KALAEOLA
PARTNERS, LP
Clean and Efficient Energy

Kalaeloa Cogeneration Plant (KCP)

Kapolei, Hawaii

Greenhouse Gas Reduction Plan Submittal

Prepared for:

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Table of Contents

1. Introduction

A. Executive Summary

Kalaeloa Cogeneration Plant (KCP) generates electrical energy for distribution on Oahu by the local electric utility, and steam for use by the neighboring refinery. Reliable electric power and continued supply of fuels are critical to Hawaii's economy, safety, public health, communications, information technology, healthcare, and defense. This document outlines KCP's greenhouse gas emissions reduction plan, with review of the state requirements, discussion of baseline GHG emissions, review of EPA clearinghouse of best available control technologies, and evaluation of those control technologies. Finally, KCP proposes a greenhouse gas emissions baseline based on 2009 as an alternate to 2010 and a partnering agreement with other Hawaii power generation assets to meet the State goal.

B. KCP Description

KCP is a combined-cycle cogeneration plant capable of producing 208 megawatts (MW) of electricity, nearly 20% of Oahu's annual electrical needs. Two combustion turbines burn low sulfur fuel oil (LSFO) to power their respective generators as the primary cycle. Waste heat that would otherwise be exhausted to the atmosphere from each of these turbines is captured to make additional steam as a secondary cycle. This additional useful steam is sent to a steam turbine which provides approximately 90% of the thermal requirements of the neighboring refinery. Primary advantages include:

Nearly 50% higher efficiency than a standard oil-fired power plant. The plant is a Qualified Facility (QF) under Public Utility Regulatory Policies Act (PURPA) regulations and maintains a minimum of 42.5% efficiency and 15% steam export.

Fuel Flexibility – able to provide low cost power utilizing a wide range of liquid or gaseous fuels, including low sulfur residual oil (as designed), diesel, kerosene, crude oil, other petroleum products; natural gas, propane (diluted), low heat content gases, and/or biofuel.

Flexible output – able to rapidly start, load up, or load down in response to needs of the electrical grid, supporting addition of non-dispatchable sources of energy (i.e. wind / solar).

Reliability – with planned maintenance, trained personnel, and expert support, KCP reliability has averaged over 99%.

Sustainability - KCP began commercial operations in May of 1991. Use of reclaimed water for plant makeup began in 2001. A significant gas turbine efficiency upgrade was completed in 2004. A successful test run on liquid biofuel was completed in January 2010. KCP strives to be a trusted supplier, fair customer, and community partner.

C. Hawaii Department of Health (DOH) Greenhouse Gas (GHG) Reduction Plan Regulation/Requirements

On June 30, 2014, Hawaii Administrative Rules, Chapter 11-60.1 was amended to adopt a new Hawaii GHG program. Specifically, Hawaii Administrative Rules 11-60.1-204 specify a 16% GHG emissions reduction for large existing stationary sources ("affected sources") with potential carbon dioxide equivalent (CO2e) emissions at or above 100,000 tons per year. Each affected source must submit a GHG emission reduction plan for establishing measures that will be used to meet the emission cap. The approved GHG emission cap and associated monitoring, recordkeeping, and reporting provisions will be made part of the facility's covered source permit. The deadline for submitting GHG emission reduction plans is June 30, 2015. The minimum facility-wide GHG emissions cap shall be 16% below the facility's baseline actual GHG emissions levels, unless this amount is unattainable and can be substantiated by the owner or operator to the satisfaction of the Director. Calendar year 2010 shall be used as the baseline year unless another year or average of other years can be shown to be more representative of normal operations.

2. **Facility-Wide Baseline Annual Emission Rate (tpy CO2e)**

A. Proposed alternate baseline emission rate

KCP's baseline annual emission rate for calendar year 2010 is not representative of the facility's annual emissions due to a major overhaul of the site steam turbine and its associated generator that year. The steam turbine overhaul is condition based, but generally routinely occurs once every eight to ten years. Overhaul of the steam turbine requires both site combustion turbines to be shut down also, so no fuel is consumed and no emissions occur during this period (site electrical power is supplied from the HECO grid during this major outage). This steam turbine overhaul outage occurred from February 14, 2010 to March 15, 2010. Based on the units being in an extended outage period in 2010, this year is not representative of normal actual operations where typically only one gas turbine major maintenance and other minor maintenance outages occur.

Calendar year 2009 is the most recent representative year in the 2006-2010 period, as all EGU (energy generating units) CT1, CT2, and the steam turbine operated at normal capacity throughout the year with typical maintenance downtime. Table 1 shows power output, fuel usage, and CO2 emissions for both 2009 and 2010.

Table 1 - Plant Operating Data 2009 – 2010, Tier 2 calculation method

Year	Combustion Turbine Hours Operated	Power Output (Megawatt-hours)	Low Sulfur Residual Oil Fuel (gal)	Diesel (gal)	Used oil or Bio-Fuel (gal)	CO2e Emissions (metric tons)	Biogenic CO2e (metric tons)
2009	15,218	1,451,424	87,676,100	211,968	1680	993,198	0
2010	14,217	1,406,941	84,281,794	391,610	23555	953,433	223

B. Proposed 2020 Facility-Wide GHG Emissions Cap

KCP proposes a partnership agreement with Hawaii power generation assets, with a Partnership total GHG emissions cap of 8,361,022 tons per year

KCP proposes a facility emissions cap of 1,094,813 tons per year (993,198 metric tons per year) as measured by Tier 3 method.

3. GHG Control Technology Analysis

A. Approach Used in Analysis

EPA clean air technology center was extensively reviewed to determine feasible methods for GHG reduction. Appendix A shows the most relevant examples from the BACT / LAER database. The results indicated energy efficiency, good combustion practices, low carbon fuels, and limited operation as methods of GHG reduction for a combustion turbine combined cycle power plant.

B. Previous GHG Reduction Projects Implemented

Energy efficiency projects like the gas turbine efficiency upgrades in 2004 and good combustion practices built into our daily operations have previously been implemented, and there is significant economic incentive to continue these practices as they reduce fuel purchased and consumed to generate power and steam.

C. Available Control Measures

i. GHG capture and control

No GHG capture and control systems are currently commercially available for combustion turbine exhaust treatment. Research and development efforts are focused on coal or oil-fired boilers with higher concentration of CO_2 in the exhaust gases. Additionally, captured CO_2 would require a storage location or subsequent use, with none identified locally.

ii. Fuel switching or co-fired fuels

a) Biofuel co-firing

KCP has successfully tested operation using a palm-based biodiesel product at up to 100% biodiesel. During the 3-hour test, generator output, engine operation, and emissions were monitored, and all were satisfactory (at or below current PSD limits).

KCP continues to seek locally produced biofuels in sufficient quantity and at reasonable cost to co-fire with existing fuels, contingent upon Hawaii DOH view of GHG emissions from biofuel combustion as a reduction from actual GHG emissions from KCP, and upon acceptance by HECO and the PUC.

b) Natural gas (LNG)

The majority of combined cycle combustion turbines use natural gas as their primary fuel. Per AP-42 tables, a reduction of nearly 30% GHG emissions would be expected from utilizing this fuel versus the current fuel oil that is combusted at KCP.

KCP investigated the option with both Hawaii Gas and HECO to import liquefied natural gas to the island to supply power generation needs. Preliminary estimates indicate this fuel would be cost competitive with existing liquid fuels if the fuel was commercially available and infrastructure investments were made on the island. Current political and economic factors oppose this option.

c) Propane

Propane, diluted with air, is successfully utilized as a backup fuel to natural gas in some mainland applications. Per AP-42 tables, a reduction of 16% GHG emissions would be expected from utilizing this fuel. Propane is currently imported to Hawaii via established infrastructure, but not in the quantity necessary to support power generation from KCP. However, it is not typical that combined cycle combustion turbines of KCP's size burn propane as a commercially viable primary fuel.

d) Diesel

Diesel is available and utilized for combustion turbine startup and shutdown. A very slight (approximately 1/2%) reduction in GHG emissions would be expected. Cost premium is approximately 10% to the cost of residual oil.

iii. Energy Efficiency

KCP continues to apply the most energy efficient equipment and methods available to keep power generation costs down for the island. Combustion turbine blades are made up of the latest three dimensional designs to yield maximum efficiency for this equipment type. Heat recovery steam generators (HRSGs) are routinely cleaned as required to optimize performance. Large motors utilize a variable speed coupling to reduce consumption at lower output, and premium efficiency motors are utilized throughout the plant where applicable.

iv. Combustion or Operational Improvements

KCP's combustion chambers utilize a silo design, allowing a very long residence time for combustion to complete fully. Diesel fuel is utilized for startup and shutdown to ensure the fuel nozzle remains free of coked residual oil and maintains an optimum spray pattern for complete combustion. These factors maintain design efficiency and result in less GHG per megawatt hour of electrical production.

v. Restrictive Operations

Restrictive operations include limiting electrical output (reduced load) and / or limiting operating time. While both of these have occurred over the last several years as a result of market forces, mainly due to added renewable generation (both commercial and residential) and conservation, KCP makes two clarifying notes:

a) Reduced load does reduce GHG production, but less than linearly due to lower efficiency as load is reduced. For example, a 20% reduction in power output yields a 16% drop in fuel usage.
b) Due to its combined cycle design, KCP produces power with lower GHG emissions per megawatt hour than standard oil fired dispatchable generators on Oahu. Energy Information Administration data from 2016 shows average heat rate of an oil fired steam generator at 10,189 Btu/kwh, 15% higher (less efficient) than KCP's 2016 heat rate of 8812 Btu/kwh. A reduction in KCP output may require other less efficient generators to run at a higher overall emissions output which would not be in line with the intention of this regulation to reduce GHG emissions in the State.

vi. Planned Upgrades, Overhaul, or Retirement of Equipment

KCP follows a long term strategic maintenance schedule in keeping with recommendations of the original equipment manufacturer. Each combustion turbine is overhauled every other year. The current power purchase and steam tolling agreements expired in May, 2016, with short term extensions in place. KCP is pursuing extended contracts for both electricity and steam production.

vii. Outstanding Regulatory Mandates

No other regulatory mandates are outstanding that would lead to any reductions in GHG emissions.

viii. Other GHG Reduction Initiatives

KCP has not been able to identify any other GHG reduction initiatives that would apply to this facility.

D. Technically Feasible Measures

KCP has only been able to identify the following three control measures as technically feasible for reducing site GHG emissions, 1) Fuel co-firing; 2) Fuel switching; and 3) Restrictive operations. Overall reduction in Hawaii GHG emissions can be achieved by partnering with other power generation facilities.

E. Control Effectiveness and Cost Evaluation

i. Fuel co-firing (Biofuels)

a) Control effectiveness

Biofuel provides a reduction in GHG emissions in direct proportion to the quantity utilized (as measured by heat value). Use of 16% biofuel would provide a 16% reduction in GHG emissions (biogenic CO2 emissions neglected)

b) Expected emission rate

834,286 metric tons per year (993,198 * (1-16%))

c) Expected emission reduction
158,912 metric ton reduction

d) Energy impacts
No energy impact

e) Environmental impacts
Biofuels generally have less fuel bound nitrogen and sulfur content, resulting in some decrease in nitrogen oxides (NOx) and sulfur dioxide (SO_2) emissions respectively. However, to have a true effect on GHG emissions, the biofuels would need to be sustainably produced.

f) Secondary emissions or impacts
No on-site secondary emissions or impacts are expected. Some impact may result from production of biofuels, varying depending on type of fuel, where produced, etc.

g) Economic impact
KCP can utilize biofuel or blends with existing equipment, with lead time of 1 month from contracting a firm source of fuel.

No sources have been identified that match or better existing liquid fuel pricing. Previous local biofuel contracts (estimated pricing $170/barrel) have been rejected by the state PUC as not cost effective.

U.S. Energy Information Administration estimates 2020 residual oil pricing of $72 per barrel. Adding $8 per barrel for transportation to Hawaii yields an estimate of $80 per barrel.

Using this price difference as an estimate, increased fuel cost totals $29 million per year (2 million barrels *16% * $90/bbl difference);

$20/megawatt-hour;

$182/metric ton CO_2e reduction

ii. Fuel switching (Natural Gas)

a) Control effectiveness
Natural gas provides a 29.9% reduction in GHG emissions (reference AP-42 emissions factors 110 pounds per million British thermal units (lb/mmBtu) for natural gas vs. 157 lb/mmBtu for diesel fuel); (157-110)/157 = 29.9%)

b) Expected emission rate
696,232 metric tons per year (993,198 * (1-29.9%))

c) Expected emission reduction
296,966 metric ton reduction

d) Energy impacts
No energy impact.

e) Environmental impacts
Natural gas provides a reduction in several other criteria pollutants (see Appendix A, Table 3.1-1, for water-steam injection), with reduction by over 50% expected for NOx and carbon monoxide (CO) emissions. Table 3.1-2a shows similar or better reductions for Lead, SO2 (due to lower S content of natural gas, and particulate matter (all categories).

Some minor increases may be expected based on emissions factors for nitrous oxide (N20), methane (CH4), and volatile organic compounds (VOC).

f) Secondary emissions or impacts
No on-site secondary emissions or impacts are expected. Some impact may result from acquisition and transportation of natural gas / liquefied natural gas, varying depending on where produced, method of transport, etc.

g) Economic impact
KCP can utilize natural gas with some modification to existing equipment. A new dual fuel (liquid and gaseous) burner would be necessary at a cost of approximately $10 million, and with lead time of 1 year from contracting a firm source of fuel.

Currently no sources have been identified that have provided firm pricing. Previous estimates of natural gas provided to the plant property line range from $14 to $18 per million British thermal units (mmBtu). This is equivalent to $84 to $108 per barrel of fuel oil. For comparison with fuel oil, analysis uses the midpoint of these estimates, or equivalent of $96 per barrel.

U.S. Energy Information Administration estimates 2020 residual oil pricing of $72 per barrel. Add $8 per barrel for transportation to Hawaii yields an estimate of $80 per barrel.

Using the price difference of these estimates, increased fuel cost totals $34.5 million per year ($32 million per year increased fuel cost (2 million barrels * $16), plus $10 million simply amortized over 4 years ($2.5 million per year);

$24/megawatt-hour;

$116/metric ton CO2e

iii. Fuel switching (Propane)

a) Control effectiveness
Propane provides a 16% reduction in GHG emissions (reference appendix B of this reduction plan)

b) Expected emission rate
834,286 metric tons per year (993,198 * (1-16%))

c) Expected emission reduction
158,912 metric ton reduction

d) Energy impacts
No energy impact

e) Environmental impacts
Propane is expected to provide a reduction in several other criteria pollutants, with reductions expected for NOx and CO emissions, Lead, SO2 (due to lower S content, and particulate matter (all categories). Specific reductions are not available

Some increase may be expected, similar to natural gas, for nitrous oxide (N20), methane (CH4), and volatile organic compounds (VOC).

f) Secondary emissions or impacts
No on-site secondary emissions or impacts are expected. Some impact may result from acquisition and transportation of propane, varying depending on where produced, method of transport, etc.

g) Economic impact
KCP can utilize propane with some modification to existing equipment. A new dual fuel (liquid and gaseous) burner would be necessary at a cost of approximately $10 million, and with lead time of 1 year from contracting a firm source of fuel.

Currently no sources have provided firm pricing. Previous estimates of propane, provided to the plant property line range from $16 to $18 per million British thermal units (MMBTU). This is equivalent to $96 to $108 per barrel of fuel oil. For comparison, analysis uses the midpoint of these estimates, or equivalent of $102 per barrel.

U.S. Energy Information Administration estimates 2020 residual oil pricing of $72 per barrel. Add $8 per barrel for transportation to Hawaii yields an estimate of $80 per barrel.

Using the price difference of these estimates, increased fuel cost totals $46.5 million per year ($44 million per year (2 million barrels * $22) increased fuel cost, plus $10 million simply amortized over 4 years ($2.5 million per year);

$32/megawatt-hour;

$293/metric ton CO2e

iv. Restrictive operations

a) Control effectiveness
GHG emissions are directly proportional to the quantity of fuel utilized. A reduction in operating hours will provide direct reduction in GHG emissions. Similarly, operation at reduced load reduces fuel consumption, however lower loads reduce the overall efficiency of the power plant.

Recent operation and projected future load indicates both reduced operating time and operation at lower loads can be expected as additional renewable energy sources are introduced.

b) Expected emission rate
834,286metric tons per year (993,198 * (1-16%))

c) Expected emission reduction
158,912 metric ton reduction

d) Energy impacts
Reduced operating time and lower loads while operating will reduce the annual megawatt-hour production by 18 – 20%. Wind, solar, and conservation are main factors in the difference in necessary power production. However, KCP is the most efficient power plant on Oahu. Additional gains could be made by running KCP at higher loads and removing older plants from service entirely.

e) Environmental impacts
All emissions remain within permitted limits.

f) Secondary emissions or impacts
Restrictive operations reduce the flexibility of KCP to provide power as needed to Hawaiian Electric and Oahu's customers. A larger overall reduction would be possible by running KCP at higher loads and removing

older plants from service. Current contractual obligations allow Hawaiian Electric to dispatch KCP at any load desired (within plant limitations).

g) Economic impact
Operation at lower loads increases the cost per kilowatt-hour per the existing power purchase agreement. A 20% reduction in output reduces plant efficiency and increases the cost per kilowatt-hour by 4%, with exponentially increasing costs as output is reduced. Operation at minimum load with both combustion turbines in operation increases the cost per kilowatt-hour by 14%

These costs are covered in the power purchase agreement and billed to Hawaiian Electric, ultimately covered by the end consumer.

Reduced efficiency of 14% is equivalent to $22 million per year;

$15/megawatt-hour;

$138/metric ton CO2e

v. Partnering with other power generation facilities
a) Control effectiveness
Partnering provides a reduction in GHG emissions in direct proportion to the reduced quantity of fuel utilized. Removal from service of older power plants, addition of renewable resources (sun, wind), and conservation all contribute to reduced need to utilize older power plants.

b) Expected emission rate
993,198 metric tons per year (2009 baseline).

c) Expected emission reduction
Overall reduction by partnership to reach 16% of partnership baseline, 1,337,764 tons per year (1,213,599 metric tons per year).

d) Energy impacts
No energy impact. Partnership allows HECO to dispatch the most efficient power generation assets as needed to meet demand.

e) Environmental impacts
Partnership allows HECO to dispatch the most effective power generation assets to meet environmental goals.

f) Secondary emissions or impacts
No on-site secondary emissions or impacts are expected.

g) Economic impact

No economic impact.

h) \$0/metric ton CO2e

F. Proposed Control Strategy and Timeline

KCP proposes to partner with other power generation assets in Hawaii to meet the mandated 16% reduction in GHG emissions by the year 2020.

Table 2: Proposed Control Strategy comparison

	Biofuel	Natural Gas	Propane	Restrictive Ops	Partnering
Control Effectiveness	16%	29.9%	16%	16%	16%
Schedule	1 month	1 year	1 year	Immediate	Immediate
GHG reductions	158,912	283,658	158,912	158,912	Per partnership goals
\$/ton reduction	\$182	\$116	\$293	\$138	\$0

G. Additional Notes

i. Several organizations have made efforts to coordinate fuel alternatives to Hawaii, including natural gas, propane, methanol, biofuel, etc. KCP supports these efforts but realizes that any alternate fuel option will require approval and support from a variety of organizations within business, government, and community.

ii. Greenhouse gas emissions monitoring, recordkeeping, and reporting measures shall comply with applicable sections of 40 CFR 98, Mandatory GHG Reporting, and HAR 11-60.1.

Appendix A: Excerpts from BACT/LAER Clearinghouse related to CO2e control in combined cycle power plants

Technology Transfer Network
Clean Air Technology Center - RACT/BACT/LAER Clearinghouse

Pollutant Information

Click on the Process Information button to see more information about the process associated with this pollutant.
Or click on the Process List button to return to the list of processes.

RBLC Home | New Search | Search Results | Facility Information | Process List | Process Information | Pollutant Information

Help
DRAFT

RBLC ID: AL-0282
Corporate/Company: LENZING FIBERS, INC.
Facility Name: LENZING FIBERS, INC.
Process: Gas Turbine with HRSG

Pollutant: Carbon Dioxide Equivalent (CO2e) **CAS Number:** CO2e

Pollutant Group(s): Greenhouse Gasses (GHG), **Substance Registry System:** Carbon Dioxide Equivalent (CO2e)

Pollution Prevention/Add-on Control Equipment/Both/No Controls Feasible: P
P2/Add-on Description: Good combustion practices.

Test Method: EPA/OAR Methods | All Other Methods

Percent Efficiency:	0
Compliance Verified:	Unknown
EMISSION LIMITS:	
Case-by-Case Basis:	BACT-PSD
Other Applicable Requirements:	OPERATING PERMIT
Other Factors Influence Decision:	Unknown
Emission Limit 1:	137908.0000 TPY OF CO2E 12 - MONTH ROLLING
Emission Limit 2:	0
Standard Emission Limit:	0
COST DATA:	
Cost Verified?	No
Dollar Year Used in Cost Estimates:	
Cost Effectiveness:	0 $/ton
Incremental Cost Effectiveness:	0 $/ton
Pollutant Notes:	

Pollutant Information

Click on the Process Information button to see more information about the process associated with this pollutant.
Or click on the Process List button to return to the list of processes.

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Help
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RBLC ID: WV-0025
Corporate/Company: MOUNDSVILLE POWER, LLC
Facility Name: MOUNDSVILLE COMBINED CYCLE POWER PLANT
Process: Combined Cycle Turbine/Duct Burner

Pollutant: Carbon Dioxide Equivalent (CO2e) **CAS Number:** CO2e

Pollutant Group(s): Greenhouse Gasses (GHG), **Substance Registry System:** Carbon Dioxide Equivalent (CO2e)

Pollution Prevention/Add-on Control Equipment/Both/No Controls Feasible: P
P2/Add-on Description: Use of GE Frame 7EA CT Low Carbon Fuel

Test Method: EPA/OAR Methods | All Other Methods

Percent Efficiency:	0
Compliance Verified:	Unknown
EMISSION LIMITS:	
Case-by-Case Basis:	BACT-PSD
Other Applicable Requirements:	
Other Factors Influence Decision:	Unknown
Emission Limit 1:	254315.0000 LB/HR
Emission Limit 2:	793.0000 LB/MW/HR
Standard Emission Limit:	0
COST DATA:	
Cost Verified?	No
Dollar Year Used in Cost Estimates:	
Cost Effectiveness:	0 $/ton
Incremental Cost Effectiveness:	0 $/ton
Pollutant Notes:	CO2e limit is applicable with and without duct firing.

Pollutant Information

Click on the Process Information button to see more information about the process associated with this pollutant.
Or click on the Process List button to return to the list of processes.

RBLC Home | New Search | Search Results | Facility Information | Process List | Process Information | Pollutant Information

Help
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RBLC ID: TX-0735
Corporate/Company: GOLDEN SPREAD ELECTRIC COOPERATIVE, INC.
Facility Name: ANTELOPE ELK ENERGY CENTER
Process: Simple Cycle Turbine & Generator

Pollutant: Carbon Dioxide Equivalent (CO2e) **CAS Number:** CO2e

Pollutant Group(s): Greenhouse Gasses (GHG), **Substance Registry System:** Carbon Dioxide Equivalent (CO2e)

Pollution Prevention/Add-on Control Equipment/Both/No Controls Feasible: P

P2/Add-on Description: Energy efficiency, good design & combustion practices

Test Method:	Unspecified (EPA/OAR Methods) (All Other Methods)
Percent Efficiency:	0
Compliance Verified:	Unknown
EMISSION LIMITS:	
Case-by-Case Basis:	BACT-PSD
Other Applicable Requirements:	
Other Factors Influence Decision:	No
Emission Limit 1:	1304.0000 LB CO2/MWHR
Emission Limit 2:	0
Standard Emission Limit:	0
COST DATA:	
Cost Verified?	No
Dollar Year Used in Cost Estimates:	
Cost Effectiveness:	0 $/ton
Incremental Cost Effectiveness:	0 $/ton
Pollutant Notes:	Operation of each turbine is limited to 4,572 hours per year

Appendix B: Excerpt from AP-42 emissions factors

Table 3.1-1. EMISSION FACTORS FOR NITROGEN OXIDES (NO_X) AND CARBON MONOXIDE (CO) FROM STATIONARY GAS TURBINES

Emission Factors[a]				
Turbine Type	Nitrogen Oxides		Carbon Monoxide	
Natural Gas-Fired Turbines[b]	(lb/MMBtu)[c] (Fuel Input)	Emission Factor Rating	(lb/MMBtu)[c] (Fuel Input)	Emission Factor Rating
Uncontrolled	3.2 E-01	A	8.2 E-02[d]	A
Water-Steam Injection	1.3 E-01	A	3.0 E-02	A
Lean-Premix	9.9 E-02	D	1.5 E-02	D
Distillate Oil-Fired Turbines[e]	(lb/MMBtu)[f] (Fuel Input)	Emission Factor Rating	(lb/MMBtu)[f] (Fuel Input)	Emission Factor Rating
Uncontrolled	8.8 E-01	C	3.3 E-03	C
Water-Steam Injection	2.4 E-01	B	7.6 E-02	C
Landfill Gas-Fired Turbines[g]	(lb/MMBtu)[h] (Fuel Input)	Emission Factor Rating	(lb/MMBtu)[h] (Fuel Input)	Emission Factor Rating
Uncontrolled	1.4 E-01	A	4.4 E-01	A
Digester Gas-Fired Turbines[j]	(lb/MMBtu)[k] (Fuel Input)	Emission Factor Rating	(lb/MMBtu)[k] (Fuel Input)	Emission Factor Rating
Uncontrolled	1.6 E-01	D	1.7 E-02	D

[a] Factors are derived from units operating at high loads ($\geq$80 percent load) only. For information on units operating at other loads, consult the background report for this chapter (Reference 16), available at "www.epa.gov/ttn/chief".

[b] Source Classification Codes (SCCs) for natural gas-fired turbines include 2-01-002-01, 2-02-002-01, 2-02-002-03, 2-03-002-02, and 2-03-002-03. The emission factors in this table may be converted to other natural gas heating values by multiplying the given emission factor by the ratio of the specified heating value to this average heating value.

[c] Emission factors based on an average natural gas heating value (HHV) of 1020 Btu/scf at 60°F. To convert from (lb/MMBtu) to (lb/10^6 scf), multiply by 1020.

[d] It is recognized that the uncontrolled emission factor for CO is higher than the water-steam injection and lean-premix emission factors, which is contrary to expectation. The EPA could not identify the reason for this behavior, except that the data sets used for developing these factors are different.

[e] SCCs for distillate oil-fired turbines include 2-01-001-01, 2-02-001-01, 2-02-001-03, and 2-03-001-02.

[f] Emission factors based on an average distillate oil heating value of 139 MMBtu/10^3 gallons. To convert from (lb/MMBtu) to (lb/10^3 gallons), multiply by 139.

[g] SCC for landfill gas-fired turbines is 2-03-008-01.

[h] Emission factors based on an average landfill gas heating value of 400 Btu/scf at 60°F. To convert from (lb/MMBtu), to (lb/10^6 scf) multiply by 400.

[j] SCC for digester gas-fired turbine is 2-03-007-01.

[k] Emission factors based on an average digester gas heating value of 600 Btu/scf at 60°F. To convert from (lb/MMBtu) to (lb/10^6 scf) multiply by 600.

Table 3.1-2a. EMISSION FACTORS FOR CRITERIA POLLUTANTS AND GREENHOUSE GASES FROM STATIONARY GAS TURBINES

Emission Factors[a] - Uncontrolled				
Pollutant	Natural Gas-Fired Turbines[b]		Distillate Oil-Fired Turbines[d]	
	(lb/MMBtu)[c] (Fuel Input)	Emission Factor Rating	(lb/MMBtu)[e] (Fuel Input)	Emission Factor Rating
CO_2[f]	110	A	157	A
N_2O	0.003[g]	E	ND	NA
Lead	ND	NA	1.4 E-05	C
SO_2	0.94S[h]	B	1.01S[h]	B
Methane	8.6 E-03	C	ND	NA
VOC	2.1 E-03	D	4.1 E-04[j]	E
TOC[k]	1.1 E-02	B	4.0 E-03[l]	C
PM (condensible)	4.7 E-03[l]	C	7.2 E-03[l]	C
PM (filterable)	1.9 E-03[l]	C	4.3 E-03[l]	C
PM (total)	6.6 E-03[l]	C	1.2 E-02[l]	C

[a] Factors are derived from units operating at high loads (≥80 percent load) only. For information on units operating at other loads, consult the background report for this chapter (Reference 16), available at "www.epa.gov/ttn/chief". ND = No Data, NA = Not Applicable.

[b] SCCs for natural gas-fired turbines include 2-01-002-01, 2-02-002-01 & 03, and 2-03-002-02 & 03.

[c] Emission factors based on an average natural gas heating value (HHV) of 1020 Btu/scf at 60°F. To convert from (lb/MMBtu) to (lb/10^6 scf), multiply by 1020. Similarly, these emission factors can be converted to other natural gas heating values.

[d] SCCs for distillate oil-fired turbines are 2-01-001-01, 2-02-001-01, 2-02-001-03, and 2-03-001-02.

[e] Emission factors based on an average distillate oil heating value of 139 MMBtu/10^3 gallons. To convert from (lb/MMBtu) to (lb/10^3 gallons), multiply by 139.

[f] Based on 99.5% conversion of fuel carbon to CO_2 for natural gas and 99% conversion of fuel carbon to CO_2 for distillate oil. CO_2 (Natural Gas) [lb/MMBtu] = (0.0036 scf/Btu)(%CON)(C)(D), where %CON = weight percent conversion of fuel carbon to CO_2, C = carbon content of fuel by weight, and D = density of fuel. For natural gas, C is assumed at 75%, and D is assumed at 4.1 E+04 lb/10^6scf. For distillate oil, CO_2 (Distillate Oil) [lb/MMBtu] = (26.4 gal/MMBtu) (%CON)(C)(D), where C is assumed at 87%, and the D is assumed at 6.9 lb/gallon.

[g] Emission factor is carried over from the previous revision to AP-42 (Supplement B, October 1996) and is based on limited source tests on a single turbine with water-steam injection (Reference 5).

[h] All sulfur in the fuel is assumed to be converted to SO_2. S = percent sulfur in fuel. Example, if sulfur content in the fuel is 3.4 percent, then S = 3.4. If S is not available, use 3.4 E-03 lb/MMBtu for natural gas turbines, and 3.3 E-02 lb/MMBtu for distillate oil turbines (the equations are more accurate).

[j] VOC emissions are assumed equal to the sum of organic emissions.

[k] Pollutant referenced as THC in the gathered emission tests. It is assumed as TOC, because it is based on EPA Test Method 25A.

[l] Emission factors are based on combustion turbines using water-steam injection.

Table 1.3-12. DEFAULT CO_2 EMISSION FACTORS FOR LIQUID FUELS[a]

EMISSION FACTOR RATING: B

Fuel Type	%C[b]	Density[c] (lb/gal)	Emission Factor (lb/10^3 gal)
No. 1 (kerosene)	86.25	6.88	21,500
No. 2	87.25	7.05	22,300
Low Sulfur No. 6	87.26	7.88	25,000
High Sulfur No. 6	85.14	7.88	24,400

[a] Based on 99% conversion of fuel carbon content to CO_2. To convert from lb/gal to gram/cm^3, multiply by 0.12. To convert from lb/10^3 gal to kg/m^3, multiply by 0.12.
[b] Based on an average of fuel carbon contents given in references 73-74.
[c] References 73, 75.

Table 1.5-1. EMISSION FACTORS FOR LPG COMBUSTION[a]

EMISSION FACTOR RATING: E

Pollutant	Butane Emission Factor (lb/10^3 gal)		Propane Emission Factor (lb/10^3 gal)	
	Industrial Boilers[b] (SCC 1-02-010-01)	Commercial Boilers[c] (SCC 1-03-010-01)	Industrial Boilers[b] (SCC 1-02-010-02)	Commercial Boilers[c] (SCC 1-03-010-02)
PM, Filterable[d]	0.2	0.2	0.2	0.2
PM, Condensable	0.6	0.6	0.5	0.5
PM, Total	0.8	0.8	0.7	0.7
SO_2[e]	0.09S	0.09S	0.10S	0.10S
NO_x[f]	15	15	13	13
N_2O[g]	0.9	0.9	0.9	0.9
CO_2[h,j]	14,300	14,300	12,500	12,500
CO	8.4	8.4	7.5	7.5
TOC	1.1	1.1	1.0	1.0
CH_4[k]	0.2	0.2	0.2	0.2

[a] Assumes PM, CO, and TOC emissions are the same, on a heat input basis, as for natural gas combustion. Use heat contents of 91.5 x 10^6 Btu/10^3 gallon for propane, 102 x 10^6 Btu/10^3 gallon for butane, 1020 x 10^6 Btu/10^6 scf for methane when calculating an equivalent heat input basis. For example, the equation for converting from methane's emissions factors to propane's emissions factors is as follows: lb pollutant/10^3 gallons of propane = (lb pollutant /10^6 ft^3 methane) . (91.5 x 10^6 Btu/10^3 gallons of propane) / (1020 x 10^6 Btu/10^6 scf of methane). The NO_x emission factors have been multiplied by a correction factor of 1.5, which is the approximate ratio of propane/butane NO_x emissions to natural gas NO_x emissions. To convert from lb/10^3 gal to kg/10^3 L, multiply by 0.12. SCC = Source Classification Code.

[b] Heat input capacities generally between 10 and 100 million Btu/hour.

[c] Heat input capacities generally between 0.3 and 10 million Btu/hour.

[d] Filterable particulate matter (PM) is that PM collected on or prior to the filter of an EPA Method 5 (or equivalent) sampling train. For natural gas, a fuel with similar combustion characteristics, all PM is less than 10 µm in aerodynamic equivalent diameter (PM-10).

[e] S equals the sulfur content expressed in gr/100 ft^3 gas vapor. For example, if the butane sulfur content is 0.18 gr/100 ft^3, the emission factor would be (0.09 x 0.18) = 0.016 lb of SO_2/10^3 gal butane burned.

[f] Expressed as NO_2.

[g] Reference 12.

[h] Assuming 99.5% conversion of fuel carbon to CO_2.

[j] EMISSION FACTOR RATING = C.

[k] Reference 13.

Appendix C: U.S. Energy Information Administration long term forecast

Table A12. Petroleum and other liquids prices
(2013 dollars per gallon, unless otherwise noted)

Sector and fuel	Reference case 2012	2013	2020	2025	2030	2035	2040	Annual growth 2013-2040 (percent)
Crude oil prices (2013 dollars per barrel)								
Brent spot	113	109	79	91	106	122	141	1.0%
West Texas Intermediate spot	96	98	73	85	99	116	136	1.2%
Average imported refiners acquisition cost[1]	103	98	71	82	96	112	131	1.1%
Brent / West Texas Intermediate spread	17.8	10.7	6.2	6.1	6.2	6.0	5.6	-2.4%
Delivered sector product prices								
Residential								
Propane	2.22	2.13	2.10	2.16	2.23	2.33	2.43	0.5%
Distillate fuel oil	3.79	3.78	2.99	3.28	3.65	4.08	4.56	0.7%
Commercial								
Distillate fuel oil	3.69	3.68	2.89	3.20	3.56	3.99	4.47	0.7%
Residual fuel oil	3.43	3.31	2.12	2.39	2.71	3.08	3.64	0.4%
Residual fuel oil (2013 dollars per barrel)	144	139	89	101	114	129	153	0.4%
Industrial[2]								
Propane	1.95	1.85	1.79	1.87	1.96	2.09	2.24	0.7%
Distillate fuel oil	3.76	3.75	2.91	3.23	3.58	4.00	4.49	0.7%
Residual fuel oil	3.09	3.00	2.00	2.27	2.58	2.95	3.51	0.6%
Residual fuel oil (2013 dollars per barrel)	130	126	84	95	108	124	147	0.6%
Transportation								
Propane	2.31	2.24	2.19	2.25	2.32	2.42	2.52	0.4%
E85[3]	3.39	3.14	2.90	2.77	2.98	3.16	3.38	0.3%
Ethanol wholesale price	2.58	2.37	2.49	2.47	2.35	2.49	2.64	0.4%
Motor gasoline[4]	3.72	3.55	2.74	2.95	3.20	3.53	3.90	0.3%
Jet fuel[5]	3.10	2.94	2.17	2.47	2.88	3.31	3.81	1.0%
Diesel fuel (distillate fuel oil)[6]	3.94	3.86	3.17	3.49	3.84	4.26	4.75	0.8%
Residual fuel oil	3.00	2.89	1.74	2.00	2.30	2.64	3.03	0.2%
Residual fuel oil (2013 dollars per barrel)	126	122	73	84	97	111	127	0.2%
Electric power[7]								
Distillate fuel oil	3.34	3.33	2.60	2.90	3.28	3.70	4.19	0.9%
Residual fuel oil	3.12	2.83	1.71	1.99	2.30	2.67	3.23	0.5%
Residual fuel oil (2013 dollars per barrel)	131	119	72	83	97	112	136	0.5%
Average prices, all sectors[8]								
Propane	2.09	2.00	1.93	1.99	2.06	2.18	2.30	0.5%
Motor gasoline[4]	3.70	3.53	2.74	2.95	3.20	3.53	3.90	0.4%
Jet fuel[5]	3.10	2.94	2.17	2.47	2.88	3.31	3.81	1.0%
Distillate fuel oil	3.89	3.83	3.11	3.43	3.78	4.20	4.69	0.8%
Residual fuel oil	3.04	2.90	1.83	2.10	2.40	2.75	3.22	0.4%
Residual fuel oil (2013 dollars per barrel)	128	122	77	88	101	116	135	0.4%
Average	3.29	3.16	2.46	2.65	2.89	3.23	3.62	0.6%

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ENVIRONMENT

Carbon Dioxide Emissions Coefficients

Release Date: February 14, 2013 | Also available in SPREADSHEET

Carbon Dioxide Emissions Coefficients by Fuel

Carbon Dioxide (CO_2) Factors:	Pounds CO_2 Per Unit of Volume or Mass	Kilograms CO_2 Per Unit of Volume or Mass	Pounds CO_2 Per Million Btu	Kilograms CO_2 Per Million Btu
For homes and businesses				
Propane	12.7/gallon	5.8/gallon	139.0	63.1
Butane	14.8/gallon	6.7/gallon	143.2	65.0
Butane/Propane Mix	13.7/gallon	6.2/gallon	141.1	64.0
Home Heating and Diesel Fuel	22.4/gallon	10.2/gallon	161.3	73.2
Kerosene	21.5/gallon	9.8/gallon	159.4	72.3
Coal (All types)	4,631.5/short ton	2,100.8/short ton	210.2	95.3
Natural Gas	119.9/thousand cubic feet	54.4/thousand cubic feet	117.0	53.1
Gasoline	19.6/gallon	8.9/gallon	157.2	71.3
Residual Heating Fuel (Businesses only)	26/gallon	11.8/gallon	173.7	78.8