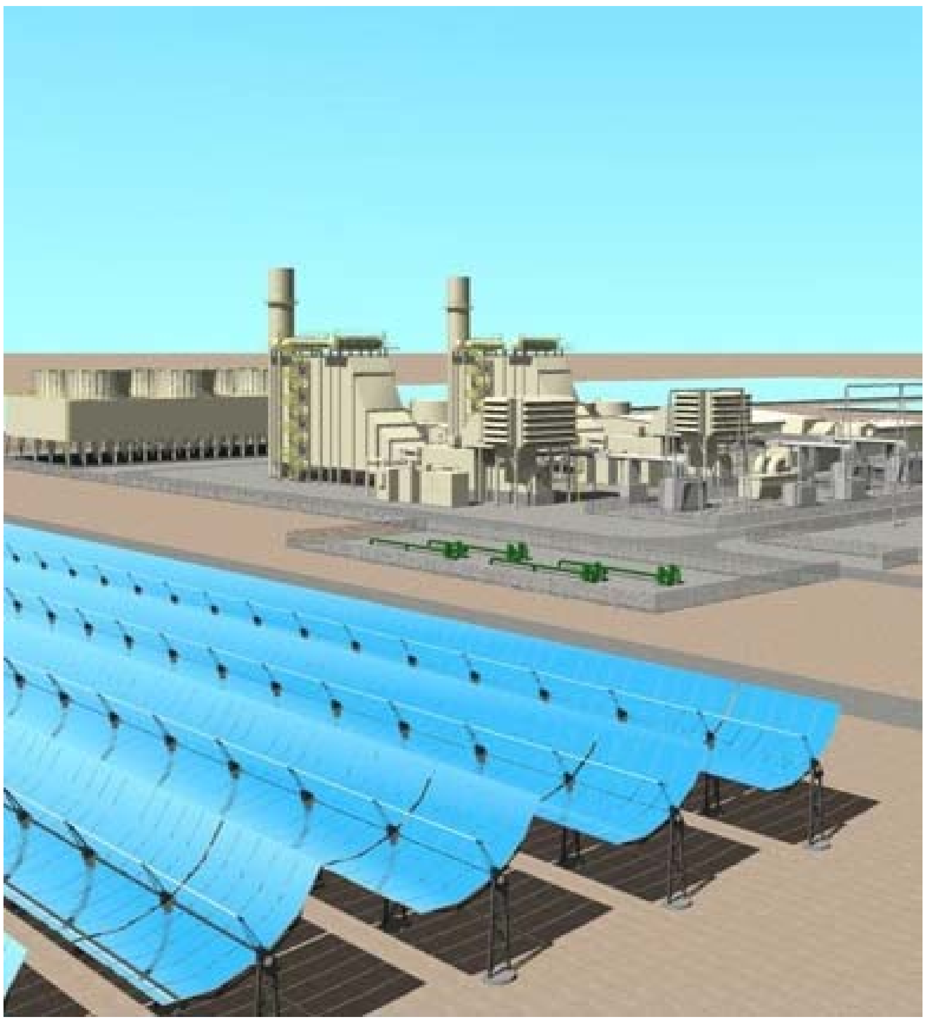
Exhibit 6

Environment

Prepared for:
City of Palmdale / Inland Energy
Palmdale Hybrid Power Project
Document #60138827-040GB

Submitted by:
AECOM
Camarillo, CA
May 2011

Palmdale Hybrid Power Project Greenhouse Gas BACT Analysis



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1.0 Introduction

This Best Available Control Technology (BACT) evaluation was prepared for the Palmdale Hybrid Power Project (PHPP) specifically to address greenhouse gas (GHG) emissions from the project. A BACT analysis for criteria pollutants was submitted to the U.S. Environmental Protection Agency (EPA) with the original Prevention of Significant Deterioration (PSD) application on April 1, 2009. This BACT evaluation follows the EPA PSD and Title V Permitting Guidance for Greenhouse Gases issued in March 2011.

This Project is also subject to licensing by the California Energy Commission (CEC) as a thermal power plant with over 50 megawatts (MW) of electrical generation. The CEC produced a Final Staff Assessment (FSA) which was issued in December 2010 and reviewed the potential for environmental impacts from the PHPP (CEC 2010a). The FSA included a detailed review of this Project's GHG emissions and potential affects. Because the FSA includes a recent, comprehensive analysis of GHG emissions, this GHG BACT analysis incorporates much of the information provided in the FSA.

As will be shown later in this document, the PHPP will be a new 570 MW "state-of-the art," "hybrid" natural gas-fired combined-cycle power plant integrated with solar thermal generating equipment. PHPP will also employ a "Rapid Start Process", which will minimize emissions during startup and increase the efficiency of the power plant. GHG pollutants are emitted during the combustion process when fossil fuels are burned. One of the possible ways to reduce GHG emissions from fossil fuel combustion is to minimize the use of fuel, which is achieved by using a thermally efficient process. A power plant such as PHPP is considered to have met GHG BACT requirements because of its high thermal efficiency. The solar component of the PHPP facility adds to this efficiency.

1.1 Project Overview

The PHPP is a 570 MW "hybrid" natural gas-fired combined-cycle power plant integrated with solar thermal generating equipment, which enhances PHPP's overall thermal efficiency. The combined-cycle equipment utilizes two state-of-the-art (i.e., thermally efficient) natural gas-fired combustion turbine generators (CTGs), two heat recovery steam generators (HRSGs), and one steam turbine generator (STG). The solar thermal component of the PHPP has the potential to produce up to almost 10 percent of facility total generation.

PHPP will also employ General Electric Power Systems (GE) Rapid Start Process (RSP) to minimize emissions during startup and increase the efficiency of the power plant. RSP allows for faster starting of the gas turbines by mitigating the restrictions of former HRSG designs. Traditionally, the CTGs are brought to full load slowly to limit thermal stresses in the high-pressure (HP) steam drum of the HRSG due to the exhaust temperature of the CTGs. The new GE RSP design eliminates this restriction by modifying the steam drum design. Additional equipment to support the RSP includes an auxiliary boiler, which will supply sealing steam and allow startup of the steam turbine shortly after the gas turbines.

PHPP fully integrates a 50 MW solar thermal generation component into the natural-gas generation component which enhances PHPP's overall thermal efficiency. The solar generation component utilizes arrays of parabolic collectors that use solar energy to heat a HTF). The HTF is used to boil water to generate steam. The combined-cycle equipment is integrated thermally with the solar equipment at the HRSG and both utilize the single STG that is part of the project. The solar thermal input will provide almost ten percent of the peak power generated by the facility during the time of day when electrical demand is highest, enhancing the peak thermal efficiency of the PHPP.

According to the CEC (2010a), the operation of PHPP would enhance the overall efficiency of the electricity system operation in California and thereby reduce GHG emissions by providing the following necessary functions:

- PHPP would provide flexible, dispatchable power necessary to integrate some of the growing generation from intermittent renewable sources, such as wind and solar generation.
- PHPP would displace some less efficient local generation in the dispatch order of gas-fired facilities that are required to provide electricity.
- PHPP would facilitate to some degree the replacement of high GHG emitting (e.g., out-of-state coal) electricity generation that must be phased out to meet the State's Emissions Performance Standard (EPS) as required by SB 1368.
- PHPP could facilitate to some extent the replacement of generation provided by aging and once-through cooling power plants.
- PHPP would utilize the General Electric Power Systems (GE) Rapid Start Process (RSP) to allow for fast startup capability.
- PHPP, while located outside Big Creek/Ventura and the Los Angeles Local Reliability Areas (LRAs), could help a load-serving entity (LSE) meet resource adequacy (RA) requirements in these areas.

Addition of the high thermal efficiency of PHPP's generation to the state's electricity system would displace other less efficient, higher GHG-emitting generation and facilitate the integration of renewable resources. Because the project's GHG emissions per megawatt-hour (MWh) would be lower than those of other power plants that the project would displace, the addition PHPP would contribute to a reduction of the California and overall Western Electricity Coordinating Council system GHG[1] emissions and GHG emission rate average. Thus, although PHPP would emit GHG emissions, the high thermal efficiency of PHPP and the system build-out of renewable resources in California would result in a net cumulative reduction of GHG emissions from new and existing fossil resources (CEC 2010a).

1.2 Regulatory Overview

On May 13, 2010 EPA issued the greenhouse gas (GHG) permitting rule officially known as "Prevention of Significant Deterioration and Title V Greenhouse Gas Tailoring Rule" (or in short form, GHG Tailoring Rule) to regulate the six GHG pollutants codified at 40 CFR Parts 51, 52, 70 and 71. Beginning January 2, 2011, GHGs are regulated New Source Review (NSR) pollutants under the Prevention of Significant Deterioration (PSD) major source permitting program when they are emitted by new sources or modifications. Beginning July 1, 2011, any source which has a potential to emit GHG in amount greater than 100,000 tons per year (tpy) of carbon dioxide equivalent (CO_2e) will be

[1] Fuel-use closely correlates to the efficiency of and carbon dioxide (CO_2) emissions from natural gas-fired power plants. And since CO_2 emissions from the fuel combustion dominate GHG emissions from power plants, the terms CO_2 and GHG are used interchangeably in this document.

considered a major source and is required to undergo PSD permitting, including preparation of a BACT analysis for GHG emissions. In addition, pursuant to 40 CFR Part 98, facilities that emit more than 25,000 metric tons (MT) of CO_2e emissions per year are required to file annual emission reports for GHG emissions. The PHPP has the potential to emit more than 100,000 MT CO_2e, and as such is subject to the GHG Tailoring Rule.

The State of California has also adopted a number of laws related to GHG requirements, including emissions and performance standards that are relevant to GHG BACT analyses. In September 2006, Governor Schwarzenegger signed Assembly Bill (AB) 32, the California Global Warming Solutions Act of 2006. AB32 establishes regulatory, reporting, and market mechanisms to achieve quantifiable reductions in GHG emissions and a cap on statewide GHG emissions. Senate Bill (SB) 1368 is the companion bill of AB32 and required the California Public Utilities Commission (CPUC) to establish a GHG emission performance standard for base load generation from investor owned utilities by February 1, 2007. The CEC was required to establish a similar standard for local publicly owned utilities by June 30, 2007. These standards cannot exceed the GHG emission rate from a base load combined-cycle natural gas-fired plant of 1,100 pounds per megawatt-hour (MWh). The legislation further requires that all electricity provided to California, including imported electricity, must be generated from plants that meet the standards set by the CPUC and the CEC.

1.3 BACT Evaluation Overview

BACT requirements are intended to ensure that a proposed project will incorporate control systems that reflect the latest demonstrated practical techniques for that particular facility. BACT is defined under the Clean Air Act as follows (Section 169(3), 42 United States Code Section 7479(3)):

> *The term "best available control technology" means an emission limitation based on the maximum degree of reduction of each pollutant subject to regulation under this chapter emitted from or which results from any major emitting facility, which the permitting authority, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such facility through application of production processes and available methods, systems, and techniques, including fuel cleaning, clean fuels, or treatment or innovative fuel combustion techniques for control of each such pollutant. BACT is defined as the emission control means an emission limitation (including opacity limits) based on the maximum degree of reduction which is achievable for each pollutant, taking into account energy, environmental, and economic impacts, and other costs. ….*

A BACT analysis must be pollutant and emission unit specific with respect to each pollutant subject to a BACT review. The analysis must evaluate the entire range of demonstrated options, including alternatives that may be transferable or innovative. The level of detail in the control options analysis should vary with the relative magnitude of the emissions reduction achievable. A BACT analysis is performed in a top-down manner in which all applicable control technologies are evaluated based on their effectiveness and then ranked by decreasing level of control. Once ranked, control technologies on the list are eliminated one by one based on infeasibility due to energy, environmental, and economic impacts, and other costs. The first control technology in the ranked list that cannot be so eliminated is then defined as BACT for that pollutant and process.

For a facility subject to the GHG Tailoring Rule, the six covered GHG pollutants are:

- Carbon dioxide (CO2),
- Nitrous oxide (N2O),
- Methane (CH4),
- Hydrofluorocarbons (HFCs),
- Perfluorocarbons (PFCs), and
- Sulfur hexafluoride (SF6).

EPA guidance for a “top-down” BACT analysis requires reviewing the possible control options starting with the best control efficiency. In the course of the BACT analysis, one or more options may be eliminated from consideration because they are demonstrated to be technically infeasible or have unacceptable energy, economic, or environmental impacts on a case-by-case (site-specific) basis.

The steps required for a “top-down” BACT review are given below:

1. Identify available control technologies;
2. Eliminate technically infeasible options;
3. Rank remaining technologies;
4. Evaluate remaining technologies (in terms of economic, energy, and environmental impacts); and
5. Select BACT (the most efficient technology that cannot be rejected for economic, energy, or environmental impact reasons).

This document presents a more detail Project Description in Section 2, including the GHG emissions expected from the facility. The top-down GHG BACT determination for the PHPP combustion turbines and duct burners in provided in Section 3. The BACT determination for the auxiliary boiler and HTF heater is provided in Section 4.

2.0 Project Description and GHG Emissions

2.1 Overview

The City of Palmdale proposes to construct and operate the PHPP. The PHPP is expected to supply power to the rapidly growing Southern California market. The City has contracted with Inland Energy, Inc. to develop the Project.

The PHPP consists of a hybrid of natural gas-fired combined-cycle generating equipment integrated with solar thermal generating equipment to be developed on a site in the northern portion of the City of Palmdale. The combined-cycle equipment utilizes two natural gas-fired CTGs, two HRSGs, and one STG. The solar thermal equipment utilizes arrays of parabolic collectors to collect heat used to generate steam. The combined-cycle equipment is integrated thermally with the solar equipment at the HRSG, and both utilize the single STG to generate power.

The Project will have a nominal electrical output of 570 MW and commercial operation is planned for two and a half to three years after permitting is complete. The solar thermal input will provide almost ten percent of the peak power generated by the Project during the daily periods of highest energy demand.

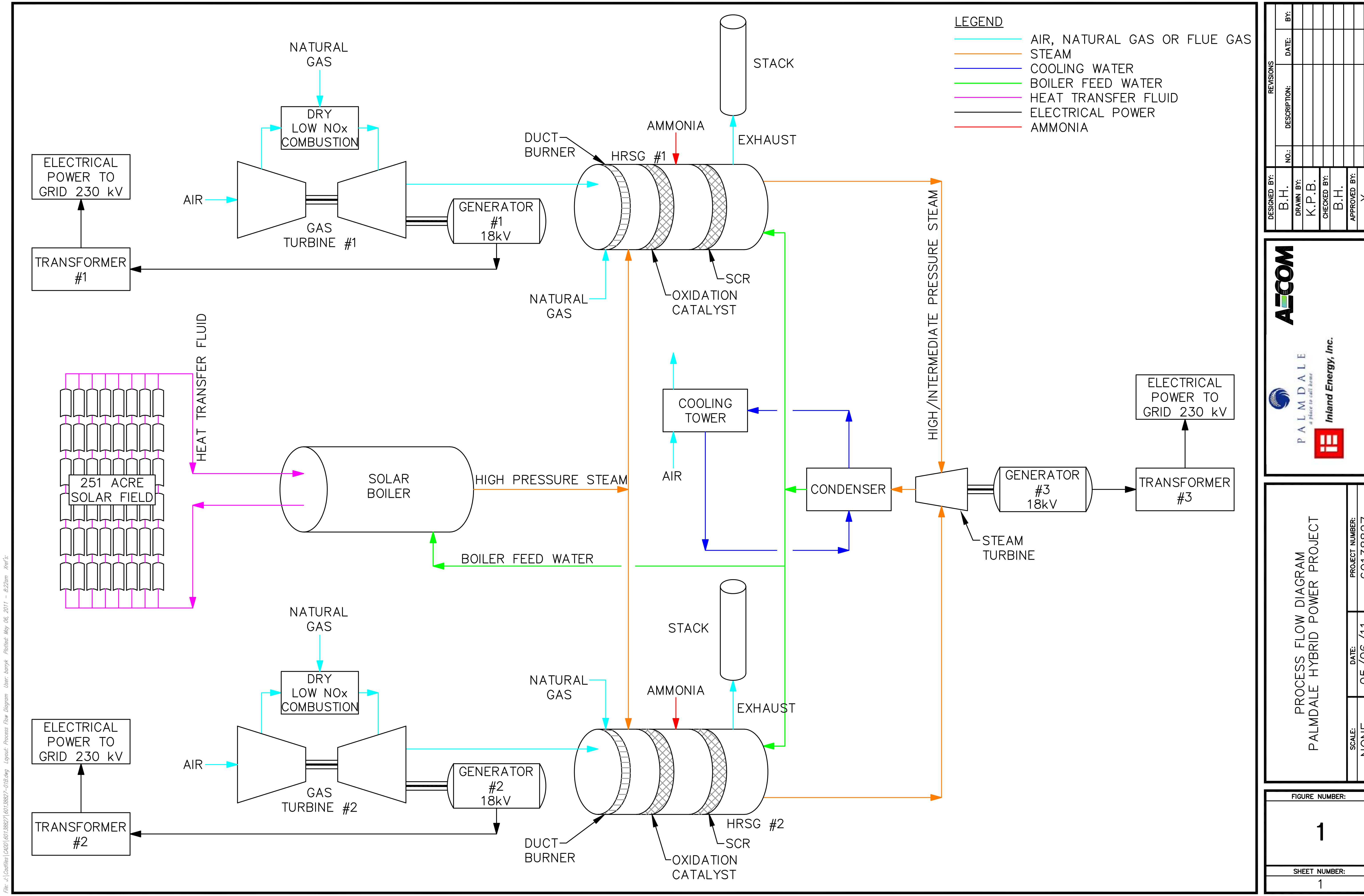
2.2 Generating Facility Components

The major components of the Project include:

- Two natural gas-fired CTGs equipped with dry low-NOX (DLN) combustors and evaporative inlet air coolers,
- Two natural gas-fired HRSGs equipped with duct burners,
- Selective catalytic reduction (SCR) and oxidation catalyst emissions control systems,
- One STG,
- Approximately 251-acre solar thermal array field with a solar steam boiler and associated auxiliary systems and equipment;
- One wet cooling tower;
- Auxiliary boiler, HTF heater, and fire water pump module;
- Water tanks and brine crystallizer facilities;
- A 230-kilovolt (kV) switchyard; and
- An operations building that incorporates control, warehouse, maintenance, and administrative functions.

2.3 Process Description

A Process Flow Diagram of the facility is shown in Figure 1. The CTGs and duct burners are fueled exclusively with pipeline natural gas. The duct burners provide additional heat, which enable the HRSGs to produce more steam in order to obtain peak output from the STG.


LEGEND
AIR, NATURAL GAS OR FLUE GAS
STEAM
COOLING WATER
BOILER FEED WATER
HEAT TRANSFER FLUID
ELECTRICAL POWER
AMMONIA
NATURAL GAS
DRY LOW NOx COMBUSTION
AIR
GAS TURBINE #1
GENERATOR #1 18kV
ELECTRICAL POWER TO GRID 230 kV
TRANSFORMER #1
DUCT BURNER
HRSG #1
AMMONIA
STACK
EXHAUST
NATURAL GAS
OXIDATION CATALYST
SCR
HIGH/INTERMEDIATE PRESSURE STEAM
HEAT TRANSFER FLUID
251 ACRE SOLAR FIELD
SOLAR BOILER
HIGH PRESSURE STEAM
BOILER FEED WATER
COOLING TOWER
AIR
CONDENSER
GENERATOR #3 18kV
STEAM TURBINE
TRANSFORMER #3
ELECTRICAL POWER TO GRID 230 kV
NATURAL GAS
DRY LOW NOx COMBUSTION
AIR
GAS TURBINE #2
GENERATOR #2 18kV
ELECTRICAL POWER TO GRID 230 kV
TRANSFORMER #2
STACK
NATURAL GAS
AMMONIA
EXHAUST
HRSG #2
SCR
DUCT BURNER
OXIDATION CATALYST
REVISIONS
NO.: DESCRIPTION: DATE: BY:
DESIGNED BY: B.H.
DRAWN BY: K.P.B.
CHECKED BY: B.H.
APPROVED BY: X
AECOM
PALMDALE a place to call home
Inland Energy, Inc.
PROCESS FLOW DIAGRAM
PALMDALE HYBRID POWER PROJECT
PROJECT NUMBER: 60138827
DATE: 05/06/11
SCALE: NONE
FIGURE NUMBER: 1
SHEET NUMBER: 1

At full load, each CTG generates approximately 154 MW (gross) at average ambient conditions. Heat from the CTG exhausts is used in the HRSGs to generate steam and to reheat steam. With the CTGs at full load and the duct burners and solar field out-of-service, the HRSGs produce sufficient steam for operation of the STG at an output of 169 MW (gross) at average ambient conditions, which results in an overall plant output of approximately 477 MW (gross) (see Table 1). With the CTGs at full load and the duct burners in-service, the HRSGs produce sufficient steam for operation of the STG at its peaking output of 267 MW (gross) at average ambient conditions, which results in an overall plant gross output of approximately 563 MW (net). It is expected that approximately 3 to 5 percent of the total annual energy generation from the PHPP will come from the renewable solar generation.

Table 1 Generation Configurations and Output

Configuration	Output (MW)
Full Load (average ambient conditions)/No Duct Burners/No Solar	477
Full Load (average ambient conditions)/Full Duct Burners/No Solar	563
Full Load (average ambient conditions)/Partial Duct Burners/Full Solar	563
Full Load (average ambient conditions)/No Duct Burners/Full Solar	527

Overall, annual availability of the PHPP is expected to be in the range of 90 to 95 percent. The design of the Project provides for operating flexibility (the ability to rapidly startup, shutdown, turn down and provide peaking output), so operations may be readily adapted to changing market conditions. Included in this flexibility is the ability of the Project to startup the combined-cycle system in approximately one-half the time of the industry standard for combined-cycle plants in the United States.

The “Rapid Start Process” (RSP) offered by General Electric Power Systems (GE), the planned supplier of the Project’s combustion equipment, allows for faster starting of the gas turbines by mitigating the restrictions of former HRSG designs. Traditionally, the CTGs are brought to full load slowly to limit thermal stresses in the high-pressure (HP) steam drum of the HRSG due to the exhaust temperature of the CTGs. The new GE RSP design eliminates this restriction by modifying the steam drum design. Additional equipment to support the RSP includes an auxiliary boiler, which will supply sealing steam and allow startup of the steam turbine shortly after the gas turbines.

2.4 Energy Generation Facilities Description

This section describes the major energy generation components of the proposed PHPP including the CTGs, HRSGs, STG, and solar thermal system.

2.4.1 Combustion Turbine-Generators (CTGs)

Thermal energy is produced in each of the two CTGs through the combustion of natural gas. The thermal energy is then converted into mechanical energy by the CTG turbine that drives the CTG compressor and electric generator. The CTGs proposed for the PHPP employ ‘F’ technology supplied by GE Power Systems. Each CTG consists of a heavy duty, single shaft, combustion turbine-generator, and associated auxiliary equipment. The CTGs are equipped with DLN combustors designed for natural gas combustion.

2.4.2 Heat Recovery Steam Generators (HRSGs) and Steam Cycle

In the combined-cycle configuration, each CTG will exhaust through a dedicated HRSG. Each of the two trains will consist of one CTG and one HRSG. Both CTG-HRSG trains will feed steam into a common STG, a standard 2-on-1 configuration.

Each HRSG is a horizontal, natural circulation type unit with three pressure levels of steam generation and reheat loop. Super-heated high pressure (HP) steam at 1,800 pounds per square inch gauge (psig) and 1,050 degrees Fahrenheit (°F) is produced in the HRSG and flows to the steam turbine throttle inlet. The exhausted cold reheat steam is mixed with intermediate pressure steam and reintroduced into the HRSG through the reheat loop. The hot reheat steam flows to the intermediate-pressure section of the STG, and then to the low-pressure (LP) section of the STG. LP steam from the HRSG also flows to the LP section of the STG. The STG drives an electric generator. Each HRSG has a 550 million British thermal units per hour (MMBtu/hr) natural gas-fired duct burner.

In the proposed hybrid configuration with the solar thermal component integrated into the PHPP, additional HP steam is produced during daylight hours from heat collected via the solar array. The solar array heats the HTF that is used to produce HP steam in a heat exchanger. This HP steam is introduced into the combined-cycle system via injection into the HP drum of the HRSG. This steam is then superheated in the HRSG superheaters along with the HP steam produced within the HRSG evaporator.

The STG exhaust steam is condensed in the de-aerating surface condenser with water from a multi-cell wet cooling tower. Makeup water to the cooling tower will be tertiary-treated reclaimed water.

As noted earlier, the PHPP is designed with GE's RSP, which will allow the CTG to reach base load more quickly, reducing startup emissions. Since emission rates of some pollutants (e.g., NOx, CO, VOC) are higher during startup than during normal steady-state operations, RSP facilitates lower overall emissions per MW-hour produced. The RSP reduces CTG startup times by more than 50 percent during cold starts, with smaller reductions in startup time and corresponding emissions during warm and hot starts. The RSP does not affect STG startup times.

To facilitate the RSP approach, the HRSG design is modified compared to a conventional HRSG design. Typical HRSG designs limit the CTG start rate due to the exhaust temperature heating the steam drum too quickly. This limitation is caused by thermal stress limitations on the HP steam drum due to the shell thickness. To avoid this limitation, a modified drum design is used that allows for thinner wall thickness. This revised design is achieved by elongating the steam drum and reducing its diameter, which leaves the steam drum volume relatively unchanged compared to conventional designs.

2.4.3 Auxiliary Boiler

Another limiting factor for startup of combined-cycle equipment is the ability to draw a vacuum on the condenser, which is necessary to commence STG startup. The PHPP will use one 110 MMBtu/hr, natural gas-fired auxiliary boiler to facilitate rapid startup by providing STG sealing steam prior to CTG startup, thereby allowing the condenser vacuum to be established and the condenser be in a condition ready to accept steam as soon as it is available. This also avoids the need to vent considerable steam to the atmosphere while waiting for condenser vacuum to be established following CTG startup.

2.4.4 Steam Turbine-Generator (STG)

Steam from the HRSGs is sent to the STG. The steam expands through the STG turbine blades to drive the steam turbine, which in turn drives the generator. The PHPP's STG is a "reheat" type and is equipped with accessories required to provide efficient, safe, and reliable operation.

2.4.5 Solar Thermal System

The PHPP 50 MW solar field is made up of a large field of diurnal, single-axis-tracking parabolic trough solar collectors. The solar field is modular in nature and comprises many parallel rows of solar collectors, normally aligned on a north-south horizontal axis. Each solar collector has a linear parabolic-shaped reflector (referred to as the Heat Collection Element) that focuses the sun's direct beam radiation on a linear receiver located at the focus of the parabola. The collectors track the sun from east to west during the diurnal cycle to ensure maximum focusing of incident sunlight on the linear receiver.

The HTF is heated up to approximately 740°F as it circulates through the receiver and returns to a series of heat exchangers, where the HTF is used to generate HP steam. At the PHPP, these heat exchangers are located in the power block area. To integrate the solar and combined-cycle Project components, the solar-generated HP steam is injected in the HP steam section of a HRSG where it is superheated.

The Project will require periodic vehicle travel over the unpaved portions of the solar field to perform routine maintenance including mirror washing, maintenance inspections and repairs of the piping network, herbicide application and dust suppressant application.

2.4.6 HTF Heater

To eliminate the problem of the HTF freezing during cold winter nights, one 40 MMBtu/hr, natural gas-fired HTF heater will be installed and used as needed to ensure that the temperature of the HTF fluid in the system stays above 54°F whenever the solar steam unit is off-line.

2.4.7 Emergency Generator

The emergency diesel generator will supply electrical power to the power plant critical services in the event of a total power outage of the switchyard and the plant. The plant critical services will include battery chargers, turning gear, lubricating oil systems, Distributed Control System and Programmable Logic Controller controls and critical lighting. The generator will be standby rated at 2,000 kilowatt (kW), at 480 volts. The emergency diesel generator will be periodically tested to confirm it's mechanical, electrical and control equipment integrity. The emergency generator system will be synchronized with the normal auxiliary power system from time to time to test its total output power into the system. This emergency diesel engine will operate for a maximum of 50 hours per year for testing and maintenance.

2.4.8 Emergency Fire Water Pump

The Project will include an emergency diesel-fired fire water pump rated at approximately 135 kW. This emergency diesel engine will operate for a maximum of 50 hours per year for testing and maintenance.

2.5 Operating Schedule

The power plant will be operated up to seven days per week, 24 hours per day. When the plant is not operating, personnel will be present as necessary for maintenance, to prepare the plant for startup, and/or for site security.

2.6 Greenhouse Gas Emissions

The primary GHG of concern for the PHPP is CO_2. This report primarily presents the GHG BACT analysis for CO_2 emissions, as CH_4, N_2O and SF_6 emissions are insignificant, at less than 0.3 percent of facility GHG CO_2e emissions. No sources with HFCs or PFCs pollutants are identified with this Project.

The primary sources of GHG emissions would be the natural gas-fired combustion turbines with duct burners, the auxiliary boiler and the HTF heater. There would also be a small amount of GHG emissions from maintenance vehicles required to wash mirror surfaces and otherwise maintain the facility, diesel fuel combustion in the emergency fire water pump and emergency generator engines, and SF_6 emissions from electrical component equipment.

Appendix A presents the GHG emission calculations for the PHPP taken from the PHPP Application for Certification (AFC) as submitted to the California Energy Commission in July 2008. All emissions are converted to metric tons of CO_2-equivalents (CO_2e) and totaled. Electricity generation GHG emissions are dominated by CO_2 emissions from natural gas combustion. The remaining PHPP GHG emissions of CH_4, N_2O, and SF_6 contribute only 0.3 percent of the total CO_2e emissions due to facility operation, notwithstanding the relatively high global warming potentials (GWPs) of these three compounds.

The proposed project would be permitted, on an annual basis, to emit approximately 1,850,000 metric tons of CO_2e per year if operated at its maximum permitted level. This annual emission estimate is based on 8,760 hours of operation of the combustion turbines at full load plus operation of the duct burners for an additional 2,000 hours. Operation of the solar array to generate electricity would reduce the greenhouse emissions of the facility below the above estimated emission rate.

As discussed above, the combustion of natural gas for project power production from the combustion turbines and associated duct burners, auxiliary boiler, and HTF heater is responsible for 99.7 percent of facility GHG CO_2e emissions. Based on these emission estimates, a GHG BACT analysis was not performed for the negligible GHG emission sources at this facility, i.e., the emergency generator engine, the emergency fire water pump engine, SF_6 leakage, or vehicle emissions.

Table 2 Estimated Potential Greenhouse Gas (GHG) Emissions

Emissions Source	Operational GHG Emissions [a] ($MTCO_2e/yr$)
CTG/HRSG 1 w/duct burner	924,000
CTG/HRSG 2 w/duct burner	924,000
Auxiliary Boiler	2,660
HTF Heater	2,130
Emergency Generator	25
Emergency Fire Water Pump	4
Sulfur Hexafluoride (SF6) Leakage	9
Vehicles (includes mirror washing)	10
Total Project GHG Emissions (MTCO2e/yr) [b]	**1,850,000**
Estimated Annual Energy Output (MWh/yr) [c]	4,993,200
Estimated Annualized GHG Performance (MTCO2/MWh)	0.370
Estimated Annualized GHG Performance (MTCO2e/MWh)	0.371

a. One metric ton (MT) equals 1.1 short tons or 2,204.6 pounds or 1,000 kilograms

b. The facility emissions are rounded to three significant figures. Note that the emissions contribution from the emergency equipment, SF_6 leakage, and vehicles are less than the round-off error for the combustion turbines/duct burners emissions.

c. Annualized basis uses the project owner’s assumed maximum operating basis.

Sources: PHPP AFC 2008 and CEC 2010a, including CEC staff analysis for estimated energy output.

3.0 BACT Determination for Combustion Turbines and Duct Burners

This section presents the top-down GHG BACT determination for the combustion turbines and duct burners. The BACT determination for the auxiliary boiler and HTF heater is given in the next section.

3.1 Step1 - Identification of Available Control Technologies

The proposed combustion turbines will operate in combined-cycle mode. In a combined-cycle configuration, hot exhaust from the CTG is ducted through a HRSG, which is also fired, to produce steam to drive a steam turbine generator. Since the combustion turbine and HRSG are coupled together in a combined-cycle configuration, and exhaust through a single stack, they are considered to be one combustion train for purposes of the evaluation of GHG emissions control.

Publicly-available information on emission control technologies for Combined Cycle Combustion Turbines was reviewed for step one of this analysis. Databases reviewed included South Coast Air Quality Management District (SCAQMD) BACT/lowest achievable emission rate (LAER) Guidelines, the Bay Area Air Quality Management District (BAAQMD) BACT Guidelines, EPA's Reasonably Available Control Technology/BACT/LAER Clearinghouse (RBLC), and the recent or pending projects in the CEC database. SCAQMD did not list any specific determinations for GHG BACT in their guidelines and BAAQMD had only one determination for the Russell City Energy Center. An internet search found one other GHG BACT analyses for natural gas-fired combined-cycle facilities, Portland General Electric Company's Carty Power Plant (SLR International, 2010).

In addition, GHG BACT analyses were found for two Integrated Gasification Combined-Cycle (ICGG) facilities:

- Hyperion Energy Center, BACT Review for Greenhouse Gas Emissions, RTP Environmental Consultants, October 2010.
- PurGen One Facility, Revised PSD Application, December 2010.

The U.S. Department of Energy (DOE) website also contained applicable information regarding available CO_2 control technologies which are discussed below.

For review of the CO_2 control technologies for PHPP's CTGs/HRSGs, the following list of potentially applicable technologies available is evaluated (listed in alphabetical order):

- Carbon Capture and Sequestration (CCS) (DOE Website, EPA 2010b, CEC 2009)
- Lower Emitting Alternative Technology (EPA 2010b, National Laboratory Directors 1997)
- Thermal Efficiency (EPA 2010b)

Each of these technologies is further discussed in the following subsections.

3.1.1 Carbon Capture and Sequestration

CCS is a multiple step process which involves capturing of CO_2 emissions, transportation of CO_2 emissions to the sequestration site, and ultimate sequestration of CO_2 emissions.

Capturing of CO_2 Emissions

Carbon capture begins with the separation and capture of CO_2 from the flue gas. Post-combustion capture systems being developed are expected to be capable of capturing more than 90 percent of flue gas CO_2. Amine-based solvent systems are in commercial use for scrubbing CO_2 from industrial flue gases and process gases. However, solvents have yet to be applied and demonstrated in practice to remove the much larger volumes of CO_2 that are encountered in commercial scale power plants.

Solid sorbents can be used to capture CO_2 from flue gas through chemical adsorption, physical adsorption, or a combination of the two effects. Possible configurations for contacting the flue gas with solid sorbents include fixed, moving, and fluidized beds. Membrane-based capture uses permeable or semi-permeable materials that allow for the selective transport/separation of CO_2 from flue gas. The process of separating CO_2 from the flue has high energy demand and is cost intensive.

Transportation of CO_2 Emissions

CO_2 captured by any of the above mentioned processes would have to be transported to a storage site. For geologic sequestration, a pipeline may be suitable. For other types of sequestration (e.g., ocean storage, mineral carbonation), transportation would depend on specific project requirements, and may involve pipelines, truck transport, ocean-going vessels, etc.

Sequestration of CO_2 emissions

<u>Geologic Sequestration</u>

Under geologic sequestration, a suitable geological formation is identified close to the proposed project and the captured CO_2 from the process is compressed and transported to the sequestration location. CO_2 is injected into that formation at a high pressure and to depths generally greater than 2,625 feet (800 meters). Below this depth, the pressurized CO_2 remains "supercritical" and behaves like a liquid. Supercritical CO_2 is denser and takes up less space than gaseous CO_2. Once injected, the CO_2 occupies pore spaces in the surrounding rock, like water in a sponge. Saline water which already resides in the pore space would be displaced by the denser CO_2. Over time, the CO_2 can dissolve in residual water and chemical reactions between the dissolved CO_2 and rock can create solid carbonate minerals, more permanently trapping the CO_2.

There are several geologic formations identified in California that might provide a suitable site for geologic sequestration. As shown in Figure 2, the nearest potential sequestration basins to PHPP are north of the facility in the Lower San Joaquin Valley and southwest of the facility in Ventura County (NETL, 2010). While these sites may eventually prove to be suitable, the geotechnical analyses needed to confirm their suitability have not been conducted. For both the San Joaquin Valley and Ventura County basins, there are significant mountain ranges that lie between the PHPP and potential sequestration sites that would produce very costly transportation options for a CCS project. In addition, NETL states in the 2010 Carbon Sequestration Atlas that the highly fractured shale in the Ventura Basin is not a good candidate for CO_2 sequestration (NETL, 2010, pg 111).

Ocean Storage

Ocean storage is accomplished by injecting CO_2 into the ocean water typically below 1,000 meters via pipe or ship. At these depths, CO_2 is expected to dissolve or form into a horizontal lens which would delay the dissolution of CO_2 into the surrounding environment. The depth of the overlying water and the lensing of the CO_2 will form a natural impediment to the vertical movement of the injected CO_2.

Mineral Carbonation

Mineral carbonation is the reaction of CO_2 with the metal oxides forming metal carbonates which are very stable. These metal oxides are abundant in silicate minerals and in waste streams. The natural reaction of CO_2 with metal oxides is a very slow process. However, the reaction time can be increased by enhancing the purity of these metal oxides. Large scale production of metal oxides to meet the demand of electrical generation is very energy and cost intensive.

3.1.2 Lower Emitting Alternative Technology

There are power production technologies commercially available that are either low GHG-emitting or non-GHG emitting technologies, such as wind, solar, geothermal, hydroelectric, nuclear, and biomass-fueled plants. The project already includes 50 MW of potential solar thermal power generation and so already incorporates a lower emitting alternative technology.

Alternatives analyses were prepared as part of the PHPP AFC (2008) and the CEC's FSA (2010a), and included reviews of alternative technologies including wind, additional solar, geothermal, hydroelectric, nuclear and biomass, all of which were determined to be infeasible for this site.

The modification of the project to include alternative lower GHG-emitting technology, or an increase in the amount of solar thermal generation beyond 50 MW would fundamentally alter the business purpose of the Project. However, as stated by EPA (EPA 2010b, pg. 27), a BACT analysis is not generally used to redefine the applicant's project.

> *While Step 1 [of a BACT Analysis] is intended to capture a broad array of potential options for pollution control, this step of the process is not without limits. EPA has recognized that a Step 1 list of options need not necessarily include inherently lower polluting processes that would fundamentally redefine the nature of the source proposed by the permit applicant. BACT should generally not be applied to regulate the applicant's purpose or objective for the proposed facility.*

Consequently, no additional lower emitting alternative technologies are feasible to incorporate into the project without fundamentally changing the business purpose of the Project.

Figure 2. Potential CO_2 Sequestration Locations by Type in Southern California

Source: National Energy Technology Laboratory, Department of Energy. 2010 Carbon Sequestration Atlas of the United States and Canada, Third Edition.

3.1.3 Thermal Efficiency

CO_2 is formed when fossil fuels are combusted and the thermal efficiency of that combustion process is determined by the thermodynamics of the system. The thermal efficiency is defined as the dimensionless ratio of the useful work performed by the process and the heat input to the process. It is not possible to alter the combustion process from the optimum stoichiometric conditions to reduce CO_2 emissions without also reducing the thermal efficiency at the same time. The only useful means to reduce CO_2 from a fossil fuel combustion process is to minimize the amount of fuel used, which is achieved by establishing a more thermally efficient process, or by substitution of a lower GHG emitting fuel.

The PHPP is already proposing to combust natural gas, the lowest emitting fossil fuel available. In addition, the PHPP is a state-of-the-art highly efficient thermal electric power plant. Finally, the PHPP is a “hybrid” natural gas-fired combined-cycle power plant integrated with solar thermal generating equipment to enhance PHPP’s already high thermal efficiency. The PHPP utilizes two highly efficient state-of-the-art natural gas-fired combustion turbine generators (CTGs), two heat recovery steam generators (HRSGs), and one steam turbine generator (STG), combined with an additional 50 MW of solar thermal generation capacity. The solar thermal input will provide almost ten percent of the peak power generated by the facility during the time of day when electrical demand is highest, enhancing the peak thermal efficiency of the PHPP.

The state-of-the-art design of the PHPP employs the General Electric Power Systems (GE) Rapid Start Process (RSP) to minimize emissions during startup and increase the efficiency of the power plant. RSP allows for faster starting of the gas turbines by mitigating the restrictions of former HRSG designs. This design modification produces a significant reduction in startup time that minimizes GHG emissions during startup. Traditionally, the CTGs are brought to full load slowly to limit thermal stresses in the high-pressure (HP) steam drum of the HRSG due to the high exhaust temperature of the CTGs. The new GE RSP design eliminates this restriction by modifying the steam drum design. Additional equipment to support the RSP includes an auxiliary boiler, which will supply sealing steam and allow startup of the steam turbine shortly after the gas turbines.

A natural gas-fired combined-cycle power plant such as PHPP uses a relatively small amount of electricity to operate the facility compared to the energy in the fossil fuel combusted. Thus, there is negligible benefit in terms of energy efficiency and GHG emission reductions of the facility associated with lowering electricity usage at the facility compared to increasing the thermal efficiency of the process.

Addition of the high thermal efficiency of PHPP’s generation to the state’s electricity system will facilitate the integration of renewable resources in California’s generation supply and will displace other less efficient, higher GHG-emitting generation. Because the project’s GHG emissions per megawatt-hour (MWh) will be lower than those of other power plants that the project would displace, the addition of PHPP to California’s energy supply will contribute to a reduction of the California and overall Western Electricity Coordinating Council system GHG emissions and GHG emission rate average. Thus, although PHPP would emit GHG emissions, the high thermal efficiency of PHPP and the system build-out of renewable resources in California would result in a net cumulative reduction of GHG emissions from new and existing fossil resources (CEC 2010a).

California’s Renewable Portfolio Standard (RPS) was increased from 20% by 2010 to 33% by 2020 with the adoption of Senate Bill 2 on April 12, 2011. To meet the new RPS requirements, the amount of dispatchable, high-efficiency, natural gas generation used as regulation resources, fast ramping resources, or load following or supplemental energy dispatches will have to be significantly increased. The construction of the PHPP will aid in the effort to meet California's RPS standard. Finally, the CEC has determined that the operation of PHPP will enhance the overall efficiency of California's electricity system operation and thereby reduce GHG emissions (CEC, 2010a).

In summary, state-of-the-art technologies including the RSP capability, highly efficient natural gas combustion, and the solar thermal component, are already integrated into PHPP and the project represents the apex of energy efficiency for similar plants.

3.2 Step 2 - Eliminate Technically Infeasible Options

The second step for the BACT analysis is to eliminate technically infeasible options from the control technologies identified in Step 1. For each option that was identified, a technology evaluation was conducted to determine the technical feasibility. The technology is feasible only when the technology is available and applicable. A technology that is not commercially available for the scale of the project is also considered infeasible. An available technology is applicable if it can be reasonably be installed and operated on the proposed project.

3.2.1 Carbon Capture and Sequestration

The technical feasibility of each step of the CCS alternative is discussed separately below.

Carbon Capture

There are three basic processes considered for post-combustion capture of CO_2 from flue gas.

Solvent-based process

There is limited experience available in the post-combustion solvent-based capture technology for a commercial scale power plant. Existing demonstration solvent-based capturing facilities for the power industries are only utilizing a fraction of the flue gas. Significant cost and operating issues would have to be addressed before such technology can be scaled up for a commercial scale power generation system. Consequently, a solvent-based carbon capture process is currently judged to be technologically infeasible for a commercial power plant application.

Sorbent-based process

Solid particle sorbents can be used for post-combustion capture of CO_2. Most of the U.S. Department of Energy (DOE) funded projects employing solid adsorption are in demonstration phase for coal-fired plants, but there currently are neither demonstration scale nor commercial scale installations for a combined-cycle gas turbine application. Consequently, a sorbent-based carbon capture process is currently judged to be technologically infeasible for a natural gas-fired commercial power plant application.

Membrane-based process

Membranes are commercially available in the chemical industry for CO_2 removal but have not been demonstrated in practice for power generation applications. Consequently, a membrane-based carbon capture process is currently judged to be technologically infeasible for a commercial power plant application.

CO_2 Transportation

The basic technologies required for CO_2 transportation (i.e., pipeline, tanker truck, ship) are in commercial use today for a number of applications and can be considered commercially available for liquid CO_2.

Sequestration

Geologic Sequestration

Geologic sequestration has been demonstrated on the pilot scale. These pilot scale projects indicate that geologic sequestration has potential to be a viable long-term storage solution for CO_2. However, a number of significant technical issues remain to be resolved before the technology can be applied to a successful commercial scale application at a specific site. These technical issues include:

- A suitable geologic repository must exist for injection of the recovered CO_2. The repository must have one or more injection zones that can accept and store large quantities of CO_2 and is overlain by suitable caprocks.
- The geologic repository must capable of sequestering the CO_2 for the length of time necessary to accomplish the goal of sequestration. The seismicity of Southern California works against long-term sequestration and there are very limited locations in Southern California that meet these requirements.
- The geologic repository is located close enough to the power plant such that efficient transport of the recovered CO_2 is possible.
- Standards for site security, and for measuring, monitoring, and verification (MMV) of containment must be established to allow confidence that long-term sequestration will occur.

Without existing detailed hydrogeologic studies of nearby potentially suitable repositories, the solution of long-term containment issues associated with the seismicity of Southern California, and standards for long-term security and MMV, the technical feasibility for geological sequestration for the PHPP cannot be determined. Therefore CCS using geological sequestration cannot be demonstrated to be technically feasible in practice for the PHPP.

Ocean Storage

Ocean storage and its ecological impacts are still in the research phase. Given the potential for acidification of the oceans and the resultant biological consequences such as the weakening of the carbonate shells of marine invertrabrates, the use of ocean storage may never be realized. Using the oceans as a storage location for CO_2 is essentially moving the issue from climatic impacts to biological and marine impacts. Long term studies are still required to understand the potential unintended consequences of such disposal of CO_2 in ocean basins before ocean storage can be considered to be technically feasible.

Mineral Carbonation

The formation of metal carbonates is technically feasible, as reaction chemistry is well understood. However, the sequestration of CO_2 through mineral carbonation has not been demonstrated on a commercial scale.

Summary of CCS Feasibility

In summary, the post-combustion carbon capture technologies are still in the development stage or pilot scale projects. These technologies would not be considered commercially availability for the project size of a full-scale commercial power plant. In addition, there are no comprehensive standards in place defining requirements for security and MMV to verify long term sequestration. Therefore, CCS is not yet demonstrated in practice for a commercial scale natural gas power plant such as PHPP.

In consideration of the uncertainty in the technical feasibility of CCS and its emergence as a promising technology, CCS is carried forward in this BACT analysis as a potential GHG control technology. However, substantial evidence demonstrates that CCS is not yet demonstrated as technically feasible for PHPP.

3.2.2 Lower Emitting Alternative Technology

As discussed previously, any of the commercially available low GHG-emitting technologies that could be implemented, including additional solar thermal generating capacity, were determined to be infeasible for this site (CEC 2010a) and would fundamentally alter the business purpose of the emission source. As such, lower emitting alternative technology was not considered as part of the BACT analysis (EPA 2010b, pg. 27).

3.2.3 Thermal Efficiency

The State of California has established a GHG performance standard of 1,100 pounds of CO_2 per MWh. Senate Bill (SB) 1368 required the CPUC to establish a GHG emission performance standard for base load generation from investor owned utilities by February 1, 2007. The CEC was required to establish a similar standard for local publicly owned utilities by June 30, 2007. These standards cannot exceed the GHG emission rate from a base load combined-cycle natural gas-fired plant of 1,100 pounds per MW-hour. The California Legislature in Assembly Bill (AB) 1613 (2007), as amended by AB 2791 (2008), established a CO_2 Emission Performance Standard (EPS) for combined heat and power facilities of 1,100 lbs CO_2/MWh. In 2010, the CEC promulgated its regulation to implement AB 1613 in its Guidelines for Certification of Combined Heat and Power Systems Pursuant to the Waste Heat and Carbon Emissions Reduction Act (CEC 2010b).

The PHPP meets the California GHG emission performance standard (EPS) of 1,100 pounds of CO_2 per MWh with its state-of-the-art natural gas combustion turbines with RSP technology. As presented below in Table 3, the PHPP will emit CO_2 at a rate of 0.370 MT CO_2/MWh (815 lb/MWh), well below the required EPS. In addition, PHPP has added a low-emitting component to the project in the form of its 50 MW of dispatchable solar thermal generation capability, which further improves the power plant's efficiency.

The thermal efficiency for the PHPP achieved by the state-of-the-art technologies described above is a technically feasible alternative for reducing GHG emissions from a fossil-fuel fired power plant. The conclusion is that the combustion process inherent in the PHPP is achieved in practice and is eligible for consideration under Step 3 of the BACT analysis.

3.3 Step 3 - Rank Remaining Control Technologies

While CCS was determined to be technically infeasible for this Project, the Applicant understands that the technical feasibility of CCS is a topic of considerable uncertainty and technical debate and, therefore, this option is carried forward in the BACT analysis to Step 3. The rank order of control, starting from the most effective control (1) to the least effective control (2), is as follows:

1. CCS

2. Thermal efficiency

The control effectiveness is explained below.

3.3.1 Carbon Capture and Sequestration

Post-combustion capture systems being developed are expected to be capable of capturing more than 90 percent of flue gas CO_2. At an assumed control efficiency of 90%, this would be equivalent to an emission rate of 10 percent of the California EPS, or approximately 110 lb CO_2/MWh. This makes CCS the top-ranked technology on a theoretical basis. However, as discussed in Step 2, CCS was found to be technically infeasible for PHPP.

3.3.2 Thermal Efficiency

Thermal efficiency is capable of lowering GHG emissions, but the potential is much less than CCS on a theoretic basis. As discussed in Section 2, PHPP already incorporates increased thermal efficiency in its design by incorporation of state-of-the-art combined-cycle combustion turbines with the addition of RPS startup capability. Since the parasitic load is already relatively low at this facility, further increases to thermal efficiency are not achievable without changing basic objectives of the power project, if at all, and hence are not required by EPA guidelines for GHG BACT (EPA 2010b).

3.4 Step 4 - Evaluating the Most Effective Controls

Step 4 of the BACT analysis is to evaluate the most effective control. This step involves the consideration of energy, environmental, and economic impacts associated with each control technology. The top-down approach requires that the evaluation begin with the most effective technology.

3.4.1 Carbon Capture and Sequestration

As noted earlier, at this time, the Applicant does not believe that CCS is technically feasible for application at PHPP; however, it was carried forward to Step 4 of this analysis. At this point, CCS is evaluated for economic, energy, or environmental impacts. Regarding economic impacts, in its PSD BACT guidance, EPA states:

> *EPA recognizes that at present CCS is an expensive technology, largely because of the costs associated with CO_2 capture and compression, and these costs will generally make the price of electricity from power plants with CCS uncompetitive compared to electricity from plants with other GHG controls. Even if not eliminated in Step 2 of the BACT analysis, on the basis of the current costs of CCS, we expect that CCS will often be eliminated from consideration in Step 4 of the BACT analysis, even in some cases where underground storage of the captured CO_2 near the power plant is feasible. However, there may be cases at present where the economics of CCS are more favorable (for example, where the captured CO_2 could be readily sold for enhanced oil recovery), making CCS a more viable option under Step 4.* (EPA 2010b).

In addition to the cost of CO_2 capture, CCS involves geologic or terrestrial sequestration or conversion of the CO_2 into long-term storage. The costs associated with sequestration are very site-specific and can involve substantial costs for items such geotechnical studies to define identify and define feasible potential repositories, pipeline construction, pumping, drilling and well construction, and monitoring. Due to these limitations, quantitative cost analyses were determined to be both impractical and unreliable for this analysis and were not performed. In addition, as CCS has been determined to be not feasible for PHPP, the expenditure of funds for these studies is not warranted.

In order to determine a capture/control efficiency for CCS, there must be sufficient technical data including drilling studies, pilot studies, and geotechnical studies. Currently those data are unavailable to even estimate a control efficiency. Therefore CCS can only be looked at qualitatively as whether it is feasible or not. Since a control efficiency cannot be established, even with cost information available, there is insufficient information for the denominator of the BACT formula to calculate a dollar per ton of CO_2 controlled. Therefore the cost feasibility of CCS cannot be provided.

As noted in Section 3.1, the database review found information about two IGCC facilities, including the Hyperion Energy Center. Because the IGCC technology is fundamentally different than the power generation units being proposed by PHPP, the GHG BACT findings are not considered relevant to PHPP; however, there is interesting information related to CCS. In February 2011, the South Dakota Department of Environment and Natural Resources (SD-DENR) issued a draft PSD permit for this 400,000 barrel per day greenfield petroleum refinery proposed by Hyperion Energy. The permit covers the refinery and an associated IGCC plant that will power the refinery's operations. As discussed in its statement of basis for the permit, SD-DENR conducted an extensive analysis of BACT for GHG emissions, including consideration of CCS. According to SD-DENR's analysis, the implementation of CCS at the Hyperion refinery would require an additional 400 MW of power generation capacity for gas drying and boosting, and the additional power generation capacity required to run CCS would significantly increase emissions of conventional pollutants, increase energy demands, and emit 23 percent of the GHG emissions that the CCS was designed to capture. SD-DENR rejected CCS as BACT for GHG emissions based on these factors and its high costs. Through a comparison of GHG emissions at other refineries, SD-DENR concluded that Hyperion's proposed measures of good combustion practices and energy efficiency measures incorporated into the plant design were BACT (Vinson & Elkins 2011).

As described in Step 2, CCS is not technically feasible for the PHPP. Even to the extent there is any uncertainty regarding the feasibility determination in Step 2, this Step 4 analysis demonstrates that CCS is not cost effective for CO_2 control from the proposed Project, and has been eliminated from further consideration.

3.4.2 Thermal Efficiency

The database review of BACT determinations described in Section 3.1 identified two facilities with natural gas-fired combined-cycle combustion turbines for which a GHG BACT analysis was done:

- The Bay Area Air Quality Management District (BAAQMD) issued a GHG BACT determination for the Calpine Russell City Energy Center in Hayward, Alameda County, California. According to a presentation by Calpine (Calpine 2010), thermal efficiency was the only feasible combustion control technology considered as CCS was determined to be not commercially available. Thermal efficiency was found to be the top level of control feasible for a combined-cycle power plant, and hence was the technology selected at GHG BACT for Russell City.

- A voluntary GHG BACT review was performed for the proposed addition of a 415 MW combined-cycle power plant at the existing Carty Power Plant operated by Portland General Electric Company near Boardman, Oregon (SLR International 2010). This review concluded that using natural gas fuel, with good operation and maintenance to maintain the thermal efficiency, was BACT for the GHG emissions.

Because the Russell City Energy Facility is similar to the PHPP, its thermal efficiency is compared to PHPP. The PHPP compares favorably with the Russell City facility in terms of energy efficiency of the CTGs proposed for each facility. In order to compare the thermal efficiency of the two facilities, the Power Plant Efficiency section of the CEC FSA was reviewed for each facility. According to the CEC, the Russell City Energy Center (01-AFC-7C) will employ two Siemens Westinghouse 501FD Phase 2 combustion turbine generators with inlet air fogging systems and steam injection producing approximately 200 MW each, two multi-pressure HRSGs with duct burners, and one single 3-pressure, reheat, condensing STG producing a maximum of 235 MW, arranged in a two-on-one combined-cycle train, totaling approximately 600 MW (CEC 2002). The Russell City FSA states that the F-class turbines proposed by the Russell City Energy Center are nominally rated 550 MW of output and have a 55.8 percent efficiency Lower Heating Value (LHV) at International Standards Organization (ISO) conditions. By comparison, the CEC PHPP FSA (CEC 2010a) indicates PHPP will have a higher maximum full load efficiency of 56.5 percent at ISO conditions for the two GE Frame 7FA CTGs in a two-on-one combined-cycle power train nominally rated at 530 MW.

The PHPP CTG trains each will have slightly higher energy efficiency (56.5 v. 55.8) than does the Russell City facility by 0.7% percent based solely on the prime movers. The energy efficiency difference is even larger for two reasons. First, the PHPP will be located in the City of Palmdale at approximately 3,240 feet above sea level while the Russell City Energy Center is located approximately 16 feet above sea level. Combustion turbine efficiency is sensitive to air density with higher efficiency at the higher air density of a lower altitude. Thus there is an energy efficiency associated with the PHPP due to it base elevation. Second, the stated energy efficiency for the PHPP is without the solar generating component contributing to the efficiency. When the solar generation is added into the analysis, the PHPP thermal efficiency will increase. Consequently, the use of GE Frame7FA natural gas-fired CTGs produces an energy efficiency greater than that of the Russell City Energy Center, the one power generation facility in California for which a GHG BACT level has been established.

The thermal efficiency of operating power generation facilities in Southern California, in terms of GHG performance, has been compared by the CEC in the FSA for the PHPP project (CEC 2010a). The thermal efficiency of the PHPP is the lowest (i.e., best) of any of the 37 power generation facilities listed in Greenhouse Gas Tables 4 and 5 in the FSA (Tables 3 and 4, below) examined by the CEC. In fact, the PHPP exceeds the next best facility (La Paloma Generating Station) by 5.6 percent. Once it is in operation, the PHPP will be one of the most thermally efficient power plants in Southern California. Consequently, the PHPP meets any reasonable thermal efficiency standard for definition as BACT.

3.5 Step 5 - Select BACT

Based on the above analysis, thermal efficiency is the only technically and economically feasible alternative for CO_2 / GHG emissions control at PHPP and the current design of the facility meets the BACT requirement for GHG emission reductions. For the PHPP, the BACT emission limit for each combustion turbine generating unit should be 930,000 metric tons of CO_2 per year, rounded up to two significant figures. Compliance can be based on a 12-month rolling average, as determined using a CO_2 Continuous Emissions Monitoring System (CEMS) for each CTG unit.

Table 3 Local Generation Heat Rates and 2008 Energy Outputs, Los Angeles Basin

Plant Name	Heat Rate (Btu/kWh)[a]	2008 Energy Output (GWh)	GHG Performance ($MTCO_2$/MWh)[c]
Palmdale Hybrid Power Project	**6,970**	**4,993** [b]	**0.370**
Watson Cgeneration Co	8,512	3,017	0.452
Corona Cogen	9,430	274	0.500
Civic Center	9,447	467	0.501
San Gabriel	9,859	155	0.523
THUMS	10,123	379	0.537
ARCO Products Co	10,140	477	0.538
Harbor Cogeneration Co	10,649	44	0.565
Alamitos	10,782	2,533	0.572
Huntington Beach (AES)	10,927	1,536	0.580
El Segundo Power	11,044	508	0.586
Carson Cogeneration Co	11,513	540	0.611
Redondo Beach LLC (AES)	11,726	317	0.622
Total Energy Facilities	12,281	137	0.652
Torrance Refinery	12,370	161	0.656
Long Beach Generation LLC	15,323	27	0.813
UCLA Energy Systems Facility	15,418	206	0.818
BP West Coast Wilmington Calciner	16,953	201	0.900

Source: CEC PHPP FSA (2010a), Greenhouse Table 4. Energy Commission staff based on Quarterly Fuel and Energy Report (QFER); with independent Energy Commission staff analysis for PHPP based on maximum utilization.

Notes:

a. Based on the Higher Heating Value or HHV of the fuel.
b. Includes solar generation component
c. Based on continuous operation at peak capacity.

Table 4 Local Generation Heat Rates and 2008 Energy Outputs, Big Creek/Ventura LSA

Plant Name	Heat Rate (Btu/kWh)[a]	2008 Energy Output (GWh)[b]	GHG Performance ($MTCO_2$/MWh)[c]
Palmdale Hybrid Power Project	**6,970**	**4,993**[c]	**0.370**
La Paloma Generating	7,172	6,185	0.392
Pastoria Energy Facility LLC	7,025	4,905	0.384
Sunrise Power	7,266	3,605	0.397
Elk Hills Power, LLC	7,048	3,552	0.374
Sycamore Cogeneration Co	12,398	2,096	0.677
Midway-Sunset Cogeneration	11,805	1,941	0.645
Kern River Cogeneration Co	13,934	1,258	0.761
Ormond Beach Generating Station	10,656	783	0.582
Mandalay Generating Station	10,082	597	0.551
McKittrick Cogeneration Plant	7,732	592	0.422
Mt Poso Cogeneration (coal/pet. coke)	9,934	410	0.930
South Belridge Cogen Facility	11,452	409	0.625
McKittrick Cogeneration	9,037	378	0.494
KRCD Malaga Peaking Plant [d]	9,957	151	0.528
Henrietta Peaker [d]	10,351	48	0.549
CalPeak Power – Panoche	10,376	7	0.550
Wellhead Power Gates, LLC [d]	12,305	5	0.652
Wellhead Power Panoche, LLC [d]	13,716	3	0.727
MMC Mid-Sun, LLC [d]	12,738	1.4	0.675
Fresno Cogen Partners, LP PKR [d]	16,898	0.8	0.896

Source: CEC PHPP FSA (2010a), Greenhouse Table 5. Energy Commission staff based on Quarterly Fuel and Energy Report (QFER); with independent Energy Commission staff analysis for PHPP based on maximum utilization.

Notes:

a. Based on the Higher Heating Value or HHV of the fuel.
b. Includes solar generation component
c. Based on continuous operation at peak capacity.
d. Peaker facility

4.0 Auxiliary Boiler and HTF Heater GHG BACT Analysis

The auxiliary boiler is part of the RSP system. The RSP offered by GE, the expected supplier of the Project's combustion equipment, allows for faster starting of the gas turbines by mitigating the restrictions of former HRSG designs. Traditionally, the CTGs are brought to full load slowly to limit thermal stresses in the HP steam drum of the HRSG due to the exhaust temperature of the CTGs. The GE RSP design eliminates this restriction by modifying the steam drum design. Equipment required to support the RSP includes an auxiliary boiler, which will supply sealing steam and allow startup of the steam turbine shortly after the gas turbines.

As part of the RSP design, the auxiliary boiler is an essential part of the emission control system for the conventional criteria pollutants during start-up periods, specifically, NOx, CO and VOC. As such, removing or eliminating the boiler would be detrimental to the overall plant emissions.

PHPP will also have an HTF heater. The HTF heater will be needed for the solar thermal component of the Project design. The HTF heater is used infrequently to prevent the HTF from freezing on cold nights. Because boilers and heaters operate similarly, the GHG BACT for both these equipment are discussed together.

4.1 Step 1 - Identification of Available Control Technologies

The first step in this top-down analysis is to identify available control technology options. For review of the CO_2 control technologies for the auxiliary boiler and HTF heater, the following list of potentially applicable technologies available is evaluated:

- Carbon Capture and Sequestration; and
- Thermal Efficiency

4.1.1 Carbon Capture and Sequestration

Considering the design size, purpose, and operation of the auxiliary boiler and HTF heater, post-combustion carbon capture is the only possible means of capturing CO_2 emissions. CO_2 emissions from the flue gas can be separated by the solvent, sorbent or membrane based technologies. Separated CO_2 would be compressed, transported and stored in geological, oceanic or mineral formations.

4.1.2 Thermal Efficiency

Thermal efficiency is a control technology for CO_2 because fuel use is directly related to CO_2 emissions from the auxiliary boiler and HTF heater. Periodic tune-up and automated adjustment of air intake improves the thermal efficiency of the boiler and heater.

4.2 Step 2 - Eliminating Technically Infeasible Options

The second step of the BACT analysis is to eliminate technically infeasible options from the control technologies identified in Step 1.

4.2.1 Carbon Capture and Sequestration

As discussed in Section 3.1.1, CCS control technologies are either at pilot, demonstration or bench scale levels. Based on EPA and DOE assessments, CCS is not a technically feasible control technology for the control of CO_2 emissions from a small auxiliary boiler or HTF heater.

4.2.2 Thermal Efficiency

Thermal efficiency is a technically feasible alternative. It is achieved by combusting natural gas and use of best operating practice and operating procedures.

4.3 Step 3 - Rank Remaining Control Technologies

The third step of the BACT analysis is to rank the feasible control technologies; the following are the list of control technologies to be considered:

- Thermal Efficiency.

Thermal efficiency is capable of lowering GHG emissions, but is not quantified for the auxiliary boiler or small HTF heater, and is less than 100 percent.

4.4 Step 4 - Evaluation of Most Effective Control

Thermal efficiency is the only remaining technology.

4.5 Step 5 - Select BACT

Thermal efficiency is selected as BACT. Combustion of natural gas and implementation of best operating practice including periodic tune-up and automated adjustment of air intake will maintains the thermal efficiencies of the auxiliary boiler and HTF heater at or near their design values.

5.0 References

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Appendix A

GHG Emissions Calculations

PHPP Greenhouse Gas Emissions

This appendix contains a description of the greenhouse gas (GHG) emissions calculated for the Palmdale Hybrid Power Project (PHPP).

The combustion sources and circuit breakers proposed for PHPP may emit greenhouse gases (GHG), including carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), and sulfur hexafluoride (SF_6). The methodology used to calculate GHG emissions from these sources is explained below.

Combustion Turbine and Duct Burner GHG Emissions

GHG emissions from operation of each of the two combustion turbines and duct burners are based upon the estimated usage of each at 8,760 hours/year, the estimated natural gas usage rate of 1.93 million standard cubic feet per hour (MMscf/hr), the estimated heat content of natural gas of 1,024 Btu/scf and the emission factors listed in Tables C.6 and C.7 of the California Climate Action Registry General Reporting Protocol (GRP), Version 3.0.[1] Annual emissions of GHG are calculated using Equation A-1. Emission calculations are shown in Table A-1.

$$E_{GHG} = \text{Fuel} \times \text{Operation} \times \text{HV} \times EF_{GHG} \times \text{conversion factor} \quad \text{(Eq. A-1)}$$

Where:

E_{GHG}	=	Emissions_{GHG} (metric tons/yr)
Fuel	=	natural gas usage rate (MMscf/hr)
Operation	=	Operating schedule (hrs/yr)
HV	=	heating value of natural gas (MMBtu/MMscf)
EF_{GHG}	=	emission factor for each GHG from Tables C.6 and C.7 of GRP (kg/MMBtu)
conversion factor	=	conversion factor for kilograms to metric tons

Auxiliary Boiler and HTF Heater GHG Emissions

GHG emissions from operation of the 100 MMBtu per hour auxiliary boiler and 40 MMBtu per hour HTF heater are based upon the estimated usage of the units by the Project (500 hours per year for the boiler and 1,000 hours per year for the heater) and the emission factors listed in Tables C.6 and C.7 of the GRP.[1] Annual emissions of GHG are calculated using Equation A-1. Emission calculations are shown in Table A-1.

Emergency Internal Combustion Engine GHG Emissions

GHG emissions from operation of the emergency diesel-fueled engines are based upon the estimated usage by the Project (50 hours per year, per engine), the estimated fuel consumption and the emission factors listed in Tables C.6 and C.7 of the GRP.[1] The emissions are calculated according to Equation A-2. Emission calculations are shown in Table A-1. Note that the GHG emissions are estimated for maintenance and testing operations, and do not reflect emergency use.

[1] GRP, 2008. California Climate Action Registry General Reporting Protocol, Version 3.0, April.

E_{GHG} = fuel use x EF_{GHG} x conversion factor (Eq. A-2)

Where: E_{GHG} = $Emissions_{GHG}$, (metric tons/yr)
EF_{GHG} = emission factor for each GHG from Tables C.6 and C.7 of GRP
conversion factor = conversion factor for kg to metric tons

Circuit Breakers

There are 160 pounds of SF_6 in use in circuit breakers in the Project equipment. Emissions are calculated according to Equation A-3.

E_{SF6} = Q x LR / 2,200 lbs/ton (Eq. A-3)

Where: E_{SF6} = Emissions of SF6 (metric tons/yr)
Q = Quantity of SF6 in the Project circuit breakers
LR = Leak Rate (dimensionless)

The SF_6 leakage rate from operating equipment is guaranteed at 0.5 percent per year and can be kept below 0.2 percent per year with current best technology. At the maximum guaranteed leak rate of 0.5 percent, this corresponds to 0.8 pounds per year of emissions, or 8.7 metric tons /year of CO_2 equivalent (CO_2e) emissions. The more probable, technically feasible leak rate is 0.2 percent, which corresponds to approximately 3.5 metric tons CO_2e emissions per year, or 105 metric tons CO_2e emissions over the 30-year plant lifetime. Emission summaries are shown in Table A-1. Emission calculations are shown in Attachment 1 to this appendix.

On-site Vehicular Traffic

GHG emissions from on-site light-duty vehicles (LDV), heavy-duty trucks (HDT) and the mirror wash vehicle are based upon the predicted annual miles traveled for the Project, average fuel economy values from the EMFAC2007 BURDEN model[2] results for 2009, and the emission factors listed in Tables C.4 and C.5 of the GRP.[1] Annual emissions of GHG are calculated using the following equations:

CO_2, metric tons/yr = (AR/ M) x EF x conversion factor of kg to metric tons (Eq. A-4)

Where: AR = vehicle-miles-traveled (miles/year)
M = distance traveled per gallon of fuel consumed (miles/gallon)
EF = CO_2 emission factor (kg/gal)

Methane (CH_4) and nitrous oxide (N_2O) emissions are calculated according to Equation A-5.

CH_4 or N_2O, metric tons/yr = AR x EF x conversion factor of kg to metric tons (Eq. A-5)

Where: AR = vehicle-miles-traveled (miles/year)
EF = CH_4 or N_2O emission factor (kg/mile)

Emission calculations are shown in Table A-2.

[2] ARB, 2007. California Air Resources Board EMFAC2007 (version 2.3) Burden Model available online at: http://www.arb.ca.gov/msei/onroad/latest_version.htm.

Summary of GHG Emissions

CO_2 equivalent emissions are calculated using the global warming potential (GWP) provided in Appendix A.3, Table 2 of California Air Resources Board Mandatory Reporting of Greenhouse Gas Emissions Regulation[3]. The GWP values used are 1 for CO_2, 21 for methane, 310 for nitrous oxide, and 23,900 for sulfur hexafluoride. Total CO_2e emissions are shown in Table A-1. Due to the inherent uncertainties in these calculations, emission should be rounded up to two significant digits.

[3] California Code of Regulations, Title 17, Subchapter 10, Article 2, Sections 95100 to 95133.

Table A-1 Estimated Potential Greenhouse Gas (GHG) Emissions

Source	Annual Usage, MMBTU/year	Annual Usage, gallons/year	CO_2 Emission Factor, kg CO_2/MMBTU (a)	CH_4 Emission Factor, kg CH_4/MMBTU (b)	N_2O Emission Factor, kg N_2O/MMBTU (b)	CH_4 Emission Factor, kg CH_4/gallon (b)	N_2O Emission Factor, kg N_2O/gallon (b)	CO_2 Emissions, metric tons/year	CH_4 Emissions, metric tons/year	N_2O Emissions, metric tons/year	SF_6 Emissions, metric tons/year	CO_2 Equivalents, metric tons/year
Turbine 1	17,356,845	--	53.06	0.0059	0.0001	--	--	920,954	102	1.74		923,643
Turbine 2	17,356,845	--	53.06	0.0059	0.0001	--	--	920,954	102	1.74		923,643
Auxiliary Boiler	50,000	--	53.06	0.0059	0.0001	--	--	2,653	0.30	5.00E-03		2,661
HTF Heater	40,000	--	53.06	0.0059	0.0001	--	--	2,122	0.24	4.00E-03		2,129
Emergency Generator	341	2,633	73.15	--	--	0.0003	0.0001	25	2.63E-04	2.63E-04		25
Fire Pump	50	390	73.15	--	--	0.0003	0.0001	4	3.90E-05	3.90E-05		4
SF_6 in circuit breakers											3.63E-04	8.67
Vehicles								10	1.00E-03	1.19E-03		10.33
TOTAL								1,846,722	205	3.48	3.63E-04	1,852,123

Notes:

(a) Table C.6, California Climate Action Registry General Reporting Protocol, Version 3.0, April 2008

(b) Table C.7, Industrial Sector, California Climate Action Registry General Reporting Protocol, Version 3.0, April 2008

Diesel fuel heat content, BTUs/gallon - 129,500

Global warming potential of CH4, Table C.1, California Climate Action Registry General Reporting Protocol, Version 3.0, April 2008 - 21

Global warming potential of N2O, Table C.1, California Climate Action Registry General Reporting Protocol, Version 3.0, April 2008 - 310

Global warming potential of SF6, Table C.1, California Climate Action Registry General Reporting Protocol, Version 3.0, April 2008 - 23900

Table A-2 GHG Emissions from On-Site Vehicular Traffic – Operation

Activity	Amount	Units
Heavy-duty truck trips	136	mi/yr
Light-duty vehicle trips	19,200	mi/yr
Water rinse truck	600	mi/yr
Heavy heavy -duty truck gas mileage	5.37	mpg
Light-duty vehicle gas mileage	19.1	mpg
Reference: EMFAC2007 V2.3 November 1, 2006, KCAPCD Burden 2009		

Activity	Amount	Units	Amount	Units	Emission Factor Category	CO_2 EF, kg/gal	CH_4 EF, g/mi	N_2O EF, g/mi	CO_2 Emissions, metric tons/year	CH_4 Emissions, metric tons/year	N_2O Emissions, metric tons/year	CO_2e emissions, metric tons/year
Heavy-duty truck trips	136	miles/yr	25	gal/yr	HDT diesel 1996+ model year	9.96	0.06	0.05	0.25	0.0000	0.0000	0.25
Light-duty vehicle trips	19,200	miles/yr	1,003	gal/yr	LDT gasoline 2000+ model year	8.55	0.05	0.06	8.6	0.0010	0.0012	9.0
Water rinse truck	600	miles/yr	112	gal/yr	HDT diesel 1996+ model year	9.96	0.06	0.05	1.11	0.0000	0.0000	1.12
Total	19,936	miles/yr	1,141	gal/yr					9.95	0.00	0.00	10.33
Notes: CO2e = CO2 emisions + 21 x CH4 emissions + 310 x N2O emissions												