method by which a public hearing can be requested, and an opportunity for public comment on the draft Covered Source Permit renewal in accordance with HAR §11-60.1-99.

X. The Director shall provide a statement that sets forth the legal and factual bases for the draft permit conditions (including references to the applicable statutory or regulatory provisions) to EPA and any other person requesting it.

XI. Each application for renewal and proposed Covered Source Permit shall be subject to EPA oversight in accordance with HAR §11-60.1-95.

File No.: ________

C-1: Compliance Plan

The Responsible Official shall submit a Compliance Plan as indicated in the Instructions for Applying for an Air Pollution Control Permit and at such other times as requested by the Director of Health (hereafter, Director).

Use separate sheets if necessary.

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1. Compliance status with respect to all Applicable Requirements:

   Will your facility be in compliance, or is your facility in compliance, with all applicable requirements in effect at the time of your permit application submittal?

   ■ YES { If YES, Complete items a and c below}

   ☐ NO { If NO, complete items a-c below}

   a. Identify all applicable requirement(s) for which compliance is achieved:

      Refer to CSP No. 0007-01-C issued on August 7, 2008 and the June 23, 2009 Administrative Amendment for all applicable requirements. The National Ambient Air Quality Standards (NAAQS) and State Ambient Air Quality Standards (SAAQS) are "Applicable requirement[s]" as defined in HAR § 11-60.1-81.

      Provide a statement that the source is in compliance and will continue to comply with all such requirements.

      The facility is in compliance and will continue to comply with the applicable requirements identified in CSP No. 0007-01-C issued on August 7, 2008 and the June 23, 2009 Administrative Amendment. The NAAQS and SAAQS are "Applicable requirement[s]" as defined in HAR § 11-60.1-81.

   b. Identify all applicable requirement(s) for which compliance is NOT achieved:

      Provide a detailed Schedule of Compliance and a description of how the source will achieve compliance with all such applicable requirements. Use separate sheets of paper, if necessary.

Description of Remedial Action	Expected Date of Completion

c. Identify any other applicable requirement(s) with a future date that your source is subject to. These applicable requirements may be in effect AFTER permit issuance:

Applicable Requirement	Effective Date	Currently in Compliance? Yes

If the source is not currently in compliance, submit a Schedule of Compliance and a description of how the source will achieve compliance with all such requirements:

Description of Proposed Action/Steps to Achieve Compliance	Expected Date of Achieving Compliance

Provide a statement that the source on a timely basis will meet all these applicable requirements.

____

____

____

____

____

If the expected date of achieving compliance will NOT meet the applicable requirement's effective date, provide a more detailed description of all remedial actions and the expected dates of completion.

Description of Remedial Action and Explanation	Expected Date of Completion

2. Compliance Progress Reports:

   a. If a compliance plan is being submitted to remedy a violation, complete the following information:

   Frequency of Submittal: ____________________ Beginning Date: ____________________
   (less than or equal to 6 months)

b. Date(s) that the Action described in (1)(b) was achieved:

Remedial Action	Date Achieved

c. Narrative description of why any date(s) in (1) (b) was not met, and any preventive or corrective measures taken in the interim:

RESPONSIBLE OFFICIAL (as defined in HAR §11-60.1-1)

Name (Last): Uchida (First): Norman (MI): M.

Title: Interim Manager, Technical, Maintenance and Special Projects Phone: (808) 969-0422

Mailing Address: P.O. Box 1027

City: Hilo State: HI Zip Code: 96721-1027

Certification by Responsible Official (pursuant to HAR §11-60.1-4)

I certify that I have knowledge of the facts herein set forth, that the same are true, accurate and complete to the best of my knowledge and belief, and that all information not identified by me as confidential in nature shall be treated by the Department of Health as public record. I further state that I will assume responsibility for the construction, modification, or operation of the source in accordance with the Hawaii Administrative Rules, Title 11, Chapter 60.1, Air Pollution Control, and any permit issued thereof.

Name (Print/Type): Norman M. Uchida

(Signature): Norman Uchida Date: 11/24/15

Facility Name: Keahole Generating Station

Location: 73-4249 Pukiawe Street, Kailua Kona, HI 96740

Permit Number: CSP No. 0007-01-C

FOR AGENCY USE ONLY

File/Application No.:

Island:

Date Received:

File No.: ______

C-2: Compliance Certification

The Responsible Official shall submit a Compliance Certification as indicated in the Instructions for Applying for an Air Pollution Control Permit and at such other times as requested by the Director of Health (hereafter, Director).

Complete as many copies of this form as necessary. Use separate sheets of paper if necessary.

RESPONSIBLE OFFICIAL (as defined in HAR §11-60.1-1)

Name (Last): Uchida (First): Norman (MI): M.

Title: Interim Manager, Technical, Maintenance and Special Projects Phone: (808) 969-0422

Mailing Address: P.O. Box 1027

City: Hilo State: HI Zip Code: 96721-1027

Certification by Responsible Official (pursuant to HAR §11-60.1-4)

I certify that I have knowledge of the facts herein set forth, that the same are true, accurate and complete to the best of my knowledge and belief, and that all information not identified by me as confidential in nature shall be treated by the Department of Health as public record. I further state that I will assume responsibility for the construction, modification, or operation of the source in accordance with the Hawaii Administrative Rules, Title 11, Chapter 60.1, Air Pollution Control, and any permit issued thereof.

Name (Print/Type): Norman M. Uchida

(Signature): Norman Uchida Date: 11/24/15

Facility Name: Keahole Generating Station

Location: 73-4249 Pukiawe Street, Kailua Kona, HI 96740

Permit Number: CSP Nos. 0007-01-C

FOR AGENCY USE ONLY	
File/Application No.:	
Island:	
Date Received:	

Complete the following information for ***each*** applicable requirement that applies to ***each*** emissions unit at the source. Also include any additional information as required by the Director. The compliance certification may reference information contained in a previous compliance certification submittal to the director, provided such referenced information is certified as being current and still applicable.

1. Schedule for submission of Compliance Certifications during the term of the permit:

   Frequency of Submittal: In accordance with §11-60.1-86.

   Beginning Date: In accordance with §11-60.1-86.

2. Emissions Unit No./Description:

Unit ID	Manufacturer	Model No.	Capacity (Nominal)
D-21	General Motors	20-645F4B	2.5 MW
D-22	General Motors	20-645F4B	2.5 MW
D-23	General Motors	20-645E4	2.5 MW
CT-2	Jupiter	GT-35	18 MW
CT-4	General Electric	LM2500	20 MW
CT-5	General Electric	LM2500	20 MW
BS-1	Caterpillar	3412	500 kW

3. Identify the applicable requirement(s) that is/are the basis of this certification:

   See Attachments C-2a (CSP No. 0007-01-C issued August 7, 2008) and C-2b (CSP No. 0070-01-C issued January 12, 2006).

4. Compliance status:

   a. Will the emissions unit be in compliance with the identified applicable requirement(s)?

      ■ YES ☐ NO

   b. If YES, will compliance be continuous or intermittent?

      ■Continuous ☐ Intermittent

   c. If NO, explain.

5. Describe the methods to be used in determining compliance of the emissions unit with the applicable requirement(s), including any monitoring, recordkeeping, reporting requirements, and/or test methods:

   See Attachments C-2a (CSP No. 0007-01-C issued August 7, 2008) and C-2b (CSP No. 0070-01-C issued January 12, 2006).

Provide a detailed description of the methods used to determine compliance: (e. g. monitoring device type and location, test method description, or parameter being recorded, frequency of recordkeeping, etc.)

See Attachments C-2a (CSP No. 0007-01-C issued August 7, 2008) and C-2b (CSP No. 0070-01-C issued January 12, 2006).

6. Statement of Compliance with Enhanced Monitoring and Compliance Certification Requirements.

a. Will the emissions unit identified in this application be in compliance with applicable enhanced monitoring and compliance certification requirements?

■YES ☐NO

b. If YES, identify the requirements and the provisions being taken to achieve compliance:

The final Enhanced Monitoring Rule was published in the Federal Register on October 22, 1997 (62 FR 54900). According to that final rule, the Enhanced Monitoring Rules do not apply. The compliance certification requirement is established by 40 CFR 70 and HAR 11-60.1.

c. If NO, describe below which requirements will not be met:

Attachment C-2a

Compliance Status

Attachment C-2a
Compliance Status
Keahole Generating Station – CSP No. 0007-01-C
Issuance Date: August 7, 2008

A. Attachment I, Standard Conditions

Permit term/condition	Equipment(s)	Method	Compliance
All standard conditions	All Equipment listed in the permit	■ monitoring ☐ recordkeeping ☐ reporting ☐ testing ☐ none of the above	■ Continuous ☐ Intermittent

B. Special Conditions - Equipment Description, Applicable Federal Regulations, Monitoring, Recordkeeping, Reporting, Testing, and INSIG

Permit term/condition	Equipment(s)	Method	Compliance
All equipment description conditions	All Equipment listed in the permit	■ monitoring ☐ recordkeeping ☐ reporting ☐ testing ☐ none of the above	■ Continuous ☐ Intermittent
All applicable Federal Regulations	All Equipment listed in the permit	■ monitoring ■ recordkeeping ☐ reporting ■ testing ☐ none of the above	■ Continuous ☐ Intermittent
All monitoring and recordkeeping conditions	All Equipment listed in the permit	■ monitoring ■ recordkeeping ■ reporting ☐ testing ☐ none of the above	■ Continuous ☐ Intermittent
All notification and reporting conditions, except Attachment IIA, Special Condition F.3.	All Equipment listed in the permit	☐ monitoring ■ recordkeeping ■ reporting ☐ testing ☐ none of the above	■ Continuous ☐ Intermittent
Notification and reporting condition, Attachment IIA, Special Condition F.3.	<u>Units CT-4 & CT-5</u> 20 MW General Electric LM2500 combustion turbine generators	☐ monitoring ■ recordkeeping ■ reporting ☐ testing ☐ none of the above	■ Continuous ☐ Intermittent

Attachment C-2a (Continued)
Compliance Status
Keahole Generating Station – CSP No. 0007-01-C
Issuance Date: August 7, 2008

B. Special Conditions - Equipment Description, Applicable Federal Regulations, Monitoring, Recordkeeping, Reporting, Testing, and INSIG

Permit term/condition	Equipment(s)	Method	Compliance
All testing conditions	All Equipment listed in the permit	■ monitoring ■ recordkeeping ☐ reporting ☐ testing ☐ none of the above	■ Continuous ☐ Intermittent
All INSIG conditions	All Equipment listed in the permit	☐ monitoring ■ recordkeeping ☐ reporting ☐ testing ☐ none of the above	■ Continuous ☐ Intermittent

C. Special Conditions - Operational and Emissions Limitations

Permit term/condition	Equipment(s)	Method	Compliance
Attachment IIA, Special Condition C.1.a (Startup limit)	Units CT-4 & CT-5 20 MW General Electric LM2500 combustion turbine generators	■ monitoring ■ recordkeeping ☐ reporting ☐ testing ☐ none of the above	■ Continuous ☐ Intermittent
Attachment IIA, Special Condition C.1.b (Shutdown limit)	Units CT-4 & CT-5 20 MW General Electric LM2500 combustion turbine generators	■ monitoring ■ recordkeeping ☐ reporting ☐ testing ☐ none of the above	■ Continuous ☐ Intermittent
Attachment IIA, Special Condition C.2 (Minimum operating load)	Units CT-4 & CT-5 20 MW General Electric LM2500 combustion turbine generators	■ monitoring ■ recordkeeping ☐ reporting ☐ testing ☐ none of the above	☐ Continuous ■ Intermittent
Attachment IIA, Special Condition C.3.a (Combustor water injection system and minimum water-to-fuel ratios)	Units CT-4 & CT-5 20 MW General Electric LM2500 combustion turbine generators	■ monitoring ■ recordkeeping ■ reporting ☐ testing ☐ none of the above	☐ Continuous ■ Intermittent
Attachment IIA, Special Condition C.3.b (Selective Catalytic Reduction)	Units CT-4 & CT-5 20 MW General Electric LM2500 combustion turbine generators	■ monitoring ■ recordkeeping ■ reporting ☐ testing ☐ none of the above	☐ Continuous ■ Intermittent

Attachment C-2a (Continued)
Compliance Status
Keahole Generating Station – CSP No. 0007-01-C
Issuance Date: August 7, 2008

C. Special Conditions - Operational and Emissions Limitations

Permit term/condition	Equipment(s)	Method	Compliance
Attachment IIA, Special Condition C.4.a (Fuel specifications and fuel sulfur limit)	Units CT-4 & CT-5 20 MW General Electric LM2500 combustion turbine generators	☐ monitoring ■ recordkeeping ■ reporting ■ testing ☐ none of the above	■ Continuous ☐ Intermittent
Attachment IIA, Special Condition C.4.b (Fuel specifications and fuel nitrogen limit)	Units CT-4 & CT-5 20 MW General Electric LM2500 combustion turbine generators	☐ monitoring ■ recordkeeping ■ reporting ■ testing ☐ none of the above	■ Continuous ☐ Intermittent
Attachment IIA, Special Condition C.5.a (Alt. operating scenario - temporary unit replacement)	Units CT-4 & CT-5 20 MW General Electric LM2500 combustion turbine generators	☐ monitoring ☐ recordkeeping ☐ reporting ☐ testing ■ none of the above	■ Continuous ☐ Intermittent
Attachment IIA, Special Condition C.5.b (Alt. operating scenario –low load operation)	Units CT-4 & CT-5 20 MW General Electric LM2500 combustion turbine generators	☐ monitoring ■ recordkeeping ☐ reporting ☐ testing ☐ none of the above	■ Continuous ☐ Intermittent
Attachment IIA, Special Condition C.5.c (Alt. operating scenario – emergency load operations)	Units CT-4 & CT-5 20 MW General Electric LM2500 combustion turbine generators	☐ monitoring ■ recordkeeping ☐ reporting ☐ testing ☐ none of the above	■ Continuous ☐ Intermittent
Attachment IIA, Special Condition C.5.d (Alt. operating scenario – fuel switching)	Units CT-4 & CT-5 20 MW General Electric LM2500 combustion turbine generators	☐ monitoring ☐ recordkeeping ☐ reporting ☐ testing ■ none of the above	■ Continuous ☐ Intermittent
Attachment IIA, Special Condition C.5.e (Alt. operating scenario – fuel additives)	Units CT-4 & CT-5 20 MW General Electric LM2500 combustion turbine generators	☐ monitoring ☐ recordkeeping ☐ reporting ☐ testing ■ none of the above	■ Continuous ☐ Intermittent
Attachment IIA, Special Condition C.5.f (Alt. operating scenario – control systems)	Units CT-4 & CT-5 20 MW General Electric LM2500 combustion turbine generators	☐ monitoring ☐ recordkeeping ☐ reporting ☐ testing ■ none of the above	■ Continuous ☐ Intermittent
Attachment IIA, Special Condition C.5.g (Alt. operating scenario log)	Units CT-4 & CT-5 20 MW General Electric LM2500 combustion turbine generators	☐ monitoring ■ recordkeeping ☐ reporting ☐ testing ☐ none of the above	■ Continuous ☐ Intermittent

Attachment C-2a (Continued)
Compliance Status
Keahole Generating Station – CSP No. 0007-01-C
Issuance Date: August 7, 2008

C. Special Conditions - Operational and Emissions Limitations

Permit term/condition	Equipment(s)	Method	Compliance
Attachment IIA, Special Condition C.5.h (Alt. operating scenario must meet permit requirements)	Units CT-4 & CT-5 20 MW General Electric LM2500 combustion turbine generators Unit ST-7 16 MW steam turbine generator and 2 unfired heat recovery steam generators	☐ monitoring ☐ recordkeeping ☐ reporting ☐ testing ■ none of the above	■ Continuous ☐ Intermittent
Attachment IIA, Special Condition D.1 (NO_x, SO_2, PM, CO, NH_3, and VOC maximum emission limits)	Units CT-4 & CT-5 20 MW General Electric LM2500 combustion turbine generators	■ monitoring ■ recordkeeping ■ reporting ■ testing ☐ none of the above	■ Continuous ☐ Intermittent
Attachment IIA, Special Condition D.2 (Opacity limits)	Units CT-4 & CT-5 20 MW General Electric LM2500 combustion turbine generators	■ monitoring ■ recordkeeping ■ reporting ■ testing ☐ none of the above	☐ Continuous ■ Intermittent
Attachment IIA, Special Condition D.3.a (Inspection and maintenance of fuel oil transfer systems to mitigate fugitive VOC emissions)	Fuel oil transfer system	☐ monitoring ■ recordkeeping ☐ reporting ☐ testing ☐ none of the above	■ Continuous ☐ Intermittent
Attachment IIA, Special Condition D.3.b (Fuel oil transfer systems operational log)	Fuel oil transfer system	☐ monitoring ■ recordkeeping ☐ reporting ☐ testing ☐ none of the above	■ Continuous ☐ Intermittent
Attachment IIA, Special Condition D.3.c (HELCO shall provide DoH access to tanks)	Fuel tanks	☐ monitoring ☐ recordkeeping ☐ reporting ☐ testing ■ none of the above	■ Continuous ☐ Intermittent
Attachment IIB, Special Condition B.1 (BS-1 Operating Hours)	Unit BS-1 – 500 kW Caterpillar Model 3412 Black Start Diesel Engine Generator	☐ monitoring ■ recordkeeping ☐ reporting ☐ testing ☐ none of the above	■ Continuous ☐ Intermittent
Attachment IIB, Special Condition B.2 (D21 Fuel Consumption Limit)	Unit D21 – 2.5 MW General Motors EMD Model 20-645F4B Diesel Engine Generator	☐ monitoring ■ recordkeeping ☐ reporting ☐ testing ☐ none of the above	■ Continuous ☐ Intermittent

Attachment C-2a (Continued)
Compliance Status
Keahole Generating Station – CSP No. 0007-01-C
Issuance Date: August 7, 2008

C. Special Conditions - Operational and Emissions Limitations

Permit term/condition	Equipment(s)	Method	Compliance
Attachment IIB, Special Condition B.3 (Air pollution control equipment - FITR)	Units D21, and D22 – 2.5 MW General Motors EMD Model 20-645F4B diesel engine generators Units D23 – 2.5 MW General Motors EMD Model 20-645E4 diesel engine generator	☐ monitoring ☐ recordkeeping ☐ reporting ☐ testing ■ none of the above	■ Continuous ☐ Intermittent
Attachment IIB, Special Condition B.4 (Fuel specifications and sulfur limits)	Units D21, and D22 – 2.5 MW General Motors EMD Model 20-645F4B diesel engine generators Units D23 – 2.5 MW General Motors EMD Model 20-645E4 diesel engine generator Unit BS-1 – 500 kW Caterpillar Model 3412 Black Start Diesel Engine Generator	☐ monitoring ■ recordkeeping ■ reporting ■ testing ☐ none of the above	■ Continuous ☐ Intermittent
Attachment IIB, Special Condition B.5 (NO_x emission limits)	Units D21, and D22 – 2.5 MW General Motors EMD Model 20-645F4B diesel engine generators Units D23 – 2.5 MW General Motors EMD Model 20-645E4 diesel engine generator	☐ monitoring ☐ recordkeeping ■ reporting ■ testing ☐ none of the above	■ Continuous ☐ Intermittent
Attachment IIB, Special Condition B.6 (Opacity limits)	Units D21, and D22 – 2.5 MW General Motors EMD Model 20-645F4B diesel engine generators Units D23 – 2.5 MW General Motors EMD Model 20-645E4 diesel engine generator	☐ monitoring ■ recordkeeping ■ reporting ■ testing ☐ none of the above	■ Continuous ☐ Intermittent
Attachment IIB, Special Condition B.7.a (Alt. operating scenario – temporary unit replacement)	Units D21, and D22 – 2.5 MW General Motors EMD Model 20-645F4B diesel engine generators Units D23 – 2.5 MW General Motors EMD Model 20-645E4 diesel engine generator	☐ monitoring ☐ recordkeeping ☐ reporting ☐ testing ■ none of the above	■ Continuous ☐ Intermittent
Attachment IIB, Special Condition B.7.b (Alt. operating scenario – fuel switching and fuel additives)	Units D21, and D22 – 2.5 MW General Motors EMD Model 20-645F4B diesel engine generators Units D23 – 2.5 MW General Motors EMD Model 20-645E4 diesel engine generator	☐ monitoring ☐ recordkeeping ☐ reporting ☐ testing ■ none of the above	■ Continuous ☐ Intermittent
Attachment IIB, Special Condition B.7.c (Alt. operating scenario log)	Units D21, and D22 – 2.5 MW General Motors EMD Model 20-645F4B diesel engine generators Units D23 – 2.5 MW General Motors EMD Model 20-645E4 diesel engine generator	☐ monitoring ■ recordkeeping ☐ reporting ☐ testing ☐ none of the above	■ Continuous ☐ Intermittent
Attachment IIB, Special Condition B.7.d (Alt. operating scenario must meet permit requirements)	Units D21, and D22 – 2.5 MW General Motors EMD Model 20-645F4B diesel engine generators Units D23 – 2.5 MW General Motors EMD Model 20-645E4 Unit BS-1 – 500 kW Caterpillar Model 3412 Black Start Diesel Engine Generator	☐ monitoring ☐ recordkeeping ☐ reporting ☐ testing ■ none of the above	■ Continuous ☐ Intermittent

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Hawaiian Electric Company. • PO Box 2750 • Honolulu, HI 96840-0001

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July 30, 2012

Brenner Munger, Ph.D., P.E.
Manager
Environmental Department

Mr. Nolan Hirai, Acting Manager
Clean Air Branch
State of Hawaii Department of Health
P.O. Box 3378
Honolulu, Hawaii 96801-3378

Dear Mr. Hirai:

Subject: Application for a Covered Source Permit Renewal
CSP No. 0007-01-C
Keahole Generating Station
Hawaii Electric Light Company, Inc.

In accordance with HAR 11-60.1-101 and on behalf of Hawaii Electric Light Company, Inc. (HELCO), Hawaiian Electric Company, Inc. submits an original and one copy of the renewal application materials for the Keahole Generating Station.

The renewal application materials include Forms S-1, S-3, C-1 and C-2. Certifications in accordance with HAR 11-60.1-4 are included on Forms S-1, C-1 and C-2. Also enclosed is a check (number 512423) in the amount of $3,000.00 for the renewal fee.

This renewal application seeks to merge CSP No. 0070-01-C into CSP No. 0007-01-C.

As part of the CSP renewal application and HELCO's program to comply with 40 CFR Part 63 Subpart ZZZZ, National Emissions Standards for Reciprocating Internal Combustion Engines (RICE NESHAP), HELCO proposes the installation and operation of Miratech Diesel Oxidation Catalyst Manifold Kit (V-CAT) air pollution control equipment on Units D-21, D-22, and D-23.

In accordance with HAR § 11-60.1-82(k)(1), HELCO requests the Department of Health to provide written approval of these proposed modifications prior to issuance of the amended CSP. Additional information regarding these proposed modifications is included in Form S-3 and Attachment S-3c.

MD 20224

If you have any questions regarding this submittal, please contact Karin Kimura at 543-4522 or karin.kimura@heco.com.

Sincerely,

c (w/encl): Deborah Jordan, EPA Region IX
ec (w/encl): Norman Verbanic, HELCO

File / Application No.: 0007-05

S-1: Standard Air Pollution Control Permit Application Form

(Covered Source Permit and Noncovered Source Permit)

State of Hawaii
Department of Health
Environmental Management Division
Clean Air Branch
P. O. Box 3378 • Honolulu, HI 96801-3378 • Phone: (808) 586-4200

1. Company Name: Hawaii Electric Light Company, Inc. (HELCO)

2. Facility Name (if different from the Company): Keahole Generating Station

3. Mailing Address: 73-4249 Pukiawe Street

   City: Kailua Kona State: HI Zip Code: 96740

   Phone Number: (808) 935-1711

4. Name of Owner/Owner's Agent: Sherri-Ann Loo (Owner's Agent)

   Title: Manager, Environmental Department Phone: (808) 543-4500

   Mailing Address: Hawaiian Electric Company; PO Box 2750

   City: Honolulu State: HI Zip Code: 96840-0001

5. Plant Site Manager/Other Contact: Norman Verbanic

   Title: Manager, Production Department Phone: (808) 543-4236

   Mailing Address: P.O. Box 1027

   City: Hilo State: HI Zip Code: 96721

6. Permit Application Basis: (Check appropriate boxes)

   ☐ Initial Permit for a New Source ☐ Initial Permit for an Existing Source

   ■ Renewal of Existing Permit ☐ General Permit

   ☐ Temporary Source ☐ Transfer of Permit

   ☐ Modification to a Covered Source: ➔ Is modification? ☐ Significant ☐ Minor ☐ Uncertain

   ☐ Modification to a Noncovered Source

7. If renewal or modification, include existing permit number: CSP Nos. 0007-01-C and 0070-01-C

8. Does the Proposed Source require a County Special Management Area Permit? ☐ Yes ■ No

9. Type of Source (Check One): ☐ Covered Source ■ Covered & PSD Source

   ☐ Noncovered Source ☐ Uncertain

10. Standard Industrial Classification Code (SICC), if known: 4911

11. Proposed Equipment/Plant Location (e.g. street address): 73-4249 Pukiawe Street

City: Kailua Kona State: HI Zip Code: 96740

UTM Coordinates (meters): East: 811,293 North: 2,184,955

UTM Zone: 4 UTM Horizontal Datum: ■ Old Hawaiian ☐ NAD-27 ☐ NAD-83

12. General Nature of Business: Electrical Generation

13. Date of Planned Commencement of Installation or Modification: Upon approval of modification.

14. Is ***any*** of the equipment to be leased to another individual or entity? ☐ Yes ■ No

15. Type of Organization: ■ Corporation ☐ Individual Owner ☐ Partnership

☐ Government Agency (Government Facility Code: ____________)

☐ Other: ____________

Any applicant for a permit who fails to submit any relevant facts or who has submitted incorrect information in any permit application shall, upon becoming aware of such failure or incorrect submittal, promptly submit such supplementary facts or corrected information. In addition, an applicant shall provide additional information as necessary to address any requirements that become applicable to the source after the date it filed a complete application, but prior to the issuance of the noncovered source permit or release of a draft covered source permit. (HAR § 11-60.1-64 & 11-60.1-84)

RESPONSIBLE OFFICIAL (as defined in §11-60.1-1):

Name (Last): Verbanic (First): Norman (MI): ____________

Title: Manager Production Department Phone: (808) 969-0421

Mailing Address: P.O. Box 1027

City: Hilo State: HI Zip Code: 96721-1027

CERTIFICATION by Responsible Official (pursuant to §11-60.1-4):

I certify that I have knowledge of the facts herein set forth, that the same are true, accurate and complete to the best of my knowledge and belief, and that all information not identified by me as confidential in nature shall be treated by the Department of Health as public record. I further state that I will assume responsibility for the construction, modification, or operation of the source in accordance with the Hawaii Administrative Rules (HAR), Title 11, Chapter 60.1, Air Pollution Control, and any permit issued thereof.

NAME (Print/Type): Norman Verbanic

(Signature): Norman Verbanic Date: 26 JUL 12

FOR AGENCY USE ONLY:

File/Application No: 0007-05

Island: HAWAII

Date Received: 7/31/12

Submit the following documents as part of your application:

A. The ***Emissions Units Table***, filled in as completely as possible. Use separate sheets of paper as needed. General instructions include the following:

1. Identify each **emission point** with a unique number for this plant site, consistent with emission point identification used on the location drawing and previous permits; if known, provide the SICC number. Emission points shall be identified and described in sufficient detail to establish the basis for **fees** and applicability of requirements of HAR, Chapter 11-60.1. Examples of emission point names are: heater, vent, boiler, tank, baghouse, fugitive, etc. Abbreviations may be used.
   a. For each emission point use as many lines as necessary to list regulated and hazardous air pollutant data. For hazardous air pollutants, also list the Chemical Abstracts Service number (CAS#).
   b. Indicate the emission points that discharge together for any length of time.
   c. The **Equipment Date** is the date of equipment construction, reconstruction, or modification. Provide supporting documentation.

2. State the **maximum emission rates** in terms sufficient to establish compliance with the applicable requirements and standard reference test methods. Provide all supporting emission calculations and assumptions:
   a. Include all regulated and hazardous air pollutants and air pollutants for which the source is major, as defined in HAR §11-60.1-1. Examples of regulated pollutant names are: Carbon Monoxide (CO), Nitrogen Oxides (NO_X), Sulfur Dioxide (SO_2), Volatile Organic Compounds (VOC), particulate matter (PM), and particulate less than 10 microns (PM_{10}). Abbreviations may be used.
   b. Include fugitive emissions.
   c. **Pounds per hour (#/HR)** is the maximum potential emission rate expected by applicant.
   Tons per year is the annual maximum potential emissions expected by the applicant, taking into account the typical operating schedule.

3. Describe ***Stack Source Parameters***:
   a. **Stack Height** is the height above the ground.
   b. **Direction** refers to the exit direction of stack emissions: up, down or horizontal.
   c. **Flow Rate** is the actual, not the calculated, flow rate.

4. Provide any additional information, if applicable, as follows:
   a. If combinations of different fuels are used that cause any of the stack source parameters to differ, complete one row for each possible set of stack parameters and identify each fuel in the **Equipment Description**.
   b. For a rectangular stack, indicate the length and width.
   c. Provide any information on stack parameters or any stack height limitations developed pursuant to Section 123 of the Clean Air Act.

B. A **process flow diagram** identifying all equipment used in the process, including the following:
   1. Identify and describe each emission point.
   2. Identify the locations of safety valves, bypasses, and other such devices which when activated may release air pollutants to the atmosphere.

C. A **facility location map**, drawn to a reasonable scale and showing the following:
   1. The property involved and all structures on it. Identify property/fence lines plainly.
   2. Layout of the facility.
   3. Location and identification of the proposed emissions unit on the property.
   4. Location of the property and equipment with respect to streets and all adjacent property. Show the location of all structures within 325 meters of the applicant's emissions unit. Provide the building dimensions (height, length, and width) of all structures that have heights greater than 40% of the stack height of the emissions unit.

D. Provide a description of any proposed modifications or permit revisions. Include any justification or supporting information for the proposed modifications or permit revisions.

Attachment S-1a
Responses to Emission Unit Table Instructions for Form S-1

A.1. Emission Point Identification and Description	Refer to Form S-1 and Attachments S-1b, S-1c, and S-1d.
A.2. Maximum Emission Rates	Refer to Form S-1 and Attachments S-1b, S-1c, S-1d, and S-1e.
A.3. Stack Parameters	Refer to Forms S-1 Emissions Units Tables.
A.4. Additional Information	
B. Process Flow Diagram	Refer to Figures S-1.1, S-1.2, S-1.3, and S-1.4.
C. Facility Location Map	Refer to Figure S-1.5.
D. Proposed Revisions	Refer to Attachments S-3c and S-3d.

Figure S-1.1
Process Flow Diagram for Unit CT-2

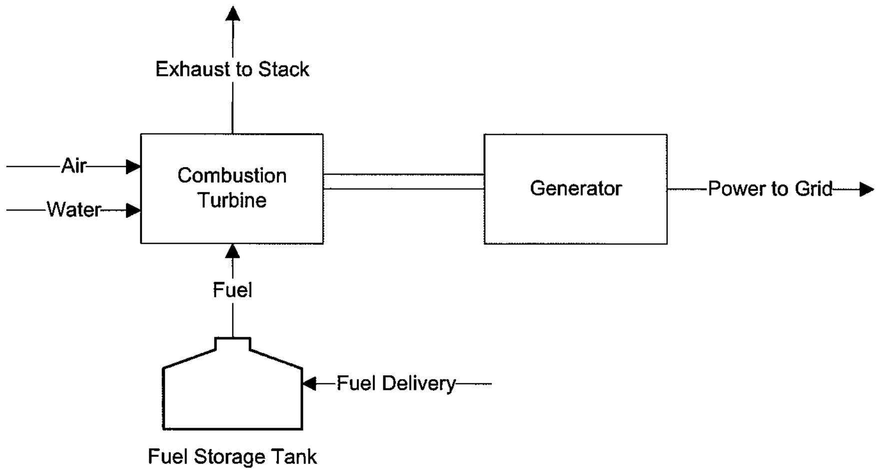


Figure S-1.2
Process Flow Diagram for Units CT-4 and CT-5

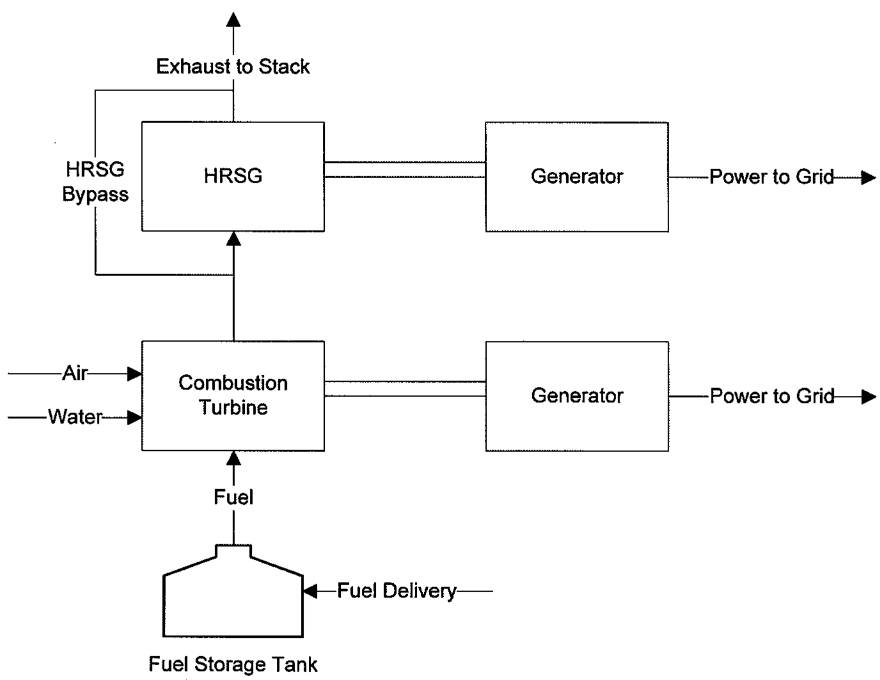


FIGURE S-1.3

PROCESS FLOW DIAGRAM FOR UNITS D-21, D-22, AND D-23

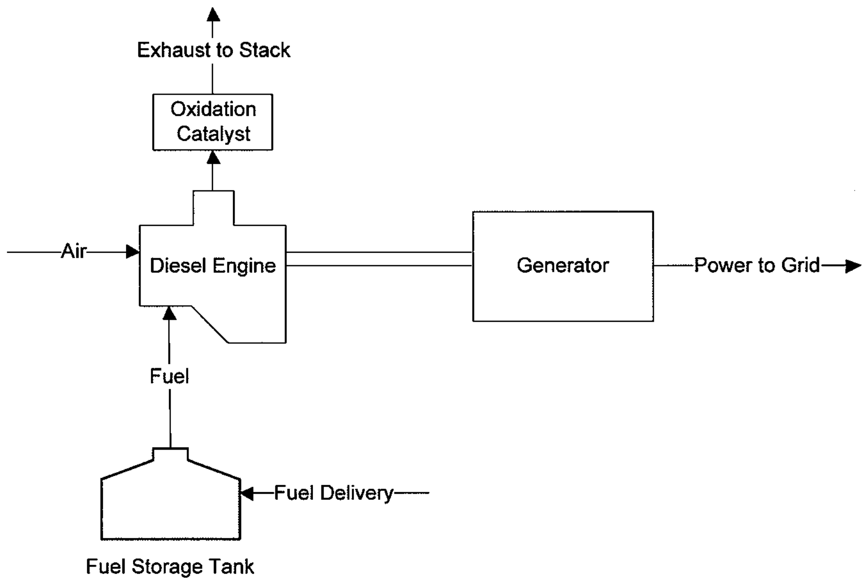


FIGURE S-1.4

PROCESS FLOW DIAGRAM FOR UNIT BS-1

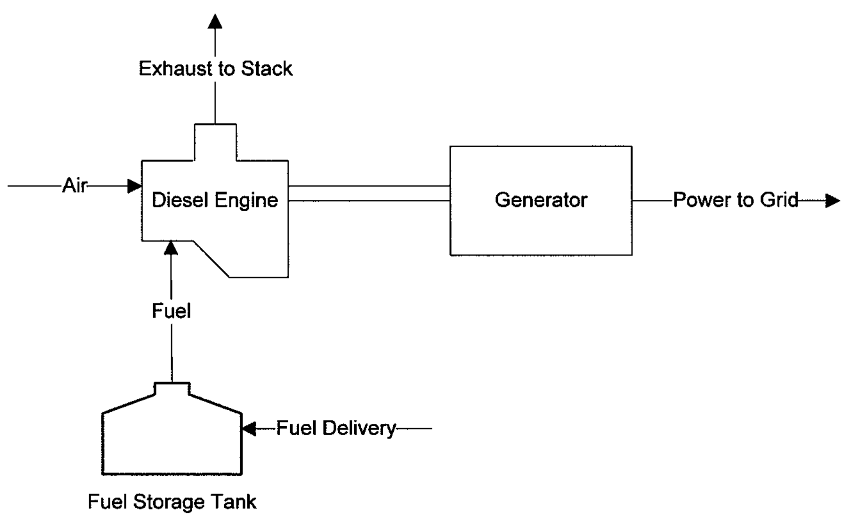
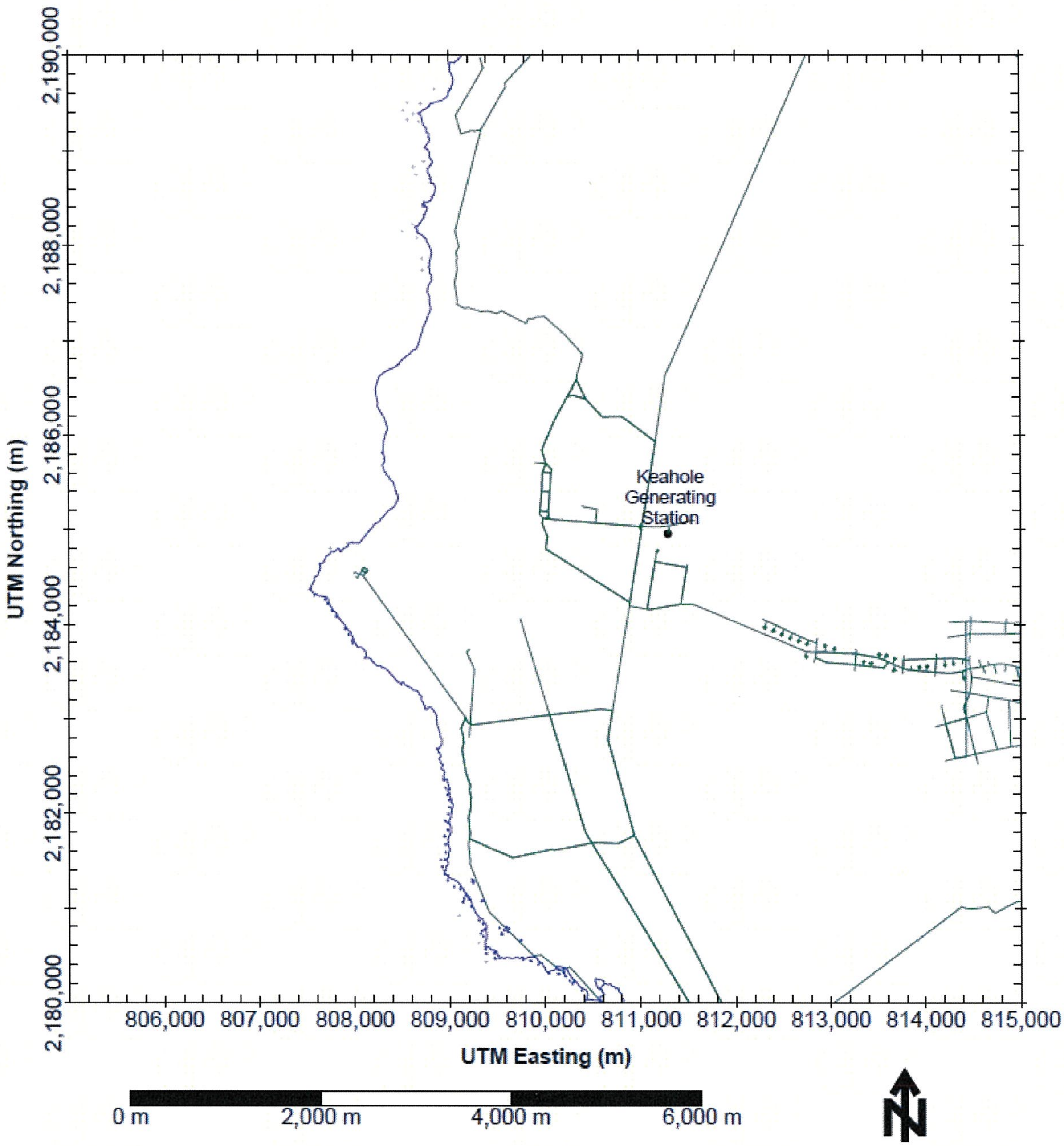


FIGURE S-1.5 LOCATION MAP



Company Name: Hawaii Electric Light Company, Inc.

Location: Keahole Generating Station

(Make as many copies of this page as necessary)

File No.: ____________

EMISSIONS UNITS TABLE

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AIR POLLUTANT DATA: EMISSION POINTS				AIR POLLUTANT	AIR POLLUTANT EMISSION RATE		UTM Zone: 4 Horizontal Datum [a]: Old Hawaiian		STACK SOURCE PARAMETERS						
Stack No.	Unit No.	EQUIPMENT NAME/DESCRIPTION & SICC number	Equipment Date	Regulated/Hazardous Air Pollutant Name & CAS#	#/HR.	Tons/Year	Coordinates (mtrs)		Stack Height (mtrs)	Direction (u/d/h)[b]	Inside Diameter (mtrs)	Velocity (m/s)	Flow Rate (m^3/s)	Temp. (°K)	Capped (Y/N)
2	CT-2	18 MW (Nominal) Jupiter GT-35 Combustion Turbine supplied by Solar Turbines, (SICC Code 4911)	6/29/1989	SO_2	110.0	478.4	East	811,250	21.3	U	3.40	19.8	175.0	647	N
							North	2,184,848							
				NO_x	39.0	169.6	East	811,250	21.3	U	3.40	19.8	175.0	647	N
							North	2,184,848							
				CO	22.4	97.4	East	811,250	21.3	U	3.40	19.8	175.0	647	N
							North	2,184,848							
				VOC	22.4	97.4	East	811,250	21.3	U	3.40	19.8	175.0	647	N
							North	2,184,848							
				PM/PM-10	20.0	87.0	East	811,250	21.3	U	3.40	19.8	175.0	647	N
							North	2,184,848							
				H_2SO_4 Mist	14.4	62.8	East	811,250	21.3	U	3.40	19.8	175.0	647	N
							North	2,184,848							
				Pb	See Attachment S-1a		East	811,250	21.3	U	3.40	19.8	175.0	647	N
							North	2,184,848							
				Fluorides	1.99E-03	8.67E-03	East	811,250	21.3	U	3.40	19.8	175.0	647	N
							North	2,184,848							
				TRS	Not Expected		East	811,250	21.3	U	3.40	19.8	175.0	647	N
							North	2,184,848							
				CFCs	Not Expected		East	811,250	21.3	U	3.40	19.8	175.0	647	N
							North	2,184,848							
				HAPs	See Attachment S-1a		East	811,250	21.3	U	3.40	19.8	175.0	647	N
							North	2,184,848							

[a] Specify UTM Horizontal Datum as Old Hawaiian, NAD-83, or NAD-27

[b] Specify the direction of the stack exhaust as u=upward, d=downward, h=horizontal

Notes:
1. The equipment date is the date that HI 88-01 was issued.
2. Stack parameters are from the PSD Permit Application for CT-2, dated January 1989.
3. Unit CT-2 'tpy' values are based on 12,301,254 gallon per rolling 12-month period fuel limit, AP-42 no. 2 fuel oil heat content of 140,000 Btu/gal, and unit heat input of 198 MMBtu/hr.
4. SO_2, NO_x, CO, VOC, and PM/PM_{10} emission rates were established by HI 88-01.
5. NO_x and PM/PM_{10} emission rates were established by CSP No. 0070-01-C, dated January 12, 2006.
6. Emission rate for H_2SO_4 is 13.12% of the SO_2 rate (5.57 lb/hr H_2SO_4/42.44 lb/hr SO_2). This ratio is derived from the August 19, 1994 SCEC report of Maalaea M16 source tests.
7. Emission rate for Fluorides based on fuel test results of 0.2 ppm dated 04/11/85.

Company Name: Hawaii Electric Light Company, Inc.

Location: Keahole Generating Station

(Make as many copies of this page as necessary)

File No.: ____

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AIR POLLUTANT DATA: EMISSION POINTS				AIR POLLUTANT	AIR POLLUTANT EMISSION RATE		UTM Zone: 4 Horizontal Datum [a]: Old Hawaiian		STACK SOURCE PARAMETERS						
Stack No.	Unit No.	EQUIPMENT NAME/DESCRIPTION & SICC number	Equipment Date	Regulated/Hazardous Air Pollutant Name & CAS#	#/HR.	Tons/Year	Coordinates (mtrs)		Stack Height (mtrs)	Direction (u/d/h)[b]	Inside Diameter (mtrs)	Velocity (m/s)	Flow Rate (m^3/s)	Temp. (°K)	Capped (Y/N)
4 or 5	CT-4 or CT-5	20 MW (Nominal) General Electric LM2500 Combustion Turbine, (SICC Code 4911), Simple Cyle, Peak Load	7/25/2001	SO_2	110.0	481.8	East North	811,293 2,184,955	31.5	U	2.44	38.5	179.9	821	N
				NO_x	42.3	185.3	East North	811,293 2,184,955	31.5	U	2.44	38.5	179.9	821	N
				CO	26.8	117.4	East North	811,293 2,184,955	31.5	U	2.44	38.5	179.9	821	N
				VOC	0.8	3.5	East North	811,293 2,184,955	31.5	U	2.44	38.5	179.9	821	N
				PM/PM-10	19.7	86.3	East North	811,293 2,184,955	31.5	U	2.44	38.5	179.9	821	N
				H_2SO_4 Mist	14.4	63.2	East North	811,293 2,184,955	31.5	U	2.44	38.5	179.9	821	N
				Pb	See Attachment S-1a		East North	811,293 2,184,955	31.5	U	2.44	38.5	179.9	821	N
				Fluorides	2.77E-03	1.21E-02	East North	811,293 2,184,955	31.5	U	2.44	38.5	179.9	821	N
				TRS	Not Expected		East North	811,293 2,184,955	31.5	U	2.44	38.5	179.9	821	N
				CFCs	Not Expected		East North	811,293 2,184,955	31.5	U	2.44	38.5	179.9	821	N
				HAPs	See Attachment S-1a		East North	811,293 2,184,955	31.5	U	2.44	38.5	179.9	821	N

[a] Specify UTM Horizontal Datum as Old Hawaiian, NAD-83, or NAD-27

[b] Specify the direction of the stack exhaust as u=upward, d=downward, h=horizontal

Notes: 1. The equipment date is the date that CSP No. 0007-01-C was issued.
2. Stack parameters and SO_2, NO_x, CO, VOC, and PM/PM_{10} emission rates are from the PSD Permit Application for CT-4 and CT-5, dated January 1993.
3. Emission rate for H_2SO_4 is 13.12% of the SO_2 rate (5.57 lb/hr H_2SO_4/42.44 lb/hr SO_2). This ratio is derived from the August 19, 1994 SCEC report of Maalaea M16 source tests.
4. Emission rate for Fluorides based on fuel tests results of 0.2 ppm dated April 11, 1985.

Company Name: Hawaii Electric Light Company, Inc.

Location: Keahole Generating Station

(Make as many copies of this page as necessary)

File No.: ____

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AIR POLLUTANT DATA: EMISSION POINTS				AIR POLLUTANT	AIR POLLUTANT EMISSION RATE		UTM Zone: 4 Horizontal Datum[a]: Old Hawaiian		STACK SOURCE PARAMETERS						
Stack No.	Unit No.	EQUIPMENT NAME/DESCRIPTION & SICC number	Equipment Date	Regulated/Hazardous Air Pollutant Name & CAS#	#/HR.	Tons/Year	Coordinates (mtrs)		Stack Height (mtrs)	Direction (u/d/h)[b]	Inside Diameter (mtrs)	Velocity (m/s)	Flow Rate (m^3/s)	Temp. (°K)	Capped (Y/N)
4 or 5	CT-4 or CT-5	20 MW (Nominal) General Electric LM2500 Combustion Turbine, (SICC Code 4911), Simple Cyle, 75% of Peak Load	7/25/2001	SO_2	82.9	363.1	East North	811,293 2,184,955	31.5	U	2.44	38.5	179.9	821	N
				NO_x	42.3	185.3	East North	811,293 2,184,955	31.5	U	2.44	38.5	179.9	821	N
				CO	56.4	247.0	East North	811,293 2,184,955	31.5	U	2.44	38.5	179.9	821	N
				VOC	2.6	11.4	East North	811,293 2,184,955	31.5	U	2.44	38.5	179.9	821	N
				PM/PM-10	19.7	86.3	East North	811,293 2,184,955	31.5	U	2.44	38.5	179.9	821	N

[a] Specify UTM Horizontal Datum as Old Hawaiian, NAD-83, or NAD-27

[b] Specify the direction of the stack exhaust as u=upward, d=downward, h=horizontal

Notes: 1. The equipment date is the date that CSP No. 0007-01-C was issued.

2. Stack parameters and SO_2, NO_x, CO, VOC, and PM/PM_{10} emission rates are from the PSD Permit Application for CT-4 and CT-5, dated January 1993.

Company Name: Hawaii Electric Light Company, Inc.

Location: Keahole Generating Station

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AIR POLLUTANT DATA: EMISSION POINTS				AIR POLLUTANT	AIR POLLUTANT EMISSION RATE		UTM Zone: 4 Horizontal Datum[a]: Old Hawaiian		STACK SOURCE PARAMETERS						
Stack No.	Unit No.	EQUIPMENT NAME/DESCRIPTION & SICC number	Equipment Date	Regulated/Hazardous Air Pollutant Name & CAS#	#/HR.	Tons/Year	Coordinates (mtrs)		Stack Height (mtrs)	Direction (u/d/h)[b]	Inside Diameter (mtrs)	Velocity (m/s)	Flow Rate (m^3/s)	Temp. (°K)	Capped (Y/N)
4 or 5	CT-4 or CT-5	20 MW (Nominal) General Electric LM2500 Combustion Turbine, (SICC Code 4911), Simple Cyle, 50% of Peak Load	7/25/2001	SO_2	58.0	254.0	East	811,293	31.5	U	2.44	38.5	179.9	821	N
							North	2,184,955							
				NO_x	42.3	185.3	East	811,293	31.5	U	2.44	38.5	179.9	821	N
							North	2,184,955							
				CO	181.0	792.8	East	811,293	31.5	U	2.44	38.5	179.9	821	N
							North	2,184,955							
				VOC	28.1	123.1	East	811,293	31.5	U	2.44	38.5	179.9	821	N
							North	2,184,955							
				PM/PM-10	19.7	86.3	East	811,293	31.5	U	2.44	38.5	179.9	821	N
							North	2,184,955							

[a] Specify UTM Horizontal Datum as Old Hawaiian, NAD-83, or NAD-27

[b] Specify the direction of the stack exhaust as u=upward, d=downward, h=horizontal

Notes: 1. The equipment date is the date that CSP No. 0007-01-C was issued.

2. Stack parameters and SO_2, NO_x, CO, VOC, and PM/PM_{10} emission rates are from the PSD Permit Application for CT-4 and CT-5, dated January 1993.

Company Name: Hawaii Electric Light Company, Inc.

Location: Keahole Generating Station

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AIR POLLUTANT DATA: EMISSION POINTS				AIR POLLUTANT	AIR POLLUTANT EMISSION RATE		UTM Zone: 4 Horizontal Datum[a]: Old Hawaiian		STACK SOURCE PARAMETERS						
Stack No.	Unit No.	EQUIPMENT NAME/DESCRIPTION & SICC number	Equipment Date	Regulated/Hazardous Air Pollutant Name & CAS#	#/HR.	Tons/Year	Coordinates (mtrs)		Stack Height (mtrs)	Direction (u/d/h)[b]	Inside Diameter (mtrs)	Velocity (m/s)	Flow Rate (m^3/s)	Temp. (°K)	Capped (Y/N)
4 or 5	CT-4 or CT-5	20 MW (Nominal) General Electric LM2500 Combustion Turbine, (SICC Code 4911), Simple Cyle, 25% of Peak Load	7/25/2001	SO_2	39.0	170.8	East	811,293	31.5	U	2.44	38.5	179.9	821	N
							North	2,184,955							
				NO_x	42.3	185.3	East	811,293	31.5	U	2.44	38.5	179.9	821	N
							North	2,184,955							
				CO	475.6	2083.1	East	811,293	31.5	U	2.44	38.5	179.9	821	N
							North	2,184,955							
				VOC	297.6	1303.5	East	811,293	31.5	U	2.44	38.5	179.9	821	N
							North	2,184,955							
				PM/PM-10	19.7	86.3	East	811,293	31.5	U	2.44	38.5	179.9	821	N
							North	2,184,955							

[a] Specify UTM Horizontal Datum as Old Hawaiian, NAD-83, or NAD-27

[b] Specify the direction of the stack exhaust as u=upward, d=downward, h=horizontal

Notes: 1. The equipment date is the date that CSP No. 0007-01-C was issued.

2. Stack parameters and SO_2, NO_x, CO, VOC, and PM/PM_{10} emission rates are from the PSD Permit Application for CT-4 and CT-5, dated January 1993.

Company Name: Hawaii Electric Light Company, Inc.

File No.:

Location: Keahole Generating Station

(Make as many copies of this page as necessary)

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EMISSIONS UNITS TABLE

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AIR POLLUTANT DATA: EMISSION POINTS				AIR POLLUTANT	AIR POLLUTANT EMISSION RATE		UTM Zone: 4 Horizontal Datum [a]: Old Hawaiian		STACK SOURCE PARAMETERS						
Stack No.	Unit No.	EQUIPMENT NAME/DESCRIPTION & SICC number	Equipment Date	Regulated/Hazardous Air Pollutant Name & CAS#	#/HR.	Tons/Year	Coordinates (mtrs)		Stack Height (mtrs)	Direction (u/d/h)[b]	Inside Diameter (mtrs)	Velocity (m/s)	Flow Rate (m^3/s)	Temp. (°K)	Capped (Y/N)
4 or 5	CT-4 or CT-5	20 MW (Nominal) General Electric LM2500 Combustion Turbine, (SICC Code 4911), Combined Cyle, Peak Load	7/25/2001	SO_2	110.0	481.8	East	811,293	31.5	U	2.44	38.5	179.9	821	N
							North	2,184,955							
				NO_x	15.1	66.1	East	811,293	31.5	U	2.44	38.5	179.9	821	N
							North	2,184,955							
				CO	26.9	117.8	East	811,293	31.5	U	2.44	38.5	179.9	821	N
							North	2,184,955							
				VOC	0.8	3.5	East	811,293	31.5	U	2.44	38.5	179.9	821	N
							North	2,184,955							
				PM/PM-10	19.7	86.3	East	811,293	31.5	U	2.44	38.5	179.9	821	N
							North	2,184,955							
				H_2SO_4 Mist	14.4	63.2	East	811,293	31.5	U	2.44	38.5	179.9	821	N
							North	2,184,955							
				Pb	See Attachment S-1a		East	811,293	31.5	U	2.44	38.5	179.9	821	N
							North	2,184,955							
				Fluorides	2.77E-03	1.21E-02	East	811,293	31.5	U	2.44	38.5	179.9	821	N
							North	2,184,955							
				TRS	Not Expected		East	811,293	31.5	U	2.44	38.5	179.9	821	N
							North	2,184,955							
				CFCs	Not Expected		East	811,293	31.5	U	2.44	38.5	179.9	821	N
							North	2,184,955							
				HAPs	See Attachment S-1a		East	811,293	31.5	U	2.44	38.5	179.9	821	N
							North	2,184,955							
				NH_3	4.3	18.8	East	811,293	31.5	U	2.44	38.5	179.9	821	N
							North	2,184,955							

[a] Specify UTM Horizontal Datum as Old Hawaiian, NAD-83, or NAD-27

[b] Specify the direction of the stack exhaust as u=upward, d=downward, h=horizontal

Notes:
1. The equipment date is the date that CSP No. 0007-01-C was issued.
2. Stack parameters and SO_2, NO_x, CO, VOC, and PM/PM_{10} emission rates are from the PSD Permit Application for CT-4 and CT-5, dated January 1993.
3. NO_x emission rate is based on SCR + water injection reducing emissions to 15 ppmvd (15.1 = 42.3 x (15 ppmvd/42 ppmvd)).
4. Emission rate for H_2SO_4 is 13.12% of the SO_2 rate (5.57 lb/hr H_2SO_4/42.44 lb/hr SO_2). This ratio is derived from the August 19, 1994 SCEC report of Maalaea M16 source tests.
5. Emission rate for Fluorides based on fuel tests results of 0.2 ppm dated April 11, 1985.
6. NH_3 emission rate is based on manufacturer's maximum ammonia slip of 10 ppmvd and a peak load flow rate of 559,400 lb/hr at 59 degrees F.

Company Name: Hawaii Electric Light Company, Inc.
Location: Keahole Generating Station
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EMISSIONS UNITS TABLE

Review of applications and issuance of permits will be expedited by supplying all necessary information on this table.

AIR POLLUTANT DATA: EMISSION POINTS				AIR POLLUTANT	AIR POLLUTANT EMISSION RATE		UTM Zone: 4 Horizontal Datum[a]: Old Hawaiian	STACK SOURCE PARAMETERS						
Stack No.	Unit No.	EQUIPMENT NAME/DESCRIPTION & SICC number	Equipment Date	Regulated/Hazardous Air Pollutant Name & CAS#	#/HR.	Tons/Year	Coordinates (mtrs)	Stack Height (mtrs)	Direction (u/d/h)[b]	Inside Diameter (mtrs)	Velocity (m/s)	Flow Rate (m^3/s)	Temp. (°K)	Capped (Y/N)
4 or 5	CT-4 or CT-5	20 MW (Nominal) General Electric LM2500 Combustion Turbine, (SICC Code 4911), Combined Cyle, 75% of Peak Load	7/25/2001	SO_2	86.0	376.7	East 811,293 North 2,184,955	31.5	U	2.44	38.5	179.9	821	N
				NO_x	15.1	66.1	East 811,293 North 2,184,955	31.5	U	2.44	38.5	179.9	821	N
				CO	50.2	219.9	East 811,293 North 2,184,955	31.5	U	2.44	38.5	179.9	821	N
				VOC	2.0	8.8	East 811,293 North 2,184,955	31.5	U	2.44	38.5	179.9	821	N
				PM/PM-10	19.7	86.3	East 811,293 North 2,184,955	31.5	U	2.44	38.5	179.9	821	N
				NH_3	4.3	18.8	East 811,293 North 2,184,955	31.5	U	2.44	38.5	179.9	821	N

[a] Specify UTM Horizontal Datum as Old Hawaiian, NAD-83, or NAD-27

[b] Specify the direction of the stack exhaust as u=upward, d=downward, h=horizontal

Notes:
1. The equipment date is the date that CSP No. 0007-01-C was issued.
2. Stack parameters and SO_2, NO_x, CO, VOC, and PM/PM_{10} emission rates are from the PSD Permit Application for CT-4 and CT-5, dated January 1993.
3. NO_x emission rate is based on SCR + water injection reducing emissions to 15 ppmvd (15.1 = 42.3 x (15 ppmvd/42 ppmvd)).
4. NH_3 emissions are the worst-case emission rate based on the manufacturer's guaranteed ammonia slip of 10 ppmvd and a 100 percent load flow rate of 559,400 lb/hr at 59 degrees F.

Company Name: Hawaii Electric Light Company, Inc.

Location: Keahole Generating Station

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EMISSIONS UNITS TABLE

Review of applications and issuance of permits will be expedited by supplying all necessary information on this table.

AIR POLLUTANT DATA: EMISSION POINTS				AIR POLLUTANT	AIR POLLUTANT EMISSION RATE		UTM Zone: 4 Horizontal Datum[a]: Old Hawaiian		STACK SOURCE PARAMETERS						
Stack No.	Unit No.	EQUIPMENT NAME/DESCRIPTION & SICC number	Equipment Date	Regulated/Hazardous Air Pollutant Name & CAS#	#/HR.	Tons/Year	Coordinates (mtrs)		Stack Height (mtrs)	Direction (u/d/h)[b]	Inside Diameter (mtrs)	Velocity (m/s)	Flow Rate (m^3/s)	Temp. (°K)	Capped (Y/N)
4 or 5	CT-4 or CT-5	20 MW (Nominal) General Electric LM2500 Combustion Turbine, (SICC Code 4911), Combined Cycle, 50% of Peak Load	7/25/2001	SO_2	59.0	258.4	East	811,293	31.5	U	2.44	14.2	66.4	419	N
							North	2,184,955							
				NO_x	42.3	185.3	East	811,293	31.5	U	2.44	14.2	66.4	419	N
							North	2,184,955							
				CO	170.4	746.4	East	811,293	31.5	U	2.44	14.2	66.4	419	N
							North	2,184,955							
				VOC	25.0	109.5	East	811,293	31.5	U	2.44	14.2	66.4	419	N
							North	2,184,955							
				PM/PM-10	19.7	86.3	East	811,293	31.5	U	2.44	14.2	66.4	419	N
							North	2,184,955							
				NH_3	4.3	18.8	East	811,293	31.5	U	2.44	14.2	66.4	419	N
							North	2,184,955							

[a] Specify UTM Horizontal Datum as Old Hawaiian, NAD-83, or NAD-27

[b] Specify the direction of the stack exhaust as u=upward, d=downward, h=horizontal

Notes:
1. The equipment date is the date that CSP No. 0007-01-C was issued.
2. Stack parameters and SO_2, NO_x, CO, VOC, and PM/PM_{10} emission rates are from the PSD Permit Application for CT-4 and CT-5, dated January 1993.
3. NO_x emission rate is based on SCR + water injection reducing emissions to 15 ppmvd (15.1 = 42.3 x (15 ppmvd/42 ppmvd)).
4. NH_3 emissions are the worst-case emission rate based on the manufacturer's guaranteed ammonia slip of 10 ppmvd and a 100 percent load flow rate of 559,400 lb/hr at 59 degrees F.

Company Name: Hawaii Electric Light Company, Inc.

Location: Keahole Generating Station

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EMISSIONS UNITS TABLE

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AIR POLLUTANT DATA: EMISSION POINTS				AIR POLLUTANT	AIR POLLUTANT EMISSION RATE		UTM Zone: 4 Horizontal Datum[a]: Old Hawaiian		STACK SOURCE PARAMETERS						
Stack No.	Unit No.	EQUIPMENT NAME/DESCRIPTION & SICC number	Equipment Date	Regulated/Hazardous Air Pollutant Name & CAS#	#/HR.	Tons/Year	Coordinates (mtrs)		Stack Height (mtrs)	Direction (u/d/h)[b]	Inside Diameter (mtrs)	Velocity (m/s)	Flow Rate (m^3/s)	Temp. (°K)	Capped (Y/N)
4 or 5	CT-4 or CT-5	20 MW (Nominal) General Electric LM2500 Combustion Turbine, (SICC Code 4911), Combined Cyle, 25% of Peak Load	7/25/2001	SO_2	39.9	174.8	East	811,293	31.5	U	2.44	10.8	50.5	414	N
							North	2,184,955							
				NO_x	42.3	185.3	East	811,293	31.5	U	2.44	10.8	50.5	414	N
							North	2,184,955							
				CO	457.4	2003.4	East	811,293	31.5	U	2.44	10.8	50.5	414	N
							North	2,184,955							
				VOC	271.0	1187.0	East	811,293	31.5	U	2.44	10.8	50.5	414	N
							North	2,184,955							
				PM/PM-10	19.7	86.3	East	811,293	31.5	U	2.44	10.8	50.5	414	N
							North	2,184,955							

[a] Specify UTM Horizontal Datum as Old Hawaiian, NAD-83, or NAD-27

[b] Specify the direction of the stack exhaust as u=upward, d=downward, h=horizontal

Notes:
1. The equipment date is the date that CSP No. 0007-01-C was issued.
2. Stack parameters and SO_2, NO_x, CO, VOC, and PM/PM_{10} emission rates are from the PSD Permit Application for CT-4 and CT-5, dated January 1993.
3. NO_X emission rate is based on water injection reducing emissions to 42 ppmvd. SCR is not required for loads less than 50% of peak. Operating the SCR at loads less than 50% of peak will cause ammonium sulfates to form in the catalyst and on the boiler tubes in the heat recovery steam generator.

Company Name: Hawaii Electric Light Company, Inc.

Location: Keahole Generating Station

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EMISSIONS UNITS TABLE

Review of applications and issuance of permits will be expedited by supplying all necessary information on this table.

AIR POLLUTANT DATA: EMISSION POINTS				AIR POLLUTANT	AIR POLLUTANT EMISSION RATE		UTM Zone: 4 Horizontal Datum[a]: Old Hawaiian		STACK SOURCE PARAMETERS						
Stack No.	Unit No.	EQUIPMENT NAME/DESCRIPTION & SICC number	Equipment Date	Regulated/Hazardous Air Pollutant Name & CAS#	#/HR.	Tons/Year	Coordinates (mtrs)		Stack Height (mtrs)	Direction (u/d/h)[b]	Inside Diameter (mtrs)	Velocity (m/s)	Flow Rate (m^3/s)	Temp. (°K)	Capped (Y/N)
21	D-21	2.5 MW (Nominal) General Motors EMD Model 20-645F4B Diesel Engine Generator (SICC Code 4911)	1974	SO_2	0.04	0.0	East North	811,255 2,184,884	12.2	U	0.90	18.3	11.6	677	N
				NO_x	68.4	11.9	East North	811,255 2,184,884	12.2	U	0.90	18.3	11.6	677	N
				CO	23.6	4.1	East North	811,255 2,184,884	12.2	U	0.90	18.3	11.6	677	N
				VOC	6.69	1.17	East North	811,255 2,184,884	12.2	U	0.90	18.3	11.6	677	N
				PM/PM-10	5.06	0.88	East North	811,255 2,184,884	12.2	U	0.90	18.3	11.6	677	N
				H_2SO_4 Mist	0.01	0.00	East North	811,255 2,184,884	12.2	U	0.90	18.3	11.6	677	N
				Pb	See Attachment S-1a		East North	811,255 2,184,884	12.2	U	0.90	18.3	11.6	677	N
				Fluorides	2.83E-04	4.94E-05	East North	811,255 2,184,884	12.2	U	0.90	18.3	11.6	677	N
				TRS	Not Expected		East North	811,255 2,184,884	12.2	U	0.90	18.3	11.6	677	N
				CFCs	Not Expected		East North	811,255 2,184,884	12.2	U	0.90	18.3	11.6	677	N
				HAPs	See Attachment S-1a		East North	811,255 2,184,884	12.2	U	0.90	18.3	11.6	677	N

[a] Specify UTM Horizontal Datum as Old Hawaiian, NAD-83, or NAD-27

[b] Specify the direction of the stack exhaust as u=upward, d=downward, h=horizontal

Notes: 1. NO_x, CO, VOC, and PM/PM_{10} emission rates are based on an evaluation of AP-42 calculations and stack test data. Emission rate for CO includes a 70% reduction in accordance with 40 CFR Part 63 Subpart ZZZZ.

2. SO_2 emission rate based on mass balance with maximum fuel sulfur content of 0.0015 percent and assuming conversion of all sulfur to SO_2

3. Emission rate for H_2SO_4 is 13.83% of the SO_2 rate (0.73 lb/hr H_2SO_4/5.28 lb/hr SO_2). This ratio is derived from the August 19, 1994 SCEC report of Maalaea M3 source tests.

4. Emission rate for Fluorides based on fuel test results of 0.2 ppm dated April 11, 1985.

5. Unit D-21 'tpy' values are based on 70,000 gal/yr fuel limit, AP-42 no. 2 fuel oil heat content of 140,000 Btu/gal, and unit heat input of 28.1 MMBtu/hr.

Company Name: Hawaii Electric Light Company, Inc.

Location: Keahole Generating Station

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EMISSIONS UNITS TABLE

Review of applications and issuance of permits will be expedited by supplying all necessary information on this table.

AIR POLLUTANT DATA: EMISSION POINTS				AIR POLLUTANT	AIR POLLUTANT EMISSION RATE		UTM Zone: 4 Horizontal Datum[a]: Old Hawaiian		STACK SOURCE PARAMETERS						
Stack No.	Unit No.	EQUIPMENT NAME/DESCRIPTION & SICC number	Equipment Date	Regulated/Hazardous Air Pollutant Name & CAS#	#/HR.	Tons/Year	Coordinates (mtrs)		Stack Height (mtrs)	Direction (u/d/h)[b]	Inside Diameter (mtrs)	Velocity (m/s)	Flow Rate (m^3/s)	Temp. (°K)	Capped (Y/N)
22	D-22	2.5 MW (Nominal) General Motors EMD Model 20-645F4B Diesel Engine Generator (SICC Code 4911)	1966	SO_2	0.04	0.2	East North	811,253 2,184,874	12.2	U	0.90	18.3	11.6	877	N
				NO_x	68.4	299.6	East North	811,253 2,184,874	12.2	U	0.90	18.3	11.6	877	N
				CO	23.6	103.1	East North	811,253 2,184,874	12.2	U	0.90	18.3	11.6	877	N
				VOC	6.69	29.30	East North	811,253 2,184,874	12.2	U	0.90	18.3	11.6	877	N
				PM/PM-10	5.06	22.16	East North	811,253 2,184,874	12.2	U	0.90	18.3	11.6	877	N
				H_2SO_4 Mist	0.01	0.03	East North	811,253 2,184,874	12.2	U	0.90	18.3	11.6	877	N
				Pb	See Attachment S-1a		East North	811,253 2,184,874	12.2	U	0.90	18.3	11.6	877	N
				Fluorides	2.83E-04	1.24E-03	East North	811,253 2,184,874	12.2	U	0.90	18.3	11.6	877	N
				TRS	Not Expected		East North	811,253 2,184,874	12.2	U	0.90	18.3	11.6	877	N
				CFCs	Not Expected		East North	811,253 2,184,874	12.2	U	0.90	18.3	11.6	877	N
				HAPs	See Attachment S-1a		East North	811,253 2,184,874	12.2	U	0.90	18.3	11.6	877	N

[a] Specify UTM Horizontal Datum as Old Hawaiian, NAD-83, or NAD-27

[b] Specify the direction of the stack exhaust as u=upward, d=downward, h=horizontal

Notes:
1. NO_x, CO, VOC, and PM/PM_{10} emission rates are based on an evaluation of AP-42 calculations and stack test data. Emission rate for CO includes a 70% reduction in accordance with 40 CFR Part 63 Subpart ZZZZ.
2. SO_2 emission rate based on mass balance with maximum fuel sulfur content of 0.0015 percent and assuming conversion of all sulfur to SO_2
3. Emission rate for H_2SO_4 is 13.83% of the SO_2 rate (0.73 lb/hr H_2SO_4/5.28 lb/hr SO_2). This ratio is derived from the August 19, 1994 SCEC report of Maalaea M3 source tests.
4. Emission rate for Fluorides based on fuel test results of 0.2 ppm dated April 11, 1985.

Company Name: Hawaii Electric Light Company, Inc.

Location: Keahole Generating Station

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EMISSIONS UNITS TABLE

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AIR POLLUTANT DATA: EMISSION POINTS				AIR POLLUTANT	AIR POLLUTANT EMISSION RATE		UTM Zone: 4 Horizontal Datum[a]: Old Hawaiian		STACK SOURCE PARAMETERS						
Stack No.	Unit No.	EQUIPMENT NAME/DESCRIPTION & SICC number	Equipment Date	Regulated/Hazardous Air Pollutant Name & CAS#	#/HR.	Tons/Year	Coordinates (mtrs)		Stack Height (mtrs)	Direction (u/d/h)[b]	Inside Diameter (mtrs)	Velocity (m/s)	Flow Rate (m^3/s)	Temp. (°K)	Capped (Y/N)
23	D-23	2.5 MW (Nominal) General Motors EMD Model 20-645F4B Diesel Engine Generator (SICC Code 4911)	1969	SO_2	0.04	0.2	East North	811,251 2,184,869	12.2	U	0.90	18.3	11.6	677	N
				NO_x	68.4	299.6	East North	811,251 2,184,869	12.2	U	0.90	18.3	11.6	677	N
				CO	23.6	103.1	East North	811,251 2,184,869	12.2	U	0.90	18.3	11.6	677	N
				VOC	6.69	29.3	East North	811,251 2,184,869	12.2	U	0.90	18.3	11.6	677	N
				PM/PM-10	5.06	22.2	East North	811,251 2,184,869	12.2	U	0.90	18.3	11.6	677	N
				H_2SO_4 Mist	0.01	0.0	East North	811,251 2,184,869	12.2	U	0.90	18.3	11.6	677	N
				Pb	See Attachment S-1a		East North	811,251 2,184,869	12.2	U	0.90	18.3	11.6	677	N
				Fluorides	2.83E-04	1.24E-03	East North	811,251 2,184,869	12.2	U	0.90	18.3	11.6	677	N
				TRS	Not Expected		East North	811,251 2,184,869	12.2	U	0.90	18.3	11.6	677	N
				CFCs	Not Expected		East North	811,251 2,184,869	12.2	U	0.90	18.3	11.6	677	N
				HAPs	See Attachment S-1a		East North	811,251 2,184,869	12.2	U	0.90	18.3	11.6	677	N

[a] Specify UTM Horizontal Datum as Old Hawaiian, NAD-83, or NAD-27

[b] Specify the direction of the stack exhaust as u=upward, d=downward, h=horizontal

Notes: 1. NO_x, CO, VOC, and PM/PM_{10} emission rates are based on an evaluation of AP-42 calculations and stack test data. Emission rate for CO includes a 70% reduction in accordance with 40 CFR Part 63 Subpart ZZZZ.

2. SO_2 emission rate based on mass balance with maximum fuel sulfur content of 0.0015 percent and assuming conversion of all sulfur to SO_2

3. Emission rate for H_2SO_4 is 13.83% of the SO_2 rate (0.73 lb/hr H_2SO_4/5.28 lb/hr SO_2). This ratio is derived from the August 19, 1994 SCEC report of Maalaea M3 source tests.

4. Emission rate for Fluorides based on fuel test results of 0.2 ppm dated April 11, 1985.

Company Name: Hawaii Electric Light Company, Inc. File No.: ______

Location: Keahole Generating Station

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EMISSIONS UNITS TABLE

Review of applications and issuance of permits will be expedited by supplying all necessary information on this table.

AIR POLLUTANT DATA: EMISSION POINTS				AIR POLLUTANT	AIR POLLUTANT EMISSION RATE		UTM Zone: 4 Horizontal Datum [a]: Old Hawaiian		STACK SOURCE PARAMETERS						
Stack No.	Unit No.	EQUIPMENT NAME/DESCRIPTION & SICC number	Equipment Date	Regulated/Hazardous Air Pollutant Name & CAS#	#/HR.	Tons/Year	Coordinates (mtrs)		Stack Height (mtrs)	Direction (u/d/h)[b]	Inside Diameter (mtrs)	Velocity (m/s)	Flow Rate (m^3/s)	Temp. (°K)	Capped (Y/N)
1	BS-1	500 kW Caterpillar Model 3412 Blackstart Diesel Engine Generator (SICC Code 4911)	Nov. 4, 1991	SO_2	2.86	0.43	East North	811,250 2,184,848	21.3	U	0.20	62.2	2.0	894	N
				NO_x	12.50	1.88	East North	811,250 2,184,848	21.3	U	0.20	62.2	2.0	894	N
				CO	2.38	0.36	East North	811,250 2,184,848	21.3	U	0.20	62.2	2.0	894	N
				VOC	0.46	0.07	East North	811,250 2,184,848	21.3	U	0.20	62.2	2.0	894	N
				PM/PM-10	1.98	0.30	East North	811,250 2,184,848	21.3	U	0.20	62.2	2.0	894	N
				H_2SO_4 Mist	0.40	0.06	East North	811,250 2,184,848	21.3	U	0.20	62.2	2.0	894	N
				Pb	See Attachment S-1a		East North	811,250 2,184,848	21.3	U	0.20	62.2	2.0	894	N
				Fluorides	5.61E-05	8.41E-06	East North	811,250 2,184,848	21.3	U	0.20	62.2	2.0	894	N
				TRS	Not Expected		East North	811,250 2,184,848	21.3	U	0.20	62.2	2.0	894	N
				CFCs	Not Expected		East North	811,250 2,184,848	21.3	U	0.20	62.2	2.0	894	N
				HAPs (see Table S-1a)	See Attachment S-1a		East North	811,250 2,184,848	21.3	U	0.20	62.2	2.0	894	N

[a] Specify UTM Horizontal Datum as Old Hawaiian, NAD-83, or NAD-27

[b] Specify the direction of the stack exhaust as u=upward, d=downward, h=horizontal

Notes:
1. Equipment date is the date that PTO No. P-936-1287 was issued.
2. SO_2, NO_x, CO, and PM/PM_{10} emission rates are from ATC application dated Jan. 30, 1981. VOC emissions are based on AP-42, Section 3.4, dated 10/96.
3. BS-1 is limited to 300 hours per year.
4. Emission rate for H_2SO_4 is 13.83% of the SO_2 rate (0.73 lb/hr H_2SO_4/5.28 lb/hr SO_2). This ratio is derived from the August 19, 1994 SCEC report of Maalaea M3 source tests.
5. Emission rate for Fluorides based on fuel test results of 0.2 ppm dated April 11, 1985.

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Attachment S-1b
Air Toxic Emissions for CT-2

SECTION 112 HAZARDOUS AIR POLLUTANTS

EPA ID #	CAS Number	Pollutant	Source of Emission Factor	Emission Factor (lb/MMBtu)	Heat Input (MMBtu/hr)	Heat Input (MMBtu/yr)	Emissions (lb/hr)	Emissions (tpy)
1	75-07-0	Acetaldehyde	AP-42, Section 3.4, Table 3.4-3	2.52E-05	198	1,722,176	4.99E-03	2.17E-02
2	60-35-5	Acetamide			198	1,722,176		
3	75-05-8	Acetonitrile			198	1,722,176		
4	98-86-2	Acetophenone			198	1,722,176		
5	53-96-3	2-Acetylaminofluorene			198	1,722,176		
6	107-02-8	Acrolein	AP-42, Section 3.4, Table 3.4-3	7.88E-06	198	1,722,176	1.56E-03	6.79E-03
7	79-06-1	Acrylamide			198	1,722,176		
8	79-10-7	Acrylic acid			198	1,722,176		
9	107-13-1	Acrylonitrile			198	1,722,176		
10	107-05-1	Allyl chloride			198	1,722,176		
11	92-67-1	4-Aminobiphenyl			198	1,722,176		
12	62-53-3	Aniline			198	1,722,176		
13	90-04-0	o-Anisidine			198	1,722,176		
14	1332-21-4	Asbestos			198	1,722,176		
15	71-43-2	Benzene (including benzene from gasoline)	AP-42, Section 3.1, Table 3.1-4	5.50E-05	198	1,722,176	1.09E-02	4.74E-02
16	92-87-5	Benzidine			198	1,722,176		
17	98-07-7	Benzotrichloride			198	1,722,176		
18	100-44-7	Benzyl chloride			198	1,722,176		
19	92-52-4	Biphenyl			198	1,722,176		
20	117-81-7	Bis(2-ethylhexyl)phthalate (DEHP)			198	1,722,176		
21	542-88-1	Bis(chloromethyl) ether			198	1,722,176		
22	75-25-2	Bromoform			198	1,722,176		
23	106-99-0	1,3-Butadiene	AP-42, Section 3.1, Table 3.1-4	1.60E-05	198	1,722,176	3.17E-03	1.38E-02
24	156-62-7	Calcium cyanamide			198	1,722,176		
25	105-60-2	Caprolactam (Removed 06/18/96, See 61FR30816)			198	1,722,176		
26	133-06-2	Captan			198	1,722,176		
27	63-25-2	Carbaryl			198	1,722,176		
28	75-15-0	Carbon disulfide			198	1,722,176		
29	56-23-5	Carbon tetrachloride			198	1,722,176		
30	463-58-1	Carbonyl sulfide			198	1,722,176		
31	120-80-9	Catechol			198	1,722,176		
32	133-90-4	Chloramben			198	1,722,176		
33	57-74-9	Chlordane			198	1,722,176		
34	7782-50-5	Chlorine			198	1,722,176		
35	79-11-8	Chloroacetic acid			198	1,722,176		
36	532-27-4	2-Chloroacetophenone			198	1,722,176		
37	108-90-7	Chlorobenzene			198	1,722,176		
38	510-15-6	Chlorobenzilate			198	1,722,176		
39	67-66-3	Chloroform			198	1,722,176		
40	107-30-2	Chloromethyl methyl ether			198	1,722,176		
41	126-99-8	Chloroprene			198	1,722,176		
42	1319-77-3	Cresol/Cresylic acid(mixed isomers)			198	1,722,176		
43	95-48-7	o-Cresol			198	1,722,176		
44	108-39-4	m-Cresol			198	1,722,176		
45	106-44-5	p-Cresol			198	1,722,176		
46	98-82-8	Cumene			198	1,722,176		
47		2,4-D(2,4-Dichlorophenoxyacetic Acid) (including salts and esters)			198	1,722,176		
48	72-55-9	DDE(1,1-dichloro-2,2-bis(p-chlorophenyl) ethylene)			198	1,722,176		
49	334-88-3	Diazomethane			198	1,722,176		
50	132-64-9	Dibenzofuran			198	1,722,176		
51	96-12-8	1,2-Dibromo-3-chloropropane			198	1,722,176		
52	84-74-2	Dibutyl phthalate			198	1,722,176		
53	106-46-7	1,4-Dichlorobenzene			198	1,722,176		
54	91-94-1	Dichlorobenzidine			198	1,722,176		
55	111-44-4	Dichloroethyl ether(Bis[2-chloroethyl]ether)			198	1,722,176		
56	542-75-6	1,3-Dichloropropene			198	1,722,176		
57	62-73-7	Dichlorvos			198	1,722,176		
58	111-42-2	Diethanolamine			198	1,722,176		
59	64-67-5	Diethyl sulfate			198	1,722,176		
60	119-90-4	3,3'-Dimethoxybenzidine			198	1,722,176		
61	60-11-7	4-Dimethylaminoazobenzene			198	1,722,176		
62	121-69-7	N,N-Dimethylaniline			198	1,722,176		
63	119-93-7	3,3'-Dimethylbenzidine			198	1,722,176		
64	79-44-7	Dimethylcarbamoyl chloride			198	1,722,176		
65	68-12-2	N,N-Dimethylformamide			198	1,722,176		
66	57-14-7	1,1-Dimethylhydrazine			198	1,722,176		
67	131-11-3	Dimethyl phthalate			198	1,722,176		
68	77-78-1	Dimethyl sulfate			198	1,722,176		
69		4,6-Dinitro-o-cresol (including salts)			198	1,722,176		
70	51-28-5	2,4-Dinitrophenol			198	1,722,176		
71	121-14-2	2,4-Dinitrotoluene			198	1,722,176		
72	123-91-1	1,4-Dioxane (1,4-Diethyleneoxide)			198	1,722,176		
73	122-66-7	1,2-Diphenylhydrazine			198	1,722,176		
74	106-89-8	Epichlorohydrin (l-Chloro-2,3-epoxypropane)			198	1,722,176		
75	106-88-7	1,2-Epoxybutane			198	1,722,176		
76	140-88-5	Ethyl acrylate			198	1,722,176		
77	100-41-4	Ethylbenzene			198	1,722,176		
78	51-79-6	Ethyl carbamate (Urethane)			198	1,722,176		

Attachment S-1b
Air Toxic Emissions for CT-2

SECTION 112 HAZARDOUS AIR POLLUTANTS

EPA ID #	CAS Number	Pollutant	Source of Emission Factor	Emission Factor (lb/MMBtu)	Heat Input (MMBtu/hr)	Heat Input (MMBtu/yr)	Emissions (lb/hr)	Emissions (tpy)
79	75-00-3	Ethyl chloride (Chloroethane)			198	1,722,176		
80	106-93-4	Ethylene dibromide (Dibromoethane)			198	1,722,176		
81	107-06-2	Ethylene dichloride (1,2-Dichloroethane)			198	1,722,176		
82	107-21-1	Ethylene glycol			198	1,722,176		
83	151-56-4	Ethyleneimine (Aziridine)			198	1,722,176		
84	75-21-8	Ethylene oxide			198	1,722,176		
85	96-45-7	Ethylene thiourea			198	1,722,176		
86	75-34-3	Ethylidene dichloride (1,1-Dichloroethane)			198	1,722,176		
87	50-00-0	Formaldehyde	AP-42, Section 3.1, Table 3.1-4	2.80E-04	198	1,722,176	5.54E-02	2.41E-01
88	76-44-8	Heptachlor			198	1,722,176		
89	118-74-1	Hexachlorobenzene			198	1,722,176		
90	87-68-3	Hexachlorobutadiene			198	1,722,176		
91		1,2,3,4,5,6-Hexachlorocyclyhexane (all stereo isomers including lindane)			198	1,722,176		
92	77-47-4	Hexachlorocyclopentadiene			198	1,722,176		
93	67-72-1	Hexachloroethane			198	1,722,176		
94	822-06-0	Hexamethylene diisocyanate			198	1,722,176		
95	680-31-9	Hexamethylphosphoramide			198	1,722,176		
96	110-54-3	Hexane			198	1,722,176		
97	302-01-2	Hydrazine			198	1,722,176		
98	7647-01-0	Hydrochloric acid (Hydrogen chloride [gas only])			198	1,722,176		
99	7664-39-3	Hydrogen fluoride (Hydrofluoric acid)			198	1,722,176		
100	123-31-9	Hydroquinone			198	1,722,176		
101	78-59-1	Isophorone			198	1,722,176		
102	108-31-6	Maleic anhydride			198	1,722,176		
103	67-56-1	Methanol			198	1,722,176		
104	72-43-5	Methoxychlor			198	1,722,176		
105	74-83-9	Methyl bromide (Bromomethane)			198	1,722,176		
106	74-87-3	Methyl chloride(Chloromethane)			198	1,722,176		
107	71-55-6	Methyl chloroform(1,1,1-Trichloroethane)			198	1,722,176		
108	78-93-3	Methyl ethyl ketone (2-Butanone) (Removed 12/19/05, See 70FR75047)			198	1,722,176		
109	60-34-4	Methylhydrazine			198	1,722,176		
110	74-88-4	Methyl iodide (Iodomethane)			198	1,722,176		
111	108-10-1	Methyl isobutyl ketone(Hexone)			198	1,722,176		
112	624-83-9	Methyl isocyanate			198	1,722,176		
113	80-62-6	Methyl methacrylate			198	1,722,176		
114	1634-04-4	Methyl tert-butyl ether			198	1,722,176		
115	101-14-4	4,4'-Methylenebis(2-chloroaniline)			198	1,722,176		
116	75-09-2	Methylene chloride(Dichloromethane)			198	1,722,176		
117	101-68-8	4,4'-Methylenediphenyl diisocyanate(MDI)			198	1,722,176		
118	101-77-9	4,4'-Methylenedianiline			198	1,722,176		
119	91-20-3	Naphthalene	AP-42, Section 3.1, Table 3.1-4	3.50E-05	198	1,722,176	6.93E-03	3.01E-02
120	98-95-3	Nitrobenzene			198	1,722,176		
121	92-93-3	4-Nitrobiphenyl			198	1,722,176		
122	100-02-7	4-Nitrophenol			198	1,722,176		
123	79-46-9	2-Nitropropane			198	1,722,176		
124	684-93-5	N-Nitroso-N-methylurea			198	1,722,176		
125	62-75-9	N-Nitrosodimethylamine			198	1,722,176		
126	59-89-2	N-Nitrosomorpholine			198	1,722,176		
127	56-38-2	Parathion			198	1,722,176		
128	82-68-8	Pentachloronitrobenzene(Quintobenzene)			198	1,722,176		
129	87-86-5	Pentachlorophenol			198	1,722,176		
130	108-95-2	Phenol			198	1,722,176		
131	106-50-3	p-Phenylenediamine			198	1,722,176		
132	75-44-5	Phosgene			198	1,722,176		
133	7803-51-2	Phosphine			198	1,722,176		
134	7723-14-0	Phosphorus			198	1,722,176		
135	85-44-9	Phthalic anhydride			198	1,722,176		
136	1336-36-3	Polychlorinated biphenyls(Aroclors)			198	1,722,176		
137	1120-71-4	1,3-Propane sultone			198	1,722,176		
138	57-57-8	beta-Propiolactone			198	1,722,176		
139	123-38-6	Propionaldehyde			198	1,722,176		
140	114-26-1	Propoxur (Baygon)			198	1,722,176		
141	78-87-5	Propylene dichloride (1,2-Dichloropropane)			198	1,722,176		
142	75-56-9	Propylene oxide			198	1,722,176		
143	75-55-8	1,2-Propylenimine (2-Methylaziridine)			198	1,722,176		
144	91-22-5	Quinoline			198	1,722,176		
145	106-51-4	Quinone(p-Benzoquinone)			198	1,722,176		
146	100-42-5	Styrene			198	1,722,176		
147	96-09-3	Styrene oxide			198	1,722,176		
148	1746-01-6	2,3,7,8-Tetrachlorodibenzo-p-dioxin			198	1,722,176		
149	79-34-5	1,1,2,2-Tetrachloroethane			198	1,722,176		
150	127-18-4	Tetrachloroethylene(Perchloroethylene)			198	1,722,176		
151	7550-45-0	Titanium tetrachloride			198	1,722,176		
152	108-88-3	Toluene	AP-42, Section 3.4, Table 3.4-3	2.81E-04	198	1,722,176	5.56E-02	2.42E-01
153	95-80-7	Toluene-2,4-diamine			198	1,722,176		
154	584-84-9	2,4-Toluene diisocyanate			198	1,722,176		
155	95-53-4	o-Toluidine			198	1,722,176		
156	8001-35-2	Toxaphene (chlorinated camphene)			198	1,722,176		

Attachment S-1b
Air Toxic Emissions for CT-2

SECTION 112 HAZARDOUS AIR POLLUTANTS

EPA ID #	CAS Number	Pollutant	Source of Emission Factor	Emission Factor (lb/MMBtu)	Heat Input (MMBtu/hr)	Heat Input (MMBtu/yr)	Emissions (lb/hr)	Emissions (tpy)
157	120-82-1	1,2,4-Trichlorobenzene			198	1,722,176		
158	79-00-5	1,1,2-Trichloroethane			198	1,722,176		
159	79-01-6	Trichloroethylene			198	1,722,176		
160	95-95-4	2,4,5-Trichlorophenol			198	1,722,176		
161	88-06-2	2,4,6-Trichlorophenol			198	1,722,176		
162	121-44-8	Triethylamine			198	1,722,176		
163	1582-09-8	Trifluralin			198	1,722,176		
164	540-84-1	2,2,4-Trimethylpentane			198	1,722,176		
165	108-05-4	Vinyl acetate			198	1,722,176		
166	593-60-2	Vinyl bromide			198	1,722,176		
167	75-01-4	Vinyl chloride			198	1,722,176		
168	75-35-4	Vinylidene chloride (1,1-Dichloroethylene)			198	1,722,176		
169	1330-20-7	Xylene (mixed isomers)	AP-42, Section 3.4, Table 3.4-3	1.93E-04	198	1,722,176	3.82E-02	1.66E-01
170	95-47-6	o-Xylene			198	1,722,176		
171	108-38-3	m-Xylene			198	1,722,176		
172	106-42-3	p-Xylene			198	1,722,176		
173		Antimony Compounds			198	1,722,176		
174		Arsenic Compounds (inorganic including arsine)	AP-42, Section 3.1, Table 3.1-5	1.10E-05	198	1,722,176	2.18E-03	9.47E-03
175		Beryllium Compounds	AP-42, Section 3.1, Table 3.1-5	3.10E-07	198	1,722,176	6.14E-05	2.67E-04
176		Cadmium Compounds	AP-42, Section 3.1, Table 3.1-5	4.80E-06	198	1,722,176	9.50E-04	4.13E-03
177		Chromium Compounds	AP-42, Section 3.1, Table 3.1-5	1.10E-05	198	1,722,176	2.18E-03	9.47E-03
178		Cobalt Compounds			198	1,722,176		
179		Coke Oven Emissions			198	1,722,176		
180		Cyanide Compounds1			198	1,722,176		
181		Glycol ethers2			198	1,722,176		
182		Lead Compounds	AP-42, Section 3.1, Table 3.1-5	1.40E-05	198	1,722,176	2.77E-03	1.21E-02
183		Manganese Compounds	AP-42, Section 3.1, Table 3.1-5	7.90E-04	198	1,722,176	1.56E-01	6.80E-01
184		Mercury Compounds	AP-42, Section 3.1, Table 3.1-5	1.20E-06	198	1,722,176	2.38E-04	1.03E-03
185		Fine mineral fibers3			198	1,722,176		
186		Nickel Compounds	AP-42, Section 3.1, Table 3.1-5	4.60E-06	198	1,722,176	9.11E-04	3.96E-03
187		Polycyclic Organic Matter4	AP-42, Section 3.1, Table 3.1-4	4.00E-05	198	1,722,176	7.92E-03	3.44E-02
188		Radionuclides (including radon)5			198	1,722,176		
189		Selenium Compounds	AP-42, Section 3.1, Table 3.1-5	2.50E-05	198	1,722,176	4.95E-03	2.15E-02
		Total					**3.55E-01**	**1.55**

NOTE: For all listings above which contain the word "compounds" and for glycol ethers, the following applies:
Unless otherwise specified, these listings are defined as including any unique chemical substance that contains the named chemical (i.e., antimony, arsenic, etc.) as part of that chemical's infrastructure.

1. X'CN where X = H' or any other group where a formal dissociation may occur. For example, KCN or Ca(CN)2.

2. R-(OCH2CH2)n-OR'

where:
n = 1, 2, or 3
R = alkyl C7 or less
or R = phenyl or alkyl substituted phenyl
R' = H, or alkyl C7 or less
or ester, sulfate, phosphate, nitrate, sulfonate

3. Includes mineral fiber emissions from facilities manufacturing or processing glass, rock, or slag fibers (or other mineral derived fibers) of average diameter 1 micrometer or less.

4. Includes substituted and/or unsubstituted polycyclic aromatic hydrocarbons and aromatic heterocyclic compounds, with two or more fused rings, at least one of which is benzenoid (i.e., containing six carbon atoms and is aromatic) in structure. Polycyclic Organic Matter is a mixture of organic compounds containing one or more of these polycyclic aromatic chemicals. Polycyclic Organic Matter is generally formed or emitted during thermal processes including (1) incomplete combustion, (2) pyrolysis, (3) the volatilization, distillation or processing of fossil fuels or bitumens, or (4) the distillation or thermal processing of non-fossil fuels. The Administrator may delineate, by test method, what is included in polycyclic organic matter.

5. A type of atom which spontaneously undergoes radioactive decay.

Attachment S-1b
Air Toxic Emissions for CT-4 or CT-5

SECTION 112 HAZARDOUS AIR POLLUTANTS

EPA ID #	CAS Number	Pollutant	Source of Emission Factor	Emission Factor (lb/MMBtu)	Heat Input (MMBtu/hr)	Emissions (lb/hr)	Emissions (tpy)
1	75-07-0	Acetaldehyde	AP-42, Section 3.4, Table 3.4-3	2.52E-05	275	6.93E-03	3.04E-02
2	60-35-5	Acetamide			275		
3	75-05-8	Acetonitrile			275		
4	98-86-2	Acetophenone			275		
5	53-96-3	2-Acetylaminofluorene			275		
6	107-02-8	Acrolein	AP-42, Section 3.4, Table 3.4-3	7.88E-06	275	2.17E-03	9.49E-03
7	79-06-1	Acrylamide			275		
8	79-10-7	Acrylic acid			275		
9	107-13-1	Acrylonitrile			275		
10	107-05-1	Allyl chloride			275		
11	92-67-1	4-Aminobiphenyl			275		
12	62-53-3	Aniline			275		
13	90-04-0	o-Anisidine			275		
14	1332-21-4	Asbestos			275		
15	71-43-2	Benzene (including benzene from gasoline)	AP-42, Section 3.1, Table 3.1-4	5.50E-05	275	1.51E-02	6.61E-02
16	92-87-5	Benzidine			275		
17	98-07-7	Benzotrichloride			275		
18	100-44-7	Benzyl chloride			275		
19	92-52-4	Biphenyl			275		
20	117-81-7	Bis(2-ethylhexyl)phthalate (DEHP)			275		
21	542-88-1	Bis(chloromethyl) ether			275		
22	75-25-2	Bromoform			275		
23	106-99-0	1,3-Butadiene	AP-42, Section 3.1, Table 3.1-4	1.60E-05	275	4.40E-03	1.93E-02
24	156-62-7	Calcium cyanamide			275		
25	105-60-2	Caprolactam (Removed 06/18/96, See 61FR30816)			275		
26	133-06-2	Captan			275		
27	63-25-2	Carbaryl			275		
28	75-15-0	Carbon disulfide			275		
29	56-23-5	Carbon tetrachloride			275		
30	463-58-1	Carbonyl sulfide			275		
31	120-80-9	Catechol			275		
32	133-90-4	Chloramben			275		
33	57-74-9	Chlordane			275		
34	7782-50-5	Chlorine			275		
35	79-11-8	Chloroacetic acid			275		
36	532-27-4	2-Chloroacetophenone			275		
37	108-90-7	Chlorobenzene			275		
38	510-15-6	Chlorobenzilate			275		
39	67-66-3	Chloroform			275		
40	107-30-2	Chloromethyl methyl ether			275		
41	126-99-8	Chloroprene			275		
42	1319-77-3	Cresol/Cresylic acid(mixed isomers)			275		
43	95-48-7	o-Cresol			275		
44	108-39-4	m-Cresol			275		
45	106-44-5	p-Cresol			275		
46	98-82-8	Cumene			275		
47		2,4-D(2,4-Dichlorophenoxyacetic Acid) (including salts and esters)			275		
48	72-55-9	DDE(1,1-dichloro-2,2-bis(p-chlorophenyl) ethylene)			275		
49	334-88-3	Diazomethane			275		
50	132-64-9	Dibenzofuran			275		
51	96-12-8	1,2-Dibromo-3-chloropropane			275		
52	84-74-2	Dibutyl phthalate			275		
53	106-46-7	1,4-Dichlorobenzene			275		
54	91-94-1	Dichlorobenzidine			275		
55	111-44-4	Dichloroethyl ether(Bis[2-chloroethyl]ether)			275		
56	542-75-6	1,3-Dichloropropene			275		
57	62-73-7	Dichlorvos			275		
58	111-42-2	Diethanolamine			275		
59	64-67-5	Diethyl sulfate			275		
60	119-90-4	3,3'-Dimethoxybenzidine			275		
61	60-11-7	4-Dimethylaminoazobenzene			275		
62	121-69-7	N,N-Dimethylaniline			275		
63	119-93-7	3,3'-Dimethylbenzidine			275		
64	79-44-7	Dimethylcarbamoyl chloride			275		
65	68-12-2	N,N-Dimethylformamide			275		
66	57-14-7	1,1-Dimethylhydrazine			275		
67	131-11-3	Dimethyl phthalate			275		
68	77-78-1	Dimethyl sulfate			275		
69		4,6-Dinitro-o-cresol (including salts)			275		
70	51-28-5	2,4-Dinitrophenol			275		
71	121-14-2	2,4-Dinitrotoluene			275		
72	123-91-1	1,4-Dioxane (1,4-Diethyleneoxide)			275		
73	122-66-7	1,2-Diphenylhydrazine			275		
74	106-89-8	Epichlorohydrin (l-Chloro-2,3-epoxypropane)			275		
75	106-88-7	1,2-Epoxybutane			275		
76	140-88-5	Ethyl acrylate			275		
77	100-41-4	Ethylbenzene			275		
78	51-79-6	Ethyl carbamate (Urethane)			275		

Attachment S-1b
Air Toxic Emissions for CT-4 or CT-5

SECTION 112 HAZARDOUS AIR POLLUTANTS

EPA ID #	CAS Number	Pollutant	Source of Emission Factor	Emission Factor (lb/MMBtu)	Heat Input (MMBtu/hr)	Emissions (lb/hr)	Emissions (tpy)
79	75-00-3	Ethyl chloride (Chloroethane)			275		
80	106-93-4	Ethylene dibromide (Dibromoethane)			275		
81	107-06-2	Ethylene dichloride (1,2-Dichloroethane)			275		
82	107-21-1	Ethylene glycol			275		
83	151-56-4	Ethyleneimine (Aziridine)			275		
84	75-21-8	Ethylene oxide			275		
85	96-45-7	Ethylene thiourea			275		
86	75-34-3	Ethylidene dichloride (1,1-Dichloroethane)			275		
87	50-00-0	Formaldehyde	AP-42, Section 3.1, Table 3.1-4	2.80E-04	275	7.70E-02	3.37E-01
88	76-44-8	Heptachlor			275		
89	118-74-1	Hexachlorobenzene			275		
90	87-68-3	Hexachlorobutadiene			275		
91		1,2,3,4,5,6-Hexachlorocyclyhexane (all stereo isomers including lindane)			275		
92	77-47-4	Hexachlorocyclopentadiene			275		
93	67-72-1	Hexachloroethane			275		
94	822-06-0	Hexamethylene diisocyanate			275		
95	680-31-9	Hexamethylphosphoramide			275		
96	110-54-3	Hexane			275		
97	302-01-2	Hydrazine			275		
98	7647-01-0	Hydrochloric acid (Hydrogen chloride [gas only])			275		
99	7664-39-3	Hydrogen fluoride (Hydrofluoric acid)			275		
100	123-31-9	Hydroquinone			275		
101	78-59-1	Isophorone			275		
102	108-31-6	Maleic anhydride			275		
103	67-56-1	Methanol			275		
104	72-43-5	Methoxychlor			275		
105	74-83-9	Methyl bromide (Bromomethane)			275		
106	74-87-3	Methyl chloride(Chloromethane)			275		
107	71-55-6	Methyl chloroform(1,1,1-Trichloroethane)			275		
108	78-93-3	Methyl ethyl ketone (2-Butanone) (Removed 12/19/05, See 70FR75047)			275		
109	60-34-4	Methylhydrazine			275		
110	74-88-4	Methyl iodide (Iodomethane)			275		
111	108-10-1	Methyl isobutyl ketone(Hexone)			275		
112	624-83-9	Methyl isocyanate			275		
113	80-62-6	Methyl methacrylate			275		
114	1634-04-4	Methyl tert-butyl ether			275		
115	101-14-4	4,4'-Methylenebis(2-chloroaniline)			275		
116	75-09-2	Methylene chloride(Dichloromethane)			275		
117	101-68-8	4,4'-Methylenediphenyl diisocyanate(MDI)			275		
118	101-77-9	4,4'-Methylenedianiline			275		
119	91-20-3	Naphthalene	AP-42, Section 3.1, Table 3.1-4	3.50E-05	275	9.63E-03	4.22E-02
120	98-95-3	Nitrobenzene			275		
121	92-93-3	4-Nitrobiphenyl			275		
122	100-02-7	4-Nitrophenol			275		
123	79-46-9	2-Nitropropane			275		
124	684-93-5	N-Nitroso-N-methylurea			275		
125	62-75-9	N-Nitrosodimethylamine			275		
126	59-89-2	N-Nitrosomorpholine			275		
127	56-38-2	Parathion			275		
128	82-68-8	Pentachloronitrobenzene(Quintobenzene)			275		
129	87-86-5	Pentachlorophenol			275		
130	108-95-2	Phenol			275		
131	106-50-3	p-Phenylenediamine			275		
132	75-44-5	Phosgene			275		
133	7803-51-2	Phosphine			275		
134	7723-14-0	Phosphorus			275		
135	85-44-9	Phthalic anhydride			275		
136	1336-36-3	Polychlorinated biphenyls(Aroclors)			275		
137	1120-71-4	1,3-Propane sultone			275		
138	57-57-8	beta-Propiolactone			275		
139	123-38-6	Propionaldehyde			275		
140	114-26-1	Propoxur (Baygon)			275		
141	78-87-5	Propylene dichloride (1,2-Dichloropropane)			275		
142	75-56-9	Propylene oxide			275		
143	75-55-8	1,2-Propylenimine (2-Methylaziridine)			275		
144	91-22-5	Quinoline			275		
145	106-51-4	Quinone(p-Benzoquinone)			275		
146	100-42-5	Styrene			275		
147	96-09-3	Styrene oxide			275		
148	1746-01-6	2,3,7,8-Tetrachlorodibenzo-p-dioxin			275		
149	79-34-5	1,1,2,2-Tetrachloroethane			275		
150	127-18-4	Tetrachloroethylene(Perchloroethylene)			275		
151	7550-45-0	Titanium tetrachloride			275		
152	108-88-3	Toluene	AP-42, Section 3.4, Table 3.4-3	2.81E-04	275	7.73E-02	3.38E-01
153	95-80-7	Toluene-2,4-diamine			275		
154	584-84-9	2,4-Toluene diisocyanate			275		
155	95-53-4	o-Toluidine			275		
156	8001-35-2	Toxaphene (chlorinated camphene)			275		

Attachment S-1b
Air Toxic Emissions for CT-4 or CT-5

SECTION 112 HAZARDOUS AIR POLLUTANTS

EPA ID #	CAS Number	Pollutant	Source of Emission Factor	Emission Factor (lb/MMBtu)	Heat Input (MMBtu/hr)	Emissions (lb/hr)	Emissions (tpy)
157	120-82-1	1,2,4-Trichlorobenzene			275		
158	79-00-5	1,1,2-Trichloroethane			275		
159	79-01-6	Trichloroethylene			275		
160	95-95-4	2,4,5-Trichlorophenol			275		
161	88-06-2	2,4,6-Trichlorophenol			275		
162	121-44-8	Triethylamine			275		
163	1582-09-8	Trifluralin			275		
164	540-84-1	2,2,4-Trimethylpentane			275		
165	108-05-4	Vinyl acetate			275		
166	593-60-2	Vinyl bromide			275		
167	75-01-4	Vinyl chloride			275		
168	75-35-4	Vinylidene chloride (1,1-Dichloroethylene)			275		
169	1330-20-7	Xylene (mixed isomers)	AP-42, Section 3.4, Table 3.4-3	1.93E-04	275	5.31E-02	2.32E-01
170	95-47-6	o-Xylene			275		
171	108-38-3	m-Xylene			275		
172	106-42-3	p-Xylene			275		
173		Antimony Compounds			275		
174		Arsenic Compounds (inorganic including arsine)	AP-42, Section 3.1, Table 3.1-5	1.10E-05	275	3.03E-03	1.33E-02
175		Beryllium Compounds	AP-42, Section 3.1, Table 3.1-5	3.10E-07	275	8.53E-05	3.73E-04
176		Cadmium Compounds	AP-42, Section 3.1, Table 3.1-5	4.80E-06	275	1.32E-03	5.78E-03
177		Chromium Compounds	AP-42, Section 3.1, Table 3.1-5	1.10E-05	275	3.03E-03	1.32E-02
178		Cobalt Compounds			275		
179		Coke Oven Emissions			275		
180		Cyanide Compounds1			275		
181		Glycol ethers2			275		
182		Lead Compounds	AP-42, Section 3.1, Table 3.1-5	1.40E-05	275	3.85E-03	1.69E-02
183		Manganese Compounds	AP-42, Section 3.1, Table 3.1-5	7.90E-04	275	2.17E-01	9.52E-01
184		Mercury Compounds	AP-42, Section 3.1, Table 3.1-5	1.20E-06	275	3.30E-04	1.45E-03
185		Fine mineral fibers3			275		
186		Nickel Compounds	AP-42, Section 3.1, Table 3.1-5	4.60E-06	275	1.27E-03	5.54E-03
187		Polycyclic Organic Matter4	AP-42, Section 3.1, Table 3.1-4	4.00E-05	275	1.10E-02	4.82E-02
188		Radionuclides (including radon)5			275		
189		Selenium Compounds	AP-42, Section 3.1, Table 3.1-5	2.50E-05	275	6.88E-03	3.01E-02
		Total				**4.94E-01**	**2.16**

NOTE: For all listings above which contain the word "compounds" and for glycol ethers, the following applies:
Unless otherwise specified, these listings are defined as including any unique chemical substance
that contains the named chemical (i.e., antimony, arsenic, etc.) as part of that chemical's infrastructure.

1. X'CN where X = H' or any other group where a formal dissociation may occur. For example, KCN or Ca(CN)2.

2. R-(OCH2CH2)n-OR'
where: n = 1, 2, or 3
R = alkyl C7 or less
or R = phenyl or alkyl substituted phenyl
R' = H, or alkyl C7 or less
or ester, sulfate, phosphate, nitrate, sulfonate

3. Includes mineral fiber emissions from facilities manufacturing or processing glass, rock, or slag fibers (or other mineral derived fibers) of average diameter 1 micrometer or less.

4. Includes substituted and/or unsubstituted polycyclic aromatic hydrocarbons and aromatic heterocyclic compounds, with two or more fused rings, at least one of which is benzenoid (i.e., containing six carbon atoms and is aromatic) in structure. Polycyclic Organic Matter is a mixture of organic compounds containing one or more of these polycyclic aromatic chemicals. Polycyclic Organic Matter is generally formed or emitted during thermal processes including (1) incomplete combustion, (2) pyrolysis, (3) the volatilization, distillation or processing of fossil fuels or bitumens, or (4) the distillation or thermal processing of non-fossil fuels. The Administrator may delineate, by test method, what is included in polycyclic organic matter.

5. A type of atom which spontaneously undergoes radioactive decay.

Attachment S-1b
Air Toxic Emissions for D-21

SECTION 112 HAZARDOUS AIR POLLUTANTS

EPA ID #	CAS Number	Pollutant	Source of Emission Factor	Emission Factor (lb/MMBtu)	Heat Input (MMBtu/hr)	Heat Input (MMBtu/yr)	Emissions (lb/hr)	Emissions (tpy)
1	75-07-0	Acetaldehyde	AP-42, Section 3.4, Table 3.4-3	2.52E-05	28.1	9,800	7.08E-04	1.23E-04
2	60-35-5	Acetamide			28.1	9,800		
3	75-05-8	Acetonitrile			28.1	9,800		
4	98-86-2	Acetophenone			28.1	9,800		
5	53-96-3	2-Acetylaminofluorene			28.1	9,800		
6	107-02-8	Acrolein	AP-42, Section 3.4, Table 3.4-3	7.88E-06	28.1	9,800	2.21E-04	3.86E-05
7	79-06-1	Acrylamide			28.1	9,800		
8	79-10-7	Acrylic acid			28.1	9,800		
9	107-13-1	Acrylonitrile			28.1	9,800		
10	107-05-1	Allyl chloride			28.1	9,800		
11	92-67-1	4-Aminobiphenyl			28.1	9,800		
12	62-53-3	Aniline			28.1	9,800		
13	90-04-0	o-Anisidine			28.1	9,800		
14	1332-21-4	Asbestos			28.1	9,800		
15	71-43-2	Benzene (including benzene from gasoline)	AP-42, Section 3.4, Table 3.4-3	7.76E-04	28.1	9,800	2.18E-02	3.80E-03
16	92-87-5	Benzidine			28.1	9,800		
17	98-07-7	Benzotrichloride			28.1	9,800		
18	100-44-7	Benzyl chloride			28.1	9,800		
19	92-52-4	Biphenyl			28.1	9,800		
20	117-81-7	Bis(2-ethylhexyl)phthalate (DEHP)			28.1	9,800		
21	542-88-1	Bis(chloromethyl) ether			28.1	9,800		
22	75-25-2	Bromoform			28.1	9,800		
23	106-99-0	1,3-Butadiene	AP-42, Section 3.1, Table 3.1-4	1.60E-05	28.1	9,800	4.50E-04	7.84E-05
24	156-62-7	Calcium cyanamide			28.1	9,800		
25	105-60-2	Caprolactam (Removed 06/18/96, See 61FR30816)			28.1	9,800		
26	133-06-2	Captan			28.1	9,800		
27	63-25-2	Carbaryl			28.1	9,800		
28	75-15-0	Carbon disulfide			28.1	9,800		
29	56-23-5	Carbon tetrachloride			28.1	9,800		
30	463-58-1	Carbonyl sulfide			28.1	9,800		
31	120-80-9	Catechol			28.1	9,800		
32	133-90-4	Chloramben			28.1	9,800		
33	57-74-9	Chlordane			28.1	9,800		
34	7782-50-5	Chlorine			28.1	9,800		
35	79-11-8	Chloroacetic acid			28.1	9,800		
36	532-27-4	2-Chloroacetophenone			28.1	9,800		
37	108-90-7	Chlorobenzene			28.1	9,800		
38	510-15-6	Chlorobenzilate			28.1	9,800		
39	67-66-3	Chloroform			28.1	9,800		
40	107-30-2	Chloromethyl methyl ether			28.1	9,800		
41	126-99-8	Chloroprene			28.1	9,800		
42	1319-77-3	Cresol/Cresylic acid(mixed isomers)			28.1	9,800		
43	95-48-7	o-Cresol			28.1	9,800		
44	108-39-4	m-Cresol			28.1	9,800		
45	106-44-5	p-Cresol			28.1	9,800		
46	98-82-8	Cumene			28.1	9,800		
47		2,4-D(2,4-Dichlorophenoxyacetic Acid) (including salts and esters)			28.1	9,800		
48	72-55-9	DDE(1,1-dichloro-2,2-bis(p-chlorophenyl) ethylene)			28.1	9,800		
49	334-88-3	Diazomethane			28.1	9,800		
50	132-64-9	Dibenzofuran			28.1	9,800		
51	96-12-8	1,2-Dibromo-3-chloropropane			28.1	9,800		
52	84-74-2	Dibutyl phthalate			28.1	9,800		
53	106-46-7	1,4-Dichlorobenzene			28.1	9,800		
54	91-94-1	Dichlorobenzidine			28.1	9,800		
55	111-44-4	Dichloroethyl ether(Bis[2-chloroethyl]ether)			28.1	9,800		
56	542-75-6	1,3-Dichloropropene			28.1	9,800		
57	62-73-7	Dichlorvos			28.1	9,800		
58	111-42-2	Diethanolamine			28.1	9,800		
59	64-67-5	Diethyl sulfate			28.1	9,800		
60	119-90-4	3,3'-Dimethoxybenzidine			28.1	9,800		
61	60-11-7	4-Dimethylaminoazobenzene			28.1	9,800		
62	121-69-7	N,N-Dimethylaniline			28.1	9,800		
63	119-93-7	3,3'-Dimethylbenzidine			28.1	9,800		
64	79-44-7	Dimethylcarbamoyl chloride			28.1	9,800		
65	68-12-2	N,N-Dimethylformamide			28.1	9,800		
66	57-14-7	1,1-Dimethylhydrazine			28.1	9,800		
67	131-11-3	Dimethyl phthalate			28.1	9,800		
68	77-78-1	Dimethyl sulfate			28.1	9,800		
69		4,6-Dinitro-o-cresol (including salts)			28.1	9,800		
70	51-28-5	2,4-Dinitrophenol			28.1	9,800		
71	121-14-2	2,4-Dinitrotoluene			28.1	9,800		
72	123-91-1	1,4-Dioxane (1,4-Diethyleneoxide)			28.1	9,800		
73	122-66-7	1,2-Diphenylhydrazine			28.1	9,800		
74	106-89-8	Epichlorohydrin (l-Chloro-2,3-epoxypropane)			28.1	9,800		
75	106-88-7	1,2-Epoxybutane			28.1	9,800		
76	140-88-5	Ethyl acrylate			28.1	9,800		
77	100-41-4	Ethylbenzene			28.1	9,800		
78	51-79-6	Ethyl carbamate (Urethane)			28.1	9,800		

Attachment S-1b
Air Toxic Emissions for D-21

SECTION 112 HAZARDOUS AIR POLLUTANTS

EPA ID #	CAS Number	Pollutant	Source of Emission Factor	Emission Factor (lb/MMBtu)	Heat Input (MMBtu/hr)	Heat Input (MMBtu/yr)	Emissions (lb/hr)	Emissions (tpy)
79	75-00-3	Ethyl chloride (Chloroethane)			28.1	9,800		
80	106-93-4	Ethylene dibromide (Dibromoethane)			28.1	9,800		
81	107-06-2	Ethylene dichloride (1,2-Dichloroethane)			28.1	9,800		
82	107-21-1	Ethylene glycol			28.1	9,800		
83	151-56-4	Ethyleneimine (Aziridine)			28.1	9,800		
84	75-21-8	Ethylene oxide			28.1	9,800		
85	96-45-7	Ethylene thiourea			28.1	9,800		
86	75-34-3	Ethylidene dichloride (1,1-Dichloroethane)			28.1	9,800		
87	50-00-0	Formaldehyde	AP-42, Section 3.4, Table 3.4-3	7.89E-05	28.1	9,800	2.22E-03	3.87E-04
88	76-44-8	Heptachlor			28.1	9,800		
89	118-74-1	Hexachlorobenzene			28.1	9,800		
90	87-68-3	Hexachlorobutadiene			28.1	9,800		
91		1,2,3,4,5,6-Hexachlorocyclyhexane (all stereo isomers including lindane)			28.1	9,800		
92	77-47-4	Hexachlorocyclopentadiene			28.1	9,800		
93	67-72-1	Hexachloroethane			28.1	9,800		
94	822-06-0	Hexamethylene diisocyanate			28.1	9,800		
95	680-31-9	Hexamethylphosphoramide			28.1	9,800		
96	110-54-3	Hexane			28.1	9,800		
97	302-01-2	Hydrazine			28.1	9,800		
98	7647-01-0	Hydrochloric acid (Hydrogen chloride [gas only])			28.1	9,800		
99	7664-39-3	Hydrogen fluoride (Hydrofluoric acid)			28.1	9,800		
100	123-31-9	Hydroquinone			28.1	9,800		
101	78-59-1	Isophorone			28.1	9,800		
102	108-31-6	Maleic anhydride			28.1	9,800		
103	67-56-1	Methanol			28.1	9,800		
104	72-43-5	Methoxychlor			28.1	9,800		
105	74-83-9	Methyl bromide (Bromomethane)			28.1	9,800		
106	74-87-3	Methyl chloride(Chloromethane)			28.1	9,800		
107	71-55-6	Methyl chloroform(1,1,1-Trichloroethane)			28.1	9,800		
108	78-93-3	Methyl ethyl ketone (2-Butanone) (Removed 12/19/05, See 70FR75047)			28.1	9,800		
109	60-34-4	Methylhydrazine			28.1	9,800		
110	74-88-4	Methyl iodide (Iodomethane)			28.1	9,800		
111	108-10-1	Methyl isobutyl ketone(Hexone)			28.1	9,800		
112	624-83-9	Methyl isocyanate			28.1	9,800		
113	80-62-6	Methyl methacrylate			28.1	9,800		
114	1634-04-4	Methyl tert-butyl ether			28.1	9,800		
115	101-14-4	4,4'-Methylenebis(2-chloroaniline)			28.1	9,800		
116	75-09-2	Methylene chloride(Dichloromethane)			28.1	9,800		
117	101-68-8	4,4'-Methylenediphenyl diisocyanate(MDI)			28.1	9,800		
118	101-77-9	4,4'-Methylenedianiline			28.1	9,800		
119	91-20-3	Naphthalene	AP-42, Section 3.4, Table 3.4-4	1.30E-04	28.1	9,800	3.65E-03	6.37E-04
120	98-95-3	Nitrobenzene			28.1	9,800		
121	92-93-3	4-Nitrobiphenyl			28.1	9,800		
122	100-02-7	4-Nitrophenol			28.1	9,800		
123	79-46-9	2-Nitropropane			28.1	9,800		
124	684-93-5	N-Nitroso-N-methylurea			28.1	9,800		
125	62-75-9	N-Nitrosodimethylamine			28.1	9,800		
126	59-89-2	N-Nitrosomorpholine			28.1	9,800		
127	56-38-2	Parathion			28.1	9,800		
128	82-68-8	Pentachloronitrobenzene(Quintobenzene)			28.1	9,800		
129	87-86-5	Pentachlorophenol			28.1	9,800		
130	108-95-2	Phenol			28.1	9,800		
131	106-50-3	p-Phenylenediamine			28.1	9,800		
132	75-44-5	Phosgene			28.1	9,800		
133	7803-51-2	Phosphine			28.1	9,800		
134	7723-14-0	Phosphorus			28.1	9,800		
135	85-44-9	Phthalic anhydride			28.1	9,800		
136	1336-36-3	Polychlorinated biphenyls(Aroclors)			28.1	9,800		
137	1120-71-4	1,3-Propane sultone			28.1	9,800		
138	57-57-8	beta-Propiolactone			28.1	9,800		
139	123-38-6	Propionaldehyde			28.1	9,800		
140	114-26-1	Propoxur (Baygon)			28.1	9,800		
141	78-87-5	Propylene dichloride (1,2-Dichloropropane)			28.1	9,800		
142	75-56-9	Propylene oxide			28.1	9,800		
143	75-55-8	1,2-Propylenimine (2-Methylaziridine)			28.1	9,800		
144	91-22-5	Quinoline			28.1	9,800		
145	106-51-4	Quinone(p-Benzoquinone)			28.1	9,800		
146	100-42-5	Styrene			28.1	9,800		
147	96-09-3	Styrene oxide			28.1	9,800		
148	1746-01-6	2,3,7,8-Tetrachlorodibenzo-p-dioxin			28.1	9,800		
149	79-34-5	1,1,2,2-Tetrachloroethane			28.1	9,800		
150	127-18-4	Tetrachloroethylene(Perchloroethylene)			28.1	9,800		
151	7550-45-0	Titanium tetrachloride			28.1	9,800		
152	108-88-3	Toluene	AP-42, Section 3.4, Table 3.4-3	2.81E-04	28.1	9,800	7.90E-03	1.38E-03
153	95-80-7	Toluene-2,4-diamine			28.1	9,800		
154	584-84-9	2,4-Toluene diisocyanate			28.1	9,800		
155	95-53-4	o-Toluidine			28.1	9,800		
156	8001-35-2	Toxaphene (chlorinated camphene)			28.1	9,800		

Attachment S-1b
Air Toxic Emissions for D-21

SECTION 112 HAZARDOUS AIR POLLUTANTS

EPA ID #	CAS Number	Pollutant	Source of Emission Factor	Emission Factor (lb/MMBtu)	Heat Input (MMBtu/hr)	Heat Input (MMBtu/yr)	Emissions (lb/hr)	Emissions (tpy)
157	120-82-1	1,2,4-Trichlorobenzene			28.1	9,800		
158	79-00-5	1,1,2-Trichloroethane			28.1	9,800		
159	79-01-6	Trichloroethylene			28.1	9,800		
160	95-95-4	2,4,5-Trichlorophenol			28.1	9,800		
161	88-06-2	2,4,6-Trichlorophenol			28.1	9,800		
162	121-44-8	Triethylamine			28.1	9,800		
163	1582-09-8	Trifluralin			28.1	9,800		
164	540-84-1	2,2,4-Trimethylpentane			28.1	9,800		
165	108-05-4	Vinyl acetate			28.1	9,800		
166	593-60-2	Vinyl bromide			28.1	9,800		
167	75-01-4	Vinyl chloride			28.1	9,800		
168	75-35-4	Vinylidene chloride (1,1-Dichloroethylene)			28.1	9,800		
169	1330-20-7	Xylene (mixed isomers)	AP-42, Section 3.4, Table 3.4-3	1.93E-04	28.1	9,800	5.42E-03	9.46E-04
170	95-47-6	o-Xylene			28.1	9,800		
171	108-38-3	m-Xylene			28.1	9,800		
172	106-42-3	p-Xylene			28.1	9,800		
173		Antimony Compounds			28.1	9,800		
174		Arsenic Compounds (inorganic including arsine)	AP-42, Section 3.1, Table 3.1-5	1.10E-05	28.1	9,800	3.09E-04	5.39E-05
175		Beryllium Compounds	AP-42, Section 3.1, Table 3.1-5	3.10E-07	28.1	9,800	8.71E-06	1.52E-06
176		Cadmium Compounds	AP-42, Section 3.1, Table 3.1-5	4.80E-06	28.1	9,800	1.35E-04	2.35E-05
177		Chromium Compounds	AP-42, Section 3.1, Table 3.1-5	1.10E-05	28.1	9,800	3.09E-04	5.39E-05
178		Cobalt Compounds			28.1	9,800		
179		Coke Oven Emissions			28.1	9,800		
180		Cyanide Compounds1			28.1	9,800		
181		Glycol ethers2			28.1	9,800		
182		Lead Compounds	AP-42, Section 3.1, Table 3.1-5	1.40E-05	28.1	9,800	3.93E-04	6.86E-05
183		Manganese Compounds	AP-42, Section 3.1, Table 3.1-5	7.90E-04	28.1	9,800	2.22E-02	3.87E-03
184		Mercury Compounds	AP-42, Section 3.1, Table 3.1-5	1.20E-06	28.1	9,800	3.37E-05	5.88E-06
185		Fine mineral fibers3			28.1	9,800		
186		Nickel Compounds	AP-42, Section 3.1, Table 3.1-5	4.60E-06	28.1	9,800	1.29E-04	2.25E-05
187		Polycyclic Organic Matter4	AP-42, Section 3.4, Table 3.4-4	2.12E-04	28.1	9,800	5.96E-03	1.04E-03
188		Radionuclides (including radon)5			28.1	9,800		
189		Selenium Compounds	AP-42, Section 3.1, Table 3.1-5	2.50E-05	28.1	9,800	7.03E-04	1.23E-04
		Total					**7.26E-02**	**1.27E-02**

NOTE: For all listings above which contain the word "compounds" and for glycol ethers, the following applies:
Unless otherwise specified, these listings are defined as including any unique chemical substance
that contains the named chemical (i.e., antimony, arsenic, etc.) as part of that chemical's infrastructure.

1. X'CN where X = H' or any other group where a formal dissociation may occur. For example, KCN or Ca(CN)2.

2. R-(OCH2CH2)n-OR'
where:
n = 1, 2, or 3
R = alkyl C7 or less
or R = phenyl or alkyl substituted phenyl
R' = H, or alkyl C7 or less
or ester, sulfate, phosphate, nitrate, sulfonate

3. Includes mineral fiber emissions from facilities manufacturing or processing glass, rock, or slag fibers (or other mineral derived fibers) of average diameter 1 micrometer or less.

4. Includes substituted and/or unsubstituted polycyclic aromatic hydrocarbons and aromatic heterocyclic compounds, with two or more fused rings, at least one of which is benzenoid (i.e., containing six carbon atoms and is aromatic) in structure. Polycyclic Organic Matter is a mixture of organic compounds containing one or more of these polycyclic aromatic chemicals. Polycyclic Organic Matter is generally formed or emitted during thermal processes including (1) incomplete combustion, (2) pyrolysis, (3) the volatilization, distillation or processing of fossil fuels or bitumens, or (4) the distillation or thermal processing of non-fossil fuels. The Administrator may delineate, by test method, what is included in polycyclic organic matter.

5. A type of atom which spontaneously undergoes radioactive decay.

Attachment S-1b
Air Toxic Emissions for D-22 or D-23

SECTION 112 HAZARDOUS AIR POLLUTANTS

EPA ID #	CAS Number	Pollutant	Source of Emission Factor	Emission Factor (lb/MMBtu)	Heat Input (MMBtu/hr)	Emissions (lb/hr)	Emissions (tpy)
1	75-07-0	Acetaldehyde	AP-42, Section 3.4, Table 3.4-3	2.52E-05	28.1	7.08E-04	3.10E-03
2	60-35-5	Acetamide			28.1		
3	75-05-8	Acetonitrile			28.1		
4	98-86-2	Acetophenone			28.1		
5	53-96-3	2-Acetylaminofluorene			28.1		
6	107-02-8	Acrolein	AP-42, Section 3.4, Table 3.4-3	7.88E-06	28.1	2.21E-04	9.70E-04
7	79-06-1	Acrylamide			28.1		
8	79-10-7	Acrylic acid			28.1		
9	107-13-1	Acrylonitrile			28.1		
10	107-05-1	Allyl chloride			28.1		
11	92-67-1	4-Aminobiphenyl			28.1		
12	62-53-3	Aniline			28.1		
13	90-04-0	o-Anisidine			28.1		
14	1332-21-4	Asbestos			28.1		
15	71-43-2	Benzene (including benzene from gasoline)	AP-42, Section 3.4, Table 3.4-3	7.76E-04	28.1	2.18E-02	9.55E-02
16	92-87-5	Benzidine			28.1		
17	98-07-7	Benzotrichloride			28.1		
18	100-44-7	Benzyl chloride			28.1		
19	92-52-4	Biphenyl			28.1		
20	117-81-7	Bis(2-ethylhexyl)phthalate (DEHP)			28.1		
21	542-88-1	Bis(chloromethyl) ether			28.1		
22	75-25-2	Bromoform			28.1		
23	106-99-0	1,3-Butadiene	AP-42, Section 3.1, Table 3.1-4	1.60E-05	28.1	4.50E-04	1.97E-03
24	156-62-7	Calcium cyanamide			28.1		
25	105-60-2	Caprolactam (Removed 06/18/96, See 61FR30816)			28.1		
26	133-06-2	Captan			28.1		
27	63-25-2	Carbaryl			28.1		
28	75-15-0	Carbon disulfide			28.1		
29	56-23-5	Carbon tetrachloride			28.1		
30	463-58-1	Carbonyl sulfide			28.1		
31	120-80-9	Catechol			28.1		
32	133-90-4	Chloramben			28.1		
33	57-74-9	Chlordane			28.1		
34	7782-50-5	Chlorine			28.1		
35	79-11-8	Chloroacetic acid			28.1		
36	532-27-4	2-Chloroacetophenone			28.1		
37	108-90-7	Chlorobenzene			28.1		
38	510-15-6	Chlorobenzilate			28.1		
39	67-66-3	Chloroform			28.1		
40	107-30-2	Chloromethyl methyl ether			28.1		
41	126-99-8	Chloroprene			28.1		
42	1319-77-3	Cresol/Cresylic acid(mixed isomers)			28.1		
43	95-48-7	o-Cresol			28.1		
44	108-39-4	m-Cresol			28.1		
45	106-44-5	p-Cresol			28.1		
46	98-82-8	Cumene			28.1		
47		2,4-D(2,4-Dichlorophenoxyacetic Acid) (including salts and esters)			28.1		
48	72-55-9	DDE(1,1-dichloro-2,2-bis(p-chlorophenyl) ethylene)			28.1		
49	334-88-3	Diazomethane			28.1		
50	132-64-9	Dibenzofuran			28.1		
51	96-12-8	1,2-Dibromo-3-chloropropane			28.1		
52	84-74-2	Dibutyl phthalate			28.1		
53	106-46-7	1,4-Dichlorobenzene			28.1		
54	91-94-1	Dichlorobenzidine			28.1		
55	111-44-4	Dichloroethyl ether(Bis[2-chloroethyl]ether)			28.1		
56	542-75-6	1,3-Dichloropropene			28.1		
57	62-73-7	Dichlorvos			28.1		
58	111-42-2	Diethanolamine			28.1		
59	64-67-5	Diethyl sulfate			28.1		
60	119-90-4	3,3'-Dimethoxybenzidine			28.1		
61	60-11-7	4-Dimethylaminoazobenzene			28.1		
62	121-69-7	N,N-Dimethylaniline			28.1		
63	119-93-7	3,3'-Dimethylbenzidine			28.1		
64	79-44-7	Dimethylcarbamoyl chloride			28.1		
65	68-12-2	N,N-Dimethylformamide			28.1		
66	57-14-7	1,1-Dimethylhydrazine			28.1		
67	131-11-3	Dimethyl phthalate			28.1		
68	77-78-1	Dimethyl sulfate			28.1		
69		4,6-Dinitro-o-cresol (including salts)			28.1		
70	51-28-5	2,4-Dinitrophenol			28.1		
71	121-14-2	2,4-Dinitrotoluene			28.1		
72	123-91-1	1,4-Dioxane (1,4-Diethyleneoxide)			28.1		
73	122-66-7	1,2-Diphenylhydrazine			28.1		
74	106-89-8	Epichlorohydrin (l-Chloro-2,3-epoxypropane)			28.1		
75	106-88-7	1,2-Epoxybutane			28.1		
76	140-88-5	Ethyl acrylate			28.1		
77	100-41-4	Ethylbenzene			28.1		
78	51-79-6	Ethyl carbamate (Urethane)			28.1		

Attachment S-1b
Air Toxic Emissions for D-22 or D-23

SECTION 112 HAZARDOUS AIR POLLUTANTS

EPA ID #	CAS Number	Pollutant	Source of Emission Factor	Emission Factor (lb/MMBtu)	Heat Input (MMBtu/hr)	Emissions (lb/hr)	Emissions (tpy)
79	75-00-3	Ethyl chloride (Chloroethane)			28.1		
80	106-93-4	Ethylene dibromide (Dibromoethane)			28.1		
81	107-06-2	Ethylene dichloride (1,2-Dichloroethane)			28.1		
82	107-21-1	Ethylene glycol			28.1		
83	151-56-4	Ethyleneimine (Aziridine)			28.1		
84	75-21-8	Ethylene oxide			28.1		
85	96-45-7	Ethylene thiourea			28.1		
86	75-34-3	Ethylidene dichloride (1,1-Dichloroethane)			28.1		
87	50-00-0	Formaldehyde	AP-42, Section 3.4, Table 3.4-3	7.89E-05	28.1	2.22E-03	9.71E-03
88	76-44-8	Heptachlor			28.1		
89	118-74-1	Hexachlorobenzene			28.1		
90	87-68-3	Hexachlorobutadiene			28.1		
91		1,2,3,4,5,6-Hexachlorocyclyhexane (all stereo isomers including lindane)			28.1		
92	77-47-4	Hexachlorocyclopentadiene			28.1		
93	67-72-1	Hexachloroethane			28.1		
94	822-06-0	Hexamethylene diisocyanate			28.1		
95	680-31-9	Hexamethylphosphoramide			28.1		
96	110-54-3	Hexane			28.1		
97	302-01-2	Hydrazine			28.1		
98	7647-01-0	Hydrochloric acid (Hydrogen chloride [gas only])			28.1		
99	7664-39-3	Hydrogen fluoride (Hydrofluoric acid)			28.1		
100	123-31-9	Hydroquinone			28.1		
101	78-59-1	Isophorone			28.1		
102	108-31-6	Maleic anhydride			28.1		
103	67-56-1	Methanol			28.1		
104	72-43-5	Methoxychlor			28.1		
105	74-83-9	Methyl bromide (Bromomethane)			28.1		
106	74-87-3	Methyl chloride(Chloromethane)			28.1		
107	71-55-6	Methyl chloroform(1,1,1-Trichloroethane)			28.1		
108	78-93-3	Methyl ethyl ketone (2-Butanone) (Removed 12/19/05, See 70FR75047)			28.1		
109	60-34-4	Methylhydrazine			28.1		
110	74-88-4	Methyl iodide (Iodomethane)			28.1		
111	108-10-1	Methyl isobutyl ketone(Hexone)			28.1		
112	624-83-9	Methyl isocyanate			28.1		
113	80-62-6	Methyl methacrylate			28.1		
114	1634-04-4	Methyl tert-butyl ether			28.1		
115	101-14-4	4,4'-Methylenebis(2-chloroaniline)			28.1		
116	75-09-2	Methylene chloride(Dichloromethane)			28.1		
117	101-68-8	4,4'-Methylenediphenyl diisocyanate(MDI)			28.1		
118	101-77-9	4,4'-Methylenedianiline			28.1		
119	91-20-3	Naphthalene	AP-42, Section 3.4, Table 3.4-4	1.30E-04	28.1	3.65E-03	1.60E-02
120	98-95-3	Nitrobenzene			28.1		
121	92-93-3	4-Nitrobiphenyl			28.1		
122	100-02-7	4-Nitrophenol			28.1		
123	79-46-9	2-Nitropropane			28.1		
124	684-93-5	N-Nitroso-N-methylurea			28.1		
125	62-75-9	N-Nitrosodimethylamine			28.1		
126	59-89-2	N-Nitrosomorpholine			28.1		
127	56-38-2	Parathion			28.1		
128	82-68-8	Pentachloronitrobenzene(Quintobenzene)			28.1		
129	87-86-5	Pentachlorophenol			28.1		
130	108-95-2	Phenol			28.1		
131	106-50-3	p-Phenylenediamine			28.1		
132	75-44-5	Phosgene			28.1		
133	7803-51-2	Phosphine			28.1		
134	7723-14-0	Phosphorus			28.1		
135	85-44-9	Phthalic anhydride			28.1		
136	1336-36-3	Polychlorinated biphenyls(Aroclors)			28.1		
137	1120-71-4	1,3-Propane sultone			28.1		
138	57-57-8	beta-Propiolactone			28.1		
139	123-38-6	Propionaldehyde			28.1		
140	114-26-1	Propoxur (Baygon)			28.1		
141	78-87-5	Propylene dichloride (1,2-Dichloropropane)			28.1		
142	75-56-9	Propylene oxide			28.1		
143	75-55-8	1,2-Propylenimine (2-Methylaziridine)			28.1		
144	91-22-5	Quinoline			28.1		
145	106-51-4	Quinone(p-Benzoquinone)			28.1		
146	100-42-5	Styrene			28.1		
147	96-09-3	Styrene oxide			28.1		
148	1746-01-6	2,3,7,8-Tetrachlorodibenzo-p-dioxin			28.1		
149	79-34-5	1,1,2,2-Tetrachloroethane			28.1		
150	127-18-4	Tetrachloroethylene(Perchloroethylene)			28.1		
151	7550-45-0	Titanium tetrachloride			28.1		
152	108-88-3	Toluene	AP-42, Section 3.4, Table 3.4-3	2.81E-04	28.1	7.90E-03	3.46E-02
153	95-80-7	Toluene-2,4-diamine			28.1		
154	584-84-9	2,4-Toluene diisocyanate			28.1		
155	95-53-4	o-Toluidine			28.1		
156	8001-35-2	Toxaphene (chlorinated camphene)			28.1		

Attachment S-1b
Air Toxic Emissions for D-22 or D-23

SECTION 112 HAZARDOUS AIR POLLUTANTS

EPA ID #	CAS Number	Pollutant	Source of Emission Factor	Emission Factor (lb/MMBtu)	Heat Input (MMBtu/hr)	Emissions (lb/hr)	Emissions (tpy)
157	120-82-1	1,2,4-Trichlorobenzene			28.1		
158	79-00-5	1,1,2-Trichloroethane			28.1		
159	79-01-6	Trichloroethylene			28.1		
160	95-95-4	2,4,5-Trichlorophenol			28.1		
161	88-06-2	2,4,6-Trichlorophenol			28.1		
162	121-44-8	Triethylamine			28.1		
163	1582-09-8	Trifluralin			28.1		
164	540-84-1	2,2,4-Trimethylpentane			28.1		
165	108-05-4	Vinyl acetate			28.1		
166	593-60-2	Vinyl bromide			28.1		
167	75-01-4	Vinyl chloride			28.1		
168	75-35-4	Vinylidene chloride (1,1-Dichloroethylene)			28.1		
169	1330-20-7	Xylene (mixed isomers)	AP-42, Section 3.4, Table 3.4-3	1.93E-04	28.1	5.42E-03	2.38E-02
170	95-47-6	o-Xylene			28.1		
171	108-38-3	m-Xylene			28.1		
172	106-42-3	p-Xylene			28.1		
173		Antimony Compounds			28.1		
174		Arsenic Compounds (inorganic including arsine)	AP-42, Section 3.1, Table 3.1-5	1.10E-05	28.1	3.09E-04	1.35E-03
175		Beryllium Compounds	AP-42, Section 3.1, Table 3.1-5	3.10E-07	28.1	8.71E-06	3.82E-05
176		Cadmium Compounds	AP-42, Section 3.1, Table 3.1-5	4.80E-06	28.1	1.35E-04	5.91E-04
177		Chromium Compounds	AP-42, Section 3.1, Table 3.1-5	1.10E-05	28.1	3.09E-04	1.35E-03
178		Cobalt Compounds			28.1		
179		Coke Oven Emissions			28.1		
180		Cyanide Compounds1			28.1		
181		Glycol ethers2			28.1		
182		Lead Compounds	AP-42, Section 3.1, Table 3.1-5	1.40E-05	28.1	3.93E-04	1.72E-03
183		Manganese Compounds	AP-42, Section 3.1, Table 3.1-5	7.90E-04	28.1	2.22E-02	9.72E-02
184		Mercury Compounds	AP-42, Section 3.1, Table 3.1-5	1.20E-06	28.1	3.37E-05	1.48E-04
185		Fine mineral fibers3			28.1		
186		Nickel Compounds	AP-42, Section 3.1, Table 3.1-5	4.60E-06	28.1	1.29E-04	5.66E-04
187		Polycyclic Organic Matter4	AP-42, Section 3.4, Table 3.4-4	2.12E-04	28.1	5.96E-03	2.61E-02
188		Radionuclides (including radon)5			28.1		
189		Selenium Compounds	AP-42, Section 3.1, Table 3.1-5	2.50E-05	28.1	7.03E-04	3.08E-03
		Total				**7.25E-02**	**3.18E-01**

NOTE: For all listings above which contain the word "compounds" and for glycol ethers, the following applies:
Unless otherwise specified, these listings are defined as including any unique chemical substance
that contains the named chemical (i.e., antimony, arsenic, etc.) as part of that chemical's infrastructure.

1. X'CN where X = H' or any other group where a formal dissociation may occur. For example, KCN or Ca(CN)2.

2. R-(OCH2CH2)n-OR'
where: n = 1, 2, or 3
R = alkyl C7 or less
or R = phenyl or alkyl substituted phenyl
R' = H, or alkyl C7 or less
or ester, sulfate, phosphate, nitrate, sulfonate

3. Includes mineral fiber emissions from facilities manufacturing or processing glass, rock, or slag fibers (or other mineral derived fibers) of average diameter 1 micrometer or less.

4. Includes substituted and/or unsubstituted polycyclic aromatic hydrocarbons and aromatic heterocyclic compounds, with two or more fused rings, at least one of which is benzenoid (i.e., containing six carbon atoms and is aromatic) in structure. Polycyclic Organic Matter is a mixture of organic compounds containing one or more of these polycyclic aromatic chemicals. Polycyclic Organic Matter is generally formed or emitted during thermal processes including (1) incomplete combustion, (2) pyrolysis, (3) the volatilization, distillation or processing of fossil fuels or bitumens, or (4) the distillation or thermal processing of non-fossil fuels. The Administrator may delineate, by test method, what is included in polycyclic organic matter.

5. A type of atom which spontaneously undergoes radioactive decay.

Attachment S-1b
Air Toxic Emissions for BS-1

SECTION 112 HAZARDOUS AIR POLLUTANTS

EPA ID #	CAS Number	Pollutant	Source of Emission Factor	Emission Factor (lb/MMBtu)	Heat Input (MMBtu/hr)	Emissions (lb/hr)	Emissions (tpy)
1	75-07-0	Acetaldehyde	AP-42, Section 3.4, Table 3.4-3	2.52E-05	5.57	1.40E-04	2.11E-05
2	60-35-5	Acetamide			5.57		
3	75-05-8	Acetonitrile			5.57		
4	98-86-2	Acetophenone			5.57		
5	53-96-3	2-Acetylaminofluorene			5.57		
6	107-02-8	Acrolein	AP-42, Section 3.4, Table 3.4-3	7.88E-06	5.57	4.39E-05	6.58E-06
7	79-06-1	Acrylamide			5.57		
8	79-10-7	Acrylic acid			5.57		
9	107-13-1	Acrylonitrile			5.57		
10	107-05-1	Allyl chloride			5.57		
11	92-67-1	4-Aminobiphenyl			5.57		
12	62-53-3	Aniline			5.57		
13	90-04-0	o-Anisidine			5.57		
14	1332-21-4	Asbestos			5.57		
15	71-43-2	Benzene (including benzene from gasoline)	AP-42, Section 3.4, Table 3.4-3	7.76E-04	5.57	4.32E-03	6.48E-04
16	92-87-5	Benzidine			5.57		
17	98-07-7	Benzotrichloride			5.57		
18	100-44-7	Benzyl chloride			5.57		
19	92-52-4	Biphenyl			5.57		
20	117-81-7	Bis(2-ethylhexyl)phthalate (DEHP)			5.57		
21	542-88-1	Bis(chloromethyl) ether			5.57		
22	75-25-2	Bromoform			5.57		
23	106-99-0	1,3-Butadiene	AP-42, Section 3.1, Table 3.1-4	1.60E-05	5.57	8.91E-05	1.34E-05
24	156-62-7	Calcium cyanamide			5.57		
25	105-60-2	Caprolactam (Removed 06/18/96, See 61FR30816)			5.57		
26	133-06-2	Captan			5.57		
27	63-25-2	Carbaryl			5.57		
28	75-15-0	Carbon disulfide			5.57		
29	56-23-5	Carbon tetrachloride			5.57		
30	463-58-1	Carbonyl sulfide			5.57		
31	120-80-9	Catechol			5.57		
32	133-90-4	Chloramben			5.57		
33	57-74-9	Chlordane			5.57		
34	7782-50-5	Chlorine			5.57		
35	79-11-8	Chloroacetic acid			5.57		
36	532-27-4	2-Chloroacetophenone			5.57		
37	108-90-7	Chlorobenzene			5.57		
38	510-15-6	Chlorobenzilate			5.57		
39	67-66-3	Chloroform			5.57		
40	107-30-2	Chloromethyl methyl ether			5.57		
41	126-99-8	Chloroprene			5.57		
42	1319-77-3	Cresol/Cresylic acid(mixed isomers)			5.57		
43	95-48-7	o-Cresol			5.57		
44	108-39-4	m-Cresol			5.57		
45	106-44-5	p-Cresol			5.57		
46	98-82-8	Cumene			5.57		
47		2,4-D(2,4-Dichlorophenoxyacetic Acid) (including salts and esters)			5.57		
48	72-55-9	DDE(1,1-dichloro-2,2-bis(p-chlorophenyl) ethylene)			5.57		
49	334-88-3	Diazomethane			5.57		
50	132-64-9	Dibenzofuran			5.57		
51	96-12-8	1,2-Dibromo-3-chloropropane			5.57		
52	84-74-2	Dibutyl phthalate			5.57		
53	106-46-7	1,4-Dichlorobenzene			5.57		
54	91-94-1	Dichlorobenzidine			5.57		
55	111-44-4	Dichloroethyl ether(Bis[2-chloroethyl]ether)			5.57		
56	542-75-6	1,3-Dichloropropene			5.57		
57	62-73-7	Dichlorvos			5.57		
58	111-42-2	Diethanolamine			5.57		
59	64-67-5	Diethyl sulfate			5.57		
60	119-90-4	3,3'-Dimethoxybenzidine			5.57		
61	60-11-7	4-Dimethylaminoazobenzene			5.57		
62	121-69-7	N,N-Dimethylaniline			5.57		
63	119-93-7	3,3'-Dimethylbenzidine			5.57		
64	79-44-7	Dimethylcarbamoyl chloride			5.57		
65	68-12-2	N,N-Dimethylformamide			5.57		
66	57-14-7	1,1-Dimethylhydrazine			5.57		
67	131-11-3	Dimethyl phthalate			5.57		
68	77-78-1	Dimethyl sulfate			5.57		
69		4,6-Dinitro-o-cresol (including salts)			5.57		
70	51-28-5	2,4-Dinitrophenol			5.57		
71	121-14-2	2,4-Dinitrotoluene			5.57		
72	123-91-1	1,4-Dioxane (1,4-Diethyleneoxide)			5.57		
73	122-66-7	1,2-Diphenylhydrazine			5.57		
74	106-89-8	Epichlorohydrin (l-Chloro-2,3-epoxypropane)			5.57		
75	106-88-7	1,2-Epoxybutane			5.57		
76	140-88-5	Ethyl acrylate			5.57		
77	100-41-4	Ethylbenzene			5.57		
78	51-79-6	Ethyl carbamate (Urethane)			5.57		

Attachment S-1b
Air Toxic Emissions for BS-1

SECTION 112 HAZARDOUS AIR POLLUTANTS

EPA ID #	CAS Number	Pollutant	Source of Emission Factor	Emission Factor (lb/MMBtu)	Heat Input (MMBtu/hr)	Emissions (lb/hr)	Emissions (tpy)
79	75-00-3	Ethyl chloride (Chloroethane)			5.57		
80	106-93-4	Ethylene dibromide (Dibromoethane)			5.57		
81	107-06-2	Ethylene dichloride (1,2-Dichloroethane)			5.57		
82	107-21-1	Ethylene glycol			5.57		
83	151-56-4	Ethyleneimine (Aziridine)			5.57		
84	75-21-8	Ethylene oxide			5.57		
85	96-45-7	Ethylene thiourea			5.57		
86	75-34-3	Ethylidene dichloride (1,1-Dichloroethane)			5.57		
87	50-00-0	Formaldehyde	AP-42, Section 3.4, Table 3.4-3	7.89E-05	5.57	4.39E-04	6.59E-05
88	76-44-8	Heptachlor			5.57		
89	118-74-1	Hexachlorobenzene			5.57		
90	87-68-3	Hexachlorobutadiene			5.57		
91		1,2,3,4,5,6-Hexachlorocyclyhexane (all stereo isomers including lindane)			5.57		
92	77-47-4	Hexachlorocyclopentadiene			5.57		
93	67-72-1	Hexachloroethane			5.57		
94	822-06-0	Hexamethylene diisocyanate			5.57		
95	680-31-9	Hexamethylphosphoramide			5.57		
96	110-54-3	Hexane			5.57		
97	302-01-2	Hydrazine			5.57		
98	7647-01-0	Hydrochloric acid (Hydrogen chloride [gas only])			5.57		
99	7664-39-3	Hydrogen fluoride (Hydrofluoric acid)			5.57		
100	123-31-9	Hydroquinone			5.57		
101	78-59-1	Isophorone			5.57		
102	108-31-6	Maleic anhydride			5.57		
103	67-56-1	Methanol			5.57		
104	72-43-5	Methoxychlor			5.57		
105	74-83-9	Methyl bromide (Bromomethane)			5.57		
106	74-87-3	Methyl chloride(Chloromethane)			5.57		
107	71-55-6	Methyl chloroform(1,1,1-Trichloroethane)			5.57		
108	78-93-3	Methyl ethyl ketone (2-Butanone) (Removed 12/19/05, See 70FR75047)			5.57		
109	60-34-4	Methylhydrazine			5.57		
110	74-88-4	Methyl iodide (Iodomethane)			5.57		
111	108-10-1	Methyl isobutyl ketone(Hexone)			5.57		
112	624-83-9	Methyl isocyanate			5.57		
113	80-62-6	Methyl methacrylate			5.57		
114	1634-04-4	Methyl tert-butyl ether			5.57		
115	101-14-4	4,4'-Methylenebis(2-chloroaniline)			5.57		
116	75-09-2	Methylene chloride(Dichloromethane)			5.57		
117	101-68-8	4,4'-Methylenediphenyl diisocyanate(MDI)			5.57		
118	101-77-9	4,4'-Methylenedianiline			5.57		
119	91-20-3	Naphthalene	AP-42, Section 3.4, Table 3.4-4	1.30E-04	5.57	7.24E-04	1.09E-04
120	98-95-3	Nitrobenzene			5.57		
121	92-93-3	4-Nitrobiphenyl			5.57		
122	100-02-7	4-Nitrophenol			5.57		
123	79-46-9	2-Nitropropane			5.57		
124	684-93-5	N-Nitroso-N-methylurea			5.57		
125	62-75-9	N-Nitrosodimethylamine			5.57		
126	59-89-2	N-Nitrosomorpholine			5.57		
127	56-38-2	Parathion			5.57		
128	82-68-8	Pentachloronitrobenzene(Quintobenzene)			5.57		
129	87-86-5	Pentachlorophenol			5.57		
130	108-95-2	Phenol			5.57		
131	106-50-3	p-Phenylenediamine			5.57		
132	75-44-5	Phosgene			5.57		
133	7803-51-2	Phosphine			5.57		
134	7723-14-0	Phosphorus			5.57		
135	85-44-9	Phthalic anhydride			5.57		
136	1336-36-3	Polychlorinated biphenyls(Aroclors)			5.57		
137	1120-71-4	1,3-Propane sultone			5.57		
138	57-57-8	beta-Propiolactone			5.57		
139	123-38-6	Propionaldehyde			5.57		
140	114-26-1	Propoxur (Baygon)			5.57		
141	78-87-5	Propylene dichloride (1,2-Dichloropropane)			5.57		
142	75-56-9	Propylene oxide			5.57		
143	75-55-8	1,2-Propylenimine (2-Methylaziridine)			5.57		
144	91-22-5	Quinoline			5.57		
145	106-51-4	Quinone(p-Benzoquinone)			5.57		
146	100-42-5	Styrene			5.57		
147	96-09-3	Styrene oxide			5.57		
148	1746-01-6	2,3,7,8-Tetrachlorodibenzo-p-dioxin			5.57		
149	79-34-5	1,1,2,2-Tetrachloroethane			5.57		
150	127-18-4	Tetrachloroethylene(Perchloroethylene)			5.57		
151	7550-45-0	Titanium tetrachloride			5.57		
152	108-88-3	Toluene	AP-42, Section 3.4, Table 3.4-3	2.81E-04	5.57	1.57E-03	2.35E-04
153	95-80-7	Toluene-2,4-diamine			5.57		
154	584-84-9	2,4-Toluene diisocyanate			5.57		
155	95-53-4	o-Toluidine			5.57		
156	8001-35-2	Toxaphene (chlorinated camphene)			5.57		

Attachment S-1b
Air Toxic Emissions for BS-1

SECTION 112 HAZARDOUS AIR POLLUTANTS

EPA ID #	CAS Number	Pollutant	Source of Emission Factor	Emission Factor (lb/MMBtu)	Heat Input (MMBtu/hr)	Emissions (lb/hr)	Emissions (tpy)
157	120-82-1	1,2,4-Trichlorobenzene			5.57		
158	79-00-5	1,1,2-Trichloroethane			5.57		
159	79-01-6	Trichloroethylene			5.57		
160	95-95-4	2,4,5-Trichlorophenol			5.57		
161	88-06-2	2,4,6-Trichlorophenol			5.57		
162	121-44-8	Triethylamine			5.57		
163	1582-09-8	Trifluralin			5.57		
164	540-84-1	2,2,4-Trimethylpentane			5.57		
165	108-05-4	Vinyl acetate			5.57		
166	593-60-2	Vinyl bromide			5.57		
167	75-01-4	Vinyl chloride			5.57		
168	75-35-4	Vinylidene chloride (1,1-Dichloroethylene)			5.57		
169	1330-20-7	Xylene (mixed isomers)	AP-42, Section 3.4, Table 3.4-3	1.93E-04	5.57	1.08E-03	1.61E-04
170	95-47-6	o-Xylene			5.57		
171	108-38-3	m-Xylene			5.57		
172	106-42-3	p-Xylene			5.57		
173		Antimony Compounds			5.57		
174		Arsenic Compounds (inorganic including arsine)	AP-42, Section 3.1, Table 3.1-5	1.10E-05	5.57	6.13E-05	9.19E-06
175		Beryllium Compounds	AP-42, Section 3.1, Table 3.1-5	3.10E-07	5.57	1.73E-06	2.59E-07
176		Cadmium Compounds	AP-42, Section 3.1, Table 3.1-5	4.80E-06	5.57	2.67E-05	4.01E-06
177		Chromium Compounds	AP-42, Section 3.1, Table 3.1-5	1.10E-05	5.57	6.13E-05	9.19E-06
178		Cobalt Compounds			5.57		
179		Coke Oven Emissions			5.57		
180		Cyanide Compounds1			5.57		
181		Glycol ethers2			5.57		
182		Lead Compounds	AP-42, Section 3.1, Table 3.1-5	1.40E-05	5.57	7.80E-05	1.17E-05
183		Manganese Compounds	AP-42, Section 3.1, Table 3.1-5	7.90E-04	5.57	4.40E-03	6.60E-04
184		Mercury Compounds	AP-42, Section 3.1, Table 3.1-5	1.20E-06	5.57	6.68E-06	1.00E-06
185		Fine mineral fibers3			5.57		
186		Nickel Compounds	AP-42, Section 3.1, Table 3.1-5	4.60E-06	5.57	2.56E-05	3.84E-06
187		Polycyclic Organic Matter4	AP-42, Section 3.4, Table 3.4-4	2.12E-04	5.57	1.18E-03	1.77E-04
188		Radionuclides (including radon)5			5.57		
189		Selenium Compounds	AP-42, Section 3.1, Table 3.1-5	2.50E-05	5.57	1.39E-04	2.09E-05
		Total				**1.44E-02**	**2.16E-03**

NOTE: For all listings above which contain the word "compounds" and for glycol ethers, the following applies:
Unless otherwise specified, these listings are defined as including any unique chemical substance that contains the named chemical (i.e., antimony, arsenic, etc.) as part of that chemical's infrastructure.

1. X'CN where X = H' or any other group where a formal dissociation may occur. For example, KCN or Ca(CN)2.

2. R-(OCH2CH2)n-OR'
where: n = 1, 2, or 3
R = alkyl C7 or less
or R = phenyl or alkyl substituted phenyl
R' = H, or alkyl C7 or less
or ester, sulfate, phosphate, nitrate, sulfonate

3. Includes mineral fiber emissions from facilities manufacturing or processing glass, rock, or slag fibers (or other mineral derived fibers) of average diameter 1 micrometer or less.

4. Includes substituted and/or unsubstituted polycyclic aromatic hydrocarbons and aromatic heterocyclic compounds, with two or more fused rings, at least one of which is benzenoid (i.e., containing six carbon atoms and is aromatic) in structure. Polycyclic Organic Matter is a mixture of organic compounds containing one or more of these polycyclic aromatic chemicals. Polycyclic Organic Matter is generally formed or emitted during thermal processes including (1) incomplete combustion, (2) pyrolysis, (3) the volatilization, distillation or processing of fossil fuels or bitumens, or (4) the distillation or thermal processing of non-fossil fuels. The Administrator may delineate, by test method, what is included in polycyclic organic matter.

5. A type of atom which spontaneously undergoes radioactive decay.

Attachment S-1b
Total Air Toxic Emissions

SECTION 112 HAZARDOUS AIR POLLUTANTS

EPA ID #	CAS Number	Pollutant	CT-2 Emissions (tpy)	CT-4 Emissions (tpy)	CT-5 Emissions (tpy)	D-21 Emissions (tpy)	D-22 Emissions (tpy)	D-23 Emissions (tpy)	BS-1 Emissions (tpy)	Total Emissions (tpy)
1	75-07-0	Acetaldehyde	2.17E-02	3.04E-02	3.04E-02	1.23E-04	3.10E-03	3.10E-03	2.11E-05	8.88E-02
2	60-35-5	Acetamide								
3	75-05-8	Acetonitrile								
4	98-86-2	Acetophenone								
5	53-96-3	2-Acetylaminofluorene								
6	107-02-8	Acrolein	6.79E-03	9.49E-03	9.49E-03	3.86E-05	9.70E-04	9.70E-04	6.58E-06	2.78E-02
7	79-06-1	Acrylamide								
8	79-10-7	Acrylic acid								
9	107-13-1	Acrylonitrile								
10	107-05-1	Allyl chloride								
11	92-67-1	4-Aminobiphenyl								
12	62-53-3	Aniline								
13	90-04-0	o-Anisidine								
14	1332-21-4	Asbestos								
15	71-43-2	Benzene (including benzene from gasoline)	4.74E-02	6.61E-02	6.61E-02	3.80E-03	9.55E-02	9.55E-02	6.48E-04	3.75E-01
16	92-87-5	Benzidine								
17	98-07-7	Benzotrichloride								
18	100-44-7	Benzyl chloride								
19	92-52-4	Biphenyl								
20	117-81-7	Bis(2-ethylhexyl)phthalate (DEHP)								
21	542-88-1	Bis(chloromethyl) ether								
22	75-25-2	Bromoform								
23	106-99-0	1,3-Butadiene	1.38E-02	1.93E-02	1.93E-02	7.84E-05	1.97E-03	1.97E-03	1.34E-05	5.64E-02
24	156-62-7	Calcium cyanamide								
25	105-60-2	Caprolactam (Removed 06/18/96, See 61FR30816)								
26	133-06-2	Captan								
27	63-25-2	Carbaryl								
28	75-15-0	Carbon disulfide								
29	56-23-5	Carbon tetrachloride								
30	463-58-1	Carbonyl sulfide								
31	120-80-9	Catechol								
32	133-90-4	Chloramben								
33	57-74-9	Chlordane								
34	7782-50-5	Chlorine								
35	79-11-8	Chloroacetic acid								
36	532-27-4	2-Chloroacetophenone								
37	108-90-7	Chlorobenzene								
38	510-15-6	Chlorobenzilate								
39	67-66-3	Chloroform								
40	107-30-2	Chloromethyl methyl ether								
41	126-99-8	Chloroprene								
42	1319-77-3	Cresol/Cresylic acid(mixed isomers)								
43	95-48-7	o-Cresol								
44	108-39-4	m-Cresol								
45	106-44-5	p-Cresol								
46	98-82-8	Cumene								
47		2,4-D(2,4-Dichlorophenoxyacetic Acid) (including salts and esters)								
48	72-55-9	DDE(1,1-dichloro-2,2-bis(p-chlorophenyl) ethylene)								
49	334-88-3	Diazomethane								
50	132-64-9	Dibenzofuran								
51	96-12-8	1,2-Dibromo-3-chloropropane								
52	84-74-2	Dibutyl phthalate								
53	106-46-7	1,4-Dichlorobenzene								
54	91-94-1	Dichlorobenzidine								
55	111-44-4	Dichloroethyl ether(Bis[2-chloroethyl]ether)								
56	542-75-6	1,3-Dichloropropene								
57	62-73-7	Dichlorvos								
58	111-42-2	Diethanolamine								
59	64-67-5	Diethyl sulfate								
60	119-90-4	3,3'-Dimethoxybenzidine								
61	60-11-7	4-Dimethylaminoazobenzene								
62	121-69-7	N,N-Dimethylaniline								
63	119-93-7	3,3'-Dimethylbenzidine								
64	79-44-7	Dimethylcarbamoyl chloride								
65	68-12-2	N,N-Dimethylformamide								
66	57-14-7	1,1-Dimethylhydrazine								
67	131-11-3	Dimethyl phthalate								
68	77-78-1	Dimethyl sulfate								
69		4,6-Dinitro-o-cresol (including salts)								
70	51-28-5	2,4-Dinitrophenol								
71	121-14-2	2,4-Dinitrotoluene								
72	123-91-1	1,4-Dioxane (1,4-Diethyleneoxide)								
73	122-66-7	1,2-Diphenylhydrazine								
74	106-89-8	Epichlorohydrin (l-Chloro-2,3-epoxypropane)								
75	106-88-7	1,2-Epoxybutane								
76	140-88-5	Ethyl acrylate								
77	100-41-4	Ethylbenzene								
78	51-79-6	Ethyl carbamate (Urethane)								

Attachment S-1b
Total Air Toxic Emissions

SECTION 112 HAZARDOUS AIR POLLUTANTS

EPA ID #	CAS Number	Pollutant	CT-2 Emissions (tpy)	CT-4 Emissions (tpy)	CT-5 Emissions (tpy)	D-21 Emissions (tpy)	D-22 Emissions (tpy)	D-23 Emissions (tpy)	BS-1 Emissions (tpy)	Total Emissions (tpy)
79	75-00-3	Ethyl chloride (Chloroethane)								
80	106-93-4	Ethylene dibromide (Dibromoethane)								
81	107-06-2	Ethylene dichloride (1,2-Dichloroethane)								
82	107-21-1	Ethylene glycol								
83	151-56-4	Ethyleneimine (Aziridine)								
84	75-21-8	Ethylene oxide								
85	96-45-7	Ethylene thiourea								
86	75-34-3	Ethylidene dichloride (1,1-Dichloroethane)								
87	50-00-0	Formaldehyde	2.41E-01	3.37E-01	3.37E-01	3.87E-04	9.71E-03	9.71E-03	6.59E-05	9.35E-01
88	76-44-8	Heptachlor								
89	118-74-1	Hexachlorobenzene								
90	87-68-3	Hexachlorobutadiene								
91		1,2,3,4,5,6-Hexachlorocyclyhexane (all stereo isomers including lindane)								
92	77-47-4	Hexachlorocyclopentadiene								
93	67-72-1	Hexachloroethane								
94	822-06-0	Hexamethylene diisocyanate								
95	680-31-9	Hexamethylphosphoramide								
96	110-54-3	Hexane								
97	302-01-2	Hydrazine								
98	7647-01-0	Hydrochloric acid (Hydrogen chloride [gas only])								
99	7664-39-3	Hydrogen fluoride (Hydrofluoric acid)								
100	123-31-9	Hydroquinone								
101	78-59-1	Isophorone								
102	108-31-6	Maleic anhydride								
103	67-56-1	Methanol								
104	72-43-5	Methoxychlor								
105	74-83-9	Methyl bromide (Bromomethane)								
106	74-87-3	Methyl chloride(Chloromethane)								
107	71-55-6	Methyl chloroform(1,1,1-Trichloroethane)								
108	78-93-3	Methyl ethyl ketone (2-Butanone) (Removed 12/19/05, S								
109	60-34-4	Methylhydrazine								
110	74-88-4	Methyl iodide (Iodomethane)								
111	108-10-1	Methyl isobutyl ketone(Hexone)								
112	624-83-9	Methyl isocyanate								
113	80-62-6	Methyl methacrylate								
114	1634-04-4	Methyl tert-butyl ether								
115	101-14-4	4,4'-Methylenebis(2-chloroaniline)								
116	75-09-2	Methylene chloride(Dichloromethane)								
117	101-68-8	4,4'-Methylenediphenyl diisocyanate(MDI)								
118	101-77-9	4,4'-Methylenedianiline								
119	91-20-3	Naphthalene	3.01E-02	4.22E-02	4.22E-02	6.37E-04	1.60E-02	1.60E-02	1.09E-04	1.47E-01
120	98-95-3	Nitrobenzene								
121	92-93-3	4-Nitrobiphenyl								
122	100-02-7	4-Nitrophenol								
123	79-46-9	2-Nitropropane								
124	684-93-5	N-Nitroso-N-methylurea								
125	62-75-9	N-Nitrosodimethylamine								
126	59-89-2	N-Nitrosomorpholine								
127	56-38-2	Parathion								
128	82-68-8	Pentachloronitrobenzene(Quintobenzene)								
129	87-86-5	Pentachlorophenol								
130	108-95-2	Phenol								
131	106-50-3	p-Phenylenediamine								
132	75-44-5	Phosgene								
133	7803-51-2	Phosphine								
134	7723-14-0	Phosphorus								
135	85-44-9	Phthalic anhydride								
136	1336-36-3	Polychlorinated biphenyls(Aroclors)								
137	1120-71-4	1,3-Propane sultone								
138	57-57-8	beta-Propiolactone								
139	123-38-6	Propionaldehyde								
140	114-26-1	Propoxur (Baygon)								
141	78-87-5	Propylene dichloride (1,2-Dichloropropane)								
142	75-56-9	Propylene oxide								
143	75-55-8	1,2-Propylenimine (2-Methylaziridine)								
144	91-22-5	Quinoline								
145	106-51-4	Quinone(p-Benzoquinone)								
146	100-42-5	Styrene								
147	96-09-3	Styrene oxide								
148	1746-01-6	2,3,7,8-Tetrachlorodibenzo-p-dioxin								
149	79-34-5	1,1,2,2-Tetrachloroethane								
150	127-18-4	Tetrachloroethylene(Perchloroethylene)								
151	7550-45-0	Titanium tetrachloride								
152	108-88-3	Toluene	2.42E-01	3.38E-01	3.38E-01	1.38E-03	3.46E-02	3.46E-02	2.35E-04	9.90E-01
153	95-80-7	Toluene-2,4-diamine								
154	584-84-9	2,4-Toluene diisocyanate								
155	95-53-4	o-Toluidine								
156	8001-35-2	Toxaphene (chlorinated camphene)								

Attachment S-1b
Total Air Toxic Emissions

SECTION 112 HAZARDOUS AIR POLLUTANTS

EPA ID #	CAS Number	Pollutant	CT-2 Emissions (tpy)	CT-4 Emissions (tpy)	CT-5 Emissions (tpy)	D-21 Emissions (tpy)	D-22 Emissions (tpy)	D-23 Emissions (tpy)	BS-1 Emissions (tpy)	Total Emissions (tpy)
157	120-82-1	1,2,4-Trichlorobenzene								
158	79-00-5	1,1,2-Trichloroethane								
159	79-01-6	Trichloroethylene								
160	95-95-4	2,4,5-Trichlorophenol								
161	88-06-2	2,4,6-Trichlorophenol								
162	121-44-8	Triethylamine								
163	1582-09-8	Trifluralin								
164	540-84-1	2,2,4-Trimethylpentane								
165	108-05-4	Vinyl acetate								
166	593-60-2	Vinyl bromide								
167	75-01-4	Vinyl chloride								
168	75-35-4	Vinylidene chloride (1,1-Dichloroethylene)								
169	1330-20-7	Xylene (mixed isomers)	1.66E-01	2.32E-01	2.32E-01	9.46E-04	2.38E-02	2.38E-02	1.61E-04	6.80E-01
170	95-47-6	o-Xylene								
171	108-38-3	m-Xylene								
172	106-42-3	p-Xylene								
173		Antimony Compounds								
174		Arsenic Compounds (inorganic including arsine)	9.47E-03	1.33E-02	1.33E-02	5.39E-05	1.35E-03	1.35E-03	9.19E-06	3.88E-02
175		Beryllium Compounds	2.67E-04	3.73E-04	3.73E-04	1.52E-06	3.82E-05	3.82E-05	2.59E-07	1.09E-03
176		Cadmium Compounds	4.13E-03	5.78E-03	5.78E-03	2.35E-05	5.91E-04	5.91E-04	4.01E-06	1.69E-02
177		Chromium Compounds	9.47E-03	1.32E-02	1.32E-02	5.39E-05	1.35E-03	1.35E-03	9.19E-06	3.87E-02
178		Cobalt Compounds								
179		Coke Oven Emissions								
180		Cyanide Compounds1								
181		Glycol ethers2								
182		Lead Compounds	1.21E-02	1.69E-02	1.69E-02	6.86E-05	1.72E-03	1.72E-03	1.17E-05	4.93E-02
183		Manganese Compounds	6.80E-01	9.52E-01	9.52E-01	3.87E-03	9.72E-02	9.72E-02	6.60E-04	2.78E+00
184		Mercury Compounds	1.03E-03	1.45E-03	1.45E-03	5.88E-06	1.48E-04	1.48E-04	1.00E-06	4.23E-03
185		Fine mineral fibers3								
186		Nickel Compounds	3.96E-03	5.54E-03	5.54E-03	2.25E-05	5.66E-04	5.66E-04	3.84E-06	1.62E-02
187		Polycyclic Organic Matter4	3.44E-02	4.82E-02	4.82E-02	1.04E-03	2.61E-02	2.61E-02	1.77E-04	1.84E-01
188		Radionuclides (including radon)5								
189		Selenium Compounds	2.15E-02	3.01E-02	3.01E-02	1.23E-04	3.08E-03	3.08E-03	2.09E-05	8.80E-02
		Total	**1.55**	**2.16**	**2.16**	**0.013**	**0.32**	**0.32**	**0.0022**	**6.52**

NOTE: For all listings above which contain the word "compounds" and for glycol ethers, the following applies:
Unless otherwise specified, these listings are defined as including any unique chemical substance that contains the named chemical (i.e., antimony, arsenic, etc.) as part of that chemical's infrastructure.

1. X'CN where X = H' or any other group where a formal dissociation may occur. For example, KCN or Ca(CN)2.

2. R-(OCH2CH2)n-OR'

where:
n = 1, 2, or 3
R = alkyl C7 or less
or R = phenyl or alkyl substituted phenyl
R' = H, or alkyl C7 or less
or ester, sulfate, phosphate, nitrate, sulfonate

3. Includes mineral fiber emissions from facilities manufacturing or processing glass, rock, or slag fibers (or other mineral derived fibers) of average diameter 1 micrometer or less.

4. Includes substituted and/or unsubstituted polycyclic aromatic hydrocarbons and aromatic heterocyclic compounds, with two or more fused rings, at least one of which is benzenoid (i.e., containing six carbon atoms and is aromatic) in structure. Polycyclic Organic Matter is a mixture of organic compounds containing one or more of these polycyclic aromatic chemicals. Polycyclic Organic Matter is generally formed or emitted during thermal processes including (1) incomplete combustion, (2) pyrolysis, (3) the volatilization, distillation or processing of fossil fuels or bitumens, or (4) the distillation or thermal processing of non-fossil fuels. The Administrator may delineate, by test method, what is included in polycyclic organic matter.

5. A type of atom which spontaneously undergoes radioactive decay.

Attachment S-1c
Other Regulated Pollutants

Emissions for Unit CT-2	Emissions (lb/hr)	Emissions (tpy)
Beryllium	See Attachment S-1b	
Mercury	See Attachment S-1b	
Asbestos	neg.	neg.
Hydrogen Sulfide	neg.	neg.
Halons	neg.	neg.
MWC Acid Gases	neg.	neg.
MWC Metals	neg.	neg.
MWC Organics	neg.	neg.

Emissions for Unit CT-4 or CT-5	Emissions (lb/hr)	Emissions (tpy)
Beryllium	See Attachment S-1b	
Mercury	See Attachment S-1b	
Asbestos	neg.	neg.
Hydrogen Sulfide	neg.	neg.
Halons	neg.	neg.
MWC Acid Gases	neg.	neg.
MWC Metals	neg.	neg.
MWC Organics	neg.	neg.

Emissions for Unit D-21	Emissions (lb/hr)	Emissions (tpy)
Beryllium	See Attachment S-1b	
Mercury	See Attachment S-1b	
Asbestos	neg.	neg.
Hydrogen Sulfide	neg.	neg.
Halons	neg.	neg.
MWC Acid Gases	neg.	neg.
MWC Metals	neg.	neg.
MWC Organics	neg.	neg.

Emissions for Unit D-22 or D-23	Emissions (lb/hr)	Emissions (tpy)
Beryllium	See Attachment S-1b	
Mercury	See Attachment S-1b	
Asbestos	neg.	neg.
Hydrogen Sulfide	neg.	neg.
Halons	neg.	neg.
MWC Acid Gases	neg.	neg.
MWC Metals	neg.	neg.
MWC Organics	neg.	neg.

Emissions for Unit BS-1	Emissions (lb/hr)	Emissions (tpy)
Beryllium	See Attachment S-1b	
Mercury	See Attachment S-1b	
Asbestos	neg.	neg.
Hydrogen Sulfide	neg.	neg.
Halons	neg.	neg.
MWC Acid Gases	neg.	neg.
MWC Metals	neg.	neg.
MWC Organics	neg.	neg.

Notes:
MWC = Municipal Waste Combustor
neg. = negligible

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Attachment S-1d
Pollutant Emission Rate Calculations

Sulfur Dioxide (SO_2)

Unit	Heat Input (MMBtu/hr)	AP-42 Emission Factor[1,2] (lb/MMBtu)	CSP Application Emission Factor[3] (lb/MMBtu)	CSP Application Emission Rate (lb/hr)
CT-2	198	0.404	0.556	110.0
CT-4	275	0.404	0.400	110.0
CT-5	275	0.404	0.400	110.0
D-21	28.1	0.002	0.002	0.04
D-22	28.1	0.002	0.002	0.04
D-23	28.1	0.002	0.002	0.04
BS-1	5.57	0.404	0.513	2.86

1. AP-42 emission factor for CT-2, CT-4, and CT-5 from Section 3.1, dated April 2000, Tabel 3.1-2a, using a sulfur content of 0.4%.
2. AP-42 emission factor for D-21, D-22, and D-23 from Section 3.4, dated October 1996, Table 3.4-1, using a sulfur content of 0.0015%.
3. AP-42 emission factor for BS-1 from Section 3.4, dated October 1996, Table 3.4-1, using a sulfur content of 0.4%.

Nitrogen Oxides (NO_X)

Unit	Heat Input (MMBtu/hr)	AP-42 Emission Factor[1,2] (lb/MMBtu)	CSP Application Emission Factor (lb/MMBtu)	CSP Application Emission Rate (lb/hr)
CT-2	198	0.24	0.197	39.0
CT-4	275	0.24	0.154	42.3
CT-5	275	0.24	0.154	42.3
D-21	28.1	3.2	2.434	68.4
D-22	28.1	3.2	2.434	68.4
D-23	28.1	3.2	2.434	68.4
BS-1	5.57	3.2	2.244	12.5

1. AP-42 emission factor for CT-2, CT-4, and CT-5 from Section 3.1, dated April 2000, Tabel 3.1-1.
2. AP-42 emission factor for D-21, D-22, D-23, and BS-1 from Section 3.4, dated October 1996, Table 3.4-1.

Attachment S-1d
Pollutant Emission Rate Calculations

Carbon Monoxide (CO)

Unit	Heat Input (MMBtu/hr)	AP-42 Emission Factor[1,2] (lb/MMBtu)	CSP Application Emission Factor (lb/MMBtu)	CSP Application Emission Rate (lb/hr)
CT-2	198	0.076	0.113	22.4
CT-4	275	0.076	0.097	26.8
CT-5	275	0.076	0.097	26.8
D-21	28.1	0.255	0.838	23.6
D-22	28.1	0.255	0.838	23.6
D-23	28.1	0.255	0.838	23.6
BS-1	5.57	0.85	0.427	2.38

1. AP-42 emission factor for CT-2, CT-4, and CT-5 from Section 3.1, dated April 2000, Tabel 3.1-1.
2. AP-42 emission factor for D-21, D-22, D-23, and BS-1 from Section 3.4, dated October 1996, Table 3.4-1. A 70% reduction is applied to the CO AP-42 emission factor (uncontrolled) to account for the emission reduction required in accordance with 40 CFR Part 63 Subpart ZZZZ.

Particulate Matter (PM/PM_{10})

Unit	Heat Input (MMBtu/hr)	AP-42 Emission Factor[1,2] (lb/MMBtu)	CSP Application Emission Factor (lb/MMBtu)	CSP Application Emission Rate (lb/hr)
CT-2	198	0.012	0.101	20.0
CT-4	275	0.012	0.072	19.7
CT-5	275	0.012	0.072	19.7
D-21	28.1	0.1	0.180	5.06
D-22	28.1	0.1	0.180	5.06
D-23	28.1	0.1	0.180	5.06
BS-1	5.57	0.1	0.355	1.98

1. AP-42 emission factor for CT-2, CT-4, and CT-5 from Section 3.1, dated April 2000, Tabel 3.1-2a.
2. AP-42 emission factor for D-21, D-22, D-23, and BS-1 from Section 3.4, dated October 1996, Table 3.4-2.

Volatile Organic Compounds (VOC)

Unit	Heat Input (MMBtu/hr)	AP-42 Emission Factor[1,2] (lb/MMBtu)	CSP Application Emission Factor (lb/MMBtu)	CSP Application Emission Rate (lb/hr)
CT-2	198	0.00041	0.113	22.4
CT-4	275	0.00041	0.003	0.80
CT-5	275	0.00041	0.003	0.80
D-21	28.1	0.082	0.238	6.69
D-22	28.1	0.082	0.238	6.69
D-23	28.1	0.082	0.238	6.69
BS-1	5.57	0.082	0.083	0.46

1. AP-42 emission factor for CT-2, CT-4, and CT-5 from Section 3.1, dated April 2000, Tabel 3.1-2a.
2. AP-42 emission factor for D-21, D-22, D-23, and BS-1 from Section 3.4, dated October 1996, Table 3.4-1.

Attachment S-1e
Greenhouse Gas Emissions Calculations

Mass Greenhouse Gas (GHG) Emissions

Unit	Fuel Type	Annual Operating Hours	Heat Input Capacity (MMBtu/hr)	Annual Fuel Use Limit[2] (gal/yr)	Fuel Heat Content (Btu/gal)	CO_2 Emission Factor[1] (lb/MMBtu)	CO_2 Annual Emissions (tons/yr)	N_2O Emission Factor[1] (lb/MMBtu)	N_2O Annual Emissions (tons/yr)	CH_4 Emission Factor[1] (lb/MMBtu)	CH_4 Annual Emissions (tons/yr)
D-21	No. 2 Fuel Oil	344	28.1	70,000	138,000	163.1	788	1.32E-03	0.01	6.61E-03	0.03
D-22	No. 2 Fuel Oil	8,760	28.1	NA	NA	163.1	20,074	1.32E-03	0.16	6.61E-03	0.81
D-23	No. 2 Fuel Oil	8,760	28.1	NA	NA	163.1	20,074	1.32E-03	0.16	6.61E-03	0.81
CT-2	No. 2 Fuel Oil	8,574	198	12,301,254	138,000	163.1	138,437	1.32E-03	1.12	6.61E-03	5.61
CT-4	No. 2 Fuel Oil	8,760	275	NA	NA	163.1	196,454	1.32E-03	1.59	6.61E-03	7.96
CT-5	No. 2 Fuel Oil	8,760	275	NA	NA	163.1	196,454	1.32E-03	1.59	6.61E-03	7.96
BS	No. 2 Fuel Oil	300	5.57	NA	NA	163.1	136	1.32E-03	1.10E-03	6.61E-03	0.01
Total Annual Greenhouse Gas Emissions							**572,417**		**4.63**		**23.20**

1. 40 CFR Part 98 Subpart C, Table C-1 and Table C-2.
2. Annual emissions for D-21 and CT-2 are based on the fuel limit and 138,000 Btu/gal (40 CFR Part 98 Subpart C, Table C-1).

CO_2 Equivalent (CO_2e) Emissions

Unit	CO_2e (tpy)[1] CO_2	N_2O	CH_4
D-21	788	2	1
D-22	20,074	50	17
D-23	20,074	50	17
CT-2	138,437	347	118
CT-4	196,454	493	167
CT-5	196,454	493	167
BS	136	3.42E-01	1.16E-01
		Total Annual CO_2e (tpy) =	**574,340**

1. CO_2e calculated using global warming potential (GWP) from 40 CFR Part 98 Subpart A, Table A-1.
GWP: CO_2 = 1; N_2O = 310; CH_4 = 21.

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File No.: ________

S-3: Application for a Covered Source Permit Renewal

Each application for permit renewal shall be submitted to the Director of Health, (hereafter, Director) a minimum of **twelve months** prior to the date of permit expiration. In providing the required information, please reference the corresponding letters and numbers listed below.

Provide a minimum of **two (2)** sets (1 original and 1 copy) of all application materials to the Hawaii Department of Health. Also, mail **one (1)** set directly to EPA at the following address:

Chief (Attention: AIR-3)
Permits Office, Air Division
U.S. Environmental Protection Agency
Region 9
75 Hawthorne Street
San Francisco, CA 94105

I. In accordance with Hawaii Administrative Rules (HAR) §11-60.1-101, the following information is required:

A. Statement certifying that no changes have been made in the design or operation of the source as proposed in the initial and any subsequent Covered Source Permit applications. If changes have occurred or are being proposed, the applicant shall provide a description of those changes such as work practices, operations, equipment design, and monitoring procedures, including the affected applicable requirements associated with the changes and the corresponding information to determine the applicability of all applicable requirements.

The source continues to operate as proposed in the initial and subsequent covered source permit applications.

Diesel engine generators, D-21, D-22, and D-23, are subject to 40 CFR Part 63 Subpart ZZZZ, National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines (RICE NESHAP). These units are subject to the applicable emissions and operating limitations for existing non-emergency compression ignition (CI) stationary RICE with a site rating of greater than 500 brake HP located at area sources of HAP emissions and to the fuel requirements applicable to existing non-emergency CI stationary RICE with a site rating of more than 300 brake HP with a displacement of less than 30 liters per cylinder. To comply with these applicable RICE NESHAP requirements, HELCO proposes the following modifications for D-21, D-22, and D-23.

a. Replacement of the existing engine exhaust housing manifold with the Miratech Diesel Oxidation Catalyst Manifold Kit (V-CAT). This modification will not affect stack parameters or increase pollutant emission rates; refer to Attachment S-3a. The V-CAT will reduce CO emissions by at least 70 percent or limit CO emissions to 23 ppmvd at 15 percent O_2 as required by RICE NESHAP.

b. Use of diesel fuel with a maximum sulfur content of 0.0015 percent by weight and a minimum Cetane index of 40 or a maximum aromatic content of 35 volume percent. Ultra Low Sulfur Diesel (ULSD) shipments to HELCO will begin within one to three months following the Public Utilities Commission (PUC) approval of an amendment to its Interisland Diesel Fuel Supply Contract. HELCO has requested that the PUC expedite its decision and final order on or before September 30, 2012 so that HELCO will be able to meet the RICE NESHAP compliance date of May 3, 2013.

HELCO requests DOH to approve the modification to install the diesel oxidation catalyst (DOC) on units D-21, D-22, and D-23 by letter prior to the amendment of the CSP in accordance with HAR § 11-60.1-82(k)(1). Upon receipt of DOH approval, HELCO will complete these modifications on or before May 3, 2013 as required by the RICE NESHAP.

Units D-21, D-22, and D-23 are equipped with a lube oil separator that conforms with 40 CFR § 63.6625(g). Refer to manufacturer literature in Attachment S-3a. These EMD 645 units are turbo charged units.

HELCO requests incorporation of the applicable RICE NESHAP operational and emission limitations, monitoring and recordkeeping, notification and reporting, and testing requirements into CSP No. 0007-01-C.

As part of the renewal process, HELCO proposes permit condition changes. Attachments S-3c and S-3d lists the proposed changes to CSP Nos. 0007-01-C and 0070-01-C, respectively. Proposed additions are underlined and proposed deletions are struck through. The renewal application also seeks to merge CSP No. 0070-1-C into CSP No. 0007-01-C.

B. Equipment Specifications:

1. Maximum design capacity. See table below.
2. Fuel type. No. 2 diesel fuel with 0.4% by weight maximum sulfur content.
3. Fuel use. See table below.

Maximum Capacity and Fuel Use Per Unit

Unit ID	Manufacturer	Model Number	Serial Number	Capacity (Nominal)	Fuel Flow Rate
D-21	General Motors	20-645F4B	74-B1-1078	2.5 MW	28.1 MMBtu/hr
D-22	General Motors	20-645F4B	66-K1-1062	2.5 MW	28.1 MMBtu/hr
D-23	General Motors	20-645E4	69-H1-1057	2.5 MW	28.1 MMBtu/hr
BS-1	Caterpillar	3412	81Z07275	500 kW	5.57 MMBtu/hr
CT-2	Jupiter	GT-35	JF88702	18 MW	198 MMBtu/hr
CT-4	General Electric	LM2500	481-688	20 MW	275 MMBtu/hr
CT-5	General Electric	LM2500	481-692	20 MW	275 MMBtu/hr
ST-7				16 MW	NA

4. Production capacity. Not applicable.
5. Production rates. Not applicable.
6. Raw materials. Not applicable.
7. Provide any manufacturer's literature. See Attachment S-3a for manufacturer's literature.

C. Provide detailed descriptions of all processes and products defined by Standard Industrial Classification Code (SICC). Also, provide any reasonably anticipated alternative operating scenarios, associated processes, and products, by SICC.

Electrical power generation through combustion of fossil fuels (SICC code 4911) is the only product or process.

Several types of alternative operating scenarios apply to the generating station as described below:

a. Use of a temporary replacement unit in the event of a failure or major overhaul of an installed unit. In the event that the projected down time of the unit increases the likelihood of an interruption in electrical service, the down unit would be replaced with an equivalent unit. Emissions from the replacement unit will comply with the original unit's permitted emission limits. Proposed changes to add a permanent replacement AOS are in Attachment S-3c.

b. CT-4 and CT-5 may operate below 25% of peak load during testing of the heat recovery steam generators and steam turbine and steam blows needed to clean the steam tubes prior to initial operation.

c. Should less expensive fuels become available, or the supply of No. 2 diesel become limited, HELCO may use alternative fuels with prior approval from the Department of Health.

d. In the event of emergency load conditions such as the sudden loss of a unit, CT-2, CT-4 and CT-5 may operate up to 110 percent of peak load for up to 30 minutes. Such operation will not exceed the permitted 3-hour average emission rates.

e. Fuel additives to reduce corrosion, control biological growth, and enhance combustion may be used in CT-4 and CT-5.

f. HELCO, with the approval from the Department of Health, may use alternate means and methods to improve combustion and/or reduce emissions for CT-4 and CT-5.

1. Identify and describe in detail all air pollution control equipment and compliance monitoring devices or activities, and to the extent of available information, an estimate of emissions before and after controls. Provide all calculations and assumptions.

   Fuel injection timing retard (FITR) is used on D-21, D-22, and D-23 to control NO_X emissions. Water injection is used on CT-2 reduce NO_X emissions to 47 ppmvd at 15 percent O_2, with a fuel-bound nitrogen content of 0.015 percent or less. When CT-4 and CT-5 are operating in combined cycle mode at loads less than 50% of peak load and simple cycle mode, water injection is used on CT-4 and CT-5 to reduce NO_X emissions to 42 ppmvd at 15 percent O_2, with a fuel-bound nitrogen content of 0.015 percent of less. When CT-4 and CT-5 are operating in combined cycle mode at 50% or more of peak load, water injection in combination with selective catalytic reduction (SCR) is used to reduce NO_X emissions to 15 ppmvd at 15 percent O_2, with a fuel-bound nitrogen content of 0.015 percent or less. The design of the SCR system will limit ammonia slip to 10 ppmvd at 15 percent O_2. SO_2 emissions are controlled by limiting the fuel sulfur content to 0.4 percent by weight for CT-2, CT-4, CT-5, and BS-1 and 0.0015 percent by weight for D-21, D-22, and D-23. Emissions of PM, PM_{10}, CO, and VOC are controlled by combustion design and good combustion practices. CO emissions for D-21, D-22, and D-23 will be controlled by a DOC. The DOC will reduce CO emissions by at least 70 percent beginning on or before May 3, 2013. Emissions of hazardous air pollutants are controlled by the use of No. 2 fuel oil and combustion system design. Refer to Attachment S-1d for emission rate calculations.

   Compliance monitoring devices and activities are discussed in Form C-2.

2. List all ***insignificant*** activities in accordance with HAR §11-60.1-82.

   Refer to Attachment S-3b for a list of insignificant activities.

D. Maximum Operating Schedule (to the extent needed to determine or regulate emissions):

1. Total hours per day, per week, and/or per month.

   The planned operation of units D-22, D-23, CT-2, CT-4, and CT-5 is up to 24 hours per day, seven days per week. Units BS-1 and D-21 will operate as needed. Depending on future dispatch requirements, the plant may cycle off-line daily, or operate at reduced loads. While expected operating levels are less than continuous, there may be times when the units must be run continuously for extended periods of time. Thus, this application does not propose any annual operating limits for units D-22, D-23, CT-4, and CT-5. Fuel consumption is limited on a rolling 12-month basis to 12,301,254 gallons (292,887 barrels) in CT-2 and 70,000 gallons in D-21.

2. Total hours per year.

Units D-22, D-23, CT-4, and CT-5 will operate 8760 hours per year. Fuel consumption is limited on a rolling 12-month basis to 12,301,254 gallons (292,887 barrels) in CT-2 and 70,000 gallons in D-21. Operation of BS-1 is limited to 300 hours on a rolling 12-month basis.

3. If operation is seasonal or irregular, describe. Refer to D.1 and 2 above.

E. Cite and describe all applicable requirements as defined in HAR §11-60.1-81, including the following:

1. Description of or reference to any applicable test methods for determining compliance with each applicable requirement. Refer to Form C-2.

2. Explanation of all proposed exemptions from any applicable requirements.

Refer to Forms C-1 and C-2.

F. Identify and describe current operational limitations or work practices that affect emissions of any regulated or hazardous air pollutant. Provide all calculations and assumptions.

Fuel injection timing retard (FITR) is used on units D-21, D-22, and D-23 to control NO_X emissions. Water injection is used on CT-2 reduce NO_X emissions to 47 ppmvd at 15 percent O_2, with a fuel-bound nitrogen content of 0.015 percent or less. When CT-4 and CT-5 are operating in combined cycle mode at loads less than 50% of peak load and simple cycle mode, water injection is used on CT-4 and CT-5 to reduce NO_X emissions to 42 ppmvd at 15 percent O_2, with a fuel-bound nitrogen content of 0.015 percent of less. When CT-4 and CT-4 are operating in combined cycle mode at 50% or more of peak load, water injection in combination with selective catalytic reduction (SCR) is used to reduce NO_X emissions to 15 ppmvd at 15 percent O_2, with a fuel-bound nitrogen content of 0.015 percent or less. The design of the SCR system will limit ammonia slip to 10 ppmvd at 15 percent O_2. Sulfur dioxide emissions are controlled by limiting the fuel sulfur content to 0.4 percent by weight for CT-2, CT-4, CT-5, and BS-1 and 0.0015 percent by weight for D-21, D-22, and D-23. Emissions of PM, PM_{10}, CO, and VOC are controlled by combustion design and good combustion practices. Emissions of hazardous air pollutants are controlled by the use of No. 2 fuel oil and combustion system design.

G. For ***new*** covered sources and ***significant*** modifications which increase the emissions of any air pollutant or result in the emission of any air pollutant not previously emitted, an assessment of the ambient air quality impact of the covered source or significant modification, with the inclusion of any available background air quality data. The assessment shall include all supporting data, calculations and assumptions, and a comparison with the NAAQS and SAAQS.

Not applicable. The facility is an existing covered source and is undergoing a renewal of an existing permit as defined by the covered source rules.

H. For ***new*** covered sources and ***significant*** modifications subject to the requirements of subchapter 7 of HAR Chapter 11-60.1, all analyses, assessments, monitoring, and other application requirements of subchapter 7.

Not applicable. The facility is an existing covered source and is not undergoing any modification or increase in emissions as defined in Subchapter 7.

I. Provide detailed information to define permit terms and conditions for any proposed ***emissions trading*** within the facility in accordance with HAR §11-60.1-96.

No emissions trading is proposed.

J. Provide the following for Compliance purposes:
   1. A Compliance Plan, Form C-1.
   2. A Compliance Certification, Form C-2.

II. Submit an application fee according to the Application Fee Schedule in the <u>Instructions for Applying for an Air Pollution Control Permit</u>.

III. Provide other information as follows:

A. As required by any applicable requirement or as requested and deemed necessary by the Director to make a decision on the application.

B. As may be necessary to implement and enforce other applicable requirements of the Clean Air Act or of HAR Chapter 11-60.1 or to determine the applicability of such requirements.

IV. The Director reserves the right to request the following information:

A. An assessment of the ambient air quality impact of the source or modification. The assessment shall include all supporting data, calculations and assumptions, and a comparison with the National Ambient Air Quality Standards and State Ambient Air Quality Standards.

B. A risk assessment of the air quality related impacts caused by the covered source or significant modification to the surrounding environment.

C. Results of source emissions testing, ambient air quality monitoring, or both.

D. Information on other available control technologies.

V. An application shall be determined to be complete only when all of the following have been complied with:

A. All information required or requested in numbers **I, III, and IV** has been submitted.

B. All documents requiring certification have been certified pursuant to HAR §11-60.1-4.
C. All applicable fees have been submitted.

D. The Director has certified that the application is complete.

VI. The Director shall not continue to act upon or consider an incomplete application.

A. The applicant shall be notified in writing whether the application is complete. Unless the Director requests additional information or notifies the applicant of incompleteness within sixty days of receipt of an application, the application shall be deemed complete.

B. During the processing of an application that has been determined or deemed complete, if the Director determines that additional information is necessary to evaluate or take final action on the application, the Director may request such information in writing and set a reasonable deadline for a response. As set forth in HAR §11-60.1-82, the covered source's ability to operate and the validity of the Covered Source Permit shall continue beyond the permit expiration date until the final permit is issued or denied, provided the applicant submits all additional information within the reasonable deadline specified by the Director.

VII. After receipt of a complete application, the Director, in writing, shall approve, conditionally approve, or deny an application:

A. Within twelve months, ***except*** for applications for renewal for coverage under a covered source general permit. If the application for renewal has not been approved or denied within twelve months, the Covered Source Permit and all its terms and conditions shall remain in effect and not expire until the application for renewal has been approved or denied and provided the applicant has submitted any additional information within the reasonable deadline specified by the Director.

B. Within six months for applications for renewal requesting coverage under a covered source general permit. If the application for renewal has not been approved or denied within six months, the coverage under the covered source general permit and all its terms and conditions shall remain in effect and not expire until the application for renewal has been approved or denied and provided the applicant has submitted any additional information within the reasonable deadline specified by the Director.

VIII. A Covered Source Permit renewal application shall be approved only if the Director determines that the operation of the covered source will be in compliance with all applicable requirements.

IX. The Director shall provide for public notice, including the method by which a public hearing can be requested, and an opportunity for public comment on the draft Covered Source Permit renewal in accordance with HAR §11-60.1-99.

X. The Director shall provide a statement that sets forth the legal and factual bases for the draft permit conditions (including references to the applicable statutory or regulatory provisions) to EPA and any other person requesting it.

XI. Each application for renewal and proposed Covered Source Permit shall be subject to EPA oversight in accordance with HAR §11-60.1-95.

Attachment S-3a

Manufacturer's Literature

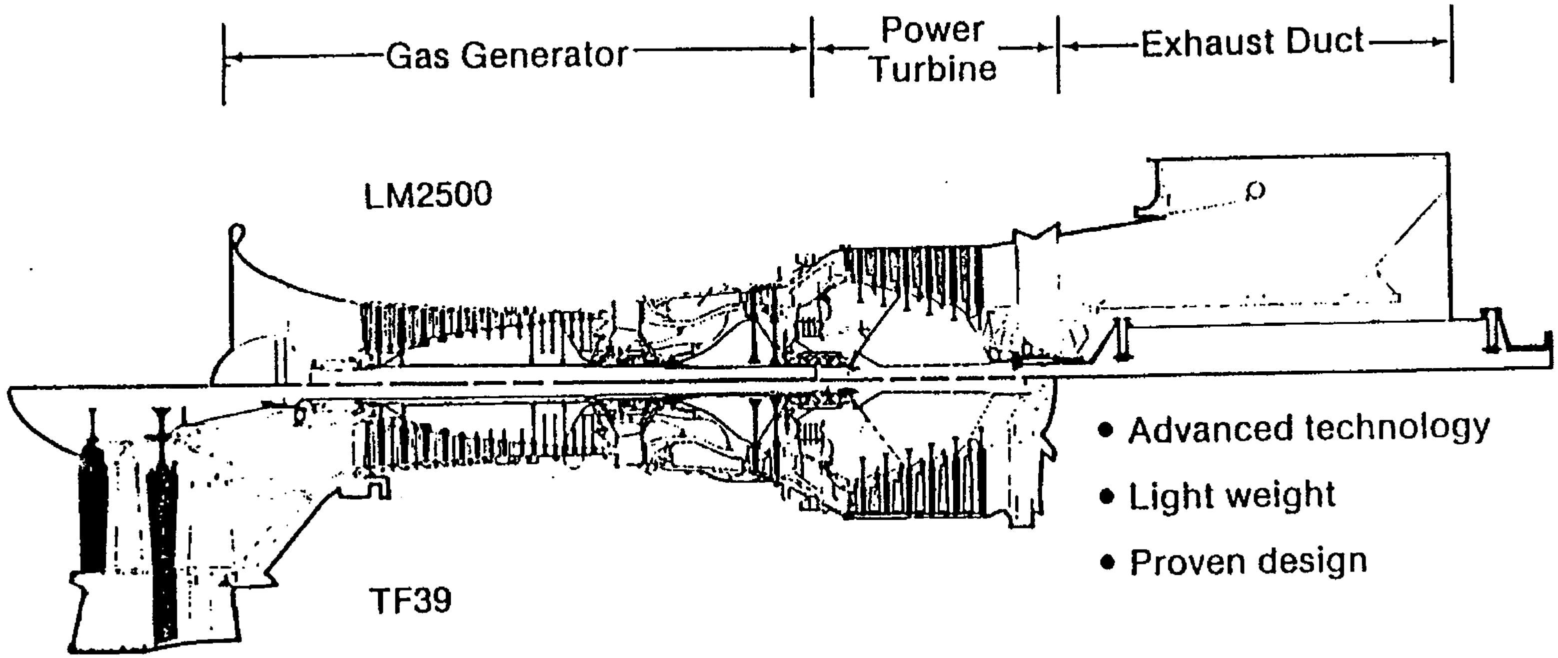
LM2500 Overview

General Electric
LM2500 Gas Turbine Advantages

• Unsurpassed efficiency* (simple cycle in power range)	37%
• Demonstrated availability	>98%
• Application cycle flexibility	Gas fuel, liquid fuel, low BTU gas, STIG
• Installation simplicity, transportation & mobility	Modular design, light weight
• Large experience base	>500 engines in operation >5,500,000 hours in service
• After-sale support	Backed by wide variety of GE customer support programs
• Environmental compatibility	Meets stringent emission requirements with water or steam injection

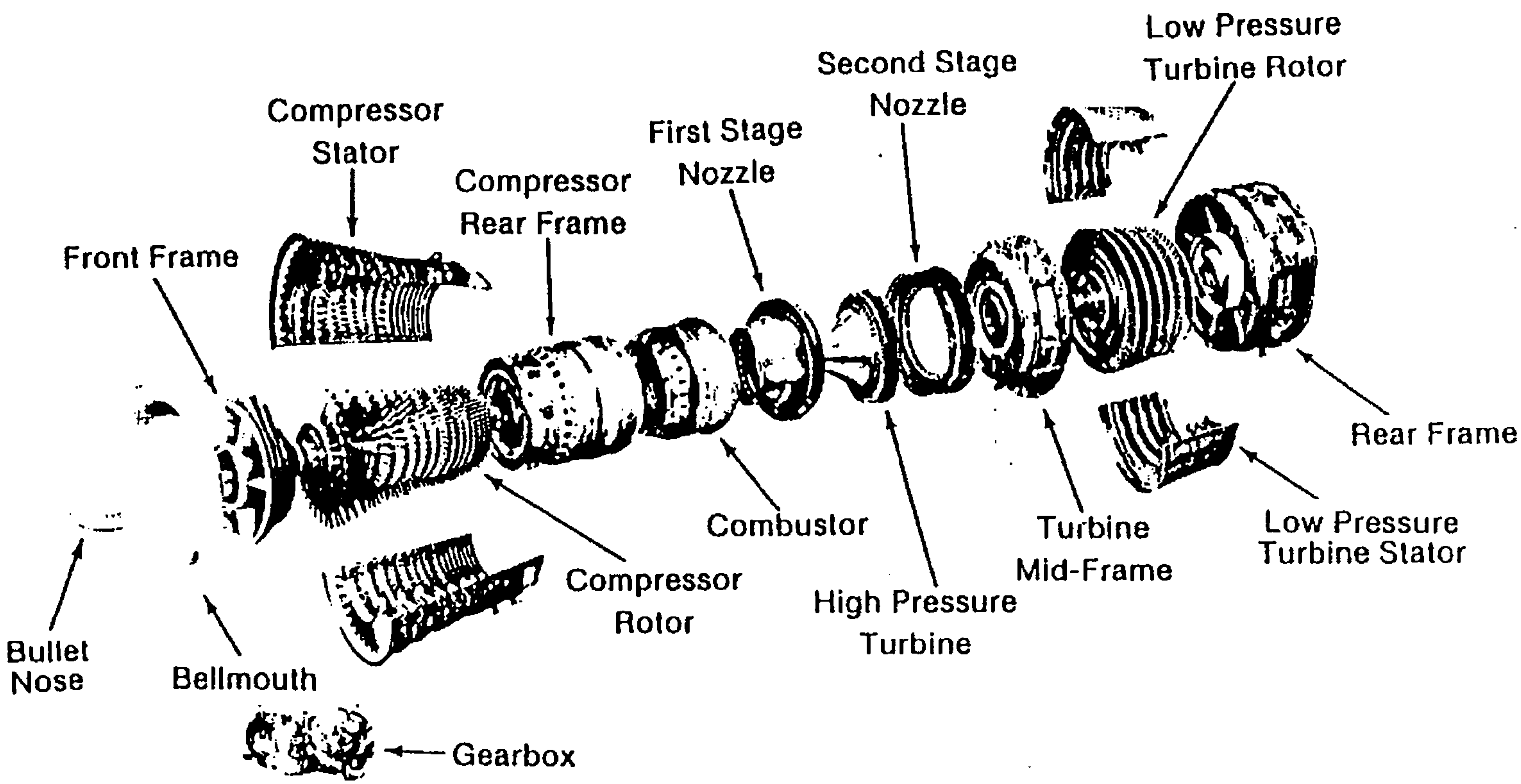
*At ISO conditions and 3600 rpm

LM2500 Gas Turbine and TF39/CF6 Turbofan



- Advanced technology
- Light weight
- Proven design

LM2500 Component Parts



LM2500 Power Turbine

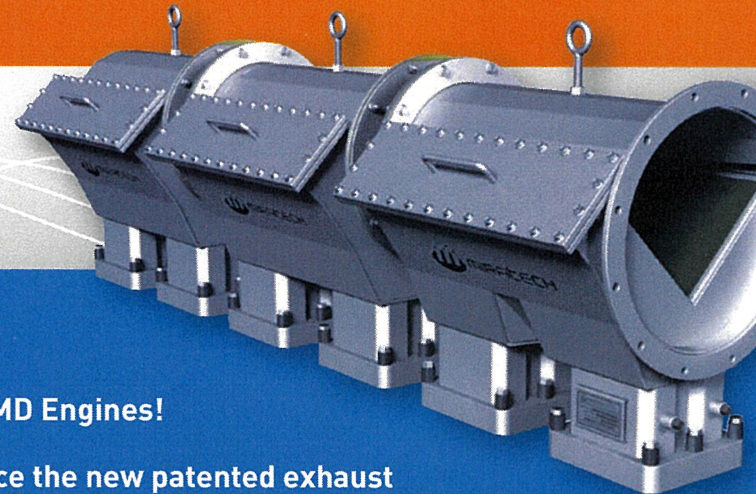
- Designed for:
  - 10,000 HP greater than LM2500 rating
  - 200°F (111°C) - higher temperature than LM2500 rating
- 20,000,000 hours experience
  - 180 units in aircraft service with greater than 10,000 hrs
  - 17 units in marine service with greater than 10,000 hrs
  - 48 units in industrial service with greater than 10,000 hrs
- 90% of all LM2500's were selected with GE power turbine
- Efficiency - 92.5%

LM2500 Intrinsic Features

- Fast start-up ____ 1 minute
- High efficiency - 3600 rpm ____ 37%
- Full load testing ____ All units
- Low weight ____ 7500 lbs (3402 kg)
- Minimum space ____ 21 ft 8 in (6.6m) length x 6 ft (1.8m) diameter
- Low airflow ____ 145 lb/sec (65.8 kg/sec)
- High availability ____ 98%
- Easy changeout ____ 9 hours
- On-site maintenance ____ 1 day "hot section"
- Proven concept ____ Over 5,500,000 operating hours
- Engine improvement programs ____ Active
- Maintenance & support programs ____ Comprehensive & operational

MIRATECH CORPORATION

V-CAT™



Diesel Oxidation Catalyst Manifold Kits for EMD Engines!

MIRATECH Corporation is pleased to announce the new patented exhaust manifold kit for EMD engines with integrated catalysts to reduce exhaust emissions.

Known as V-CAT, the manifold kit replaces the existing exhaust manifolds on EMD 710, 645 and 567 engines found in rail, marine and power generation applications. The kit is applicable to both roots-blown and turbo-charged engine models. These kits provide significant reductions of PM, HC, and CO, which may allow EMD engines to be rebuilt to the new EPA rebuild standards.

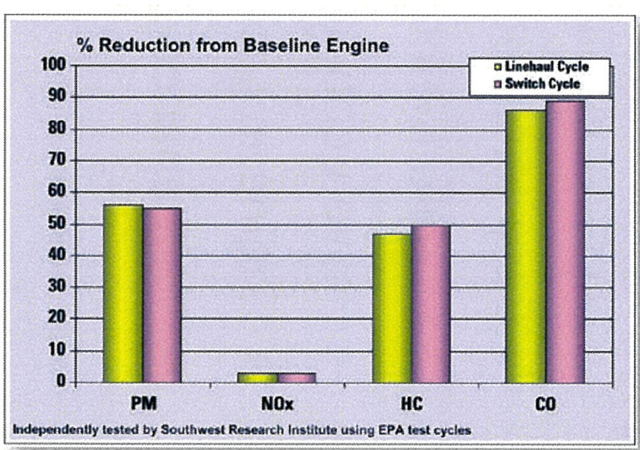
BENEFITS OF THE V-CAT MANIFOLD KIT

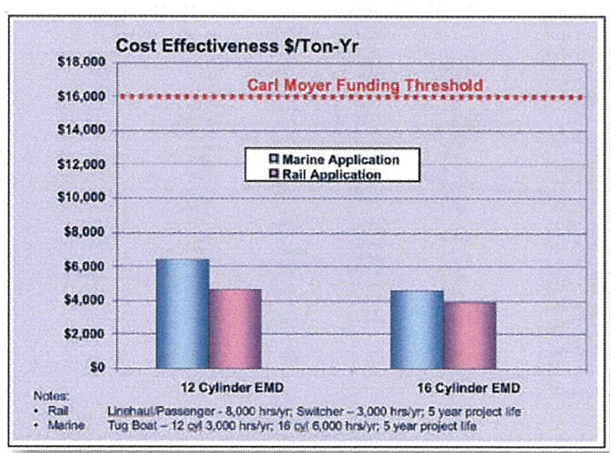
- Cost effective emission reductions
  - Up to 50 % PM reduction
  - Up to 80% CO reduction
  - Up to 50% HC reduction
- Negligible fuel penalty
- Engine serviceability maintained
- Works with up to 500 ppm sulfur fuel
- Works on roots blown and turbocharged EMD engines
- Perfect for meeting future EPA rebuild regulations for rail and marine markets

INSTALLS IN EXISTING FOOTPRINT

12 Cylinder Kit P/N: VCAT-EMD12-XS
16 Cylinder Kit P/N: VCAT-EMD16-XS
20 cylinder kits also available

PROVEN PERFORMANCE





miratechcorp.com • 800.640.3141
420 SOUTH 145TH EAST AVENUE • TULSA, OK 74108

MIRATECH CORPORATION

April 23, 2012

Ms. Karin Kimura
Hawaiian Electric Company, Inc.
P.O. Box 2750
Honolulu, HI 96840

Re: NESHAP Catalytic Converter Retrofits at MECO and HELCO

Dear Karin,

The catalytic converters which we are supplying to Maui Electric Company and Hawaii Electric Light Company are designed to oxidize CO, reducing CO by 70% or more. The catalytic converters will not affect the exhaust flow or exhaust temperature measured at the stack.

Emission rates for species other than CO (NOx, HC, SOx, etc.) will not be affected, except that there may be a slight decrease in unburned hydrocarbons and soot.

MECO Maalaea units M8 and M9 may require a tapered stack in order to accommodate the pressure drop limits of the engines. If this is required, the stack will taper to the original diameter (28") such that the gas velocity at the outlet will be the same as the original stack. We do not anticipate a change in exhaust temperature due to the stack taper, nor will the exhaust volume flow change.

If you have any questions or would like to discuss anything further, please don't hesitate to contact me in my office at 918-628-6119 on my cell at 918-605-2093.

Very truly yours,
MIRATECH Corporation

Nick J. Detor / cc

Nick J. Detor
Director of Sales Operations

cc: Scott McBryde, Courtney Coloney / MIRATECH

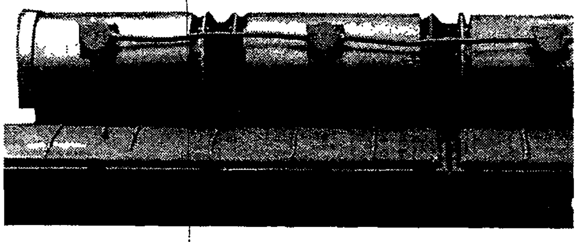
EXHAUST MANIFOLDS (Cont'd.)

necessary flexibility to compensate for expansion and contraction of the manifold due to temperature changes. The adapter includes a stainless steel screen which is provided to prevent foreign objects from entering the turbocharger.

Heat shields are provided.

THERMOCOUPLES

Type J thermocouples for measuring the temperature of the exhaust gases are available as optional equipment. The thermocouples, one per cylinder, are located in the exhaust manifold risers.



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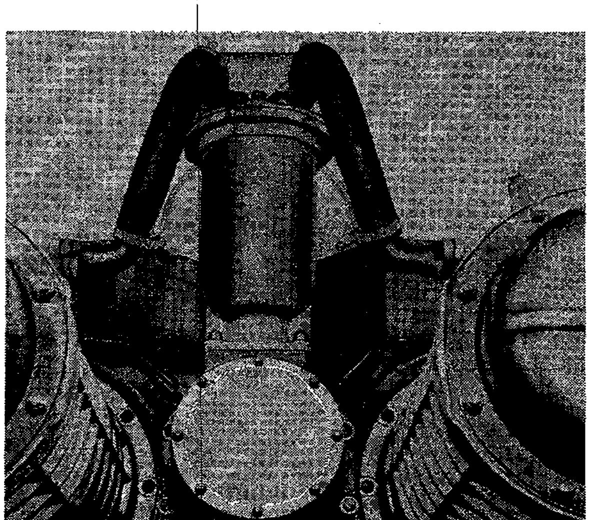
Lead wire is supplied for installation by the shipbuilder between thermocouples and the pyrometer.

LUBE OIL SEPARATOR

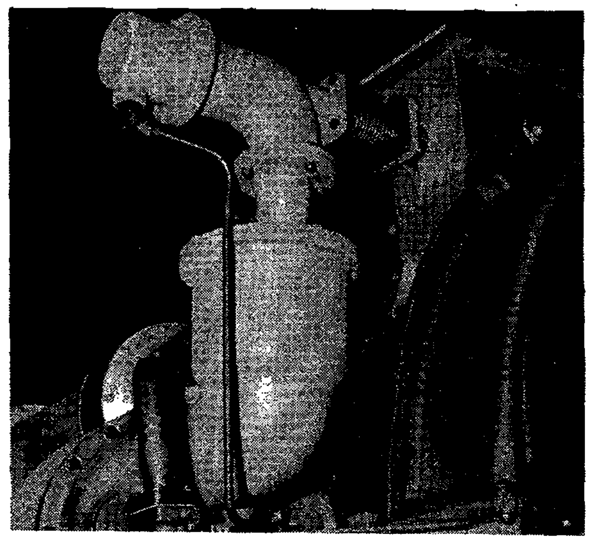
Roots-Blower Engines

Blower suction draws engine oil vapors from the oil pan through the rear gear train housing into the oil separator mounted on the auxiliary drive housing. Oil in the air collects on the wire mesh screen of the oil separator element and drains back into the engine.



Turbocharged Engines

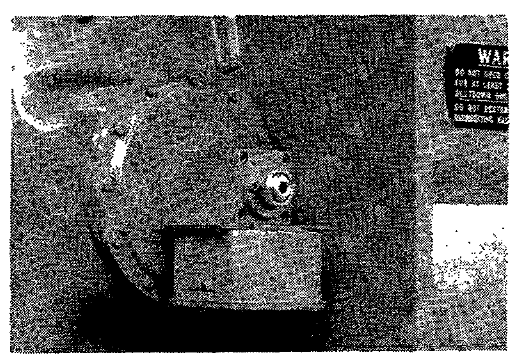
An oil separator is mounted on the turbocharger housing with an ejector assembly on the separator cover extending into the turbine exhaust stack. Air under pressure passing through the ejector assembly



creates a suction to draw engine oil vapors through the wire mesh screen of the oil separator element. The oil collected on the element then drains back into the engine.

CRANKCASE PRESSURE DETECTOR AND ALARM CONTACTOR

The 645 series engines are equipped with a crankcase pressure alarm device to detect a change from a normally negative crankcase pressure to a positive pressure. Should this condition take place, the device will actuate the alarm system operating the basic alarm siren and shutting the engine down.



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In the event an alarm signal light is installed as a standard extra, the rotating beam light will operate until the abnormal condition is corrected.

Attachment S-3b
Insignificant Activities

Attachment S-3b
Insignificant Activities §11-60.1-82(f)

Rule Citation and Requirement	Activity Present	Description
(f) Insignificant activities based on size, emission level, or production rate, are as follows:	**See below:**	**See case-by-case descriptions below:**
(1) Any storage tank, reservoir, or other container of capacity equal to or less than forty thousand gallons storing volatile organic compounds, except those storage tanks, reservoirs, or other containers subject to any standard or other requirement Pursuant to Sections 111 and 112 of the Act;	Yes	The Keahole Generating Station contains VOC storage tanks with a capacity less than 40,000 gallons that are not subject to Section 111 or 112 which include: • CT-4 Day Tank (Tank 5) – 13,500 gal. capacity storing No. 2 diesel fuel • CT-5 Day Tank (Tank 6) – 13,500 gal. capacity storing No. 2 diesel fuel • Used Oil North Tank – 1,500 gal. capacity • Used Oil South Tank – 1,500 gal. capacity • Fire Pump Diesel Tank – 350 gal. capacity • EMD Used Oil Tank – 500 gal. capacity • EMD Lube Oil Tank – 500 gal. capacity • EMD Lube Oil (5) Tank – 670 gal. capacity • EMD Lube Oil (6) Tank – 670 gal. capacity • Used Oil Tote – 200 gal. capacity • Used Oil Tote – 342 gal. capacity
(2) Other than smoke house generators and gasoline fired industrial equipment, fuel burning equipment with a heat input capacity less than 1 MMBtu per hour, or a combination of fuel burning equipment operated simultaneously as a single unit having a total combined heat input capacity of less than 1 MMBtu per hour;	Yes	These types of units may be on site occasionally.
(3) Steam generators, steam superheaters, water boilers, or water heaters, all of which have a heat input capacity of less than five million BTU per hour, and are fired exclusively with one of the following: (A) Natural or synthetic gas; (B) Liquefied petroleum gas; or (C) A combination of natural, synthetic, or liquefied petroleum gas;	No	None.
(4) Kilns used for firing ceramic water heated exclusively by natural gas, electricity, liquid petroleum gas, or any combination of these and have a heat input capacity of 5 MMBTU/hr or less;	No	None.

Attachment S-3b
Insignificant Activities §11-60.1-82(f)

Rule Citation and Requirement	Activity Present	Description
(5) Standby generators used exclusively to provide electricity, standby sewage pump drives, and other emergency equipment used to protect the health and welfare of personnel and the public, all of which are used only during power outages, emergency equipment maintenance and testing, and which: (A) Are fired exclusively by natural or synthetic gas; or liquefied petroleum gas; or fuel oil No. 1 or No. 2; or diesel fuel oil No. 1D or No. 2D; and (B) Do not trigger a PSD or covered source review, based on their potential to emit regulated or hazardous air pollutants;	Yes	Units of this type may be on site occasionally.
(6) Paint spray booths that emit less than two tons per year of any regulated air pollutant except for paint spray booths subject to any standard or other requirement pursuant to Section 112 (d) of the Act; and	Yes	None.
(7) Other activities which emit less than: (A) 500 pounds per year of a hazardous air pollutant; (B) 25% of significant amounts of emission as defined in Section 11-60.1-1, paragraph (1) in the definition of "significant"; (C) 5 tons per year of carbon monoxide and (D) 2 tons per year of each regulated air pollutant other than carbon monoxide which the director determines on a case-by-case basis to be insignificant.	Yes	• Tank 1 – 3,080 bbl capacity storing No. 2 diesel fuel • Tank 2 – 6,290 bbl capacity storing No. 2 diesel fuel • Tank 3 – 617,000 gal. capacity storing No. 2 diesel fuel • Tank 4 – 617,000 gal. capacity storing No. 2 diesel fuel • Tank 7[1] – 1,475,000 gal. capacity storing No. 2 diesel fuel Tanks 4.0.9d Emissions Report Summary Attached for Tanks 1, 2, 3, 4 and 7. • Fugitive equipment leaks from valves, flanges, pump seals and any VOC water separators. • Solvents are used for maintenance purposes. [1] Previously identified as Tank 5 in the Addendum to the CSP Application No. 0007-01 dated July 12, 1994.

TANKS 4.0.9d
Emissions Report - Summary Format
Tank Indentification and Physical Characteristics

Identification

User Identification:	Keahole Tank 1	
City:		
State:		
Company:	HELCO	
Type of Tank:	Vertical Fixed Roof Tank	
Description:	Based on 1) Nov. 1994 Initial CSP Application information - Annual Throughput: 75,500 bbl and 2) plot plan in Jan. 1991 ATC Application for a Black Start Diesel Generator - tank dimensions 35' diameter, 18' height and capacity 3080 bbl.	

Tank Dimensions

Shell Height (ft):		18.00
Diameter (ft):		35.00
Liquid Height (ft) :		18.00
Avg. Liquid Height (ft):		9.00
Volume (gallons):		129,548.29
Turnovers:		24.48
Net Throughput(gal/yr):		3,171,000.00
Is Tank Heated (y/n):	N	

Paint Characteristics

Shell Color/Shade:	Gray/Medium	
Shell Condition	Good	
Roof Color/Shade:	Gray/Medium	
Roof Condition:	Good	

Roof Characteristics

Type:	Cone	
Height (ft)		0.00
Slope (ft/ft) (Cone Roof)		0.06

Breather Vent Settings

Vacuum Settings (psig):		-0.03
Pressure Settings (psig)		0.03

Meterological Data used in Emissions Calculations: Hilo, Hawaii (Avg Atmospheric Pressure = 14.72 psia)

TANKS 4.0.9d
Emissions Report - Summary Format
Liquid Contents of Storage Tank

Keahole Tank 1 - Vertical Fixed Roof Tank

Mixture/Component	Month	Daily Liquid Surf. Temperature (deg F) Avg.	Min.	Max.	Liquid Bulk Temp (deg F)	Vapor Pressure (psia) Avg.	Min.	Max.	Vapor Mol. Weight.	Liquid Mass Fract.	Vapor Mass Fract.	Mol. Weight	Basis for Vapor Pressure Calculations
Distillate fuel oil no. 2	All	83.48	73.85	93.11	77.03	0.0134	0.0102	0.0179	130.0000			188.00	Option 1: VP70 = .009 VP80 = .012

TANKS 4.0.9d
Emissions Report - Summary Format
Individual Tank Emission Totals

Emissions Report for: Annual

Keahole Tank 1 - Vertical Fixed Roof Tank

	Losses(lbs)		
Components	Working Loss	Breathing Loss	Total Emissions
Distillate fuel oil no. 2	131.45	65.73	197.18

TANKS 4.0.9d
Emissions Report - Summary Format
Tank Indentification and Physical Characteristics

Identification

User Identification:	Keahole Tank 2
City:	
State:	
Company:	HELCO
Type of Tank:	Vertical Fixed Roof Tank
Description:	Based on 1) Nov. 1994 Initial CSP Application information - Annual Throughput: 141,675 bbl and 2) plot plan in Jan. 1991 ATC Application for a Black Start Diesel Generator - tank dimensions 50' diameter, 18' height and capacity 6,290 bbl.

Tank Dimensions

Shell Height (ft):	18.00
Diameter (ft):	50.00
Liquid Height (ft) :	18.00
Avg. Liquid Height (ft):	9.00
Volume (gallons):	264,384.26
Turnovers:	22.51
Net Throughput(gal/yr):	5,950,350.00
Is Tank Heated (y/n):	N

Paint Characteristics

Shell Color/Shade:	Gray/Medium
Shell Condition	Good
Roof Color/Shade:	Gray/Medium
Roof Condition:	Good

Roof Characteristics

Type:	Cone
Height (ft)	0.00
Slope (ft/ft) (Cone Roof)	0.06

Breather Vent Settings

Vacuum Settings (psig):	-0.03
Pressure Settings (psig)	0.03

Meterological Data used in Emissions Calculations: Hilo, Hawaii (Avg Atmospheric Pressure = 14.72 psia)

TANKS 4.0.9d
Emissions Report - Summary Format
Liquid Contents of Storage Tank

Keahole Tank 2 - Vertical Fixed Roof Tank

Mixture/Component	Month	Daily Liquid Surf. Temperature (deg F) Avg.	Min.	Max.	Liquid Bulk Temp (deg F)	Vapor Pressure (psia) Avg.	Min.	Max.	Vapor Mol. Weight.	Liquid Mass Fract.	Vapor Mass Fract.	Mol. Weight	Basis for Vapor Pressure Calculations
Distillate fuel oil no. 2	All	83.48	73.85	93.11	77.03	0.0134	0.0102	0.0179	130.0000			188.00	Option 1: VP70 = .009 VP80 = .012

TANKS 4.0.9d
Emissions Report - Summary Format
Individual Tank Emission Totals

Emissions Report for: Annual

Keahole Tank 2 - Vertical Fixed Roof Tank

	Losses(lbs)		
Components	Working Loss	Breathing Loss	Total Emissions
Distillate fuel oil no. 2	246.66	136.36	383.02

TANKS 4.0.9d
Emissions Report - Summary Format
Tank Indentification and Physical Characteristics

Identification

User Identification:	Keahole Tank 3 or 4	
City:		
State:		
Company:	HELCO	
Type of Tank:	Vertical Fixed Roof Tank	
Description:	Based on information from the July 12, 1994 Addendum to CSP Application submitted on Feb. 1, 1994. Tank 50' diameter, 42' height, 14,688 bbl capacity and annual throughput 101,561 bbl.	

Tank Dimensions

Shell Height (ft):		42.00
Diameter (ft):		50.00
Liquid Height (ft) :		42.00
Avg. Liquid Height (ft):		21.00
Volume (gallons):		617,000.00
Turnovers:		6.91
Net Throughput(gal/yr):		4,265,562.00
Is Tank Heated (y/n):	N	

Paint Characteristics

Shell Color/Shade:	Gray/Medium	
Shell Condition	Good	
Roof Color/Shade:	Gray/Medium	
Roof Condition:	Good	

Roof Characteristics

Type:	Cone	
Height (ft)		0.00
Slope (ft/ft) (Cone Roof)		0.06

Breather Vent Settings

Vacuum Settings (psig):		-0.03
Pressure Settings (psig)		0.03

Meterological Data used in Emissions Calculations: Hilo, Hawaii (Avg Atmospheric Pressure = 14.72 psia)

TANKS 4.0.9d
Emissions Report - Summary Format
Liquid Contents of Storage Tank

Keahole Tank 3 or 4 - Vertical Fixed Roof Tank

Mixture/Component	Month	Daily Liquid Surf. Temperature (deg F) Avg.	Min.	Max.	Liquid Bulk Temp (deg F)	Vapor Pressure (psia) Avg.	Min.	Max.	Vapor Mol. Weight.	Liquid Mass Fract.	Vapor Mass Fract.	Mol. Weight	Basis for Vapor Pressure Calculations
Distillate fuel oil no. 2	All	83.48	73.85	93.11	77.03	0.0134	0.0102	0.0179	130.0000			188.00	Option 1: VP70 = .009 VP80 = .012

TANKS 4.0.9d
Emissions Report - Summary Format
Individual Tank Emission Totals

Emissions Report for: Annual

Keahole Tank 3 or 4 - Vertical Fixed Roof Tank

	Losses(lbs)		
Components	Working Loss	Breathing Loss	Total Emissions
Distillate fuel oil no. 2	176.82	305.65	482.47

TANKS 4.0.9d
Emissions Report - Summary Format
Tank Indentification and Physical Characteristics

Identification

User Identification:	Keahole Tank 7	
City:		
State:		
Company:	HELCO	
Type of Tank:	Vertical Fixed Roof Tank	
Description:	Based on information from the July 12, 1994 Addendum to CSP Application submitted on Feb. 1, 1994. Previously identified as Tank 5; Tank 80' diameter, 42' height, 34,602 bbl capacity and annual throughput 239,258 bbl.	

Tank Dimensions

Shell Height (ft):		42.00
Diameter (ft):		80.00
Liquid Height (ft) :		42.00
Avg. Liquid Height (ft):		21.00
Volume (gallons):		1,475,000.00
Turnovers:		6.81
Net Throughput(gal/yr):		10,048,836.00
Is Tank Heated (y/n):	N	

Paint Characteristics

Shell Color/Shade:	Gray/Medium
Shell Condition	Good
Roof Color/Shade:	Gray/Medium
Roof Condition:	Good

Roof Characteristics

Type:	Cone	
Height (ft)		0.00
Slope (ft/ft) (Cone Roof)		0.06

Breather Vent Settings

Vacuum Settings (psig):	-0.03
Pressure Settings (psig)	0.03

Meterological Data used in Emissions Calculations: Hilo, Hawaii (Avg Atmospheric Pressure = 14.72 psia)

TANKS 4.0.9d
Emissions Report - Summary Format
Liquid Contents of Storage Tank

Keahole Tank 7 - Vertical Fixed Roof Tank

Mixture/Component	Month	Daily Liquid Surf. Temperature (deg F) Avg.	Min.	Max.	Liquid Bulk Temp (deg F)	Vapor Pressure (psia) Avg.	Min.	Max.	Vapor Mol. Weight.	Liquid Mass Fract.	Vapor Mass Fract.	Mol. Weight	Basis for Vapor Pressure Calculations
Distillate fuel oil no. 2	All	83.48	73.85	93.11	77.03	0.0134	0.0102	0.0179	130.0000			188.00	Option 1: VP70 = .009 VP80 = .012

TANKS 4.0.9d
Emissions Report - Summary Format
Individual Tank Emission Totals

Emissions Report for: Annual

Keahole Tank 7 - Vertical Fixed Roof Tank

	Losses(lbs)		
Components	Working Loss	Breathing Loss	Total Emissions
Distillate fuel oil no. 2	416.55	793.65	1,210.21

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Attachment S-3c

Requested Changes to CSP No. 0007-01-C

Attachment S-3c

Requested Changes to CSP No. 0007-01-C

Proposed Changes to Attachment IIA

Proposed change to Attachment IIA, Special Condition A.1.a.:

Two (2) 20 MW Nominal (24.66 MW (gross) peak load) General Electric LM2500 combustion turbine generators, units CT-4 and CT-5; and

Justification – The requested change updates the equipment description to include the maximum peak load rating for the combustion turbine generators.

Proposed change to Attachment IIA, Special Condition C.1.:

~~Start-up~~ Startup and Shutdown

a. ~~The "start up" time shall not exceed twenty (20) minutes for any combustion turbine generator operating in simple cycle and ninety (90) minutes for any combustion turbine generator operating in combined cycle. Except during maintenance (e.g., equipment installations and inspections, and electrical switching work), testing, and emergency power demands due to sudden loss of a power generating unit, each combustion turbine generator shall not be started up more than four times per calendar day. A "start up" sequence shall be from the time fuel use at the combustion turbine generator begins, until the time the combustion turbine generator is initially brought up to 25 percent of peak load at which time the operation of the air pollution control equipment shall commence.~~

   The startup sequence for the combustion turbine generators shall be a twenty (20) minute period in simple or combined cycle mode starting from the time fuel use at the combustion turbine generator begins. Upon completion of the twenty (20) minute startup sequence, the combustion turbine generator shall be at 25 percent of peak load (6.17 MW) or more and the water injection system shall be operational.

b. The "shutdown" ~~time~~ sequence for ~~any~~ combustion turbine generators ~~operating in either simple cycle or combined cycle~~ shall not exceed twenty (20) minutes in simple or combined cycle mode. ~~Except during maintenance (e.g., equipment installations and inspections, and electrical switching work), testing, and emergency power demands due to sudden loss of a power generating unit, each combustion turbine generator shall not be shut down more than four (4) times per calendar day.~~ A "shutdown" sequence shall be ~~considered~~ from the time ~~when~~ the combustion turbine controls stop signal is initiated for the combustion turbine generator and the combustion turbine generator is ~~operating~~ below 25 percent of peak load (6.17 MW), until fuel ~~consumption~~ use at the combustion turbine generator ceases.

Justification – The requested changes are needed to: 1) clarify peak load and the description of startup and shutdown sequences; 2) remove the limit of the number of startups per day because startup periods longer than 20 minutes for both simple and combined cycle modes should not be needed; and 3) allow for stabilization of the water injection system following initiation of the system and address the misalignment of the CEMS NO_X, CO and CO_2 measurement readings with the instantaneous readings of operational parameters such as load (MW), fuel flow, and water injection rate due to lag from the CEMS analyzer response time.

Proposed change to Attachment IIA, Special Condition C.2.:

Minimum Operational Load~~s~~

~~The combustion turbine generators shall not operate below 25 percent of peak load except during equipment start-up, shutdown, maintenance, or testing.~~ The combined time of operation of the combustion turbine generators, CT-2, CT-4, and CT-5, below 25 percent of peak load with water injection shall not exceed 268 hours in any rolling 12 month period, excluding startup and shutdown sequences, maintenance, testing, and as approved pursuant to Attachment IIA, Special Condition C.5.b.

Justification – The requested change is needed to clarify peak load and allow the operation of CT-4 and CT-5 below 25 percent of peak load with water injection to address high system frequency issues. The emissions calculations for CT-2, CT-4 and CT-5 for this proposed change are in Tables 1a and 1b below.

Table 1a - Less Than 25% Load Operation Project Emissions (CT-4, CT-5)

	Pollutant	
Parameter	**CO**	**VOC**
Actual Emissions (lb/hr) Before Change[1]	0.0	0.0
Maximum 10% Load (2.5 MW) Emissions (lb/hr)[2]	475.6	297.6
Expected Increase (lb/hr)	475.6	297.6
Maximum Unit-Hours Below 25% Load[3]	268	268
Projected Emissions Increase (tpy)[4]	63.7	39.9
PSD Significance Level (tpy)	100	40
Significant Emissions Increase (Yes/No)	No	No

Table 1b - Less Than 25% Load Operation Project Emissions (CT-2)

	Pollutant	
Parameter	**CO**	**VOC**
Actual Emissions (lb/hr) Before Change[1]	0.0	0.0
Maximum 10% Load (1.8 MW) Emissions (lb/hr)[5]	22.4	22.4
Expected Increase (lb/hr)	22.4	22.4
Maximum Unit-Hours Below 25% Load	3560	3560
Projected Emissions Increase (tpy)[4]	39.9	39.9
PSD Significance Level (tpy)	100	40
Significant Emissions Increase (Yes/No)	No	No

1 Past actuals set to zero (operation below 25% of peak load not allowed, except for startup, shutdown, maintenance and testing.
2 CT-4 and CT-5 permit limits for 25% of peak load in simple cycle mode.
3 Calculated limit to remain below PSD significance levels.
4 (Expected Increase) x (Unit-Hours/Year) / (2000 lb/ton)
5 CT-2 permit limits.

Proposed change to Attachment IIA, Special Condition C.3.:

Air Pollution Equipment

~~The use of an alternative control system other than those specified below is contingent upon receiving the Department of Health's written approval to use such a system and shall not relieve the permittee from the responsibility to meet all emission limitations contained within this Covered Source Permit.~~

a. ~~Combustor~~ Water Injection

i. The permittee shall continuously operate and maintain a ~~combustor~~ water injection system to meet the emission limits ~~as~~ specified for nitrogen oxides (NO_X) in Attachment IIA, Special Condition D.1.a. ~~of this Covered Source Permit~~. Water injection shall be initiated during the startup sequence of each combustion turbine generator and may be terminated at the beginning of or during the shutdown sequence of each combustion turbine generator. ~~The combustor water injection system shall be fully operational and commence operation immediately after the start-up sequence of the combustion turbine generators. The combustor water injection system shall continue to operate until the commencement of the shutdown sequence of the combustion turbine generators.~~

ii. ~~The operation of the combustor water injection system shall be used whenever the combustion turbine generators are operating at 25 percent peak load and above.~~ After completion of the startup sequence of the combustion turbine generators and until the beginning of the shutdown sequence of the combustion turbine generators, ~~T~~the following water-to-fuel mass ratios, on a one (1) average hour basis, shall be maintained when the combustion turbine generators are firing fuel oil No. 2 in simple cycle operation or in combined cycle operation at loads less than 50 percent of peak load (12.33 MW).

WATER INJECTION SYSTEM
MINIMUM WATER-TO-FUEL MASS RATIO BASED ON LOAD

Combustion Turbine Generator Peak L~~l~~oad (Percent)	**Ratio** (lb-water/lb-fuel)
100 (24.66 MW)	1.04
75 - < 100 (18.50 MW - < 24.66 MW)	0.94
50 - < 75 (12.33 MW - < 18.50 MW)	0.87
~~25 -~~ < 50 (< 12.33 MW)	0.72

For operating periods during which the combustion turbine generator operates at multiple loads where multiple water-to-fuel mass ratios apply, the applicable water-to-fuel mass ratio shall be determined based on the load that corresponded to the lowest minimum water-to-fuel mass ratio.

b. Selective Catalytic Reduction System

The permittee shall design, install, maintain, and continuously operate a selective catalytic reduction system with ammonia injection to meet the emission limits as specified in Attachment IIA, Special Condition D.1.a. of this Covered Source Permit.

The selective catalytic reduction system shall be fully functional and in operation whenever the combustion turbine generators are in combined cycle operation at loads greater than or equal to 50 percent of ~~the peakload~~ peak load (12.33 MW). The selective catalytic reduction system shall continue to operate until the load is reduced to below 50 percent of the ~~peakload~~ peak load (12.33 MW).

c. The use of an alternative control system other than those specified above is contingent upon receiving the Department of Health's written approval to use such a system and shall not relieve the permittee from the responsibility to meet all emission limitations contained within this Covered Source Permit.

Justification – The requested changes are to: 1) clarify the method of determining the applicable minimum water-to-fuel mass ratio for operating hours during which multiple minimum water-to-fuel mass ratios apply; 2) correct a typographical error; 3) clarify peak load; and 4) revise the water injection system table to address operation of the combustion turbine generators below 25 percent of peak load with water injection.

Proposed change to Attachment IIA, Special Condition C.4.:

~~a.~~ Sulfur Content

The combustion turbine generators ~~and diesel engines~~ shall be fired only on fuel oil no. 2 with a maximum sulfur content not to exceed 0.4 percent by weight or an alternate fuel allowed under Special Condition C.5.d. of this Attachment.

~~b. Nitrogen Content~~

~~The fuel bound nitrogen content of the fuel fired in the combustion turbine generators, units CT-4 and CT-5, shall not exceed 0.015 percent by weight on a rolling twelve (12) month average.~~

Justification – The requested changes are needed to clarify the approved fuels and remove the fuel bound nitrogen monitoring conditions because it is not required by NSPS Subpart GG if an emission allowance for fuel bound nitrogen is not claimed; HELCO has not claimed an emission allowance under NSPS Subpart GG.

Proposed change to Attachment IIA, Special Condition C.5.: Alternate Operating Scenarios

~~Terms and conditions for reasonably anticipated operating scenarios identified by the source in the covered source permit application and approved by the Department of Health are as follows:~~

The terms and conditions under the following alternate operating scenarios shall meet all applicable requirements including all conditions of this permit. Requests for written approval to operate under the applicable alternate operating scenario shall be in accordance with Attachment IIA, Special Condition No. F.3.

a. Temporary Replacement. ~~Upon receiving written approval from the Department of Health, the~~ The permittee may replace ~~any of the~~ combustion turbine generators, CT-4 and CT-5, with an equivalent temporary replacement unit with equal or lesser emissions in the event of a failure or ~~sudden malfunction or a planned~~ major overhaul. ~~The temporary replacement unit shall comply with all applicable permit conditions.~~

   ~~A written request shall be submitted to the Department of Health prior to the exchange and at a minimum, the request shall include the following:~~

   ~~i. the reason for temporary replacement;~~

   ~~ii. the removal and estimated return dates of the permitted unit;~~

   ~~iii. the make, model, serial number, and size of the temporary replacement unit; and~~

   ~~iv. the emissions data of the permitted temporary replacement unit.~~

   ~~The Department of Health may require an ambient air quality impact analysis and/or may impose additional requirements on the temporary replacement unit to ensure compliance with the conditions of this permit.~~

b. The combustion turbine generators may operate below 25 percent of peak load (6.17 MW) during:

   i. Testing of the heat recovery steam generators and steam turbine; ~~and~~

   ii. Steam blows needed to clean the steam tubes prior to initial operation~~.~~;

   iii. Testing of combustion turbine generator controls; and

   iv. Dry running the Once Through Steam Generator (OTSG) to remove deposits from the OTSG.

c. ~~In the event of equipment malfunctions, such as the sudden loss of a unit; the combustion turbine generators may operate up to 110 percent of peak load (27.126 MW). The time period for operating the combustion turbines above 100 percent peak load (24.66 MW) shall be limited to no more than 30 minutes in duration. Under no circumstances shall the emission limits specified in Special Condition D.1.a. of this attachment be exceeded.~~

   Combustion Turbine Operation Above Peak Load. The permittee may operate combustion turbine generators up to 110% peak load in the event of equipment malfunction such as a sudden loss of a unit occurs. The time period of this operation shall not exceed thirty (30) minutes in duration, and shall not result in an exceedence of the maximum emission limits specified in Special Condition IIA: D.1.

d. Alternate Fuels. Upon receiving written approval from the Department of Health, the permittee may burn an ~~alternative~~ alternate fuel (e.g., but not limited to, biodiesel, jet fuel, hydrogen, or ethanol).~~provided the permittee demonstrates compliance with all applicable state and federal requirements and applicable conditions of this covered source permit. The alternative fuel shall be burned only temporarily, and shall not result in an increase in emissions of any air pollutant or in the emission of any pollutant not previously emitted. The permittee shall not be allowed to switch fuel unless all the following information is provided:~~

   ~~i. Specific type of fuel provided;~~

   ~~ii. Consumption rate of the fuel;~~

   ~~iii. Fuel blending rate;~~

~~iv. Emissions calculations;~~

~~v. Ambient air quality analyses verifying that SAAQS will be met;~~

~~vi. Fuel storage; and~~

~~vii. Plan to monitor and record the fuel analyses and consumption.~~

e. Fuel Additives. The permittee may use fuel additives to reduce corrosion, control biological growth, and enhance combustion. Additives used during this scenario shall not affect emission estimates.

f. ~~Upon receiving approval from the Department of Health, the permittee may use alternate means and methods to improve combustion and/or reduce emissions provided the permittee demonstrate that the following conditions will be met.~~

~~i. The national and state ambient air quality standards will not be violated.~~

~~ii. The emissions and emission rates do not exceed the permitted emission limits.~~

~~iii. The facility shall continue to operate and comply with the conditions of this permit.~~

~~iv. There are no emissions of air pollutants not previously emitted.~~

~~The Department of Health may approve, conditionally approve, or deny any request for using an alternate means or methods. Under no circumstance shall an alternate means and/or methods be employed without prior written approval, or conditional approval, of the Department of Health.~~

~~g.~~ ~~The permittee shall, contemporaneously with making a change from one operating scenario to another, record in a log at the permitted facility the scenario under which it is operating and, if required by any applicable requirement of the Department of Health, submit written notification to the Department of Health; and~~

Permanent Replacement. The permittee may replace the combustion turbine generators, CT-4 and CT-5, with another General Electric LM2500 if any repair work reasonably warrants the removal (i.e., equipment failure or malfunction, overhaul, or any major equipment problems requiring maintenance for efficient operation) of a combustion turbine generator from its site and the following provisions are adhered to:

i. The replacement combustion turbine generator is a General Electric LM2500 with one of the following serial numbers:

1) 481-688

2) 481-692

3) 481-651

ii. The permittee may continue using the replacement combustion turbine generator and is not required to return the original combustion turbine generator after it is repaired.

~~h.~~ ~~The terms and conditions under each alternate operating scenario shall meet all applicable requirements, including conditions of this permit.~~

Justification – The requested changes are also needed to: 1) include additional maintenance and testing activities. Dry running (i.e., dry operation) of the OTSG may be needed to remove deposits in the OTSG caused by ammonia from the SCR and sulfur in the fuel oil. The OTSG manufacturer's operating manual recommends dry running for approximately 60 to 100 minutes. The duration depends on the depth and density of the deposits; 2) clarify peak load; 3) relocate permit monitoring and recordkeeping and notification and reporting conditions from Section C. Operational Limitations to Section E. Monitoring and Recordkeeping Requirements and Section F. Notification and Reporting Requirements; and 4) add the ability to permanently replace combustion turbine generators, CT-4 and CT-5, with another General Electric LM2500 within HELCO's General Electric LM2500 combustion turbine pool.

Currently, HELCO utilizes the temporary replacement alternate operating scenario (AOS) when a combustion turbine is taken out of service for maintenance and/or repair. However, under the current AOS, HELCO is required to remove the replacement combustion turbine and re-install the original combustion turbine when maintenance and/or repairs are completed which is costly and time consuming. The addition of this AOS provision would allow HELCO to permanently replace combustion turbines with spare combustion turbines of the same make and model (General Electric LM2500) owned by HELCO.

Per 40 CFR § 60.14(e)(6), relocation of an emission unit is not considered a modification. Therefore, relocation of a combustion turbine does not result in applicability of NSPS Subpart IIII.

The permanent replacement AOS incorporates the "replacement unit" provisions contained in 40 CFR § 52.21 which were added on November 7, 2003 (68 FR 63023-63024). The November 7, 2003 revisions added the "replacement unit" definition to clarify EPA's December 31, 2002 decision to allow the use of the actual-to-projected actual applicability test for unit replacement (67 FR 80194).

The EPA December 31, 2002 decision states:

> *...the fact that replacement units are replacing similar units with a record of historical operational data provides sufficient reasons to believe that a projection of future actual emissions can be sufficiently reliable that an up-front emissions cap based on PTE is unnecessary. In other words, a source replacing a unit should be able to adequately project and track emissions for the replacement unit based, in part, on the operating history of the replaced unit.*

(67 FR 80186, at 80194)

Whether, the existing diesel engine is returned or not has no impact on projected-actual annual emissions. Therefore, no annual emissions increase is expected. Per 40 § 52.21(b)(41)(ii)(c), projected-actual annual emissions do not include emission increases unrelated to the particular project, including any increase utilization due to product demand growth.

Review of permits from other states has identified two permits allowing for the installation of permanent replacement units: 1) Draft Permit No. 97-179-C (M-2) from the Oklahoma Department of Environmental Quality. Refer to Specific Condition 9 of the draft permit; and 2) Operating Permit (02OPEP246) issues by the Colorado Department of Public Health and Environment, Air Pollution Control Division. Refer to Section I.2 of the permit.

The permits identified above address units that have been through New Source Review and have emission testing requirements. The testing requirements for the original HELCO units are identical to the replacement units as specified in Attachment II, Section F of the CSP.

An applicability determination for grandfathered units was also identified. On April 1, 1999, EPA Region 2 made an applicability determination in regards to PSE&G combustion turbine replacement. The EPA Region 2 applicability determination states:

> *The act of physically removing a turbine from one spot, performing the routine repair and maintenance on that turbine and placing it in a*

different but identically designed spot, is not the construction of a new source.

The above examples illustrate the proposed permanent replacement alternate operating scenario is allowed under NSPS and PSD permitting rules.

Proposed change to Attachment IIA, Special Condition D.1.:

Maximum Emission Limits

a. Except during the startup and shutdown sequences, ~~T~~the permittee shall not discharge or cause the discharge into the atmosphere from the combustion turbine generator nitrogen oxides, sulfur dioxide, particulate matter/PM_{10}, carbon monoxide, volatile organic compounds, and ammonia in excess of the following specified limits:

Combustion Turbine Generator Operating in Simple Cycle Mode

Compound	**Maximum Emission Limit (3-hour Average)**	
	(lbs/hr)	(ppmvd @ 15 percent O_2)
Nitrogen Oxides as NO_2	42.3	42
Sulfur Dioxide	110	79
Particulate Matter/PM_{10}	19.7	0.045 (g/dscf @ 12 percent O_2)
Carbon Monoxide		
100% Peak load (24.66 MW)	26.8	44
75% (18.50 MW) - < 100% (24.66 MW) Peak load	56.4	123
50% (12.33 MW) - < 75% (18.50 MW) Peak load	181.0	566
~~25% (6.17 MW) -~~ < 50% (12.33 MW) Peak load	475.6	2,386
Volatile Organic Compounds		
100% Peak load (24.66 MW)	0.8	2.5
75% (18.50 MW) - < 100% (24.66 MW) Peak load	2.6	11.8
50% (12.33 MW) - < 75% (18.50 MW) Peak load	18.1	178
~~25% (6.17 MW) -~~ < 50% (12.33 MW) Peak load	297.6	3,025

Combustion Turbine Generator Operating in Combined Cycle Mode

Compound	Maximum Emission Limit (3-hour Average)	
	(lbs/hr)	(ppmvd @ 15 percent O_2)
Nitrogen Oxides as NO_2		
50% (12.33 MW) - 100% (24.66 MW) Peak load	15.1	15
~~25% (6.17 MW) -~~ < 50% (12.33 MW) Peak load	42.3	42
Sulfur Dioxide	110	79
Particulate Matter/PM_{10}	19.7	0.045 (g/dscf @ 12 percent O_2)
Carbon Monoxide		
100% Peak load (24.66 MW)	26.9	44
75% (18.50 MW) - < 100% (24.66 MW) Peak load	50.2	105
50% (12.33 MW) - < 75% (18.50 MW) Peak load	170.4	523
~~25% (6.17 MW) -~~ < 50% (12.33 MW) Peak load	457.4	2,218
Volatile Organic Compounds		
100% Peak load (24.66 MW)	0.8	2.5
75% (18.50 MW) - < 100% (24.66 MW) Peak load	2.0	8.6
50% (12.33 MW) - < 75% (18.50 MW) Peak load	25.0	156
~~25% (6.17 MW) -~~ < 50% (12.33 MW) Peak load	271.0	2,662
Ammonia	4.30	10

b. The three-hour averaging period shall begin immediately upon completion of the combustion turbine generator's startup sequence and end immediately prior to the combustion turbine generator's shutdown sequence. For operating periods during which the combustion turbine generator operates at multiple loads where multiple NO_X and CO emission standards apply, the applicable NO_X and CO emissions limit shall be determined in accordance with 40 CFR § 60.4380(b)(3).

c. The Department of Health, with U.S. EPA Region 9 concurrence, may revise the allowable emission limitation for nitrogen oxides, particulate matter, carbon monoxide, volatile organic compounds, and ammonia after reviewing the initial performance test results required under Attachment IIA, Section G of this Covered Source Permit. The Department of Health, with U.S. EPA Region 9 concurrence, may also revise the water-to-fuel ratios or include ammonia-to-NO_X injection rates if findings through operating parameters and performance test results show an optimum operating range which minimizes emissions.

d. If the nitrogen oxides, particulate matter, carbon monoxide, volatile organic compounds, or ammonia emission limit is revised, the difference between the applicable emission limit set forth above and the revised lower emission limit shall not be allowed as an emission offset for future construction or modification.

Justification – The requested changes are needed to: 1) revise the emission limits table to clarify peak load; 2) clarify the method of determining the applicable emission limit for operating

periods during which multiple emission standards apply; and 3) revise the emission limits tables to address operation of CT-4 and CT-5 below 25 percent of peak load.

Proposed change to Attachment IIA, Special Condition E.: Monitoring and Recordkeeping

All records, including support information, shall be maintained for at least five (5) years from the date of the monitoring ~~sample,~~ ~~measurement,~~ test, report, or application. Support information includes all ~~calibration and~~ maintenance, inspection, and repair records and copies of all reports required by ~~the~~ this permit. These records shall be ~~true, accurate,~~ maintained in a permanent form suitable for inspection and made available to the Department of Health or their representative upon request.

Justification – The requested change is needed for consistency with other HECO, HELCO, and MECO

Proposed change to Attachment IIA, Special Condition E.1.: Continuous Monitoring Systems

~~All monitoring systems shall record the date and time that the measured parameters and data were collected.~~

The permittee shall at its own expense operate and maintain the following continuous monitoring systems for each combustion turbine generator to measure and record the following parameters and data. The associate date and time of the monitored data shall also be recorded.

a. ~~The permittee shall continuously monitor and record the operating~~ Operating load ~~of the combustion turbine generators.~~ in MW;

b. ~~The permittee shall operate and maintain a continuous monitoring system to monitor and record the ratio of water-to-fuel being fired in the combustion turbine generators.~~ Water-to-fuel ratio. The water-to-fuel monitor/recorder shall be accurate to +/- 5 percent.

c. ~~The permittee shall operate and maintain a total volumetric flow metering system for the continuous measurement and recording of the fuel usage of the combustion turbine generators. The permittee shall maintain records on the total amount of fuel fired in the combustion turbine generators.~~ Fuel consumption using a flow metering system;

d. ~~The permittee shall operate and maintain a continuous monitoring system to measure and record the~~ NO_X, CO, and carbon dioxide (CO_2) or oxygen (O_2) concentrations in the stack gases and in the exhaust gas stream at a point between the exit of the combustion turbine with water injection and the entrance to the SCR system using a Continuous Emissions Monitoring System (CEMS) ~~from the combustion turbines~~. If CO_2 is measured with the CEMS to adjust the pollutant concentration, the CO_2 correction factor equations listed in 40 CFR §60.4213(d)(3) shall be used to determine compliance with the applicable emissions limit and a diluent cap value for CO_2 may be used in accordance with 40 CFR §60.4350(b). The emissions ~~rates~~ for NO_X and CO shall be recorded in parts per million by volume dry (ppmvd) at 15 percent O_2 and pounds per hour (lbs/hr).

e. ~~Prior to the startup of the selective catalytic reduction system and thereafter, the permittee shall at its own expense install, operate, and maintain a continuous monitoring system for each combustion turbine to measure and record the following parameters and data:~~

~~i.~~ The ammonia injection rate in pounds per hour (lbs/hr) and the ammonia-to-NO_X ratio. The ratio shall be based on the pounds per hour of ammonia injected into the SCR to the pounds of NO_X entering the SCR system.

~~ii. The NO_X and carbon dioxide (CO_2) or oxygen (O_2) concentrations in the exhaust gas stream at a point between the exit of the combustion turbine with water injection and the entrance to the SCR system.~~

~~The emissions rates for NO_X shall be recorded in parts per million by volume dry (ppmvd) at 15 percent O_2 and in lbs/hr. The continuous emissions monitoring system used for these measurements shall meet the U.S. EPA performance specifications of 40 CFR Part 60 Section 60.13, Appendix B, and Appendix F.~~

f. [No changes proposed]

~~g. The permittee shall maintain a file of all measurements and monitoring data, performance testing requirements and results, system performance evaluations, calibration checks, adjustments and maintenance as performed, and all other information required by 40 CFR Part 60 recorded in a permanent form suitable for inspection.~~

Justification – The requested changes are needed to: 1) allow volumetric or mass flow meters; 2) remove redundant permit conditions; and 3) incorporate by reference the CO_2 correction factor equations required for the CEMS and allow the use of a diluent cap address any hour in which the hourly average CO_2 concentration is less than 1.0 percent. 40 CFR Part 60, Subpart KKKK and Part 75 include a diluent cap for both O_2 and CO_2 for stationary turbines. However, 40 CFR Part 60, Subpart GG includes a diluent cap only for O_2.

Proposed change to Attachment IIA, Special Condition E.3.:

a. The ~~fuel~~ sulfur content of the fuel fired in the combustion turbines shall be determined using of one of the following sampling options described in sections 2.2.3, 2.2.4.1, 2.2.4.2 and 2.2.4.3 of Appendix D to 40 CFR Part 75. The analysis may be performed by the permittee, the supplier, or other qualified third party lab. The analysis shall be performed using one of the following ASTM International (ASTM) methods: D129-00, D2622-98, D4294-02, D1266-98, D5453-00, or D1552-01 or a more current version of these ASTM methods. ~~verified by one of the following methods:~~

~~i. A representative sample of each batch of the fuel received shall be analyzed using the most current version of any of the following American Society for Testing and Materials (ASTM) methods: D129, D2622, D4292, D5453, or D1552; or~~

~~ii. A certificate of analysis on the sulfur content (percent by weight) shall be obtained from the fuel supplier for each batch of fuel received.~~

b. ~~The fuel bound nitrogen content of the fuel fired in the combustion turbines shall be verified by the following method. A representative sample of each batch of fuel received shall be analyzed for its nitrogen content by weight using the most current version of any of the following American Society for Testing and Materials (ASTM) methods: D6366, D4629, D5762.~~

c. The permittee shall maintain records of the fuel deliveries.~~y~~ identifying the delivery dates and the type and amount of fuel received. ~~receipts, the supplier's certificate of analysis showing the sulfur content of the fuel delivered, and all test analysis. At a minimum, the test analysis shall include the following:~~

~~i. Type of fuel;~~

~~ii. Date and time the fuel sample was drawn;~~

~~iii. Date the analyses were performed;~~

~~iv. Name and address of the company or entity that performed the analyses;~~

~~v. Means and methods used to analyze the fuel; and~~

~~vi. Analyses results.~~

Records of~~n~~ the sulfur ~~and nitrogen~~ content~~s~~ of the fuel shall be maintained on a monthly basis.

Justification – The requested changes are needed to: 1) provide consistency with NSPS Subpart GG. The requested changes include the addition of the NSPS Subpart GG fuel oil no. 2 sulfur test methods and authorization of the fuel testing to be conducted by the permittee, supplier, or other qualified third party lab; 2) remove the fuel bound nitrogen monitoring conditions because it is not required by NSPS Subpart GG if an emission allowance for fuel bound nitrogen is not claimed; HELCO has not claimed an emission allowance under NSPS Subpart GG; and 3) provide consistency with the proposed change to Attachment IIA, Special Condition E.3.b. and CSP No. 0070-01-C.

Proposed change to Attachment IIA, Section E.: Add monitoring and recordkeeping conditions.

4. Operation Below 25 Percent of Peak Load with Water Injection. The permittee shall maintain records of the total time the combustion turbine generators operate below 25 percent of peak load with water injection. Records of the total time CT-2, CT-4, and CT-5 operated below 25 percent of peak load with water injection, excluding startup and shutdown sequences, and maintenance, testing, and as approved pursuant to Special Condition C.5. of this Attachment, shall be maintained on a monthly and rolling twelve (12) month basis using data recorded by the CEMS.

5. Startup and shutdown.

   a. The following shall be recorded for each startup sequence:

      i. The date, start and end times, and corresponding load (MW) at the end of each twenty (20) minute startup sequence.

      ii. Duration (minutes) of the startup sequence.

      iii. The operating load (MW) at which water injection was initiated.

   b. The following shall be recorded for each shutdown sequence:

      i. The date, start and end times, and corresponding load (MW) at which the combustion turbine controls stop signal was initiated.

      ii. Duration (minutes) of the shutdown sequence.

      iii. The operating load (MW) at which water injection was terminated.

6. Alternate Operating Scenarios

   a. The permittee shall contemporaneously with making a change from one operating scenario to another in accordance with Attachment IIA, Special Condition No. C.9, record in a log at the permitted facility the scenario under which it is operating.

b. The permittee shall maintain all records corresponding to the implementation of an alternate operating scenario specified in Attachment IIA, Special Condition No. C.9.

c. The reason for operating the combustion turbine generator, CT-3, above peak load shall be clearly documented, with the event's date, time, duration, operating load, and resulting three-hour average emission rates.

Justification – The requested changes are needed to: 1) relocate permit conditions for the emergency diesel fire pump and D21; 2) allow for volumetric or mass flow meters 3) relocate monitoring and recordkeeping conditions from Section B. Operational Limitations to Section E. Monitoring and Recordkeeping Requirements; 4) monitor and record operation of CT-4 and CT-5 below 25 percent of peak load with water injection; and 5) provide consistency with notification and reporting requirements in Attachment IIA, Special Condition F.6.a.

Proposed change to Attachment IIA, Special Condition F.3.: Delete condition.

~~**Within sixty (60) days** after initial start-up of the selective catalytic reduction system, the permittee shall submit to the Department of Health a quality assurance project plan for the continuous monitoring system conforming to 40 CFR Part 60, Appendix F.~~

Justification – The quality assurance project plan has been submitted to the Department of Health and therefore, this permit condition is no longer needed.

Proposed change to Attachment IIA, Special Condition F.4.:

~~The permittee shall notify the Department of Health in writing **within thirty (30) days** prior to conducting performance specification tests on the continuous monitoring system. The testing date shall be in accordance with the performance test date identified in 40 CFR Part 60 Section 60.13.~~

Performance Test.

a. At least thirty (30) days prior to conducting a source performance test as required by Attachment IIA, Section G, the permittee shall submit a written performance test plan to the Department of Health that includes the date(s) of the test, test duration, test locations, test methods, source operation, and other parameters that may affect test results. Such a plan shall conform to U.S. EPA guidelines including quality assurance procedures. A test plan or quality assurance plan that does not have the approval of the Department of Health may be grounds to invalidate any test and require a retest.

b. Within sixty (60) days after completion of a source performance test required by Attachment IIA, Section G, the permittee shall submit to the Department of Health and U.S. EPA Region 9 (Attention: AIR-3) the test report which shall include the operating conditions of the combustion turbine generators and diesel engine generators at the time of the test, the analysis of the fuel, the summarized test results, comparative results with the permit emission limits, and other pertinent field and laboratory data.

Justification – The requested changes are needed: 1) for consistency with CSP No. 0070-01-C and the notification requirements of 40 CFR Part 60 Subpart A; and 2) to relocate notification and reporting requirements from Section G Testing Requirements to Section F Notification and Reporting Requirements.

Proposed change to Attachment IIA, Special Condition F.5.: Excess Emissions.

The permittee shall submit to the Department of Health and U.S. EPA Region 9 for every semi-annual calendar period ~~a written~~ reports of ~~all~~ excess emissions and monitor downtime in accordance with 40 CFR Part 60, Section 60.7(c).~~, including those associated with the water-to-fuel ratio requirement, to the Department of Health and U.S. EPA Region 9 every semi-annual period.~~ The report shall include the following:

a. The magnitude of excess emissions computed in accordance with 40 CFR Part 60 ~~Subsection~~ Section 60.13(h), any conversion factors used, and the date and time of commencement, completion of each time period of excess emissions, and the corresponding operating load of the combustion turbine generators.

b. Specific identification of each period of excess emissions that occurs during ~~start-ups,~~ startups, shutdowns, and malfunctions of the combustion turbine generators. The nature and cause of any malfunction (if known), and the corrective action taken or preventive measures adopted~~, shall also be reported~~.

c. The date and time identifying each period during which the continuous monitoring system was inoperative except for zero and span checks~~. The~~ and the nature of ~~each~~ the system repairs or adjustments ~~shall be described~~.

d. ~~The report shall state if no excess emissions have occurred. Also, the report shall state if the CEMS operated properly during the period and was not subject to any repairs or adjustments except for zero and span checks.~~ When no excess emissions have occurred or the CEMS has not been inoperative, repaired, or adjusted, such information shall be stated in the report.

e. [No changes proposed]

f. For purposes of this Covered Source Permit, excess emissions shall be defined as follows:

   i. [No changes proposed]

   ii. During simple cycle operation and combined cycle operation at loads less than 50 percent of peak load (12.33 MW), any one (1) hour period during which the average water-to-fuel ratio, as measured by the continuous monitoring system, falls below the water-to-fuel ratio at the corresponding operating load specified in Special Condition C.3.a. of this attachment. For operating periods during which the combustion turbine generator operates at multiple loads where multiple water-to-fuel mass ratios apply, the applicable water-to-fuel mass ratio shall be determined based on the load that corresponded to the lowest minimum water-to-fuel mass ratio; and

   iii. Any opacity measurements, as measured by the transmissometer continuous monitoring system, exceeding the opacity limits and corresponding averaging times set forth in Special Condition D.2. of this attachment. During periods of opacity exceedences as measured by the transmissometer continuous monitoring system, compliance with the opacity limits set forth in this Attachment Condition No. C.5 may be demonstrated with visible emissions observations conducted in accordance with 40 CFR Part 60, Appendix A, Method 9.

g. [No changes proposed]

Justification – The requested changes are needed for consistency with reporting requirements under 40 CFR § 60.7(c) and CSP No. 0007-01-C.

Proposed change to Attachment IIA, Special Condition F.5.g.iii.:

Nitrogen oxide emissions in excess of 42 ppmvd at 15 percent O_2 while operating in simple cycle mode and combined cycle mode at loads less than 50 percent of peak load (12.33 MW) or 15 ppmvd at 15 percent O_2 while operating in combined cycle mode at loads equal to or greater than 50 percent of peak load (12.33 MW) if it can be shown that the excess emissions resulted from the firing of fuel with a fuel-bound nitrogen content in excess of 0.015 percent by weight. Under no circumstance shall the nitrogen oxide emission limit of 42.3 pounds per hour while operating in simple cycle mode and combined cycle mode at loads less than 50 percent of peak load (12.33 MW) or 15.1 pounds per hour while operating in combined cycle mode at loads equal to or greater than 50 percent of peak load (12.33 MW), as specified in Special Condition D.1.a. of this attachment, be exceeded.

Justification – The requested change is to clarify peak load.

Proposed change to Attachment IIA, Special Condition F.6.:

The permittee shall submit **semi-annually** the following written reports to the Department of Health. The report shall be submitted **within sixty (60) days** after the end of each semi-annual calendar period, and shall include the following:

a. A ~~monthly~~ summary ~~listing the time and duration of all~~ ~~start-up~~ identifying all dates, times and durations when the startup and ~~shut-down~~ shutdown sequences for ~~each~~ the combustion turbine generators exceeded twenty (20) minutes. ~~The summary shall include the combustion turbine generator load (MW) at the time the air pollution control devices and systems are initiated and terminated.~~ The enclosed **Monitoring Report Form: ~~*Daily Start-up*~~ *Combustion Turbine Generator Operation* ~~*and Shut-down*~~** or ~~similar~~ equivalent form, shall be used.

b. Minimum Operating Loads~~Except for all start-up and shutdown sequences report all periods where the minimum operating load for each combustion turbine was less than 25 percent of the rated capacity. The report shall include the date, time, and duration of each period.~~

   i. All periods when the operating load for the combustion turbine generators was below 25 percent of peak load (4.6 MW) except for all startup and shutdown sequences and as authorized pursuant to Special Condition C.2. of this Attachment. The report shall include the date, time and duration of each period using data recorded by the CEMS. The report shall include the date, time and duration of each period using data recorded by the CEMS. The enclosed Monitoring Report Form: Combustion Turbine Generator Operation or an equivalent form shall be used.

   ii. A monthly summary and rolling 12-month total of the hours of operation of the combustion turbine generators, CT-2, CT-4, and CT-5, below 25 percent of peak load (6.17 MW) with water injection excluding startup and shutdown sequences, maintenance, testing, and as approved pursuant to Special Condition C.5. of this Attachment. The report shall be based on data recorded by the CEMS. The enclosed Monitoring Report Form: Monthly Combustion Turbine Generator Operation Below Minimum Operating Load with Water Injection or equivalent form shall be completed for each reporting period. The enclosed Monitoring Report Form: Combustion Turbine Generator Monthly Operation Below Minimum Load with Water Injection or equivalent form shall be used.

c. [No changes proposed]

d. A report identifying the type of fuel fired in each of the combustion turbines during the semi-annual reporting period. The report shall include the maximum sulfur content (percent by weight) ~~and the average nitrogen content (percent by weight)~~ of the fuel for the reporting period. ~~The report shall identify the means and methods used to verify the sulfur and nitrogen content of each fuel.~~ The enclosed **Monitoring Report Form: *Fuel Certification,*** or ~~similar~~ <u>equivalent</u> form, shall be used.

e. [No changes proposed]

Justification – The requested changes are needed: 1) to clarify peak load; 2) for consistency with CSP No. 0070-01-C; 3) for consistency with the proposed change to Special Condition E.3.b. to remove the fuel bound nitrogen monitoring conditions because it is not required by NSPS Subpart GG if an emission allowance for fuel bound nitrogen is not claimed; HELCO has not claimed an emission allowance under NSPS Subpart GG; and 4) for operation of CT-4 and CT-5 below 25 percent of peak load with water injection.

Proposed change to Attachment IIA, Section F.: Add notification and reporting condition:

<u>3. Alternate Operating Scenarios</u>

<u>a. Temporary Replacement. Within thirty (30) days of commencement of the temporary replacement, the permittee shall submit in writing to the Department of Health, the reason for the temporary replacement, removal and return dates, and the make, model, and serial number of the existing and temporary replacement units.</u>

<u>b. Alternate Fuels. In requesting for approval to fire CT-4 and CT-5 on alternate fuels, the permittee shall at a minimum, provided the Department of Health with information on the type of fuel proposed, reason for using the alternate fuel, emissions data, and the manufacturer's recommended water-to-fuel ratio and minimum operating load for compliance with the emission limits. The Department of Health may require an ambient air quality impact assessment for firing the alternate fuel and/or provide a conditional approval to impose additional monitoring, testing, recordkeeping, and reporting requirements. The Department of Health may establish minimum water-to-fuel ratio conditions in the permit for firing CT-4 and CT-5 on alternate fuels.</u>

<u>c. The permittee shall request for approval to use alternate means and methods to improve combustion and/or reduce emissions. The Department of Health may approve, conditionally approve, or deny any request for using alternate means and methods.</u>

<u>d. Permanent Replacement. For permanent replacement of CT4 and CT5, the permittee shall submit to the Department of Health, the make, model, and serial number of the existing and replacement units within thirty (30) days of the replacement.</u>

<u>e. Fuel Additives. In requesting for approval to use fuel additives, the permittee shall, at a minimum, provide the Department of Health the specifications of the fuel additive(s), maximum expected emission rates of any criteria or non-criteria pollutant, certification that corresponding emission rates will not exceed permitted rates, and any other related information as requested by the Department of Health. The Department of Health may provide a conditional approval to impose additional monitoring, testing, recordkeeping, and reporting requirements to ensure the use of the fuel additive is in compliance with the applicable requirements.</u>

Justification – The requested changes are needed to: 1) revise the alternate operating scenario for alternate fuels to allow adjustment of the minimum operating load and water-to-fuel mass ratios for alternate fuels, if necessary, to comply with the CSP emission limits; and 2) relocate permit notification and reporting conditions from Section B. Operational Limitations to Section F. Notification and Reporting Requirements.

Proposed change to Attachment IIA, Special Condition G.1.: Delete condition.

> ~~**Within sixty (60) days** after achieving the maximum production rate of the 16 MW steam turbine, but not later than one hundred eighty (180) days after the initial start-up of the 16 MW steam turbine (as defined in 40 CFR Part 60.2), the permittee shall conduct or cause to be conducted performance tests on the combustion turbine generators operating with SCR in the combined cycle mode.~~

Justification – These performance tests have been conducted, and therefore the permit condition is no longer needed.

Proposed change to Attachment IIA, Special Condition G.3.:

> All performance tests shall be conducted at 25, 50, 75, and 100 <u>or highest achievable</u> percent of peak load of the combustion turbine generators. The Department of Health may require the permittee to conduct the performance tests at additional operating loads.

Justification – The requested change is to clarify peak load.

Proposed change to Attachment IIA, Special Conditions G.8.:

> Performance tests for the emissions of SO_2, NO_X, CO, VOC, PM, CO_2, and NH_3 shall be conducted and results reported in accordance with test methods set forth in 40 CFR Part 60 Appendix A, and 40 CFR Part 60.8. The following test methods or U.S. EPA-approved equivalent methods, or alternate methods with prior written approval from the Department of Health, shall be used. <u>Method 3A may be used in place of Method 3.</u>
>
> a. Performance tests for the emissions of SO_2 shall be conducted using the 40 CFR Part 60, Methods 1-4 and <u>6C or Method</u> 20.
>
> b. Performance tests for the emissions of NO_X shall be conducted using 40 CFR Part 60, Methods 1-4 and <u>7E or Method</u> 20.
>
> c. Performance tests for the emissions of CO shall be conducted using 40 CFR Part 60, Methods 1-4 and 10 <u>or Methods 3A, 10, and 19</u>.
>
> d. Performance tests for the emissions of VOC shall be conducted using 40 CFR Part 60, Methods 1-4 and 25A or <u>Methods 3A, 25A, and 19</u>. <u>Method 18 may be used to account for the actual methane fraction of the measured VOC emissions.</u>
>
> e. Performance tests for the emissions of particulate matter shall be conducted using 40 CFR Part 60, Methods 1-5.
>
> f. Performance tests for the emissions of CO_2 shall be conducted using 40 CFR Part 60 Method 20 <u>or U.S. EPA-approved equivalent methods</u>~~, Equations 20-2 and 20-5~~ <u>and the CO_2 correction factor calculations listed in § 60.4213(d)(3)</u>.

g. Performance test for the emissions of NH_3 shall be conducted using U.S. EPA Conditional Test Method 027(CTM-027).

Justification – The requested changes are needed to add specific U.S. EPA-approved equivalent methods to the permit condition and incorporate by reference the new location of the CO_2 correction factor equations required for the CEMS. This addition is needed because the equations are no longer in the referenced test method (Method 20).

Proposed change to Attachment IIA, Special Condition G.11.: Delete condition.

~~At least thirty (30) calendar days prior to performing a test, the permittee shall submit a written performance test plan to the Department of Health and U.S. EPA Region 9 that describes the test duration, test locations, test methods, source operation and other parameters that may affect test results. Such a plan shall conform to U.S. EPA guidelines including quality assurance procedures. A test plan or quality assurance plan that does not have the approval of the Department of Health may be grounds to invalidate any test and require a retest.~~

Justification – The requested change is needed to relocate notification and reporting requirements from Section G. Testing Requirements to Section F. Notification and Reporting Requirements.

Proposed change to Attachment IIA, Special Condition G.14.: Delete condition.

~~Within sixty (60) days after completion of the performance test, the permittee shall submit to the Department of Health and U.S. EPA Region 9 the test report which shall include the operating conditions of the combustion turbine generators at the time of the test, the analysis of the fuel, the summarized test results, and other pertinent field and laboratory data.~~

Justification – The requested change is needed to relocate notification and reporting requirements from Section G. Testing Requirements to Section F. Notification and Reporting Requirements.

Proposed Changes to Attachment IIB

Proposed change to Attachment IIB, Special Condition A.1.d.:

One (1) 500 kW Caterpillar Model 3412 Black Start Diesel Engine Generator ~~with an exhaust stack height of 70 feet~~ unit no. BS-1.

Justification – The requested change updates the description of the black start diesel engine generator, BS-1 because the relocation and extension of the stack height has been completed.

Proposed change to Attachment IIB: Add Applicable Federal Regulations Section

1. The diesel engine generators, unit nos. D21, D22, and D23 are subject to the provisions of the following federal regulations.
    a. 40 CFR Part 63, National Emission Standards for Hazardous Air Pollutants, Subpart A, General Provisions; and
    b. 40 CFR Part 63, National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines, Subpart ZZZZ.
2. The permittee shall comply with all of the applicable requirements of these standards, including all emission limits, notification, testing, monitoring, recordkeeping, and reporting requirements. The major requirements of these standards are detailed in Special Conditions of this permit.

Justification – The requested change is needed to incorporate the federal regulation under which Units D21, D22, and D23 are subject beginning May 3, 2010.

Proposed change to Attachment IIB, Special Condition B.4.: Fuel Specifications

a. ~~The diesel engines~~ Diesel engine generator, unit no. BS-1 shall be fired only on fuel oil no. 2 with a maximum sulfur content not to exceed 0.4 percent by weight, or alternative fuel allowed under Special Condition No. B.7.b of this attachment.

b. Diesel engine generators, unit nos. D21, D22, and D23, shall be fired on the following fuels:
    i. Through May 2, 2013, fuel oil no. 2 with a maximum sulfur content not to exceed 0.4 percent by weight;
    ii. Beginning May 3, 2013, fuel oil no. 2 with:
        (1) A maximum sulfur content of 0.0015 percent by weight; and
        (2) Minimum Cetane index of 40 or maximum aromatic content of 35 volume percent;
    iii. Alternate fuels as allowed under Special Condition B.5.b. of this Attachment; or
    iv. Any combination thereof.

Justification – The requested change incorporates fuel requirements from 40 CFR Part 63 Subpart ZZZZ with a compliance date of May 3, 2013.

Proposed change to Attachment IIB, Special Condition B.7.: Alternate Operating Scenarios

~~Terms and conditions for reasonably anticipated operating scenarios identified by the permittee in the covered source permit application and approved by the Department of Health are as follows:~~

The terms and conditions under the following alternate operating scenarios shall meet all applicable requirements including all conditions of this permit. Requests for written approval to operate under the applicable alternate operating scenario shall be in accordance with Attachment IIB, Special Condition No. D.7.

a. Temporary Replacement. ~~Upon receiving written approval from the Department of Health, the~~ The permittee may replace ~~any of the permitted~~ diesel engine generators, D-21, D-22, D-23, and BS-1, with an equivalent temporary replacement unit with equal or lesser emissions in the event of a failure or ~~sudden malfunction or planned~~ major overhaul. ~~The temporary replacement unit shall comply with all applicable permit conditions.~~

   ~~A written request shall be submitted to the Department of Health prior to the exchange and at a minimum, the request shall include the following:~~

   ~~i. the reason for temporary replacement;~~

   ~~ii. the removal and estimated return dates of the permitted unit;~~

   ~~iii. the make, model, serial number, and size of the temporary replacement unit;~~

   ~~iv. the emissions data of the permitted and temporary replacement unit.~~

   ~~The Department of Health may require an ambient air quality analysis and/or impose additional requirements on the temporary replacement unit to ensure compliance with the conditions of this permit.~~

b. Fuel Additives. Upon receiving written approval from the Department of Health, the permittee may ~~burn an~~ use ~~alternative~~ fuel or fuel additives to inhibit corrosion, control biological growth, improve combustion, improve lubricity, or other reasons. Additives used during this scenario shall not result in an increase in emission estimates.~~provided the permittee demonstrates compliance with all applicable State and Federal requirements and applicable conditions of this covered source permit. The burning of the alternative fuel or fuel additive shall not result in an increase in emissions of any air pollutant or in the emission of any air pollutant not previously emitted. As a minimum, the following information must be included with any request to burn an alternate fuel or fuel additive.~~

c. ~~The permittee shall contemporaneously with making a change from one alternate operating scenario to another, record in a log at the permitted facility the scenario under which it is operating and submit written notification to the Department of Health.~~

   Alternate fuels. Upon receiving approval from the Department of Health, the permittee may burn an alternate fuel (e.g., but not limited to, biodiesel).

d. ~~The terms and conditions under each alternate operating scenario shall meet all applicable requirements, including conditions of this permit.~~

   Permanent Replacement. The permittee may replace the diesel engines, D21, D22, and D23, with another EMD 20-645 if any repair work reasonably warrants the removal (i.e., equipment failure, engine overhaul, or any major equipment problems requiring maintenance for efficient operation) of a diesel engine from its site and the following provisions are adhered to:

i. The replacement engine is an EMD 20-645 with one of the following serial numbers:

1) 74-K3-1540
2) 71-M1-1092
3) 71-M1-1045
4) 74-B1-1078
5) 66-K1-1062
6) 69-H1-1057
7) 74-B1-1063
8) 72-E1-1027
9) 72-B1-1122
10) 73-G1-1129
11) 66-K1-1057
12) 72-E1-1094
13) 66-J1-1156

iii. The permittee may continue using the replacement diesel engine and is not required to return the original diesel engine after it is repaired.

Justification – The requested changes are needed to: 1) relocate monitoring and recordkeeping and notification and reporting conditions from Section B. Operational and Emission Limitations to Section C. Monitoring and Recordkeeping Requirements and Section D. Notification and Reporting Requirements; and 2) add the ability to permanently replace diesel engines, D21, D22, and D23, with another EMD 20-645 within HELCO's EMD diesel engine pool. Currently, HELCO utilizes the temporary replacement alternate operating scenario (AOS) when a diesel engine is taken out of service for maintenance and/or repair. However, under the current AOS, HELCO is required to remove the spare diesel engine and re-install the original diesel engine when maintenance and/or repairs are completed which is costly and time consuming. The addition of this AOS provision would allow HELCO to permanently replace diesel engines with spare diesel engines of the same make and model (EMD 20-645) owned by HELCO.

Per 40 CFR § 60.14(e)(6), relocation of an emission unit is not considered a modification. Therefore, relocation of a combustion turbine does not result in applicability of NSPS Subpart IIII.

The permanent replacement AOS incorporates the "replacement unit" provisions contained in 40 CFR § 52.21 which were added on November 7, 2003 (68 FR 63023-63024). The November 7, 2003 revisions added the "replacement unit" definition to clarify EPA's December 31, 2002 decision to allow the use of the actual-to-projected actual applicability test for unit replacement (67 FR 80194).

The EPA December 31, 2002 decision states:

> *...the fact that replacement units are replacing similar units with a record of historical operational data provides sufficient reasons to*

believe that a projection of future actual emissions can be sufficiently reliable that an up-front emissions cap based on PTE is unnecessary. In other words, a source replacing a unit should be able to adequately project and track emissions for the replacement unit based, in part, on the operating history of the replaced unit.

(67 FR 80186, at 80194)

Whether, the existing diesel engine is returned or not has no impact on projected-actual annual emissions. Therefore, no annual emissions increase is expected. Per 40 § 52.21(b)(41)(ii)(c), projected-actual annual emissions do not include emission increases unrelated to the particular project, including any increase utilization due to product demand growth.

Review of permits from other states has identified two permits allowing for the installation of permanent replacement units: 1) Draft Permit No. 97-179-C (M-2) from the Oklahoma Department of Environmental Quality. Refer to Specific Condition 9 of the draft permit; and 2) Operating Permit (02OPEP246) issues by the Colorado Department of Public Health and Environment, Air Pollution Control Division. Refer to Section I.2 of the permit.

The permits identified above address units that have been through New Source Review and have emission testing requirements. The testing requirements for the original HELCO units are identical to the replacement units as specified in Attachment II, Section F of the CSP.

An applicability determination for grandfathered units was also identified. On April 1, 1999, EPA Region 2 made an applicability determination in regards to PSE&G combustion turbine replacement. The EPA Region 2 applicability determination states:

The act of physically removing a turbine from one spot, performing the routine repair and maintenance on that turbine and placing it in a different but identically designed spot, is not the construction of a new source.

The above examples illustrate the proposed permanent replacement alternate operating scenario is allowed under NSPS and PSD permitting rules.

Proposed change to Attachment IIB: Add Operational and Emission Limitations conditions.

8. On and after May 3, 2013, the permittee shall comply with the following requirements for the diesel engine generators in accordance with 40 CFR Part 63 Subpart ZZZZ:
   a. An oxidation catalyst system shall be installed, operated, and maintained.
   b. Except during startup, the diesel engine generators shall comply with one of the following emission limits:
      i. Limit the concentration of CO in the engine exhaust to 23 ppmvd at 15 percent O_2; or
      ii. Reduce CO emissions by 70 percent or more.
   c. The engine exhaust temperature shall be maintained such that the temperature at the oxidation catalyst inlet is greater than or equal to 450°F and less than or equal to 1350°F, excluding periods of startup.
   d. In accordance with 40 CFR § 63.6640(a), the oxidation catalyst shall be maintained such that the pressure drop does not change by more than 2" H_2O from the pressure

drop across the catalyst measured during the initial performance test, excluding periods of startup.

e. The engine idling during startup shall be minimized and startup shall not exceed 30 minutes.

f. A closed crankcase ventilation system or a filtration system on an open crankcase ventilation system shall be installed, operated, and maintained.

Justification – The requested changes are needed to incorporate applicable emissions and operating limitations for the diesel engine generators from 40 CFR Part 63 Subpart ZZZZ.

Proposed change to Attachment IIB, Special Condition C.: Monitoring and Recordkeeping

All records, including support information, shall be maintained for at least five (5) years from the date of any required ~~the~~ monitoring, ~~measurement,~~ test, report or application. Support information, ~~including~~ includes all maintenance, inspection and repair records and copies of all reports required by this permit. ~~for the diesel engine generators, shall be true, accurate, and maintained~~ These records shall be in a permanent form suitable for inspection and made available to the Department of Health or their representative upon request.

Justification – The requested change is needed for consistency with other HECO, HELCO, and MECO CSPs.

Proposed change to Attachment IIB, Special Condition C.1.

1. Fuel Specifications

~~1~~a. Sulfur Content

The sulfur content (% by weight) of the fuel fired in the diesel engines shall be ~~verified by one of the following methods:~~ determined by sampling each batch of fuel received. The analysis may be performed by the permittee, the supplier, or other qualified third party lab. The analysis shall be performed using one of the following ASTM International (ASTM) methods: D129-00, D2622-98, D4294-02, D1266-98, D5453-00, or D1552-01 or a more current version of these ASTM methods.

~~a. A representative sample of each batch of fuel received shall be analyzed using the most current version of the following American Society for Testing and Materials (ASTM) methods: D129, D2622, D4292, D5453, or D1552 or~~

b. ~~A certificate of analysis on the sulfur content shall be obtained from the fuel supplier for each batch of fuel received.~~

Cetane Index and Aromatic Content

Cetane index or aromatic content may be demonstrated by providing the supplier's fuel specification sheet for the type of fuel purchased and received.

Justification – The fuel testing requirements were revised to allow testing to be performed by the permittee, supplier, or qualified third party and to incorporate applicable fuel requirements from 40 CFR Part 63 Subpart ZZZZ

Proposed change to Attachment IIB, Special Condition C.3.: Fuel Consumption, Unit No. D21

The permittee shall operate and maintain a non-resetting ~~volumetric~~ flow meter system on diesel engine generator unit no. D21 for the continuous measurement and recording of the fuel consumed by the diesel engine generator. The flow meter reading shall be recorded at the beginning and end of each calendar month. Records on the total gallons of fuel consumed shall be maintained on a monthly and rolling 12-month basis.

Justification – The requested change is needed to allow a volumetric or mass flow meter.

Proposed change to Attachment IIB, Section C.: Add monitoring and recordkeeping conditions.

6. Alternate Operating Scenarios
   a. The permittee shall contemporaneously with making a change from one operating scenario to another in accordance with Attachment IIB, Special Condition No. B.7., record in a log at the permitted facility the scenario under which it is operating.
   b. The permittee shall maintain all records corresponding to the implementation of an Alternate Operating Scenario specified in Attachment IIB, Special Condition B.7.
7. No later than May 3, 2013, the permittee shall install, operate, and maintain a continuous parameter monitoring system (CPMS) to monitor and record temperature at the oxidation catalyst inlet on the diesel engine generators. The permittee must prepare a site-specific monitoring plan. The CPMS and the site-specific monitoring plan must meet the requirements of 40 CFR §63.6625(b).
8. Once the testing required pursuant to Attachment IIB, Special Condition No. [*Enter condition number*] is completed, the permittee shall measure and record the pressure drop across each oxidation catalyst on a monthly basis except during months in which the diesel engine generator does not operate.

Justification – The requested changes are needed to relocate monitoring and recordkeeping conditions from Section B. Operational and Emission Limitations to Section C. Monitoring and Recordkeeping Requirements and to incorporate applicable monitoring and recordkeeping requirements from 40 CFR Part 63 Subpart ZZZZ.

Proposed change to Attachment IIB, Special Condition D.3.:

~~At least thirty (30) days prior to conducting a source performance test, the permittee shall notify the Department of Health in writing as required by this Attachment, Section E, Testing Requirements.~~

Performance Test.

a. At least thirty (30) days prior to conducting a source performance test as required by Attachment IIA, Special Condition No. E.1, the permittee shall submit a written performance test plan to the Department of Health that includes the date(s) of the test, test duration, test locations, test methods, source operation, and other parameters that may affect test results. Such a plan shall conform to U.S. EPA guidelines including quality assurance procedures. A test plan or quality assurance plan that does not have the approval of the Department of Health may be grounds to invalidate any test and require a retest.

b. The permittee shall notify the Department of Health of its intent to conduct compliance tests as required by Attachment IIB, Special Condition E.5 at least sixty (60) days prior to the scheduled date.

c. At least sixty (60) days prior to performing a performance test as required by Attachment IIB, Special Condition E.5, the permittee shall submit a written performance test plan to the Department of Health that describes the test duration, test locations, test methods, source operation and other parameters that may affect test results. Such a plan shall conform to U.S. EPA guidelines including quality assurance procedures. A test plan or quality assurance plan that does not have the approval of the Department of Health may be grounds to invalidate any test and require a retest.

d. Within sixty (60) days after completion of a source performance test required by Attachment IIA, Special Condition Nos. E.1 and E.5, the permittee shall submit to the Department of Health and U.S. EPA Region 9 (Attention: AIR-3) the test report which shall include the operating conditions of the diesel engine generators and diesel engine generators at the time of the test, the analysis of the fuel, the summarized test results, comparative results with the permit emission limits, and other pertinent field and laboratory data.

Justification – The requested changes are needed: 1) for consistency with CSP No. 0070-01-C and the notification requirements of 40 CFR Part 60 Subpart A; 2) to relocate notification and reporting requirements from Section E Testing Requirements to Section D Notification and Reporting Requirements; 3) to incorporate applicable notification and reporting requirements from 40 CFR Part 63 Subpart ZZZZ.

Proposed change to Attachment IIB, Special Condition D.4.d.: Semi-annual Reporting.

~~Analysis of the sulfur content in the fuel for which there were exceedances of the sulfur content limits specified in Special Condition No. B.4. of this attachment. If there were no exceedances, the permittee shall submit in writing a statement indicating that there were no exceedances of the sulfur content limit for that semi-annual period.~~

A report identifying the type of fuel fired in each of the diesel engines during the semi-annual reporting period. The report shall include the maximum sulfur content (percent by weight) of the fuel for the reporting period. The enclosed **Monitoring Report Form: *Fuel Certification*,** or equivalent form, shall be used.

Justification – The requested change is needed for consistency with Attachment IIA, Special Condition F.6.d. to report the maximum sulfur content of the fuel fired in the diesel engines during the reporting period.

Proposed change to Attachment IIB, Special Condition D.6.: Annual Emissions.

As required by Attachment IV and in conjunction with the requirements of Attachment III, Annual Fee Requirements, the permittee shall report annually the total tons/yr emitted of each regulated air pollutant, including hazardous air pollutants. The reporting of annual emission is due within sixty (60) days following the end of each calendar year. The enclosed Annual Emissions Reporting Form~~s~~: Combustion Turbines and Diesel Engines~~,~~ or an equivalent form shall be used.

Justification – The requested change is needed for consistency with CSP No. 0070-01-C.

Proposed change to Attachment IIB, Section D.: Add notification and reporting conditions.

7. Alternate Operating Scenarios

   a. Temporary Replacement. Within thirty (30) days of commencement of the temporary replacement, the permittee shall submit in writing to the Department of Health, the reason for the temporary replacement, removal and return dates, and the make, model, and serial number of the existing and temporary replacement units.

   b. Alternate Fuels. In requesting for approval to fire alternate fuels, the permittee shall at a minimum, provide the Department of Health with information on the type of fuel proposed, reason for using the alternate fuel, and emissions data. The Department of Health may require an ambient air quality impact assessment for firing the alternate fuel and/or provide a conditional approval to impose additional monitoring, testing, recordkeeping, and reporting requirements. The Department of Health may establish minimum water-to-fuel ratio conditions in the permit for firing alternate fuels.

   c. Fuel Additives. In requesting for approval to use fuel additives, the permittee shall, at a minimum, provide the Department of Health the specifications of the fuel additive(s), maximum expected emission rates of any criteria or non-criteria pollutant, certification that corresponding emission rates will not exceed permitted rates, and any other related information as requested by the Department of Health. The Department of Health may provide a conditional approval to impose additional monitoring, testing, recordkeeping, and reporting requirements to ensure the use of the fuel additive is in compliance with the applicable requirements.

   d. Permanent Replacement. For permanent replacement of the diesel engine generators, the permittee shall submit to the Department of Health, the make, model, and serial number of the existing and replacement units within thirty (30) days of the replacement.

8. The permittee shall submit semi-annual and annual compliance reports to the Department of Health and EPA Region 9 in accordance with 40 CFR §63.6650. The semi-annual report shall be submitted with thirty-one (31) days after the end of each semi-annual reporting period (January through June 30 and July 1 through December 31). The annual report shall be submitted with thirty-one (31) days after the end of the annual reporting period (January 1 through December 31). The enclosed Excess Emissions and Continuous Monitoring System (CMS) Performance Report and/or Summary Report Form or an equivalent form shall be used.

Justification – The requested changes are needed to 1) relocate notification and reporting requirements from Section E Testing Requirements to Section D Notification and Reporting Requirements; and 2) incorporate applicable notification and reporting requirements from 40 CFR Part 63 Subpart ZZZZ.

Proposed change to Attachment IIB, Special Condition E.2.:

2. Performance tests for the emissions of NO_X (as NO_2) shall be conducted and results reported in accordance with the test methods set forth in 40 CFR Part 60 Appendix A~~,~~ and 40 CFR Part 60.8. The performance tests for the emissions of NO_X (as NO_2) shall be conducted using the following test methods in 40 CFR Part 60 ~~Methods 1-4 and 7~~ or U.S. EPA-approved equivalent methods, or alternate methods with prior written approval from the Department of Health~~.~~:

a. Methods 1-4 (Method 3A may be used in place of Method 3) and 7 or 7E; or

b. Methods 3A, 7E and 19.

Justification – The requested change adds specific U.S. EPA-approved equivalent methods to the permit condition.

Proposed change to Attachment IIB, Special Condition E.5.:

~~At least 30 calendar days prior to performing a test, the permittee shall submit a written performance test plan to the Department of Health that describes the test duration, test locations, test methods, source operation and other parameters that may affect test results. Such a plan shall conform to U.S. EPA guidelines including quality assurance procedures. A test plan or quality assurance plan that does not have the approval of the Department of Health may be grounds to invalidate any test and require a retest.~~

In accordance with 40 CFR § 63.6612, the permittee shall conduct initial performance tests on the diesel engine generators to demonstrate compliance with the requirements of Attachment II, Special Condition No. C.8.b no later than October 30, 2013. Subsequent performance tests shall be conducted after every 8,760 hours of operation or three (3) years of operation, whichever comes first. Performance tests for emissions of CO shall be conducted and results recorded and reported in accordance with the test methods and procedures set forth in 40 CFR §63.6620.

Justification – The requested change is needed to relocate notification and reporting requirements from Section E. Testing Requirements to Section D. Notification and Reporting Requirements and to incorporate applicable source testing requirements from 40 CFR Part 63 Subpart ZZZZ.

Proposed change to Attachment IIB, Special Condition E.7.: Delete condition.

~~Within sixty (60) days after completion of the performance test, the permittee shall submit to the Department of Health and U.S. EPA Region 9 the test report which shall include the operating conditions of the diesel engine generators at the time of the test, the analysis of the fuel, the summarized test results, comparative results with the permit emission limits, and other pertinent field and laboratory data.~~

Justification – The requested change is needed to relocate notification and reporting requirements from Section E. Testing Requirements to Section D. Notification and Reporting Requirements.

Proposed change to Attachment IV: Annual Emissions Reporting Requirements:

Revise Section 1 as follows:

1. Complete the attached forms:

Annual Emissions Report Form: ***Combustion Turbines and Diesel Engines;*** and

Annual Emissions Report Form: ***Ammonia Slip.*** ~~; and~~

~~**Annual Emissions Report Form:** ***Diesel Engines.***~~

Justification – The requested change is needed for consistency with the proposed change to the Annual Emissions Report Forms and CSP No. 0070-01-C.

Proposed change to Annual Emissions Report Form – Combustion Turbines:

Delete form and replace with proposed Annual Emissions Report Form for Combustion Turbines and Diesel Engines.

Justification – The requested changes are needed: 1) to eliminate redundant forms; 2) to remove information not required to be reported (i.e., nitrogen content of the fuel; 3) to use the same form for all units with the combining of CSP Nos. 0007-01-C and 0070-01-C; and 4) for consistency with the proposed change to Attachment IIA, Special Condition C.4.b to remove the fuel bound nitrogen monitoring conditions because it is not required by NSPS Subpart GG if an emission allowance for fuel bound nitrogen is not claimed. HELCO has not claimed an emission allowance under NSPS Subpart GG.

Proposed change to Annual Emissions Report Form – Diesel Engines:

Delete form and replace with proposed Annual Emissions Report Form for Combustion Turbines and Diesel Engines.

Justification – The requested changes are needed to eliminate redundant forms.

Proposed change to Monitoring Report Form – Daily Start-Up and Shutdown Combustion Turbine Generator, Unit CT-4 and Unit CT-5

Replace form with "Monitoring Report Form Combustion Turbine Generator Operation." Refer to the revised form attached.

Justification – The requested change is needed for consistency with proposed changes to Attachment IIA, Special Condition F.6.

Proposed change to Monitoring Report Form – Fuel Consumption Diesel Engine Generator:

Revise Fuel Consumption Form so that form may be used for reporting fuel consumption for CT-2 and delete the % sulfur content by weight. Refer to the revised form attached. Proposed changes to the form are highlighted.

Justification – The requested change is needed to eliminate duplicate report forms when combining CSP Nos. 0007-01-C and 0070-01-C and redundant reporting of information.

Proposed change to Monitoring Report Form – Fuel Certification:

Revise form to add CT-2, delete Nitrogen Content and the means and methods used to determine the sulfur and nitrogen content of the fuel, and add columns for Cetane index and aromatic content. Refer to the revised form attached.

Justification – The requested changes are needed: 1) for consistency with CSP No. 0070-01-C; 2) to add CT-2 to the table and for consistency with proposed change to Special Condition E.3.b; 3) to remove the fuel bound nitrogen monitoring conditions because it is not required by NSPS Subpart GG if an emission allowance for fuel bound nitrogen is not claimed; HELCO has not claimed an emission allowance under NSPS Subpart GG; and 3) to add columns for Cetane index and aromatic content.

Proposed change to Monitoring Report Form Visible Emissions:

Revise form to report opacity exceedences as measured by the transmissometer continuous monitoring system for CT-4 and CT-5. Refer to the revised form attached; revisions to the form are highlighted.

Justification – The requested change is needed to include reporting of opacity exceedences as measured by the transmissometer continuous monitoring system for CT-4 and CT-5.

Proposed change: Add Monitoring Report Form Combustion Turbine Generator Monthly Operation Below Minimum Load with Water Injection.

Add new form. Refer to proposed form attached.

Justification – The requested change is needed to report monthly and rolling 12-month total hours of operation below minimum operating load with water injection consistent with proposed changes to CSP No. 0070-01-C Attachment II, Special Condition C.3 and CSP No. 0007-01-C Attachment IIA, Special Condition C.2.

Proposed change: Add compliance status report form.

Add new Excess Emissions and Continuous Monitoring System (CMS) Performance Report and Summary Report. Refer to proposed form attached.

Justification – The requested change is needed to incorporate the applicable compliance reporting form for 40 CFR Part 63 Subpart ZZZZ compliance status reporting.

ANNUAL EMISSIONS REPORT FORM
COMBUSTION TURBINES AND DIESEL ENGINES
COVERED SOURCE PERMIT NO. 0007-01-C

Issuance Date: **August 7, 2008** **Expiration Date:** **August 6, 2013**

In accordance with the Hawaii Administrative Rules, Title 11, Chapter 60.1, Air Pollution Control, the permittee shall report to the Department of Health the nature and amounts of emissions.

(Make Copies for Future Use)

For Reporting Period: ______________________ Date: ____________

Company Name: ______________________

Facility Name: ______________________

I certify that I have knowledge of the facts herein set forth, that the same are true, accurate and complete to the best of my knowledge and belief, and that all information not identified by me as confidential in nature shall be treated by the Department of Health as public record.

Responsible Official (Print): ______________________

Title: ______________________

Responsible Official (Signature): ______________________

1. Report the Combustion Turbine Generators fuel consumption as follows:

CT-2		
Fuel Type	Fuel Use	Maximum Sulfur Content
	gallons	% by weight
Fuel Oil No. 2		

CT-4		
Fuel Type	Fuel Use	Maximum Sulfur Content
	Gallons	% by weight
Fuel Oil No. 2		

CT-5		
Fuel Type	Fuel Use	Maximum Sulfur Content
	gallons	% by weight
Fuel Oil No. 2		

2. Report Diesel Engine Generators fuel consumption as follows:

D-21		
Fuel Type	Fuel Use gallons	Maximum Sulfur Content % by weight
Fuel Oil No. 2		

D-22		
Fuel Type	Fuel Use gallons	Maximum Sulfur Content % by weight
Fuel Oil No. 2		

D-23		
Fuel Type	Fuel Use gallons	Maximum Sulfur Content % by weight
Fuel Oil No. 2		

BS-1		
Fuel Type	Fuel Use gallons	Maximum Sulfur Content % by weight
Fuel Oil No. 2		

3. Report the type of air pollution control, pollutant(s) controlled, and control efficiency:

CT-2			
Type of Air Pollution Control	In Use?	Pollutant(s) Controlled	Control Efficiency / % Reduction

CT-4			
Type of Air Pollution Control	In Use?	Pollutant(s) Controlled	Control Efficiency / % Reduction

ANNUAL EMISSIONS REPORT FORM
COMBUSTION TURBINE GENERATORS AND DIESEL ENGINE GENERATORS
COVERED SOURCE PERMIT NO. 0007-01-C
(Page 3 of 3)

Issuance Date: DATE **Expiration Date: DATE**

CT-5			
Type of Air Pollution Control	In Use?	Pollutant(s) Controlled	Control Efficiency / % Reduction

D-21			
Type of Air Pollution Control	In Use?	Pollutant(s) Controlled	Control Efficiency / % Reduction

D-22			
Type of Air Pollution Control	In Use?	Pollutant(s) Controlled	Control Efficiency / % Reduction

D-23			
Type of Air Pollution Control	In Use?	Pollutant(s) Controlled	Control Efficiency / % Reduction

BS-1			
Type of Air Pollution Control	In Use?	Pollutant(s) Controlled	Control Efficiency / % Reduction

MONITORING REPORT FORM
COMBUSTION TURBINE GENERATOR
COVERED SOURCE PERMIT NO. 0007-01-C
(PAGE 1 OF 2)

Issuance Date: ____________ **Expiration Date:** ____________

In accordance with the HAR, Title 11, Chapter 60.1, Air Pollution Control, the permittee shall report to the Department of Health the following information semi-annually:

(Make Copies for Future Use)

COMPLETE SEPARATE FORMS FOR EACH COMBUSTION TURBINE GENERATOR

For Reporting Period: ______________________________ Date: ______________

Company Name: ______________________________

Facility Name: ______________________________

Equipment Location: ______________________________

Equipment Description: ______________________________

Serial/ID No.: ______________________________

I certify that I have knowledge of the facts herein set forth, that the same are true, accurate, and complete to the best of my knowledge and belief, and that all information not identified by me as confidential in nature shall be treated by the Department of Health as public record.

Responsible Official (Print): ______________________________

Title: ______________________________

Responsible Official (Signature): ______________________________

Use additional sheets if necessary. Indicate in the appropriate table if there were no exceedances during the reporting period.

1. Combustion turbine generator unit no.: ____________
2. Identify the months of operation: ______________
3. Exceedence of Startup and Shutdown durations:

Exceedence		Duration (minutes)		Reason for Exceedence/ Final Outcome/ Corrective Actions
Date	Time	Startup	Shutdown	

MONITORING REPORT FORM
COMBUSTION TURBINE GENERATOR
COVERED SOURCE PERMIT NO. 0007-01-C
(PAGE 2 OF 2)

Issuance Date: ____________ **Expiration Date: ______________**

Combustion Turbine Generator Unit No.: ___________

4. Dates, times and durations when the water injection system was not operated as specified in Special Condition No. C.3.:

Exceedence		**Specify Startup, Shutdown or other**	**Duration (minutes)**	**Reason for Exceedence Final Outcome/ Corrective Actions**
Date	**Time**			

5. Dates, times, and durations when the combustion turbine generators were operated below 25% of peak load at periods other than during startup, shutdown, or as authorized pursuant to Special Condition C.2. and approved pursuant to Special Condition C.5.:

Date	**Time**	**Duration Below 25% of Peak Load (minutes)**	**Reason for Exceedence / Final Outcome/ Corrective Actions**

MONITORING REPORT FORM
COMBUSTION TURBINE GENERATOR
MONTHLY OPERATION BELOW MINIMUM LOAD WITH WATER INJECTION
COVERED SOURCE PERMIT NO. 0007-01-C

Issuance Date: ______________ **Expiration Date:** ______________

In accordance with the HAR, Title 11, Chapter 60.1, Air Pollution Control, the permittee shall report to the Department of Health the following information semi-annually:

(Make Copies for Future Use)

For Reporting Period: ______________________________ Date: ______________

Company Name: ______________________________

Facility Name: ______________________________

Equipment Location: ______________________________

Equipment Description: ______________________________

Serial/ID Nos.: ______________________________

I certify that I have knowledge of the facts herein set forth, that the same are true, accurate, and complete to the best of my knowledge and belief, and that all information not identified by me as confidential in nature shall be treated by the Department of Health as public record.

Responsible Official (Print): ______________________________

Title: ______________________________

Responsible Official (Signature): ______________________________

Report periods of operation below 25% of peak load with water injection for Units CT2, CT4 and CT5 excluding startup, shutdown, maintenance, testing, and as approved pursuant to Special Condition C.5.

Month	CT2, CT4, CT5 Monthly Total (hours)	Rolling 12-Month Total (hours)

MONITORING REPORT FORM
FUEL CONSUMPTION ~~– DIESEL ENGINE GENERATOR~~
COVERED SOURCE PERMIT NO. 0007-01-C

Issuance Date: ____________ **Expiration Date:** ____________

In accordance with the Hawaii Administrative Rules, Title 11, Chapter 60.1, Air Pollution Control, the permittee shall report to the Department of Health the ~~nature and amounts of emissions~~ following information, semi-annually.

(Make Copies for Future Use)

For Period: ______________________ Date: ____________

Facility Name: ______________________

Equipment Description: ~~2.5 MW General Motors Diesel Engine Generator~~

Serial/ID No.: ~~Unit D21~~

Type of Fuel: ~~Fuel Oil No. 2~~ ~~% Sulfur Content by Weight:~~ ____________

Responsible Official (Print): ______________________

Title: ______________________

I certify that I have knowledge of the facts herein set forth, that the same are true, accurate, and complete to the best of my knowledge and belief, and that all information not identified by me as confidential in nature shall be treated by the Department of Health as public record.

Responsible Official (Signature): ______________________

Month	Monthly Fuel Consumption (Gallons)	Rolling 12-Month Fuel Usage (Gallons)
January		
February		
March		
April		
May		
June		
July		
August		
September		
October		
November		
December		

MONITORING REPORT FORM
FUEL CERTIFICATION
COVERED SOURCE PERMIT NO. 0007-01-C

Issuance Date: August 7, 2008 **Expiration Date: August 6, 2013**

In accordance with the Hawaii Administrative Rules, Title 11, Chapter 60.1, Air Pollution Control, the permittee shall report to the Department of Health the nature of fuel used for the permitted equipment.

(Make Copies for Future Use)

For Reporting Period: ______________________________ Date: ______________

Company Name: ____

Facility Name: ____

I certify that I have knowledge of the facts herein set forth, that the same are true, accurate, and complete to the best of my knowledge and belief, and that all information not identified by me as confidential in nature shall be treated by the Department of Health as public record.

Responsible Official (Print): ______________________________________

Title: ____

Responsible Official (Signature): ___________________________________

Equipment Description	Type of Fuel Fired	Maximum Sulfur Content (% by weight)	Minimum Cetane Index	Maximum Aromatic Content (Volume %)

MONITORING REPORT FORM
VISIBLE EMISSIONS
COVERED SOURCE PERMIT NO. 0067-02-C

Issuance Date: <u>DATE</u> **Expiration Date: <u>DATE</u>**

In accordance with the Hawaii Administrative Rules, Title 11, Chapter 60.1, Air Pollution Control, the permittee shall report to the Department of Health the following information semi-annually:

(Make Copies for Additional Use)

For Reporting Period: ____ Date: ______________

Company Name:____

Facility Name: ____

I certify that I have knowledge of the facts herein set forth, that the same are true, accurate and complete to the best of my knowledge and belief, and that all information not identified by me as confidential in nature shall be treated by the Department of Health as public record.

Responsible Official (Print):____

Title: ____

Responsible Official (Signature): ____

<u>Visible Emissions:</u>

Report the following on the lines provided below all date(s) and six (6) minute average opacity reading(s) which the opacity limit was exceeded during the monthly observations or as measured by the transmissometer continuous monitoring system; or if there were no exceedences during the monthly observations or as measured by the transmissometer continuous monitoring system, then write no exceedences in the comment column.

EQUIPMENT	SERIAL/ID NO.	DATE	6 MIN. AVG. (%)	COMMENTS

Excess Emissions and Continuous Monitoring System (CMS) Performance Report and Summary Report (Page 1 of 5)

SECTION I. GENERAL INFORMATION [63.66509(c)(1), 63.10(e)(vi)(A)]

Company Name	Permit No.

Street Address

City	State	ZIP Code

Facility Name

Facility Street Address (If different than Company Address)

City	State	ZIP Code

Report Date and Submittal Reporting Period [63.6650(c)(3), 63.10(e)(3)(vi)(C), 63.10(e)(3)(vi)(M)]

Reporting period beginning date (mm/dd/yyyy)	Reporting period ending date (mm/dd/yyyy)	Summary report date (mm/dd/yyyy)

A. Excess Emissions and Operating Limitations/Parameters [63.6650(c)(5)]

Have any excess emissions or exceedances of an operating limitation/parameter occurred during this reporting period?

☐ Yes ☐ No

If yes, complete the Excess Emissions and Parameter Monitoring Exceedances table ***for each period*** of excess emissions and/or parameter monitoring exceedances that occurred ***during*** startups, shutdowns, and/or malfunctions, ***or during periods other than*** startups, shutdowns, and/or malfunctions.

B. CMS Performance [63.6650(c)(6)]

Has a CMS been inoperative (except for zero/low-level and high-level checks) or out of control during this reporting period?

☐ Yes ☐ No

If yes, complete the CMS Performance table ***for each period*** a CMS was inoperative or out of control.

SECTION II. CERTIFICATION [63.6650(c)(2), 63.10(e)(3)(vi)(L)]

I certify that I have knowledge of the facts herein set forth, that the same are true, accurate and complete to the best of my knowledge and belief, and that all information not identified by me as confidential in nature shall be treated by the Department of Health as public record.

Name of Responsible Official (Print or Type)	Title	Date (mm/dd/yy)

Signature of Responsible Official

Excess Emissions and Continuous Monitoring System (CMS) Performance Report and Summary Report (Page 2 of 5)

SECTION III. EXCESS EMISSIONS AND CMS PERFORMANCE REPORT

Excess Emissions and Parameter Monitoring Exceedances [63.6650(e)(1), (4); 63.6650(c)(4); 63.10(c)(7), (8), (10), (11)]

Note: Use a separate line for each period of excess emissions and/or parameter monitoring exceedances.

Nature of Event or Problem		Excess Emissions and/or Parameter Monitoring Exceedances Occurred *During*:				Start Date (mm/dd/yyyy)	Completion Date (mm/dd/yyyy)	Nature and Cause of any Malfunction (if known)	Corrective Action Taken or Preventive Measures Adopted
Excess Emissions	Parameter Monitoring Exceedance	Startup	Shutdown	Malfunction	Another Period				
☐	☐	☐	☐	☐	☐				
☐	☐	☐	☐	☐	☐				
☐	☐	☐	☐	☐	☐				
☐	☐	☐	☐	☐	☐				
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☐	☐	☐	☐	☐	☐				

Excess Emissions and Continuous Monitoring System (CMS) Performance Report and Summary Report (Page 3 of 5)

Continuous Monitoring System (CMS) Performance [63.6650(e)(2), (3); 63.10(c)(5), (6), (8), (10), (11), (12); 63.8(c)(8)]

Note: Use a separate line for each period a CMS was inoperative or out of control.

CMS Type	Manufacturer	Start Date (mm/dd/yyyy)	Completion Date (mm/dd/yyyy)	Nature and Cause of Any Malfunction (if known)	Corrective Action Taken or Preventive Measures Adopted	Nature of the Repairs or Adjustments Made to the CMS that was Inoperative or Out of Control

Excess Emissions and Continuous Monitoring System (CMS) Performance Report and Summary Report (Page 4 of 5)

SECTION IV. SUMMARY REPORT: GASEOUS EXCESS EMISSION AND CONTINUOUS MONITORING SYSTEM PERFORMANCE

A. Process Description and Monitoring Equipment Information

Unit Name

Unit Description [63.6650(e)(9), 63.10(e)(3)(vi)(D)]

Emission and/or operating parameter limitations [63.6650(e)(8), 63.10(e)(3)(vi)(E)]

Monitoring Equipment Information [63.6650(e)(10), (11); 63.10(e)(3)(vi)(F), (G)]

Type	Latest Certification or Audit Date (mm/dd/yyyy)	Manufacturer	Model	HAPs Monitored

B. Emission Data Summary [63.6650(e)(5), (6); 63.10(e)(3)(vi)(I)]

Total duration of excess emissions/parameter exceedances (hours)

Total operating time of affected source during the reporting period (days) [63.10(c)(13), 63.10(e)(3)(vi)(H)]

Percent of total source operating time during which excess emissions/parameter exceedances occurred (percent)

Summary of causes of excess emissions/parameter exceedances (percent of total duration by cause)

Startup/shutdown	%
Control equipment problems	%
Process problems	%
Other known causes	%
Other unknown causes	%
TOTAL	100%

Excess Emissions and Continuous Monitoring System (CMS) Performance Report and Summary Report

C. CMS Performance Summary [63.6650(e)(7), 63.10(e)(3)(vi)(J)]

Total duration of CMS downtime (hours)

Total operating time of affected source during the reporting period (days) [63.10(c)(13), 63.10(e)(3)(vi)(H)]

Percent of total source operating time during which CMS were down (percent)

Summary of causes of CMS downtime (percent of downtime by cause)

Monitoring equipment malfunctions	%
Nonmonitoring equipment malfunctions	%
Quality assurance/quality control calibrations	%
Other known causes	%
Other unknown causes	%
TOTAL	100%

D. CMS, Process, or Control Changes

Have you made any changes in CMS, processes, or controls since the last reporting period?

☐ Yes ☐ No

If you answered yes, please describe the changes below:

Changes in CMS, processes, or controls since the last reporting period [63.6650(e)(12), 63.10(e)(3)(vi)(K)]

Attachment S-3d

Requested Changes to CSP No. 0070-01-C

Attachment S-3d

Requested Changes to CSP No. 0070-01-C

Proposed change to Attachment II, Special Condition A.1.:

This permit encompasses the following equipment and associated appurtenances:

Unit No.	Description
CT-2	One (1) 18 MW (nominal) (18.3 MW peak load) Simple Cycle Combustion Turbine Generator, model Jupiter GT-35 (manufactured by Asea Brown Boveri (ABB) and supplied by Solar Turbines) with a maximum design heat input rate of 198 MMBtu/hr.

Justification – The requested change updates the equipment description to include the maximum peak load rating for the combustion turbine generator.

Proposed change to Attachment II, Special Condition C.1.:

The ~~"start-up"~~ startup sequence ~~time~~ for Unit CT-2 shall ~~not exceed~~ be a twenty (20) minute~~s~~ period starting at the time fuel use at Unit CT-2 begins. ~~A "start-up" sequence shall be from the time fuel use at Unit CT-2 commences, until the time Unit CT-2 is initially brought up to~~ At the end of the startup sequence, Unit CT-2 shall be at 25~~%~~ percent of peak load (4.6 MW) or more, the water-to-fuel ratio shall be maintained, and the permittee shall not exceed the maximum emission limitations as specified in Attachment II, Special Conditions C.3, C.4 and C.6, respectively. ~~at which time the operation of the air pollution control equipment shall commence.~~

The ~~"start-up"~~ startup sequence ~~time~~ for Unit CT-2 shall ~~not exceed~~ be a twenty (20) minute~~s~~ period starting from the time fuel use at Unit CT-2 begins. ~~A "start-up" sequence shall be from the time fuel use at Unit CT-2 commences, until the time Unit CT-2 is initially brought up to~~ Upon completion of the twenty (20) minute startup sequence, the combustion turbine generator shall be at 25~~%~~ percent of peak load (4.6 MW) or more and the water injection system shall be operational. ~~at which time the operation of the air pollution control equipment shall commence.~~

Justification –The requested changes are needed: 1) to clarify peak load and the description of a startup sequence; and 2) to allow for stabilization of the water injection system following initiation of the system and address the misalignment of the CEMS NO_X, CO and CO_2 measurement readings with the instantaneous readings of operational parameters such as load (MW), fuel flow, and water injection rate due to lag from the CEMS analyzer response time.

Proposed change to Attachment II, Special Condition C.2.:

The ~~"shut-down" time~~ shutdown sequence for ~~Unit CT-2~~ the combustion turbine generator shall not exceed twenty (20) minutes. A ~~"shut-down"~~ shutdown sequence shall be ~~considered~~ from the time ~~when Unit CT-2~~ the combustion turbine controls stop signal is initiated for the combustion turbine generator and the combustion turbine generator is below 25~~%~~ percent of peak load (4.6 MW) until fuel use at ~~Unit CT-2~~ combustion turbine generator ceases.

Justification – The requested changes include the load rating for CT-2 at 25 percent of peak load and clarify the description of a shutdown sequence.

Proposed change to Attachment II, Special Condition C.3.:

~~Except during Unit CT-2's "start-up" and "shut-down," maintenance, or testing., Unit CT-2's load shall not be less than 25% of the rated capacity~~. <u>The combined time of operation of combustion turbine generators, CT-2, CT-4 and CT-5, below 25 percent of peak load with water injection shall not exceed 268 hours in any rolling twelve (12) month period, excluding startup and shutdown sequences, maintenance, testing, and as approved pursuant to Attachment II, Special Condition C.8.a.</u>

Justification – The requested change is needed to include the load rating for CT-2 at 25 percent of peak load and allow operation of the CT-2 below 25 percent of peak load with water injection to address high system frequency issues. The emissions calculations for CT-2, CT-4 and CT-5 for this proposed change are in Tables 1a and 1b below.

Table 1a - Less Than 25% Load Operation Project Emissions (CT-4, CT-5)

	Pollutant	
Parameter	**CO**	**VOC**
Actual Emissions (lb/hr) Before Change[1]	0.0	0.0
Maximum 10% Load (2.5 MW) Emissions (lb/hr)[2]	475.6	297.6
Expected Increase (lb/hr)	475.6	297.6
Maximum Unit-Hours Below 25% Load[3]	268	268
Projected Emissions Increase (tpy)[4]	63.7	39.9
PSD Significance Level (tpy)	100	40
Significant Emissions Increase (Yes/No)	No	No

Table 1b - Less Than 25% Load Operation Project Emissions (CT-2)

	Pollutant	
Parameter	**CO**	**VOC**
Actual Emissions (lb/hr) Before Change[1]	0.0	0.0
Maximum 10% Load (1.8 MW) Emissions (lb/hr)[5]	22.4	22.4
Expected Increase (lb/hr)	22.4	22.4
Maximum Unit-Hours Below 25% Load	3560	3560
Projected Emissions Increase (tpy)[4]	39.9	39.9
PSD Significance Level (tpy)	100	40
Significant Emissions Increase (Yes/No)	No	No

[1] Past actuals set to zero (operation below 25% of peak load not allowed, except for startup, shutdown, maintenance and testing.
[2] CT-4 and CT-5 permit limits for 25% of peak load in simple cycle mode.
[3] Calculated limit to remain below PSD significance levels.
[4] (Expected Increase) x (Unit-Hours/Year) / (2000 lb/ton)
[5] CT-2 permit limits.

Proposed change to Attachment II, Special Condition C.4.:

Air Pollution Control Equipment

a. The permittee shall continuously operate and maintain a combustor water injection system to meet the emission limits as specified for nitrogen oxides (NO_X) in Attachment II, Special Condition C.6.a. ~~of this Covered Source Permit.~~ Water injection shall be initiated during the startup sequence of the combustion turbine generator and may be terminated at the beginning of or during the shutdown sequence of the combustion turbine generator.

b. ~~The operation of the combustor water injection system shall commence operation within twenty (20) minutes of start-up of Unit CT-2, and shall continue to operate within twenty (20) minutes of shutdown of Unit CT-2. The combustor water injection system shall be used whenever Unit CT-2 is operating at 25% peakload and above, and shall be maintained at a minimum water-to-fuel mass ratio as follows:~~ After completion of the startup sequence of the combustion turbine generator and until the beginning of the shutdown sequence of the combustion turbine generator, the following water-to-fuel mass ratio, on a one (1) hour average basis, shall be maintained when the combustion turbine generator is firing fuel oil No. 2:

WATER INJECTION SYSTEM
MINIMUM WATER INJECTION RATES BASED ON LOAD

Percent Peak load	Load (MW)	Ratio (lb-water/lb-fuel)
100	18.3	1.00
75 - < 100	13.7 - < 18.3	0.75
50 - < 75	9.15 - < 13.7	0.55
~~25 -~~ < 50	~~4.6 -~~ < 9.15	0.3

For operating periods during which the combustion turbine generator operates at multiple loads where multiple water-to-fuel mass ratios apply, the applicable water-to-fuel mass ratio shall be determined based on the load that corresponded to the lowest minimum water-to-fuel mass ratio.

c. [No changes proposed]

d. [No changes proposed]

Justification – The requested changes are to: 1) clarify the method of determining the applicable minimum water-to-fuel mass ratio for operating hours during which multiple minimum water-to-fuel mass ratios apply; 2) revise the water injection system table to address operation of the combustion turbine generator below 25 percent of peak load with water injection; and 3) provide consistency with proposed changes to CSP No. 0007-01-C.

Proposed change to Attachment II, Special Condition C.5.:

a. Unit CT-2 shall be fired only on fuel oil no. 2 with a maximum sulfur content not to exceed 0.4 percent by weight or an alternate fuel allowed under Attachment II, Special Condition C.8.a.ii. The use of fuel additives to control algae, inhibit corrosion or improve fuel combustion may be used in combination with the fuel oil no.2.

b. The maximum amount of fuel oil no. 2 fired in Unit CT-2 shall not exceed ~~24,407 barrels per month or~~ ~~292,887 barrels~~ 12,301,254 gallons per any rolling twelve (12) month period.

Justification – The requested changes clarify the approved fuel and convert the maximum amount of fuel oil units from barrels to gallons.

Proposed change to Attachment II, Special Condition C.5.c.: Delete condition.

~~The fuel bound nitrogen content of the fuel fired in Unit CT-2 shall not exceed 0.015 percent by weight on a rolling twelve (12) month average.~~

Justification – Removal of fuel bound nitrogen monitoring requirement is requested because it is not required by NSPS Subpart GG if an emission allowance for fuel bound nitrogen is not claimed and HELCO has not claimed an emission allowance under NSPS Subpart GG.

Proposed change to Attachment II, Special Condition C.6.:

Maximum Emission Limits

a. Except for Unit CT-2's ~~"start-up"~~ startup and ~~"shut-down"~~ shutdown sequences, the permittee shall not discharge or cause the discharge into the atmosphere from Unit CT-2, nitrogen oxides, sulfur dioxide, particulate matter/PM_{10}, carbon monoxide, and volatile organic compounds in excess of the following specified limits ~~as noted below~~:

[No changes proposed for emission limits table]

~~For the purposes of the annual performance tests and the continuous monitoring system, emissions limits shall be measured on a rolling three (3) hour average.~~ The three-hour averaging period shall begin immediately upon completion of the combustion turbine generator's startup sequence and end immediately prior to the combustion turbine generator's shutdown sequence.

b. The Department of Health, with U.S. EPA's concurrence, may lower the allowable emission limitation for nitrogen oxides, sulfur dioxide, particulate matter/PM_{10}, carbon monoxide, volatile organic compounds after reviewing the performance test results required in Attachment II, Section F, Testing Requirements.

c. If the nitrogen oxides, sulfur dioxide, particulate matter/PM_{10}, carbon monoxide or volatile organic compounds emission limit is revised, the difference between the applicable emission limit set forth above and the revised lower emission limit shall not be allowed as an emission offset for future construction or modification.

Justification – The requested change is needed for clarification regarding the three-hour averaging period.

Proposed change to Attachment II, Special Condition C.8.:

a. ~~Terms and conditions for reasonably anticipated operating scenarios identified by the source in the Covered Source Permit Application and approved by the Department of Health are as follows:~~

The terms and conditions under the following alternate operating scenarios shall meet all applicable requirements including all conditions of this permit. Requests for written approval to operate under the applicable alternate operating scenario shall be in accordance with Attachment II, Special Condition No. E.8.

~~i.~~ Temporary Replacement. ~~Upon receiving written approval from the Department of Health, the~~ The permittee may replace combustion turbine generator, CT-2, with an equivalent temporary replacement unit with equal or lesser emissions ~~use a temporary replacement unit identical to the permitted equipment~~ in the event of a failure or major overhaul of the ~~permitted~~ equipment. ~~Emissions from the replacement unit shall comply with all applicable requirements of the permitted unit. In requesting for approval, the permittee shall at a minimum provide the Department of Health the reason and estimated time period/dates for temporary replacement, type and size of the temporary unit, emissions data, stack parameters, and measures to be taken in minimizing the time period needed for a temporary unit. The Department of Health may require an ambient air quality assessment of the temporary unit, and/or provide a conditional approval.~~

ii. Alternate Fuels. Upon receiving written approval from the Department of Health, the ~~use of alternative fuels may be allowed provided that all permit conditions are met. The permittee must submit all pertinent documentation (e.g., calculations, specifications, etc.) to the Department of Health to demonstrate compliance with permit conditions~~ permittee may burn an alternate fuel (e.g., but not limited to, biodiesel, jet fuel, hydrogen, or ethanol).

~~iii. Emergency load conditions. Certain equipment malfunctions (such as the sudden loss of a unit) may necessitate the operation of Unit CT-2 at loads as high as 110 percent of peak load. The time period of this operation will be limited to no more than 30 minutes in duration. These operations shall not exceed the 3-hour average maximum emission limits as specified in Attachment II, Special Condition No. C.6.~~

Combustion Turbine Operation Above Peak Load. The permittee may operate the combustion turbine generators up to 110% peak load in the event equipment malfunction such as a sudden loss of a unit occurs. The time period of this operation shall not exceed thirty (30) minutes in duration, and shall not result in an exceedence of the maximum emission limits specified in Special Condition IIA: C.6.

iv. Unpredictable periods of equipment failure, upsets, or emergency conditions. During any emergency condition, the permittee will operate the subject equipment in such a manner as to minimize emissions. The permittee shall comply with the Emergency Provisions.

~~v. If approved by the Department of Health, the burning of naphtha or other cleaner burning fuels.~~

~~b. The permittee shall, contemporaneously with making a change from one operating scenario to another, record in a log at the permitted facility the scenario under which it is operating and, if required by any applicable requirement or by the Department of Health, submit written notification to the Department of Health.~~

c. ~~The terms and conditions under each alternative operating scenario shall meet all applicable requirements including all conditions of this permit.~~

Justification – The requested changes are needed: 1) to increase operational flexibility of the temporary unit replacement provision; and 2) to relocate permit monitoring and recordkeeping and notification and reporting conditions for alternate operating scenarios from Section C. Operational and Emission Limitations to Section D. Monitoring and Recordkeeping Requirements and Section E. Notification and Reporting Requirements.

Proposed change to Attachment II, Special Condition D.1.:

The permittee shall at its own expense continue to operate~~, calibrate,~~ and maintain a continuous monitoring system ~~and total volumetric flow metering system for Unit CT-2~~ to measure and record the following parameters or data. The associated date and time of the monitored data shall also be recorded.

a. [No changes proposed]

b. [No changes proposed]

c. Fuel consumption ~~in gallons/hr~~ using a ~~volumetric~~ flow metering system; and

d. NO_X, CO, and CO_2 or O_2 concentrations in the stack gases using a Continuous Emissions Monitoring System (CEMS). The system shall meet U.S. EPA performance specifications (40 CFR Part 60, Section 60.13 and 40 CFR Part 60, Appendix B and Appendix F). If CO_2 is measured with the CEMS to adjust the pollutant concentration, the CO_2 correction factor equations listed in 40 CFR §60.4213(d)(3) shall be used to determine compliance with the applicable emission limit <u>and a diluent cap value for CO_2 may be used in accordance with 40 CFR §60.4350(b)</u>. The CEMS shall be on-line and fully operational, upon completion and thereafter of the performance specification test. The emissions for NO_X and CO shall be recorded in parts per million by volume (ppmvd) at 15 percent O_2 and pounds per hour (lbs/hr).

Justification – The requested changes are needed: 1) because there is no regulatory requirement or permit limit that requires recording fuel consumption in gallons/hour; 2) to allow for volumetric or mass flow meters; and 3) to allow the use of a diluent cap to address any hour in which the hourly average CO_2 concentration is less than 1.0 percent. 40 CFR Part 60, Subpart KKKK and Part 75 include a diluent cap for both O_2 and CO_2 for stationary turbines. However, 40 CFR Part 60, Subpart GG includes a diluent cap only for O_2.

Proposed change to Attachment II, Special Condition D.3.:

~~Daily "start-up" and "shut-down" times. The start and end times of each sequence shall be recorded. In addition, the operating load (MW) at which the air pollution control equipment was initiated and terminated shall be recorded.~~.

<u>Startup and shutdown</u>

<u>a. The following shall be recorded for each startup sequence:</u>

<u>i. The date, start and end times, and corresponding load (MW) at the end of each twenty (20) minute startup sequence.</u>

<u>ii. Duration (minutes) of the startup sequence.</u>

<u>iii. The operating load (MW) at which water injection was initiated.</u>

b. The following shall be recorded for each shutdown sequence:

i. The date, start and end times, and corresponding load (MW) at which the combustion turbine controls stop signal was initiated.

ii. Duration (minutes) of the shutdown sequence.

iii. The operating load (MW) at which water injection was terminated.

Justification – The requested change is needed for consistency with CSP No. 0007-01-C.

Proposed change to Attachment II, Special Condition D.4.:

a. Sulfur content in the fuel. The sulfur content in the fuel to be fired in Unit CT-2 shall be ~~tested in accordance with the most current American Society of Testing and Materials (ASTM) methods. ASTM method D4294-98 is a suitable alternative to Method D129-00 for determining the sulfur content. The fuel sulfur content shall be verified by both of the following methods:~~ determined using of one of the following sampling options described in sections 2.2.3, 2.2.4.1, 2.2.4.2 and 2.2.4.3 of Appendix D to 40 CFR Part 75. The analysis may be performed by the permittee, the supplier, or other qualified third party lab. The analysis shall be performed using one of the following ASTM International (ASTM) methods: D129-00, D2622-98, D4294-02, D1266-98, D5453-00, or D1552-01 or a more current version of these ASTM methods.

   ~~i. A representative sample of each batch of fuel received shall be analyzed for its sulfur content; and~~

   ~~ii. A certificate of analysis on the sulfur content of the fuel shall be for each batch of the fuel delivered by the supplier.~~.

b. [No changes proposed]

c. [No changes proposed]

~~d. Nitrogen content in the fuel. The fuel bound nitrogen content of the fuel to be fired in Unit CT-2 shall be verified by taking and analyzing a representative sample of each batch of fuel received to determine the nitrogen content by weight.~~

~~e. Records of the nitrogen content of the fuel shall be maintained on a monthly and rolling twelve (12) month basis.~~

Justification – The requested changes are needed to: 1) provide consistency with NSPS Subpart GG with the addition of the NSPS Subpart GG fuel oil no. 2 sulfur test methods and authorization of the fuel testing to be conducted by the permittee, supplier, or other qualified third party lab; and 2) remove the fuel bound nitrogen monitoring conditions because it is not required by NSPS Subpart GG if an emission allowance for fuel bound nitrogen is not claimed; HELCO has not claimed an emission allowance under NSPS Subpart GG.

Proposed change to Attachment II, Special Condition D.7.:

~~The permittee shall maintain a permanent file of all measurements, including continuous monitoring system, monitoring device, and performance testing requirements: all continuous monitoring system performance evaluations; all continuous monitoring device calibration checks; adjustments and maintenance performed on these systems or devices; and all other information required by 40 CFR Part 60 recorded in a permanent form suitable for~~

~~inspection. The file shall be retained for at least five (5) years following the date of such measurements, maintenance reports, and records.~~

All records, including support information, shall be maintained for at least five (5) years from the date of any required monitoring, test, report, or application. Support information includes all maintenance, inspection, and repair records, and copies of all reports required by this permit. These records shall be in a permanent form suitable for inspection and made available to the Department of Health or their representative upon request.

Justification – The requested change is needed for consistency with other HECO, HELCO and MECO CSPs.

Proposed change to Attachment II, Section D: Add monitoring and recordkeeping conditions.

8. Operation Below 25 Percent of Peak Load with Water Injection. The permittee shall maintain records of the total time the combustion turbine generators operate below 25 percent of peak load with water injection. Records of the total time CT-2, CT-4, and CT-5 operated below 25 percent of peak load with water injection, excluding startup and shutdown sequences, maintenance, testing, and as approved pursuant to Special Condition C.8 of this Attachment, shall be maintained on a monthly and rolling twelve (12) month basis using data recorded by the CEMS.

9. Alternate Operating Scenarios

   a. The permittee shall contemporaneously with making a change from one operating scenario to another in accordance with Attachment IIA, Special Condition No. C.9, record in a log at the permitted facility the scenario under which it is operating.

   b. The permittee shall maintain all records corresponding to the implementation of an alternate operating scenario specified in Attachment IIA, Special Condition No. C.9.

   c. The reason for operating the combustion turbine generator, CT-3, above peak load shall be clearly documented, with the event's date, time, duration, operating load, and resulting three-hour average emission rates.

Justification – The requested changes are needed to relocate permit monitoring and recordkeeping conditions for alternate operating scenarios from Section C. Operational and Emission Limitations to Section D. Monitoring and Recordkeeping Requirements and to monitor and record operation of CT-2 below 25 percent of peak load with water injection.

Proposed change to Attachment II, Special Condition E.3.:

~~At least thirty (30) days prior to the following events, the permittee shall notify the Department of Health in writing of:~~

~~a. Conducting a performance specification test on the CEMS. The testing date shall be in accordance with the performance test date identified in 40 CFR Part 60, Section 60.13.~~

~~b. Conducting a source performance test as required in Attachment II, Section F, Testing Requirements.~~

Performance Test.

a. At least thirty (30) days prior to conducting a source performance test as required by Attachment IIA, Section G, the permittee shall submit a written performance test plan to the Department of Health that includes the date(s) of the test, test duration, test locations, test methods, source operation, and other parameters that may affect test results. Such a plan shall conform to U.S. EPA guidelines including quality assurance procedures. A test plan or quality assurance plan that does not have the approval of the Department of Health may be grounds to invalidate any test and require a retest.

b. Within sixty (60) days after completion of a source performance test required by Attachment IIA, Section G, the permittee shall submit to the Department of Health and U.S. EPA Region 9 (Attention: AIR-3) the test report which shall include the operating conditions of the combustion turbine generators and diesel engine generators at the time of the test, the analysis of the fuel, the summarized test results, comparative results with the permit emission limits, and other pertinent field and laboratory data.

Justification – The requested changes are needed: 1) for consistency with CSP No. 0007-01-C and the notification requirements of 40 CFR Part 60 Subpart A; and 2) to relocate notification and reporting requirements from Section F Testing Requirements to Section E Notification and Reporting Requirements.

Proposed change to Attachment II, Special Condition E.4.: Excess Emissions

The permittee shall submit to the Department of Health and U.S. EPA Region 9 for every semi-annual calendar period reports of~~ an~~ excess emissions and monitor downtime in accordance with 40 CFR, Part 60, Section 60.7(c).~~ monitoring systems performance report of all excess emissions, including those associated with the water-to-fuel ratio requirement and implementation of any alternate operating scenarios, to the Department of Health for every semi-annual calendar period.~~ The report shall include the following:

a. The magnitude of excess emissions computed in accordance with 40 CFR Part 60, Section 60.13(h), any conversion factors used, and the date and time of commencement and completion of each time period of excess emissions, and the corresponding load of Unit CT-2.

b. Specific identification of each period of excess emissions that occurs during ~~"start-ups," "shut-downs,"~~ startups, shutdowns, and malfunctions of Unit CT-2. The nature and cause of any malfunction (if known), and the corrective action taken or preventive measures adopted~~, shall also be reported~~.

c. The date and time identifying each period during which the continuous monitoring system was inoperative except for zero and span checks~~. The~~ and the nature of~~ each~~ the system repairs or adjustments~~ shall be described~~.

d. ~~The report shall so stat if no excess emissions have occurred. Also, the report shall so state if the CEMS operated properly during the period and was not subject to any repairs or adjustments except for zero or span checks.~~ When no excess emissions have occurred or the CEMS has not been inoperative, repaired, or adjusted, such information shall be stated in the report.

e. ~~For periods of excess emissions as defined in Special Condition No. E.4.g.ii. of this Attachment, the report shall also include the average water-to-fuel ratio, average fuel consumption, ambient temperature, gas turbine load, and nitrogen content of the fuel during the period of excess emissions.~~

f. [No changes proposed]

Justification – The requested change is needed for consistency with reporting requirements under 40 CFR § 60.7(c) and CSP No. 0007-01-C.

Proposed change to Attachment II, Special Condition E.4.g.:

For purposes of this Covered Source Permit, excess emissions shall be defined as follows:

i. [No changes proposed]

ii. Any one (1) hour period during which the average water-to-fuel ratio, as measured by the continuous monitoring system, falls below the water-to-fuel mass ratio, as measured by the continuous monitoring system, falls below the water-to-fuel mass ratio at the corresponding operating load specified in Attachment II, Special Condition No. C.4.b. ~~When the load is not constant, provided that the above water injection rates at the four different peak load conditions are maintained, and NO_x emissions do not exceed the limits given in Attachment II, Special Condition C.6., a mathematical deviation on the one-hour average will not be considered out of compliance.~~ For operating periods during which the combustion turbine generator operates at multiple loads where multiple water-to-fuel mass ratios apply, the applicable water-to-fuel mass ratio shall be determined based on the load that corresponded to the lowest minimum water-to-fuel mass ratio.

Justification – The requested change clarifies the method of determining the applicable minimum water-to-fuel mass ratio for operating hours during which multiple minimum water-to-fuel mass ratios apply and provides consistency with proposed changes to Attachment II, Special Condition C.4.b. and CSP No. 0007-01-C.

Proposed change to Attachment II, Special Condition E.5.:

The permittee shall submit semi-annually the following written reports to the Department of Health. The report shall be submitted within sixty (60) days after the end of each semi-annual calendar period (January 1 to June 30 and July 1 to December 31), and shall include the following:

a. ~~Monthly~~ A summary ~~showing the daily "start-up"~~ identifying all dates, times and durations when the startup and ~~"shut-down" times~~ shutdown ~~and duration~~ sequence for ~~Unit CT-2~~ the combustion turbine generator exceeded twenty (20) minutes. ~~Include the associated load (MW) of Unit CT-2 at the start-up startup and termination of the air pollution control device. Include total operating hours per day and the total operating hours by month for Unit CT-2.~~ The enclosed Monitoring Report Form: ~~Daily "Start-up" and "Shut-down"~~ Combustion Turbine Generator Operation or an equivalent form ~~approved by the Department of Health~~ shall be used. ~~in reporting Unit CT-2's "start-up" and "shut-down" sequence.~~

b. [No changes proposed]

c. ~~Receipt dates of fuel deliveries, type of fuel, date batch sample taken, and the analyzed sulfur and nitrogen content in the fuel. Include copies of the supplier's certificate of analysis showing the sulfur content of the fuel delivered.~~ A report identifying the type of fuel fired in the combustion turbine during the semi-annual reporting period. The report shall include the maximum sulfur content (percent by weight) of the fuel for the reporting period. The enclosed Monitoring Report Form: *Fuel Certification*, or an equivalent form, shall be used.

d. Minimum ~~combustion turbine generator load~~ Operating Loads. ~~Except for Unit CT-2's "start-up" and "shut-down" sequences, report all periods of time (date, time and duration using data recorded by the CEMS) when the minimum operating load for Unit CT-2 is less than 25% of the rated capacity.~~

i. All periods when the operating load for the combustion turbine generators was below 25 percent of peak load (4.6 MW) except for all startup and shutdown sequences and as authorized pursuant to Special Condition C.2. of this Attachment. The report shall include the date, time and duration of each period using data recorded by the CEMS. The enclosed Monitoring Report Form: Combustion Turbine Generator Operation or an equivalent form shall be used.

ii. A monthly summary and rolling twelve (12) month total of the hours of operation of the combustion turbine generators, CT-2, CT-4, and CT-5, below 25 percent of peak load with water injection, excluding startup and shutdown sequences, maintenance, testing, and as approved pursuant to Special Condition C.8 of this Attachment. The report shall be based on data recorded by the CEMS. The enclosed Monitoring Report Form: Combustion Turbine Generator Monthly Operation Below Minimum Load with Water Injection or equivalent form shall be used.

e. [No changes proposed]

f. [No changes proposed]

g. Deviations from permit requirements shall be clearly identified and addressed in these reports.

Justification – The requested changes are needed: 1) for operation of CT-2 below 25 percent of peak load with water injection; and 2) for consistency with CSP No. 0007-01-C and proposed change to Special Condition D.4.d and e to remove the fuel bound nitrogen monitoring conditions because it is not required by NSPS Subpart GG if an emission allowance for fuel bound nitrogen is not claimed; HELCO has not claimed an emission allowance under NSPS Subpart GG.

Proposed change to Attachment II, Special Condition E.7.:

As required by Attachment IV and in conjunction with the requirements of Attachment III, the permittee shall submit annually the total tons/year emitted of each regulated air pollutant, including hazardous air pollutants. The reporting of annual emissions is due within sixty (60) days following the end of each calendar year. The enclosed Annual Emission Reporting Form: ~~Gas~~ Combustion Turbines and Diesel Engines or an equivalent form ~~approved by the Department of Health,~~ shall be used~~ in reporting~~.

Justification – The requested change is needed for consistency with CSP No. 0007-01-C.

Proposed change to Attachment II, Section E.: Add notification and reporting condition.

8. Alternate Operating Scenarios

a. Temporary Replacement. Within thirty (30) days of commencement of the temporary replacement, the permittee shall submit in writing to the Department of Health, the reason for the temporary replacement, removal and return dates, and the make, model, and serial number of the existing and temporary replacement units.

b. Alternate Fuels. In requesting for approval to fire CT-2 on alternate fuels, the permittee shall at a minimum, provided the Department of Health with information on the type of fuel proposed, reason for using the alternate fuel, emissions data, and the manufacturer's recommended water-to-fuel ratio and minimum operating load for compliance with the emission limits. The Department of Health may require an ambient air quality impact assessment for firing the alternate fuel and/or provide a conditional approval to impose additional monitoring, testing, recordkeeping, and reporting requirements. The Department of Health may establish minimum water-to-fuel ratio conditions in the permit for firing CT-2 on alternate fuels.

c. Low Load Operation without Water Injection. In requesting for approval, the permittee shall at a minimum provide the Department of Health the date and time period for testing, reason why it is necessary to test at loads less than 25 percent of peak load (4.6 MW) without water injection, procedures to be taken to minimize testing or maintenance at low load without water injection, maximum expected emissions, and any other supporting information as requested by the Department of Health. The Department of Health may require an ambient air quality assessment for the combustion turbine generator at low load without water injection, and/or provide a conditional approval to limit the maintenance and testing period, and impose additional monitoring, recordkeeping, and reporting requirements to ensure that operation at lower loads without water injection are in compliance with emission limits established in Special Condition C.6. of this Attachment.

Justification – The requested changes are needed to: 1) revise the alternate operating scenario for alternate fuels to allow adjustment of the minimum operating load and water-to-fuel mass ratios for alternate fuels, if necessary, to comply with the CSP emission limits; and 2) relocate permit notification and reporting conditions for alternate operating scenarios from Section C. Operational and Emission Limitations to Section E. Notification and Reporting Requirements.

Proposed change to Attachment II, Special Condition F.1:

The permittee shall conduct or cause to be conducted performance tests on Unit CT-2 in the simple cycle mode. Performance test on Unit CT-2 shall be conducted for nitrogen oxides (NO_X), sulfur dioxide (SO_2), carbon monoxide (CO), particulate matter (PM/PM_{10}), and volatile organic compounds (VOC). The performance tests for NO_X shall be conducted at 25, 50, 75, and 100 or highest achievable percent of peak load of Unit CT-2, or at other operating loads as may be specified by the Department of Health. The performance tests for SO_2, CO, PM/PM_{10} and VOC shall be conducted at 100 or highest achievable percent of peak load of Unit CT-2. Performance tests shall be conducted on an annual basis or at such times as may be specified by the Department of Health. The Department of Health may define specific water-to-fuel injection ratios for which the performance tests will be conducted. For any performance test, a continuous monitoring system shall be in operation to monitor and record the ratio of water-to-fuel in Unit CT-2.

Justification – The requested change is to clarify peak load.

Proposed change to Attachment II, Special Condition F.2.:

Performance tests for the emissions of NO_X, SO_2, CO, VOC and PM/PM_{10} shall be conducted and results reported in accordance with the test methods set forth in 40 CFR Part 60, Appendix A and 40 CFR Part 60, Section 60.8. The following test methods or U.S. EPA-approved equivalent methods, or alternate methods with prior written approval from the Department of Health shall be used:

a. Performance tests for the emissions of SO_2 shall be conducted using 40 CFR Part 60 Methods 1-4 and 6C or Methods 6C and 20.

b. Performance tests for the emissions of NO_X shall be conducted using 40 CFR Part 60 Methods 1-4 and 7E or Methods 7E and 20.

c. Performance tests for the emissions of CO shall be conducted using 40 CFR Part 60 Methods 1-4 and 10 or Methods 10 and 19.

d. Performance tests for the emissions of VOC shall be conducted using 40 CFR Part 60 Methods 1-4 and 25A (Method 19 may be used to account for the actual methane fraction of the measured VOC emissions).

e. Performance tests for the emissions of particulate matter shall be conducted using 40 CFR Part 60 Methods 1-5.

Justification – The requested changes expand the listed test methods to include the methods commonly used and incorporate DOH's standard permit language to authorize use of EPA-approved equivalent methods.

Proposed change to Attachment II, Special Condition F.4.: Delete condition.

~~At least thirty (30) days prior to performing a test, the permittee shall submit a written performance test plan to the Department of Health that describes the test duration, test locations, test methods, source operation and other parameters that may affect test results. Such a plan shall conform to U.S. EPA guidelines including quality assurance procedures. A test plan or quality assurance plan that does not have the approval of the Department of Health may be grounds to invalidate any test and require a retest.~~

Justification –The requested change is needed to relocate notification and reporting requirements from Section F. Testing Requirements to Section E. Notification and Reporting Requirements.

Proposed change to Attachment II, Special Condition F.7.: Delete condition.

~~Within sixty (60) days after completion of the performance test, the permittee shall submit to the Department of Health and U.S. EPA Region 9 (Attention: AIR-3) the test report which shall include the operating conditions of Unit CT-2 at the time of the test, the analysis of the fuel oil, the summarized test results, comparative results with the permit emission limits, and other pertinent field and laboratory data.~~

Justification –The requested change is needed to relocate notification and reporting requirements from Section F. Testing Requirements to Section E. Notification and Reporting Requirements.

Proposed change to Attachment IV: Annual Emissions Reporting Requirements:

Revise Section 1 as follows:

1. Complete the attached Annual Emissions Report Form for ~~Gas~~ Combustion Turbines and Diesel Engines.

Justification – The requested change is to eliminate redundant forms.

Proposed change to Monitoring Report Form – Daily "Start-Up" and "Shut-Down": Delete form.

Delete form and require use of Monitoring Report Form – Combustion Turbine Generator Operation as proposed in Attachment S-3c.

Justification – The requested change is needed for consistency with proposed changes to Attachment II, Special Condition E.5.d.

Proposed change to Annual Emissions Report Form – Gas Turbines: Delete form.

Delete form and replace with Annual Emissions Report Form – Combustion Turbines and Diesel Engines as proposed in Attachment S-3c.

Justification – The requested change is to eliminate redundant forms.

Proposed change to Monitoring Report Form - Fuel Consumption:

Delete form and require use of Monitoring Report Form – Fuel Consumption form in CSP No. 0007-01-C.

Justification – The requested change is to eliminate redundant forms.

Proposed change: Add Monitoring Report Form Combustion Turbine Generator Monthly Operation Below Minimum Load with Water Injection

Add new form. Refer to proposed form in Attachment S-3c.

Justification – The requested change is needed to report monthly and rolling 12-month total hours of operation below minimum operating load with water injection consistent with proposed changes to CSP No. 0070-01-C Attachment II, Special Condition C.3 and CSP No. 0007-01-C Attachment IIA, Special Condition C.2.

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File No.: __________

C-1: Compliance Plan

The Responsible Official shall submit a Compliance Plan as indicated in the Instructions for Applying for an Air Pollution Control Permit and at such other times as requested by the Director of Health (hereafter, Director).

Use separate sheets if necessary.

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1. Compliance status with respect to all Applicable Requirements:

   Will your facility be in compliance, or is your facility in compliance, with all applicable requirements in effect at the time of your permit application submittal?

   ■ YES { If YES, Complete items a and c below}

   ☐ NO { If NO, complete items a-c below}

   a. Identify all applicable requirement(s) for which compliance is achieved:
   Refer to CSP No. 0007-01-C issued on August 7, 2008, CSP No. 0070-01-C issued on January 12, 2006and the June 23, 2009 Administrative Amendment for CSP No. 0070-01-C for all applicable requirements. The National Ambient Air Quality Standards (NAAQS) and State Ambient Air Quality Standards (SAAQS) are "Applicable requirement[s]" as defined in HAR 11-60.1-81.[1]

   Provide a statement that the source is in compliance and will continue to comply with all such requirements.
   The facility is in compliance and will continue to comply with the applicable requirements identified in CSP No. 0007-01-C issued on August 7, 2008, CSP No. 0070-01-C issued on January 12, 2006, and the June 23, 2009 Administrative Amendment for CSP No. 0070-01-C. The NAAQS and SAAQS are "Applicable requirement[s]" as defined in HAR 11-60.1-81.[1]

   b. Identify all applicable requirement(s) for which compliance is NOT achieved:

   ____

   ____

   Provide a detailed Schedule of Compliance and a description of how the source will achieve compliance with all such applicable requirements. Use separate sheets of paper, if necessary.

Description of Remedial Action	Expected Date of Completion

[1] Preliminary air dispersion modeling analysis using the CSP emission rates was performed to evaluate compliance with the 1-hour SO_2 NAAQS. Although this modeling does not demonstrate compliance with the 1-hour SO_2 NAAQS, it is not a monitoring exceedence. The use of Ultra Low Sulfur Diesel (ULSD) in D-21, D-22, and D-23, as required by the RICE NESHAP with a compliance date of May 3, 2013, will result in modeled compliance with the 1-hour SO_2 NAAQS. ULSD shipments to HELCO will begin within one to three months following the Public Utilities Commission (PUC) approval of an amendment to its Interisland Diesel Fuel Supply Contract. HELCO has requested that the PUC expedite its decision and final order on or before September 30, 2012 to ensure HELCO will be able to meet the RICE NESHAP compliance date of May 3, 2013.

c. Identify any other applicable requirement(s) with a future date that your source is subject to. These applicable requirements may be in effect AFTER permit issuance:

Applicable Requirement	Effective Date	Currently in Compliance?
40 CFR Part 63 Subpart ZZZZ (RICE NESHAP)	May 3, 2010 Compliance Date: May 3, 2013	Yes

If the source is not currently in compliance, submit a Schedule of Compliance and a description of how the source will achieve compliance with all such requirements:

Description of Proposed Action/Steps to Achieve Compliance	Expected Date of Achieving Compliance

Provide a statement that the source on a timely basis will meet all these applicable requirements.
HELCO will comply with all applicable RICE NESHAP requirements on or before the May 3, 2013.

If the expected date of achieving compliance will NOT meet the applicable requirement's effective date, provide a more detailed description of all remedial actions and the expected dates of completion.

Description of Remedial Action and Explanation	Expected Date of Completion

2. Compliance Progress Reports:

a. If a compliance plan is being submitted to remedy a violation, complete the following information:

Frequency of Submittal: ______________ Beginning Date: ______________
(less than or equal to 6 months)

b. Date(s) that the Action described in (1)(b) was achieved:

Remedial Action	Date Achieved

c. Narrative description of why any date(s) in (1) (b) was not met, and any preventive or corrective measures taken in the interim:

____

____

____

RESPONSIBLE OFFICIAL (as defined in HAR §11-60.1-1)

Name (Last): Verbanic (First): Norman (MI): ______

Title: Manager Production Department Phone: (808) 969-0421

Mailing Address: P.O. Box 1027

City: Hilo State: HI Zip Code: 96721-1027

Certification by Responsible Official (pursuant to HAR §11-60.1-4)

I certify that I have knowledge of the facts herein set forth, that the same are true, accurate and complete to the best of my knowledge and belief, and that all information not identified by me as confidential in nature shall be treated by the Department of Health as public record. I further state that I will assume responsibility for the construction, modification, or operation of the source in accordance with the Hawaii Administrative Rules, Title 11, Chapter 60.1, Air Pollution Control, and any permit issued thereof.

Name (Print/Type): Norman Verbanic

(Signature): Norman Verbanic Date: 26 JUL 12

Facility Name: Keahole Generating Station

Location: 73-4249 Pukiawe Street, Kailua Kona, HI 96740

Permit Number: CSP Nos. 0007-01-C and 0070-01-C

FOR AGENCY USE ONLY

File/Application No.: ______

Island: ______

Date Received: ______

File No.: __________

C-2: Compliance Certification

The Responsible Official shall submit a Compliance Certification as indicated in the Instructions for Applying for an Air Pollution Control Permit and at such other times as requested by the Director of Health (hereafter, Director).

Complete as many copies of this form as necessary. Use separate sheets of paper if necessary.

RESPONSIBLE OFFICIAL (as defined in HAR §11-60.1-1)

Name (Last): Verbanic (First): Norman (MI): ______

Title: Manager Production Department Phone: (808) 969-0421

Mailing Address: P.O. Box 1027

City: Hilo State: HI Zip Code: 96740

Certification by Responsible Official (pursuant to HAR §11-60.1-4)

I certify that I have knowledge of the facts herein set forth, that the same are true, accurate and complete to the best of my knowledge and belief, and that all information not identified by me as confidential in nature shall be treated by the Department of Health as public record. I further state that I will assume responsibility for the construction, modification, or operation of the source in accordance with the Hawaii Administrative Rules, Title 11, Chapter 60.1, Air Pollution Control, and any permit issued thereof.

Name (Print/Type): Norman Verbanic

(Signature): Norman Verbanic Date: 26 JUL 12

Facility Name: Keahole Generating Station

Location: 73-4249 Pukiawe Street, Kailua Kona, HI 96740

Permit Number: CSP Nos. 0007-01-C and 0070-01-C

FOR AGENCY USE ONLY

File/Application No.: __________

Island: __________

Date Received: __________

Complete the following information for ***each*** applicable requirement that applies to ***each*** emissions unit at the source. Also include any additional information as required by the Director. The compliance certification may reference information contained in a previous compliance certification submittal to the director, provided such referenced information is certified as being current and still applicable.

1. Schedule for submission of Compliance Certifications during the term of the permit:

   Frequency of Submittal: In accordance with §11-60.1-86.

   Beginning Date: In accordance with §11-60.1-86.

2. Emissions Unit No./Description:

Unit ID	Manufacturer	Model No.	Capacity (Nominal)
D-21	General Motors	20-645F4B	2.5 MW
D-22	General Motors	20-645F4B	2.5 MW
D-23	General Motors	20-645E4	2.5 MW
CT-2	Jupiter	GT-35	18 MW
CT-4	General Electric	LM2500	20 MW
CT-5	General Electric	LM2500	20 MW
BS-1	Caterpillar	3412	500 kW

3. Identify the applicable requirement(s) that is/are the basis of this certification:

   See Attachments C-2a (CSP No. 0007-01-C issued August 7, 2008) and C-2b (CSP No. 0070-01-C issued January 12, 2006).

4. Compliance status:

   a. Will the emissions unit be in compliance with the identified applicable requirement(s)?

      ■ YES ☐ NO

   b. If YES, will compliance be continuous or intermittent?

      ■Continuous ☐ Intermittent

   c. If NO, explain.

5. Describe the methods to be used in determining compliance of the emissions unit with the applicable requirement(s), including any monitoring, recordkeeping, reporting requirements, and/or test methods:

   See Attachments C-2a (CSP No. 0007-01-C issued August 7, 2008) and C-2b (CSP No. 0070-01-C issued January 12, 2006).

Provide a detailed description of the methods used to determine compliance: (e. g. monitoring device type and location, test method description, or parameter being recorded, frequency of recordkeeping, etc.)

See Attachments C-2a (CSP No. 0007-01-C issued August 7, 2008) and C-2b (CSP No. 0070-01-C issued January 12, 2006).

6. Statement of Compliance with Enhanced Monitoring and Compliance Certification Requirements.

   a. Will the emissions unit identified in this application be in compliance with applicable enhanced monitoring and compliance certification requirements?

      ■YES ☐NO

   b. If YES, identify the requirements and the provisions being taken to achieve compliance:

      The final Enhanced Monitoring Rule was published in the Federal Register on October 22, 1997 (62 FR 54900). According to that final rule, the Enhanced Monitoring Rules do not apply. The compliance certification requirement is established by 40 CFR 70 and HAR 11-60.1.

   c. If NO, describe below which requirements will not be met:

Attachment C-2a

Compliance Status CSP No. 0007-01-C

Attachment C-2a
Compliance Status
Keahole Generating Station – CSP No. 0007-01-C
Issuance Date: August 7, 2008

A. Attachment I, Standard Conditions

Permit term/condition	Equipment(s)	Method	Compliance
All standard conditions	All Equipment listed in the permit	■ monitoring ☐ recordkeeping ☐ reporting ☐ testing ☐ none of the above	■ Continuous ☐ Intermittent

B. Special Conditions - Equipment Description, Applicable Federal Regulations, Monitoring, Recordkeeping, Reporting, Testing, and INSIG

Permit term/condition	Equipment(s)	Method	Compliance
All equipment description conditions	All Equipment listed in the permit	■ monitoring ☐ recordkeeping ☐ reporting ☐ testing ☐ none of the above	■ Continuous ☐ Intermittent
All applicable Federal Regulations	All Equipment listed in the permit	■ monitoring ■ recordkeeping ☐ reporting ■ testing ☐ none of the above	■ Continuous ☐ Intermittent
All monitoring and recordkeeping conditions	All Equipment listed in the permit	■ monitoring ■ recordkeeping ■ reporting ☐ testing ☐ none of the above	■ Continuous ☐ Intermittent
All notification and reporting conditions, except Attachment IIA, Special Condition F.3.	All Equipment listed in the permit	☐ monitoring ■ recordkeeping ■ reporting ☐ testing ☐ none of the above	■ Continuous ☐ Intermittent
Notification and reporting condition, Attachment IIA, Special Condition F.3.	<u>Units CT-4 & CT-5</u> 20 MW General Electric LM2500 combustion turbine generators	☐ monitoring ■ recordkeeping ■ reporting ☐ testing ☐ none of the above	☐ Continuous ■ Intermittent

Attachment C-2a (Continued)
Compliance Status
Keahole Generating Station – CSP No. 0007-01-C
Issuance Date: August 7, 2008

B. Special Conditions - Equipment Description, Applicable Federal Regulations, Monitoring, Recordkeeping, Reporting, Testing, and INSIG

Permit term/condition	Equipment(s)	Method	Compliance
All testing conditions	All Equipment listed in the permit	■ monitoring ■ recordkeeping □ reporting □ testing □ none of the above	■ Continuous □ Intermittent
All INSIG conditions	All Equipment listed in the permit	□ monitoring ■ recordkeeping □ reporting □ testing □ none of the above	■ Continuous □ Intermittent

C. Special Conditions - Operational and Emissions Limitations

Permit term/condition	Equipment(s)	Method	Compliance
Attachment IIA, Special Condition C.1.a (Startup limit)	Units CT-4 & CT-5 20 MW General Electric LM2500 combustion turbine generators	■ monitoring ■ recordkeeping □ reporting □ testing □ none of the above	■ Continuous □ Intermittent
Attachment IIA, Special Condition C.1.b (Shutdown limit)	Units CT-4 & CT-5 20 MW General Electric LM2500 combustion turbine generators	■ monitoring ■ recordkeeping □ reporting □ testing □ none of the above	■ Continuous □ Intermittent
Attachment IIA, Special Condition C.2 (Minimum operating load)	Units CT-4 & CT-5 20 MW General Electric LM2500 combustion turbine generators	■ monitoring ■ recordkeeping □ reporting □ testing □ none of the above	□ Continuous ■ Intermittent
Attachment IIA, Special Condition C.3.a (Combustor water injection system and minimum water-to-fuel ratios)	Units CT-4 & CT-5 20 MW General Electric LM2500 combustion turbine generators	■ monitoring ■ recordkeeping ■ reporting □ testing □ none of the above	□ Continuous ■ Intermittent
Attachment IIA, Special Condition C.3.b (Selective Catalytic Reduction)	Units CT-4 & CT-5 20 MW General Electric LM2500 combustion turbine generators	■ monitoring ■ recordkeeping ■ reporting □ testing □ none of the above	□ Continuous ■ Intermittent

Attachment C-2a (Continued)
Compliance Status
Keahole Generating Station – CSP No. 0007-01-C
Issuance Date: August 7, 2008

C. Special Conditions - Operational and Emissions Limitations

Permit term/condition	Equipment(s)	Method	Compliance
Attachment IIA, Special Condition C.4.a (Fuel specifications and fuel sulfur limit)	Units CT-4 & CT-5 20 MW General Electric LM2500 combustion turbine generators	□ monitoring ■ recordkeeping ■ reporting ■ testing □ none of the above	■ Continuous □ Intermittent
Attachment IIA, Special Condition C.4.b (Fuel specifications and fuel nitrogen limit)	Units CT-4 & CT-5 20 MW General Electric LM2500 combustion turbine generators	□ monitoring ■ recordkeeping ■ reporting ■ testing □ none of the above	■ Continuous □ Intermittent
Attachment IIA, Special Condition C.5.a (Alt. operating scenario - temporary unit replacement)	Units CT-4 & CT-5 20 MW General Electric LM2500 combustion turbine generators	□ monitoring □ recordkeeping □ reporting □ testing ■ none of the above	■ Continuous □ Intermittent
Attachment IIA, Special Condition C.5.b (Alt. operating scenario –low load operation)	Units CT-4 & CT-5 20 MW General Electric LM2500 combustion turbine generators	□ monitoring ■ recordkeeping □ reporting □ testing □ none of the above	■ Continuous □ Intermittent
Attachment IIA, Special Condition C.5.c (Alt. operating scenario – emergency load operations)	Units CT-4 & CT-5 20 MW General Electric LM2500 combustion turbine generators	□ monitoring ■ recordkeeping □ reporting □ testing □ none of the above	■ Continuous □ Intermittent
Attachment IIA, Special Condition C.5.d (Alt. operating scenario – fuel switching)	Units CT-4 & CT-5 20 MW General Electric LM2500 combustion turbine generators	□ monitoring □ recordkeeping □ reporting □ testing ■ none of the above	■ Continuous □ Intermittent
Attachment IIA, Special Condition C.5.e (Alt. operating scenario – fuel additives)	Units CT-4 & CT-5 20 MW General Electric LM2500 combustion turbine generators	□ monitoring □ recordkeeping □ reporting □ testing ■ none of the above	■ Continuous □ Intermittent
Attachment IIA, Special Condition C.5.f (Alt. operating scenario – control systems)	Units CT-4 & CT-5 20 MW General Electric LM2500 combustion turbine generators	□ monitoring □ recordkeeping □ reporting □ testing ■ none of the above	■ Continuous □ Intermittent
Attachment IIA, Special Condition C.5.g (Alt. operating scenario log)	Units CT-4 & CT-5 20 MW General Electric LM2500 combustion turbine generators	□ monitoring ■ recordkeeping □ reporting □ testing □ none of the above	■ Continuous □ Intermittent

Attachment C-2a (Continued)
Compliance Status
Keahole Generating Station – CSP No. 0007-01-C
Issuance Date: August 7, 2008

C. Special Conditions - Operational and Emissions Limitations

Permit term/condition	Equipment(s)	Method	Compliance
Attachment IIA, Special Condition C.5.h (Alt. operating scenario must meet permit requirements)	Units CT-4 & CT-5 20 MW General Electric LM2500 combustion turbine generators Unit ST-7 16 MW steam turbine generator and 2 unfired heat recovery steam generators	□ monitoring □ recordkeeping □ reporting □ testing ■ none of the above	■ Continuous □ Intermittent
Attachment IIA, Special Condition D.1 (NO_x, SO_2, PM, CO, NH_3, and VOC maximum emission limits)	Units CT-4 & CT-5 20 MW General Electric LM2500 combustion turbine generators	■ monitoring ■ recordkeeping ■ reporting ■ testing □ none of the above	■ Continuous □ Intermittent
Attachment IIA, Special Condition D.2 (Opacity limits)	Units CT-4 & CT-5 20 MW General Electric LM2500 combustion turbine generators	■ monitoring ■ recordkeeping ■ reporting ■ testing □ none of the above	□ Continuous ■ Intermittent
Attachment IIA, Special Condition D.3.a (Inspection and maintenance of fuel oil transfer systems to mitigate fugitive VOC emissions)	Fuel oil transfer system	□ monitoring ■ recordkeeping □ reporting □ testing □ none of the above	■ Continuous □ Intermittent
Attachment IIA, Special Condition D.3.b (Fuel oil transfer systems operational log)	Fuel oil transfer system	□ monitoring ■ recordkeeping □ reporting □ testing □ none of the above	■ Continuous □ Intermittent
Attachment IIA, Special Condition D.3.c (HELCO shall provide DoH access to tanks)	Fuel tanks	□ monitoring □ recordkeeping □ reporting □ testing ■ none of the above	■ Continuous □ Intermittent
Attachment IIB, Special Condition B.1 (BS-1 Operating Hours)	Unit BS-1 – 500 kW Caterpillar Model 3412 Black Start Diesel Engine Generator	□ monitoring ■ recordkeeping □ reporting □ testing □ none of the above	■ Continuous □ Intermittent
Attachment IIB, Special Condition B.2 (D21 Fuel Consumption Limit)	Unit D21 – 2.5 MW General Motors EMD Model 20-645F4B Diesel Engine Generator	□ monitoring ■ recordkeeping □ reporting □ testing □ none of the above	■ Continuous □ Intermittent

Attachment C-2a (Continued)
Compliance Status
Keahole Generating Station – CSP No. 0007-01-C
Issuance Date: August 7, 2008

C. Special Conditions - Operational and Emissions Limitations

Permit term/condition	Equipment(s)	Method	Compliance
Attachment IIB, Special Condition B.3 (Air pollution control equipment - FITR)	Units D21, and D22 – 2.5 MW General Motors EMD Model 20-645F4B diesel engine generators Units D23 – 2.5 MW General Motors EMD Model 20-645E4 diesel engine generator	☐ monitoring ☐ recordkeeping ☐ reporting ☐ testing ■ none of the above	■ Continuous ☐ Intermittent
Attachment IIB, Special Condition B.4 (Fuel specifications and sulfur limits)	Units D21, and D22 – 2.5 MW General Motors EMD Model 20-645F4B diesel engine generators Units D23 – 2.5 MW General Motors EMD Model 20-645E4 diesel engine generator Unit BS-1 – 500 kW Caterpillar Model 3412 Black Start Diesel Engine Generator	☐ monitoring ■ recordkeeping ■ reporting ■ testing ☐ none of the above	■ Continuous ☐ Intermittent
Attachment IIB, Special Condition B.5 (NO_x emission limits)	Units D21, and D22 – 2.5 MW General Motors EMD Model 20-645F4B diesel engine generators Units D23 – 2.5 MW General Motors EMD Model 20-645E4 diesel engine generator	☐ monitoring ☐ recordkeeping ■ reporting ■ testing ☐ none of the above	■ Continuous ☐ Intermittent
Attachment IIB, Special Condition B.6 (Opacity limits)	Units D21, and D22 – 2.5 MW General Motors EMD Model 20-645F4B diesel engine generators Units D23 – 2.5 MW General Motors EMD Model 20-645E4 diesel engine generator	☐ monitoring ■ recordkeeping ■ reporting ■ testing ☐ none of the above	■ Continuous ☐ Intermittent
Attachment IIB, Special Condition B.7.a (Alt. operating scenario – temporary unit replacement)	Units D21, and D22 – 2.5 MW General Motors EMD Model 20-645F4B diesel engine generators Units D23 – 2.5 MW General Motors EMD Model 20-645E4 diesel engine generator	☐ monitoring ☐ recordkeeping ☐ reporting ☐ testing ■ none of the above	■ Continuous ☐ Intermittent
Attachment IIB, Special Condition B.7.b (Alt. operating scenario – fuel switching and fuel additives)	Units D21, and D22 – 2.5 MW General Motors EMD Model 20-645F4B diesel engine generators Units D23 – 2.5 MW General Motors EMD Model 20-645E4 diesel engine generator	☐ monitoring ☐ recordkeeping ☐ reporting ☐ testing ■ none of the above	■ Continuous ☐ Intermittent
Attachment IIB, Special Condition B.7.c (Alt. operating scenario log)	Units D21, and D22 – 2.5 MW General Motors EMD Model 20-645F4B diesel engine generators Units D23 – 2.5 MW General Motors EMD Model 20-645E4 diesel engine generator	☐ monitoring ■ recordkeeping ☐ reporting ☐ testing ☐ none of the above	■ Continuous ☐ Intermittent
Attachment IIB, Special Condition B.7.d (Alt. operating scenario must meet permit requirements)	Units D21, and D22 – 2.5 MW General Motors EMD Model 20-645F4B diesel engine generators Units D23 – 2.5 MW General Motors EMD Model 20-645E4 Unit BS-1 – 500 kW Caterpillar Model 3412 Black Start Diesel Engine Generator	☐ monitoring ☐ recordkeeping ☐ reporting ☐ testing ■ none of the above	■ Continuous ☐ Intermittent

Attachment C-2b

Compliance Status CSP No. 0070-01-C

Attachment C-2b
Compliance Status
Keahole Generating Station – CSP No. 0070-01-C
Issuance Date: January 12, 2006

A. Attachment I, Standard Conditions

Permit term/condition	Equipment(s)	Method	Compliance
All standard conditions	All Equipment listed in the permit	■ monitoring ☐ recordkeeping ☐ reporting ☐ testing ☐ none of the above	■ Continuous ☐ Intermittent

B. Special Conditions - Equipment Description, Applicable Federal Regulations, Monitoring, Notification, Recordkeeping, Reporting, Testing, and INSIG

Permit term/condition	Equipment(s)	Method	Compliance
All equipment description conditions	All Equipment listed in the permit	■ monitoring ☐ recordkeeping ☐ reporting ☐ testing ☐ none of the above	■ Continuous ☐ Intermittent
All applicable Federal Regulations	All Equipment listed in the permit	■ monitoring ■ recordkeeping ☐ reporting ■ testing ☐ none of the above	■ Continuous ☐ Intermittent
All monitoring and recordkeeping conditions	All Equipment listed in the permit	■ monitoring ■ recordkeeping ☐ reporting ☐ testing ☐ none of the above	■ Continuous ☐ Intermittent
All notification and reporting conditions	All Equipment listed in the permit	☐ monitoring ■ recordkeeping ■ reporting ☐ testing ☐ none of the above	■ Continuous ☐ Intermittent
All testing conditions	All Equipment listed in the permit	■ monitoring ■ recordkeeping ☐ reporting ☐ testing ☐ none of the above	■ Continuous ☐ Intermittent
All INSIG conditions	All Equipment listed in the permit	☐ monitoring ■ recordkeeping ☐ reporting ☐ testing ☐ none of the above	■ Continuous ☐ Intermittent

Attachment C-2b (Continued)
Compliance Status
Keahole Generating Station – CSP No. 0007-01-C
Issuance Date: January 12, 2006

C. Special Conditions - Operational and Emissions Limitations

Permit term/condition	Equipment(s)	Method	Compliance
Attachment II, Special Condition C.1. (Start-up limit)	Unit CT-2 18 MW Jupiter GT-35 Simple Cycle Combustion Turbine (manufactured by Asea Brown Boveri (ABB) and supplied by Solar Turbines)	■ monitoring ■ recordkeeping □ reporting □ testing □ none of the above	■ Continuous □ Intermittent
Attachment II, Special Condition C.2 (Shut-down limit)	Unit CT-2 18 MW Jupiter GT-35 Simple Cycle Combustion Turbine (manufactured by Asea Brown Boveri (ABB) and supplied by Solar Turbines)	■ monitoring ■ recordkeeping □ reporting □ testing □ none of the above	■ Continuous □ Intermittent
Attachment II, Special Condition C.3 (Minimum operating load)	Unit CT-2 18 MW Jupiter GT-35 Simple Cycle Combustion Turbine (manufactured by Asea Brown Boveri (ABB) and supplied by Solar Turbines)	■ monitoring ■ recordkeeping □ reporting □ testing □ none of the above	■ Continuous □ Intermittent
Attachment II, Special Condition C.4.a (HELCO shall operate a combustor water injection system)	Unit CT-2 18 MW Jupiter GT-35 Simple Cycle Combustion Turbine (manufactured by Asea Brown Boveri (ABB) and supplied by Solar Turbines)	□ monitoring □ recordkeeping □ reporting □ testing ■ none of the above	■ Continuous □ Intermittent
Attachment II, Special Condition C.4.b (Minimum water-to-fuel ratios)	Unit CT-2 18 MW Jupiter GT-35 Simple Cycle Combustion Turbine (manufactured by Asea Brown Boveri (ABB) and supplied by Solar Turbines)	■ monitoring ■ recordkeeping ■ reporting □ testing □ none of the above	■ Continuous □ Intermittent
Attachment II, Special Condition C.4.c (DOH may revise water-to-fuel rates)	Unit CT-2 18 MW Jupiter GT-35 Simple Cycle Combustion Turbine (manufactured by Asea Brown Boveri (ABB) and supplied by Solar Turbines)	□ monitoring □ recordkeeping □ reporting □ testing ■ none of the above	■ Continuous □ Intermittent
Attachment II, Special Condition C.4.d (Alternative control systems)	Unit CT-2 18 MW Jupiter GT-35 Simple Cycle Combustion Turbine (manufactured by Asea Brown Boveri (ABB) and supplied by Solar Turbines)	□ monitoring □ recordkeeping □ reporting □ testing ■ none of the above	■ Continuous □ Intermittent
Attachment II, Special Condition C.5.a (Fuel specifications and sulfur limit)	Unit CT-2 18 MW Jupiter GT-35 Simple Cycle Combustion Turbine (manufactured by Asea Brown Boveri (ABB) and supplied by Solar Turbines)	□ monitoring ■ recordkeeping ■ reporting ■ testing □ none of the above	■ Continuous □ Intermittent

Attachment C-2b (Continued)
Compliance Status
Keahole Generating Station – CSP No. 0007-01-C
Issuance Date: January 12, 2006

C. Special Conditions - Operational and Emissions Limitations

Permit term/condition	Equipment(s)	Method	Compliance
Attachment II, Special Condition C.5.b (Monthly and rolling 12-month fuel limit)	Unit CT-2 18 MW Jupiter GT-35 Simple Cycle Combustion Turbine (manufactured by Asea Brown Boveri (ABB) and supplied by Solar Turbines)	■ monitoring ■ recordkeeping ■ reporting ☐ testing ☐ none of the above	■ Continuous ☐ Intermittent
Attachment II, Special Condition C.5.c (Fuel nitrogen limit)	Unit CT-2 18 MW Jupiter GT-35 Simple Cycle Combustion Turbine (manufactured by Asea Brown Boveri (ABB) and supplied by Solar Turbines)	☐ monitoring ■ recordkeeping ■ reporting ■ testing ☐ none of the above	■ Continuous ☐ Intermittent
Attachment II, Special Condition C.6 (NO_X, SO_2, PM_{10}, CO and VOC emission limits)	Unit CT-2 18 MW Jupiter GT-35 Simple Cycle Combustion Turbine (manufactured by Asea Brown Boveri (ABB) and supplied by Solar Turbines)	■ monitoring ■ recordkeeping ■ reporting ■ testing ☐ none of the above	■ Continuous ☐ Intermittent
Attachment II, Special Condition C.7 (Opacity limits)	Unit CT-2 18 MW Jupiter GT-35 Simple Cycle Combustion Turbine (manufactured by Asea Brown Boveri (ABB) and supplied by Solar Turbines)	☐ monitoring ■ recordkeeping ■ reporting ■ testing ☐ none of the above	■ Continuous ☐ Intermittent
Attachment II, Special Condition C.8.a.i (Alt. operating scenario – temporary unit replacement)	Unit CT-2 18 MW Jupiter GT-35 Simple Cycle Combustion Turbine (manufactured by Asea Brown Boveri (ABB) and supplied by Solar Turbines)	☐ monitoring ☐ recordkeeping ☐ reporting ☐ testing ■ none of the above	■ Continuous ☐ Intermittent
Attachment II, Special Condition C.8.a.ii (Alt. operating scenario – fuel switching)	Unit CT-2 18 MW Jupiter GT-35 Simple Cycle Combustion Turbine (manufactured by Asea Brown Boveri (ABB) and supplied by Solar Turbines)	☐ monitoring ☐ recordkeeping ☐ reporting ☐ testing ■ none of the above	■ Continuous ☐ Intermittent
Attachment II, Special Condition C.8.a.iii (Alt. operating scenario – emergency load conditions)	Unit CT-2 18 MW Jupiter GT-35 Simple Cycle Combustion Turbine (manufactured by Asea Brown Boveri (ABB) and supplied by Solar Turbines)	☐ monitoring ■ recordkeeping ☐ reporting ☐ testing ☐ none of the above	■ Continuous ☐ Intermittent
Attachment II, Special Condition 8.a.iv (Alt. operating scenario – unpredictable periods of equipment failure, upsets, or emergency conditions)	Unit CT-2 18 MW Jupiter GT-35 Simple Cycle Combustion Turbine (manufactured by Asea Brown Boveri (ABB) and supplied by Solar Turbines)	☐ monitoring ☐ recordkeeping ☐ reporting ☐ testing ■ none of the above	■ Continuous ☐ Intermittent

Attachment C-2b (Continued)
Compliance Status
Keahole Generating Station – CSP No. 0007-01-C
Issuance Date: January 12, 2006

C. Special Conditions - Operational and Emissions Limitations

Permit term/condition	Equipment(s)	Method	Compliance
Attachment II, Special Condition C.8.a.v (Alt. operating scenario – Use of naphtha or cleaner burning fuel)	Unit CT-2 18 MW Jupiter GT-35 Simple Cycle Combustion Turbine (manufactured by Asea Brown Boveri (ABB) and supplied by Solar Turbines)	☐ monitoring ☐ recordkeeping ☐ reporting ☐ testing ■ none of the above	■ Continuous ☐ Intermittent
Attachment II, Special Condition C.8.b (Alt. operating scenario log)	Unit CT-2 18 MW Jupiter GT-35 Simple Cycle Combustion Turbine (manufactured by Asea Brown Boveri (ABB) and supplied by Solar Turbines)	☐ monitoring ■ recordkeeping ☐ reporting ☐ testing ☐ none of the above	■ Continuous ☐ Intermittent
Attachment II, Special Condition C.8.c (Alt. operating scenario must meet permit requirements)	Unit CT-2 18 MW Jupiter GT-35 Simple Cycle Combustion Turbine (manufactured by Asea Brown Boveri (ABB) and supplied by Solar Turbines)	☐ monitoring ☐ recordkeeping ☐ reporting ☐ testing ■ none of the above	■ Continuous ☐ Intermittent

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FEB 8 2011

Hawaiian Electric Company, Inc. • PO Box 2750 • Honolulu, HI 96840-0001

HELCO
Keahole

POSTMARKED
FEB 4 2011
DATE

February 3, 2011

Mr. Wilfred K. Nagamine, Manager
Clean Air Branch
State of Hawaii Department of Health
P.O. Box 3378
Honolulu, Hawaii 96801-3378

Dear Mr. Nagamine:

Subject: Application for a Covered Source Permit Renewal
CSP Nos. 0070-01-C and 0007-01-C
Keahole Generating Station
Hawaii Electricity Light Company, Inc. (HELCO)

Hawaiian Electric Company, Inc. on behalf of HELCO submits the enclosed revisions to HELCO's application dated January 8, 2010 to renew CSP Nos. 0070-01-C and 0007-01-C for the Keahole Generating Station.

The following revisions are enclosed:

- Attachment S-3c: Requested Changes to CSP No. 0007-01-C; and
- Attachment S-3e: Requested Changes to CSP No. 00701-01-C.

The enclosed attachments are direct replacements for the attachments in the application submitted to the DOH on January 8, 2010.

If you have any questions regarding this submittal, please contact Karin Kimura at 543-4522 or karin.kimura@heco.com.

Sincerely,

Donn T. Fukuda

Donn T. Fukuda
Acting Manager
Environmental Department

Enclosures
cc (w/encl.): Deborah Jordan, EPA Region 9
ec: Norman Verbanic, HELCO

MD 14895
MD 14898

FEB 8 2011

Attachment S-3c

Requested Changes to CSP No. 0007-01-C

Proposed Changes to Attachment IIA

Proposed change to Attachment IIA, Special Condition A.1.a.:

Two (2) 20 MW Nominal (24.66 MW (gross) peak load) General Electric LM2500 combustion turbine generators, units CT-4 and CT-5; and

Justification – The requested change updates the equipment description to include the maximum peak load rating for the combustion turbine generators.

Proposed change to Attachment IIA, Special Condition C.1.:

~~Start-up~~ Startup and Shutdown

a. ~~The "start up" time shall not exceed twenty (20) minutes for any combustion turbine generator operating in simple cycle and ninety (90) minutes for any combustion turbine generator operating in combined cycle. Except during maintenance (e.g., equipment installations and inspections, and electrical switching work), testing, and emergency power demands due to sudden loss of a power generating unit, each combustion turbine generator shall not be started up more than four times per calendar day. A "start up" sequence shall be from the time fuel use at the combustion turbine generator begins, until the time the combustion turbine generator is initially brought up to 25 percent of peak load at which time the operation of the air pollution control equipment shall commence.~~

   The startup sequence for the combustion turbine generators shall be a twenty (20) minute period in simple or combined cycle mode starting from the time fuel use at the combustion turbine generator begins. Upon completion of the twenty (20) minute startup sequence, the combustion turbine generator shall be at 25 percent of peak load (6.17 MW) or more and the water injection system shall be operational.

b. The ~~"~~shutdown~~" time~~ sequence for ~~any~~ combustion turbine generators ~~operating in either simple cycle or combined cycle~~ shall not exceed twenty (20) minutes in simple or combined cycle mode. ~~Except during maintenance (e.g., equipment installations and inspections, and electrical switching work), testing, and emergency power demands due to sudden loss of a power generating unit, each combustion turbine generator shall not be shut down more than four (4) times per calendar day.~~ A ~~"~~shutdown~~"~~ sequence shall be ~~considered~~ from the time ~~when~~ the combustion turbine controls stop signal is initiated for the combustion turbine generator and the combustion turbine generator is ~~operating~~ below 25 percent of peak load (6.17 MW), until fuel ~~consumption~~ use at the combustion turbine generator ceases.

Justification – The requested changes are needed to: 1) clarify peak load and the description of startup and shutdown sequences; 2) remove the limit of the number of startups per day because startup periods longer than 20 minutes for both simple and combined cycle modes should not be needed; and 3) allow for stabilization of the water injection system following initiation of the system and address the misalignment of the CEMS NO_X, CO and CO_2 measurement readings with the instantaneous readings of operational parameters such as load (MW), fuel flow, and water injection rate due to lag from the CEMS analyzer response time.

MD 11/006

Proposed change to Attachment IIA, Special Condition C.2.:

Minimum Operational Loads~~s~~

~~The combustion turbine generators shall not operate below 25 percent of peak load except during equipment start-up, shutdown, maintenance, or testing.~~ <u>The combined time of operation of the combustion turbine generators, CT-2, CT-4, and CT-5, below 25 percent of peak load (6.17 MW) with water injection shall not exceed 268 hours in any rolling 12 month period, excluding startup and shutdown sequences, maintenance, testing, and as approved pursuant to Attachment IIA, Special Condition C.5.b.</u>

Justification – The requested change is needed to clarify peak load and allow the operation of CT-4 and CT-5 below 25 percent of peak load with water injection to address high system frequency issues. The emissions calculations for CT-2, CT-4 and CT-5 for this proposed change are in Tables 1a and 1b below.

Table 1a - Less Than 25% Load Operation Project Emissions (CT-4, CT-5)

	Pollutant	
Parameter	**CO**	**VOC**
Actual Emissions (lb/hr) Before Change[1]	0.0	0.0
Maximum 10% Load (2.5 MW) Emissions (lb/hr)[2]	475.6	297.6
Expected Increase (lb/hr)	475.6	297.6
Maximum Unit-Hours Below 25% Load[3]	268	268
Projected Emissions Increase (tpy)[4]	63.7	39.9
PSD Significance Level (tpy)	100	40
Significant Emissions Increase (Yes/No)	No	No

Table 1b - Less Than 25% Load Operation Project Emissions (CT-2)

	Pollutant	
Parameter	**CO**	**VOC**
Actual Emissions (lb/hr) Before Change[1]	0.0	0.0
Maximum 10% Load (1.8 MW) Emissions (lb/hr)[5]	22.4	22.4
Expected Increase (lb/hr)	22.4	22.4
Maximum Unit-Hours Below 25% Load	3560	3560
Projected Emissions Increase (tpy)[4]	39.9	39.9
PSD Significance Level (tpy)	100	40
Significant Emissions Increase (Yes/No)	No	No

1 Past actuals set to zero (operation below 25% of peak load not allowed, except for startup, shutdown, maintenance and testing.
2 CT-4 and CT-5 permit limits for 25% of peak load in simple cycle mode.
3 Calculated limit to remain below PSD significance levels.
4 (Expected Increase) x (Unit-Hours/Year) / (2000 lb/ton)
5 CT-2 permit limits.

Proposed change to Attachment IIA, Special Condition C.3.:

Air Pollution Equipment

~~The use of an alternative control system other than those specified below is contingent upon receiving the Department of Health's written approval to use such a system and shall not relieve the permittee from the responsibility to meet all emission limitations contained within this Covered Source Permit.~~

a. ~~Combustor~~ Water Injection

i. The permittee shall continuously operate and maintain a ~~combustor~~ water injection system to meet the emission limits ~~as~~ specified for nitrogen oxides (NO_X) in Attachment IIA, Special Condition D.1.a.~~of this Covered Source Permit~~. Water injection shall be initiated during the startup sequence of each combustion turbine generator and may be terminated at the beginning of or during the shutdown sequence of each combustion turbine generator. ~~The combustor water injection system shall be fully operational and commence operation immediately after the start-up sequence of the combustion turbine generators. The combustor water injection system shall continue to operate until the commencement of the shutdown sequence of the combustion turbine generators.~~

ii. ~~The operation of the combustor water injection system shall be used whenever the combustion turbine generators are operating at 25 percent peak load and above.~~ After completion of the startup sequence of the combustion turbine generators and until the beginning of the shutdown sequence of the combustion turbine generators, ~~T~~the following water-to-fuel mass ratios, on a one (1) average hour basis, shall be maintained when the combustion turbine generators are firing fuel oil No. 2 in simple cycle operation or in combined cycle operation at loads less than 50 percent of peak load (12.33 MW).

WATER INJECTION SYSTEM
MINIMUM WATER-TO-FUEL MASS RATIO BASED ON LOAD

Combustion Turbine Generator Peak L~~l~~oad (Percent)	**Ratio** (lb-water/lb-fuel)
100 (24.66 MW)	1.04
75 - < 100 (18.50 MW - < 24.66 MW)	0.94
50 - < 75 (12.33 MW - < 18.50 MW)	0.87
~~25 -~~ < 50 (< 12.33 MW)	0.72

For operating periods during which the combustion turbine generator operates at multiple loads where multiple water-to-fuel mass ratios apply, the applicable water-to-fuel mass ratio shall be determined based on the load that corresponded to the lowest minimum water-to-fuel mass ratio.

b. Selective Catalytic Reduction System

The permittee shall design, install, maintain, and continuously operate a selective catalytic reduction system with ammonia injection to meet the emission limits as specified in Attachment IIA, Special Condition D.1.a. of this Covered Source Permit.

The selective catalytic reduction system shall be fully functional and in operation whenever the combustion turbine generators are in combined cycle operation at loads greater than or equal to 50 percent of ~~the peakload~~ peak load (12.33 MW). The selective catalytic reduction system shall continue to operate until the load is reduced to below 50 percent of the ~~peakload~~ peak load (12.33 MW).

c. The use of an alternative control system other than those specified above is contingent upon receiving the Department of Health's written approval to use such a system and shall not relieve the permittee from the responsibility to meet all emission limitations contained within this Covered Source Permit.

Justification – The requested changes are to: 1) clarify the method of determining the applicable minimum water-to-fuel mass ratio for operating hours during which multiple minimum water-to-fuel mass ratios apply; 2) correct a typographical error; 3) clarify peak load; and 4) revise the water injection system table to address operation of the combustion turbine generators below 25 percent of peak load with water injection.

Proposed change to Attachment IIA, Special Condition C.4.:

~~a.~~ Sulfur Content

The combustion turbine generators ~~and diesel engines~~ shall be fired only on fuel oil no. 2 with a maximum sulfur content not to exceed 0.4 percent by weight or an alternate fuel allowed under Special Condition C.5.d. of this Attachment.

~~b. Nitrogen Content~~

~~The fuel bound nitrogen content of the fuel fired in the combustion turbine generators, units CT-4 and CT-5, shall not exceed 0.015 percent by weight on a rolling twelve (12) month average.~~

Justification – The requested changes are needed to clarify the approved fuels and remove the fuel bound nitrogen monitoring conditions because it is not required by NSPS Subpart GG if an emission allowance for fuel bound nitrogen is not claimed; HELCO has not claimed an emission allowance under NSPS Subpart GG.

Proposed change to Attachment IIA, Special Condition C.5.: Alternate Operating Scenarios

~~Terms and conditions for reasonably anticipated operating scenarios identified by the source in the covered source permit application and approved by the Department of Health are as follows:~~

The terms and conditions under the following alternate operating scenarios shall meet all applicable requirements including all conditions of this permit. Requests for written approval to operate under the applicable alternate operating scenario shall be in accordance with Attachment IIA, Special Condition No. F.3.

a. Temporary Replacement. ~~Upon receiving written approval from the Department of Health, the~~ The permittee may replace ~~any of the~~ combustion turbine generators, CT-4 and CT-5, with an equivalent temporary replacement unit with equal or lesser emissions in the event of a failure or ~~sudden malfunction or a planned~~ major overhaul. ~~The temporary replacement unit shall comply with all applicable permit conditions.~~

~~A written request shall be submitted to the Department of Health prior to the exchange and at a minimum, the request shall include the following:~~

~~i. the reason for temporary replacement;~~

~~ii. the removal and estimated return dates of the permitted unit;~~

~~iii. the make, model, serial number, and size of the temporary replacement unit; and~~

~~iv. the emissions data of the permitted temporary replacement unit~~.

~~The Department of Health may require an ambient air quality impact analysis and/or may impose additional requirements on the temporary replacement unit to ensure compliance with the conditions of this permit.~~

b. The combustion turbine generators may operate below 25 percent of peak load (6.17 MW) during:

   i. Testing of the heat recovery steam generators and steam turbine; ~~and~~

   ii. Steam blows needed to clean the steam tubes prior to initial operation~~.~~;

   iii. Testing of combustion turbine generator controls; and

   iv. Dry running the Once Through Steam Generator (OTSG) to remove deposits from the OTSG.

c. ~~In the event of equipment malfunctions, such as the sudden loss of a unit; the combustion turbine generators may operate up to 110 percent of peak load (27.126 MW). The time period for operating the combustion turbines above 100 percent peak load (24.66 MW) shall be limited to no more than 30 minutes in duration. Under no circumstances shall the emission limits specified in Special Condition D.1.a. of this attachment be exceeded.~~

Combustion Turbine Operation Above Peak Load. The permittee may operate combustion turbine generators up to 110% peak load in the event of equipment malfunction such as a sudden loss of a unit occurs. The time period of this operation shall not exceed thirty (30) minutes in duration, and shall not result in an exceedence of the maximum emission limits specified in Special Condition IIA: D.1.

d. Alternate Fuels. Upon receiving written approval from the Department of Health, the permittee may burn an ~~alternative~~ alternate fuel (e.g., but not limited to, biodiesel, jet fuel, hydrogen, or ethanol).~~provided the permittee demonstrates compliance with all applicable state and federal requirements and applicable conditions of this covered source permit. The alternative fuel shall be burned only temporarily, and shall not result in an increase in emissions of any air pollutant or in the emission of any pollutant not previously emitted. The permittee shall not be allowed to switch fuel unless all the following information is provided:~~

~~i. Specific type of fuel provided;~~

~~ii. Consumption rate of the fuel;~~

~~iii. Fuel blending rate;~~

~~iv. Emissions calculations;~~

~~v. Ambient air quality analyses verifying that SAAQS will be met;~~

~~vi. Fuel storage; and~~

~~vii. Plan to monitor and record the fuel analyses and consumption.~~

e. Fuel Additives. The permittee may use fuel additives to reduce corrosion, control biological growth, and enhance combustion. Additives used during this scenario shall not affect emission estimates.

f. ~~Upon receiving approval from the Department of Health, the permittee may use alternate means and methods to improve combustion and/or reduce emissions provided the permittee demonstrate that the following conditions will be met.~~

~~i. The national and state ambient air quality standards will not be violated.~~

~~ii. The emissions and emission rates do not exceed the permitted emission limits.~~

~~iii. The facility shall continue to operate and comply with the conditions of this permit.~~

~~iv. There are no emissions of air pollutants not previously emitted.~~

~~The Department of Health may approve, conditionally approve, or deny any request for using an alternate means or methods. Under no circumstance shall an alternate means and/or methods be employed without prior written approval, or conditional approval, of the Department of Health.~~

~~g. The permittee shall, contemporaneously with making a change from one operating scenario to another, record in a log at the permitted facility the scenario under which it is operating and, if required by any applicable requirement of the Department of Health, submit written notification to the Department of Health; and~~

Permanent Replacement. The permittee may replace the combustion turbine generators, CT-4 and CT-5, with another General Electric LM2500 if any repair work reasonably warrants the removal (i.e., equipment failure or malfunction, overhaul, or any major equipment problems requiring maintenance for efficient operation) of a combustion turbine generator from its site and the following provisions are adhered to:

i. The replacement combustion turbine generator is a General Electric LM2500 with one of the following serial numbers:

1) 481-688

2) 481-692

3) 481-651

ii. The permittee may continue using the replacement combustion turbine generator and is not required to return the original combustion turbine generator after it is repaired.

~~h. The terms and conditions under each alternate operating scenario shall meet all applicable requirements, including conditions of this permit.~~

Justification – The requested changes are also needed to: 1) include additional maintenance and testing activities. Dry running (i.e., dry operation) of the OTSG may be needed to remove deposits in the OTSG caused by ammonia from the SCR and sulfur in the fuel oil. The OTSG manufacturer's operating manual recommends dry running for approximately 60 to 100 minutes. The duration depends on the depth and density of the deposits; 2) clarify peak load; 3) relocate permit monitoring and recordkeeping and notification and reporting conditions from Section C. Operational Limitations to Section E. Monitoring and Recordkeeping Requirements and Section F. Notification and Reporting Requirements; and 4) add the ability to permanently replace combustion turbine generators, CT-4 and CT-5, with another General Electric LM2500 within HELCO's General Electric LM2500 combustion turbine pool.

Currently, HELCO utilizes the temporary replacement alternate operating scenario (AOS) when a combustion turbine is taken out of service for maintenance and/or repair. However, under the current AOS, HELCO is required to remove the replacement combustion turbine and re-install the original combustion turbine when maintenance and/or repairs are completed which is costly and time consuming. The addition of this AOS provision would allow HELCO to permanently replace combustion turbines with spare combustion turbines of the same make and model (General Electric LM2500) owned by HELCO.

Per 40 CFR § 60.14(e)(6), relocation of an emission unit is not considered a modification. Therefore, relocation of a combustion turbine does not result in applicability of NSPS Subpart IIII.

The permanent replacement AOS incorporates the "replacement unit" provisions contained in 40 CFR § 52.21 which were added on November 7, 2003 (68 FR 63023-63024). The November 7, 2003 revisions added the "replacement unit" definition to clarify EPA's December 31, 2002 decision to allow the use of the actual-to-projected actual applicability test for unit replacement (67 FR 80194).

The EPA December 31, 2002 decision states:

> *...the fact that replacement units are replacing similar units with a record of historical operational data provides sufficient reasons to believe that a projection of future actual emissions can be sufficiently reliable that an up-front emissions cap based on PTE is unnecessary. In other words, a source replacing a unit should be able to adequately project and track emissions for the replacement unit based, in part, on the operating history of the replaced unit.*

(67 FR 80186, at 80194)

Whether, the existing diesel engine is returned or not has no impact on projected-actual annual emissions. Therefore, no annual emissions increase is expected. Per 40 § 52.21(b)(41)(ii)(c), projected-actual annual emissions do not include emission increases unrelated to the particular project, including any increase utilization due to product demand growth.

Review of permits from other states has identified two permits allowing for the installation of permanent replacement units: 1) Draft Permit No. 97-179-C (M-2) from the Oklahoma Department of Environmental Quality. Refer to Specific Condition 9 of the draft permit; and 2) Operating Permit (02OPEP246) issues by the Colorado Department of Public Health and Environment, Air Pollution Control Division. Refer to Section I.2 of the permit.

The permits identified above address units that have been through New Source Review and have emission testing requirements. The testing requirements for the original HELCO units are identical to the replacement units as specified in Attachment II, Section F of the CSP.

An applicability determination for grandfathered units was also identified. On April 1, 1999, EPA Region 2 made an applicability determination in regards to PSE&G combustion turbine replacement. The EPA Region 2 applicability determination states:

> *The act of physically removing a turbine from one spot, performing the routine repair and maintenance on that turbine and placing it in a*

different but identically designed spot, is not the construction of a new source.

The above examples illustrate the proposed permanent replacement alternate operating scenario is allowed under NSPS and PSD permitting rules.

Proposed change to Attachment IIA, Special Condition D.1.:

Maximum Emission Limits

a. Except during the startup and shutdown sequences, ~~T~~the permittee shall not discharge or cause the discharge into the atmosphere from the combustion turbine generator nitrogen oxides, sulfur dioxide, particulate matter/PM_{10}, carbon monoxide, volatile organic compounds, and ammonia in excess of the following specified limits:

Combustion Turbine Generator Operating in Simple Cycle Mode

Compound	**Maximum Emission Limit (3-hour Average)**	
	(lbs/hr)	(ppmvd @ 15 percent O_2)
Nitrogen Oxides as NO_2	42.3	42
Sulfur Dioxide	110	79
Particulate Matter/PM_{10}	19.7	0.045 (g/dscf @ 12 percent O_2)
Carbon Monoxide		
100% Peak load (24.66 MW)	26.8	44
75% (18.50 MW) - < 100% (24.66 MW) Peak load	56.4	123
50% (12.33 MW) - < 75% (18.50 MW) Peak load	181.0	566
~~25% (6.17 MW) -~~ < 50% (12.33 MW) Peak load	475.6	2,386
Volatile Organic Compounds		
100% Peak load (24.66 MW)	0.8	2.5
75% (18.50 MW) - < 100% (24.66 MW) Peak load	2.6	11.8
50% (12.33 MW) - < 75% (18.50 MW) Peak load	18.1	178
~~25% (6.17 MW) -~~ < 50% (12.33 MW) Peak load	297.6	3,025

Combustion Turbine Generator Operating in Combined Cycle Mode

Compound	Maximum Emission Limit (3-hour Average) (lbs/hr)	Maximum Emission Limit (3-hour Average) (ppmvd @ 15 percent O_2)
Nitrogen Oxides as NO_2		
50% <u>(12.33 MW)</u> - 100% <u>(24.66 MW)</u> Peak ~~_~~load	15.1	15
~~25% (6.17 MW) -~~ < 50% <u>(12.33 MW)</u> Peak ~~_~~load	42.3	42
Sulfur Dioxide	110	79
Particulate Matter/PM_{10}	19.7	0.045 (g/dscf @ 12 percent O_2)
Carbon Monoxide		
100% Peak ~~_~~load <u>(24.66 MW)</u>	26.9	44
75% <u>(18.50 MW)</u> - < 100% <u>(24.66 MW)</u> Peak ~~_~~load	50.2	105
50% <u>(12.33 MW)</u> - < 75% <u>(18.50 MW)</u> Peak ~~_~~load	170.4	523
~~25% (6.17 MW) -~~ < 50% <u>(12.33 MW)</u> Peak ~~_~~load	457.4	2,218
Volatile Organic Compounds		
100% Peak ~~_~~load <u>(24.66 MW)</u>	0.8	2.5
75% <u>(18.50 MW)</u> - < 100% <u>(24.66 MW)</u> Peak ~~_~~load	2.0	8.6
50% <u>(12.33 MW)</u> - < 75% <u>(18.50 MW)</u> Peak ~~_~~load	25.0	156
~~25% (6.17 MW) -~~ < 50% <u>(12.33 MW)</u> Peak ~~_~~load	271.0	2,662
Ammonia	4.30	10

<u>b.</u> <u>The three-hour averaging period shall begin immediately upon completion of the combustion turbine generator's startup sequence and end immediately prior to the combustion turbine generator's shutdown sequence. For operating periods during which the combustion turbine generator operates at multiple loads where multiple NO_X and CO emission standards apply, the applicable NO_X and CO emissions limit shall be determined in accordance with 40 CFR § 60.4380(b)(3).</u>

<u>c.</u> The Department of Health, with U.S. EPA Region 9 concurrence, may revise the allowable emission limitation for nitrogen oxides, particulate matter, carbon monoxide, volatile organic compounds, and ammonia after reviewing the initial performance test results required under Attachment II<u>A</u>, Section G of this Covered Source Permit. The Department of Health, with U.S. EPA Region 9 concurrence, may also revise the water-to-fuel ratios or include ammonia-to-NO_X injection rates if findings through operating parameters and performance test results show an optimum operating range which minimizes emissions.

<u>d.</u> If the nitrogen oxides, particulate matter, carbon monoxide, volatile organic compounds, or ammonia emission limit is revised, the difference between the applicable emission limit set forth above and the revised lower emission limit shall not be allowed as an emission offset for future construction or modification.

Justification – The requested changes are needed to: 1) revise the emission limits table to clarify peak load; 2) clarify the method of determining the applicable emission limit for operating

periods during which multiple emission standards apply; and 3) revise the emission limits tables to address operation of CT-4 and CT-5 below 25 percent of peak load.

Proposed change to Attachment IIA, Special Condition E.: Monitoring and Recordkeeping

All records, including support information, shall be maintained for at least five (5) years from the date of the monitoring~~ sample~~, ~~measurement,~~ test, report, or application. Support information includes all ~~calibration and~~ maintenance, inspection, and repair records and copies of all reports required by ~~the~~ this permit. These records shall be ~~true, accurate,~~ maintained in a permanent form suitable for inspection and made available to the Department of Health or their representative upon request.

Justification – The requested change is needed for consistency with other HECO, HELCO, and MECO

Proposed change to Attachment IIA, Special Condition E.1.: Continuous Monitoring Systems

~~All monitoring systems shall record the date and time that the measured parameters and data were collected.~~

The permittee shall at its own expense operate and maintain the following continuous monitoring systems for each combustion turbine generator to measure and record the following parameters and data. The associate date and time of the monitored data shall also be recorded.

a. ~~The permittee shall continuously monitor and record the operating~~ Operating load ~~of the combustion turbine generators.~~ in MW;

b. ~~The permittee shall operate and maintain a continuous monitoring system to monitor and record the ratio of water-to-fuel being fired in the combustion turbine generators.~~ Water-to-fuel ratio. The water-to-fuel monitor/recorder shall be accurate to +/- 5 percent.

c. ~~The permittee shall operate and maintain a total volumetric flow metering system for the continuous measurement and recording of the fuel usage of the combustion turbine generators. The permittee shall maintain records on the total amount of fuel fired in the combustion turbine generators.~~ Fuel consumption using a flow metering system;

d. ~~The permittee shall operate and maintain a continuous monitoring system to measure and record the~~ NO_X, CO, and carbon dioxide (CO_2) or oxygen (O_2) concentrations in the stack gases and in the exhaust gas stream at a point between the exit of the combustion turbine with water injection and the entrance to the SCR system using a Continuous Emissions Monitoring System (CEMS) ~~from the combustion turbines~~. If CO_2 is measured with the CEMS to adjust the pollutant concentration, the CO_2 correction factor equations listed in 40 CFR §60.4213(d)(3) shall be used to determine compliance with the applicable emissions limit and a diluent cap value for CO_2 may be used in accordance with 40 CFR §60.4350(b). The emissions ~~rates~~ for NO_X and CO shall be recorded in parts per million by volume dry (ppmvd) at 15 percent O_2 and pounds per hour (lbs/hr).

e. ~~Prior to the startup of the selective catalytic reduction system and thereafter, the permittee shall at its own expense install, operate, and maintain a continuous monitoring system for each combustion turbine to measure and record the following parameters and data:~~

~~i.~~ The ammonia injection rate in pounds per hour (lbs/hr) and the ammonia-to-NO_X ratio. The ratio shall be based on the pounds per hour of ammonia injected into the SCR to the pounds of NO_X entering the SCR system.

~~ii. The NO_X and carbon dioxide (CO_2) or oxygen (O_2) concentrations in the exhaust gas stream at a point between the exit of the combustion turbine with water injection and the entrance to the SCR system.~~

~~The emissions rates for NO_X shall be recorded in parts per million by volume dry (ppmvd) at 15 percent O_2 and in lbs/hr. The continuous emissions monitoring system used for these measurements shall meet the U.S. EPA performance specifications of 40 CFR Part 60 Section 60.13, Appendix B, and Appendix F.~~

f. [No changes proposed]

~~g. The permittee shall maintain a file of all measurements and monitoring data, performance testing requirements and results, system performance evaluations, calibration checks, adjustments and maintenance as performed, and all other information required by 40 CFR Part 60 recorded in a permanent form suitable for inspection.~~

Justification – The requested changes are needed to: 1) allow volumetric or mass flow meters; 2) remove redundant permit conditions; and 3) incorporate by reference the CO_2 correction factor equations required for the CEMS and allow the use of a diluent cap address any hour in which the hourly average CO_2 concentration is less than 1.0 percent. 40 CFR Part 60, Subpart KKKK and Part 75 include a diluent cap for both O_2 and CO_2 for stationary turbines. However, 40 CFR Part 60, Subpart GG includes a diluent cap only for O_2.

Proposed change to Attachment IIA, Special Condition E.3.:

a. The ~~fuel~~ sulfur content of the fuel fired in the combustion turbines shall be determined using of one of the following sampling options described in sections 2.2.3, 2.2.4.1, 2.2.4.2 and 2.2.4.3 of Appendix D to 40 CFR Part 75. The analysis may be performed by the permittee, the supplier, or other qualified third party lab. The analysis shall be performed using one of the following ASTM International (ASTM) methods: D129-00, D2622-98, D4294-02, D1266-98, D5453-00, or D1552-01 or a more current version of these ASTM methods. ~~verified by one of the following methods:~~

~~i. A representative sample of each batch of the fuel received shall be analyzed using the most current version of any of the following American Society for Testing and Materials (ASTM) methods: D129, D2622, D4292, D5453, or D1552; or~~

~~ii. A certificate of analysis on the sulfur content (percent by weight) shall be obtained from the fuel supplier for each batch of fuel received.~~

b. ~~The fuel bound nitrogen content of the fuel fired in the combustion turbines shall be verified by the following method. A representative sample of each batch of fuel received shall be analyzed for its nitrogen content by weight using the most current version of any of the following American Society for Testing and Materials (ASTM) methods: D6366, D4629, D5762.~~

c. The permittee shall maintain records of the fuel deliveries.~~y~~ identifying the delivery dates and the type and amount of fuel received. ~~receipts, the supplier's certificate of analysis showing the sulfur content of the fuel delivered, and all test analysis. At a minimum, the test analysis shall include the following:~~

~~i. Type of fuel;~~

~~ii. Date and time the fuel sample was drawn;~~

~~iii. Date the analyses were performed;~~

~~iv. Name and address of the company or entity that performed the analyses;~~

~~v. Means and methods used to analyze the fuel; and~~

~~vi. Analyses results.~~

Records of~~n~~ the sulfur ~~and nitrogen~~ content~~s~~ of the fuel shall be maintained on a monthly basis.

Justification – The requested changes are needed to: 1) provide consistency with NSPS Subpart GG. The requested changes include the addition of the NSPS Subpart GG fuel oil no. 2 sulfur test methods and authorization of the fuel testing to be conducted by the permittee, supplier, or other qualified third party lab; 2) remove the fuel bound nitrogen monitoring conditions because it is not required by NSPS Subpart GG if an emission allowance for fuel bound nitrogen is not claimed; HELCO has not claimed an emission allowance under NSPS Subpart GG; and 3) provide consistency with the proposed change to Attachment IIA, Special Condition E.3.b. and CSP No. 0070-01-C.

Proposed change to Attachment IIA, Section E.: Add monitoring and recordkeeping conditions.

4. Operation Below 25 Percent of Peak Load with Water Injection. The permittee shall maintain records of the total time the combustion turbine generators operate below 25 percent of peak load with water injection. Records of the total time CT-2, CT-4, and CT-5 operated below 25 percent of peak load with water injection, excluding startup and shutdown sequences, and maintenance, testing, and as approved pursuant to Special Condition C.5. of this Attachment, shall be maintained on a monthly and rolling twelve (12) month basis using data recorded by the CEMS.

5. Startup and shutdown.

    a. The following shall be recorded for each startup sequence:

        i. The date, start and end times, and corresponding load (MW) at the end of each twenty (20) minute startup sequence.

        ii. Duration (minutes) of the startup sequence.

        iii. The operating load (MW) at which water injection was initiated.

    b. The following shall be recorded for each shutdown sequence:

        i. The date, start and end times, and corresponding load (MW) at which the combustion turbine controls stop signal was initiated.

        ii. Duration (minutes) of the shutdown sequence.

        iii. The operating load (MW) at which water injection was terminated.

6. Alternate Operating Scenarios

    a. The permittee shall contemporaneously with making a change from one operating scenario to another in accordance with Attachment IIA, Special Condition No. C.9. record in a log at the permitted facility the scenario under which it is operating.

b. The permittee shall maintain all records corresponding to the implementation of an alternate operating scenario specified in Attachment IIA, Special Condition No. C.9.

c. The reason for operating the combustion turbine generator, CT-3, above peak load shall be clearly documented, with the event's date, time, duration, operating load, and resulting three-hour average emission rates.

Justification – The requested changes are needed to: 1) relocate permit conditions for the emergency diesel fire pump and D21; 2) allow for volumetric or mass flow meters 3) relocate monitoring and recordkeeping conditions from Section B. Operational Limitations to Section E. Monitoring and Recordkeeping Requirements; 4) monitor and record operation of CT-4 and CT-5 below 25 percent of peak load with water injection; and 5) provide consistency with notification and reporting requirements in Attachment IIA, Special Condition F.6.a.

Proposed change to Attachment IIA, Special Condition F.3.: Delete condition.

~~**Within sixty (60) days** after initial start-up of the selective catalytic reduction system, the permittee shall submit to the Department of Health a quality assurance project plan for the continuous monitoring system conforming to 40 CFR Part 60, Appendix F.~~

Justification – The quality assurance project plan has been submitted to the Department of Health and therefore, this permit condition is no longer needed.

Proposed change to Attachment IIA, Special Condition F.4.:

~~The permittee shall notify the Department of Health in writing **within thirty (30) days** prior to conducting performance specification tests on the continuous monitoring system. The testing date shall be in accordance with the performance test date identified in 40 CFR Part 60 Section 60.13.~~

Performance Test.

a. At least thirty (30) days prior to conducting a source performance test as required by Attachment IIA, Section G, the permittee shall submit a written performance test plan to the Department of Health that includes the date(s) of the test, test duration, test locations, test methods, source operation, and other parameters that may affect test results. Such a plan shall conform to U.S. EPA guidelines including quality assurance procedures. A test plan or quality assurance plan that does not have the approval of the Department of Health may be grounds to invalidate any test and require a retest.

b. Within sixty (60) days after completion of a source performance test required by Attachment IIA, Section G, the permittee shall submit to the Department of Health and U.S. EPA Region 9 (Attention: AIR-3) the test report which shall include the operating conditions of the combustion turbine generators and diesel engine generators at the time of the test, the analysis of the fuel, the summarized test results, comparative results with the permit emission limits, and other pertinent field and laboratory data.

Justification – The requested changes are needed: 1) for consistency with CSP No. 0070-01-C and the notification requirements of 40 CFR Part 60 Subpart A; and 2) to relocate notification and reporting requirements from Section G Testing Requirements to Section F Notification and Reporting Requirements.

Proposed change to Attachment IIA, Special Condition F.5.:

The permittee shall submit to the Department of Health and U.S. EPA Region 9 for every semi-annual calendar period ~~a written~~ reports of ~~all~~ excess emissions and monitor downtime in accordance with 40 CFR Part 60, Section 60.7(c).~~, including those associated with the water-to-fuel ratio requirement, to the Department of Health and U.S. EPA Region 9 every semi-annual period.~~ The report shall include the following:

a. The magnitude of excess emissions computed in accordance with 40 CFR Part 60 ~~Subsection~~ Section 60.13(h), any conversion factors used, and the date and time of commencement, completion of each time period of excess emissions, and the corresponding operating load of the combustion turbine generators.

b. Specific identification of each period of excess emissions that occurs during ~~start-ups,~~ startups, shutdowns, and malfunctions of the combustion turbine generators. The nature and cause of any malfunction (if known), and the corrective action taken or preventive measures adopted~~, shall also be reported~~.

c. The date and time identifying each period during which the continuous monitoring system was inoperative except for zero and span checks~~. The~~ and the nature of ~~each~~ the system repairs or adjustments ~~shall be described~~.

d. ~~The report shall state if no excess emissions have occurred. Also, the report shall state if the CEMS operated properly during the period and was not subject to any repairs or adjustments except for zero and span checks.~~ When no excess emissions have occurred or the CEMS has not been inoperative, repaired, or adjusted, such information shall be stated in the report.

e. [No changes proposed]

f. For purposes of this Covered Source Permit, excess emissions shall be defined as follows:

   i. [No changes proposed]

   ii. During simple cycle operation and combined cycle operation at loads less than 50 percent of peak load (12.33 MW), any one (1) hour period during which the average water-to-fuel ratio, as measured by the continuous monitoring system, falls below the water-to-fuel ratio at the corresponding operating load specified in Special Condition C.3.a. of this attachment. For operating periods during which the combustion turbine generator operates at multiple loads where multiple water-to-fuel mass ratios apply, the applicable water-to-fuel mass ratio shall be determined based on the load that corresponded to the lowest minimum water-to-fuel mass ratio; and

   iii. [No changes proposed]

g. [No changes proposed]

Justification – The requested changes are needed for consistency with reporting requirements under 40 CFR § 60.7(c) and CSP No. 0007-01-C.

Proposed change to Attachment IIA, Special Condition F.5.g.iii.:

Nitrogen oxide emissions in excess of 42 ppmvd at 15 percent O_2 while operating in simple cycle mode and combined cycle mode at loads less than 50 percent of peak load (12.33 MW) or 15 ppmvd at 15 percent O_2 while operating in combined cycle mode at loads equal to or greater than 50 percent of peak load (12.33 MW) if it can be shown that the excess emissions resulted from the firing of fuel with a fuel-bound nitrogen content in excess of 0.015 percent by weight. Under no circumstance shall the nitrogen oxide emission limit of 42.3 pounds per hour while operating in simple cycle mode and combined cycle mode at loads less than 50 percent of peak load (12.33 MW) or 15.1 pounds per hour while operating in combined cycle mode at loads equal to or greater than 50 percent of peak load (12.33 MW), as specified in Special Condition D.1.a. of this attachment, be exceeded.

Justification – The requested change is to clarify peak load.

Proposed change to Attachment IIA, Special Condition F.6.:

The permittee shall submit **semi-annually** the following written reports to the Department of Health. The report shall be submitted **within sixty (60) days** after the end of each semi-annual calendar period, and shall include the following:

a. A ~~monthly~~ summary ~~listing the time and duration of all~~ ~~start-up~~ identifying all dates, times and durations when the startup and ~~shut-down~~ shutdown sequences for ~~each~~ the combustion turbine generators exceeded twenty (20) minutes. ~~The summary shall include the combustion turbine generator load (MW) at the time the air pollution control devices and systems are initiated and terminated.~~ The enclosed **Monitoring Report Form:** ~~***Daily Start-up***~~ ***Combustion Turbine Generator Operation*** ~~***and Shut-down***~~ or ~~similar~~ equivalent form, shall be used.

b. Minimum Operating Loads~~Except for all start-up and shutdown sequences report all periods where the minimum operating load for each combustion turbine was less than 25 percent of the rated capacity. The report shall include the date, time, and duration of each period.~~

   i. All periods when the operating load for the combustion turbine generators was below 25 percent of peak load (4.6 MW) except for all startup and shutdown sequences and as authorized pursuant to Special Condition C.2. of this Attachment. The report shall include the date, time and duration of each period using data recorded by the CEMS. The report shall include the date, time and duration of each period using data recorded by the CEMS. The enclosed Monitoring Report Form: Combustion Turbine Generator Operation or an equivalent form shall be used.

   ii. A monthly summary and rolling 12-month total of the hours of operation of the combustion turbine generators, CT-2, CT-4, and CT-5, below 25 percent of peak load (6.17 MW) with water injection excluding startup and shutdown sequences, maintenance, testing, and as approved pursuant to Special Condition C.5. of this Attachment. The report shall be based on data recorded by the CEMS. The enclosed Monitoring Report Form: Monthly Combustion Turbine Generator Operation Below Minimum Operating Load with Water Injection or equivalent form shall be completed for each reporting period. The enclosed Monitoring Report Form: Combustion Turbine Generator Monthly Operation Below Minimum Load with Water Injection or equivalent form shall be used.

c. [No changes proposed]

d. A report identifying the type of fuel fired in each of the combustion turbines during the semi-annual reporting period. The report shall include the maximum sulfur content (percent by weight) ~~and the average nitrogen content (percent by weight)~~ of the fuel for the reporting period. ~~The report shall identify the means and methods used to verify the sulfur and nitrogen content of each fuel.~~ The enclosed **Monitoring Report Form: *Fuel Certification,*** or ~~similar~~ equivalent form, shall be used.

e. [No changes proposed]

Justification – The requested changes are needed: 1) to clarify peak load; 2) for consistency with CSP No. 0070-01-C; 3) for consistency with the proposed change to Special Condition E.3.b. to remove the fuel bound nitrogen monitoring conditions because it is not required by NSPS Subpart GG if an emission allowance for fuel bound nitrogen is not claimed; HELCO has not claimed an emission allowance under NSPS Subpart GG; and 4) for operation of CT-4 and CT-5 below 25 percent of peak load with water injection.

Proposed change to Attachment IIA, Section F.: Add notification and reporting condition:

3. Alternate Operating Scenarios

   a. Temporary Replacement. Within thirty (30) days of commencement of the temporary replacement, the permittee shall submit in writing to the Department of Health, the reason for the temporary replacement, removal and return dates, and the make, model, and serial number of the existing and temporary replacement units.

   b. Alternate Fuels. In requesting for approval to fire CT-4 and CT-5 on alternate fuels, the permittee shall at a minimum, provided the Department of Health with information on the type of fuel proposed, reason for using the alternate fuel, emissions data, and the manufacturer's recommended water-to-fuel ratio and minimum operating load for compliance with the emission limits. The Department of Health may require an ambient air quality impact assessment for firing the alternate fuel and/or provide a conditional approval to impose additional monitoring, testing, recordkeeping, and reporting requirements. The Department of Health may establish minimum water-to-fuel ratio conditions in the permit for firing CT-4 and CT-5 on alternate fuels.

   c. The permittee shall request for approval to use alternate means and methods to improve combustion and/or reduce emissions. The Department of Health may approve, conditionally approve, or deny any request for using alternate means and methods.

   d. Permanent Replacement. For permanent replacement of CT4 and CT5, the permittee shall submit to the Department of Health, the make, model, and serial number of the existing and replacement units within thirty (30) days of the replacement.

   e. Fuel Additives. In requesting for approval to use fuel additives, the permittee shall, at a minimum, provide the Department of Health the specifications of the fuel additive(s), maximum expected emission rates of any criteria or non-criteria pollutant, certification that corresponding emission rates will not exceed permitted rates, and any other related information as requested by the Department of Health. The Department of Health may provide a conditional approval to impose additional monitoring, testing, recordkeeping, and reporting requirements to ensure the use of the fuel additive is in compliance with the applicable requirements.

Justification – The requested changes are needed to: 1) revise the alternate operating scenario for alternate fuels to allow adjustment of the minimum operating load and water-to-fuel mass ratios for alternate fuels, if necessary, to comply with the CSP emission limits; and 2) relocate permit notification and reporting conditions from Section B. Operational Limitations to Section F. Notification and Reporting Requirements.

Proposed change to Attachment IIA, Special Condition G.1.: Delete condition.

> ~~**Within sixty (60) days** after achieving the maximum production rate of the 16 MW steam turbine, but not later than one hundred eighty (180) days after the initial start-up of the 16 MW steam turbine (as defined in 40 CFR Part 60.2), the permittee shall conduct or cause to be conducted performance tests on the combustion turbine generators operating with SCR in the combined cycle mode.~~

Justification – These performance tests have been conducted, and therefore the permit condition is no longer needed.

Proposed change to Attachment IIA, Special Condition G.3.:

> All performance tests shall be conducted at 25 (6.17 MW), 50 (12.33 MW), 75 (18.50 MW), and 100 (24.66 MW) or highest achievable percent of peak load of the combustion turbine generators. The Department of Health may require the permittee to conduct the performance tests at additional operating loads.

Justification – The requested change is to clarify peak load.

Proposed change to Attachment IIA, Special Conditions G.8.:

> Performance tests for the emissions of SO_2, NO_X, CO, VOC, PM, CO_2, and NH_3 shall be conducted and results reported in accordance with test methods set forth in 40 CFR Part 60 Appendix A, and 40 CFR Part 60.8. The following test methods or U.S. EPA-approved equivalent methods, or alternate methods with prior written approval from the Department of Health, shall be used. Method 3A may be used in place of Method 3.
>
> a. Performance tests for the emissions of SO_2 shall be conducted using the 40 CFR Part 60, Methods 1-4 and 6C or Method 20.
>
> b. Performance tests for the emissions of NO_X shall be conducted using 40 CFR Part 60, Methods 1-4 and 7E or Method 20.
>
> c. Performance tests for the emissions of CO shall be conducted using 40 CFR Part 60, Methods 1-4 and 10 or Methods 3A, 10, and 19.
>
> d. Performance tests for the emissions of VOC shall be conducted using 40 CFR Part 60, Methods 1-4 and 25A or Methods 3A, 25A, and 19. Method 18 may be used to account for the actual methane fraction of the measured VOC emissions.
>
> e. Performance tests for the emissions of particulate matter shall be conducted using 40 CFR Part 60, Methods 1-5.
>
> f. Performance tests for the emissions of CO_2 shall be conducted using 40 CFR Part 60 Method 20 or U.S. EPA-approved equivalent methods~~, Equations 20-2 and 20-5~~ and the CO_2 correction factor calculations listed in § 60.4213(d)(3).

g. Performance test for the emissions of NH_3 shall be conducted using U.S. EPA Conditional Test Method 027(CTM-027).

Justification – The requested changes are needed to add specific U.S. EPA-approved equivalent methods to the permit condition and incorporate by reference the new location of the CO_2 correction factor equations required for the CEMS. This addition is needed because the equations are no longer in the referenced test method (Method 20).

Proposed change to Attachment IIA, Special Condition G.11.: Delete condition.

~~At least thirty (30) calendar days prior to performing a test, the permittee shall submit a written performance test plan to the Department of Health and U.S. EPA Region 9 that describes the test duration, test locations, test methods, source operation and other parameters that may affect test results. Such a plan shall conform to U.S. EPA guidelines including quality assurance procedures. A test plan or quality assurance plan that does not have the approval of the Department of Health may be grounds to invalidate any test and require a retest.~~

Justification – The requested change is needed to relocate notification and reporting requirements from Section G. Testing Requirements to Section F. Notification and Reporting Requirements.

Proposed change to Attachment IIA, Special Condition G.14.: Delete condition.

~~Within sixty (60) days after completion of the performance test, the permittee shall submit to the Department of Health and U.S. EPA Region 9 the test report which shall include the operating conditions of the combustion turbine generators at the time of the test, the analysis of the fuel, the summarized test results, and other pertinent field and laboratory data.~~

Justification – The requested change is needed to relocate notification and reporting requirements from Section G. Testing Requirements to Section F. Notification and Reporting Requirements.

Proposed Changes to Attachment IIB

Proposed change to Attachment IIB, Special Condition A.1.d.:

One (1) 500 kW Caterpillar Model 3412 Black Start Diesel Engine Generator ~~with an exhaust stack height of 70 feet~~ unit no. BS-1.

Justification – The requested change updates the description of the black start diesel engine generator, BS-1 because the relocation and extension of the stack height has been completed.

Proposed change to Attachment IIB, Special Condition B.7.:

Alternate Operating Scenarios

~~Terms and conditions for reasonably anticipated operating scenarios identified by the permittee in the covered source permit application and approved by the Department of Health are as follows:~~

The terms and conditions under the following alternate operating scenarios shall meet all applicable requirements including all conditions of this permit. Requests for written approval to operate under the applicable alternate operating scenario shall be in accordance with Attachment IIB, Special Condition No. D.7.

a. Temporary Replacement. ~~Upon receiving written approval from the Department of Health, the~~ The permittee may replace ~~any of the permitted~~ diesel engine generators, D-21, D-22, D-23, and BS-1, with an equivalent temporary replacement unit with equal or lesser emissions in the event of a failure or ~~sudden malfunction or planned~~ major overhaul. ~~The temporary replacement unit shall comply with all applicable permit conditions.~~

   ~~A written request shall be submitted to the Department of Health prior to the exchange and at a minimum, the request shall include the following:~~

   ~~i. the reason for temporary replacement;~~

   ~~ii. the removal and estimated return dates of the permitted unit;~~

   ~~iii. the make, model, serial number, and size of the temporary replacement unit;~~

   ~~iv. the emissions data of the permitted and temporary replacement unit.~~

   ~~The Department of Health may require an ambient air quality analysis and/or impose additional requirements on the temporary replacement unit to ensure compliance with the conditions of this permit.~~

b. Fuel Additives. Upon receiving written approval from the Department of Health, the permittee may ~~burn an~~ use ~~alternative~~ fuel or fuel additives to inhibit corrosion, control biological growth, improve combustion, improve lubricity, or other reasons. Additives used during this scenario shall not result in an increase in emission estimates.~~provided the permittee demonstrates compliance with all applicable State and Federal requirements and applicable conditions of this covered source permit. The burning of the alternative fuel or fuel additive shall not result in an increase in emissions of any air pollutant or in the emission of any air pollutant not previously emitted. As a minimum, the following information must be included with any request to burn an alternate fuel or fuel additive.~~

c. ~~The permittee shall contemporaneously with making a change from one alternate operating scenario to another, record in a log at the permitted facility the scenario under which it is operating and submit written notification to the Department of Health.~~

Alternate fuels. Upon receiving approval from the Department of Health, the permittee may burn an alternate fuel (e.g., but not limited to, biodiesel).

d. ~~The terms and conditions under each alternate operating scenario shall meet all applicable requirements, including conditions of this permit.~~

Permanent Replacement. The permittee may replace the diesel engines, D21, D22, and D23, with another EMD 20-645 if any repair work reasonably warrants the removal (i.e., equipment failure, engine overhaul, or any major equipment problems requiring maintenance for efficient operation) of a diesel engine from its site and the following provisions are adhered to:

i. The replacement engine is an EMD 20-645 with one of the following serial numbers:

1) 74-K3-1540
2) 71-M1-1092
3) 71-M1-1045
4) 74-B1-1078
5) 66-K1-1062
6) 69-H1-1057
7) 74-B1-1063
8) 72-E1-1027
9) 72-B1-1122
10) 73-G1-1129
11) 66-K1-1057
12) 72-E1-1094
13) 66-J1-1156

iii. The permittee may continue using the replacement diesel engine and is not required to return the original diesel engine after it is repaired.

Justification – The requested changes are needed to: 1) relocate monitoring and recordkeeping and notification and reporting conditions from Section B. Operational and Emission Limitations to Section C. Monitoring and Recordkeeping Requirements and Section D. Notification and Reporting Requirements; and 2) add the ability to permanently replace diesel engines, D21, D22, and D23, with another EMD 20-645 within HELCO's EMD diesel engine pool. Currently, HELCO utilizes the temporary replacement alternate operating scenario (AOS) when a diesel engine is taken out of service for maintenance and/or repair. However, under the current AOS, HELCO is required to remove the spare diesel engine and re-install the original diesel engine when maintenance and/or repairs are completed which is costly and time consuming. The addition of this AOS provision would allow HELCO to permanently replace diesel engines with spare diesel engines of the same make and model (EMD 20-645) owned by HELCO.

Per 40 CFR § 60.14(e)(6), relocation of an emission unit is not considered a modification. Therefore, relocation of a combustion turbine does not result in applicability of NSPS Subpart IIII.

The permanent replacement AOS incorporates the "replacement unit" provisions contained in 40 CFR § 52.21 which were added on November 7, 2003 (68 FR 63023-63024). The November 7, 2003 revisions added the "replacement unit" definition to clarify EPA's December 31, 2002 decision to allow the use of the actual-to-projected actual applicability test for unit replacement (67 FR 80194).

The EPA December 31, 2002 decision states:

> *...the fact that replacement units are replacing similar units with a record of historical operational data provides sufficient reasons to believe that a projection of future actual emissions can be sufficiently reliable that an up-front emissions cap based on PTE is unnecessary. In other words, a source replacing a unit should be able to adequately project and track emissions for the replacement unit based, in part, on the operating history of the replaced unit.*

(67 FR 80186, at 80194)

Whether, the existing diesel engine is returned or not has no impact on projected-actual annual emissions. Therefore, no annual emissions increase is expected. Per 40 § 52.21(b)(41)(ii)(c), projected-actual annual emissions do not include emission increases unrelated to the particular project, including any increase utilization due to product demand growth.

Review of permits from other states has identified two permits allowing for the installation of permanent replacement units: 1) Draft Permit No. 97-179-C (M-2) from the Oklahoma Department of Environmental Quality. Refer to Specific Condition 9 of the draft permit; and 2) Operating Permit (02OPEP246) issues by the Colorado Department of Public Health and Environment, Air Pollution Control Division. Refer to Section I.2 of the permit.

The permits identified above address units that have been through New Source Review and have emission testing requirements. The testing requirements for the original HELCO units are identical to the replacement units as specified in Attachment II, Section F of the CSP.

An applicability determination for grandfathered units was also identified. On April 1, 1999, EPA Region 2 made an applicability determination in regards to PSE&G combustion turbine replacement. The EPA Region 2 applicability determination states:

> *The act of physically removing a turbine from one spot, performing the routine repair and maintenance on that turbine and placing it in a different but identically designed spot, is not the construction of a new source.*

The above examples illustrate the proposed permanent replacement alternate operating scenario is allowed under NSPS and PSD permitting rules.

Proposed change to Attachment IIB, Special Condition C.: Monitoring and Recordkeeping

All records, including support information, shall be maintained for at least five (5) years from the date of any required ~~the~~ monitoring, ~~measurement,~~ test, report or application. Support information, ~~including~~ includes all maintenance, inspection and repair records and copies of all reports required by this permit. ~~for the diesel engine generators, shall be true, accurate, and maintained~~ These records shall be in a permanent form suitable for inspection and made available to the Department of Health or their representative upon request.

Justification – The requested change is needed for consistency with other HECO, HELCO, and MECO CSPs.

Proposed change to Attachment IIB, Special Condition C.1.

1. Sulfur Content

The sulfur content (% by weight) of the fuel fired in the diesel engines shall be ~~verified by one of the following methods:~~ determined by sampling each batch of fuel received. The analysis may be performed by the permittee, the supplier, or other qualified third party lab. The analysis shall be performed using one of the following ASTM International (ASTM) methods: D129-00, D2622-98, D4294-02, D1266-98, D5453-00, or D1552-01 or a more current version of these ASTM methods.

~~a. A representative sample of each batch of fuel received shall be analyzed using the most current version of the following American Society for Testing and Materials (ASTM) methods: D129, D2622, D4292, D5453, or D1552 or~~

~~b. A certificate of analysis on the sulfur content shall be obtained from the fuel supplier for each batch of fuel received.~~

Justification – The fuel testing requirements were revised to allow testing to be performed by the permittee, supplier, or qualified third party.

Proposed change to Attachment IIB, Special Condition C.3.: Fuel Consumption, Unit No. D21

The permittee shall operate and maintain a non-resetting ~~volumetric~~ flow meter system on diesel engine generator unit no. D21 for the continuous measurement and recording of the fuel consumed by the diesel engine generator. The flow meter reading shall be recorded at the beginning and end of each calendar month. Records on the total gallons of fuel consumed shall be maintained on a monthly and rolling 12-month basis.

Justification – The requested change is needed to allow a volumetric or mass flow meter.

Proposed change to Attachment IIB, Section C.: Add monitoring and recordkeeping condition.

6. Alternate Operating Scenarios

   a. The permittee shall contemporaneously with making a change from one operating scenario to another in accordance with Attachment IIB, Special Condition No. B.7., record in a log at the permitted facility the scenario under which it is operating.

b. The permittee shall maintain all records corresponding to the implementation of an Alternate Operating Scenario specified in Attachment IIB, Special Condition B.7.

Justification – The requested changes are needed to relocate monitoring and recordkeeping conditions from Section B. Operational and Emission Limitations to Section C. Monitoring and Recordkeeping Requirements.

Proposed change to Attachment IIB, Special Condition D.3.:

Performance Test.

a. At least thirty (30) days prior to conducting a source performance test as required by Attachment IIA, Section G, the permittee shall submit a written performance test plan to the Department of Health that includes the date(s) of the test, test duration, test locations, test methods, source operation, and other parameters that may affect test results. Such a plan shall conform to U.S. EPA guidelines including quality assurance procedures. A test plan or quality assurance plan that does not have the approval of the Department of Health may be grounds to invalidate any test and require a retest.

b. Within sixty (60) days after completion of a source performance test required by Attachment IIA, Section G, the permittee shall submit to the Department of Health and U.S. EPA Region 9 (Attention: AIR-3) the test report which shall include the operating conditions of the combustion turbine generators and diesel engine generators at the time of the test, the analysis of the fuel, the summarized test results, comparative results with the permit emission limits, and other pertinent field and laboratory data.

Justification – The requested changes are needed: 1) for consistency with CSP No. 0070-01-C and the notification requirements of 40 CFR Part 60 Subpart A; and 2) to relocate notification and reporting requirements from Section E Testing Requirements to Section D Notification and Reporting Requirements.

Proposed change to Attachment IIB, Special Condition D.4.d.:

~~Analysis of the sulfur content in the fuel for which there were exceedances of the sulfur content limits specified in Special Condition No. B.4. of this attachment. If there were no exceedances, the permittee shall submit in writing a statement indicating that there were no exceedances of the sulfur content limit for that semi-annual period.~~

A report identifying the type of fuel fired in each of the diesel engines during the semi-annual reporting period. The report shall include the maximum sulfur content (percent by weight) of the fuel for the reporting period. The enclosed **Monitoring Report Form: *Fuel Certification,*** or equivalent form, shall be used.

Justification – The requested change is needed for consistency with Attachment IIA, Special Condition F.6.d. to report the maximum sulfur content of the fuel fired in the diesel engines during the reporting period.

Proposed change to Attachment IIB, Section D.: Add notification and reporting condition.

7. Alternate Operating Scenarios

a. Temporary Replacement. Within thirty (30) days of commencement of the temporary replacement, the permittee shall submit in writing to the Department of Health, the reason for the temporary replacement, removal and return dates, and the make, model, and serial number of the existing and temporary replacement units.

   b. Alternate Fuels. In requesting for approval to fire alternate fuels, the permittee shall at a minimum, provide the Department of Health with information on the type of fuel proposed, reason for using the alternate fuel, and emissions data. The Department of Health may require an ambient air quality impact assessment for firing the alternate fuel and/or provide a conditional approval to impose additional monitoring, testing, recordkeeping, and reporting requirements. The Department of Health may establish minimum water-to-fuel ratio conditions in the permit for firing alternate fuels.

c. Fuel Additives. In requesting for approval to use fuel additives, the permittee shall, at a minimum, provide the Department of Health the specifications of the fuel additive(s), maximum expected emission rates of any criteria or non-criteria pollutant, certification that corresponding emission rates will not exceed permitted rates, and any other related information as requested by the Department of Health. The Department of Health may provide a conditional approval to impose additional monitoring, testing, recordkeeping, and reporting requirements to ensure the use of the fuel additive is in compliance with the applicable requirements.

d. Permanent Replacement. For permanent replacement of the diesel engine generators, the permittee shall submit to the Department of Health, the make, model, and serial number of the existing and replacement units within thirty (30) days of the replacement.

Proposed change to Attachment IIB, Special Condition E.2.:

2. Performance tests for the emissions of NO_X (as NO_2) shall be conducted and results reported in accordance with the test methods set forth in 40 CFR Part 60 Appendix A~~,~~ and 40 CFR Part 60.8. The performance tests for the emissions of NO_X (as NO_2) shall be conducted using the following test methods in 40 CFR Part 60 ~~Methods 1-4 and 7~~ or U.S. EPA-approved equivalent methods, or alternate methods with prior written approval from the Department of Health~~.~~:

   a. Methods 1-4 (Method 3A may be used in place of Method 3) and 7 or 7E; or

   b. Methods 3A, 7E and 19.

Justification – The requested change adds specific U.S. EPA-approved equivalent methods to the permit condition.

Proposed change to Attachment IIB, Special Condition E.5.: Delete condition.

~~At least 30 calendar days prior to performing a test, the permittee shall submit a written performance test plan to the Department of Health that describes the test duration, test locations, test methods, source operation and other parameters that may affect test results. Such a plan shall conform to U.S. EPA guidelines including quality assurance procedures. A test plan or quality assurance plan that does not have the approval of the Department of Health may be grounds to invalidate any test and require a retest.~~

Justification – The requested change is needed to relocate notification and reporting requirements from Section E. Testing Requirements to Section D. Notification and Reporting Requirements.

Proposed change to Attachment IIB, Special Condition E.7.: Delete condition.

~~Within sixty (60) days after completion of the performance test, the permittee shall submit to the Department of Health and U.S. EPA Region 9 the test report which shall include the operating conditions of the diesel engine generators at the time of the test, the analysis of the fuel, the summarized test results, comparative results with the permit emission limits, and other pertinent field and laboratory data.~~

Justification – The requested change is needed to relocate notification and reporting requirements from Section E. Testing Requirements to Section D. Notification and Reporting Requirements.

Proposed change to Attachment IV: Annual Emissions Reporting Requirements:

Revise Section 1 as follows:

1. Complete the attached forms:

Annual Emissions Report Form: ***Combustion Turbines and Diesel Engines;*** and

Annual Emissions Report Form: ***Ammonia Slip.*** ~~; and~~

~~**Annual Emissions Report Form:** ***Diesel Engines.***~~

Justification – The requested change is needed for consistency with the proposed change to the Annual Emissions Report Forms and CSP No. 0070-01-C.

Proposed change to Annual Emissions Report Form – Combustion Turbines:

Delete form and combine with the Annual Emission Report Form – Diesel Engines.

Justification – The requested changes are needed: 1) to eliminate redundant forms; 2) to remove information not required to be reported (i.e., nitrogen content of the fuel and control efficiency % reduction); 2) to use the same form for D-21, CT-2, CT-4, and CT-5 with the combining of CSP Nos. 0007-01-C and 0070-01-C; and 3) for consistency with the proposed change to Attachment IIA, Special Condition C.4.b to remove the fuel bound nitrogen monitoring conditions because it is not required by NSPS Subpart GG if an emission allowance for fuel bound nitrogen is not claimed. HELCO has not claimed an emission allowance under NSPS Subpart GG.

Proposed change to Annual Emissions Report Form – Diesel Engines:

Allow use of the form for the combustion turbine generators, CT-2, CT-4 and CT-5, and delete information not required to be reported (i.e., Control Efficiency % reduction). Refer to the revised form attached. Proposed changes to the form are highlighted.

Justification – The requested changes are needed to eliminate redundant forms and information not required to be reported.

Proposed change to Monitoring Report Form – Daily Start-Up and Shutdown Combustion Turbine Generator, Unit CT-4 and Unit CT-5

Replace form with "Monitoring Report Form Combustion Turbine Generator Operation." Refer to the revised form attached.

Justification – The requested change is needed for consistency with proposed changes to Attachment IIA, Special Condition F.6.

Proposed change to Monitoring Report Form – Fuel Consumption Diesel Engine Generator:

Revise Fuel Consumption Form so that form may be used for reporting fuel consumption for CT-2 and delete the % sulfur content by weight. Refer to the revised form attached. Proposed changes to the form are highlighted.

Justification – The requested change is needed to eliminate duplicate report forms when combining CSP Nos. 0007-01-C and 0070-01-C and redundant reporting of information.

Proposed change to Monitoring Report Form – Fuel Certification:

Revise form to add CT-2, delete Nitrogen Content and the means and methods used to determine the sulfur and nitrogen content of the fuel, and add columns for alternate fuels. Refer to the revised form attached.

Justification – The requested changes are needed: 1) for consistency with CSP No. 0070-01-C; 2) to add CT-2 to the table and for consistency with proposed change to Special Condition E.3.b; 3) to remove the fuel bound nitrogen monitoring conditions because it is not required by NSPS Subpart GG if an emission allowance for fuel bound nitrogen is not claimed; HELCO has not claimed an emission allowance under NSPS Subpart GG; and 3) to add columns for alternate fuels.

Proposed change: Add Monitoring Report Form Combustion Turbine Generator Monthly Operation Below Minimum Load with Water Injection.

Add new form. Refer to proposed form attached.

Justification – The requested change is needed to report monthly and rolling 12-month total hours of operation below minimum operating load with water injection consistent with proposed changes to CSP No. 0070-01-C Attachment II, Special Condition C.3 and CSP No. 0007-01-C Attachment IIA, Special Condition C.2

ANNUAL EMISSIONS REPORT FORM
COMBUSTION TURBINES AND DIESEL ENGINES
COVERED SOURCE PERMIT NO. 0007-01-C

Issuance Date: August 7, 2008 **Expiration Date: August 6, 2013**

In accordance with the Hawaii Administrative Rules, Title 11, Chapter 60.1, Air Pollution Control, the permittee shall report to the Department of Health the nature and amounts of emissions.

(Make Copies for Future Use)

For Period: ______________________ Date: ______________

Facility Name: HELCO Keahole Generating Station

Equipment Description: ~~2.5 MW General Motors EMD DEG~~

Serial/ID No(s).: ______________________

Responsible Official (Print): ______________________

Title: ______________________

I certify that I have knowledge of the facts herein set forth, that the same are true, accurate, and complete to the best of my knowledge and belief, and that all information not identified by me as confidential in nature shall be treated by the Department of Health as public record.

Responsible Official (Signature): ______________________

~~2.5 MW kilowatt rating~~

Unit No./Type of Fuel Fired	Fuel Usage (Gallons)	% Sulfur Content by weight
~~D21/Fuel Oil No. 2~~		
~~D22/Fuel Oil No. 2~~		
~~D23/Fuel Oil No. 2~~		
~~BS-1/Fuel Oil No. 2~~		

Unit No./Type of Air Pollution Control	In Use? Yes or No	Pollutant(s) Controlled	~~Control Efficiency % Reduction~~
	~~Yes or No~~		
	~~Yes or No~~		
	~~Yes or No~~		

MONITORING REPORT FORM
COMBUSTION TURBINE GENERATOR
COVERED SOURCE PERMIT NO. 0007-01-C
(PAGE 1 OF 2)

Issuance Date: ____________ **Expiration Date:** ____________

In accordance with the HAR, Title 11, Chapter 60.1, Air Pollution Control, the permittee shall report to the Department of Health the following information semi-annually:

(Make Copies for Future Use)

COMPLETE SEPARATE FORMS FOR EACH COMBUSTION TURBINE GENERATOR

For Reporting Period: ________________________________ Date: ______________

Company Name: ____

Facility Name: ____

Equipment Location: ____

Equipment Description: ____

Serial/ID No.: ____

I certify that I have knowledge of the facts herein set forth, that the same are true, accurate, and complete to the best of my knowledge and belief, and that all information not identified by me as confidential in nature shall be treated by the Department of Health as public record.

Responsible Official (Print): _____________________________________

Title: ____

Responsible Official (Signature): __________________________________

Use additional sheets if necessary. Indicate in the appropriate table if there were no exceedances during the reporting period.

1. Combustion turbine generator unit no.: ____________
2. Identify the months of operation: ________________
3. Exceedence of Startup and Shutdown durations:

Exceedence		Duration (minutes)		Reason for Exceedence/ Final Outcome/ Corrective Actions
Date	Time	Startup	Shutdown	

MONITORING REPORT FORM
COMBUSTION TURBINE GENERATOR
COVERED SOURCE PERMIT NO. 0007-01-C
(PAGE 2 OF 2)

Issuance Date: ____________ **Expiration Date:** ______________

Combustion Turbine Generator Unit No.: ___________

4. Dates, times and durations when the water injection system was not operated as specified in Special Condition No. C.3.:

Exceedence		Specify Startup, Shutdown or other	Duration (minutes)	Reason for Exceedence Final Outcome/ Corrective Actions
Date	Time			

5. Dates, times, and durations when the combustion turbine generators were operated below 25% of peak load at periods other than during startup, shutdown, or as authorized pursuant to Special Condition C.2. and approved pursuant to Special Condition C.5.:

Date	Time	Duration Below 25% of Peak Load (minutes)	Reason for Exceedence / Final Outcome/ Corrective Actions

MONITORING REPORT FORM
COMBUSTION TURBINE GENERATOR
MONTHLY OPERATION BELOW MINIMUM LOAD WITH WATER INJECTION
COVERED SOURCE PERMIT NO. 0007-01-C

Issuance Date: ______________ **Expiration Date:** ______________

In accordance with the HAR, Title 11, Chapter 60.1, Air Pollution Control, the permittee shall report to the Department of Health the following information semi-annually:

(Make Copies for Future Use)

For Reporting Period: ______________________________ Date: ______________

Company Name: ____

Facility Name: ____

Equipment Location: ____

Equipment Description: ____

Serial/ID Nos.: ____

I certify that I have knowledge of the facts herein set forth, that the same are true, accurate, and complete to the best of my knowledge and belief, and that all information not identified by me as confidential in nature shall be treated by the Department of Health as public record.

Responsible Official (Print): ____

Title: ____

Responsible Official (Signature): ____

Report periods of operation below 25% of peak load with water injection for Units CT2, CT4 and CT5 excluding startup, shutdown, maintenance, testing, and as approved pursuant to Special Condition C.5.

Month	CT2, CT4, CT5 Monthly Total (hours)	Rolling 12-Month Total (hours)

MONITORING REPORT FORM
FUEL CONSUMPTION ~~– DIESEL ENGINE GENERATOR~~
COVERED SOURCE PERMIT NO. 0007-01-C

Issuance Date: ______________ **Expiration Date:** ______________

In accordance with the Hawaii Administrative Rules, Title 11, Chapter 60.1, Air Pollution Control, the permittee shall report to the Department of Health the ~~nature and amounts of emissions~~ following information, semi-annually.

(Make Copies for Future Use)

For Period: ______________________________ Date: ______________

Facility Name: ______________________________

Equipment Description: ~~2.5 MW General Motors Diesel Engine Generator~~

Serial/ID No.: ~~Unit D21~~

Type of Fuel: ~~Fuel Oil No. 2~~ ~~% Sulfur Content by Weight:~~ ______________

Responsible Official (Print): ______________________________

Title: ______________________________

I certify that I have knowledge of the facts herein set forth, that the same are true, accurate, and complete to the best of my knowledge and belief, and that all information not identified by me as confidential in nature shall be treated by the Department of Health as public record.

Responsible Official (Signature): ______________________________

Month[1]	Monthly Fuel Consumption (Gallons)	Rolling 12-Month Fuel Usage (Gallons)
~~January~~		
~~February~~		
~~March~~		
~~April~~		
~~May~~		
~~June~~		
~~July~~		
~~August~~		
~~September~~		
~~October~~		
~~November~~		
~~December~~		

[1] Report the monthly and rolling 12-month fuel usage for the applicable semi-annual reporting period and the previous semi-annual reporting period.

MONITORING EMISSION REPORT FORM
FUEL CERTIFICATION
COVERED SOURCE PERMIT NO. 0007-01-C

Issuance Date: August 7, 2008 **Expiration Date: August 6, 2013**

In accordance with the Hawaii Administrative Rules, Title 11, Chapter 60.1, Air Pollution Control, the permittee shall report to the Department of Health the nature of fuel used for the permitted equipment.

(Make Copies for Future Use)

For Reporting Period: ______________________ Date: ____________

Company Name: ______________________________________

Facility Name: ______________________________________

I certify that I have knowledge of the facts herein set forth, that the same are true, accurate, and complete to the best of my knowledge and belief, and that all information not identified by me as confidential in nature shall be treated by the Department of Health as public record.

Responsible Official (Print): ______________________________

Title: ______________________________

Responsible Official (Signature): ______________________________

Equipment Description	Maximum Fuel Sulfur Content (% by weight)		
	Fuel Oil No. 2	Other ________	Other ________

Attachment S-3e

Requested Changes to CSP No. 0070-01-C

Proposed change to Attachment II, Special Condition A.1.:

This permit encompasses the following equipment and associated appurtenances:

Unit No.	Description
CT-2	One (1) 18 MW (nominal) (18.3 MW peak load) Simple Cycle Combustion Turbine Generator, model Jupiter GT-35 (manufactured by Asea Brown Boveri (ABB) and supplied by Solar Turbines) with a maximum design heat input rate of 198 MMBtu/hr.

Justification – The requested change updates the equipment description to include the maximum peak load rating for the combustion turbine generator.

Proposed change to Attachment II, Special Condition C.1.:

The ~~"start-up"~~ startup sequence ~~time~~ for Unit CT-2 shall ~~not exceed~~ be a twenty (20) minute~~s~~ period starting at the time fuel use at Unit CT-2 begins. ~~A "start-up" sequence shall be from the time fuel use at Unit CT-2 commences, until the time Unit CT-2 is initially brought up to~~ At the end of the startup sequence, Unit CT-2 shall be at 25~~%~~ percent of peak load (4.6 MW) or more, the water-to-fuel ratio shall be maintained, and the permittee shall not exceed the maximum emission limitations as specified in Attachment II, Special Conditions C.3, C.4 and C.6, respectively. ~~at which time the operation of the air pollution control equipment shall commence.~~

The ~~"start-up"~~ startup sequence ~~time~~ for Unit CT-2 shall ~~not exceed~~ be a twenty (20) minute~~s~~ period starting from the time fuel use at Unit CT-2 begins. ~~A "start-up" sequence shall be from the time fuel use at Unit CT-2 commences, until the time Unit CT-2 is initially brought up to~~ Upon completion of the twenty (20) minute startup sequence, the combustion turbine generator shall be at 25~~%~~ percent of peak load (4.6 MW) or more and the water injection system shall be operational. ~~at which time the operation of the air pollution control equipment shall commence.~~

Justification –The requested changes are needed: 1) to clarify peak load and the description of a startup sequence; and 2) to allow for stabilization of the water injection system following initiation of the system and address the misalignment of the CEMS NO_X, CO and CO_2 measurement readings with the instantaneous readings of operational parameters such as load (MW), fuel flow, and water injection rate due to lag from the CEMS analyzer response time.

Proposed change to Attachment II, Special Condition C.2.:

The ~~"shut-down" time~~ shutdown sequence for ~~Unit CT-2~~ the combustion turbine generator shall not exceed twenty (20) minutes. A ~~"shut-down"~~ shutdown sequence shall be ~~considered~~ from the time ~~when Unit CT-2~~ the combustion turbine controls stop signal is initiated for the combustion turbine generator and the combustion turbine generator is below 25~~%~~ percent of peak load (4.6 MW) until fuel use at ~~Unit CT-2~~ combustion turbine generator ceases.

MD1489

Justification – The requested changes include the load rating for CT-2 at 25 percent of peak load and clarify the description of a shutdown sequence.

Proposed change to Attachment II, Special Condition C.3.:

~~Except during Unit CT-2's "start-up" and "shut-down," maintenance, or testing.,~~ ~~Unit CT-2's load shall not be less than 25% of the rated capacity~~. The combined time of operation of combustion turbine generators, CT-2, CT-4 and CT-5, below 25 percent of peak load (4.6 MW) with water injection shall not exceed 268 hours in any rolling twelve (12) month period, excluding startup and shutdown sequences, maintenance, testing, and as approved pursuant to Attachment II, Special Condition C.8.a.

Justification – The requested change is needed to include the load rating for CT-2 at 25 percent of peak load and allow operation of the CT-2 below 25 percent of peak load with water injection to address high system frequency issues. The emissions calculations for CT-2, CT-4 and CT-5 for this proposed change are in Tables 1a and 1b below.

Table 1a - Less Than 25% Load Operation Project Emissions (CT-4, CT-5)

	Pollutant	
Parameter	**CO**	**VOC**
Actual Emissions (lb/hr) Before Change[1]	0.0	0.0
Maximum 10% Load (2.5 MW) Emissions (lb/hr)[2]	475.6	297.6
Expected Increase (lb/hr)	475.6	297.6
Maximum Unit-Hours Below 25% Load[3]	268	268
Projected Emissions Increase (tpy)[4]	63.7	39.9
PSD Significance Level (tpy)	100	40
Significant Emissions Increase (Yes/No)	No	No

Table 1b - Less Than 25% Load Operation Project Emissions (CT-2)

	Pollutant	
Parameter	**CO**	**VOC**
Actual Emissions (lb/hr) Before Change[1]	0.0	0.0
Maximum 10% Load (1.8 MW) Emissions (lb/hr)[5]	22.4	22.4
Expected Increase (lb/hr)	22.4	22.4
Maximum Unit-Hours Below 25% Load	3560	3560
Projected Emissions Increase (tpy)[4]	39.9	39.9
PSD Significance Level (tpy)	100	40
Significant Emissions Increase (Yes/No)	No	No

1 Past actuals set to zero (operation below 25% of peak load not allowed, except for startup, shutdown, maintenance and testing.
2 CT-4 and CT-5 permit limits for 25% of peak load in simple cycle mode.
3 Calculated limit to remain below PSD significance levels.
4 (Expected Increase) x (Unit-Hours/Year) / (2000 lb/ton)
5 CT-2 permit limits.

Proposed change to Attachment II, Special Condition C.4.:

Air Pollution Control Equipment

a. The permittee shall continuously operate and maintain a combustor water injection system to meet the emission limits as specified for nitrogen oxides (NO_X) in Attachment II, Special Condition C.6.a. ~~of this Covered Source Permit.~~ Water injection shall be initiated during the startup sequence of the combustion turbine generator and may be terminated at the beginning of or during the shutdown sequence of the combustion turbine generator.

b. ~~The operation of the combustor water injection system shall commence operation within twenty (20) minutes of start-up of Unit CT-2, and shall continue to operate within twenty (20) minutes of shutdown of Unit CT-2. The combustor water injection system shall be used whenever Unit CT-2 is operating at 25% peakload and above, and shall be maintained at a minimum water-to-fuel mass ratio as follows:~~ After completion of the startup sequence of the combustion turbine generator and until the beginning of the shutdown sequence of the combustion turbine generator, the following water-to-fuel mass ratio, on a one (1) hour average basis, shall be maintained when the combustion turbine generator is firing fuel oil No. 2:

WATER INJECTION SYSTEM
MINIMUM WATER INJECTION RATES BASED ON LOAD

Percent Peak load	Load (MW)	Ratio (lb-water/lb-fuel)
100	18.3	1.00
75 - < 100	13.7 - < 18.3	0.75
50 - < 75	9.15 - < 13.7	0.55
~~25 -~~ < 50	~~4.6 -~~ < 9.15	0.3

For operating periods during which the combustion turbine generator operates at multiple loads where multiple water-to-fuel mass ratios apply, the applicable water-to-fuel mass ratio shall be determined based on the load that corresponded to the lowest minimum water-to-fuel mass ratio.

c. [No changes proposed]

d. [No changes proposed]

Justification – The requested changes are to: 1) clarify the method of determining the applicable minimum water-to-fuel mass ratio for operating hours during which multiple minimum water-to-fuel mass ratios apply; 2) revise the water injection system table to address operation of the combustion turbine generator below 25 percent of peak load with water injection; and 3) provide consistency with proposed changes to CSP No. 0007-01-C.

Proposed change to Attachment II, Special Condition C.5.:

a. Unit CT-2 shall be fired only on fuel oil no. 2 with a maximum sulfur content not to exceed 0.4 percent by weight or an alternate fuel allowed under Attachment II, Special Condition C.8.a.ii. The use of fuel additives to control algae, inhibit corrosion or improve fuel combustion may be used in combination with the fuel oil no.2.

b. The maximum amount of fuel oil no. 2 fired in Unit CT-2 shall not exceed ~~24,407 barrels per month or 292,887 barrels~~ 12,301,254 gallons per any rolling twelve (12) month period.

Justification – The requested changes clarify the approved fuel and convert the maximum amount of fuel oil units from barrels to gallons.

Proposed change to Attachment II, Special Condition C.5.c.: Delete condition.

~~The fuel bound nitrogen content of the fuel fired in Unit CT-2 shall not exceed 0.015 percent by weight on a rolling twelve (12) month average.~~

Justification – Removal of fuel bound nitrogen monitoring requirement is requested because it is not required by NSPS Subpart GG if an emission allowance for fuel bound nitrogen is not claimed and HELCO has not claimed an emission allowance under NSPS Subpart GG.

Proposed change to Attachment II, Special Condition C.6.:

Maximum Emission Limits

a. Except for Unit CT-2's ~~"start-up"~~ startup and ~~"shut-down"~~ shutdown sequences, the permittee shall not discharge or cause the discharge into the atmosphere from Unit CT-2, nitrogen oxides, sulfur dioxide, particulate matter/PM_{10}, carbon monoxide, and volatile organic compounds in excess of the following specified limits ~~as noted below~~:

[No changes proposed for emission limits table]

~~For the purposes of the annual performance tests and the continuous monitoring system, emissions limits shall be measured on a rolling three (3) hour average.~~ The three-hour averaging period shall begin immediately upon completion of the combustion turbine generator's startup sequence and end immediately prior to the combustion turbine generator's shutdown sequence.

b. The Department of Health, with U.S. EPA's concurrence, may lower the allowable emission limitation for nitrogen oxides, sulfur dioxide, particulate matter/PM_{10}, carbon monoxide, volatile organic compounds after reviewing the performance test results required in Attachment II, Section F, Testing Requirements.

c. If the nitrogen oxides, sulfur dioxide, particulate matter/PM_{10}, carbon monoxide or volatile organic compounds emission limit is revised, the difference between the applicable emission limit set forth above and the revised lower emission limit shall not be allowed as an emission offset for future construction or modification.

Justification – The requested change is needed for clarification regarding the three-hour averaging period.

Proposed change to Attachment II, Special Condition C.8.:

a. ~~Terms and conditions for reasonably anticipated operating scenarios identified by the source in the Covered Source Permit Application and approved by the Department of Health are as follows:~~

The terms and conditions under the following alternate operating scenarios shall meet all applicable requirements including all conditions of this permit. Requests for written approval to operate under the applicable alternate operating scenario shall be in accordance with Attachment II, Special Condition No. E.8.

~~i.~~ Temporary Replacement. ~~Upon receiving written approval from the Department of Health, the~~ The permittee may replace combustion turbine generator, CT-2, with an equivalent temporary replacement unit with equal or lesser emissions ~~use a temporary replacement unit identical to the permitted equipment~~ in the event of a failure or major overhaul of the ~~permitted~~ equipment. ~~Emissions from the replacement unit shall comply with all applicable requirements of the permitted unit. In requesting for approval, the permittee shall at a minimum provide the Department of Health the reason and estimated time period/dates for temporary replacement, type and size of the temporary unit, emissions data, stack parameters, and measures to be taken in minimizing the time period needed for a temporary unit. The Department of Health may require an ambient air quality assessment of the temporary unit, and/or provide a conditional approval.~~

ii. Alternate Fuels. Upon receiving written approval from the Department of Health, the ~~use of alternative fuels may be allowed provided that all permit conditions are met. The permittee must submit all pertinent documentation (e.g., calculations, specifications, etc.) to the Department of Health to demonstrate compliance with permit conditions~~ permittee may burn an alternate fuel (e.g., but not limited to, biodiesel, jet fuel, hydrogen, or ethanol).

~~iii. Emergency load conditions. Certain equipment malfunctions (such as the sudden loss of a unit) may necessitate the operation of Unit CT-2 at loads as high as 110 percent of peak load. The time period of this operation will be limited to no more than 30 minutes in duration. These operations shall not exceed the 3-hour average maximum emission limits as specified in Attachment II, Special Condition No. C.6.~~

Combustion Turbine Operation Above Peak Load. The permittee may operate the combustion turbine generators up to 110% peak load in the event equipment malfunction such as a sudden loss of a unit occurs. The time period of this operation shall not exceed thirty (30) minutes in duration, and shall not result in an exceedence of the maximum emission limits specified in Special Condition IIA: C.6.

iv. Unpredictable periods of equipment failure, upsets, or emergency conditions. During any emergency condition, the permittee will operate the subject equipment in such a manner as to minimize emissions. The permittee shall comply with the Emergency Provisions.

~~v. If approved by the Department of Health, the burning of naphtha or other cleaner burning fuels.~~

~~b. The permittee shall, contemporaneously with making a change from one operating scenario to another, record in a log at the permitted facility the scenario under which it is operating and, if required by any applicable requirement or by the Department of Health, submit written notification to the Department of Health.~~

c. ~~The terms and conditions under each alternative operating scenario shall meet all applicable requirements including all conditions of this permit.~~

Justification – The requested changes are needed: 1) to increase operational flexibility of the temporary unit replacement provision; and 2) to relocate permit monitoring and recordkeeping and notification and reporting conditions for alternate operating scenarios from Section C. Operational and Emission Limitations to Section D. Monitoring and Recordkeeping Requirements and Section E. Notification and Reporting Requirements.

Proposed change to Attachment II, Special Condition D.1.:

The permittee shall at its own expense continue to operate~~, calibrate,~~ and maintain a continuous monitoring system ~~and total volumetric flow metering system for Unit CT-2~~ to measure and record the following parameters or data. The associated date and time of the monitored data shall also be recorded.

a. [No changes proposed]

b. [No changes proposed]

c. Fuel consumption ~~in gallons/hr~~ using a ~~volumetric~~ flow metering system; and

d. NO_X, CO, and CO_2 or O_2 concentrations in the stack gases using a Continuous Emissions Monitoring System (CEMS). The system shall meet U.S. EPA performance specifications (40 CFR Part 60, Section 60.13 and 40 CFR Part 60, Appendix B and Appendix F). If CO_2 is measured with the CEMS to adjust the pollutant concentration, the CO_2 correction factor equations listed in 40 CFR §60.4213(d)(3) shall be used to determine compliance with the applicable emission limit <u>and a diluent cap value for CO_2 may be used in accordance with 40 CFR §60.4350(b)</u>. The CEMS shall be on-line and fully operational, upon completion and thereafter of the performance specification test. The emissions for NO_X and CO shall be recorded in parts per million by volume (ppmvd) at 15 percent O_2 and pounds per hour (lbs/hr).

Justification – The requested changes are needed: 1) because there is no regulatory requirement or permit limit that requires recording fuel consumption in gallons/hour; 2) to allow for volumetric or mass flow meters; and 3) to allow the use of a diluent cap to address any hour in which the hourly average CO_2 concentration is less than 1.0 percent. 40 CFR Part 60, Subpart KKKK and Part 75 include a diluent cap for both O_2 and CO_2 for stationary turbines. However, 40 CFR Part 60, Subpart GG includes a diluent cap only for O_2.

Proposed change to Attachment II, Special Condition D.3.:

~~Daily "start-up" and "shut-down" times. The start and end times of each sequence shall be recorded. In addition, the operating load (MW) at which the air pollution control equipment was initiated and terminated shall be recorded.~~.

<u>Startup and shutdown</u>

<u>a. The following shall be recorded for each startup sequence:</u>

<u>i. The date, start and end times, and corresponding load (MW) at the end of each twenty (20) minute startup sequence.</u>

<u>ii. Duration (minutes) of the startup sequence.</u>

<u>iii. The operating load (MW) at which water injection was initiated.</u>

b. The following shall be recorded for each shutdown sequence:

   i. The date, start and end times, and corresponding load (MW) at which the combustion turbine controls stop signal was initiated.

   ii. Duration (minutes) of the shutdown sequence.

   iii. The operating load (MW) at which water injection was terminated.

Justification – The requested change is needed for consistency with CSP No. 0007-01-C.

Proposed change to Attachment II, Special Condition D.4.:

a. Sulfur content in the fuel. The sulfur content in the fuel to be fired in Unit CT-2 shall be ~~tested in accordance with the most current American Society of Testing and Materials (ASTM) methods. ASTM method D4294-98 is a suitable alternative to Method D129-00 for determining the sulfur content. The fuel sulfur content shall be verified by both of the following methods:~~ determined using of one of the following sampling options described in sections 2.2.3, 2.2.4.1, 2.2.4.2 and 2.2.4.3 of Appendix D to 40 CFR Part 75. The analysis may be performed by the permittee, the supplier, or other qualified third party lab. The analysis shall be performed using one of the following ASTM International (ASTM) methods: D129-00, D2622-98, D4294-02, D1266-98, D5453-00, or D1552-01 or a more current version of these ASTM methods.

   ~~i. A representative sample of each batch of fuel received shall be analyzed for its sulfur content; and~~

   ~~ii. A certificate of analysis on the sulfur content of the fuel shall be for each batch of the fuel delivered by the supplier.~~.

b. [No changes proposed]

c. [No changes proposed]

~~d. Nitrogen content in the fuel. The fuel bound nitrogen content of the fuel to be fired in Unit CT-2 shall be verified by taking and analyzing a representative sample of each batch of fuel received to determine the nitrogen content by weight.~~

~~e. Records of the nitrogen content of the fuel shall be maintained on a monthly and rolling twelve (12) month basis.~~

Justification – The requested changes are needed to: 1) provide consistency with NSPS Subpart GG with the addition of the NSPS Subpart GG fuel oil no. 2 sulfur test methods and authorization of the fuel testing to be conducted by the permittee, supplier, or other qualified third party lab; and 2) remove the fuel bound nitrogen monitoring conditions because it is not required by NSPS Subpart GG if an emission allowance for fuel bound nitrogen is not claimed; HELCO has not claimed an emission allowance under NSPS Subpart GG.

Proposed change to Attachment II, Special Condition D.7.:

~~The permittee shall maintain a permanent file of all measurements, including continuous monitoring system, monitoring device, and performance testing requirements: all continuous monitoring system performance evaluations; all continuous monitoring device calibration checks; adjustments and maintenance performed on these systems or devices; and all other information required by 40 CFR Part 60 recorded in a permanent form suitable for~~

~~inspection. The file shall be retained for at least five (5) years following the date of such measurements, maintenance reports, and records.~~

All records, including support information, shall be maintained for at least five (5) years from the date of any required monitoring, test, report, or application. Support information includes all maintenance, inspection, and repair records, and copies of all reports required by this permit. These records shall be in a permanent form suitable for inspection and made available to the Department of Health or their representative upon request.

Justification – The requested change is needed for consistency with other HECO, HELCO and MECO CSPs.

Proposed change to Attachment II, Section D: Add monitoring and recordkeeping conditions.

8. Operation Below 25 Percent of Peak Load with Water Injection. The permittee shall maintain records of the total time the combustion turbine generators operate below 25 percent of peak load with water injection. Records of the total time CT-2, CT-4, and CT-5 operated below 25 percent of peak load with water injection, excluding startup and shutdown sequences, maintenance, testing, and as approved pursuant to Special Condition C.8 of this Attachment, shall be maintained on a monthly and rolling twelve (12) month basis using data recorded by the CEMS.

9. Alternate Operating Scenarios

   a. The permittee shall contemporaneously with making a change from one operating scenario to another in accordance with Attachment IIA, Special Condition No. C.9, record in a log at the permitted facility the scenario under which it is operating.

   b. The permittee shall maintain all records corresponding to the implementation of an alternate operating scenario specified in Attachment IIA, Special Condition No. C.9.

   c. The reason for operating the combustion turbine generator, CT-3, above peak load shall be clearly documented, with the event's date, time, duration, operating load, and resulting three-hour average emission rates.

Justification – The requested changes are needed to relocate permit monitoring and recordkeeping conditions for alternate operating scenarios from Section C. Operational and Emission Limitations to Section D. Monitoring and Recordkeeping Requirements and to monitor and record operation of CT-2 below 25 percent of peak load with water injection.

Proposed change to Attachment II, Special Condition E.3.:

~~At least thirty (30) days prior to the following events, the permittee shall notify the Department of Health in writing of:~~

~~a. Conducting a performance specification test on the CEMS. The testing date shall be in accordance with the performance test date identified in 40 CFR Part 60, Section 60.13.~~

~~b. Conducting a source performance test as required in Attachment II, Section F, Testing Requirements.~~

Performance Test.

a. At least thirty (30) days prior to conducting a source performance test as required by Attachment IIA, Section G, the permittee shall submit a written performance test plan to the Department of Health that includes the date(s) of the test, test duration, test locations, test methods, source operation, and other parameters that may affect test results. Such a plan shall conform to U.S. EPA guidelines including quality assurance procedures. A test plan or quality assurance plan that does not have the approval of the Department of Health may be grounds to invalidate any test and require a retest.

b. Within sixty (60) days after completion of a source performance test required by Attachment IIA, Section G, the permittee shall submit to the Department of Health and U.S. EPA Region 9 (Attention: AIR-3) the test report which shall include the operating conditions of the combustion turbine generators and diesel engine generators at the time of the test, the analysis of the fuel, the summarized test results, comparative results with the permit emission limits, and other pertinent field and laboratory data.

Justification – The requested changes are needed: 1) for consistency with CSP No. 0007-01-C and the notification requirements of 40 CFR Part 60 Subpart A; and 2) to relocate notification and reporting requirements from Section F Testing Requirements to Section E Notification and Reporting Requirements.

Proposed change to Attachment II, Special Condition E.4.: Excess Emissions

The permittee shall submit to the Department of Health and U.S. EPA Region 9 for every semi-annual calendar period reports of ~~an~~ excess emissions and monitor downtime in accordance with 40 CFR, Part 60, Section 60.7(c). ~~monitoring systems performance report of all excess emissions, including those associated with the water-to-fuel ratio requirement and implementation of any alternate operating scenarios, to the Department of Health for every semi-annual calendar period.~~ The report shall include the following:

a. The magnitude of excess emissions computed in accordance with 40 CFR Part 60, Section 60.13(h), any conversion factors used, and the date and time of commencement and completion of each time period of excess emissions, and the corresponding load of Unit CT-2.

b. Specific identification of each period of excess emissions that occurs during ~~"start-ups," "shut-downs,"~~ startups, shutdowns, and malfunctions of Unit CT-2. The nature and cause of any malfunction (if known), and the corrective action taken or preventive measures adopted~~, shall also be reported~~.

c. The date and time identifying each period during which the continuous monitoring system was inoperative except for zero and span checks~~. The~~ and the nature of ~~each~~ the system repairs or adjustments ~~shall be described~~.

d. ~~The report shall so stat if no excess emissions have occurred. Also, the report shall so state if the CEMS operated properly during the period and was not subject to any repairs or adjustments except for zero or span checks.~~ When no excess emissions have occurred or the CEMS has not been inoperative, repaired, or adjusted, such information shall be stated in the report.

e. ~~For periods of excess emissions as defined in Special Condition No. E.4.g.ii. of this Attachment, the report shall also include the average water-to-fuel ratio, average fuel consumption, ambient temperature, gas turbine load, and nitrogen content of the fuel during the period of excess emissions.~~

f. [No changes proposed]

Justification – The requested change is needed for consistency with reporting requirements under 40 CFR § 60.7(c) and CSP No. 0007-01-C.

Proposed change to Attachment II, Special Condition E.4.g.:

For purposes of this Covered Source Permit, excess emissions shall be defined as follows:

i. [No changes proposed]

ii. Any one (1) hour period during which the average water-to-fuel ratio, as measured by the continuous monitoring system, falls below the water-to-fuel mass ratio, as measured by the continuous monitoring system, falls below the water-to-fuel mass ratio at the corresponding operating load specified in Attachment II, Special Condition No. C.4.b. ~~When the load is not constant, provided that the above water injection rates at the four different peak load conditions are maintained, and NO_X emissions do not exceed the limits given in Attachment II, Special Condition C.6., a mathematical deviation on the one-hour average will not be considered out of compliance.~~ For operating periods during which the combustion turbine generator operates at multiple loads where multiple water-to-fuel mass ratios apply, the applicable water-to-fuel mass ratio shall be determined based on the load that corresponded to the lowest minimum water-to-fuel mass ratio.

Justification – The requested change clarifies the method of determining the applicable minimum water-to-fuel mass ratio for operating hours during which multiple minimum water-to-fuel mass ratios apply and provides consistency with proposed changes to Attachment II, Special Condition C.4.b. and CSP No. 0007-01-C.

Proposed change to Attachment II, Special Condition E.5.:

The permittee shall submit semi-annually the following written reports to the Department of Health. The report shall be submitted within sixty (60) days after the end of each semi-annual calendar period (January 1 to June 30 and July 1 to December 31), and shall include the following:

a. ~~Monthly~~ A summary ~~showing the daily "start-up"~~ identifying all dates, times and durations when the startup and ~~"shut-down" times~~ shutdown ~~and duration~~ sequence for ~~Unit CT-2~~ the combustion turbine generator exceeded twenty (20) minutes. ~~Include the associated load (MW) of Unit CT-2 at the start-up startup and termination of the air pollution control device. Include total operating hours per day and the total operating hours by month for Unit CT-2.~~ The enclosed Monitoring Report Form: ~~Daily "Start-up" and "Shut-down"~~ Combustion Turbine Generator Operation or an equivalent form ~~approved by the Department of Health~~ shall be used. ~~in reporting Unit CT-2's "start-up" and "shut-down" sequence.~~

b. [No changes proposed]

c. ~~Receipt dates of fuel deliveries, type of fuel, date batch sample taken, and the analyzed sulfur and nitrogen content in the fuel. Include copies of the supplier's certificate of analysis showing the sulfur content of the fuel delivered.~~ A report identifying the type of fuel fired in the combustion turbine during the semi-annual reporting period. The report shall include the maximum sulfur content (percent by weight) of the fuel for the reporting period. The enclosed Monitoring Report Form: *Fuel Certification*, or an equivalent form, shall be used.

d. Minimum ~~combustion turbine generator load~~ Operating Loads. ~~Except for Unit CT-2's "start-up" and "shut-down" sequences, report all periods of time (date, time and duration using data recorded by the CEMS) when the minimum operating load for Unit CT-2 is less than 25% of the rated capacity.~~

i. All periods when the operating load for the combustion turbine generators was below 25 percent of peak load (4.6 MW) except for all startup and shutdown sequences and as authorized pursuant to Special Condition C.2. of this Attachment. The report shall include the date, time and duration of each period using data recorded by the CEMS. The enclosed Monitoring Report Form: Combustion Turbine Generator Operation or an equivalent form shall be used.

ii. A monthly summary and rolling twelve (12) month total of the hours of operation of the combustion turbine generators, CT-2, CT-4, and CT-5, below 25 percent of peak load with water injection, excluding startup and shutdown sequences, maintenance, testing, and as approved pursuant to Special Condition C.8 of this Attachment. The report shall be based on data recorded by the CEMS. The enclosed Monitoring Report Form: Combustion Turbine Generator Monthly Operation Below Minimum Load with Water Injection or equivalent form shall be used.

e. [No changes proposed]

f. [No changes proposed]

g. Deviations from permit requirements shall be clearly identified and addressed in these reports.

Justification – The requested changes are needed: 1) for operation of CT-2 below 25 percent of peak load with water injection; and 2) for consistency with CSP No. 0007-01-C and proposed change to Special Condition D.4.d and e to remove the fuel bound nitrogen monitoring conditions because it is not required by NSPS Subpart GG if an emission allowance for fuel bound nitrogen is not claimed; HELCO has not claimed an emission allowance under NSPS Subpart GG.

Proposed change to Attachment II, Special Condition E.7.:

As required by Attachment IV and in conjunction with the requirements of Attachment III, the permittee shall submit annually the total tons/year emitted of each regulated air pollutant, including hazardous air pollutants. The reporting of annual emissions is due within sixty (60) days following the end of each calendar year. The enclosed Annual Emission Reporting Form: ~~Gas~~ Combustion Turbines and Diesel Engines or an equivalent form ~~approved by the Department of Health,~~ shall be used ~~in reporting~~.

Justification – The requested change is needed for consistency with CSP No. 0007-01-C.

Proposed change to Attachment II, Section E.: Add notification and reporting condition.

8. Alternate Operating Scenarios

a. Temporary Replacement. Within thirty (30) days of commencement of the temporary replacement, the permittee shall submit in writing to the Department of Health, the reason for the temporary replacement, removal and return dates, and the make, model, and serial number of the existing and temporary replacement units.

b. Alternate Fuels. In requesting for approval to fire CT-2 on alternate fuels, the permittee shall at a minimum, provided the Department of Health with information on the type of fuel proposed, reason for using the alternate fuel, emissions data, and the manufacturer's recommended water-to-fuel ratio and minimum operating load for compliance with the emission limits. The Department of Health may require an ambient air quality impact assessment for firing the alternate fuel and/or provide a conditional approval to impose additional monitoring, testing, recordkeeping, and reporting requirements. The Department of Health may establish minimum water-to-fuel ratio conditions in the permit for firing CT-2 on alternate fuels.

c. Low Load Operation without Water Injection. In requesting for approval, the permittee shall at a minimum provide the Department of Health the date and time period for testing, reason why it is necessary to test at loads less than 25 percent of peak load (4.6 MW) without water injection, procedures to be taken to minimize testing or maintenance at low load without water injection, maximum expected emissions, and any other supporting information as requested by the Department of Health. The Department of Health may require an ambient air quality assessment for the combustion turbine generator at low load without water injection, and/or provide a conditional approval to limit the maintenance and testing period, and impose additional monitoring, recordkeeping, and reporting requirements to ensure that operation at lower loads without water injection are in compliance with emission limits established in Special Condition C.6. of this Attachment.

Justification – The requested changes are needed to: 1) revise the alternate operating scenario for alternate fuels to allow adjustment of the minimum operating load and water-to-fuel mass ratios for alternate fuels, if necessary, to comply with the CSP emission limits; and 2) relocate permit notification and reporting conditions for alternate operating scenarios from Section C. Operational and Emission Limitations to Section E. Notification and Reporting Requirements.

Proposed change to Attachment II, Special Condition F.2.:

Performance tests for the emissions of NO_X, SO_2, CO, VOC and PM/PM_{10} shall be conducted and results reported in accordance with the test methods set forth in 40 CFR Part 60, Appendix A and 40 CFR Part 60, Section 60.8. The following test methods or U.S. EPA-approved equivalent methods, or alternate methods with prior written approval from the Department of Health shall be used:

a. Performance tests for the emissions of SO_2 shall be conducted using 40 CFR Part 60 Methods 1-4 and 6C or Methods 6C and 20.

b. Performance tests for the emissions of NO_X shall be conducted using 40 CFR Part 60 Methods 1-4 and 7E or Methods 7E and 20.

c. Performance tests for the emissions of CO shall be conducted using 40 CFR Part 60 Methods 1-4 and 10 or Methods 10 and 19.

d. Performance tests for the emissions of VOC shall be conducted using 40 CFR Part 60 Methods 1-4 and 25A (Method 19 may be used to account for the actual methane fraction of the measured VOC emissions).

e. Performance tests for the emissions of particulate matter shall be conducted using 40 CFR Part 60 Methods 1-5.

Justification – The requested changes expand the listed test methods to include the methods commonly used and incorporate DOH's standard permit language to authorize use of EPA-approved equivalent methods.

Proposed change to Attachment II, Special Condition F.4.: Delete condition.

~~At least thirty (30) days prior to performing a test, the permittee shall submit a written performance test plan to the Department of Health that describes the test duration, test locations, test methods, source operation and other parameters that may affect test results. Such a plan shall conform to U.S. EPA guidelines including quality assurance procedures. A test plan or quality assurance plan that does not have the approval of the Department of Health may be grounds to invalidate any test and require a retest.~~

Justification –The requested change is needed to relocate notification and reporting requirements from Section F. Testing Requirements to Section E. Notification and Reporting Requirements.

Proposed change to Attachment II, Special Condition F.7.: Delete condition.

~~Within sixty (60) days after completion of the performance test, the permittee shall submit to the Department of Health and U.S. EPA Region 9 (Attention: AIR-3) the test report which shall include the operating conditions of Unit CT-2 at the time of the test, the analysis of the fuel oil, the summarized test results, comparative results with the permit emission limits, and other pertinent field and laboratory data.~~

Justification –The requested change is needed to relocate notification and reporting requirements from Section F. Testing Requirements to Section E. Notification and Reporting Requirements.

Proposed change to Attachment IV: Annual Emissions Reporting Requirements:

Revise Section 1 as follows:

1. Complete the attached Annual Emissions Report Form for ~~Gas~~ Combustion Turbines and Diesel Engines.

Justification – The requested change is to eliminate redundant forms.

Proposed change to Monitoring Report Form – Daily "Start-Up" and "Shut-Down": Delete form.

Delete form and require use of Monitoring Report Form – Combustion Turbine Generator Operation as proposed in Attachment S-3c.

Justification – The requested change is needed for consistency with proposed changes to Attachment II, Special Condition E.5.d.

Proposed change to Annual Emissions Report Form – Gas Turbines: Delete form.

Delete form and require use of Annual Emissions Report Form – Combustion Turbines and Diesel Engines as proposed in Attachment S-3c.

Justification – The requested change is to eliminate redundant forms.

Proposed change to Monitoring Report Form - Fuel Consumption:

Delete form and require use of Monitoring Report Form – Fuel Consumption form in CSP No. 0007-01-C.

Justification – The requested change is to eliminate redundant forms.

Proposed change: Add Monitoring Report Form Combustion Turbine Generator Monthly Operation Below Minimum Load with Water Injection

Add new form. Refer to proposed form in Attachment S-3c.

Justification – The requested change is needed to report monthly and rolling 12-month total hours of operation below minimum operating load with water injection consistent with proposed changes to CSP No. 0070-01-C Attachment II, Special Condition C.3 and CSP No. 0007-01-C Attachment IIA, Special Condition C.2.

Hawaiian Electric Company, Inc. • PO Box 2750 • Honolulu, HI 96840-0001

CU | DV 0070-02
HELCO
Keahole

HAND DELIVERED
JAN - 8 2010

January 8, 2010

Sherri-Ann Loo, Esq.
Manager
Environmental Department

Mr. Wilfred K. Nagamine, Manager
Clean Air Branch
State of Hawaii Department of Health
P.O. Box 3378
Honolulu, Hawaii 96801-3378

Dear Mr. Nagamine:

Subject: Application for a Covered Source Permit Renewal
CSP No. 0070-01-C
Keahole Generating Station
Hawaii Electric Light Company, Inc. (HELCO)

In accordance with HAR 11-60.1-101, Hawaiian Electric Company, Inc. (HECO) on behalf of HELCO submits an original and one copy of the renewal application materials for the Keahole Generating Station.

The renewal application materials include Forms S-1, S-3, C-1 and C-2. Certifications in accordance with HAR 11-60.1-4 are included on Forms S-1, C-1 and C-2. Also enclosed is a check (number 382145) in the amount of $3000.00 for the renewal fee and supporting information for the requested permanent replacement alternate operating scenario.

This renewal application seeks to merge CSP No. 0070-01-C into CSP No. 0007-01-C.

If you have any questions regarding this submittal, please contact Karin Kimura at 543-4522 or karin.kimura@heco.com.

Sincerely,

S. A. Loo

Enclosures

cc: Deborah Jordan, EPA Region 9
Norman Verbanic, HELCO

md11179

HAND DELIVERED
JAN - 8 2010

File / Application No.: 0070-02

S-1: Standard Air Pollution Control Permit Application Form

(Covered Source Permit and Noncovered Source Permit)

State of Hawaii
Department of Health
Environmental Management Division
Clean Air Branch
P. O. Box 3378 • Honolulu, HI 96801-3378 • Phone: (808) 586-4200

1. Company Name: Hawaii Electric Light Company, Inc. (HELCO)
2. Facility Name (if different from the Company): Keahole Generating Station
3. Mailing Address: 73-4249 Pukiawe Street

   City: Kailua Kona State: HI Zip Code: 96740

   Phone Number: (808) 935-1711
4. Name of Owner/Owner's Agent: Sherri-Ann Loo (Owner's Agent)

   Title: Manager, Environmental Department Phone: (808) 543-4500

   Mailing Address: Hawaiian Electric Company; PO Box 2750

   City: Honolulu State: HI Zip Code: 96840-0001
5. Plant Site Manager/Other Contact: Norman Verbanic

   Title: Manager, Power Supply Operations and Management Phone: (808) 543-4236

   Mailing Address: P.O. Box 1027

   City: Hilo State: HI Zip Code: 96721
6. Permit Application Basis: (Check appropriate boxes)

   ☐ Initial Permit for a New Source ☐ Initial Permit for an Existing Source

   ■ Renewal of Existing Permit ☐ General Permit

   ☐ Temporary Source ☐ Transfer of Permit

   ☐ Modification to a Covered Source: ➔ Is modification? ☐ Significant ☐ Minor ☐ Uncertain

   ☐ Modification to a Noncovered Source
7. If renewal or modification, include existing permit number: CSP Nos. 0007-01-C and 0070-01-C
8. Does the Proposed Source require a County Special Management Area Permit? ☐ Yes ■ No
9. Type of Source (Check One): ☐ Covered Source ■ Covered & PSD Source

   ☐ Noncovered Source ☐ Uncertain
10. Standard Industrial Classification Code (SICC), if known: 4911

mcl 11/19

11. Proposed Equipment/Plant Location (e.g. street address): 73-4249 Pukiawe Street

City: Kailua Kona State: HI Zip Code: 96740

UTM Coordinates (meters): East: 811,293 North: 2,184,955

UTM Zone: 4 UTM Horizontal Datum: ■ Old Hawaiian ☐ NAD-27 ☐ NAD-83

12. General Nature of Business: Electrical Generation

13. Date of Planned Commencement of Installation or Modification: Upon approval of modification.

14. Is ***any*** of the equipment to be leased to another individual or entity? ☐ Yes ■ No

15. Type of Organization: ■ Corporation ☐ Individual Owner ☐ Partnership

☐ Government Agency (Government Facility Code: ____________)

☐ Other: ____________

Any applicant for a permit who fails to submit any relevant facts or who has submitted incorrect information in any permit application shall, upon becoming aware of such failure or incorrect submittal, promptly submit such supplementary facts or corrected information. In addition, an applicant shall provide additional information as necessary to address any requirements that become applicable to the source after the date it filed a complete application, but prior to the issuance of the noncovered source permit or release of a draft covered source permit. (HAR § 11-60.1-64 & 11-60.1-84)

RESPONSIBLE OFFICIAL (as defined in §11-60.1-1):

Name (Last): Verbanic (First): Norman (MI): ____________

Title: Manager Production Department Phone: (808) 969-0421

Mailing Address: P.O. Box 1027

City: Hilo State: HI Zip Code: 96721-1027

CERTIFICATION by Responsible Official (pursuant to §11-60.1-4):

I certify that I have knowledge of the facts herein set forth, that the same are true, accurate and complete to the best of my knowledge and belief, and that all information not identified by me as confidential in nature shall be treated by the Department of Health as public record. I further state that I will assume responsibility for the construction, modification, or operation of the source in accordance with the Hawaii Administrative Rules (HAR), Title 11, Chapter 60.1, Air Pollution Control, and any permit issued thereof.

NAME (Print/Type): Norman Verbanic

(Signature): Norman Verbanic Date: 05 JAN 10

FOR AGENCY USE ONLY:

File/Application No: 0070-02

Island: HAWAII

Date Received: 1/8/10

Submit the following documents as part of your application:

A. The ***Emissions Units Table***, filled in as completely as possible. Use separate sheets of paper as needed. General instructions include the following:

   1. Identify each **emission point** with a unique number for this plant site, consistent with emission point identification used on the location drawing and previous permits; if known, provide the SICC number. Emission points shall be identified and described in sufficient detail to establish the basis for **fees** and applicability of requirements of HAR, Chapter 11-60.1. Examples of emission point names are: heater, vent, boiler, tank, baghouse, fugitive, etc. Abbreviations may be used.
      a. For each emission point use as many lines as necessary to list regulated and hazardous air pollutant data. For hazardous air pollutants, also list the Chemical Abstracts Service number (CAS#).
      b. Indicate the emission points that discharge together for any length of time.
      c. The **Equipment Date** is the date of equipment construction, reconstruction, or modification. Provide supporting documentation.

   2. State the **maximum emission rates** in terms sufficient to establish compliance with the applicable requirements and standard reference test methods. Provide all supporting emission calculations and assumptions:
      a. Include all regulated and hazardous air pollutants and air pollutants for which the source is major, as defined in HAR §11-60.1-1. Examples of regulated pollutant names are: Carbon Monoxide (CO), Nitrogen Oxides (NO_X), Sulfur Dioxide (SO_2), Volatile Organic Compounds (VOC), particulate matter (PM), and particulate less than 10 microns (PM_{10}). Abbreviations may be used.
      b. Include fugitive emissions.
      c. **Pounds per hour (#/HR)** is the maximum potential emission rate expected by applicant.
      Tons per year is the annual maximum potential emissions expected by the applicant, taking into account the typical operating schedule.

   3. Describe ***Stack Source Parameters***:
      a. **Stack Height** is the height above the ground.
      b. **Direction** refers to the exit direction of stack emissions: up, down or horizontal.
      c. **Flow Rate** is the actual, not the calculated, flow rate.

   4. Provide any additional information, if applicable, as follows:
      a. If combinations of different fuels are used that cause any of the stack source parameters to differ, complete one row for each possible set of stack parameters and identify each fuel in the **Equipment Description**.
      b. For a rectangular stack, indicate the length and width.
      c. Provide any information on stack parameters or any stack height limitations developed pursuant to Section 123 of the Clean Air Act.

B. A **process flow diagram** identifying all equipment used in the process, including the following:
   1. Identify and describe each emission point.
   2. Identify the locations of safety valves, bypasses, and other such devices which when activated may release air pollutants to the atmosphere.

C. A **facility location map**, drawn to a reasonable scale and showing the following:
   1. The property involved and all structures on it. Identify property/fence lines plainly.
   2. Layout of the facility.
   3. Location and identification of the proposed emissions unit on the property.
   4. Location of the property and equipment with respect to streets and all adjacent property. Show the location of all structures within 325 meters of the applicant's emissions unit. Provide the building dimensions (height, length, and width) of all structures that have heights greater than 40% of the stack height of the emissions unit.

D. Provide a description of any proposed modifications or permit revisions. Include any justification or supporting information for the proposed modifications or permit revisions.

Responses to Emission Unit Table Instructions for Form S-1

A.1. Emission Point Identification and Description	See Form S-1 and Attachments S-1a, S-1b, and S-1c (attached).
A.2. Maximum Emission Rates	See Form S-1 and Attachments S-1a, S-1b, and S-1c (attached).
A.3. Stack Parameters	See Forms S-1 (attached). Emission points include a single flue stack serving CT-2, one-dual flue stack serving combustion turbines CT-4 and CT-5, and four single flue stacks serving diesel generators D-21, D-22, D-23, and BS-1.
A.4. Additional Information	Units operate on No. 2 fuel oil. Three hours is the averaging period for the lb/hr emission rates defined in the attached Form S-1 tables.
B. Process Flow Diagram	See Figures S-1.1, S-1.2, and S-1.3.
C. Facility Location Map	See Figure S-1.4.
D. Proposed Revisions	See Attachments S-3c and S-3d.

FIGURE S-1.1

PROCESS FLOW DIAGRAM FOR CT-2

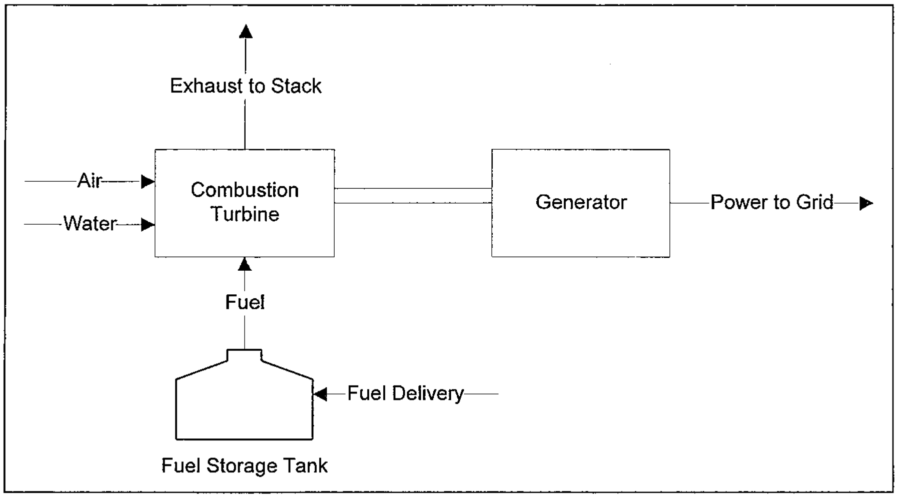


FIGURE S-1.2

PROCESS FLOW DIAGRAM FOR CT-4 OR CT-5

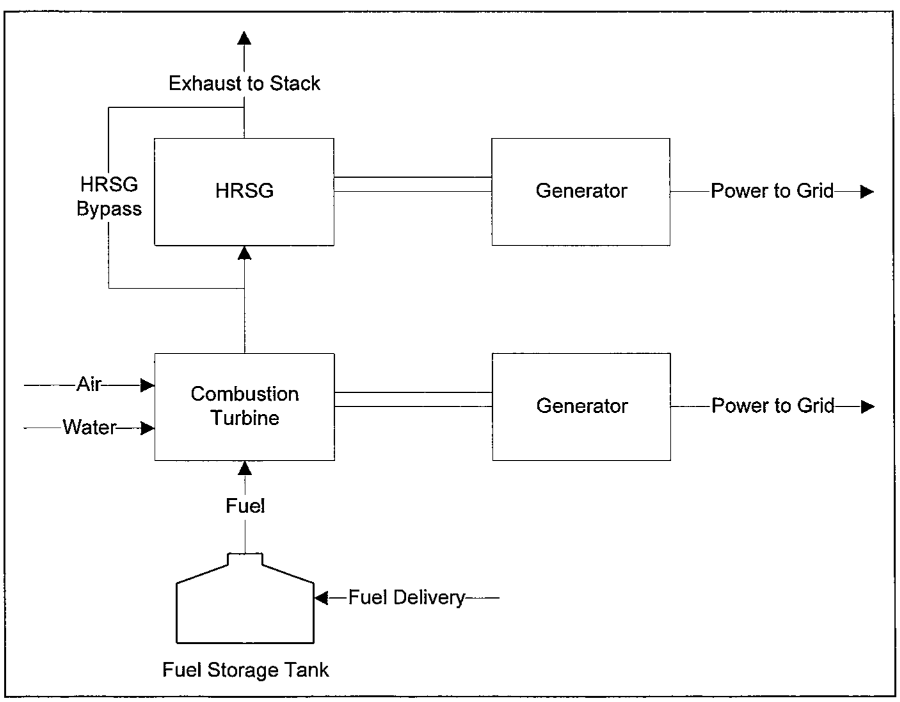


FIGURE S-1.3

PROCESS FLOW DIAGRAM FOR DIESEL UNITS, D-21, D-22, D-23, OR BS-1

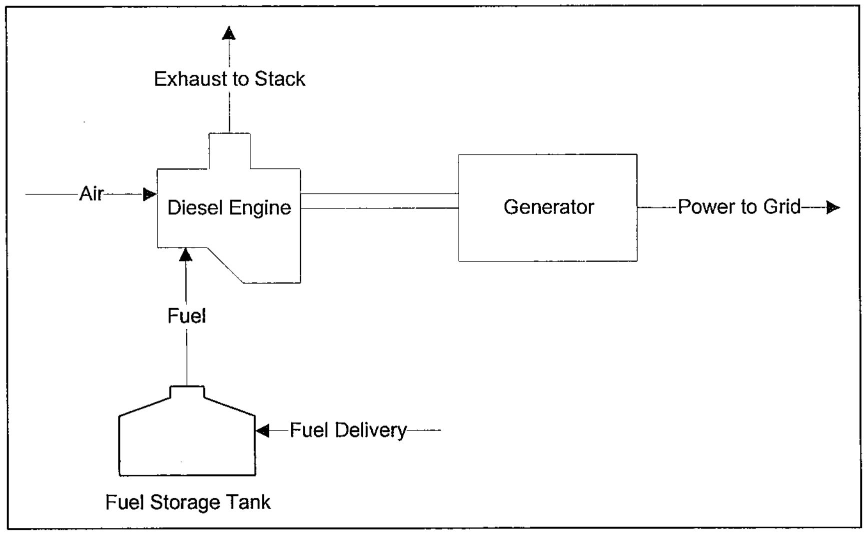
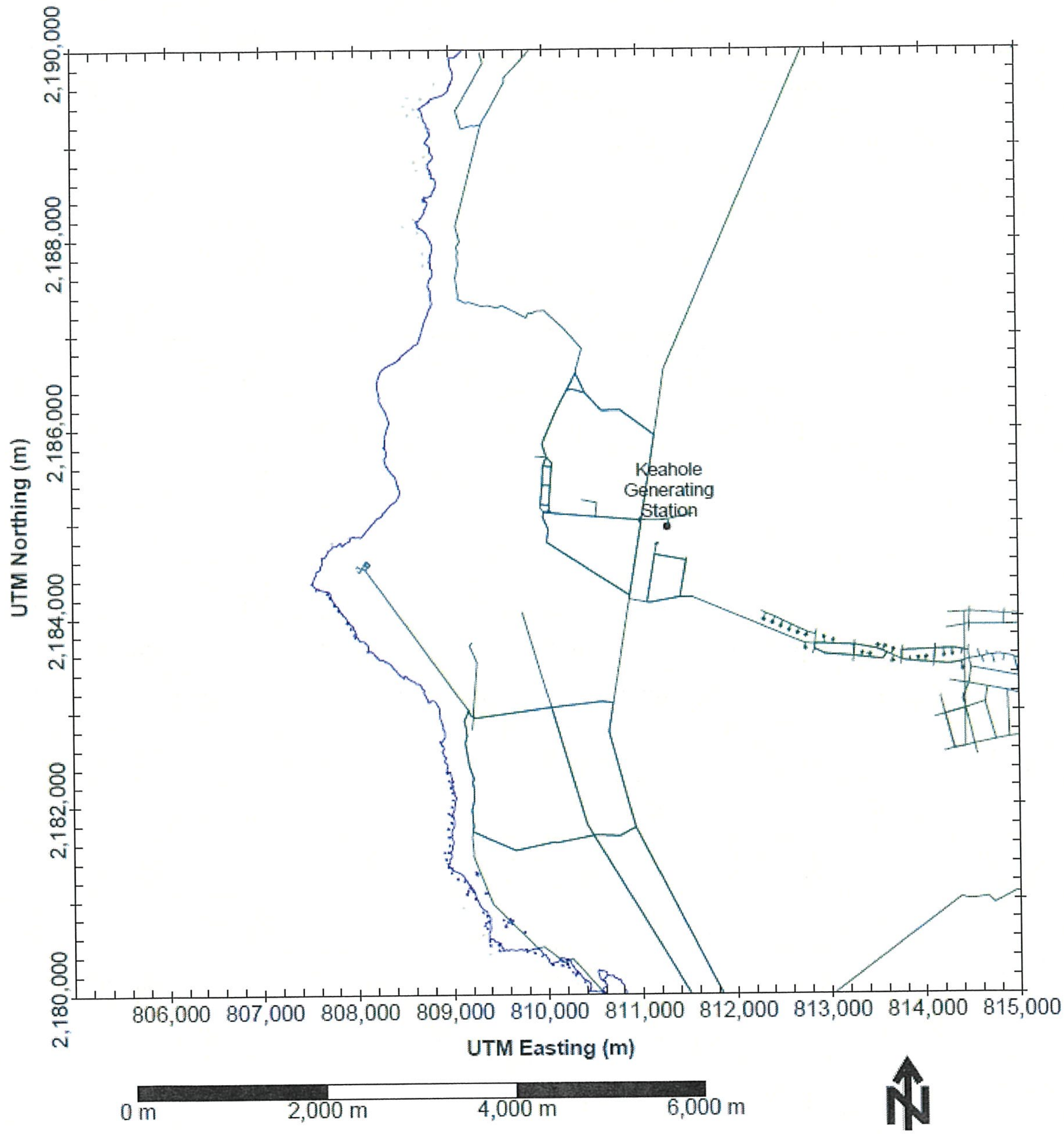


FIGURE S-1.4 LOCATION MAP



Company Name: Hawaii Electric Light Company, Inc. File No.: ______

Location: Keahole Generating Station

(Make as many copies of this page as necessary) Page 1

EMISSIONS UNITS TABLE

Review of applications and issuance of permits will be expedited by supplying all necessary information on this table.

AIR POLLUTANT DATA: EMISSION POINTS				AIR POLLUTANT	AIR POLLUTANT EMISSION RATE		UTM Zone: 4 Horizontal Datum [a]: Old Hawaiian	STACK SOURCE PARAMETERS						
Stack No.	Unit No.	EQUIPMENT NAME/DESCRIPTION & SICC number	Equipment Date	Regulated/Hazardous Air Pollutant Name & CAS#	#/HR.	Tons/Year	Coordinates (mtrs)	Stack Height (mtrs)	Direction (u/d/h)[b]	Inside Diameter (mtrs)	Velocity (m/s)	Flow Rate (m^3/s)	Temp. (°K)	Capped (Y/N)
2	CT-2	18 MW (Nominal) Jupiter GT-35 Combustion Turbine supplied by Solar Turbines, (SICC Code 4911)	6/29/1989	SO_2	110.0	478.4	East 811,250 North 2,184,848	21.3	U	3.40	19.8	175.0	647	N
				NO_x	39.0	169.6	East 811,250 North 2,184,848	21.3	U	3.40	19.8	175.0	647	N
				CO	22.4	97.4	East 811,250 North 2,184,848	21.3	U	3.40	19.8	175.0	647	N
				VOC	22.4	97.4	East 811,250 North 2,184,848	21.3	U	3.40	19.8	175.0	647	N
				PM/PM-10	20.0	87.0	East 811,250 North 2,184,848	21.3	U	3.40	19.8	175.0	647	N
				H_2SO_4 Mist	14.4	62.8	East 811,250 North 2,184,848	21.3	U	3.40	19.8	175.0	647	N
				Pb	See Attachment S-1a		East 811,250 North 2,184,848	21.3	U	3.40	19.8	175.0	647	N
				Fluorides	1.99E-03	8.67E-03	East 811,250 North 2,184,848	21.3	U	3.40	19.8	175.0	647	N
				TRS	Not Expected		East 811,250 North 2,184,848	21.3	U	3.40	19.8	175.0	647	N
				CFCs	Not Expected		East 811,250 North 2,184,848	21.3	U	3.40	19.8	175.0	647	N
				HAPs (see Table S-1a)	See Attachment S-1a		East 811,250 North 2,184,848	21.3	U	3.40	19.8	175.0	647	N

[a] Specify UTM Horizontal Datum as Old Hawaiian, NAD-83, or NAD-27

[b] Specify the direction of the stack exhaust as u=upward, d=downward, h=horizontal

Notes:
1. The equipment date is the date that HI 88-01 was issued.
2. Stack parameters are from the PSD Permit Application for CT-2, dated January 1989.
3. Unit CT-2 'tpy' values are based on 12,301,254 gallon per rolling 12-month period fuel limit, AP-42 no. 2 fuel oil heat content of 140,000 Btu/gal, and unit heat input of 198 MMBtu/hr.
4. SO_2, NO_x, CO, VOC, and PM/PM_{10} emission rates were established by HI 88-01.
5. NO_x and PM/PM_{10} emission rates were established by CSP No. 0070-01-C, dated January 12, 2006.
6. Emission rate for H_2SO_4 is 13.12% of the SO_2 rate (5.57 lb/hr H_2SO_4/42.44 lb/hr SO_2). This ratio is derived from the August 19, 1994 SCEC report of Maalaea M16 source tests.
7. Emission rate for Fluorides based on fuel test results of 0.2 ppm dated 04/11/85.

Company Name: Hawaii Electric Light Company, Inc. File No.: ______

Location: Keahole Generating Station

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EMISSIONS UNITS TABLE

Review of applications and issuance of permits will be expedited by supplying all necessary information on this table.

AIR POLLUTANT DATA: EMISSION POINTS				AIR POLLUTANT	AIR POLLUTANT EMISSION RATE		UTM Zone: 4 Horizontal Datum [a]: Old Hawaiian		STACK SOURCE PARAMETERS						
Stack No.	Unit No.	EQUIPMENT NAME/DESCRIPTION & SICC number	Equipment Date	Regulated/Hazardous Air Pollutant Name & CAS#	#/HR.	Tons/Year	Coordinates (mtrs)		Stack Height (mtrs)	Direction (u/d/h)[b]	Inside Diameter (mtrs)	Velocity (m/s)	Flow Rate (m^3/s)	Temp. (°K)	Capped (Y/N)
4 or 5	CT-4 or CT-5	20 MW (Nominal) General Electric LM2500 Combustion Turbine, (SICC Code 4911), Simple Cyle, Peak Load	7/25/2001	SO_2	110.0	481.8	East North	811,293 2,184,955	31.5	U	2.44	38.5	179.9	821	N
				NO_x	42.3	185.3	East North	811,293 2,184,955	31.5	U	2.44	38.5	179.9	821	N
				CO	26.8	117.4	East North	811,293 2,184,955	31.5	U	2.44	38.5	179.9	821	N
				VOC	0.8	3.5	East North	811,293 2,184,955	31.5	U	2.44	38.5	179.9	821	N
				PM/PM-10	19.7	86.3	East North	811,293 2,184,955	31.5	U	2.44	38.5	179.9	821	N
				H_2SO_4 Mist	14.4	63.2	East North	811,293 2,184,955	31.5	U	2.44	38.5	179.9	821	N
				Pb	See Attachment S-1a		East North	811,293 2,184,955	31.5	U	2.44	38.5	179.9	821	N
				Fluorides	2.77E-03	1.21E-02	East North	811,293 2,184,955	31.5	U	2.44	38.5	179.9	821	N
				TRS	Not Expected		East North	811,293 2,184,955	31.5	U	2.44	38.5	179.9	821	N
				CFCs	Not Expected		East North	811,293 2,184,955	31.5	U	2.44	38.5	179.9	821	N
				HAPs (see Table S-1a)	See Attachment S-1a		East North	811,293 2,184,955	31.5	U	2.44	38.5	179.9	821	N

[a] Specify UTM Horizontal Datum as Old Hawaiian, NAD-83, or NAD-27

[b] Specify the direction of the stack exhaust as u=upward, d=downward, h=horizontal

Notes:
1. The equipment date is the date that CSP No. 0007-01-C was issued.
2. Stack parameters and SO_2, NO_x, CO, VOC, and PM/PM_{10} emission rates are from the PSD Permit Application for CT-4 and CT-5, dated January 1993.
3. Emission rate for H_2SO_4 is 13.12% of the SO_2 rate (5.57 lb/hr H_2SO_4/42.44 lb/hr SO_2). This ratio is derived from the August 19, 1994 SCEC report of Maalaea M16 source tests.
4. Emission rate for Fluorides based on fuel tests results of 0.2 ppm dated April 11, 1985.

Company Name: Hawaii Electric Light Company, Inc. | File No.: ______

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EMISSIONS UNITS TABLE

Review of applications and issuance of permits will be expedited by supplying all necessary information on this table.

AIR POLLUTANT DATA: EMISSION POINTS				AIR POLLUTANT	AIR POLLUTANT EMISSION RATE		UTM Zone: 4 Horizontal Datum[a]: Old Hawaiian		STACK SOURCE PARAMETERS						
Stack No.	Unit No.	EQUIPMENT NAME/DESCRIPTION & SICC number	Equipment Date	Regulated/Hazardous Air Pollutant Name & CAS#	~~#/HR~~ ? 110 lb/hr	Tons/Year	Coordinates (mtrs)		Stack Height (mtrs)	Direction (u/d/h)[b]	Inside Diameter (mtrs)	Velocity (m/s)	Flow Rate (m^3/s)	Temp. (°K)	Capped (Y/N)
4 or 5	CT-4 or CT-5	20 MW (Nominal) General Electric LM2500 Combustion Turbine, (SICC Code 4911), Simple Cyle, 75% of Peak Load	7/25/2001	SO_2	82.9	363.1	East North	811,293 2,184,955	31.5	U	2.44	38.5	179.9	821	N
				NO_x	42.3	185.3	East North	811,293 2,184,955	31.5	U	2.44	38.5	179.9	821	N
				CO	56.4	247.0	East North	811,293 2,184,955	31.5	U	2.44	38.5	179.9	821	N
				VOC	2.6	11.4	East North	811,293 2,184,955	31.5	U	2.44	38.5	179.9	821	N
				PM/PM-10	19.7	86.3	East North	811,293 2,184,955	31.5	U	2.44	38.5	179.9	821	N

[a] Specify UTM Horizontal Datum as Old Hawaiian, NAD-83, or NAD-27

[b] Specify the direction of the stack exhaust as u=upward, d=downward, h=horizontal

Notes: 1. The equipment date is the date that CSP No. 0007-01-C was issued.

2. Stack parameters and SO_2, NO_x, CO, VOC, and PM/PM_{10} emission rates are from the PSD Permit Application for CT-4 and CT-5, dated January 1993.

Company Name: Hawaii Electric Light Company, Inc.
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EMISSIONS UNITS TABLE

Review of applications and issuance of permits will be expedited by supplying all necessary information on this table.

AIR POLLUTANT DATA: EMISSION POINTS				AIR POLLUTANT	AIR POLLUTANT EMISSION RATE		UTM Zone: 4 Horizontal Datum [a]: Old Hawaiian		STACK SOURCE PARAMETERS						
Stack No.	Unit No.	EQUIPMENT NAME/DESCRIPTION & SICC number	Equipment Date	Regulated/Hazardous Air Pollutant Name & CAS#	#/HR.	Tons/Year	Coordinates (mtrs)		Stack Height (mtrs)	Direction (u/d/h)[b]	Inside Diameter (mtrs)	Velocity (m/s)	Flow Rate (m^3/s)	Temp. (°K)	Capped (Y/N)
4 or 5	CT-4 or CT-5	20 MW (Nominal) General Electric LM2500 Combustion Turbine, (SICC Code 4911), Simple Cyle, 50% of Peak Load	7/25/2001	SO_2	58.0	254.0	East	811,293	31.5	U	2.44	38.5	179.9	821	N
							North	2,184,955							
				NO_x	42.3	185.3	East	811,293	31.5	U	2.44	38.5	179.9	821	N
							North	2,184,955							
				CO	181.0	792.8	East	811,293	31.5	U	2.44	38.5	179.9	821	N
							North	2,184,955							
				VOC	28.1	123.1	East	811,293	31.5	U	2.44	38.5	179.9	821	N
							North	2,184,955							
				PM/PM-10	19.7	86.3	East	811,293	31.5	U	2.44	38.5	179.9	821	N
							North	2,184,955							

[a] Specify UTM Horizontal Datum as Old Hawaiian, NAD-83, or NAD-27

[b] Specify the direction of the stack exhaust as u=upward, d=downward, h=horizontal

Notes: 1. The equipment date is the date that CSP No. 0007-01-C was issued.
2. Stack parameters and SO_2, NO_x, CO, VOC, and PM/PM_{10} emission rates are from the PSD Permit Application for CT-4 and CT-5, dated January 1993.

Company Name: Hawaii Electric Light Company, Inc.

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EMISSIONS UNITS TABLE

Review of applications and issuance of permits will be expedited by supplying all necessary information on this table.

AIR POLLUTANT DATA: EMISSION POINTS				AIR POLLUTANT	AIR POLLUTANT EMISSION RATE		UTM Zone: 4 Horizontal Datum [a]: Old Hawaiian		STACK SOURCE PARAMETERS						
Stack No.	Unit No.	EQUIPMENT NAME/DESCRIPTION & SICC number	Equipment Date	Regulated/Hazardous Air Pollutant Name & CAS#	#/HR.	Tons/Year	Coordinates (mtrs)		Stack Height (mtrs)	Direction (u/d/h)[b]	Inside Diameter (mtrs)	Velocity (m/s)	Flow Rate (m^3/s)	Temp. (°K)	Capped (Y/N)
4 or 5	CT-4 or CT-5	20 MW (Nominal) General Electric LM2500 Combustion Turbine, (SICC Code 4911), Simple Cyle, 25% of Peak Load	7/25/2001	SO_2	39.0	170.8	East North	811,293 2,184,955	31.5	U	2.44	38.5	179.9	821	N
				NO_x	42.3	185.3	East North	811,293 2,184,955	31.5	U	2.44	38.5	179.9	821	N
				CO	475.6	2083.1	East North	811,293 2,184,955	31.5	U	2.44	38.5	179.9	821	N
				VOC	297.6	1303.5	East North	811,293 2,184,955	31.5	U	2.44	38.5	179.9	821	N
				PM/PM-10	19.7	86.3	East North	811,293 2,184,955	31.5	U	2.44	38.5	179.9	821	N

[a] Specify UTM Horizontal Datum as Old Hawaiian, NAD-83, or NAD-27

[b] Specify the direction of the stack exhaust as u=upward, d=downward, h=horizontal

Notes: 1. The equipment date is the date that CSP No. 0007-01-C was issued.

2. Stack parameters and SO_2, NO_x, CO, VOC, and PM/PM_{10} emission rates are from the PSD Permit Application for CT-4 and CT-5, dated January 1993.

Company Name: Hawaii Electric Light Company, Inc.

Location: Keahole Generating Station

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EMISSIONS UNITS TABLE

Review of applications and issuance of permits will be expedited by supplying all necessary information on this table.

AIR POLLUTANT DATA: EMISSION POINTS				AIR POLLUTANT	AIR POLLUTANT EMISSION RATE		UTM Zone: 4 Horizontal Datum [a]: Old Hawaiian	STACK SOURCE PARAMETERS						
Stack No.	Unit No.	EQUIPMENT NAME/DESCRIPTION & SICC number	Equipment Date	Regulated/Hazardous Air Pollutant Name & CAS#	#/HR.	Tons/Year	Coordinates (mtrs)	Stack Height (mtrs)	Direction (u/d/h)[b]	Inside Diameter (mtrs)	Velocity (m/s)	Flow Rate (m^3/s)	Temp. (°K)	Capped (Y/N)
4 or 5	CT-4 or CT-5	20 MW (Nominal) General Electric LM2500 Combustion Turbine, (SICC Code 4911), Combined Cyle, Peak Load	7/25/2001	SO_2	110.0	481.8	East 811,293 North 2,184,955	31.5	U	2.44	38.5	179.9	821	N
				NO_x	15.1	66.1	East 811,293 North 2,184,955	31.5	U	2.44	38.5	179.9	821	N
				CO	26.9	117.8	East 811,293 North 2,184,955	31.5	U	2.44	38.5	179.9	821	N
				VOC	0.8	3.5	East 811,293 North 2,184,955	31.5	U	2.44	38.5	179.9	821	N
				PM/PM-10	19.7	86.3	East 811,293 North 2,184,955	31.5	U	2.44	38.5	179.9	821	N
				H_2SO_4 Mist	14.4	63.2	East 811,293 North 2,184,955	31.5	U	2.44	38.5	179.9	821	N
				Pb	See Form S-1a		East 811,293 North 2,184,955	31.5	U	2.44	38.5	179.9	821	N
				Fluorides	2.77E-03	1.21E-02	East 811,293 North 2,184,955	31.5	U	2.44	38.5	179.9	821	N
				TRS	Not Expected		East 811,293 North 2,184,955	31.5	U	2.44	38.5	179.9	821	N
				CFCs	Not Expected		East 811,293 North 2,184,955	31.5	U	2.44	38.5	179.9	821	N
				HAPs (see Table S-1a)	See Form S-1a		East 811,293 North 2,184,955	31.5	U	2.44	38.5	179.9	821	N
				NH_3	4.3	18.8	East 811,293 North 2,184,955	31.5	U	2.44	38.5	179.9	821	N

[a] Specify UTM Horizontal Datum as Old Hawaiian, NAD-83, or NAD-27

[b] Specify the direction of the stack exhaust as u=upward, d=downward, h=horizontal

Notes:
1. The equipment date is the date that CSP No. 0007-01-C was issued.
2. Stack parameters and SO_2, NO_x, CO, VOC, and PM/PM_{10} emission rates are from the PSD Permit Application for CT-4 and CT-5, dated January 1993.
3. NO_x emission rate is based on SCR + water injection reducing emissions to 15 ppmvd (15.1 = 42.3 x (15 ppmvd/42 ppmvd)).
4. Emission rate for H_2SO_4 is 13.12% of the SO_2 rate (5.57 lb/hr H_2SO_4/42.44 lb/hr SO_2). This ratio is derived from the August 19, 1994 SCEC report of Maalaea M16 source tests.
5. Emission rate for Fluorides based on fuel tests results of 0.2 ppm dated April 11, 1985.
6. NH_3 emission rate is based on manufacturer's maximum ammonia slip of 10 ppmvd and a peak load flow rate of 559,400 lb/hr at 59 degrees F.

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AIR POLLUTANT DATA: EMISSION POINTS				AIR POLLUTANT	AIR POLLUTANT EMISSION RATE		UTM Zone: 4 Horizontal Datum [a]: Old Hawaiian		STACK SOURCE PARAMETERS						
Stack No.	Unit No.	EQUIPMENT NAME/DESCRIPTION & SICC number	Equipment Date	Regulated/Hazardous Air Pollutant Name & CAS#	#/HR.	Tons/Year	Coordinates (mtrs)		Stack Height (mtrs)	Direction (u/d/h)[b]	Inside Diameter (mtrs)	Velocity (m/s)	Flow Rate (m^3/s)	Temp. (°K)	Capped (Y/N)
4 or 5	CT-4 or CT-5	20 MW (Nominal) General Electric LM2500 Combustion Turbine, (SICC Code 4911), Combined Cyle, 75% of Peak Load	7/25/2001	SO_2	86.0	376.7	East	811,293	31.5	U	2.44	38.5	179.9	821	N
							North	2,184,955							
				NO_x	15.1	66.1	East	811,293	31.5	U	2.44	38.5	179.9	821	N
							North	2,184,955							
				CO	50.2	219.9	East	811,293	31.5	U	2.44	38.5	179.9	821	N
							North	2,184,955							
				VOC	2.0	8.8	East	811,293	31.5	U	2.44	38.5	179.9	821	N
							North	2,184,955							
				PM/PM-10	19.7	86.3	East	811,293	31.5	U	2.44	38.5	179.9	821	N
							North	2,184,955							
				NH_3	4.3	18.8	East	811,293	31.5	U	2.44	38.5	179.9	821	N
							North	2,184,955							

[a] Specify UTM Horizontal Datum as Old Hawaiian, NAD-83, or NAD-27

[b] Specify the direction of the stack exhaust as u=upward, d=downward, h=horizontal

Notes:
1. The equipment date is the date that CSP No. 0007-01-C was issued.
2. Stack parameters and SO_2, NO_x, CO, VOC, and PM/PM_{10} emission rates are from the PSD Permit Application for CT-4 and CT-5, dated January 1993.
3. NO_x emission rate is based on SCR + water injection reducing emissions to 15 ppmvd (15.1 = 42.3 x (15 ppmvd/42 ppmvd)).
4. NH_3 emissions are the worst-case emission rate based on the manufacturer's guaranteed ammonia slip of 10 ppmvd and a 100 percent load flow rate of 559,400 lb/hr at 59 degrees F.

Company Name: Hawaii Electric Light Company, Inc.

Location: Keahole Generating Station

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EMISSIONS UNITS TABLE

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AIR POLLUTANT DATA: EMISSION POINTS				AIR POLLUTANT	AIR POLLUTANT EMISSION RATE		UTM Zone: 4 Horizontal Datum [a]: Old Hawaiian		STACK SOURCE PARAMETERS						
Stack No.	Unit No.	EQUIPMENT NAME/DESCRIPTION & SICC number	Equipment Date	Regulated/Hazardous Air Pollutant Name & CAS#	#/HR.	Tons/Year	Coordinates (mtrs)		Stack Height (mtrs)	Direction (u/d/h)[b]	Inside Diameter (mtrs)	Velocity (m/s)	Flow Rate (m^3/s)	Temp. (°K)	Capped (Y/N)
4 or 5	CT-4 or CT-5	20 MW (Nominal) General Electric LM2500 Combustion Turbine, (SICC Code 4911), Combined Cycle, 50% of Peak Load	7/25/2001	SO_2	59.0	258.4	East	811,293	31.5	U	2.44	14.2	66.4	419	N
							North	2,184,955							
				NO_x	42.3	185.3	East	811,293	31.5	U	2.44	14.2	66.4	419	N
							North	2,184,955							
				CO	170.4	746.4	East	811,293	31.5	U	2.44	14.2	66.4	419	N
							North	2,184,955							
				VOC	25.0	109.5	East	811,293	31.5	U	2.44	14.2	66.4	419	N
							North	2,184,955							
				PM/PM-10	19.7	86.3	East	811,293	31.5	U	2.44	14.2	66.4	419	N
							North	2,184,955							
				NH_3	4.3	18.8	East	811,293	31.5	U	2.44	14.2	66.4	419	N
							North	2,184,955							

[a] Specify UTM Horizontal Datum as Old Hawaiian, NAD-83, or NAD-27

[b] Specify the direction of the stack exhaust as u=upward, d=downward, h=horizontal

Notes:
1. The equipment date is the date that CSP No. 0007-01-C was issued.
2. Stack parameters and SO_2, NO_x, CO, VOC, and PM/PM_{10} emission rates are from the PSD Permit Application for CT-4 and CT-5, dated January 1993.
3. NO_x emission rate is based on SCR + water injection reducing emissions to 15 ppmvd (15.1 = 42.3 x (15 ppmvd/42 ppmvd)).
4. NH_3 emissions are the worst-case emission rate based on the manufacturer's guaranteed ammonia slip of 10 ppmvd and a 100 percent load flow rate of 559,400 lb/hr at 59 degrees F.

Company Name: Hawaii Electric Light Company, Inc.

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AIR POLLUTANT DATA: EMISSION POINTS				AIR POLLUTANT	AIR POLLUTANT EMISSION RATE		UTM Zone: 4 Horizontal Datum [a]: Old Hawaiian		STACK SOURCE PARAMETERS						
Stack No.	Unit No.	EQUIPMENT NAME/DESCRIPTION & SICC number	Equipment Date	Regulated/Hazardous Air Pollutant Name & CAS#	#/HR.	Tons/Year	Coordinates (mtrs)		Stack Height (mtrs)	Direction (u/d/h)[b]	Inside Diameter (mtrs)	Velocity (m/s)	Flow Rate (m^3/s)	Temp. (°K)	Capped (Y/N)
4 or 5	CT-4 or CT-5	20 MW (Nominal) General Electric LM2500 Combustion Turbine, (SICC Code 4911), Combined Cyle, 25% of Peak Load	7/25/2001	SO_2	39.9	174.8	East	811,293	31.5	U	2.44	10.8	50.5	414	N
							North	2,184,955							
				NO_x	42.3	185.3	East	811,293	31.5	U	2.44	10.8	50.5	414	N
							North	2,184,955							
				CO	457.4	2003.4	East	811,293	31.5	U	2.44	10.8	50.5	414	N
							North	2,184,955							
				VOC	271.0	1187.0	East	811,293	31.5	U	2.44	10.8	50.5	414	N
							North	2,184,955							
				PM/PM-10	19.7	86.3	East	811,293	31.5	U	2.44	10.8	50.5	414	N
							North	2,184,955							

[a] Specify UTM Horizontal Datum as Old Hawaiian, NAD-83, or NAD-27

[b] Specify the direction of the stack exhaust as u=upward, d=downward, h=horizontal

Notes:
1. The equipment date is the date that CSP No. 0007-01-C was issued.
2. Stack parameters and SO_2, NO_x, CO, VOC, and PM/PM_{10} emission rates are from the PSD Permit Application for CT-4 and CT-5, dated January 1993.
3. NO_X emission rate is based on water injection reducing emissions to 42 ppmvd. SCR is not required for loads less than 50% of peak. Operating the SCR at loads less than 50% of peak will cause ammonium sulfates to form in the catalyst and on the boiler tubes in the heat recovery steam generator.

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AIR POLLUTANT DATA: EMISSION POINTS				AIR POLLUTANT	AIR POLLUTANT EMISSION RATE		UTM Zone: 4 Horizontal Datum [a]: Old Hawaiian	STACK SOURCE PARAMETERS						
Stack No.	Unit No.	EQUIPMENT NAME/DESCRIPTION & SICC number	Equipment Date	Regulated/Hazardous Air Pollutant Name & CAS#	#/HR.	Tons/Year	Coordinates (mtrs)	Stack Height (mtrs)	Direction (u/d/h) [b]	Inside Diameter (mtrs)	Velocity (m/s)	Flow Rate (m^3/s)	Temp. (°K)	Capped (Y/N)
21	D-21	2.5 MW (Nominal) General Motors EMD Model 20-645F4B Diesel Engine Generator (SICC Code 4911)	1974	SO_2	11.6	2.0	East 811,255 North 2,184,884	12.2	U	0.90	18.3	11.6	677	N
				NO_x	68.4	11.9	East 811,255 North 2,184,884	12.2	U	0.90	18.3	11.6	677	N
				CO	78.5	13.7	East 811,255 North 2,184,884	12.2	U	0.90	18.3	11.6	677	N
				VOC	6.69	1.17	East 811,255 North 2,184,884	12.2	U	0.90	18.3	11.6	677	N
				PM/PM-10	5.06	0.88	East 811,255 North 2,184,884	12.2	U	0.90	18.3	11.6	677	N
				H_2SO_4 Mist	1.60	0.28	East 811,255 North 2,184,884	12.2	U	0.90	18.3	11.6	677	N
				Pb	See Attachment S-1a		East 811,255 North 2,184,884	12.2	U	0.90	18.3	11.6	677	N
				Fluorides	2.83E-04	4.94E-05	East 811,255 North 2,184,884	12.2	U	0.90	18.3	11.6	677	N
				TRS	Not Expected		East 811,255 North 2,184,884	12.2	U	0.90	18.3	11.6	677	N
				CFCs	Not Expected		East 811,255 North 2,184,884	12.2	U	0.90	18.3	11.6	677	N
				HAPs (see Table S-1a)	See Attachment S-1a		East 811,255 North 2,184,884	12.2	U	0.90	18.3	11.6	677	N

[a] Specify UTM Horizontal Datum as Old Hawaiian, NAD-83, or NAD-27

[b] Specify the direction of the stack exhaust as u=upward, d=downward, h=horizontal

Notes: 1 SO_2, NO_x, CO, VOC, and PM/PM_{10} emission rates are based on an evaluation of AP-42 calculations and stack test data.

2. Emission rate for H_2SO_4 is 13.83% of the SO_2 rate (0.73 lb/hr H_2SO_4/5.28 lb/hr SO_2). This ratio is derived from the August 19, 1994 SCEC report of Maalaea M3 source tests.

3. Emission rate for Fluorides based on fuel test results of 0.2 ppm dated April 11, 1985.

4. Unit D-21 'tpy' values are based on 70,000 gal/yr fuel limit, AP-42 no. 2 fuel oil heat content of 140,000 Btu/gal, and unit heat input of 28.1 MMBtu/hr.

Company Name: Hawaii Electric Light Company, Inc. File No.: ____

Location: Keahole Generating Station

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EMISSIONS UNITS TABLE

Review of applications and issuance of permits will be expedited by supplying all necessary information on this table.

AIR POLLUTANT DATA: EMISSION POINTS				AIR POLLUTANT	AIR POLLUTANT EMISSION RATE		UTM Zone: 4 Horizontal Datum [a]: Old Hawaiian		STACK SOURCE PARAMETERS						
Stack No.	Unit No.	EQUIPMENT NAME/DESCRIPTION & SICC number	Equipment Date	Regulated/Hazardous Air Pollutant Name & CAS#	#/HR.	Tons/Year	Coordinates (mtrs)		Stack Height (mtrs)	Direction (u/d/h)[b]	Inside Diameter (mtrs)	Velocity (m/s)	Flow Rate (m^3/s)	Temp. (°K)	Capped (Y/N)
22	D-22	2.5 MW (Nominal) General Motors EMD Model 20-645F4B Diesel Engine Generator (SICC Code 4911)	1966	SO_2	11.6	50.8	East North	811,253 2,184,874	12.2	U	0.90	18.3	11.6	877	N
				NO_x	68.4	299.6	East North	811,253 2,184,874	12.2	U	0.90	18.3	11.6	877	N
				CO	78.5	343.8	East North	811,253 2,184,874	12.2	U	0.90	18.3	11.6	877	N
				VOC	6.69	29.30	East North	811,253 2,184,874	12.2	U	0.90	18.3	11.6	877	N
				PM/PM-10	5.06	22.16	East North	811,253 2,184,874	12.2	U	0.90	18.3	11.6	877	N
				H_2SO_4 Mist	1.60	7.03	East North	811,253 2,184,874	12.2	U	0.90	18.3	11.6	877	N
				Pb	See Attachment S-1a		East North	811,253 2,184,874	12.2	U	0.90	18.3	11.6	877	N
				Fluorides	2.83E-04	1.24E-03	East North	811,253 2,184,874	12.2	U	0.90	18.3	11.6	877	N
				TRS	Not Expected		East North	811,253 2,184,874	12.2	U	0.90	18.3	11.6	877	N
				CFCs	Not Expected		East North	811,253 2,184,874	12.2	U	0.90	18.3	11.6	877	N
				HAPs (see Table S-1a)	See Attachment S-1a		East North	811,253 2,184,874	12.2	U	0.90	18.3	11.6	877	N

[a] Specify UTM Horizontal Datum as Old Hawaiian, NAD-83, or NAD-27

[b] Specify the direction of the stack exhaust as u=upward, d=downward, h=horizontal

Notes: 1 SO_2, NO_x, CO, VOC, and PM/PM_{10} emission rates are based on an evaluation of AP-42 calculations and stack test data.

2. Emission rate for H_2SO_4 is 13.83% of the SO_2 rate (0.73 lb/hr H_2SO_4/5.28 lb/hr SO_2). This ratio is derived from the August 19, 1994 SCEC report of Maalaea M3 source tests.

3. Emission rate for Fluorides based on fuel test results of 0.2 ppm dated April 11, 1985.

Company Name: Hawaii Electric Light Company, Inc. File No.:

Location: Keahole Generating Station

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EMISSIONS UNITS TABLE

Review of applications and issuance of permits will be expedited by supplying all necessary information on this table.

AIR POLLUTANT DATA: EMISSION POINTS				AIR POLLUTANT	AIR POLLUTANT EMISSION RATE		UTM Zone: 4 Horizontal Datum [a]: Old Hawaiian		STACK SOURCE PARAMETERS						
Stack No.	Unit No.	EQUIPMENT NAME/DESCRIPTION & SICC number	Equipment Date	Regulated/Hazardous Air Pollutant Name & CAS#	#/HR.	Tons/Year	Coordinates (mtrs)		Stack Height (mtrs)	Direction (u/d/h)[b]	Inside Diameter (mtrs)	Velocity (m/s)	Flow Rate (m^3/s)	Temp. (°K)	Capped (Y/N)
23	D-23	2.5 MW (Nominal) General Motors EMD Model 20-645F4B Diesel Engine Generator (SICC Code 4911)	1969	SO_2	11.6	50.8	East	811,251	12.2	U	0.90	18.3	11.6	677	N
							North	2,184,869							
				NO_x	68.4	299.6	East	811,251	12.2	U	0.90	18.3	11.6	677	N
							North	2,184,869							
				CO	78.5	343.8	East	811,251	12.2	U	0.90	18.3	11.6	677	N
							North	2,184,869							
				VOC	6.69	29.3	East	811,251	12.2	U	0.90	18.3	11.6	677	N
							North	2,184,869							
				PM/PM-10	5.06	22.2	East	811,251	12.2	U	0.90	18.3	11.6	677	N
							North	2,184,869							
				H_2SO_4 Mist	1.60	7.0	East	811,251	12.2	U	0.90	18.3	11.6	677	N
							North	2,184,869							
				Pb	See Attachment S-1a		East	811,251	12.2	U	0.90	18.3	11.6	677	N
							North	2,184,869							
				Fluorides	2.83E-04	1.24E-03	East	811,251	12.2	U	0.90	18.3	11.6	677	N
							North	2,184,869							
				TRS	Not Expected		East	811,251	12.2	U	0.90	18.3	11.6	677	N
							North	2,184,869							
				CFCs	Not Expected		East	811,251	12.2	U	0.90	18.3	11.6	677	N
							North	2,184,869							
				HAPs (see Table S-1a)	See Attachment S-1a		East	811,251	12.2	U	0.90	18.3	11.6	677	N
							North	2,184,869							

[a] Specify UTM Horizontal Datum as Old Hawaiian, NAD-83, or NAD-27

[b] Specify the direction of the stack exhaust as u=upward, d=downward, h=horizontal

Notes: 1 SO_2, NO_x, CO, VOC, and PM/PM_{10} emission rates are based on an evaluation of AP-42 calculations and stack test data.

2. Emission rate for H_2SO_4 is 13.83% of the SO_2 rate (0.73 lb/hr H_2SO_4/5.28 lb/hr SO_2). This ratio is derived from the August 19, 1994 SCEC report of Maalaea M3 source tests.

3. Emission rate for Fluorides based on fuel test results of 0.2 ppm dated April 11, 1985.

Company Name: Hawaii Electric Light Company, Inc.

Location: Keahole Generating Station

(Make as many copies of this page as necessary)

File No.: ______

EMISSIONS UNITS TABLE

Review of applications and issuance of permits will be expedited by supplying all necessary information on this table.

AIR POLLUTANT DATA: EMISSION POINTS				AIR POLLUTANT	AIR POLLUTANT EMISSION RATE		UTM Zone: 4 Horizontal Datum [a]: Old Hawaiian		STACK SOURCE PARAMETERS						
Stack No.	Unit No.	EQUIPMENT NAME/DESCRIPTION & SICC number	Equipment Date	Regulated/Hazardous Air Pollutant Name & CAS#	#/HR.	Tons/Year	Coordinates (mtrs)		Stack Height (mtrs)	Direction (u/d/h)[b]	Inside Diameter (mtrs)	Velocity (m/s)	Flow Rate (m^3/s)	Temp. (°K)	Capped (Y/N)
1	BS-1	500 kW Caterpillar Model 3412 Blackstart Diesel Engine Generator (SICC Code 4911)	Nov. 4, 1991	SO_2	2.86	0.43	East	811,250	21.3	U	0.20	62.2	2.0	894	N
							North	2,184,848							
				NO_x	12.50	1.88	East	811,250	21.3	U	0.20	62.2	2.0	894	N
							North	2,184,848							
				CO	2.38	0.36	East	811,250	21.3	U	0.20	62.2	2.0	894	N
							North	2,184,848							
				VOC	0.46	0.07	East	811,250	21.3	U	0.20	62.2	2.0	894	N
							North	2,184,848							
				PM/PM-10	1.98	0.30	East	811,250	21.3	U	0.20	62.2	2.0	894	N
							North	2,184,848							
				H_2SO_4 Mist	0.40	0.06	East	811,250	21.3	U	0.20	62.2	2.0	894	N
							North	2,184,848							
				Pb	See Attachment S-1a		East	811,250	21.3	U	0.20	62.2	2.0	894	N
							North	2,184,848							
				Fluorides	5.61E-05	8.41E-06	East	811,250	21.3	U	0.20	62.2	2.0	894	N
							North	2,184,848							
				TRS	Not Expected		East	811,250	21.3	U	0.20	62.2	2.0	894	N
							North	2,184,848							
				CFCs	Not Expected		East	811,250	21.3	U	0.20	62.2	2.0	894	N
							North	2,184,848							
				HAPs (see Table S-1a)	See Attachment S-1a		East	811,250	21.3	U	0.20	62.2	2.0	894	N
							North	2,184,848							

[a] Specify UTM Horizontal Datum as Old Hawaiian, NAD-83, or NAD-27

[b] Specify the direction of the stack exhaust as u=upward, d=downward, h=horizontal

Notes:
1. Equipment date is the date that PTO No. P-936-1287 was issued.
2. SO_2, NO_x, CO, and PM/PM_{10} emission rates are from ATC application dated Jan. 30, 1981. VOC emissions are based on AP-42, Section 3.4, dated 10/96.
3. BS-1 is limited to 300 hours per year.
4. Emission rate for H_2SO_4 is 13.83% of the SO_2 rate (0.73 lb/hr H_2SO_4/5.28 lb/hr SO_2). This ratio is derived from the August 19, 1994 SCEC report of Maalaea M3 source tests.
5. Emission rate for Fluorides based on fuel test results of 0.2 ppm dated April 11, 1985.

Attachment S-1a
Air Toxic Emissions for CT-2

SECTION 112 HAZARDOUS AIR POLLUTANTS

EPA ID #	CAS Number	Pollutant	Source of Emission Factor	Emission Factor (lb/MMBtu)	Heat Input (MMBtu/hr)	Heat Input (MMBtu/yr)	Emissions (lb/hr)	Emissions (tpy)
1	75-07-0	Acetaldehyde	AP-42, Section 3.4, Table 3.4-3	2.52E-05	198	1,722,176	4.99E-03	2.17E-02
2	60-35-5	Acetamide			198	1,722,176		
3	75-05-8	Acetonitrile			198	1,722,176		
4	98-86-2	Acetophenone			198	1,722,176		
5	53-96-3	2-Acetylaminofluorene			198	1,722,176		
6	107-02-8	Acrolein	AP-42, Section 3.4, Table 3.4-3	7.88E-06	198	1,722,176	1.56E-03	6.79E-03
7	79-06-1	Acrylamide			198	1,722,176		
8	79-10-7	Acrylic acid			198	1,722,176		
9	107-13-1	Acrylonitrile			198	1,722,176		
10	107-05-1	Allyl chloride			198	1,722,176		
11	92-67-1	4-Aminobiphenyl			198	1,722,176		
12	62-53-3	Aniline			198	1,722,176		
13	90-04-0	o-Anisidine			198	1,722,176		
14	1332-21-4	Asbestos			198	1,722,176		
15	71-43-2	Benzene (including benzene from gasoline)	AP-42, Section 3.1, Table 3.1-4	5.50E-05	198	1,722,176	1.09E-02	4.74E-02
16	92-87-5	Benzidine			198	1,722,176		
17	98-07-7	Benzotrichloride			198	1,722,176		
18	100-44-7	Benzyl chloride			198	1,722,176		
19	92-52-4	Biphenyl			198	1,722,176		
20	117-81-7	Bis(2-ethylhexyl)phthalate (DEHP)			198	1,722,176		
21	542-88-1	Bis(chloromethyl) ether			198	1,722,176		
22	75-25-2	Bromoform			198	1,722,176		
23	106-99-0	1,3-Butadiene	AP-42, Section 3.1, Table 3.1-4	1.60E-05	198	1,722,176	3.17E-03	1.38E-02
24	156-62-7	Calcium cyanamide			198	1,722,176		
25	105-60-2	Caprolactam (Removed 06/18/96, See 61FR30816)			198	1,722,176		
26	133-06-2	Captan			198	1,722,176		
27	63-25-2	Carbaryl			198	1,722,176		
28	75-15-0	Carbon disulfide			198	1,722,176		
29	56-23-5	Carbon tetrachloride			198	1,722,176		
30	463-58-1	Carbonyl sulfide			198	1,722,176		
31	120-80-9	Catechol			198	1,722,176		
32	133-90-4	Chloramben			198	1,722,176		
33	57-74-9	Chlordane			198	1,722,176		
34	7782-50-5	Chlorine			198	1,722,176		
35	79-11-8	Chloroacetic acid			198	1,722,176		
36	532-27-4	2-Chloroacetophenone			198	1,722,176		
37	108-90-7	Chlorobenzene			198	1,722,176		
38	510-15-6	Chlorobenzilate			198	1,722,176		
39	67-66-3	Chloroform			198	1,722,176		
40	107-30-2	Chloromethyl methyl ether			198	1,722,176		
41	126-99-8	Chloroprene			198	1,722,176		
42	1319-77-3	Cresol/Cresylic acid(mixed isomers)			198	1,722,176		
43	95-48-7	o-Cresol			198	1,722,176		
44	108-39-4	m-Cresol			198	1,722,176		
45	106-44-5	p-Cresol			198	1,722,176		
46	98-82-8	Cumene			198	1,722,176		
47		2,4-D(2,4-Dichlorophenoxyacetic Acid) (including salts and esters)			198	1,722,176		
48	72-55-9	DDE(1,1-dichloro-2,2-bis(p-chlorophenyl) ethylene)			198	1,722,176		
49	334-88-3	Diazomethane			198	1,722,176		
50	132-64-9	Dibenzofuran			198	1,722,176		
51	96-12-8	1,2-Dibromo-3-chloropropane			198	1,722,176		
52	84-74-2	Dibutyl phthalate			198	1,722,176		
53	106-46-7	1,4-Dichlorobenzene			198	1,722,176		
54	91-94-1	Dichlorobenzidine			198	1,722,176		
55	111-44-4	Dichloroethyl ether(Bis[2-chloroethyl]ether)			198	1,722,176		
56	542-75-6	1,3-Dichloropropene			198	1,722,176		
57	62-73-7	Dichlorvos			198	1,722,176		
58	111-42-2	Diethanolamine			198	1,722,176		
59	64-67-5	Diethyl sulfate			198	1,722,176		
60	119-90-4	3,3'-Dimethoxybenzidine			198	1,722,176		
61	60-11-7	4-Dimethylaminoazobenzene			198	1,722,176		
62	121-69-7	N,N-Dimethylaniline			198	1,722,176		
63	119-93-7	3,3'-Dimethylbenzidine			198	1,722,176		
64	79-44-7	Dimethylcarbamoyl chloride			198	1,722,176		
65	68-12-2	N,N-Dimethylformamide			198	1,722,176		
66	57-14-7	1,1-Dimethylhydrazine			198	1,722,176		
67	131-11-3	Dimethyl phthalate			198	1,722,176		
68	77-78-1	Dimethyl sulfate			198	1,722,176		
69		4,6-Dinitro-o-cresol (including salts)			198	1,722,176		
70	51-28-5	2,4-Dinitrophenol			198	1,722,176		
71	121-14-2	2,4-Dinitrotoluene			198	1,722,176		
72	123-91-1	1,4-Dioxane (1,4-Diethyleneoxide)			198	1,722,176		
73	122-66-7	1,2-Diphenylhydrazine			198	1,722,176		
74	106-89-8	Epichlorohydrin (l-Chloro-2,3-epoxypropane)			198	1,722,176		
75	106-88-7	1,2-Epoxybutane			198	1,722,176		
76	140-88-5	Ethyl acrylate			198	1,722,176		
77	100-41-4	Ethylbenzene			198	1,722,176		
78	51-79-6	Ethyl carbamate (Urethane)			198	1,722,176		

Attachment S-1a
Air Toxic Emissions for CT-2

SECTION 112 HAZARDOUS AIR POLLUTANTS

EPA ID #	CAS Number	Pollutant	Source of Emission Factor	Emission Factor (lb/MMBtu)	Heat Input (MMBtu/hr)	Heat Input (MMBtu/yr)	Emissions (lb/hr)	Emissions (tpy)
79	75-00-3	Ethyl chloride (Chloroethane)			198	1,722,176		
80	106-93-4	Ethylene dibromide (Dibromoethane)			198	1,722,176		
81	107-06-2	Ethylene dichloride (1,2-Dichloroethane)			198	1,722,176		
82	107-21-1	Ethylene glycol			198	1,722,176		
83	151-56-4	Ethyleneimine (Aziridine)			198	1,722,176		
84	75-21-8	Ethylene oxide			198	1,722,176		
85	96-45-7	Ethylene thiourea			198	1,722,176		
86	75-34-3	Ethylidene dichloride (1,1-Dichloroethane)			198	1,722,176		
87	50-00-0	Formaldehyde	AP-42, Section 3.1, Table 3.1-4	2.80E-04	198	1,722,176	5.54E-02	2.41E-01
88	76-44-8	Heptachlor			198	1,722,176		
89	118-74-1	Hexachlorobenzene			198	1,722,176		
90	87-68-3	Hexachlorobutadiene			198	1,722,176		
91		1,2,3,4,5,6-Hexachlorocyclyhexane (all stereo isomers including lindane)			198	1,722,176		
92	77-47-4	Hexachlorocyclopentadiene			198	1,722,176		
93	67-72-1	Hexachloroethane			198	1,722,176		
94	822-06-0	Hexamethylene diisocyanate			198	1,722,176		
95	680-31-9	Hexamethylphosphoramide			198	1,722,176		
96	110-54-3	Hexane			198	1,722,176		
97	302-01-2	Hydrazine			198	1,722,176		
98	7647-01-0	Hydrochloric acid (Hydrogen chloride [gas only])			198	1,722,176		
99	7664-39-3	Hydrogen fluoride (Hydrofluoric acid)			198	1,722,176		
100	123-31-9	Hydroquinone			198	1,722,176		
101	78-59-1	Isophorone			198	1,722,176		
102	108-31-6	Maleic anhydride			198	1,722,176		
103	67-56-1	Methanol			198	1,722,176		
104	72-43-5	Methoxychlor			198	1,722,176		
105	74-83-9	Methyl bromide (Bromomethane)			198	1,722,176		
106	74-87-3	Methyl chloride(Chloromethane)			198	1,722,176		
107	71-55-6	Methyl chloroform(1,1,1-Trichloroethane)			198	1,722,176		
108	78-93-3	Methyl ethyl ketone (2-Butanone) (Removed 12/19/05, See 70FR75047)			198	1,722,176		
109	60-34-4	Methylhydrazine			198	1,722,176		
110	74-88-4	Methyl iodide (Iodomethane)			198	1,722,176		
111	108-10-1	Methyl isobutyl ketone(Hexone)			198	1,722,176		
112	624-83-9	Methyl isocyanate			198	1,722,176		
113	80-62-6	Methyl methacrylate			198	1,722,176		
114	1634-04-4	Methyl tert-butyl ether			198	1,722,176		
115	101-14-4	4,4'-Methylenebis(2-chloroaniline)			198	1,722,176		
116	75-09-2	Methylene chloride(Dichloromethane)			198	1,722,176		
117	101-68-8	4,4'-Methylenediphenyl diisocyanate(MDI)			198	1,722,176		
118	101-77-9	4,4'-Methylenedianiline			198	1,722,176		
119	91-20-3	Naphthalene	AP-42, Section 3.1, Table 3.1-4	3.50E-05	198	1,722,176	6.93E-03	3.01E-02
120	98-95-3	Nitrobenzene			198	1,722,176		
121	92-93-3	4-Nitrobiphenyl			198	1,722,176		
122	100-02-7	4-Nitrophenol			198	1,722,176		
123	79-46-9	2-Nitropropane			198	1,722,176		
124	684-93-5	N-Nitroso-N-methylurea			198	1,722,176		
125	62-75-9	N-Nitrosodimethylamine			198	1,722,176		
126	59-89-2	N-Nitrosomorpholine			198	1,722,176		
127	56-38-2	Parathion			198	1,722,176		
128	82-68-8	Pentachloronitrobenzene(Quintobenzene)			198	1,722,176		
129	87-86-5	Pentachlorophenol			198	1,722,176		
130	108-95-2	Phenol			198	1,722,176		
131	106-50-3	p-Phenylenediamine			198	1,722,176		
132	75-44-5	Phosgene			198	1,722,176		
133	7803-51-2	Phosphine			198	1,722,176		
134	7723-14-0	Phosphorus			198	1,722,176		
135	85-44-9	Phthalic anhydride			198	1,722,176		
136	1336-36-3	Polychlorinated biphenyls(Aroclors)			198	1,722,176		
137	1120-71-4	1,3-Propane sultone			198	1,722,176		
138	57-57-8	beta-Propiolactone			198	1,722,176		
139	123-38-6	Propionaldehyde			198	1,722,176		
140	114-26-1	Propoxur (Baygon)			198	1,722,176		
141	78-87-5	Propylene dichloride (1,2-Dichloropropane)			198	1,722,176		
142	75-56-9	Propylene oxide			198	1,722,176		
143	75-55-8	1,2-Propylenimine (2-Methylaziridine)			198	1,722,176		
144	91-22-5	Quinoline			198	1,722,176		
145	106-51-4	Quinone(p-Benzoquinone)			198	1,722,176		
146	100-42-5	Styrene			198	1,722,176		
147	96-09-3	Styrene oxide			198	1,722,176		
148	1746-01-6	2,3,7,8-Tetrachlorodibenzo-p-dioxin			198	1,722,176		
149	79-34-5	1,1,2,2-Tetrachloroethane			198	1,722,176		
150	127-18-4	Tetrachloroethylene(Perchloroethylene)			198	1,722,176		
151	7550-45-0	Titanium tetrachloride			198	1,722,176		
152	108-88-3	Toluene	AP-42, Section 3.4, Table 3.4-3	2.81E-04	198	1,722,176	5.56E-02	2.42E-01
153	95-80-7	Toluene-2,4-diamine			198	1,722,176		
154	584-84-9	2,4-Toluene diisocyanate			198	1,722,176		
155	95-53-4	o-Toluidine			198	1,722,176		
156	8001-35-2	Toxaphene (chlorinated camphene)			198	1,722,176		

Attachment S-1a
Air Toxic Emissions for CT-2

SECTION 112 HAZARDOUS AIR POLLUTANTS

EPA ID #	CAS Number	Pollutant	Source of Emission Factor	Emission Factor (lb/MMBtu)	Heat Input (MMBtu/hr)	Heat Input (MMBtu/yr)	Emissions (lb/hr)	Emissions (tpy)
157	120-82-1	1,2,4-Trichlorobenzene			198	1,722,176		
158	79-00-5	1,1,2-Trichloroethane			198	1,722,176		
159	79-01-6	Trichloroethylene			198	1,722,176		
160	95-95-4	2,4,5-Trichlorophenol			198	1,722,176		
161	88-06-2	2,4,6-Trichlorophenol			198	1,722,176		
162	121-44-8	Triethylamine			198	1,722,176		
163	1582-09-8	Trifluralin			198	1,722,176		
164	540-84-1	2,2,4-Trimethylpentane			198	1,722,176		
165	108-05-4	Vinyl acetate			198	1,722,176		
166	593-60-2	Vinyl bromide			198	1,722,176		
167	75-01-4	Vinyl chloride			198	1,722,176		
168	75-35-4	Vinylidene chloride (1,1-Dichloroethylene)			198	1,722,176		
169	1330-20-7	Xylene (mixed isomers)	AP-42, Section 3.4, Table 3.4-3	1.93E-04	198	1,722,176	3.82E-02	1.66E-01
170	95-47-6	o-Xylene			198	1,722,176		
171	108-38-3	m-Xylene			198	1,722,176		
172	106-42-3	p-Xylene			198	1,722,176		
173		Antimony Compounds			198	1,722,176		
174		Arsenic Compounds (inorganic including arsine)	AP-42, Section 3.1, Table 3.1-5	1.10E-05	198	1,722,176	2.18E-03	9.47E-03
175		Beryllium Compounds	AP-42, Section 3.1, Table 3.1-5	3.10E-07	198	1,722,176	6.14E-05	2.67E-04
176		Cadmium Compounds	AP-42, Section 3.1, Table 3.1-5	4.80E-06	198	1,722,176	9.50E-04	4.13E-03
177		Chromium Compounds	AP-42, Section 3.1, Table 3.1-5	1.10E-05	198	1,722,176	2.18E-03	9.47E-03
178		Cobalt Compounds			198	1,722,176		
179		Coke Oven Emissions			198	1,722,176		
180		Cyanide Compounds1			198	1,722,176		
181		Glycol ethers2			198	1,722,176		
182		Lead Compounds	AP-42, Section 3.1, Table 3.1-5	1.40E-05	198	1,722,176	2.77E-03	1.21E-02
183		Manganese Compounds	AP-42, Section 3.1, Table 3.1-5	7.90E-04	198	1,722,176	1.56E-01	6.80E-01
184		Mercury Compounds	AP-42, Section 3.1, Table 3.1-5	1.20E-06	198	1,722,176	2.38E-04	1.03E-03
185		Fine mineral fibers3			198	1,722,176		
186		Nickel Compounds	AP-42, Section 3.1, Table 3.1-5	4.60E-06	198	1,722,176	9.11E-04	3.96E-03
187		Polycyclic Organic Matter4	AP-42, Section 3.1, Table 3.1-4	4.00E-05	198	1,722,176	7.92E-03	3.44E-02
188		Radionuclides (including radon)5			198	1,722,176		
189		Selenium Compounds	AP-42, Section 3.1, Table 3.1-5	2.50E-05	198	1,722,176	4.95E-03	2.15E-02
		Total					**3.55E-01**	**1.55**

NOTE: For all listings above which contain the word "compounds" and for glycol ethers, the following applies:
Unless otherwise specified, these listings are defined as including any unique chemical substance
that contains the named chemical (i.e., antimony, arsenic, etc.) as part of that chemical's infrastructure.

1. X'CN where X = H' or any other group where a formal dissociation may occur. For example, KCN or Ca(CN)2.

2. R-(OCH2CH2)n-OR'
where: n = 1, 2, or 3
R = alkyl C7 or less
or R = phenyl or alkyl substituted phenyl
R' = H, or alkyl C7 or less
or ester, sulfate, phosphate, nitrate, sulfonate

3. Includes mineral fiber emissions from facilities manufacturing or processing glass, rock, or slag fibers (or other mineral derived fibers) of average diameter 1 micrometer or less.

4. Includes substituted and/or unsubstituted polycyclic aromatic hydrocarbons and aromatic heterocyclic compounds, with two or more fused rings, at least one of which is benzenoid (i.e., containing six carbon atoms and is aromatic) in structure. Polycyclic Organic Matter is a mixture of organic compounds containing one or more of these polycyclic aromatic chemicals. Polycyclic Organic Matter is generally formed or emitted during thermal processes including (1) incomplete combustion, (2) pyrolysis, (3) the volatilization, distillation or processing of fossil fuels or bitumens, or (4) the distillation or thermal processing of non-fossil fuels. The Administrator may delineate, by test method, what is included in polycyclic organic matter.

5. A type of atom which spontaneously undergoes radioactive decay.

Attachment S-1a
Air Toxic Emissions for CT-4 or CT-5

SECTION 112 HAZARDOUS AIR POLLUTANTS

EPA ID #	CAS Number	Pollutant	Source of Emission Factor	Emission Factor (lb/MMBtu)	Heat Input (MMBtu/hr)	Emissions (lb/hr)	Emissions (tpy)
1	75-07-0	Acetaldehyde	AP-42, Section 3.4, Table 3.4-3	2.52E-05	275	6.93E-03	3.04E-02
2	60-35-5	Acetamide			275		
3	75-05-8	Acetonitrile			275		
4	98-86-2	Acetophenone			275		
5	53-96-3	2-Acetylaminofluorene			275		
6	107-02-8	Acrolein	AP-42, Section 3.4, Table 3.4-3	7.88E-06	275	2.17E-03	9.49E-03
7	79-06-1	Acrylamide			275		
8	79-10-7	Acrylic acid			275		
9	107-13-1	Acrylonitrile			275		
10	107-05-1	Allyl chloride			275		
11	92-67-1	4-Aminobiphenyl			275		
12	62-53-3	Aniline			275		
13	90-04-0	o-Anisidine			275		
14	1332-21-4	Asbestos			275		
15	71-43-2	Benzene (including benzene from gasoline)	AP-42, Section 3.1, Table 3.1-4	5.50E-05	275	1.51E-02	6.61E-02
16	92-87-5	Benzidine			275		
17	98-07-7	Benzotrichloride			275		
18	100-44-7	Benzyl chloride			275		
19	92-52-4	Biphenyl			275		
20	117-81-7	Bis(2-ethylhexyl)phthalate (DEHP)			275		
21	542-88-1	Bis(chloromethyl) ether			275		
22	75-25-2	Bromoform			275		
23	106-99-0	1,3-Butadiene	AP-42, Section 3.1, Table 3.1-4	1.60E-05	275	4.40E-03	1.93E-02
24	156-62-7	Calcium cyanamide			275		
25	105-60-2	Caprolactam (Removed 06/18/96, See 61FR30816)			275		
26	133-06-2	Captan			275		
27	63-25-2	Carbaryl			275		
28	75-15-0	Carbon disulfide			275		
29	56-23-5	Carbon tetrachloride			275		
30	463-58-1	Carbonyl sulfide			275		
31	120-80-9	Catechol			275		
32	133-90-4	Chloramben			275		
33	57-74-9	Chlordane			275		
34	7782-50-5	Chlorine			275		
35	79-11-8	Chloroacetic acid			275		
36	532-27-4	2-Chloroacetophenone			275		
37	108-90-7	Chlorobenzene			275		
38	510-15-6	Chlorobenzilate			275		
39	67-66-3	Chloroform			275		
40	107-30-2	Chloromethyl methyl ether			275		
41	126-99-8	Chloroprene			275		
42	1319-77-3	Cresol/Cresylic acid(mixed isomers)			275		
43	95-48-7	o-Cresol			275		
44	108-39-4	m-Cresol			275		
45	106-44-5	p-Cresol			275		
46	98-82-8	Cumene			275		
47		2,4-D(2,4-Dichlorophenoxyacetic Acid) (including salts and esters)			275		
48	72-55-9	DDE(1,1-dichloro-2,2-bis(p-chlorophenyl) ethylene)			275		
49	334-88-3	Diazomethane			275		
50	132-64-9	Dibenzofuran			275		
51	96-12-8	1,2-Dibromo-3-chloropropane			275		
52	84-74-2	Dibutyl phthalate			275		
53	106-46-7	1,4-Dichlorobenzene			275		
54	91-94-1	Dichlorobenzidine			275		
55	111-44-4	Dichloroethyl ether(Bis[2-chloroethyl]ether)			275		
56	542-75-6	1,3-Dichloropropene			275		
57	62-73-7	Dichlorvos			275		
58	111-42-2	Diethanolamine			275		
59	64-67-5	Diethyl sulfate			275		
60	119-90-4	3,3'-Dimethoxybenzidine			275		
61	60-11-7	4-Dimethylaminoazobenzene			275		
62	121-69-7	N,N-Dimethylaniline			275		
63	119-93-7	3,3'-Dimethylbenzidine			275		
64	79-44-7	Dimethylcarbamoyl chloride			275		
65	68-12-2	N,N-Dimethylformamide			275		
66	57-14-7	1,1-Dimethylhydrazine			275		
67	131-11-3	Dimethyl phthalate			275		
68	77-78-1	Dimethyl sulfate			275		
69		4,6-Dinitro-o-cresol (including salts)			275		
70	51-28-5	2,4-Dinitrophenol			275		
71	121-14-2	2,4-Dinitrotoluene			275		
72	123-91-1	1,4-Dioxane (1,4-Diethyleneoxide)			275		
73	122-66-7	1,2-Diphenylhydrazine			275		
74	106-89-8	Epichlorohydrin (l-Chloro-2,3-epoxypropane)			275		
75	106-88-7	1,2-Epoxybutane			275		
76	140-88-5	Ethyl acrylate			275		
77	100-41-4	Ethylbenzene			275		
78	51-79-6	Ethyl carbamate (Urethane)			275		

Attachment S-1a
Air Toxic Emissions for CT-4 or CT-5

SECTION 112 HAZARDOUS AIR POLLUTANTS

EPA ID #	CAS Number	Pollutant	Source of Emission Factor	Emission Factor (lb/MMBtu)	Heat Input (MMBtu/hr)	Emissions (lb/hr)	Emissions (tpy)
79	75-00-3	Ethyl chloride (Chloroethane)			275		
80	106-93-4	Ethylene dibromide (Dibromoethane)			275		
81	107-06-2	Ethylene dichloride (1,2-Dichloroethane)			275		
82	107-21-1	Ethylene glycol			275		
83	151-56-4	Ethyleneimine (Aziridine)			275		
84	75-21-8	Ethylene oxide			275		
85	96-45-7	Ethylene thiourea			275		
86	75-34-3	Ethylidene dichloride (1,1-Dichloroethane)			275		
87	50-00-0	Formaldehyde	AP-42, Section 3.1, Table 3.1-4	2.80E-04	275	7.70E-02	3.37E-01
88	76-44-8	Heptachlor			275		
89	118-74-1	Hexachlorobenzene			275		
90	87-68-3	Hexachlorobutadiene			275		
91		1,2,3,4,5,6-Hexachlorocyclyhexane (all stereo isomers including lindane)			275		
92	77-47-4	Hexachlorocyclopentadiene			275		
93	67-72-1	Hexachloroethane			275		
94	822-06-0	Hexamethylene diisocyanate			275		
95	680-31-9	Hexamethylphosphoramide			275		
96	110-54-3	Hexane			275		
97	302-01-2	Hydrazine			275		
98	7647-01-0	Hydrochloric acid (Hydrogen chloride [gas only])			275		
99	7664-39-3	Hydrogen fluoride (Hydrofluoric acid)			275		
100	123-31-9	Hydroquinone			275		
101	78-59-1	Isophorone			275		
102	108-31-6	Maleic anhydride			275		
103	67-56-1	Methanol			275		
104	72-43-5	Methoxychlor			275		
105	74-83-9	Methyl bromide (Bromomethane)			275		
106	74-87-3	Methyl chloride(Chloromethane)			275		
107	71-55-6	Methyl chloroform(1,1,1-Trichloroethane)			275		
108	78-93-3	Methyl ethyl ketone (2-Butanone) (Removed 12/19/05, See 70FR75047)			275		
109	60-34-4	Methylhydrazine			275		
110	74-88-4	Methyl iodide (Iodomethane)			275		
111	108-10-1	Methyl isobutyl ketone(Hexone)			275		
112	624-83-9	Methyl isocyanate			275		
113	80-62-6	Methyl methacrylate			275		
114	1634-04-4	Methyl tert-butyl ether			275		
115	101-14-4	4,4'-Methylenebis(2-chloroaniline)			275		
116	75-09-2	Methylene chloride(Dichloromethane)			275		
117	101-68-8	4,4'-Methylenediphenyl diisocyanate(MDI)			275		
118	101-77-9	4,4'-Methylenedianiline			275		
119	91-20-3	Naphthalene	AP-42, Section 3.1, Table 3.1-4	3.50E-05	275	9.63E-03	4.22E-02
120	98-95-3	Nitrobenzene			275		
121	92-93-3	4-Nitrobiphenyl			275		
122	100-02-7	4-Nitrophenol			275		
123	79-46-9	2-Nitropropane			275		
124	684-93-5	N-Nitroso-N-methylurea			275		
125	62-75-9	N-Nitrosodimethylamine			275		
126	59-89-2	N-Nitrosomorpholine			275		
127	56-38-2	Parathion			275		
128	82-68-8	Pentachloronitrobenzene(Quintobenzene)			275		
129	87-86-5	Pentachlorophenol			275		
130	108-95-2	Phenol			275		
131	106-50-3	p-Phenylenediamine			275		
132	75-44-5	Phosgene			275		
133	7803-51-2	Phosphine			275		
134	7723-14-0	Phosphorus			275		
135	85-44-9	Phthalic anhydride			275		
136	1336-36-3	Polychlorinated biphenyls(Aroclors)			275		
137	1120-71-4	1,3-Propane sultone			275		
138	57-57-8	beta-Propiolactone			275		
139	123-38-6	Propionaldehyde			275		
140	114-26-1	Propoxur (Baygon)			275		
141	78-87-5	Propylene dichloride (1,2-Dichloropropane)			275		
142	75-56-9	Propylene oxide			275		
143	75-55-8	1,2-Propylenimine (2-Methylaziridine)			275		
144	91-22-5	Quinoline			275		
145	106-51-4	Quinone(p-Benzoquinone)			275		
146	100-42-5	Styrene			275		
147	96-09-3	Styrene oxide			275		
148	1746-01-6	2,3,7,8-Tetrachlorodibenzo-p-dioxin			275		
149	79-34-5	1,1,2,2-Tetrachloroethane			275		
150	127-18-4	Tetrachloroethylene(Perchloroethylene)			275		
151	7550-45-0	Titanium tetrachloride			275		
152	108-88-3	Toluene	AP-42, Section 3.4, Table 3.4-3	2.81E-04	275	7.73E-02	3.38E-01
153	95-80-7	Toluene-2,4-diamine			275		
154	584-84-9	2,4-Toluene diisocyanate			275		
155	95-53-4	o-Toluidine			275		
156	8001-35-2	Toxaphene (chlorinated camphene)			275		

Attachment S-1a
Air Toxic Emissions for CT-4 or CT-5

SECTION 112 HAZARDOUS AIR POLLUTANTS

EPA ID #	CAS Number	Pollutant	Source of Emission Factor	Emission Factor (lb/MMBtu)	Heat Input (MMBtu/hr)	Emissions (lb/hr)	Emissions (tpy)
157	120-82-1	1,2,4-Trichlorobenzene			275		
158	79-00-5	1,1,2-Trichloroethane			275		
159	79-01-6	Trichloroethylene			275		
160	95-95-4	2,4,5-Trichlorophenol			275		
161	88-06-2	2,4,6-Trichlorophenol			275		
162	121-44-8	Triethylamine			275		
163	1582-09-8	Trifluralin			275		
164	540-84-1	2,2,4-Trimethylpentane			275		
165	108-05-4	Vinyl acetate			275		
166	593-60-2	Vinyl bromide			275		
167	75-01-4	Vinyl chloride			275		
168	75-35-4	Vinylidene chloride (1,1-Dichloroethylene)			275		
169	1330-20-7	Xylene (mixed isomers)	AP-42, Section 3.4, Table 3.4-3	1.93E-04	275	5.31E-02	2.32E-01
170	95-47-6	o-Xylene			275		
171	108-38-3	m-Xylene			275		
172	106-42-3	p-Xylene			275		
173		Antimony Compounds			275		
174		Arsenic Compounds (inorganic including arsine)	AP-42, Section 3.1, Table 3.1-5	1.10E-05	275	3.03E-03	1.33E-02
175		Beryllium Compounds	AP-42, Section 3.1, Table 3.1-5	3.10E-07	275	8.53E-05	3.73E-04
176		Cadmium Compounds	AP-42, Section 3.1, Table 3.1-5	4.80E-06	275	1.32E-03	5.78E-03
177		Chromium Compounds	AP-42, Section 3.1, Table 3.1-5	1.10E-05	275	3.03E-03	1.32E-02
178		Cobalt Compounds			275		
179		Coke Oven Emissions			275		
180		Cyanide Compounds1			275		
181		Glycol ethers2			275		
182		Lead Compounds	AP-42, Section 3.1, Table 3.1-5	1.40E-05	275	3.85E-03	1.69E-02
183		Manganese Compounds	AP-42, Section 3.1, Table 3.1-5	7.90E-04	275	2.17E-01	9.52E-01
184		Mercury Compounds	AP-42, Section 3.1, Table 3.1-5	1.20E-06	275	3.30E-04	1.45E-03
185		Fine mineral fibers3			275		
186		Nickel Compounds	AP-42, Section 3.1, Table 3.1-5	4.60E-06	275	1.27E-03	5.54E-03
187		Polycyclic Organic Matter4	AP-42, Section 3.1, Table 3.1-4	4.00E-05	275	1.10E-02	4.82E-02
188		Radionuclides (including radon)5			275		
189		Selenium Compounds	AP-42, Section 3.1, Table 3.1-5	2.50E-05	275	6.88E-03	3.01E-02
		Total				**4.94E-01**	**2.16**

NOTE: For all listings above which contain the word "compounds" and for glycol ethers, the following applies:
Unless otherwise specified, these listings are defined as including any unique chemical substance that contains the named chemical (i.e., antimony, arsenic, etc.) as part of that chemical's infrastructure.

1. X'CN where X = H' or any other group where a formal dissociation may occur. For example, KCN or Ca(CN)2.

2. R-(OCH2CH2)n-OR'
where:
n = 1, 2, or 3
R = alkyl C7 or less
or R = phenyl or alkyl substituted phenyl
R' = H, or alkyl C7 or less
or ester, sulfate, phosphate, nitrate, sulfonate

3. Includes mineral fiber emissions from facilities manufacturing or processing glass, rock, or slag fibers (or other mineral derived fibers) of average diameter 1 micrometer or less.

4. Includes substituted and/or unsubstituted polycyclic aromatic hydrocarbons and aromatic heterocyclic compounds, with two or more fused rings, at least one of which is benzenoid (i.e., containing six carbon atoms and is aromatic) in structure. Polycyclic Organic Matter is a mixture of organic compounds containing one or more of these polycyclic aromatic chemicals. Polycyclic Organic Matter is generally formed or emitted during thermal processes including (1) incomplete combustion, (2) pyrolysis, (3) the volatilization, distillation or processing of fossil fuels or bitumens, or (4) the distillation or thermal processing of non-fossil fuels. The Administrator may delineate, by test method, what is included in polycyclic organic matter.

5. A type of atom which spontaneously undergoes radioactive decay.

Attachment S-1a
Air Toxic Emissions for D-21

SECTION 112 HAZARDOUS AIR POLLUTANTS

EPA ID #	CAS Number	Pollutant	Source of Emission Factor	Emission Factor (lb/MMBtu)	Heat Input (MMBtu/hr)	Heat Input (MMBtu/yr)	Emissions (lb/hr)	Emissions (tpy)
1	75-07-0	Acetaldehyde	AP-42, Section 3.4, Table 3.4-3	2.52E-05	28.1	9,800	7.08E-04	1.23E-04
2	60-35-5	Acetamide			28.1	9,800		
3	75-05-8	Acetonitrile			28.1	9,800		
4	98-86-2	Acetophenone			28.1	9,800		
5	53-96-3	2-Acetylaminofluorene			28.1	9,800		
6	107-02-8	Acrolein	AP-42, Section 3.4, Table 3.4-3	7.88E-06	28.1	9,800	2.21E-04	3.86E-05
7	79-06-1	Acrylamide			28.1	9,800		
8	79-10-7	Acrylic acid			28.1	9,800		
9	107-13-1	Acrylonitrile			28.1	9,800		
10	107-05-1	Allyl chloride			28.1	9,800		
11	92-67-1	4-Aminobiphenyl			28.1	9,800		
12	62-53-3	Aniline			28.1	9,800		
13	90-04-0	o-Anisidine			28.1	9,800		
14	1332-21-4	Asbestos			28.1	9,800		
15	71-43-2	Benzene (including benzene from gasoline)	AP-42, Section 3.4, Table 3.4-3	7.76E-04	28.1	9,800	2.18E-02	3.80E-03
16	92-87-5	Benzidine			28.1	9,800		
17	98-07-7	Benzotrichloride			28.1	9,800		
18	100-44-7	Benzyl chloride			28.1	9,800		
19	92-52-4	Biphenyl			28.1	9,800		
20	117-81-7	Bis(2-ethylhexyl)phthalate (DEHP)			28.1	9,800		
21	542-88-1	Bis(chloromethyl) ether			28.1	9,800		
22	75-25-2	Bromoform			28.1	9,800		
23	106-99-0	1,3-Butadiene	AP-42, Section 3.1, Table 3.1-4	1.60E-05	28.1	9,800	4.50E-04	7.84E-05
24	156-62-7	Calcium cyanamide			28.1	9,800		
25	105-60-2	Caprolactam (Removed 06/18/96, See 61FR30816)			28.1	9,800		
26	133-06-2	Captan			28.1	9,800		
27	63-25-2	Carbaryl			28.1	9,800		
28	75-15-0	Carbon disulfide			28.1	9,800		
29	56-23-5	Carbon tetrachloride			28.1	9,800		
30	463-58-1	Carbonyl sulfide			28.1	9,800		
31	120-80-9	Catechol			28.1	9,800		
32	133-90-4	Chloramben			28.1	9,800		
33	57-74-9	Chlordane			28.1	9,800		
34	7782-50-5	Chlorine			28.1	9,800		
35	79-11-8	Chloroacetic acid			28.1	9,800		
36	532-27-4	2-Chloroacetophenone			28.1	9,800		
37	108-90-7	Chlorobenzene			28.1	9,800		
38	510-15-6	Chlorobenzilate			28.1	9,800		
39	67-66-3	Chloroform			28.1	9,800		
40	107-30-2	Chloromethyl methyl ether			28.1	9,800		
41	126-99-8	Chloroprene			28.1	9,800		
42	1319-77-3	Cresol/Cresylic acid(mixed isomers)			28.1	9,800		
43	95-48-7	o-Cresol			28.1	9,800		
44	108-39-4	m-Cresol			28.1	9,800		
45	106-44-5	p-Cresol			28.1	9,800		
46	98-82-8	Cumene			28.1	9,800		
47		2,4-D(2,4-Dichlorophenoxyacetic Acid) (including salts and esters)			28.1	9,800		
48	72-55-9	DDE(1,1-dichloro-2,2-bis(p-chlorophenyl) ethylene)			28.1	9,800		
49	334-88-3	Diazomethane			28.1	9,800		
50	132-64-9	Dibenzofuran			28.1	9,800		
51	96-12-8	1,2-Dibromo-3-chloropropane			28.1	9,800		
52	84-74-2	Dibutyl phthalate			28.1	9,800		
53	106-46-7	1,4-Dichlorobenzene			28.1	9,800		
54	91-94-1	Dichlorobenzidine			28.1	9,800		
55	111-44-4	Dichloroethyl ether(Bis[2-chloroethyl]ether)			28.1	9,800		
56	542-75-6	1,3-Dichloropropene			28.1	9,800		
57	62-73-7	Dichlorvos			28.1	9,800		
58	111-42-2	Diethanolamine			28.1	9,800		
59	64-67-5	Diethyl sulfate			28.1	9,800		
60	119-90-4	3,3'-Dimethoxybenzidine			28.1	9,800		
61	60-11-7	4-Dimethylaminoazobenzene			28.1	9,800		
62	121-69-7	N,N-Dimethylaniline			28.1	9,800		
63	119-93-7	3,3'-Dimethylbenzidine			28.1	9,800		
64	79-44-7	Dimethylcarbamoyl chloride			28.1	9,800		
65	68-12-2	N,N-Dimethylformamide			28.1	9,800		
66	57-14-7	1,1-Dimethylhydrazine			28.1	9,800		
67	131-11-3	Dimethyl phthalate			28.1	9,800		
68	77-78-1	Dimethyl sulfate			28.1	9,800		
69		4,6-Dinitro-o-cresol (including salts)			28.1	9,800		
70	51-28-5	2,4-Dinitrophenol			28.1	9,800		
71	121-14-2	2,4-Dinitrotoluene			28.1	9,800		
72	123-91-1	1,4-Dioxane (1,4-Diethyleneoxide)			28.1	9,800		
73	122-66-7	1,2-Diphenylhydrazine			28.1	9,800		
74	106-89-8	Epichlorohydrin (l-Chloro-2,3-epoxypropane)			28.1	9,800		
75	106-88-7	1,2-Epoxybutane			28.1	9,800		
76	140-88-5	Ethyl acrylate			28.1	9,800		
77	100-41-4	Ethylbenzene			28.1	9,800		
78	51-79-6	Ethyl carbamate (Urethane)			28.1	9,800		

Attachment S-1a
Air Toxic Emissions for D-21

SECTION 112 HAZARDOUS AIR POLLUTANTS

EPA ID #	CAS Number	Pollutant	Source of Emission Factor	Emission Factor (lb/MMBtu)	Heat Input (MMBtu/hr)	Heat Input (MMBtu/yr)	Emissions (lb/hr)	Emissions (tpy)
79	75-00-3	Ethyl chloride (Chloroethane)			28.1	9,800		
80	106-93-4	Ethylene dibromide (Dibromoethane)			28.1	9,800		
81	107-06-2	Ethylene dichloride (1,2-Dichloroethane)			28.1	9,800		
82	107-21-1	Ethylene glycol			28.1	9,800		
83	151-56-4	Ethyleneimine (Aziridine)			28.1	9,800		
84	75-21-8	Ethylene oxide			28.1	9,800		
85	96-45-7	Ethylene thiourea			28.1	9,800		
86	75-34-3	Ethylidene dichloride (1,1-Dichloroethane)			28.1	9,800		
87	50-00-0	Formaldehyde	AP-42, Section 3.4, Table 3.4-3	7.89E-05	28.1	9,800	2.22E-03	3.87E-04
88	76-44-8	Heptachlor			28.1	9,800		
89	118-74-1	Hexachlorobenzene			28.1	9,800		
90	87-68-3	Hexachlorobutadiene			28.1	9,800		
91		1,2,3,4,5,6-Hexachlorocyclyhexane (all stereo isomers including lindane)			28.1	9,800		
92	77-47-4	Hexachlorocyclopentadiene			28.1	9,800		
93	67-72-1	Hexachloroethane			28.1	9,800		
94	822-06-0	Hexamethylene diisocyanate			28.1	9,800		
95	680-31-9	Hexamethylphosphoramide			28.1	9,800		
96	110-54-3	Hexane			28.1	9,800		
97	302-01-2	Hydrazine			28.1	9,800		
98	7647-01-0	Hydrochloric acid (Hydrogen chloride [gas only])			28.1	9,800		
99	7664-39-3	Hydrogen fluoride (Hydrofluoric acid)			28.1	9,800		
100	123-31-9	Hydroquinone			28.1	9,800		
101	78-59-1	Isophorone			28.1	9,800		
102	108-31-6	Maleic anhydride			28.1	9,800		
103	67-56-1	Methanol			28.1	9,800		
104	72-43-5	Methoxychlor			28.1	9,800		
105	74-83-9	Methyl bromide (Bromomethane)			28.1	9,800		
106	74-87-3	Methyl chloride(Chloromethane)			28.1	9,800		
107	71-55-6	Methyl chloroform(1,1,1-Trichloroethane)			28.1	9,800		
108	78-93-3	Methyl ethyl ketone (2-Butanone) (Removed 12/19/05, See 70FR75047)			28.1	9,800		
109	60-34-4	Methylhydrazine			28.1	9,800		
110	74-88-4	Methyl iodide (Iodomethane)			28.1	9,800		
111	108-10-1	Methyl isobutyl ketone(Hexone)			28.1	9,800		
112	624-83-9	Methyl isocyanate			28.1	9,800		
113	80-62-6	Methyl methacrylate			28.1	9,800		
114	1634-04-4	Methyl tert-butyl ether			28.1	9,800		
115	101-14-4	4,4'-Methylenebis(2-chloroaniline)			28.1	9,800		
116	75-09-2	Methylene chloride(Dichloromethane)			28.1	9,800		
117	101-68-8	4,4'-Methylenediphenyl diisocyanate(MDI)			28.1	9,800		
118	101-77-9	4,4'-Methylenedianiline			28.1	9,800		
119	91-20-3	Naphthalene	AP-42, Section 3.4, Table 3.4-4	1.30E-04	28.1	9,800	3.65E-03	6.37E-04
120	98-95-3	Nitrobenzene			28.1	9,800		
121	92-93-3	4-Nitrobiphenyl			28.1	9,800		
122	100-02-7	4-Nitrophenol			28.1	9,800		
123	79-46-9	2-Nitropropane			28.1	9,800		
124	684-93-5	N-Nitroso-N-methylurea			28.1	9,800		
125	62-75-9	N-Nitrosodimethylamine			28.1	9,800		
126	59-89-2	N-Nitrosomorpholine			28.1	9,800		
127	56-38-2	Parathion			28.1	9,800		
128	82-68-8	Pentachloronitrobenzene(Quintobenzene)			28.1	9,800		
129	87-86-5	Pentachlorophenol			28.1	9,800		
130	108-95-2	Phenol			28.1	9,800		
131	106-50-3	p-Phenylenediamine			28.1	9,800		
132	75-44-5	Phosgene			28.1	9,800		
133	7803-51-2	Phosphine			28.1	9,800		
134	7723-14-0	Phosphorus			28.1	9,800		
135	85-44-9	Phthalic anhydride			28.1	9,800		
136	1336-36-3	Polychlorinated biphenyls(Aroclors)			28.1	9,800		
137	1120-71-4	1,3-Propane sultone			28.1	9,800		
138	57-57-8	beta-Propiolactone			28.1	9,800		
139	123-38-6	Propionaldehyde			28.1	9,800		
140	114-26-1	Propoxur (Baygon)			28.1	9,800		
141	78-87-5	Propylene dichloride (1,2-Dichloropropane)			28.1	9,800		
142	75-56-9	Propylene oxide			28.1	9,800		
143	75-55-8	1,2-Propylenimine (2-Methylaziridine)			28.1	9,800		
144	91-22-5	Quinoline			28.1	9,800		
145	106-51-4	Quinone(p-Benzoquinone)			28.1	9,800		
146	100-42-5	Styrene			28.1	9,800		
147	96-09-3	Styrene oxide			28.1	9,800		
148	1746-01-6	2,3,7,8-Tetrachlorodibenzo-p-dioxin			28.1	9,800		
149	79-34-5	1,1,2,2-Tetrachloroethane			28.1	9,800		
150	127-18-4	Tetrachloroethylene(Perchloroethylene)			28.1	9,800		
151	7550-45-0	Titanium tetrachloride			28.1	9,800		
152	108-88-3	Toluene	AP-42, Section 3.4, Table 3.4-3	2.81E-04	28.1	9,800	7.90E-03	1.38E-03
153	95-80-7	Toluene-2,4-diamine			28.1	9,800		
154	584-84-9	2,4-Toluene diisocyanate			28.1	9,800		
155	95-53-4	o-Toluidine			28.1	9,800		
156	8001-35-2	Toxaphene (chlorinated camphene)			28.1	9,800		

Attachment S-1a
Air Toxic Emissions for D-21

SECTION 112 HAZARDOUS AIR POLLUTANTS

EPA ID #	CAS Number	Pollutant	Source of Emission Factor	Emission Factor (lb/MMBtu)	Heat Input (MMBtu/hr)	Heat Input (MMBtu/yr)	Emissions (lb/hr)	Emissions (tpy)
157	120-82-1	1,2,4-Trichlorobenzene			28.1	9,800		
158	79-00-5	1,1,2-Trichloroethane			28.1	9,800		
159	79-01-6	Trichloroethylene			28.1	9,800		
160	95-95-4	2,4,5-Trichlorophenol			28.1	9,800		
161	88-06-2	2,4,6-Trichlorophenol			28.1	9,800		
162	121-44-8	Triethylamine			28.1	9,800		
163	1582-09-8	Trifluralin			28.1	9,800		
164	540-84-1	2,2,4-Trimethylpentane			28.1	9,800		
165	108-05-4	Vinyl acetate			28.1	9,800		
166	593-60-2	Vinyl bromide			28.1	9,800		
167	75-01-4	Vinyl chloride			28.1	9,800		
168	75-35-4	Vinylidene chloride (1,1-Dichloroethylene)			28.1	9,800		
169	1330-20-7	Xylene (mixed isomers)	AP-42, Section 3.4, Table 3.4-3	1.93E-04	28.1	9,800	5.42E-03	9.46E-04
170	95-47-6	o-Xylene			28.1	9,800		
171	108-38-3	m-Xylene			28.1	9,800		
172	106-42-3	p-Xylene			28.1	9,800		
173		Antimony Compounds			28.1	9,800		
174		Arsenic Compounds (inorganic including arsine)	AP-42, Section 3.1, Table 3.1-5	1.10E-05	28.1	9,800	3.09E-04	5.39E-05
175		Beryllium Compounds	AP-42, Section 3.1, Table 3.1-5	3.10E-07	28.1	9,800	8.71E-06	1.52E-06
176		Cadmium Compounds	AP-42, Section 3.1, Table 3.1-5	4.80E-06	28.1	9,800	1.35E-04	2.35E-05
177		Chromium Compounds	AP-42, Section 3.1, Table 3.1-5	1.10E-05	28.1	9,800	3.09E-04	5.39E-05
178		Cobalt Compounds			28.1	9,800		
179		Coke Oven Emissions			28.1	9,800		
180		Cyanide Compounds1			28.1	9,800		
181		Glycol ethers2			28.1	9,800		
182		Lead Compounds	AP-42, Section 3.1, Table 3.1-5	1.40E-05	28.1	9,800	3.93E-04	6.86E-05
183		Manganese Compounds	AP-42, Section 3.1, Table 3.1-5	7.90E-04	28.1	9,800	2.22E-02	3.87E-03
184		Mercury Compounds	AP-42, Section 3.1, Table 3.1-5	1.20E-06	28.1	9,800	3.37E-05	5.88E-06
185		Fine mineral fibers3			28.1	9,800		
186		Nickel Compounds	AP-42, Section 3.1, Table 3.1-5	4.60E-06	28.1	9,800	1.29E-04	2.25E-05
187		Polycyclic Organic Matter4	AP-42, Section 3.4, Table 3.4-4	2.12E-04	28.1	9,800	5.96E-03	1.04E-03
188		Radionuclides (including radon)5			28.1	9,800		
189		Selenium Compounds	AP-42, Section 3.1, Table 3.1-5	2.50E-05	28.1	9,800	7.03E-04	1.23E-04
		Total					**7.26E-02**	**1.27E-02**

NOTE: For all listings above which contain the word "compounds" and for glycol ethers, the following applies:
Unless otherwise specified, these listings are defined as including any unique chemical substance
that contains the named chemical (i.e., antimony, arsenic, etc.) as part of that chemical's infrastructure.

1. X'CN where X = H' or any other group where a formal dissociation may occur. For example, KCN or Ca(CN)2.

2. R-(OCH2CH2)n-OR'
where: n = 1, 2, or 3
R = alkyl C7 or less
or R = phenyl or alkyl substituted phenyl
R' = H, or alkyl C7 or less
or ester, sulfate, phosphate, nitrate, sulfonate

3. Includes mineral fiber emissions from facilities manufacturing or processing glass, rock, or slag fibers (or other mineral derived fibers) of average diameter 1 micrometer or less.

4. Includes substituted and/or unsubstituted polycyclic aromatic hydrocarbons and aromatic heterocyclic compounds, with two or more fused rings, at least one of which is benzenoid (i.e., containing six carbon atoms and is aromatic) in structure. Polycyclic Organic Matter is a mixture of organic compounds containing one or more of these polycyclic aromatic chemicals. Polycyclic Organic Matter is generally formed or emitted during thermal processes including (1) incomplete combustion, (2) pyrolysis, (3) the volatilization, distillation or processing of fossil fuels or bitumens, or (4) the distillation or thermal processing of non-fossil fuels. The Administrator may delineate, by test method, what is included in polycyclic organic matter.

5. A type of atom which spontaneously undergoes radioactive decay.

Attachment S-1a
Air Toxic Emissions for D-22 or D-23

SECTION 112 HAZARDOUS AIR POLLUTANTS

EPA ID #	CAS Number	Pollutant	Source of Emission Factor	Emission Factor (lb/MMBtu)	Heat Input (MMBtu/hr)	Emissions (lb/hr)	Emissions (tpy)
1	75-07-0	Acetaldehyde	AP-42, Section 3.4, Table 3.4-3	2.52E-05	28.1	7.08E-04	3.10E-03
2	60-35-5	Acetamide			28.1		
3	75-05-8	Acetonitrile			28.1		
4	98-86-2	Acetophenone			28.1		
5	53-96-3	2-Acetylaminofluorene			28.1		
6	107-02-8	Acrolein	AP-42, Section 3.4, Table 3.4-3	7.88E-06	28.1	2.21E-04	9.70E-04
7	79-06-1	Acrylamide			28.1		
8	79-10-7	Acrylic acid			28.1		
9	107-13-1	Acrylonitrile			28.1		
10	107-05-1	Allyl chloride			28.1		
11	92-67-1	4-Aminobiphenyl			28.1		
12	62-53-3	Aniline			28.1		
13	90-04-0	o-Anisidine			28.1		
14	1332-21-4	Asbestos			28.1		
15	71-43-2	Benzene (including benzene from gasoline)	AP-42, Section 3.4, Table 3.4-3	7.76E-04	28.1	2.18E-02	9.55E-02
16	92-87-5	Benzidine			28.1		
17	98-07-7	Benzotrichloride			28.1		
18	100-44-7	Benzyl chloride			28.1		
19	92-52-4	Biphenyl			28.1		
20	117-81-7	Bis(2-ethylhexyl)phthalate (DEHP)			28.1		
21	542-88-1	Bis(chloromethyl) ether			28.1		
22	75-25-2	Bromoform			28.1		
23	106-99-0	1,3-Butadiene	AP-42, Section 3.1, Table 3.1-4	1.60E-05	28.1	4.50E-04	1.97E-03
24	156-62-7	Calcium cyanamide			28.1		
25	105-60-2	Caprolactam (Removed 06/18/96, See 61FR30816)			28.1		
26	133-06-2	Captan			28.1		
27	63-25-2	Carbaryl			28.1		
28	75-15-0	Carbon disulfide			28.1		
29	56-23-5	Carbon tetrachloride			28.1		
30	463-58-1	Carbonyl sulfide			28.1		
31	120-80-9	Catechol			28.1		
32	133-90-4	Chloramben			28.1		
33	57-74-9	Chlordane			28.1		
34	7782-50-5	Chlorine			28.1		
35	79-11-8	Chloroacetic acid			28.1		
36	532-27-4	2-Chloroacetophenone			28.1		
37	108-90-7	Chlorobenzene			28.1		
38	510-15-6	Chlorobenzilate			28.1		
39	67-66-3	Chloroform			28.1		
40	107-30-2	Chloromethyl methyl ether			28.1		
41	126-99-8	Chloroprene			28.1		
42	1319-77-3	Cresol/Cresylic acid(mixed isomers)			28.1		
43	95-48-7	o-Cresol			28.1		
44	108-39-4	m-Cresol			28.1		
45	106-44-5	p-Cresol			28.1		
46	98-82-8	Cumene			28.1		
47		2,4-D(2,4-Dichlorophenoxyacetic Acid) (including salts and esters)			28.1		
48	72-55-9	DDE(1,1-dichloro-2,2-bis(p-chlorophenyl) ethylene)			28.1		
49	334-88-3	Diazomethane			28.1		
50	132-64-9	Dibenzofuran			28.1		
51	96-12-8	1,2-Dibromo-3-chloropropane			28.1		
52	84-74-2	Dibutyl phthalate			28.1		
53	106-46-7	1,4-Dichlorobenzene			28.1		
54	91-94-1	Dichlorobenzidine			28.1		
55	111-44-4	Dichloroethyl ether(Bis[2-chloroethyl]ether)			28.1		
56	542-75-6	1,3-Dichloropropene			28.1		
57	62-73-7	Dichlorvos			28.1		
58	111-42-2	Diethanolamine			28.1		
59	64-67-5	Diethyl sulfate			28.1		
60	119-90-4	3,3'-Dimethoxybenzidine			28.1		
61	60-11-7	4-Dimethylaminoazobenzene			28.1		
62	121-69-7	N,N-Dimethylaniline			28.1		
63	119-93-7	3,3'-Dimethylbenzidine			28.1		
64	79-44-7	Dimethylcarbamoyl chloride			28.1		
65	68-12-2	N,N-Dimethylformamide			28.1		
66	57-14-7	1,1-Dimethylhydrazine			28.1		
67	131-11-3	Dimethyl phthalate			28.1		
68	77-78-1	Dimethyl sulfate			28.1		
69		4,6-Dinitro-o-cresol (including salts)			28.1		
70	51-28-5	2,4-Dinitrophenol			28.1		
71	121-14-2	2,4-Dinitrotoluene			28.1		
72	123-91-1	1,4-Dioxane (1,4-Diethyleneoxide)			28.1		
73	122-66-7	1,2-Diphenylhydrazine			28.1		
74	106-89-8	Epichlorohydrin (l-Chloro-2,3-epoxypropane)			28.1		
75	106-88-7	1,2-Epoxybutane			28.1		
76	140-88-5	Ethyl acrylate			28.1		
77	100-41-4	Ethylbenzene			28.1		
78	51-79-6	Ethyl carbamate (Urethane)			28.1		

Attachment S-1a
Air Toxic Emissions for D-22 or D-23

SECTION 112 HAZARDOUS AIR POLLUTANTS

EPA ID #	CAS Number	Pollutant	Source of Emission Factor	Emission Factor (lb/MMBtu)	Heat Input (MMBtu/hr)	Emissions (lb/hr)	Emissions (tpy)
79	75-00-3	Ethyl chloride (Chloroethane)			28.1		
80	106-93-4	Ethylene dibromide (Dibromoethane)			28.1		
81	107-06-2	Ethylene dichloride (1,2-Dichloroethane)			28.1		
82	107-21-1	Ethylene glycol			28.1		
83	151-56-4	Ethyleneimine (Aziridine)			28.1		
84	75-21-8	Ethylene oxide			28.1		
85	96-45-7	Ethylene thiourea			28.1		
86	75-34-3	Ethylidene dichloride (1,1-Dichloroethane)			28.1		
87	50-00-0	Formaldehyde	AP-42, Section 3.4, Table 3.4-3	7.89E-05	28.1	2.22E-03	9.71E-03
88	76-44-8	Heptachlor			28.1		
89	118-74-1	Hexachlorobenzene			28.1		
90	87-68-3	Hexachlorobutadiene			28.1		
91		1,2,3,4,5,6-Hexachlorocyclyhexane (all stereo isomers including lindane)			28.1		
92	77-47-4	Hexachlorocyclopentadiene			28.1		
93	67-72-1	Hexachloroethane			28.1		
94	822-06-0	Hexamethylene diisocyanate			28.1		
95	680-31-9	Hexamethylphosphoramide			28.1		
96	110-54-3	Hexane			28.1		
97	302-01-2	Hydrazine			28.1		
98	7647-01-0	Hydrochloric acid (Hydrogen chloride [gas only])			28.1		
99	7664-39-3	Hydrogen fluoride (Hydrofluoric acid)			28.1		
100	123-31-9	Hydroquinone			28.1		
101	78-59-1	Isophorone			28.1		
102	108-31-6	Maleic anhydride			28.1		
103	67-56-1	Methanol			28.1		
104	72-43-5	Methoxychlor			28.1		
105	74-83-9	Methyl bromide (Bromomethane)			28.1		
106	74-87-3	Methyl chloride(Chloromethane)			28.1		
107	71-55-6	Methyl chloroform(1,1,1-Trichloroethane)			28.1		
108	78-93-3	Methyl ethyl ketone (2-Butanone) (Removed 12/19/05, See 70FR75047)			28.1		
109	60-34-4	Methylhydrazine			28.1		
110	74-88-4	Methyl iodide (Iodomethane)			28.1		
111	108-10-1	Methyl isobutyl ketone(Hexone)			28.1		
112	624-83-9	Methyl isocyanate			28.1		
113	80-62-6	Methyl methacrylate			28.1		
114	1634-04-4	Methyl tert-butyl ether			28.1		
115	101-14-4	4,4'-Methylenebis(2-chloroaniline)			28.1		
116	75-09-2	Methylene chloride(Dichloromethane)			28.1		
117	101-68-8	4,4'-Methylenediphenyl diisocyanate(MDI)			28.1		
118	101-77-9	4,4'-Methylenedianiline			28.1		
119	91-20-3	Naphthalene	AP-42, Section 3.4, Table 3.4-4	1.30E-04	28.1	3.65E-03	1.60E-02
120	98-95-3	Nitrobenzene			28.1		
121	92-93-3	4-Nitrobiphenyl			28.1		
122	100-02-7	4-Nitrophenol			28.1		
123	79-46-9	2-Nitropropane			28.1		
124	684-93-5	N-Nitroso-N-methylurea			28.1		
125	62-75-9	N-Nitrosodimethylamine			28.1		
126	59-89-2	N-Nitrosomorpholine			28.1		
127	56-38-2	Parathion			28.1		
128	82-68-8	Pentachloronitrobenzene(Quintobenzene)			28.1		
129	87-86-5	Pentachlorophenol			28.1		
130	108-95-2	Phenol			28.1		
131	106-50-3	p-Phenylenediamine			28.1		
132	75-44-5	Phosgene			28.1		
133	7803-51-2	Phosphine			28.1		
134	7723-14-0	Phosphorus			28.1		
135	85-44-9	Phthalic anhydride			28.1		
136	1336-36-3	Polychlorinated biphenyls(Aroclors)			28.1		
137	1120-71-4	1,3-Propane sultone			28.1		
138	57-57-8	beta-Propiolactone			28.1		
139	123-38-6	Propionaldehyde			28.1		
140	114-26-1	Propoxur (Baygon)			28.1		
141	78-87-5	Propylene dichloride (1,2-Dichloropropane)			28.1		
142	75-56-9	Propylene oxide			28.1		
143	75-55-8	1,2-Propylenimine (2-Methylaziridine)			28.1		
144	91-22-5	Quinoline			28.1		
145	106-51-4	Quinone(p-Benzoquinone)			28.1		
146	100-42-5	Styrene			28.1		
147	96-09-3	Styrene oxide			28.1		
148	1746-01-6	2,3,7,8-Tetrachlorodibenzo-p-dioxin			28.1		
149	79-34-5	1,1,2,2-Tetrachloroethane			28.1		
150	127-18-4	Tetrachloroethylene(Perchloroethylene)			28.1		
151	7550-45-0	Titanium tetrachloride			28.1		
152	108-88-3	Toluene	AP-42, Section 3.4, Table 3.4-3	2.81E-04	28.1	7.90E-03	3.46E-02
153	95-80-7	Toluene-2,4-diamine			28.1		
154	584-84-9	2,4-Toluene diisocyanate			28.1		
155	95-53-4	o-Toluidine			28.1		
156	8001-35-2	Toxaphene (chlorinated camphene)			28.1		

Attachment S-1a
Air Toxic Emissions for D-22 or D-23

SECTION 112 HAZARDOUS AIR POLLUTANTS

EPA ID #	CAS Number	Pollutant	Source of Emission Factor	Emission Factor (lb/MMBtu)	Heat Input (MMBtu/hr)	Emissions (lb/hr)	Emissions (tpy)
157	120-82-1	1,2,4-Trichlorobenzene			28.1		
158	79-00-5	1,1,2-Trichloroethane			28.1		
159	79-01-6	Trichloroethylene			28.1		
160	95-95-4	2,4,5-Trichlorophenol			28.1		
161	88-06-2	2,4,6-Trichlorophenol			28.1		
162	121-44-8	Triethylamine			28.1		
163	1582-09-8	Trifluralin			28.1		
164	540-84-1	2,2,4-Trimethylpentane			28.1		
165	108-05-4	Vinyl acetate			28.1		
166	593-60-2	Vinyl bromide			28.1		
167	75-01-4	Vinyl chloride			28.1		
168	75-35-4	Vinylidene chloride (1,1-Dichloroethylene)			28.1		
169	1330-20-7	Xylene (mixed isomers)	AP-42, Section 3.4, Table 3.4-3	1.93E-04	28.1	5.42E-03	2.38E-02
170	95-47-6	o-Xylene			28.1		
171	108-38-3	m-Xylene			28.1		
172	106-42-3	p-Xylene			28.1		
173		Antimony Compounds			28.1		
174		Arsenic Compounds (inorganic including arsine)	AP-42, Section 3.1, Table 3.1-5	1.10E-05	28.1	3.09E-04	1.35E-03
175		Beryllium Compounds	AP-42, Section 3.1, Table 3.1-5	3.10E-07	28.1	8.71E-06	3.82E-05
176		Cadmium Compounds	AP-42, Section 3.1, Table 3.1-5	4.80E-06	28.1	1.35E-04	5.91E-04
177		Chromium Compounds	AP-42, Section 3.1, Table 3.1-5	1.10E-05	28.1	3.09E-04	1.35E-03
178		Cobalt Compounds			28.1		
179		Coke Oven Emissions			28.1		
180		Cyanide Compounds1			28.1		
181		Glycol ethers2			28.1		
182		Lead Compounds	AP-42, Section 3.1, Table 3.1-5	1.40E-05	28.1	3.93E-04	1.72E-03
183		Manganese Compounds	AP-42, Section 3.1, Table 3.1-5	7.90E-04	28.1	2.22E-02	9.72E-02
184		Mercury Compounds	AP-42, Section 3.1, Table 3.1-5	1.20E-06	28.1	3.37E-05	1.48E-04
185		Fine mineral fibers3			28.1		
186		Nickel Compounds	AP-42, Section 3.1, Table 3.1-5	4.60E-06	28.1	1.29E-04	5.66E-04
187		Polycyclic Organic Matter4	AP-42, Section 3.4, Table 3.4-4	2.12E-04	28.1	5.96E-03	2.61E-02
188		Radionuclides (including radon)5			28.1		
189		Selenium Compounds	AP-42, Section 3.1, Table 3.1-5	2.50E-05	28.1	7.03E-04	3.08E-03
		Total				**7.25E-02**	**3.18E-01**

NOTE: For all listings above which contain the word "compounds" and for glycol ethers, the following applies:
Unless otherwise specified, these listings are defined as including any unique chemical substance that contains the named chemical (i.e., antimony, arsenic, etc.) as part of that chemical's infrastructure.

1. X'CN where X = H' or any other group where a formal dissociation may occur. For example, KCN or Ca(CN)2.

2. R-(OCH2CH2)n-OR'
where: n = 1, 2, or 3
R = alkyl C7 or less
or R = phenyl or alkyl substituted phenyl
R' = H, or alkyl C7 or less
or ester, sulfate, phosphate, nitrate, sulfonate

3. Includes mineral fiber emissions from facilities manufacturing or processing glass, rock, or slag fibers (or other mineral derived fibers) of average diameter 1 micrometer or less.

4. Includes substituted and/or unsubstituted polycyclic aromatic hydrocarbons and aromatic heterocyclic compounds, with two or more fused rings, at least one of which is benzenoid (i.e., containing six carbon atoms and is aromatic) in structure. Polycyclic Organic Matter is a mixture of organic compounds containing one or more of these polycyclic aromatic chemicals. Polycyclic Organic Matter is generally formed or emitted during thermal processes including (1) incomplete combustion, (2) pyrolysis, (3) the volatilization, distillation or processing of fossil fuels or bitumens, or (4) the distillation or thermal processing of non-fossil fuels. The Administrator may delineate, by test method, what is included in polycyclic organic matter.

5. A type of atom which spontaneously undergoes radioactive decay.

Attachment S-1a
Air Toxic Emissions for BS-1

SECTION 112 HAZARDOUS AIR POLLUTANTS

EPA ID #	CAS Number	Pollutant	Source of Emission Factor	Emission Factor (lb/MMBtu)	Heat Input (MMBtu/hr)	Emissions (lb/hr)	Emissions (tpy)
1	75-07-0	Acetaldehyde	AP-42, Section 3.4, Table 3.4-3	2.52E-05	5.57	1.40E-04	2.11E-05
2	60-35-5	Acetamide			5.57		
3	75-05-8	Acetonitrile			5.57		
4	98-86-2	Acetophenone			5.57		
5	53-96-3	2-Acetylaminofluorene			5.57		
6	107-02-8	Acrolein	AP-42, Section 3.4, Table 3.4-3	7.88E-06	5.57	4.39E-05	6.58E-06
7	79-06-1	Acrylamide			5.57		
8	79-10-7	Acrylic acid			5.57		
9	107-13-1	Acrylonitrile			5.57		
10	107-05-1	Allyl chloride			5.57		
11	92-67-1	4-Aminobiphenyl			5.57		
12	62-53-3	Aniline			5.57		
13	90-04-0	o-Anisidine			5.57		
14	1332-21-4	Asbestos			5.57		
15	71-43-2	Benzene (including benzene from gasoline)	AP-42, Section 3.4, Table 3.4-3	7.76E-04	5.57	4.32E-03	6.48E-04
16	92-87-5	Benzidine			5.57		
17	98-07-7	Benzotrichloride			5.57		
18	100-44-7	Benzyl chloride			5.57		
19	92-52-4	Biphenyl			5.57		
20	117-81-7	Bis(2-ethylhexyl)phthalate (DEHP)			5.57		
21	542-88-1	Bis(chloromethyl) ether			5.57		
22	75-25-2	Bromoform			5.57		
23	106-99-0	1,3-Butadiene	AP-42, Section 3.1, Table 3.1-4	1.60E-05	5.57	8.91E-05	1.34E-05
24	156-62-7	Calcium cyanamide			5.57		
25	105-60-2	Caprolactam (Removed 06/18/96, See 61FR30816)			5.57		
26	133-06-2	Captan			5.57		
27	63-25-2	Carbaryl			5.57		
28	75-15-0	Carbon disulfide			5.57		
29	56-23-5	Carbon tetrachloride			5.57		
30	463-58-1	Carbonyl sulfide			5.57		
31	120-80-9	Catechol			5.57		
32	133-90-4	Chloramben			5.57		
33	57-74-9	Chlordane			5.57		
34	7782-50-5	Chlorine			5.57		
35	79-11-8	Chloroacetic acid			5.57		
36	532-27-4	2-Chloroacetophenone			5.57		
37	108-90-7	Chlorobenzene			5.57		
38	510-15-6	Chlorobenzilate			5.57		
39	67-66-3	Chloroform			5.57		
40	107-30-2	Chloromethyl methyl ether			5.57		
41	126-99-8	Chloroprene			5.57		
42	1319-77-3	Cresol/Cresylic acid(mixed isomers)			5.57		
43	95-48-7	o-Cresol			5.57		
44	108-39-4	m-Cresol			5.57		
45	106-44-5	p-Cresol			5.57		
46	98-82-8	Cumene			5.57		
47		2,4-D(2,4-Dichlorophenoxyacetic Acid) (including salts and esters)			5.57		
48	72-55-9	DDE(1,1-dichloro-2,2-bis(p-chlorophenyl) ethylene)			5.57		
49	334-88-3	Diazomethane			5.57		
50	132-64-9	Dibenzofuran			5.57		
51	96-12-8	1,2-Dibromo-3-chloropropane			5.57		
52	84-74-2	Dibutyl phthalate			5.57		
53	106-46-7	1,4-Dichlorobenzene			5.57		
54	91-94-1	Dichlorobenzidine			5.57		
55	111-44-4	Dichloroethyl ether(Bis[2-chloroethyl]ether)			5.57		
56	542-75-6	1,3-Dichloropropene			5.57		
57	62-73-7	Dichlorvos			5.57		
58	111-42-2	Diethanolamine			5.57		
59	64-67-5	Diethyl sulfate			5.57		
60	119-90-4	3,3'-Dimethoxybenzidine			5.57		
61	60-11-7	4-Dimethylaminoazobenzene			5.57		
62	121-69-7	N,N-Dimethylaniline			5.57		
63	119-93-7	3,3'-Dimethylbenzidine			5.57		
64	79-44-7	Dimethylcarbamoyl chloride			5.57		
65	68-12-2	N,N-Dimethylformamide			5.57		
66	57-14-7	1,1-Dimethylhydrazine			5.57		
67	131-11-3	Dimethyl phthalate			5.57		
68	77-78-1	Dimethyl sulfate			5.57		
69		4,6-Dinitro-o-cresol (including salts)			5.57		
70	51-28-5	2,4-Dinitrophenol			5.57		
71	121-14-2	2,4-Dinitrotoluene			5.57		
72	123-91-1	1,4-Dioxane (1,4-Diethyleneoxide)			5.57		
73	122-66-7	1,2-Diphenylhydrazine			5.57		
74	106-89-8	Epichlorohydrin (l-Chloro-2,3-epoxypropane)			5.57		
75	106-88-7	1,2-Epoxybutane			5.57		
76	140-88-5	Ethyl acrylate			5.57		
77	100-41-4	Ethylbenzene			5.57		
78	51-79-6	Ethyl carbamate (Urethane)			5.57		

Attachment S-1a
Air Toxic Emissions for BS-1

SECTION 112 HAZARDOUS AIR POLLUTANTS

EPA ID #	CAS Number	Pollutant	Source of Emission Factor	Emission Factor (lb/MMBtu)	Heat Input (MMBtu/hr)	Emissions (lb/hr)	Emissions (tpy)
79	75-00-3	Ethyl chloride (Chloroethane)			5.57		
80	106-93-4	Ethylene dibromide (Dibromoethane)			5.57		
81	107-06-2	Ethylene dichloride (1,2-Dichloroethane)			5.57		
82	107-21-1	Ethylene glycol			5.57		
83	151-56-4	Ethyleneimine (Aziridine)			5.57		
84	75-21-8	Ethylene oxide			5.57		
85	96-45-7	Ethylene thiourea			5.57		
86	75-34-3	Ethylidene dichloride (1,1-Dichloroethane)			5.57		
87	50-00-0	Formaldehyde	AP-42, Section 3.4, Table 3.4-3	7.89E-05	5.57	4.39E-04	6.59E-05
88	76-44-8	Heptachlor			5.57		
89	118-74-1	Hexachlorobenzene			5.57		
90	87-68-3	Hexachlorobutadiene			5.57		
91		1,2,3,4,5,6-Hexachlorocyclyhexane (all stereo isomers including lindane)			5.57		
92	77-47-4	Hexachlorocyclopentadiene			5.57		
93	67-72-1	Hexachloroethane			5.57		
94	822-06-0	Hexamethylene diisocyanate			5.57		
95	680-31-9	Hexamethylphosphoramide			5.57		
96	110-54-3	Hexane			5.57		
97	302-01-2	Hydrazine			5.57		
98	7647-01-0	Hydrochloric acid (Hydrogen chloride [gas only])			5.57		
99	7664-39-3	Hydrogen fluoride (Hydrofluoric acid)			5.57		
100	123-31-9	Hydroquinone			5.57		
101	78-59-1	Isophorone			5.57		
102	108-31-6	Maleic anhydride			5.57		
103	67-56-1	Methanol			5.57		
104	72-43-5	Methoxychlor			5.57		
105	74-83-9	Methyl bromide (Bromomethane)			5.57		
106	74-87-3	Methyl chloride(Chloromethane)			5.57		
107	71-55-6	Methyl chloroform(1,1,1-Trichloroethane)			5.57		
108	78-93-3	Methyl ethyl ketone (2-Butanone) (Removed 12/19/05, See 70FR75047)			5.57		
109	60-34-4	Methylhydrazine			5.57		
110	74-88-4	Methyl iodide (Iodomethane)			5.57		
111	108-10-1	Methyl isobutyl ketone(Hexone)			5.57		
112	624-83-9	Methyl isocyanate			5.57		
113	80-62-6	Methyl methacrylate			5.57		
114	1634-04-4	Methyl tert-butyl ether			5.57		
115	101-14-4	4,4'-Methylenebis(2-chloroaniline)			5.57		
116	75-09-2	Methylene chloride(Dichloromethane)			5.57		
117	101-68-8	4,4'-Methylenediphenyl diisocyanate(MDI)			5.57		
118	101-77-9	4,4'-Methylenedianiline			5.57		
119	91-20-3	Naphthalene	AP-42, Section 3.4, Table 3.4-4	1.30E-04	5.57	7.24E-04	1.09E-04
120	98-95-3	Nitrobenzene			5.57		
121	92-93-3	4-Nitrobiphenyl			5.57		
122	100-02-7	4-Nitrophenol			5.57		
123	79-46-9	2-Nitropropane			5.57		
124	684-93-5	N-Nitroso-N-methylurea			5.57		
125	62-75-9	N-Nitrosodimethylamine			5.57		
126	59-89-2	N-Nitrosomorpholine			5.57		
127	56-38-2	Parathion			5.57		
128	82-68-8	Pentachloronitrobenzene(Quintobenzene)			5.57		
129	87-86-5	Pentachlorophenol			5.57		
130	108-95-2	Phenol			5.57		
131	106-50-3	p-Phenylenediamine			5.57		
132	75-44-5	Phosgene			5.57		
133	7803-51-2	Phosphine			5.57		
134	7723-14-0	Phosphorus			5.57		
135	85-44-9	Phthalic anhydride			5.57		
136	1336-36-3	Polychlorinated biphenyls(Aroclors)			5.57		
137	1120-71-4	1,3-Propane sultone			5.57		
138	57-57-8	beta-Propiolactone			5.57		
139	123-38-6	Propionaldehyde			5.57		
140	114-26-1	Propoxur (Baygon)			5.57		
141	78-87-5	Propylene dichloride (1,2-Dichloropropane)			5.57		
142	75-56-9	Propylene oxide			5.57		
143	75-55-8	1,2-Propylenimine (2-Methylaziridine)			5.57		
144	91-22-5	Quinoline			5.57		
145	106-51-4	Quinone(p-Benzoquinone)			5.57		
146	100-42-5	Styrene			5.57		
147	96-09-3	Styrene oxide			5.57		
148	1746-01-6	2,3,7,8-Tetrachlorodibenzo-p-dioxin			5.57		
149	79-34-5	1,1,2,2-Tetrachloroethane			5.57		
150	127-18-4	Tetrachloroethylene(Perchloroethylene)			5.57		
151	7550-45-0	Titanium tetrachloride			5.57		
152	108-88-3	Toluene	AP-42, Section 3.4, Table 3.4-3	2.81E-04	5.57	1.57E-03	2.35E-04
153	95-80-7	Toluene-2,4-diamine			5.57		
154	584-84-9	2,4-Toluene diisocyanate			5.57		
155	95-53-4	o-Toluidine			5.57		
156	8001-35-2	Toxaphene (chlorinated camphene)			5.57		

Attachment S-1a
Air Toxic Emissions for BS-1

SECTION 112 HAZARDOUS AIR POLLUTANTS

EPA ID #	CAS Number	Pollutant	Source of Emission Factor	Emission Factor (lb/MMBtu)	Heat Input (MMBtu/hr)	Emissions (lb/hr)	Emissions (tpy)
157	120-82-1	1,2,4-Trichlorobenzene			5.57		
158	79-00-5	1,1,2-Trichloroethane			5.57		
159	79-01-6	Trichloroethylene			5.57		
160	95-95-4	2,4,5-Trichlorophenol			5.57		
161	88-06-2	2,4,6-Trichlorophenol			5.57		
162	121-44-8	Triethylamine			5.57		
163	1582-09-8	Trifluralin			5.57		
164	540-84-1	2,2,4-Trimethylpentane			5.57		
165	108-05-4	Vinyl acetate			5.57		
166	593-60-2	Vinyl bromide			5.57		
167	75-01-4	Vinyl chloride			5.57		
168	75-35-4	Vinylidene chloride (1,1-Dichloroethylene)			5.57		
169	1330-20-7	Xylene (mixed isomers)	AP-42, Section 3.4, Table 3.4-3	1.93E-04	5.57	1.08E-03	1.61E-04
170	95-47-6	o-Xylene			5.57		
171	108-38-3	m-Xylene			5.57		
172	106-42-3	p-Xylene			5.57		
173		Antimony Compounds			5.57		
174		Arsenic Compounds (inorganic including arsine)	AP-42, Section 3.1, Table 3.1-5	1.10E-05	5.57	6.13E-05	9.19E-06
175		Beryllium Compounds	AP-42, Section 3.1, Table 3.1-5	3.10E-07	5.57	1.73E-06	2.59E-07
176		Cadmium Compounds	AP-42, Section 3.1, Table 3.1-5	4.80E-06	5.57	2.67E-05	4.01E-06
177		Chromium Compounds	AP-42, Section 3.1, Table 3.1-5	1.10E-05	5.57	6.13E-05	9.19E-06
178		Cobalt Compounds			5.57		
179		Coke Oven Emissions			5.57		
180		Cyanide Compounds1			5.57		
181		Glycol ethers2			5.57		
182		Lead Compounds	AP-42, Section 3.1, Table 3.1-5	1.40E-05	5.57	7.80E-05	1.17E-05
183		Manganese Compounds	AP-42, Section 3.1, Table 3.1-5	7.90E-04	5.57	4.40E-03	6.60E-04
184		Mercury Compounds	AP-42, Section 3.1, Table 3.1-5	1.20E-06	5.57	6.68E-06	1.00E-06
185		Fine mineral fibers3			5.57		
186		Nickel Compounds	AP-42, Section 3.1, Table 3.1-5	4.60E-06	5.57	2.56E-05	3.84E-06
187		Polycyclic Organic Matter4	AP-42, Section 3.4, Table 3.4-4	2.12E-04	5.57	1.18E-03	1.77E-04
188		Radionuclides (including radon)5			5.57		
189		Selenium Compounds	AP-42, Section 3.1, Table 3.1-5	2.50E-05	5.57	1.39E-04	2.09E-05
		Total				**1.44E-02**	**2.16E-03**

NOTE: For all listings above which contain the word "compounds" and for glycol ethers, the following applies:
Unless otherwise specified, these listings are defined as including any unique chemical substance that contains the named chemical (i.e., antimony, arsenic, etc.) as part of that chemical's infrastructure.

1. X'CN where X = H' or any other group where a formal dissociation may occur. For example, KCN or Ca(CN)2.

2. R-(OCH2CH2)n-OR'
where:
n = 1, 2, or 3
R = alkyl C7 or less
or R = phenyl or alkyl substituted phenyl
R' = H, or alkyl C7 or less
or ester, sulfate, phosphate, nitrate, sulfonate

3. Includes mineral fiber emissions from facilities manufacturing or processing glass, rock, or slag fibers (or other mineral derived fibers) of average diameter 1 micrometer or less.

4. Includes substituted and/or unsubstituted polycyclic aromatic hydrocarbons and aromatic heterocyclic compounds, with two or more fused rings, at least one of which is benzenoid (i.e., containing six carbon atoms and is aromatic) in structure. Polycyclic Organic Matter is a mixture of organic compounds containing one or more of these polycyclic aromatic chemicals. Polycyclic Organic Matter is generally formed or emitted during thermal processes including (1) incomplete combustion, (2) pyrolysis, (3) the volatilization, distillation or processing of fossil fuels or bitumens, or (4) the distillation or thermal processing of non-fossil fuels. The Administrator may delineate, by test method, what is included in polycyclic organic matter.

5. A type of atom which spontaneously undergoes radioactive decay.

Attachment S-1a
Total Air Toxic Emissions

SECTION 112 HAZARDOUS AIR POLLUTANTS

EPA ID #	CAS Number	Pollutant	CT-2 Emissions (tpy)	CT-4 Emissions (tpy)	CT-5 Emissions (tpy)	D-21 Emissions (tpy)	D-22 Emissions (tpy)	D-23 Emissions (tpy)	BS-1 Emissions (tpy)	Total Emissions (tpy)
1	75-07-0	Acetaldehyde	2.17E-02	3.04E-02	3.04E-02	1.23E-04	3.10E-03	3.10E-03	2.11E-05	8.88E-02
2	60-35-5	Acetamide								
3	75-05-8	Acetonitrile								
4	98-86-2	Acetophenone								
5	53-96-3	2-Acetylaminofluorene								
6	107-02-8	Acrolein	6.79E-03	9.49E-03	9.49E-03	3.86E-05	9.70E-04	9.70E-04	6.58E-06	2.78E-02
7	79-06-1	Acrylamide								
8	79-10-7	Acrylic acid								
9	107-13-1	Acrylonitrile								
10	107-05-1	Allyl chloride								
11	92-67-1	4-Aminobiphenyl								
12	62-53-3	Aniline								
13	90-04-0	o-Anisidine								
14	1332-21-4	Asbestos								
15	71-43-2	Benzene (including benzene from gasoline)	4.74E-02	6.61E-02	6.61E-02	3.80E-03	9.55E-02	9.55E-02	6.48E-04	3.75E-01
16	92-87-5	Benzidine								
17	98-07-7	Benzotrichloride								
18	100-44-7	Benzyl chloride								
19	92-52-4	Biphenyl								
20	117-81-7	Bis(2-ethylhexyl)phthalate (DEHP)								
21	542-88-1	Bis(chloromethyl) ether								
22	75-25-2	Bromoform								
23	106-99-0	1,3-Butadiene	1.38E-02	1.93E-02	1.93E-02	7.84E-05	1.97E-03	1.97E-03	1.34E-05	5.64E-02
24	156-62-7	Calcium cyanamide								
25	105-60-2	Caprolactam (Removed 06/18/96, See 61FR30816)								
26	133-06-2	Captan								
27	63-25-2	Carbaryl								
28	75-15-0	Carbon disulfide								
29	56-23-5	Carbon tetrachloride								
30	463-58-1	Carbonyl sulfide								
31	120-80-9	Catechol								
32	133-90-4	Chloramben								
33	57-74-9	Chlordane								
34	7782-50-5	Chlorine								
35	79-11-8	Chloroacetic acid								
36	532-27-4	2-Chloroacetophenone								
37	108-90-7	Chlorobenzene								
38	510-15-6	Chlorobenzilate								
39	67-66-3	Chloroform								
40	107-30-2	Chloromethyl methyl ether								
41	126-99-8	Chloroprene								
42	1319-77-3	Cresol/Cresylic acid(mixed isomers)								
43	95-48-7	o-Cresol								
44	108-39-4	m-Cresol								
45	106-44-5	p-Cresol								
46	98-82-8	Cumene								
47		2,4-D(2,4-Dichlorophenoxyacetic Acid) (including salts and esters)								
48	72-55-9	DDE(1,1-dichloro-2,2-bis(p-chlorophenyl) ethylene)								
49	334-88-3	Diazomethane								
50	132-64-9	Dibenzofuran								
51	96-12-8	1,2-Dibromo-3-chloropropane								
52	84-74-2	Dibutyl phthalate								
53	106-46-7	1,4-Dichlorobenzene								
54	91-94-1	Dichlorobenzidine								
55	111-44-4	Dichloroethyl ether(Bis[2-chloroethyl]ether)								
56	542-75-6	1,3-Dichloropropene								
57	62-73-7	Dichlorvos								
58	111-42-2	Diethanolamine								
59	64-67-5	Diethyl sulfate								
60	119-90-4	3,3'-Dimethoxybenzidine								
61	60-11-7	4-Dimethylaminoazobenzene								
62	121-69-7	N,N-Dimethylaniline								
63	119-93-7	3,3'-Dimethylbenzidine								
64	79-44-7	Dimethylcarbamoyl chloride								
65	68-12-2	N,N-Dimethylformamide								
66	57-14-7	1,1-Dimethylhydrazine								
67	131-11-3	Dimethyl phthalate								
68	77-78-1	Dimethyl sulfate								
69		4,6-Dinitro-o-cresol (including salts)								
70	51-28-5	2,4-Dinitrophenol								
71	121-14-2	2,4-Dinitrotoluene								
72	123-91-1	1,4-Dioxane (1,4-Diethyleneoxide)								
73	122-66-7	1,2-Diphenylhydrazine								
74	106-89-8	Epichlorohydrin (l-Chloro-2,3-epoxypropane)								
75	106-88-7	1,2-Epoxybutane								
76	140-88-5	Ethyl acrylate								
77	100-41-4	Ethylbenzene								
78	51-79-6	Ethyl carbamate (Urethane)								

Attachment S-1a
Total Air Toxic Emissions

SECTION 112 HAZARDOUS AIR POLLUTANTS

EPA ID #	CAS Number	Pollutant	CT-2 Emissions (tpy)	CT-4 Emissions (tpy)	CT-5 Emissions (tpy)	D-21 Emissions (tpy)	D-22 Emissions (tpy)	D-23 Emissions (tpy)	BS-1 Emissions (tpy)	Total Emissions (tpy)
79	75-00-3	Ethyl chloride (Chloroethane)								
80	106-93-4	Ethylene dibromide (Dibromoethane)								
81	107-06-2	Ethylene dichloride (1,2-Dichloroethane)								
82	107-21-1	Ethylene glycol								
83	151-56-4	Ethyleneimine (Aziridine)								
84	75-21-8	Ethylene oxide								
85	96-45-7	Ethylene thiourea								
86	75-34-3	Ethylidene dichloride (1,1-Dichloroethane)								
87	50-00-0	Formaldehyde	2.41E-01	3.37E-01	3.37E-01	3.87E-04	9.71E-03	9.71E-03	6.59E-05	9.35E-01
88	76-44-8	Heptachlor								
89	118-74-1	Hexachlorobenzene								
90	87-68-3	Hexachlorobutadiene								
91		1,2,3,4,5,6-Hexachlorocyclyhexane (all stereo isomers including lindane)								
92	77-47-4	Hexachlorocyclopentadiene								
93	67-72-1	Hexachloroethane								
94	822-06-0	Hexamethylene diisocyanate								
95	680-31-9	Hexamethylphosphoramide								
96	110-54-3	Hexane								
97	302-01-2	Hydrazine								
98	7647-01-0	Hydrochloric acid (Hydrogen chloride [gas only])								
99	7664-39-3	Hydrogen fluoride (Hydrofluoric acid)								
100	123-31-9	Hydroquinone								
101	78-59-1	Isophorone								
102	108-31-6	Maleic anhydride								
103	67-56-1	Methanol								
104	72-43-5	Methoxychlor								
105	74-83-9	Methyl bromide (Bromomethane)								
106	74-87-3	Methyl chloride(Chloromethane)								
107	71-55-6	Methyl chloroform(1,1,1-Trichloroethane)								
108	78-93-3	Methyl ethyl ketone (2-Butanone) (Removed 12/19/05, S								
109	60-34-4	Methylhydrazine								
110	74-88-4	Methyl iodide (Iodomethane)								
111	108-10-1	Methyl isobutyl ketone(Hexone)								
112	624-83-9	Methyl isocyanate								
113	80-62-6	Methyl methacrylate								
114	1634-04-4	Methyl tert-butyl ether								
115	101-14-4	4,4'-Methylenebis(2-chloroaniline)								
116	75-09-2	Methylene chloride(Dichloromethane)								
117	101-68-8	4,4'-Methylenediphenyl diisocyanate(MDI)								
118	101-77-9	4,4'-Methylenedianiline								
119	91-20-3	Naphthalene	3.01E-02	4.22E-02	4.22E-02	6.37E-04	1.60E-02	1.60E-02	1.09E-04	1.47E-01
120	98-95-3	Nitrobenzene								
121	92-93-3	4-Nitrobiphenyl								
122	100-02-7	4-Nitrophenol								
123	79-46-9	2-Nitropropane								
124	684-93-5	N-Nitroso-N-methylurea								
125	62-75-9	N-Nitrosodimethylamine								
126	59-89-2	N-Nitrosomorpholine								
127	56-38-2	Parathion								
128	82-68-8	Pentachloronitrobenzene(Quintobenzene)								
129	87-86-5	Pentachlorophenol								
130	108-95-2	Phenol								
131	106-50-3	p-Phenylenediamine								
132	75-44-5	Phosgene								
133	7803-51-2	Phosphine								
134	7723-14-0	Phosphorus								
135	85-44-9	Phthalic anhydride								
136	1336-36-3	Polychlorinated biphenyls(Aroclors)								
137	1120-71-4	1,3-Propane sultone								
138	57-57-8	beta-Propiolactone								
139	123-38-6	Propionaldehyde								
140	114-26-1	Propoxur (Baygon)								
141	78-87-5	Propylene dichloride (1,2-Dichloropropane)								
142	75-56-9	Propylene oxide								
143	75-55-8	1,2-Propylenimine (2-Methylaziridine)								
144	91-22-5	Quinoline								
145	106-51-4	Quinone(p-Benzoquinone)								
146	100-42-5	Styrene								
147	96-09-3	Styrene oxide								
148	1746-01-6	2,3,7,8-Tetrachlorodibenzo-p-dioxin								
149	79-34-5	1,1,2,2-Tetrachloroethane								
150	127-18-4	Tetrachloroethylene(Perchloroethylene)								
151	7550-45-0	Titanium tetrachloride								
152	108-88-3	Toluene	2.42E-01	3.38E-01	3.38E-01	1.38E-03	3.46E-02	3.46E-02	2.35E-04	9.90E-01
153	95-80-7	Toluene-2,4-diamine								
154	584-84-9	2,4-Toluene diisocyanate								
155	95-53-4	o-Toluidine								
156	8001-35-2	Toxaphene (chlorinated camphene)								

Attachment S-1a
Total Air Toxic Emissions

SECTION 112 HAZARDOUS AIR POLLUTANTS

EPA ID #	CAS Number	Pollutant	CT-2 Emissions (tpy)	CT-4 Emissions (tpy)	CT-5 Emissions (tpy)	D-21 Emissions (tpy)	D-22 Emissions (tpy)	D-23 Emissions (tpy)	BS-1 Emissions (tpy)	Total Emissions (tpy)
157	120-82-1	1,2,4-Trichlorobenzene								
158	79-00-5	1,1,2-Trichloroethane								
159	79-01-6	Trichloroethylene								
160	95-95-4	2,4,5-Trichlorophenol								
161	88-06-2	2,4,6-Trichlorophenol								
162	121-44-8	Triethylamine								
163	1582-09-8	Trifluralin								
164	540-84-1	2,2,4-Trimethylpentane								
165	108-05-4	Vinyl acetate								
166	593-60-2	Vinyl bromide								
167	75-01-4	Vinyl chloride								
168	75-35-4	Vinylidene chloride (1,1-Dichloroethylene)								
169	1330-20-7	Xylene (mixed isomers)	1.66E-01	2.32E-01	2.32E-01	9.46E-04	2.38E-02	2.38E-02	1.61E-04	6.80E-01
170	95-47-6	o-Xylene								
171	108-38-3	m-Xylene								
172	106-42-3	p-Xylene								
173		Antimony Compounds								
174		Arsenic Compounds (inorganic including arsine)	9.47E-03	1.33E-02	1.33E-02	5.39E-05	1.35E-03	1.35E-03	9.19E-06	3.88E-02
175		Beryllium Compounds	2.67E-04	3.73E-04	3.73E-04	1.52E-06	3.82E-05	3.82E-05	2.59E-07	1.09E-03
176		Cadmium Compounds	4.13E-03	5.78E-03	5.78E-03	2.35E-05	5.91E-04	5.91E-04	4.01E-06	1.69E-02
177		Chromium Compounds	9.47E-03	1.32E-02	1.32E-02	5.39E-05	1.35E-03	1.35E-03	9.19E-06	3.87E-02
178		Cobalt Compounds								
179		Coke Oven Emissions								
180		Cyanide Compounds1								
181		Glycol ethers2								
182		Lead Compounds	1.21E-02	1.69E-02	1.69E-02	6.86E-05	1.72E-03	1.72E-03	1.17E-05	4.93E-02
183		Manganese Compounds	6.80E-01	9.52E-01	9.52E-01	3.87E-03	9.72E-02	9.72E-02	6.60E-04	2.78E+00
184		Mercury Compounds	1.03E-03	1.45E-03	1.45E-03	5.88E-06	1.48E-04	1.48E-04	1.00E-06	4.23E-03
185		Fine mineral fibers3								
186		Nickel Compounds	3.96E-03	5.54E-03	5.54E-03	2.25E-05	5.66E-04	5.66E-04	3.84E-06	1.62E-02
187		Polycyclic Organic Matter4	3.44E-02	4.82E-02	4.82E-02	1.04E-03	2.61E-02	2.61E-02	1.77E-04	1.84E-01
188		Radionuclides (including radon)5								
189		Selenium Compounds	2.15E-02	3.01E-02	3.01E-02	1.23E-04	3.08E-03	3.08E-03	2.09E-05	8.80E-02
		Total	**1.55**	**2.16**	**2.16**	**0.013**	**0.32**	**0.32**	**0.0022**	**6.52**

NOTE: For all listings above which contain the word "compounds" and for glycol ethers, the following applies:
Unless otherwise specified, these listings are defined as including any unique chemical substance that contains the named chemical (i.e., antimony, arsenic, etc.) as part of that chemical's infrastructure.

1. X'CN where X = H' or any other group where a formal dissociation may occur. For example, KCN or Ca(CN)2.

2. R-(OCH2CH2)n-OR'
where: n = 1, 2, or 3
R = alkyl C7 or less
or R = phenyl or alkyl substituted phenyl
R' = H, or alkyl C7 or less
or ester, sulfate, phosphate, nitrate, sulfonate

3. Includes mineral fiber emissions from facilities manufacturing or processing glass, rock, or slag fibers (or other mineral derived fibers) of average diameter 1 micrometer or less.

4. Includes substituted and/or unsubstituted polycyclic aromatic hydrocarbons and aromatic heterocyclic compounds, with two or more fused rings, at least one of which is benzenoid (i.e., containing six carbon atoms and is aromatic) in structure. Polycyclic Organic Matter is a mixture of organic compounds containing one or more of these polycyclic aromatic chemicals. Polycyclic Organic Matter is generally formed or emitted during thermal processes including (1) incomplete combustion, (2) pyrolysis, (3) the volatilization, distillation or processing of fossil fuels or bitumens, or (4) the distillation or thermal processing of non-fossil fuels. The Administrator may delineate, by test method, what is included in polycyclic organic matter.

5. A type of atom which spontaneously undergoes radioactive decay.

Attachment S-1b
Other Regulated Pollutants

Emissions for Unit CT-2	Emissions (lb/hr)	Emissions (tpy)
Beryllium	See Attachment S-1a	
Mercury	See Attachment S-1a	
Asbestos	neg.	neg.
Hydrogen Sulfide	neg.	neg.
Halons	neg.	neg.
MWC Acid Gases	neg.	neg.
MWC Metals	neg.	neg.
MWC Organics	neg.	neg.

Emissions for Unit CT-4 or CT-5	Emissions (lb/hr)	Emissions (tpy)
Beryllium	See Attachment S-1a	
Mercury	See Attachment S-1a	
Asbestos	neg.	neg.
Hydrogen Sulfide	neg.	neg.
Halons	neg.	neg.
MWC Acid Gases	neg.	neg.
MWC Metals	neg.	neg.
MWC Organics	neg.	neg.

Emissions for Unit D-21	Emissions (lb/hr)	Emissions (tpy)
Beryllium	See Attachment S-1a	
Mercury	See Attachment S-1a	
Asbestos	neg.	neg.
Hydrogen Sulfide	neg.	neg.
Halons	neg.	neg.
MWC Acid Gases	neg.	neg.
MWC Metals	neg.	neg.
MWC Organics	neg.	neg.

Emissions for Unit D-22 or D-23	Emissions (lb/hr)	Emissions (tpy)
Beryllium	See Attachment S-1a	
Mercury	See Attachment S-1a	
Asbestos	neg.	neg.
Hydrogen Sulfide	neg.	neg.
Halons	neg.	neg.
MWC Acid Gases	neg.	neg.
MWC Metals	neg.	neg.
MWC Organics	neg.	neg.

Emissions for Unit BS-1	Emissions (lb/hr)	Emissions (tpy)
Beryllium	See Attachment S-1a	
Mercury	See Attachment S-1a	
Asbestos	neg.	neg.
Hydrogen Sulfide	neg.	neg.
Halons	neg.	neg.
MWC Acid Gases	neg.	neg.
MWC Metals	neg.	neg.
MWC Organics	neg.	neg.

Notes:
MWC = Municipal Waste Combustor
neg. = negligible

Attachment S-1c
Pollutant Emission Rate Calculations

Sulfur Dioxide (SO_2)

Unit	Heat Input (MMBtu/hr)	AP-42 Emission Factor[1,2] (lb/MMBtu)	CSP Application Emission Factor[3] (lb/MMBtu)	CSP Application Emission Rate (lb/hr)
CT-2	198	0.404	0.556	110
CT-4	275	0.404	0.400	110
CT-5	275	0.404	0.400	110
D-21	28.1	0.404	0.413	11.6
D-22	28.1	0.404	0.413	11.6
D-23	28.1	0.404	0.413	11.6
BS-1	5.57	0.404	0.513	2.86

1. AP-42 emission factor for CT-2, CT-4, and CT-5 from Section 3.1, dated April 2000, Tabel 3.1-2a, using a sulfur content of 0.4%.

2. AP-42 emission factor for D-21, D-22, D-23, and BS-1 from Section 3.4, dated October 1996, Table 3.4-1, using a sulfur content of 0.4%.

Nitrogen Oxides (NO_X)

Unit	Heat Input (MMBtu/hr)	AP-42 Emission Factor[1,2] (lb/MMBtu)	CSP Application Emission Factor (lb/MMBtu)	CSP Application Emission Rate (lb/hr)
CT-2	198	0.24	0.197	39.0
CT-4	275	0.24	0.154	42.3
CT-5	275	0.24	0.154	42.3
D-21	28.1	3.2	2.434	68.4
D-22	28.1	3.2	2.434	68.4
D-23	28.1	3.2	2.434	68.4
BS-1	5.57	3.2	2.244	12.5

1. AP-42 emission factor for CT-2, CT-4, and CT-5 from Section 3.1, dated April 2000, Tabel 3.1-1.
2. AP-42 emission factor for D-21, D-22, D-23, and BS-1 from Section 3.4, dated October 1996, Table 3.4-1.

Attachment S-1c
Pollutant Emission Rate Calculations

Carbon Monoxide (CO)

Unit	Heat Input (MMBtu/hr)	AP-42 Emission Factor[1,2] (lb/MMBtu)	CSP Application Emission Factor (lb/MMBtu)	CSP Application Emission Rate (lb/hr)
CT-2	198	0.076	0.113	22.4
CT-4	275	0.076	0.097	26.8
CT-5	275	0.076	0.097	26.8
D-21	28.1	0.85	2.794	78.5
D-22	28.1	0.85	2.794	78.5
D-23	28.1	0.85	2.794	78.5
BS-1	5.57	0.85	0.427	2.38

1. AP-42 emission factor for CT-2, CT-4, and CT-5 from Section 3.1, dated April 2000, Tabel 3.1-1.
2. AP-42 emission factor for D-21, D-22, D-23, and BS-1 from Section 3.4, dated October 1996, Table 3.4-1.

Particulate Matter (PM/PM_{10})

Unit	Heat Input (MMBtu/hr)	AP-42 Emission Factor[1,2] (lb/MMBtu)	CSP Application Emission Factor (lb/MMBtu)	CSP Application Emission Rate (lb/hr)
CT-2	198	0.012	0.101	20.0
CT-4	275	0.012	0.072	19.7
CT-5	275	0.012	0.072	19.7
D-21	28.1	0.1	0.180	5.06
D-22	28.1	0.1	0.180	5.06
D-23	28.1	0.1	0.180	5.06
BS-1	5.57	0.1	0.355	1.98

1. AP-42 emission factor for CT-2, CT-4, and CT-5 from Section 3.1, dated April 2000, Tabel 3.1-2a.
2. AP-42 emission factor for D-21, D-22, D-23, and BS-1 from Section 3.4, dated October 1996, Table 3.4-2.

Volatile Organic Compounds (VOC)

Unit	Heat Input (MMBtu/hr)	AP-42 Emission Factor[1,2] (lb/MMBtu)	CSP Application Emission Factor (lb/MMBtu)	CSP Application Emission Rate (lb/hr)
CT-2	198	0.00041	0.113	22.4
CT-4	275	0.00041	0.003	0.8
CT-5	275	0.00041	0.003	0.8
D-21	28.1	0.082	0.238	6.69
D-22	28.1	0.082	0.238	6.69
D-23	28.1	0.082	0.238	6.69
BS-1	5.57	0.082	0.083	0.46

1. AP-42 emission factor for CT-2, CT-4, and CT-5 from Section 3.1, dated April 2000, Tabel 3.1-2a.
2. AP-42 emission factor for D-21, D-22, D-23, and BS-1 from Section 3.4, dated October 1996, Table 3.4-1.

File No.: ________

S-3: Application for a Covered Source Permit Renewal

Each application for permit renewal shall be submitted to the Director of Health, (hereafter, Director) a minimum of **twelve months** prior to the date of permit expiration. In providing the required information, please reference the corresponding letters and numbers listed below.

Provide a minimum of **two (2)** sets (1 original and 1 copy) of all application materials to the Hawaii Department of Health. Also, mail **one (1)** set directly to EPA at the following address:

Chief (Attention: AIR-3)
Permits Office, Air Division
U.S. Environmental Protection Agency
Region 9
75 Hawthorne Street
San Francisco, CA 94105

I. In accordance with Hawaii Administrative Rules (HAR) §11-60.1-101, the following information is required:

A. Statement certifying that no changes have been made in the design or operation of the source as proposed in the initial and any subsequent Covered Source Permit applications. If changes have occurred or are being proposed, the applicant shall provide a description of those changes such as work practices, operations, equipment design, and monitoring procedures, including the affected applicable requirements associated with the changes and the corresponding information to determine the applicability of all applicable requirements.

The source continues to operate as proposed in the initial and subsequent covered source permit applications. As part of the renewal process, HELCO proposes permit condition changes. Attachments S-3c and S-3e lists the proposed changes to CSP Nos. 0007-01-C and 0070-01-C, respectively. Proposed additions are underlined and proposed deletions are struck through. The renewal application also seeks to merge CSP No. 0070-1-C into CSP No. 0007-01-C.

B. Equipment Specifications:

1. Maximum design capacity. See table below.
2. Fuel type. No. 2 diesel fuel with 0.4% by weight maximum sulfur content.
3. Fuel use. See table below.

Maximum Capacity and Fuel Use Per Unit

Unit ID	Manufacturer	Model Number	Serial Number	Capacity (Nominal)	Fuel Flow Rate
D-21	General Motors	20-645F4B	74-B1-1078	2.5 MW	28.1 MMBtu/hr
D-22	General Motors	20-645F4B	66-K1-1062	2.5 MW	28.1 MMBtu/hr
D-23	General Motors	20-645E4	69-H1-1057	2.5 MW	28.1 MMBtu/hr
BS-1	Caterpillar	3412	81Z07275	500 kW	5.57 MMBtu/hr
CT-2	Jupiter	GT-35	JF88702	18 MW	198 MMBtu/hr
CT-4	General Electric	LM2500	481-688	20 MW	275 MMBtu/hr
CT-5	General Electric	LM2500	481-692	20 MW	275 MMBtu/hr
ST-7				16 MW	NA

4. Production capacity. Not applicable.

5. Production rates. Not applicable.

6. Raw materials. Not applicable.

7. Provide any manufacturer's literature. See Attachment S-3a for manufacturer's literature for CT-4 and CT-5. No manufacturer's literature is available for the other units.

C. Provide detailed descriptions of all processes and products defined by Standard Industrial Classification Code (SICC). Also, provide any reasonably anticipated alternative operating scenarios, associated processes, and products, by SICC.

Electrical power generation through combustion of fossil fuels (SICC code 4911) is the only product or process.

Several types of alternative operating scenarios apply to the generating station as described below:

a. Use of a temporary replacement unit in the event of a failure or major overhaul of an installed unit. In the event that the projected down time of the unit increases the likelihood of an interruption in electrical service, the down unit would be replaced with an equivalent unit. Emissions from the replacement unit will comply with the original unit's permitted emission limits. Proposed changes to add a permanent replacement AOS are in Attachment S-3c.

b. CT-4 and CT-5 may operate below 25% of peak load during testing of the heat recovery steam generators and steam turbine and steam blows needed to clean the steam tubes prior to initial operation.

c. Should less expensive fuels become available, or the supply of No. 2 diesel become limited, HELCO may use alternative fuels with prior approval from the Department of Health.

d. In the event of emergency load conditions such as the sudden loss of a unit, CT-2, CT-4 and CT-5 may operate up to 110 percent of peak load for up to 30 minutes. Such operation will not exceed the permitted 3-hour average emission rates.

e. Fuel additives to reduce corrosion, control biological growth, and enhance combustion may be used in CT-4 and CT-5.

f. HELCO, with the approval from the Department of Health, may use alternate means and methods to improve combustion and/or reduce emissions for CT-4 and CT-5.

1. Identify and describe in detail all air pollution control equipment and compliance monitoring devices or activities, and to the extent of available information, an estimate of emissions before and after controls. Provide all calculations and assumptions.

   Fuel injection timing retard (FITR) is used on units D-21, D-22, and D-23 to control NO_X emissions. Water injection is used on CT-2 reduce NO_X emissions to 47 ppmvd at 15 percent O_2, with a fuel-bound nitrogen content of 0.015 percent or less. When CT-4 and CT-5 are operating in combined cycle mode at loads less than 50% of peak load and simple cycle mode, water injection is used on CT-4 and CT-5 to reduce NO_X emissions to 42 ppmvd at 15 percent O_2, with a fuel-bound nitrogen content of 0.015 percent of less. When CT-4 and CT-4 are operating in combined cycle mode at 50% or more of peak load, water injection in combination with selective catalytic reduction (SCR) is used to reduce NO_X emissions to 15 ppmvd at 15 percent O_2, with a fuel-bound nitrogen content of 0.015 percent or less. The design of the SCR system will limit ammonia slip to 10 ppmvd at 15 percent O_2. Sulfur dioxide emissions are controlled by limiting the fuel sulfur content to 0.4 percent by weight. Emissions of PM, PM_{10}, CO, and VOC are controlled by combustion design and good combustion practices. Emissions of hazardous air pollutants are controlled by the use of No. 2 fuel oil and combustion system design.

Compliance monitoring devices and activities are discussed in Form C-2.

2. List all ***insignificant*** activities in accordance with HAR §11-60.1-82.

   See Attachment S-3b for a list of insignificant activities.

D. Maximum Operating Schedule (to the extent needed to determine or regulate emissions):

1. Total hours per day, per week, and/or per month.

   The planned operation of units D-22, D-23, CT-2, CT-4, and CT-5 is up to 24 hours per day, seven days per week. Units BS-1 and D-21 will operate as needed. Depending on future dispatch requirements, the plant may cycle off-line daily, or operate at reduced loads. While expected operating levels are less than continuous, there may be times when the units must be run continuously for extended periods of time. Thus, this application does not propose any annual operating limits for units D-22, D-23, CT-4, and CT-5. Fuel consumption is limited on a rolling 12-month basis to 12,301,254 gallons (292,887 barrels) in CT-2 and 70,000 gallons in D-21.

2. Total hours per year.

   Units D-22, D-23, CT-4, and CT-5 will operate 8760 hours per year. Fuel consumption is limited on a rolling 12-month basis to 12,301,254 gallons (292,887 barrels) in CT-2 and 70,000 gallons in D-21. Operation of BS-1 is limited to 300 hours on a rolling 12-month basis.

3. If operation is seasonal or irregular, describe. See D.1 and 2 above.

E. Cite and describe all applicable requirements as defined in HAR §11-60.1-81, including the following:

1. Description of or reference to any applicable test methods for determining compliance with each applicable requirement. See Form C-2.

2. Explanation of all proposed exemptions from any applicable requirements.

   See Forms C-1 and C-2.

F. Identify and describe current operational limitations or work practices that affect emissions of any regulated or hazardous air pollutant. Provide all calculations and assumptions.

Fuel injection timing retard (FITR) is used on units D-21, D-22, and D-23 to control NO_X emissions. Water injection is used on CT-2 reduce NO_X emissions to 47 ppmvd at 15 percent O_2, with a fuel-bound nitrogen content of 0.015 percent or less. When CT-4 and CT-5 are operating in combined cycle mode at loads less than 50% of peak load and simple cycle mode, water injection is used on CT-4 and CT-5 to reduce NO_X emissions to 42 ppmvd at 15 percent O_2, with a fuel-bound nitrogen content of 0.015 percent of less. When CT-4 and CT-4 are operating in combined cycle mode at 50% or more of peak load, water injection in combination with selective catalytic reduction (SCR) is used to reduce NO_X emissions to 15 ppmvd at 15 percent O_2, with a fuel-bound nitrogen content of 0.015 percent or less. The design of the SCR system will limit ammonia slip to 10 ppmvd at 15 percent O_2. Sulfur dioxide emissions are controlled by limiting the fuel sulfur content to 0.4 percent by weight. Emissions of PM, PM_{10}, CO, and VOC are controlled by combustion design and good combustion practices. Emissions of hazardous air pollutants are controlled by the use of No. 2 fuel oil and combustion system design.

G. For ***new*** covered sources and ***significant*** modifications which increase the emissions of any air pollutant or result in the emission of any air pollutant not previously emitted, an assessment of the ambient air quality impact of the covered source or significant modification, with the inclusion of any available background air quality data. The assessment shall include all supporting data, calculations and assumptions, and a comparison with the NAAQS and SAAQS.

Not applicable. The facility is an existing covered source and is undergoing a renewal of an existing permit as defined by the covered source rules.

H. For ***new*** covered sources and ***significant*** modifications subject to the requirements of subchapter 7 of HAR Chapter 11-60.1, all analyses, assessments, monitoring, and other application requirements of subchapter 7.

Not applicable. The facility is an existing covered source and is not undergoing any modification or increase in emissions as defined in Subchapter 7.

I. Provide detailed information to define permit terms and conditions for any proposed ***emissions trading*** within the facility in accordance with HAR §11-60.1-96.

No emissions trading is proposed.

J. Provide the following for Compliance purposes:
   1. A Compliance Plan, Form C-1.
   2. A Compliance Certification, Form C-2.

II. Submit an application fee according to the Application Fee Schedule in the Instructions for Applying for an Air Pollution Control Permit.

III. Provide other information as follows:

A. As required by any applicable requirement or as requested and deemed necessary by the Director to make a decision on the application.

B. As may be necessary to implement and enforce other applicable requirements of the Clean Air Act or of HAR Chapter 11-60.1 or to determine the applicability of such requirements.

IV. The Director reserves the right to request the following information:

A. An assessment of the ambient air quality impact of the source or modification. The assessment shall include all supporting data, calculations and assumptions, and a comparison with the National Ambient Air Quality Standards and State Ambient Air Quality Standards.

B. A risk assessment of the air quality related impacts caused by the covered source or significant modification to the surrounding environment.

C. Results of source emissions testing, ambient air quality monitoring, or both.

D. Information on other available control technologies.

V. An application shall be determined to be complete only when all of the following have been complied with:

A. All information required or requested in numbers **I, III, and IV** has been submitted.

B. All documents requiring certification have been certified pursuant to HAR §11-60.1-4.

C. All applicable fees have been submitted.

D. The Director has certified that the application is complete.

VI. The Director shall not continue to act upon or consider an incomplete application.

A. The applicant shall be notified in writing whether the application is complete. Unless the Director requests additional information or notifies the applicant of incompleteness within sixty days of receipt of an application, the application shall be deemed complete.

B. During the processing of an application that has been determined or deemed complete, if the Director determines that additional information is necessary to evaluate or take final action on the application, the Director may request such information in writing and set a reasonable deadline for a response. As set forth in HAR §11-60.1-82, the covered source's ability to operate and the validity of the Covered Source Permit shall continue beyond the permit expiration date until the final permit is issued or denied, provided the applicant submits all additional information within the reasonable deadline specified by the Director.

VII. After receipt of a complete application, the Director, in writing, shall approve, conditionally approve, or deny an application:

A. Within twelve months, ***except*** for applications for renewal for coverage under a covered source general permit. If the application for renewal has not been approved or denied within twelve months, the Covered Source Permit and all its terms and conditions shall remain in effect and not expire until the application for renewal has been approved or denied and provided the applicant has submitted any additional information within the reasonable deadline specified by the Director.

B. Within six months for applications for renewal requesting coverage under a covered source general permit. If the application for renewal has not been approved or denied within six months, the coverage under the covered source general permit and all its terms and conditions shall remain in effect and not expire until the application for renewal has been approved or denied and provided the applicant has submitted any additional information within the reasonable deadline specified by the Director.

VIII. A Covered Source Permit renewal application shall be approved only if the Director determines that the operation of the covered source will be in compliance with all applicable requirements.

IX. The Director shall provide for public notice, including the method by which a public hearing can be requested, and an opportunity for public comment on the draft Covered Source Permit renewal in accordance with HAR §11-60.1-99.

X. The Director shall provide a statement that sets forth the legal and factual bases for the draft permit conditions (including references to the applicable statutory or regulatory provisions) to EPA and any other person requesting it.

XI. Each application for renewal and proposed Covered Source Permit shall be subject to EPA oversight in accordance with HAR §11-60.1-95.

Attachment S-3a

Manufacturer's Literature

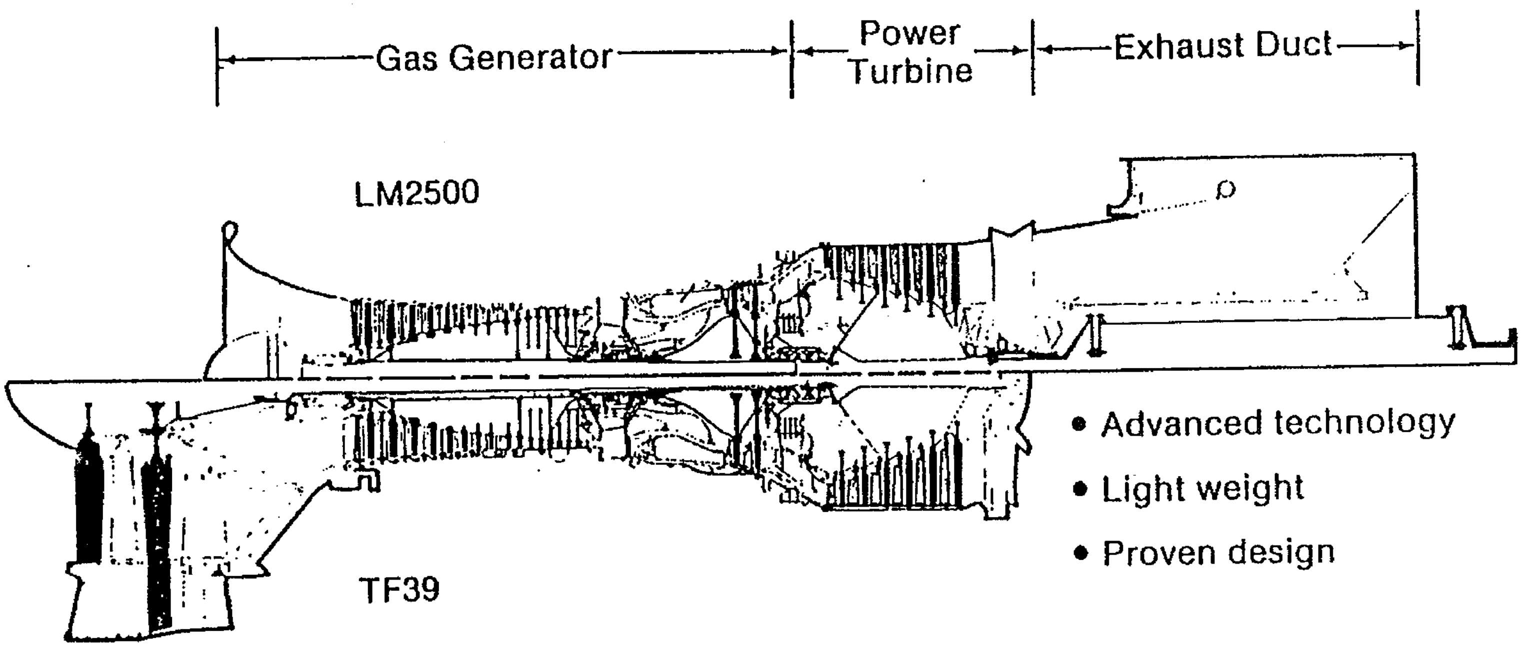
LM2500 Overview

General Electric
LM2500 Gas Turbine Advantages

• Unsurpassed efficiency* (simple cycle in power range)	37%
• Demonstrated availability	>98%
• Application cycle flexibility	Gas fuel, liquid fuel, low BTU gas, STIG
• Installation simplicity, transportation & mobility	Modular design, light weight
• Large experience base	>500 engines in operation >5,500,000 hours in service
• After-sale support	Backed by wide variety of GE customer support programs
• Environmental compatibility	Meets stringent emission requirements with water or steam injection

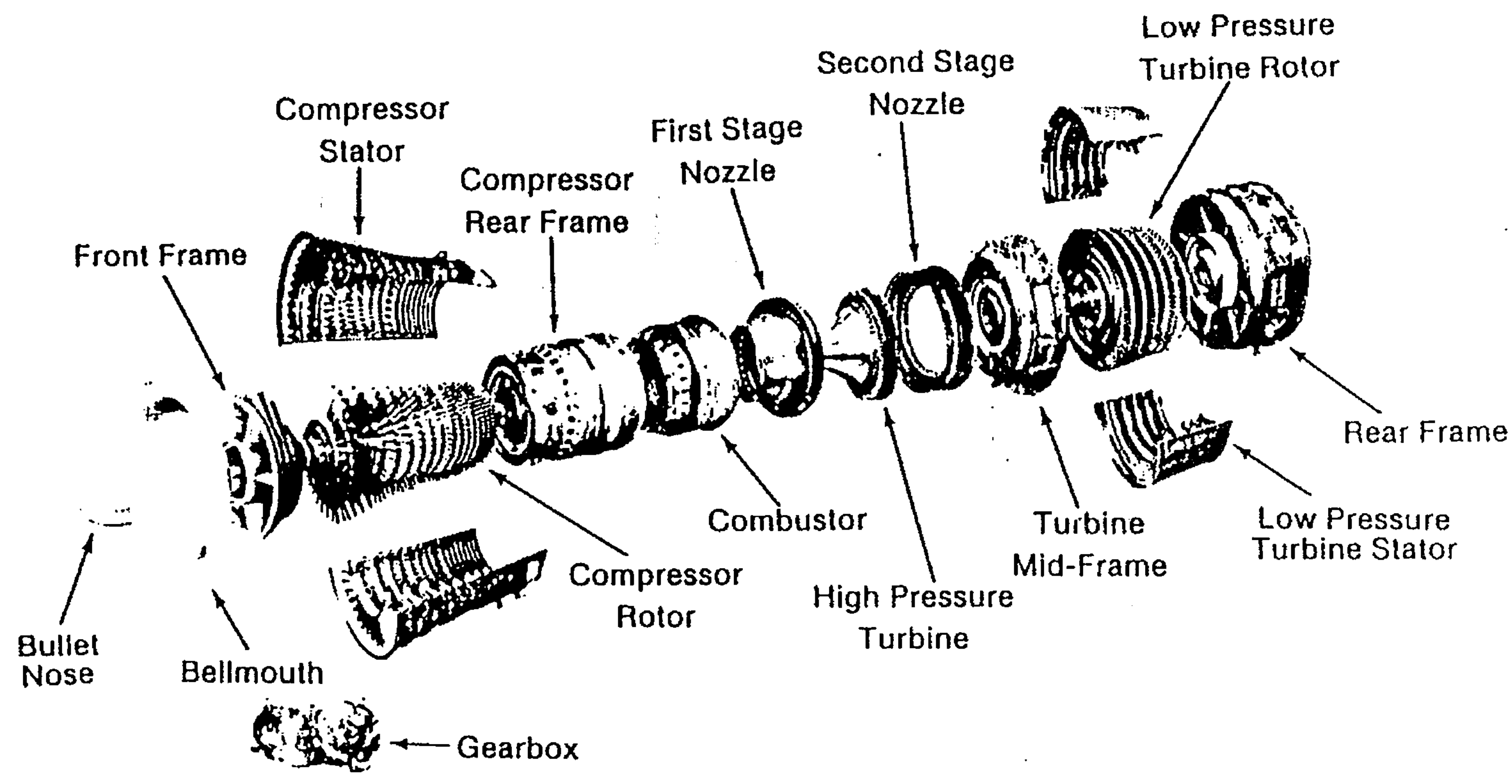
*At ISO conditions and 3600 rpm

LM2500 Gas Turbine and TF39/CF6 Turbofan



- Advanced technology
- Light weight
- Proven design

LM2500 Component Parts



LM2500 Power Turbine

- Designed for:
  - 10,000 HP greater than LM2500 rating
  - 200°F (111°C) - higher temperature than LM2500 rating
- 20,000,000 hours experience
  - 180 units in aircraft service with greater than 10,000 hrs
  - 17 units in marine service with greater than 10,000 hrs
  - 48 units in industrial service with greater than 10,000 hrs
- 90% of all LM2500's were selected with GE power turbine
- Efficiency - 92.5%

LM2500 Intrinsic Features

- Fast start-up ____ 1 minute
- High efficiency - 3600 rpm ____ 37%
- Full load testing ____ All units
- Low weight ____ 7500 lbs (3402 kg)
- Minimum space ____ 21 ft 8 in (6.6m) length x 6 ft (1.8m) diameter
- Low airflow ____ 145 lb/sec (65.8 kg/sec)
- High availability ____ 98%
- Easy changeout ____ 9 hours
- On-site maintenance ____ 1 day "hot section"
- Proven concept ____ Over 5,500,000 operating hours
- Engine improvement programs ____ Active
- Maintenance & support programs ____ Comprehensive & operational

Attachment S-3b

Insignificant Activities §11-60.1-82(f) and (g)

Attachment S-3b
Insignificant Activities §11-60.1-82(f) and (g)

Rule Citation and Requirement	Activity Present	Description
(f) Insignificant activities based on size, emission level, or production rate, are as follows:	**See below:**	**See case-by-case descriptions below:**
(1) Any storage tank, reservoir, or other container of capacity equal to or less than forty thousand gallons storing volatile organic compounds, except those storage tanks, reservoirs, or other containers subject to any standard or other requirement Pursuant to Sections 111 and 112 of the Act;	Yes	The Keahole Generating Station contains VOC storage tanks with a capacity less than 40,000 gallons that are not subject to Section 111 or 112 which include: • CT-4 Day Tank (Tank 5) – 13,500 gal. capacity storing No. 2 diesel fuel • CT-5 Day Tank (Tank 6) – 13,500 gal. capacity storing No. 2 diesel fuel • Used Oil North Tank – 1,500 gal. capacity • Used Oil South Tank – 1,500 gal. capacity • Fire Pump Diesel Tank – 350 gal. capacity • EMD Used Oil Tank – 500 gal. capacity • EMD Lube Oil Tank – 500 gal. capacity • EMD Lube Oil (5) Tank – 670 gal. capacity • EMD Lube Oil (6) Tank – 670 gal. capacity • Used Oil Tote – 200 gal. capacity • Used Oil Tote – 342 gal. capacity
(2) Other than smoke house generators and gasoline fired industrial equipment, fuel burning equipment with a heat input capacity less than 1 MMBtu per hour, or a combination of fuel burning equipment operated simultaneously as a single unit having a total combined heat input capacity of less than 1 MMBtu per hour;	Yes	These types of units may be on site occasionally. However, they would be associated with plant maintenance and are covered under item (g)(9).
(3) Steam generators, steam superheaters, water boilers, or water heaters, all of which have a heat input capacity of less than five million BTU per hour, and are fired exclusively with one of the following: (A) Natural or synthetic gas; (B) Liquefied petroleum gas; or (C) A combination of natural, synthetic, or liquefied petroleum gas;	No	None.
(4) Kilns used for firing ceramic water heated exclusively by natural gas, electricity, liquid petroleum gas, or any combination of these and have a heat input capacity of 5 MMBTU/hr or less;	No	None.
(5) Standby generators used exclusively to provide electricity, standby sewage pump drives, and other emergency equipment used to protect the health and welfare of	Yes	These types of units may be on site occasionally.

Attachment S-3b
Insignificant Activities §11-60.1-82(f) and (g)

Rule Citation and Requirement	Activity Present	Description
personnel and the public, all of which are used only during power outages, emergency equipment maintenance and testing, and which: (A) Are fired exclusively by natural or synthetic gas; or liquefied petroleum gas; or fuel oil No. 1 or No. 2; or diesel fuel oil No. 1D or No. 2D; and (B) Do not trigger a PSD or covered source review, based on their potential to emit regulated or hazardous air pollutants;		
(6) Paint spray booths that emit less than two tons per year of any regulated air pollutant except for paint spray booths subject to any standard or other requirement pursuant to Section 112 (d) of the Act; and	Yes	The Keahole Generating Station uses paint for maintenance purposes, which is covered under (g)(9).
(7) Other activities which emit less than: (A) 500 pounds per year of a hazardous air pollutant; (B) 25% of significant amounts of emission as defined in Section 11-60.1-1, paragraph (1) in the definition of "significant"; (C) 5 tons per year of carbon monoxide and (D) 2 tons per year of each regulated air pollutant other than carbon monoxide which the director determines on a case-by-case basis to be insignificant.	Yes	• Tank 1 – 3,080 bbl capacity storing No. 2 diesel fuel • Tank 2 – 6,290 bbl capacity storing No. 2 diesel fuel • Tank 3 – 617,000 gal. capacity storing No. 2 diesel fuel • Tank 4 – 617,000 gal. capacity storing No. 2 diesel fuel • Tank 7[1] – 1,475,000 gal. capacity storing No. 2 diesel fuel Tanks 4.0.9d Emissions Report Summary Attached for Tanks 1, 2, 3, 4 and 7. • Fugitive equipment leaks from valves, flanges, pump seals and any VOC water separators. • Solvents are used for maintenance purposes.
(g) Insignificant activities in addition to those listed in subsection (f) are:	**See below:**	**See case-by-case descriptions below:**
(1) Welding booths;	Yes	The Keahole Generating Station uses welding for maintenance purposes. This activity is covered under item (g)(9).
(2) Gasoline fired portable industrial equipment less than 25 horsepower in size;	Yes	These types of equipment are on site for maintenance purposes which are covered under item (g)(9).

[1] Previously identified as Tank 5 in the Addendum to the CSP Application No. 0007-01 dated July 12, 1994.

Attachment S-3b
Insignificant Activities §11-60.1-82(f) and (g)

Rule Citation and Requirement	Activity Present	Description
(3) Hand held equipment used for buffing, polishing, carving, cutting, drilling, machining, routing, sanding, sawing, surface grinding, or turning of ceramic are work, precision parts, leather, metals, plastics, fiber board, masonry, carbon, glass, or wood, provided reasonable precautions are taken to prevent particulate matter from becoming airborne. Reasonable precautions include the use of dust collection systems, dust barriers, or containment systems;	Yes	The Keahole Generating Station uses several types of hand held equipment for maintenance and testing purposes. Sandblasting equipment is the most likely to generate particulate emissions. Reasonable precautions are taken to prevent particulate matter from becoming airborne. This activity is covered under item (g)(9).
(4) Laboratory equipment used exclusively for chemical and physical analysis;	Yes	The Keahole Generating Station uses laboratory equipment for chemical and physical analyses.
(5) Containers, reservoirs, or tanks used exclusively for dipping operations for coating objects with oils, waxes, or greases where no organic solvents, diluents, or thinners are used; or dipping operations for applying coatings of natural or synthetic resins which contain no organic solvents;	No	None.
(6) Closed tumblers used for cleaning or deburring metal products without abrasive blasting, and pen tumblers with batch capacity of one thousand pounds or less;	No	None.
(7) Fire-water system pump engines dedicated for fire fighting and to maintain fire water system pressure, which are operated only during fire fighting and periodically for engine maintenance, and fired exclusively by natural or synthetic gas; or liquefied petroleum gas; or fuel oil No. 1 or No. 2; or diesel fuel No 1D or No. 2D;	Yes	One 235 hp Detroit Diesel fire pump diesel engine.
(8) Smoke generating systems used exclusively for training or certified fire fighting training facilities;	No	None.
(9) Plant maintenance and upkeep activities (e.g., grounds-keeping, general repairs, cleaning, painting, welding, plumbing, re-tarring roofs, installing insulation, and paving parking lots), including equipment used to conduct these activities, provided these activities are not conducted as part of a manufacturing process, are not related to the source's primary business activity, and are not otherwise subject to an applicable requirement triggering a permit modification.	Yes	These types of activities and equipment are on site.
(10) Fuel burning equipment which is used in a private dwelling or for space heating, other than internal combustion engines, boilers or hot furnaces;	No	None.
(11) Ovens, stoves, and grills used solely for the purposes of preparing food for human consumption operated in private dwellings, restaurants, or stores;	Yes	The Keahole Generating Station is not a private dwelling, restaurant, or store. However, plant employees may occasionally use outdoor grills for food preparation.

Attachment S-3b
Insignificant Activities §11-60.1-82(f) and (g)

Rule Citation and Requirement	Activity Present	Description
(12) Stacks or vents to prevent escape of sewer gases through plumbing traps;	Yes	The facility contains stacks and vents.
(13) Consumer use of office equipment and products; and	Yes	These types of activities and equipment are on site.
(14) Wood working shops with a sawdust collection system.	Yes	There is no shop with a sawdust collection system. However, there are woodworking activities at the Keahole Generating Station. These activities are covered under item (g)(9).

TANKS 4.0.9d
Emissions Report - Summary Format
Tank Indentification and Physical Characteristics

Identification

User Identification:	Keahole Tank 1
City:	
State:	
Company:	HELCO
Type of Tank:	Vertical Fixed Roof Tank
Description:	Based on 1) Nov. 1994 Initial CSP Application information - Annual Throughput: 75,500 bbl and 2) plot plan in Jan. 1991 ATC Application for a Black Start Diesel Generator - tank dimensions 35' diameter, 18' height and capacity 3080 bbl.

Tank Dimensions

Shell Height (ft):		18.00
Diameter (ft):		35.00
Liquid Height (ft) :		18.00
Avg. Liquid Height (ft):		9.00
Volume (gallons):		129,548.29
Turnovers:		24.48
Net Throughput(gal/yr):		3,171,000.00
Is Tank Heated (y/n):	N	

Paint Characteristics

Shell Color/Shade:	Gray/Medium
Shell Condition	Good
Roof Color/Shade:	Gray/Medium
Roof Condition:	Good

Roof Characteristics

Type:	Cone	
Height (ft)		0.00
Slope (ft/ft) (Cone Roof)		0.06

Breather Vent Settings

Vacuum Settings (psig):	-0.03
Pressure Settings (psig)	0.03

Meterological Data used in Emissions Calculations: Hilo, Hawaii (Avg Atmospheric Pressure = 14.72 psia)

TANKS 4.0.9d
Emissions Report - Summary Format
Liquid Contents of Storage Tank

Keahole Tank 1 - Vertical Fixed Roof Tank

		Daily Liquid Surf. Temperature (deg F)			Liquid Bulk Temp	Vapor Pressure (psia)			Vapor Mol.	Liquid Mass	Vapor Mass	Mol.	Basis for Vapor Pressure
Mixture/Component	Month	Avg.	Min.	Max.	(deg F)	Avg.	Min.	Max.	Weight.	Fract.	Fract.	Weight	Calculations
Distillate fuel oil no. 2	All	83.48	73.85	93.11	77.03	0.0134	0.0102	0.0179	130.0000			188.00	Option 1: VP70 = .009 VP80 = .012

TANKS 4.0.9d
Emissions Report - Summary Format
Individual Tank Emission Totals

Emissions Report for: Annual

Keahole Tank 1 - Vertical Fixed Roof Tank

	Losses(lbs)		
Components	Working Loss	Breathing Loss	Total Emissions
Distillate fuel oil no. 2	131.45	65.73	197.18

TANKS 4.0.9d
Emissions Report - Summary Format
Tank Indentification and Physical Characteristics

Identification

User Identification:	Keahole Tank 2
City:	
State:	
Company:	HELCO
Type of Tank:	Vertical Fixed Roof Tank
Description:	Based on 1) Nov. 1994 Initial CSP Application information - Annual Throughput: 141,675 bbl and 2) plot plan in Jan. 1991 ATC Application for a Black Start Diesel Generator - tank dimensions 50' diameter, 18' height and capacity 6,290 bbl.

Tank Dimensions

Shell Height (ft):	18.00
Diameter (ft):	50.00
Liquid Height (ft) :	18.00
Avg. Liquid Height (ft):	9.00
Volume (gallons):	264,384.26
Turnovers:	22.51
Net Throughput(gal/yr):	5,950,350.00
Is Tank Heated (y/n):	N

Paint Characteristics

Shell Color/Shade:	Gray/Medium
Shell Condition	Good
Roof Color/Shade:	Gray/Medium
Roof Condition:	Good

Roof Characteristics

Type:	Cone
Height (ft)	0.00
Slope (ft/ft) (Cone Roof)	0.06

Breather Vent Settings

Vacuum Settings (psig):	-0.03
Pressure Settings (psig)	0.03

Meterological Data used in Emissions Calculations: Hilo, Hawaii (Avg Atmospheric Pressure = 14.72 psia)

TANKS 4.0.9d
Emissions Report - Summary Format
Liquid Contents of Storage Tank

Keahole Tank 2 - Vertical Fixed Roof Tank

Mixture/Component	Month	Daily Liquid Surf. Temperature (deg F) Avg.	Min.	Max.	Liquid Bulk Temp (deg F)	Vapor Pressure (psia) Avg.	Min.	Max.	Vapor Mol. Weight.	Liquid Mass Fract.	Vapor Mass Fract.	Mol. Weight	Basis for Vapor Pressure Calculations
Distillate fuel oil no. 2	All	83.48	73.85	93.11	77.03	0.0134	0.0102	0.0179	130.0000			188.00	Option 1: VP70 = .009 VP80 = .012

TANKS 4.0.9d
Emissions Report - Summary Format
Individual Tank Emission Totals

Emissions Report for: Annual

Keahole Tank 2 - Vertical Fixed Roof Tank

	Losses(lbs)		
Components	Working Loss	Breathing Loss	Total Emissions
Distillate fuel oil no. 2	246.66	136.36	383.02

TANKS 4.0.9d
Emissions Report - Summary Format
Tank Indentification and Physical Characteristics

Identification

User Identification:	Keahole Tank 3 or 4
City:	
State:	
Company:	HELCO
Type of Tank:	Vertical Fixed Roof Tank
Description:	Based on information from the July 12, 1994 Addendum to CSP Application submitted on Feb. 1, 1994. Tank 50' diameter, 42' height, 14,688 bbl capacity and annual throughput 101,561 bbl.

Tank Dimensions

Shell Height (ft):	42.00
Diameter (ft):	50.00
Liquid Height (ft) :	42.00
Avg. Liquid Height (ft):	21.00
Volume (gallons):	617,000.00
Turnovers:	6.91
Net Throughput(gal/yr):	4,265,562.00
Is Tank Heated (y/n):	N

Paint Characteristics

Shell Color/Shade:	Gray/Medium
Shell Condition	Good
Roof Color/Shade:	Gray/Medium
Roof Condition:	Good

Roof Characteristics

Type:	Cone
Height (ft)	0.00
Slope (ft/ft) (Cone Roof)	0.06

Breather Vent Settings

Vacuum Settings (psig):	-0.03
Pressure Settings (psig)	0.03

Meterological Data used in Emissions Calculations: Hilo, Hawaii (Avg Atmospheric Pressure = 14.72 psia)

TANKS 4.0.9d
Emissions Report - Summary Format
Liquid Contents of Storage Tank

Keahole Tank 3 or 4 - Vertical Fixed Roof Tank

Mixture/Component	Month	Daily Liquid Surf. Temperature (deg F) Avg.	Min.	Max.	Liquid Bulk Temp (deg F)	Vapor Pressure (psia) Avg.	Min.	Max.	Vapor Mol. Weight.	Liquid Mass Fract.	Vapor Mass Fract.	Mol. Weight	Basis for Vapor Pressure Calculations
Distillate fuel oil no. 2	All	83.48	73.85	93.11	77.03	0.0134	0.0102	0.0179	130.0000			188.00	Option 1: VP70 = .009 VP80 = .012

TANKS 4.0.9d
Emissions Report - Summary Format
Individual Tank Emission Totals

Emissions Report for: Annual

Keahole Tank 3 or 4 - Vertical Fixed Roof Tank

	Losses(lbs)		
Components	Working Loss	Breathing Loss	Total Emissions
Distillate fuel oil no. 2	176.82	305.65	482.47

TANKS 4.0.9d
Emissions Report - Summary Format
Tank Indentification and Physical Characteristics

Identification

User Identification:	Keahole Tank 7
City:	
State:	
Company:	HELCO
Type of Tank:	Vertical Fixed Roof Tank
Description:	Based on information from the July 12, 1994 Addendum to CSP Application submitted on Feb. 1, 1994. Previously identified as Tank 5; Tank 80' diameter, 42' height, 34,602 bbl capacity and annual throughput 239,258 bbl.

Tank Dimensions

Shell Height (ft):		42.00
Diameter (ft):		80.00
Liquid Height (ft) :		42.00
Avg. Liquid Height (ft):		21.00
Volume (gallons):		1,475,000.00
Turnovers:		6.81
Net Throughput(gal/yr):		10,048,836.00
Is Tank Heated (y/n):	N	

Paint Characteristics

Shell Color/Shade:	Gray/Medium
Shell Condition	Good
Roof Color/Shade:	Gray/Medium
Roof Condition:	Good

Roof Characteristics

Type:	Cone	
Height (ft)		0.00
Slope (ft/ft) (Cone Roof)		0.06

Breather Vent Settings

Vacuum Settings (psig):	-0.03
Pressure Settings (psig)	0.03

Meterological Data used in Emissions Calculations: Hilo, Hawaii (Avg Atmospheric Pressure = 14.72 psia)

TANKS 4.0.9d
Emissions Report - Summary Format
Liquid Contents of Storage Tank

Keahole Tank 7 - Vertical Fixed Roof Tank

Mixture/Component	Month	Daily Liquid Surf. Temperature (deg F) Avg.	Min.	Max.	Liquid Bulk Temp (deg F)	Vapor Pressure (psia) Avg.	Min.	Max.	Vapor Mol. Weight.	Liquid Mass Fract.	Vapor Mass Fract.	Mol. Weight	Basis for Vapor Pressure Calculations
Distillate fuel oil no. 2	All	83.48	73.85	93.11	77.03	0.0134	0.0102	0.0179	130.0000			188.00	Option 1: VP70 = .009 VP80 = .012

TANKS 4.0.9d
Emissions Report - Summary Format
Individual Tank Emission Totals

Emissions Report for: Annual

Keahole Tank 7 - Vertical Fixed Roof Tank

	Losses(lbs)		
Components	Working Loss	Breathing Loss	Total Emissions
Distillate fuel oil no. 2	416.55	793.65	1,210.21

Attachment S-3c

Requested Changes to CSP No. 0007-01-C

Attachment S-3c

Requested Changes to CSP No. 0007-01-C

Proposed Changes to Attachment IIA

Proposed change to Attachment IIA, Special Condition A.1.a.:

Two (2) 20 MW Nominal (24.66 MW (gross) peak load) General Electric LM2500 combustion turbine generators, units CT-4 and CT-5; and

Justification – The requested change updates the equipment description to include the maximum peak load rating for the combustion turbine generators.

Proposed change to Attachment IIA, Special Condition C.1. :

~~Start-up~~ Startup and Shutdown

a. ~~The "start-up" time shall not exceed twenty (20) minutes for any combustion turbine generator operating in simple cycle and ninety (90) minutes for any combustion turbine generator operating in combined cycle. Except during maintenance (e.g., equipment installations and inspections, and electrical switching work), testing, and emergency power demands due to sudden loss of a power generating unit, each combustion turbine generator shall not be started up more than four times per calendar day. A "start-up" sequence shall be from the time fuel use at the combustion turbine generator begins, until the time the combustion turbine generator is initially brought up to 25 percent of peak load at which time the operation of the air pollution control equipment shall commence.~~

   The startup sequence for the combustion turbine generators shall be a twenty (20) minute period in simple or combined cycle mode starting at the time fuel use at the combustion turbine generator begins. At the end of the startup sequence, the combustion turbine generator shall be at 25 percent of peak load (6.17 MW) or more, the water-to-fuel ratio shall be maintained, and the permittee shall not exceed the maximum emission limitations as specified in Attachment IIA, Special Conditions C.2, C.3, and D.1, respectively.

b. The ~~"~~shutdown~~" time~~ sequence for any combustion turbine generator operating in either simple cycle or combined cycle shall not exceed twenty (20) minutes. ~~Except during maintenance (e.g., equipment installations and inspections, and electrical switching work), testing, and emergency power demands due to sudden loss of a power generating unit, each combustion turbine generator shall not be shut down more than four (4) times per calendar day.~~ A ~~"~~shutdown~~"~~ sequence shall be ~~considered~~ from the time ~~when~~ the combustion turbine generator is operating below 25 percent of peak load (6.17 MW), until fuel consumption at the combustion turbine generator ceases, except as provided in Attachment IIA, Special Condition C.2.

Justification – The requested changes are needed to: 1) clarify peak load and the description of startup and shutdown sequences; 2) remove the limit of the number of startups per day because startup periods longer than 20 minutes for both simple and combined cycle modes should not be needed; and 3) allow for stabilization of the water injection system following initiation of the system and address the misalignment of the CEMS NO_X, CO and CO_2

measurement readings with the instantaneous readings of operational parameters such as load (MW), fuel flow, and water injection rate due to lag from the CEMS analyzer response time.

Proposed change to Attachment IIA, Special Condition C.2.:

Minimum Operational Loads

12/10/15
Minor Mo

~~The combustion turbine generators shall not operate below 25 percent of peak load except during equipment start-up, shutdown, maintenance, or testing.~~ The combined time of operation of the combustion turbine generators, CT-2, CT-4, and CT-5, below 25 percent of peak load with water injection shall not exceed 268 hours in any rolling 12 month period, excluding startup and shutdown sequences, maintenance, testing, and as approved pursuant to Attachment IIA, Special Condition C.5.b.

Justification – The requested change is needed to clarify peak load and allow the operation of CT-4 and CT-5 below 25 percent of peak load with water injection to address high system frequency issues. The emissions calculations for CT-2, CT-4 and CT-5 for this proposed change are in Tables 1a and 1b below.

Table 1a - Less Than 25% Load Operation Project Emissions (CT-4, CT-5)

	Pollutant	
Parameter	**CO**	**VOC**
Actual Emissions (lb/hr) Before Change[1]	0.0	0.0
Maximum 10% Load (2.5 MW) Emissions (lb/hr)[2]	475.6	297.6
Expected Increase (lb/hr)	475.6	297.6
Maximum Unit-Hours Below 25% Load[3]	268	268
Projected Emissions Increase (tpy)[4]	63.7	39.9
PSD Significance Level (tpy)	100	40
Significant Emissions Increase (Yes/No)	No	No

Table 1b - Less Than 25% Load Operation Project Emissions (CT-2)

	Pollutant	
Parameter	**CO**	**VOC**
Actual Emissions (lb/hr) Before Change[1]	0.0	0.0
Maximum 10% Load (1.8 MW) Emissions (lb/hr)[5]	22.4	22.4
Expected Increase (lb/hr)	22.4	22.4
Maximum Unit-Hours Below 25% Load	3560	3560
Projected Emissions Increase (tpy)[4]	39.9	39.9
PSD Significance Level (tpy)	100	40
Significant Emissions Increase (Yes/No)	No	No

1 Past actuals set to zero (operation below 25% of peak load not allowed, except for startup, shutdown, maintenance and testing.
2 CT-4 and CT-5 permit limits for 25% of peak load in simple cycle mode.
3 Calculated limit to remain below PSD significance levels.
4 (Expected Increase) x (Unit-Hours/Year) / (2000 lb/ton)
5 CT-2 permit limits.

Proposed change to Attachment IIA, Special Condition C.3.:

Air Pollution Equipment

~~The use of an alternative control system other than those specified below is contingent upon receiving the Department of Health's written approval to use such a system and shall not relieve the permittee from the responsibility to meet all emission limitations contained within this Covered Source Permit.~~

a. ~~Combustor~~ Water Injection

i. The permittee shall continuously operate and maintain a ~~combustor~~ water injection system to meet the emission limits ~~as~~ specified for nitrogen oxides (NO_X) in Attachment IIA, Special Condition D.1.a. ~~of this Covered Source Permit~~. Water injection shall be initiated during the startup sequence of each combustion turbine generator and may be terminated at the beginning of or during the shutdown sequence of each combustion turbine generator. ~~The combustor water injection system shall be fully operational and commence operation immediately after the start-up sequence of the combustion turbine generators. The combustor water injection system shall continue to operate until the commencement of the shutdown sequence of the combustion turbine generators.~~

ii. ~~The operation of the combustor water injection system shall be used whenever the combustion turbine generators are operating at 25 percent peak load and above.~~ After completion of the startup sequence ~~T~~the following water-to-fuel mass ratios, on a one (1) average hour basis, shall be maintained when the combustion turbine generators are in simple cycle operation or in combined cycle operation at loads less than 50 percent of peak load (12.33 MW).

WATER INJECTION SYSTEM
MINIMUM WATER-TO-FUEL MASS RATIO BASED ON LOAD

Combustion Turbine Generator Peak L~~l~~oad (Percent)	**Ratio** (lb-water/lb-fuel)
100 (24.66 MW)	1.04
75 - < 100 (18.50 MW - < 24.66 MW)	0.94
50 - < 75 (12.33 MW - < 18.50 MW)	0.87
~~25 -~~ < 50 (< 12.33 MW)	0.72

For operating periods during which multiple water-to-fuel mass ratios apply, the applicable water-to-fuel mass ratio shall be determined based on the load that corresponded to the lowest minimum water-to-fuel mass ratio.

b. Selective Catalytic Reduction System

The permittee shall design, install, maintain, and continuously operate a selective catalytic reduction system with ammonia injection to meet the emission limits as specified in Attachment IIA, Special Condition D.1.a. of this Covered Source Permit.

The selective catalytic reduction system shall be fully functional and in operation whenever the combustion turbine generators are in combined cycle operation at loads greater than or equal to 50 percent of ~~the peakload~~ peak load (12.33 MW). The selective catalytic reduction system shall continue to operate until the load is reduced to below 50 percent of the ~~peakload~~ peak load (12.33 MW).

c. The use of an alternative control system other than those specified above is contingent upon receiving the Department of Health's written approval to use such a system and shall not relieve the permittee from the responsibility to meet all emission limitations contained within this Covered Source Permit.

Justification – The requested changes are to: 1) clarify the method of determining the applicable minimum water-to-fuel mass ratio for operating hours during which multiple minimum water-to-fuel mass ratios apply; 2) correct a typographical error; 3) clarify peak load; and 4) revise the water injection system table to address operation of the combustion turbine generators below 25 percent of peak load with water injection.

Proposed change to Attachment IIA, Special Condition C.4.:

a. Sulfur Content

The combustion turbine generators ~~and diesel engines~~ shall be fired only on fuel oil no. 2 with a maximum sulfur content not to exceed 0.4 percent by weight or an alternate fuel allowed under Special Condition C.5.d. of this Attachment.

~~b. Nitrogen Content~~

~~The fuel bound nitrogen content of the fuel fired in the combustion turbine generators, units CT-4 and CT-5, shall not exceed 0.015 percent by weight on a rolling twelve (12) month average.~~

Justification – The requested changes are needed to clarify the approved fuels and remove the fuel bound nitrogen monitoring conditions because it is not required by NSPS Subpart GG if an emission allowance for fuel bound nitrogen is not claimed; HELCO has not claimed an emission allowance under NSPS Subpart GG.

Proposed change to Attachment IIA, Special Condition C.5.:

Terms and conditions for reasonably anticipated operating scenarios identified by the source in the covered source permit application and approved by the Department of Health are as follows:

a. Temporary Replacement. Upon receiving written approval from the Department of Health, the permittee may replace any of the combustion turbine generators with a temporary replacement unit in the event of a sudden malfunction or a planned major overhaul. The temporary replacement unit shall comply with all applicable permit conditions.

A written request shall be submitted to the Department of Health prior to the exchange and at a minimum, the request shall include the following:

i. the reason for temporary replacement;

ii. the removal and estimated return dates of the permitted unit;

iii. the make, model, serial number, and size of the temporary replacement unit; and

iv. the emissions data of the permitted temporary replacement unit.

The Department of Health may require an ambient air quality impact analysis and/or may impose additional requirements on the temporary replacement unit to ensure compliance with the conditions of this permit.

b. Permanent Replacement. The permittee may replace the combustion turbine generators, CT-4 and CT-5, with another General Electric LM2500 if any repair work reasonably warrants the removal i.e., equipment failure or malfunction, overhaul, or any major equipment problems requiring maintenance for efficient operation) of a combustion turbine generator form its site and the following provisions are adhered to:

   i. The replacement combustion turbine generator is a General Electric LM2500 with one of the following serial numbers:

      1) 481-688

      2) 481-692

      3) 481-651

   ii. The permittee shall submit to the Department of Health, the make, model, and serial number of the existing and replacement unit within 30 days of the replacement.

   iii. The permittee may continue using the replacement combustion turbine generator and is not required to return the original combustion turbine generator after it is repaired.

~~b~~c. Upon receiving written approval from the Department of Health, the permittee may burn an alternative fuel additive provided the permittee demonstrates compliance with all applicable State and Federal requirements and applicable conditions of this covered source permit. The burning of the alternative fuel or fuel additive shall not result in an increase in emissions of any air pollutant or in the emission of any air pollutant not previously emitted. As a minimum, the following information must be included with any request to burn an alternate fuel or fuel additive.

~~c~~d. The permittee shall contemporaneously with making a change from one alternate operating scenario to another, record in a log at the permitted facility the scenario under which it is operating and submit written notification to the Department of Health.

~~d~~e. The terms and conditions under each alternate operating scenario shall meet all applicable requirements, including conditions of this permit.

~~b~~c. The combustion turbine generators may operate below 25 percent of peak load (6.17 MW) during:

   i. Testing of the heat recovery steam generators and steam turbine; ~~and~~

   ii. Steam blows needed to clean the steam tubes prior to initial operation~~.~~;

   iii. Testing of combustion turbine generator controls; and

   iv. Dry running the Once Through Steam Generator (OTSG) to remove deposits from the OTSG.

~~c~~d. In the event of equipment malfunctions, such as the sudden loss of a unit; the combustion turbine generators may operate up to 110 percent of peak load (27.126 MW). The time period for operating the combustion turbines above 100 percent peak load (24.66 MW) shall be limited to no more than 30 minutes in duration. Under no circumstances shall the emission limits specified in Special Condition D.1.a. of this attachment be exceeded.

~~d~~e. [No changes proposed]

~~e~~f. [No changes proposed]

~~f~~g. [No changes proposed

h. Low Load Operation without Water Injection. Upon receiving written approval from the Department of Health, the permittee may be allowed to operate the combustion turbine generator below 25 percent of peak load (6.17 MW) without water injection for maintenance and testing. In requesting for approval, the permittee shall at a minimum provide the Department of Health the date and time period for testing, reason why it is necessary to test at loads less than 25 percent of peak load (6.17 MW) without water injection, procedures to be taken to minimize testing or maintenance at low load without water injection, maximum expected emissions, and any other supporting information as requested by the Department of Health. The Department of Health may require an ambient air quality assessment for the combustion turbine generator at low load without water injection, and/or provide a conditional approval to limit the maintenance and testing period, and impose additional monitoring, recordkeeping, and reporting requirements to ensure that operation at lower loads without water injection are in compliance with emission limits established in Special Condition D.1. of this Attachment.

~~g~~i. [No changes proposed]

~~h~~j. [No changes proposed]

Justification – The requested changes are also needed to: 1) include additional maintenance and testing activities. Dry running (i.e., dry operation) of the OTSG may be needed to remove deposits in the OTSG caused by ammonia from the SCR and sulfur in the fuel oil. The OTSG manufacturer's operating manual recommends dry running for approximately 60 to 100 minutes; the duration depends on the depth and density of the deposits; 2) clarify peak load; 3) allow operation of the combustion turbine generators below 25 percent of peak load without water injection for maintenance and testing; and 4) add the ability to replace combustion turbine generators, CT-4 and CT-5, with another General Electric LM2500 within HELCO's General Electric LM2500 combustion turbine pool.

Currently, HELCO utilizes the temporary replacement alternate operating scenario (AOS) when a combustion turbine is taken out of service for maintenance and/or repair. However, under the current AOS, HELCO is required to remove the replacement combustion turbine and re-install the original combustion turbine when maintenance and/or repairs are completed which is costly and time consuming. The addition of this AOS provision would allow HELCO to permanently replace combustion turbines with spare combustion turbines of the same make and model (General Electric LM2500) owned by HELCO.

Per 40 CFR § 60.14(e)(6), relocation of an emission unit is not considered a modification. Therefore, relocation of a combustion turbine does not result in applicability of NSPS Subpart IIII.

The permanent replacement AOS incorporates the "replacement unit" provisions contained in 40 CFR § 52.21 which were added on November 7, 2003 (68 FR 63023-63024). The November 7, 2003 revisions added the "replacement unit" definition to clarify EPA's December 31, 2002 decision to allow the use of the actual-to-projected actual applicability test for unit replacement (67 FR 80194).

The EPA December 31, 2002 decision states:

> *...the fact that replacement units are replacing similar units with a record of historical operational data provides sufficient reasons to believe that a projection of future actual emissions can be sufficiently reliable that an up-front emissions cap based on PTE is unnecessary. In other words, a source replacing a unit should be able to adequately project and track emissions for the replacement unit based, in part, on the operating history of the replaced unit.*

(67 FR 80186, at 80194)

Whether, the existing diesel engine is returned or not has no impact on projected-actual annual emissions. Therefore, no annual emissions increase is expected. Per 40 § 52.21(b)(41)(ii)(c), projected-actual annual emissions do not include emission increases unrelated to the particular project, including any increase utilization due to product demand growth.

Review of permits from other states has identified two permits allowing for the installation of permanent replacement units. The first example is a draft permit from the Oklahoma Department of Environmental Quality. Specific Condition 9 of Permit No. 97-179-C (M-2) states:

9. *Replacement (including temporary periods of up to six months for maintenance, etc.) of internal combustion engines shown in this permit with engines of lesser or equal emissions of each pollutant is authorized under the following conditions: [OAC 252:100-8-6 (f)]*

    a. *The permittee shall notify AQD in writing not later than 7 days in advance of the replacement engine(s)/turbine(s). Said notice shall identify the old engine/turbine and shall include the new engine/turbine make and model, serial number, horsepower rating, fuel usage, stack flow (ACFM), stack temperature (°F), stack height (feet), stack diameter (inches), and pollutant emission rates (g/hp-hr, lb/hr, and TPY) at maximum horsepower for the altitude/location.*

    b. *Quarterly emissions tests for the replacement engine(s)/turbine(s) shall be conducted to confirm continued compliance with NO_x and CO emissions limitations. A copy of the first quarter testing shall be provided to AQD within 60 days of start-up of each replacement engine/turbine. The test report shall include the engine/turbine fuel usage, stack flow (ACFM), stack temperature (°F), stack height (feet), stack diameter (inches), and pollutant emission rates (g/hp-hr, lbs/hr, and TPY) at maximum rated horsepower for the altitude/location.*

    c. *Replacement equipment and emissions are limited to equipment and emissions which are not subject to NSPS, NESHAP, or PSD."*

The second example is from an Operating Permit (02OPEP246) issues by the Colorado Department of Public Health and Environment, Air Pollution Control Division. Operating Permit 02OPEP246, Section I.2 states:

2. Alternative Operating Scenarios

The following Alternative Operating Scenario (AOS) for either temporary or permanent combustion turbine replacement has been reviewed in accordance with the requirements of Regulation No.3,Part A, Section IV.A, Operational Flexibility-Alternative Operating Scenarios, and Regulation No. 3, Part B, Construction Permits, and has been found to meet all applicable substantive and procedural requirements. This permit incorporates and shall be considered a construction permit for any combustion turbine replacement performed in accordance with this AOS, and the permittee shall be allowed to perform such turbine replacement without applying for a revision to this permit or obtaining a new Construction Permit. For purposes of Regulation No. 3, Part B, Section IV.G.4.a, any turbine replacement authorized under this AOS shall commence operation upon notation of same in the contemporaneous log as required below. Results of any data collection required below shall be normalized for comparison to the applicable permitted emission limits. Any permanent turbine replacement under this AOS shall result in the replacement turbine being considered a new affected facility for purposes of NSPS GG or any applicable MACT and shall be subject to all applicable requirements in that Subpart.

2.1 Turbine Replacement

The following AOS is incorporated into this permit in order to deal with a turbine breakdown or periodic routine maintenance and repair which requires either the temporary or permanent replacement of the entire turbine. Note that the compliance demonstrations made as part of this AOS are in addition to any compliance demonstrations required by the permit.

2.1.1 The permittee may replace an existing turbine provided such replacement turbines are GE Sprint Model LM6000-PC combustion turbines without modifying this permit.

2.1.2 Replacement turbines are subject to all federally applicable and state-only requirements set forth in this permit (including monitoring and recordkeeping), and shall be subject to any shield afforded by this permit.

2.1.3 The permittee shall maintain a log on-site to contemporaneously record the date of any turbine replacement, the manufacturer, model number, and serial number of the turbine(s) that are replaced during the term of this permit, and the manufacturer, model number, and serial number of the replacement turbine. All records related to any testing shall be maintained on-site for five (5) years and made available to the Division upon request.

2.1.4 *For permanent turbine replacements, an Air Pollutant Emissions Notice (APEN) that includes the specific manufacturer, model and serial number of the permanent replacement turbine shall be filed with the Division within 14 calendar days of commencing operation of the replacement turbine. The APEN shall be accompanied by the appropriate APEN filing fee and a cover letter explaining that the permittee is exercising an AOS and is installing a permanent replacement turbine.*

2.1.5 *In the absence of credible evidence to the contrary, data from the CEM shall be evidence of enforceable compliance or noncompliance of the replacement turbine with the emission limitations of the original turbine. If the CEM data fails to demonstrate compliance with either the NO_X or CO emission limitations and in the absence of credible evidence to the contrary, the turbine will be considered to be out of compliance for the purposes of this AOS from the date the replacement turbine commenced operation until the turbine is taken off line. All data that indicates noncompliance shall be submitted to the Division within 14 calendar days after the data is collected.*

2.1.6 *The permittee shall agree to pay fees based on the normal permit processing rate for review of information submitted to the Division in regard to any permanent turbine replacement.*

2.1.7 *All data collected pursuant to this AOS shall be kept on site for five (5) years and made available to the Division upon request.*

2.1.8 *For comparison with an annual or short term emissions limit, data collected pursuant to this AOS shall be converted to a lb/hr basis and multiplied by the allowable operating hours in the month or year (whichever applies) in order to monitor compliance. If a source is not limited in its hours of operation, the test results shall be multiplied by the maximum number of hours in the month or year (8760), whichever applies."*

The above example permits address units that have been through New Source Review and have emission testing requirements. The testing requirements for the original units (CT-4 and CT-5) are identical to the replacement unit (CT-3 at the Puna Generating Station), except for NH_3 because CT-3 is not a combined cycle unit. CT-4 and CT-5 are required to conduct annual performance tests for NO_X, SO_2, CO, and PM as specified in Attachment IIA, Section G.

An applicability determination for grandfathered units was also identified. On April 1, 1999, EPA Region 2 made an applicability determination in regards to PSE&G combustion turbine replacement. The EPA Region 2 applicability determination states:

The act of physically removing a turbine from one spot, performing the routine repair and maintenance on that turbine and placing it in a different but identically designed spot, is not the construction of a new source.

EPA Region 2 recommended incorporating the following essential monitoring, recordkeeping and reporting requirements into PSE&G's Title V permit:

1. *A complete list of all turbines purchased as part of the original fleet must be complied with detailed information on the Make, Model, Serial Number, Maximum Heat Input, and Location for each turbine. This list must be made part of the Title V permit and updated with regard to the location of each turbine unit as it is being moved among the 12 stations.*
2. *Notify NJDEP in writing no later than 7 days after any turbine from the original fleet is switched with another turbine from the original fleet.*
3. *Record the following information each time a turbine is switched:*
   - *i. date switch occurred;*
   - *ii. description of the maintenance/repairs/parts replacement performed on the malfunctioning turbine since it was last in service;*
   - *iii. identify malfunctioning turbine and substitute turbine by make, model, serial number and location; and*
   - *iv. a demonstration (such as mass balance) showing that the switch did not result in an increase in emission of any pollutant or the emission of a new pollutant not previously emitted.*
4. *All information recorded must be kept on site for at least 5 years from date of issuance of the Title V permit.*

The above examples illustrate the proposed permanent replacement alternate operating scenario is allowed under NSPS and PSD permitting rules. Supporting information for the permanent alternate operating scenario is included in Attachment S-3d.

Proposed change to Attachment IIA, Special Condition D.1.:

Maximum Emission Limits

a. Except during the startup and shutdown sequences, ~~T~~the permittee shall not discharge or cause the discharge into the atmosphere from the combustion turbine generator nitrogen oxides, sulfur dioxide, particulate matter/PM_{10}, carbon monoxide, volatile organic compounds, and ammonia in excess of the following specified limits:

Combustion Turbine Generator Operating in Simple Cycle Mode

Compound	**Maximum Emission Limit (3-hour Average)**	
	(lbs/hr)	(ppmvd @ 15 percent O_2)
Nitrogen Oxides as NO_2	42.3	42
Sulfur Dioxide	110	79
Particulate Matter/PM_{10}	19.7	0.045 (g/dscf @ 12 percent O_2)
Carbon Monoxide		
100% Peak load (24.66 MW)	26.8	44
75% (18.50 MW) - < 100% (24.66 MW) Peak load	56.4	123
50% (12.33 MW) - < 75% (18.50 MW) Peak load	181.0	566
~~25% (6.17 MW) -~~ < 50% (12.33 MW) Peak load	475.6	2,386
Volatile Organic Compounds		
100% Peak load (24.66 MW)	0.8	2.5
75% (18.50 MW) - < 100% (24.66 MW) Peak load	2.6	11.8
50% (12.33 MW) - < 75% (18.50 MW) Peak load	18.1	178
~~25% (6.17 MW) -~~ < 50% (12.33 MW) Peak load	297.6	3,025

Combustion Turbine Generator Operating in Combined Cycle Mode

Compound	Maximum Emission Limit (3-hour Average) (lbs/hr)	(ppmvd @ 15 percent O_2)
Nitrogen Oxides as NO_2		
50% (12.33 MW) - 100% (24.66 MW) Peak load	15.1	15
~~25% (6.17 MW) -~~ < 50% (12.33 MW) Peak load	42.3	42
Sulfur Dioxide	110	79
Particulate Matter/PM_{10}	19.7	0.045 (g/dscf @ 12 percent O_2)
Carbon Monoxide		
100% Peak load (24.66 MW)	26.9	44
75% (18.50 MW) - < 100% (24.66 MW) Peak load	50.2	105
50% (12.33 MW) - < 75% (18.50 MW) Peak load	170.4	523
~~25% (6.17 MW) -~~ < 50% (12.33 MW) Peak load	457.4	2,218
Volatile Organic Compounds		
100% Peak load (24.66 MW)	0.8	2.5
75% (18.50 MW) - < 100% (24.66 MW) Peak load	2.0	8.6
50% (12.33 MW) - < 75% (18.50 MW) Peak load	25.0	156
~~25% (6.17 MW) -~~ < 50% (12.33 MW) Peak load	271.0	2,662
Ammonia	4.30	10

For operating periods during which multiple NO_X and CO emission standards specified in the tables above apply, the applicable NO_X and CO emissions limit shall be determined in accordance with 40 CFR § 60.4380(b)(3).

The three-hour averaging period shall begin immediately after the combustion turbine generator's startup sequence and end immediately prior to the combustion turbine generator's shutdown sequence.

b. The Department of Health, with U.S. EPA Region 9 concurrence, may revise the allowable emission limitation for nitrogen oxides, particulate matter, carbon monoxide, volatile organic compounds, and ammonia after reviewing the initial performance test results required under Attachment IIA, Section G of this Covered Source Permit. The Department of Health, with U.S. EPA Region 9 concurrence, may also revise the water-to-fuel ratios or include ammonia-to-NO_X injection rates if findings through operating parameters and performance test results show an optimum operating range which minimizes emissions.

c. If the nitrogen oxides, particulate matter, carbon monoxide, volatile organic compounds, or ammonia emission limit is revised, the difference between the applicable emission limit set forth above and the revised lower emission limit shall not be allowed as an emission offset for future construction or modification.

Justification –.The requested changes are needed to: 1) revise the emission limits table to clarify peak load; 2) clarify the method of determining the applicable emission limit for operating

periods during which multiple emission standards apply; and 3) revise the emission limits tables to address operation of CT-4 and CT-5 below 25 percent of peak load.

Proposed change to Attachment IIA, Special Condition E.1.c.:

The permittee shall operate and maintain a ~~total volumetric~~ flow metering system for the continuous measurement and recording of the fuel usage of the combustion turbine generators. The permittee shall maintain records on the total amount of fuel fired in the combustion turbine generators.

Justification – The requested change is needed to allow volumetric or mass flow meters.

Proposed change to Attachment IIA, Special Condition E.1.d.:

The permittee shall operate and maintain a continuous monitoring system to measure and record the NO_X, CO, and carbon dioxide (CO_2) or oxygen (O_2) concentrations in the stack gas from the combustion turbines. If CO_2 is measured with the CEMS to adjust the pollutant concentration, the CO_2 correction factor equations listed in 40 CFR §60.4213(d)(3) shall be used to determine compliance with the applicable emissions limit and a diluent cap value for CO_2 may be used in accordance with 40 CFR §60.4350(b). The emissions ~~rates~~ for NO_X and CO shall be recorded in parts per million by volume dry (ppmvd) at 15 percent O_2 and pounds per hour (lbs/hr).

Justification – The requested changes are needed to incorporate by reference the CO_2 correction factor equations required for the CEMS and allow the use of a diluent cap address any hour in which the hourly average CO_2 concentration is less than 1.0 percent. 40 CFR Part 60, Subpart KKKK and Part 75 include a diluent cap for both O_2 and CO_2 for stationary turbines. However, 40 CFR Part 60, Subpart GG includes a diluent cap only for O_2.

Proposed change to Attachment IIA, Special Condition E.1.e.ii.:

The NO_X and carbon dioxide (CO_2) or oxygen (O_2) concentrations in the exhaust gas stream at a point between the exit of the combustion turbine with water injection and the entrance to the SCR system. If CO_2 is measured with the CEMS to adjust the pollutant concentration, the CO_2 correction factor equations listed in 40 CFR §60.4213(d)(3) shall be used to determine compliance with the applicable emissions limit and a diluent cap value for CO_2 may be used in accordance with 40 CFR §60.4350(b).

The emissions ~~rates~~ for NO_X shall be recorded in parts per million by volume dry (ppmvd) at 15 percent O_2 and in lbs/hr. The continuous emissions monitoring system used for these measurements shall meet the U.S. EPA performance specifications of 40 CFR Part 60 Section 60.13, Appendix B, and Appendix F.

Justification – The requested changes are needed to incorporate by reference the CO_2 correction factor equations required for the CEMS and allow the use of a diluent cap address any hour in which the hourly average CO_2 concentration is less than 1.0 percent. 40 CFR Part 60, Subpart KKKK and Part 75 include a diluent cap for both O_2 and CO_2 for stationary turbines. However, 40 CFR Part 60, Subpart GG includes a diluent cap only for O_2.

Proposed change to Attachment IIA, Special Condition E.3.a.:

The fuel sulfur content of the fuel fired in the combustion turbines shall be determined by sampling each delivery prior to combining with the existing fuel supply in accordance with 40 CFR, Appendix D to part 75, Section 2.2.4.3. The analysis may be performed by the permittee, the supplier, or other qualified third party lab. The analysis shall be performed using one of the following ASTM International (ASTM) methods: D129-00, D2622-98, D4294-02, D1266-98, D5453- 00, or D1552-01 or a more current version of these ASTM methods. ~~verified by one of the following methods:~~

- ~~i. A representative sample of each batch of the fuel received shall be analyzed using the most current version of any of the following American Society for Testing and Materials (ASTM) methods: D129, D2622, D4292, D5453, or D1552; or~~
- ~~ii. A certificate of analysis on the sulfur content (percent by weight) shall be obtained from the fuel supplier for each batch of fuel received.~~

Justification – The fuel testing requirements were revised to provide consistency with NSPS Subpart GG. The requested changes include the addition of the NSPS Subpart GG fuel oil no. 2 sulfur test methods and authorization of the fuel testing to be conducted by the permittee, supplier, or other qualified third party lab.

Proposed change to Attachment IIA, Special Condition E.3.b.: Delete condition.

~~The fuel bound nitrogen content of the fuel fired in the combustion turbines shall be verified by the following method. A representative sample of each batch of fuel received shall be analyzed for its nitrogen content by weight using the most current version of any of the following American Society for Testing and Materials (ASTM) methods: D6366, D4629, D5762.~~

Justification – The requested change removes the fuel bound nitrogen monitoring conditions because it is not required by NSPS Subpart GG if an emission allowance for fuel bound nitrogen is not claimed; HELCO has not claimed an emission allowance under NSPS Subpart GG.

Proposed change to Attachment IIA, Special Condition E.3.c.

The permittee shall maintain records of the fuel deliveries.~~y~~ identifying the delivery dates and the type and amount of fuel received.~~receipts, the supplier's certificate of analysis showing the sulfur content of the fuel delivered, and all test analysis. At a minimum, the test analysis shall include the following:~~

- ~~i. Type of fuel;~~
- ~~ii. Date and time the fuel sample was drawn;~~
- ~~iii. Date the analyses were performed;~~
- ~~iv. Name and address of the company or entity that performed the analyses;~~
- ~~v. Means and methods used to analyze the fuel; and~~
- ~~vi. Analyses results.~~

Records of~~n~~ the sulfur ~~and nitrogen~~ content~~s~~ of the fuel shall be maintained on a monthly basis.

Justification – The requested changes are needed for consistency with the proposed change to Attachment IIA, Special Condition E.3.b. and CSP No. 0070-01-C.

Proposed change to Attachment IIA, Special Condition E.: Add monitoring and recordkeeping requirement.

Operation Below 25 Percent of Peak Load with Water Injection. The permittee shall maintain records of the time the combustion turbine generator operates below 25 percent of peak load with water injection. Records of the total time CT-2, CT-4, and CT-5 operated below 25 percent of peak load with water injection, excluding startup and shutdown sequences, and maintenance, testing, and as approved pursuant to Special Condition C.5. of this Attachment, shall be maintained on a monthly and rolling 12-month basis using data recorded by the CEMS.

Justification – The requested change is needed to monitor and record operation of CT-4 and CT-5 below 25 percent of peak load with water injection.

Proposed change to Attachment IIA, Section E: Add condition.

Daily startup and shutdown times. The start and end times of each sequence shall be recorded. In addition, the operating load (MW) at which the air pollution control equipment was initiated and terminated shall be recorded.

Justification – The requested change is needed for consistency with notification and reporting requirements in Attachment IIA, Special Condition F.6.a.

Proposed change to Attachment IIA, Special Condition F.3.: Delete condition.

~~**Within sixty (60) days** after initial start-up of the selective catalytic reduction system, the permittee shall submit to the Department of Health a quality assurance project plan for the continuous monitoring system conforming to 40 CFR Part 60, Appendix F.~~

Justification – The quality assurance project plan has been submitted to the Department of Health and therefore, this permit condition is no longer needed.

Proposed change to Attachment IIA, Special Condition F.4.:

~~The permittee shall notify the Department of Health in writing **within thirty (30) days** prior to conducting performance specification tests on the continuous monitoring system. The testing date shall be in accordance with the performance test date identified in 40 CFR Part 60 Section 60.13.~~

At least thirty (30) days prior to the following events, the permittee shall notify the Department of Health in writing of:

a. Conducting a performance specification test on the CEMS. The testing date shall be in accordance with the performance test date identified in 40 CFR Part 60, Section 60.13(c).

b. Conducting a source performance test as required in Attachment IIA, Section G, Testing Requirements.

Justification – The requested changes are needed for consistency with CSP No. 0070-01-C and NSPS Subpart A.

Proposed change to Attachment IIA, Special Condition F.5.f.:

For purposes of this Covered Source Permit, excess emissions shall be defined as follows:

i. [No changes proposed]

ii. During simple cycle operation and combined cycle operation at loads less than 50 percent of peak load (12.33 MW), any one (1) hour period during which the average water-to-fuel ratio, as measured by the continuous monitoring system, falls below the water-to-fuel ratio at the corresponding operating load specified in Special Condition C.3.a. of this attachment. For operating periods during which multiple water-to-fuel mass ratios apply, the applicable water-to-fuel mass ratio shall be determined based on the load that corresponded to the lowest minimum water-to-fuel mass ratio; and

iii. Any opacity measurements, as measured by the transmissometer continuous monitoring system, exceeding the opacity limits and corresponding averaging times set forth in Special Condition D.2. of this attachment~~.~~, except when it can be demonstrated that the opacity exceedance is attributed to non-combustion sources.

Justification – The requested changes clarifies the method of determining the applicable minimum water-to-fuel mass ratio for operating hours during which multiple minimum water-to-fuel mass ratios apply and excludes periods of excess opacity when the unit is off as excess emissions.

Proposed change to Attachment IIA, Special Condition F.5.g.iii.:

Nitrogen oxide emissions in excess of 42 ppmvd at 15 percent O_2 while operating in simple cycle mode and combined cycle mode at loads less than 50 percent of peak load (12.33 MW) or 15 ppmvd at 15 percent O_2 while operating in combined cycle mode at loads equal to or greater than 50 percent of peak load (12.33 MW) if it can be shown that the excess emissions resulted from the firing of fuel with a fuel-bound nitrogen content in excess of 0.015 percent by weight. Under no circumstance shall the nitrogen oxide emission limit of 42.3 pounds per hour while operating in simple cycle mode and combined cycle mode at loads less than 50 percent of peak load (12.33 MW) or 15.1 pounds per hour while operating in combined cycle mode at loads equal to or greater than 50 percent of peak load (12.33 MW), as specified in Special Condition D.1.a. of this attachment, be exceeded.

Justification – The requested change is to clarify peak load.

Proposed change to Attachment IIA, Special Condition F.6.:

The permittee shall submit **semi-annually** the following written reports to the Department of Health. The report shall be submitted **within sixty (60) days** after the end of each semi-annual calendar period, and shall include the following:

a.. A monthly summary listing the time and duration of all ~~start-up~~ startup and ~~shut-down~~ shutdown sequences for each combustion turbine. The summary shall include the combustion turbine generator load (MW) at the time the air pollution control devices and systems are initiated and terminated and the total operating hours per day and by month. The enclosed **Monitoring Report Form:** ***Daily ~~Start-up~~ Startup and ~~Shut-down~~ Shutdown***, or similar form, shall be used.

b. Except for all ~~start-up~~ startup and shutdown sequences report all periods where the minimum operating load for each combustion turbine was less than 25 percent of ~~the~~ peak load (6.17 MW) ~~rated capacity~~. The report shall include the date, time, and duration of each period using the data recorded by the CEMS.

c. [No changes proposed]

d. A report identifying the type of fuel fired in each of the combustion turbines during the semi-annual reporting period. The report shall include the maximum sulfur content (percent by weight) ~~and the average nitrogen content (percent by weight)~~ of the fuel for the reporting period. ~~The report shall identify the means and methods used to verify the sulfur and nitrogen content of each fuel.~~ The enclosed **Monitoring Report Form:** ***Fuel Certification,*** or similar form, shall be used.

e. [No changes proposed]

f. A monthly summary and rolling 12-month total of the hours of operation of the combustion turbine generators, CT-2, CT-4, and CT-5, below 25 percent of peak load with water injection excluding startup and shutdown sequences, maintenance, testing, and as approved pursuant to Special Condition C.5. of this Attachment. The report shall be based on data recorded by the CEMS.

Justification – The requested changes are needed: 1) to clarify peak load; 2) for consistency with CSP No. 0070-01-C; 3) for consistency with the proposed change to Special Condition E.3.b. to remove the fuel bound nitrogen monitoring conditions because it is not required by NSPS Subpart GG if an emission allowance for fuel bound nitrogen is not claimed; HELCO has not claimed an emission allowance under NSPS Subpart GG; and 4) for operation of CT-4 and CT-5 below 25 percent of peak load with water injection.

Proposed change to Attachment IIA, Special Condition G.1.: Delete condition.

~~**Within sixty (60) days** after achieving the maximum production rate of the 16 MW steam turbine, but not later than one hundred eighty (180) days after the initial start-up of the 16 MW steam turbine (as defined in 40 CFR Part 60.2), the permittee shall conduct or cause to be conducted performance tests on the combustion turbine generators operating with SCR in the combined cycle mode.~~

Justification – These performance tests have been conducted, and therefore the permit condition is no longer needed.

Proposed change to Attachment IIA, Special Condition G.3.:

All performance tests shall be conducted at 25 (6.17 MW), 50 (12.33 MW), 75 (18.50 MW), and 100 (24.66 MW) or highest achievable percent of peak load of the combustion turbine generators. The Department of Health may require the permittee to conduct the performance tests at additional operating loads.

Justification – The requested change is to clarify peak load.

Proposed change to Attachment IIA, Special Conditions G.8.:

Performance tests for the emissions of SO_2, NO_X, CO, VOC, PM, CO_2, and NH_3 shall be conducted and results reported in accordance with test methods set forth in 40 CFR Part 60 Appendix A, and 40 CFR Part 60.8. The following test methods or U.S. EPA-approved equivalent methods, or alternate methods with prior written approval from the Department of Health, shall be used. Method 3A may be used in place of Method 3.

a. Performance tests for the emissions of SO_2 shall be conducted using the 40 CFR Part 60, Methods 1-4 and 6C or Method 20.
b. Performance tests for the emissions of NO_X shall be conducted using 40 CFR Part 60, Methods 1-4 and 7E or Method 20.
c. Performance tests for the emissions of CO shall be conducted using 40 CFR Part 60, Methods 1-4 and 10 or Methods 3A, 10, and 19.
d. Performance tests for the emissions of VOC shall be conducted using 40 CFR Part 60, Methods 1-4 and 25A or Methods 3A, 25A, and 19. Method 18 may be used to account for the actual methane fraction of the measured VOC emissions.
e. Performance tests for the emissions of particulate matter shall be conducted using 40 CFR Part 60, Methods 1-5.
f. Performance tests for the emissions of CO_2 shall be conducted using 40 CFR Part 60 Method 20 or U.S. EPA-approved equivalent methods~~, Equations 20-2 and 20-5~~ and the CO_2 correction factor calculations listed in § 60.4213(d)(3).
g. Performance test for the emissions of NH_3 shall be conducted using U.S. EPA Conditional Test Method 027(CTM-027).

Justification – The requested changes are needed to add specific U.S. EPA-approved equivalent methods to the permit condition and incorporate by reference the new location of the CO_2 correction factor equations required for the CEMS. This addition is needed because the equations are no longer in the referenced test method (Method 20).

Proposed Changes to Attachment IIB

Proposed change to Attachment IIB, Special Condition A.1.d.:

One (1) 500 kW Caterpillar Model 3412 Black Start Diesel Engine Generator ~~with an exhaust stack height of 70 feet~~ unit no. BS-1.

Justification – The requested change updates the description of the black start diesel engine generator, BS-1 because the relocation and extension of the stack height has been completed.

Proposed change to Attachment IIB, Special Condition B.7.:

Alternate Operating Scenarios

Terms and conditions for reasonably anticipated operating scenarios identified by the permittee in the covered source permit application and approved by the Department of Health are as follows:

a. Temporary Replacement. Upon receiving written approval from the Department of Health, the permittee may replace any of the permitted diesel engines ~~generators~~ with a temporary replacement unit in the event of a sudden malfunction or planned major overhaul. The temporary replacement unit shall comply with all applicable permit conditions.

   A written request shall be submitted to the Department of Health prior to the exchange and at a minimum, the request shall include the following:

   i. the reason for temporary replacement;

   ii. the removal and estimated return dates of the permitted unit;

   iii. the make, model, serial number, and size of the temporary replacement unit;

   iv. the emissions data of the permitted and temporary replacement unit.

   The Department of Health may require an ambient air quality analysis and/or impose additional requirements on the temporary replacement unit to ensure compliance with the conditions of this permit.

b. Permanent Replacement. The permittee may replace the diesel engines, D21, D22, and D23, with another EMD 20-645 if any repair work reasonably warrants the removal (i.e., equipment failure, engine overhaul, or any major equipment problems requiring maintenance for efficient operation) of a diesel engine from its site and the following provisions are adhered to:

   i. The replacement engine is an EMD 20-645 with one of the following serial numbers:

      1) 74-K3-1540

      2) 71-M1-1092

      3) 71-M1-1045

      4) 74-B1-1078

      5) 66-K1-1062

      6) 69-H1-1057

      7) 74-B1-1063

      8) 72-E1-1027

      9) 72-B1-1122

      10) 73-G1-1129

      11) 66-K1-1057

      12) 72-E1-1094

      13) 66-J1-1156

   ii. The permittee shall submit to the Department of Health, the make, model, and serial number of the existing and replacement unit within 30 days of the replacement.

   iii. The permittee may continue using the replacement diesel engine and is not required to return the original diesel engine after it is repaired.

~~b~~c. Upon receiving written approval from the Department of Health, the permittee may burn an alternative fuel additive provided the permittee demonstrates compliance with all applicable State and Federal requirements and applicable conditions of this covered source permit. The burning of the alternative fuel or fuel additive shall not result in an increase in emissions of any air pollutant or in the emission of any air pollutant not previously emitted. As a minimum, the following information must be included with any request to burn an alternate fuel or fuel additive.

~~c~~d. The permittee shall contemporaneously with making a change from one alternate operating scenario to another, record in a log at the permitted facility the scenario under which it is operating and submit written notification to the Department of Health.

~~d~~e. The terms and conditions under each alternate operating scenario shall meet all applicable requirements, including conditions of this permit.

Justification – The requested changes are needed to add the ability to permanently replace diesel engines, D21, D22, and D23, with another EMD 20-645 within HELCO's EMD diesel engine pool. Currently, HELCO utilizes the temporary replacement alternate operating scenario (AOS) when a diesel engine is taken out of service for maintenance and/or repair. However, under the current AOS, HELCO is required to remove the spare diesel engine and re-install the original diesel engine when maintenance and/or repairs are completed which is costly and time consuming. The addition of this AOS provision would allow HELCO to permanently replace diesel engines with spare diesel engines of the same make and model (EMD 20-645) owned by HELCO.

Per 40 CFR § 60.14(e)(6), relocation of an emission unit is not considered a modification. Therefore, relocation of a diesel engine does not result in applicability of NSPS Subpart IIII.

The permanent replacement AOS incorporates the "replacement unit" provisions contained in 40 CFR § 52.21 which were added on November 7, 2003 (68 FR 63023-63024). The November 7, 2003 revisions added the "replacement unit" definition to clarify EPA's December 31, 2002 decision to allow the use of the actual-to-projected actual applicability test for unit replacement (67 FR 80194).

The EPA December 31, 2002 decision states:

> *...the fact that replacement units are replacing similar units with a record of historical operational data provides sufficient reasons to believe that a projection of future actual emissions can be sufficiently reliable that an up-front emissions cap based on PTE is unnecessary. In other words, a source replacing a unit should be able to adequately project and track emissions for the replacement unit based, in part, on the operating history of the replaced unit.*

(67 FR 80186, at 80194)

Whether, the existing diesel engine is returned or not has no impact on projected-actual annual emissions. Therefore, no annual emissions increase is expected. Per 40 § 52.21(b)(41)(ii)(c), projected-actual annual emissions do not include emission increases unrelated to the particular project, including any increase utilization due to product demand growth.

Review of permits from other states has identified two permits allowing for the installation of permanent replacement units. The first example is a draft permit from the Oklahoma Department of Environmental Quality. Specific Condition 9 of Permit No. 97-179-C (M-2) states:

> 9. *Replacement (including temporary periods of up to six months for maintenance, etc.) of internal combustion engines shown in this*

permit with engines of lesser or equal emissions of each pollutant is authorized under the following conditions: [OAC 252:100-8-6 (f)]

a. The permittee shall notify AQD in writing not later than 7 days in advance of the replacement engine(s)/turbine(s). Said notice shall identify the old engine/turbine and shall include the new engine/turbine make and model, serial number, horsepower rating, fuel usage, stack flow (ACFM), stack temperature (°F), stack height (feet), stack diameter (inches), and pollutant emission rates (g/hp-hr, lb/hr, and TPY) at maximum horsepower for the altitude/location.

b. Quarterly emissions tests for the replacement engine(s)/turbine(s) shall be conducted to confirm continued compliance with NOx and CO emissions limitations. A copy of the first quarter testing shall be provided to AQD within 60 days of start-up of each replacement engine/turbine. The test report shall include the engine/turbine fuel usage, stack flow (ACFM), stack temperature (°F), stack height (feet), stack diameter (inches), and pollutant emission rates (g/hp-hr, lbs/hr, and TPY) at maximum rated horsepower for the altitude/location.

c. Replacement equipment and emissions are limited to equipment and emissions which are not subject to NSPS, NESHAP, or PSD."

The second example is from an Operating Permit (02OPEP246) issues by the Colorado Department of Public Health and Environment, Air Pollution Control Division. Operating Permit 02OPEP246, Section I.2 states:

2. Alternative Operating Scenarios

The following Alternative Operating Scenario (AOS) for either temporary or permanent combustion turbine replacement has been reviewed in accordance with the requirements of Regulation No.3,Part A, Section IV.A, Operational Flexibility-Alternative Operating Scenarios, and Regulation No. 3, Part B, Construction Permits, and has been found to meet all applicable substantive and procedural requirements. This permit incorporates and shall be considered a construction permit for any combustion turbine replacement performed in accordance with this AOS, and the permittee shall be allowed to perform such turbine replacement without applying for a revision to this permit or obtaining a new Construction Permit. For purposes of Regulation No. 3, Part B, Section IV.G.4.a, any turbine replacement authorized under this AOS shall commence operation upon notation of same in the contemporaneous log as required below. Results of any data collection required below shall be normalized for comparison to the applicable permitted emission limits. Any permanent turbine replacement under this AOS shall result in the replacement turbine being considered a new affected facility for purposes of NSPS GG or any applicable MACT and shall be subject to all applicable requirements in that Subpart.

2.1 Turbine Replacement

The following AOS is incorporated into this permit in order to deal with a turbine breakdown or periodic routine maintenance and repair which requires either the temporary or permanent replacement of the entire turbine. Note that the compliance demonstrations made as part of this AOS are in addition to any compliance demonstrations required by the permit.

2.1.1 The permittee may replace an existing turbine provided such replacement turbines are GE Sprint Model LM6000-PC combustion turbines without modifying this permit.

2.1.2 Replacement turbines are subject to all federally applicable and state-only requirements set forth in this permit (including monitoring and recordkeeping), and shall be subject to any shield afforded by this permit.

2.1.3 The permittee shall maintain a log on-site to contemporaneously record the date of any turbine replacement, the manufacturer, model number, and serial number of the turbine(s) that are replaced during the term of this permit, and the manufacturer, model number, and serial number of the replacement turbine. All records related to any testing shall be maintained on-site for five (5) years and made available to the Division upon request.

2.1.4 For permanent turbine replacements, an Air Pollutant Emissions Notice (APEN) that includes the specific manufacturer, model and serial number of the permanent replacement turbine shall be filed with the Division within 14 calendar days of commencing operation of the replacement turbine. The APEN shall be accompanied by the appropriate APEN filing fee and a cover letter explaining that the permittee is exercising an AOS and is installing a permanent replacement turbine.

2.1.5 In the absence of credible evidence to the contrary, data from the CEM shall be evidence of enforceable compliance or noncompliance of the replacement turbine with the emission limitations of the original turbine. If the CEM data fails to demonstrate compliance with either the NO_X *or CO emission limitations and in the absence of credible evidence to the contrary, the turbine will be considered to be out of compliance for the purposes of this AOS from the date the replacement turbine commenced operation until the turbine is taken off line. All data that indicates noncompliance shall be submitted to the Division within 14 calendar days after the data is collected.*

2.1.6 *The permittee shall agree to pay fees based on the normal permit processing rate for review of information submitted to the Division in regard to any permanent turbine replacement.*

2.1.7 *All data collected pursuant to this AOS shall be kept on site for five (5) years and made available to the Division upon request.*

2.1.8 *For comparison with an annual or short term emissions limit, data collected pursuant to this AOS shall be converted to a lb/hr basis and multiplied by the allowable operating hours in the month or year (whichever applies) in order to monitor compliance. If a source is not limited in its hours of operation, the test results shall be multiplied by the maximum number of hours in the month or year (8760), whichever applies."*

The above example permits address units that have been through New Source Review and have emission testing requirements. The testing requirements for the replacement units are identical to the original units. Units D-21, D-22, and D-23 are required to conduct annual performance tests for NO_X as specified in Attachment IIB, Special Condition E.1.

An applicability determination for grandfathered units was also identified. On April 1, 1999, EPA Region 2 made an applicability determination in regards to PSE&G combustion turbine replacement. In a case similar to HELCO, PSE&G purchased a fleet of identical turbine units in the early 1970s. These units are installed at 12 generating stations with the extras kept as spares. When a running unit malfunctions, it is removed and replaced with the spare unit. The malfunctioning unit is repaired and remains in storage until another unit needs to be replaced. HELCO would like to implement a similar process with their EMD diesel engines. The EPA Region 2 applicability determination states:

> *The act of physically removing a turbine from one spot, performing the routine repair and maintenance on that turbine and placing it in a different but identically designed spot, is not the construction of a new source.*

EPA Region 2 recommended incorporating the following essential monitoring, recordkeeping and reporting requirements into PSE&G's Title V permit:

1. *A complete list of all turbines purchased as part of the original fleet must be complied with detailed information on the Make, Model, Serial Number, Maximum Heat Input, and Location for each turbine. This list must be made part of the Title V permit and updated with regard to the location of each turbine unit as it is being moved among the 12 stations.*
2. *Notify NJDEP in writing no later than 7 days after any turbine from the original fleet is switched with another turbine from the original fleet.*
3. *Record the following information each time a turbine is switched:*
    i. *date switch occurred;*

ii. description of the maintenance/repairs/parts replacement performed on the malfunctioning turbine since it was last in service;

iii. identify malfunctioning turbine and substitute turbine by make, model, serial number and location; and

iv. a demonstration (such as mass balance) showing that the switch did not result in an increase in emission of any pollutant or the emission of a new pollutant not previously emitted.

4. All information recorded must be kept on site for at least 5 years from date of issuance of the Title V permit.

The above examples illustrate the proposed permanent replacement alternate operating scenario is allowed under NSPS and PSD permitting rules. Supporting information for the permanent alternate operating scenario is included in Attachment S-3d.

Proposed change to Attachment IIB, Special Condition C.1.

1. Sulfur Content

   The sulfur content (% by weight) of the fuel fired in the diesel engines shall be ~~verified by one of the following methods:~~ determined by sampling each delivery prior to combining with the existing fuel supply in accordance with 40 CFR, Appendix D to part 75, Section 2.2.4.3. The analysis may be performed by the permittee, the supplier, or other qualified third party lab. The analysis shall be performed using one of the following ASTM International (ASTM) methods: D129-00, D2622-98, D4294-02, D1266-98, D5453-00, or D1552-01 or a more current version of these ASTM methods.

   ~~a.~~ ~~A representative sample of each batch of fuel received shall be analyzed using the most current version of the following American Society for Testing and Materials (ASTM) methods: D129, D2622, D4292, D5453, or D1552~~ clarifies the method of determining the applicable minimum water-to-fuel mass ratio for operating hours during which multiple minimum water-to-fuel mass ratios apply and~~; or~~

   ~~b.~~ ~~A certificate of analysis on the sulfur content shall be obtained from the fuel supplier for each batch of fuel received.~~

Justification – The fuel testing requirements were revised to provide consistency with Attachment IIA, Special Condition E.3.a.

Proposed change to Attachment IIB, Special Condition E.2.:

2. Performance tests for the emissions of NO_X (as NO_2) shall be conducted and results reported in accordance with the test methods set forth in 40 CFR Part 60 Appendix A~~,~~ and 40 CFR Part 60.8. The performance tests for the emissions of NO_X (as NO_2) shall be conducted using the following test methods in 40 CFR Part 60 ~~Methods 1-4 and 7~~ or U.S. EPA-approved equivalent methods, or alternate methods with prior written approval from the Department of Health~~.~~:

   a. Methods 1-4 (Method 3A may be used in place of Method 3) and 7 or 7E; or

   b. Methods 3A, 7E and 19.

Justification – The requested change adds specific U.S. EPA-approved equivalent methods to the permit condition.

Proposed change to Attachment IV: Annual Emissions Reporting Requirements:

Revise Section 1 as follows:

1. Complete the attached forms:

   Annual Emissions Report Form: *Combustion Turbines and Diesel Engines;* and

   Annual Emissions Report Form: *Ammonia Slip.* ~~; and~~

   ~~**Annual Emissions Report Form: *Diesel Engines.***~~

Justification – The requested change is needed for consistency with the proposed change to the Annual Emissions Report Forms and CSP No. 0070-01-C.

Proposed change to Annual Emissions Report Form – Combustion Turbines:

Delete form and combine with the Annual Emission Report Form – Diesel Engines.

Justification – The requested changes are needed: 1) to eliminate redundant forms; 2) to remove information not required to be reported (i.e., nitrogen content of the fuel and control efficiency % reduction); 2) to use the same form for D-21, CT-2, CT-4, and CT-5 with the combining of CSP Nos. 0007-01-C and 0070-01-C; and 3) for consistency with the proposed change to Attachment IIA, Special Condition C.4.b to remove the fuel bound nitrogen monitoring conditions because it is not required by NSPS Subpart GG if an emission allowance for fuel bound nitrogen is not claimed. HELCO has not claimed an emission allowance under NSPS Subpart GG.

Proposed change to Annual Emissions Report Form – Diesel Engines:

Allow use of the form for the combustion turbine generators, CT-2, CT-4 and CT-5, and delete information not required to be reported (i.e., Control Efficiency % reduction). Refer to the revised form attached. Proposed changes to the form are highlighted.

Justification – The requested changes are needed to eliminate redundant forms and information not required to be reported.

Proposed change to Monitoring Report Form – Fuel Consumption – Diesel Engine Generator:

Revise Fuel Consumption Form so that form may be used for reporting fuel consumption for CT-2 and delete the % sulfur content by weight. Refer to the revised form attached. Proposed changes to the form are highlighted.

Justification – The requested change is needed to eliminate duplicate report forms when combining CSP Nos. 0007-01-C and 0070-01-C and redundant reporting of information.

Proposed change to Monitoring Report Form – Fuel Certification:

Add CT-2 to the form and delete Nitrogen Content and the means and methods used to determine the sulfur and nitrogen content of the fuel. Refer to the revised form attached. Proposed changes to the form are highlighted.

Justification – The requested changes are needed: 1) for consistency with CSP No. 0070-01-C; 2) to add CT-2 to the table and for consistency with proposed change to Special Condition E.3.b; and 3) to remove the fuel bound nitrogen monitoring conditions because it is not required by NSPS Subpart GG if an emission allowance for fuel bound nitrogen is not claimed; HELCO has not claimed an emission allowance under NSPS Subpart GG.

ANNUAL EMISSIONS REPORT FORM
COMBUSTION TURBINES AND DIESEL ENGINES
COVERED SOURCE PERMIT NO. 0007-01-C

Issuance Date: **August 7, 2008** **Expiration Date:** **August 6, 2013**

In accordance with the Hawaii Administrative Rules, Title 11, Chapter 60.1, Air Pollution Control, the permittee shall report to the Department of Health the nature and amounts of emissions.

(Make Copies for Future Use)

For Period: ______________________ Date: ____________

Facility Name: HELCO Keahole Generating Station

Equipment Description: ~~2.5 MW General Motors EMD DEG~~

Serial/ID No(s).: ______________________

Responsible Official (Print): ______________________

Title: ______________________

I certify that I have knowledge of the facts herein set forth, that the same are true, accurate, and complete to the best of my knowledge and belief, and that all information not identified by me as confidential in nature shall be treated by the Department of Health as public record.

Responsible Official (Signature): ______________________

~~2.5 MW kilowatt rating~~

Unit No./Type of Fuel Fired	Fuel Usage (Gallons)	% Sulfur Content by weight
~~D21/Fuel Oil No. 2~~		
~~D22/Fuel Oil No. 2~~		
~~D23/Fuel Oil No. 2~~		
~~BS-1/Fuel Oil No. 2~~		

Unit No./Type of Air Pollution Control	In Use? Yes or No	Pollutant(s) Controlled	~~Control Efficiency % Reduction~~
	~~Yes or No~~		
	~~Yes or No~~		
	~~Yes or No~~		

MONITORING REPORT FORM
FUEL CONSUMPTION ~~– DIESEL ENGINE GENERATOR~~
COVERED SOURCE PERMIT NO. 0007-01-C

Issuance Date: _______________ **Expiration Date:** _______________

In accordance with the Hawaii Administrative Rules, Title 11, Chapter 60.1, Air Pollution Control, the permittee shall report to the Department of Health the ~~nature and amounts of emissions~~ following information, semi-annually.

(Make Copies for Future Use)

For Period: ______________________________ Date: _______________

Facility Name: ______________________________

Equipment Description: ~~2.5 MW General Motors Diesel Engine Generator~~ ____________

Serial/ID No.: ~~Unit D21~~ ______________________________

Type of Fuel: ~~Fuel Oil No. 2~~ ______________ ~~% Sulfur Content by Weight:~~ ____________

Responsible Official (Print): ______________________________

Title: ______________________________

I certify that I have knowledge of the facts herein set forth, that the same are true, accurate, and complete to the best of my knowledge and belief, and that all information not identified by me as confidential in nature shall be treated by the Department of Health as public record.

Responsible Official (Signature): ______________________________

Month[1]	**Monthly Fuel Consumption (Gallons)**	**Rolling 12-Month Fuel Usage (Gallons)**
~~January~~		
~~February~~		
~~March~~		
~~April~~		
~~May~~		
~~June~~		
~~July~~		
~~August~~		
~~September~~		
~~October~~		
~~November~~		
~~December~~		

[1]Report the monthly and rolling 12-month fuel usage for the applicable semi-annual reporting period and the previous semi-annual reporting period.

MONITORING EMISSION REPORT FORM
FUEL CERTIFICATION
COVERED SOURCE PERMIT NO. 0007-01-C

Issuance Date: **August 7, 2008** **Expiration Date:** **August 6, 2013**

In accordance with the Hawaii Administrative Rules, Title 11, Chapter 60.1, Air Pollution Control, the permittee shall report to the Department of Health the nature of fuel used for the permitted equipment.

(Make Copies for Future Use)

For Period: ______________________________ Date: ______________

Facility Name: Hawaii Electric Light Co. Keahole Generating Station

~~Equipment Location: Keahole Generating Station~~

Responsible Official (Print): ______________________________

Title: ______________________________

I certify that I have knowledge of the facts herein set forth, that the same are true, accurate, and complete to the best of my knowledge and belief, and that all information not identified by me as confidential in nature shall be treated by the Department of Health as public record.

Responsible Official (Signature): ______________________________

Unit No.	Equipment Description	Fuel Fired	Sulfur Content[1]
CT-2	18 MW Combustion Turbine	Fuel Oil No. 2	
CT-4	20 MW Combustion Turbine	Fuel Oil No. 2	
CT-5	20 MW Combustion Turbine	Fuel Oil No. 2	
D-21	2.5 MW General Motors EMD DEG	Fuel Oil No. 2	
D-22	2.5 MW General Motors EMD DEG	Fuel Oil No. 2	
D-23	2.5 MW General Motors EMD DEG	Fuel Oil No. 2	
BS-1	500 kW Caterpillar Black Start DEG	Fuel Oil No. 2	

1 – Report the maximum sulfur content (% by weight) recorded during the reporting period.

~~2 – Report the average nitrogen content (% by weight) for the reporting period.~~

~~List means and methods used to determine the sulfur content.~~

~~List means and methods used to determine the nitrogen content.~~

Attachment S-3d

Information Supporting HELCO's Request for a Permanent Replacement Alternative Operating Scenario For Combustion Turbine Generators and Diesel Engine Units

by the IB for that purpose. These forms may be downloaded from the IB Web site, *http://www.wipo.int/madrid/en/*. Please note that the IB will not process paper submissions that are not prepared using IB forms.

Applicants Should Mail Madrid Submissions to a Designated Address

Pursuant to 37 CFR 2.190(a), all trademark-related documents submitted on paper must be mailed to the USPTO address at 2900 Crystal Drive, Arlington, Virginia 22202–3514. However, the notice of October 24, 2003, waived that rule with respect to international applications, subsequent designations, and responses to notices of irregularities that are filed on paper. The notice further provided that all Madrid submissions made on paper should be mailed to the following address: Commissioner for Trademarks, PO Box 16471, Arlington, Virginia 22215–1471, Attn: MPU.

The limited waiver of 37 CFR 2.190(a) remains in effect. However, the following is noted: pursuant to the notice of October 24, 2003, the waiver, and the instruction to utilize the above-identified address, applied to Madrid submissions made on paper. Pursuant to the present notice, all Madrid submissions must be made on paper. Hence, the provisions of the notice of October 24, 2003, regarding the USPTO mailing address apply to all Madrid submissions.

Please note that any trademark-related correspondence other than international applications, subsequent designations, and responses to irregularity notices that is sent to the above-identified address will not be accepted, and will be returned to the sender.

If a submission mailed to the above address pursuant to this notice and to the Notice of October 24, 2003, is delivered by the Express Mail service of the United States Postal Service, the USPTO will deem that the date of receipt of the submission in the USPTO is the date the submission was deposited as Express Mail, provided that the submitter complies with the requirements set forth in 37 CFR 2.198.

Dated: October 31, 2003.

James E. Rogan,

Under Secretary of Commerce for Intellectual Property and Director of the United States Patent and Trademark Office.

[FR Doc. 03–27917 Filed 11–6–03; 8:45 am]

BILLING CODE 3510–16–P

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Parts 51 and 52

[FRL–7583–7, E–Docket ID No. A–2001–0004 (Legacy Docket ID No. A–90–37)]

Prevention of Significant Deterioration (PSD) and Non-Attainment New Source Review (NSR): Reconsideration

AGENCY: Environmental Protection Agency (EPA).

ACTION: Notice of final action on reconsideration; amendment to final rules.

SUMMARY: On December 31, 2002 and March 10, 2003, EPA revised regulations governing the major New Source Review (NSR) programs mandated by parts C and D of title I of the Clean Air Act (CAA or Act). Following these actions, the Administrator received a number of petitions for reconsideration. On July 30, 2003, EPA announced its reconsideration of certain issues arising from the final rules of December 31, 2002. We (the EPA) requested public comment on six issues for which we granted reconsideration. As a result of this reconsideration process, we have concluded that two clarifications to the underlying rules are warranted, which are: To include a definition of "replacement unit" and to clarify that the plantwide applicability limitation (PAL) baseline calculation procedures for newly constructed units do not apply to modified units. With respect to all other issues raised by the petitioners, we deny the requests for reconsideration.

EFFECTIVE DATE: This final action is effective on January 6, 2004.

ADDRESSES: *Docket.* Docket No. A–90–37 (E–Docket ID No. OAR–2001–0004), containing supporting information used to develop the proposed rule and the final rule, is available for public inspection and copying between 8 a.m. and 4:30 p.m., Monday through Friday (except government holidays) at the Air and Radiation Docket and Information Center (6102T), Room B108, EPA West Building, 1301 Constitution Avenue, NW., Washington, DC 20460; telephone (202) 566–1742, fax (202) 566–1741. A reasonable fee may be charged for copying docket materials.

Worldwide Web (WWW). In addition to being available in the docket, an electronic copy of this final action will also be available on the WWW. Following signature, a copy of the notice will be posted on the EPA's NSR page: *http://www.epa.gov/nsr*.

FOR FURTHER INFORMATION CONTACT: Ms. Lynn Hutchinson, Information Transfer and Program Integration Division (C339–03), U.S. Environmental Protection Agency, Research Triangle Park, NC 27711, telephone (919) 541–5795, or electronic mail at *hutchinson.lynn@epa.gov*, or Ms. Janet McDonald, at the same street address, telephone (919) 541–1450, or electronic mail at *mcdonald.janet@epa.gov*.

SUPPLEMENTARY INFORMATION:

I. General Information

A. What Are the Regulated Entities?

Entities potentially affected by the subject rule for today's action include sources in all industry groups. The majority of sources potentially affected are expected to be in the following groups.

Industry Group	SIC [a]	NAICS [b]
Electric Services	491	221111, 221112, 221113, 221119, 221121, 221122
Petroleum Refining	291	324110
Industrial Inorganic Chemicals	281	325181, 325120, 325131, 325182, 211112, 325998, 331311, 325188
Industrial Organic Chemicals	286	325110, 325132, 325192, 325188, 325193, 325120, 325199
Miscellaneous Chemical Products	289	325520, 325920, 325910, 325182, 325510
Natural Gas Liquids	132	211112
Natural Gas Transport	492	486210, 221210
Pulp and Paper Mills	261	322110, 322121, 322122, 322130
Paper Mills	262	322121, 322122
Automobile Manufacturing	371	336111, 336112, 336211, 336992, 336322, 336312, 336330, 336340, 336350, 336399, 336212, 336213
Pharmaceuticals	283	325411, 325412, 325413, 325414

[a] Standard Industrial Classification

[b] North American Industry Classification System. Entities potentially affected by the subject rule for today's action also include State, local, and tribal governments.

B. How Can I Get Copies of This Document and Other Related—Information?

1. Docket. EPA has established an official public docket for this action under E–Docket ID No. OAR–2001–0004 (Legacy Docket ID No. A–90–37). The official public docket consists of the documents specifically referenced in this action, any public comments received, and other information related to this action. Although a part of the official docket, the public docket does not include Confidential Business Information (CBI) or other information whose disclosure is restricted by statute. The official public docket is the collection of materials that is available for public viewing at the EPA Docket Center (Air Docket), U.S. Environmental Protection Agency, EPA West Building, 1301 Constitution Avenue, NW., Room B108, Mail Code: 6102T, Washington, DC 20460. The EPA Docket Center Public Reading Room is open from 8:30 a.m. to 4:30 p.m., Monday through Friday, excluding legal holidays. The telephone number for the Reading Room is (202) 566–1742. A reasonable fee may be charged for copying.

2. Electronic Access. You may access this **Federal Register** document electronically through the EPA Internet under the **Federal Register** listings at *http://www.epa.gov/fedrgstr/*.

An electronic version of a portion of the public docket is available through EPA's electronic public docket and comment system, EPA Dockets. Interested persons may use EPA Dockets at *http://www.epa.gov/edocket/* to submit or view public comments, access the index listing of the contents of the official public docket, and access those documents in the public docket that are available electronically. Once in the system, select "search," then key in the appropriate docket identification number.

Certain types of information will not be placed in the EPA Dockets. Information claimed as CBI and other information whose disclosure is restricted by statute, which is not included in the official public docket, will not be available for public viewing in EPA's electronic public docket. EPA's policy is that copyrighted material will not be placed in EPA's electronic public docket but will be available only in printed, paper form in the official public docket. To the extent feasible, publicly available docket materials will be made available in EPA's electronic public docket. When a document is selected from the index list in EPA Dockets, the system will identify whether the document is available for viewing in EPA's electronic public docket. Although not all docket materials may be available electronically, you may still access any of the publicly available docket materials through the docket facility identified in section I.B.1. EPA intends to work towards providing electronic access to all of the publicly available docket materials through EPA's electronic public docket.

For additional information about EPA's electronic public docket visit EPA Dockets online or see 67 FR 38102, May 31, 2002.

C. Where Can I Obtain Additional Information?

In addition to being available in the docket, an electronic copy of this final action will also be available on the WWW. Following signature, a copy of the notice will be posted on the EPA's NSR page: http://www.epa.gov/nsr.

D. How Is This Preamble Organized?

The information presented in this preamble is organized as follows:

II. Background

For a brief history of the NSR rulemaking process that preceded today's final action, see our discussion at 68 FR 44623 (July 30, 2003). On December 31, 2002, we issued a final rule (67 FR 80186) that revised regulations governing the major NSR programs (final rules).[1] The revisions included five major changes to the major NSR program that will reduce burden, maximize operating flexibility, improve environmental quality, provide additional certainty, and promote administrative efficiency. These elements include baseline actual emissions, actual-to-projected-actual emissions methodology, plantwide applicability limitations (PALs), Clean Units, and pollution control projects (PCPs). The final rules also codified our longstanding policy regarding the calculation of baseline emissions for electric utility steam generating units (EUSGUs). In addition, the final action: (1) Responded to comments we received on a proposal to adopt a methodology, developed by the American Chemistry Council (formerly known as the Chemical Manufacturers Association (CMA)) and other industry petitioners, to determine whether a major stationary source has undertaken a major modification based on its potential emissions; and (2) included a new section that spells out in one place how a major modification is determined under the various major NSR applicability options. This topic had previously been addressed primarily in the definition section of the major NSR regulations. We also clarified where to find the provisions in the revised rules and codified a definition of "regulated NSR pollutant" that clarifies which pollutants are regulated under the Act for purposes of major NSR.

On February 28, 2003, we sent notice to affected States that, consistent with our proposal in 1996, we were revising the references to 40 CFR 52.21 in delegated States' plans to reflect the December 31, 2002 changes in the Prevention of Significant Deterioration (PSD) Federal Implementation Plan (FIP) (40 CFR 52.21(a)(2) and (b) through (bb)). This FIP applies in any area that does not have an approved PSD program in the State Implementation Plan (SIP), and in all Indian country. The notice was subsequently published in the **Federal Register** on March 10, 2003 (68 FR 11316).

Following publication of the December 31, 2002 and March 10, 2003 **Federal Register** notices, and prior to July 2003, the Administrator received numerous petitions, filed pursuant to section 307(d)(7)(B) of the CAA,

[1] The December 31, 2002 final rules did not act on several issues proposed in 1996. We intend to act on some or all issues from the 1996 proposal in subsequent **Federal Register** notices.

requesting reconsideration of many aspects of the final rules.[2]

On July 30, 2003 (68 FR 44624), we granted reconsideration on six issues raised by petitioners who had filed petitions prior to July 2003.[3] At that time, we did not act on any of the remaining issues in those petitions. Instead, we indicated that we planned to announce our final decision on whether to reconsider the remaining petition issues no later than 90 days after the publication of the **Federal Register** notice.

The first of the six issues on which we granted reconsideration involves a document we released in November 2002, entitled "Supplemental Analysis of the Environmental Impact of the 2002 Final NSR Improvement Rules."[4] Our purpose in granting reconsideration on this issue was to provide the public an opportunity to comment on our analysis and to submit any additional information that they believe to be relevant to the inquiry. The remaining issues for which we granted reconsideration involved five narrow aspects of the final rule as follows:

- Using potential-to-emit (PTE) to determine baseline actual emissions for an emissions unit on which actual construction began after the 24-month PAL baseline period when establishing a PAL;
- Eliminating synthetic minor limits [(r)(4) limits] under the PAL;
- Including a "reasonable possibility" requirement for triggering recordkeeping and reporting provisions;
- Using the actual-to-projected-actual test for replacement units; and,
- Effect of redesignation of an area from attainment to nonattainment on Clean Unit status.

We describe these issues at 68 FR 44624. For the reasons indicated at 68 FR 44624, we did not grant a stay of the final rules pending our reconsideration of these issues.

On August 14, 2003, we held a public hearing on the issues for which we granted reconsideration. Twenty-two individuals gave oral presentations at the hearing. The transcript of their comments is located in Docket OAR–2001–0004 (Legacy Number A–90–37), which can be accessed on the internet at *http://www.epa.gov/edocket.*

We provided a public comment period on the reconsideration issues that ended on August 29, 2003. For issues arising out of the August 14th public hearing, the comment period was extended until September 15, 2003. More than 400 written public comments on the reconsideration issues were received. The individual comment letters can be found in Docket OAR–2001–0004 (Legacy Number A–90–37).

III. Today's Action

At this time, we are announcing our final action after reconsideration of these six issues. We are also announcing our final decision on reconsideration of the remaining issues that were raised by the petitioners. Today, we are making available a document entitled, "Technical Support Document for Prevention of Significant Deterioration (PSD) and Non-attainment New Source Review (NSR): Reconsideration," EPA 456/R–03–005 (Technical Support Document). This document contains (1) a summary of comments received on the issues for which we granted reconsideration and our responses to these comments, and (2) a summary of petition issues for which we are not granting reconsideration, and our rationale for denying reconsideration. This document is available on our Web site at *http://www.epa.gov/nsr/;* and, through the National Technical Information Services, 5285 Port Royal Road, Springfield, VA 22161; telephone (800) 553–6846, e-mail *http://www.ntis.gov;* and, from the US EPA, Library Services, MD C267–01, Research Triangle Park, NC 27711, telephone (919) 541–2777, e-mail *library.rtp@epa.gov.*

A. Six Issues for Which Reconsideration Was Granted

We received numerous responses to our request for comment on the "Supplemental Analysis of the Environmental Impact of the 2002 Final NSR Improvement Rule." After carefully considering the information that was submitted, we have determined that none of the new information presented leads us to conclude that the analysis was incorrect or substantially flawed. Therefore, we are re-affirming the validity of the original conclusions. A summary of the comments received and our responses to these comments can be found in our Technical Support Document.

With respect to the five remaining issues on which we granted reconsideration, we have concluded that two clarifications to the underlying rules are warranted. These changes relate to issues raised as a result of our request for comment on: (1) Whether replacement units should be allowed to use the actual-to-projected-actual applicability test to determine whether installing a replacement unit results in a significant emissions increase; and, (2) using potential-to-emit (PTE) to determine the baseline actual emissions for an emissions unit on which construction began after the 24-month baseline period when establishing a PAL. As explained below, while we are not making any changes to the general approach in the final rules with respect to these issues, we are making two clarifying changes to the regulations. First, we are adding a definition of replacement unit to the final rules. Second, we are clarifying that the potential-to-emit approach for determining baseline actual emissions when establishing a PAL is only available to emissions units that are added to the major stationary source after the 24-month baseline period, and is not available to emissions units that existed during the baseline period whether or not they have been modified since that time.

We are not making any changes to the final rules with respect to eliminating synthetic minor limits [(r)(4) limits] under the PAL, the "reasonable possibility" requirement for triggering recordkeeping and reporting provisions, or the effect of redesignation of an area from attainment to nonattainment on Clean Unit status. Our reasons for this conclusion, and our response to significant comments received, are summarized in our Technical Support Document.

1. Replacement Units

[2] Petitions for reconsideration of the December 31, 2002 final rule that EPA received before July 2003 were filed by: Northeastern States (CT, ME, MD, MA, NH, NJ, NY, PA, RI, VT); South Coast Air Quality Management District (CA); and Environmental Groups (led by NRDC, Earthjustice, Clean Air Task Force, and Environmental Defense). Additional petitioners joined existing petitions: The People of California and California Air Resources Board (joined South Coast and Northeastern States petitions); Yolo-Solano Air Quality Management District (CA) (joined South Coast petition); Santa Barbara, Ventura, and Monterey Air Pollution Control Districts (CA); and Sacramento Air Quality Management District (CA) (joined South Coast petition). Petitions for reconsideration of the FIP rule were filed by: Delegated States (CA, CT, IL, MA, NJ, NY, DC, South Coast Air Quality Management District (CA), and Santa Barbara Air Pollution Control District (CA)); and Environmental Groups (essentially the same groups that filed petitions to reconsider the December 31, 2002 rule).

On July 11, 2003, we received another petition for reconsideration filed by Newmont USA Limited, dba Newmont Mining Corporation. This petition was subsequently joined by the National Cattlemen's Beef Association and the National Mining Association. We are not responding to that petition at this time, but will do so in the near future.

[3] In this notice, the term "petitioner" refers only to those entities that filed petitions for reconsideration with EPA prior to July 2003.

[4] Available through our NSR Web site at *http://www.epa.gov/nsr* and in Docket ID No. A–90–37, Document IV–A–7.

We have decided to continue to allow the owner or operator of a major stationary source (you) to use the actual-to-projected-actual applicability test to determine whether installing a replacement unit results in a significant emissions increase. However, as we reconsidered this issue and reviewed comments, we found one commenter that recommended that EPA include a definition of "replacement unit" in the regulations. The commenter asked that this definition describe how the replacement unit may differ from the replaced unit. The commenter also recommended that we indicate that the replaced unit must be removed from the site or rendered permanently inoperable.

We believe that the current rules, as supplemented by the discussion in the December 2002 preamble, are self-implementing for replacement units. Nevertheless, we agree with the commenter that a definition of "replacement unit" would render implementation easier. Thus, today we are adding regulatory language to further clarify our intentions regarding replacement units. Today's action revises the definition of "emissions unit" to clarify that a replacement unit is considered an existing emissions unit (*e.g.*, § 51.166(b)(7)(ii)) and therefore is eligible for the actual-to-projected-actual test for major NSR applicability determinations.

In addition, today's rule revisions add a definition of "replacement unit" that codifies longstanding policy and practice. In the preamble to the 1992 WEPCO rule, we first stated that we would "consider a unit to be replaced if it would constitute a reconstructed unit within the meaning of 40 CFR 60.15," which is the section of the New Source Performance Standards (NSPS) General Provisions that governs reconstruction. *See* 57 FR 32323, column 1. We have adopted this threshold in today's rule, by defining "replacement unit" to include reconstructed units, as well as emissions units that completely take the place of an existing emissions unit. *See, e.g.*, § 51.166(b)(32)(i).

We note that we have never considered "replacement units" to include replacements that significantly change the nature of the replaced unit; it is this inherent limitation that makes the application of the actual-to-projected-actual applicability test appropriate. It is reasonable to compare the baseline actual emissions from the replaced unit to the projected actual emissions of the replacement unit because the units are effectively the same existing emissions unit. Thus, consistent with the recently finalized equipment replacement exclusion provisions, the limiting principle here is that the replacement unit must be identical or functionally equivalent and must not change the basic design parameters of the affected process unit (*e.g.*, for EUSGUs this might mean heat input and fuel consumption specifications). *See, e.g.*, §§ 51.166(b)(32)(ii) and (iii). We also believe, however, that we need not and should not treat efficiency as a basic design parameter, as we do not believe major NSR was intended to impede industry in making energy and process efficiency improvements. We believe such improvements, on balance, will be beneficial both economically and environmentally.

We also believe that it has always been implicit in the concept of a replacement unit that the replaced unit must cease operation. Today's rule makes this principle explicit by requiring you to remove or permanently disable the replaced unit, or take a permit condition to permanently prohibit its operation. In general, if you bring the replaced unit back into operation, it must be treated as a new emissions unit, to which the actual-to-potential emissions test applies. *See, e.g.*, § 51.166(b)(32)(iv).

Finally, today's rule spells out that you cannot generate an emissions reduction credit from emissions reductions that are attributable to the shutdown of the replaced emissions unit. *See, e.g.*, § 51.166(b)(32). This provision addresses concerns about the possible double-counting of emissions reductions that could otherwise occur. Thus, if you use the baseline actual emissions of the replaced unit when applying the actual-to-projected-actual emissions test to measure the emissions increase resulting from the replacement unit, you cannot subsequently take credit for the emissions reductions that occur when you shut down the replaced unit. However, this provision is not intended to prevent you from generating creditable emissions reductions through other activities at the replacement unit. For example, you may be able to generate an emissions reduction credit if you reduce emissions by installing an inherently less-polluting replacement unit and accept an enforceable emission limitation that is lower than the baseline actual emissions of the replaced unit. Such an emissions reduction would be creditable if all other criteria for generating such credit are met.

2. Emission Units for Which You Began Actual Construction After the PAL Baseline Period

We have decided to retain the calculation method that uses potential-to-emit (PTE) to determine the baseline actual emissions for an emissions unit for which you began actual construction after the 24-month PAL baseline period when establishing a PAL. As we reconsidered this issue and reviewed comments, however, we decided it was appropriate to clarify that this method of calculation applies only to emissions units initially constructed after the PAL baseline period.

As reflected in the July 30, 2003 **Federal Register** notice, our intent was to limit the use of PTE to emissions units that were not in existence during the baseline period. We explained in the July notice that we included this provision, and the provision requiring the emissions of shut down units to be subtracted from the PAL level, "in recognition that the set of emissions units at your source at the time of PAL permit issuance may be different from the set of emissions units that existed during the baseline period. You may have constructed additional emissions units, permanently shut down previously existing emissions units, or both." *See* 68 FR 44625, column 3.

However, in providing for the inclusion of PTE for some units, the language of the rule referred only to "units on which actual construction began" after the PAL baseline period. *See, e.g.*, 40 CFR 52.21(aa)(6). "Construction" is defined as "any physical change or change in the method of operation (including fabrication, erection, installation, demolition, or modification of an emissions unit) which would result in a change in actual emissions." *See, e.g.*, 40 CFR 52.21(b)(8). Because the definition of "construction" encompasses modifications, we are concerned that, in the future, there might be confusion regarding the intended scope of this provision. It was not our intention to extend this provision to units that merely undergo a modification following the baseline period. Therefore, we are changing the rule language to explicitly exclude such units.

B. Remaining Issues in Petitions for Reconsideration

We deny the petitioners' requests for reconsideration on the remaining issues raised in the petitions, because they have failed to meet the standard for reconsideration under section 307(d)(7)(B) of the CAA. Specifically, the petitioners have failed to show: That it was impracticable to raise their objections during the comment period, or that the grounds for their objections arose after the close of the comment period; and/or that their concern is of central relevance to the outcome of the rule. We discuss our reasons for denying reconsideration in the Technical Support Document, which is available on our Web site at *http://www.epa.gov/nsr.*

IV. Statutory and Executive Order Reviews

On December 31, 2002, we finalized rule changes to the regulations governing the NSR programs mandated by parts C and D of title I of the Act. With today's action we are promulgating two minor clarifications to the final rules. Accordingly, we believe that the rationale provided with the final rules is still applicable and sufficient.

A. Executive Order 12866—Regulatory Planning and Review

Under Executive Order 12866 (58 FR 51735, October 4, 1993), the Agency must determine whether the regulatory action is "significant" and therefore subject to Office of Management and Budget (OMB) review and the requirements of the Executive Order. The Order defines "significant regulatory action" as one that is likely to result in a rule that may:

(1) Have an annual effect on the economy of $100 million or more or adversely affect in a material way the economy, a sector of the economy, productivity, competition, jobs, the environment, public health or safety, or State, local, or tribal governments or communities;

(2) Create a serious inconsistency or otherwise interfere with an action taken or planned by another agency;

(3) Materially alter the budgetary impact of entitlements, grants, user fees, or loan programs, or the rights and obligations of recipients thereof; or

(4) Raise novel legal or policy issues arising out of legal mandates, the President's priorities, or the principles set forth in the Executive Order.

Pursuant to the terms of Executive Order 12866, OMB has notified EPA that it considers this a "significant regulatory action" within the meaning of the Executive Order. EPA has submitted this action to OMB for review. Changes made in response to OMB suggestions or recommendations will be documented in the public record.

B. Paperwork Reduction Act

This action does not impose any new information collection burden. We are not promulgating any new paperwork (*e.g.*, monitoring, reporting, recordkeeping) as part of today's final action. The OMB has previously approved the information collection requirements contained in the existing regulations (40 CFR parts 51 and 52) under the provisions of the Paperwork Reduction Act, 44 U.S.C. 3501 *et seq.*, and has assigned OMB control number 2060–0003, EPA ICR number 1230.11. A copy of the OMB approved Information Collection Request (ICR) may be obtained from Susan Auby, Collection Strategies Division; U.S. Environmental Protection Agency (2822T); 1200 Pennsylvania Avenue, NW., Washington, DC 20460 or by calling (202) 566–1672.

Burden means the total time, effort, or financial resources expended by persons to generate, maintain, retain, or disclose or provide information to or for a Federal agency. This includes the time needed to review instructions; develop, acquire, install, and utilize technology and systems for the purposes of collecting, validating, and verifying information, processing and maintaining information, and disclosing and providing information; adjust the existing ways to comply with any previously applicable instructions and requirements; train personnel to be able to respond to a collection of information; search data sources; complete and review the collection of information; and transmit or otherwise disclose the information.

An agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless it displays a currently valid OMB control number. The OMB control numbers for EPA's regulations in 40 CFR are listed in 40 CFR part 9.

C. Regulatory Flexibility Analysis

The EPA has determined that it is not necessary to prepare a regulatory flexibility analysis in connection with this final rule.

For purposes of assessing the impacts of today's action on small entities, a small entity is defined as: (1) A small business that is a small industrial entity as defined in the U.S. Small Business Administration (SBA) size standards (*see* 13 CFR 121.201); (2) a small governmental jurisdiction that is a government of a city, county, town, school district, or special district with a population of less than 50,000; or (3) a small organization that is any not-for-profit enterprise that is independently owned and operated and is not dominant in its field.

After considering the economic impacts of today's action on small entities, EPA has concluded that this action will not have a significant economic impact on a substantial number of small entities. In determining whether a rule has a significant economic impact on a substantial number of small entities, the impact of concern is any significant adverse economic impact on small entities, since the primary purpose of the regulatory flexibility analyses is to identify and address regulatory alternatives "which minimize any significant economic impact of the proposed rule on small entities." 5 U.S.C. 603 and 604. Thus, an agency may conclude that a rule will not have a significant economic impact on a substantial number of small entities if the rule relieves regulatory burden, or otherwise has a positive economic effect, on all of the small entities subject to the rule. A Regulatory Flexibility Act Screening Analysis (RFASA), developed as part of a 1994 draft Regulatory Impact Analysis (RIA) and incorporated into the September 1995 ICR renewal analysis, showed that the changes to the NSR program due to the 1990 Clean Air Act amendments would not have an adverse impact on small entities. This analysis encompassed the entire universe of applicable major sources that were likely to also be small businesses (approximately 50 "small business" major sources). Because the administrative burden of the NSR program is the primary source of the NSR program's regulatory costs, the analysis estimated a negligible "cost to sales" (regulatory cost divided by the business category mean revenue) ratio for this source group. Currently, and as reported in the current ICR, there is no economic basis for a different conclusion.

We believe the rule changes in the December 31, 2002 final rule will reduce the regulatory burden associated with the major NSR program for all sources, including all small businesses, by improving the operational flexibility of owners and operators, improving the clarity of requirements, and providing alternatives that sources may take advantage of to further improve their operational flexibility. Today's action consists of two minor clarifications to the December 31, 2002 final rule and does not change our overall assessment of regulatory burden. We have therefore concluded that the rule changes in December 31, 2002 final rule, as clarified by today's action, will relieve regulatory burden for all small entities.

D. Unfunded Mandates Reform Act

Title II of the Unfunded Mandates Reform Act of 1995 (UMRA), Public Law 104–4, establishes requirements for Federal agencies to assess the effects of their regulatory actions on State, local, and tribal governments and the private sector. Under section 202 of the UMRA, EPA generally must prepare a written statement, including a cost-benefit analysis, for proposed and final rules with "Federal mandates" that may result in expenditures to State, local, and tribal governments, in the aggregate, or to the private sector, of $100 million or more in any 1 year. Before promulgating an EPA rule for which a written statement is needed, section 205 of the UMRA generally requires EPA to identify and consider a reasonable number of regulatory alternatives and adopt the least costly, most cost-effective or least burdensome alternative that achieves the objectives of the rule. The provisions of section 205 do not apply when they are inconsistent with applicable law. Moreover, section 205 allows EPA to adopt an alternative other than the least costly, most cost-effective or least burdensome alternative if the Administrator publishes with the final rule an explanation as to why that alternative was not adopted. Before EPA establishes any regulatory requirements that may significantly or uniquely affect small governments, including tribal governments, it must have developed under section 203 of the UMRA a small government agency plan.

The plan must provide for notifying potentially affected small governments, enabling officials of affected small governments to have meaningful and timely input in the development of EPA regulatory proposals with significant Federal intergovernmental mandates, and informing, educating, and advising small governments on compliance with the regulatory requirements.

We have determined that today's action does not contain a Federal mandate that may result in expenditures of $100 million or more for State, local, and tribal governments, in the aggregate, or the private sector in any 1 year. Although initially the changes in the December 31, 2002 final rule are expected to result in a small increase in the burden imposed upon reviewing authorities in order for them to be included in the State's SIP, as well as other small increases in burden discussed under "Paperwork Reduction Act" in the preamble to the December 31, 2002 final rule, those revisions will ultimately provide greater operational flexibility to sources permitted by the States, which will in turn reduce the overall burden of the program on State and local authorities by reducing the number of required permit modifications. In addition, we believe the 2002 rule changes will actually reduce the regulatory burden associated with the major NSR program by improving the operational flexibility of owners and operators, improving the clarity of requirements, and providing alternatives that sources may take advantage of to further improve their operational flexibility. Today's action does not increase regulatory burden but merely clarifies two aspects of the 2002 rule changes. Thus, today's action is not subject to the requirements of sections 202 and 205 of the UMRA. For the same reasons stated above, we have determined that today's action contains no regulatory requirements that might significantly or uniquely affect small governments. Thus, today's action is not subject to the requirements of section 203 of the UMRA.

E. Executive Order 13132—Federalism

Executive Order 13132, entitled "Federalism" (64 FR 43255, August 10, 1999), requires EPA to develop an accountable process to ensure "meaningful and timely input by State and local officials in the development of regulatory policies that have federalism implications." "Policies that have federalism implications" is defined in the Executive Order to include regulations that have "substantial direct effects on the States, on the relationship between the national government and the States, or on the distribution of power and responsibilities among the various levels of government."

Today's action does not have federalism implications. It will not have substantial direct effects on the States, on the relationship between the national government and the States, or on the distribution of power and responsibilities among the various levels of government, as specified in Executive Order 13132. While the final rule published on December 31, 2002 will result in some expenditures by the States, we expect those expenditures to be limited to $331,250 per year. This figure includes the small increase in the burden imposed upon reviewing authorities in order for them to revise the State's SIP. However, the revisions contained in the December 31, 2002 final rule provide greater operational flexibility to sources permitted by the States, which will in turn reduce the overall burden of the program on State and local authorities by reducing the number of required permit modifications. Today's action does not increase regulatory burden but merely clarifies two aspects of the December 31, 2002 final rule. Thus, Executive Order 13132 does not apply to today's action.

F. Executive Order 13175—Consultation and Coordination With Indian Tribal Governments

Executive Order 13175, entitled "Consultation and Coordination with Indian Tribal Governments" (65 FR 67249, November 9, 2000), requires EPA to develop an accountable process to ensure "meaningful and timely input by tribal officials in the development of regulatory policies that have tribal implications." Today's action does not have tribal implications as specified in Executive Order 13175. Thus, Executive Order 13175 does not apply to this action.

The purpose of the December 31, 2002 final rule is to add greater flexibility to the existing major NSR regulations. Those changes will benefit permitting authorities and the regulated community, including any major source owned by a tribal government or located in or near tribal land, by providing increased certainty as to when the requirements of the NSR program apply. Taken as a whole, the December 31, 2002 final rule should result in no added burden or compliance costs and should not substantially change the level of environmental performance achieved under the previous rules.

EPA anticipates that initially the changes in the December 31, 2002 final rule will result in a small increase in the burden imposed upon Reviewing Authorities in order for them to be included in the State's SIP. Nevertheless, those revisions will ultimately provide greater operational flexibility to sources permitted by the States, which will in turn reduce the overall burden of the program on State and local authorities by reducing the number of required permit modifications. In comparison, no tribal government currently has an approved tribal implementation plan (TIP) under the Clean Air Act to implement the NSR program. The Federal government is currently the NSR permitting authority in Indian country. Thus, tribal governments should not experience added burden from the December 31, 2002 final rule, nor should their laws be affected with respect to implementation of that rule. Additionally, although major stationary sources affected by the December 31, 2002 final rule could be located in or near Indian country and/or be owned or operated by tribal governments, such sources would not incur additional costs or compliance burdens as a result of that rule. Instead, the only effect on such sources should be the benefit of the added certainty and flexibility provided by that rule. For the reasons stated above, we do not believe that today's action, which clarifies two aspects of the December 31, 2002 final rule, would increase burden for tribal governments. In addition, we do not anticipate that today's action would have substantial direct effects on sources located in or near Indian country or sources owned or operated by tribal governments.

In our July 30, 2003 notice, EPA specifically solicited additional comment on today's final action from tribal officials.

G. Executive Order 13045—Protection of Children From Environmental Health Risks and Safety Risks

Executive Order 13045, entitled "Protection of Children from Environmental Health Risks and Safety Risks" (62 FR 19885, April 23, 1997), applies to any rule that: (1) Is determined to be "economically significant" as defined under Executive Order 12866; and (2) concerns an environmental health or safety risk that EPA has reason to believe may have a disproportionate effect on children. If the regulatory action meets both criteria, the Agency must evaluate the environmental health or safety effects of the planned rule on children, and explain why the planned regulation is preferable to other potentially effective and reasonably feasible alternatives considered by the Agency.

Today's action is not subject to the Executive Order because it is not economically significant as defined in Executive Order 12866, and because the Agency does not have reason to believe the environmental health or safety risks addressed by this action present a disproportionate risk to children. We believe that the December 31, 2002 final rule as a whole will result in equal or better environmental protection than provided by earlier regulations, and do so in a more streamlined and effective manner. Similarly, today's action merely clarifies two aspects of the December 31, 2002 final rule and does not change substantially the level of environmental protection provided by that rule. As a result, today's action is not expected to present a disproportionate environmental health or safety risk for children.

H. Executive Order 13211—Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use

Today's action is not a "significant energy action" as defined in Executive Order 13211, "Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use" (66 FR 28355, May 22, 2001) because it is not likely to have a significant adverse effect on the supply, distribution, or use of energy. The December 31, 2002 final rule improves the ability of sources to undertake pollution prevention or energy efficiency projects, switch to less polluting fuels or raw materials, maintain the reliability of production facilities, and effectively utilize and improve existing capacity. That rule also includes a number of provisions to streamline administrative and permitting processes so that facilities can quickly accommodate changes in supply and demand. It provides several alternatives that are specifically designed to reduce administrative burden for sources that use pollution prevention or energy efficient projects. Today's action merely clarifies two aspects of the December 31, 2002 final rule and thus is not likely to have a significant adverse effect on the supply, distribution, or use of energy.

I. National Technology Transfer and Advancement Act

Section 12(d) of the National Technology Transfer and Advancement Act of 1995 (NTTAA), Public Law 104–113, 12(d) (15 U.S.C. 272 note) directs EPA to use voluntary consensus standards in its regulatory activities unless to do so would be inconsistent with applicable law or otherwise impractical.

Voluntary consensus standards are technical standards (for example, materials specifications, test methods, sampling procedures, and business practices) that are developed or adopted by voluntary consensus standards bodies. The NTTAA directs EPA to provide Congress, through OMB, explanations when the Agency decides not to use available and applicable voluntary consensus standards.

Today's action does not involve technical standards. Therefore, EPA did not consider the use of any voluntary consensus standards.

J. Congressional Review Act

The Congressional Review Act, § 5 U.S.C. 801, *et seq.*, as added by the Small Business Regulatory Enforcement Fairness Act of 1996, generally provides that before a rule may take effect, the agency promulgating the rule must submit a rule report, which includes a copy of the rule, to each House of the Congress and to the Comptroller General of the United States. The EPA will submit a report containing the final rule and other required information to the United States Senate, the United States House of Representatives, and the Comptroller General of the United States prior to publication of the final rule in the **Federal Register**. A major rule cannot take effect until 60 days after it is published in the **Federal Register**. This action is not a "major rule" as defined by 5 U.S.C. § 804(2). The rule will be effective November 7, 2003.

V. Statutory Authority

The statutory authority for this action is provided by sections 101, 111, 114, 116, 301, and 307 of the CAA as amended (42 U.S.C. 7401, 7407, 7411, 7414, 7416, and 7601).

VI. Judicial Review

Under section 307(b)(1) of the Act, judicial review of the December 31, 2002 final rule is available only by the filing of a petition for review in the U.S. Court of Appeals for the District of Columbia Circuit by March 3, 2003. Any such judicial review is limited to only those objections that are raised with reasonable specificity in timely comments. Under section 307(b)(2) of the Act, the requirements that are the subject of the December 31, 2002 final rule may not be challenged later in civil or criminal proceedings brought by us to enforce these requirements.

List of Subjects in 40 CFR Parts 51 and 52

Environmental protection, Administrative practice and procedure, Air pollution control, Carbon monoxide, Hydrocarbons, Intergovernmental relations, Lead, Nitrogen oxides, Ozone, Particulate matter, Reporting and recordkeeping requirements, Sulfur oxides.

Dated: October 30, 2003.

Marianne Horinko,

Acting Administrator.

■ For the reasons set out in the preamble, title 40, chapter I of the Code of Federal Regulations is amended as follows:

PART 51—[AMENDED]

■ 1. The authority citation for part 51 continues to read as follows:

Authority: 23 U.S.C. 101; 42 U.S.C. 7401–7671q.

Subpart I—[Amended]

■ 2. Section 51.165 is amended:

■ a. By revising paragraph (a)(1)(vii)(B).

■ b. By adding paragraph (a)(1)(xxi).

■ c. By revising paragraph (f)(6).

The revisions read as follows:

§ 51.165 Permit requirements.

(a) * * *

(1) * * *

(vii) * * *

(B) An existing emissions unit is any emissions unit that does not meet the requirements in paragraph (a)(1)(vii)(A) of this section. A replacement unit, as defined in paragraph (a)(1)(xxi) of this section, is an existing emissions unit.

* * * * *

(xxi) *Replacement unit* means an emissions unit for which all the criteria listed in paragraphs (a)(1)(xxi)(A) through (D) of this section are met. No creditable emission reductions shall be generated from shutting down the existing emissions unit that is replaced.

(A) The emissions unit is a reconstructed unit within the meaning of § 60.15(b)(1) of this chapter, or the emissions unit completely takes the place of an existing emissions unit.

(B) The emissions unit is identical to or functionally equivalent to the replaced emissions unit.

(C) The replacement does not alter the basic design parameters (as discussed in paragraph (h)(2) of this section) of the process unit.

(D) The replaced emissions unit is permanently removed from the major stationary source, otherwise permanently disabled, or permanently barred from operation by a permit that is enforceable as a practical matter. If the replaced emissions unit is brought back into operation, it shall constitute a new emissions unit.

* * * * *

(f) * * *

(6) *Setting the 10-year actuals PAL level.* (i) Except as provided in paragraph (f)(6)(ii) of this section, the plan shall provide that the actuals PAL level for a major stationary source shall be established as the sum of the baseline actual emissions (as defined in paragraph (a)(1)(xxxv) of this section) of the PAL pollutant for each emissions unit at the source; plus an amount equal to the applicable significant level for the PAL pollutant under paragraph (a)(1)(x) of this section or under the Act, whichever is lower. When establishing the actuals PAL level, for a PAL pollutant, only one consecutive 24-month period must be used to determine the baseline actual emissions for all existing emissions units. However, a different consecutive 24-month period may be used for each different PAL pollutant. Emissions associated with units that were permanently shut down after this 24-month period must be subtracted from the PAL level. The reviewing authority shall specify a reduced PAL level(s) (in tons/yr) in the PAL permit to become effective on the future compliance date(s) of any applicable Federal or State regulatory requirement(s) that the reviewing authority is aware of prior to issuance of the PAL permit. For instance, if the source owner or operator will be required to reduce emissions from industrial boilers in half from baseline emissions of 60 ppm NO_X to a new rule limit of 30 ppm, then the permit shall contain a future effective PAL level that is equal to the current PAL level reduced by half of the original baseline emissions of such unit(s).

(ii) For newly constructed units (which do not include modifications to existing units) on which actual construction began after the 24-month period, in lieu of adding the baseline actual emissions as specified in paragraph (f)(6)(i) of this section, the emissions must be added to the PAL level in an amount equal to the potential to emit of the units.

* * * * *

■ 3. Section 51.166 is amended:

■ a. By revising paragraph (b)(7)(ii).

■ b. By adding paragraph (b)(32).

■ c. By revising paragraph (w)(6).

The revisions read as follows:

§ 51.166 Prevention of significant deterioration of air quality.

(b) * * *

(7) * * *

(ii) An existing emissions unit is any emissions unit that does not meet the requirements in paragraph (b)(7)(i) of this section. A replacement unit, as defined in paragraph (b)(32) of this section, is an existing emissions unit.

* * * * *

(32) *Replacement unit* means an emissions unit for which all the criteria listed in paragraphs (b)(32)(i) through (iv) of this section are met. No creditable emission reductions shall be generated from shutting down the existing emissions unit that is replaced.

(i) The emissions unit is a reconstructed unit within the meaning of § 60.15(b)(1) of this chapter, or the emissions unit completely takes the place of an existing emissions unit.

(ii) The emissions unit is identical to or functionally equivalent to the replaced emissions unit.

(iii) The replacement does not change the basic design parameter(s) (as discussed in paragraph (y)(2) of this section) of the process unit.

(iv) The replaced emissions unit is permanently removed from the major stationary source, otherwise permanently disabled, or permanently barred from operation by a permit that is enforceable as a practical matter. If the replaced emissions unit is brought back into operation, it shall constitute a new emissions unit.

* * * * *

(w) * * *

(6) *Setting the 10-year actuals PAL level.* (i) Except as provided in paragraph (w)(6)(ii) of this section, the plan shall provide that the actuals PAL level for a major stationary source shall be established as the sum of the baseline actual emissions (as defined in paragraph (b)(47) of this section) of the PAL pollutant for each emissions unit at the source; plus an amount equal to the applicable significant level for the PAL pollutant under paragraph (b)(23) of this section or under the Act, whichever is lower. When establishing the actuals PAL level, for a PAL pollutant, only one consecutive 24-month period must be used to determine the baseline actual emissions for all existing emissions units. However, a different consecutive 24-month period may be used for each different PAL pollutant. Emissions associated with units that were permanently shut down after this 24-month period must be subtracted from the PAL level. The reviewing authority shall specify a reduced PAL level(s) (in tons/yr) in the PAL permit to become effective on the future compliance date(s) of any applicable Federal or State regulatory requirement(s) that the reviewing authority is aware of prior to issuance of the PAL permit. For instance, if the source owner or operator will be required to reduce emissions from industrial boilers in half from baseline emissions of 60 ppm NO_X to a new rule limit of 30 ppm, then the permit shall contain a future effective PAL level that is equal to the current PAL level reduced by half of the original baseline emissions of such unit(s).

(ii) For newly constructed units (which do not include modifications to existing units) on which actual construction began after the 24-month period, in lieu of adding the baseline actual emissions as specified in paragraph (w)(6)(i) of this section, the emissions must be added to the PAL level in an amount equal to the potential to emit of the units.

* * * * *

PART 52—[AMENDED]

■ 1. The authority citation for part 52 continues to read as follows:

Authority: 42 U.S.C. 7401, *et seq.*

Subpart A—[Amended]

■ 2. Section 52.21 is amended:

■ a. By revising paragraph (b)(7)(ii).

■ b. By adding paragraph (b)(33).

■ c. By revising paragraph (aa)(6).

The revisions read as follows:

§ 52.21 Prevention of significant deterioration of air quality.

(b) * * *

(7) * * *

(ii) An existing emissions unit is any emissions unit that does not meet the requirements in paragraph (b)(7)(i) of this section. A replacement unit, as defined in paragraph (b)(33) of this section, is an existing emissions unit.

* * * * *

(33) *Replacement unit* means an emissions unit for which all the criteria listed in paragraphs (b)(33)(i) through (iv) of this section are met. No creditable emission reductions shall be generated from shutting down the existing emissions unit that is replaced.

(i) The emissions unit is a reconstructed unit within the meaning of § 60.15(b)(1) of this chapter, or the emissions unit completely takes the place of an existing emissions unit.

(ii) The emissions unit is identical to or functionally equivalent to the replaced emissions unit.

(iii) The replacement does not alter the basic design parameters (as discussed in paragraph (cc)(2) of this section) of the process unit.

(iv) The replaced emissions unit is permanently removed from the major stationary source, otherwise permanently disabled, or permanently barred from operation by a permit that is enforceable as a practical matter. If the replaced emissions unit is brought back into operation, it shall constitute a new emissions unit.

* * * * *

(aa) * * *

(6) *Setting the 10-year actuals PAL level.* (i) Except as provided in paragraph (aa)(6)(ii) of this section, the plan shall provide that the actuals PAL level for a major stationary source shall be established as the sum of the baseline actual emissions (as defined in paragraph (b)(48) of this section) of the PAL pollutant for each emissions unit at the source; plus an amount equal to the applicable significant level for the PAL pollutant under paragraph (b)(23) of this section or under the Act, whichever is lower. When establishing the actuals PAL level, for a PAL pollutant, only one consecutive 24-month period must be used to determine the baseline actual emissions for all existing emissions units. However, a different consecutive 24-month period may be used for each different PAL pollutant. Emissions associated with units that were permanently shut down after this 24-month period must be subtracted from the PAL level. The reviewing authority shall specify a reduced PAL level(s) (in tons/yr) in the PAL permit to become effective on the future compliance date(s) of any applicable Federal or State regulatory requirement(s) that the reviewing authority is aware of prior to issuance of the PAL permit. For instance, if the source owner or operator will be required to reduce emissions from industrial boilers in half from baseline emissions of 60 ppm NO_X to a new rule limit of 30 ppm, then the permit shall contain a future effective PAL level that is equal to the current PAL level reduced by half of the original baseline emissions of such unit(s).

(ii) For newly constructed units (which do not include modifications to existing units) on which actual construction began after the 24-month period, in lieu of adding the baseline actual emissions as specified in paragraph (aa)(6)(i) of this section, the emissions must be added to the PAL level in an amount equal to the potential to emit of the units.

[FR Doc. 03–28104 Filed 11–6–03; 8:45 am]

BILLING CODE 6560–50–P

FEDERAL COMMUNICATIONS COMMISSION

47 CFR Part 64

[CC Docket No. 98–67, DA 03–3109]

Telecommunication Relay Services and Speech-to-Speech Services for Individuals With Hearing and Speech Disabilities

AGENCY: Federal Communications Commission.

ACTION: Final rule; petition for reconsideration, comments requested.

SUMMARY: This document seeks public comment on petitions filed for reconsideration of certain rules adopted by the Commission in the *Second Improved TRS Order,* published at 68 FR 50973 (August 25, 2003). The petitions request that the Commission waive and reconsider its rules regarding the emergency call handling of TRS calls, and that the Commission waive its rules regarding three-way call processing at telecommunications relay centers.

DATES: Interested parties may file comments in this proceeding on or before October 20, 2003. Reply comments may be filed on or before October 30, 2003. Parties that may have already submitted comments in this proceeding need not resubmit those comments unless they choose to update them.

ADDRESSES: Federal Communications Commission, 445 12th Street, SW., Washington, DC 20554.

FOR FURTHER INFORMATION CONTACT: Dana Jackson, Consumer & Governmental Affairs Bureau, Disability Rights Office at (202) 418–2247 (voice), (202) 418–7898 (TTY), or e-mail at *Dana.Jackson@fcc.gov.*

SUPPLEMENTARY INFORMATION: When filing comments, please reference CC Docket No. 98–67. Comments may be filed using the Commission's Electronic Comment Filing System (ECFS) or by filing paper copies. *See* Electronic Filing of Documents in Rulemaking Proceedings, 63 FR 24121 (May 1, 1998). Comments filed through the ECFS can be sent as an electronic file via the Internet to *http://www.fcc.gov/e-file/ecfs.html.* Generally, only one copy of an electronic submission must be filed. If multiple docket or rulemaking numbers appear in the caption of this proceeding, however, commenters must transmit one electronic copy of the comments to each docket or rulemaking number referenced in the caption. In completing the transmittal screen, commenters should include their full name, Postal Service mailing address, and the applicable docket or rulemaking number. Parties may also submit an electronic comment by Internet e-mail. To get filing instructions for e-mail comments, commenters should send an e-mail to *ecfs@fcc.gov,* and should include the following words in the body of the message, "get form <your e-mail address>." A sample form and directions will be sent in reply.

Parties who choose to file by paper must file an original and four copies of each filing. If more than one docket or rulemaking number appears in the caption of this proceeding, commenters must submit two additional copies for each additional docket or rulemaking number. Filings can be sent by hand or messenger delivery, by commercial overnight courier, or by first-class or overnight U.S. Postal Services mail (although we continue to experience delays in receiving U.S. Postal Service mail). The Commission's contractor, Natek, Inc., will receive hand-delivered or messenger-delivered paper filings for the Commission's Secretary at 236 Massachusetts Avenue, NE., Suite 110, Washington, DC 20002. The filing hours at this location are 8 a.m. to 7 p.m. All hand deliveries must be held together with rubber bands or fasteners. Any envelopes must be disposed of before entering the building. Commercial overnight mail (other than U.S. Postal Service Express Mail and Priority Mail) must be sent to 9300 East Hampton

Federal Register

Tuesday,

December 31, 2002

Part III

Environmental Protection Agency

40 CFR Parts 51 and 52

Prevention of Significant Deterioration (PSD) and Nonattainment New Source Review (NSR); Final Rule and Proposed Rule

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Parts 51 and 52

[AD–FRL–7414–5]

RIN 2060–AE11

Prevention of Significant Deterioration (PSD) and Nonattainment New Source Review (NSR): Baseline Emissions Determination, Actual-to-Future-Actual Methodology, Plantwide Applicability Limitations, Clean Units, Pollution Control Projects

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule.

SUMMARY: The EPA is revising regulations governing the New Source Review (NSR) programs mandated by parts C and D of title I of the Clean Air Act (CAA or Act). These revisions include changes in NSR applicability requirements for modifications to allow sources more flexibility to respond to rapidly changing markets and to plan for future investments in pollution control and prevention technologies. Today's changes reflect EPA's consideration of discussions and recommendations of the Clean Air Act Advisory Committee's (CAAAC) Subcommittee on NSR, Permits and Toxics, comments filed by the public, and meetings and discussions with interested stakeholders. The changes are intended to provide greater regulatory certainty, administrative flexibility, and permit streamlining, while ensuring the current level of environmental protection and benefit derived from the program and, in certain respects, resulting in greater environmental protection.

EFFECTIVE DATE: This final rule is effective on March 3, 2003.

ADDRESSES: *Docket.* Docket No. A–90–37, containing supporting information used to develop the proposed rule and the final rule, is available for public inspection and copying between 8 a.m. and 4:30 p.m., Monday through Friday (except government holidays) at the Air and Radiation Docket and Information Center (6102T), Room B–108, EPA West Building, 1301 Constitution Avenue, NW., Washington, DC 20460; telephone (202) 566–1742, fax (202) 566–1741. A reasonable fee may be charged for copying docket materials. *Worldwide Web (WWW).* In addition to being available in the docket, an electronic copy of this final rule will also be available on the WWW through the Technology Transfer Network (TTN). Following signature, a copy of the rule will be posted on the TTN's policy and guidance page for newly proposed or promulgated rules: *http://www.epa.gov/ttn/oarpg.*

FOR FURTHER INFORMATION CONTACT: Ms. Lynn Hutchinson, Information Transfer and Program Integration Division (C339–03), U.S. EPA Office of Air Quality Planning and Standards, Research Triangle Park, North Carolina 27711, telephone 919–541–5795, or electronic mail at *hutchinson.lynn@epa.gov,* for general questions on this rule. For questions on baseline emissions determination or the actual-to-projected-actual applicability test, contact Mr. Dan DeRoeck, at the same address, telephone 919–541–5593, or electronic mail at *deroeck.dan@epa.gov.* For questions on Plantwide Applicability Limitations (PALs), contact Mr. Raj Rao, at the same address, telephone 919–541–5344, or electronic mail at rao.raj@epa.gov. For questions on Clean Units, contact Mr. Juan Santiago, at the same address, telephone 919–541–1084, or electronic mail at santiago.juan@epa.gov. For questions on Pollution Control Projects (PCPs), contact Mr. Dave Svendsgaard, at the same address, telephone 919–541–2380, or electronic mail at *svendsgaard.dave@epa.gov.*

SUPPLEMENTARY INFORMATION:

Regulated Entities

Entities potentially affected by this final action include sources in all industry groups. The majority of sources potentially affected are expected to be in the following groups.

Industry group	SIC[a]	NAICS[b]
Electric Services	491	221111, 221112, 221113, 221119, 221121, 221122
Petroleum Refining	291	32411
Chemical Processes	281	325181, 32512, 325131, 325182, 211112, 325998, 331311, 325188
Natural Gas Transport	492	48621, 22121
Pulp and Paper Mills	261	32211, 322121, 322122, 32213
Paper Mills	262	322121, 322122
Automobile Manufacturing	371	336111, 336112, 336712, 336211, 336992, 336322, 336312, 33633, 33634, 33635, 336399, 336212, 336213
Pharmaceuticals	283	325411, 325412, 325413, 325414

[a] Standard Industrial Classification
[b] North American Industry Classification System.

Entities potentially affected by this final action also include State, local, and tribal governments that are delegated authority to implement these regulations.

Outline. The information presented in this preamble is organized as follows:

I. Overview of Today's Final Action

A. Background

We[1] proposed revisions to the NSR rules in a notice published in the **Federal Register** on July 23, 1996 (61 FR 38250). On July 24, 1998, we published a notice (63 FR 39857) to solicit further comment on two specific aspects of the proposed revisions. Today's **Federal Register** action announces EPA's final action on the proposed revisions for baseline emissions determinations, the actual-to-future-actual methodology, actuals PALs, Clean Units, and PCPs. We have not made final determinations on any other proposed changes to the regulations.

Today's actions finalize these changes to the regulations for both the approval and promulgation of implementation plans and requirements for preparation, adoption, and submittal of implementation plans governing the NSR programs mandated by parts C and D of title I of the Act. We also proposed conforming changes to 40 CFR (Code of Federal Regulations) part 51, appendix S, and part 52.24. Today we have not included the final regulatory language for these regulations. It is our intention to include regulatory changes that conform appendix S and 40 CFR 52.24 to today's final rules in any final regulations that set forth an interim implementation strategy for the 8-hour ozone standard. We intend to finalize changes to these sections precisely as we have finalized requirements for other parts of the program. Because these are conforming changes and the public has had an opportunity for review and comment, we will not be soliciting additional comments before we finalize them.

The major NSR program contained in parts C and D of title I of the Act is a preconstruction review and permitting program applicable to new or modified major stationary sources of air pollutants regulated under the Act. In areas not meeting health-based National Ambient Air Quality Standards (NAAQS) and in ozone transport regions (OTR), the program is implemented under the requirements of part D of title I of the Act. We call this program the "nonattainment" NSR program. In areas meeting NAAQS ("attainment" areas) or for which there is insufficient information to determine whether they meet the NAAQS ("unclassifiable" areas), the NSR requirements under part C of title I of the Act apply. We call this program the Prevention of Significant Deterioration (PSD) program. Collectively, we also commonly refer to these programs as the major NSR program. These regulations are contained in 40 CFR 51.165, 51.166, 52.21, 52.24, and part 51, appendix S.

The NSR provisions of the Act are a combination of air quality planning and air pollution control technology program requirements for new and modified stationary sources of air pollution. In brief, section 109 of the Act requires us to promulgate primary NAAQS to protect public health and secondary NAAQS to protect public welfare. Once we have set these standards, States must develop, adopt, and submit to us for approval a State Implementation Plan (SIP) that contains emission limitations and other control measures to attain and maintain the NAAQS and to meet the other requirements of section 110(a) of the Act.

Each SIP is required to contain a preconstruction review program for the construction and modification of any stationary source of air pollution to assure that the NAAQS are achieved and maintained; to protect areas of clean air; to protect Air Quality Related Values (AQRVs) (including visibility) in national parks and other natural areas of special concern; to assure that appropriate emissions controls are applied; to maximize opportunities for economic development consistent with the preservation of clean air resources; and to ensure that any decision to increase air pollution is made only after full public consideration of all the consequences of such a decision.

For newly constructed, "greenfield" sources, the determination of whether an activity is subject to the major NSR program is fairly straightforward. The Act, as implemented by our regulations, sets applicability thresholds for major sources in nonattainment areas [potential to emit (PTE) above 100 tons per year (tpy) of any pollutant subject to regulation under the Act, or smaller amounts, depending on the nonattainment classification] and attainment areas (100 or 250 tpy, depending on the source type). A new source with a PTE at or above the applicable threshold amount "triggers," or is subject to, major NSR.

The determination of what should be classified as a modification subject to major NSR presents more difficult issues. The modification provisions of the NSR program in parts C and D are based on the definition of modification in section 111(a)(4) of the Act: the term "modification" means "any physical change in, or change in the method of operation of, a stationary source which increases the amount of any air pollutant emitted by such source or which results in the emission of any air pollutant not previously emitted." That definition contemplates that, first, you will determine whether a physical or operational change will occur. If so, then you will proceed to determine whether the physical or operational change will result in an emissions increase over baseline levels.

The expression "any physical change * * * or change in the method of operation" in section 111(a)(4) of the Act is not defined. We have recognized that Congress did not intend to make every activity at a source subject to the major NSR program. As a result, we have previously adopted several exclusions from what may constitute a "physical or operational change." For instance, we have specifically recognized that routine maintenance, repair and replacement, and changes in hours of operation or in the production rate are not considered a physical change or change in the method of

[1] In this preamble the term "we" refers to EPA and the term "you" refers to major stationary sources of air pollution and their owners and operators. All other entities are referred to by their respective names (for example, reviewing authorities.)

operation within the definition of major modification.[2]

We have likewise addressed the scope of the statutory definition of modification by excluding all changes that do not result in a "significant" emissions increase from a major source.[3] This regulatory framework applies the major NSR program at existing sources to only "major modifications" at major stationary sources.

One key attribute of the major NSR program in general is that you may "net" modifications out of review by coupling proposed emissions increases at your source with contemporaneous emissions reductions. Thus, under regulations we promulgated in 1980, you may modify, or even completely replace, or add, emissions units without obtaining a major NSR permit, so long as "actual emissions" do not increase by a significant amount over baseline levels at the plant as a whole.

Applicability of the major NSR program must be determined in advance of construction and is pollutant-specific. In cases involving existing sources, this requires a pollutant-by-pollutant determination of the emissions change, if any, that will result from the physical or operational change. Our 1980 regulations implementing the PSD and nonattainment major NSR programs thus inquire whether the proposed change constitutes a "major modification," that is, a physical change or change in the method of operation "that would result in a significant net emissions increase of any pollutant subject to regulation under the Act." A "net emissions increase" is defined as the increase in "actual emissions" from the particular physical or operational change (taking into account the use of emissions control technology and restrictions on hours of operation or rates of production where such controls and restrictions are enforceable), together with your other contemporaneous increases or decreases in actual emissions.[4] In order to trigger applicability of the major NSR program, the net emissions increase must be "significant."[5]

[2] *See* 40 CFR 52.21(b)(2).

[3] *See* 40 CFR 52.21(b)(23).

[4] In approximate terms, "contemporaneous" emissions increases or decreases are those that have occurred between the date 5 years immediately preceding the proposed physical or operational change and the date that the increase from the change occurs. *See*, for example, § 52.21(b)(3)(ii).

[5] Once a modification is determined to be major, the PSD requirements apply only to those specific pollutants for which there would be a significant net emissions increase. See, for example, § 52.21(j)(3) (BACT) and § 52.21(m)(1)(b) (air quality analysis).

Before today's changes, our regulations generally defined actual emissions as "the average rate, in tpy, at which the unit actually emitted the pollutant during a 2-year period which precedes the particular date and which is representative of normal source operation." The reviewing authorities will allow use of a different time period "upon a determination that it is more representative of normal source operation." We have historically used the 2 years immediately preceding the proposed change to establish a source's actual emissions. However, in some cases we have allowed use of an earlier period.

With respect to changes at existing sources, a prediction of whether the physical or operational change would result in a significant net increase in your actual emissions following the change was thus necessary. In part, this involved a straightforward and readily predictable engineering judgment—how would the change affect the emission factor or emissions rate of the emissions units that are to be changed.

Before today's changes, the regulations provided that when your emissions unit, other than an electric utility steam generating unit (EUSGU), "has not begun normal operations," actual emissions equal the PTE of the unit. When you have not begun normal operations following a change, you must assume that your source will operate at its full capacity year round, that is, at its full emissions potential. This is referred to as the actual-to-potential test. You may avoid the need for an NSR permit by reducing your source's potential emissions through the use of enforceable restrictions to pre-modification actual emissions levels plus an amount that is less than "significant".

In 1992, we promulgated revisions to our applicability regulations creating special rules for physical and operational changes at EUSGUs. *See* 57 FR 32314 (July 21, 1992).[6] In this rule, prompted by litigation involving the Wisconsin Electric Power Company (WEPCO) and commonly referred to as the "WEPCO rule," we adopted an actual-to-future-actual methodology for all changes at EUSGUs except the construction of a new electric generating unit or the replacement of an existing emissions unit. Under this methodology, the actual annual emissions before the change are compared with the projected actual emissions after the change to determine if a physical or operational change would result in a significant increase in emissions. To ensure that the projection is valid, the rule requires the utility to track its emissions for the next 5 years and provide to the reviewing authority information demonstrating that the physical or operational change did not result in an emissions increase.

[6] The regulations define "electric utility steam generating units" as any steam electric generating unit that is constructed for the purpose of supplying more than one-third of its potential electric output capacity and more than 25 megawatts (MW) of electrical output to any utility power distribution system for sale. *See*, for example, § 51.166(b)(30).

In promulgating the WEPCO rule, we also adopted a presumption that utilities may use as baseline emissions the actual annual emissions from any 2 consecutive years within the 5 years immediately preceding the change.

In attainment areas, once major NSR is triggered, you must, among other things, install best available control technology (BACT) and conduct modeling and monitoring as necessary. If your source is located in a nonattainment area, you must install technology that meets the lowest achievable emissions rate (LAER), secure emissions reductions to offset any increases above baseline emission levels, and perform other analyses.

B. Introduction

Today's final regulations were proposed as part of a larger regulatory package on July 23, 1996 (61 FR 38250). That package proposed a number of changes to our existing major NSR requirements. (Please refer to the outline of that proposed rulemaking for a complete list of changes that were proposed to our existing regulations.) On July 24, 1998, we published a **Federal Register** Notice of Availability (NOA) that requested additional comment on three of the proposed changes: determining baseline emissions, actual-to-future-actual methodology, and PALs. Following the 1996 proposals, we held two public hearings and more than 50 stakeholder meetings. Environmental groups, industry, and State, local, and Federal agency representatives participated in these many discussions.

In May 2001, President Bush's National Energy Policy Development Group issued findings and key recommendations for a National Energy Policy. This document included numerous recommendations for action, including a recommendation that the EPA Administrator, in consultation with the Secretary of Energy and other relevant agencies, review NSR regulations, including administrative interpretation and implementation. The recommendation requested that we issue a report to the President on the impact of the regulations on investment in new utility and refinery generation capacity, energy efficiency, and environmental protection.

In response, in June 2001, we issued a background paper giving an overview of the NSR program. This paper is available on the Internet at *http://www.epa.gov/air/nsr-review/background.html.* We solicited public comments on the background paper and other information relevant to the New Source Review 90-day Review and Report to the President. During our review of the NSR program, we met with more than 100 groups, held four public meetings around the country, and received more than 130,000 written comments. Our report to the President and our recommendations in response to the energy policy were issued on June 13, 2002. A copy of this information is available at *http://www.epa.gov/air/nsr-review/.* We expect that our recommendations in response to the energy policy will be reflected in the future in various programs and regulatory actions. Today's actions implement several of those recommendations.

Today, we are finalizing five actions that we previously proposed in 1996 (three of which were re-noticed in the 1998 NOA). We are not taking final action on any of the remaining issues in the 1996 proposal at this time. We have not decided what final action we will take on those issues.

C. Overview of Final Actions

Today we are taking final action on five changes to the NSR program that will reduce burden, maximize operating flexibility, improve environmental quality, provide additional certainty, and promote administrative efficiency. These elements include baseline actual emissions, actual-to-projected-actual emissions methodology, PALs, Clean Units, and PCPs. We are also codifying our longstanding policy regarding the calculation of baseline emissions for EUSGUs. In addition, we are responding to comments we received on a proposal to adopt a methodology, developed by the American Chemistry Council (formerly known as the Chemical Manufacturers Association (CMA)) and other industry petitioners, to determine whether a source has undertaken a modification based on its potential emissions. We are including a new section in today's final rules that outlines how a major modification is determined under the various major NSR applicability options and clarifies where you will find the provisions in our revised rules. Finally, we have codified a new definition of "regulated NSR pollutant" that clarifies which pollutants are regulated under the Act for purposes of major NSR.

This section briefly introduces each improvement. Detailed discussions of the improvements are found in sections II through VII of this preamble.

1. Determining Whether a Proposed Modification Results in a Significant Emissions Increase

Today we are finalizing two changes to our existing major NSR regulations that will affect how you calculate emissions increases to determine whether physical changes or changes in the method of operation trigger the major NSR requirements. First, we have a new procedure for determining "baseline actual emissions." That is, the relevant terminology for calculating pre-change emissions for most applications is now "baseline actual emissions" rather than "actual emissions." You may use any consecutive 24-month period in the past 10 years to determine your baseline actual emissions. Second, we are supplementing the existing actual-to-potential applicability test with an actual-to-projected-actual applicability test for determining if a physical or operational change at an existing emissions unit will result in an emissions increase. Notwithstanding the new test, you will still have the ability to conduct an actual-to-potential type test within the new actual-to-projected-actual applicability test. In this case, you will not be subject to recordkeeping requirements that are being established and would otherwise apply as part of the new actual-to-projected actual applicability test.

For EUSGUs, we are making several changes to the existing procedures and are codifying our current policy for calculating the baseline actual emissions. That is, the baseline actual emissions for EUSGUs is the average rate, in tpy, at which that unit actually emitted the pollutant during a 2-year (consecutive 24-month) period within the 5-year period immediately preceding when the owner or operator begins actual construction. We are also retaining the option that allows the use of a different time period if the reviewing authority determines it is more representative of normal source operation.

2. CMA Exhibit B

As described in section I.C.1 above, we have decided to adopt an actual-to-projected-actual methodology, combined with a revised process to determine baseline emissions, to use in determining when sources are considered to have made a modification and are thereby subject to NSR. We are not adopting the methodology based on potential emissions as discussed in the CMA Exhibit B proposal. *See* section III of this preamble for a discussion of the comments we received on this proposal and our responses.

3. Plantwide Applicability Limitations

A PAL is a voluntary option that will provide you with the ability to manage facility-wide emissions without triggering major NSR review. We believe that the added flexibility provided under a PAL will facilitate your ability to respond rapidly to changing market conditions while enhancing the environmental protection afforded under the program.

Today we are promulgating a PAL based on plantwide actual emissions. If you keep the emissions from your facility below a plantwide actual emissions cap (that is, an actuals PAL), then these regulations will allow you to avoid the major NSR permitting process when you make alterations to the facility or individual emissions units. In return for this flexibility, you must monitor emissions from all of your emissions units under the PAL. The benefit to you is that you can alter your facility without first obtaining a Federal NSR permit or going through a netting review. A PAL will allow you to make changes quickly at your facility. If you are willing to undertake the necessary recordkeeping, monitoring, and reporting, a PAL offers you flexibility and regulatory certainty.

4. Clean Units

We are promulgating a new type of applicability test for emissions units that are designated as Clean Units. The new applicability test recognizes that when you go through major NSR review and install BACT or LAER, you may make any changes to the Clean Unit without triggering an additional major NSR review, if the project at a Clean Unit does not cause the need for a change in the emission limitations or work practice requirements in the permit for the unit that were adopted in conjunction with BACT or LAER and the project would not alter any physical or operational characteristics that formed the basis for the BACT or LAER determination. If the project causes the need for a change in the emission limitations or work practice requirements in the permit for the unit adopted in conjunction with BACT or LAER or would alter any physical or operational characteristics that formed the basis for the BACT or LAER determination, you lose Clean Unit status. You may still proceed with the project without triggering major NSR review, if the increase is not a significant net emissions increase. Emissions units that have not been through major NSR may still qualify for Clean Unit status if they demonstrate that the emissions control level is comparable to BACT or LAER. Clean Unit status will be valid for up to a 10-year period. The new applicability test does not exclude consideration of physical changes or changes in the method of operation of Clean Units from major NSR, but rather changes the way emissions increases are calculated for these changes. This new applicability test therefore protects air quality, creates incentives for sources to install state-of-the-art controls, provides flexibility for sources, and promotes administrative efficiency.

5. Pollution Control Projects

Today's rule contains a new list of environmentally beneficial technologies that qualify as PCPs for all types of sources. Installation of a PCP is not subject to the major modification provisions. An owner or operator installing a listed PCP automatically qualifies for the exclusion if there is no adverse air quality impact—that is, if it will not cause or contribute to a violation of NAAQS or PSD increment, or adversely impact an AQRV (such as visibility) that has been identified for a Federal Class I area by a Federal Land Manager (FLM) and for which information is available to the general public. The PCPs that are not listed in today's rules may also qualify for the PCP Exclusion if the reviewing authority determines on a case-specific basis that a non-listed PCP is environmentally beneficial when used for a particular application. Also, in the future, we may add to the listed PCPs through a rulemaking that provides for public notice and opportunity for comment. The PCP Exclusion allows sources to install emissions controls that are known to be environmentally beneficial. These provisions thus offer flexibility while improving air quality.

6. Major NSR Applicability

We have briefly described the new provisions for baseline actual emissions, actual-to-projected-actual methodology, PALs, and Clean Units. Sections II, IV, and V describe the new provisions in detail. These provisions offer major new changes to NSR applicability, especially regarding how a major modification is determined. The major NSR applicability provisions have developed over time and therefore have been added to the NSR rules in a piecemeal fashion. In today's final rules we are including a new section that outlines how a major modification is determined under the various major NSR applicability options and clarifies where you will find the provisions in our revised rules. For each applicability option, we describe how a major modification is determined in detail. You'll find this new applicability "roadmap" in §§ 51.165(a)(2), 51.166(a)(7), and 52.21(a)(2). To summarize, the various provisions for major modifications are now as follows.

• Actual-to-projected-actual applicability test for all existing emissions units. (Including an actual-to-potential option)
• Actual-to-potential test for any new unit, including EUSGUs.
• The Clean Unit Test for existing emissions units with Clean Unit status.
• The hybrid test for modifications with multiple types of emissions units. (Used when a physical or operational change affects a combination of more than one type of unit.)

We describe actuals PALs, which are an alternative way of complying with major NSR, in section IV of this preamble. If you have a PAL, as long as you are complying with the PAL requirements, any physical or operational changes are not major modifications.

We have revised the definition of major modification to clarify what has always been our policy—that determining whether a major modification has occurred is a two-step process. The new definition of major modification is "any physical change in or change in the method of operation of a major stationary source that would result in: (1) A significant emissions increase of a regulated NSR pollutant; and (2) a significant net emissions increase of that pollutant from the major stationary source." We have also revised the definitions of actual emissions, emissions unit, net emissions increase, and construction. We have deleted the word "actual" as related to emissions from the definition of "construction." This change was necessary because of how the definition of "actual emissions" is used in the final rule, but the deletion is not intended to change any meaning in the term "construction." We have added new definitions for baseline actual emissions, projected actual emissions, project, and significant emissions increase. These revisions and additions implement our new provisions for major modifications under the actual-to-projected-actual applicability test, actual-to-potential test, Clean Unit Test, and hybrid test. You will find a complete discussion of the Clean Unit Test, including how modifications to Clean Units are treated, in section V of this preamble. The other tests are discussed in section II.

"Actual emissions," as the term has been historically applied, will still be used to determine air quality impacts (for example, compliance with NAAQS, PSD increments, and AQRVs) and to compute the required amount of emissions offsets.

To further clarify major NSR applicability in one location, we have moved § 51.166(i)(1) through (3) and § 52.21(i)(1) through (3) into the new applicability sections at § 51.166(a)(7) and § 52.21(a)(2). These provisions clarify that you must obtain a permit before you begin construction (including for major modifications), that the provisions apply for each regulated NSR pollutant that your source emits, and that the provisions apply to any source located in the area designated as attainment or unclassifiable (for §§ 51.166 and 52.21).

We have also added a new definition for reviewing authority that clarifies who has authority to implement major NSR programs. Reviewing authority means the State air pollution control agency, local agency, other State agency, Indian tribe, or other agency authorized by the Administrator to carry out a permit program under §§ 51.165 and 51.166, or the Administrator in the case of EPA-implemented permit programs under § 52.21.

7. Enforcement

As noted above, today we are taking final action on five changes to the NSR program that create alternative means of determining NSR applicability for projects that begin actual construction after these provisions become effective in your jurisdiction. If you are subsequently determined not to have met any of the obligations of these new alternatives (for example, failure to meet emissions or applicability limits, properly project emissions, and/or properly implement the PCP Exclusion or Clean Unit Test), you will be subject to any applicable enforcement provisions (including the possibility of citizens' suits) under the applicable sections of the Act. Sanctions for violations of these provisions may include monetary penalties of up to $27,500 per day of violation, as well as the possibility of injunctive relief, which may include the requirement to install air pollution controls.

8. Enforceability

This rule uses several terms related to enforceability of particular provisions. A requirement is "legally enforceable" if some authority has the right to enforce the restriction. Practical enforceability for a source-specific permit will be achieved if the permit's provisions specify: (1) A technically-accurate limitation and the portions of the source subject to the limitation; (2) the time period for the limitation (hourly, daily, monthly, and annual limits such as rolling annual limits); and (3) the method to determine compliance, including appropriate monitoring, recordkeeping, and reporting. For rules and general permits that apply to categories of sources, practicable enforceability additionally requires that the provisions: (1) Identify the types or categories of sources that are covered by the rule; (2) where coverage is optional, provide for notice to the permitting authority of the source's election to be covered by the rule; and (3) specify the enforcement consequences relevant to the rule.[7, 8] "Enforceable as a practical matter" will be achieved if a requirement is both legally and practically enforceable.

Note that we continue to require offsets to be federally enforceable. "Federal enforceability" means that not only is a requirement practically enforceable, as described above, but in addition, "EPA must have a direct right to enforce restrictions and limitations imposed on a source to limit its exposure to Act programs."[9] Also note that, for computing baseline actual emissions for use in determining major NSR applicability or for establishing a PAL, you must consider "legally enforceable" requirements. A requirement will be legally enforceable if the Administrator, State, local or tribal air pollution control agency has the authority to enforce the requirement irrespective of its practical enforceability.

In our existing regulations that are unamended by today's action, the term "federally enforceability" still appears. In 1995, the court in *Chemical Manufacturers Ass'n* v. *EPA* remanded the definition of PTE in the major NSR program to EPA. No. 89–1514 (D.C. Cir. Sept. 150 1995). Because the court vacated the requirements in the nationwide rules, the term federal enforceability as it relates to PTE is not in effect (pending final rule making by the Agency) in the Federal rules. The decision, however, did not address the term "federally enforceable" as used in SIPs, because that issue was not before the court.

II. Revisions to the Method for Determining Whether a Proposed Modification Results in a Significant Emissions Increase

A. Introduction

Today we are finalizing two sets of amendments to our existing major NSR regulations that provide another way in which you may calculate emissions increases to determine whether certain types of physical changes or changes in the method of operation (physical or operational changes) of an existing emissions unit trigger the major NSR requirements.[10] The first set of amendments relates to the way in which you will determine your baseline actual emissions for such emissions units in accordance with a new definition of "baseline actual emissions." *See,* for example, new § 52.21(b)(48). We will be allowing you to use any consecutive 24-month period during the 10-year period prior to the change to determine your baseline actual emissions for existing emissions units (other than EUSGUs). The second set of amendments replaces the existing actual-to-potential and actual-to-representative-actual-annual emissions applicability tests for existing emissions units (including EUSGUs) with an actual-to-projected-actual applicability test for determining if a physical or operational change will result in an emissions increase at such units. (Notwithstanding this new test, the actual-to-potential methodology is still available at your option under the new applicability tests.) The new procedure for determining your pre-change baseline actual emissions will not apply to EUSGUs.[11] Instead, for EUSGUs we are retaining the existing procedures for determining the baseline actual emissions.[12] *See,* for example, existing § 52.21(b)(33). We are also affirming our current method used for calculating the baseline actual emissions for EUSGUs (allowing any consecutive 2 years in the past 5 years, or another more representative period) by codifying it in the NSR regulations. *See,* for example, new § 52.21(b)(48).

For existing emissions units other than EUSGUs, the changes we are making to the method for calculating a unit's baseline actual emissions will apply only for the following three purposes.

- For modifications, to determine a modified unit's pre-change baseline actual emissions as part of the new actual-to-projected-actual applicability test.
- For netting, to determine the pre-change baseline actual emissions of an emissions unit that underwent a physical or operational change within the contemporaneous period.
- For PALs, to establish the PAL emissions cap.

Today's new procedures for calculating baseline actual emissions and for the actual-to-projected-actual applicability test should not be used when determining a source's actual emissions on a particular date as may be used for other NSR-related requirements. Such requirements include, but are not limited to, air quality impacts analyses (for example, compliance with NAAQS, PSD increments, and AQRVs) and computing the required amount of emissions offsets. For each of these requirements, the existing definition of "actual emissions" continues to apply. This is discussed in greater detail in section II.D.9.

We believe that these changes will greatly improve the major NSR program by responding to industry concerns with our existing methodology without compromising air quality. One common complaint about the current emissions baseline process is that you have a limited ability to consider the operational fluctuations associated with normal business cycles when establishing baseline actual emissions unless your reviewing authority agrees that another period is "more representative of normal source

[7] See memorandum, "Release of Interim Policy on Federal Enforceability of Limitations on Potential to Emit," signed by John Seitz and Robert Van Heuvelen, Jan. 22, 1996 at 5–6 and Attachment 4, available on the Web as *http://www.epa.gov/rgytgrnj/programs/artd/air/title5/t5memos/pottoemi.pdf.* More detailed guidance on practical enforceability is contained in the memorandum.

[8] The Agency has frequently used the term "practicably enforceable" and "practical enforceability," interchangeably. There is no difference in the meaning of these terms.

[9] *See* generally memorandum, "Options for Limiting the Potential to Emit (PTE) of a Stationary Source Under Section 112 and Title V of the Clean Air Act," signed by John Seitz and Robert Van Heuvelen, Jan. 25, 1995, at 2–3.

[10] By definition, the modification of an existing source is potentially subject to major NSR only if that existing source is "major." In addition, when an existing "minor" source makes a physical or operational change that by itself is major, that change constitutes a major stationary source that is subject to major NSR. *See,* for example, § 52.21(b)(1)(*c*).

[11] For NSR purposes, the definition of "electric utility steam generating unit" means any steam electric generating unit that is constructed for the purpose of supplying more than one-third of its potential electric output capacity and more than 25 MW electrical output to any utility power distribution system for sale. Any steam supplied to a steam distribution system for the purpose of providing steam to a steam electric generator that would produce electrical energy for sale is also considered in determining the electrical energy output capacity of the affected facility. See, for example, § 52.21(b)(31). Reference in this notice to utility units is meant to include all emissions units covered by this definition.

[12] We promulgated special applicability rules for physical and operational changes at EUSGUs in 1992. *See* 57 FR 32314 (July 21, 1992).

operation."[13] By extending the time period from which you may establish your baseline actual emissions, the new procedures should reflect the emissions levels that occur during a normal business cycle, without requiring you to demonstrate to your reviewing authority that another period is "more representative of normal source operations."

Commenters also believe that the current methodology requires many changes made to existing equipment to go through major NSR, without taking into account operating history, even when such changes will not result in increased pollution to the environment. Our new applicability requirements address these commenters' concerns and will focus limited resources more effectively.

We are also modifying the way you may determine whether emissions at existing units (including EUSGUs) will increase, by allowing you to use projected actual emissions for purposes of this determination. Under this approach, in circumstances where there is a reasonable possibility that a project that is not part of a major modification may result in a significant increase of a regulated NSR pollutant, before beginning actual construction, you may choose to make and record a projection of post-change emissions of that pollutant from changed units.[14]

To make this projection, you must use the maximum annual rate at which the changed units are projected to emit the pollutant in any of the 5 calendar years following the time the unit resumes regular operations after the project (or 10 years if the project increases the unit's design capacity or potential to emit the regulated NSR pollutant). You then use these projections to calculate whether the project will result in a significant emissions increase. In making this calculation, you could exclude any emissions that the unit could have accommodated before the change and that are unrelated to the project. You could also exclude emissions resulting from increased utilization due to demand growth that the unit could have accommodated before the change.

With respect to the covered changes, if you use this procedure, you are required to track post-change annual emissions of the units in tpy for the next 5 years (or 10 years if the project increases the unit's design capacity or potential to emit the regulated NSR pollutant). At the end of each year, if post-change annual emissions exceed the baseline actual emissions by a significant amount, and differ from your projections, you must submit a report to the reviewing authority with that information within 60 days after the end of the year.

Instead of relying on projected actual emissions, you may instead elect to use the unit's PTE, in tpy. In that case, you need not track or report post-change emissions.

We are also revising the procedures for projecting future emissions for EUSGUs to conform with these new procedures and consolidate the EUSGU and non-EUSGU procedures into a single set of provisions. As a result of our 1992 rulemaking, EUSGUs have available to them a similar set of procedures. We believe the procedures we are implementing for other units represent a sensible refinement of the rules we promulgated in 1992 and that we should make these procedures available to all existing units. We do, however, impose two requirements on EUSGUs beyond those we impose on other units. First, with respect to covered projects, EUSGUs that project post-change emissions will have to submit a copy of their projections to their reviewing authority before beginning actual construction. You will not be required to obtain any kind of determination from the reviewing authority before proceeding with construction. Second, we are requiring that if you project post-change emissions for your EUSGUs, you must send a copy of your tracked emissions to your reviewing authority, without regard to whether these emissions have increased by a significant amount or exceed your projections. The effect of this consolidation is that we make minor changes to the existing procedures for EUSGUs. For example, you must project emissions for EUSGUs on a 12-month basis, rather than the current approach of projecting average annual emissions for the 2 years immediately following the change. Also, you need only make and report a projection for EUSGUs when there is a reasonable possibility that the given project may result in a significant emissions increase.

By allowing you to use today's new version of the actual-to-projected-actual applicability test to evaluate modified existing emissions units, we expect that fewer projects will trigger the major NSR permitting requirements. Nonetheless, we believe that the environment will not be adversely affected by these changes and in some respects will benefit from these changes. The new test will remove disincentives that discourage sources from making the types of changes that improve operating efficiency, implement pollution prevention projects, and result in other environmentally beneficial changes. Moreover, the end result is that State and local reviewing authorities can appropriately focus their limited resources on those activities that could cause real and significant increases in pollution.

In addition, today's changes provide benefits to the public and the environment through the improved recordkeeping and reporting requirements as discussed above. We believe that these added recordkeeping and reporting measures will provide the information necessary for reviewing authorities to assure that such changes are made consistent with the CAA requirements. The new rule also does not affect the way in which a source's ambient air quality impacts are evaluated. Altogether, we believe that today's regulatory amendments focus on the types of changes occurring at existing emissions units that are more likely to result in significant contributions to air pollution.

B. What We Proposed and How Today's Action Compares

1. July 23, 1996 Notice of Proposed Rulemaking (NPRM)

In 1996, we proposed to amend the NSR rules to allow States to use, among other things, a new test as an alternative to the actual-to-potential test for determining the applicability of the NSR requirements when you wish to make modifications at an existing major stationary source. The proposed test was intended to apply exclusively to modifications of existing emissions units at major stationary sources—not to new emissions units. As described more completely below, the proposed test involved changes to the procedures for calculating an emissions unit's pre-change (baseline) actual emissions and post-change (future) actual emissions. The method would have also required you to monitor and report future emissions from certain modified

[13] The definition of "actual emissions" requires that a unit's actual emissions be based on a consecutive 24-month period immediately preceding the particular change. Also, however, it directs the reviewing authority to allow the use of another time period upon a determination that it is more representative. This procedure continues to be appropriate under the pre-existing regulation and for other NSR purposes, such as determining a source's ambient impact against the PSD increments, and we continue to require its use for such purposes.

[14] Note that we plan, in the near future, to issue a Notice of Proposed Rulemaking that will address the issue of "debottlenecking." In today's rulemaking, we do not intend to change current requirements related to "debottlenecking." Use of the term "changed unit" should not be interpreted as a change to those requirements.

emissions units, based on the monitoring and reporting requirements adopted under the WEPCO amendments.

Baseline actual emissions. In our 1996 NPRM, we proposed to change the definition of baseline emissions from the average annual rate of actual emissions during the 2-year period preceding the date of the modification to the annual rate associated with the highest level of utilization from any consecutive 12-month period during the 10-year period preceding the date of the modification, adjusted for any more stringent limits that may have been imposed since the end of the 12-month period selected. The proposed method was intended to be used for calculating baseline actual emissions for any existing emissions unit, including EUSGUs, by replacing both the original method (that was part of the actual-to-potential test) and the 2-in-5-years method (as adopted under the WEPCO for modified EUSGUs).

As indicated above, the proposed procedure also would have required you to take into account any legally enforceable constraints imposed on the facility since the selected 12-month time frame, and currently in effect. Thus, you would generally have been required to calculate the modified emissions unit's baseline actual emissions by using the appropriate utilization level from the selected 12-month period, in combination with the emissions unit's current enforceable emission factors. Such enforceable emission factors would have included current Federal and State limits, such as RACT (Reasonably Available Control Technology), MACT (Maximum Achievable Control Technology), BACT, LAER, and New Source Performance Standards (NSPS), as well as enforceable limits resulting from any voluntary reductions you may have taken (for example, for netting, offsets, or Emission Reduction Credits (ERCs)). Also, you would have had to consider any operational constraints that are enforceable, such as production limits, fuel use limits, or limits to the number of hours per day or days per year at which the unit modified, or affected by such modification, could operate.

Finally, we indicated that it was not our intent to extend the 5-year contemporaneous period (for considering creditable emissions increases and decreases as part of the netting calculus), even if we established a 10-year baseline look back period.

Post-change actual emissions. In the 1996 proposal, we proposed to extend the availability of the actual-to-future-actual emissions method, established under the WEPCO amendments exclusively for EUSGUs, to predict the future actual emissions from any emissions unit undergoing a physical or operational change. Thus, we proposed extending availability of the definition of "representative actual annual emissions" to all emissions units undergoing a physical or operational change. This definition would have provided the basis for you to project an emissions unit's future actual emissions, excluding any emissions increases caused by demand growth or other independent factors, when determining whether the change at issue will increase emissions over the baseline levels.[15]

The proposal also retained the WEPCO provision requiring that, for any modified emissions unit using the actual-to-future-actual test, you must submit annually for 5 years after the change sufficient records to demonstrate that the change has not resulted in a significant emissions increase over the baseline levels. As a safeguard, the WEPCO rule also provides that this tracking period could be extended to 10 years when the reviewing authority is concerned that the first 5 years will not be representative of normal source operation. We sought comments on numerous issues, including whether any changes should be made to the 5-year tracking requirement or to the demand growth exclusion in the event that we decided to broaden use of the actual-to-future-actual test for modifications to any existing emissions unit.

2. July 24, 1998 Notice of Availability

In 1998, we announced that comments received on the 1996 proposal and changed circumstances had caused us to ask whether we should reconsider some of the aspects of the proposed changes to the "major modification" applicability test. The 1998 NOA set forth for public comment an additional applicability test. In brief, the alternative presented for additional comment would have: (1) Retained the actual-to-future-actual test for EUSGUs and applied it to all source categories; (2) made binding for a 10-year period the emissions levels used in projecting future actual emissions following the modification for all source categories; and (3) eliminated the demand growth exclusion for calculating a modified emissions unit's future actual emissions.

Consistent with the 1996 NPRM, this alternative methodology would have applied to any existing emissions unit at a major stationary source for which you might plan a non-routine physical or operational change. The methodology would have required you first to determine which emissions units were being changed, or were affected by the change, then to calculate those units' baseline actual emissions based on the highest consecutive 12 months of source operation during the past 10 years, adjusted to reflect current emission factors.

The second step involved the forecast of future emissions resulting from the physical or operational change. Under this calculation of future actual emissions, one would not have been allowed to exclude predicted capacity utilization increases that were due to demand growth. If the difference between the pre-change and post-change actual emissions equaled or exceeded the significant emissions rate defined for a particular pollutant, major NSR would have been triggered (unless you took enforceable limits to keep the increase below significant levels or were otherwise able to net out of review using creditable, contemporaneous emissions increases and decreases occurring at your facility). If the difference between baseline and future actual emissions did not exceed the applicable significant emissions rate, your facility would not be subject to major NSR, but you would have been required to accept a temporary emissions cap based on the predicted future actual emissions for each affected pollutant at the emissions units being modified or affected by the modification.

The temporary cap would have become an enforceable condition of a preconstruction permit. Also, the sole purpose of the temporary cap would have been to make sure that the physical or operational change did not result in a significant emissions increase, and the cap would have applied to those emissions units for at least 10 years after the changes were completed. You would also have been required to supply information annually to demonstrate that the future actual emissions did not exceed the applicable emissions caps during the 10-year period following the modification.

3. Summary of Major Changes in the Final Rule

Today's action amends the existing NSR regulations to provide you with a common applicability test for all existing emissions units—the actual-to-projected-actual applicability test. This test has changed in some ways from both the 1996 NPRM and the 1998 NOA. As described in greater detail in sections

[15] This method, as well as the WEPCO amendments as a whole, was limited to modifications of existing EUSGUs and did not apply to the addition of a new emissions unit or the replacement of an existing unit.

II.C and II.D below, the key features of the methodology are as follows.

- If you are an existing emissions unit (other than an EUSGU), you will determine the pre-change (baseline) actual emissions by calculating an average annual emissions rate, in tpy, using any consecutive 24 months during the 10-year period immediately preceding the change. This rate must be adjusted downward to reflect any legally enforceable emission limitations imposed after the selected baseline period.
- We are codifying the "2-in-5-years" presumption for calculating the baseline actual emissions for EUSGUs.
- If you are an existing emissions unit (including EUSGUs), you will estimate post-change emissions (projected actual emissions), in tpy, to reflect any increase in annual emissions that may result from the proposed change. You should exclude, in calculating any increase in emissions that results from the particular project, that portion of the unit's emissions following the project that an existing unit could have accommodated during the baseline period and that is also unrelated to the particular project, including any increased utilization due to product demand growth. You must make the projection before you begin actual construction. When using this method, you must record the projection and certain other information in circumstances where there is a reasonable possibility that a change may result in a significant emissions increase. In addition, EUSGUs must send a copy of the projections and other information to your reviewing authority before beginning actual construction.
- If, for a project at an existing emissions unit (other than an EUSGU) at a major stationary source, you elect to project your post-change emissions, we are also requiring you to maintain information on these emissions, for 5 years following a physical or operational change, or in some cases for 10 years depending on the nature of the change. If your annual emissions exceed the baseline actual emissions by a significant amount and also exceed your projection, you must report this information to your reviewing authority within 60 days after the end of the year.
- If you project post-change emissions for EUSGUs, you must report these emissions to your reviewing authority within 60 days after the end of the year without regard to whether such emissions exceed the baseline actual emissions or projected actual emissions for a period of 5 years (or in some cases 10 years, depending on the nature of the change).
- Instead of projecting your post-change emissions, for all existing emissions units you may instead project post-change emissions on the basis of each unit's post-change PTE. If you use this method, you need not record your projections or track or report post-change emissions.

As discussed earlier, our prior regulations provide that when your emissions unit, other than an EUSGU, "has not begun normal operations, "actual emissions equal the PTE of the unit. There have been considerable number issues raised with this approach. For example, using PTE as a measure of post-change emissions automatically attributes all possible emissions increases to the change. There are many cases, however, where this simply is not true. Moreover, when the actual-to-potential test is applied, it is automatically assumed that the emissions unit has not begun normal operations after the change period. In many such cases, however, the changed unit as a practical matter will function essentially as it did before the change. We are, therefore, allowing all existing emissions units to use an actual-to-projected-actual applicability test. Accordingly, we are generally eliminating the term "begun normal operations" from the determination of whether a change results in a significant emissions increase.[16]

For essentially the same reasons, while our 1992 rules did not authorize use of projections in evaluating whether replacement of an existing emissions unit (which we understood to require application of the NSPS 50 percent cost threshold) constitutes a major modification, upon reflection we have decided this exception to the availability of the actual-to-projected-actual applicability test is also unnecessary. In our 1980 rulemaking, we decided against applying PSD to "reconstruction," even of entire sources, on the grounds that, as to existing sources that would not otherwise be subjected to PSD review as a major modification (*i.e.*, such source would not cause a significant net emissions increase), changes that had no emission consequences should not be subject to PSD regardless of their magnitude.[17]

In addition, we now believe that, as with modified units, the fact that replacement units are replacing similar units with a record of historical operational data provides sufficient reasons to believe that a projection of future actual emissions can be sufficiently reliable that an up-front emissions cap based on PTE is unnecessary. In other words, a source replacing a unit should be able to adequately project and track emissions for the replacement unit based, in part, on the operating history of the replaced unit. In contrast, sources adding "new" units that do not qualify as replacement units must project that the future emissions of the new unit equal its PTE, effectively applying the "actual-to-potential" test because there is no relevant historical data that could be used to establish an actual emissions baseline or projection of future actual emissions for such new units.

For these reasons, we have eliminated the requirement that replaced or reconstructed units be evaluated as to whether they constitute major modifications on an actual-to-potential basis. Instead, you may compare an emission unit's baseline actual emissions with your projected actual emission in measuring whether the replacement or reconstruction has resulted in a significant emissions increase. You must treat these emissions units as modifications only if the replacement or reconstruction of the unit results in a signficant increase so measured.[18]

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[16] We do make use of the term "resumes regular operations" (as opposed to "normal operations") in the final rule, but that term has a very different meaning and we are using it for an entirely different purpose. Specifically, we are not using the term for purposes of determining whether a change results in a significant emissions increase. Rather, we use it only to identify the date on which the owner or operator must begin tracking emissions of changed units when using the actual-to-projected-actual method.

[17] The 1980 rulemaking also discussed that "reconstruction" would have only been applied on a plantwide basis and EPA believed that there would be few instances of plantwide reconstructions.

[18] For simplicity, we state this rule without addressing whether the replacement or reconstruction has resulted in a significant net emissions increase, but under our two-step approach for evaluating whether a change constitutes a major modification, a significant net emissions increase would of course also be required. We have also retained the term "representative of normal operations" in the context of an EUSGU's option to seek use of a different baseline period, but there the question whether to seek such use is at the source's option, obviating many of the difficulties with it in other contexts.

C. Changes to the Procedures for Calculating the Pre-Change Baseline Actual Emissions for Existing Emissions Units Other Than EUSGUs

1. Under Today's New Requirements, How Should I Calculate the Pre-Change Baseline Actual Emissions for an Existing Emissions Unit That Is Not an EUSGU?

When you calculate the baseline actual emissions for an existing emissions unit (other than an EUSGU), you may select any consecutive 24 months of source operation within the past 10 years. Using the relevant source records for that 24-month period, including such information as the utilization rate of the equipment, fuels and raw materials used in the operation of the equipment, and applicable emission factors, you must be able to calculate an average annual emissions rate, in tpy, for each pollutant emitted by the emissions unit that is modified, or is affected by the modification.

The new requirements prohibit you from counting as part of the baseline actual emissions any pollution levels that are not allowed under any legally enforceable limitations and that apply at the time of the project. Therefore, you must identify the most current legally enforceable limits on your emissions unit. If these legally enforceable emission limitations and operating restrictions are more stringent than those that applied during the 24-month period, you must adjust downward the average annual emissions rate that you calculated from the consecutive 24-month period to reflect these current restrictions. (*See* section II.C.5 of this preamble for further discussion of the adjustment that you may need to make.)

In summary, when the average annual emissions rate that you originally calculated is still legally achievable (see discussion below), then your baseline actual emissions will be the same as the average annual emissions rate calculated from the 24-month period. If it is not, you must adjust it downward so that it does not reflect emissions that are no longer legally allowed.

2. Can Existing Emissions Units (Other Than EUSGUs) Still Use a "More Representative Time Period" for Selecting the Baseline Actual Emissions?

No, under today's new requirements neither you nor your reviewing authority will have the authority to select another period of time from which to calculate your baseline actual emissions. You must select a 24-month period within the 10-year period before the physical or operational change.

3. From What Point in Time Is the 10-Year Look Back Measured?

If you believe that you will need either a major or minor NSR permit to proceed with your proposed physical or operational change, then you must use the 10-year period immediately preceding the date on which you submit a complete permit application. If, however, you believe that the physical or operational change(s) you plan to make will not result in either a significant emissions increase from the project or a significant net emissions increase at your major stationary source (that is, your project will not be a major modification), and you are not otherwise required to obtain a minor NSR permit before making such change, then you must use the 10-year period that immediately precedes the date on which you begin actual construction of the physical or operational change.

4. What if, for an Existing Emissions Unit (Other Than an EUSGU), I Do Not Have Adequate Documentation for Its Operation for the Past 10 Years?

Your ability to use the full 10 years of the look back period will depend upon the availability of relevant data for the consecutive 24-month period you wish to select. The data must adequately describe the operation and associated pollution levels for the emissions units being changed. If you do not have the data necessary to determine the units' actual emission factors, utilization rate, and other relevant information needed to accurately calculate your average annual emissions rate during that period of time, then you must select another consecutive 24-month period within the 10-year look back period for which you have adequate data.

5. For an Existing Unit (Other Than EUSGUs), When Must I Adjust My Calculation of the Pre-Change Baseline Actual Emissions?

Today's amendments require you to adjust the average annual emissions rate derived from the selected 24-month period under certain circumstances. Specifically, you must adjust downward this average annual rate if any legally enforceable emission limitations, including but not limited to any State or Federal requirements such as RACT, BACT, LAER, NSPS, and National Emission Standards for Hazardous Air Pollutants (NESHAP), restrict the emissions unit's ability to emit a particular pollutant or to operate at levels that existed during the selected 24-month period from which you calculate the average annual emissions rate. For example, assume that during the selected consecutive 24-month period you burned fuel oil and you were subjected to a sulfur limit of 2 percent sulfur (by weight). Today, you are only allowed to burn fuel oil with a sulfur content of 0.5 percent or less. Consequently, you would be required to adjust your preliminary calculation of baseline actual emissions for sulfur dioxide (SO_2) (that is, substitute the lower sulfur limit into the emissions calculation, yielding a 75 percent reduction in the emissions rate from the initial calculation) to reflect the current restriction allowing only 0.5 percent sulfur in fuel oil. The original average annual utilization rate would not be adjusted unless a more stringent legally enforceable operational limitation has since been imposed that restricts that rate.

You must also adjust for legally enforceable emission limitations you may have voluntarily agreed to, such as limits you may have taken in your permit for netting, emissions offsets, or the creation of ERCs. Also, you must adjust your emissions from the 24-month period if a raw material you used during the baseline period is now prohibited. For example, you may have used a paint with a high solvent concentration during a portion of the consecutive 24-month period. Today, you are prohibited from using that particular paint. You must then adjust your emissions rate to reflect the raw material restriction.

6. How Should I Calculate the Baseline Actual Emissions for Emissions Units (Other Than EUSGUs) That Use Multiple Fuels or Raw Materials?

For an emissions unit that is capable of burning more than one type of fuel, you must relate the current emission factors to the fuel or fuels that were actually used during the selected 24-month period. For example, when calculating the baseline actual emissions for an emissions unit that burned natural gas for a portion of the 24-month period and fuel oil for the remainder, you must retain that fuel apportionment (for example, natural gas to fuel oil ratio), but you must also use the current legally enforceable emission factors for natural gas and fuel oil, respectively, to calculate the baseline actual emissions. If, however, you are no longer allowed or able to use one of those fuel types, then you must make your calculations assuming use of the currently allowed fuel for the entire 24-month period. You must use the same approach for emissions units that use multiple feedstock or raw materials, which may vary in use during the unit's ongoing production process.

7. How Should I Calculate the Baseline Actual Emissions for Construction Projects That Involve Multiple Units?

Today's new requirements require that you select the same single consecutive 24-month period within the 10-year look back period to calculate the baseline actual emissions for all existing emissions units that will be changed. *See,* for example, new § 52.21(b)(48)(ii)(*e*). The result will be that the baseline actual emissions for each affected pollutant will be based on the same consecutive 24-month period as well.

You will have the option to select the single 24-month period that best represents the collective level of operation (and emissions) for your existing emissions units.

If a particular existing emissions unit did not yet exist during the 24-month period you select to calculate the baseline actual emissions, you must count that emissions unit's emissions rate as zero for that full period of time. If an emissions unit operated for only a portion of the particular 24-month period that you select, you must calculate its average annual emissions rate using an emissions rate of zero for that portion of time when the unit was not in operation.

For new emissions units (a unit that has existed for less than 2 years) that will be changed by the project, the baseline actual emissions rate is zero if you have not yet begun operation of the unit, and is equal to the unit's PTE once it has begun to operate.

8. Am I Able To Apply Today's Changes for Calculating the Baseline Actual Emissions to Other Major NSR Requirements?

No, as stated in section II.A, you are only allowed to use the new baseline methodology in today's rule for three specific purposes involving existing emissions units as follows.

- For modifications, to determine a modified unit's pre-change baseline actual emissions as part of the new actual-to-projected-actual applicability test
- For netting, to determine the pre-change actual emissions of an emissions unit that underwent a physical or operational change within the contemporaneous period. You may select separate baseline periods for each contemporaneous increase or decrease.
- For PALs, to establish the PAL level.

If you determine that the modification of your source is a major modification, you must revert to using the existing definition of "actual emissions" to determine your source's actual emissions on a particular date to satisfy all other NSR permitting requirements, including any air quality analyses (for example, compliance with NAAQS, PSD increments, AQRVs) and the amount of emissions offsets required.

For example, when you must determine your source's compliance with the PSD increments following a major modification, you must still use the allowable emissions from each emissions unit that is modified, or is affected by the modification. An existing source's contribution to the amount of increment consumed should be based on that source's actual emissions rate from the 2 years immediately preceding the date of the change, although the reviewing authority shall allow the use of another 2-year period if it determines that such period is more representative of that source's normal operation. *See,* for example, § 52.21(b)(21)(ii).

Also, any determination of the amount of emissions offset that must be obtained by a major modification subject to the nonattainment NSR requirements under § 51.165(a) should be based on calculations using the existing definitions of "actual emissions" and "allowable emissions." See new § 51.165(a)(3)(ii)(H).

D. The Actual-to-Projected-Actual Applicability Test for Physical or Operational Changes to Existing Emissions Units Including EUSGUs

1. How are post-change actual emissions calculated under today's revised rule?

Today, we are amending the major NSR rules to enable you to use an applicability test that is similar to the applicability test that currently applies to EUSGUs (that is, the actual-to-representative-actual-annual emissions test). The new test allows you to project the post-change emissions of all modified existing emissions units (including EUSGUs) in the same manner. That is, under today's new provisions for non-routine physical or operational changes to existing emissions units, rather than basing a unit's post-change emissions on its PTE, you may project an annual rate, in tpy, that reflects the maximum annual emissions rate that will occur during any one of the 5 (or in some circumstances 10) years immediately after the physical or operational change. The first year begins on the day the emissions unit resumes regular operation following the change and includes the 12 months after this date. This projection of the unit's annual emissions rate following the change is defined as the "projected actual emissions" (see, for example, § 52.21(b)(48)), and will be based on your maximum annual rate in tons per year at which you are projected to emit a regulated NSR pollutant, less any amount of emissions that could have been accommodated during the selected 24-month baseline period and is not related to the change. Accordingly, you will calculate the unit's projected actual emissions as the product of: (1) The hourly emissions rate, which is based on the emissions unit's operational capabilities following the change(s), taking into account legally enforceable restrictions that could affect the hourly emissions rate following the change(s); and (2) the projected level of utilization, which is based on both the emissions unit's historical annual utilization rate and available information regarding the emissions unit's likely post-change capacity utilization. In calculating the projected actual emissions, you should consider both the expected and the highest projections of the business activity that you expect could be achieved and that are consistent with information your company publishes for business-related purposes such as a stockholder prospectus, or applications for business loans. From the initial calculation, you may then make the appropriate adjustment to subtract out any portion of the emissions increase that could have been accommodated during the unit's 24-month baseline period and is unrelated to the change. Once the appropriate subtractions have been made, the final value for the projected actual emissions, in tpy, is the value that you compare to the baseline actual emissions to determine whether your project will result in a significant emissions increase.

The adjustment to the projected actual emissions allows you to exclude from your projection only the amount of the emissions increase that is not related to the physical or operational change(s). In comparing your projected actual emissions to the units' baseline actual emissions, you only count emissions increases that will result from the project. For example, as with the electric utility industry, you may be able to attribute a portion of your emissions increase to a growth in demand for your product if you were able to achieve this higher level of production during the consecutive 24-month period you selected to establish the baseline actual emissions, and the increased demand for the product is unrelated to the change.

For Clean Units, if a given project can be constructed and operated at a Clean Unit without causing the emissions unit to lose its Clean Unit status, then no emissions increase will occur.

For new units, however, you must continue to calculate post-change emissions on the basis of a unit's PTE.

2. Will My Projection of Projected Actual Emissions Become an Enforceable Emission Limitation as Suggested in the 1998 NOA?

No, we did not adopt such a requirement. If you have an existing emissions unit and your project results in an increase in annual emissions that exceeds the baseline actual emissions by a significant amount, and differs from your projection of post-change emissions that you were required to calculate and maintain records of, then you must report this increase to your reviewing authority within 60 days after the end of the year. Since modified EUSGUs are required to report their post-change annual emissions to the reviewing authority annually, any occurrence of a significant increase will be covered under that report for the affected calendar year. *See* section II.D.6 of this preamble for a more detailed discussion of the reporting requirements.

3. How Do I Determine How Long My Post-Change Emissions Will Be Tracked To Ensure That My Project Is Not a Major Modification?

Generally, your projected actual emissions must be tracked against your facility's post-change emissions for 5 years following resumption of regular operations whether you are an EUSGU or other type of existing emissions unit. We will presume that any increases that occur after 5 years are not associated with the physical or operational changes. However, you may be required to track emissions for a longer period of time under the following circumstances. If you are an existing emissions unit and one of the effects of your physical or operational change(s) is to increase a unit's design capacity or PTE, you must track your emissions for a period of 10 years after the completion of the project. This extended period allows for the possibility that you could end up using the increased capacity more than you projected and such use might lead to significant emissions increases.

4. What Are the Reporting and Recordkeeping Requirements for Projects?

Reporting and recordkeeping for a project is required when three criteria are met: (1) You elect to project post-change emissions rather than use PTE; (2) there is a reasonable possibility that the project will result in a significant emissions increase; and (3) the project will not constitute a major modification. In such circumstances, you must document and maintain a record of the following information: a description of the project; an identification of emissions units whose emissions could increase as a result of the project; the baseline actual emissions for each emissions unit; and your projected actual emissions, including any emissions excluded as unrelated to the change and the reason for the exclusion. In addition, if your project increase is significant, you must record your netting calculations if you use emissions reductions elsewhere at your major stationary source to conclude that the project is not a major modification. For covered projects, you must record this information before beginning actual construction. If you are an EUSGU, you must also send this information to your reviewing authority before beginning actual construction. Note, however, that if you chose to use potential emissions as your projection of post-change emissions, you are not required to maintain a record of this decision.

In addition, today's final rules require you to maintain emissions data for all emissions units that are changed by the project. You must maintain this information for 5 years, or 10 years if applicable. The information you must maintain may include continuous emissions monitoring data, operational levels, fuel usage data, source test results, or any other readily available information of sufficient accuracy for the purpose of determining an emissions unit's post-change emissions.

If you are an EUSGU, you must report this information to your reviewing authority within 60 days after the end of any year in which you are required to generate such information. Other existing units must report to the reviewing authority any increase in the post-change annual emissions rate when that rate: (1) Exceeds the baseline actual emissions by a significant amount, and (2) differs from the projection that was calculated before the change. See, for example, new § 52.21(r)(6)(iii).

In addition to the reporting requirements discussed above, you are also obligated to ensure that the necessary emissions information you are required to maintain is available for examination upon request by the reviewing authority or the general public.

5. How Do Today's Changes Affect the Netting Methodology for Existing Emissions Units (Other Than EUSGUs)?

If your calculations show that a significant emissions increase will result from a modification, you have the option of taking into consideration any contemporaneous emissions changes that may enable you to "net out" of review, that is, show that the net emissions increase at the major stationary source will not be significant. The contemporaneous time period will not change under the Federal PSD program as a result of today's action. That is, creditable increases and decreases in emissions that have occurred between the date 5 years before construction of the particular change commences and the date the increase from that change occurs are contemporaneous. *See* § 52.21(b)(3)(ii). States will continue to have some discretion in defining "contemporaneous" for their own NSR programs.

Although we are not changing our definition of "contemporaneous," today's action allows existing emissions units (other than EUSGUs) to calculate the baseline actual emissions for each contemporaneous event using the 10-year look back period. That is, you can select any consecutive 24-month period during the 10-year period immediately preceding the change occurring in the contemporaneous period to determine the baseline actual emissions for each creditable emissions change. Generally, for each emissions unit at which a contemporaneous emissions change has occurred, you should use the 10-year look back period relevant to that change.[19] When evaluating emissions increases from multi-unit modifications, if more than one emissions unit was changed as part of a single project during the contemporaneous period, you may select a separate consecutive 24-month period to represent each emissions unit that is part of the project. In any case, the calculated baseline actual emissions for each emissions unit must be adjusted to reflect the most current emission limitations (including operational restrictions) applying to that unit. "Current" in the context of a contemporaneous emissions change refers to limitations on emissions and source operation that existed just prior to the date of the contemporaneous change.

E. Clarifying Changes to WEPCO Provisions for EUSGUs

The method you use to calculate the baseline actual emissions for an existing EUSGU to determine whether there is a

[19] Your ability to use the full 10 years for calculating any contemporaneous emissions change is contingent upon the availability of valid and sufficient source information for the selected 24-month period. *See*, for example, new § 52.21(b)(48)(ii)(*f*).

significant emissions increase from a physical or operational change at an EUSGU, and to determine whether a significant net emissions increase will occur at the major stationary source, will not change as a result of today's final rulemaking. The rule provides that for an existing EUSGU you may calculate the baseline actual emissions as the average annual emissions (tpy) of the emissions unit using any 2-year period out of the 5 years immediately preceding the modification. (This was set out as a presumption in the preamble for the 1992 WEPCO amendments.) This rule recognizes the ordinary variability in demand for electricity. *See,* for example, new § 52.21(b)(21)(ii).

For example, a cold winter or hot summer will result in high levels of demand while a relatively mild year will produce lower demand. By allowing a utility to use any consecutive 2 years within the past 5, the rule recognizes that electricity demand and resultant utility operations fluctuate in response to various factors such as annual variability in climatic or economic conditions that affect demand, or changes at other plants in the utility system that affect the dispatch of a particular plant. By allowing utilities to use as a baseline any consecutive 2 years in the last 5 years, these types of fluctuations in operations can be more realistically considered.

The reviewing authority shall allow the use of a different time period upon a determination that it is more representative of normal source operation.

In an August 6, 2001 letter,[20] we addressed the issue of whether combined cycle gas turbines (the gas turbines and waste heat recovery components) came within the definition of "electric utility steam generating units" for the purpose of determining whether such units are eligible to use the WEPCO "applicability test." The letter concluded that "steam generating units" include not only electric utility plants with boilers, but also plants with combined cycle gas turbines if the combined cycle gas turbine systems supply more than one-third of their potential electric output capacity and more than 25 MW electrical output to any utility power distribution system for sale. Consequently, qualifying combined cycle gas turbines must also use the 2-in-5-years baseline method.

[20] Letter from John S. Seitz, Director, Office of Air Quality Planning and Standards, to Patrick M. Raher, August 6, 2001.

Finally, today's rules provide the same method for EUSGUs that will exist for all other existing emissions units to project post-change emissions following a physical or operational change to a unit. In the 1996 proposal, we proposed a range of options for addressing the applicability of changes that are made to existing emissions units, including the option of extending the actual-to-future-actual test, then available only to utilities, to all source categories. While we have decided to leave the WEPCO rules intact in most respects, we believe that it is reasonable and appropriate to establish a consistent method for sources to use for projecting the post-change emissions that will result from a physical or operational change to an existing emissions unit. Therefore, under today's new rules, the current method of basing the projection on the 2 years following the change to an EUSGU is being replaced with the method available to all other existing units, under which you project a unit's post-change emissions as the maximum annual rate that the unit will emit in any one of the 5 years following resumption of regular operations.

F. The "Hybrid" Applicability Test for Projects Affecting Multiple Types of Emissions Units

1. When Does the Hybrid Applicability Test Apply to You?

The hybrid applicability test applies if you plan a project (or series of related projects) that will affect emissions units of two or more of the following types.

- Existing emissions units
- New emissions units
- Clean Units

2. How Do I Determine Whether My Project Will Result in a Significant Emissions Increase Under the Hybrid Test?

For the first two types of emissions units listed above that are affected by the project, calculate the emissions increase as we have discussed previously in this preamble. That is, use the actual-to-projected-actual applicability test for existing units and the actual-to-potential test for new emissions units.

Clean Units are discussed fully in section V of this preamble. If a given project can be constructed and operated at a Clean Unit without causing the emissions unit to lose its Clean Unit status, no emissions increase shall be deemed to occur at that Clean Unit. If a given project would cause the emissions unit to lose its Clean Unit status, then the increase in emissions should be calculated as if the emissions unit is not a Clean Unit.

After you calculate the emissions increase for each relevant unit, total the increases across all the emissions units of all types. If this total emissions increase equals or exceeds the level defined as significant for the regulated NSR pollutant in question, the project will result in a significant emissions increase for that pollutant. You'll find the regulatory language for determining whether a project will result in a significant emissions increase at §§ 51.165(a)(2)(vii)(D), 51.166(a)(7)(vi)(*d*), and 52.21(a)(2)(vi)(*d*).

In section II.C.8 of this preamble, we indicate that the baseline actual emissions for all units that are not EUSGUs that are changed by a project must be calculated based on the same consecutive 24-month period within the previous 10 years. The same principle applies under the hybrid test, but it can be slightly more complicated if both EUSGUs and non-EUSGUs are involved. In this case, you must use the same baseline period for all emissions units affected by the project. This baseline period must be selected so as to meet the requirements for both EUSGUs and non-EUSGUs. Thus, you must select a 2-year period out of the previous 5 years for your baseline period, as required for EUSGUs (and within the requirements for non-EUSGUs). If you wish to use another period that you believe is more representative (as allowed for EUSGUs), the entire period must fall within the previous 10 years (as required for non-EUSGUs).

3. How Do I Determine the Net Emissions Increase From My Project Under the Hybrid Test?

If you conclude that a significant emissions increase will result from the proposed project, you have the option of taking into consideration any contemporaneous emissions changes that may enable you to "net out" of review, that is, show that the net emissions increase at the major stationary source will not be significant. The netting analysis is carried out under the hybrid test just as it is under the other applicability tests. Refer to section II.D.7 of this preamble for a discussion of netting methodology.

G. Legal Basis for Today's Action

The Act defines modification for the purposes of PSD and nonattainment NSR through cross-reference to the NSPS definition of "modification." The NSPS definition states that a modification "means any physical change in, or change in the method of operation of, a stationary source which increases the amount of any air pollutant emitted by such source or which results in the emission of any air pollutant not previously emitted." CAA section 111(a)(4), 42 U.S.C. 7411(a)(4). The Act is silent, however, on the issue of how one is to determine whether a physical or operational change increases the amount of any air pollutant emitted by the source.

Accordingly, EPA is exercising its discretion in interpreting and providing clarity to this issue. We believe that the rules set forth today are "a permissible construction of the statute." *Chevron U.S.A., Inc.* v. *NRDC,* 467 U.S. 843–4 (1984). The reviewing court should defer to it. *Id.* at 837.

In the NSPS program, we determine whether there has been an "increase in any air pollutant emitted" by the source by comparing its maximum hourly achievable emissions before and after the change. EPA and the courts have recognized, however, that the NSR programs and the NSPS programs have different goals,[21] and thus, we have utilized different emissions tests in the NSR programs. Prior to today, the regulations applied an actual-to-future-actual applicability test for EUSGUs and an actual-to-potential applicability test for all other emissions units. Today, we are establishing a new applicability test for calculating emissions increases for "Clean Units" and an actual-to-projected-actual applicability test for all other emissions units. We believe that establishing an actual-to-projected-actual applicability test for all emissions units is a reasonable interpretation of the phrase "increase of any pollutant emitted."[22]

H. Response to Comments and Rationale for Today's Actions

We received numerous comments on our proposed rule regarding the calculation of the baseline actual emissions and the actual-to-future-actual test. Some of the significant comments and our responses to them are provided below. A complete set of comments and our responses can be found in the Technical Support Document located in the docket for this rulemaking.

1. Why Are We Extending the Look Back Period for Determining the Baseline Actual Emissions to 10 Years?

Most commenters generally support our proposal to allow owners and operators to use a 10-year look back period to determine the baseline actual emissions for modifications at any existing emissions unit. Commenters have various reasons for supporting or opposing the proposed approach. Many supporters agree that extending the baseline look back period to 10 years would simplify current regulations and provide certainty to sources who otherwise would have to demonstrate to the reviewing authority that a period other than the 2 years immediately preceding the proposed change was more representative of normal source operation. Some commenters support the proposal because it would prevent the perceived confiscation of underused capacity at sources that have had low utilization rates for an extended period. These commenters agree that a 10-year look back period is more likely to afford a source a baseline actual emissions calculation that best reflects representative source operating conditions and would also account for fluctuations in the business cycle.

Some commenters criticize the proposed 10-year look back period as being too long. These commenters recommend either a 5-year or 2-year look back period. One of these commenters states that the 10-year look back creates the opportunity for a source to increase production to the 10-year maximum, and prevents the State or local air regulators from addressing the increase in emissions. Thus, the commenter believes that sources would be allowed to use historic emissions levels that are higher than current levels to establish the baseline actual emissions. Some commenters add that the proposed change would not reduce program complexity.

Some commenters believe that instead of extending the period for establishing baseline actual emissions, the test for establishing modifications should be changed. According to the commenters, the problem is not that the current system does not go back far enough to set a fair actual emissions baseline, but that the methodology does not account for the fact that most emissions units are operating at an activity level much lower than the allowed activity level. The commenters believe that many of the real problems associated with the current major modification applicability test would be eliminated if the procedure was modified in an equitable manner.

A commenter also adds that EPA may also want to include provisions that prevent a source from applying the new definition of actual emissions in a way that would retroactively enable the source to reverse a previous major modification determination and to eliminate any emissions reduction previously required for that major modification.

We continue to believe that it is reasonable and appropriate to adopt the new method for establishing a modified unit's baseline actual emissions. It is important to understand the difference between the purpose of the new procedure, which uses the 10-year look back, and the existing procedure under the pre-existing definition of "actual emissions" at § 52.21(b)(21(ii), which generally requires the use of an average annual emissions rate based on the 2-year period immediately preceding a particular date. The latter procedure is designed to estimate a source's actual emissions at a particular time and continues to be appropriate for such things as estimating a source's impact on air quality for PSD increment consumption.

On the other hand, the new baseline procedure is specifically designed to allow a source to consider a full business cycle in determining whether there will be an emissions increase from a physical or operational change. Generally, a source's operations over a business cycle cover a range of operating (and emissions) levels—not simply a single level of utilization. The new procedure recognizes that market fluctuations are a normal occurrence in most industries, and that a source's operating level (and emissions) does not remain constant throughout a source's business cycle. The use of a 24-month period within the past 10 years to establish an average annual rate is intended to adjust for unusually high short-term peaks in utilization.

Consequently, the new procedure ensures that a source seeking to make changes at its facility at a time when utilization may not be at its highest can use a normal business cycle baseline by allowing the source to identify capacity actually used in order to determine an average annual emissions rate from which to calculate any projected actual emissions resulting from the change.

With respect to the commenters' general concerns that a 10-year look back period is too long, we sought to better understand what time period best represents an industry's normal business cycle. Therefore, we contracted for a study of several industries in 1997.[23] This study found that, for the

[21] See, for example, WEPCO Rule, 57 FR 32316 ("fundamental distinctions between the technology-based provisions of NSPS and the air quality-based provisions of NSR"). See also *ASARCO Inc.* v. *EPA,* 578 F.2d 319 (D.C. Cir. 1978).

[22] The explanation of the applicability test for "Clean Units" is discussed in section V.

[23] "Business Cycles in Major Emitting Source Industries." Eastern Research Group; September 25, 1997. This study examined the business fluctuations for nine source categories described as CAA major emitting sources. Industry business cycles were examined using industry output data

Continued

industries analyzed, business cycles differ markedly by industry, and may vary greatly both in duration and intensity even within a particular industry. Nevertheless, we concluded from the study that 10 years of data is reasonable to capture an entire industry cycle. Comments from various industries support a conclusion that a 10-year look back period is a fair and representative time frame for encompassing a source's normal business cycle.

We believe that the use of a 10-year look back period will help provide certainty to the process and eliminate the ambiguity and confusion that occurred when an applicant and the reviewing authority disagreed on what time frame provides the period most representative of normal source operation. The new requirements also provide certainty to the look back period, since there is no opportunity to select another period of time outside this 10-year period. (See additional discussion in section II.E.2.) In addition, we have placed certain restrictions on when the full 10-year look back period may be used. (*See* section II.E.3.)

With regard to the concern that industry may try to apply the new requirements retroactively to undo current restrictions on existing sources, we want to reiterate that the new procedures do not apply retroactively to existing NSR permits or changes that sources have made in the past. Prior applicability determinations on major modifications and the control requirements that currently apply to sources remain valid and enforceable and have to be adjusted for in the calculation of baseline actual emissions. However, as part of the transition process for implementing the new provisions, we do intend to allow permit applicants to withdraw any permit applications submitted for review under the part 52 Federal PSD permit program so that they may re-evaluate their projects in light of the new requirements. States may allow for the same type of transition process under their own NSR programs.

Finally, we considered whether we should change the length of the look back period for EUSGUs for establishing the actual emissions baseline period to be consistent with the 10-year look back period we are adopting for other existing emissions units. The data we collected to support the 1992 rule changes show that allowing EUSGUs to use any 2-year period out of the preceding 5 years is a sufficient period of time to capture normal business cycles at an EUSGU. We do not believe that any information received during the public comment period for this final rule adequately supports a different conclusion. Thus, we have decided to retain the 2-in-5-years baseline period for EUSGUs. However, for consistency with the baseline period for other existing emissions units, we have specified that the 2-year period is a consecutive 24-month period.

for the years 1982 to 1994 inclusive, based on the Office of Management and Budget's SIC codes for individual industries (OMB, 1987).

2. Why Do the New Requirements Not Provide Discretion for the Reviewing Authority To Consider Another Time Period More Representative of Normal Operation for Non-EUSGUs?

Several commenters oppose our proposed elimination of the reviewing authority's discretion to allow a different representative period (outside of the 10-year period), because they argue certain sources (for example, emissions units placed in cold reserve due to reduced demand) require this flexibility. Some commenters say the discretion should be given to the reviewing authority, while other commenters wanted the discretion given directly to source owners and operators. Instead of the discretion to use an alternate period, one commenter prefers that all sources should be required to show that they have selected a representative period that precedes the most recent 2-year period.

We believe that use of a fixed 10-year look back period provides the desired clarity and certainty to the process of selecting an appropriate utilization/emissions level that is representative of a source's normal operation. A bounded 10-year look back provides certainty to the regulated community that may be undermined by an option to allow an unbounded alternative period as well.

3. Why Are We Placing Restrictions on the Use of a 10-Year Look Back for Setting the Baseline Actual Emissions?

Numerous commenters responded to our concern that many sources might lack accurate records for the full 10-year look back period, and to our request for comments on the need to condition the full use of the 10-year period upon the accuracy and completeness of available data, as well as the need to establish specific criteria for accuracy, completeness, and recordkeeping when using older data. A number of commenters generally support limiting full use of the 10-year look back period to situations in which adequate emissions and/or capacity utilization data are available. Some commenters also recommend that EPA issue minimum criteria to reduce the number of case-by-case determinations and help reviewing authorities avoid debates with sources on what constitutes sufficient data.

On the other hand, one commenter recommends that we not adopt a variable look back period based on the quality of the older data because it would "add considerable uncertainty and protracted debate to the process. . . ." If, however, we choose to limit the look back period based on the quality of older data, then this commenter and several others prefer provisions allowing for case-by-case decisions by State or local reviewing authorities over specific criteria established by EPA.

Today's amendments condition the full use of the new 10-year look back period on the accuracy and completeness of your records of emissions and capacity utilization, with respect to the 24-month period you select, for any emissions unit that undergoes a physical or operational change. *See,* for example, new § 52.21(b)(48)(*f*). As with all emissions calculations, accuracy and completeness are central elements for applicability determinations. In many cases, sources presently maintain accurate records on emissions and operations for only 3 to 5 years. Thus, we think it is appropriate to limit use of the full 10-year look back period when you do not have adequate data for the time period you wish to select. However, this limitation should be alleviated over time as sources begin to maintain records for longer periods to accommodate the 10-year look back opportunity.

We also agree that adequacy of any given data should be left to the case-by-case judgment of individual reviewing authorities. The type of data necessary to determine emissions will vary drastically from source category to source category and from process to process within a source category. At this time, we are not able to issue generic criteria that would apply to all types of industries.

We are further restricting your use of the 10-year look back for emissions units that are located in nonattainment areas and OTRs. In such cases, you are precluded from using any portion of the 10-year look back that precedes November 15, 1990—the date of the 1990 CAA Amendments—to establish baseline actual emissions for those units. This limit on the use of the 10-year look back is consistent the intent of the 1996 NPRM, which was originally proposed to apply to the use of the 10-year look back for any modification of an existing facility in a nonattainment area or OTR. See 61 FR 38259 (July 23, 1996). However, because we are now beyond the point where the November 15, 1990 limit is relevant to modifications, we are only applying this limitation in the netting context with respect to emissions units changed within the contemporaneous period.

4. Why Were Changes Made to the Proposed Approach for Establishing Baseline Actual Emissions Using a 10-Year Look Back?

Commenters raise specific questions about how to use the 10-year look back to calculate an emissions unit's baseline actual emissions. Several commenters are concerned about how the utilization rate would be considered in the calculation. For example, some commenters support the proposal to allow sources to use their highest capacity achieved during any consecutive 12 months, because it provides improved flexibility in establishing a capacity level that is representative of normal operations. However, other commenters object to using the 12 months with the highest utilization. These commenters argue that the use of production rates can be unworkable because there is not always a clear relationship between production rate and emissions. In addition, reliable records may not be available to determine the highest production rates. As an alternative, commenters suggest using emissions from any 12-month period in the preceding 10 years, adjusted to reflect current rules, or allowing the source to use any 12-month period of its choice.

A related issue raised by commenters is whether to require any current Federal, State, or voluntary limit to be included in the establishment of the baseline actual emissions. Some commenters say these provisions would penalize sources that complied with other regulatory requirements or chose to implement pollution prevention programs. Commenters are particularly concerned that sources be given credit for voluntary reductions. However, other commenters support including all of these factors in the baseline to better represent actual emissions and avoid inconsistencies between emissions units that have permits and those that do not. Commenters also raise specific questions about how the calculation would include the effect of other emission limitations.

As described earlier, we have decided to require the use of a consecutive 24-month period within the 10-year look back instead of the proposed 12-month period to calculate the baseline actual emissions for any emissions unit that undergoes a physical or operational change, or is affected by such change. The longer 24-month period allows you to reference levels of utilization achieved in the past, but also eliminates the potential problem associated with short-term peaks that do not truly represent the unit's normal operation. In this respect, the use of a 24-month period is consistent with the pre-existing approach for calculating actual emissions.

With respect to commenters' concerns about being required to use the period of highest utilization, our reference in the proposal preamble to selecting the period of highest utilization was based on our general assumption that the period of maximum utilization also represents the period of highest pollution levels for the unit of concern. However, you are not required to select the period of highest utilization. The choice of which consecutive 24-month period within the 10-year window to use is up to you. The two restrictions on the selection of the appropriate consecutive 24-month period, as described earlier, are the availability of adequate and complete source records for the unit of concern and the limit on using dates earlier than November 15, 1990 for contemporaneous emissions changes in nonattainment areas and OTRs.

We agree with the concerns expressed by some commenters that the baseline actual emissions calculated from the consecutive 24-month period selected could yield a higher pollution level than a unit is currently allowed to emit. We do not believe that we should allow a source to take credit for baseline actual emissions that exceed the current, legally allowable emissions rate. Consequently, the new requirements require you to determine whether any legally enforceable limitations currently exist that would prevent the affected unit from emitting a pollutant at the levels calculated from the 24-month baseline period. The approach that we have adopted allows you to reference plant capacity that has actually been used, but not pollution levels that are not legally allowed at the time the modification is to occur. You will be required to make adjustments for voluntary reductions that you may have taken only to the extent that the reductions resulted from conditions that are legally enforceable limitations.

5. How Does the Change in the Baseline Period Affect Related Requirements Regarding Protection of Air Quality?

a. How Does the Extended Baseline Period Conform With the Special Modification Provisions Under Sections 182(c) and (e) of the Act?

Most commenters feel the proposed extension of the look back period fits within the design and intent of the special modification procedures set forth in sections 182(c) and (e) of the Act, applicable in serious, severe, and extreme ozone nonattainment areas. However, one commenter representing State and local air pollution control agencies considers the new requirements to be in significant conflict with the special modification procedures contained in those sections of the Act. The commenter indicates that this conflict could be resolved by deferring to relevant requirements for modifications in serious, severe, and extreme areas. The commenter adds that while NSR programs are tools to attain and maintain compliance with the NAAQS, they should not be available to undermine specific statutory and SIP requirements designed to resolve nonattainment problems.

We disagree with the commenter's concern that the use of a 10-year look back period to implement sections 182(c) and (e) of the Act for purposes of establishing a modified unit's baseline emissions will undermine any statutory or SIP requirements designed to address nonattainment problems. The two sections establish special procedures for determining whether a proposed modification of a major stationary source of ozone in a serious, severe, or extreme ozone nonattainment area will be subject to major NSR under part D of the Act. The Act is silent on the issue of how one is to determine whether a physical or operational change increases the amount of a pollutant for a changed emissions unit. We believe, therefore, that we have the authority to establish a regulatory procedure for making the required determinations concerning emissions increases resulting from physical or operational changes.

In light of the fact that the 10-year look back period may be used for emissions units (other than EUSGUs) that are involved in contemporaneous emissions changes (for netting purposes), it should be noted that the new requirements prohibit the use of the look back period earlier than November 15, 1990. Consequently, for emissions units whose contemporaneous emissions changes occurred before November 15, 2000, the consecutive 24-month period selected for calculating the baseline actual emissions relevant to the contemporaneous emissions change cannot include a date prior to November 15, 1990. It should be pointed out, however, that for modifications involving emissions of volatile organic compounds (VOC) in areas classified as "extreme," the statutory language is clear that the increase in emissions resulting from the change is not required to be a significant increase, but rather that "any increase" that is projected using the new actual-to-projected-actual applicability test will trigger the applicable NSR requirements.

b. Will the Longer Look Back Period Related to the Baseline Actual Emissions Protect Short-term Increments and NAAQS?

Some commenters express concerns that the opportunity to take credit for older baseline actual emissions would result in adverse environmental consequences. One commenter specifically indicates that the proposed baseline actual emissions determination process, involving a 10-year look back, would allow significant increases in emissions to escape the ambient impact review requirements otherwise required by NSR.

Today's new rule modifies the way your NSR applicability determinations are made for changes made to existing emissions units. The new rule does not affect the way in which a source's ambient air quality impacts are evaluated. Compliance with the NAAQS is accomplished with air quality dispersion models using maximum allowable emission limitations (or federally enforceable permit limits) combined with operating factors, which consider either design capacity or actual operating factors averaged over the most recent 2 years of operation, from all modeled sources.[24] In addition, any increase in actual emissions, based on the existing definition of "actual emissions," consumes PSD increment whether it occurs through normal source operation or as a result of a physical or operational change. As mentioned earlier, the existing definition of "actual emissions" continues to apply with regard to all NSR requirements other than the new source applicability tests. *See,* for example, new § 52.21(b)(21)(i). Thus, we do not believe there is a basis for concluding that the use of a longer look back period for determining a modified emissions unit's baseline actual emissions (for purposes of determining whether a physical or operational change will result in a significant emissions increase) will cause any adverse environmental impacts.

6. Why Was the Contemporaneous Period for Netting Not Also Changed to a 10-Year Look Back Period?

In the 1996 NPRM, we indicated that we were not proposing to extend the 5-year contemporaneous period along with the proposed 10-year look back period associated with the establishment of baseline actual emissions. *See* 61 FR 38259 (July 23, 1996). We did, however, solicit comments on the effect of the differing look back periods and any reasons why these periods should be the same. Commenters responded in a variety of ways to our request, with no clear consensus as to whether it would be appropriate to establish a uniform look back period. One commenter supports the 10-year contemporaneous period for reasons of consistency. Other commenters believe that it was reasonable to use two different time frames. Some commenters support retaining the 5-year contemporaneous period because changing it could have adverse effects on existing permit determinations. Several commenters support the selection of a different contemporaneous time frame than the existing 5-year period, but they differ in their recommendations for changing it. One suggests giving the source the option of choosing either a 10-year or 5-year contemporaneous period. Another commenter believes that a 1-year period would reduce confusion. Finally, another commenter proposes a 5-year contemporaneous period that would not mandate that 5 consecutive years be considered.

We do not believe that there is a compelling reason to change the existing 5-year contemporaneous period. The look back periods serve different purposes and need not be the same in order to effectively implement the NSR program objectives. States retain the flexibility in defining a different contemporaneous period under SIP-approved NSR programs, and may use that flexibility to adjust the contemporaneous period if they believe that a different period is more appropriate for their purposes under the new applicability requirements. *See,* for example, § 51.166(b)(3)(ii). Therefore, under today's new requirements, we have not changed the 5-year contemporaneous period under the Federal PSD program. It should be noted that for purposes of determining the baseline actual emissions of a contemporaneous change in emissions from an emissions unit that was an existing unit at the time of the contemporaneous change, the new requirements authorize a source to use the 10-year look back period.

7. Why Was the Demand Growth Exclusion Retained?

When we proposed to expand the scope of the WEPCO rulemaking to cover modifications at any existing emissions unit, we solicited comment on whether the demand growth exclusion (currently available only to EUSGUs) should also be available to all source categories. In 1998, we noted that there were problems that could arise with the demand growth exclusion. 63 FR 39860–39861 (July 24, 1998). Accordingly, we solicited comment on this new position.

Several regulatory agency and environmental commenters support the total elimination of the demand growth exclusion. These commenters maintain that a facility's post-change emissions increases due to demand growth could not be disassociated from those that resulted directly from the physical or operational change. These commenters believe the demand growth exclusion would be difficult to enforce. The demand growth exclusion would, they claim, also be burdensome because it would require projections, estimates, and post-modification evaluations of increased emissions to determine whether the increases were the result of increased demand.

On the other hand, numerous industry commenters oppose eliminating the demand growth provisions, stating that market factors do independently cause emissions increases absent physical and operational changes. These commenters maintain that when projected increased capacity utilization is in response to an independent factor, such as demand growth, the increased utilization cannot be said to result from the change and therefore may rightfully be excluded from the projection of the emissions unit's future-actual emissions. They further argue that such increases should not be included in post-change emissions even in the absence of a demand growth exclusion, as the increases would not be the result of the physical or operational changes that were made. Consequently, these commenters state that the proposed demand growth exclusion simply makes that principle explicit and eliminates confusion as to how emissions should

[24] Guidance for modeling NAAQS compliance under the PSD program is set forth in EPA's Guideline on Air Quality Models contained in appendix W of 40 CFR part 51. This guidance is incorporated by reference both in the Federal PSD regulations and in the minimum requirements for SIPs under the part 51 PSD regulations.

be calculated. The same commenters who support retaining demand growth provisions for utilities also believe these provisions should be extended to non-utilities.

Under today's new requirements, you will be allowed to apply the causation provision as originally contained in the WEPCO amendments. Both the statute and implementing regulations indicate that there should be a causal link between the proposed change and any post-change increase in emissions, that is, "* * * any physical change or change in the method of operation *that would result in* a significant net emissions increase * * *" [emphasis added]. See, for example, existing § 52.21(b)(2)(i). Consequently, under today's new rules, when a projected increase in equipment utilization is in response to a factor such as growth in market demand, you may subtract the emissions increases from the unit's projected actual emissions if: (1) The unit could have achieved the necessary level of utilization during the consecutive 24-month period you selected to establish the baseline actual emissions; and (2) the increase is not related to the physical or operational change(s) made to the unit. See for example, new § 52.21(b)(41)(ii)(*c*).

On the other hand, demand growth can only be excluded to the extent that the physical or operational change is not related to the emissions increase. Thus, even if the operation of an emissions unit to meet a particular level of demand could have been accomplished during the representative baseline period, but the increase is related to the changes made to the unit, then the emissions increases resulting from the increased operation must be attributed to the project, and cannot be subtracted from the projection of projected actual emissions.

8. Should Increases in Plant Utilization Be Reviewed as Potential Major Modifications?

Many commenters argue that emissions increases resulting from increased utilization should not be subjected to review as major modifications. They insist that EPA's policy and rules have always allowed increases in capacity utilization without triggering a modification, and not allowing utilization increases will limit new capacity to new emissions units instead of promoting increased efficiency at existing emissions units. One commenter argues that these sorts of changes do not require any sort of applicability determination and that Congress never anticipated that the NSR program would hamper a source's ability to increase utilization up to the original design capacity.

We believe that an increase in utilization should not trigger the major NSR requirements unless it is related to a physical or operational change. As explained earlier, the CAA only applies the major NSR requirements to emissions increases that are the result of a physical or operational change. Thus, we do not believe that the major NSR requirements should apply to a utilization increase unless the increase is related to the modification. Under today's final rules, you may exclude emissions related to an increase in utilization if you were able to accommodate the increase in utilization during the 24-month period you select to establish your baseline actual emissions and the increased utilization is not related to the change.

9. Why Must You Track Physical or Operational Changes That Increase a Unit's Design Capacity or Potential To Emit Post-Change Actual Emissions for a Longer Period of Time?

We raised this issue in the 1998 NOA. Several commenters support applying what we then termed the "actual-to-enforceable-future-actual" test to increases in design capacity or PTE because it would be inappropriate to automatically assume that such increases will affect normal operations, which would require the actual-to-potential test. They say that these types of modifications are common and do not generally increase emissions because they improve efficiency and add control devices.

One commenter explains that it is not uncommon for an emissions unit's capacity to be increased so as to speed up normal operations without increasing production, and that projected actual emissions could easily be calculated on the basis of past operating experience. On the other hand, another commenter indicates that it is very expensive to increase design capacity. Therefore, it can be assumed that a company would use the additional capacity as soon as it becomes available.

Several regulatory agency commenters support the use of the actual-to-potential test for modifications that increase design capacity or PTE. One of these commenters stated that such modifications would alter an emissions unit's normal operation and make previous actual emissions "unreliable and irrelevant."

We do not believe that every modification that includes added capacity or an increase in the PTE is intended for full use of that new capacity or PTE. Such actions could well be intended to enhance current operations without resulting in increased production or operation. Therefore, under today's new requirements, you are not required to count the emissions increase that would result from full use of new capacity or PTE if you conclude that: (1) Such capacity or PTE will not be fully utilized, and (2) the emissions increase resulting from that portion of the capacity that will be used will not result in a significant emissions increase from the modification or a significant net emissions increase at the source. The new requirements include a provision that requires you to monitor the emissions from the project for 10 years following the resumption of regular operation of the emissions units modified. The 10-year period reflects our determination that this time frame best captures the normal business cycle for industry in general. Thus, in situations where your proposed project will in fact add new capacity or PTE to an existing emissions unit, yet you determine that the objective of the physical or operational change is not to use the increased capacity, your calculation of representative projected actual emissions may reflect this. However, you must maintain adequate information for 10 years following the completion of the project to track the actual annual emissions from the units associated with the project. This represents a special condition that supersedes the normal 5-year period for the recordkeeping requirements being adopted today. During the 10-year period, you must report to your reviewing authority within 60 days after any year if the annual emissions, in tpy, from the project exceed the baseline actual emissions by a significant amount for the regulated NSR pollutant and if such emissions differ from the preconstruction projection.

10. Does the Actual-To-Projected-Actual Applicability Test Apply to Netting?

We did not specifically request comment on this issue in the 1996 proposal. Nonetheless, we received several comments that assert that use of different methods to compute an emissions increase and determine a net emissions increase would result in "absurd results" and require two separate accounting records. Other commenters oppose using the actual-to-future-actual test for netting. One commenter says that the sole purpose of the actual-to-future-actual test was to determine if an emissions increase will occur. One commenter says we should go further and revise the definition of "contemporaneous" to limit it to project activities (vs. plantwide) and reduce credits for shutdowns and curtailments.

As stated previously, we did not specifically request comment on this issue and we are not promulgating amendments to the netting regulations, on this point, at this time.

11. Should We Impose an Enforceable Projected Actual Emissions Level?

Some commenters on our 1996 proposal support the establishment of an enforceable limitation on the modified source's projected future emissions level. Other commenters support our specific proposal in the 1998 NOA to use the projected actual emissions as a temporary cap for the emissions units involved in the project, that is, an enforceable 10-year emissions level.

On the other hand, many other commenters oppose the concept, citing various reasons for their opposition. These included concerns that it would become a *de facto* baseline for any additional permitting and create additional enforcement liability, usurp State prerogatives, be inconsistent with the CAA, and require enforceable restrictions for too long. A few State and local air reviewing agencies indicate that they do not have the resources to adequately administer a program that would require permits to be issued for every physical or operational change at a major stationary source.

Today's new requirements follow the 1996 proposal. You will not be required to make the projected actual emissions projection through a permitting action. After considering the comments received, we are concerned that such a requirement may place an unmanageable resource burden on reviewing authorities. We also believe that it is not necessary to make your future projections enforceable in order to adequately enforce the major NSR requirements. The Act provides ample authority to enforce the major NSR requirements if your physical or operational change results in a significant net emissions increase at your major stationary source.

12. Why Are Modified Sources That Are Not Considered Major Modifications Not Required To Submit Annual Reports of Actual Emissions Under the New Requirements?

Several commenters support our proposal to require sources to track post-change emissions for a 5-year period so that there is a factual finding as to whether emissions from the modified units actually increased. These commenters believe that the requirement to track emissions is a needed safeguard and that it should not be too difficult to track various operating parameters. They add that non-utilities should be able to track emissions as well as utilities. Finally, commenters who oppose the proposed 10-year enforceable limit support retaining the 5-year tracking period in its place.

Many other commenters object to the burden that tracking would impose in the absence of any additional environmental benefit. Some commenters suggest ways to reduce the burden, such as not requiring sources to report emissions unless there is a problem or reducing the tracking period to 2 or 3 years. Another industry commenter suggests that we require an up-front notification to the reviewing authority whenever the actual-to-future-actual applicability test is used.

We agree with those commenters who recommend that you should be required to track emissions for a period of time following a modification. Thus, we have retained our proposed requirement to maintain annual emissions information for a period of 5 years following resumption of regular operations after the change. As discussed previously, we expanded this requirement to 10 years for changes that increase an emissions unit's capacity or its potential to emit a regulated NSR pollutant. However, although we proposed a requirement for annual emissions reporting, we have concluded that the combination of the recordkeeping requirements of this rule, along with a requirement to report to the reviewing authority any annual emissions that exceed your baseline actual emissions by a significant amount for the regulated NSR pollutant and differ from your preconstruction projection, is an equally effective way to ensure that a reviewing authority can receive the information necessary to enforce the major NSR requirements. Moreover, your reviewing authority has the authority to request emissions information from you at any time to determine the status of your post-change emissions.

In response to the concern that these requirements might impose unnecessary burdens, we have also included further limits. First, you are only required to keep records if you elect to use the actual-to-projected-actual applicability test to calculate your emissions increase from the project. Second, you are only required to keep the records if there is a reasonable possibility that your project might result in a significant emissions increase. Finally, you only need keep those records for projects that are not major modifications.

We also considered requiring you to submit an up-front notification to your reviewing authority, but concluded that this would result in an unnecessary paperwork burden. (EUSGUs, however, will be required to submit a copy of their projections to reviewing authorities before beginning actual construction.) We anticipate that a large majority of the projects that are not major modifications may nonetheless be required to undergo a permit action through States' minor NSR permit programs. In such cases, the minor NSR permitting procedures could provide an opportunity to ensure that your reviewing authority agrees with your emission projections. Requiring a separate notification would not provide the reviewing authority with any additional information in such circumstances. Accordingly, we believe today's requirements provide reviewing agencies with the ability to obtain all the information necessary to ensure compliance.

13. Why Are We Promulgating Different Reporting Requirements for Existing Emissions Units Than for EUSGUs?

Today we are finalizing slightly different requirements for EUSGUs than other industries. In 2000, boilers and turbines with greater than 25 MWe or 250 mmBTU/hr of generating capacity represented 76 percent of this nation's emissions of nitrogen oxides (NO_X) and 85 percent of this nation's emissions of SO_2 from stationary sources.[25]

In view of the disproportionate amount of emissions generated by EUSGUs compared to other industry sectors, we believe that it is appropriate for reviewing authorities to have information on construction and modification activities at EUSGUs readily available. Accordingly, we are requiring EUSGUs to provide a copy of their emissions projection to the reviewing authority before beginning actual construction of a project. We are also requiring them to report their post-change annual emissions for every year they are required to generate them. This approach also makes sense because it focuses the limited resources of both sources and agencies on the sources that matter most.

III. CMA Exhibit B

In addition to the proposed changes based on the 1992 WEPCO amendments (*see* section II of this preamble), the 1996 proposal package included alternative regulatory language that would enable you to determine whether

[25] Information supporting these values can be found in the docket for today's rulemaking.

your facility has undertaken a modification based on the facility's pre-change and post-change potential emissions instead of its actual emissions. This action was part of the settlement of a challenge to our 1980 NSR regulations by CMA and other industry petitioners. The exact language we proposed was set forth in Exhibit B to the Settlement Agreement, which is contained in the docket for this rulemaking.

Under this method, sources may calculate emissions increases and decreases based on the actual emissions method or the unit's pre-change and post-change potential emissions, measured in terms of hourly emissions (that is, pounds of pollutant per hour). Sources could use this potential-to-potential test for NSR applicability, as well as for calculating offsets, netting credits, and other ERCs.

We proposed to make several changes to the NSR regulations. First, we proposed to add the following exclusion to the definition of "major modification":

A major modification shall be deemed not to occur if one of the following occurs: (a) there is no significant net increase in the source's PTE (as calculated in terms of pounds of pollutant emitted per hour); or (b) there is no significant net increase in the source's actual emissions.

Second, we proposed to delete all references to "actual emissions" in the definition of "net emissions increase" and added language indicating that all references to "increase in emissions" and "decreases in emissions" in the definition of "net emissions increases" "shall refer to changes in the source's PTE (as calculated in terms of pounds of pollutant emitted per hour) or in its actual emissions." Third, we proposed to modify the applicability baseline by eliminating the reference to the 2-year baseline period and to a method for determining actual emissions during the representative period. Finally, we proposed to provide express authorization for sources to use potential emissions in calculating offsets and in creating ERCs.

We also indicated in the preamble for the 1996 proposed rulemaking that if we promulgated the Exhibit B settlement as a final rule, the Exhibit B rules would need to be updated to reflect other rule changes since 1980, as well as relevant provisions of the 1990 Amendments.

Before proposing the Exhibit B language, we did a preliminary analysis of the impact on the NSR program of the Exhibit B changes. These changes would provide maximum flexibility to existing facilities with respect to determining if a significant net emissions increase would result from a physical or operational change. However, we also expressed concern about the environmental consequences associated with the Exhibit B provisions. For one, you could modernize your aging facilities (restoring lost efficiency and reliability while lowering operating costs) without undergoing preconstruction review, while increasing annual pollution levels as long as hourly potential emissions did not change. Also, Exhibit B would allow your facilities to generate netting credits and ERCs for offsets based on potential hourly emissions, even if never actually emitted. This could sanction greater actual emissions increases to the environment, often from older facilities, without any preconstruction review. In addition, actual emissions increases resulting from unreviewed projects could go largely undocumented until a PSD review is performed by a new or modified facility that ultimately must undergo review. By that time, however, a violation of an increment could have unknowingly occurred. We were also concerned that Exhibit B would ultimately stymie major new source growth by allowing unreviewed increases of emissions from modifications of existing sources to consume all available increment in PSD areas.

In our analysis supporting the 1996 proposal, we were unable to reach any conclusions as to the magnitude of any environmental impacts beyond noting that the effects would vary from State to State depending on how much cumulative difference exists between the unused potential emissions and actual emissions in a given inventory of sources and on the extent to which any unused potential emissions have been used in attainment demonstrations. However, our analysis did show that typical source operation frequently does result in actual emissions that are below allowable emission levels.

We received many comments in response to the 1996 proposal regarding CMA Exhibit B. Some commenters believe the potential-to-potential test appropriately focuses on the significant emissions changes that could produce an adverse environmental impact. Several other commenters believe that a potential-to-potential test would be environmentally detrimental. These commenters believe that CMA Exhibit B represents a substantial weakening of the PSD program with large increases in actual emissions, which in itself could lead to a significant deterioration of air quality. They also express concerns regarding the creation of paper credits and other impacts on the broader air quality planning process. One commenter states that the potential-to-potential test would conflict with SIPs that are based on actual emissions, threaten a State's efforts to make reasonable further progress (RFP) demonstrations, and interfere with emission credits relied on by SIPs. These commenters also cite the following concerns.

- The potential-to-potential test would allow sources to escape the major modification provisions and could virtually eliminate NSR in most modification cases.
- Once a facility has proceeded without NSR based on actual emissions, it would be difficult to take an enforcement action years later that would successfully require that facility to retrofit LAER and obtain offsets retrospectively.

We agree that a potential-to-potential test for major NSR applicability could lead to unreviewed increases in emissions that would be detrimental to air quality and could make it difficult to implement the statutory requirements for state-of-the-art controls.

After consideration, we believe some of the comments in support of Exhibit B have merit. As noted by commenters who supported the CMA Exhibit B proposal, a potential-to-potential test could simplify and improve the NSR process. According to commenters, the CMA Exhibit B approach would have the following benefits.

- Limit the scope of the program to encompass only those significant physical changes that Congress intended to cover
- Reduce unnecessary NSR costs and delays and improve compliance and enforcement
- Lower the cost of the NSR process by reducing the complexity of the NSR applicability determinations
- Facilitate applicability decisions at the plant level

The commenters also say that the CMA Exhibit B approach is more equitable than the existing actual-to-potential approach, which results in the capture of a source's unused capacity. These commenters prefer the potential-to-potential test because it would allow utilization increases. This provision is especially useful for sources in cyclical industries where using existing capacity is critical. Sources in sectors where utilization and demand are closely related would also benefit.

Our own concerns, coupled with the concerns expressed by some commenters, have caused us to reject the use of the Exhibit B regulatory changes for general purposes of determining whether a proposed physical or operational change would result in a major modification. For the reasons stated above, we do not believe that a potential-to-potential approach is acceptable for major NSR applicability as a general matter. However, we agree with the commenters in part—some of the benefits of a potential-to-potential approach are desirable. We believe that in more limited circumstances a "potential-to-potential"-like approach would be acceptable. Therefore, we are promulgating two new applicability provisions that capture the benefits of a potential-to-potential approach but still have the necessary safeguards to ensure environmental protection—PALs, and the Clean Unit Test.

Today's rules provide for a PAL based on plantwide actual emissions. If you keep the emissions from your facility below a plantwide actual emissions cap, then you need not evaluate whether each change might be subject to the major NSR permitting when you make alterations to the facility or individual emissions units. The cumulative actual emissions become the *de facto* potential emissions for the plant, and you may emit up to the permitted level without going through major NSR, even if you are making changes to the facility. The PAL allows you to make changes quickly by allowing you to alter your facility without first going through major NSR review. It thus limits the number and complexity of NSR applicability determinations, and reduces unnecessary costs and delays. It also allows a plant manager to authorize changes, as long as the emissions remain under the permitted level, without first obtaining reviewing authority review. Furthermore, it provides an incentive to use state-of-the-art controls and install new, lower emitting equipment, which will allow sources to increase utilization. In return for the flexibility a PAL allows, you must monitor emissions from all of your emissions units under the PAL. Therefore, the PAL ensures good controls and protection of air quality. We believe there are other mechanisms for establishing PALs that would achieve beneficial results. For example, we believe PALs based on allowable emissions would produce flexibility and assure environmental protection, provided affected sources had adequate safeguards. Therefore, we intend in the near future to propose a rule that would adopt PALs based on allowable emissions.

Analogous to what the PAL does for facilities, the Clean Unit Test sets emission limitations or work practice requirements in conjunction with BACT, LAER, or Clean Unit determinations and identifies any physical or operational characteristics that formed the basis for the BACT, LAER, or Clean Unit determination for a particular unit. The Clean Unit Test recognizes that if you go through major NSR review (including air quality review) and install BACT or LAER or comparable technology, then you may make any subsequent changes to the Clean Unit without triggering an additional major NSR review, as long as there is no need for a change in the emission limitations or work practice requirements in the permit for the unit that were adopted in conjunction with BACT, LAER, or Clean Unit determination or to alter any physical or operational characteristics that formed the basis for the BACT, LAER, or Clean Unit determination. Therefore, for Clean Units, given that the permit is based on a determination that is protective of air quality, the new test would deem there is no emissions increase as a result of any physical change or change in the method of operation. With these provisions, sources will have improved certainty and flexibility, reduced burden, and opportunity for utilization increases without compromising air quality. Like the PAL, the Clean Unit includes necessary safeguards by requiring enforceable permit terms and conditions to ensure environmental protection.

IV. Plantwide Applicability Limitations

A. Introduction

Today we are adopting a final rule for a PAL option that is based on the baseline actual emissions [26] from major stationary sources. A PAL is an optional approach that will provide you, the owners or operators of major stationary sources, with the ability to manage facility-wide emissions without triggering major NSR. We believe the added flexibility of a PAL allows you to respond rapidly to market changes consistent with the goals of the NSR program.

The final rules we are adopting today also benefit the public and the environment. Reviewing authorities, usually States, can only establish a PAL by using a public process that affords citizens the opportunity to comment upon the proposed PAL. This process is designed to assure local communities that air emissions from your major stationary source will not exceed the facility-wide cap set forth in the permit unless you first meet the major NSR requirements. We believe that a PAL provides a more complete perspective to the public because in setting a PAL, your reviewing authority accounts for all current processes and all emissions units together and reflects the long-term maximum amount of emissions it would allow from your source. Moreover, to comply with a PAL you must meet monitoring requirements prescribed in the rules that ensure that both your reviewing authority and the public have sufficient information from which to determine plantwide compliance. Additionally, through the final PAL regulations, we are promoting voluntary improvements in pollution controls by creating an incentive for you to control existing and new emissions units to maintain a maximum amount of operational flexibility under the PAL. Most importantly, for pollutants subject to a PAL, we are prohibiting serial, small, unrelated emissions increases,[27] which otherwise can occur under our existing regulations.

If you choose to use it, we believe you will benefit from the PAL option because you will have increased operational flexibility and regulatory certainty, a simpler NSR applicability approach, and fewer administrative burdens. To comply with a PAL, you need to ensure that there are no emissions increases from your major stationary source, as measured against the PAL. For you to do that, there is no need for you to quantify

[26] In our 1996 proposal we used the term "actual emissions," while today we are using the term "baseline actual emissions." This change in terminology is consistent with the regulatory changes discussed in section II of today's preamble. Despite this change in terminology, there may be places in this section of the preamble where we still use the phrase "actual emissions." In such cases we are either discussing PALs established under the old regulatory provisions, or summarizing and responding to comments received on the 1996 proposal.

[27] Under our current NSR program, you can make physical changes or changes in the method of operation without triggering major NSR applicability, provided the individual changes do not result in significant net emissions increases. We have interpreted this requirement to permit you to make unrelated changes that, standing alone, do not result in significant emissions increases and to allow such changes to occur without considering whether other contemporaneous emissions increases render the change significant. Over time you could undertake numerous unrelated projects without triggering major NSR, provided the individual projects did not increase emissions by a significant amount, thus allowing source-wide emissions to increase over time without requiring any emissions controls for these individual projects. For example, a large chemical plant that is located in an ozone attainment area adds a new product line in 2001 and properly avoids PSD (including the BACT requirement) by limiting the VOC emissions increase to 39 tpy. Later, in 2003 the plant adds a different product line and also properly avoids PSD by limiting VOC emissions from the new line to 39 tpy. For this example, two process lines at the same plant with total potential emissions (78 tpy) above the 40 tpy VOC significant level under PSD were properly permitted over a 3-year period without BACT applying to either new product line.

contemporaneous emissions increases and decreases for individual emissions units. Through the PAL we are allowing you to make timely changes to react to market demand and providing you additional certainty regarding the level of emissions at which your source will be required to undergo major NSR. The benefit to you is that you will not have to make numerous applicability decisions using different baselines. Also, in some situations where you would have been unable to "net out" a new project in the major NSR program, under a PAL you can begin construction on your new project without obtaining a major NSR permit, which can take from a few months up to 2 years. In addition, because you may make emissions reductions at emissions units under the PAL to create room for growth at other units, through the PAL we are providing a strong incentive for you to employ innovative control technologies and pollution prevention measures, to create voluntary emissions reductions to facilitate economic expansion.

B. Relevant Background

1. What Is a PAL and How Does a PAL Compare to Other Major NSR Requirements and Netting?

The concept of a PAL is simple. Under the Act, you are not subject to major NSR unless you make a "modification," which by definition cannot occur without an emissions increase. CAA section 111(a)(4). A PAL is a source-wide cap on emissions and is one way of making sure that emissions increases from your major stationary source do not occur.

The existing regulations require "major modifications" to undergo NSR, and the existence of a "significant net emissions increase" at the facility is a necessary prerequisite to a "major modification." *See,* for example, §§ 52.21(b)(2) & (3); *see also Chevron* v. *Natural Resources Defense Council,* 467 U.S. 837, 863–64 (1984). Under our current system, we determine whether a "significant net emissions increase" occurs at your major stationary source by focusing initially on the change to the emissions unit(s) and then broadening the analysis to include other changes within the source. In order to determine whether there is a "significant net emissions increase" under major NSR as revised today, you must establish a pre-change baseline for each change, project the actual level of emissions after the change, calculate the creditable emissions increases and decreases that have occurred that are contemporaneous with the change, and determine whether the change would result in a significant net emissions increase. We refer to this applicability process as "netting" under the major NSR regulations. Both you and reviewing authorities have maintained that the netting rules are unnecessarily complex and burdensome, and have urged us to craft rules that link NSR applicability to compliance with a predictable source-wide emissions cap. We are responding to that request with the PAL concept. A PAL is a voluntary,[28] source-specific, straightforward, flexible approach to account for changes, including alterations to existing emissions units and the addition of new emissions units, at your existing major stationary sources. Complying with the PAL ensures that there are no emissions increases that trigger major NSR. If your emissions of the PAL pollutant remain below the PAL, and you comply with all other PAL requirements, whatever changes occur at your plant will not be subject to major NSR for the PAL pollutant. Our July 23, 1996 proposal contains a thorough discussion of the proposed PAL concept and the background information used to develop the proposal.

2. Why Does EPA Believe That PALs Will Benefit the Environment?

Over the past several years, we have allowed use of major stationary source-wide emissions caps to demonstrate compliance with major NSR in a select number of pilot projects. We recently reviewed six of these innovative air permitting efforts and found substantial benefits associated with the implementation of permits containing emissions caps (among other types of permit terms offering greater flexibility than major NSR permitting programs).[29] Specifically, we reviewed on-site records to track utilization of these flexible permit provisions, to assess how well the permits are working and any emissions reductions achieved, and to determine if there were any economic benefits of the permits.

Overall, we found that significant environmental benefits occurred for each of the permits reviewed. In particular, the six flexible permits established emissions cap-based frameworks that encouraged emissions reductions and pollution prevention, even though such environmental improvements were not an explicit requirement of the permits. We found that in a cap-based program, sources strive to create enough headroom for future expansions by voluntarily controlling emissions. For instance, one company lowered its actual VOC emissions over threefold in becoming a synthetic minor source (that is, 190 tpy to 56 tpy). Other companies lowered their actual VOC emissions by as much as 3600 tpy by increasing capture, by using voluntary pollution prevention and other voluntary emissions control measures, and by reducing production rates.

Participants reported that having the ability to make rapid, iterative changes to optimize process performance in ways that minimize emissions, and that reduce the administrative "friction" (time delays and uncertainty) associated with making operational and equipment changes, encourages facilities to make changes that improve yields and reduce per-unit emissions. It is also critical for responding to product development needs and market demand, and for maintaining overall competitiveness.

Reviewing authorities consistently reported that the permits worked well and proved beneficial, and that there was a reduction in the number of case-by-case permitting actions they needed to undertake. Specifically, we found that flexible permit provisions (for example, emissions caps) are enforceable as a practical matter by using a mixture of mass balance-based equations, CEMS, and parameter monitoring. No emissions cap exceedances or violations of the monitoring provisions were experienced by any of the pilot sources. In addition, the monitoring and reporting approaches worked well and were generally of higher quality and of more extensive scope than those directly required by individual applicable requirements.

Based on the results of these pilot projects, we believe that PALs will over time tend to shift growth in emissions to cleaner units, because the growth will have to be accommodated under the PAL cap. Specifically, we expect that PALs will encourage you to undertake such projects as: replacing outdated, dirty emissions units with new, more efficient models; installing voluntary emissions controls; and researching and implementing improvements in process efficiency and use of pollution prevention technologies, so that you can maintain maximum operational flexibility. We also expect that you and the reviewing authority will need to devote substantially fewer resources to

[28] The term "voluntary" means that you have the option of entering into a PAL, rather than voluntary compliance with a PAL that is in place. Once you have a permit with PAL requirements, you must comply with the requirements.

[29] Results of our study are reported in "Evaluation of the Implementation Experience with Innovative Air Permits." A complete copy of this report is located in the docket for today's rulemaking.

discussing and reviewing whether major NSR applies to individual changes. Thus, overall, we believe that PALs will prove to be as beneficial to the environment as they are to you and your reviewing authority.

3. What Did We Propose for PALs?

On July 23, 1996, we proposed to amend the NSR regulations to specifically authorize PALs and to clarify the methodology under which you can obtain a PAL. Under the proposal, your reviewing authority could have elected to include provisions in its SIP to allow you to apply for a permit that based your source's major NSR applicability on compliance with a pollutant-specific, source-wide emissions cap. We proposed that a facility's PAL would generally be based on source-wide "actual emissions" plus an operating margin of emissions less than a significant emissions increase. We also sought comment on the circumstances under which it would be appropriate to use something other than actual (for example, "allowable") emissions to set the PAL.

On July 24, 1998, we published a notice in the **Federal Register** seeking further comment on how the PAL regulations could be reconciled with several environmental and legal concerns. The notice discussed how the PAL alternative fits within the Act's requirements for determining if changes at existing sources are subject to major NSR. Today we are adopting final regulations that address the issues and comments raised in the 1998 notice and the 1996 proposal.

C. Final Regulations for Actuals PALs

Today's action establishes final regulatory provisions for actuals PALs. We are placing these requirements in the major NSR rules for nonattainment areas at § 51.165(f), and in the PSD regulations (applicable in attainment and unclassifiable areas) at §§ 51.166(w) and 52.21(aa).

The PAL option adopted today provides you with a voluntary alternative for determining NSR applicability. Actuals PALs are rolling 12-month emissions caps (that is, tpy limits) that include all conditions necessary to make the limitation enforceable as a practical matter. Through the regulations, we are allowing PALs on a pollutant-specific basis and are also allowing you to opt for actuals PALs for more than one pollutant at your existing major stationary sources. You must continue to apply the major NSR applicability provisions to air pollutants at your source for which you have no PAL.

This section sets forth the specific requirements for actuals PALs. The section addresses the following items: (1) The process used to establish a PAL and the public participation requirements; (2) how the PAL level is determined; (3) how long a PAL is effective and what happens when a PAL expires; (4) can a PAL be terminated before the end of its effective period; (5) how a PAL is renewed; (6) how a PAL can be increased during the effective period; (7) circumstances that would cause your PAL to be adjusted during the PAL effective period; (8) whether a PAL can eliminate enforceable emission limitations previously taken to avoid major NSR; (9) the compliance requirements and monitoring, recordkeeping, reporting, and testing (MRRT) requirements that the permit must contain for emissions units under your PAL; (10) the process for incorporating conditions of the PAL into your title V operating permit; and (11) an example of how an actuals PAL would work under the regulations finalized today.

1. What Are the Permit Application Requirements, What Is the Process Used To Establish a PAL, and What Are the Public Participation Requirements?

Under today's final rules, you must submit a complete application to your reviewing authority requesting a PAL. The application, at a minimum, must include a list of all emissions units, their size (major, significant, or small); the Federal and State applicable requirements, emission limitations and work practice requirements that each emissions unit is subject to; and the baseline actual emissions for the emissions units at the source (with supporting documentation). The calculation of baseline actual emissions must include fugitive emissions to the extent they are quantifiable. The reviewing authority must establish a PAL in a federally enforceable permit (for example, a "minor" NSR construction permit, a major NSR permit, or a SIP-approved operating permit program). To comply with our final regulations, the reviewing authority must provide an opportunity for public participation when issuing a PAL permit. This process must be consistent with the requirements at § 51.161 and include a minimum of a 30-day period for public notice and opportunity for public comment on the proposed permit. Where the PAL is established in a major NSR permit, major NSR public participation procedures apply. When establishing a PAL, you must comply with all applicable requirements of the reviewing authority's minor NSR program, including modeling to ensure the protection of the ambient air quality. Additionally, you must meet all applicable title V operating permit requirements. When adding new emissions units under a PAL, you must comply with the reviewing authority's minor NSR permit requirements for public notice, review, and comment. In contrast, when adding new emissions units that will require an increase in a PAL, you must comply with the reviewing authority's major NSR permit requirements for public notice, review, and comment.

2. How Is the Level of the PAL Determined?

We calculate the PAL level for a specific pollutant by summing the baseline actual emissions of the PAL pollutant for each emissions unit at your existing major stationary source, and then adding an amount equal to the applicable significant level for the PAL pollutant under § 52.21(b)(23) or under the CAA, whichever is lower.

You must first identify all your existing emissions units (greater than 2 years of operating history) and new emissions units (less than 2 years of operating history since construction). When establishing the actuals PAL level, you must calculate the baseline actual emissions from existing emissions units that existed during the 24-month period as described below. The baseline actual emissions will equal the average rate, in tpy, at which your emissions units emitted the PAL pollutant during a consecutive 24-month period, within the 10-year period immediately preceding the application for a PAL. Consistent with today's final rules, you will have broad discretion to select any consecutive 24-month period in the last 10 years to determine the baseline actual emissions. Only one consecutive 24-month period may be used to determine the baseline actual emissions for such existing emissions units. For any emissions unit (currently classified as existing or new) that is constructed after the 24-month period, emissions equal to its PTE must be added to the PAL level. Additionally, for any emissions unit that is permanently shut down or dismantled[30] since the 24-month

[30] The key determination to be made is whether an emissions unit is "permanently shut down." This issue is discussed in the Administrator's response to a petition objecting to an operating permit for a facility in Monroe, Louisiana. See *Monroe Electric Generating Plant*, Petition No. 6–99–2 (Adm'r 1999). A copy of this decision is in the docket. In general, we explained in our "reactivation policy" that whether or not a

period, its emissions must be subtracted from the PAL level. Different rules apply for determining baseline actual emissions for EUSGUs. You should refer to the definition of baseline actual emissions to determine the specific method for calculating baseline actual emissions for your emissions units. Consistent with today's final rules for determining baseline actual emissions, your baseline actual emissions for an emissions unit cannot exceed the emission limitation allowed by your permit or newly applicable State or Federal rules (RACT, NSPS, etc.) in effect at the time the reviewing authority sets the PAL. This means that for the purpose of setting the PAL, your baseline actual emissions for an emissions unit will include an adjustment downward to reflect currently applicable requirements. Additionally, your reviewing authority shall specify a reduced PAL level(s) (in tpy) in the PAL permit to become effective on the future compliance date(s) of any applicable Federal or State regulatory requirement(s) that the reviewing authority is aware of prior to issuance of the PAL permit. *See* section II of today's preamble for additional information on determining the baseline actual emissions for your emissions units.

3. How Long Can a PAL Be Effective and What Happens When a PAL Expires?

Through the final rules, we are requiring that the term of an actual PAL be 10 years. At least 6 months prior to, but not earlier than 18 months from, the expiration date of your PAL, you must submit a complete application either to request renewal or expiration of the PAL. If you meet this application deadline for a permit renewal, the existing PAL will continue as an enforceable requirement until the reviewing authority renews your PAL, even if the reviewing authority fails to issue a PAL renewal within the specified period of time.

As part of an application to request expiration of the PAL, you must submit a proposed approach for allocating the PAL among your existing emissions units. The reviewing authority will retain the ultimate discretion to decide whether and how the allowable emission limitations will be allocated, including whether to establish limits on individual emissions units or groups of emissions units. As under the PAL, your emissions units must comply with their allowable emission limitations on a 12-month rolling basis. However, the reviewing authority retains the discretion to accept monitoring systems other than CEMS, CPMS, PEMS, etc., from you to demonstrate compliance with these unit-specific limits.

Until the reviewing authority issues the revised permit with allowable emission limitations covering each of your emissions units, your source must comply with a source-wide multi-unit emissions cap equivalent to the PAL level. After a PAL expires, physical or operational changes will no longer be evaluated under the PAL applicability provisions.

Notwithstanding the expiration of the PAL, you must continue to comply with any State or Federal applicable requirements for a specific emissions unit. (BACT, RACT, NSPS, etc.) When the PAL expires, none of the limits established pursuant to §§ 51.166(r)(2), 51.165(a)(5)(ii), or 52.21(r)(4), which the PAL originally eliminated, would return under today's final rules.

4. Can a PAL Be Terminated Before the End of Its Effective Period?

Today's final rules do not contain specific provisions related to the issue of terminating a PAL. Decisions about whether a PAL can or should be terminated will be handled between you and your reviewing authority in accordance with the requirements of the applicable permitting program.

5. How Is a PAL Renewed?

As previously discussed, you must submit a complete application to renew a PAL at least 6 months prior to, but not earlier than 18 months from, the expiration date of your PAL. If you submit a complete application to renew the PAL by this deadline, the existing PAL will continue as an enforceable requirement until the reviewing authority issues the permit with the renewed PAL. As part of your renewal application, you must recalculate and propose your maximum PAL level, taking into account newly applicable requirements and the factors described below.

Your reviewing authority must review the complete application and issue a proposed permit for public comment consistent with the permitting procedures for issuing the initial PAL. As part of this public process, the reviewing authority must provide a written rationale for its proposed PAL level. If your source's PTE has declined below the PAL level, the reviewing authority must adjust the PAL downward so that it does not exceed your source's PTE.

In addition, the reviewing authority may renew the PAL at the same level without consideration of other factors, if the sum of the baseline actual emissions for all emissions units at your source (as calculated using the definition of "baseline actual emissions" at §§ 51.165(a)(1)(xii)(B), 51.166(b)(21), and 52.21(b)(21) as amended by today's final rules) plus an amount equal to the significant level is equal to or greater than 80 percent of the PAL level (unless greater than the current PTE of the major stationary source). However, if the baseline actual emissions plus an amount equal to the significant level is less than 80 percent of the PAL level, the reviewing authority may set the PAL at a level that it determines to be more representative of the source's baseline actual emissions, or that it determines to be appropriate considering air quality needs, advances in control technology, anticipated economic growth in the area, desire to reward or encourage the source's voluntary emissions reductions, cost effective emissions control alternatives, or other factors as specifically identified by the reviewing authority in its written rationale. For instance, a reviewing authority may determine that PAL levels are inconsistent with the levels necessary to achieve the NAAQS, or a State may determine that PAL levels need to be reduced to provide room for new economic growth in the area.

In some circumstances, such as in the example cited below, the reviewing authority may exercise its discretion in deciding that an adjustment is not warranted. We believe that such discretion is appropriate, based in part on our experience with the pilot projects previously mentioned. In one instance, a participant voluntarily agreed to reduce its actual emissions by 54 percent in exchange for obtaining a source-wide emissions cap. After agreeing to this emissions reduction, the participant further reduced emissions by increasing capture efficiency and incorporating pollution prevention strategies into its operations. Unexpectedly, the participant also suffered an unusual economic downturn that caused a decrease in the rate of production and a corresponding decrease in actual emissions. At the time of renewal of the source-wide emissions cap, the participant's actual emissions were 10 percent of its actual emissions before committing to the emissions cap. The participant chose not to renew its emissions caps, because renewal required an automatic

shutdown should be treated as permanent depends on the intention of the owner or operator at the time of shutdown based on all facts and circumstances. Shutdowns of more than 2 years, or that have resulted in the removal of the source from the State's emissions inventory, are presumed to be permanent. In such cases it is up to the facility owner or operator to rebut the presumption.

adjustment to its current actual emissions level. Clearly, such a result contravenes the mutual benefits that operating under a PAL provides, and discourages you from undertaking voluntary reductions. If your source would ordinarily be subject to a downward adjustment, but you believe such an adjustment is not appropriate, you may propose another level. The reviewing authority may approve the level that you propose if it determines, in writing, that the level is reasonably representative of the source's baseline actual emissions. Similarly, the reviewing authority may determine that a lower level best represents the baseline actual emissions from the source.

Consistent with the effective period for the initial PAL, all renewed PALs will have a 10-year effective period.

6. How Can a PAL Be Increased During the Effective Period?

The reviewing authority may allow you to increase a PAL during the effective period if you are adding new emissions units or changing existing emissions units in a way that would cause you to exceed your PAL. However, today's rule only authorizes your reviewing authority to allow such an increase if you would not be able to maintain emissions below the PAL level even if you assumed application of BACT equivalent controls on all existing major and significant units (emissions units that have a PTE greater than a significant amount (as defined by § 52.21(b)(23) or the CAA, whichever is lower). Such units must be adjusted for current BACT levels of control unless they are currently subject to a BACT or LAER requirement that has been determined within the preceding 10 years, in which case the assumed control level shall be equal to the emissions unit's existing BACT or LAER control level. The PAL permit must require that the increased PAL level will be effective on the day any emissions unit that is part of the PAL major modification becomes operational and begins to emit the PAL pollutant.

Your proposed new emissions unit(s) and your existing emissions units undergoing a change must go through major NSR permitting, regardless of the magnitude of the proposed emissions increase that would result (for example, no significant level applies). This is because the significant level for the pollutant is incorporated into the PAL. These emissions units must comply with any emissions requirements resulting from the major NSR process (for example, LAER), even though they have also become subject to the PAL program or remain subject to the PAL.

To request a PAL increase, you must submit a complete major NSR permit application. As part of this application, you must demonstrate that the sum of the baseline actual emissions of your small emissions units, plus the sum of the baseline actual emissions from your significant and major emissions units (adjusted for a current BACT level of control unless the emissions units are currently subject to a BACT or LAER requirement that has been determined within the preceding 10 years, in which case the assumed control level shall be equal to the emissions unit's existing BACT or LAER control level), plus the sum of the allowable emissions of the new or modified existing emissions unit(s), exceeds the PAL.

After the reviewing authority has completed the major NSR process, and thereby determined the allowable emissions for the new or modified emissions unit(s), the reviewing authority will calculate the new PAL as the sum of the allowable emissions of the new or modified emissions unit(s), plus the sum of the baseline actual emissions of your small emissions units, plus the sum of the baseline actual emissions from significant and major emissions units adjusted for the appropriate BACT level of control as described above. Your reviewing authority must modify the PAL permit to reflect the increased PAL level pursuant to the public notice requirements of §§ 51.166(w)(5), 51.165(f)(5), or 52.21(aa)(5) of today's final rule.

7. Are There Any Circumstances That Would Cause Your PAL To Be Adjusted During the PAL Effective Period?

During the term of the PAL, at PAL renewal or at title V permit renewal, your reviewing authority may reopen your PAL permit and adjust the PAL level, either upward or downward, as needed by the reviewing authority. While certain activities require mandatory reopening, for others the reviewing authority may reopen at its discretion. The reviewing authority must reopen the permit for the following reasons: (1) To correct typographical/calculation errors made in setting the PAL or to reflect a more accurate determination of emissions used to establish the PAL; (2) to reduce the PAL if the owner or operator of the major stationary source creates creditable emissions reductions for use as offsets; or (3) to revise a PAL to reflect an increase in the PAL.

The reviewing authority may reopen the permit to: (1) Reduce the PAL to reflect newly applicable Federal requirements (for example, NSPS) with compliance dates after the PAL effective date; (2) reduce the PAL consistent with any other requirement that is enforceable as a practical matter, and that the State may impose on the major stationary source under the SIP; or (3) reduce the PAL if the reviewing authority determines that a reduction is necessary to avoid causing or contributing to a NAAQS or PSD increment violation, or to an adverse impact on an AQRV that has been identified for a Federal Class I area by an FLM and for which information is available to the general public.

While the final rule does not require your reviewing authority to immediately reopen the PAL permit to reflect newly applicable Federal or State regulatory requirements (for example, NSPS, RACT) that become effective during the PAL effective period, it does require the PAL to be adjusted at the time of your title V permit renewal or PAL permit renewal, whichever occurs first. Notwithstanding this requirement, today's final rule provides your reviewing authority discretion to reopen the PAL permit to reduce the PAL to reflect newly applicable Federal or State regulatory requirements before the time we otherwise require.

8. Can a PAL Eliminate Existing Emission Limitations?

An actuals PAL may eliminate enforceable permit limits you may have previously taken to avoid the applicability of major NSR to new or modified emissions units. Under the major NSR regulations at §§ 52.21(r)(4), 51.166(r)(2), and 51.165(a)(5)(ii), if you relax these limits, the units become subject to major NSR as if construction had not yet commenced on the source or modification. Should you request a PAL, today's revised regulations allow the PAL to eliminate annual emissions or operational limits that you previously took at your stationary source to avoid major NSR for the PAL pollutant. This means that you may relax or remove these limits without triggering major NSR when the PAL becomes effective. Before removing the limits, your reviewing authority should make sure that you are meeting all other regulatory requirements and that the removal of the limits does not adversely impact the NAAQS or PSD increments.

We are not taking a position on whether compliance with requirements contained in a PAL permit could serve to demonstrate compliance with certain pre-existing requirements on individual units. The reviewing authority may assess on a case-by-case basis whether any streamlining would be appropriate in the title V permit consistent with part 70 procedures and our existing policies and guidance on permit streamlining.

9. What MRRT (Collectively Referred to as "Monitoring") Requirements Must the Permit Contain for Emissions Units Under Your PAL?

Each permit must contain enforceable requirements that accurately determine plantwide emissions. A PAL monitoring system must be comprised of one or more of the four general approaches that meet the minimum requirements discussed below, and such monitoring systems must be approved by the reviewing authority. You may also employ an alternative approach if approved by the reviewing authority. Use of monitoring systems that do not meet the minimum requirements approved by the reviewing authority renders the PAL invalid. Any monitoring system authorized for use in the PAL permit must be based on sound science and must conform to generally acceptable scientific procedures for data quality and manipulation.

In return for the increased operational flexibility of a PAL, your permit must include sufficient data collection requirements to ensure compliance with the PAL at all times. In addition, the PAL permit must contain enforceable provisions that ensure that the monitoring data meet the minimum legal requirements for admissibility in a judicial proceeding to enforce the PAL permit.

This section addresses a number of issues associated with the practical enforceability of PALs and describes concepts that you and reviewing authorities must follow when establishing your PAL. The issues addressed include the following.

- How do monitoring requirements for emissions units under a PAL differ from those for emissions units that are not under a PAL?
- What are the testing requirements for your emissions units under a PAL?
- What monitoring systems are appropriate to demonstrate compliance with your PAL?
- What information about your proposed data collection systems must be submitted to your reviewing authority for approval?
- What recordkeeping requirements must your permit contain to demonstrate compliance with your PAL?
- What reporting requirements for your PAL must your permit contain?

a. How Do Monitoring Requirements for Emissions Units Under a PAL Differ From Those for Emissions Units That Are Not Under a PAL?

Typically, when an emission limitation applies on a unit-by-unit basis, the monitoring must be sufficient to provide data that demonstrate that emissions do not exceed the applicable limit for a particular unit. Under this approach, if an emissions unit has to meet an NSPS VOC limit of 9 ppm, the monitoring need only demonstrate that VOC emissions are no higher than 9 ppm but not measure VOC emissions at any precise level below 9 ppm (for example, 7 ppm, 8 ppm).

In contrast, under a VOC emissions actual PAL, the VOC emissions from each emissions unit must be quantified (in tpy), generally each month as the sum of the previous 12 months of VOC emissions. Thus, it becomes necessary to require monitoring that quantifies the emissions from each emissions unit to ensure that the annual limit is enforceable as a practical matter. As a result, the monitoring requirements for emissions units under a PAL may be more stringent than for those emissions units not under a PAL. In many instances, your emissions units may have monitoring suitable for determining compliance with a unit-specific emission limitation on a periodic basis, in accordance with title V requirements, but that monitoring frequency of data collection may not be appropriate for ongoing emissions quantification for a 12-month rolling total. Thus, even if your emissions unit's monitoring meets the title V requirements in §§ 70.6(a)(3)(i)(B) or 70.6(c)(1), you must upgrade that monitoring if you request a PAL and the existing monitoring does not meet the minimum requirements of the PAL regulations.

All units operating under a PAL must have sufficient monitoring to accurately determine plantwide emissions for a 12-month rolling total. For example, a source owner or operator with five units must be able, at any time, to quantify the baseline actual emissions for the past 12 months for each of the five units. That source should, in advance, outline how it plans to monitor each of the units in order to quantify the emissions. If one of the five units cannot accommodate one of the monitoring options provided in the rule in order to quantify the emissions, then the source owner or operator would be incapable of demonstrating ongoing compliance with the source's PAL.

b. What Are the Testing Requirements for Your Emissions Units Under a PAL?

As part of your PAL application and as directed by your reviewing authority, you must use current emissions or other current direct measurement data to demonstrate that your monitoring systems accurately determine emissions from each unit subject to a PAL. You will need to collect such data from all units subject to the PAL, including those that are unregulated at the present time. If you do not have current emissions data, or if your emissions unit's operation and equipment have changed since collection of that data, you will need to obtain current, accurate data, typically by conducting performance tests or other direct measurements before submission of your complete permit application to obtain a PAL.

In addition, you will need to re-validate the data and any correlation to demonstrate that your monitoring systems continue to accurately determine emissions from each unit subject to a PAL. This re-validation must occur at least once every 5 years for the life of the PAL. Data must be re-validated through a performance evaluation test or other scientifically valid means that is approved by the reviewing authority.

You must conduct all testing in accordance with test methods appropriate to your emissions unit and applicable requirements. For example, among the test methods for measuring organic emissions are Methods 18, 25, 25A, and 25B, which can be found in 40 CFR part 60, appendix A. During testing, your emissions unit must operate within the range you wish to operate, so as to provide an accurate quantification of emissions across the entire range. This may require you to perform more than one performance test.

c. What Monitoring Systems Are Appropriate To Demonstrate Compliance With Your PAL?

The PAL monitoring system must be comprised of one or more of four general approaches: (1) Mass balance for processes, work practices, or emissions sources using coatings or solvents; (2) Continuous Emissions Monitoring System (CEMS); (3) Continuous Parameter Monitoring System (CPMS) or Predictive Emissions Monitoring System (PEMS) with Continuous Emissions Rate Monitoring System (CERMS) or automated data acquisition and handling system (ADHS), as needed; or (4) emission factors. Alternatively, another monitoring approach may be used if approved in advance by the reviewing authority. The monitoring approaches mentioned above must meet minimum requirements established by today's rule.

In the mass balance approach, you would consider all of the PAL pollutant contained in or created by any raw material or fuel used in or at your emissions unit to be emitted. Currently, we are limiting this approach to monitoring for processes, work practices, or emissions sources using coatings or solvents. In order to use the mass balance approach, you must validate the content of the PAL pollutant that is contained in or created by any raw material or fuel used on site. This validation may be accomplished by a regular testing program conducted by the vendor of the materials or by an independent laboratory. In addition, you are required to use the upper limit of any content range in the calculations, unless the reviewing authority determines that there is a site-specific data monitoring system in place at the unit or that there are data to support the use of another content within the range.

If your reviewing authority allows you to use a mass balance approach, then the PAL permit must require you to account for all material containing the PAL pollutant or use of all materials that could create PAL pollutant emissions (through chemical decomposition, by-product formation, etc.). For instance, if you are subject to a VOC PAL and your emissions units do not utilize add-on control devices, you may use a mass balance approach to determine compliance. For example, suppose over 1 month you were using 8 tons of solvent with 25 percent VOCs (as demonstrated using Method 311). You would be required to report and include 2 tons of VOC emissions (since $8 \times 0.25 = 2$) for that month to compare with the PAL, even though some of the VOCs may not ultimately be emitted. (For example, they could be retained in your emissions unit's product or in a process waste.)

A CEMS, coupled with a CERMS as well as an ADHS (collectively known as a CEMS), may be used to measure and verify the PAL pollutant concentration, volumetric gas flow (if applicable), and PAL pollutant mass emissions discharged to the atmosphere from each emissions unit emitting the PAL pollutant. If your source utilize a CEMS approach, you must ensure that the CEMS meets the applicable Performance Specifications in 40 CFR part 60, appendix B. The CEMS must be capable of data sampling at least once every 15 minutes. In addition, you must be able to convert the data obtained from the CEMS system to a mass emissions rate.

These types of monitoring systems are appropriate for emissions sources subject to respective SO_2, NO_X, carbon monoxide, particulate matter (PM), VOC, total reduced sulfur (TRS), or hydrogen sulfide (H_2S) regulations.

A CPMS or PEMS coupled with CERMS and ADHS (collectively known as parameter monitoring), may be used for emissions units as reviewed and approved by your reviewing authority.

To determine emissions, parameter monitoring relies on: (1) Use of physical principles; (2) parameters such as temperature, mass flow, or pressure differential; and (3) performance testing results. Users of parameter monitoring must show a correlation between predicted and actual emissions across the anticipated operating range of the unit.

An example is a source owner or operator who determines VOC emissions from an incinerator by multiplying the incinerator efficiency by the amount of VOC-containing material used. Three assumptions are built into the emissions algorithm: (1) The VOC content remains constant; (2) the control device reduction efficiency remains constant over the temperature range established during performance testing; and (3) the unit load remains constant. Checks on these assumptions are established by: ongoing monitoring requirements (for example, combustion chamber temperature and control device load); ongoing emissions testing requirements (for example, periodic re-evaluation of the correlation between combustion chamber temperature and control device efficiency); and ongoing testing of the VOC content of the material.

Another example of parameter monitoring is an organic emissions condenser. The parameter monitoring design in this case is based on the laws of physics and the physical properties of the material (for example, the lowest condensation temperature of the VOC constituent), the temperature of the condenser, and the maximum material feed rate.

Some parameter monitoring works by calculating emissions using data from monitored parameters and a neural network system to optimize performance of a unit. By measuring numerous parameters, the network can then automatically analyze current operations, as well as emissions, and make adjustments to optimize performance.

Establishing parameter monitoring is a resource-intensive effort, requiring extensive up-front testing, analysis, and development. Recently, we have developed draft performance specifications for evaluating appropriate, acceptable parameter monitoring accuracy, repeatability, and reproducibility (*e.g.*, Performance Specification 16). You and your reviewing authority should review these performance specifications in developing an interim protocol for using parameter monitoring to demonstrate continuous compliance with a PAL. Your approved protocol may require revision as we finalize performance specifications.

Today's rule requires you to re-validate your monitoring systems, including parameter re-certification emissions testing, at least once every 5 years during the PAL permit term. You may conduct such re-validation as part of any other testing required by other non-PAL program requirements, such as title V program requirements.

If a parameter monitoring approach is taken, the owner or operator must use current site-specific data to establish the emissions correlations between the monitored parameter and the PAL pollutant emissions across the entire range of the operation of the emissions unit. If the owner or operator cannot establish a correlation for the entire operation range, the reviewing authority shall, at the time of the permit issuance, establish a default value(s) for determining compliance with the PAL based on the highest potential emissions reasonably estimated during the operational times when an emissions correlation is not available.

Alternatively, the reviewing authority may decide that operation of the emissions unit during periods where there is no emissions correlation is a violation of the PAL. The PAL permit must include enforceable requirements if either of these alternatives to the required correlation for parameter monitoring are used.

Emission factors may be used for demonstrating compliance with PALs, so long as the factors are adjusted for the degree of uncertainty or limitations in the factors' development. In ascertaining whether an emission factor is appropriate, you and your reviewing authority should consider the contribution of emissions from the emissions unit in relation to the PAL, the size of the emissions unit, and the margin of compliance of the emissions unit. In addition, if the emission factor approach is taken, the emissions unit shall operate within the designated range of use for the emission factor.

The owner or operator of a significant emissions unit that relies on an emission factor to calculate PAL pollutant emissions shall conduct validation testing using other monitoring approaches (if technically practicable) to determine a site-specific emission factor within 6 months of PAL permit issuance, unless the reviewing authority determines that testing is not required. For example, should you demonstrate to your reviewing authority's satisfaction that the use of your emission factor would yield a result that is protective of the environment, then you may not need to conduct site-specific performance testing. An emissions unit is considered significant if the emissions unit has the potential to emit the PAL pollutant in amounts greater than those listed in § 51.165(a)(1)(x).

In the event you choose to use one or more emission factors for your significant or small emissions units, you bear the burden to prove to the reviewing authority that the emission factors are appropriate and adjusted for any uncertainty in the factors' development. By way of example, the sulfur dioxide emission factor for 2-stroke, lean-burn, natural gas fired reciprocating engines, $5.88 * 10^{-4}$ pounds of sulfur dioxide emitted per million British Thermal Unit (mmBTU) of natural gas combusted, as published in our *Compilation of Air Pollutant Emission Factors AP–42, Fifth Edition Volume 1: Stationary Point and Area Sources,* which is found on our Internet Web site at *http://www.epa.gov/ttn/chief/ap42/index.html,* represents an appropriate emission factor.

The reviewing authority may approve other types of monitoring systems that quantify emissions to demonstrate compliance with PALs. Other types of monitoring that may be approved include a Gas Chromatographic (GC) or a Fourier Transform Infrared Spectroscopy (FTIR) CEMS that relies on extractive techniques, coupled with a CERMS as well as an ADHS, to measure and verify the VOC concentration, volumetric gas flow (if applicable), and VOC mass emissions (in lb/hr) discharged from stacks (that is, non-fugitive emissions) to the atmosphere. For processes, work practices, or emissions sources subject to VOC or organic hazardous air pollutant (HAP) regulations, these types of monitoring systems may be used for each emissions unit emitting VOC.

d. *What information about your monitoring system must be submitted to your reviewing authority for approval?*

You need to propose a monitoring system as part of your PAL permit application submission to your reviewing authority. The monitoring system proposed must accurately determine plantwide emissions. In your permit application, you must describe how you will collect and transform data from each emissions unit subject to a PAL permit, so that the emissions from each unit can be quantified as a 12-month rolling total. In addition, you need to demonstrate how you can be assured the data are and remain accurate by describing how you will install, operate, certify, test, calibrate, and maintain the performance of your monitoring system(s) on each emissions unit that will be subject to the PAL.

You will also need to provide calculations for the maximum potential emissions without considering enforceable emission limitations or operational restrictions for each unit in order to determine emissions during periods when the monitoring system is not in operation or fails to provide data. In lieu of the permit requiring maximum potential emissions during periods when there is no monitoring data, you may propose another alternate monitoring approach as a backup. This backup monitoring, however, must still meet the minimum requirements for the monitoring approaches prescribed in the regulation.

Note that each monitoring system with applicable requirements contained in appendix B of 40 CFR part 60 must be installed, operated, and maintained according to the applicable Performance Specification of 40 CFR part 60, appendix B.

For purposes of determining emissions from an emissions unit, a unit is considered operational not only during periods of normal operation, but also during periods of startup, shutdown, maintenance, and malfunction'even if compliance with a non-PAL emission limitation is excused during these latter periods. Your reviewing authority may approve different monitoring for various operating conditions (for example, startup, shutdown, low load, or high load conditions as demonstrated through multiple performance tests) for each emissions unit. You must, however, use one of the accepted monitoring approaches, including alternative monitoring approved by the reviewing authority, for these periods or calculate the emissions during these periods by assuming the highest PTE without considering enforceable emission limitations or operational restrictions.

In addition, the rule permits the reviewing authority to use the reasonably estimated highest potential emissions for periods when your emissions unit operates outside its parameter range(s) established in the performance test, unless another method is specified in the permit, and include those emissions in the 12-month rolling total in order to demonstrate compliance with the PAL. Alternatively, the reviewing authority may decide that operation outside the range(s) established in the performance test is a violation of the PAL. The reviewing authority must decide how to handle emissions when the unit is operating outside the ranges established in the performance tests prior to the issuance of the PAL permit and must include appropriate enforceable conditions in the PAL permit.

For parameter monitoring to be approved by your reviewing authority, your proposed monitoring system must measure the operational parameter value(s) within the established site-specific range(s) of operating parameter values demonstrated in recent performance testing. The monitoring system must then record the associated PAL pollutant mass emissions rate for that period based on the correlations demonstrated with the current test data.

e. *What Recordkeeping Requirements Must Your Permit Contain To Demonstrate Compliance With Your PAL?*

Your permit must require you to maintain records of your monitoring and testing data that support any compliance certifications, reports, or other compliance demonstrations. This information should contain, but is not necessarily limited to, the following data.

- The date, place (specific location), and time that testing or measuring occurs
- The date(s) sample analysis or analyses occur
- The entity that performs the analysis or analyses
- The analytical techniques or methods used
- The results of the analyses
- Each emissions unit's operating conditions during the testing or monitoring
- A summary of total monthly emissions for each emissions unit at the major stationary source for each calendar month
- A copy of any report submitted to the reviewing authority
- A list of the allowable emissions and the date operation began for any new emissions units added to the major stationary source.

You must also record all periods of deviation, including the date and time that a deviation started and stopped and whether the deviation occurred during a period of startup, shutdown, or malfunction.

You must retain records of all required testing and monitoring data, as well as supporting information, for at least 5 years from the date of the monitoring sample, measurement, report, or application. Supporting information includes all calibration and maintenance records and all original strip-chart recordings for continuous monitoring instrumentation, and copies of all required reports. Instead of paper records, you may maintain records on alternative media, such as microfilm, computer files, magnetic tape disks, or microfiche, provided that the use of such alternative media allows for expeditious inspection and review and does not conflict with other recordkeeping requirements.

You must also retain a copy of the following records for the duration of the PAL effective period plus 5 years: (1) A copy of the PAL permit application and any applications for revisions to the PAL; and (2) each annual certification of compliance pursuant to title V and the data relied on in certifying the compliance.

f. *What reporting requirements for your PAL must your permit contain?*

You must provide semi-annual monitoring and prompt deviation reports. The terms and conditions of an approved PAL become title V applicable requirements that will be placed in your title V permit. Therefore, the reports required under title V may meet the requirements of the PAL rule, so long as the minimum reporting requirements listed in the regulations are met. You must submit a semi-annual emissions report to the reviewing authority within 30 days after the end of each reporting period. The reviewing authority will use this report to determine compliance with the conditions of the PAL, including the PAL level.

The compliance period for an actuals PAL emissions level is a consecutive 12-month period, rolled monthly. Block 12-month periods are not allowed (for example, Jan.-Dec. of each year). The emissions report must include the total baseline actual emissions of the PAL pollutant for the previous 12 months and compare the previous 12 months' total emissions with the PAL level to determine compliance. Additionally, the emissions report must identify: the site; the owner or operator; the applicable PAL; the monitored parameters, the method of calculation with appropriate formulas, any emission factors used, the capture and control efficiencies used and the calculated emissions; total monthly emissions (tons) and the equations used to compute this value for each of the 12 months before submission of the emissions report (or for all prior months if the PAL has not been effective for 1 year); total annual emissions (tpy); a PAL compliance statement; a list of any emissions units added or modified to the site; and information concerning shutdown of any monitoring system, including the method that was used to measure emissions during that period. Finally, in accordance with title V requirements, your permit will require all reports to be certified by your responsible official as true, accurate, and complete.

10. What is the process for incorporating conditions of the PAL into your title V operating permit?

As discussed previously, the reviewing authority establishes a PAL in a federally enforceable permit using its minor NSR construction permit process or the major NSR permit construction process and eventually rolling these requirements into its title V operating permit. The reviewing authorities' rules for establishing or renewing PALs must include a public participation process prior to permit approval of the PAL. The process must be consistent with the requirements at § 51.161 and include a minimum 30-day period for public notice and opportunity for public comment on the proposed permit. PALs established through the major NSR process are subject to major NSR public participation requirements. When adding a new emissions unit under an established PAL, you must comply with the reviewing authority's minor NSR permit requirements for public notice, review, and comment.

The process for incorporating the conditions of a PAL into the title V operating permit depends on whether the initial title V permit has already been issued for the source. If the initial title V permit has not been issued, a PAL created in a minor or major NSR permit would be incorporated during initial issuance of the title V permit. If the initial title V permit has already been issued, the PAL would be incorporated through the appropriate part 70 modification procedures. As discussed later in this preamble, we suggest that you request that your reviewing authority renew your title V permit concurrently with issuance of your PAL in order to align the two processes together and decrease the administrative burden on you and your reviewing authority.

Once a PAL is established, a change at a facility is exempt from major NSR and netting calculations, but could require a title V permit modification, as could any other change. Whether a title V permit modification would be required, and which permit modification process would be used, is governed by the current part 70 rule as implemented by the reviewing authority.

11. What is an example of an actuals PAL?

The following example is based upon a hypothetical source that wishes to obtain an actuals PAL under the final regulations adopted today.

A manufacturing plant (a major stationary source) located in a serious ozone nonattainment area seeks an actuals PAL for VOC in January 2002. The major source threshold for VOC in a serious ozone nonattainment area is 50 tpy and the significant level for VOC modifications is 25 tpy. The plant has 5 emissions units with a total PTE of 640 tpy of VOC. The PTE for VOC for each of the emissions units at the plant is as follows: (1) Unit A is 335 tpy; (2) unit B is 20 tpy; (3) Unit C is 125 tpy; (4) unit D is 60 tpy; and (5) unit E is 100 tpy. Units A, B, C, and D are existing emissions units with more than 2 years of operating history. Unit E has been in operation for only a year. Unit D was dismantled in year 2000 and is considered permanently shutdown.

For units A, B, C, and D, the source has selected July 1, 1996 to June 30, 1998 (a consecutive 24-month period) to determine baseline actual emissions. Unit A is subject to a RACT requirement that became effective in year 2000. The baseline actual emissions for each emissions unit during this period are as follows: unit A, 140 tpy (including RACT adjustment); unit B, 10 tpy; unit C, 90 tpy; and unit D, 20 tpy.

The actuals PAL level for VOC is = 260 + 100 − 20 + 25 = 365 tpy

WHERE

- 260 tpy = the sum of the baseline actual emissions for emissions units A–D (with 2 or more years of operation)
- 100 tpy = the allowable emissions (PTE) of unit E, which was constructed after the 24-month period;
- 20 tpy = baseline actual emissions of unit D, which is permanently shut down since the 24-month period; and
- 25 tpy = significant level for VOC in a serious nonattainment area.

D. Rationale for Today's Final Action on Actuals PALs

We received voluminous comments and suggestions in response to the 1996 NSR proposal, the 1998 NOA, and numerous meetings with interested stakeholders. This section addresses the more significant comments we received. For a more detailed discussion of the comments received and our responses, please refer to the Technical Support Document included in the docket for this rulemaking. The comment areas addressed in this section include: (1) How do the PAL regulations meet the major NSR requirements of the Act? (2) Are PALs consistent with the concept of "contemporaneity'? (3) Are PALs permissible in serious and severe nonattainment areas? (4) Is it appropriate for a PAL to be based on actual emissions? (5) How should actual emissions be determined in setting the PAL level? (6) Should emissions from shut down or dismantled units be excluded from a PAL? (7) Should a PAL include a margin for growth? (8) Should PALs be required to expire? (9) Should we require PALs to be adjusted at the time of PAL renewal? (10) Should certain new emissions units that are added under a PAL be required to meet some level of emissions control? (11) Under what circumstances should you be allowed to increase your PAL and how should we apply the major NSR requirements to that increase? (12) What monitoring requirements are necessary to ensure the enforceability of PALs as a practical matter? (13) Is EPA adopting an approach that allows area-wide PALs? and (14) When should modeling or other types of ambient impact assessments be required for changes occurring under a PAL?

1. How do the PAL regulations meet the major NSR requirements of the Act?

The PAL regulations adopted today meet the requirements of the CAA and are consistent with the Congressional purpose and intent underlying NSR. We believe the PAL regulations constitute a reasonable interpretation of the Act's definition of "modification" and are permissible under current law.

The definition of "modification" set forth in section 111(a)(4) of the Act is fundamental to determining major NSR applicability. Pursuant to the Act, the term modification means "any physical change in or change in the method of operation of a stationary source which increases the amount of any air pollutant emitted by such source or which results in the emission of any air pollutant not previously emitted." The statute, however, does not prescribe the methodology for establishing a stationary source's emissions baseline from which emissions increases are measured. When a statute is silent or ambiguous with respect to specific issues, the relevant inquiry is whether the agency's interpretation of the statutory provisions is permissible. *Chevron U.S.A., Inc.* v. *NRDC, Inc.*, 467 U.S. 837, 865 (1984).

Accordingly, EPA is exercising its discretion to develop reasonable alternatives to determine NSR applicability that are consistent with the statutory provisions and Congressional intent underlying the NSR requirements. We believe that the PAL regulations adopted today represent a permissible construction of the Act.

2. Are PALs consistent with the concept of "contemporaneity"?

In the 1998 NOA, we solicited comment on whether and how a program that recognizes PALs as an alternate method for determining NSR applicability should address a particular legal concern: the need to have some "contemporaneity" between an emissions increase and any decrease relied upon to net the increase out of review. As we discussed in the 1998 notice, the current regulations specify that, to be creditable, emissions increases and decreases must have occurred within a "contemporaneous" period. Our current regulations governing SIP-approved programs do not specify a precise time frame. However, the Federal PSD rules generally only credit those emissions increases and decreases that occur within the 5 years preceding a given change. We established these regulatory requirements after the court's decision in *Alabama Power,* in which the court interpreted the Act as requiring plantwide bubbling in the PSD program, but stated that "any offset changes claimed by industry must be substantially contemporaneous." 636 F.2d 402. In the 1998 notice, we sought comment on whether a PAL program that never required PALs to be periodically updated to reflect current emissions at the source would allow sources to make emissions reductions and hold them indefinitely, only to use them several decades later to offset new increases, and whether such a system would contravene the contemporaneity principle the court announced.

Many commenters, including several regulatory agencies, maintain that PALs are consistent with the NSR requirements under the Act. These commenters contend that the court gave EPA the discretion to define contemporaneity. See 636 F.2d 402 ("The Agency has discretion, within reason, to define which changes are substantially contemporaneous."). Others contend that changes made under a PAL are not subject to the *Alabama Power* "contemporaneity" requirement because a change made under the PAL is either excluded from NSR or alternatively does not exceed the applicable NSR significance threshold. Therefore, they contend that netting is not implicated by such changes. On the other hand, a few commenters assert that PALs conflict with the purpose of the Act.

We believe that the concept of contemporaneity, as articulated in *Alabama Power* and as set forth in the regulations governing the major NSR program, does not apply to PALs. The PAL program differs in certain important respects from our current regulations and from the 1978 regulations at issue in *Alabama Power.* The *Alabama Power* court was not presented with the PAL approach for determining whether there was an increase in emissions and did not consider whether the principles it set forth in its opinion would apply to such an approach.

Under the 1978 PSD regulations (43 FR 26380), a source was subject to BACT review only if "no net increase in emissions of an applicable pollutant would occur at the source, taking into account all emissions increases and decreases at the source which would accompany the modification." 43 FR 26385. The test for whether a "major modification" had occurred required the source to sum all accumulated increases in potential emissions that had occurred at the source since issuance of the regulations, or since issuance of the last construction permit, whichever was more recent. Reductions achieved elsewhere in the source could not be taken into account.

In *Alabama Power,* the D.C. Circuit held that EPA was correct in excluding from BACT review any changes that did not result in a net increase of a pollutant. 636 F.2d 401. It concluded, however, that EPA had incorrectly excluded contemporaneous decreases from the calculation of whether a "major modification" had occurred. *Id.* at 402–03.

The current regulations take contemporaneous decreases into account for all PSD review purposes. Under the current regulations, you look initially at the emissions unit undergoing the change and determine whether there will be a significant increase at that unit. If there is no significant increase at the unit, the inquiry ends there. While we continue to believe that this is a permissible approach, one drawback to this approach is that it allows a series of small, unrelated emissions increases to occur, which is discussed elsewhere in this preamble. If there will be a significant increase at the unit, then you expand the inquiry to other units at the source. You take into account contemporaneous increases and decreases at the source in determining whether there will be an increase for the source as a whole. Thus, you must calculate increases and decreases at individual units in order to arrive at a net figure for the entire source.

In contrast, under today's PAL regulations, the inquiry begins and ends with the source. Your PAL represents source-wide baseline actual emissions. As such, it is the reference point for calculating increases in baseline actual emissions. If your source's emissions will equal or exceed the PAL, then there will be an emissions increase at your source. There is no need to calculate increases and decreases at individual units.

Today's PAL regulations constitute a reasonable, though not the only, approach to determining whether there is an emissions increase at your source. While we believe that the principle of contemporaneity continues to be important for purposes of major NSR netting calculations, we do not believe that it is a necessary concept for purposes of PALs. This is because if your source has a PAL, you have accepted a different means of calculating an emissions increase for the PAL pollutant. The only relevant question is whether your source has reached or exceeded the PAL level.

Even though PALs are a new approach, they do not alter the fundamental question, which is whether there will be an increase in emissions from your source. For actuals PALs, we consider whether there will be an increase in baseline actual emissions. Because the PAL serves as the baseline for measuring an increase, we have taken steps to ensure that the PAL is reasonably representative of baseline actual emissions. In taking these steps, we have also ensured that actuals PALs as finalized today are consistent with the concept of contemporaneity, to the extent such a concept has any application in this context. One way of viewing a PAL is to focus on the increases and decreases at individual emissions units that, taken together, result in the net emissions from your source as a whole. As long as the decreases that have occurred during the term of the PAL are sufficient to offset any increase that occurs, total emissions for your source will remain below the PAL, and your source will not experience a "significant net emissions increase." Viewed from this perspective, the term of the PAL constitutes the "contemporaneous" period. We believe that 10 years is a reasonable contemporaneous period for PALs for the following two reasons. First, we believe that a 10-year period is practical and reasonable both for you and for the reviewing authority. While a logical stopping point may seem to be 5 years in line with the title V permit period, setting a PAL can be a complex and time consuming process, so a 5-year period would be too short and hence not beneficial either to you or to the reviewing authority. Second, a study conducted by Eastern Research Group, Inc.[31] supported a 10-year look back to ensure that the normal business cycle would be captured generally for any industry.

In addition, we believe that the PAL renewal provisions ensure that each 10-year term represents a distinct "contemporaneous" period. The renewal process is designed to prevent decreases that occurred outside of the current 10-year PAL term from being used to offset increases during that term. At renewal, the reviewing authority must consider whether decreases have occurred at your source because of compliance with newly applicable requirements. Thus, for example, if the compliance date for a new RACT requirement occurred during the initial term of the PAL, and the reviewing authority has not already adjusted the PAL downward to account for that requirement, it must do so at renewal. More generally, the reviewing authority is required to evaluate baseline actual emissions and provide a written rationale for public comment if it determines that an adjustment to the PAL is warranted. As part of this process, the reviewing authority must adjust the PAL downward if your source's current PTE is below the PAL level. We believe that this adjustment is important for air quality planning purposes. Additionally, the reviewing authority may renew the PAL at the same level if your source's baseline actual emissions plus the significant level are equal to or greater than 80 percent of the PAL level without consideration of other factors. We believe that this level is reasonably representative of the source's baseline actual emissions. If your source's baseline actual emissions plus the significant level are less than 80 percent of the PAL level, the reviewing authority may set the PAL at a level that it determines to be more representative of the source's baseline actual emissions, or that it determines to be appropriate considering air quality needs, advances in control technology, anticipated economic growth in the area, desire to reward or encourage the source's voluntary emissions reductions, or other factors as specifically identified by the reviewing authority in its written rationale. We recognize that fluctuations in baseline actual emissions will occur at most sources as part of the normal business cycle. We also recognize that requiring the reviewing authority to adjust the PAL downward if your source's baseline actual emissions do not equal 100 percent of the PAL level could create an incentive for you to maximize your baseline actual emissions. In addition, most sources do not emit at a level just below the maximum allowable level but rather build in a margin to prevent accidental exceedances. However, the PAL should be reasonably representative of baseline actual emissions so that it can continue to serve as the baseline for calculating an emissions increase. We have balanced these competing concerns in adopting a requirement, subject to the provisions noted below, to provide discretion to the reviewing authority to adjust the PAL level if baseline actual emissions plus the significant level do not equal at least 80 percent of the PAL level.

To maintain flexibility, today's actuals PAL regulations allow the reviewing authority to determine representativeness on a case-by-case basis. If you believe that the new PAL level that the reviewing authority proposes for your source is not representative of your source's baseline actual emissions, you may propose a different level. In addition, any person may propose a different level as being more representative of your source's baseline actual emissions. The reviewing authority may approve a higher or lower level if it determines that it is reasonably representative of your source's baseline actual emissions.

For example, assume that your source was designed to burn either fuel oil or natural gas, and that your source's permit allowed the use of either fuel. During the initial term of the PAL, you used only natural gas at the source and your source-wide emissions were consistently less than 80 percent of the PAL level. However, due to shifting market conditions, you expected to use fuel oil for a period beginning after PAL renewal. Under these circumstances, the reviewing authority could reasonably determine that a higher level would be more representative of your source's baseline actual emissions.

Similarly, your source might be designed to manufacture several different products, and your permit might allow you to switch from one product to another. During the initial term of the PAL, you might produce a

[31] Eastern Research Group Inc. report on "Business Cycles in Major Emitting Source Industries" dated September 25, 1997.

product associated with low emissions, resulting in source-wide emissions that were consistently less than 80 percent of the PAL level. However, you might be planning to produce a product that would cause the source to emit at a higher level following PAL renewal. This is another example of a circumstance in which the reviewing authority could reasonably determine that a higher level was more representative of your source's baseline actual emissions.

In addition, for SIP planning purposes, the reviewing authority may adjust the PAL level at its discretion based on air quality needs, advances in control technology, anticipated economic growth in the area, or other relevant factors.

Because of the safeguards described above, we believe that the actuals PAL program as finalized today ensures that the PAL will serve as an appropriate baseline for determining whether there is a significant net "increase" in overall emissions from the source, and thus whether the source is undergoing a "modification."

Moreover, we believe that a PAL approach satisfies Congressional intent to only apply the NSR permit process when industrial changes cause significant net emissions increases to an area and not when changes in plant operations result in no emissions increase from the major stationary source. *See Alabama Power,* 636 F.2d 401.

3. Are PALs Permissible in Serious, Severe, and Extreme Ozone Nonattainment Areas?

In our 1996 proposal, we requested comment on whether PALs could be implemented in serious and severe ozone nonattainment areas in a manner that was consistent with section 182(c)(6) of the Act. Section 182(c)(6) contains special provisions for major stationary sources that increase VOC emissions in serious or severe ozone nonattainment areas as a result of a physical change or a change in the method of operation. In some of these areas, the provisions also apply if you increase NO_X emissions. In general, these special provisions change the significant level for VOC emissions in serious and severe nonattainment areas from 40 tpy to greater than 25 tpy. They also specify that you must go through a major NSR permitting review if you have a net emissions increase in the aggregate of more than 25 tpy over a period of 5 years.

In addition, we requested comment on whether PALs could be implemented in extreme ozone nonattainment areas. Section 182(e)(2), which applies in such areas, provides that any physical change or change in the method of operation at the source that results in "any increase" from any discrete operation, unit, or other pollutant-emitting activity at the source, generally must be considered a modification subject to major NSR permit requirements, regardless of any decreases elsewhere at the source.

A few industry commenters believe that the "accumulation" provisions of CAA section 182(c)(6) should make no difference to the acceptability of a PAL in "serious" and "severe" ozone nonattainment areas. They contend that we have correctly concluded that CAA section 182(c)(6) only applies when net emissions at the source as a whole increase above the 25 ton level. Accordingly, any change that triggered CAA section 182(c)(6) would already have breached the PAL limits. On the other hand, an environmental commenter states that a PAL in a serious, severe, or extreme ozone nonattainment area could be problematic because it could allow for an increase at an emissions unit in situations where source-wide emissions would not exceed the PAL.

We agree with commenters who believe that the PAL approach does not conflict with the provisions of CAA section 182(c)(6). We do not interpret section 182(c)(6) to be a limitation on our ability to authorize PALs in serious and severe nonattainment areas. This section directs that when there is an increase meeting certain criteria, it may not be considered *de minimis*, but it does not specify the methodology by which an emissions increase must be calculated. Accordingly, we exercise our discretion in establishing the methodology, and we are doing so today by having the PAL serve as the actuals emissions baseline against which future emissions increases are measured. *Chevron U.S.A., Inc.* v. *NRDC, Inc.,* 467 U.S. 837, 865 (1984). If your source's emissions equal or exceed the PAL, it will trigger NSR, whereas maintaining plant emissions below the PAL ensures that there is no emissions increase. We believe that our interpretation reasonably implements the statutory purpose of the section, given that PAL sources agree to be subject to a plantwide cap that serves as the reference point for determining whether there has been an increase and given that the appropriateness of the PAL level is reviewed at 10-year intervals. Actuals PALs effectively prevent the uncontrolled, unrelated, small, serial emissions increases section 182(c)(6) is designed to address.

Because CAA section 182(e)(2) clearly requires consideration of increases at individual emissions units in extreme ozone nonattainment areas, PALs are not allowed in such areas, since any increase in emissions from any unit in those areas constitutes a modification.

4. Is It Appropriate for a PAL to Be Based on Actual Emissions?

In 1996, we proposed and sought comment on a broad range of alternative approaches for setting PAL emission limitations, including a PAL based on the following: (1) Actual emissions as defined under the current and then proposed regulations at § 51.166(b)(21)(ii); (2) actual emissions with the addition of an operating margin greater than the applicable significance rate; (3) for new stationary sources, limits established pursuant to a review of the entire facility under PSD; and (4) for nonattainment pollutants (in nonattainment areas), any emissions level completely offset and relied upon in an EPA-approved State attainment demonstration plan. 61 FR 38250, 38256 (July 23, 1996).

We received general support for the PAL concept and for the different approaches we proposed. Some comments express support for a PAL approach based on allowable emissions, and others indicate support for a PAL approach based on actual emissions. Some commenters generally believe that an allowables approach is necessary to ensure increased operating flexibility and capacity utilization. They also assert that an allowables approach would protect air quality management goals, because they claim that air quality planning historically has been based on permitted emissions levels. Other commenters believe that an actuals approach is preferable because it facilitates more accurate air quality planning and provides a more reliable basis for determining the availability of offsets.

We have concluded that a major stationary source's compliance with an actuals-based PAL system is a permissible means of assuring that a major stationary source does not have a significant emissions increase. We also conclude that this approach can be implemented in a manner that is consistent with the Act. Thus, in today's action, we are adopting regulations that authorize States to issue actuals PALs. We plan to address allowables PALs in an upcoming rulemaking.

5. How Should Actual Emissions Be Determined in Setting the PAL Level?

In the 1996 proposal, we requested comment on whether the definition of actual emissions for the purpose of determining the level of the PAL should be based on the definition of actual emissions in the current major NSR regulations, or whether it should be based on the proposed revisions to the actual emissions definition contained in that 1996 proposal. The fundamental difference between these two approaches is that the current NSR regulations would only allow you to look back 5 years to determine the actual emissions (the sum of actual emissions for all emissions units at your major stationary source). The 1996 proposed changes to this definition would allow you to look back 10 years to determine the actual emissions.

Several commenters prefer a 10-year baseline period for setting PALs based on actual emissions. A few commenters prefer a 5-year baseline period. One commenter advocates use of an actual emissions level that is initially based on the previous 2 years but that would decline over time.

In a separate section of today's final rules, we are finalizing changes to our definition of baseline actual emissions. Among other changes to the definition, you will be allowed to look back for a period of 10 years to establish the baseline actual emissions (except for EUSGUs). For program consistency and ease of implementation, we believe that the procedure for determining the baseline actual emissions for establishing your PAL should be the same as the baseline actual emissions that you will be required to use under the other major NSR program requirements. Accordingly, we are adopting an approach for establishing your actuals PAL that is consistent with how the baseline actual emissions are determined for an emissions unit under other requirements of the major NSR program.

We are, however, including a special allowance for emissions units that have operated for less than 2 years. Under such circumstances, the emissions unit has not operated long enough to establish a reliable baseline actual emissions calculation. Therefore, today's rule allows your reviewing authority to consider the allowable emissions of such emissions units when establishing or renewing the PAL. The baseline actual emissions of such emissions units would be adjusted to reflect a more representative level of baseline actual emissions at the time of the next PAL renewal.

6. Are Emissions From Shut Down or Dismantled Units Excluded From a PAL?

We proposed several options to adjust PAL levels to account for emissions units that are shut down or dismantled before setting a PAL. Several commenters support adjusting the PAL level for permanently shut down or dismantled units. A few commenters maintain that PAL adjustments are only appropriate for long-term shutdowns. Other commenters oppose allowing adjustments for shutdowns. They indicate that it would be difficult to implement and that it could penalize sources that were meeting environmental goals.

We agree with commenters that the baseline actual emissions used in establishing the PAL should exclude emissions from units that are permanently shut down or dismantled after the 24-month period selected for establishment of baseline emissions. We believe that excluding such emissions from your PAL level is appropriate for air quality planning purposes. Moreover, the environment has already seen the benefit of the reduced emissions. We also do not agree with those commenters who advocate adjusting the PAL only for long-term shutdowns, because it is too difficult to define and enforce "long-term."

As described in section IV.C.2 of this preamble, the PAL level includes baseline actual emissions from each existing emissions unit and new emissions unit at the source. For any emissions unit that has been permanently shut down since the 24-month period, its emissions should not be included in calculating the PAL level. Conversely, for an emissions unit that began construction after the 24-month period, the emissions (equal to the potential emissions of that emissions unit) must be included in setting the PAL level.

One shutdown option we considered, but did not adopt, is to exclude emissions from PALs only for units that did not operate at all during the 10-year life of the PAL. Under this option, the PAL would not be adjusted downward if you utilized those emissions from the shut down or dismantled units elsewhere at your source during the period since the shutdown (for example, by adding new emissions units or capacity, or by increasing capacity utilization at existing emissions units). As we indicated in our proposal, we believe it would be too difficult to determine whether you have actually relied on these emissions decreases in undertaking other activities at your source. We did not receive any comments suggesting ways to overcome this identified problem.

7. Does a PAL Include a Reasonable Operating Margin?

In the July 23, 1996 action, we proposed that a PAL for existing sources be based on source-wide actual emissions, including a reasonable operating margin less than the applicable significant emissions rate. We also requested comment on several other options for establishing a PAL. Several commenters support the option of basing the PAL on source-wide actual emissions plus a reasonable operating margin less than the applicable significance amount. Other commenters believe an operating margin tied to significant levels would be too restrictive.

Today we are finalizing an option that allows you to include, when setting the initial PAL, an amount that corresponds to the significant level for modifications of the PAL pollutant as specified in the major NSR rules [for example, in the PSD regulations at § 52.21(b)(23)(i)], or as specified in the CAA, whichever is lower. For example, for SO_2 PALs you may add to the PAL baseline level the 40 tpy significant level; for CO PALs you may add 100 tpy to the PAL baseline level. Also, for serious and severe ozone nonattainment areas the VOC significant level added to the PAL level is 25 tpy. For major sources of NO_X located in serious and severe ozone nonattainment areas, where NO_X is regulated as an ozone precursor, you may add to the NO_X PAL baseline the NO_X significant level of 25 tpy, and not the 40 tpy NO_X significant level specified under PSD. In extreme ozone nonattainment areas, PALs are not allowed since any increase in emissions in these areas constitutes a modification.

While other approaches to providing a reasonable operating margin may be consistent with the CAA, we believe that the approach we are adopting today comports most closely with existing regulatory provisions for major NSR applicability. That is, it assures that the environment sees no significant increases in emissions compared to the baseline actual emissions existing before the PAL is established.

In our 1998 NOA, we also requested comment on whether we should provide for an operating margin when renewing a PAL. We proposed four possible approaches for maintaining a reasonable operating margin, including an option that would include in the adjusted PAL level an operating cushion equal to 20 percent of the current PAL. In a separate section of the NOA, we also requested comment on how PALs should be adjusted for emissions units that have installed good emissions controls.

Many commenters indicate that we must provide for a reasonable operating margin. However, we generally received unfavorable comments on all the approaches we suggested. Several commenters believe that our suggested approaches do not provide an adequate operating margin. In responding to our request for comment on how to adjust PALs for emissions units that have installed good emissions controls, many commenters indicate that it would be inappropriate for EPA to "confiscate" such emissions reductions. Such an approach would encourage sources to pollute to maintain higher baseline emissions, and would penalize those sources who would voluntarily reduce emissions. At least one commenter maintains that both you and the environment should benefit from these reductions, and thus, you should be allowed to retain a portion of your voluntary emissions reductions.

We agree with some commenters that mandating an adjustment at renewal, based solely on current operations and emissions levels, would discourage the voluntary emissions reductions the PAL is specifically designed to encourage. We agree with commenters that both you and the environment should benefit from your commitment to comply with a PAL. Should you engage in voluntary emissions reductions, we believe you should be able to retain the accompanying flexibility that encouraged you to make these reductions. At the time of renewal, it may be very difficult for a reviewing authority to distinguish the reason for a decrease in your baseline actual emissions level. It could be because you have aggressively applied emissions controls, or because of a decrease in utilization, a loss of capacity, a desire to maintain a compliance margin, or any of a number of other reasons. Accordingly, we believe that it would be difficult to advise a reviewing authority to only retain a certain percentage of your emissions reductions that resulted from applying emissions controls. Therefore, for simplicity, and for what we believe to be a reasonable policy position to encourage you to voluntarily reduce emissions without a fear of a complete loss of operational flexibility, we are allowing your reviewing authority discretion to renew the PAL at an appropriate level. Hence, your reviewing authority may renew the PAL at the same level without consideration of other factors, if the baseline actual emissions plus the significant level is equal to or greater than 80 percent of the PAL level. If not, today's rules also allow your reviewing authority to renew the PAL at a different level if it determines that level is more representative of baseline actual emissions. See section II.D.9, "Should we require PALs to be adjusted at the time of PAL renewal," for more information on our rationale for allowing this discretion.

8. Are PALs Required to Expire?

In our 1998 NOA, we announced that we were considering, and requested comment on, an approach that would require PALs to expire after 10 years unless you choose to renew the PAL. We proposed that the PAL term would be 10 years. Several commenters agree with our suggested time frame of 10 years for the term of a PAL. Others support a 5-year period, which would fit with the title V permit review period. Some commenters support a period longer than 10 years.

Today, we are finalizing rules that require a PAL to be effective for a period of 10 years. We believe that a fixed-term PAL provides you with an appropriate time of regulatory certainty and allows a sufficient period of time for planning long-term capital improvements.

We also agree with those commenters who think it is beneficial to align the PAL renewal process with the title V permitting process for your major stationary source. Similar to a PAL permit process, the title V permit process provides the public with a comprehensive review of your source. We believe that aligning the PAL permit with the title V process will allow you and your reviewing authority to consolidate the administrative process for the two permitting actions. It also provides the public with a better understanding of your emissions characteristics relative to the surrounding community. However, we do not believe that requiring PALS to be reviewed every 5 years, consistent with the title V renewal period, provides industry with a sufficient period of regulatory certainty. We also believe that while the overall administrative burden for you and the reviewing authority is reduced if you are complying with a PAL, the establishment of a PAL requires an initial commitment of substantial resources. Given this initial resource investment, we do not believe that a 5-year fixed term for a PAL provides you or your reviewing authority with an adequate incentive to participate in the PAL system. Thus, in an effort to balance the need for regulatory certainty, the administrative burden, and a desire to align the PAL renewal with the title V permit renewal, we believe a fixed term of 10 years, the equivalent of two title V effective periods (10 years), is most appropriate. You may elect to renew your PAL after 10 years, for a subsequent 10-year period, rather than allow the PAL to expire.

In order to align the PAL renewal process with the title V permitting process, we suggest that you request that the reviewing authorities renew title V permits concurrent with issuance of the initial PAL permit, regardless of how many years are actually left on your title V permit.

9. Are PALs Required To Be Adjusted at the Time of PAL Renewal?

In 1996, we requested comment on "why, how, and when a PAL should be lowered or increased without being subject to major NSR." In 1998, we announced that we were considering an option that required PALs to be renewed to reflect new current baseline actual emissions. We were also considering requiring a PAL to be adjusted for unused capacity. Under this approach, we would adjust a PAL downward when an emissions unit operates below the capacity level that was used to establish the PAL. In our 1998 NOA, we expressed three reasons why it might be appropriate to require PALs to be periodically adjusted. First, we expressed concern that the allowable-to-allowable applicability system of the PAL would allow you to indefinitely retain the right to pollute at an historical level of actual emissions. Second, we were concerned that a PAL may allow you to retain unused emissions credits that would otherwise be available for economic growth in the area. And third, we were concerned that a PAL may interfere with a State's ability to plan for attainment if your actual emissions to the atmosphere are lower during a SIP planning year than in a subsequent year.

Some commenters generally oppose any periodic reviewing or adjustment of a PAL. They believe that such an approach would limit operational flexibility, discourage efficiency improvements, and create disincentives for voluntary reductions. However, other commenters generally support an approach that would require a periodic adjustment to PALs.

We continue to have concerns with an approach that would allow a PAL to be renewed without any evaluation of the appropriateness of the current PAL level. We believe such an approach would be contrary to the Act, and contrary to the court's decision in *WEPCO* v. *Reilly*, 893 F.2d 901, 908 (7th Circ. 1990). In WEPCO, the court determined that one statutory purpose of the NSR requirements is "to stimulate the advancement of pollution control technology," and that "allowing increased production (and pollution) through the extensive replacement of deteriorated generating system" without triggering NSR review would create "vistas of indefinite immunity from the provisions of * * * PSD."

We believe today's rules avoid this inappropriate outcome, by requiring the reviewing authority to evaluate your baseline actual emissions at the time of PAL permit renewal.

Although we believe that a periodic review of the level of the PAL may be necessary, and that this may result in an adjustment in your PAL to a level that is representative of your baseline actual emissions, we do not believe that we should mandate an adjustment to the PAL based on only one prescribed methodology. Such an approach could lead to inappropriate results, as discussed below. Instead, we believe that our concerns can be appropriately addressed by providing the States the authority to adjust the PAL based on what is representative of your baseline actual emissions.

We believe that some discretion in determining what is representative of actual emissions is appropriate, based in part on our experience with the pilot projects previously mentioned. In one instance, a participant voluntarily agreed to reduce its actual emissions by 54 percent in exchange for obtaining a source-wide emissions cap. After agreeing to this emissions reduction, the participant further reduced emissions by increasing capture efficiency and incorporating pollution prevention strategies into its operations. Unexpectedly, the participant also suffered an unusual economic downturn that caused a decrease in the rate of production and a corresponding decrease in actual emissions. At the time of renewal of the source-wide emissions cap, the participant's actual emissions were 10 percent of its actual emissions before committing to the emissions cap. The participant chose not to renew its emissions caps, because renewal required an automatic adjustment to its current actual emissions level. Clearly, such a result contravenes the mutual benefits operating under a PAL provides, and discourages you from undertaking voluntary reductions. Accordingly, although today's final rules require the reviewing authority to consider the need for adjusting the PAL when your current baseline actual emissions plus the significant level are less than 80 percent of your PAL level, it also provides the reviewing authority discretion to consider a variety of factors in determining whether the PAL should be adjusted.

We are also providing your reviewing authority discretion to take into account measures necessary to prevent a violation of a NAAQS or PSD increment, and to prevent an adverse impact on an AQRV in a Federal Class I area. For example, although we remain concerned that a PAL may allow you to retain unused emissions credits that would otherwise be available for economic growth in your area, we believe that managing an area's economic growth is the primary responsibility of the State. As such, the State, through your reviewing authority, should have discretion to manage the growth increment for your area. If your State wishes to encourage economic growth, then it may, at its discretion, reduce your PAL for that reason. Conversely, it may decide that encouraging economic growth is not a priority for the area and concurrently find no other concerns that warrant a downward adjustment in your PAL.

After further reflection, we also believe that it is inappropriate for us to mandate in all cases a prescribed methodology for adjusting PALs based on our concern that a PAL system may interfere with a State's ability to plan for attainment. We believe that the concern regarding planning for attainment is not unique to a PAL system. Most importantly, nothing in this rule reduces the State's discretion in developing plans to attain and maintain NAAQS. Under our major NSR applicability system, you could increase your emissions over your historical actual emissions by increasing utilization or hours of operation. If this occurs, there may be a discrepancy between the amount the State carries in the emissions inventory and the amount that you emit to the atmosphere. States should be cognizant of these issues and take appropriate measures in their SIP planning procedures to assure that emissions from any major stationary source, including a PAL participant, are properly characterized in the emissions inventory.

And finally, we agree with industry commenters that if we were to mandate an adjustment because your baseline actual emissions did not equal 100 percent of the PAL level, it would encourage you to increase production and emissions, and such an outcome would be counterproductive. We have accordingly provided your reviewing authority the ability to add a reasonable operating margin to your baseline actual emissions at the time of renewal. This operating margin was discussed previously in section II.D.7 above—"Should a PAL include a reasonable operating margin?"

10. Are Certain New Emissions Units That Are Added Under a PAL Required To Meet Some Level of Emissions Control?

We solicited comments on whether we should require you to control emissions from new emissions units that are added under an established PAL. Several commenters believe that BACT or LAER should not be required for these emissions units. A few commenters favor adding a requirement that BACT or LAER be required on new emissions units.

We believe that it is unnecessary to mandate a specific control level on new emissions units that you add under an established PAL. After reviewing the performance of a limited number of facilities that are participating in PAL pilot projects, we have concluded that these facilities' desire to maintain a large degree of operational flexibility under a PAL system has encouraged them to voluntarily install state-of-the-art controls on new emissions units. (See footnote 26 regarding our study, "Evaluation of the Implementation Experience with Innovative Air Permits.") We anticipate similar results as we extend the PAL program more broadly. Alternatively, we believe that you will add emissions controls to existing emissions units if this is a more cost effective approach to controlling your emissions. This is precisely the type of flexibility you should have for managing your total source-wide emissions under a PAL system. Furthermore, this cost effective approach was contemplated and supported by the statements of the court in *Alabama Power*. The court concluded that you should be allowed to add new emissions units if the new emissions from this unit could be "set-off against decreases" from other emissions units at the major stationary source. Accordingly, we do not believe that it is necessary to mandate the installation of emissions controls on new emissions units if you are able to continue to comply with your PAL even after installing the new emissions unit. If our projections on this matter prove to be incorrect in practice, we will consider revising our regulations in the future to require a specific control level on new and/or existing emissions units.

11. Under What Circumstances Are You Allowed To Increase Your PAL and How Are the Major NSR Requirements Applied To That Increase?

We proposed that whenever a PAL is increased due to the addition of a new unit, or due to a physical or operational change to an existing emissions unit, the units associated with the increase would be reviewed for current BACT or current LAER, air quality impacts modeling, and emissions offsets, if applicable. We noted that it may be difficult for a reviewing authority to determine which emissions units are associated with a physical change or change in method of operation when the emissions increase is the result of a source-wide production increase. We requested comment on five possible ways to apply the major NSR requirements when emissions increases are not directly associated with a particular change.

Commenters offered various suggestions for addressing emissions increases above the PAL. Several commenters believe that major NSR should only be applied to the emissions unit primarily responsible for the increase. Among the various commenters, there are a few supporters for each one of the options we proposed. In addition, one commenter suggests that we add *de minimis* increase levels; another suggests that we require offsets for each increase. Several industry commenters believe that we should not apply major NSR when an increase above the PAL is solely due to a production increase. One commenter believes all increases should be subject to BACT.

After considering the comments received, we agree with the commenters who believe that major NSR should only be applied to the emissions units (either new or modifications of existing units) primarily causing the increase. Accordingly, in the final regulations, we are confirming our proposed requirement that only those emissions units that are part of a PAL major modification would be subject to major NSR.

As discussed earlier, we believe that a PAL provides you with an incentive to control existing and new emissions units to maximize your operational flexibility under your PAL. We also recognize that there may be valid economic reasons for requesting an upward adjustment in a PAL. We are, however, concerned that if there were no restrictions on your ability to request a PAL increase, you would not have an incentive to control emissions. Therefore, under today's final rules, before the reviewing authority may approve a mid-term increase in your PAL, you must demonstrate that you are unable to maintain emissions below your current PAL even with a good faith effort to control emissions from existing emissions units. To make this demonstration, you must show that even if BACT equivalent control (adjusted for a current BACT level of control unless the emissions units are currently subject to a BACT or LAER requirement that has been determined within the preceding 10 years, in which case the assumed control level shall be equal to the emissions unit's existing BACT or LAER control level) were to be applied to all of your significant and major emissions units, the resulting emissions level will exceed your current PAL when combined with the emissions from both your small emissions units and your new emissions unit's allowable emissions.

12. What Compliance Monitoring, Reporting, Recordkeeping, and Testing (MRRT) Requirements Are Necessary to Ensure the Enforceability of PALs as a Practical Matter?

The MRRT requirements for PALs are addressed below. Numerous commenters, generally State agencies and environmental groups, state that adequate monitoring, reporting, and recordkeeping requirements would be necessary to ensure that the PAL limits were enforceable. Some commenters hold that the monitoring, recordkeeping, and reporting provisions would be too burdensome and restrictive. Some believe that PALs would not be viable because of these requirements.

Several commenters request that we clarify the monitoring that is necessary to show compliance with a PAL, especially in relation to the CAM and title V programs. Several commenters prefer that the monitoring requirements be flexible and simple. These commenters urge us not to use CAM, require CEMS, or establish stringent protocols. A few commenters prefer that we not define what would be enforceable as a practical matter for PAL limits. Others insisted that the PAL limits must be federally enforceable.

We believe that the PAL must assure that the source maintains emissions below the PAL level to assure that major NSR does not apply. Therefore, we agree with the commenters who stated that adequate data collection requirements through means such as monitoring, reporting, and recordkeeping requirements are necessary to ensure that the PAL limits are enforceable as a practical matter. In fact, we find that not only monitoring, recordkeeping, and reporting requirements, but also emissions testing requirements, for emissions units subject to a PAL differ from other MRRT in one important aspect: actual unit emissions must be measured to provide a 12-month rolling total, and compared against a limit. Currently, many emissions units are required only to have MRRT suitable for initial or spot checks on emissions concentrations, not emissions quantification. Even emissions units whose MRRT meets the title V requirements in §§ 70.6(a)(3)(i)(B) or 70.6(c)(1), including those imposed by part 64 (the CAM rule), may need to be upgraded when those units are proposed to become subject to a PAL, because the approved title V MRRT may not be able to count emissions against a cap. While we believe you can obtain data for emissions quantification best through the use of CEMS or PEMS, in today's final rule we are allowing you to propose other types of emissions monitoring quantification systems, depending upon such factors as the size category of the emissions unit and its margin of compliance.

13. Is EPA Adopting an Approach That Allows Area-Wide PALs?

In 1996, we proposed an option that would allow a State to adopt an area-wide PAL approach. Under such an approach, all major stationary sources within a given geographic area would have a PAL. Our 1996 proposal contained little detail on how this would be implemented.

While a few commenters support area-wide PALs, many more oppose them. State agency commenters generally believe they would need time to develop PALs consistent with the approaches provided in the final NSR rule, as well as to develop data management and compliance assurance approaches that would accommodate the PAL approach. Thus, adding the area-wide PAL at the same time as the source-specific PAL may create several administrative headaches. Industry commenters maintain that area-wide PALs would ratchet down emissions and reduce flexibility.

We agree with the many commenters who opposed an area-wide PAL system, believing that the approach would be complex and resource and time intensive. We also perceived little interest in such an approach from the various stakeholders with whom we have met. Accordingly, we are not including any provisions in our final rules to implement an area-wide PAL system. However, we are not precluding such a program either. If a State currently has or wants to pursue an area-wide PAL program, then it must demonstrate that its program is equivalent to or more stringent than our final rules.

14. When Should Modeling or Other Types of Ambient Impact Assessments Be Required for Changes Occurring Under a PAL?

In our 1996 proposal, we requested comment on when modeling or other air quality impacts analysis is needed for changes occurring under a PAL to demonstrate protection of NAAQS, increments, and AQRVs.

One environmental commenter recommends modeling or other types of ambient impacts assessment whenever a change in emissions occurred under the PAL. One commenter recommends that FLMs be consulted whenever changes under the PAL are proposed, to determine whether an impact analysis for adverse impact on AQRVs would be necessary. Several commenters recommend modeling whenever a significant change occurred, but also recommend that EPA define significant change and how the modeling would be conducted. A facility could report the modeled effects of a minor change after the change is made (in a quarterly, semi-annual, or perhaps annual modeling summary), while more significant changes should be modeled prior to construction. The facility could be given a lot of responsibility in these cases and then held accountable (that is, required to mitigate) should an air quality increment or NAAQS be exceeded. These commenters also recommend that the impacts evaluation should be conducted at the time the PAL is established and that the PAL should clearly define what flexibility the source is allowed without further review and the types of changes for which additional review will be required. Some commenters generally believe that the proposed regulatory language concerning changes to PALs for air quality reasons was too vague and broad, but only a few of these commenters directly oppose modeling for changes under the PAL. One commenter states that if many changes were to require ambient air quality analysis, the PAL approach would have little if any benefit. The commenter believes that sources ought to discuss up front with permit authorities which emissions shifts might have consequences that would later require additional modeling/monitoring. If questions existed about certain emissions sources under a PAL, PALs could be approved with conditions assuring that certain post-approval modeling analysis be submitted.

In today's final rules, we believe we can rely on the reviewing authority's existing programs for addressing air quality issues. Certain changes in effective stack parameters under the PAL would generally be covered by the reviewing authority's minor NSR construction permit program. The reviewing authority would ordinarily request air quality modeling for any changes if it believes that the changes under the PAL may affect the NAAQS and PSD increments.

V. Clean Units

A. Introduction

In today's final rulemaking, we are promulgating a new type of applicability test for emissions units that are designated as Clean Units. This new applicability test will measure whether an emissions increase occurs, based on whether the physical change or change in the method of operation affects the Clean Unit status of the unit. This new applicability test provides that when you meet emission limitations based on installing state-of-the-art emissions control technologies (add-on control technology, pollution prevention techniques, or work practices) that are determined to be BACT or LAER, you may make any physical or operational changes to the Clean Unit without triggering major NSR, unless the change causes the need for a revision in the emission limitations or work practice requirements in the permit for the unit adopted in conjunction with BACT, LAER, or Clean Unit determinations, or would alter any physical or operational characteristics that formed the basis for the BACT, LAER, or Clean Unit determination for a particular unit. Emissions units that have not been through major NSR may also qualify for the Clean Unit applicability test if you demonstrate that their emission limitations based on their emissions control technology (that is, add-on control technology, pollution prevention technique, or work practice) is comparable to BACT or LAER and you demonstrate that the allowable emissions will not cause or contribute to a NAAQS or PSD increment violation, or adversely impact an AQRV (such as visibility) that has been identified for a Federal Class I area by an FLM and for which information is available to the general public. To be comparable to BACT/LAER, the controls must meet the specific comparability test that we describe in section V.C.3 of this preamble. That is, you must show that the air pollution control technology (which includes pollution prevention or work practices) is comparable to BACT/LAER in one of two ways: (1) By comparing your emissions unit's control level to BACT/LAER determinations for other similar sources in the RACT/BACT/LAER Clearinghouse (RBLC); or (2) by making a case-by-case demonstration that your emissions control is "substantially as effective" as BACT or LAER.

The Clean Unit applicability test benefits the public and the environment by providing you with an incentive to install state-of-the-art emissions controls, even if you would not otherwise be required to control emissions to this level. You will benefit from these final rules because they provide you with increased operational flexibility. Once you have installed state-of-the-art emissions controls on an emissions unit and it is considered a Clean Unit, you may make changes to respond rapidly to market demands without having to obtain a preconstruction major NSR permit. Moreover, you and your reviewing authority will benefit from increased administrative efficiency. We believe that once you have installed state-of-the-art emissions control, an additional major NSR review will generally not result in any additional emissions controls for a period of years after the original control technology determination is made. In such cases, the major NSR permitting requirements impose a paperwork burden with little to no additional environmental benefit. The Clean Unit applicability test eliminates this unnecessary administrative action.

B. Summary of 1996 Clean Unit Proposal

In the 1996 NSR Reform package, we proposed an innovative approach to NSR applicability called the Clean Unit Exclusion. The proposed Clean Unit Exclusion would allow you to modify qualifying emissions units without being subject to the NSR permitting process for a period of 10 years, as long as your maximum hourly emissions rates would not increase. We proposed that your pre-change hourly potential emissions rate must be established at any time up to 6 months prior to the proposed activity or project.

We proposed three methods by which an emissions unit could qualify for the Clean Unit Exclusion. One was that the emissions unit went through a major NSR action within the last 10 years and had an enforceable limit based on BACT or LAER. The second was if the emissions unit was permitted under a State or local agency minor NSR program within the last 10 years and the minor NSR control technology requirements were comparable to BACT or LAER. As part of this second method, we proposed that State and local agencies would submit their minor NSR programs for certification so that case-by-case determinations for emissions units permitted under a minor NSR program would not be necessary. The third method was a case-by-case determination that an emission limitation was comparable to BACT or LAER for that emissions unit. For these units, we proposed that the Clean Unit Exclusion would last for 5 years. We proposed that a determination that a limit was comparable to BACT or LAER could be based on one of two methods: (1) the average of the BACT or LAER for equivalent sources over a recent period of time (such as 3 years); or (2) the unit's control level is within some percentage (such as 5 or 10) of the most recent, or average of the most recent, BACT or LAER levels for equivalent or similar sources.

In addition, we asked for public comment on whether Clean Unit status should apply to emissions units with limits based on MACT or RACT. Although we did not propose accompanying regulatory language, we suggested that reviewing authorities use the title V permitting process to designate Clean Units.

C. Final Regulations for Clean Units

1. Summary of Final Action

Today's rule provides that your emissions unit qualifies as a Clean Unit, and qualifies to use the Clean Unit applicability test, if it has gone through a major NSR permitting review and is complying with BACT or LAER. Conversely, if your emissions unit has not gone through a major NSR permitting review, you do not automatically qualify for Clean Unit status. These emissions units must first go through a SIP-approved permitting process that includes a process for determining whether the emissions unit meets the criteria to be designated as a Clean Unit. This process must include public notice and opportunity for public comment.

To obtain Clean Unit status and qualify for the Clean Unit applicability test using a SIP-approved permitting process, you must pass a two-part test: (1) The air pollution control technology (which includes pollution prevention or work practices) must be comparable to BACT or LAER; and (2) you must demonstrate that the allowable emissions will not cause or contribute to a NAAQS or PSD increment violation, or adversely impact an AQRV (such as visibility) that has been identified for a Federal Class I area by an FLM and for which information is available to the general public. You may make a showing that the air pollution control technology (which includes pollution prevention or work practices) is comparable to BACT/LAER in two ways: (1) By comparing your emissions unit's control level to BACT/LAER determinations for similar sources in the RBLC; or (2) by making a case-by-case demonstration that your emissions control is "substantially as effective" as BACT or LAER.

If your emissions unit automatically qualifies as a Clean Unit because it has been through major NSR permitting, you may use the Clean Unit applicability test for up to 10 years. Today's rules allow you to apply for Clean Unit status for control technologies you have installed in the past if you go through a SIP-approved permitting program that authorizes Clean Units and you qualify as a Clean Unit. The Clean Unit effective period for emissions units that must go through a SIP-approved permitting process to obtain Clean Unit status is consistent with the time frame for emissions units that automatically qualify as Clean Units. That is, you may only use the Clean Unit applicability test for a period of 10 years. If you meet the requirements that we describe in section V.C.9 of this preamble, you may re-qualify for Clean Unit status. Upon expiration of Clean Unit status, the Clean Unit applicability test no longer applies to changes at the emissions unit.

It is worth noting that in 1996, we proposed the provisions for Clean Units as a "Clean Unit Exclusion," although we discussed the provisions as a new applicability test. We received criticism from at least one commenter that our characterization of the test as an exclusion was inappropriate. We agree with this commenter, and have thus renamed the test as the Clean Unit applicability test. We believe that this title more appropriately reflects that the test is not whether you are excluded from review under major NSR, but whether using a more appropriate emissions test you trigger major NSR review.

2. Is Clean Unit Status Available in Both Attainment and Nonattainment Areas?

You may obtain Clean Unit status regardless of whether you are located in an attainment area or in a nonattainment area. Our proposed Clean Unit provisions were unclear on how emissions offsets and other nonattainment area requirements are affected by Clean Unit status. We want to clarify this issue. For sources in nonattainment areas which went through major NSR permitting while the area was nonattainment or which have qualified for Clean Unit status showing they are comparable to LAER, the permitted emissions level for the Clean Unit must have been offset. The emissions reductions resulting from installation of the control technology that is the basis of an emissions unit's status as a Clean Unit may not be used as offsets; however, emissions reductions below the level that qualified the unit as a Clean Unit may be used as offsets if they are surplus, quantifiable, permanent, and federally enforceable. Furthermore, for emissions units that are designated as Clean Units and that are located in nonattainment areas, RACT and any other requirements for nonattainment area sources under the SIP will still apply. The only exception to this is that the specific major NSR requirements related to calculating emissions increases from a physical change or change in the method of operation for all other existing sources that we describe in this preamble and codify in today's rules are not applicable to Clean Units, because the Clean Units are subject to an alternative major NSR applicability requirement for calculating emissions increases when changes are made.

As we discuss in detail in section V.C.3 of this preamble, the "substantially as effective" test for sources in nonattainment areas must consider only LAER determinations, except that emissions units in nonattainment areas that went through major NSR permitting while the area was designated an attainment area for that regulated NSR pollutant, and that received a permit based on a qualifying air pollution control technology, automatically qualify as Clean Units.

If your emissions unit received Clean Unit status while the unit was located in an attainment area and the area's attainment status subsequently changes to nonattainment, your emissions unit retains Clean Unit status until expiration. However, to re-qualify as a Clean Unit (see section V.C.9), the unit will have to meet the requirements that apply in nonattainment areas.

3. How Do You Qualify As A Clean Unit?

Any emissions unit permitted through major NSR automatically qualifies as a Clean Unit, provided the BACT/LAER determination results in some degree of emissions control. (We discuss the specific requirements for qualifying controls in section V.C.4 of this preamble.) These units already meet both the control technology and air quality criteria of the CAA and the NSR regulations. We believe that the emission limitations (based on the BACT/LAER determination) and other permit terms and conditions (such as any limits on hours of operation, raw materials, etc., that were used to determine BACT/LAER) are protective of air quality. Although emissions units that have been through major NSR automatically qualify for Clean Unit status, there are specific procedures for establishing and maintaining Clean Unit status. We discuss these procedures in detail in sections V.C.6 through 9 of this preamble.

Your emissions units that have not gone through a major NSR permitting action that resulted in a requirement to comply with BACT or LAER may qualify for Clean Unit status if they are permitted under a SIP-approved permitting program that provides for public notice of the proposed determination and opportunity for public comment. You must pass a two-part test to obtain Clean Unit status: (1) The air pollution control technology (which includes pollution prevention or work practices) must be comparable to BACT or LAER; and (2) the allowable emissions will not cause or contribute to a NAAQS or PSD increment violation, or adversely impact an AQRV (such as visibility) that has been identified for a Federal Class I area by an FLM and for which information is available to the general public.

You may show that the air pollution control technology (which includes pollution prevention or work practices) is comparable to BACT/LAER in one of two ways: (1) By comparing your emissions unit's control level to BACT/LAER determinations for other similar sources in the RBLC; or (2) by making a case-by-case demonstration that your emissions control is "substantially as effective" as BACT or LAER.

To make a demonstration using the first methodology in a nonattainment area, you must compare your control technology to the best-performing 5 similar sources in the RBLC for which LAER has been determined within the past 5 years. If the emission limitation that is achieved by your control technology is at least as stringent as any one of the 5 best-performing units, and the emissions unit also passes the air quality test, then the reviewing authority shall presume that it qualifies as a Clean Unit. In attainment areas, you must compare your control technology to all BACT and LAER decisions that have been entered into the RBLC in the past 5 years, and for which it is technically feasible to apply the BACT or LAER control to your emissions unit type. If your control technology achieves a level of control that is equal to or better than the average of these determinations, and the emissions unit also passes the air quality test, then the reviewing authority shall presume that your emissions unit qualifies as a Clean Unit.

After you have submitted your demonstration, the reviewing authority will also consider other BACT/LAER determinations that are not included in the RBLC to determine whether the proposed emissions rate is comparable to BACT/LAER, and incorporate this information into its determination as appropriate. In addition, the public will have an opportunity to review and comment on the reviewing authority's decision to designate an emissions unit as a Clean Unit. This approach ensures that you are meeting an emissions level comparable to that of BACT or LAER, while providing you flexibility to use the controls that are best suited to your processes.

We are providing this first methodology as a streamlined methodology for identifying Clean Units. Any unit that meets these qualifications shall be presumed to be a Clean Unit. Conversely, the opposite is not true. The reviewing authority shall not presume that a unit that does not meet the test is not a Clean Unit. The quality and number of determinations in the RBLC vary by different type of sources. The RBLC may not always identify all the types of control technology strategies that should qualify an emissions unit as a Clean Unit, or it may not provide a representative sample for making an appropriate determination. Therefore, even if you are unable to demonstrate that your emissions unit is a Clean Unit using this methodology, your reviewing authority shall not allow this outcome to prejudice its decision-making.

Accordingly, we are providing a second option for determining whether you qualify as a Clean Unit. If your emissions unit does not meet the emission limitation determined from the analysis of the RBLC described above (as appropriate for the area in which it is located), or if there is insufficient information in the RBLC to conduct the analysis, then you may still show, on a case-by-case basis, that your emissions unit will achieve a level of control that is "substantially as effective" as BACT or LAER, depending whether your emissions unit is in an attainment area or a nonattainment area. In an attainment area, your emissions unit must achieve a level of control that is "substantially as effective" as BACT. In a nonattainment area, your emissions unit must achieve a level of control that is "substantially as effective" as LAER. The reviewing authority will make a decision on whether a particular air pollution control technology (which includes pollution prevention or work practices) is "substantially as effective" as the BACT/LAER technology for a specific source on a case-by-case basis.

We are not promulgating specific requirements or performance criteria for satisfying the "substantially as effective" test, because we believe reviewing authorities are in the best position to determine whether in fact a particular air pollution control technology (which includes pollution prevention or work practices) is "substantially as effective" as the BACT/LAER technology for a specific source. The case-by-case determinations must meet the same air quality test as those units going through a BACT/LAER determination. Moreover, the public has opportunity for public review and comment on the "substantially as effective" decision. With these safeguards, we believe the "substantially as effective" test will ensure determinations that meet both the control technology and air quality tests, as well as allow sources to implement the controls that are best suited to their individual processes.

Under the second part of the test to determine whether your unit qualifies for Clean Unit status, you must demonstrate that the allowable emissions will not cause or contribute to a NAAQS or PSD increment violation, or adversely impact an AQRV (such as visibility) that has been identified for a Federal Class I area by an FLM and for which information is available to the general public. If your emissions unit has already been permitted under minor NSR or another SIP-approved permitting program, you may have already satisfied the second part of this test. If not, consistent with the requirements in sections 165(a)(3) and 173(a) of the CAA, you will be required to show that the allowable emissions will not cause or contribute to a NAAQS or PSD increment violation, or adversely impact an AQRV (such as visibility) that has been identified for a Federal Class I area by an FLM and for which information is available to the general public. For areas that do not already attain the NAAQS, the source would be required to show that the emissions for the unit have been previously offset.

4. Can an Emissions Unit That Applies No Emissions Control Technology Qualify as a Clean Unit?

In most cases, BACT/LAER will result in significant emissions decreases (such as 90 percent control for many VOC coating sources).[32] In some circumstances, however, the outcome of a reviewing authority's BACT or LAER determination may result in an emission limitation that you will meet without using a control technology (add-on control, pollution prevention technique, or work practice). Under today's rules, you will not qualify as a Clean Unit in such circumstances. More specifically, today's rules also require you to make an investment to qualify initially as a Clean Unit. An investment includes any cost which would ordinarily qualify as a capital expense under the Internal Revenue Service's filing guidelines whether or not you actually choose to capitalize that cost. An investment also includes any cost you incur to change your emissions unit or process to implement a pollution prevention approach, including research expenses, or costs to retool or reformulate your emissions unit or process to accommodate an add-on control, pollution prevention approach, or work practice.

5. When Do the Major NSR Requirements Apply to Clean Units?

Once an emissions unit qualifies as a Clean Unit, it is subject to an alternative major NSR applicability test for calculating emissions increases for subsequent changes. As we discussed in section II of this preamble, we have codified our longstanding policy (for emissions units that are not Clean Units) that a major modification occurs if both of the following result from the modification: (1) A significant emissions increase following the physical or operational change; and (2) a significant net emissions increase from the major stationary source. The major NSR applicability test for Clean Units is a different process.

For Clean Units, you must first determine whether a project causes the need to change the emission limitations or work practice requirements in the permit which were established in conjunction with BACT, LAER, or Clean Unit determinations and any physical or operational characteristics that formed the basis for the BACT, LAER, or Clean Unit determination for a particular unit. If it does, you lose Clean Unit status, and the project is subject to the applicability requirements as if the emissions unit were never a Clean Unit. If the project does not cause the need to change the emission limitations or work practice requirements in the permit which were established in conjunction with BACT, LAER, or Clean Unit determinations and any physical or operational characteristics that formed the basis for the BACT, LAER, or Clean Unit determination for a particular unit, then you maintain Clean Unit status, and no emissions increase is deemed to occur from the project for the purposes of major NSR. Once you have lost Clean Unit status, you can only re-qualify for Clean Unit status by going through the process that we describe in section V.C.9 of this preamble.

6. Can You Get Clean Unit Status for Controls That Have Already Been Installed?

As discussed in section V.C.3, emissions units that have been through major NSR permitting automatically qualify for Clean Unit status. This includes those emissions units that went through major NSR before promulgation of today's final rules. If an emissions unit automatically qualifies for Clean Unit status because it went through major NSR, its Clean Unit status is based on the BACT/LAER controls that went into service as a result of the major NSR review. That is, Clean Unit status is based on the BACT/LAER controls regardless of whether the actual process for designating Clean Unit status through title V occurs at some time after the controls went into service. However, Clean Unit status, and the ability to use the applicability process for Clean Units, does not begin until the Clean Unit effective date. We discuss the specific procedures for when Clean Unit status starts, when it ends, and how it is designated in sections V.C.7 through 9.

For emissions units that have not been through major NSR, our rules allow your reviewing authority to provide you with Clean Unit status for emissions control that you have already installed and operated. However, our final rules also limit the time frame under which your reviewing authority is allowed to make such determinations for Clean Unit status that is granted through a SIP-approved permitting process other than major NSR. Your reviewing authority will only be able to grant Clean Unit status for previously installed emissions controls if they were installed before the effective date of the program in your area. If the emissions unit's control technology is installed on or after the date that provisions for the Clean Unit applicability test are effective in your area, you must apply for Clean Unit status from your reviewing authority at the time the control technology is installed. As for emissions units that went through major NSR review, Clean Unit status for emissions units permitted through SIP-approved programs other than major NSR does not begin until the Clean Unit effective date.

If you are applying for retroactive Clean Unit status, today's final rules allow your reviewing authority to compare your emissions control level to the BACT or LAER level that would have applied at the time you began construction of your emissions unit. However, in some cases, such a comparability analysis may be difficult for you to demonstrate because of lack of sufficient information from which your reviewing authority can make a reasoned determination. If this is the case, then you will have to demonstrate that your emissions controls are comparable to a BACT or LAER limit from a subsequent or current date.

7. When Can I Begin To Use the Clean Unit Test?

The exact effective date depends on the circumstances of the individual emissions unit, as explained further below. As a general principle, however, the effective date for Clean Unit status can never be before the Clean Unit provision becomes effective in the relevant jurisdiction.

For emissions units that automatically qualify for their original Clean Unit status because they have been through major NSR review, and for units that re-qualify for Clean Unit status (see section V.C.9) by going through major NSR review and implementing new control technology to meet current-day BACT/LAER, the effective date is the date the emissions unit's air pollution control technology is placed into service, or 3 years after the issuance date of the major NSR permit, whichever is earlier. However, the effective date can be no sooner than the date that provisions for the Clean Unit applicability test are approved by the Administrator for incorporation into the SIP and become effective for the State in which the unit is located. That is, if the source had a major NSR permit and began operating before the Clean Unit provision becomes effective in the relevant jurisdiction, the effective date is the date the State or local agency begins authorizing Clean Unit status. As we noted earlier, if the emissions unit previously went through major NSR, it automatically qualifies as a Clean Unit. The original Clean Unit status would be based on the controls

[32] It is possible that a BACT/LAER analysis will not always result in the requirement of add-on controls at a source. In some situations, a reviewing authority may appropriately determine that the control technology that best represents BACT/LAER is a work practice, or a combination of work practices and add-on controls. As a result, a requirement to use work practices, or a combination of add-on controls and work practices, as an emissions control technology, could qualify an emissions unit for Clean Unit status, provided it meets the criteria established.

that were installed to meet major NSR. An additional investment at the time the original Clean Unit status becomes effective is not required.

For emissions units that re-qualify for Clean Unit status (see section V.C.9) by going through major NSR using an existing control technology that continues to meet current-day BACT/LAER, the effective date is the date the new major NSR permit is issued.

If you obtain Clean Unit status from your State or local reviewing authority using a SIP-approved permitting process other than major NSR, the Clean Unit effective date is the later of the following dates: (1) The date that the State or local agency permit that designates the emissions unit as a Clean Unit is issued; and (2) the date that the emissions unit's air pollution control measures went into service. That is, if the controls went into service before the issuance date of the State or local agency permit that designates the unit as a Clean Unit, the Clean Unit effective date is the date that the permit is issued. As with units that have been through major NSR, additional investment is not required for the limited cases where there is a retroactive designation. If the issuance date of the State or local agency permit that designates the emissions unit as a Clean Unit is before the date the controls went into service (as would likely be the case for a unit that is new or modified after the State or local agency begins to authorize Clean Unit status), then the effective date of Clean Unit status is the date the controls went into service.

8. How Long Does Clean Unit Status Last?

In most cases, you may use the Clean Unit applicability test for a period of 10 years.[33] As a general principle, the Clean Unit expiration date can never be later than the date that is 10 years after the controls are brought into service.

For emissions units that automatically qualify for their original Clean Unit status because they have been through major NSR review, and for units that re-qualify for Clean Unit status (*see* section V.C.9) by going through major NSR review and implementing new control technology to meet current-day BACT/LAER, Clean Unit status expires 10 years after the effective date, or the date the equipment went into service, whichever is earlier. However, Clean Unit status expires sooner if, at any time, the owner or operator fails to comply with the provisions for maintaining Clean Unit status that are included in the final rules.

For emissions units that re-qualify for Clean Unit status (*see* section V.C.9) by going through major NSR using an existing control technology that continues to meet current-day BACT/LAER, Clean Unit status expires 10 years after the effective date. However, as noted above, Clean Unit status expires sooner if, at any time, the owner or operator fails to comply with the provisions for maintaining Clean Unit status that are included in the final rules.

The expiration date for Clean Units that have not been through major NSR permitting depends on whether the owner or operator qualifies for Clean Unit status based on current BACT/LAER, or on BACT/LAER at the time the control technology was installed. If the owner or operator of a previously installed unit demonstrates that the emission limitation achieved by the emissions unit's control technology is comparable to the BACT/LAER requirements that applied at the time the control technology was installed, then Clean Unit status expires 10 years from the date that the control technology was installed. For all other emissions units (that is, previously installed units that are demonstrated to be comparable to current BACT/LAER, new units, and units that re-qualify as Clean Units), Clean Unit status expires 10 years from the effective date of the Clean Unit status. In addition, for all emissions units, Clean Unit status expires any time the owner or operator fails to comply with the provisions for maintaining Clean Unit status that are included in the final rules.

When your Clean Unit status expires, you are subject to the major NSR applicability test as if your emissions unit is not a Clean Unit. The permitted emissions levels established for the Clean Unit do not expire.

9. Can I Re-qualify for Clean Unit Status?

You may re-qualify for Clean Unit status after the status has expired or you have otherwise lost Clean Unit status, if you meet the conditions in our final regulations. As we stated before, we believe that once you have installed state-of-the-art emissions control, an additional major NSR review will generally not result in any additional emissions controls for a period of years after the original control technology determination is made. Also, the period for which any specific air pollution control technology (which includes pollution prevention or work practices) will continue to achieve the same level of control depends on many factors. As a practical matter, we have established a single time frame of 10 years for Clean Unit status, to provide simplicity in our final rules. However, for reasons we discuss in detail in section V.E.1 of this preamble, we determined that a reasonable average equipment life for a control technology is generally longer than 10 years. Certainly we want to encourage source owner/operators to install and maintain state-of-the-art control. We believe this is more likely when you can be assured that you can retain Clean Unit status for the useful life of the equipment, as long as air quality continues to be assured. The useful life of the equipment may extend beyond the original Clean Unit expiration date. Therefore, we are promulgating final regulations that allow you to apply to re-qualify for Clean Unit status.

To re-qualify for Clean Unit status, you would generally follow the same process that you used in first qualifying for Clean Unit status. However, we will not necessarily require you to meet an additional investment test to re-qualify for Clean Unit status for the same controls. That is, unless the controls used to establish Clean Unit status are no longer BACT/LAER or comparable, there will be no requirement for an investment to re-qualify for Clean Unit status.

You may re-qualify for Clean Unit status either by going through major NSR or by going through the alternative Clean Unit Test that we described in section V.C.3 of this preamble: (1) The air pollution control technology (which includes pollution prevention or work practices) must be comparable to BACT or LAER; and (2) the allowable emissions will not cause or contribute to a NAAQS or PSD increment violation, or adversely impact an AQRV (such as visibility) that has been identified for a Federal Class I area by an FLM and for which information is available to the general public. Regardless of which process you used to establish Clean Unit status initially, you may choose to re-qualify for Clean Unit status by going through major NSR or by going through the alternative two-part test.

Once you have submitted an application to re-qualify for Clean Unit status, the reviewing authority will make a determination concerning current BACT/LAER or comparable control technology. For example, suppose you had Clean Unit status for an emissions unit for which the controls

[33] As discussed in section III.E of today's preamble, we believe that 15 years represents a reasonable time period for designating a Clean Unit. However, we proposed and took comment on a 10-year period; therefore, we are finalizing today's rule with a 10-year duration. In a separate **Federal Register** notice we will be proposing to change this duration to 15 years.

went into service June 1, 1996, the permit application for Clean Unit re-qualification was submitted December 1, 2004, and the Clean Unit status expires June 1, 2006. In cases where the controls you installed in 1996 are still BACT/LAER or comparable when the reviewing authority makes the determination following your application submittal in 2004, the emissions unit can re-qualify for Clean Unit status based on the controls installed in 1996 if your emissions unit still meets all of the criteria for Clean Unit status. That is, in addition to the control technology review, the emissions unit must go through an air quality review and public participation.

A safeguard related to Clean Unit controls is that for re-qualifying for Clean Unit status when the emissions unit is located in a nonattainment area, the control determination must be LAER or comparable to LAER. If you previously received Clean Unit status based on the BACT level of control while the source was located in an attainment area and the attainment area becomes a nonattainment area by the time your Clean Unit status expires, the Clean Unit status for re-qualification must be based on controls that are LAER or comparable to LAER.

The air quality analysis for Clean Unit re-qualifications will be that of the path that you have chosen'major NSR, or comparable. As we discuss in detail in section V.C.3 of this preamble, for emissions units qualifying for Clean Unit status through the comparable test, you must show that the allowable emissions will not cause or contribute to a NAAQS or PSD increment violation, or adversely impact an AQRV (such as visibility) that has been identified for a Federal Class I area by an FLM and for which information is available to the general public.

We believe that the control technology determination, air quality review, and public participation requirements of the Clean Unit re-qualification process will ensure that Clean Units will continue to protect air quality throughout the 10-year re-qualification period. Moreover, any offset or mitigation requirements as a result of a previous major NSR determination will remain in force.

We expect that in many cases the controls used to initially establish Clean Unit status will still be operating efficiently and the Clean Unit status can be reestablished for an additional 10 years based on those controls. Suppose, however, you submitted an application to re-qualify for Clean Unit status and the reviewing authority determines that your existing controls do not meet the level of current BACT/LAER or comparable controls. In this case, you must install new or upgraded controls to re-qualify for Clean Unit status. You must go through the control technology determination, air quality review, and public participation requirements of the Clean Unit re-qualification process as described above.

10. What Terms and Conditions Must the Permit for my Clean Unit Contain?

Major NSR permits contain the emission limitations based on BACT/LAER, other permit terms and conditions that the reviewing authority identifies as representative of BACT/LAER (such as limits on hours of operation), and monitoring, recordkeeping and reporting requirements for the emissions unit. If you are qualifying for Clean Unit status through the major NSR review, your major NSR permit will have such terms and conditions. Likewise, any permit under a SIP-approved permitting process other than major NSR that designates an emissions unit as a Clean Unit must specify: (1) The source-specific allowable permit emission limitations, the exceedance of which, in combination with a significant net emissions increase, will trigger major NSR review; (2) other permit terms and conditions that the reviewing authority identifies as representative or comparable to BACT/LAER for your control technology (such as limits on operating parameters, etc.); (3) any conditions used as the basis for the control technology determinations (hours of operation, limits on raw materials, etc.); and (4) the monitoring, recordkeeping, and reporting requirements necessary to demonstrate that a "clean" level of emissions control is being achieved. Additional monitoring, recordkeeping, and reporting may be required to assure compliance under §§ 70.6(a)(3) or 70.6(c)(1) (that is, to assure compliance under title V).

The State and local agency permits establishing Clean Unit status must contain a statement designating the emissions unit as a Clean Unit. The State or local agency permit must also include general terms and conditions indicating the Clean Unit effective date and expiration date. Suppose the State or local agency permit has an effective date of May 5, 2006, and the controls will be installed after this date. The SIP permit would state that the effective date of the Clean Unit status is the date the controls go into service. The permit would also state that Clean Unit status will expire no later than May 5, 2016.

Your title V permit must include the Clean Unit status, as well as the effective and expiration dates of the Clean Unit status. Your title V permit must also include: the emission limitation(s) that reflect BACT/LAER or comparable control; other permit terms and conditions that the reviewing authority has determined represent BACT/LAER or comparable control (such as limits on hours of operation) and that ensure that air quality is protected; and the monitoring, recordkeeping, and reporting requirements necessary to demonstrate that a "clean" level of emissions control is being achieved.

11. How Will my Clean Unit Status be Incorporated Into my Title V Permit?

Clean Unit status and other permit terms and conditions must be incorporated into the major stationary source's title V permit in accordance with the provisions of the applicable title V permit program under part 70 or part 71, but no later than when the title V permit is renewed.

The title V permit must also contain the specific dates on which your Clean Unit status is effective and on which it expires. We are aware that the specific Clean Unit effective and expiration dates will frequently not be determined at the time that Clean Unit status is established. Therefore, the initial title V permit action that incorporates Clean Unit status and other permit terms and conditions may need to state the Clean Unit effective and expiration dates in general terms. For example, for units that have been through major NSR, the initial title V permit might state that the expiration date is the earlier of the following dates: the date 10 years after (1) the Clean Unit's effective date, or (2) the date the equipment went into service. The permit does not have to include the specific Clean Unit effective and expiration dates where they cannot be determined at the time of initial incorporation, such as would be the case when the Clean Unit has yet to be constructed. Furthermore, in these instances, we are not requiring that the title V permit be modified to incorporate the specific Clean Unit effective and expiration dates until the next permit renewal, reopening, or modification after such dates are known.

As soon as the specific Clean Unit effective and expiration dates are known, the source must report them to the reviewing authority. The specific Clean Unit effective and expiration dates must then be incorporated into the title V permit at the first opportunity, such as a modification, revision, reopening, or renewal of the title V permit for any reason, whichever comes first, but in no case later than the next renewal. However, it is not necessary to amend the SIP-approved permit to incorporate the specific Clean Unit effective and expiration dates, as long as these dates are incorporated into the title V permit at the next renewal. If you wish to incorporate the Clean Unit effective and expiration dates into the SIP permit, a title V modification would be required.

While the title V permit contains the Clean Unit permit terms and conditions, we want to emphasize that any changes to Clean Unit permit terms and conditions (other than incorporating the specific Clean Unit effective and expiration dates) must first be made through a SIP-approved permitting process that provides for public review and opportunity for comment. Any such changes would be incorporated into the title V permit in the manner described above.

12. Can a Clean Unit Be Used in a Netting Analysis?

Generally, for an emissions unit that has Clean Unit status because it has gone through major NSR permitting, you must not include emissions changes at the Clean Unit in a netting analysis, or use them for generating offsets, unless the emissions changes occur and you use them for these purposes before the effective date of Clean Unit status or after Clean Unit status expires. However, if you reduce emissions from the Clean Unit below the level that qualified the unit as a Clean Unit, you may generate a credit for the difference between the level that qualified the unit as a Clean Unit and the new emission limitation, if such reductions are surplus, quantifiable, permanent, and federally enforceable (for the purposes of generating offsets) and enforceable as a practical matter (for purposes of determining creditable net emissions increases and decreases). Such credits may be used for netting or as offsets. We are allowing the credit to be computed in this manner because the owner or operator has already obtained an actual emissions-based offset for the emissions up to the Clean Unit emission limitations. By the owner/operator's accepting a federally enforceable emission limitation below this level, these offsets are now available to create additional actual emissions reductions.

The final rules are similar for emissions units that are designated as Clean Units in a SIP-approved permitting process other than major NSR. You must not include emissions changes that occur at such units in a netting analysis, or use them for generating offsets, unless the emissions changes occur and you use them for these purposes before the effective date of the SIP requirements adopted to implement the Clean Units or after Clean Unit status expires. However, if you reduce emissions from the Clean Unit below the level that qualified the unit as a Clean Unit, you may generate a credit for the difference between the level that qualified the unit as a Clean Unit and the new emission limitation, if such reductions are surplus, quantifiable, permanent, and federally enforceable (for purposes of generating offsets) and enforceable as a practical matter (for purposes of determining creditable net emissions increases and decreases). Such credits may be used for netting or as offsets.

13. How Does Clean Unit Status Apply When There Are Multiple Pollutants?

Clean Unit status is pollutant-specific and may not be granted for more than one pollutant, except in cases where a group of pollutants is characterized as a single pollutant, such as VOCs. You may, however, qualify for simultaneous Clean Unit status for other pollutants at those emissions units that are sufficiently controlled to independently qualify as "clean" for each pollutant. For units applying for Clean Unit status and that do not already have a major NSR permit, the reviewing authority must specify the pollutants for which Clean Unit status applies as part of the permitting process establishing Clean Unit status.

D. Legal Basis for the Clean Unit Test

As discussed above, the Clean Unit applicability test would provide an alternative emissions test for determining if a significant increase in emissions has occurred after a physical change or change in the method of operation at units that are designated as "clean." We believe that we have the authority to allow these specific types of units to use a different applicability test.

The CAA is silent on whether increases in emissions for purposes of determining whether a physical or operational change constitutes a modification must be measured in terms of actual emissions, potential emissions, or some other currency. We believe that it is a reasonable interpretation of the CAA to determine applicability of the major NSR program for units qualifying as Clean Units in terms of the emission limitations or work practice requirements in the permit, and that this interpretation is consistent with the statutory purposes of NSR.

The PSD permitting program has 5 key elements: (1) Control technology review; (2) air quality review; (3) monitoring requirements; (4) information on the source; and (5) procedures for processing applications, including public notice and the opportunity for comment. A new major source or major modification in an attainment area must go through PSD permitting to become a Clean Unit. That process would have had to include the elements listed above. CAA section 165.

Similarly, the CAA requires new major sources or major modifications undertaken in nonattainment areas to obtain permits that require them to meet LAER and to obtain offsetting emissions reductions. CAA section 173. In order to be designated a Clean Unit, a major source or modification in a nonattainment area would have had to have gone through major NSR permitting review in the last 10 years.

We believe that units that have undergone minor source permitting in a manner that fulfills the statutory purposes of major NSR—either because a State's minor NSR program already contains equivalent provisions or because the existing program is enhanced for the purpose of allowing the reviewing authority to satisfy Clean Unit criteria—also will have satisfied the requirements of the CAA in a manner sufficient to justify Clean Unit status. As we have discussed in section V.C of this preamble, to obtain Clean Unit status through a minor NSR program, that process must include a requirement for public participation. Furthermore, emissions units that are designated as Clean Units through SIP-approved minor NSR programs must satisfy an air quality test. You must provide information demonstrating that you will not cause or contribute to a NAAQS or PSD increment violation or adverse impact on an AQRV in a Federal Class I area. If your emissions unit has already been permitted under minor NSR or another SIP-approved permitting program, you may have already satisfied the second part of this test. If not, consistent with the requirements in sections 165(a)(3) and 173(a) of the CAA, you will be required to show that the allowable emissions will not cause or contribute to a NAAQS or PSD increment violation, or adversely impact an AQRV (such as visibility) that has been identified for a Federal Class I area by an FLM and for which information is available to the general public. For areas that do not already attain the NAAQS, the source would be required to show that the emissions for the unit have been previously offset, or the reviewing authority will have to show that these emissions will not interfere with the State's ability to achieve attainment.

For Clean Units that have emission limitations and/or work practice requirements established through programs that fulfill relevant major NSR statutory requirements, we believe that the alternative way to estimate emissions increases to evaluate applicability set forth under the Clean Unit Test is appropriate and consistent with Congress's intent. A project at a Clean Unit that would require a revision to the emission limitations or work practice requirements established through permitting programs that meet the requirements of the Act, or that would alter any physical or operational characteristics that formed the basis for the permitting action, must go through a new permitting process. The reviewing authority must have already required state-of-the-art pollution control technology (or, through an investment, its pollution prevention or work practice equivalent), conducted the required air quality analyses based on the emissions level in the permit, and provided the public with an appropriate opportunity to comment on that level of emissions and air quality impact. Therefore, we believe that allowing an alternative means of evaluating applicability based on a revised emissions test for this category of unit is consistent with the CAA.

E. Summary of Major Comments and Responses

Although a few commenters categorically oppose the Clean Unit Test, most commenters support the concept. Practically all commenters oppose some aspect of the test or request that the test be clarified. Below are the major comments and our responses.

1. How Long Should You Be Eligible for the Clean Unit Applicability Test?

We received numerous comments on the duration of Clean Unit status. In the proposal, we suggested a 10-year duration and asked for comments regarding this period. We received comments supporting various lengths of time from 2 to 20 years. Although some commenters support a 10-year duration, other commenters oppose it.

Many commenters believe that 10 years is too short for Clean Unit status. These commenters argue that BACT/LAER technologies accomplish substantial pollutant removals, and that the cost of a slight increase in pollutant removal is usually significant. These commenters urge us to establish a Clean Unit status duration that comports with the useful life of the control equipment, which would enable you to recover the costs of installing the pollution control technology. They believe that you should be able to recoup the investments in pollution control before being forced to abandon that technology and pay again for newer technology. Some commenters request that a presumptive life of 20 years be awarded to Clean Units, which is approximately how long the control equipment should be effective.

Some commenters believe that 10 years would be too long, because they believe that advances in control technology occur more rapidly. A 10-year duration would allow old, less effective technologies to be the basis of immunity from the NSR program. These commenters are particularly concerned about the 10-year duration for BACT/LAER determinations that were based on no controls.

We believe that we have discretion to determine the appropriate period for which you should be eligible for the Clean Unit applicability test. As a policy matter, we believe that this time period should reach a balance between the unit's useful emissions control equipment life and the time frame in which additional major NSR review is likely to result in no added environmental benefit. As a practical matter, we realize that the "ideal" time frame will vary by emissions control technology and by pollutant; however, we believe using a single time frame will provide simplicity in our final rules.

To determine an average life expectancy for a variety of control technologies, we relied on the guidelines for equipment life for 9 commonly used emissions control technologies published in "Estimating Costs of Air Pollution Control Systems, Part II, Factors for Estimating Capital and Operating Costs." [34] Using the average of the low, average, and high values, we determined that a reasonable average equipment life for a control technology is equal to 15 years.

We then looked at the incremental improvement in control technology over time. We found that the evolution of pollution control equipment over time is dominated by innovation, rather than invention. In other words, the change in design and capacity for any given device type occurs infrequently as a series of marginal improvements over the preceding design. Consequently, the marginal improvement in pollution abatement one can expect between generations of the same type of device is also very small—too small to justify the cost of an entirely new unit. For example, flue gas desulfurization (FGD) units have been used in the United States for about 20 years, and were used in Japan and Germany for 10 years before that. During the early 1980's, a typical FGD system removed about 90 percent of the sulfur from a flue gas stream. Today, modern FGD systems typically average 95 to 99 percent removal efficiency—less than a 10 percent improvement in 20 years.

We also evaluated, from a cost-per-ton basis, whether the marginal improvement in removal efficiency is too expensive. Again, we considered the FGD example. From an actual NSR determination for a coal-fired electrical generating unit in the Midwest, the installation of an FGD system in 1985 would have cost $189 million and had a removal efficiency of 90 percent (76,500 tons of sulfur per year). The identical boiler in 2001 would use an FGD system with a 95 percent efficiency, costing $285 million, and removing 80,750 tpy, an additional 4,250 tons. The additional cost for the improved design for the 2001 installation (including the retrofit and upgrade of existing components and the new cost of larger pumps and other auxiliary equipment) would have been more than $100 million, or greater than $24,000 per ton. Consequently, from an efficiency standpoint, requiring an upgrade on this unit to BACT or LAER levels would not have been economical.

After reviewing all of this information, we determined that a 15-year period represents a reasonable and appropriate time frame during which you should be allowed to use your permitted allowable emissions to determine whether an increase triggers major NSR review. However, we proposed and took comment on a 10-year duration. Therefore, today we are finalizing a single time frame of 10 years that applies to all types of emissions control technologies and all types of pollutants. Because we believe that 15 years represents a reasonable time frame, we will be proposing a 15-year duration for Clean Unit status. After considering any public comments on a 15-year duration for Clean Unit status, we may amend today's final regulations.

We believe it is beneficial to allow emissions units using pollution prevention techniques or work practices to qualify for Clean Unit status where those units meet certain criteria. In some cases (coating operations, for example), pollution prevention techniques or work practices are state-of-the-art pollution control, and either

[34] Vatavuk, William, "Part II, Factors for Estimating Capital and Operating Costs," *Chemical Engineering*, Nov. 3, 1980.

there would not be an improvement in pollution control if the unit were required to install add-on controls or the incremental cost effectiveness of the add-on control installation would be too high for it to qualify as BACT. In other cases, the most stringent control is based on add-on control and pollution prevention. Therefore, under many circumstances, we believe that pollution prevention techniques and work practices can be implemented to achieve a level of emissions reductions comparable to that achieved by BACT/LAER add-on controls. Also, initiation of a pollution prevention technique or a work practice can require a substantial investment in research to retool or reformulate your operations. Thus, we do not believe that a blanket exclusion from Clean Unit status is appropriate for emissions units that are controlled with pollution control techniques.

Implementation of pollution prevention approaches and work practices usually requires research, followed by some retooling or reformulation of a process line or unit operation. As part of this retooling or reformulation, some equipment has to be purchased up front (for example, sniffers for leak detection and repair operations, improved process control consoles and/or software for recycle streams, initial modeling for combustion optimization systems). This equipment purchase or initial modeling involves a one-time investment; hence, there is an investment associated with pollution prevention or work practice implementation. Researching the application of an approach also qualifies as an investment for these purposes.

We received comment from a number of commenters who are concerned about Clean Unit status when BACT/LAER determinations are based on no control. As these commenters note, "no controls" does not equate to a well-controlled emissions unit. We agree with these commenters, and today's final rules clarify that Clean Unit status can be based on add-on control, pollution prevention techniques, work practices, or a combination of them. We recognize that there are some circumstances when the outcome of a reviewing authority's BACT or LAER determination may result in an emission limitation that you will meet without using an air pollution control technology (which includes pollution prevention or work practices). We believe that such emissions units should not qualify as Clean Units, because they fail the very premise under which we established the Clean Unit applicability test. That is, there is no period of time in which we can reach a balance between the unit's useful emissions control equipment life and the time frame in which additional major NSR review is likely to result in no added environmental benefit. Source categories that currently have few or no control technology options are likely to be the categories that will experience a rapid advancement in emissions control technology over a short period of time. Accordingly, today's final rules contain two limitations on use of the Clean Unit applicability test. You may not use the Clean Unit applicability test for any emissions unit that is not using an air pollution control technology (which includes pollution prevention or work practices) and for which you have not made an investment to control emissions.

2. Does the Clean Unit Applicability Test Measure the Increase in Maximum Hourly Potential Emissions?

We proposed that the Clean Unit Test would continue to apply as long as the emissions unit's maximum hourly potential emissions did not increase. The baseline for the maximum hourly potential emissions rate could be established at any time in the 6 months before the activity or project that increases emissions. Almost all commenters oppose basing the Clean Unit Test on the hourly PTE, as well as the 6-month period for setting the emissions rate. Some commenters argue that an hourly PTE test is not environmentally protective enough. One commenter notes that we were inappropriately using the applicability test under the NSPS as the applicability test for major NSR, which should be based on tpy. Many commenters view the hourly PTE test as so restrictive that few sources would take advantage of the Clean Unit Test. These commenters believe that the hourly emissions rate obscures the real basis for Clean Unit status, which is the add-on control efficiency.

We agree with the commenters who maintain that Clean Unit status should be based on the emissions level achievable through the use of control technologies. As these commenters note, once an emissions level has been determined based on BACT/LAER, it is unlikely that additional review would result in a more stringent level of control. As a result, we are not finalizing the Clean Unit Test as proposed with the hourly PTE test. Instead, today's final rules for Clean Units are based on reduction of air pollution through the use of control technology (which includes pollution prevention or work practices) that meet both the following requirements. First, the control technology achieves a BACT/LAER level of emissions reduction as determined through issuance of a major NSR permit within the past 10 years. However, the emissions unit is not eligible for Clean Unit status if the BACT/LAER determination resulted in no requirement to reduce emissions below the level of a standard, uncontrolled, new emissions unit of the same type. Second, the owner or operator made an investment to install the control technology. For the purpose of this determination, an investment includes expenses to research the application of a pollution prevention technique to the emissions unit or expenses to apply a pollution prevention technique to an emissions unit.

By adopting this approach, we are allowing the reviewing authority to decide the appropriate emission limitations or work practice requirements that will be used to obtain and maintain Clean Unit status. If a project at a Clean Unit does not cause the need for a change in the emission limitations or work practice requirements that form the basis for Clean Unit status, the emissions unit remains a Clean Unit. On the other hand, if the project causes the need for such change to the emission limitations or work practice requirements, the emissions unit loses Clean Unit status and is subject to the applicability requirements of major NSR.

3. What Kind of Changes Are Allowed Under Clean Unit Status?

It is not our intention to limit increases in emissions unit capacity as long as emissions are under the source-specific allowable levels and the increase is within the capacity for which you obtained approval when applying for Clean Unit status. Incremental improvements to existing units are acceptable. However, complete changes to emissions units making them into completely different units than were originally permitted are not acceptable. For example, switching to a smaller but more polluting process than originally permitted may trigger stricter BACT/LAER requirements, even at the same annual emissions rate, since higher percentage removal rates and lower costs would be possible at higher concentrations.

We expect that changes such as, but not limited to, increasing production to permitted levels, reconfiguring the process, changing process chemicals if consistent with the original Clean Unit application, replacing components, replacing catalysts, or adding other controls, or other changes would be allowable for Clean Units. In no instances are we authorizing violations of any existing permit conditions or other applicable requirements that may apply to the Clean Unit. You may not reconstruct a Clean Unit under an existing Clean Unit status.

4. Does the Clean Unit Applicability Test Apply to Units That Have Not Gone Through a Major NSR Permitting Review?

In 1996, we proposed that reviewing authorities submit their minor source permit decisions for us to determine whether the emission limitations were comparable to BACT or LAER. Commenters generally support allowing units permitted through minor NSR programs to qualify for Clean Unit status. These commenters believe State and local agencies are well-equipped to make control technology determinations. A few commenters are concerned that control technology determinations made under minor NSR programs do not always require adequate air quality review or opportunity for public comment and review. They maintain that these program elements are essential for making control technology determinations that are equivalent to BACT/LAER.

We also received comments on allowing Clean Unit status for emissions units that have not gone through either major or minor NSR, such as those that decrease emissions to meet other requirements under the Act. These comments are mixed. A few commenters support this option. Others believe it makes no sense to extend the status to units that had not had a recent control technology determination, particularly considering the burden the review would place on reviewing authorities.

We agree that control technology determinations made by State and local agencies can be comparable to BACT/LAER, regardless of the purpose for which the control technology decision is made. However, we also agree with those commenters who believe a thorough analysis is necessary to ensure that air quality is protected. Moreover, we agree that a control technology determination is incomplete unless it has been through public review.

Therefore, today we are promulgating regulations that allow emissions units that have not had a BACT/LAER determination to qualify for Clean Unit status, if they are permitted under a SIP-approved permitting program that provides for public notice of the proposed determination and opportunity for public comment to determine whether you should qualify as a Clean Unit.

5. Does Clean Unit Status Apply to Units That Have RACT or MACT Limits?

A number of commenters maintain that emission limitations based on RACT and MACT achieve control comparable to those based on BACT and LAER. These commenters therefore believe Clean Unit status should be available for emissions units with RACT or MACT limits. However, other commenters agree with us that RACT and MACT limits should not automatically be considered equivalent to BACT/LAER limits.

We are maintaining our position in the proposal rule that Clean Unit status does not presumptively apply to units with limits based on RACT or MACT. However, when you believe a specific RACT or MACT limit is comparable to BACT/LAER, you may choose to use a SIP-approved permitting process to try to obtain Clean Unit status.

6. How Should We Determine Whether a Control Technology Is Comparable to BACT or LAER?

We proposed two methods for determining that control technology was comparable to BACT/LAER—average of the level of control for the last 3 years, and percent control. None of the commenters support using the average emissions rates to determine comparability. The commenters believe that in some cases this approach could lead to skewed results, or that the average control determination can differ substantially from the most recent determination. The commenters suggested that EPA consider all technologies required to be considered in a BACT/LAER determination, not just those listed in the RBLC. The commenters also say that it is not acceptable to call an uncontrolled unit a "clean" unit, when the Clean Unit Test is meant for companies that have taken the effort and expense to install controls or low emitting equipment. Although a few commenters support using percent control, several commenters oppose it. They maintain that defining control levels based on a certain percentage derived from BACT or LAER for equivalent sources is not simple and would require the frequent collection and maintenance of large quantities of information.

Based on the public comments on our two proposed methods, we have decided to develop a modified version of the proposed averaging method for determining when an air pollution control technology (which includes pollution prevention or work practices) is comparable to BACT/LAER. You can make a showing that the air pollution control technology (which includes pollution prevention or work practices) is comparable to BACT/LAER in one of two ways: (1) by comparing your emissions unit's control level to BACT/LAER determinations for other similar sources in the RBLC; or (2) by making a case-by-case demonstration that your emissions control is "substantially as effective" as BACT or LAER.

Under the first approach, we have developed slightly different approaches for sources located in attainment and nonattainment areas. For those emissions units located in attainment areas, the emissions unit's control technology is presumed to be comparable to BACT if it achieves an emission limitation that is equal to or better than the average of the emission limitations achieved by all the sources for which a BACT or LAER determination has been made within the preceding 5 years and entered into the RBLC, and for which it is technically feasible to apply the BACT or LAER control technology to the emissions unit. To address the commenters' concerns regarding other BACT/LAER determinations that might not be in the RBLC, we have included a provision that allows the reviewing authority to also compare this presumption to any additional BACT or LAER determinations of which it is aware, and to consider any information on achieved-in-practice pollution control technologies provided during the public comment period, to determine whether any presumptive determination that the control technology is comparable to BACT is correct.

For sources in nonattainment areas, the emissions unit's control technology is presumed to be comparable to LAER if it achieves an emission limitation that is at least as stringent as any one of the 5 best-performing similar sources for which a LAER determination has been made within the preceding 5 years, and for which information has been entered into the RBLC. As is the case for units in attainment areas, the reviewing authority shall also compare this presumption to any additional LAER determinations of which it is aware, and shall consider any information on achieved-in-practice pollution control technologies provided during the public comment period, to determine whether any presumptive determination that the control technology is comparable to LAER is correct.

The second approach, the "substantially as effective" test, avoids a "one-size-fits-all" approach that could preclude some well-controlled sources from benefitting from the Clean Unit Test simply because there is insufficient information in the RBLC or because they are using an innovative approach to emissions control. This provision will allow you to use alternative controls as long as they achieve comparable control and air quality results. We believe that the reviewing authority is in the best position to judge whether a particular control technology achieves an emissions control level that is comparable to BACT or LAER for a specific application, as well as to assure that air quality impacts have been accounted for. Thus, rather than requiring the reviewing authority to submit its permit decisions to us for approval as a comparable technology, our final rules allow the reviewing authority the ability to make this determination after the public comment process.

7. Can Clean Unit Status Be Made Using the Title V Permitting Process?

We proposed that for sources that had not undergone major NSR, Clean Unit status would occur as part of the title V permitting process. Although a few commenters support this concept, several State and local agency commenters strongly disagree. These commenters believe that title V is an appropriate mechanism for documenting Clean Units, but that the process for certifying sources should be separate from title V to avoid delays in title V permitting.

We agree with these commenters, and today are promulgating provisions that an emissions unit may be designated as a Clean Unit once it has gone through major NSR or another SIP-approved permitting program that provides for public notice and opportunity for comment. This allows the reviewing authority the flexibility to use the permitting process that it believes is most appropriate to make a Clean Unit status determination. However, once Clean Unit status has been established through a SIP-approved permitting program, it must be incorporated into the title V permit. *See* section V.C.7 for a discussion of this process.

VI. Pollution Control Projects

A. Description and Purpose of This Action

Our policy is to promote pollution control and prevention projects whenever possible. Today we are finalizing a rule provision that would exclude from major NSR permitting requirements certain work practices and the installation of qualifying pollution control and pollution prevention projects. With these provisions, we are removing a regulatory disincentive that might otherwise prevent industry from undertaking pollution control and prevention measures that result in a net environmental benefit. The "Pollution Control Project Exclusion" (or "PCP Exclusion") will allow the installation of certain projects that result in net overall environmental benefits to avoid the permitting requirements of major NSR for their collateral emissions increases that exceed the significant level. This action was proposed on July 23, 1996, and closely paralleled our existing policy memorandum [35] which, in effect, enabled a control project exclusion for EUSGUs which was implemented under the electric utility-specific NSR rule (*see* 57 FR 32314, hereinafter "WEPCO PCP Exclusion") to apply to all types of sources, and enabled qualifying pollution prevention projects to apply for an exclusion as well. This action will replace both the WEPCO PCP Exclusion and the July 1, 1994 policy guidance with a single, comprehensive NSR exclusion for all types of qualifying PCPs—including add-on controls, switches to less polluting fuels, work practices, and pollution prevention projects. Morever, this final rule will minimize procedural delays in getting a PCP approved, while ensuring appropriate environmental protection.

We define a PCP as an activity, set of work practices, or project at an existing emissions unit that reduces emissions of air pollution from the unit. The PCP Exclusion may be sought when a project is installed at an existing source where it reduces the emissions rate of one air pollutant while causing an increase in emissions of a different, "collateral" pollutant. A common example of such a project is installation of a thermal incinerator, which forms NO_X as a collateral pollutant while reducing VOC emissions. For evaluating the environmental impact of a collateral emissions increase, the source and reviewing authority will assess the difference between the emissions unit's post-change actual emissions and its pre-change baseline actual emissions. This test is discussed in section II of today's preamble. That increase is then weighed against the emissions decrease of the primary pollutant to determine whether the PCP, as a whole, provides an environmental benefit. The source and reviewing authority also must ensure that the change does not cause or contribute to an air quality violation, that no ERCs are generated (through initial application of the PCP), and that any significant emissions increase of a nonattainment pollutant is accounted for with acceptable offsets or SIP measures. In performing the air quality analysis under this provision, the procedures established for conducting air quality analysis in conjunction with NSR permitting will be used.

This rule excludes the installation of qualifying PCPs—including add-on control devices, raw material substitutions, work practices, process changes and other pollution prevention strategies—from the definition of "physical or operational change" within the definition of major modification in our Federal regulations (*e.g.*, § 52.21). We are also requiring that States adopt the same exclusion in their NSR programs.

The decision to make codifying changes to the existing WEPCO PCP Exclusion and the July 1, 1994 policy guidance draws largely from recommendations of the CAAAC Subcommittee on NSR Reform. The members of the Subcommittee included representatives of State and Federal regulatory agencies, Federal natural resource managers, industry, and environmental and public health interest groups. The Subcommittee's recommendations reflected the consensus of this balanced group of stakeholders.

B. What We Proposed and How Today's Action Compares To It

Our proposed PCP Exclusion provisions essentially restated the July 1, 1994 policy guidance, and incorporated a "primary purpose" test as an initial hurdle for candidate PCPs. The "primary purpose" test would have limited the exclusion to those projects whose primary function is to reduce air pollution. The proposal, like the previous PCP Exclusion rule and policy guidance, maintained that the exclusion was not applicable to air pollution controls and emissions associated with the construction of a new emissions unit, nor to the replacement or reconstruction of an entire existing emissions unit with a newer or different one. In addition, the fabrication, manufacture, or production of pollution control/prevention equipment and inherently less polluting fuels or raw materials would not, in and of themselves, qualify as a PCP. We also incorporated two safeguards that were taken directly from the WEPCO PCP Exclusion and the July 1, 1994 policy

[35] July 1, 1994 memorandum from John S. Seitz, Director, OAQPS, "Pollution Control Projects and New Source Review (NSR) Applicability" and hereinafter referred to as the "July 1, 1994 policy guidance."

guidance. First, the reviewing authority would be required to determine that the PCP is "environmentally beneficial." A second safeguard from our proposal would direct reviewing authorities to evaluate the air quality impacts of a proposed PCP and ensure that it does not cause or contribute to a NAAQS or PSD increment violation, or adversely impact an AQRV (such as visibility) that has been identified for a Federal Class I area by an FLM and for which information is available to the general public.

We proposed specific add-on control technologies that would be considered presumptively "environmentally beneficial" based on their proven history of positive environmental impact. The proposal also allowed for fuel switches to less polluting fuels and substitutions to less potent ozone depleting substances (ODS) to be presumptively environmentally beneficial projects. For other pollution prevention projects and new add-on control technologies to qualify as a PCP, the proposal required the reviewing authority to determine that the project was environmentally beneficial and, additionally for new add-on control devices, that they be "demonstrated in practice."

We received comments on every key aspect of the proposed PCP Exclusion. Although most parties support the PCP Exclusion, their suggestions regarding implementation of the exclusion vary considerably. Industry commenters generally desire maximum flexibility, and suggest extending the exclusion to cross-media control projects, limiting the "environmentally beneficial" and "primary purpose" requirements, allowing for the generation of ERCs from PCPs, and broadening which pollution prevention projects qualified. Other commenters, including State agencies and environmental organizations, generally favor a more restrictive approach that involves more agency oversight and creates more enforceable mechanisms to ensure that the exclusion would not be abused. All comments are specifically addressed in the Technical Support Document.

Today's rule revises the proposed PCP Exclusion in several ways, including the following.

- Eliminating the "primary purpose" requirement.
- Expanding the list of presumptively environmentally beneficial projects to include additional control technologies and strategies.
- Enabling projects that otherwise are PCPs and result in utilization increases to qualify for the exclusion.
- Using an actual-to-projected-actual format for determining emissions changes for all source categories to demonstrate net environmental benefit supplemented by air quality analysis under certain circumstances, regardless of their projected emissions increases resulting from utilization.
- Clarifying that the replacement, reconstruction, or modification of an existing emissions control technology could qualify for the exclusion.
- Detailing the calculations for determining whether a switch to a different ODS is environmentally beneficial.
- Changing the visibility component of the air quality analysis to "an air quality related value (such as visibility) that has been identified for a Federal Class I area by a FLM, and for which information is available to the general public".
- Identifying which fuel switches are presumed "inherently less polluting".
- Enabling work practice standards to qualify for the exclusion.
- Clarifying that modeling for air quality impacts analyses may use projected actual emissions.
- Detailing proper noticing requirements for listed projects to use this exclusion.
- Describing in detail the process for granting the PCP Exclusion for non-listed control technologies and pollution prevention strategies.
- Disqualifying projects that cannot secure acceptable offsetting emissions reductions or SIP measures for PCPs resulting in a significant net increase of a nonattainment pollutant.
- Disallowing generation of netting and offset credits from the initial application of PCPs that qualify for this exclusion.
- Clarifying that non-air pollution impacts will not be considered in the "environmentally beneficial" determination.

By today's action we are superseding the PCP regulatory exclusion that applied only to EUSGUs. Today's action covers all types of sources, including EUSGUs. The new, broader PCP Exclusion will ensure equitable treatment of all source categories and remove any disincentive for companies that wish to install pollution control and pollution prevention projects, to the extent allowed by the CAA. Thus, owners or operators of EUSGUs who want a PCP Exclusion may, like any other source category, use the expanded definition of "pollution control project," which includes the lengthened list of environmentally acceptable control devices. Despite today's rule revisions addressing a broader array of pollution control and pollution prevention projects at a larger variety of sources, we feel that the rule's procedures are less complex than and are clearer than the WEPCO PCP Exclusion and the July 1, 1994 policy guidance. We are satisfied that the final PCP Exclusion best achieves the goals of minimizing regulatory burden and reducing procedural delays for projects that ensure net overall environmental protection.

1. Applicability

a. *What types of projects may qualify for the PCP Exclusion?*

In the WEPCO PCP Exclusion, we found that installation of add-on emissions control projects, switches to less polluting fuels, and certain clean coal demonstration projects could be PCPs, "unless the project renders the unit less environmentally beneficial." 57 FR 32319. Today's rule affirms that these types of projects are appropriate candidates for the exclusion, and it expands the types of projects that can qualify to include installation of other control devices that were not previously listed in the regulations, as well as work practice standards and switches to less potent quantities of ODS. Some of the control technologies (for example, oxidation/absorption catalyst and biofiltration) listed in today's revisions were either not well known or not demonstrated in practice as of the release of the WEPCO PCP Exclusion and the July 1, 1994 policy guidance exclusion; consequently, today's rule brings the list of approved PCPs up to date.

We believe that the overall net impact of installing and operating the listed add-on control systems is environmentally beneficial and that such projects are desirable from an environmental perspective. The add-on controls in the approved list historically have been applied to many different kinds of sources to reduce emissions. They have been consistently used because it is generally understood that, from an overall environmental perspective, these controls are effective in reducing emissions when they are applied to existing plants in a manner consistent with standard and reasonable practices. Certain pollution prevention projects—for example, fuel switches and low-NO_X burners—are also presumed to be environmentally beneficial when properly applied. Consequently, as part of the exclusion for PCPs, we do not require a case-by-case "environmentally beneficial" demonstration for the "listed" PCPs, as long as they are properly applied and site-specific factors do not indicate that their application would be environmentally harmful. Thus, the "environmentally beneficial" presumption created by the list may be rebutted. For companies wishing to install and operate non-listed PCPs, however, the process is more rigorous. In these cases, the reviewing authority first must consider case-specific factors to determine whether the non-listed project results in a net environmental benefit and then must provide an opportunity for, and respond to, public notice and comment before approving the project as a PCP.

b. Why does the PCP Exclusion not apply to greenfield sources?

Today's rule restricts applicability of the PCP Exclusion to physical changes being made at existing sources. Installing or implementing a project on an existing source is more likely to improve the environment than is the construction of a new source, since one can reasonably expect a PCP to reduce overall emissions, barring a considerable utilization increase. New sources, however, introduce new emissions to the air without reducing existing emissions, and consequently should be as clean as possible. Furthermore, new emissions units are among the major capital investments in industrial equipment, which are the very types of projects that Congress intended to address in the NSR provisions when such projects result in an overall emissions increase from the major stationary source. Thus, when emissions from a new source exceed the significant level, they are subject to NSR, and all emissions that are generated from the new project should be addressed in the major NSR permit evaluation for the major stationary source.

c. Does the PCP Exclusion apply to rebuilt or upgraded control devices?

We are clarifying in today's rule that upgrading or replacing existing emissions control equipment with a more effective emissions control project can qualify for the PCP Exclusion. However, the new PCP would have to result in a level of control more stringent than the original control equipment, in terms of emissions rate or output-based emissions rate, such as upgrading a scrubber to increase removal efficiency. Another example that would qualify is a control device that achieves an emissions reduction equivalent to that of the original device, but is more energy efficient. An example of this is the conversion of a thermal oxidizer to a catalytic oxidizer. As long as the catalytic oxidizer achieved emissions control equivalent to that of the thermal oxidizer, it would qualify for a PCP Exclusion since it reduces energy use.

2. Environmental Benefits

a. *What projects do we presume to be environmentally beneficial?*

Commenters recommend that we expand the list of presumptively environmentally beneficial projects to include other add-on control technologies that are commonly used to reduce emissions at major stationary sources. We agree with this recommendation and have expanded the list of presumptively environmentally beneficial PCPs accordingly in today's rule.

We presume the projects listed in Table 2 are environmentally beneficial. We based our decision to add certain projects to the list on two criteria: (1) The PCP is "demonstrated in practice"; and (2) its overall effectiveness in reducing emissions of the primary pollutant(s) when balanced against its potential for emissions increases of collateral pollutant(s).

TABLE 2.—ENVIRONMENTALLY BENEFICIAL POLLUTION CONTROL PROJECTS

Control device/PCP	Pollutant controlled
Conventional & advanced flue gas desulfurization.	SO_2
Sorbent injection	
Electrostatic precipitators	Particulates and other pollutants.
Baghouses	
High efficiency multiclones	
Scrubbers	
Flue gas recirculation	NO_X
Low-NO_X burners or combustors	
Selective non-catalytic reduction	
Selective catalytic reduction	
Low emission combustion (for internal combustion engines)	
oxidation/absorption catalyst (e.g., $SCONO_X$™)	
Regenerative thermal oxidizers	VOC and HAP.
Catalytic oxidizers	
Thermal incinerators	
Hydrocarbon combustion flares [36]	
Condensers	
Absorbers & adsorbers	
Biofiltration	
Floating roofs (for storage vessels)	

[36] For the purposes of these rules, "Hydrocarbon combustion flare" means either a flare used to comply with an applicable NSPS or MACT standard (including use of flares during startup, shutdown, or malfunction permitted under such a standard), or a flare that serves to control emissions from waste streams comprised predominantly of hydrocarbons and containing no more than 230 mg/dscm hydrogen sulfide.

Other presumed environmentally beneficial PCPs include activities or projects undertaken to accommodate: (1) switching to different ODS with a less damaging ozone-depleting effect (factoring in its ozone depletion potential and projected usage); and (2) switching to an inherently less polluting fuel, to be limited to the following.

- Switching from a heavier grade of fuel oil to a lighter fuel oil, or any grade of oil to 0.05 percent sulfur diesel. (that is, from a higher sulfur content #2 fuel, or from #6 fuel, to CA 0.05 percent sulfur #2 diesel)
- Switching from coal, oil, or any solid fuel to natural gas, propane, or gasified coal.
- Switching from coal to wood, excluding construction or demolition waste, chemical or pesticide treated wood, and other forms of "unclean" wood
- Switching from coal to #2 fuel oil (0.5 percent maximum sulfur content)
- Switching from high sulfur coal to low sulfur coal (maximum 1.2 percent sulfur content)

We are presuming that the application of a PCP listed above is environmentally beneficial and would be eligible for a PCP Exclusion. This presumption is premised on an understanding that you will design and operate the controls in a manner that is consistent with proper industry, engineering, and reasonable practices, and that you minimize increases in collateral pollutants within the physical configuration and operational standards usually associated with the emissions control device or strategy. You will be required to certify that this is true in the notification you send your reviewing authority.

As stated before, the "environmentally beneficial" determination is a presumption, so it can be rebutted in cases in which a reviewing authority determines that a particular proposed PCP project would not be environmentally beneficial. Also, April 1, 1999

Mr. Thomas Micai
Chief, Bureau of Operating Permits
Air Quality Permitting Program
NJDEP
401 E. State Street
CN027
Trenton, New Jersey 08625-0027

Dear Mr. Micai:

This is to inform you of the findings of EPA Region 2's review of the turbine replacement issue as it relates to the PSE&G plants. Although this determination addresses the PSE&G situation, it may be applied to other utilities in the State of New Jersey of the same design, but this is a specific application of EPA rules and should not be relied upon as a general interpretation of EPA rules. By way of background, PSE&G purchased a fleet of identical turbine units in the early 70's, prior to any applicable EPA preconstruction regulations. These units are installed and used at 12 different generating stations with the extra units kept as spares at the Central Repair Shop. When a unit malfunctions at any of the 12 generating stations, it is removed and switched with one of the spare units from the repair shop. After the malfunctioning unit is repaired, it remains at the repair shop as a spare until it is once again used to switch with another malfunctioning unit at any of the 12 stations. Other than repairs, the units are not modified. The issue of whether such replacements are considered modifications which should be reviewed under new source requirements has been evaluated by Region 2. These include NSPS, major and minor source preconstruction permits, and PSD.

Based upon the information submitted by PSE&G and that obtained during our visit to PSE&G's Central Repair Shop, we believe the kind of repair/maintenance program implemented by PSE&G may occur without triggering new source requirements if certain conditions were met. We are only recognizing that the movement of the turbines from place to place is not sufficient to trigger new source requirements. However, whenever one of the existing turbines from the original fleet is replaced, modified or reconstructed, it will be considered a new source. It is our belief that this accommodates the intent of the design and operation of these generating facilities. The act of physically removing a turbine from one spot, performing the routine repair and maintenance on that turbine and placing it in a different but identically designed spot, is not the construction of a new source. However, whenever new source requirements are triggered as a result of the repair or replacement involving any one of the turbines, the facility will be viewed as a new source and must meet those requirements. We believe that this is in accord with the design of these generating facilities. We would like to note that the scope of our review of the repair/maintenance program as discussed above is limited to the existing 12 generating stations and the original fleet of 24 turbines. Should a new generating station be constructed in the future, PSE&G would not be allowed to include the new station in the existing repair/maintenance program.

We understand the practice to be addressed in the Title V permit is a repair and maintenance procedure. In order to monitor this practice and assure that it is what we understand it to be, we recommend that the following essential monitoring, recordkeeping and reporting requirements be incorporated into PSE&G's Title V permit:

1. A complete list of all turbines purchased as part of the original fleet must be compiled with detailed information on the Make, Model, Serial Number, Maximum Heat Input, and Location for each turbine. This list must be made part of the Title V permit and updated with regard to the location of each turbine unit as it is being moved among the 12 stations.

2. Notify NJDEP in writing no later than 7 days after any turbine from the original fleet is switched with another turbine from the original fleet.

3. Record the following information each time a turbine is switched:

    i. date switch occurred;
    ii. description of the maintenance/repairs/parts replacement performed on the malfunctioning turbine since it was last in service;
    iii. identify malfunctioning turbine and substitute turbine by make, model, serial number and location; and
    iv a demonstration (such as mass balance) showing that the switch did not result in an increase in emission of any pollutant or the emission of a new pollutant not previously emitted.

5. All information recorded must be kept on site for at least 5 years from date of issuance of the Title V permit.

If you have any questions regarding the above, please feel free to contact me at (212) 637-4074 or have your staff contact Suilin Chan at (212) 637-4019.

Sincerely yours,

/s/

Steven C. Riva, Chief
Permitting Section
Air Programs Branch

cc: I. Atay, NJDEP

Draft/Proposed

OKLAHOMA DEPARTMENT OF ENVIRONMENTAL QUALITY
AIR QUALITY DIVISION

MEMORANDUM **August 25, 2008**

TO:	Phillip Fielder, P.E., Permits and Engineering Group Manager Air Quality Division
THROUGH:	Kendal Stegmann, Senior Environmental Manager, Compliance and Enforcement
THROUGH:	Phil Martin, P.E., Engineering Section
THROUGH:	Peer Review
FROM:	Mark Chen, P.E., New Source Permits Section
SUBJECT:	Evaluation of Construction Permit Application **No. 97-179-C (M-2)** DCP Midstream, L.P. Cimarron Natural Gas Processing Plant Latitude N 36.1828°, Longitude W 98.9942° NE/4 Section 27, Township 20N, Range 17W Woodward County, Oklahoma. Directions: From Seiling, 4 miles NW on U.S. Hwy 270 (also SH 3) and turn south into facility.

SECTION I. INTRODUCTION

DCP Midstream, L.P. (DCPM) has requested a construction permit for their Cimarron Natural Gas Processing Plant (SIC Code 1321). The facility was originally constructed and operated as a cryogenic-type natural gas processing plant operating under Permits 80-018-O and 84-066-O. A Title-V operating permit 97-179-TV was issued to the facility on April 5, 2005. The facility is currently operated under Permit No. 97-179-TV (M-1) dated March 3, 2006. In the past several years, the facility has not operated as a gas processing plant but as a compressor station only, and most of the compression units have either operated sporadically or been out-of-service during that time. With this construction permit application, DCPM plans to re-vitalize the facility and re-start processing plant operation. DCPM also plans to add three additional compressor engines. DCPM also uses this opportunity to add catalytic converters to all existing compressor engines and update the compressor engine emissions, condensate throughput, compressor blowdown, and process piping fugitive emissions.

SECTION II. FACILITY DESCRIPTION

In Permit No. 97-179-TV (M-1), the permitted sources consist of eight compressor engines (two in refrigeration service and six in residue service), two hot-oil heaters, five condensate tanks, two methanol tanks, two pressurized natural gas liquids product tanks (bullet type), an oil sales tank, numerous tanks containing very low vapor pressure liquids, a mole-sieve dehydrator (not in use), fugitive equipment leaks, condensate loading operations, and a process/emergency flare. Three more compressor engines will be added to the compression service in this construction permit application. Three compressors will be used in residue gas services after cryogenic operation.

SECTION III. EQUIPMENT

EUG 1 Internal Combustion Engines

EU	Make/Model	Serial #	HP	MMBtu/hr	Const./Instal. Date
ENG-1*	White-Superior 6G825 (refrig.)	67692	600	4.80	7/4/81
ENG-2*	White-Superior 6G825 (refrig.)	297485	600	4.80	7/4/81
ENG-6*	Waukesha L7042	133700	687	4.97	5/26/85
ENG-8*	Waukesha L7042	231089	687	4.97	March 85/July 06
ENG-9*	Waukesha L7042	165698	687	4.97	7/3/81
ENG-10*	Waukesha L7042	169752	687	4.97	7/3/81
ENG-11*	Waukesha L7042	133698	687	4.97	1/26/70
ENG-12*	Waukesha L7042	297485	687	4.97	1/26/70
ENG-13*	Waukesha L5794GSI	TBD**	1380	10.69	June 2008***
ENG-14*	Waukesha L5794GSI	TBD**	1380	10.69	June 2008***
ENG-15*	Waukesha L5794GSI	TBD**	1380	10.69	June 2008***

* Equipped with a Non-selective catalytic converter.
** TBD = To Be Determined *** Proposed Date

EUG 2 VOL Storage Tanks

EU	Contents	Capacity	Mfg. Date (Installed Date)
TNK-1	Condensate/Slop Oil	300 bbls	2005 (Replacement)
TNK-2	Condensate/Slop Oil	300 bbls	2005 (Replacement)
TNK-3	Condensate/Slop Oil	300 bbls	2005 (Replacement)
TNK-4	Condensate/Slop Oil	300 bbls	2005 (Replacement)
TNK-16	Condensate/Slop Oil	210 bbls	2005 (Replacement)
TNK-14	Methanol	752 gals	1969
TNK-15	Methanol	752 gals	Mid 1980's
TNK-5	Methanol/Water	180 bbls	1996
TNK-6	Methanol/Water	180 bbls	1996
TNK-7	Methanol/Water	180 bbls	1996
TNK-8	Methanol/Water	180 bbls	1996
TNK-9	Wastewater	300 bbls	1995
TNK-10	Wastewater	300 bbls	1995
TNK-11	Wastewater	300 bbls	1995
TNK-12	Wastewater	300 bbls	1995

EUG 3 Process Heaters

EU	Point	MMBtu/hr	Serial #	Installation Date
HTR-1	Hot-oil Heater	10	68524	1969
HTR-2	Hot-oil Heater (standby)	6	J71-858	1969

EUG 4 Plant Flare

EU	Point	MMBTUH	Date Installed
FLARE-1	Plant Flare	-----	1969

EUG 5 Fugitive VOC Emission Sources

EU	Type of Service	Estimated Number of Items	Type of Equipment
FUG-1	Gas	646	Valves
	Gas	90	Relief Valves
	Gas	48	Compressor Seals
	Gas	3,475	Flanges
	Heavy Liquid	66	Valves
	Heavy Liquid	22	Pump Seals
	Heavy Liquid	440	Flanges
	Light Liquid	264	Valves
	Light Liquid	24	Pump Seals
	Light Liquid	420	Flanges

SECTION IV. AIR EMISSIONS

Table 1 Engines Emissions Factors

EU ID#	Qty	NOx(g/hp-hr)	CO(g/hp-hr)	VOC(g/hp-hr)
ENG-1 & -2, 600-hp White-Superior 6G825 with C.C.	2	2.00	2.00	1.00
ENG-6 to -12, 687-hp Waukesha L-7042 with C.C.	6	2.00	2.00	1.00
ENG-13 to -15, 1,380-hp Waukesha L5794 GSI with C.C.	3	2.00	2.00	1.00

Based on manufacturer's data (including a safety factor for operational flexibility), the emission factors for compressor engines are presented in Table 1. The criteria pollutant emissions are estimated from the compressor engines based on 8,760 hours per year operation and 1,000 BTU/SCF average heating value. In the next page, Table 2 lists the engine specifications and stack parameters. Criteria pollutants emissions from the natural gas-fired equipment, hot oil heaters, HTR-1 and HTR-2, are estimated based on the emission factors in AP-42 (7/98), Tables 1.4-1 and 1.4-2, Section 1.4, "Natural Gas Combustion."

The numbers of fugitive VOC emission sources were estimated using DCP's Asset Management System (AMS). Fugitive emissions were based on Table 2-4 of "1995 Protocol for Equipment Leak Emission Estimates (EPA 453/R-95-017)," Oil and Gas Production Operations Average Emission Factors. VOC content in the vapor lines was averaged at 16.61% by weight which included 20% safety factor. Condensate tank emissions were calculated using the TANKS 4.0 computer software using a total annual throughput of 3,150,000 gallons for each condensate tank from TNK-1 to TNK-4, a molecular weight of 66, and an average vapor pressure of 5.39 psia. The total annual throughput for condensate tank TNK-16 was 317,520 gallons. The total annual throughput for methanol tanks, TNK-14 and TNK-15, was 27,072 gallons each tank. The VOC emissions from methanol tanks are used as a reference and not to be used as a permit limitation.

Table 2 Engine Specifications and Stack Parameters

Parameter	**ENG-1 & -2**	**ENG-6 to -12**	**ENG-13 to -15**
Manufacturer	White Superior	Waukesha	Waukesha
Model	6G825	L-7042	L-5794 GSI
Control	Cat. Conv. and AFR Controller	Cat. Conv. and AFR Controller	Cat. Conv. and AFR Controller
Input Parameter			
Horsepower (Maximum)	600	687	1,380
Fuel Consumption (BTU/hp-hr)	8,000	7,238	7,743
Fuel Usage (SCFH)	4,800	4,793	10,685
Stack Diameter (Inches)	10	10	12
Height above Grade (Feet)	18.00	17.00	20.00
Exhaust Flow (ACFM)	3,575	3,100	6,525
Exhaust Temperature (°F)	1,250	952	1,149
Calculated Parameter			
Moisture Content (%)	14.5	14.3	16.6

Table 3 Total Facility-Wide Emissions

EU ID#	**Source**	**NOx**		**CO**		**VOC**	
		lb/hr	**TPY**	**lb/hr**	**TPY**	**lb/hr**	**TPY**
ENG-1	White-Superior 6G825 with C.C.	2.65	11.59	2.65	11.59	1.32	5.79
ENG-2	White-Superior 6G825 with C.C.	2.65	11.59	2.65	11.59	1.32	5.79
ENG-6	Waukesha L-7042 with C.C.	3.03	13.27	3.03	13.27	1.51	6.63
ENG-8	Waukesha L-7042 with C.C.	3.03	13.27	3.03	13.27	1.51	6.63
ENG-9	Waukesha L-7042 with C.C.	3.03	13.27	3.03	13.27	1.51	6.63
ENG-10	Waukesha L-7042 with C.C.	3.03	13.27	3.03	13.27	1.51	6.63
ENG-11	Waukesha L-7042 with C.C.	3.03	13.27	3.03	13.27	1.51	6.63
ENG-12	Waukesha L-7042 with C.C.	3.03	13.27	3.03	13.27	1.51	6.63
ENG-13	Waukesha L5794 GSI with C.C.	6.08	26.65	6.08	26.65	3.04	13.33
ENG-14	Waukesha L5794 GSI with C.C.	6.08	26.65	6.08	26.65	3.04	13.33
ENG-15	Waukesha L5794 GSI with C.C.	6.08	26.65	6.08	26.65	3.04	13.33
HTR-1	Hot Oil Heater	1.00	4.38	0.84	3.68	0.055	0.24
HTR-2	Hot Oil Heater (Standby)	0.60	2.63	0.50	2.21	0.033	0.14
TNK-1	Condensate/Slop Oil Tank	--	--	--	--	--	4.23
TNK-2	Condensate/Slop Oil Tank	--	--	--	--	--	4.23
TNK-3	Condensate/Slop Oil Tank	--	--	--	--	--	4.23
TNK-4	Condensate/Slop Oil Tank	--	--	--	--	--	4.23
TNK-14	Methanol Tank	--	--	--	--	--	0.02
TNK-15	Methanol Tank	--	--	--	--	--	0.02
TNK-16	Condensate Tank	--	--	--	--	--	1.73
FLARE-1	Process Flare	0.52	2.26	2.81	12.31	1.06	4.66
FUG-1	Fugitive VOC Emissions	--	--	--	--	4.28	18.93
B-1	Compressor Blowdown	--	--	--	--	--	3.67
Total Emissions After Construction		**47.84**	**209.55**	**47.82**	**209.48**	**20.20**	**137.80**
Total Emissions In No. 97-179-TVR (M-1)		**--**	**276.10**	**--**	**318.10**	**--**	**144.20**
Total Emissions Decrease		**--**	**66.55**	**--**	**108.62**	**--**	**6.40**

The condensate transfer at the facility is operated with pump as liquid transfer at atmospheric pressure and does not produce flash emissions. No condensate is transferred by pressure difference in the plant except to pressurize the condensate out of the plant. The condensate produced at the facility and the condensate trucked in from other facilities is transferred out of the plant through pipes. Therefore, no loadout emissions are included. The flare is only used for emergency operations. VOC emissions from pipeline vents and compressor blowdowns for maintenance activities were estimated using mass balance and engineering calculation. The VOC blowdown emissions are presented as a reference for information purpose and not to be used as a permit limitation. The VOC flow vented to the flare was estimated as 158,160 SCF per day, which was based on 30% of flare header flow in Okarche Processing Plant. The average heating value of flare gas was 1,153 BTU/SCF, which was taken from PGAS Mooreland flare meter 0P1571-00. The emission factors were taken from AP-42 (9/91), Table 13.5-1. VOC emissions from other methanol/water tank, wastewater tanks, lube oil tanks, and antifreeze tanks are considered negligible. In the preceding page, Table 3 presents the total facility-wide emissions of criteria pollutants after the construction. The total facility-wide emissions, which were shown in the previous Permit No. 97-179-TVR (M-1), are also presented in Table 3 for comparison. All emissions of criteria pollutants are decreased and less than 250 TPY, therefore, this facility will not be considered an existing PSD source after construction.

The primary hazardous air pollutant (HAP) emission from the engine is formaldehyde (HCHO). Formaldehyde emissions from the rich-burn engines are estimated based on formaldehyde emission factor derived from AP-42 (7/00), Section 3.2, Table 3.2-3, for uncontrolled 4-stroke rich burn natural gas-fired stationary engines, 0.0205 lb/MMBtu. The installation of a catalytic converter reduces the formaldehyde emissions by 75% to 0.00513 lb/MMBtu. Table 4 lists annual formaldehyde emissions based on 8,760 hours per year operation. The facility-wide formaldehyde emissions do not exceed the major source threshold, 10 TPY.

Table 4 Facility-Wide Controlled Formaldehyde Emissions

Emissions Source	Formaldehyde	
	lb/hr	TPY
ENG-1, 600-hp White-Superior 6G825 with C.C.	0.025	0.109
ENG-2, 600-hp White-Superior 6G825 with C.C.	0.025	0.109
ENG-7, 687-hp Waukesha L-7042 with C.C.	0.026	0.112
ENG-8, 687-hp Waukesha L-7042 with C.C.	0.026	0.112
ENG-9, 687-hp Waukesha L-7042 with C.C.	0.026	0.112
ENG-10, 687-hp Waukesha L-7042 with C.C.	0.026	0.112
ENG-11, 687-hp Waukesha L-7042 with C.C.	0.026	0.112
ENG-12, 687-hp Waukesha L-7042 with C.C.	0.026	0.112
ENG-13, 1,380-hp Waukesha L-5794 GSI with C.C.	0.055	0.240
ENG-14, 1,380-hp Waukesha L-5794 GSI with C.C.	0.055	0.240
ENG-15, 1,380-hp Waukesha L-5794 GSI with C.C.	0.055	0.240
Total	**0.365**	**1.610**

SECTION V. BEST AVAILABLE CONTROL TECHNOLOGY

Based on Table 3 in Section IV, the total facility-wide emissions of criteria pollutants do not show any increase of any pollutant, therefore, a BACT determination is not required based on OAC 252:100-8-5(d)(1)(A). It is indicated in OAC 252:100-8-5(d)(1)(A) that a BACT determination is not required for a construction modification that will result in an increase of emissions of less than 100 tons per year of any regulated air pollutant. Air quality impacts analysis is not required either.

SECTION VI. INSIGNIFICANT ACTIVITIES

The insignificant activities identified and justified in the application are duplicated below. Records are available to confirm the insignificance of the activities. Appropriate recordkeeping of activities indicated below with "*" is specified in the Specific Conditions.

1. Stationary reciprocating engines burning natural gas, gasoline, aircraft fuels, or diesel fuel which are either used exclusively for emergency power generation or for peaking power service not exceeding 500 hours/year. None listed, but may be added in the future.

2. Space heaters, boilers, process heaters, and emergency flares less than or equal to 5 MMBtu/hr heat input (commercial natural gas). None listed, but may be added in the future.

3. * Storage tanks with a capacity of less than or equal to 10,000 gallons which store VOLs with a true vapor pressure less than or equal to 1.0 psia at maximum storage temperature. This covers the following tanks: four 180-bbl methanol/water (TNK5-TNK8); four 300-bbl wastewater (TNK9-TNK12); six lube oil; 4,512-gal hot oil; 3,807-gal solvent; 1,036-gal TEG; five antifreeze; and 265-gal diesel.

4. Gasoline and aircraft fuel handling facilities, equipment, and storage tanks except those subject to New Source Performance Standards and standards in OAC 252:100-37-15, 39-30, 39-41, and 39-48.

5. Emissions from condensate tanks with a design capacity of 400 gallons or less in ozone attainment areas.

6. * Emissions from crude oil and condensate storage tanks with a capacity of less than or equal to 420,000 gallons that store crude oil and condensate prior to custody transfer. None listed, but may be added in the future.

7. Welding and soldering operations utilizing less than 100 pounds of solder and 53 tons per year of electrodes. Any welding or soldering operations are conducted as maintenance activities and therefore need not keep any records.

8. Torch cutting and welding of under 200,000 tons of steel fabricated per year. Any torch cutting or welding operations are conducted as maintenance activities and therefore need not keep any records.

9. Hand wiping and spraying of solvents from containers with less than 1 liter capacity used for spot cleaning and/or degreasing in ozone attainment areas.

10. * Activities that have the potential to emit no more than 5 TPY (actual) of any criteria pollutant. This covers the process heaters, the 300-bbl condensate tanks (TNK1-TNK4), and the methanol storage tanks (TNK14, TNK15).

SECTION VII. OKLAHOMA AIR POLLUTION CONTROL RULES

OAC 252:100-1 (General Provisions) [Applicable]
Subchapter 1 includes definitions but there are no regulatory requirements.

OAC 252:100-2 (Incorporation by Reference) [Applicable]
This Subchapter incorporates by reference applicable provisions of Title 40 of the Code of Federal Regulations. These requirements are addressed in the "Federal Regulations" section.

OAC 252:100-3 (Air Quality Standards and Increments) [Applicable]
Primary Standards are in Appendix E and Secondary Standards are in Appendix F of the Air Pollution Control Rules. At this time, all of Oklahoma is in attainment of these standards.

OAC 252:100-5 (Registration, Emissions Inventory and Annual Operating Fees) [Applicable]
Subchapter 5 requires sources of air contaminants to register with Air Quality, file emission inventories annually, and pay annual operating fees based upon total annual emissions of regulated pollutants. Emission inventories have been submitted and fees paid for the past years.

OAC 252:100-8 (Permits For Part 70 Sources) [Applicable]
Part 5 includes the general administrative requirements for Part 70 permits. Any planned changes in the operation of the facility that result in emissions not authorized in the permit and that exceed the "Insignificant Activities" or "Trivial Activities" thresholds require prior notification to AQD and may require a permit modification. Insignificant activities refer to those individual emission units either listed in Appendix I (OAC 252:100) or whose actual calendar year emissions do not exceed the following limits.

- 5 TPY of any one criteria pollutant
- 2 TPY of any one hazardous air pollutant (HAP) or 5 TPY of multiple HAPs or 20% of any threshold less than 10 TPY for a HAP that the EPA may establish by rule.

Emissions estimates are from the permit application, which was received by AQD on Februare 6, 2008.

OAC 252:100-9 (Excess Emission Reporting Requirements) [Applicable]
In the event of any release which results in excess emissions, the owner or operator of such facility shall notify the Air Quality Division as soon as the owner or operator of the facility has knowledge of such emissions, but no later than 4:30 p.m. the next working day. Within ten (10) working days after the immediate notice is given, the owner operator shall submit a written report describing the extent of the excess emissions and response actions taken by the facility. In addition, if the owner or operator wishes to be considered for the exemption established in

252:100-9-3.3, a Demonstration of Cause must be submitted within 30 calendar days after the occurrence has ended.

OAC 252:100-13 (Open Burning) [Applicable]
Open burning of refuse and other combustible material is prohibited except as authorized in the specific examples and under the conditions listed in this subchapter.

OAC 252:100-19 (Particulate Matter) [Applicable]
This subchapter specifies a particulate matter (PM) emissions limitation of 0.60 lb/MMBTU from fuel-burning equipment with a rated heat input of 10 MMBTUH or less. For 4-cycle lean-burn engines, AP-42 (7/00), Table 3.2-2 lists the total PM emissions for natural gas to be 0.01 lbs/MMBTU. For 4-cycle rich-burn engines, AP-42 (7/00), Table 3.2-3 lists the total PM emissions for natural gas to be 0.02 lbs/MMBTU. For the heaters, AP-42 (7/98), Table 1.4-2 lists total PM emissions for natural gas combustion from heaters, boilers, etc., to be 0.01 lbs/MMBTU. Both rich-burn engines' emission value and heaters' emission values are below their corresponding limit. The permit requires the use of natural gas for all fuel-burning units to ensure compliance with Subchapter 19.

This subchapter also limits emissions of PM from industrial processes. Per AP-42 factors, there are no significant PM emissions from any other industrial activities at this facility.

OAC 252:100-25 (Visible Emissions and Particulates) [Applicable]
No discharge of greater than 20% opacity is allowed except for short-term occurrences that consist of not more than one six-minute period in any consecutive 60 minutes, not to exceed three such periods in any consecutive 24 hours. In no case shall the average of any six-minute period exceed 60% opacity. When burning natural gas there is little possibility of exceeding the opacity standards.

OAC 252:100-29 (Fugitive Dust) [Applicable]
No person shall cause or permit the discharge of any visible fugitive dust emissions beyond the property line on which the emissions originate in such a manner as to damage or to interfere with the use of adjacent properties, or cause air quality standards to be exceeded, or interfere with the maintenance of air quality standards. Under normal operating conditions, this facility will not cause a problem in this area, therefore it is not necessary to require specific precautions to be taken.

OAC 252:100-31 (Sulfur Compounds) [Applicable]
Part 5 limits sulfur dioxide emissions from new petroleum or natural gas process equipment (constructed after July 1, 1972). For gaseous fuels the limit is 0.2 lb/MMBTU heat input averaged over 3 hours. For fuel gas having a gross calorific value of 1,000 BTU/SCF, this limit corresponds to fuel sulfur content of 1,203 ppmv. Thus, a limitation of 343 ppmv sulfur in a field gas supply will be in compliance. The permit requires the use of pipeline-grade natural gas or field gas with a maximum sulfur content of 343 ppmv for all fuel-burning equipment to ensure compliance with Subchapter 31.

OAC 252:100-33 (Nitrogen Oxides) [Not Applicable]
This subchapter limits NOx emissions from new fuel-burning equipment with rated heat input greater than or equal to 50 MMBTUH to emissions of 0.2 lb of NOx per MMBTU. There are no equipment items that exceed the 50 MMBTUH threshold.

OAC 252:100-35 (Carbon Monoxide) [Not Applicable]
None of the following affected processes are located at this facility: gray iron cupola, blast furnace, basic oxygen furnace, petroleum catalytic cracking unit, or petroleum catalytic reforming unit.

OAC 252:100-37 (Volatile Organic Compounds) [Applicable]
Part 3 requires storage tanks constructed after December 28, 1974, with a capacity of 400 gallons or more and storing a VOC with a vapor pressure greater than 1.5 psia at maximum storage temperature to be equipped with a permanent submerged fill pipe or with an organic vapor recovery system. This applies to the condensate tanks and slop oil tank, T-1R, T-2R, and T-3R.
Part 3 requires VOC loading facilities with a throughput equal to or less than 40,000 gallons per day to be equipped with a system for submerged filling of tank trucks or trailers if the capacity of the vehicle is greater than 200 gallons. This facility does not have the physical equipment (loading arm and pump) to conduct this type of loading and is not subject to this requirement.
Part 5 limits the VOC content of coatings from any coating line or other coating operation. This facility does not normally conduct coating or painting operations except for routine maintenance of the facility and equipment. No coating operation is located at this facility.
Part 7 requires fuel-burning and refuse-burning equipment to be operated to minimize emissions of VOC. The equipment at this location is subject to this requirement.
Part 7 requires all effluent water separator openings which receive water containing more than 200 gallons per day of any VOC, to be sealed or the separator to be equipped with an external floating roof or a fixed roof with an internal floating roof or a vapor recovery system. No effluent water separators are located at this facility.
Part 7 also requires all reciprocating pumps and compressors handling VOCs to be equipped with packing glands and rotating pumps and compressors handling VOCs to be equipped with mechanical seals. All of the pumps and compressors at this facility are subject to these requirements.

OAC 252:100-42 (Toxic Air Contaminants (TAC)) [Applicable]
This Subchapter regulates toxic air contaminants (TAC) that are emitted into the ambient air in areas of concern (AOC). Any work practice, material substitution, or control equipment required by the Department prior to June 11, 2004, to control a TAC, shall be retained, unless a modification is approved by the Director. Since no AOC has been designated there are no specific requirements for this facility at this time.

OAC 252:100-43 (Testing, Monitoring, and Recordkeeping) [Applicable]
This subchapter provides general requirements for testing, monitoring and recordkeeping and applies to any testing, monitoring or recordkeeping activity conducted at any stationary source. To determine compliance with emissions limitations or standards, the Air Quality Director may require the owner or operator of any source in the state of Oklahoma to install, maintain and operate monitoring equipment or to conduct tests, including stack tests, of the air contaminant source. All required testing must be conducted by methods approved by the Air Quality Director

and under the direction of qualified personnel. A notice-of-intent to test and a testing protocol shall be submitted to Air Quality at least 30 days prior to any EPA Reference Method stack tests. Emissions and other data required to demonstrate compliance with any federal or state emission limit or standard, or any requirement set forth in a valid permit shall be recorded, maintained, and submitted as required by this subchapter, an applicable rule, or permit requirement. Data from any required testing or monitoring not conducted in accordance with the provisions of this subchapter shall be considered invalid. Nothing shall preclude the use, including the exclusive use, of any credible evidence or information relevant to whether a source would have been in compliance with applicable requirements if the appropriate performance or compliance test or procedure had been performed.

The following Oklahoma Air Pollution Control Rules are not applicable to this facility:

OAC 252:100-11	Alternative Emissions Reduction	not requested
OAC 252:100-15	Mobile Sources	not in source category
OAC 252:100-17	Incinerators	not type of emission unit
OAC 252:100-23	Cotton Gins	not type of emission unit
OAC 252:100-24	Grain Elevators	not in source category
OAC 252:100-39	Nonattainment Areas	not in area category
OAC 252:100-47	Landfills	not in source category

SECTION VIII. FEDERAL REGULATIONS

PSD, 40 CFR Part 52 [Not Applicable]
After construction modification, final total emissions will be less than the major source threshold of 250 TPY of any single regulated pollutant and the facility is not one of the 26 specific industries with a threshold of 100 TPY. This facility will no longer be applicable to Part 52.

NSPS, 40 CFR Part 60 [Subpart KKK Applicable]
Subparts K, Ka, Kb, VOL Storage Vessels. None of the tanks on-site are large enough to trigger any of these subparts. The pressurized tanks are also exempt. TNKs 1 through 4 were also constructed prior to the effective date of the regulations.
Subpart GG, Stationary Gas Turbines. There are none at this facility.
Subpart VV, Equipment Leaks of VOC in the Synthetic Organic Chemical Manufacturing Industry. The equipment is not in a SOCMI plant.
Subpart KKK, Equipment Leaks of VOC from Onshore Natural Gas Processing Plants. The facility may engage in natural gas processing, but the majority of the plant is not subject since it was built before 1984. Although they were installed in 1985, ENG-6 and ENG-8 compressor units are exempt from all requirements, except recordkeeping, because they are listed as being in residue gas service (not in VOC service). Therefore, valves, flanges, etc., associated with these units are also exempt. The recordkeeping involves verification that the units and associated equipment are not in VOC service, e.g., site plot plans and gas analysis prior to the units. The ENG-8 compressor remained unchanged when the ENG-8 engine was changed in 2006. Three added compressors, ENG-13,-14 and -15, will be used in residue gas services downstream of cryogenic operation. Therefore, they are not affected by this subpart.
Subpart LLL, Onshore Natural Gas Processing: SO_2 Emissions. This subpart sets standards for natural gas sweetening units. There is no natural gas sweetening operation at this site.

Subpart JJJJ, Standards of Performance for Stationary Spark Ignition Internal Combustion Engines (SI-ICE). This subpart was published in the Federal Register on January 18, 2008. It promulgates emission standards for new SI engines ordered after June 12, 2006, that are manufactured after certain dates, and for SI engines modified or reconstructed after June 12, 2006. The specific emission standards (either in g/hp-hr or as a concentration limit) vary based on engine class, engine power rating, lean-burn or rich-burn, fuel type, duty (emergency or non-emergency), and manufacture date. Engine manufacturers are required to certify certain engines to meet the emission standards and may voluntarily certify other engines. An initial notification is required only for owners and operators of engines greater than 500 HP that are non-certified. Emergency engines will be required to be equipped with a non-resettable hour meter and are limited to 100 hours per year of operation excluding use in an emergency (the length of operation and the reason the engine was in operation must be recorded). The engines in this permit are manufactured prior to June 12, 2006 and are not subject to this subpart.

NESHAP, 40 CFR Part 61 [Not Applicable]
There are no emissions of any of the regulated pollutants: arsenic, asbestos, beryllium, benzene, coke oven emissions, mercury, radionuclides or vinyl chloride except for trace amounts of benzene. Subpart J, Equipment Leaks of Benzene, only applies to process streams which contain more than 10% benzene by weight. Analysis of Oklahoma natural gas indicates a maximum benzene content of less than 1%.

NESHAP, 40 CFR Part 63 [ZZZZ Applicable]
Subpart HH, Oil and Natural Gas Production Facilities. This subpart applies to affected emission points that are located at facilities which are major and area sources of HAPs and either process, upgrade, or store hydrocarbons prior to the point of custody transfer or prior to which the natural gas enters the natural gas transmission and storage source category. For purposes of this subpart natural gas enters the natural gas transmission and storage source category after the natural gas processing plant. If no natural gas plant is present, natural gas enters the natural gas transmission and storage source category after the point of custody transfer. This facility is a minor source of HAP. The EPA promulgated the final rule for Subpart HH at area oil and gas production facilities, effective January 3, 2007. The only affected source at an area source is triethylene glycol (TEG) dehydration unit. There is no dehydration unit at the facility and the potential HAP emissions are below the 10/25 TPY threshold, therefore, this subpart is not applicable.
Subpart HHH, affects Natural Gas Transmission and Storage Facilities. Since this facility is a production facility, this subpart does not apply.
Subpart EEEE, Organic Liquids Distribution (Non-Gasoline). This subpart was promulgated on August 25, 2003, and affects organic liquid distribution (OLD) operations only at major sources of HAPs with an organic liquid throughput greater than 7.29 million gallons per year (173,571 barrels/yr). The facility is not a major source of HAPs.
Subpart YYYY, Stationary Combustion Turbines. This subpart affects stationary gas turbines located at a major source of HAP emissions. There are no combustion turbines at this facility.
Subpart ZZZZ, Reciprocating Internal Combustion Engines (RICE). This subpart previously affected only RICE with a site-rating greater than 500 brake horsepower that are located at a major source of HAP emissions. On January 18, 2008, the EPA published a final rule that promulgates standards for new and reconstructed engines (after June 12, 2006) with a site rating

less than or equal to 500 HP located at major sources, and for new and reconstructed engines (after June 12, 2006) located at area sources. Owners and operators of new engines and reconstructed engines at area sources and of new or reconstructed engines with a site rating equal to or less than 500 HP located at a major source (except new or reconstructed 4-stroke lean-burn engines with a site rating greater than or equal to 250 HP and less than or equal to 500 HP located at a major source) meet the requirements of Subpart ZZZZ by complying with either 40 CFR Part 60 Subpart IIII (for CI engines) or 40 CFR Part 60 Subpart JJJJ (for SI engines). Owners and operators of new or reconstructed 4SLB engines with a site rating greater than or equal to 250 HP and less than or equal to 500 HP located at a major source are subject to the same MACT standards previously established for 4SLB engines above 500 HP at a major source, and must also meet the requirements of 40 CFR Part 60 Subpart JJJJ, except for the emissions standards for CO. The engines in this permit are manufactured prior to June 12, 2006, and are affected units. However, an existing four-stroke rich-burn stationary RICE located at an area source does not need to meet requirements of this subpart and of Subpart A of this part.
<u>Subpart DDDDD,</u> National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial and Institutional Boilers and Process Heaters. In March, 2007, the EPA filed a motion to vacate and remand this rule back to the agency. The rule was vacated by court order, subject to appeal, on June 8, 2007. No appeals were made and the rule was vacated on July 30, 2007. Existing and new small gaseous fuel boilers and process heaters (less than 10 MMBtu/hr heat rating) were not subject to any standards, recordkeeping, or notifications under Subpart DDDDD.
EPA is planning on issuing guidance (or a rule) on what actions applicants and permitting authorities should take regarding MACT determinations under either Section112(g) or Section 112(j) for sources that were affected sources under Subpart DDDDD and other vacated MACTs. It is expected that the guidance (or rule) will establish a new timeline for submission of section 112(j) applications for vacated MACT standards. At this time, AQD has determined that a 112(j) determination is not needed for sources potentially subject to a vacated MACT, including Subpart DDDDD. This permit may be reopened to address Section 112(j) when necessary.

CAM, 40 CFR Part 64 [Not Applicable at This Time]
Compliance Assurance Monitoring (CAM), as published in the Federal Register on October 22, 1997, applies to any pollutant specific emission unit at a major source, that is required to obtain a Title V permit, if it meets all of the following criteria:

- It is subject to an emission limit or standard for an applicable regulated air pollutant
- It uses a control device to achieve compliance with the applicable emission limit or standard
- It has potential emissions, prior to the control device, of the applicable regulated air pollutant of 100 TPY

The original application was deemed administratively complete prior to promulgation of the CAM rule, therefore, the rule will not apply until permit renewal. At renewal, the rule may apply because some of the engines could exceed 100 TPY prior to a control device.

Chemical Accident Prevention Provisions, 40 CFR Part 68 [Not Applicable]
The definition of a stationary source does not apply to transportation, including storage incident to transportation, of any regulated substance or any other extremely hazardous substance under

the provisions of this part. The definition of a stationary source also does not include naturally occurring hydrocarbon reservoirs. Naturally occurring hydrocarbon mixtures, prior to entry into a natural gas processing plant or a petroleum refining process unit, including: condensate, crude oil, field gas, and produced water, are exempt for the purpose of determining whether more than a threshold quantity of a regulated substance is present at the stationary source. This facility does not process or store more than the threshold quantity of any regulated substance (Section 112r of the Clean Air Act 1990 Amendments). More information on this federal program is available on the web page: *www.epa.gov/ceppo*.

Stratospheric Ozone Protection, 40 CFR Part 82 [Subpart A and F Applicable]
These standards require phase out of Class I & II substances, reductions of emissions of Class I & II substances to the lowest achievable level in all use sectors, and banning use of nonessential products containing ozone-depleting substances (Subparts A & C); control servicing of motor vehicle air conditioners (Subpart B); require Federal agencies to adopt procurement regulations which meet phase out requirements and which maximize the substitution of safe alternatives to Class I and Class II substances (Subpart D); require warning labels on products made with or containing Class I or II substances (Subpart E); maximize the use of recycling and recovery upon disposal (Subpart F); require producers to identify substitutes for ozone-depleting compounds under the Significant New Alternatives Program (Subpart G); and reduce the emissions of halons (Subpart H).
Subpart A identifies ozone-depleting substances and divides them into two classes. Class I controlled substances are divided into seven groups; the chemicals typically used by the manufacturing industry include carbon tetrachloride (Class I, Group IV) and methyl chloroform (Class I, Group V). A complete phase-out of production of Class I substances is required by January 1, 2000 (January 1, 2002, for methyl chloroform). Class II chemicals, which are hydrochlorofluorocarbons (HCFCs), are generally seen as interim substitutes for Class I CFCs. Class II substances consist of 33 HCFCs. A complete phase-out of Class II substances, scheduled in phases starting by 2002, is required by January 1, 2030.

This facility does not utilize any Class I & II substances.

SECTION IX. COMPLIANCE

Tier Classification and Public Review

This application has been determined to be a Tier II based on the fact that it is a request for a construction permit for a Part 70 major source modification.

The permittee has submitted an affidavit that they are not seeking a permit for land use or for any operation upon land owned by others without their knowledge. The affidavit certifies that the applicant owns the land.

The applicant published the "Notice of Filing a Tier II Application" in the *Woodward News*, a daily newspaper printed in the City of Woodward, Woodward County, on March 29, 2008. The notice stated that the application was available for public review at the Woodward Public Library located at 1500 Main, Woodward, Oklahoma 73801 or the AQD office at 707 N. Robinson, Oklahoma City, Oklahoma 73101. This facility is not located within 50 miles of the Oklahoma border. A draft of this permit will also be made available for public review for a period of 30 days as stated in another newspaper announcement and will be available on the AQD Section of the DEQ Web site. The EPA review will be conducted concurrently with this public review. Public review period will be 30 days and EPA review period will be 45 days. Information on all permit actions is available for review by the public in the Air Quality Section of the DEQ Web Page: *www.deq.state.ok.us*.

Fees Paid

Construction permit application fee of $1,500 for an existing Part 70 source modification.

SECTION X. SUMMARY

The applicant has demonstrated the ability to comply with the requirements of the applicable Air Quality rules and regulations. Ambient air quality standards are not threatened at this site. There are no active Air Quality compliance and enforcement issues concerning this facility. Issuance of the construction permit is recommended, contingent on EPA and public review.

PERMIT TO CONSTRUCT
AIR POLLUTION CONTROL FACILITY
SPECIFIC CONDITIONS

DCP Midstream, L.P. **Permit No. 97-179-C (M-2)**
Cimarron Natural Gas Processing Plant

The permittee is authorized to construct in conformity with the specifications submitted to Air Quality on February 6, 2008, with supplemental information received on April 10, 2008. The Evaluation Memorandum dated August 25, 2008, explains the derivation of applicable permit requirements and estimates of emissions; however, it does not contain operating limitations or permit requirements. Commencing construction or operations under this permit constitutes acceptance of, and consent to, the conditions contained herein.

1. Points of emissions and emissions limitations for each point: [OAC 252:100-8-6 (a)]

EUG 1: Emission limitations for all compressor engines.

EU ID#	Source	NOx		CO		VOC	
		lb/hr	TPY	lb/hr	TPY	lb/hr	TPY
ENG-1	White-Superior 6G825 with C.C.	2.65	11.59	2.65	11.59	1.32	5.79
ENG-2	White-Superior 6G825 with C.C.	2.65	11.59	2.65	11.59	1.32	5.79
ENG-6	Waukesha L-7042 with C.C.	3.03	13.27	3.03	13.27	1.51	6.63
ENG-8	Waukesha L-7042 with C.C.	3.03	13.27	3.03	13.27	1.51	6.63
ENG-9	Waukesha L-7042 with C.C.	3.03	13.27	3.03	13.27	1.51	6.63
ENG-10	Waukesha L-7042 with C.C.	3.03	13.27	3.03	13.27	1.51	6.63
ENG-11	Waukesha L-7042 with C.C.	3.03	13.27	3.03	13.27	1.51	6.63
ENG-12	Waukesha L-7042 with C.C.	3.03	13.27	3.03	13.27	1.51	6.63
ENG-13	Waukesha L5794 GSI with C.C.	6.08	26.65	6.08	26.65	3.04	13.33
ENG-14	Waukesha L5794 GSI with C.C.	6.08	26.65	6.08	26.65	3.04	13.33
ENG-15	Waukesha L5794 GSI with C.C.	6.08	26.65	6.08	26.65	3.04	13.33

EUG 2: Storage tank VOC emissions.

EU ID#	Contents	Barrels	Gallons	VOC (TPY)
TNK-1	Condensate/Slop Oil	300	12,600	4.23
TNK-2	Condensate/Slop Oil	300	12,600	4.23
TNK-3	Condensate/Slop Oil	300	12,600	4.23
TNK-4	Condensate/Slop Oil	300	12,600	4.23
TNK-16	Condensate/Slop Oil	210	8,820	1.73

a. All five condensate storage tanks, from TNK-1 to TNK-4 and TNK-16, shall each be operated with submerged fill pipes. [OAC 252:100-37-15(b)]
b. For the tank's operation, the total condensate throughput is limited to 3,150,000 gallons per year per tank from TNK-1 to TNK-4 based on a 12-month rolling total.

c. The total condensate throughput is limited to 317,520 gallons per year for TNK-16 based on a 12-month rolling total.
d. Condensate tanks emissions estimates include working and breathing losses, and does not include flash emissions.

EUG 3: Process Heaters

EU	Point	MMBtu/hr	Serial #	Installation Date
HTR-1	Hot-oil Heater	10	68524	1969
HTR-2	Hot-oil Heater (standby)	6	J71-858	1969

Process heater emissions are estimated based on existing equipment, are considered to be insignificant, and do not have specific limitations.

EUG 4: Process Flare

EU	Point	NOx		CO		VOC	
		lbs/hr	TPY	lbs/hr	TPY	lbs/hr	TPY
FLARE-1	Process Flare	0.52	2.26	2.81	12.31	1.06	4.66

a. VOC gaseous stream venting to the flare shall be limited to 57.7 MMSCF per year based on a 12-month rolling total.
b. The flare shall be equipped with a flame-monitoring and auto-ignition pilot system that provides automatic flare start-up, and automatic shutdown of the VOC gaseous stream if a flare malfunction occurs (including, but not limited to, failure of the pilot). The shutdown of the VOC gaseous stream must be accomplished as quickly as possible, consistent with safety and prudent engineering practice. [OAC 252:100-43]

EUG 5: Fugitive VOC emissions are estimated based on equipment items after construction but do not have a specific limitation and are insignificant.

EU	Type of Service	Estimated Number of Items*	Type of Equipment
FUG-1	Gas	646	Valves
	Gas	90	Relief Valves
	Gas	48	Compressor Seals
	Gas	3,475	Flanges
	Heavy Liquid	66	Valves
	Heavy Liquid	22	Pump Seals
	Heavy Liquid	440	Flanges
	Light Liquid	264	Valves
	Light Liquid	24	Pump Seals
	Light Liquid	420	Flanges

*Estimate only, not a permit limit

The permittee shall maintain an updated list of all fugitive VOC emission sources for the facility.

2. The fuel-burning equipment shall be fired with pipeline grade natural gas or other gaseous fuel with a sulfur content less than 343 ppmv. Compliance can be shown by the following methods: for pipeline grade natural gas, a current gas company bill; for other gaseous fuel, a current lab analysis, stain-tube analysis, gas contract, tariff sheet, or other approved methods. Compliance shall be demonstrated at least once annually. [OAC 252:100-31]

3. Upon issuance of an operating permit, the permittee shall be authorized to operate this facility continuously (24 hours per day, every day of the year). [OAC 252:100-8-6(a)]

4. Each engine at the facility shall have a permanent identification plate attached, which shows the make, model number, and serial number. [OAC 252:100-43]

5. At least once per calendar quarter, the permittee shall conduct tests of NOx and CO emissions in exhaust gases from the engines in Specific Condition No.1 and each replacement engine when operating under representative conditions for that period. Testing is required for any engine or replacement engine, which runs for more than 220 hours during that calendar quarter. Engines shall be tested no sooner than 20 days after the last test. Testing shall be conducted using a portable engine analyzer in accordance with a protocol meeting the requirements of the "AQD Portable Analyzer Guidance" document or an equivalent method approved by Air Quality. When four consecutive quarterly tests show an engine to be in compliance with the emissions limitations shown in the permit, then the testing frequency may be reduced to semi-annual testing. A semi-annual test may be conducted no sooner than 60 calendar days nor later than 180 calendar days after the most recent test. Likewise, when the following two consecutive semi-annual tests show compliance, the testing frequency may be reduced to annual testing. An annual test may be conducted no sooner than 120 calendar days nor later than 365 calendar days after the most recent test. Upon any showing of non-compliance with emissions limitations or testing that indicate that emissions are within 10% of the emission limitation, the testing frequency shall revert to quarterly. Reduced engine testing does not apply to engines with catalytic converters. [OAC 252:100-8-6 (a)(3)(A)]

6. All engines, ENG-1, ENG-2, and from ENG-7 to ENG-15, shall each be set to operate exhaust gases passing through a properly functioning catalytic converter. [OAC 252:100-7-15(d)(3)]

7. The permittee shall keep operation and maintenance (O&M) records for those engines which do not conduct periodic testing. Such records shall at a minimum include the dates of operation, and maintenance, type of work performed, and the increase, if any, in emissions as a result. [OAC 252:100-8-6 (a)(3)(B)]

8. When periodic compliance testing shows engine exhaust emissions in excess of the lb/hr limits in Specific Condition Number 1, the permittee shall comply with the provisions of OAC 252:100-9. Requirements of OAC 252:100-9 include immediate notification and written notification of Air Quality and demonstrations that the excess emissions meet the criteria specified in OAC 252:100-9. [OAC 252:100-9]

9. Replacement (including temporary periods of up to six months for maintenance, etc.) of internal combustion engines shown in this permit with engines of lesser or equal emissions of each pollutant is authorized under the following conditions: [OAC 252:100-8-6 (f)]

   a. The permittee shall notify AQD in writing not later than 7 days in advance of the replacement engine(s)/turbine(s). Said notice shall identify the old engine/turbine and shall include the new engine/turbine make and model, serial number, horsepower rating, fuel usage, stack flow (ACFM), stack temperature (°F), stack height (feet), stack diameter (inches), and pollutant emission rates (g/hp-hr, lb/hr, and TPY) at maximum horsepower for the altitude/location.

   b. Quarterly emissions tests for the replacement engine(s)/turbine(s) shall be conducted to confirm continued compliance with NOx and CO emissions limitations. A copy of the first quarter testing shall be provided to AQD within 60 days of start-up of each replacement engine/turbine. The test report shall include the engine/turbine fuel usage, stack flow (ACFM), stack temperature (°F), stack height (feet), stack diameter (inches), and pollutant emission rates (g/hp-hr, lbs/hr, and TPY) at maximum rated horsepower for the altitude/location.

   c. Replacement equipment and emissions are limited to equipment and emissions which are not subject to NSPS, NESHAP, or PSD.

11. The permittee is subject to NSPS, 40 CFR 60, Subpart KKK, "Equipment Leaks of VOC from Onshore Natural Gas Processing Plants." For ENG-7 and ENG-8, and the associated equipment (valves, flanges, etc.) for these units, only recordkeeping is required. This involves verification that the units and associated equipment are not in VOC service, e.g., site plot plans and gas analysis prior to the units.

12. The permittee shall maintain records of operations as listed below. These records shall be retained on-site or at a local field office for a period of at least five years following dates of recording, and shall be made available to regulatory personnel upon request. [OAC 252:100-43]

   a. Periodic testing for NOx and CO exhaust from each engine and each replacement engine.
   b. Operating hours for each engine if less than 220 hours per quarter and not tested.
   c. Summary of O&M records for any engine not tested in each 6 month period
   d. For the fuel(s) burned, the appropriate document(s) as described in Specific Condition No. 2.
   e. Condensate throughput for the condensate tanks, TNK-1, TNK-2, TNK-3, TNK-4, and TNK-16 (monthly and 12-month rolling total).
   f. VOC gaseous stream flow to the flare (monthly and 12-month rolling total).
   g. Records as required by NSPS, 40 CFR Part 60, Subpart KKK.

13. The following records shall be maintained on-site to verify Insignificant Activities. No recordkeeping is required for those operations which qualify as Trivial Activities. [OAC 252:100-8-6 (a)(3)(B)]

a. For crude oil and condensate storage tanks with a capacity of less than or equal to 420,000 gallons that store crude oil and condensate prior to custody transfer: records of capacity of the tanks and the amount of throughput (annual).
b. For fluid storage tanks with a capacity of less than 39,894 gallons and a true vapor pressure less than 1.5 psia: records of capacity of the tanks and contents.
c. For activities that have the potential to emit less than 5 TPY (actual) of any criteria pollutant: the type of activity and the amount of emissions from that activity (annual).

14. The Permit Shield (Standard Conditions, Section VI) is extended to the following requirements that have been determined to be inapplicable to this facility:
[OAC 252:100-8-6(d)(2)]

a. 40 CFR Part 52, NSR
b. 40 CFR Part 61, NESHAP
c. OAC 252:100-8, Part 7, PSD
d. OAC 252:100-33, Control of Emissions of Nitrogen Oxides
e. OAC 252:100-35, Control of Emission of Carbon Monoxide

15. Within 180 days of operational start-up of the new engines, the permittee shall submit an application for an operating permit along with the following information, and noting any changes in operation from the construction permit application. [OAC 252:100-7-18(a)]

a. Initial compliance testing of the new engines.

Mr. Mike Smith, Environmental Specialist IV
DCP Midstream, L.P.
515 Central Park Drive, Building Two, Suite 100
Oklahoma City, OK 73105

Permit Number: **97-179-C (M-2)**
Permit Writer: Mark Chen, P.E.

SUBJECT: Construction Permit Application for Cimarron Natural Gas Processing Plant
NE/4 Section 27, Township 20N, Range 17W
Woodward County, Oklahoma.

Dear Mr. Smith:

Air Quality Division has completed the initial review of your permit construction application referenced above. This application has been determined to be a **Tier II.** In accordance with 27A O.S. §2-14-302 and OAC 252:002-31 the enclosed draft permit is now ready for public review. The requirement for public review include the following steps which <u>you</u> must accomplish:

1. Publish at least one legal notice (one day) in at least one newspaper of general circulation within the county where the facility is located. (Instruction enclosed)

2. Provide for public review (for a period of 30 days following the date of the newspaper announcement) a copy of this draft permit and a copy of the application at a convenient location (preferably a public location) within the county of the facility.

3. Send to AQD a copy of the proof of publication notice from Item #1 above together with any additional comments or requested changes, which you may have on the draft permit.

Thank you for your cooperation. If you have any questions, please refer to the permit number above and contact me at (405) 702-4100 or the permit writer at (405) 702-4196.

Sincerely,

Phillip Fielder, P.E.
Permits and Engineering Group Manager
AIR QUALITY DIVISION

TITLE V (PART 70) PERMIT TO OPERATE / CONSTRUCT
STANDARD CONDITIONS
(January 24, 2008)

SECTION I. DUTY TO COMPLY

A. This is a permit to operate / construct this specific facility in accordance with the federal Clean Air Act (42 U.S.C. 7401, et al.) and under the authority of the Oklahoma Clean Air Act and the rules promulgated there under. [Oklahoma Clean Air Act, 27A O.S. § 2-5-112]

B. The issuing Authority for the permit is the Air Quality Division (AQD) of the Oklahoma Department of Environmental Quality (DEQ). The permit does not relieve the holder of the obligation to comply with other applicable federal, state, or local statutes, regulations, rules, or ordinances. [Oklahoma Clean Air Act, 27A O.S. § 2-5-112]

C. The permittee shall comply with all conditions of this permit. Any permit noncompliance shall constitute a violation of the Oklahoma Clean Air Act and shall be grounds for enforcement action, permit termination, revocation and reissuance, or modification, or for denial of a permit renewal application. All terms and conditions are enforceable by the DEQ, by the Environmental Protection Agency (EPA), and by citizens under section 304 of the Federal Clean Air Act (excluding state-only requirements). This permit is valid for operations only at the specific location listed.
[40 C.F.R. §70.6(b), OAC 252:100-8-1.3 and OAC 252:100-8-6(a)(7)(A) and (b)(1)]

D. It shall not be a defense for a permittee in an enforcement action that it would have been necessary to halt or reduce the permitted activity in order to maintain compliance with the conditions of the permit. However, nothing in this paragraph shall be construed as precluding consideration of a need to halt or reduce activity as a mitigating factor in assessing penalties for noncompliance if the health, safety, or environmental impacts of halting or reducing operations would be more serious than the impacts of continuing operations. [OAC 252:100-8-6(a)(7)(B)]

SECTION II. REPORTING OF DEVIATIONS FROM PERMIT TERMS

A. Any exceedance resulting from an emergency and/or posing an imminent and substantial danger to public health, safety, or the environment shall be reported in accordance with Section XIV (Emergencies). [OAC 252:100-8-6(a)(3)(C)(iii)(I) & (II)]

B. Deviations that result in emissions exceeding those allowed in this permit shall be reported consistent with the requirements of OAC 252:100-9, Excess Emission Reporting Requirements.
[OAC 252:100-8-6(a)(3)(C)(iv)]

C. Every written report submitted under this section shall be certified as required by Section III (Monitoring, Testing, Recordkeeping & Reporting), Paragraph F.
[OAC 252:100-8-6(a)(3)(C)(iv)]

SECTION III. MONITORING, TESTING, RECORDKEEPING & REPORTING

A. The permittee shall keep records as specified in this permit. These records, including monitoring data and necessary support information, shall be retained on-site or at a nearby field office for a period of at least five years from the date of the monitoring sample, measurement, report, or application, and shall be made available for inspection by regulatory personnel upon request. Support information includes all original strip-chart recordings for continuous monitoring instrumentation, and copies of all reports required by this permit. Where appropriate, the permit may specify that records may be maintained in computerized form.

[OAC 252:100-8-6 (a)(3)(B)(ii), OAC 252:100-8-6(c)(1), and OAC 252:100-8-6(c)(2)(B)]

B. Records of required monitoring shall include:
(1) the date, place and time of sampling or measurement;
(2) the date or dates analyses were performed;
(3) the company or entity which performed the analyses;
(4) the analytical techniques or methods used;
(5) the results of such analyses; and
(6) the operating conditions existing at the time of sampling or measurement.

[OAC 252:100-8-6(a)(3)(B)(i)]

C. No later than 30 days after each six (6) month period, after the date of the issuance of the original Part 70 operating permit, the permittee shall submit to AQD a report of the results of any required monitoring. All instances of deviations from permit requirements since the previous report shall be clearly identified in the report. Submission of these periodic reports will satisfy any reporting requirement of Paragraph E below that is duplicative of the periodic reports, if so noted on the submitted report. [OAC 252:100-8-6(a)(3)(C)(i) and (ii)]

D. If any testing shows emissions in excess of limitations specified in this permit, the owner or operator shall comply with the provisions of Section II (Reporting Of Deviations From Permit Terms) of these standard conditions.

[OAC 252:100-8-6(a)(3)(C)(iii)]

E. In addition to any monitoring, recordkeeping or reporting requirement specified in this permit, monitoring and reporting may be required under the provisions of OAC 252:100-43, Testing, Monitoring, and Recordkeeping, or as required by any provision of the Federal Clean Air Act or Oklahoma Clean Air Act. [OAC 252:100-43]

F. Any document submitted in accordance with this permit shall be certified by a responsible official. This certification shall be signed by a responsible official, and shall contain the following language: "I certify, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete." However, an exceedance report that must be submitted within ten days of the exceedance under Section II (Reporting Of Deviations From Permit Terms) or Section XIV (Emergencies) may be submitted without a certification, if an appropriate certification is provided within ten days thereafter, together with any corrected or supplemental information required concerning the exceedance.

[OAC 252:100-8-5(f), OAC 252:100-8-6(a)(3)(C)(iv), OAC 252:100-8-6(c)(1) and OAC 252:100-9-3.1(c)]

G. Any owner or operator subject to the provisions of New Source Performance Standards ("NSPS") under 40 CFR Part 60 or National Emission Standards for Hazardous Air Pollutants ("NESHAPs") under 40 CFR Parts 61 and 63 shall maintain a file of all measurements and other information required by the applicable general provisions and subpart(s). These records shall be maintained in a permanent file suitable for inspection, shall be retained for a period of at least five years as required by Paragraph A of this Section, and shall include records of the occurrence and duration of any start-up, shutdown, or malfunction in the operation of an affected facility, any malfunction of the air pollution control equipment; and any periods during which a continuous monitoring system or monitoring device is inoperative.

[40 C.F.R. §§60.7 and 63.10, 40 CFR Parts 61, Subpart A, and OAC 252:100, Appendix Q]

H. [Reserved]

I. The permittee of a facility that is operating subject to a schedule of compliance shall submit to the DEQ a progress report at least semi-annually. The progress reports shall contain dates for achieving the activities, milestones or compliance required in the schedule of compliance and the dates when such activities, milestones or compliance was achieved. The progress reports shall also contain an explanation of why any dates in the schedule of compliance were not or will not be met, and any preventive or corrective measures adopted. [OAC 252:100-8-6(c)(4)]

J. All testing must be conducted under the direction of qualified personnel by methods approved by the Division Director. All tests shall be made and the results calculated in accordance with standard test procedures. The use of alternative test procedures must be approved by EPA. When a portable analyzer is used to measure emissions it shall be setup, calibrated, and operated in accordance with the manufacturer's instructions and in accordance with a protocol meeting the requirements of the "AQD Portable Analyzer Guidance" document or an equivalent method approved by Air Quality.

[OAC 252:100-8-6(a)(3)(A)(iv), and OAC 252:100-43]

K. The reporting of total particulate matter emissions as required in Part 7 of OAC 252:100-8 (Permits for Part 70 Sources), OAC 252:100-19 (Control of Emission of Particulate Matter), and OAC 252:100-5 (Emission Inventory), shall be conducted in accordance with applicable testing or calculation procedures, modified to include back-half condensables, for the concentration of particulate matter less than 10 microns in diameter (PM_{10}). NSPS may allow reporting of only particulate matter emissions caught in the filter (obtained using Reference Method 5).

L. The permittee shall submit to the AQD a copy of all reports submitted to the EPA as required by 40 C.F.R. Part 60, 61, and 63, for all equipment constructed or operated under this permit subject to such standards. [OAC 252:100-8-6(c)(1) and OAC 252:100, Appendix Q]

SECTION IV. COMPLIANCE CERTIFICATIONS

A. No later than 30 days after each anniversary date of the issuance of the original Part 70 operating permit, the permittee shall submit to the AQD, with a copy to the US EPA, Region 6, a certification of compliance with the terms and conditions of this permit and of any other applicable requirements which have become effective since the issuance of this permit. The compliance certification shall also include such other facts as the permitting authority may require to determine the compliance status of the source.

[OAC 252:100-8-6(c)(5)(A), (C)(v), and (D)]

B. The compliance certification shall describe the operating permit term or condition that is the basis of the certification; the current compliance status; whether compliance was continuous or intermittent; the methods used for determining compliance, currently and over the reporting period; and a statement that the facility will continue to comply with all applicable requirements.

[OAC 252:100-8-6(c)(5)(C)(i)-(iv)]

C. The compliance certification shall contain a certification by a responsible official as to the results of the required monitoring. This certification shall be signed by a responsible official, and shall contain the following language: "I certify, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete." [OAC 252:100-8-5(f) and OAC 252:100-8-6(c)(1)]

D. Any facility reporting noncompliance shall submit a schedule of compliance for emissions units or stationary sources that are not in compliance with all applicable requirements. This schedule shall include a schedule of remedial measures, including an enforceable sequence of actions with milestones, leading to compliance with any applicable requirements for which the emissions unit or stationary source is in noncompliance. This compliance schedule shall resemble and be at least as stringent as that contained in any judicial consent decree or administrative order to which the emissions unit or stationary source is subject. Any such schedule of compliance shall be supplemental to, and shall not sanction noncompliance with, the applicable requirements on which it is based, except that a compliance plan shall not be required for any noncompliance condition which is corrected within 24 hours of discovery.

[OAC 252:100-8-5(e)(8)(B) and OAC 252:100-8-6(c)(3)]

SECTION V. REQUIREMENTS THAT BECOME APPLICABLE DURING THE PERMIT TERM

The permittee shall comply with any additional requirements that become effective during the permit term and that are applicable to the facility. Compliance with all new requirements shall be certified in the next annual certification. [OAC 252:100-8-6(c)(6)]

SECTION VI. PERMIT SHIELD

A. Compliance with the terms and conditions of this permit (including terms and conditions established for alternate operating scenarios, emissions trading, and emissions averaging, but excluding terms and conditions for which the permit shield is expressly prohibited under OAC 252:100-8) shall be deemed compliance with the applicable requirements identified and included in this permit. [OAC 252:100-8-6(d)(1)]

B. Those requirements that are applicable are listed in the Standard Conditions and the Specific Conditions of this permit. Those requirements that the applicant requested be determined as not applicable are summarized in the Specific Conditions of this permit. [OAC 252:100-8-6(d)(2)]

SECTION VII. ANNUAL EMISSIONS INVENTORY & FEE PAYMENT

The permittee shall file with the AQD an annual emission inventory and shall pay annual fees based on emissions inventories. The methods used to calculate emissions for inventory purposes shall be based on the best available information accepted by AQD.
[OAC 252:100-5-2.1, OAC 252:100-5-2.2, and OAC 252:100-8-6(a)(8)]

SECTION VIII. TERM OF PERMIT

A. Unless specified otherwise, the term of an operating permit shall be five years from the date of issuance. [OAC 252:100-8-6(a)(2)(A)]

B. A source's right to operate shall terminate upon the expiration of its permit unless a timely and complete renewal application has been submitted at least 180 days before the date of expiration. [OAC 252:100-8-7.1(d)(1)]

C. A duly issued construction permit or authorization to construct or modify will terminate and become null and void (unless extended as provided in OAC 252:100-8-1.4(b)) if the construction is not commenced within 18 months after the date the permit or authorization was issued, or if work is suspended for more than 18 months after it is commenced. [OAC 252:100-8-1.4(a)]

D. The recipient of a construction permit shall apply for a permit to operate (or modified operating permit) within 180 days following the first day of operation. [OAC 252:100-8-4(b)(5)]

SECTION IX. SEVERABILITY

The provisions of this permit are severable and if any provision of this permit, or the application of any provision of this permit to any circumstance, is held invalid, the application of such provision to other circumstances, and the remainder of this permit, shall not be affected thereby.
[OAC 252:100-8-6 (a)(6)]

SECTION X. PROPERTY RIGHTS

A. This permit does not convey any property rights of any sort, or any exclusive privilege.
[OAC 252:100-8-6(a)(7)(D)]

B. This permit shall not be considered in any manner affecting the title of the premises upon which the equipment is located and does not release the permittee from any liability for damage to persons or property caused by or resulting from the maintenance or operation of the equipment for which the permit is issued. [OAC 252:100-8-6(c)(6)]

SECTION XI. DUTY TO PROVIDE INFORMATION

A. The permittee shall furnish to the DEQ, upon receipt of a written request and within sixty (60) days of the request unless the DEQ specifies another time period, any information that the DEQ may request to determine whether cause exists for modifying, reopening, revoking,

reissuing, terminating the permit or to determine compliance with the permit. Upon request, the permittee shall also furnish to the DEQ copies of records required to be kept by the permit.
[OAC 252:100-8-6(a)(7)(E)]

B. The permittee may make a claim of confidentiality for any information or records submitted pursuant to 27A O.S. § 2-5-105(18). Confidential information shall be clearly labeled as such and shall be separable from the main body of the document such as in an attachment.
[OAC 252:100-8-6(a)(7)(E)]

C. Notification to the AQD of the sale or transfer of ownership of this facility is required and shall be made in writing within thirty (30) days after such sale or transfer.
[Oklahoma Clean Air Act, 27A O.S. § 2-5-112(G)]

SECTION XII. REOPENING, MODIFICATION & REVOCATION

A. The permit may be modified, revoked, reopened and reissued, or terminated for cause. Except as provided for minor permit modifications, the filing of a request by the permittee for a permit modification, revocation and reissuance, termination, notification of planned changes, or anticipated noncompliance does not stay any permit condition.
[OAC 252:100-8-6(a)(7)(C) and OAC 252:100-8-7.2(b)]

B. The DEQ will reopen and revise or revoke this permit prior to the expiration date in the following circumstances:

(1) Additional requirements under the Clean Air Act become applicable to a major source category three or more years prior to the expiration date of this permit. No such reopening is required if the effective date of the requirement is later than the expiration date of this permit.
(2) The DEQ or the EPA determines that this permit contains a material mistake or that the permit must be revised or revoked to assure compliance with the applicable requirements.
(3) The DEQ or the EPA determines that inaccurate information was used in establishing the emission standards, limitations, or other conditions of this permit. The DEQ may revoke and not reissue this permit if it determines that the permittee has submitted false or misleading information to the DEQ.
(4) DEQ determines that the permit should be amended under the discretionary reopening provisions of OAC 252:100-8-7.3(b).

[OAC 252:100-8-7.3 and OAC 252:100-8-7.4(a)(2)]

C. The permit may be reopened for cause by EPA, pursuant to the provisions of OAC 100-8-7.3(d).
[OAC 100-8-7.3(d)]

D. The permittee shall notify AQD before making changes other than those described in Section XVIII (Operational Flexibility), those qualifying for administrative permit amendments, or those defined as an Insignificant Activity (Section XVI) or Trivial Activity (Section XVII). The notification should include any changes which may alter the status of a "grandfathered source," as defined under AQD rules. Such changes may require a permit modification.
[OAC 252:100-8-7.2(b) and OAC 252:100-5-1.1]

E. Activities that will result in air emissions that exceed the trivial/insignificant levels and that are not specifically approved by this permit are prohibited. [OAC 252:100-8-6(c)(6)]

SECTION XIII. INSPECTION & ENTRY

A. Upon presentation of credentials and other documents as may be required by law, the permittee shall allow authorized regulatory officials to perform the following (subject to the permittee's right to seek confidential treatment pursuant to 27A O.S. Supp. 1998, § 2-5-105(18) for confidential information submitted to or obtained by the DEQ under this section):

(1) enter upon the permittee's premises during reasonable/normal working hours where a source is located or emissions-related activity is conducted, or where records must be kept under the conditions of the permit;
(2) have access to and copy, at reasonable times, any records that must be kept under the conditions of the permit;
(3) inspect, at reasonable times and using reasonable safety practices, any facilities, equipment (including monitoring and air pollution control equipment), practices, or operations regulated or required under the permit; and
(4) as authorized by the Oklahoma Clean Air Act, sample or monitor at reasonable times substances or parameters for the purpose of assuring compliance with the permit.

[OAC 252:100-8-6(c)(2)]

SECTION XIV. EMERGENCIES

A. Any exceedance resulting from an emergency shall be reported to AQD promptly but no later than 4:30 p.m. on the next working day after the permittee first becomes aware of the exceedance. This notice shall contain a description of the emergency, the probable cause of the exceedance, any steps taken to mitigate emissions, and corrective actions taken.

[OAC 252:100-8-6 (a)(3)(C)(iii)(I) and (IV)]

B. Any exceedance that poses an imminent and substantial danger to public health, safety, or the environment shall be reported to AQD as soon as is practicable; but under no circumstance shall notification be more than 24 hours after the exceedance.

[OAC 252:100-8-6(a)(3)(C)(iii)(II)]

C. An "emergency" means any situation arising from sudden and reasonably unforeseeable events beyond the control of the source, including acts of God, which situation requires immediate corrective action to restore normal operation, and that causes the source to exceed a technology-based emission limitation under this permit, due to unavoidable increases in emissions attributable to the emergency. An emergency shall not include noncompliance to the extent caused by improperly designed equipment, lack of preventive maintenance, careless or improper operation, or operator error. [OAC 252:100-8-2]

D. The affirmative defense of emergency shall be demonstrated through properly signed, contemporaneous operating logs or other relevant evidence that:

(1) an emergency occurred and the permittee can identify the cause or causes of the emergency;
(2) the permitted facility was at the time being properly operated;
(3) during the period of the emergency the permittee took all reasonable steps to minimize levels of emissions that exceeded the emission standards or other requirements in this permit. [OAC 252:100-8-6 (e)(2)]

E. In any enforcement proceeding, the permittee seeking to establish the occurrence of an emergency shall have the burden of proof. [OAC 252:100-8-6(e)(3)]

F. Every written report or document submitted under this section shall be certified as required by Section III (Monitoring, Testing, Recordkeeping & Reporting), Paragraph F.
[OAC 252:100-8-6(a)(3)(C)(iv)]

SECTION XV. RISK MANAGEMENT PLAN

The permittee, if subject to the provision of Section 112(r) of the Clean Air Act, shall develop and register with the appropriate agency a risk management plan by June 20, 1999, or the applicable effective date. [OAC 252:100-8-6(a)(4)]

SECTION XVI. INSIGNIFICANT ACTIVITIES

Except as otherwise prohibited or limited by this permit, the permittee is hereby authorized to operate individual emissions units that are either on the list in Appendix I to OAC Title 252, Chapter 100, or whose actual calendar year emissions do not exceed any of the limits below. Any activity to which a State or Federal applicable requirement applies is not insignificant even if it meets the criteria below or is included on the insignificant activities list.

(1) 5 tons per year of any one criteria pollutant.
(2) 2 tons per year for any one hazardous air pollutant (HAP) or 5 tons per year for an aggregate of two or more HAP's, or 20 percent of any threshold less than 10 tons per year for single HAP that the EPA may establish by rule.
[OAC 252:100-8-2 and OAC 252:100, Appendix I]

SECTION XVII. TRIVIAL ACTIVITIES

Except as otherwise prohibited or limited by this permit, the permittee is hereby authorized to operate any individual or combination of air emissions units that are considered inconsequential and are on the list in Appendix J. Any activity to which a State or Federal applicable requirement applies is not trivial even if included on the trivial activities list.
[OAC 252:100-8-2 and OAC 252:100, Appendix J]

SECTION XVIII. OPERATIONAL FLEXIBILITY

A. A facility may implement any operating scenario allowed for in its Part 70 permit without the need for any permit revision or any notification to the DEQ (unless specified otherwise in the permit). When an operating scenario is changed, the permittee shall record in a log at the facility the scenario under which it is operating. [OAC 252:100-8-6(a)(10) and (f)(1)]

B. The permittee may make changes within the facility that:

(1) result in no net emissions increases,
(2) are not modifications under any provision of Title I of the federal Clean Air Act, and
(3) do not cause any hourly or annual permitted emission rate of any existing emissions unit to be exceeded;

provided that the facility provides the EPA and the DEQ with written notification as required below in advance of the proposed changes, which shall be a minimum of seven (7) days, or twenty four (24) hours for emergencies as defined in OAC 252:100-8-6 (e). The permittee, the DEQ, and the EPA shall attach each such notice to their copy of the permit. For each such change, the written notification required above shall include a brief description of the change within the permitted facility, the date on which the change will occur, any change in emissions, and any permit term or condition that is no longer applicable as a result of the change. The permit shield provided by this permit does not apply to any change made pursuant to this paragraph.

[OAC 252:100-8-6(f)(2)]

SECTION XIX. OTHER APPLICABLE & STATE-ONLY REQUIREMENTS

A. The following applicable requirements and state-only requirements apply to the facility unless elsewhere covered by a more restrictive requirement:

(1) Open burning of refuse and other combustible material is prohibited except as authorized in the specific examples and under the conditions listed in the Open Burning Subchapter. [OAC 252:100-13]

(2) No particulate emissions from any fuel-burning equipment with a rated heat input of 10 MMBTUH or less shall exceed 0.6 lb/MMBTU. [OAC 252:100-19]

(3) For all emissions units not subject to an opacity limit promulgated under 40 C.F.R., Part 60, NSPS, no discharge of greater than 20% opacity is allowed except for:
(a) Short-term occurrences which consist of not more than one six-minute period in any consecutive 60 minutes, not to exceed three such periods in any consecutive 24 hours. In no case shall the average of any six-minute period exceed 60% opacity;
(b) Smoke resulting from fires covered by the exceptions outlined in OAC 252:100-13-7;
(c) An emission, where the presence of uncombined water is the only reason for failure to meet the requirements of OAC 252:100-25-3(a); or
(d) Smoke generated due to a malfunction in a facility, when the source of the fuel producing the smoke is not under the direct and immediate control of the facility and the immediate constriction of the fuel flow at the facility would produce a hazard to life and/or property. [OAC 252:100-25]

(4) No visible fugitive dust emissions shall be discharged beyond the property line on which the emissions originate in such a manner as to damage or to interfere with the use of adjacent properties, or cause air quality standards to be exceeded, or interfere with the maintenance of air quality standards. [OAC 252:100-29]

(5) No sulfur oxide emissions from new gas-fired fuel-burning equipment shall exceed 0.2 lb/MMBTU. No existing source shall exceed the listed ambient air standards for sulfur dioxide. [OAC 252:100-31]

(6) Volatile Organic Compound (VOC) storage tanks built after December 28, 1974, and with a capacity of 400 gallons or more storing a liquid with a vapor pressure of 1.5 psia or greater under actual conditions shall be equipped with a permanent submerged fill pipe or with a vapor-recovery system. [OAC 252:100-37-15(b)]

(7) All fuel-burning equipment shall at all times be properly operated and maintained in a manner that will minimize emissions of VOCs. [OAC 252:100-37-36]

SECTION XX. STRATOSPHERIC OZONE PROTECTION

A. The permittee shall comply with the following standards for production and consumption of ozone-depleting substances:

(1) Persons producing, importing, or placing an order for production or importation of certain class I and class II substances, HCFC-22, or HCFC-141b shall be subject to the requirements of §82.4;
(2) Producers, importers, exporters, purchasers, and persons who transform or destroy certain class I and class II substances, HCFC-22, or HCFC-141b are subject to the recordkeeping requirements at §82.13; and
(3) Class I substances (listed at Appendix A to Subpart A) include certain CFCs, Halons, HBFCs, carbon tetrachloride, trichloroethane (methyl chloroform), and bromomethane (Methyl Bromide). Class II substances (listed at Appendix B to Subpart A) include HCFCs. [40 CFR 82, Subpart A]

B. If the permittee performs a service on motor (fleet) vehicles when this service involves an ozone-depleting substance refrigerant (or regulated substitute substance) in the motor vehicle air conditioner (MVAC), the permittee is subject to all applicable requirements. Note: The term "motor vehicle" as used in Subpart B does not include a vehicle in which final assembly of the vehicle has not been completed. The term "MVAC" as used in Subpart B does not include the air-tight sealed refrigeration system used as refrigerated cargo, or the system used on passenger buses using HCFC-22 refrigerant. [40 CFR 82, Subpart B]

C. The permittee shall comply with the following standards for recycling and emissions reduction except as provided for MVACs in Subpart B:

(1) Persons opening appliances for maintenance, service, repair, or disposal must comply with the required practices pursuant to § 82.156;

(2) Equipment used during the maintenance, service, repair, or disposal of appliances must comply with the standards for recycling and recovery equipment pursuant to § 82.158;
(3) Persons performing maintenance, service, repair, or disposal of appliances must be certified by an approved technician certification program pursuant to § 82.161;
(4) Persons disposing of small appliances, MVACs, and MVAC-like appliances must comply with record-keeping requirements pursuant to § 82.166;
(5) Persons owning commercial or industrial process refrigeration equipment must comply with leak repair requirements pursuant to § 82.158; and
(6) Owners/operators of appliances normally containing 50 or more pounds of refrigerant must keep records of refrigerant purchased and added to such appliances pursuant to § 82.166. [40 CFR 82, Subpart F]

SECTION XXI. TITLE V APPROVAL LANGUAGE

A. DEQ wishes to reduce the time and work associated with permit review and, wherever it is not inconsistent with Federal requirements, to provide for incorporation of requirements established through construction permitting into the Source's Title V permit without causing redundant review. Requirements from construction permits may be incorporated into the Title V permit through the administrative amendment process set forth in OAC 252:100-8-7.2(a) only if the following procedures are followed:

(1) The construction permit goes out for a 30-day public notice and comment using the procedures set forth in 40 C.F.R. § 70.7(h)(1). This public notice shall include notice to the public that this permit is subject to EPA review, EPA objection, and petition to EPA, as provided by 40 C.F.R. § 70.8; that the requirements of the construction permit will be incorporated into the Title V permit through the administrative amendment process; that the public will not receive another opportunity to provide comments when the requirements are incorporated into the Title V permit; and that EPA review, EPA objection, and petitions to EPA will not be available to the public when requirements from the construction permit are incorporated into the Title V permit.
(2) A copy of the construction permit application is sent to EPA, as provided by 40 CFR § 70.8(a)(1).
(3) A copy of the draft construction permit is sent to any affected State, as provided by 40 C.F.R. § 70.8(b).
(4) A copy of the proposed construction permit is sent to EPA for a 45-day review period as provided by 40 C.F.R.§ 70.8(a) and (c).
(5) The DEQ complies with 40 C.F.R. § 70.8(c) upon the written receipt within the 45-day comment period of any EPA objection to the construction permit. The DEQ shall not issue the permit until EPA's objections are resolved to the satisfaction of EPA.
(6) The DEQ complies with 40 C.F.R. § 70.8(d).
(7) A copy of the final construction permit is sent to EPA as provided by 40 CFR § 70.8(a).
(8) The DEQ shall not issue the proposed construction permit until any affected State and EPA have had an opportunity to review the proposed permit, as provided by these permit conditions.
(9) Any requirements of the construction permit may be reopened for cause after incorporation into the Title V permit by the administrative amendment process, by

DEQ as provided in OAC 252:100-8-7.3(a), (b), and (c), and by EPA as provided in 40 C.F.R. § 70.7(f) and (g).

(10) The DEQ shall not issue the administrative permit amendment if performance tests fail to demonstrate that the source is operating in substantial compliance with all permit requirements.

B. To the extent that these conditions are not followed, the Title V permit must go through the Title V review process.

SECTION XXII. CREDIBLE EVIDENCE

For the purpose of submitting compliance certifications or establishing whether or not a person has violated or is in violation of any provision of the Oklahoma implementation plan, nothing shall preclude the use, including the exclusive use, of any credible evidence or information, relevant to whether a source would have been in compliance with applicable requirements if the appropriate performance or compliance test or procedure had been performed.

PART 70 PERMIT

AIR QUALITY DIVISION
STATE OF OKLAHOMA
DEPARTMENT OF ENVIRONMENTAL QUALITY
707 NORTH ROBINSON, SUITE 4100
P.O. BOX 1677
OKLAHOMA CITY, OKLAHOMA 73101-1677

Permit No. 97-179-C (M-2)

DCP Midstream, L.P.,

having complied with the requirements of the law, is hereby granted permission to construct/modify their Cimarron Natural Gas Processing Plant located at Section 27, Township 20N, Range 17W, near Seiling, Woodward County, Oklahoma, subject to the Standard Conditions dated January 24, 2008, and Specific Conditions, both of which are attached.

In the absence of construction commencement, this permit shall expire 18 months from the issuance date, except as authorized under Section VIII of the Standard Conditions.

Division Director, Air Quality Division | **Date**

Colorado Department of Public Health and Environment

OPERATING PERMIT

Fountain Valley Power, L.L.C. – Fountain Valley Power Plant

Issued: November 1, 2003

Last Revised: September 24, 2008

AIR POLLUTION CONTROL DIVISION
COLORADO OPERATING PERMIT

FACILITY NAME: Fountain Valley Power Plant

OPERATING PERMIT NUMBER

02OPEP246

FACILITY ID: 0410897

ISSUE DATE: November 1, 2003
EXPIRATION DATE: November 1, 2008
MODIFICATIONS: See Appendix F of Permit

Issued in accordance with the provisions of Colorado Air Pollution Prevention and Control Act, 25-7-101 et seq. and applicable rules and regulations.

ISSUED TO:

Fountain Valley Power, L.L.C.
1515 Arapahoe, Tower I, Suite 900
Denver, CO 80202

PLANT SITE LOCATION:

Fountain Valley Power Plant
18693 Boca Raton Heights
Pueblo, Colorado 81008
El Paso County

INFORMATION RELIED UPON
Operating Permit Application Received: June 26, 2002; October 23, 2002; and December 24, 2002
And Additional Information Received: N/A

Nature of Business: Electricity Generation
Primary SIC: 4911

RESPONSIBLE OFFICIAL
Name: J.R. Krabowski
Title: Interim Operations Manager
Fountain Valley Power, L.L.C.
Phone: (713) 780-6027

FACILITY CONTACT PERSON
Name: J.R. Krabowski
Title: Interim Operations Manager
Fountain Valley Power, L.L.C.
Phone: (713) 780-6027

SUBMITTAL DEADLINES
Semi-Annual Monitoring Period: January 1 – June 30 and July 1 – December 31
Semi-Annual Monitoring Report: February 1, 2004 and August 1, 2004 subsequent years
Annual Compliance Period: January 1 through December 31
Annual Compliance Certification: February 1, 2004 and subsequent years
Note that the Semi-Annual Monitoring Report and the Annual Compliance Certification must be received at the Division office by 5:00 p.m. on the due date. Postmarked dates will not be accepted for the purposes of determining the timely receipt of those reports.

FOR ACID RAIN SUBMITTAL DEADLINES SEE SECTION III.4 OF THIS PERMIT

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Table of Contents:

SECTION I - General Activities and Summary

1. Permitted Activities

1.1 This facility consists of six combustion turbines used to generate power and is defined under Standard Industrial Classification 4911. The combustion turbine generators (CTGs) are configured to operate in a simple-cycle mode (exhausts directly to the atmosphere). Each turbine has a nominal heat input of 336 MMBtu/hour and drives an electric generator rated at 38.8 MW. The facility has two (2) 19.0 MMBtu/hour natural gas fired inlet air preheaters, and three (3) 1.9 MMBtu/hour internal combustion inlet gas compressor engines. The turbines are equipped with water injection to control nitrogen oxide emissions.

The facility is located at 18693 Boca Raton Heights, in Pueblo. The area in which the plant operates is designated as attainment for all pollutants.

There are no affected states within 50 miles of the plant. There are no Federal Class I designated areas within 100 kilometers of the plant.

1.2 Until such time as this permit expires or is modified or revoked, the permittee is allowed to discharge air pollutants from this facility in accordance with the requirements, limitations, and conditions of this permit.

1.3 This Operating Permit incorporates the applicable requirements contained in the underlying construction permits, and does not affect those applicable requirements, except as modified during review of the application or as modified subsequent to permit issuance using the modification procedures found in Regulation No. 3, Part C. These Part C procedures meet all applicable substantive New Source Review Requirements of Part B. Any revisions made using the provisions of Regulation No. 3, Part C shall become new applicable requirements for purposes of this operating permit and shall survive reissuance. This permit incorporates the applicable requirements (except as noted in Section II) from the following construction permit: 00EP0488.

1.4 All conditions in this permit are enforceable by US Environmental Protection Agency, Colorado Air Pollution Control Division (hereinafter Division) and its agents, and citizens unless otherwise specified. **State-only enforceable conditions are:** Permit Condition Number(s): Section II, Condition 1.17 (opacity) and Section V – Conditions 3.d, 3.g (last paragraph), 14 and 18 (as noted).

1.5 All information gathered pursuant to the requirements of this permit is subject to the Recordkeeping and Reporting requirements listed under Condition 22 of the General Conditions in Section V of this permit.

2. Alternative Operating Scenarios

The following Alternative Operating Scenario (AOS) for either temporary or permanent combustion turbine replacement has been reviewed in accordance with the requirements of Regulation No. 3, Part A, Section IV.A, Operational Flexibility-Alternative Operating Scenarios, and Regulation No. 3, Part B, Construction Permits, and has been found to meet all applicable substantive and procedural requirements. This permit incorporates and shall be considered a construction permit for any combustion turbine replacement performed in accordance with this AOS, and the permittee shall be allowed to perform such turbine replacement without applying for a revision to this permit or obtaining a new Construction Permit.

For purposes of Regulation No. 3, Part B, Section IV.G.4.a, any turbine replacement authorized under this AOS shall commence operation upon notation of same in the contemporaneous log as required below. Results of any data collection required below shall be normalized for comparison to the applicable permitted emission limits.

Any permanent turbine replacement under this AOS shall result in the replacement turbine being considered a new affected facility for purposes of NSPS GG or any applicable MACT and shall be subject to all applicable requirements in that Subpart.

2.1 Turbine Replacement

The following AOS is incorporated into this permit in order to deal with a turbine breakdown or periodic routine maintenance and repair which requires either the temporary or permanent replacement of the entire turbine. Note that the compliance demonstrations made as part of this AOS are in addition to any compliance demonstrations required by the permit.

2.1.1 The permittee may replace an existing turbine provided such replacement turbines are GE Sprint Model LM6000-PC combustion turbines without modifying this permit.

2.1.2 Replacement turbines are subject to all federally applicable and state-only requirements set forth in this permit (including monitoring and recordkeeping), and shall be subject to any shield afforded by this permit.

2.1.3 The permittee shall maintain a log on-site to contemporaneously record the date of any turbine replacement, the manufacturer, model number, and serial number of the turbine(s) that are replaced during the term of this permit, and the manufacturer, model number, and serial number of the replacement turbine. All records related to any testing shall be maintained on-site for five (5) years and made available to the Division upon request.

2.1.4 For permanent turbine replacements, an Air Pollutant Emissions Notice (APEN) that includes the specific manufacturer, model and serial number of the permanent replacement turbine shall be filed with the Division within 14 calendar days of commencing operation of the replacement turbine. The APEN shall be accompanied by the appropriate APEN filing fee and a cover letter explaining that the permittee is exercising an AOS and is installing a permanent replacement turbine.

2.1.5 In the absence of credible evidence to the contrary, data from the CEM shall be evidence of enforceable compliance or noncompliance of the replacement turbine with the emission limitations of the original turbine.

If the CEM data fails to demonstrate compliance with either the NOx or CO emission limitations and in the absence of credible evidence to the contrary, the turbine will be considered to be out of compliance for the purposes of this AOS from the date the replacement turbine commenced operation until the turbine is taken off line. All data that indicates noncompliance shall be submitted to the Division within 14 calendar days after the data is collected.

2.1.6 The permittee shall agree to pay fees based on the normal permit processing rate for review of information submitted to the Division in regard to any permanent turbine replacement.

2.1.7 All data collected pursuant to this AOS shall be kept on site for five (5) years and made available to the Division upon request.

2.1.8 For comparison with an annual or short term emissions limit, data collected pursuant to this AOS shall be converted to a lb/hr basis and multiplied by the allowable operating hours in the month or year (whichever applies) in order to monitor compliance. If a source is not limited in its hours of operation, the test results shall be multiplied by the maximum number of hours in the month or year (8760), whichever applies.

2.2 Additional Sources

Current State Air Quality Regulations do not allow for advanced New Source Review in the absence of discrete and verifiable information concerning future installations. Therefore, any additional operational changes requiring new equipment at this facility not addressed by this AOS will need to undergo appropriate Regulation No. 3 review procedures.

3. Prevention Of Significant Deterioration (PSD)

3.1 Based on the information provided by the applicant, this facility is categorized as a synthetic minor stationary source (no single criteria pollutant emissions with Potential to Emit of greater than 250 tons/year) as of the issue date of this permit. The source therefore is not subject to the PSD requirements of 40 CFR 52.21 (Colorado Regulation No. 3, Part B, Section IV.D.3).

Future modifications to this facility which are major in themselves will result in the application of the PSD review requirements. In addition, future modifications at this facility may result in the facility being classified as a major stationary source. Once that threshold is exceeded, future modifications at this facility resulting in a significant net emissions increase (see Regulation No.

3, Part A, Section I.B.37 and 58) for any pollutant as listed in Regulation No. 3, Part A, Section I.B.58 or a modification which is major by itself may result in the application of the PSD review requirements.

4. Accidental Release Prevention Program (112(r))

4.1 Based on the information provided by the applicant, this facility is not subject to the provisions of the Accidental Release Prevention Program (section 112(r)) of the Federal Clean Air Act.

5. Compliance Assurance Monitoring (CAM)

5.1 The following emission points at this facility use a control device to achieve compliance with an emission limitation or standard to which they are subject and have controlled emissions that exceed or are equivalent to the major source threshold. They are therefore subject to the provisions of the CAM program as set forth in 40 CFR Part 64, as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV:

Units CT001, CT002, CT003, CT004, CT005, and CT006 – Six Combustion Turbines

See Section II, Condition 2.5 for compliance assurance monitoring requirements.

6. Summary of Emission Units

6.1 The emissions units regulated by this permit are the following:

Emission Unit Number	AIRS Stack Number	Facility Identifier	Description	Pollution Control Device
CT001	001	S001	One (1) General Electric (GE) Sprint Model LM6000-PC, Natural Gas Fired Combustion Turbine Generator, Rated at 336.0 MMBtu/hour , Serial Number 191-225.	Water Injection to Control NOx Emissions
CT002	002	S002	One (1) General Electric (GE) Sprint Model LM6000-PC, Natural Gas Fired Combustion Turbine Generator, Rated at 336.0 MMBtu/hour , Serial Number 191-230.	Water Injection to Control NOx Emissions
CT003	003	S003	One (1) General Electric (GE) Sprint Model LM6000-PC, Natural Gas Fired Combustion Turbine Generator, Rated at 336.0 MMBtu/hour , Serial Number 191-229.	Water Injection to Control NOx Emissions
CT004	004	S004	One (1) General Electric (GE) Sprint Model LM6000-PC, Natural Gas Fired Combustion Turbine Generator, Rated at 336.0 MMBtu/hour , Serial Number 191-232.	Water Injection to Control NOx Emissions
CT005	005	S005	One (1) General Electric (GE) Sprint Model LM6000-PC, Natural Gas Fired Combustion Turbine Generator, Rated at 336.0 MMBtu/hour , Serial Number 191-213.	Water Injection to Control NOx Emissions
CT006	006	S006	One (1) General Electric (GE) Sprint Model LM6000-PC, Natural Gas Fired Combustion Turbine Generator, Rated at 336.0 MMBtu/hour , Serial Number 191-192.	Water Injection to Control NOx Emissions
AP001	007	S001a	One (1) Ajax Natural Gas Fired Heater, Model WFG-19000 UL/CSD-1, Rated at 19.0 MMBtu/hour, Serial Number .	N/A
AP002	008	S002a	One (1) Ajax Natural Gas Fired Heater, Model WFG-19000 UL/CSD-1, Rated at 19.0 MMBtu/hour, Serial Number .	N/A
GC001, GC002, GC003	009	S001b, S002b, S003b	One Waukesha Model 1579000, Natural Gas Fired Reciprocating Internal Combustion Engines, Rated at 750 HP, Serial Number 171809; Tw0 (2) Waukesha Model L5790G, Natural Gas Fired Reciprocating Internal Combustion Engines, each Rated at 750 HP, Serial Numbers C119281 and C119273.	Catalytic Converters Control NO_x and CO Emissions

SECTION II - Specific Permit Terms

1. Facility-Wide Limits

Parameter	Permit Condition Number	Limitations	Compliance Emission Factor	Monitoring	
				Method	Interval
PM	1.1	35.22 tons/year	Turbines: 0.008 lb/mmBtu Inlet Air Preheaters: 4.8 x 10-3 lb/mmBtu ICEs: 3.06 x 10^{-4} lb/mmBtu	Recordkeeping and Calculation	Monthly
PM_{10}		35.22 tons/year		Recordkeeping and Calculation	Monthly
VOC		51.48 tons/year	Turbines: 0.010 lb/mmBtu Inlet Air Preheaters: .025 lb/mmBtu ICEs: 0.43 lb/mmBtu	Recordkeeping and Calculation	Monthly
NO_X		249.33 tons/yr	Turbines: CEM Inlet Air Preheaters: 8.47 x 10^{-2} lb/mmBtu ICEs: 0.87 lb/mmBtu	Turbines: Continuous Emission Monitor Heaters and ICEs: Recordkeeping and Calculation	Continuously Monthly
CO		217.51 tons/yr	Turbines: CEM Inlet Air Preheaters: 0.034 lb/mmBtu ICEs: 0.87 lb/mmBtu	Turbines: Continuous Emission Monitor Heaters and ICEs: Recordkeeping and Calculation	Continuously Monthly
Fuel Use	1.7.1	See Condition 1.7	N/A	Fuel Meter	Monthly

Parameter	Permit Condition Number	Limitations	Compliance Emission Factor	Monitoring Method	Monitoring Interval
	1.7.2	N/A	N/A	Fuel BTU Analysis	Monthly
Insignificant Activities	1.8	Include NOx emissions in total facility emission calculations	Various	Recordkeeping and Calculation	Annually

1.1 **Emission Limits**

Total facility emissions of air pollutants shall not exceed the limits listed in the table above. Compliance with the annual limits shall be determined on a rolling (12) month total. By the end of each month a new twelve-month total is calculated based on the previous twelve months' data. (Construction Permit 00EP0488 and Colorado Regulation No. 3, Part B, III.A.4, revised in accordance with Section I, Condition 1.3 of this permit)(PM/PM_{10} includes condensibles)

The permittee shall calculate emissions using the CEM data, actual preheater and ICE fuel use and the emission factors listed above, and the most recent fuel BTU analysis, and maintain a record of rolling twelve month total emissions on site for Division inspection upon request. NOx emissions from insignificant activities shall be included, as set forth below in Section II, Condition 1.3.

1.2 Fuel Consumption

1.2.1 The total amount of natural gas consumed by all equipment subject to this permit resulting in the emissions of criteria pollutants shall be limited by the emissions limits specified in Condition 1.1. The permittee shall record the consumption of natural gas and determine the emissions of pollutants generated from such consumption using continuous emission monitors or Division-approved emission factors (listed in the Table above) and the most recent Btu analysis (see Condition 1.2.2). The record keeping shall be accomplished on a rolling twelve-month total. Each month a new twelve month rolling total shall be calculated using the previous twelve months data. Records shall be maintained on site for Division inspection upon request. (Construction Permit 00EP0488, revised in accordance with Section I, Condition 1.3 of this permit)

1.2.2 The Btu content of the natural gas used to fuel this equipment shall be determined monthly using the appropriate ASTM Methods or equivalent, if approved by the Division in advance. Calculation of annual emissions outlined under Conditions 1.1 shall be based on the most recent Btu analysis. The Btu content shall be based on the gross heating value (HHV) of the fuel. In lieu of monthly sampling and analysis, the Btu content of the gas may be determined based on the monthly average of the supplier's analyses, provided that the analyses were conducted using the appropriate ASTM Methods, or equivalent, if approved by the Division in advance.

1.3 **Insignificant Activities**

NO_x emissions from all insignificant activities associated with this source shall be included in monitoring compliance with the 249.33 tons/year emission limit set forth in Section II, Condition 1.1. The applicant shall track emissions from all NO_x emitting insignificant activities on a yearly basis. This information shall be kept on site and made available to the Division upon request. For the purposes of this condition, insignificant activities shall be defined as any activity or equipment, which emits any amount but does not require an Air Pollution Emission Notice (APEN). (Colorado Regulation No. 3, Part B, IV.D.3.b(iv))

2. CT001 through CT006 – Six (6) Natural Gas Fired Turbines, Rated at 336.0 MMBtu/hour each

Parameter	Permit Condition Number	Limitations		Compliance Emission Factor	Monitoring Method	Monitoring Interval
PM	2.1	**For each turbine:** See Condition 2.1		N/A	Fuel Restriction	Whenever Natural Gas is Used as Fuel
SO_2	2.2.1	**For each turbine:** 150 ppmvd @ 15% O_2 **OR** Use of Fuel Which Contains Less than 0.8 Weight % Sulfur		N/A	Fuel Restriction	See Condition 2.2.1-3
	2.2.2	**For each turbine:** 0.35 lbs/mmBtu **(state-only)**				
	2.2.3	**For each turbine:** 0.35 lbs/mmBtu, on a 3-hour rolling average				
NO_X	2.3	116 ppmvd @ 15% O_2 on a 4-hr rolling average		CEM	Continuous Emission Monitor	Continuously
Continuous Emission Monitoring System Requirements	2.4	N/A	N/A	N/A	See Condition 2.4	
Compliance Assurance Monitoring Requirements	2.5	N/A	N/A	N/A	N/A	
NSPS General Provisions	2.6	N/A	NA	N/A	As required in the General Provisions	

Parameter	Permit Condition Number	Limitations	Compliance Emission Factor	Monitoring Method	Monitoring Interval
Opacity	2.7.1	Not to Exceed 20% Except as Provided for in 2.7.2 and 2.7.3	N/A	Fuel Restriction	Whenever Natural Gas is Used
	2.8.2	For Certain Operational Activities – Not to Exceed 30%, for a Period or Periods Aggregating More than Six (6) Minutes in any 60 Consecutive Minutes	N/A		
	2.7.3	Not to Exceed 20% **(state-only)**	N/A		
Acid Rain Requirements	2.8	See Section III of this Permit		Certification	Annually

In addition to the facility wide limits set forth in Section II, Condition 1 of this permit, the following conditions apply to the turbines.

2.1 PM emissions shall not exceed the following limitations:

For fuel burning equipment with designed heat inputs greater than 1 x 10^6 BTU per hour, but less than or equal to 500 x 10^6 BTU per hour, the following equation will be used to determine the allowable Emissions from each turbine or each turbine/duct burner combination or each inlet air heater/turbine combination shall not exceed:

For each turbine:
$PE = 0.5 \times (FI)^{-0.26,}$ where: PE = particulate standard in lbs/mmBtu
FI = fuel input in mmBtu/hr

(Colorado Regulation No. 1, III.A.1.b and III.A.1.c)
In the absence of credible evidence to the contrary, compliance with the particulate matter emission limit is presumed whenever natural gas is used as fuel in the turbines.

2.2 **Sulfur Dioxide (SO_2) emissions shall not exceed the following limitations**:

2.2.1 Each turbine is subject to 40 CFR Part 60, Subpart GG – Standards of Performance for Stationary Gas Turbines, as adopted by reference in Colorado Regulation No. 6, Part A.

2.2.1.1 No owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any stationary gas turbine any gases which contain sulfur dioxide in excess of 0.015 percent by volume at 15 percent oxygen and on a dry basis (60.333(a)) **OR**

2.2.1.2 No owner or operator subject to the provisions of this subpart shall burn in any stationary gas turbine any fuel which contains sulfur in excess of 0.8 percent by weight (8000 ppmw). (60.333(b))

Monitoring of Operations (60.334)
The owner or operator of any stationary gas turbine subject to the provisions of this subpart shall monitor the total sulfur content of the fuel being fired in the turbine as set forth in 60.334.

For each affected unit required to periodically determine the fuel sulfur content under this subpart, the owner or operator shall submit reports of excess emissions in accordance with 60.7(c). Excess emissions shall be reported for all periods of unit operation, including startup, shutdown and malfunction. The purpose of reports required under 60.7(c), periods of excess emissions that shall be reported are defined as set forth in 60.334(j)(2).(60.334(j))

All reports required under 60.7(c) shall be postmarked by the 30th day following the end of each calendar quarter. (60.334(j)(5))

Test Methods and Procedures (60.335)
If the owner or operator is required under 60.334(ii)(1) or (3) to periodically determine the sulfur content of the fuel combusted in the turbine, testing shall be performed as set forth in 60.335(b)(10).

In addition, the provisions of 40 CFR Part 60, Subpart A, as set forth in Condition 2.6 of this permit apply.

2.2.2 Sulfur Dioxide (SO_2) emissions **from each turbine** shall not exceed 0.35 lbs SO_2/million BTU of heat input. (Colorado Regulation No. 1, Section VI.B.4.c.(ii)). The averaging time for all new source emissions standards for sulfur dioxide shall be three (3) hours, and any three-hour rolling average of emission rates which exceeds these standards is a violation of this regulation. (Colorado Regulation No. 1, VI.B.2)

In the absence of credible evidence to the contrary, compliance with this SO_2 limitation is presumed whenever natural gas is used as fuel in these turbines.

2.2.3 On and after the date on which the required performance test is completed, no owner or operator subject to the provisions of this regulation may discharge, or cause the discharge into the atmosphere sulfur dioxide in excess of:

0.35 lbs SO_2/million Btu.
(Colorado Regulation No. 6, Part B, II.D.3.b – **state-only** requirement)

In addition the provisions of 40 CFR Part 60, Subpart A, apply, as set forth in Condition 2.6 of this permit. (Colorado Regulation No. 6, Part B, I.A) (Note: No stack test is required for this source)

In the absence of credible evidence to the contrary, compliance with this SO_2 limitation is presumed whenever natural gas is used as fuel in these turbines.

2.3 **Emissions of Nitrogen Oxides (NO_X) shall not exceed the following limitations**:

Each turbine is subject to 40 CFR Part 60, Subpart GG – Standards of Performance for Stationary Gas Turbines, as adopted by reference in Colorado Regulation No. 6, Part A.

No owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any stationary gas turbine any gases which contain nitrogen oxides in excess of 116.0 percent by volume at 15 percent oxygen and on a dry basis. (60.332(a)(1))

Monitoring of Operations (60.334)
The CEMS required by Condition 2.4 of this permit shall be used to monitor compliance with the NOx emission limit. Note: The missing data substitution methodology provided for at 40 CFR Part 75, Subpart D, is not required for purposes of identifying excess emissions. Instead, periods of missing CEMS data are to be reported as monitor downtime in the excess emissions and monitoring performance report required in 60.7(c). (60.334(b)(3)(iii))

For each affected unit required to continuously monitor emissions under this subpart, the owner or operator shall submit reports of excess emissions and monitor downtime in accordance with 60.7(c). Excess emissions shall be reported for all periods of unit operation, including startup, shutdown and malfunction. For purpose of reports required under 60.7(c), periods of excess emissions that shall be reported are defined as set forth in 60.334(j)(1)(iii).

In addition, the provisions of 40 CFR Part 60, Subpart A, as set forth in Condition 2.6 of this permit apply.

2.4 **Each of the gas turbines shall be equipped with a continuous emission monitoring system (CEM) to continuously measure and record**:

2.4.1 Concentration of Nitrogen Oxides in the exhaust, hourly average, ppmvd, corrected to 15% Oxygen.

2.4.2 Emissions of Nitrogen Oxides, tons per month, tons per year.

2.4.3 Emissions of Carbon Monoxide, tons per month, tons per year.

2.4.4 Concentration of Oxygen, hourly average, percent

2.4.5 Quantity of water injected, expressed as a ratio of water-to-fuel in the turbine, accurate to within $\pm$ 5%.

These continuous emission monitoring systems shall be installed, calibrated, certified, maintained, and operated per 40 CFR Part 60 Appendix F, and 40 CFR Part 60, Subpart A, and also to conform to 40 CFR Part 75.

(Construction Permit 00EP0488, revised in accordance with Section I, Condition 1.3 of this permit)

2.5 Compliance Assurance Monitoring

The Compliance Assurance Monitoring (CAM) requirements in 40 CFR Part 64, as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV, apply to the turbines with respect to the NO_X limitations identified in Conditions 1.1 and 2.3 as follows:

2.5.1 The permittee shall monitor the exhaust gas NO_X concentration (ppmvd at 15% O_2) using the continuous emission monitoring system required by Condition 2.4. The NO_X concentrations will be reduced to hourly averages and converted to hourly emissions (lbs/hr) and used to calculate quarterly and annual emissions. Exceedances, for purposes of CAM, shall be any hour that the NO_X concentration exceeds the limits identified in Condition 2.3, and any rolling twelve month total in which the annual emissions exceed the limits in Condition 1.1. Exceedances of these limitations shall be reported as required by Section II, Condition 1.11 and Section V, Conditions 21 and 22.d of this permit.

2.5.2 Operation of Approved Monitoring

2.5.2.1 At all times, the owner or operator shall maintain the monitoring, including but not limited to, maintaining necessary parts for routine repairs of the monitoring equipment (40 CFR Part 64 § 64.7(b), as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV).

2.5.2.2 Except for, as applicable, monitoring malfunctions, associated repairs, and required quality assurance or control activities (including, as applicable, calibration checks and required zero and span adjustments), the owner or operator shall conduct all monitoring in continuous operation (or shall collect data at all required intervals) at all times that the pollutant-specific emissions unit is operating. Data recorded during monitoring malfunctions, associated repairs, and required quality assurance or control activities shall not be used for purposes of these CAM requirements, including data averages and calculations, or fulfilling a minimum data availability requirement, if applicable. The owner or operator shall use all the data collected during all other periods in assessing the operation of the control device and associated control system. A monitoring malfunction is any sudden, infrequent, not reasonably preventable failure of the monitoring to provide valid data. Monitoring failures that are caused in part by poor maintenance or careless operation are not malfunctions (40 CFR Part 64 § 64.7(c), as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV).

2.5.2.3 Response to excursions or exceedances

a. Upon detecting an excursion or exceedance, the owner or operator shall restore operation of the pollutant-specific emissions unit (including the control device and associated capture system) to its normal or usual manner of operation as expeditiously as practicable in accordance with good air pollution control practices for minimizing emissions. The response shall include minimizing the period of any startup, shutdown or malfunction and taking any necessary corrective actions to restore normal operation and prevent the likely recurrence of the cause of an excursion or exceedance (other than those caused by excused startup or shutdown conditions). Such actions may include initial inspection and evaluation, recording that operations returned to normal without operator action (such as through response by a computerized distribution control system), or any necessary follow-up actions to return operation to within the indicator range, designated condition, or below the applicable emission limitation or standard, as applicable (40 CFR Part 64 § 64.7(d)(1), as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV).

b. Determination of whether the owner of operator has used acceptable procedures in response to an excursion or exceedance will be based on information available, which may include but is not limited to, monitoring results, review of operation and maintenance procedures and records, and inspection of the control device, associated capture system, and the process (40 CFR Part 64 § 64.7(d)(2), as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV).

2.5.2.4 After approval of the monitoring required under the CAM requirements, if the owner or operator identifies a failure to achieve compliance with an emission limitation or standard for which the approved monitoring did not provide an indication of an excursion or exceedance while providing valid data, or the results of compliance or performance testing document a need to modify the existing indicator ranges or designated conditions, the owner or operator shall promptly notify the Division and, if necessary submit a proposed modification for this permit to address the necessary monitoring changes. Such a modification may include, but is not limited to, reestablishing indicator ranges or designated conditions, modifying the frequency of conducting monitoring and collecting data, or the monitoring of additional parameters (40 CFR Part 64 § 64.7(e), as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV).

2.5.3 Quality Improvement Plan (QIP) Requirements

2.5.3.1 Based on the results of a determination made under the provisions of Condition 2.5.2.3.b, the Division may require the owner or operator to develop and implement a QIP (40 CFR Part 64 § 64.8(a), as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV).

2.5.3.2 The owner or operator shall maintain a written QIP, if required, and have it available for inspection (40 CFR Part 64 § 64.8(b)(1), as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV).

2.5.3.3 The QIP initially shall include procedures for evaluating the control performance problems and, based on the results of the evaluation procedures, the owner or operator shall modify the plan to include procedures for conducting one or more of the following actions, as appropriate:

a. Improved preventative maintenance practices (40 CFR Part 64 § 64.8(b)(2)(i), as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV).

b. Process operation changes (40 CFR Part 64 § 64.8(b)(2)(ii), as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV).

c. Appropriate improvements to control methods (40 CFR Part 64 § 64.8(b)(2)(iii), as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV).

d. Other steps appropriate to correct control performance (40 CFR Part 64 § 64.8(b)(2)(iv), as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV).

e. More frequent or improved monitoring (only in conjunction with one or more steps under Conditions 2.5.3.3.a through d above) (40 CFR Part 64 § 64.8(b)(2)(v), as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV).

2.5.3.4 If a QIP is required, the owner or operator shall develop and implement a QIP as expeditiously as practicable and shall notify the Division if the period for completing the improvements contained in the QIP exceeds 180 days from the date on which the need to implement the QIP was determined (40 CFR Part 64 § 64.8(c), as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV).

2.5.3.5 Following implementation of a QIP, upon any subsequent determination pursuant to Condition 2.5.2.3.b, the Division or the U.S. EPA may require that an owner or operator make reasonable changes to the QIP if the QIP is found to have:

a. Failed to address the cause of the control device performance problems (40 CFR Part 64 § 64.8(d)(1), as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV); or

b. Failed to provide adequate procedures for correcting control device performance problems as expeditiously as practicable in accordance with good air pollution control practices for minimizing emissions (40 CFR Part 64 § 64.8(d)(2), as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV).

2.5.3.6 Implementation of a QIP shall not excuse the owner or operator of a source from compliance with any existing emission limitation or standard, or any existing monitoring, testing, reporting or recordkeeping requirement that may apply under federal, state, or local law, or any other applicable requirements under the federal clean air act (40 CFR Part 64 § 64.8(e), as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV).

2.5.4 Reporting and Recordkeeping Requirements

2.5.4.1 In addition to the reporting requirements in Section II, Condition 2.5 and Section V, Conditions 21 and 22.d and the recordkeeping requirements in Section V, Condition 22.a through c, the following apply:

a. The owner or operator shall submit, if necessary, a description of the actions taken to implement a QIP during the reporting period as specified in Condition 2.5.3 of this permit. Upon completion of a QIP, the owner or operator shall include in the next summary report documentation that the implementation of the plan has been completed and reduced the likelihood of similar levels of excursions or exceedances occurring (40 CFR Part 64 § 64.9(a)(2)(iii), as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV).

b. The owner or operator shall maintain records of any written QIP required pursuant to Condition 2.5.3 and any activities undertaken to implement a QIP, and any supporting information required to be maintained under these CAM requirements (such as data used to document the adequacy of monitoring, or records of monitoring maintenance or corrective actions) (40 CFR Part 64 § 64.9(b)(1), as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV).

c. Instead of paper records, the owner or operator may maintain records on alternative media, such as microfilm, computer files, magnetic tape disks, or microfiche, provided that the use of such alternative media allows for expeditious inspection and review, and does not conflict with other applicable recordkeeping requirements (40 CFR Part 64 § 64.9(b)(2), as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV).

2.5.5 Savings Provisions

2.5.5.1 Nothing in these CAM requirements shall excuse the owner or operator of a source from compliance with any existing emission limitation or standard, or any existing monitoring, testing, reporting or recordkeeping requirement that may apply under federal, state, or local law, or any other applicable requirements under the federal clean air act. These CAM requirements shall not be used to justify the approval of monitoring less stringent than the monitoring which is required under separate legal authority and are not intended to establish minimum requirements for the purposes of determining the monitoring to be imposed under separate authority under the federal clean air act, including monitoring in permits issued pursuant to title I of the federal clean air act. The purpose of the CAM requirements is to require, as part of the issuance of this Title V operating permit, improved or new monitoring at those emissions units where monitoring requirements do not exist or are inadequate to meet the requirements of CAM (40 CFR Part 64 § 64.10(a)(1), as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV).

2.5.5.2 Nothing in these CAM requirements shall restrict or abrogate the authority of the U.S. EPA or the Division to impose additional or more stringent monitoring, recordkeeping, testing or reporting requirements on any owner or operator of a source under any provision of the federal clean air act, including but not limited to sections 114(a)(1) and 504(b), or state law, as applicable (40 CFR Part 64 § 64.10(a)(2), as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV).

2.5.5.3 Nothing in these CAM requirements shall restrict or abrogate the authority of the U.S. EPA or the Division to take any enforcement action under the federal clean air act for any violation of an applicable requirement or of any person to take action under section 304 of the federal clean air act (40 CFR Part 64 § 64.10(a)(2), as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV).

Indicator	NOx Outlet Concentration

Measurement Approach	NOx CEMS
Indicator Range	Excursion: >249.33 TPY >116 ppmvd @ 15% O_2
Data representativeness	40 CFR Parts 60 and 75
QA/QC	40 CFR Parts 60 and 75
Monitoring Frequency	Continuous
Data Collection Procedures	40 CFR Parts 60 and 75
Averaging Period	Rolling twelve month 1-hour

2.6 Regulation No. 6, Part A, Subpart A, General Provisions

This Subpart applies as indicated in the Conditions listed above.

Notification and Recordkeeping

2.6.1 Any owner or operator subject to the provisions of this part shall maintain records of the occurrence and duration of any startup, shutdown, or malfunction in the operation of an affected facility; any malfunction of the air pollution control equipment; or any periods during which a continuous monitoring system or monitoring device is inoperative. (60.7(b))

2.6.2 Each owner or operator required to install a continuous monitoring system (CMS) or monitoring device shall submit an excess emissions and monitoring systems performance report (excess emissions are defined in applicable subparts) and/or a summary report form as set forth in 60.7(c).

2.6.3 Any owner or operator subject to the provisions of this part shall maintain a file of all measurements, including continuous monitoring system, system device, and performance test measurements; all continuous monitoring system performance evaluations; all continuous monitoring system or monitoring device calibration checks; adjustments and maintenance performed on these systems or devices; and all other information required by this part recorded in a permanent form suitable for inspection. (60.7(f))

Compliance with standards and maintenance requirements

2.6.4 At all times, including periods of startup, shutdown, and malfunction, owners and operators shall to the extent practicable, maintain and operate any affected facility including associated air pollution control equipment in a manner consistent with good air pollution control practice for minimizing emissions. Determination of whether acceptable operating and maintenance procedures are being used will be based on information available to the Division which may include, but is not limited to monitoring results, opacity observations, review of operating and maintenance procedures, and inspection of the source. (60.11(d))

Circumvention

2.6.5 No article, machine, equipment or process shall be used to conceal an emission which would otherwise constitute a violation of an applicable standard. Such concealment includes, but is not limited to, the use of gaseous diluents to achieve compliance with an opacity standard or with a standard which is based on the concentration of a pollutant in the gasses discharged to the atmosphere. (60.12)

Monitoring requirements

2.6.6 All continuous monitoring systems shall be subject to the provisions under 40 CFR Part 60, Appendix B and, if the continuous monitoring system is used to demonstrate compliance with emission limits on a continuous basis, 40 CFR Part 60, Appendix F. (60.13(a))

2.6.7 All continuous monitoring systems and monitoring devices shall be installed and operational prior to conducting performance tests under 60.8. Verification of operational status shall as a minimum, include completion of the manufacturer's written requirements or recommendations for installation, operation, and calibration of the device. (60.13(b))

2.6.8 Owners and operators of all continuous emission monitoring systems installed in accordance with the provisions of 40 CFR Part 60 shall check the zero and span calibration drifts as set forth in 60.13(d).

2.6.9 Except for system breakdowns, repairs, calibration checks, and zero and span adjustments required under 60.13(d), all continuous monitoring systems shall be in continuous operation and shall meet minimum frequency of operation as set forth in 60.13(e).

2.6.10 All continuous monitoring systems or monitoring devices shall be installed such that representative measurements of emissions or process parameters from the affected facility are obtained. Additional procedures for location of continuous monitoring systems contained in the applicable Performance Specifications of 40 CFR Part 60, Appendix B shall be used. (60.13(f))

2.6.11 1-hour averages shall be computed from four or more data points equally spaced over each 1-hour period. Data recorded during periods of continuous monitoring system breakdowns, repairs, calibration checks, and zero and span adjustments shall not be included in the data averages computed under 60.13(h). An arithmetic or integrated average of all data may be used. The data may be recorded in reduced or nonreduced form (e.g., ppm pollutant and percent O_2 or ng/J of pollutant). All excess emissions shall be converted into units of the standard using the applicable conversion procedures specified in the subparts. After conversion into units of the standard, the data may be rounded to the same number of significant digits as used in the applicable subparts to specify the emission limit. (60.13(h))

2.7 Opacity Limits

2.7.1 Except as provided for in Condition 2.7.2 and 2.7.3 below, no owner or operator of a source shall allow or cause the emission into the atmosphere of any air pollutant which is in excess of 20% opacity. Visible emissions shall be measured by EPA Method 9 (40 CFR, Part 60, Appendix A (July, 1992)) in all subsections of Section II.A of this regulation. (Colorado Regulation No. 1, Section II.A.1).

In the absence of credible evidence to the contrary, compliance with the 20% opacity limit shall be presumed whenever natural gas is used as fuel for the turbines.

2.7.2 No owner or operator of a source shall allow or cause to be emitted into the atmosphere any air pollutant resulting from the building of a new fire, cleaning of fire boxes, soot blowing, start-up, process modifications, or adjustment or occasional cleaning of control equipment which is in excess of 30% opacity for a period or periods aggregating more than six (6) minutes in any sixty (60) consecutive minutes (Colorado Regulation No. 1, Section II.A.4).

In the absence of credible evidence to the contrary, compliance with the 30% opacity limit shall be presumed whenever natural gas is used as fuel for the turbines.

2.7.3 No owner or operator may discharge, or cause the discharge into the atmosphere of any particulate matter which is greater than 20% opacity (Colorado Regulation No. 6, Part B, Section II.C.3 – **state-only** requirement).

This opacity standard applies at all times except during periods of startup, shutdown and malfunction (40 CFR Part 60 Subpart A § 60.11(c), as adopted by reference in Colorado Regulation No. 6, Part B, Section I.A). In addition, the provisions of 40 CFR Part 60, Subpart A as set forth in Condition 2.6 of this permit apply. (Colorado Regulation No. 6, Part B, I.A)

In the absence of credible evidence to the contrary, compliance with the 20% opacity requirement is presumed whenever natural gas is used as fuel for the turbines.

2.8 Acid Rain Requirements

These units are subject to the Title IV Acid Rain Requirements. As specified in 40 CFR Part 72.72(b)(1)(viii), the acid rain permit requirements shall be complete and segregable portion of the Operating Permit. As such the requirements are found in Section III of this permit. A copy of the annual compliance certification required by 40 CFR Part 72 § 72.90, shall be submitted to the Division as specified in Section III.4 of this permit.

3. AP001 and AP002 – Two (2) Natural Gas Fired Air Inlet Heaters, Rated at 19.0 MMBtu/hour each

Parameter	Permit Condition Number	Limitations	Compliance Emission Factor	Monitoring Method	Monitoring Interval
PM	3.1	**For each heater:** See Condition 3.1.2	N/A	Fuel Restriction	Whenever Natural Gas is Used as Fuel
		For each heater: See Condition 3.1.3 (**state-only**)			
Fuel Use	3.2	N/A	N/A	NSPS Recordkeeping	Daily
Opacity	3.3.1	Not to Exceed 20% Except as Provided for in 3.3.2 and 3.3.3	N/A	Fuel Restriction	Whenever Natural Gas is Used
	3.3.2	For Certain Operational Activities – Not to Exceed 30%, for a Period or Periods Aggregating More than Six (6) Minutes in any 60 Consecutive Minutes	N/A		
	3.3.3	Not to Exceed 20% (**state-only**)	N/A		

In addition to the facility wide limits set forth in Section II, Condition 1 of this permit, the following conditions apply to the inlet air preheaters.

3.1 **PM emissions shall not exceed the following limitations**:

3.1.1 For fuel burning equipment with designed heat inputs greater than 1 x 10^6 BTU per hour, but less than or equal to 500 x 10^6 BTU per hour, the following equation will be used to determine the allowable Emissions from each turbine or each turbine/duct burner combination or each inlet air heater/turbine combination shall not exceed:

For each heater:
$PE = 0.5 \times (FI)^{-0.26}$, where: PE = particulate standard in lbs/mmBtu
FI = fuel input in mmBtu/hr

(Colorado Regulation No. 1, III.A.1.b and III.A.1.c)
In the absence of credible evidence to the contrary, compliance with the particulate matter emission limits is presumed whenever natural gas is used as fuel in the air inlet preheaters.

3.1.2 For fuel burning equipment generating more than one million but less than 250 million Btu per hour heat input, the following equation will be used to determine the allowable particulate emission limit:

For each each heater:

$PE = 0.5 \times (FI)^{-0.26}$, where: PE = particulate standard in lbs/mmBtu
FI = fuel input in mmBtu/hr

(Colorado Regulation No. 6, Part B, II.C.2 – **state-only** condition)

In the absence of credible evidence to the contrary, compliance with the particulate matter emission limits is presumed whenever natural gas is used as fuel in the air inlet preheaters.

3.2 Fuel Consumption

The air inlet heaters are subject to the recordkeeping provisions of 40 CFR Part 60, Subpart Dc, Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units, as adopted by reference in Colorado Regulation No. 6, Part A, as follows:

The owner or operator of each affected facility shall record and maintain records of the amounts of each fuel combusted during each day. (60.48c(g))

3.3 Opacity Limits

3.3.1 Except as provided for in Condition 3.3.2 and 3.3.3 below, no owner or operator of a source shall allow or cause the emission into the atmosphere of any air pollutant which is in excess of 20% opacity. Visible emissions shall be measured by EPA Method 9 (40 CFR, Part 60, Appendix A (July, 1992)) in all subsections of Section II.A of this regulation. (Colorado Regulation No. 1, Section II.A.1).

In the absence of credible evidence to the contrary, compliance with the 20% opacity limit shall be presumed whenever natural gas is used as fuel for the air inlet heaters.

3.3.2 No owner or operator of a source shall allow or cause to be emitted into the atmosphere any air pollutant resulting from the building of a new fire, cleaning of fire boxes, soot blowing, start-up, process modifications, or adjustment or occasional cleaning of control equipment which is in excess of 30% opacity for a period or periods aggregating more than six (6) minutes in any sixty (60) consecutive minutes (Colorado Regulation No. 1, Section II.A.4).

In the absence of credible evidence to the contrary, compliance with the 30% opacity limit shall be presumed whenever natural gas is used as fuel for the air inlet heaters.

3.3.3 No owner or operator may discharge, or cause the discharge into the atmosphere of any particulate matter which is greater than 20% opacity (Colorado Regulation No. 6, Part B, Section II.C.3 – **state-only** requirement).

This opacity standard applies at all times except during periods of startup, shutdown and malfunction (40 CFR Part 60 Subpart A § 60.11(c), as adopted by reference in Colorado Regulation No. 6, Part B, Section I.A). In addition, the provisions of 40 CFR Part 60, Subpart A as set forth in Condition 2.6 of this permit apply. (Colorado Regulation No. 6, Part B, I.A)

In the absence of credible evidence to the contrary, compliance with the 20% opacity requirement is presumed whenever natural gas is used as fuel for the air inlet heaters.

4. GC001, GC002, and GC003 – Three (3) Natural Gas Fired Reciprocating ICEs, Rated at 750 HP each

Parameter	Permit Condition Number	Limitations	Compliance Emission Factor	Monitoring Method	Monitoring Interval
Compliance Tests	4.1	See Condition 4.1			
Opacity	4.2.1	Not to Exceed 20% Except as Provided for in 4.4.2	N/A	Fuel Restriction	Whenever Natural Gas is Used
	4.2.2	For Certain Operational Activities – Not to Exceed 30%, for a Period or Periods Aggregating More than Six (6) Minutes in any 60 Consecutive Minutes	N/A		
ICE Operation & Monitoring	4.3	N/A		Portable Monitoring Parametric Monitoring	Quarterly Monthly

In addition to the facility wide limits set forth in Section II, Condition 1 of this permit, the following conditions apply to the internal combustion engines.

4.1 Source compliance tests shall be conducted on the compressor engines, to measure the emission rate(s) for the pollutants listed below in order to show compliance with emission limits, and to demonstrate performance of emission control devices. The test protocol shall be submitted for Division approval at least thirty (30) days prior to any performance of the tests required under this condition. No stack test required herein shall be performed without prior written approval of the protocol by the Division. The Division reserves the right to witness the test(s). In order to facilitate the Division's ability to make plans to witness the test, notice of the date(s) for the stack test shall be submitted to the Division at least thirty calendar days prior to the test. The Division may for good cause shown, waive this thirty (30) day notice requirement. In instances when a scheduling conflict is presented, the Division shall immediately contact the permittee in order to explore the possibility of making modifications to the stack test schedule. The required number of copies of the compliance test results shall be submitted to the Division within forty-five (45) calendar days of the completion of the test unless a longer period is approved by the Division.

Particulate Matter using EPA approved methods
Sulfur Dioxide using EPA approved methods
Oxides of Nitrogen using EPA approved methods
Volatile Organic Compounds, speciated for the following hazardous air pollutants, using EPA approved methods
  Acetaldehyde
  Formaldehyde
  Propylene Oxide
Carbon Monoxide using EPA approved methods

Testing of the engines is required once the engines have operated a total of 100 hours under normal conditions. Tests shall then be conducted the next time the engines are operated under normal conditions. Only one engine need be tested. Records of the dates, times and hours of operation (including quarterly test burns) shall be maintained for Division inspection upon request.

Until compliance with the emission limits is determined as set forth above, NOx and CO emissions from the engines for determining compliance with emission limits, and for APEN purposes shall be estimated using the emission factors set forth below.

NOx: 11.31 lbs/mmBtu
CO: 7.83 lbs/mmBtu

(Construction Permit 00EP0488, revised in accordance with Section I, Condition 1.3 of this permit, and Colorado Regulation No. 3, Part B, IV.H.3)

4.2 Opacity Limits

4.2.1 Except as provided for in Condition 4.2.2 and 4.2.3 below, no owner or operator of a source shall allow or cause the emission into the atmosphere of any air pollutant which is in excess of 20% opacity. Visible emissions shall be measured by EPA Method 9 (40 CFR, Part 60, Appendix A (July, 1992)) in all subsections of Section II.A of this regulation. (Colorado Regulation No. 1, Section II.A.1).

In the absence of credible evidence to the contrary, compliance with the 20% opacity limit shall be presumed whenever natural gas is used as fuel for the internal combustion engines.

4.2.2 No owner or operator of a source shall allow or cause to be emitted into the atmosphere any air pollutant resulting from the building of a new fire, cleaning of fire boxes, soot blowing, start-up, process modifications, or adjustment or occasional cleaning of control equipment which is in excess of 30% opacity for a period or periods aggregating more than six (6) minutes in any sixty (60) consecutive minutes (Colorado Regulation No. 1, Section II.A.4).

In the absence of credible evidence to the contrary, compliance with the 30% opacity limit shall be presumed whenever natural gas is used as fuel for the internal combustion engines.

4.3 Engine Operation and Maintenance and Monitoring (S001b, S002b, and S003b)

The engines and associated catalytic converters shall be operated and maintained in accordance with manufacturer's recommendations at all times, including periods of start-up, shutdown, and malfunction.

Portable Monitoring

Emission measurements of nitrogen oxides (NO_x) and carbon monoxide (CO) from each engine shall be conducted quarterly using a portable flue gas analyzer. At least one calendar month shall separate subsequent quarterly tests. Note that if the engine is operated for less than 100 hours in any quarterly period, then the portable monitoring requirements do not apply.

A portable monitoring testing protocol shall be submitted for Division approval at least thirty (30) calendar days prior to the initial test. The protocol shall include examples of all calculations to be used to determine the emission rates and factors set forth below. Written approval of the protocol must be received prior to any testing. Prior Division-approved protocols for either the facility or the owner/operator may be used without additional review. For the initial test, calibration of the analyzer shall be conducted according to manufacturer's instructions.

Results of the portable flue gas analyzer tests shall be used to monitor the compliance status of each engine. For comparison with an annual or short term emissions limit, the results of the tests shall be converted to a lb/hr basis and multiplied by the allowable operating hours in the month or year (whichever applies) in order to monitor compliance. If a source is not limited in its hours of operation the test results will be multiplied by the maximum number of hours in the month or year (8760), whichever applies. For comparison with the emission rate/factor shown in the table above, the results of the tests shall be converted to the same units as the emission rate/factor.

An exceedance of either the NO_x or CO emission limitation or either the NOx or CO emission rates/factors shown in the table above during the initial portable flue gas analyzer test shall require a subsequent portable analyzer test indicating compliance with both the NO_x and CO emission limitations as well as verifying the NOx emission rates/factors are less than or equal to those set forth in the permit within 14 operating days of the initial test. Calibration gases shall be used to calibrate the portable analyzer for all tests conducted subsequent to the initial test.

Note that if the unit is operated for any period of time during a day, then that day counts as an operating day.

If portable flue gas analyzer results indicate compliance with both the NO_x and CO emission limitations and verifies both the NOx and CO emission rates/factors are less than or equal to those set forth in the permit within the 14 day period, in the absence of credible evidence to the contrary, the source may certify that the engine is in compliance with both the NO_x and CO emission limitations for the relevant time period.

If the portable flue gas analyzer results fail to indicate the compliance of the engine with either the NO_x or CO emission limitations or fail to verify that both the NOx and CO emission rates/factors are less than or equal to those set forth in the permit within the 14 day period, the source will notify the Division in writing within 10 calendar days of the end of the 14 day period. Results of all such testing and associated calculations shall be submitted to the Division within 10 calendar days of the end of the 14 day period. The source will be required to conduct EPA Reference Test Methods (identified as Reference Method 7E and Reference Method 10 (40 C.F.R. Part 60 Appendix A), hereinafter "EPA Reference Test Methods") or other test methods or procedures acceptable to the Division within 45 calendar days of the end of the 14 day period allowed for the portable flue gas analyzer testing. A compliance testing protocol shall be submitted for Division approval at least thirty (30) calendar days prior to the test. The protocol shall include examples of all calculations to be used to determine the emission rates set forth below. Written approval of the protocol must be received prior to any testing.

The Division shall be notified at least 30 calendar days prior to the EPA Reference Test date, so that it may choose whether to observe the testing. Results of all Reference Method tests and the associated calculations required below shall be submitted to the Division within 30 calendar days of the test.

For comparison with annual or short term emission limits, the results of the EPA Reference Tests shall be converted to a lb/hr basis and multiplied by the allowable operating hours in the month or year (whichever applies) in order to monitor compliance. If a source is not limited in its hours of operation the test results will be multiplied by the maximum number of hours in the month or year (8760), whichever applies. For comparison with the emission rates/factors shown in the table above, the emission rates determined by the tests and approved by the Division shall be converted to the same units as the emission rates/factors in the permit. If the EPA Reference Test results indicate compliance with both the NOx and CO emission l imitations and verify that both the NOx and CO emission rates/factors are less than or equal to those set forth in the permit, in the absence of credible evidence to the contrary, the source may certify that the engine is in compliance with both the NOx and CO emission limitations for the relevant time period.

If the EPA Reference Tests fail to demonstrate compliance with either the NOx or CO emission limitations and in the absence of credible evidence to the contrary, the engine will be considered to be out of compliance from the date of the initial portable flue gas analyzer test until the engine is taken off line.

If the EPA Reference Tests fail to verify that both the NOx and CO emission rates/factors are less than or equal to those set forth in the permit, the source shall re-calculate all twelve month rolling total, annual, or short-term emissions (whichever apply) using the emission rates determined by the tests and approved by the Division since the last Division-approved EPA Reference Tests using the procedures set forth in this Condition 3.9. In the absence of credible evidence to the contrary, the engine will be considered to be out of compliance for any periods that the calculated emissions are greater than either the NOx or CO emission limitations.

Results of all tests conducted shall be kept on site and made available to the Division upon request.

Catalytic Oxidizer Parameter Monitoring

Unit pressure drop and exhaust gas temperature drop shall be monitored and recorded monthly to assess engine and catalytic oxidizer operating condition. During those months when portable monitoring is scheduled, these parameters shall be monitored and recorded during the portable monitoring event.

SECTION III - Acid Rain Requirements

1. Designated Representative and Alternate Designated Representative

Designated Representative:
Name: Jerry Burke
Title: Manager
Phone: (303) 928-4400

Alternate Designated Representative:
Name: N/A
Title:
Phone:

2. Sulfur Dioxide Emission Allowances and Nitrogen Oxide Emission Limitations

Combustion Turbine 1	**2001**	**2002**	**2003**	**2004**	**2005**	**2006**
SO_2 Allowances, per 40 CFR Part 73.10(b), Table 2	0*	0*	0*	0*		0*
NO_X Limits	This Unit Has No NO_X Limits (See Section 5)					
Combustion Turbine 2	**2001**	**2002**	**2003**	**2004**	**2005**	**2006**
SO_2 Allowances, per 40 CFR Part 73.10(b), Table 2	0*	0*	0*	0*	0*	0*
NO_X Limits	This Unit Has No NO_X Limits (See Section 5)					
Combustion Turbine 3	**2001**	**2002**	**2003**	**2004**	**2005**	**2006**
SO_2 Allowances, per 40 CFR Part 73.10(b), Table 2	0*	0*	0*	0*	0*	0*
NO_X Limits	This Unit Has No NO_X Limits (See Section 5)					
Combustion Turbine 4	**2001**	**2002**	**2003**	**2004**	**2005**	**2006**
SO_2 Allowances, per 40 CFR Part 73.10(b), Table 2	0*	0*	0*	0*	0*	0*
NO_X Limits	This Unit Has No NO_X Limits (See Section 5)					
Combustion Turbine 5	**2001**	**2002**	**2003**	**2004**	**2005**	**2006**
SO_2 Allowances, per 40 CFR Part 73.10(b), Table 2	0*	0*	0*	0*	0*	0*
NO_X Limits	This Unit Has No NO_X Limits (See Section 5)					
Combustion Turbine 6	**2001**	**2002**	**2003**	**2004**	**2005**	**2006**
SO_2 Allowances, per 40 CFR Part 73.10(b), Table 2	0*	0*	0*	0*	0*	0*
NO_X Limits	This Unit Has No NO_X Limits (See Section 5)					

* Under the provisions of 72.84(a) any allowance allocations to, transfers to and deductions from an affected units Allowance Tracking System account is considered an automatic permit amendment and as such no revision to the permit is necessary. Numerical allowances shown in this table are from the 1996 edition of the CFR.

3. Standard Requirements

Combustion Turbines 1 thru 6 of this facility are subject to and the source has certified that they will comply with the following standard conditions.

Permit Requirements.

(1) The designated representative of each affected source and each affected unit at the source shall:

i) Submit a complete Acid Rain permit application (including a compliance plan) under 40 CFR part 72 in accordance with the deadlines specified in 40 CFR 72.30; and

ii) Submit in a timely manner any supplemental information that the Division determines is necessary in order to review an Acid Rain permit application and issue or deny an Acid Rain permit;

(2) The owners and operators of each affected source and each affected unit at the source shall:

i) Operate the unit in compliance with a complete Acid Rain permit application or a superseding Acid Rain permit issued by the Division; and

ii) Have an Acid Rain Permit.

Monitoring Requirements.

(1) The owners and operators and, to the extent applicable, designated representative of each affected source and each affected unit at the source shall comply with the monitoring requirements as provided in 40 CFR Part 75.

(2) The emissions measurements recorded and reported in accordance with 40 CFR Part 75 shall be used to determine compliance by the unit with the Acid Rain emissions limitations and emissions reduction requirements for sulfur dioxide and nitrogen oxides under the Acid Rain Program.

(3) The requirements of 40 CFR Part 75 shall not affect the responsibility of the owners and operators to monitor emissions of other pollutants or other emissions characteristics at the unit under other applicable requirements of the Federal Clean Air Act and other provisions of the operating permit for the source.

Sulfur Dioxide Requirements.

(1) The owners and operators of each source and each affected unit at the source shall:

i) Hold allowances, as of the allowance transfer deadline, in the unit's compliance subaccount (after deductions under 40 CFR 73.34(c)) not less than the total annual emissions of sulfur dioxide for the previous calendar year from the unit; and

ii) Comply with the applicable Acid Rain emissions limitations for sulfur dioxide.

(2) Each ton of sulfur dioxide emitted in excess of the Acid Rain emissions limitations for sulfur dioxide shall constitute a separate violation of the Federal Clean Air Act.

(3) An affected unit shall be subject to the requirements under paragraph (1) of the sulfur dioxide requirements as follows:

i) Starting January 1, 2000, an affected unit under 40 CFR 72.6(a)(2); or

ii) Starting on the later of January 1, 2000 or the deadline for monitor certification under 40 CFR part 75, an affected unit under 40 CFR 72.6(a)(3).

(4) Allowances shall be held in, deducted from, or transferred among Allowance Tracking System accounts in accordance with the Acid Rain Program.

(5) An allowance shall not be deducted in order to comply with the requirements under paragraph (1) of the sulfur dioxide requirements prior to the calendar year for which the allowance was allocated.

(6) An allowance allocated by the Administrator under the Acid Rain Program is a limited authorization to emit sulfur dioxide in accordance with the Acid Rain Program. No provision of the Acid Rain Program, the Acid Rain permit application, the Acid Rain permit, or an exemption under 40 CFR 72.7, 72.8 or 72.14 and no provision of law shall be construed to limit the authority of the United States to terminate or limit such authorization.

(7) An allowance allocated by the Administrator under the Acid Rain Program does not constitute a property right.

Nitrogen Oxides Requirements.

The owners and operators of the source and each affected unit at the source shall comply with the applicable Acid Rain emissions limitation for nitrogen oxides.

Excess Emissions Requirements.

(1) The designated representative of an affected unit that has excess emissions in any calendar year shall submit a proposed offset plan to the Administrator of the U. S. EPA, as required under 40 CFR part 77.

(2) The owners and operators of an affected unit that has excess emissions in any calendar year shall:

i) Pay without demand, to the Administrator of the U. S. EPA, the penalty required, and pay upon demand the interest on that penalty, as required by 40 CFR part 77; and

ii) Comply with the terms of an approved offset plan, as required by 40 CFR part 77.

Recordkeeping and Reporting Requirements.

(1) Unless otherwise provided, the owners and operators of the source and each affected unit at the source shall keep on site at the source each of the following documents for a period of 5 years from the date the document is created. This period may be extended for cause, at any time prior to the end of 5 years, in writing by the Administrator or the Division:

i) The certificate of representation for the designated representative for the source and each affected unit at the source and all documents that demonstrate the truth of the statements in the certificate of representation, in accordance with 40 CFR 72.24; provided that the certificate and documents shall be retained on site at the source beyond such 5-year period until such documents are superseded because of the submission of a new certificate of representation changing the designated representative;

ii) All emissions monitoring information, in accordance with 40 CFR part 75, provided that to the extent that 40 CFR part 75 provides for a 3-year period for recordkeeping, the 3-year period shall apply.

iii) Copies of all reports, compliance certifications, and other submissions and all records made or required under the Acid Rain Program; and,

iv) Copies of all documents used to complete an Acid Rain permit application and any other submission under the Acid Rain Program or to demonstrate compliance with the requirements of the Acid Rain Program.

(2) The designated representative of an affected source and each affected unit at the source shall submit the reports and compliance certifications required under the Acid Rain Program, including those under 40 CFR part 72 subpart I and 40 CFR part 75.

Liability.

(1) Any person who knowingly violates any requirement or prohibition of the Acid Rain Program, a complete Acid Rain permit application, an Acid Rain permit, or an exemption under 40 CFR 72.7, 72.8 or 72.14, including any requirement for the payment of any penalty owed to the United States, shall be subject to enforcement pursuant to section 113(c) of the Federal Clean Air Act.

(2) Any person who knowingly makes a false, material statement in any record, submission, or report under the Acid Rain Program shall be subject to criminal enforcement pursuant to section 113(c) of the Federal Clean Air Act and 18 U.S.C. 1001.

(3) No permit revision shall excuse any violation of the requirements of the Acid Rain Program that occurs prior to the date that the revision takes effect.

(4) Each affected source and each affected unit shall meet the requirements of the Acid Rain Program.

(5) Any provision of the Acid Rain Program that applies to an affected source (including a provision applicable to the designated representative of an affected source) shall also apply to the owners and operators of such source and of the affected units at the source.

(6) Any provision of the Acid Rain Program that applies to an affected unit (including a provision applicable to the designated representative of an affected unit) shall also apply to the owners and operators of such unit. Except as provided under 40 CFR 72.44 (Phase II repowering extension plans) and 40 CFR 76.11 (NO_X averaging plans), and except with regard to the requirements applicable to units with a common stack under 40 CFR part 75 (including 40 CFR 75.16, 75.17, and 75.18), the owners and operators and the designated representative of one affected unit shall not be liable for any violation by any other affected unit of which they are not owners or operators or the designated representative and that is located at a source of which they are not owners or operators or the designated representative.

(7) Each violation of a provision of 40 CFR parts 72, 73, 74, 75, 76, 77, and 78 by an affected source or affected unit, or by an owner or operator or designated representative of such source or unit, shall be a separate violation of the Federal Clean Air Act.

<u>Effect on Other Authorities.</u>

No provision of the Acid Rain Program, an Acid Rain permit application, an Acid Rain permit, or an exemption under 40 CFR 72.7, 72.8 or 72.14 shall be construed as:

(1) Except as expressly provided in title IV of the Federal Clean Air Act, exempting or excluding the owners and operators and, to the extent applicable, the designated representative of an affected source or affected unit from compliance with any other provision of the Federal Clean Air Act, including the provisions of title I of the Federal Clean Air Act relating to applicable National Ambient Air Quality Standards or State Implementation Plans;

(2) Limiting the number of allowances a unit can hold; *provided,* that the number of allowances held by the unit shall not affect the source's obligation to comply with any other provisions of the Federal Clean Air Act;

(3) Requiring a change of any kind in any State law regulating electric utility rates and charges, affecting any State law regarding such State regulation, or limiting such State regulation, including any prudence review requirements under such State law;

(4) Modifying the Federal Power Act or affecting the authority of the Federal Energy Regulatory Commission under the Federal Power Act; or,

(5) Interfering with or impairing any program for competitive bidding for power supply in a State in which such program is established.

4. Reporting Requirements

Reports shall be submitted to the addresses identified in Appendix D.

Pursuant to 40 CFR Part 75.64 quarterly reports and compliance certification requirements shall be submitted to the Administrator **within 30 days after the end of the calendar quarter**. The contents of these reports shall meet the requirements of 40 CFR 75.64.

Pursuant to 40 CFR Part 72.90 (as adopted by reference in Colorado Regulation 18) annual reports and compliance certifications shall be submitted to the Administrator **within 60 days after the end of the calendar year**. The contents of these reports shall meet the requirements of 40 CFR 72.90. A copy of the compliance certification shall also be submitted to the Division.

Revisions to this permit shall be made in accordance with 40 CFR Part 72, Subpart H, §§ 72.80 through 72.85 (as adopted by reference in Colorado Regulation 18). Permit modification requests shall be submitted to the Division at the address identified in Appendix D.

Changes to the Designated Representative or Alternate Designated Representative shall be made in accordance with 40 CFR 72.23. A copy of the complete certificate of representation shall be submitted to the Division with thirty (30) days of submittal to the Administrator of the EPA.

5. Comments, Notes and Justifications

Combustion Turbines 1 thru 6 burn only natural gas as fuel. The NO_X limitations in 40 CFR Part 76 are only applicable to coal-fired utility units.

SECTION IV - Permit Shield

Regulation No. 3, 5 CCR 1001-5, Part A, § I.B.43; Part C, §§ V.C.1.b. & D., XIII; §§ 25-7-111(2)(I), 25-7-114.4(3)(a), C.R.S.

1. Specific Non-Applicable Requirements

Based on the information available to the Division and supplied by the applicant, the following parameters and requirements have been specifically identified as non-applicable to the facility to which this permit has been issued. This shield does not protect the source from any violations that occurred prior to or at the time of permit issuance. In addition, this shield does not protect the source from any violations that occur as a result of any modifications or reconstruction on which construction commenced prior to permit issuance.

No applicable requirements were identified in the application.

2. General Conditions

Compliance with this Operating Permit shall be deemed compliance with all applicable requirements specifically identified in the permit and other requirements specifically identified in the permit as not applicable to the source. This permit shield shall not alter or affect the following:

2.1 The provisions of §§ 25-7-112 and 25-7-113, C.R.S., or § 303 of the federal act, concerning enforcement in cases of emergency;

2.2 The liability of an owner or operator of a source for any violation of applicable requirements prior to or at the time of permit issuance;

2.3 The applicable requirements of the federal Acid Rain Program, consistent with § 408(a) of the federal act;

2.4 The ability of the Air Pollution Control Division to obtain information from a source pursuant to § 25-7-111(2)(I), C.R.S., or the ability of the Administrator to obtain information pursuant to § 114 of the federal act;

2.5 The ability of the Air Pollution Control Division to reopen the Operating Permit for cause pursuant to Regulation No. 3, Part C, § XIII.

2.6 Sources are not shielded from terms and conditions that become applicable to the source subsequent to permit issuance.

SECTION V - General Permit Conditions

1. Administrative Changes

Regulation No. 3, 5 CCR 1001-5, Part A, § III.

The permittee shall submit an application for an administrative permit amendment to the Division for those permit changes that are described in Regulation No. 3, Part A, § I.B.36.a. The permittee may immediately make the change upon submission of the application to the Division.

2. Certification Requirements

Regulation No. 3, 5 CCR 1001-5, Part C, §§ III.B.9., V.C.16.a.& e. and V.C.17.

a. Any application, report, document and compliance certification submitted to the Air Pollution Control Division pursuant to Regulation No. 3 or the Operating Permit shall contain a certification by a responsible official of the truth, accuracy and completeness of such form, report or certification stating that, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate and complete.

b. All compliance certifications for terms and conditions in the Operating Permit shall be submitted to the Air Pollution Control Division at least annually unless a more frequent period is specified in the applicable requirement or by the Division in the Operating Permit.

c. Compliance certifications shall contain:

(i) the identification of each permit term and condition that is the basis of the certification;

(ii) the compliance status of the source;

(iii) whether compliance was continuous or intermittent;

(iv) method(s) used for determining the compliance status of the source, currently and over the reporting period; and

(v) such other facts as the Air Pollution Control Division may require to determine the compliance status of the source.

d. All compliance certifications shall be submitted to the Air Pollution Control Division and to the Environmental Protection Agency at the addresses listed in Appendix D of this Permit.

e. If the permittee is required to develop and register a risk management plan pursuant to § 112(r) of the federal act, the permittee shall certify its compliance with that requirement; the Operating Permit shall not incorporate the contents of the risk management plan as a permit term or condition.

3. Common Provisions

Common Provisions Regulation, 5 CCR 1001-2 §§ II.A., II.B., II.C., II,.E., II.F., II.I, and II.J

a. To Control Emissions Leaving Colorado

When emissions generated from sources in Colorado cross the State boundary line, such emissions shall not cause the air quality standards of the receiving State to be exceeded, provided reciprocal action is taken by the receiving State.

b. Emission Monitoring Requirements

The Division may require owners or operators of stationary air pollution sources to install, maintain, and use instrumentation to monitor and record emission data as a basis for periodic reports to the Division.

c. Performance Testing

The owner or operator of any air pollution source shall, upon request of the Division, conduct performance test(s) and furnish the Division a written report of the results of such test(s) in order to determine compliance with applicable emission control regulations. Performance test(s) shall be conducted and the data reduced in accordance with the applicable reference test methods unless the Division:

(i) specifies or approves, in specific cases, the use of a test method with minor changes in methodology;

(ii) approves the use of an equivalent method;

(iii) approves the use of an alternative method the results of which the Division has determined to be adequate for indicating where a specific source is in compliance; or

(iv) waives the requirement for performance test(s) because the owner or operator of a source has demonstrated by other means to the Division's satisfaction that the affected facility is in compliance with the standard. Nothing in this paragraph shall be construed to abrogate the Commission's or Division's authority to require testing under the Colorado Revised Statutes, Title 25, Article 7 1973, and pursuant to regulations promulgated by the Commission.

Compliance test(s) shall be conducted under such conditions as the Division shall specify to the plant operator based on representative performance of the affected facility. The owner or operator shall make available to the Division such records as may be necessary to determine the conditions of the performance test(s). Operations during period of startup, shutdown, and malfunction shall not constitute representative conditions of performance test(s) unless otherwise specified in the applicable standard.

The owner or operator of an affected facility shall provide the Division thirty days prior notice of the performance test to afford the Division the opportunity to have an observer present. The Division may waive the thirty day notice requirement provided that arrangements satisfactory to the Division are made for earlier testing.

The owner or operator of an affected facility shall provide, or cause to be provided, performance testing facilities as follows:

(i) Sampling ports adequate for test methods applicable to such facility,

(ii) Safe sampling platform(s),

(iii) Safe access to sampling platform(s).

(iv) Utilities for sampling and testing equipment.

Each performance test shall consist of at least three separate runs using the applicable test method. Each run shall be conducted for the time and under the conditions specified in the applicable standard. For the purpose of determining compliance with an applicable standard the arithmetic mean of results of at least three runs shall apply. In the event that a sample is accidentally lost or conditions occur in which one of the runs must be discontinued because of forced shutdown, failure of an irreplaceable portion of the sample train, extreme meteorological conditions, or other circumstances beyond the owner or operator's control, compliance may, upon the Division's approval, be determined using the arithmetic mean of the results of the two other runs.

Nothing in this section shall abrogate the Division's authority to conduct its own performance test(s) if so warranted.

d. Affirmative Defense Provision for Excess Emissions during Malfunctions

Note that until such time as the U.S. EPA approves this provision into the Colorado State Implementation Plan (SIP), it shall be enforceable only by the State.

An affirmative defense to a claim of violation under these regulations is provided to owners and operators for civil penalty actions for excess emissions during periods of malfunction. To establish the affirmative defense and to be relieved of a civil penalty in any action to enforce an applicable requirement, the owner or operator of the facility must meet the notification requirements below in a timely manner and prove by a preponderance of evidence that:

(i) The excess emissions were caused by a sudden, unavoidable breakdown of equipment, or a sudden, unavoidable failure of a process to operate in the normal or usual manner, beyond the reasonable control of the owner or operator;

(ii) The excess emissions did not stem from any activity or event that could have reasonably been foreseen and avoided, or planned for, and could not have been avoided by better operation and maintenance practices;

(iii) Repairs were made as expeditiously as possible when the applicable emission limitations were being exceeded;

(iv) The amount and duration of the excess emissions (including any bypass) were minimized to the maximum extent practicable during periods of such emissions;

(v) All reasonably possible steps were taken to minimize the impact of the excess emissions on ambient air quality;

(vi) All emissions monitoring systems were kept in operation (if at all possible);

(vii) The owner or operator's actions during the period of excess emissions were documented by properly signed, contemporaneous operating logs or other relevant evidence;

(viii) The excess emissions were not part of a recurring pattern indicative of inadequate design, operation, or maintenance;

(ix) At all times, the facility was operated in a manner consistent with good practices for minimizing emissions. This section is intended solely to be a factor in determining whether an affirmative defense is available to an owner or operator, and shall not constitute an additional applicable requirement; and

(x) During the period of excess emissions, there were no exceedances of the relevant ambient air quality standards established in the Commissions' Regulations that could be attributed to the emitting source.

The owner or operator of the facility experiencing excess emissions during a malfunction shall notify the division verbally as soon as possible, but no later than noon of the Division's next working day, and shall submit written notification following the initial occurrence of the excess emissions by the end of the source's next reporting period. The notification shall address the criteria set forth above.

The Affirmative Defense Provision contained in this section shall not be available to claims for injunctive relief.

The Affirmative Defense Provision does not apply to failures to meet federally promulgated performance standards or emission limits, including, but not limited to, new source performance standards and national emission standards for hazardous air pollutants. The affirmative defense provision does not apply to state implementation plan (sip) limits or permit limits that have been set taking into account potential emissions during malfunctions, including, but not necessarily limited to, certain limits with 30-day or longer averaging times, limits that indicate they apply during malfunctions, and limits that indicate they apply at all times or without exception.

e. Circumvention Clause

A person shall not build, erect, install, or use any article, machine, equipment, condition, or any contrivance, the use of which, without resulting in a reduction in the total release of air pollutants to the atmosphere, reduces or conceals an emission which would otherwise constitute a violation of this regulation. No person shall circumvent this regulation by using more openings than is considered normal practice by the industry or activity in question.

f. Compliance Certifications

For the purpose of submitting compliance certifications or establishing whether or not a person has violated or is in violation of any standard in the Colorado State Implementation Plan, nothing in the Colorado State Implementation Plan shall preclude the use, including the exclusive use, of any credible evidence or information, relevant to whether a source would have been in compliance with applicable requirements if the appropriate performance or compliance test or procedure had been performed. Evidence that has the effect of making any relevant standard or permit term more stringent shall not be credible for proving a violation of the standard or permit term.

When compliance or non-compliance is demonstrated by a test or procedure provided by permit or other applicable requirement, the owner or operator shall be presumed to be in compliance or non-compliance unless other relevant credible evidence overcomes that presumption.

g. Affirmative Defense Provision for Excess Emissions During Startup and Shutdown (**State-Only** requirement)

An affirmative defense is provided to owners and operators for civil penalty actions for excess emissions during periods of startup and shutdown. To establish the affirmative defense and to be relieved of a civil penalty in any action to enforce an applicable requirement, the owner or operator of the facility must meet the notification requirements below in a timely manner and prove by a preponderance of the evidence that:

(i) The periods of excess emissions that occurred during startup and shutdown were short and infrequent and could not have been prevented through careful planning and design;

(ii) The excess emissions were not part of a recurring pattern indicative of inadequate design, operation or maintenance;

(iii) If the excess emissions were caused by a bypass (an intentional diversion of control equipment), then the bypass was unavoidable to prevent loss of life, personal injury, or severe property damage;

(iv) The frequency and duration of operation in startup and shutdown periods were minimized to the maximum extent practicable;

(v) All possible steps were taken to minimize the impact of excess emissions on ambient air quality;

(vi) All emissions monitoring systems were kept in operation (if at all possible);

(vii) The owner or operator's actions during the period of excess emissions were documented by properly signed, contemporaneous operating logs or other relevant evidence; and,

(viii) At all times, the facility was operated in a manner consistent with good practices for minimizing emissions. This subparagraph is intended solely to be a factor in determining whether an affirmative defense is available to an owner or operator, and shall not constitute an additional applicable requirement.

The owner or operator of the facility experiencing excess emissions during startup and shutdown shall notify the Division verbally as soon as possible, but no later than two (2) hours after the start of the next working day, and shall submit written quarterly notification following the initial occurrence of the excess emissions. The notification shall address the criteria set forth above.

The Affirmative Defense Provision contained in this section shall not be available to claims for injunctive relief.

The Affirmative Defense Provision does not apply to State Implementation Plan provisions or other requirements that derive from new source performance standards (NSPS) or national emissions standards for hazardous air pollutants (NESHAPS), any other federally enforceable performance standard or emission limit with an averaging time greater than twenty-four hours. In addition, an affirmative defense cannot be used by a single source or small group of sources where the excess emissions have the potential to cause an exceedance of the ambient air quality standards or Prevention of Significant Deterioration (PSD) increments.

In making any determination whether a source established an affirmative defense, the Division shall consider the information within the notification required above and any other information the Division deems necessary, which may include, but is not limited to, physical inspection of the facility and review of documentation pertaining to the maintenance and operation of process and air pollution control equipment.

Note that until such time as the U.S. EPA approves this provision into the Colorado State Implementation Plan (SIP), it shall apply only to **State-Only** permit terms and conditions and shall be enforceable only by the State.

4. Compliance Requirements

Regulation No. 3, 5 CCR 1001-5, Part C, §§ III.C.9., V.C.11. & 16.d., § 25-7-122.1(2), C.R.S.

a. The permittee must comply with all conditions of the Operating Permit. Any permit noncompliance relating to federally-enforceable terms or conditions constitutes a violation of the federal act, as well as the state act and Regulation No. 3. Any permit noncompliance relating to state-only terms or conditions constitutes a violation of the state act and Regulation No. 3, shall be enforceable pursuant to state law, and shall not be enforceable by citizens under § 304 of the federal act. Any such violation of the federal act, the state act or regulations implementing either statute is grounds for enforcement action, for permit termination, revocation and reissuance or modification or for denial of a permit renewal application.

b. It shall not be a defense for a permittee in an enforcement action or a consideration in favor of a permittee in a permit termination, revocation or modification action or action denying a permit renewal application that it would have been necessary to halt or reduce the permitted activity in order to maintain compliance with the conditions of the permit.

c. The permit may be modified, revoked, reopened, and reissued, or terminated for cause. The filing of any request by the permittee for a permit modification, revocation and reissuance, or termination, or any notification of planned changes or anticipated noncompliance does not stay any permit condition, except as provided in §§ X. and XI. of Regulation No. 3, Part C.

d. The permittee shall furnish to the Air Pollution Control Division, within a reasonable time as specified by the Division, any information that the Division may request in writing to determine whether cause exists for modifying, revoking and reissuing, or terminating the permit or to determine compliance with the permit. Upon request, the permittee shall also furnish to the Division copies of records required to be kept by the permittee, including information claimed to be confidential. Any information subject to a claim of confidentiality shall be specifically identified and submitted separately from information not subject to the claim.

e. Any schedule for compliance for applicable requirements with which the source is not in compliance at the time of permit issuance shall be supplemental, and shall not sanction noncompliance with, the applicable requirements on which it is based.

f. For any compliance schedule for applicable requirements with which the source is not in compliance at the time of permit issuance, the permittee shall submit, at least every 6 months unless a more frequent period is specified in the applicable requirement or by the Air Pollution Control Division, progress reports which contain the following:

(i) dates for achieving the activities, milestones, or compliance required in the schedule for compliance, and dates when such activities, milestones, or compliance were achieved; and

(ii) an explanation of why any dates in the schedule of compliance were not or will not be met, and any preventive or corrective measures adopted.

g. The permittee shall not knowingly falsify, tamper with, or render inaccurate any monitoring device or method required to be maintained or followed under the terms and conditions of the Operating Permit.

5. Emergency Provisions

Regulation No. 3, 5 CCR 1001-5, Part C, § VII.

An emergency means any situation arising from sudden and reasonably unforeseeable events beyond the control of the source, including acts of God, which situation requires immediate corrective action to restore normal operation, and that causes the source to exceed the technology-based emission limitation under the permit due to unavoidable increases in emissions attributable to the emergency. "Emergency" does not include noncompliance to the extent caused by improperly designed equipment, lack of preventative maintenance, careless or improper operation, or operator error. An emergency constitutes an affirmative defense to an enforcement action brought for noncompliance with a technology-based emission limitation if the permittee demonstrates, through properly signed, contemporaneous operating logs, or other relevant evidence that:

a. an emergency occurred and that the permittee can identify the cause(s) of the emergency;

b. the permitted facility was at the time being properly operated;

c. during the period of the emergency the permittee took all reasonable steps to minimize levels of emissions that exceeded the emission standards, or other requirements in the permit; and

d. the permittee submitted oral notice of the emergency to the Air Pollution Control Division no later than noon of the next working day following the emergency, and followed by written notice within one month of the time when emissions limitations were exceeded due to the emergency. This notice must contain a description of the emergency, any steps taken to mitigate emissions, and corrective actions taken.

This emergency provision is in addition to any emergency or malfunction provision contained in any applicable requirement.

6. Emission Standards for Asbestos

Regulation No. 8, 5 CCR 1001-10, Part B

The permittee shall not conduct any asbestos abatement activities except in accordance with the provisions of Regulation No. 8, Part B, "emission standards for asbestos."

7. Emissions Trading, Marketable Permits, Economic Incentives

Regulation No. 3, 5 CCR 1001-5, Part C, § V.C.13.

No permit revision shall be required under any approved economic incentives, marketable permits, emissions trading and other similar programs or processes for changes that are specifically provided for in the permit.

8. Fee Payment

C.R.S. §§ 25-7-114.1(6) and 25-7-114.7

a. The permittee shall pay an annual emissions fee in accordance with the provisions of § 25-7-114.7. A 1% per month late payment fee shall be assessed against any invoice amounts not paid in full on the 91st day after the date of invoice, unless a permittee has filed a timely protest to the invoice amount.

b. The permittee shall pay a permit processing fee in accordance with the provisions of § 25-7-114.7. If the Division estimates that processing of the permit will take more than 30 hours, it will notify the permittee of its estimate of what the actual charges may be prior to commencing any work exceeding the 30 hour limit.

c. The permittee shall pay an APEN fee in accordance with the provisions of § 25-7-114.1(6) for each APEN or revised APEN filed.

9. Fugitive Particulate Emissions

Regulation No. 1, 5 CCR 1001-3, § III.D.1.

The permittee shall employ such control measures and operating procedures as are necessary to minimize fugitive particulate emissions into the atmosphere, in accordance with the provisions of Regulation No. 1, § III.D.1.

10. Inspection and Entry

Regulation No. 3, 5 CCR 1001-5, Part C, § V.C.16.b.

Upon presentation of credentials and other documents as may be required by law, the permittee shall allow the Air Pollution Control Division, or any authorized representative, to perform the following:

a. enter upon the permittee's premises where an Operating Permit source is located, or emissions-related activity is conducted, or where records must be kept under the terms of the permit;

b. have access to, and copy, at reasonable times, any records that must be kept under the conditions of the permit;

c. inspect at reasonable times any facilities, equipment (including monitoring and air pollution control equipment), practices, or operations regulated or required under the Operating Permit;

d. sample or monitor at reasonable times, for the purposes of assuring compliance with the Operating Permit or applicable requirements, any substances or parameters.

11. Minor Permit Modifications

Regulation No. 3, 5 CCR 1001-5, Part C, §§ X. & XI.

The permittee shall submit an application for a minor permit modification before making the change requested in the application. The permit shield shall not extend to minor permit modifications.

12. New Source Review

Regulation No. 3, 5 CCR 1001-5, Part B

The permittee shall not commence construction or modification of a source required to be reviewed under the New Source Review provisions of Regulation No. 3, Part B, without first receiving a construction permit.

13. No Property Rights Conveyed

Regulation No. 3, 5 CCR 1001-5, Part C, § V.C.11.d.

This permit does not convey any property rights of any sort, or any exclusive privilege.

14. Odor

Regulation No. 2, 5 CCR 1001-4, Part A

As a matter of state law only, the permittee shall comply with the provisions of Regulation No. 2 concerning odorous emissions.

15. Off-Permit Changes to the Source

Regulation No. 3, 5 CCR 1001-5, Part C, § XII.B.

The permittee shall record any off-permit change to the source that causes the emissions of a regulated pollutant subject to an applicable requirement, but not otherwise regulated under the permit, and the emissions resulting from the change, including any other data necessary to show compliance with applicable ambient air quality standards. The permittee shall provide contemporaneous notification to the Air Pollution Control Division and to the Environmental Protection Agency at the addresses listed in Appendix D of this Permit . The permit shield shall not apply to any off-permit change.

16. Opacity

Regulation No. 1, 5 CCR 1001-3, §§ I., II.

The permittee shall comply with the opacity emissions limitation set forth in Regulation No. 1, §§ I.-II.

17. Open Burning

Regulation No. 9, 5 CCR 1001-11

The permittee shall obtain a permit from the Division for any regulated open burning activities in accordance with provisions of Regulation No. 9.

18. Ozone Depleting Compounds

Regulation No. 15, 5 CCR 1001-17

The permittee shall comply with the provisions of Regulation No. 15 concerning emissions of ozone depleting compounds. Sections I., II.C., II.D., III. IV., and V. of Regulation No. 15 shall be enforced as a matter of state law only.

19. Permit Expiration and Renewal

Regulation No. 3, 5 CCR 1001-5, Part C, §§ III.B.6., IV.C., V.C.2.

a. The permit term shall be five (5) years. The permit shall expire at the end of its term. Permit expiration terminates the permittee's right to operate unless a timely and complete renewal application is submitted.

b. Applications for renewal shall be submitted at least twelve months, but not more than 18 months, prior to the expiration of the Operating Permit. An application for permit renewal may address only those portions of the permit that require revision, supplementing, or deletion, incorporating the remaining permit terms by reference from the previous permit. A copy of any materials incorporated by reference must be included with the application.

20. Portable Sources

Regulation No. 3, 5 CCR 1001-5, Part C, § II.D.

Portable Source permittees shall notify the Air Pollution Control Division at least 10 days in advance of each change in location.

21. Prompt Deviation Reporting

Regulation No. 3, 5 CCR 1001-5, Part C, § V.C.7.b.

The permittee shall promptly report any deviation from permit requirements, including those attributable to malfunction conditions as defined in the permit, the probable cause of such deviations, and any corrective actions or preventive measures taken.

"Prompt" is defined as follows:

a. Any definition of "prompt" or a specific timeframe for reporting deviations provided in an underlying applicable requirement as identified in this permit; or

b. Where the underlying applicable requirement fails to address the time frame for reporting deviations, reports of deviations will be submitted based on the following schedule:

(i) For emissions of a hazardous air pollutant or a toxic air pollutant (as identified in the applicable regulation) that continue for more than an hour in excess of permit requirements, the report shall be made within 24 hours of the occurrence;

(ii) For emissions of any regulated air pollutant, excluding a hazardous air pollutant or a toxic air pollutant that continue for more than two hours in excess of permit requirements, the report shall be made within 48 hours; and

(iii) For all other deviations from permit requirements, the report shall be submitted every six (6) months, except as otherwise specified by the Division in the permit in accordance with paragraph 22.d. below.

c. If any of the conditions in paragraphs b.i or b.ii above are met, the source shall notify the Division by telephone (303-692-3155) or facsimile (303-782-0278) based on the timetables listed above. *[Explanatory note: Notification by telephone or facsimile must specify that this notification is a deviation report for an Operating Permit.]* A written notice, certified consistent with General Condition 2.a. above (Certification Requirements), shall be submitted within 10 working days of the occurrence. All deviations reported under this section shall also be identified in the 6-month report required above.

"Prompt reporting" does not constitute an exception to the requirements of "Emergency Provisions" for the purpose of avoiding enforcement actions.

22. Record Keeping and Reporting Requirements

Regulation No. 3, 5 CCR 1001-5, Part A, § II.; Part C, §§ V.C.6., V.C.7.

a. Unless otherwise provided in the source specific conditions of this Operating Permit, the permittee shall maintain compliance monitoring records that include the following information:

(i) date, place as defined in the Operating Permit, and time of sampling or measurements;

(ii) date(s) on which analyses were performed;

(iii) the company or entity that performed the analysis;

(iv) the analytical techniques or methods used;

(v) the results of such analysis; and

(vi) the operating conditions at the time of sampling or measurement.

b. The permittee shall retain records of all required monitoring data and support information for a period of at least five (5) years from the date of the monitoring sample, measurement, report or application. Support information, for this purpose, includes all calibration and maintenance records and all original strip-chart recordings for continuous monitoring instrumentation, and copies of all reports required by the Operating Permit. With prior approval of the Air Pollution Control Division, the permittee may maintain any of the above records in a computerized form.

c. Permittees must retain records of all required monitoring data and support information for the most recent twelve (12) month period, as well as compliance certifications for the past five (5) years on-site at all times. A permittee shall make available for the Air Pollution Control Division's review all other records of required monitoring data and support information required to be retained by the permittee upon 48 hours advance notice by the Division.

d. The permittee shall submit to the Air Pollution Control Division all reports of any required monitoring at least every six (6) months, unless an applicable requirement, the enhanced monitoring rule, or the Division requires submission on a more frequent basis. All instances of deviations from any permit requirements must be clearly identified in such reports.

e. The permittee shall file an Air Pollutant Emissions Notice ("APEN") prior to constructing, modifying, or altering any facility, process, activity which constitutes a stationary source from which air pollutants are or are to be emitted, unless such source is exempt from the APEN filing requirements of Regulation No. 3, Part A, § II.D. A revised APEN shall be filed annually whenever a significant change in emissions, as defined in Regulation No. 3, Part A, § II.C.2., occurs; whenever there is a change in owner or operator of any facility, process, or activity; whenever new control equipment is installed; whenever a different type of control equipment replaces an existing type of control equipment; whenever a permit limitation must be modified; or before the APEN expires. An APEN is valid for a period of five years. The five-year period recommences when a revised APEN is received by the Air Pollution Control Division. Revised APENs shall be submitted no later than 30 days before the five-year term expires. Permittees submitting revised APENs to inform the Division of a change in actual emission rates must do so by April 30 of the following year. Where a permit revision is required, the revised APEN must be filed along with a request for permit revision. APENs for changes in control equipment must be submitted before the change occurs. Annual fees are based on the most recent APEN on file with the Division.

23. Reopenings for Cause

Regulation No. 3, 5 CCR 1001-5, Part C, § XIII.

a. The Air Pollution Control Division shall reopen, revise, and reissue Operating Permits; permit reopenings and reissuance shall be processed using the procedures set forth in Regulation No. 3, Part C, § III., except that proceedings to reopen and reissue permits affect only those parts of the permit for which cause to reopen exists.

b. The Division shall reopen a permit whenever additional applicable requirements become applicable to a major source with a remaining permit term of three or more years, unless the effective date of the requirements is later than the date on which the permit expires, or unless a general permit is obtained to address the new requirements; whenever additional requirements (including excess emissions requirements) become applicable to an affected source under the acid rain program; whenever the Division determines the permit contains a material mistake or that inaccurate statements were made in establishing the emissions standards or other terms or conditions of the permit; or whenever the Division determines that the permit must be revised or revoked to assure compliance with an applicable requirement.

c. The Division shall provide 30 days' advance notice to the permittee of its intent to reopen the permit, except that a shorter notice may be provided in the case of an emergency.

d. The permit shield shall extend to those parts of the permit that have been changed pursuant to the reopening and reissuance procedure.

24. Section 502(b)(10) Changes

Regulation No. 3, 5 CCR 1001-5, Part C, § XII.A.

The permittee shall provide a minimum 7-day advance notification to the Air Pollution Control Division and to the Environmental Protection Agency at the addresses listed in Appendix D of this Permit. The permittee shall attach a copy of each such notice given to its Operating Permit.

25. Severability Clause

Regulation No. 3, 5 CCR 1001-5, Part C, § V.C.10.

In the event of a challenge to any portion of the permit, all emissions limits, specific and general conditions, monitoring, record keeping and reporting requirements of the permit, except those being challenged, remain valid and enforceable.

26. Significant Permit Modifications

Regulation No. 3, 5 CCR 1001-5, Part C, § III.B.2.

The permittee shall not make a significant modification required to be reviewed under Regulation No. 3, Part B ("Construction Permit" requirements) without first receiving a construction permit. The permittee shall submit a complete Operating Permit application or application for an Operating Permit revision for any new or modified source within twelve months of commencing operation, to the address listed in Item 1 in Appendix D of this permit. If the permittee chooses to use the "Combined Construction/Operating Permit" application procedures of Regulation No. 3, Part C, then the Operating Permit must be received prior to commencing construction of the new or modified source.

27. Special Provisions Concerning the Acid Rain Program

Regulation No. 3, 5 CCR 1001-5, Part C, §§ V.C.1.b. & 8

a. Where an applicable requirement of the federal act is more stringent than an applicable requirement of regulations promulgated under Title IV of the federal act, 40 Code of Federal Regulations (CFR) Part 72, both provisions shall be incorporated into the permit and shall be federally enforceable.

b. Emissions exceeding any allowances that the source lawfully holds under Title IV of the federal act or the regulations promulgated thereunder, 40 CFR Part 72, are expressly prohibited.

28. Transfer or Assignment of Ownership

Regulation No. 3, 5 CCR 1001-5, Part C, § II.C.

No transfer or assignment of ownership of the Operating Permit source will be effective unless the prospective owner or operator applies to the Air Pollution Control Division on Division-supplied Administrative Permit Amendment forms, for reissuance of the existing Operating Permit. No administrative permit shall be complete until a written agreement containing a specific date for transfer of permit, responsibility, coverage, and liability between the permittee and the prospective owner or operator has been submitted to the Division.

29. Volatile Organic Compounds

Regulation No. 7, 5 CCR 1001-9, §§ III & V.

a. For sources located in an ozone non-attainment area or the Denver Metro Attainment Maintenance Area, all storage tank gauging devices, anti-rotation devices, accesses, seals, hatches, roof drainage systems, support structures, and pressure relief valves shall be maintained and operated to prevent detectable vapor loss except when opened, actuated, or used for necessary and proper activities (e.g. maintenance). Such opening, actuation, or use shall be limited so as to minimize vapor loss.

   Detectable vapor loss shall be determined visually, by touch, by presence of odor, or using a portable hydrocarbon analyzer. When an analyzer is used, detectable vapor loss means a VOC concentration exceeding 10,000 ppm. Testing shall be conducted as in Regulation No. 7, Section VIII.C.3.

   Except when otherwise provided by Regulation No. 7, all volatile organic compounds, excluding petroleum liquids, transferred to any tank, container, or vehicle compartment with a capacity exceeding 212 liters (56 gallons), shall be transferred using submerged or bottom filling equipment. For top loading, the fill tube shall reach within six inches of the bottom of the tank compartment. For bottom-fill operations, the inlet shall be flush with the tank bottom.

b. The permittee shall not dispose of volatile organic compounds by evaporation or spillage unless Reasonably Available Control Technology (RACT) is utilized.

c. No owner or operator of a bulk gasoline terminal, bulk gasoline plant, or gasoline dispensing facility as defined in Colorado Regulation No. 7, Section VI, shall permit gasoline to be intentionally spilled, discarded in sewers, stored in open containers, or disposed of in any other manner that would result in evaporation.

30. Wood Stoves and Wood burning Appliances

Regulation No. 4, 5 CCR 1001-6

The permittee shall comply with the provisions of Regulation No. 4 concerning the advertisement, sale, installation, and use of wood stoves and wood burning appliances.

OPERATING PERMIT APPENDICES

A - INSPECTION INFORMATION
B - MONITORING AND PERMIT DEVIATION REPORT
C - COMPLIANCE CERTIFICATION REPORT
D - NOTIFICATION ADDRESSES
E - PERMIT ACRONYMS
F - PERMIT MODIFICATIONS

*DISCLAIMER:

None of the information found in these Appendices shall be considered to be State or Federally enforceable, except as otherwise provided in the permit, and is presented to assist the source, permitting authority, inspectors, and citizens.

APPENDIX A - Inspection Information

Directions to Plant

The facility is located at 18693 Boca Raton Heights. This street is accessed from Exit 119 off I-25, south of Fountain.

Safety Equipment Required

Eye Protection, Hard Hat, Safety Shoes and Heating Protection

Facility Plot Plan

Figure 1 (following page) shows the plot plan as submitted on June 26, 2002 with the source's Title V Operating Permit Application.

List of Insignificant Activities

The following list of insignificant activities was provided by the source. Since there is no requirement to update such a list, activities may have changed since the last filing.

Chemical storage tanks or containers that hold less than 500 gallons, and which have a daily throughput less than 25 gallons.

Landscaping and site housekeeping devices equal to or less than 10 H.P. in size (lawnmowers, trimmers, snow blowers, etc.).

Chemical storage areas where chemicals are stored in closed containers, and where total storage capacity does not exceed 5000 gallons. This exemption applies solely to storage of such chemicals. This exemption does not apply to transfer of chemicals from, to, or between such containers.

Storage tanks of capacity <40,000 gallons of lubricating oils.

Storage tanks meeting all of the following criteria:

(i) annual throughput is less than 400,000 gallons; and

(ii) the liquid stored is one of the following:

(A) diesel fuels 1-D, 2-D, or 4-D;
(B) fuel oils #1 through #6;
(C) gas turbine fuels 1-GT through 4-GT;
(D) an oil/water mixture with a vapor pressure lower than that of diesel fuel (Reid vapor pressure of .025 psia)

Each individual piece of fuel burning equipment which uses gaseous fuel, and which has a design rate less than or equal to 10 million Btu per hour, and which is use solely for heating buildings for personal comfort.

Air pollution emission units, operations or activities with emissions less than the appropriate de minimis reporting level.

Specific Insignificant activities and/or sources of emissions as identified in the application:

Oil/Water Separator
Raw and Treated Water Storage
Lube Oil storage
Small quantity fuel storage (for miscellaneous equipment)
Used Oil storage
Station Transformers and associated oils
Maintenance Activities
Welding operations
Warehouse storage
Landscaping maintenance equipment and activities
Use of pesticides, fumigants and herbicides
Laboratory activities
Housekeeping activities
General Office activities
Steam vents
Demineralized water combustion
Solvent parts cleaning
Space heaters in Main Shop, Water Treatment Building and New Administration Building
Diesel Emergency Generator, 685 hp, less than 100 operating hours per year
Diesel Fire Pump, 160 hp, less than 250 operating hours per year

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APPENDIX B

Reporting Requirements and Definitions

with codes ver 2/20/07

Please note that, pursuant to 113(c)(2) of the federal Clean Air Act, any person who knowingly:

(A) makes any false material statement, representation, or certification in, or omits material information from, or knowingly alters, conceals, or fails to file or maintain any notice, application, record, report, plan, or other document required pursuant to the Act to be either filed or maintained (whether with respect to the requirements imposed by the Administrator or by a State);

(B) fails to notify or report as required under the Act; or

(C) falsifies, tampers with, renders inaccurate, or fails to install any monitoring device or method required to be maintained or followed under the Act shall, upon conviction, be punished by a fine pursuant to title 18 of the United States Code, or by imprisonment for not more than 2 years, or both. If a conviction of any person under this paragraph is for a violation committed after a first conviction of such person under this paragraph, the maximum punishment shall be doubled with respect to both the fine and imprisonment.

The permittee must comply with all conditions of this operating permit. Any permit noncompliance constitutes a violation of the Act and is grounds for enforcement action; for permit termination, revocation and reissuance, or modification; or for denial of a permit renewal application.

The Part 70 Operating Permit program requires three types of reports to be filed for all permits.
All required reports must be certified by a responsible official.

Report #1: Monitoring Deviation Report (due at least every six months)

For purposes of this operating permit, the Division is requiring that the monitoring reports are due every six months unless otherwise noted in the permit. All instances of deviations from permit monitoring requirements must be clearly identified in such reports.

For purposes of this operating permit, monitoring means any condition determined by observation, by data from any monitoring protocol, or by any other monitoring which is required by the permit as well as the recordkeeping associated with that monitoring. This would include, for example, fuel use or process rate monitoring, fuel analyses, and operational or control device parameter monitoring.

Report #2: Permit Deviation Report (must be reported "promptly")

In addition to the monitoring requirements set forth in the permits as discussed above, each and every requirement of the permit is subject to deviation reporting. The reports must address deviations from permit requirements, including those attributable to malfunctions as defined in this Appendix, the probable cause of such deviations, and any corrective actions or preventive measures taken. All deviations from any term or condition of the permit are required to be summarized or referenced in the annual compliance certification.

For purposes of this operating permit, "malfunction" shall refer to both emergency conditions and malfunctions. Additional discussion on these conditions is provided later in this Appendix.

For purposes of this operating permit, the Division is requiring that the permit deviation reports are due as set forth in General Condition 21. Where the underlying applicable requirement contains a definition of prompt or otherwise specifies a time frame for reporting deviations, that definition or time frame shall govern. For example, quarterly Excess Emission Reports required by an NSPS or Regulation No. 1, Section IV.

In addition to the monitoring deviations discussed above, included in the meaning of deviation for the purposes of this operating permit are any of the following:

(1) A situation where emissions exceed an emission limitation or standard contained in the permit;

(2) A situation where process or control device parameter values demonstrate that an emission limitation or standard contained in the permit has not been met;

(3) A situation in which observations or data collected demonstrates noncompliance with an emission limitation or standard or any work practice or operating condition required by the permit; or,

(4) A situation in which an excursion or exceedance as defined in 40CFR Part 64 (the Compliance Assurance Monitoring (CAM) Rule) has occurred. (only if the emission point is subject to CAM)

For reporting purposes, the Division has combined the Monitoring Deviation Report with the Permit Deviation Report. All deviations shall be reported using the following codes:

1 = Standard:	When the requirement is an emission limit or standard
2 = Process:	When the requirement is a production/process limit
3 = Monitor:	When the requirement is monitoring
4 = Test:	When the requirement is testing
5 = Maintenance:	When required maintenance is not performed
6 = Record:	When the requirement is recordkeeping
7 = Report:	When the requirement is reporting
8 = CAM:	A situation in which an excursion or exceedance as defined in 40CFR Part 64 (the Compliance Assurance Monitoring (CAM) Rule) has occurred.
9 = Other:	When the deviation is not covered by any of the above categories

Report #3: Compliance Certification (annually, as defined in the permit)

Submission of compliance certifications with terms and conditions in the permit, including emission limitations, standards, or work practices, is required not less than annually.

Compliance Certifications are intended to state the compliance status of each requirement of the permit over the certification period. They must be based, at a minimum, on the testing and monitoring methods specified in the permit that were conducted during the relevant time period. In addition, if the owner or operator knows of other material information (i.e. information beyond required monitoring that has been specifically assessed in relation to how the information potentially affects compliance status), that information must be identified and addressed in the compliance certification. The compliance certification must include the following:

- The identification of each term or condition of the permit that is the basis of the certification;

- Whether or not the method(s) used by the owner or operator for determining the compliance status with each permit term and condition during the certification period was the method(s) specified in the permit. Such methods and other means shall include, at a minimum, the methods and means required in the permit. If necessary, the owner or operator also shall identify any other material information that must be included in the certification to comply with section 113(c)(2) of the Federal Clean Air Act, which prohibits knowingly making a false certification or omitting material information;

- The status of compliance with the terms and conditions of the permit, and whether compliance was continuous or intermittent. The certification shall identify each deviation and take it into account in the compliance certification. Note that not all deviations are considered violations.[1]

- Such other facts as the Division may require, consistent with the applicable requirements to which the source is subject, to determine the compliance status of the source.

The Certification shall also identify as possible exceptions to compliance any periods during which compliance is required and in which an excursion or exceedance as defined under 40 CFR Part 64 (the Compliance Assurance Monitoring (CAM) Rule) has occurred. (only for emission points subject to CAM)

Note the requirement that the certification shall identify each deviation and take it into account in the compliance certification. Previously submitted deviation reports, including the deviation report submitted at the time of the annual certification, may be referenced in the compliance certification.

Startup, Shutdown, Malfunctions and Emergencies

Understanding the application of Startup, Shutdown, Malfunctions and Emergency Provisions, is very important in both the deviation reports and the annual compliance certifications.

[1] For example, given the various emissions limitations and monitoring requirements to which a source may be subject, a deviation from one requirement may not be a deviation under another requirement which recognizes an exception and/or special circumstances relating to that same event.

Startup, Shutdown, and Malfunctions

Please note that exceedances of some New Source Performance Standards (NSPS) and Maximum Achievable Control Technology (MACT) standards that occur during Startup, Shutdown or Malfunctions may not be considered to be non-compliance since emission limits or standards often do not apply unless specifically stated in the NSPS. Such exceedances must, however, be reported as excess emissions per the NSPS/MACT rules and would still be noted in the deviation report. In regard to compliance certifications, the permittee should be confident of the information related to those deviations when making compliance determinations since they are subject to Division review. The concepts of Startup, Shutdown and Malfunctions also exist for Best Available Control Technology (BACT) sources, but are not applied in the same fashion as for NSPS and MACT sources.

Emergency Provisions

Under the Emergency provisions of Part 70 certain operational conditions may act as an affirmative defense against enforcement action if they are properly reported.

DEFINITIONS

Malfunction (NSPS) means any sudden, infrequent, and not reasonably preventable failure of air pollution control equipment, process equipment, or a process to operate in a normal or usual manner. Failures that are caused in part by poor maintenance or careless operation are not malfunctions.

Malfunction (SIP) means any sudden and unavoidable failure of air pollution control equipment or process equipment or unintended failure of a process to operate in a normal or usual manner. Failures that are primarily caused by poor maintenance, careless operation, or any other preventable upset condition or preventable equipment breakdown shall not be considered malfunctions.

Emergency means any situation arising from sudden and reasonably unforeseeable events beyond the control of the source, including acts of God, which situation requires immediate corrective action to restore normal operation, and that causes the source to exceed a technology-based emission limitation under the permit, due to unavoidable increases in emissions attributable to the emergency. An emergency shall not include noncompliance to the extent caused by improperly designed equipment, lack of preventative maintenance, careless or improper operation, or operator error.

Monitoring and Permit Deviation Report - Part I

1. Following is the **required** format for the Monitoring and Permit Deviation report to be submitted to the Division as set forth in General Condition 21. The Table below must be completed for all equipment or processes for which specific Operating Permit terms exist.

2. Part II of this Appendix B shows the format and information the Division will require for describing periods of monitoring and permit deviations, or malfunction or emergency conditions as indicated in the Table below. One Part II Form must be completed for each Deviation. Previously submitted reports (e.g. EER's or malfunctions) may be referenced and the form need not be filled out in its entirety.

FACILITY NAME: Fountain Valley Power, L.L.C. – Fountain Valley Power Plant
OPERATING PERMIT NO: 02OPEP246
REPORTING PERIOD:_____________ (see first page of the permit for specific reporting period and dates)

Operating Permit Unit ID	Unit Description	Deviations Noted During Period?[1]		Deviation Code[2]	Upset/Emergency Condition Reported During Period?	
		YES	NO		YES	NO
CT001	GE Sprint LM6000 Natural Gas Fired Combustion Turbines, Serial Numbers: 191-225					
CT002	GE Sprint LM6000 Natural Gas Fired Combustion Turbines, Serial Numbers: 191-230					
CT003	GE Sprint LM6000 Natural Gas Fired Combustion Turbines, Serial Numbers: 191-229					
CT004	GE Sprint LM6000 Natural Gas Fired Combustion Turbines, Serial Numbers: 191-232					
CT005	GE Sprint LM6000 Natural Gas Fired Combustion Turbines, Serial Numbers: 191-213					
CT006	GE Sprint LM6000 Natural Gas Fired Combustion Turbines, Serial Numbers: 191-192					
AP001	Ajax Natural Gas Fired Heater, Serial Number					
AP002	Ajax Natural Gas Fired Heater, Serial Number					
GC001, GC002, GC003	Three (3) Waukesha Natural Gas Fired Reciprocating Engines, Serial Numbers 171809, C119281, and C119273					
	General Conditions					
	Insignificant Activities					

[1] See previous discussion regarding what is considered to be a deviation. Determination of whether or not a deviation has occurred shall be based on a reasonable inquiry using readily available information.

[2] Use the following entries, as appropriate:

1 = Standard:	When the requirement is an emission limit or standard
2 = Process:	When the requirement is a production/process limit
3 = Monitor:	When the requirement is monitoring
4 = Test:	When the requirement is testing
5 = Maintenance:	When required maintenance is not performed
6 = Record:	When the requirement is recordkeeping
7 = Report:	When the requirement is reporting
8 = CAM:	A situation in which an excursion or exceedance as defined in 40 CFR Part 64 (the Compliance Assurance Monitoring (CAM) Rule) has occurred.
9 = Other:	When the deviation is not covered by any of the above categories

Monitoring and Permit Deviation Report - Part II

FACILITY NAME: Fountain Valley Power, L.L.C. – Fountain Valley Power Plant
OPERATING PERMIT NO: 02OPEP246
REPORTING PERIOD: ____________

Is the deviation being claimed as an: Emergency ______ Malfunction______ N/A

(For NSPS/MACT) Did the deviation occur during: Startup _____ Shutdown ______ Malfunction _____
Normal Operation ____________

OPERATING PERMIT UNIT IDENTIFICATION:

Operating Permit Condition Number Citation

Explanation of Period of Deviation

Duration (start/stop date & time)

Action Taken to Correct the Problem

Measures Taken to Prevent a Reoccurrence of the Problem

Dates of Malfunctions/Emergencies Reported (if applicable)

Deviation Code ________________ Division Code QA: ______________

SEE EXAMPLE ON THE NEXT PAGE

EXAMPLE

FACILITY NAME: Acme Corp.
OPERATING PERMIT NO: 96OPZZXXX
REPORTING PERIOD: 1/1/04 - 6/30/06

Is the deviation being claimed as an: Emergency ______ Malfunction __XX____ N/A

(For NSPS/MACT) Did the deviation occur during: Startup _____ Shutdown ______ Malfunction
Normal Operation ___________________

OPERATING PERMIT UNIT IDENTIFICATION:

Asphalt Plant with a Scrubber for Particulate Control - Unit XXX

Operating Permit Condition Number Citation

Section II, Condition 3.1 - Opacity Limitation

Explanation of Period of Deviation

Slurry Line Feed Plugged

Duration

START- 1730 4/10/06
END- 1800 4/10/06

Action Taken to Correct the Problem

Line Blown Out

Measures Taken to Prevent Reoccurrence of the Problem

Replaced Line Filter

Dates of Malfunction/Emergencies Reported (if applicable)

5/30/06 to R. Flagg, APCD

Deviation Code ____________________________________ Division Code QA: ________

Monitoring and Permit Deviation Report - Part III

REPORT CERTIFICATION

SOURCE NAME: Fountain Valley Power, L.L.C. – Fountain Valley Power Plant
FACILITY IDENTIFICATION NUMBER: 0410897

PERMIT NUMBER: 02OPEP246

REPORTING PERIOD:_______________ (see first page of the permit for specific reporting period and dates)

All information for the Title V Semi-Annual Deviation Reports must be certified by a responsible official as defined in Colorado Regulation No. 3, Part A, Section I.B.38. This signed certification document must be packaged with the documents being submitted.

STATEMENT OF COMPLETENESS

I have reviewed the information being submitted in its entirety and, based on information and belief formed after reasonable inquiry, I certify that the statements and information contained in this submittal are true, accurate and complete.

Please note that the Colorado Statutes state that any person who knowingly, as defined in Sub-Section 18-1-501(6), C.R.S., makes any false material statement, representation, or certification in this document is guilty of a misdemeanor and may be punished in accordance with the provisions of Sub-Section 25-7 122.1, C.R.S.

____

Printed or Typed Name | Title

____

Signature of Responsible Official | Date Signed

Note: Deviation reports shall be submitted to the Division at the address given in Appendix D of this permit. No copies need be sent to the U.S. EPA.

APPENDIX C

Required Format for Annual Compliance Certification Reports

with codes ver 2/20/07

Following is the format for the Compliance Certification report to be submitted to the Division and the U.S. EPA annually based on the effective date of the permit. The Table below must be completed for all equipment or processes for which specific Operating Permit terms exist.

FACILITY NAME: Fountain Valley Power,L.L.C. – Fountain Valley Power Plant
OPERATING PERMIT NO: 02OPEP246
REPORTING PERIOD: ____________

I. Facility Status

___ During the entire reporting period, this source was in compliance with **ALL** terms and conditions contained in the Permit, each term and condition of which is identified and included by this reference. The method(s) used to determine compliance is/are the method(s) specified in the Permit.

___ With the possible exception of the deviations identified in the table below, this source was in compliance with all terms and conditions contained in the Permit, each term and condition of which is identified and included by this reference, with the possible exception of the deviations identified in the table below. The method used to determine compliance for each term and condition is the method specified in the Permit, unless otherwise indicated and described in the deviation report(s). **Note that a deviation is not always a violation.**

Operating Permit Unit	Unit Description	Deviations Reported [1]		Monitoring Method per Permit?[2]		Was Compliance Continuous or Intermittent?[3]	
		Previous	Current	YES	NO	Continuous	Intermittent
CT001	GE Sprint LM6000 Natural Gas Fired Combustion Turbines, Serial Numbers: 191-225						

Operating Permit Unit	Unit Description	Deviations Reported [1]		Monitoring Method per Permit? [2]		Was Compliance Continuous or Intermittent? [3]	
		Previous	Current	YES	NO	Continuous	Intermittent
CT002	GE Sprint LM6000 Natural Gas Fired Combustion Turbines, Serial Numbers: 191-230						
CT003	GE Sprint LM6000 Natural Gas Fired Combustion Turbines, Serial Numbers: 191-229						
CT004	GE Sprint LM6000 Natural Gas Fired Combustion Turbines, Serial Numbers: 191-232						
CT005	GE Sprint LM6000 Natural Gas Fired Combustion Turbines, Serial Numbers: 191-213						
CT006	GE Sprint LM6000 Natural Gas Fired Combustion Turbines, Serial Numbers: 191-192						
AP001	Ajax Natural Gas Fired Heater, Serial Number						
AP002	Ajax Natural Gas Fired Heater, Serial Number						
GC001, GC002, GC003	Three (3) Waukesha Natural Gas Fired Reciprocating Engines, Serial Numbers 171809, C119281, and C119273						
	General Conditions						
	Insignificant Activities [4]						

[1] If deviations were noted in a previous deviation report , put an "X" under "previous". If deviations were noted in the current deviation report (i.e. for the last six months of the annual reporting period), put an "X" under "current". Mark both columns if both apply.

[2] Note whether the method(s) used to determine the compliance status with each term and condition was the method(s) specified in the permit. If it was not, mark "no" and attach additional information/explanation.

[3]Note whether the compliance status with of each term and condition provided was continuous or intermittent. "Intermittent Compliance" can mean either that noncompliance has occurred or that the owner or operator has data sufficient to certify compliance only on an intermittent basis. Certification of intermittent compliance therefore does not necessarily mean that any noncompliance has occurred

NOTE:

The Periodic Monitoring requirements of the Operating Permit program rule are intended to provide assurance that even in the absence of a continuous system of monitoring the Title V source can demonstrate whether it has operated in continuous compliance for the duration of the reporting period. Therefore, if a source 1) conducts all of the monitoring and recordkeeping required in its permit, even if such activities are done periodically and not continuously, and if 2) such monitoring and recordkeeping does not indicate non-compliance, and if 3) the Responsible Official is not aware of any credible evidence that indicates non-compliance, then the Responsible Official can certify that the emission point(s) in question were in continuous compliance during the applicable time period.

[4] Compliance status for these sources shall be based on a reasonable inquiry using readily available information.

II. Status for Accidental Release Prevention Program:

A. This facility ______ is subject ______ is not subject to the provisions of the Accidental Release Prevention Program (Section 112(r) of the Federal Clean Air Act)

B. If subject: The facility ________ is _______ is not in compliance with all the requirements of section 112(r).

1. A Risk Management Plan _______ will be ______ has been submitted to the appropriate authority and/or the designated central location by the required date.

III. Certification

I have reviewed this certification in its entirety and, based on information and belief formed after reasonable inquiry, I certify that the statements and information contained in this certification are true, accurate and complete.

Please note that the Colorado Statutes state that any person who knowingly, as defined in § 18-1-501(6), C.R.S., makes any false material statement, representation, or certification in this document is guilty of a misdemeanor and may be punished in accordance with the provisions of § 25-7 122.1, C.R.S.

____

Printed or Typed Name | Title

____

Signature | Date Signed

NOTE: All compliance certifications shall be submitted to the Air Pollution Control Division and to the Environmental Protection Agency at the addresses listed in Appendix D of this Permit.

APPENDIX D

Notification Addresses

1. **Air Pollution Control Division**

Colorado Department of Public Health and Environment
Air Pollution Control Division
Operating Permits Unit
APCD-SS-B1
4300 Cherry Creek Drive S.
Denver, CO 80246-1530

ATTN: Jim King

2. **United States Environmental Protection Agency**

Compliance Notifications:

Office of Enforcement, Compliance and Environmental Justice
Mail Code 8ENF-T
U.S. Environmental Protection Agency, Region VIII
1595 Wynkoop Street
Denver, CO 80202-1129

Permit Modifications, Off Permit Changes:

Office of Partnerships and Regulatory Assistance
Air and Radiation Programs, 8P-AR
U.S. Environmental Protection Agency, Region VIII
1595 Wynkoop Street
Denver, CO 80202-1129

Acid Rain Quarterly and Annual Reports (Electronic) and Compliance Certifications:

Note: Quarterly Reports are sent to EPA electronically. Quarterly Compliance Certifications and/or any cover letter accompanying a quarterly report may be sent either electronically or as a hard copy. Annual compliance certifications are submitted as a hard copy. Listed below are the addresses for hard copy submissions.

Regular or Certified Mail:

U.S. EPA
Clean Air Markets Division
Acid Rain Program (6204N)
Attention: Annual Reconciliation or Quarterly Report, as appropriate
1200 Pennsylvania Avenue, NW
Washington, D. C. 20460

Overnight Mail:

Clean Air Markets Division
Acid Rain Program (6204N)
Attention: Annual Reconciliation or Quarterly Report, as appropriate
633 3rd Street, NW
Washington, D. C. 20001

APPENDIX E

Permit Acronyms

Listed Alphabetically:

AIRS -	Aerometric Information Retrieval System
AP-42-	EPA Document Compiling Air Pollutant Emission Factors
APEN -	Air Pollution Emission Notice (State of Colorado)
APCD -	Air Pollution Control Division (State of Colorado)
ASTM -	American Society for Testing and Materials
BACT -	Best Available Control Technology
BTU -	British Thermal Unit
CAA -	Clean Air Act (CAAA = Clean Air Act Amendments)
CCR -	Colorado Code of Regulations
CEM -	Continuous Emissions Monitor
CF -	Cubic Feet (SCF = Standard Cubic Feet)
CFR -	Code of Federal Regulations
CO -	Carbon Monoxide
COM -	Continuous Opacity Monitor
CRS -	Colorado Revised Statute
EF -	Emission Factor
EPA -	Environmental Protection Agency
FI -	Fuel Input Rate in Lbs/mmBtu
FR -	Federal Register
G -	Grams
Gal -	Gallon
GPM -	Gallons per Minute
HAPs -	Hazardous Air Pollutants
HP -	Horsepower
HP-HR -	Horsepower Hour (G/HP-HR = Grams per Horsepower Hour)
LAER -	Lowest Achievable Emission Rate
LBS -	Pounds
M -	Thousand
MM -	Million
MMscf -	Million Standard Cubic Feet
MMscfd -	Million Standard Cubic Feet per Day
N -	Normal Operation, as referenced in permit limitation table in Section II.1
N/A or NA -	Not Applicable
NO_X -	Nitrogen Oxides
NESHAP -	National Emission Standards for Hazardous Air Pollutants
NSPS -	New Source Performance Standards
P -	Process Weight Rate in Tons/Hr
PE -	Particulate Emissions
PM -	Particulate Matter

PM_{10} -	Particulate Matter Under 10 Microns
PPM -	Parts Per Million
PPMV -	Parts Per Million, by Volume
PPMVD -	Parts per Million, by Volume, Dry
PSD -	Prevention of Significant Deterioration
PTE -	Potential To Emit
RACT -	Reasonably Available Control Technology
SCC -	Source Classification Code
SCF -	Standard Cubic Feet
SD -	Shutdown, as referenced in permit limitation table in Section II.1
SIC -	Standard Industrial Classification
SO_2 -	Sulfur Dioxide
SU -	Start-Up, as referenced in permit limitation table in Section II.1
TPY -	Tons Per Year
TSP -	Total Suspended Particulate
VOC -	Volatile Organic Compounds

APPENDIX F

Permit Modifications

DATE OF REVISION	MODIFICATION TYPE	SECTION NUMBER, CONDITION NUMBER	DESCRIPTION OF REVISION
January 20, 2004	Administrative	Section II, Condition 4.1	Revised to require stack tests once the engines operate under normal conditions for 100 hours. Requires use of worst case emission factors for compliance purposes until testing is completed.
April 13, 2005	Administrative	Information Page	Change Responsible Official
	Administrative	Section II, Condition 1	Remove stack test requirement from table – remnant of previous draft – stack tests have been completed
	Minor Modification	Section II, Conditions 2.2 and 2.3	Revise to reflect new NSPS Subpart GG language/requirements
	Administrative	Section II, Condition 1.1	Revise PM/PM_{10} and VOC emission factors to reflect stack test results
September 24, 2008	Administrative Modification	Page following Cover Page	Changed Responsible Official and Permit Contact fields
		Section I, Condition 1.4	Added Section V, condition 3.d as a state-only condition in Condition 1.4
		Section II, Condition 1.2.1	Deleted the term "saturated" from Condition 1.2.2
		Section III	Updated the designated representative for the acid rain program (in accordance with information reported to EPA Clan Air Markets Division)
		Section V	The upset revisions in the Common Provisions Regulation (general condition 3.d) were revised December 15, 2006 (effective March 7, 2007) and the revisions were included in the permit. Note that these provisions are state-only enforceable until approved by EPA into Colorado's state implementation plan (SIP). Replaced the reference to "upset" in Condition 5 (emergency provisions), and updated the language in Condition 21 (prompt deviation reporting) with the latest version. Added language in condition 3.f related to credible evidence for compliance certification.
		Appendices	Replaced Appendices B and C with the latest version. Updated the addresses in Appendix D.

Attachment S-3e

Requested Changes to CSP No. 0070-01-C

Attachment S-3e

Requested Changes to CSP No. 0070-01-C

Proposed change to Attachment II, Special Condition A.1.:

This permit encompasses the following equipment and associated appurtenances:

Unit No.	Description
CT-2	One (1) 18 MW (nominal) (18.3 MW peak load) Simple Cycle Combustion Turbine Generator, model Jupiter GT-35 (manufactured by Asea Brown Boveri (ABB) and supplied by Solar Turbines) with a maximum design heat input rate of 198 MMBtu/hr.

Justification – The requested change updates the equipment description to include the maximum peak load rating for the combustion turbine generator.

Proposed change to Attachment II, Special Condition C.1.:

The ~~"start-up"~~ startup sequence ~~time~~ for Unit CT-2 shall ~~not exceed~~ be a twenty (20) minute~~s~~ period starting at the time fuel use at Unit CT-2 begins. ~~A "start-up" sequence shall be from the time fuel use at Unit CT-2 commences, until the time Unit CT-2 is initially brought up to~~ At the end of the startup sequence, Unit CT-2 shall be at 25~~%~~ percent of peak load (4.6 MW) or more, the water-to-fuel ratio shall be maintained, and the permittee shall not exceed the maximum emission limitations as specified in Attachment II, Special Conditions C.3, C.4 and C.6, respectively. ~~at which time the operation of the air pollution control equipment shall commence.~~

Justification –The requested changes are needed: 1) to clarify peak load and the description of a startup sequence; and 2) to allow for stabilization of the water injection system following initiation of the system and address the misalignment of the CEMS NO_X, CO and CO_2 measurement readings with the instantaneous readings of operational parameters such as load (MW), fuel flow, and water injection rate due to lag from the CEMS analyzer response time.

Proposed change to Attachment II, Special Condition C.2.:

The ~~"shut-down" time~~ shutdown sequence for Unit CT-2 shall not exceed twenty (20) minutes. A ~~"shut-down"~~ shutdown sequence shall be ~~considered~~ from the time ~~when~~ Unit CT-2 is below 25~~%~~ percent of peak load (4.6 MW) until fuel use at Unit CT-2 ceases, except as provided in Attachment II, Special Condition C.3.

Justification – The requested changes include the load rating for CT-2 at 25 percent of peak load and clarify the description of a shutdown sequence.

Proposed change to Attachment II, Special Condition C.3.:

~~Except during Unit CT-2's "start-up" and "shut-down," maintenance, or testing~~., ~~Unit CT-2's load shall not be less than 25% of the rated capacity~~. The combined time of operation of combustion turbine generators, CT-2, CT-4 and CT-5, below 25 percent of peak load with water injection shall not exceed 268 hours in any rolling twelve (12) month period, excluding startup and shutdown sequences, maintenance, testing, and as approved pursuant to Attachment II, Special Condition C.8.a.

Justification – The requested change is needed to include the load rating for CT-2 at 25 percent of peak load and allow operation of the CT-2 below 25 percent of peak load with water injection to address high system frequency issues. The emissions calculations for CT-2, CT-4 and CT-5 for this proposed change are in Tables 1a and 1b below.

Table 1a - Less Than 25% Load Operation Project Emissions (CT-4, CT-5)

Parameter	Pollutant CO	Pollutant VOC
Actual Emissions (lb/hr) Before Change[1]	0.0	0.0
Maximum 10% Load (2.5 MW) Emissions (lb/hr)[2]	475.6	297.6
Expected Increase (lb/hr)	475.6	297.6
Maximum Unit-Hours Below 25% Load[3]	268	268
Projected Emissions Increase (tpy)[4]	63.7	39.9
PSD Significance Level (tpy)	100	40
Significant Emissions Increase (Yes/No)	No	No

Table 1b - Less Than 25% Load Operation Project Emissions (CT-2)

Parameter	Pollutant CO	Pollutant VOC
Actual Emissions (lb/hr) Before Change[1]	0.0	0.0
Maximum 10% Load (1.8 MW) Emissions (lb/hr)[5]	22.4	22.4
Expected Increase (lb/hr)	22.4	22.4
Maximum Unit-Hours Below 25% Load	3560	3560
Projected Emissions Increase (tpy)[4]	39.9	39.9
PSD Significance Level (tpy)	100	40
Significant Emissions Increase (Yes/No)	No	No

1 Past actuals set to zero (operation below 25% of peak load not allowed, except for startup, shutdown, maintenance and testing.
2 CT-4 and CT-5 permit limits for 25% of peak load in simple cycle mode.
3 Calculated limit to remain below PSD significance levels.
4 (Expected Increase) x (Unit-Hours/Year) / (2000 lb/ton)
5 CT-2 permit limits.

Proposed change to Attachment II, Special Condition C.4.:

Air Pollution Control Equipment

a. The permittee shall continuously operate and maintain a combustor water injection system to meet the emission limits as specified for nitrogen oxides (NO_X) in Attachment II, Special Condition C.6.a. ~~of this Covered Source Permit.~~ Water injection shall be initiated during the startup sequence and may be terminated at the beginning of or during the shutdown sequence of Unit CT-2.

b. ~~The operation of the combustor water injection system shall commence operation within twenty (20) minutes of start-up of Unit CT-2, and shall continue to operate within twenty~~

~~(20) minutes of shutdown of Unit CT-2. The combustor water injection system shall be used whenever Unit CT-2 is operating at 25% peakload and above, and shall be maintained at a minimum water-to-fuel mass ratio as follows:~~ <u>After completion of the startup sequence, the following water-to-fuel mass ratio, on a one (1) hour average basis, shall be maintained:</u>

WATER INJECTION SYSTEM
MINIMUM WATER INJECTION RATES BASED ON LOAD

Percent Peak load	Load (MW)	Ratio (lb-water/lb-fuel)
100	18.3	1.00
75 - < 100	13.7 - < 18.3	0.75
50 - < 75	9.15 - < 13.7	0.55
~~25 -~~ < 50	~~4.6 -~~ < 9.15	0.3

<u>For operating periods during which the unit operates at multiple water-to-fuel mass ratios apply, the applicable water-to-fuel mass ratio shall be determined based on the load that corresponded to the lowest minimum water-to-fuel mass ratio.</u>

<u>c.</u> [No changes proposed]

<u>d.</u> [No changes proposed]

Justification – The requested changes are to: 1) clarify the method of determining the applicable minimum water-to-fuel mass ratio for operating hours during which multiple minimum water-to-fuel mass ratios apply; 2) revise the water injection system table to address operation of the combustion turbine generator below 25 percent of peak load with water injection; and 3) provide consistency with proposed changes to CSP No. 0007-01-C.

Proposed change to Attachment II, Special Condition C.5.:

a. Unit CT-2 shall be fired only on fuel oil no. 2 with a maximum sulfur content not to exceed 0.4 percent by weight <u>or an alternate fuel allowed under Attachment II, Special Condition C.8.a.ii</u>. The use of fuel additives to control algae, inhibit corrosion or improve fuel combustion may be used in combination with the fuel oil no.2.

b. The maximum amount of fuel oil no. 2 fired in Unit CT-2 shall not exceed ~~24,407 barrels per month or 292,887 barrels~~ <u>12,301,254 gallons</u> per any rolling twelve (12) month period.

Justification – The requested changes clarify the approved fuel and convert the maximum amount of fuel oil units from barrels to gallons.

Proposed change to Attachment II, Special Condition C.5.c.: Delete condition.

~~The fuel-bound nitrogen content of the fuel fired in Unit CT-2 shall not exceed 0.015 percent by weight on a rolling twelve (12) month average.~~

Justification – Removal of fuel bound nitrogen monitoring requirement is requested because it is not required by NSPS Subpart GG if an emission allowance for fuel bound nitrogen is not claimed and HELCO has not claimed an emission allowance under NSPS Subpart GG.

Proposed change to Attachment II, Special Condition C.6.:

Maximum Emission Limits

a. Except for Unit CT-2's ~~"start-up"~~ startup and ~~"shut-down"~~ shutdown sequences, the permittee shall not discharge or cause the discharge into the atmosphere from Unit CT-2, nitrogen oxides, sulfur dioxide, particulate matter/PM_{10}, carbon monoxide, and volatile organic compounds in excess of the following specified limits ~~as noted below~~:

   [No changes proposed for emission limits table]

   ~~For the purposes of the annual performance tests and the continuous monitoring system, emissions limits shall be measured on a rolling three (3) hour average.~~ The three-hour averaging period shall begin immediately after to the combustion turbine generator's startup sequence and end immediately prior to the combustion turbine generator's shutdown sequence.

b. The Department of Health, with U.S. EPA's concurrence, may lower the allowable emission limitation for nitrogen oxides, sulfur dioxide, particulate matter/PM_{10}, carbon monoxide, volatile organic compounds after reviewing the performance test results required in Attachment II, Section F, Testing Requirements.

c. If the nitrogen oxides, sulfur dioxide, particulate matter/PM_{10}, carbon monoxide or volatile organic compounds emission limit is revised, the difference between the applicable emission limit set forth above and the revised lower emission limit shall not be allowed as an emission offset for future construction or modification.

Justification – The requested change is needed for clarification regarding the three-hour averaging period.

Proposed change to Attachment II, Special Condition C.8.a.: Add permit condition.

vi. Low Load Operation without Water Injection. Upon receiving written approval from the Department of Health, the permittee may be allowed to operate the combustion turbine generator below 25 percent of peak load (4.6 MW) without water injection for maintenance and testing. In requesting for approval, the permittee shall at a minimum provide the Department of Health the date and time period for testing, reason why it is necessary to test at loads less than 25 percent of peak load (4.6 MW) without water injection, procedures to be taken to minimize testing or maintenance at low load without water injection, maximum expected emissions, and any other supporting information as requested by the Department of Health. The Department of Health may require an ambient air quality assessment for the combustion turbine generator at low load without water injection, and/or provide a conditional approval to limit the maintenance and testing period, and impose additional monitoring, recordkeeping, and reporting requirements to ensure that operation at lower loads without water injection are in compliance with emission limits established in Special Condition C.6. of this Attachment.

Justification – The requested change is needed to allow operation of CT-2 below 25 percent of peak load without water injection for maintenance or testing.

Proposed change to Attachment II, Special Condition D.1.:

The permittee shall at its own expense continue to operate, calibrate, and maintain a continuous monitoring system and ~~total volumetric~~ flow metering system for Unit CT-2 to measure and record the following parameters or data. The associated date and time of the monitored data shall also be recorded.

a. [No changes proposed]

b. [No changes proposed]

c. Fuel consumption ~~in gallons/hr~~ using a ~~volumetric~~ flow metering system; and

d. NO_X, CO, and CO_2 or O_2 concentrations in the stack gases using a Continuous Emissions Monitoring System (CEMS). The system shall meet U.S. EPA performance specifications (40 CFR Part 60, Section 60.13 and 40 CFR Part 60, Appendix B and Appendix F). If CO_2 is measured with the CEMS to adjust the pollutant concentration, the CO_2 correction factor equations listed in 40 CFR §60.4213(d)(3) shall be used to determine compliance with the applicable emission limit <u>and a diluent cap value for CO_2 may be used in accordance with 40 CFR §60.4350(b)</u>. The CEMS shall be on-line and fully operational, upon completion and thereafter of the performance specification test. The emissions for NO_X and CO shall be recorded in parts per million by volume (ppmvd) at 15 percent O_2 and pounds per hour (lbs/hr).

Justification – The requested changes are needed: 1) because there is no regulatory requirement or permit limit that requires recording fuel consumption in gallons/hour; 2) to allow for volumetric or mass flow meters; and 3) to allow the use of a diluent cap to address any hour in which the hourly average CO_2 concentration is less than 1.0 percent. 40 CFR Part 60, Subpart KKKK and Part 75 include a diluent cap for both O_2 and CO_2 for stationary turbines. However, 40 CFR Part 60, Subpart GG includes a diluent cap only for O_2.

Proposed change to Attachment II, Special Condition D.4.:

a. Sulfur content in the fuel. The sulfur content in the fuel to be fired in Unit CT-2 shall be ~~tested in accordance with the most current American Society of Testing and Materials (ASTM) methods. ASTM method D4294-98 is a suitable alternative to Method D129-00 for determining the sulfur content. The fuel sulfur content shall be verified by both of the following methods:~~ <u>determined by sampling each delivery prior to combining with the existing fuel supply in accordance with 40 CFR, Appendix D to part 75, Section 2.2.4.3. The analysis may be performed by the permittee, the supplier, or other qualified third party lab. The analysis shall be performed using one of the following ASTM International (ASTM) methods: D129-00, D2622-98, D4294-02, D1266-98, D5453-00, or D1552-01 or a more current version of these ASTM methods.</u>

   ~~i. A representative sample of each batch of fuel received shall be analyzed for its sulfur content; and~~

   ~~ii. A certificate of analysis on the sulfur content of the fuel shall be for each batch of the fuel delivered by the supplier.~~.

b. [No changes proposed]

c. [No changes proposed]

d. ~~Nitrogen content in the fuel. The fuel bound nitrogen content of the fuel to be fired in Unit CT-2 shall be verified by taking and analyzing a representative sample of each batch of fuel received to determine the nitrogen content by weight.~~

e. ~~Records of the nitrogen content of the fuel shall be maintained on a monthly and rolling twelve (12) month basis.~~

Justification – The requested changes are needed to: 1) provide consistency with NSPS Subpart GG with the addition of the NSPS Subpart GG fuel oil no. 2 sulfur test methods and authorization of the fuel testing to be conducted by the permittee, supplier, or other qualified third party lab; and 2) remove the fuel bound nitrogen monitoring conditions because it is not required by NSPS Subpart GG if an emission allowance for fuel bound nitrogen is not claimed; HELCO has not claimed an emission allowance under NSPS Subpart GG.

Proposed change to Attachment II, Special Condition D.8.: Add monitoring and recordkeeping requirement.

Operation Below 25 Percent of Peak Load with Water Injection. The permittee shall maintain records of the time the combustion turbine generator operates below 25 percent of peak load with water injection. Records of the total time CT-2, CT-4, and CT-5 operated below 25 percent of peak load with water injection, excluding startup and shutdown sequences, maintenance, testing, and as approved pursuant to Special Condition C.8 of this Attachment, shall be maintained on a monthly and rolling 12-month basis using data recorded by the CEMS.

Justification – The requested change is needed to monitor and record operation of CT-2 below 25 percent of peak load with water injection.

Proposed change to Attachment II, Special Condition E.4.e.: Delete condition.

~~For periods of excess emissions as defined in Special Condition No. E.4.g.ii. of this Attachment, the report shall also include the average water-to-fuel ratio, average fuel consumption, ambient temperature, gas turbine load, and nitrogen content of the fuel during the period of excess emissions.~~

Justification – The requested change is needed for consistency with reporting requirements under 40 CFR § 60.7(c) and CSP No. 0007-01-C.

Proposed change to Attachment II, Special Condition E.4.g.:

For purposes of this Covered Source Permit, excess emissions shall be defined as follows:

i. [No changes proposed]

ii. Any one (1) hour period during which the average water-to-fuel ratio, as measured by the continuous monitoring system, falls below the water-to-fuel mass ratio, as measured by the continuous monitoring system, falls below the water-to-fuel mass ratio at the corresponding operating load specified in Attachment II, Special Condition No. C.4.b. ~~When the load is not constant, provided that the above water injection rates at the four different peak load conditions are maintained, and NO_X emissions do not exceed the limits given in Attachment II, Special Condition C.6., a mathematical deviation on the one-hour average will not be considered out of compliance.~~ For operating periods during which the unit operates at multiple water-to-fuel mass ratios apply, the applicable water-to-fuel mass ratio shall be determined based on the load that corresponded to the lowest minimum water-to-fuel mass ratio.

Justification – The requested change clarifies the method of determining the applicable minimum water-to-fuel mass ratio for operating hours during which multiple minimum water-to-fuel mass ratios apply and provides consistency with proposed changes to Attachment II, Special Condition C.4.b. and CSP No. 0007-01-C.

Proposed change to Attachment II, Special Condition E.5.:

The permittee shall submit semi-annually the following written reports to the Department of Health. The report shall be submitted within sixty (60) days after the end of each semi-annual calendar period (January 1 to June 30 and July 1 to December 31), and shall include the following:

a. Monthly summary showing the daily ~~"start-up"~~ startup and ~~"shut-down"~~ shutdown times and duration ~~sequence~~ for Unit CT-2. Include the associated load (MW) of Unit CT-2 at the ~~start-up~~ startup and termination of the air pollution control device. Include total operating hours per day and the total operating hours by month for Unit CT-2. The enclosed Monitoring Report Form: Daily ~~"Start-up"~~ Startup and ~~"Shut-down"~~ Shutdown or an equivalent form ~~approved by the Department of Health~~ shall be used in reporting Unit CT-2's ~~"start-up"~~ and ~~"shut-down"~~ startup and shutdown sequences.

b. [No changes proposed]

c. ~~Receipt dates of fuel deliveries, type of fuel, date batch sample taken, and the analyzed sulfur and nitrogen content in the fuel. Include copies of the supplier's certificate of analysis showing the sulfur content of the fuel delivered.~~ A report identifying the type of fuel fired in the combustion turbine during the semi-annual reporting period. The report shall include the maximum sulfur content (percent by weight) of the fuel for the reporting period. The enclosed Monitoring Report Form : *Fuel Certification*, or similar form, shall be used.

d. Minimum combustion turbine generator load. Except for ~~Unit CT-2's~~ ~~"start-up"~~ startup and ~~"shut-down"~~ shutdown sequences, report all periods ~~of time~~ (date, time and duration using data recorded by the CEMS) when the ~~minimum~~ operating load for ~~Unit CT-2~~ the combustion turbine generator was ~~is~~ less than 25~~%~~ percent of ~~the rated capacity~~ peak load (4.6 MW).

e. [No changes proposed]

f. [No changes proposed]

g. A monthly summary and rolling 12-month total of the hours of operation of the combustion turbine generators, CT-2, CT-4, and CT-5, below 25 percent of peak load with water injection, excluding startup and shutdown sequences, maintenance, testing, and as approved pursuant to Special Condition C.8 of this Attachment. The report shall be based on data recorded by the CEMS.

~~g~~h. Deviations from permit requirements shall be clearly identified and addressed in these reports.

Justification – The requested changes are needed: 1) for operation of CT-2 below 25 percent of peak load with water injection; and 2) for consistency with CSP No. 0007-01-C and proposed change to Special Condition D.4.d and e to remove the fuel bound nitrogen monitoring conditions because it is not required by NSPS Subpart GG if an emission allowance for fuel bound nitrogen is not claimed; HELCO has not claimed an emission allowance under NSPS Subpart GG.

Proposed change to Attachment II, Special Condition E.7.:

As required by Attachment IV and in conjunction with the requirements of Attachment III, the permittee shall submit annually the total tons/year emitted of each regulated air pollutant, including hazardous air pollutants. The reporting of annual emissions is due within sixty (60) days following the end of each calendar year. The enclosed Annual Emission Reporting Form: ~~Gas~~ Combustion Turbines and Diesel Engines or an equivalent form approved by the Department of Health, shall be used in reporting.

Justification – The requested change is needed for consistency with CSP No. 0007-01-C.

Proposed change to Attachment II, Special Condition F.2.:

Performance tests for the emissions of NO_X, SO_2, CO, VOC and PM/PM_{10} shall be conducted and results reported in accordance with the test methods set forth in 40 CFR Part 60, Appendix A and 40 CFR Part 60, Section 60.8. The following test methods or U.S. EPA-approved equivalent methods, or alternate methods with prior written approval from the Department of Health shall be used:

a. Performance tests for the emissions of SO_2 shall be conducted using 40 CFR Part 60 Methods 1-4 and 6C or Methods 6C and 20.

b. Performance tests for the emissions of NO_X shall be conducted using 40 CFR Part 60 Methods 1-4 and 7E or Methods 7E and 20.

c. Performance tests for the emissions of CO shall be conducted using 40 CFR Part 60 Methods 1-4 and 10 or Methods 10 and 19.

d. Performance tests for the emissions of VOC shall be conducted using 40 CFR Part 60 Methods 1-4 and 25A (Method 19 may be used to account for the actual methane fraction of the measured VOC emissions).

e. Performance tests for the emissions of particulate matter shall be conducted using 40 CFR Part 60 Methods 1-5.

Justification – The requested changes expand the listed test methods to include the methods commonly used and incorporate DOH's standard permit language to authorize use of EPA-approved equivalent methods.

Proposed change to Attachment IV: Annual Emissions Reporting Requirements:

Revise Section 1 as follows:

1. Complete the attached Annual Emissions Report Form for ~~Gas~~ Combustion Turbines and Diesel Engines.

Justification – The requested change is to eliminate redundant forms.

Proposed change to Annual Emissions Report Form – Gas Turbines: Delete form.

Delete form and require use of Annual Emissions Report Form – Combustion Turbines and Diesel Engines as proposed in Attachment S-3c.

Justification – The requested change is to eliminate redundant forms.

Proposed change to Monitoring Report Form - Fuel Consumption:

Delete form and require use of Monitoring Report Form – Fuel Consumption form in CSP No. 0007-01-C.

Justification – The requested change is to eliminate redundant forms.

File No.: __________

C-1: Compliance Plan

The Responsible Official shall submit a Compliance Plan as indicated in the Instructions for Applying for an Air Pollution Control Permit and at such other times as requested by the Director of Health (hereafter, Director).

Use separate sheets if necessary.

---

1. Compliance status with respect to all Applicable Requirements:

   Will your facility be in compliance, or is your facility in compliance, with all applicable requirements in effect at the time of your permit application submittal?

   ■ YES { If YES, Complete items a and c below}

   ☐ NO { If NO, complete items a-c below}

   a. Identify all applicable requirement(s) for which compliance is achieved:
   Refer to CSP No. 0007-01-C issued on August 7, 2008, CSP No. 0070-01 issued on January 12, 2006, and the June 23, 2009 Administrative Amendment for CSP No. 0070-01-C for all applicable requirements.

   Provide a statement that the source is in compliance and will continue to comply with all such requirements.
   The facility is in compliance and will continue to comply with the applicable requirements identified in CSP No. 0007-01-C issued on August 7, 2008, CSP No. 0070-01-C issued on January 12, 2006, and the June 23, 2009 Administrative Amendment for CSP No. 0070-01-C.

   b. Identify all applicable requirement(s) for which compliance is NOT achieved:

   Provide a detailed Schedule of Compliance and a description of how the source will achieve compliance with all such applicable requirements. Use separate sheets of paper, if necessary.

Description of Remedial Action	Expected Date of Completion

c. Identify any other applicable requirement(s) with a future date that your source is subject to. These applicable requirements may be in effect AFTER permit issuance:

Applicable Requirement	Effective Date	Currently in Compliance?

If the source is not currently in compliance, submit a Schedule of Compliance and a description of how the source will achieve compliance with all such requirements:

Description of Proposed Action/Steps to Achieve Compliance	Expected Date of Achieving Compliance

Provide a statement that the source on a timely basis will meet all these applicable requirements.

____

____

____

____

____

If the expected date of achieving compliance will NOT meet the applicable requirement's effective date, provide a more detailed description of all remedial actions and the expected dates of completion.

Description of Remedial Action and Explanation	Expected Date of Completion

2. Compliance Progress Reports:

   a. If a compliance plan is being submitted to remedy a violation, complete the following information:

   Frequency of Submittal: ____________________ Beginning Date: ____________________
   (less than or equal to 6 months)

b. Date(s) that the Action described in (1)(b) was achieved:

Remedial Action | Date Achieved

c. Narrative description of why any date(s) in (1) (b) was not met, and any preventive or corrective measures taken in the interim:

RESPONSIBLE OFFICIAL (as defined in HAR §11-60.1-1)

Name (Last): Verbanic (First): Norman (MI):

Title: Manager Production Department Phone: (808) 969-0421

Mailing Address: P.O. Box 1027

City: Hilo State: HI Zip Code: 96721-1027

Certification by Responsible Official (pursuant to HAR §11-60.1-4)

I certify that I have knowledge of the facts herein set forth, that the same are true, accurate and complete to the best of my knowledge and belief, and that all information not identified by me as confidential in nature shall be treated by the Department of Health as public record. I further state that I will assume responsibility for the construction, modification, or operation of the source in accordance with the Hawaii Administrative Rules, Title 11, Chapter 60.1, Air Pollution Control, and any permit issued thereof.

Name (Print/Type): Norman Verbanic

(Signature): Norman Verbanic Date: 05 JAN 10

Facility Name: Keahole Generating Station

Location: 73-4249 Pukiawe Street, Kailua Kona, HI 96740

Permit Number: CSP Nos. 0007-01-C and 0070-01-C

FOR AGENCY USE ONLY

File/Application No.:

Island:

Date Received:

File No.: __________

C-2: Compliance Certification

The Responsible Official shall submit a Compliance Certification as indicated in the Instructions for Applying for an Air Pollution Control Permit and at such other times as requested by the Director of Health (hereafter, Director).

Complete as many copies of this form as necessary. Use separate sheets of paper if necessary.

RESPONSIBLE OFFICIAL (as defined in HAR §11-60.1-1)

Name (Last): Verbanic (First): Norman (MI): ______

Title: Manager Production Department Phone: (808) 969-0421

Mailing Address: P.O. Box 1027

City: Hilo State: HI Zip Code: 96740

Certification by Responsible Official (pursuant to HAR §11-60.1-4)

I certify that I have knowledge of the facts herein set forth, that the same are true, accurate and complete to the best of my knowledge and belief, and that all information not identified by me as confidential in nature shall be treated by the Department of Health as public record. I further state that I will assume responsibility for the construction, modification, or operation of the source in accordance with the Hawaii Administrative Rules, Title 11, Chapter 60.1, Air Pollution Control, and any permit issued thereof.

Name (Print/Type): Norman Verbanic

(Signature): Norman Verbanic Date: 05 JAN 10

Facility Name: Keahole Generating Station

Location: 73-4249 Pukiawe Street, Kailua Kona, HI 96740

Permit Number: CSP Nos. 0007-01-C and 0070-01-C

FOR AGENCY USE ONLY

File/Application No.: __________

Island: __________

Date Received: __________

Complete the following information for ***each*** applicable requirement that applies to ***each*** emissions unit at the source. Also include any additional information as required by the Director. The compliance certification may reference information contained in a previous compliance certification submittal to the director, provided such referenced information is certified as being current and still applicable.

1. Schedule for submission of Compliance Certifications during the term of the permit:

   Frequency of Submittal: In accordance with §11-60.1-86.

   Beginning Date: In accordance with §11-60.1-86.

2. Emissions Unit No./Description:

Unit ID	Manufacturer	Model No.	Capacity (Nominal)
D-21	General Motors	20-645F4B	2.5 MW
D-22	General Motors	20-645F4B	2.5 MW
D-23	General Motors	20-645E4	2.5 MW
CT-2	Jupiter	GT-35	18 MW
CT-4	General Electric	LM2500	20 MW
CT-5	General Electric	LM2500	20 MW
BS-1	Caterpillar	3412	500 kW

3. Identify the applicable requirement(s) that is/are the basis of this certification:

   See Attachments C-2a (CSP No. 0007-01-C issued August 7, 2008) and C-2b (CSP No. 0070-01-C issued January 12, 2006).

4. Compliance status:

   a. Will the emissions unit be in compliance with the identified applicable requirement(s)?

      ■ YES ☐ NO

   b. If YES, will compliance be continuous or intermittent?

      ■ Continuous ☐ Intermittent

   c. If NO, explain.

5. Describe the methods to be used in determining compliance of the emissions unit with the applicable requirement(s), including any monitoring, recordkeeping, reporting requirements, and/or test methods:

   See Attachments C-2a (CSP No. 0007-01-C issued August 7, 2008) and C-2b (CSP No. 0070-01-C issued January 12, 2006).

Provide a detailed description of the methods used to determine compliance: (e. g. monitoring device type and location, test method description, or parameter being recorded, frequency of recordkeeping, etc.)

See Attachments C-2a (CSP No. 0007-01-C issued August 7, 2008) and C-2b (CSP No. 0070-01-C issued January 12, 2006).

6. Statement of Compliance with Enhanced Monitoring and Compliance Certification Requirements.

a. Will the emissions unit identified in this application be in compliance with applicable enhanced monitoring and compliance certification requirements?

■YES ☐NO

b. If YES, identify the requirements and the provisions being taken to achieve compliance:

The final Enhanced Monitoring Rule was published in the Federal Register on October 22, 1997 (62 FR 54900). According to that final rule, the Enhanced Monitoring Rules do not apply. The compliance certification requirement is established by 40 CFR 70 and HAR 11-60.1.

c. If NO, describe below which requirements will not be met:

Attachment C-2a

Compliance Status CSP No. 0007-01-C

Attachment C-2a
Compliance Status
Keahole Generating Station – CSP No. 0007-01-C
Issuance Date: August 7, 2008

A. Attachment I, Standard Conditions

Permit term/condition	Equipment(s)	Method	Compliance
All standard conditions	All Equipment listed in the permit	■ monitoring □ recordkeeping □ reporting □ testing □ none of the above	■ Continuous □ Intermittent

B. Special Conditions - Equipment Description, Applicable Federal Regulations, Monitoring, Recordkeeping, Reporting, Testing, and INSIG

Permit term/condition	Equipment(s)	Method	Compliance
All equipment description conditions	All Equipment listed in the permit	■ monitoring □ recordkeeping □ reporting □ testing □ none of the above	■ Continuous □ Intermittent
All applicable Federal Regulations	All Equipment listed in the permit	■ monitoring ■ recordkeeping □ reporting ■ testing □ none of the above	■ Continuous □ Intermittent
All monitoring and recordkeeping conditions, except Attachment IIA, Special Condition E.1.e.	All Equipment listed in the permit	■ monitoring ■ recordkeeping ■ reporting □ testing □ none of the above	■ Continuous □ Intermittent
Monitoring and recordkeeping condition, Attachment IIA, Special Condition E.1.e.	<u>Units CT-4</u> 20 MW General Electric LM2500 combustion turbine generator	■ monitoring ■ recordkeeping ■ reporting □ testing □ none of the above	□ Continuous ■ Intermittent
All notification and reporting conditions, except Attachment IIA, Special Condition F.3.	All Equipment listed in the permit	□ monitoring ■ recordkeeping ■ reporting □ testing □ none of the above	■ Continuous □ Intermittent
Notification and reporting condition, Attachment IIA, Special Condition F.3.	<u>Units CT-4 & CT-5</u> 20 MW General Electric LM2500 combustion turbine generators	□ monitoring ■ recordkeeping ■ reporting □ testing □ none of the above	□ Continuous ■ Intermittent

Attachment C-2a (Continued)
Compliance Status
Keahole Generating Station – CSP No. 0007-01-C
Issuance Date: August 7, 2008

B. Special Conditions - Equipment Description, Applicable Federal Regulations, Monitoring, Recordkeeping, Reporting, Testing, and INSIG

Permit term/condition	Equipment(s)	Method	Compliance
All testing conditions	All Equipment listed in the permit	■ monitoring ■ recordkeeping □ reporting □ testing □ none of the above	■ Continuous □ Intermittent
All INSIG conditions	All Equipment listed in the permit	□ monitoring ■ recordkeeping □ reporting □ testing □ none of the above	■ Continuous □ Intermittent

C. Special Conditions - Operational and Emissions Limitations

Permit term/condition	Equipment(s)	Method	Compliance
Attachment IIA, Special Condition C.1.a (Startup limit)	Units CT-4 & CT-5 20 MW General Electric LM2500 combustion turbine generators	■ monitoring ■ recordkeeping □ reporting □ testing □ none of the above	■ Continuous □ Intermittent
Attachment IIA, Special Condition C.1.b (Shutdown limit)	Units CT-4 & CT-5 20 MW General Electric LM2500 combustion turbine generators	■ monitoring ■ recordkeeping □ reporting □ testing □ none of the above	■ Continuous □ Intermittent
Attachment IIA, Special Condition C.2 (Minimum operating load)	Units CT-4 & CT-5 20 MW General Electric LM2500 combustion turbine generators	■ monitoring ■ recordkeeping □ reporting □ testing □ none of the above	■ Continuous □ Intermittent
Attachment IIA, Special Condition C.3.a (Combustor water injection system and minimum water-to-fuel ratios)	Units CT-4 & CT-5 20 MW General Electric LM2500 combustion turbine generators	■ monitoring ■ recordkeeping ■ reporting □ testing □ none of the above	■ Continuous □ Intermittent
Attachment IIA, Special Condition C.3.b (Selective Catalytic Reduction)	Units CT-4 & CT-5 20 MW General Electric LM2500 combustion turbine generators	■ monitoring ■ recordkeeping ■ reporting □ testing □ none of the above	□ Continuous ■ Intermittent

Attachment C-2a (Continued)
Compliance Status
Keahole Generating Station – CSP No. 0007-01-C
Issuance Date: August 7, 2008

C. Special Conditions - Operational and Emissions Limitations

Permit term/condition	Equipment(s)	Method	Compliance
Attachment IIA, Special Condition C.4.a (Fuel specifications and fuel sulfur limit)	Units CT-4 & CT-5 20 MW General Electric LM2500 combustion turbine generators	☐ monitoring ■ recordkeeping ■ reporting ■ testing ☐ none of the above	■ Continuous ☐ Intermittent
Attachment IIA, Special Condition C.4.b (Fuel specifications and fuel nitrogen limit)	Units CT-4 & CT-5 20 MW General Electric LM2500 combustion turbine generators	☐ monitoring ■ recordkeeping ■ reporting ■ testing ☐ none of the above	■ Continuous ☐ Intermittent
Attachment IIA, Special Condition C.5.a (Alt. operating scenario - temporary unit replacement)	Units CT-4 & CT-5 20 MW General Electric LM2500 combustion turbine generators	☐ monitoring ☐ recordkeeping ☐ reporting ☐ testing ■ none of the above	■ Continuous ☐ Intermittent
Attachment IIA, Special Condition C.5.b (Alt. operating scenario –low load operation)	Units CT-4 & CT-5 20 MW General Electric LM2500 combustion turbine generators	☐ monitoring ■ recordkeeping ☐ reporting ☐ testing ☐ none of the above	■ Continuous ☐ Intermittent
Attachment IIA, Special Condition C.5.c (Alt. operating scenario – emergency load operations)	Units CT-4 & CT-5 20 MW General Electric LM2500 combustion turbine generators	☐ monitoring ■ recordkeeping ☐ reporting ☐ testing ☐ none of the above	■ Continuous ☐ Intermittent
Attachment IIA, Special Condition C.5.d (Alt. operating scenario – fuel switching)	Units CT-4 & CT-5 20 MW General Electric LM2500 combustion turbine generators	☐ monitoring ☐ recordkeeping ☐ reporting ☐ testing ■ none of the above	■ Continuous ☐ Intermittent
Attachment IIA, Special Condition C.5.e (Alt. operating scenario – fuel additives)	Units CT-4 & CT-5 20 MW General Electric LM2500 combustion turbine generators	☐ monitoring ☐ recordkeeping ☐ reporting ☐ testing ■ none of the above	■ Continuous ☐ Intermittent
Attachment IIA, Special Condition C.5.f (Alt. operating scenario – control systems)	Units CT-4 & CT-5 20 MW General Electric LM2500 combustion turbine generators	☐ monitoring ☐ recordkeeping ☐ reporting ☐ testing ■ none of the above	■ Continuous ☐ Intermittent
Attachment IIA, Special Condition C.5.g (Alt. operating scenario log)	Units CT-4 & CT-5 20 MW General Electric LM2500 combustion turbine generators	☐ monitoring ■ recordkeeping ☐ reporting ☐ testing ☐ none of the above	■ Continuous ☐ Intermittent

Attachment C-2a (Continued)
Compliance Status
Keahole Generating Station – CSP No. 0007-01-C
Issuance Date: August 7, 2008

C. Special Conditions - Operational and Emissions Limitations

Permit term/condition	Equipment(s)	Method	Compliance
Attachment IIA, Special Condition C.5.h (Alt. operating scenario must meet permit requirements)	Units CT-4 & CT-5 20 MW General Electric LM2500 combustion turbine generators Unit ST-7 16 MW steam turbine generator and 2 unfired heat recovery steam generators	☐ monitoring ☐ recordkeeping ☐ reporting ☐ testing ■ none of the above	■ Continuous ☐ Intermittent
Attachment IIA, Special Condition D.1 (NO_x, SO_2, PM, CO, NH_3, and VOC maximum emission limits)	Units CT-4 & CT-5 20 MW General Electric LM2500 combustion turbine generators	■ monitoring ■ recordkeeping ■ reporting ■ testing ☐ none of the above	■ Continuous ☐ Intermittent
Attachment IIA, Special Condition D.2 (Opacity limits)	Units CT-4 & CT-5 20 MW General Electric LM2500 combustion turbine generators	■ monitoring ■ recordkeeping ■ reporting ■ testing ☐ none of the above	☐ Continuous ■ Intermittent
Attachment IIA, Special Condition D.3.a (Inspection and maintenance of fuel oil transfer systems to mitigate fugitive VOC emissions)	Fuel oil transfer system	☐ monitoring ■ recordkeeping ☐ reporting ☐ testing ☐ none of the above	■ Continuous ☐ Intermittent
Attachment IIA, Special Condition D.3.b (Fuel oil transfer systems operational log)	Fuel oil transfer system	☐ monitoring ■ recordkeeping ☐ reporting ☐ testing ☐ none of the above	■ Continuous ☐ Intermittent
Attachment IIA, Special Condition D.3.c (HELCO shall provide DoH access to tanks)	Fuel tanks	☐ monitoring ☐ recordkeeping ☐ reporting ☐ testing ■ none of the above	■ Continuous ☐ Intermittent
Attachment IIB, Special Condition B.1 (BS-1 Operating Hours)	Unit BS-1 – 500 kW Caterpillar Model 3412 Black Start Diesel Engine Generator	☐ monitoring ■ recordkeeping ☐ reporting ☐ testing ☐ none of the above	■ Continuous ☐ Intermittent
Attachment IIB, Special Condition B.2 (D21 Fuel Consumption Limit)	Unit D21 – 2.5 MW General Motors EMD Model 20-645F4B Diesel Engine Generator	☐ monitoring ■ recordkeeping ☐ reporting ☐ testing ☐ none of the above	■ Continuous ☐ Intermittent

Attachment C-2a (Continued)
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Keahole Generating Station – CSP No. 0007-01-C
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C. Special Conditions - Operational and Emissions Limitations

Permit term/condition	Equipment(s)	Method	Compliance
Attachment IIB, Special Condition B.3 (Air pollution control equipment - FITR)	Units D21, and D22 – 2.5 MW General Motors EMD Model 20-645F4B diesel engine generators Units D23 – 2.5 MW General Motors EMD Model 20-645E4 diesel engine generator	□ monitoring □ recordkeeping □ reporting □ testing ■ none of the above	■ Continuous □ Intermittent
Attachment IIB, Special Condition B.4 (Fuel specifications and sulfur limits)	Units D21, and D22 – 2.5 MW General Motors EMD Model 20-645F4B diesel engine generators Units D23 – 2.5 MW General Motors EMD Model 20-645E4 diesel engine generator Unit BS-1 – 500 kW Caterpillar Model 3412 Black Start Diesel Engine Generator	□ monitoring ■ recordkeeping ■ reporting ■ testing □ none of the above	■ Continuous □ Intermittent
Attachment IIB, Special Condition B.5 (NO_x emission limits)	Units D21, and D22 – 2.5 MW General Motors EMD Model 20-645F4B diesel engine generators Units D23 – 2.5 MW General Motors EMD Model 20-645E4 diesel engine generator	□ monitoring □ recordkeeping ■ reporting ■ testing □ none of the above	■ Continuous □ Intermittent
Attachment IIB, Special Condition B.6 (Opacity limits)	Units D21, and D22 – 2.5 MW General Motors EMD Model 20-645F4B diesel engine generators Units D23 – 2.5 MW General Motors EMD Model 20-645E4 diesel engine generator	□ monitoring ■ recordkeeping ■ reporting ■ testing □ none of the above	■ Continuous □ Intermittent
Attachment IIB, Special Condition B.7.a (Alt. operating scenario – temporary unit replacement)	Units D21, and D22 – 2.5 MW General Motors EMD Model 20-645F4B diesel engine generators Units D23 – 2.5 MW General Motors EMD Model 20-645E4 diesel engine generator	□ monitoring □ recordkeeping □ reporting □ testing ■ none of the above	■ Continuous □ Intermittent
Attachment IIB, Special Condition B.7.b (Alt. operating scenario – fuel switching and fuel additives)	Units D21, and D22 – 2.5 MW General Motors EMD Model 20-645F4B diesel engine generators Units D23 – 2.5 MW General Motors EMD Model 20-645E4 diesel engine generator	□ monitoring □ recordkeeping □ reporting □ testing ■ none of the above	■ Continuous □ Intermittent
Attachment IIB, Special Condition B.7.c (Alt. operating scenario log)	Units D21, and D22 – 2.5 MW General Motors EMD Model 20-645F4B diesel engine generators Units D23 – 2.5 MW General Motors EMD Model 20-645E4 diesel engine generator	□ monitoring ■ recordkeeping □ reporting □ testing □ none of the above	■ Continuous □ Intermittent
Attachment IIB, Special Condition B.7.d (Alt. operating scenario must meet permit requirements)	Units D21, and D22 – 2.5 MW General Motors EMD Model 20-645F4B diesel engine generators Units D23 – 2.5 MW General Motors EMD Model 20-645E4 Unit BS-1 – 500 kW Caterpillar Model 3412 Black Start Diesel Engine Generator	□ monitoring □ recordkeeping □ reporting □ testing ■ none of the above	■ Continuous □ Intermittent

Attachment C-2b

Compliance Status CSP No. 0070-01-C

Attachment C-2b
Compliance Status
Keahole Generating Station – CSP No. 0070-01-C
Issuance Date: January 12, 2006

A. Attachment I, Standard Conditions

Permit term/condition	Equipment(s)	Method	Compliance
All standard conditions	All Equipment listed in the permit	■ monitoring □ recordkeeping □ reporting □ testing □ none of the above	■ Continuous □ Intermittent

B. Special Conditions - Equipment Description, Applicable Federal Regulations, Monitoring, Notification, Recordkeeping, Reporting, Testing, and INSIG

Permit term/condition	Equipment(s)	Method	Compliance
All equipment description conditions	All Equipment listed in the permit	■ monitoring □ recordkeeping □ reporting □ testing □ none of the above	■ Continuous □ Intermittent
All applicable Federal Regulations	All Equipment listed in the permit	■ monitoring ■ recordkeeping □ reporting ■ testing □ none of the above	■ Continuous □ Intermittent
All monitoring and recordkeeping conditions	All Equipment listed in the permit	■ monitoring ■ recordkeeping □ reporting □ testing □ none of the above	■ Continuous □ Intermittent
All notification and reporting conditions	All Equipment listed in the permit	□ monitoring ■ recordkeeping ■ reporting □ testing □ none of the above	■ Continuous □ Intermittent
All testing conditions	All Equipment listed in the permit	■ monitoring ■ recordkeeping □ reporting □ testing □ none of the above	■ Continuous □ Intermittent
All INSIG conditions	All Equipment listed in the permit	□ monitoring ■ recordkeeping □ reporting □ testing □ none of the above	■ Continuous □ Intermittent

Attachment C-2b (Continued)
Compliance Status
Keahole Generating Station – CSP No. 0007-01-C
Issuance Date: January 12, 2006

C. Special Conditions - Operational and Emissions Limitations

Permit term/condition	Equipment(s)	Method	Compliance
Attachment II, Special Condition C.1. (Start-up limit)	Unit CT-2 18 MW Jupiter GT-35 Simple Cycle Combustion Turbine (manufactured by Asea Brown Boveri (ABB) and supplied by Solar Turbines)	■ monitoring ■ recordkeeping ☐ reporting ☐ testing ☐ none of the above	■ Continuous ☐ Intermittent
Attachment II, Special Condition C.2 (Shut-down limit)	Unit CT-2 18 MW Jupiter GT-35 Simple Cycle Combustion Turbine (manufactured by Asea Brown Boveri (ABB) and supplied by Solar Turbines)	■ monitoring ■ recordkeeping ☐ reporting ☐ testing ☐ none of the above	■ Continuous ☐ Intermittent
Attachment II, Special Condition C.3 (Minimum operating load)	Unit CT-2 18 MW Jupiter GT-35 Simple Cycle Combustion Turbine (manufactured by Asea Brown Boveri (ABB) and supplied by Solar Turbines)	■ monitoring ■ recordkeeping ☐ reporting ☐ testing ☐ none of the above	☐ Continuous ■ Intermittent
Attachment II, Special Condition C.4.a (HELCO shall operate a combustor water injection system)	Unit CT-2 18 MW Jupiter GT-35 Simple Cycle Combustion Turbine (manufactured by Asea Brown Boveri (ABB) and supplied by Solar Turbines)	☐ monitoring ☐ recordkeeping ☐ reporting ☐ testing ■ none of the above	■ Continuous ☐ Intermittent
Attachment II, Special Condition C.4.b (Minimum water-to-fuel ratios)	Unit CT-2 18 MW Jupiter GT-35 Simple Cycle Combustion Turbine (manufactured by Asea Brown Boveri (ABB) and supplied by Solar Turbines)	■ monitoring ■ recordkeeping ■ reporting ☐ testing ☐ none of the above	■ Continuous ☐ Intermittent
Attachment II, Special Condition C.4.c (DOH may revise water-to-fuel rates)	Unit CT-2 18 MW Jupiter GT-35 Simple Cycle Combustion Turbine (manufactured by Asea Brown Boveri (ABB) and supplied by Solar Turbines)	☐ monitoring ☐ recordkeeping ☐ reporting ☐ testing ■ none of the above	■ Continuous ☐ Intermittent
Attachment II, Special Condition C.4.d (Alternative control systems)	Unit CT-2 18 MW Jupiter GT-35 Simple Cycle Combustion Turbine (manufactured by Asea Brown Boveri (ABB) and supplied by Solar Turbines)	☐ monitoring ☐ recordkeeping ☐ reporting ☐ testing ■ none of the above	■ Continuous ☐ Intermittent
Attachment II, Special Condition C.5.a (Fuel specifications and sulfur limit)	Unit CT-2 18 MW Jupiter GT-35 Simple Cycle Combustion Turbine (manufactured by Asea Brown Boveri (ABB) and supplied by Solar Turbines)	☐ monitoring ■ recordkeeping ■ reporting ■ testing ☐ none of the above	■ Continuous ☐ Intermittent

Attachment C-2b (Continued)
Compliance Status
Keahole Generating Station – CSP No. 0007-01-C
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C. Special Conditions - Operational and Emissions Limitations

Permit term/condition	Equipment(s)	Method	Compliance
Attachment II, Special Condition C.5.b (Monthly and rolling 12-month fuel limit)	Unit CT-2 18 MW Jupiter GT-35 Simple Cycle Combustion Turbine (manufactured by Asea Brown Boveri (ABB) and supplied by Solar Turbines)	■ monitoring ■ recordkeeping ■ reporting □ testing □ none of the above	■ Continuous □ Intermittent
Attachment II, Special Condition C.5.c (Fuel nitrogen limit)	Unit CT-2 18 MW Jupiter GT-35 Simple Cycle Combustion Turbine (manufactured by Asea Brown Boveri (ABB) and supplied by Solar Turbines)	□ monitoring ■ recordkeeping ■ reporting ■ testing □ none of the above	■ Continuous □ Intermittent
Attachment II, Special Condition C.6 (NO_X, SO_2, PM_{10}, CO and VOC emission limits)	Unit CT-2 18 MW Jupiter GT-35 Simple Cycle Combustion Turbine (manufactured by Asea Brown Boveri (ABB) and supplied by Solar Turbines)	■ monitoring ■ recordkeeping ■ reporting ■ testing □ none of the above	■ Continuous □ Intermittent
Attachment II, Special Condition C.7 (Opacity limits)	Unit CT-2 18 MW Jupiter GT-35 Simple Cycle Combustion Turbine (manufactured by Asea Brown Boveri (ABB) and supplied by Solar Turbines)	□ monitoring ■ recordkeeping ■ reporting ■ testing □ none of the above	■ Continuous □ Intermittent
Attachment II, Special Condition C.8.a.i (Alt. operating scenario – temporary unit replacement)	Unit CT-2 18 MW Jupiter GT-35 Simple Cycle Combustion Turbine (manufactured by Asea Brown Boveri (ABB) and supplied by Solar Turbines)	□ monitoring □ recordkeeping □ reporting □ testing ■ none of the above	■ Continuous □ Intermittent
Attachment II, Special Condition C.8.a.ii (Alt. operating scenario – fuel switching)	Unit CT-2 18 MW Jupiter GT-35 Simple Cycle Combustion Turbine (manufactured by Asea Brown Boveri (ABB) and supplied by Solar Turbines)	□ monitoring □ recordkeeping □ reporting □ testing ■ none of the above	■ Continuous □ Intermittent
Attachment II, Special Condition C.8.a.iii (Alt. operating scenario – emergency load conditions)	Unit CT-2 18 MW Jupiter GT-35 Simple Cycle Combustion Turbine (manufactured by Asea Brown Boveri (ABB) and supplied by Solar Turbines)	□ monitoring ■ recordkeeping □ reporting □ testing □ none of the above	■ Continuous □ Intermittent
Attachment II, Special Condition 8.a.iv (Alt. operating scenario – unpredictable periods of equipment failure, upsets, or emergency conditions)	Unit CT-2 18 MW Jupiter GT-35 Simple Cycle Combustion Turbine (manufactured by Asea Brown Boveri (ABB) and supplied by Solar Turbines)	□ monitoring □ recordkeeping □ reporting □ testing ■ none of the above	■ Continuous □ Intermittent

Attachment C-2b (Continued)
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C. Special Conditions - Operational and Emissions Limitations

Permit term/condition	Equipment(s)	Method	Compliance
Attachment II, Special Condition C.8.a.v (Alt. operating scenario – Use of naphtha or cleaner burning fuel)	Unit CT-2 18 MW Jupiter GT-35 Simple Cycle Combustion Turbine (manufactured by Asea Brown Boveri (ABB) and supplied by Solar Turbines)	☐ monitoring ☐ recordkeeping ☐ reporting ☐ testing ■ none of the above	■ Continuous ☐ Intermittent
Attachment II, Special Condition C.8.b (Alt. operating scenario log)	Unit CT-2 18 MW Jupiter GT-35 Simple Cycle Combustion Turbine (manufactured by Asea Brown Boveri (ABB) and supplied by Solar Turbines)	☐ monitoring ■ recordkeeping ☐ reporting ☐ testing ☐ none of the above	■ Continuous ☐ Intermittent
Attachment II, Special Condition C.8.c (Alt. operating scenario must meet permit requirements)	Unit CT-2 18 MW Jupiter GT-35 Simple Cycle Combustion Turbine (manufactured by Asea Brown Boveri (ABB) and supplied by Solar Turbines)	☐ monitoring ☐ recordkeeping ☐ reporting ☐ testing ■ none of the above	■ Continuous ☐ Intermittent