Appendix 5.1D
Criteria Pollutant and Greenhouse BACT Analysis

BACT Determination for the Huntington Beach Energy Project

Prepared for

AES Southland Development, LLC

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Acronyms and Abbreviations

°F	degree(s) Fahrenheit
AES-SLD	AES Southland Development, LLC
AFC	Application for Certification
BAAQMD	Bay Area Air Quality Management District
BACT	best available control technology
Btu/kWh	British thermal units per kilowatt-hour
CAISO	California Independent System Operator
CARB	California Air Resources Board
CCS	carbon capture and storage
CEC	California Energy Commission
CFR	Code of Federal Regulations
CH_4	methane
CO	carbon monoxide
CO_2	carbon dioxide
CPUC	California Public Utilities Commission
CPV	Competitive Power Ventures
CTG	combustion turbine generator
DLN	dry low NO_x
DOE	U.S. Department of Energy
EOR	enhanced oil recovery
EPA	U.S. Environmental Protection Agency
GHG Tailoring Rule	Prevention of Significant Deterioration and Title V Greenhouse Gas Tailoring Rule
GHG	greenhouse gases
GWh	gigawatt-hour(s)
H_2	hydrogen
HBEP	Huntington Beach Energy Project
HFC	hydrofluorocarbon
HHV	higher heating value
HRSG	heat recovery steam generator
IPCC	Intergovernmental Panel on Climate Change
LAER	Lowest Achievable Emission Rate
lb/hr	pound(s) per hour
lb/MMBtu	pound(s) per million British thermal unit
LHV	lower heating value
Mandatory Reporting Rule	EPA Final Mandatory Reporting of Greenhouse Gases Rule
MMBtu	million British thermal units
MMBtu/hr	million British thermal units per hour
MPSA	Mitsubishi Power Systems Americas
$MTCO_2$/MWh	metric ton(s) of carbon dioxide per megawatt-hour
MW	megawatt(s)
MWh	megawatt-hour(s)
N_2	nitrogen

N_2O	nitrous oxide
NATCARB	National Carbon Sequestration Database and Geographic Information System
NETL	National Energy Technology Laboratory
NGCC	natural gas combined-cycle
NO	nitric oxide
NO_2	nitrogen dioxide
NO_x	oxides of nitrogen
NSR	New Source Review
O_2	oxygen
OTC	once-through cooling
PFC	perfluorocarbons
PM_{10}	and particulate matter less than 10 microns in diameter
$PM_{2.5}$	particulate matter less than 2.5 microns in diameter
ppm	part(s) per million
ppmv	part(s) per million by volume
ppmvd	part(s) per million dry volume
PSA	pressure swing adsorption
PSD	Prevention of Significant Deterioration
psig	pound(s) of force per square inch gauge
PTE	Potential to Emit
RACT	Retrofit Available Control Technology
RCEC	Russell City Energy Center
RPS	Renewable Portfolio Standard
SCAQMD	South Coast Air Quality Management District
scf	standard cubic feet
SCR	selective catalytic reduction
SF_6	sulfur hexafluoride
SJVAPCD	San Joaquin Valley Air Pollution Control District
SNCR	selective non-catalytic reduction
SO_2	sulfur dioxide
SoCalCarb	Southern California Carbon Sequestration Research Consortium
SoCalGas	Southern California Gas
SO_x	sulfur oxides
STG	steam turbine generator
SWRCB	State Water Resources Control Board
tpy	ton(s) per year
VOC	volatile organic compound
WestCarb	West Coast Regional Carbon Sequestration Partnership

SECTION 1

Project Description

1.1 Project Overview

AES Southland Development, LLC (AES-SLD) proposes to construct the Huntington Beach Energy Project (HBEP) at the existing AES Huntington Beach Generating Station site at 21730 Newland Street, Huntington Beach, California 92646. HBEP will consist of two, three-on-one combined-cycle power blocks with a net capacity of 939 megawatts (MW). Each power block will consist of three Mitsubishi Power Systems Americas (MPSA) 501DA combustion turbines (CTG), one steam turbine generator (STG), and an air-cooled condenser. Each combustion turbine will be equipped with a heat recovery steam generator (HRSG) and will employ supplemental natural gas firing (duct burning). The turbines will use dry low NO_x (DLN) burners and selective catalytic reduction (SCR) to limit NO_x (oxides of nitrogen) emissions to 2 parts per million by volume (ppmv). Emissions of carbon monoxide (CO) will be limited to 2 ppmv and volatile organic compounds (VOC) to 1 ppmv through the use of best combustion practices and an oxidation catalyst. Best combustion practices and burning pipeline-quality natural gas will minimize emissions of the remaining pollutants.

HBEP will retain the use of the two existing 275-horsepower diesel-fired emergency fire water pumps installed during the Huntington Beach Generating Station Units 3 and 4 retooling project in 2001. Because the existing fire water pumps are permitted sources by the South Coast Air Quality Management District (SCAQMD) and are not being modified nor will change their operating profile, the project owner has not included the fire pumps in the best available control technology (BACT) analysis for HBEP.

Authorization for the construction and operation of HBEP will be through the California Energy Commission (CEC) Application for Certification (AFC) licensing process and the SCAQMD New Source Review/Prevention of Significant Deterioration (NSR/PSD) permitting process. Because HBEP includes the use of steam to generate electricity, the project is also categorized as one of the 28 major PSD source categories (40 Code of Federal Regulations [CFR] 52.21(b)(1)(i)). Therefore, the project is subject to PSD permitting requirements if the Potential to Emit (PTE) from the project exceeds 100 tons per year (tpy) for any regulated pollutant, with the exception of greenhouse gases (GHG). The threshold for GHGs is a PTE of 100,000 tpy. Because the existing Huntington Beach Generating Station Units 1 and 2 will be retired and removed as part of the project, the maximum 2-year historical past actual emissions from these two units between calendar years 2007 and 2011 will be subtracted from the PTE for HBEP.

Despite the netting analysis, the resulting PTE is still expected to exceed the 100-tpy or 100,000-tpy threshold for at least one of the PSD-regulated pollutants. Therefore, the project will be considered a major stationary source in accordance with PSD regulations. The SCAQMD has also been delegated partial PSD permitting authority.[1] Therefore, the PSD BACT analysis is being submitted to the SCAQMD as part of the permitting process.

1.2 Project Objectives

HBEP's key design objective is to provide up to 939 MW of environmentally responsible, cost-effective, operationally flexible, and efficient generating capacity to the western Los Angeles Basin Local Reliability Area in general, and specifically to the coastal area of Orange County. The project would serve local area reliability needs, southern California energy demand and provide controllable generation to allow the integration of the ever increasing contribution of intermittent renewable energy into the electrical grid. The project will displace older and less efficient generation in Southern California, and has been designed to start and stop very quickly and be able to quickly ramp up and down through a wide range of generating capacity. As more renewable electrical resources are brought on line as a result of electric utilities meeting California's Renewable Portfolio Standard,

[1] http://www.epa.gov/region09/air/permit/pdf/full-scagmd-psd-delegation.pdf

projects strategically located within load centers and designed for fast starts and ramp-up and down capability, such as HBEP, will be critical in supporting both local electrical reliability and grid stability.

HBEP will provide needed electric generation capacity with improved efficiency and operational flexibility to help meet southern California's long-term electricity needs. The California Independent System Operator (CAISO) has identified a need for new power generation facilities in the western Los Angeles Basin Local Reliability Area to replace the ocean water once-through-cooling (OTC) plants that are expected to retire as a result of the California State Water Resources Control Board's (SWRCB) *Water Quality Control Policy on the Use of Coastal and Estuarine Waters for Power Plant Cooling* (OTC Policy) (CAISO, 2012a; SWRCB, 2010). The base case study results from CAISO's year 2021 long-term Local Capacity Requirement proceeding estimates that between 2,424 and 3,834 MW of new generation is required in the Los Angeles Basin due to planned OTC retirements consistent with SWRCB OTC Policy. The requirement for new generation in light of OTC retirements in the Los Angeles Basin is also confirmed in CAISO's Once-Through Cooling and AB-1318 Study Results presented on December 8, 2011 (CAISO, 2011). CAISO also notes that many of the OTC facilities have characteristics that support renewable integration and that repower or replacement generating capacity must retain or improve upon such capabilities (CAISO, 2012b).

The project objectives are also contingent on the use of the offset exemption contained within the SCAQMD's Rule 1304(a)(2) that allows for the replacement of older, less-efficient electric utility steam boilers with specific new generation technologies on a megawatt-to-megawatt basis (that is, the replacement megawatts are equal to or less than the megawatts from the electric utility steam boilers). The offset exemption in Rule 1304(a)(2) requires the electric utility steam boiler be replaced with one of several specific technologies, including the combined-cycle configuration used by HBEP.

HBEP was designed to address the local capacity requirements within the Los Angeles Basin with the following objectives:

- Provide the most efficient, reliable, and predictable power supply available by using combined-cycle, natural-gas-fired combustion turbine technology to replace the OTC generation, support the local capacity requirements of Southern California's Western Los Angeles Basin and be consistent with SCAQMD Rule 1304(a)(2).
- Develop a 939-MW project that provides efficient operational flexibility with rapid-start and steep ramping capability (30 percent per minute) to allow for the efficient integration of renewable energy sources into the California electrical grid with competitive electrical generation pricing.
- Reuse existing electrical, water, wastewater, and natural gas infrastructure and land to the extent possible to minimize terrestrial resource and environmental justice impacts by developing on a brownfield site.
- Secure a sufficient-sized site to maintain existing generating capacity to meet regional grid reliability requirements during the development of HBEP.
- Site the project to serve the Western Los Angeles Basin load center without constructing new transmission facilities.
- Assist the State of California in developing increased local generation projects, thus reducing dependence on imported power.
- Site the project on property that has industrial land use designation with consistent zoning.
- Ensure potential environmental impacts can be avoided, eliminated, or mitigated to a less-than-significant level.

Locating the project on an existing power plant site avoids the need to construct new linear facilities, including gas and water supply lines, discharge lines, and transmission interconnections. This reduces potential offsite environmental impacts, and the cost of construction. The proposed HBEP site meets all project siting objectives.

The HBEP will provide power to the grid to help meet the need for electricity and to help replace dirtier, less efficient fossil fuel generation resources retired because of the use of OTC. HBEP will enhance the reliability of the state's electrical system by providing power generation near the centers of electrical demand and providing fast response generating capacity to enable increased renewable energy development. Additionally, as demonstrated by the analyses contained in this AFC, the project would not result in any significant environmental impacts.

SECTION 2

Criteria Pollutant BACT Analysis

Based on the SCAQMD's BACT definition and major source thresholds (SCAQMD Rule 1302 and 1303), a BACT analysis is required for the uncontrolled emissions of NO_x, VOCs, CO, sulfur oxides (SO_x), and particulate matter less than 10 microns in diameter (PM_{10}) and particulate matter less than 2.5 microns in diameter ($PM_{2.5}$). Also, the U.S. Environmental Protection Agency (EPA) requires a BACT analysis for the emissions of GHGs as part of the PSD permit application required under the EPA Tailoring Rule. The GHG BACT analysis is included in the following section.

The project owner plans to rely on the response characteristics of the MPSA 501DA combustion turbines and duct burners to provide a wide range of efficient, operationally flexible, fast-start, fast-ramping capacity to allow for the efficient integration of renewable energy sources into the California electrical grid. The project owner has proposed two separate permit levels to allow the flexibility of operating the turbines with and without duct burners. The HBEP emission limits are presented in Table 2-1.

TABLE 2-1
Proposed Emission Limits for the Huntington Beach Energy Project

	Emission Limit (at 15 percent O_2)	
Pollutant	**Without Duct Burners**	**With Duct Burners**
NO_x	2.0 ppm (averaged over 1 hour)	2.0 ppm (averaged over 1 hour)
CO	2.0 ppm (averaged over 1 hour)	2.0 ppm (averaged over 1 hour)
VOC	1.0 ppm (averaged over 1 hour)	1.0 ppm (averaged over 3 hours)
PM_{10}	4.5 lb/hr	9.5 lb/hr
$PM_{2.5}$	4.5 lb/hr	9.5 lb/hr
SO_x	<0.75 grain of sulfur/100 scf of natural gas	<0.75 grain of sulfur/100 scf of natural gas

Notes:

lb/hr = pound(s) per hour
O_2 = oxygen
ppm = part(s) per million
scf = standard cubic feet

The following discussion presents an assessment of the BACT for HBEP (with and without duct burners) and includes the following components:

- Outline of the methodology used to conduct the criteria pollutant BACT analyses
- Discussion of the available technology options for controlling NO_x, CO, VOCs, PM_{10}, $PM_{2.5}$, and SO_x emissions
- Presentation of the proposed BACT emission levels identified for the HBEP

2.1 Methodology for Evaluating the Criteria Pollutant BACT Emission Levels

The NO_x, CO, VOC, PM_{10}, $PM_{2.5}$, and SO_x BACT analysis for the HBEP is based on the EPA's top-down analysis method. The following top-down analysis steps are listed in the EPA's *New Source Review Workshop Manual* (EPA, 1990):

- Step 1: Identify all control technologies
- Step 2: Eliminate technically infeasible options
- Step 3: Rank remaining control technologies by control effectiveness
- Step 4: Evaluate the most-effective controls, and document the results
- Step 5: Select the BACT

As part of the control technology ranking step (Step 3), emission limits for other recently permitted natural-gas-fired combustion turbines (with and without DUCT BURNERS) were compiled based on a search of the various federal, state, and local BACT, Retrofit Available Control Technology (RACT), and Lowest Achievable Emission Rate (LAER) databases. The following databases were included in the search:

- **EPA RACT/BACT/LAER Clearinghouse (EPA, 2012)**
  - Search included the NO_x, CO, VOC, PM, and sulfur dioxide (SO_2) BACT/LAER determinations for combined-cycle and cogeneration, large combustion turbines (greater than 25 MW) with permit dates between 2001 and April 2012.
- **California Air Pollution Control Officers Association / California Air Resources Board (CARB) BACT Clearinghouse (CARB, 2012)**
  - Search included the BACT determinations listed in CARB's BACT clearinghouse for combined-cycle turbines from all California air districts.
- **Local Air Pollution Control Districts BACT Guidelines/Clearinghouses:**
  - **SCAQMD BACT Guidelines (SCAQMD, 2012)**
    - Search included the BACT determinations for combined-cycle gas turbines listed in SCAQMD BACT Guidelines for major sources.
  - **Bay Area Air Quality Management District (BAAQMD) BACT/Toxics BACT Guidelines (BAAQMD, 2012)**
    - Search included the BACT determinations for combined-cycle turbines equal to or greater than 40 MW in Section 2, Combustion Sources, in the BAAQMD BACT Guidelines.
  - **San Joaquin Valley Air Pollution Control District (SJVAPCD) BACT Clearinghouse (SJVAPCD, 2012)**
    - Search included the BACT determinations listed under the SJVAPCD BACT Guideline Section 3.4.2 (combined-cycle, uniform-load gas turbines greater than 50 MW)
- **BACT Analyses for Recently Permitted Combustion Turbine CEC Projects (CEC, 2012)**
  - Review included the BACT analysis for the Pio Pico, GWF Tracy, Hanford, and Henrietta projects, the Oakley Generating Station Project, the Mariposa Energy Project, the Russell City Energy Center, the Los Esteros Critical Energy Facility – Phase 1 and Phase 2, the Palmdale Hybrid Power Project, and the Watson Cogeneration and Electric Reliability Project.

The natural-gas-fired combustion turbine permit emission limits for each of the BACT pollutants at other recently permitted facilities were then compared to the proposed emission limits for the HBEP, as set forth in Table 2-1. If the emission limits at other facilities were less than the values in Table 2-1, additional research was conducted to find which turbine technology had been selected and whether the facilities had been constructed (Step 3). If it could be demonstrated that other units with lower emission rates either had not yet been built or used a different turbine technology than that selected for the HBEP, the proposed emission limits for the HBEP were determined to be BACT (Step 5).

2.2 Criteria Pollutant BACT Analysis

2.2.1 Oxides of Nitrogen

NO_x is a byproduct of the combustion of an air-and-fuel mixture in a high-temperature environment. NO_x is formed when the heat of combustion causes the nitrogen (N_2) molecules in the combustion air to dissociate into individual N_2 atoms, which then combine with O_2 atoms to form nitric oxide (NO) and nitrogen dioxide (NO_2). The principal form of nitrogen oxide produced during turbine combustion is NO, but NO reacts quickly to form NO_2, creating a mixture of NO and NO_2 commonly called NO_x.

2.2.1.1 Identification of Combustion Turbine NO_x Emissions Control Technologies – Step 1

Several combustion and post-combustion technologies are available for controlling turbine NO_x emissions. Combustion controls minimize the amount of NO_x created during the combustion process, and post-combustion controls remove NO_x from the exhaust stream after the combustion has occurred. Following are the three basic strategies for reducing NO_x during the combustion process:

1. Reduction of the peak combustion temperature
2. Reduction in the amount of time the air and fuel mixture is exposed to the high combustion temperature
3. Reduction in the O_2 level in the primary combustion zone

Following is a discussion of the potential control technologies for combined-cycle and cogeneration combustion turbines:

NO_x Combustion Control Technologies. The two combustion controls for combustion turbines are (1) the use of water or steam injection, and (2) DLN combustors, which include lean premix and catalytic combustors.

Water or Steam Injection. The injection of water or steam into the combustor of a gas turbine quenches the flame and absorbs heat, reducing the combustion temperature. This temperature reduction reduces the formation of thermal NO_x. Water or steam injection also allows more fuel to be burned without overheating critical turbine parts, increasing the combustion turbine maximum power output. Combined with a post-combustion control technology, water or injection can achieve a NO_x emission of 25 part(s) per million dry volume (ppmvd) at 15 percent O_2, but with the added economic, energy, and environmental expense of using water.

DLN Combustors. Conventional combustors are diffusion-controlled. The fuel and air are injected separately, with combustion occurring at the stoichiometric interfaces. This method of combustion results in combustion "hot spots," which produce higher levels of NO_x. The lean premix and catalytic technologies are two types of DLN combustors that are available alternatives to the conventional combustors to reduce NO_x combustion "hot spots."

In the lean premix combustor, which is the most popular DLN combustor available, the combustors reduce the formation of thermal NO_x through the following: (1) using excess air to reduce the flame temperature (i.e., lean combustion); (2) reducing combustor residence time to limit exposure in a high-temperature environment; (3) mixing fuel and air in an initial "pre-combustion" stage to produce a lean and uniform fuel/air mixture that is delivered to a secondary stage where combustion takes place; and/or (4) achieving two-stage rich/lean combustion using a primary fuel-rich combustion stage to limit the amount of O_2 available to combine with N_2 and then a secondary lean burn-stage to complete combustion in a cooler environment. Lean premix combustors have only been developed for gas-fired turbines. The more-advanced designs are capable of achieving a 70- to 90 percent NO_x reduction with a vendor-guaranteed NO_x concentration of 9 to 25 ppmvd.

Catalytic combustors use a catalyst to allow the combustion reaction to take place with a lower peak flame temperature to reduce thermal NO_x formation. The catalytic combustor uses a flameless catalytic combustion module, followed by completion of combustion (at lower temperatures) downstream of the catalyst.

Neither water injection nor DLN combustors can control NO_x formed from the use of duct burners to supplementally fire the HRSGs in a combined cycle configuration. NO_x from duct burners is controlled by limiting the amount of duct firing required and with post-combustion pollution control technologies.

Post-combustion NO_x Control Technologies. Three post-combustion controls are available for combustion turbines: (1) SCR, (2) SCONOx™ (that is, EMx), and (3) selective non-catalytic reduction (SNCR). Both SCR and EMx control technologies use a catalyst bed to control the NO_x emissions and, combined with DLN or water injection, are capable of achieving NO_x emissions levels of 2.0 ppmvd for combined-cycle gas turbines. EMx uses a hydrogen regeneration gas to convert the NO_x to elemental N_2 and water. SNCR also uses ammonia to control NO_x emissions but without a catalyst.

Selective Catalytic Reduction. SCR is a post-combustion control technology designed to control NO_x emissions from gas turbines. The SCR system is placed inside the exhaust ductwork and consists of a catalyst bed with an

ammonia injection grid located upstream of the catalyst. The ammonia reacts with the NO_x and O_2 in the presence of a catalyst to form N_2 and water. The catalyst consists of a support system with a catalyst coating typically of titanium dioxide, vanadium pentoxide, or zeolite. A small amount of ammonia is not consumed in the reaction and is emitted in the exhaust stream; this is referred to as "ammonia slip."

EMx System. The EMx system uses a single catalyst to remove NO_x emissions in the turbine exhaust gas by oxidizing NO to NO_2 and then absorbing NO_2 onto the catalytic surface using a potassium carbonate absorber coating. The potassium carbonate coating reacts with NO_2 to form potassium nitrites and nitrates, which are deposited onto the catalyst surface. The optimal temperature window for operation of the EMx catalyst is from 300 to 700 degrees Fahrenheit (°F). EMx does not use ammonia, so there are no ammonia emissions from this catalyst system (CARB, 2004).

When all of the potassium carbonate absorber coating has been converted to N_2 compounds, NO_x can no longer be absorbed and the catalyst must be regenerated. Regeneration is accomplished by passing a dilute hydrogen-reducing gas across the surface of the catalyst in the absence of O_2. Hydrogen in the gas reacts with the nitrites and nitrates to form water and N_2. Carbon dioxide (CO_2) in the gas reacts with the potassium nitrite and nitrates to form potassium carbonate, which is the absorbing surface coating on the catalyst. The regeneration gas is produced by reacting natural gas with a carrier gas (such as steam) over a steam-reforming catalyst (CARB, 2004).

Selective Non-catalytic Reduction. SNCR involves injection of ammonia or urea with proprietary conditioners into the exhaust gas stream without a catalyst. SNCR technology requires gas temperatures in the range of 1,600 to 2,100 °F[2]. This technology is not available for combustion turbines because gas turbine exhaust temperatures are below the minimum temperature required of 1,600°F.

2.2.1.2 Eliminate Technically Infeasible Options – Step 2

Pre-combustion NO_x Control Technologies

Water or Steam Injection. The use of water or steam injection is considered a feasible technology for reducing NO_x emissions to 25 ppmvd when firing natural gas under most ambient conditions. Combined with SCR, water or steam injection can achieve 2 ppmvd NO_x levels but at a slightly lower thermal efficiency as compared to DLN combustors.

DLN Combustors. The use of DLN combustors is a feasible technology for reducing NO_x emissions from the HBEP. DLN combustors are capable of achieving 9 to 25 ppmvd NO_x emission over a relatively large operating range (70 to 100 percent load), and when combined with SCR can achieve controlled NO_x emissions of 2 ppmvd.

The XONON™ technology has been demonstrated successfully in a 1.5-MW simple-cycle pilot facility, and it is commercially available for turbines rated up to 10 MW, but catalytic combustors such as XONON™ have not been demonstrated on an industrial E Class gas turbine. Therefore, the technology is not considered feasible for the proposed HBEP.

Post-combustion NO_x Control Technologies

Selective Catalytic Reduction. The use of SCR, with an ammonia slip of less than 5 ppm, is considered a feasible technology for reducing NO_x emissions to 2 ppmvd at 15 percent O_2 when firing natural gas.

EMx System. In the Palmdale Hybrid Power Project PSD permit, EPA noted that it appears EMx has only been demonstrated to achieve 2.5 ppm NO_x (EPA, 2011). In addition, the BAAQMD concluded in a recent permitting case that "it is clear that EMx is not as developed as SCR at this time and cannot achieve the same level of emissions performance that SCR is capable of" (BAAQMD, 2011). Therefore, EMx technology is not considered feasible for achieving the proposed HBEP NO_x limit of 2.0 ppm NO_x.

[2] http://www.icac.com/i4a/pages/index.cfm?pageid=3399

Selective Non-catalytic Reduction. SNCR requires a temperature window that is higher than the exhaust temperatures from natural-gas-fired combustion turbine installations. Therefore, SNCR is not considered technically feasible for the proposed HBEP.

2.2.1.3 Combustion Turbine NO_x Control Technology Ranking – Step 3

Based on the preceding discussion, the use of water injection, DLN combustors, and SCR are the effective and technically feasible NO_x control technologies available for the HBEP. DLN combustors were selected because these allow for lower NO_x emission rate (9 ppmvd) from the combustion turbine over either water or steam (wet) injection (25 ppmvd). Furthermore, DLN combustors result in a very slight improvement in thermal efficiency over the wet injection NO_x control alternative and reduce the HBEP's water consumption. When used in combination with SCR, these technologies will control NO_x emissions to 2.0 ppm (1-hour) with and without duct burners.

Applicable BACT clearinghouse determinations and the BAAQMD, CARB, SCAQMD, and SJVAPCD BACT determinations were reviewed to identify which NO_x emission rates have been achieved in practice for other natural-gas-fired combustion turbine projects. The results of this review are presented in Table 2-2.

TABLE 2-2
Summary of NO_x Emission Limits for Combustion Turbines
Technology Ranking for Turbines With and Without Duct Burning

Facility	Facility ID Number	NO_x Emission Limit at 15 percent O_2
Middleton Facility	ID-0010	3.0 ppm (24-hour) without duct burners; 3.5 ppm (24-hour) with duct burners
Mirant Gastonia Power Facility	NC-0095	2.5 ppm (24-hour) for first 500 hour, 3.5 ppm (24-hour) after
Berrien Energy, LLC	MI-0366	2.5 ppm (24-hour)
Black Hills Corp./Neil Simpson	WY-0061	2.5 ppm (24-hour)
COB Energy Facility, LLC	OR-0039	2.5 ppm (4-hour)
Kelson Ridge	MD-0033	2.5 ppm (3-hour)
Kyrene Generating Station, Salt River Project	AZ-0041	2.5 ppm (3-hour)
Duke Energy Wythe, LLC	VA-0289	2.5 ppm
Port Westward Plant	OR-0035	2.5 ppm
FPL Martin Plant	FL-0244	2.5 ppm
Empire Power Plant	NY-0100	2.0 ppm (3-hour) without duct burners; 3.0 ppm (3-hour) with duct burners
Tracy Substation Expansion Project	NV-0035	2.0 ppm (3-hour)
Langley Gulch Power Plant	ID-0018	2.0 ppm (3-hour)
Palomar Escondido – SDG&E	2001-AFC-24	2.0 ppm (1-hour); 2.0 ppm (3-hour) with duct burners or transient hour of +25 MW
Warren County Facility	VA-0308	2.0 ppm with or without duct burners
Ivanpah Energy Center, L.P.	NV-0038	2.0 ppm (1-hour) without duct burners; 13.96 lb/hr with duct burners
Gila Bend Power Generating Station	AZ-0038	2.0 ppm (1-hour)
Duke Energy Arlington Valley	AZ-0043	2.0 ppm (1-hour)
Colusa II Generation Station	2006-AFC-9	2.0 ppm (1-hour)
Avenal Energy – Avenal Power Center, LLC	2008-AFC-1	2.0 ppm (1-hour)
Russell City Energy Center	2001-AFC-7	2.0 ppm (1-hour)

TABLE 2-2
Summary of NO_x Emission Limits for Combustion Turbines
Technology Ranking for Turbines With and Without Duct Burning

Facility	Facility ID Number	NO_x Emission Limit at 15 percent O_2
CPV Warren	VA-0291	2.0 ppm (1-hour)
IDC Bellingham	CA-1050	2.0 ppm/1.5 ppm (1-hour)
Oakley Generating Station	2009-AFC-4	2.0 ppm (1-hour)
GWF Tracy Combined-cycle Project	2008-AFC-7	2.0 ppm (1-hour)
Watson Cogeneration Project	2009-AFC-1	2.0 ppm (1-hour)

Note: This table does not include all projects listed in the BACT databases. The purpose of this table is to present a summary of the most-stringent emission limits and to highlight any projects with an emission limit less than 2.0 ppm NO_x identified during the database search.

Source: EPA RACT/BACT/LAER Clearinghouse and the California Energy Commission (EPA, 2012 and CEC, 2012)

The review of these recent determinations identified only the IDC Bellingham Project as having emission limits less than the proposed BACT emission limit for the HBEP of 2.0 ppm NO_x. Based on the Final Determination of Compliance for the Oakley Generating Station Project, BAAQMD noted that the IDC Bellingham facility in Massachusetts was permitted with a two-tiered NO_x emission limit that imposed an absolute not-to-exceed limit of 2.0 ppm but also required the facility to maintain emissions below 1.5 ppm during normal operations (BAAQMD, 2011). However, BAAQMD also noted that the IDC Bellingham facility was never built, and that the emission limit was therefore never achieved in practice (BAAQMD, 2011). As a result, the proposed emission rate of 2.0 ppm (1-hour) with and without duct burners for HBEP is the lowest NO_x emission rate achieved in practice for similar sources and, therefore, is the BACT emission limit for NO_x control.

2.2.1.4 Evaluate Most-effective Controls and Document Results – Step 4

Based on the information presented in this BACT analysis, the proposed NO_x emission rates of 2.0 ppm (1-hour) with and without duct burners are the lowest NO_x emission rates achieved in practice at similar sources. Therefore, an assessment of the economic and environmental impacts is not necessary.

2.2.1.5 NO_x BACT Selection – Step 5

The proposed BACT for NO_x emissions from the HBEP is the use of DLN combustors with SCR to control NO_x emissions to 2.0 ppmvd (1-hour average) with and without duct burners.

2.2.2 CO

CO is discharged into the atmosphere when some of the fuel remains unburned or is only partially burned (incomplete combustion) during the combustion process. CO emissions are also affected by the gas turbine operating load conditions. CO emissions can be higher for gas turbines operating at low loads than for similar gas turbines operating at higher loads (EPA, 2006).

2.2.2.1 Identification of Combustion Turbine CO Emissions Control Technologies – Step 1

Effective combustor design and post-combustion control using an oxidation catalyst are two technologies (discussed below) for controlling CO emissions from a combustion turbine. As noted in the NO_x BACT analysis, the EMx and XONON technologies were determined to not be feasible for HBEP.

Best Combustion Control. CO is formed during the combustion process as a result of incomplete combustion of the carbon present in the fuel. The formation of CO is limited by designing the combustion system to completely oxidize the fuel carbon to CO_2. This is achieved by ensuring that the combustor is designed to allow complete mixing of the combustion air and fuel at combustion temperatures (in excess of 1,800°F) with an excess of combustion air. Higher combustion temperatures tend to reduce the formation of CO but increase the formation of NO_x. The application of water injection or staged combustion (DLN combustors) tends to lower combustion

temperatures (in order to reduce NO_x formation), potentially increasing CO formation. However, using good combustor design and following best operating practices will minimize the formation of CO while reducing the combustion temperature and NO_x emissions.

Oxidation Catalyst. An oxidation catalyst is typically a precious metal catalyst bed located in the HRSG. The catalyst enhances oxidation of CO to CO_2, without the addition of any reactant. Oxidation catalysts have been successfully installed on numerous simple- and combined-cycle combustion turbines.

2.2.2.2 Eliminate Technically Infeasible Options – Step 2

Using good combustor design, following best operating practices, and using an oxidation catalyst are technically feasible options for controlling CO emissions from the proposed HBEP.

2.2.2.3 Combustion Turbine CO Control Technology Ranking – Step 3

Based on the preceding discussion, using best combustor control and an oxidation catalyst are technically feasible combustion turbine control technologies available to control CO emissions. Accordingly, the project owner proposes to control CO emissions using both methods to meet a CO emission limit of 2.0 ppmvd (1-hour) with and without duct burners.

Applicable BACT clearinghouse determinations and the SCAQMD, EPA, BAAQMD, CARB, and SJVAPCD BACT determinations were reviewed to determine whether CO emission rates less than the proposed HBEP levels have been achieved in practice for other natural-gas-fired combustion turbine projects. A summary of the emission limits for projects identified in the database is presented in Table 2-3. As this table demonstrates, most projects have CO emission rates that are the same as or higher than the CO emission rate proposed for the HBEP. However, three projects have CO emission rates that are lower than the CO emission rate proposed for the HBEP. These projects are discussed below.

TABLE 2-3
Summary of CO Emission Limits for Combined-cycle Turbines
Emission Control Ranking for Turbines With and Without Duct Burner Firing

Facility	Facility ID Number	CO Emission Limit at 15 percent O_2
La Paz Generating Facility	AZ-0049	3.0 ppm (3-hour)
Rocky Mountain Energy Center	CO-0056	3.0 ppm
Welton Mohawk Generating Station	AZ-0047	3.0 ppm with duct burners (3-hour)
Copper Mountain Power	NV-0037	3.0 ppm with duct burners (3-hour)
Currant Creek	UT-0066	3.0 ppm (3-hour)
Lawrence Energy	OH-0248	2.0 ppm without duct burners; 10.0 ppm with duct burners
Berrien Energy, LLC	MI-0366	2.0 ppm without duct burners (3-hour); 4.0 ppm with duct burners (3-hour)
COB Energy Facility	OR-0039	2.0 ppm (4-hour)
Avenal Energy – Avenal Power Center, LLC	2008-AFC-1	2.0 ppm (3-hour)
Wallula Power Plant	WA-0291	2.0 ppm (3-hour)
Duke Energy Arlington Valley (AVEFII)	AZ-0043	2.0 ppm (3-hour)
Wanapa Energy Center	OR-0041	2.0 ppm (3-hour)
Vernon City Light and Power	CA-1096	2.0 ppm (3-hour)
Mariposa Energy Project	2009-AFC-3	2.0 ppm (3-hour)
Palmdale Hybrid Power Plant Project	08-AFC-9	2.0 ppm without duct burners (1-hour); 3.0 ppm with duct burners (1-hour)

TABLE 2-3
Summary of CO Emission Limits for Combined-cycle Turbines
Emission Control Ranking for Turbines With and Without Duct Burner Firing

Facility	Facility ID Number	CO Emission Limit at 15 percent O_2
Wansley Combined-cycle Energy Facility	GA-0102	2.0 ppm with duct burners
McIntosh Combined-cycle Facility	GA-0105	2.0 ppm with duct burners
Sumas Energy 2 Generation Facility	WA-0315	2.0 ppm (1-hour)
Oakley Generating Station	2009-AFC-4	2.0 ppm (1-hour)
Goldendale Energy	WA-302	2.0 ppm (1-hour)
IDC Bellingham	CA-1050	2.0 ppm (1-hour)
Russell City Energy Center	2001-AFC-7	2.0 ppm with duct burners (1-hour)
Watson Cogeneration Project	2009-AFC-1	2.0 ppm with duct burners (1-hour)
Magnolia Power Project	CA-1097	2.0 ppm with duct burners (1-hour)
CPV Warren	VA-0291	1.3 ppm without duct burners; 1.2 ppm with duct burners
Warren County Facility	VA-0308	1.3 ppm without duct burners
Kleen Energy Systems	CT-0151	0.9 ppm (1-hour)

Note: This table does not include all projects listed in the BACT databases. The purpose of this table is to present a summary of the most-stringent emission limits and to highlight any projects with an emission limit less than 2.0 ppm CO identified during the database search.

Source: EPA RACT/BACT/LAER Clearinghouse and the California Energy Commission (EPA, 2012 and CEC, 2012).

Competitive Power Ventures (CPV) Warren and Warren County Facilities. A new PSD permit application was submitted in April 2010 to the Virginia Department of Environmental Quality by Virginia Electric Power and Power Company (Dominion), and the final PSD permit was issued on December 21, 2010. The final PSD permit includes CO emission limits of 1.5 ppm and 2.4 ppm, on a 1-hour averaging basis for operating conditions without and with duct burner, respectively. Based on publically available information, Dominion expects commercial operation of the Warren facility to occur in late 2014 or early 2015. Therefore, this level of control has not been demonstrated in practice on a long-term basis with a short (1-hour) averaging period.

Kleen Energy Systems. The Kleen Energy Systems facility conducted the initial source tests in June 2011. Based on a November 2011 letter from the Connecticut Department of Energy & Environmental Protection, the facility was able to successfully demonstrate compliance with the CO emission limits of 0.9 and 1.5 ppmvd for unfired and fired operation, respectively. However, given the lack of long-term compliance with these lower emission limits, these CO emission levels are not considered achieved in practice at this time.

Conclusion. As shown in Table 2-3, the proposed CO emission rate of 2.0 ppmvd (1-hour) with and without duct burners for the HBEP is the lowest CO emission rate achieved in practice for other facilities using good combustion practices and an oxidation catalyst.

2.2.2.4 Evaluate Most Effective Controls and Document Results – Step 4

The proposed CO emission rate of 2.0 ppmvd (1-hour) with and without duct burners for the HBEP is the lowest CO emission rate achieved or verified with long-term compliance records for other similar facilities. Therefore, an assessment of the economic and environmental impacts is not necessary.

2.2.2.5 CO BACT Selection – Step 5

The BACT for CO emissions from the HBEP is good combustion design and the installation of an oxidation catalyst system to control CO emissions to 2.0 ppmvd (1-hour) with and without duct burners.

2.2.3 VOCs

The pollutants commonly classified as VOCs are discharged into the atmosphere when some of the fuel remains unburned or is only partially burned (incomplete combustion) during the combustion process

2.2.3.1 Identification of Combustion Turbine VOC Emissions Control Technologies – Step 1

Effective combustor design and post-combustion control using an oxidation catalyst are two technologies for controlling VOC emissions from a combustion turbine. The industrial combustion turbine proposed for HBEP is able to achieve relatively low, uncontrolled VOC emissions of approximately 3 ppmvd because the combustors have a firing temperature of approximately 2,500°F with an exhaust temperature of approximately 1,000°F. A DLN-equipped combustion turbine that incorporates an oxidation catalyst system can achieve VOC emissions in the 2 ppmvd range. As noted in the NOx BACT analysis, the EMx and XONON technologies were determined to not be feasible for HBEP.

Best Combustion Control. As previously discussed, VOCs are formed during the combustion process as a result of incomplete combustion of the carbon present in the fuel. The formation of VOC is limited by designing the combustion system to completely oxidize the fuel carbon to CO_2. This is achieved by ensuring that the combustor is designed to allow complete mixing of the combustion air and fuel at combustion temperatures with an excess of combustion air. Higher combustion temperatures tend to reduce the formation of VOC but increase the formation of NO_x. The application of water injection or staged combustion (DLN combustors) tends to lower combustion temperatures (to reduce NO_x formation), potentially increasing VOC formation. However, good combustor design and best operating practices will minimize the formation of VOC while reducing the combustion temperature and NO_x emissions.

Oxidation Catalyst. An oxidation catalyst is typically a precious metal catalyst bed located in the exhaust duct. The catalyst enhances oxidation of VOC to CO_2 without the addition of any reactant. Oxidation catalysts have been successfully installed on numerous simple- and combined-cycle combustion turbines.

2.2.3.2 Eliminate Technically Infeasible Options – Step 2

Good combustor design and the use of an oxidation catalyst are both technically feasible options for controlling VOC emissions from the proposed HBEP.

2.2.3.3 Combustion Turbine VOC Control Technology Ranking – Step 3

Based on the preceding discussion, using good combustor control and an oxidation catalyst are technically feasible combustion turbine control technologies available to control VOC emissions. Accordingly, the project owner proposes to control VOC emissions using both methods to meet a VOC emission limit of 1.0 ppmvd (1-hour) without duct burners and 1.0 ppmvd (3-hour) with duct burners.

Applicable BACT clearinghouse determinations and the SCAQMD, EPA, BAAQMD, CARB, and SJVAPCD BACT determinations were reviewed to determine whether VOC emission rates less than the proposed HBEP levels have been achieved in practice for other natural-gas-fired combustion turbine projects. A summary of the emission limits for projects identified in the database is presented in Table 2-4.

TABLE 2-4
Summary of VOC Emission Limits for Combined-cycle Turbines
Emission Control Ranking for Turbines With and Without Duct Burner Firing

Facility	Facility ID Number	VOC Emission Limit at 15 percent O_2
Florida Power and Light Martin Plant	FL-0244	1.3 ppm without duct burners; 4 ppm with duct burners
Duke Energy Arlington Valley (AVEFII)	AZ-0043	1 ppm without duct burners (3-hour); 4 ppm with duct burners (3-hour)
Fairbault Energy Park	MN-0071	1.5 ppm without duct burners; 3.0 ppm with duct burners
VA Power – Possum Point	VA-0255	1.2 ppm without duct burners; 2.3 ppm with duct burners

TABLE 2-4
Summary of VOC Emission Limits for Combined-cycle Turbines
Emission Control Ranking for Turbines With and Without Duct Burner Firing

Facility	Facility ID Number	VOC Emission Limit at 15 percent O_2
Los Esteros Critical Energy Facility – Phase 2c	2003-AFC-2	2.0 ppm with duct burners (3-hour)
GWF Tracy Combined-cycle Project	2008-AFC-7	1.5 ppm without duct burners (3-hour); 2.0 ppm with duct burners (3-hour)
Avenal Energy – Avenal Power Center, LLC	2008-AFC-1	1.4 ppm without duct burners; 2.0 ppm with duct burners (3-hour)
Watson Cogeneration Project	2009-AFC-1	2.0 ppm without duct burners (1-hour); 2.0 ppm with duct burners (1-hour)
Palmdale Hybrid Power Plant Project	SE 09-01	1.4 without duct burners (1-hour); 2.0 ppm with duct burners (1-hour)
Victorville Hybrid Gas-Solar	2007-AFC-1	1.4 ppm without duct burners; 2.0 ppm with duct burners
Colusa II Generation Station	2006-AFC-9	1.38 ppm without duct burners; 2.0 ppm with duct burners
FPL Turkey Point Power Plant	FL-0263	1.6 ppm without duct burners; 1.9 with duct burners
Plant McDonough Combined-cycle	GA-0127	1.0 ppm (1-hour) without; 1.8 ppm with duct burners (3-hour)
FPL West County Energy Center Unit 3	FL-0303	1.2 ppm with duct burners; 1.5 with duct burners
Gila Bend Power Generating Station	AZ-0038	1.4 ppm with duct burners
Liberty Generating Station	NJ-0043	1.0 ppm (no duct burners)
Empire Power Plant	NY-0100	1.0 ppm (no duct burners)
Fairbault Energy Park	MN-0053	1.0 ppm (3-hour) (no duct burners)
Oakley Generating Station	2009-AFC-4	1.0 ppm (1-hour) (no duct burners)
Sutter – Calpine	1997-AFC-02	1.0 ppm with duct burners (calendar day average)
Russell City Energy Center	2001-AFC-7	1.0 ppm with duct burners (1-hour)
CPV Warren	VA-0291	0.7 without duct burners; 1.6 with duct burners; (3-hour)
Warren County Facility	VA-0308	0.7 without duct burners; 1.0 with duct burners
Chouteau Power Plant	OK-0129	0.3 ppm (3-hour) with duct burners

Note: This table does not include all projects listed in the BACT databases. The purpose of this table is to present a summary of the most-stringent emission limits and to highlight any projects with an emission limit less than 1.0 ppm VOC identified during the database search.

Source: EPA RACT/BACT/LAER Clearinghouse and the CEC (EPA, 2012 and CEC, 2012).

As this table demonstrates, most projects have VOC emission rates that are the same as or higher than the VOC emission rate proposed for the HBEP. However, the following projects have VOC emission rates that are lower than the VOC emission rate proposed for the HBEP:

- Russell City Energy Center
- CPV Warren and Warren County facilities
- Chouteau Power Plant

Russell City Energy Center. The Russell City Energy Center (RCEC) has a VOC permit limit of 1.0 ppmvd at 15 percent O_2 with and without duct burners averaged over 1 hour. Although the 1.0 ppmvd limit averaged over a 1-hour period for the duct burners scenario is more restrictive than the proposed HBEP limit of 1.0 ppmvd at 15 percent O_2 averaged over a 3-hour period, construction of the RCEC has not been completed. Therefore, long-

term demonstration of compliance with the proposed emission rate and averaging period has not been demonstrated in practice.

CPV Warren and Warren County Facilities. The Warren County Facility and CPV Warren are the same facility (Permit Number 81391). A new application submitted in April 2010 to the Virginia Department of Environmental Quality by Virginia Electric Power and Power Company (Dominion) will replace the listed determinations, and the final PSD permit was issued on December 21, 2010. The final PSD permit includes VOC emission limits of 0.7 ppm and 1.6 ppm on a 3-hour averaging basis for operating conditions without and with duct burner, respectively. Based on publically available information, Dominion expects commercial operation of the Warren facility to occur in late 2014 or early 2015. Therefore, this level of control has not been demonstrated in practice on a long-term basis.

Chouteau Power Plant. The Oklahoma Air Quality Division issued the Chouteau Power Plant a construction permit on January 20, 2009. The facility was built and is currently operational. The BACT analysis for the Chouteau Power Plant concluded that good combustion practices with an emission limit of 0.3 ppmvd at 15 percent O_2 for the Siemens-Westinghouse V84.3A model industrial frame combustion turbines was BACT (Fielder, 2009). However, the construction permit for the Chouteau Power Plant does not include a VOC concentration limit consistent with the BACT determination, but rather includes a mass emission limit of 5.27 pounds per hour with duct burners operating. The permit also includes the heat input for each turbine/HRSG of 1,882 million British thermal units per hour (MMBtu/hr). Using these values, the VOC emission rate in pound(s) per million British thermal unit (lb/MMBtu) is 0.028, whereas the HBEP maximum VOC emission rate is 0.0012 lb/MMBtu. Therefore, HBEP's VOC emission rate is lower than the Chouteau Power Plant permit value defined in units of lb/MMBtu.

Conclusion. As shown in Table 2-4, the proposed VOC emission rate of 1.0 ppmvd (1-hour) without duct burners and 1.0 ppmvd with duct burners (3-hour) for the HBEP is the lowest VOC emission rate demonstrated in practice or permitted for other facilities using good combustion practices and an oxidation catalyst.

2.2.3.4 Evaluate Most Effective Controls and Document Results – Step 4

The proposed VOC emission rate of 1.0 ppmvd (1-hour) without duct burners and 1.0 ppmvd with duct burners (3-hour) for the HBEP is the lowest VOC emission rate achieved or permitted for other similar facilities. Therefore, an assessment of the economic and environmental impacts is not necessary.

2.2.3.5 VOC BACT Selection – Step 5

The BACT for VOC emissions from the HBEP is good combustion design and the installation of an oxidation catalyst system to control VOC emissions to 1.0 ppmvd (1-hour) without duct burners and 1.0 ppmvd (3-hour) with duct burners.

2.2.4 PM_{10} and $PM_{2.5}$

PM from natural gas combustion has been estimated to be less than 1 micron in equivalent aerodynamic diameter, has filterable and condensable fractions, and is usually hydrocarbons of larger molecular weight that are not fully combusted (EPA, 2006). Because the particulate matter is less than 2.5 microns in diameter, the BACT control technology discussion assumes the control technologies for PM_{10} and $PM_{2.5}$ are the same.

2.2.4.1 Identification of Combustion Turbine PM_{10} and $PM_{2.5}$ Emissions Control Technologies – Step 1

Pre-combustion Particulate Control Technologies. The major sources of PM_{10} and $PM_{2.5}$ emissions from a natural-gas-fired gas turbine equipped with SCR for post-combustion control of NOx are: (1) the conversion of fuel sulfur to sulfates and ammonium sulfates; (2) unburned hydrocarbons that can lead to the formation of PM in the exhaust stack; and (3) PM in the ambient air entering the gas turbine through the inlet air filtration system, and the aqueous ammonia dilution air. Therefore, the use of clean-burning, low-sulfur fuels such as natural gas will result in minimal formation of PM_{10} and $PM_{2.5}$ during combustion. Best combustion practices will ensure proper air/fuel mixing ratios to achieve complete combustion, minimizing emissions of unburned hydrocarbons that can

lead to formation of PM at the stack. In addition to good combustion, use of high-efficiency filtration on the inlet air and SCR dilution air system will minimize the entrainment of PM into the exhaust stream.

Post-combustion Particulate Control Technologies. Two post-combustion control technologies designed to reduce PM emissions from industrial sources are electrostatic precipitators and baghouses. However, neither of these control technologies is appropriate for use on natural-gas-fired turbines because of the very low levels and small aerodynamic diameter of PM from natural gas combustion.

2.2.4.2 Eliminate Technically Infeasible Options – Step 2

Electrostatic precipitators and baghouses are typically used on solid/liquid-fuel fired or other types of sources with high PM emission concentrations, and are not used in natural-gas-fired applications, which have inherently low PM emission concentrations. Therefore, electrostatic precipitators and baghouses are not considered technically feasible control technologies. However, best combustion practices, clean-burning fuels, and inlet air filtration are considered technically feasible for control of PM_{10} and $PM_{2.5}$ emissions from the HBEP.

2.2.4.3 Combustion Turbine PM_{10} and $PM_{2.5}$ Control Technology Ranking – Step 3

The use of best combustion practices, clean-burning fuels, and inlet air filtration are the technically feasible natural-gas-fired turbine control technologies proposed by the project owner to control PM_{10} and $PM_{2.5}$ emissions to 4.5 lb/hr without duct burners and 9.5 lb/hr with duct burners. Furthermore, because no add-on control devices are technically feasible to control PM emissions from natural-gas-fired turbines, there would be little an applicant could do beyond using best combustion practice and using clean-burning fuels and inlet air filtration to control particulate emissions (BAAQMD, 2011).

2.2.4.4 Evaluate Most Effective Controls and Document Results – Step 4

Based on the information presented in this BACT analysis, using proposed good combustion practice, pipeline-quality natural gas, and inlet air filtration to control $PM_{10}/PM_{2.5}$ emissions to 4.5 lb/hr without duct burners and 9.5 lb/hr with duct burners is consistent with BACT at other similar sources. Therefore, an assessment of the economic and environmental impacts is not necessary.

2.2.4.5 PM_{10} and $PM_{2.5}$ BACT Selection – Step 5

The BACT for $PM_{10}/PM_{2.5}$ emissions from the HBEP is using good combustion practice, pipeline-quality natural gas, and inlet air filtration to control $PM_{10}/PM_{2.5}$ emissions to 4.5 lb/hr without duct burners and 9.5 lb/hr with duct burners.

2.2.5 SO_2

Emissions of SO_x are entirely a function of the sulfur content in the fuel rather than any combustion variables. During the combustion process, essentially all the sulfur in the fuel is oxidized to SO_2.

2.2.5.1 Identification of Combustion Turbine SO_2 Emissions Control Technologies – Step 1

Two primary mechanisms are used to reduce SO_2 emissions from combustion sources: (1) reduce the amount of sulfur in the fuel, and (2) remove the sulfur from the combustion exhaust gases.

Limiting the amount of sulfur in the fuel is a common practice for natural-gas-fired turbines. For instance, natural-gas-fired turbines in California are typically required to combust only California Public Utilities Commission (CPUC) pipeline-quality natural gas with a sulfur content of less than 1 grain of sulfur per 100 scf. The HBEP would be supplied with natural gas from the Southern California Gas (SoCalGas) pipeline, which is limited by tariff Rule 30 to a maximum total fuel sulfur content of less than 0.75 grain of sulfur per 100 scf. Therefore, the use of pipeline-quality natural gas with low sulfur content is a BACT control technique for SO_2.

There are two principal types of post-combustion control technologies for SO_2—wet scrubbing and dry scrubbing. Wet scrubbers use an alkaline solution to remove the SO_2 from the exhaust gases. Dry scrubbers use an SO_2 sorbent injected as powder or slurry to remove the SO_2 from the exhaust stream. However, the SO_2

concentrations in the natural gas exhaust gases are too low for the scrubbing technologies to work effectively or to be technically feasible.

2.2.5.2 Eliminate Technically Infeasible Options – Step 2

Use of pipeline-quality natural gas with very low sulfur content is technically feasible for the HBEP. However, because sulfur emissions from natural-gas-fired turbines are extremely low when using pipeline-quality natural gas, the two post-combustion SO_2 controls for natural-gas fired turbines (wet and dry scrubbers) are not technically feasible.

2.2.5.3 Combustion Turbine SO_2 Control Technology Ranking – Step 3

Use of pipeline-quality natural gas with very low sulfur content is the only technically feasible SO_2 control technology for natural-gas-fired turbines, and it is the most effective SO_2 control technology used by all other natural-gas-fired turbines in California. Therefore, using pipeline-quality natural gas with a regulatory limit of 0.75 grain of sulfur per 100 scf of natural gas for the HBEP is BACT for SO_2.

2.2.5.4 Evaluate Most Effective Controls and Document Results – Step 4

Based on the information presented in this BACT analysis, the use of pipeline-quality natural gas with a maximum of 0.75 grain of sulfur per 100 scf of natural gas as a BACT control technique for SO_2 will achieve the lowest SO_2 emission rates achieved in practice at other similar sources. Therefore, an assessment of the economic and environmental impacts is not necessary.

2.2.5.5 SO_2 BACT Selection – Step 5

The BACT for SO_2 from the HBEP is use of pipeline-quality natural gas with a sulfur content of less than 0.75 grain of sulfur per 100 scf of natural gas.

2.2.6 BACT for Startups and Shutdowns

Startup and shutdown events are a normal part of the power plant operation, but they involve NO_x, CO, and VOC emissions rates that are highly variable and greater than emissions than during steady-state operation[3]. This is because emission control systems are not fully functional during these events. In the case of the DLN combustors, the turbines must achieve a minimum operating rate before these systems are functional. Likewise, the SCR and oxidation catalyst systems must be heated to a specific minimum temperature before the catalyst systems become effective. Furthermore, startup and shutdown emissions are dependent on a number of project specific factors; therefore, permitted startup and shutdown emission limits are highly variable. For these reasons, BACT for startup and shutdown will consider only the duration of these events.

2.2.6.1 Control Devices and Techniques to Limit Startup and Shutdown Emissions

The available approach to reducing startup and shutdown emissions from combustion turbines is to use best work practices. By following the plant equipment manufacturers' recommendations, power plant operators can limit the duration of each startup and shutdown event to the minimum duration achievable. Plant operators also use their own operational experience with their particular turbines and ancillary equipment to optimize startup and shutdown emissions. The proposed numerical emission limits for the startup and shutdowns are outlined below.

2.2.6.2 Determination of BACT Emissions Limit for Startups and Shutdowns

Startups. The combustion turbine vendor (MPSA) has determined a turbine startup period of 10 minutes from first fire to full load operation. This startup period does not include the warm-up time required by the SCR and oxidation catalyst systems, which is affected by the length of time the system has been inactive. The length of time is related to the temperature and pressure of the steam cycle. Three startup cases (hot, warm, and cold) were provided based on engineering estimates to reflect the different length of time between combustion turbine activity. A hot startup is defined as the turbine being inactive for up to 9 hours. A warm startup is defined as the

[3] Because $PM_{10/2.5}$ and SO_2 emissions are dependent on the amount of fuel combusted, $PM_{10/2.5}$ and SO_2 emissions during startup and shutdown would be less than full load operations since less fuel is consumed as compared to full load operations.

turbine being inactive for between 9 and 49 hours, and a cold startup is defined as the turbine being inactive for more than 49 hours. Table 2-5 presents the proposed startup emissions and durations proposed as BACT.

TABLE 2-5
Facility Startup Emission Rates Per Turbine

Startup	NO_x (lb/event)	CO (lb/event)	VOC (lb/event)	NO_x (lb/hr)	CO (lb/hr)	VOC (lb/hr)	Duration (minutes/event)
Cold	28.7	116	27.9	25.5	115.3	25.9	90
Warm	16.6	46.0	21.0	23.2	50.0	21.6	32.5
Hot	16.6	33.6	20.4	23.2	37.6	21.0	32.5

Shutdowns. The turbine vendor also supplied the emission estimates for a typical shutdown event occurring over 10 minutes, which was combined with engineering estimates to determine shutdown emissions. The shutdown process begins with the combustion turbine reducing load until the DLN system is no longer functional but the SCR and oxidation remain functional. Table 2-6 presents the shutdown emissions and duration proposed as BACT.

TABLE 2-6
Facility Shutdown Emission Rates Per Turbine

	NO_x (lb/event)	CO (lb/event)	VOC (lb/event)	NO_x (lb/hr)	CO (lb/hr)	VOC (lb/hr)	Duration (minutes/event)
Shutdown	9.0	45.3	31.0	17.8	50.7	31.8	10

2.2.6.3 Summary of the Proposed BACT for Startups and Shutdowns

The project owner proposes to limit individual startups and shutdown durations to an enforceable BACT permit limit of 32.5 minutes for a hot and warm startup, 90 minutes for a cold startup, and 10 minutes for a shutdown event.

SECTION 3

GHG BACT

3.1 Introduction

This BACT evaluation was prepared to address GHG emissions from HBEP, and the evaluation follows EPA regulations and guidance for BACT analyses as well as the EPA's PSD and Title V Permitting Guidance for Greenhouse Gases (EPA, 2011b). 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 use inherently lower GHG-emitting fuels and to minimize the use of fuel, which in this case is achieved by using thermally efficient CTGs, well-designed HRSGs, and STGs to generate additional power from the heat of the CTG exhaust. In the HBEP process, the fossil fuel burned will be pipeline quality natural gas, which is the lowest GHG-emitting fossil fuel available. The HBEP gas turbines selected to meet the project's objectives have a high operating turndown rate while maintaining a high thermal efficiency.

3.1.1 Regulatory Overview

Based on a series of actions, including the 2007 Supreme Court decision, the 2009 EPA Endangerment Finding and Cause and Contribute Finding, and the 2010 Light-Duty Vehicle Rule, GHGs became subject to permitting under the Clean Air Act. In May 2010, EPA issued the GHG permitting rule officially known as the "Prevention of Significant Deterioration and Title V Greenhouse Gas Tailoring Rule" (GHG Tailoring Rule), in which EPA defined six GHG pollutants (collectively combined and measured as CO_2e) as NSR-regulated pollutants and therefore subject to PSD permitting when new projects emitted those pollutants above certain threshold levels. Under the GHG Tailoring Rule, beginning July 1, 2011, new sources with a GHG PTE equal to or greater than 100,000 tpy of CO_2e will be considered a major source and will be required to undergo PSD permitting, including preparation of a BACT analysis for GHG emissions. Modifications to existing major sources (CO_2e PTE of 100,000 tpy or greater) that result in an increase of CO_2e greater than 75,000 tpy are similarly required to obtain a PSD permit, which includes a GHG BACT analysis. The project results in an emissions increase above the new source PSD thresholds for CO_2e. Therefore, the project is subject to the GHG Tailoring Rule, and is required to obtain a PSD permit for GHGs.

3.1.2 BACT Evaluation Overview

BACT requirements are intended to ensure that a proposed project will incorporate control systems that reflect the latest control technologies that have been demonstrated in practice for the type of facility under review. BACT is defined under the Clean Air Act (42 U.S.C. Section 7479[3]) as follows:

> *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. ….*

EPA guidance specifies that a BACT analysis should be performed using a top-down approach in which all applicable control technologies are evaluated based on their effectiveness and are then ranked by decreasing level of control. If the most-effective control technology is not being selected for the project, the control technologies on the list are evaluated as to whether they are infeasible because of energy, environmental, and/or economic impacts. The most effective control technology in the ranked list that cannot be so eliminated is then defined as BACT for that pollutant and process. A further analysis must be conducted to establish the emission

limit that is BACT, based on determining the lowest emission limit that is expected to be consistently achievable over the life of the plant, taking into account site-specific and project-specific requirements.

The steps required for a "top-down" BACT review are the following:

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).
5. Select BACT (the most-effective control technology and lowest consistently achievable emission limit) that has not been eliminated for economic, energy, or environmental impact reasons.

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

- CO_2
- Nitrous oxide (N_2O)
- Methane (CH_4)
- Hydrofluorocarbons (HFC)
- Perfluorocarbons (PFC)
- Sulfur hexafluoride (SF_6)

Although the top-down BACT analysis is applied to GHGs, there are "unique" issues in the analysis for GHG that do not arise in BACT for criteria pollutants (EPA, 2011b). For example, EPA recognizes that the range of potentially available control options for BACT Step 1 is currently limited and emphasizes the importance of energy efficiency in BACT reviews. Specifically, EPA states that (EPA, 2011b):

> *The application of methods, systems, or techniques to increase energy efficiency is a key GHG-reducing opportunity that falls under the category of "lower-polluting processes/practices." Use of inherently lower-emitting technologies, including energy efficiency measures, represents an opportunity for GHG reductions in these BACT reviews. In some cases, a more energy efficient process or project design maybe used effectively alone; whereas in other cases, an energy efficient measure may be used effectively in tandem with end-of-stack controls to achieve additional control of criteria pollutants.*
> (EPA, 2011b)

Based on this reasoning, EPA provides permitting authorities with the discretion to use energy-efficient measures as "the foundation for a BACT analysis for GHGs . . ." (EPA, 2011b).

3.2 GHG BACT Analysis

3.2.1 Assumptions

During the completion of the GHG BACT analysis, the following assumptions were made:

- The HBEP BACT analysis for criteria pollutants will result in the installation of a SCR system for NO_x emissions reduction and an oxidation catalyst for control of CO and VOCs for each turbine.
- During actual combustion turbine operation, the oxidation catalyst may result in minimal increases in CO_2 from the oxidation of any CO and CH_4 in the flue gas. However, the EPA Final Mandatory Reporting of Greenhouse Gases Rule (Mandatory Reporting Rule) (40 CFR 98) factors for estimating CO_2e emissions from natural gas combustion assume complete combustion of the fuel. While the oxidation catalyst has the potential of incrementally increasing CO_2 emissions, these emissions are already accounted for in the Mandatory Reporting Rule factors and included in the CO_2e totals.
- Similarly, the SCR catalyst may result in an increase in N_2O emissions. Although quantifying the increase is difficult, it is generally estimated to be very small or negligible. From the HBEP GHG emissions inventory, the estimated N_2O emissions only total 45.8 metric tons per year. Therefore, even if there were an

order-of-magnitude increase in N_2O as a result of the SCR, the impact to CO_2e emissions would be insignificant as compared to total estimated HBEP CO_2e emissions.

Use of the SCR and oxidation catalyst slightly decreases the project thermal efficiency due to backpressure on the turbines (these impacts are already included in the emission inventory) and, as noted above, may create a marginal but unquantifiable increase to N_2O emissions. Although elimination of the NO_x and CO/VOC controls could conceivably be considered as an option within the GHG BACT, the environmental benefits of the NO_x, CO, and VOC control are assumed to outweigh the marginal increase to GHG emissions. Therefore, even if carried forward through the GHG BACT analysis, they would be eliminated in Step 4 because of other environmental impacts. Therefore, omission of these controls within the BACT analysis was not considered.

3.2.2 BACT Determination

The top-down GHG BACT determination for the combustion turbines and HRSGs with duct burners is presented below. This BACT analysis is based on one power block consisting of three combustion turbines, three HRSGs, one steam turbine, and ancillary facilities.

The primary GHG of concern for HBEP is CO_2. This analysis primarily presents the GHG BACT analysis for CO_2 emissions because CH_4 and N_2O emissions are insignificant, at less than one percent of facility GHG CO_2e emissions. HBEP will emit insignificant quantities of SF_6, HFCs or PFCs pollutants, used in electrical switch gear and comfort cooling systems. Therefore, the primary sources of GHG emissions would be the natural-gas-fired combustion turbines with duct burners.

This determination follows EPA's top-down analysis method, as specified in EPA's GHG Permitting Guidance (EPA, 2011b). The following top-down analysis steps are listed in the EPA's *New Source Review Workshop Manual* (EPA, 1990):

- Step 1: Identify all control technologies
- Step 2: Eliminate technically infeasible options
- Step 3: Rank remaining control technologies by control effectiveness
- Step 4: Evaluate most effective controls and document results
- Step 5: Select BACT

Each of these steps, described in the following sections, was conducted for GHG emissions from the CTGs and HRSGs with duct burners. The following top-down BACT analysis has been prepared in accordance with the EPA's *New Source Review Workshop Manual* (EPA, 1990) and takes into account energy, environmental, economic, and other costs associated with each alternative technology.

The previous and current emission limits reported for combined-cycle and cogeneration turbines were based on a search of the various federal, state, and local BACT, RACT, and LAER databases. The search included the following databases:

- EPA BACT/LAER Clearinghouse (EPA, 2012)
  - Search included the CO_2 BACT/LAER determinations for combined-cycle and cogeneration, large combustion turbines (greater than 25 MW) with permit dates for the years 2001 through 2011.
- BACT Analyses for Recently Permitted Combined-cycle CEC Projects (CEC, 2012)
  - Review included the GHG BACT analysis for the RCEC, the Palmdale Hybrid Power Project, and the Watson Cogeneration Project.

3.2.2.1 Identification of Available GHG Emissions Control Technologies – Step 1

There are two basic alternatives for limiting the GHG emissions from the HBEP combined-cycle equipment:

- Carbon capture and storage (CCS)
- Thermal efficiency

The proposed HBEP design and operation will consist of two "3-by-1" combined-cycle generating power blocks, both including three natural-gas-fired Mitsubishi 501DA CTGs with fired HRSGs, and one STG. The project owner has determined that this configuration is the only alternative that meets all of the project objectives as further detailed in Section 1.2. Several of the primary objectives of the HBEP are to backstop variable renewable resources with a multiple stage generator project that incorporates fast start capability, a high degree of turndown, fast ramping capability, and a high thermal efficiency. Therefore, other potentially lower emitting renewable generation technologies were not evaluated in this BACT analysis because this would change the fundamental business purpose of the HBEP.

This is consistent with EPA's March 2011 *PSD and Title V Permitting Guidance for Greenhouse Gases,* which states:

> *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…", and "…the permitting authority should keep in mind that BACT, in most cases, should not regulate the applicant's purpose or objective for the proposed facility… (p. 26).*

The only identified GHG emission "control" options are post-combustion CCS and thermal efficiency of the proposed generation facility.

Carbon Capture and Storage. CCS technology is composed of three main components: (1) CO_2 capture and/or compression, (2) transport, and (3) storage.

CO_2 Capture and Compression. CCS systems involve use of adsorption or absorption processes to separate and capture CO_2 from the flue gas, with subsequent desorption to produce a concentrated CO_2 stream. The concentrated CO_2 is then compressed to "supercritical" temperature and pressure, a state in which CO_2 exists neither as a liquid nor a gas, but instead has physical properties of both liquids and gases. The supercritical CO_2 would then be transported to an appropriate location for underground injection into a suitable geological storage reservoir, such as a deep saline aquifer, or depleted coal seam, ocean storage site, or used in crude oil production for enhanced oil recovery.

The capture of CO_2 from gas streams can be accomplished using either physical or chemical solvents or solid sorbents. Applicability of different processes to particular applications will depend on temperature, pressure, CO_2 concentration, and contaminants in the gas or exhaust stream. Although CO_2 separation processes have been used for years in the oil and gas industries, the characteristics of the gas steams are markedly different than power plant exhaust. CO_2 separation from power plant exhaust has been demonstrated in large pilot-scale tests, but it has not been commercially implemented in full-scale power plant applications.

After separation, the CO_2 must be compressed to supercritical temperature and pressure for suitable pipeline transport and geologic storage properties. Although compressor systems for such applications are proven, commercially available technologies, specialized equipment is required, and operating energy requirements are very high.

CO_2 Transport. The supercritical CO_2 would then be transported to an appropriate location for injection into a suitable storage reservoir. The transport options may include pipeline or truck transport, or in the case of ocean storage, transport by ocean-going vessels.

Because of the extremely high pressures, as well as the unique thermodynamic and dense-phase fluid properties of supercritical CO_2, specialized designs are required for CO_2 pipelines. Control of potential propagation fractures and corrosion also require careful attention to contaminants such as oxygen, nitrogen, methane, water, and hydrogen sulfide.

While transport of CO_2 via pipeline is proven technology, doing so in urban areas will present additional concerns. Development of new rights–of-way in congested areas would require significant resources for planning and execution, and public concern about potential for leakage may present additional barriers.

CO_2 Storage. CO_2 storage methods include geologic sequestration, oceanic storage, and mineral carbonation. Oceanic storage has not been demonstrated in practice, as discussed below. Geologic sequestration is the process of injecting captured CO_2 into deep subsurface rock formations for long-term storage, which includes the use of a

deep saline aquifer or depleted coal seams, as well as the use of compressed CO_2 to enhance oil recovery in crude oil production operations.

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 that 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.

The U.S. Department of Energy (DOE) National Energy Technology Laboratory (NETL), via the West Coast Regional Carbon Sequestration Partnership (WestCarb) has researched potential geologic storage locations including those in Southern California. This information has been presented in NETL's 2010 *Carbon Sequestration Atlas of the United States and Canada* (http://www.netl.doe.gov/technologies/carbon_seq/refshelf/atlasIII/index.html), NETL's National Carbon Sequestration Database and Geographic Information System (NATCARB) database (http://www.netl.doe.gov/technologies/carbon_seq/natcarb/storage.html) and Southern California Carbon Sequestration Research Consortium's (SoCalCarb) Carbon Atlas (http://socalcarb.org/atlas.html). As shown in Figures 1 and 2, a number of deep saline aquifers and oil and gas reservoirs have been found to be potentially suitable for CO_2 storage. No potential for storage in depleted coal seams or basalt formations was identified.

The *Carbon Sequestration Atlas* lists the deep saline formations in Ventura and Los Angeles Basins as the "most promising" locations in Southern California, and it states that "California may also be a candidate for CO_2 storage in offshore basins, although the lack of available data has limited the assessment of their CO_2 storage potential to areas where oil and gas exploration has occurred." The atlas also notes the potential for use of oil and gas reservoirs in the Los Angeles and Ventura Basins, although it states that "Reservoirs in highly fractured shales within the Santa Maria and Ventura Basins are not good candidates for CO_2 storage."

Funded via the American Recovery and Reinvestment Act, the Wilmington Graben project is an ongoing, comprehensive research program for characterization of the potential for CO_2 storage in the Pliocene and Miocene sediments offshore from Los Angeles and Long Beach. The study includes analysis of existing and new well cores, seismic studies, engineering analysis of potential pipeline systems, and risk analyses. However, no pilot studies of CO_2 injection into onshore or offshore geologic formations in the vicinity of the project site have been conducted to date.

Thermal Efficiency. Because CO_2 emissions are directly related to the quantity of fuel burned, the less fuel burned per amount of energy produced (greater energy efficiency), the lower the GHG emissions per unit of energy produced. As a means of quantifying feasible energy efficiency levels, the State of California established an emissions performance standard for California power plants. California Senate Bill 1368 limits long-term investments in baseload generation by the state's utilities to power plants that meet an emissions performance standard jointly established by the CEC and the CPUC. CEC regulations establish a standard for baseload generation (that is, with capacity factors in excess of 60 percent) of 1,100 pounds (or 0.55 ton) CO_2 per megawatt-hour (MWh). This emission standard corresponds to a heat rate of approximately 9,400 British thermal units per kilowatt-hour (Btu/kWh) (CEC, 2010).

The HBEP is a highly efficient multiple-staged generator project that incorporates a high degree of turndown, fast start, and ramping capability that will support grid reliability as renewable generating sources comprise a larger share of California's energy production. This allows an increased use of wind power and other renewable energy sources, with backup power available from the HBEP. A natural-gas-fired plant such as the HBEP uses a relatively small amount of electricity to operate the facility compared to the energy in the fossil fuel combusted. Therefore, minimal benefit occurs 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.

The addition of the high thermal efficiency of the HBEP'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.

California's Renewable Portfolio Standard (RPS) requirement was increased from 20 percent by 2010 to 33 percent 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 HBEP will aid in the effort to meet California's RPS standard, because a significant attribute of the HBEP is that the combined-cycle facility can operate similarly to a peaking plant but at higher thermal efficiency.

Based on proprietary design and operational adjustments, the HBEP will allow a rapid startup of the combustion turbines. As presented in Figure 3, all combustion turbines in a power block can be started and taken from ignition to full load (~350 MW) in a 10-minute period. The HBEP HRSG operation will be integrated into the startup sequence, and full steam turbine generator output can be expected in approximately 40 minutes after fuel ignition for a hot or warm startup scenario. At maximum firing rate, the maximum power island ramp rate is 110 MW/minute for increasing in load and 250 MW/minute for decreasing load. At other load points, the load ramp rate is 30 percent.

The HBEP Mitsubishi 501DA combustion turbines allow for a unique operating configuration when integrated with the HRSG and duct burner operation. Over the anticipated projected load dispatch range presented in Figure 4, the HBEP 3-by-1 configuration maintains an efficient heat rate over almost the entire load range. Operation within this high efficiency band is maintained through operational changes by the combustion turbine, HRSG/steam turbine, and duct burners. These operational adjustments allow efficient operation over most of the project operating range. In traditional combined-cycle facilities, the duct burners are used in a peaking or power augmentation capacity. However, the HBEP closes the MW production gap between starting the second and third combustion turbines of a power block through the use of the duct burners, which tend to decrease thermal efficiency of the system but make available more MW in less time and at a lower heat rate as compared to a peaking facility.

In summary, using the Mitsubishi 501DA turbines with the flexible operational integration scheme allows the project goals to be met, while maintaining a higher efficiency than comparable peaking combustion turbine applications. The ability to produce fast-ramping power to augment renewable power sources to the grid make the HBEP a highly energy-efficient system.

3.2.2.2 Eliminate Technically Infeasible Options – Step 2

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 assess its technical feasibility. The technology is feasible only when it is available and applicable. A technology that is not commercially available for the scale of the project was considered infeasible. An available technology is considered applicable only if it can be reasonably installed and operated on the proposed project.

Carbon Capture and Storage. Although many believe that CCS will allow the future use of fossil fuels while minimizing GHG emissions, there are a number of technical barriers concerning the use of this technology for the HBEP, as follows:

- No full-scale systems for solvent-based carbon capture are currently in operation to capture CO_2 from dilute exhaust steams such as those from natural-gas-fired electrical generation systems at the scale proposed for the HEBP.
- Use of captured CO_2 for enhanced oil recovery (EOR) is widely believed to represent the practical first opportunity for CCS deployment; however, identification of suitable oil reservoirs with the necessary willing and able owners and operators is not feasible for HBEP to undertake. Oil and gas production in the vicinity of HBEP is available for EOR; however, only pilot-scale projects are known in the region and only estimates are available on the capacity of these miscible oil fields.

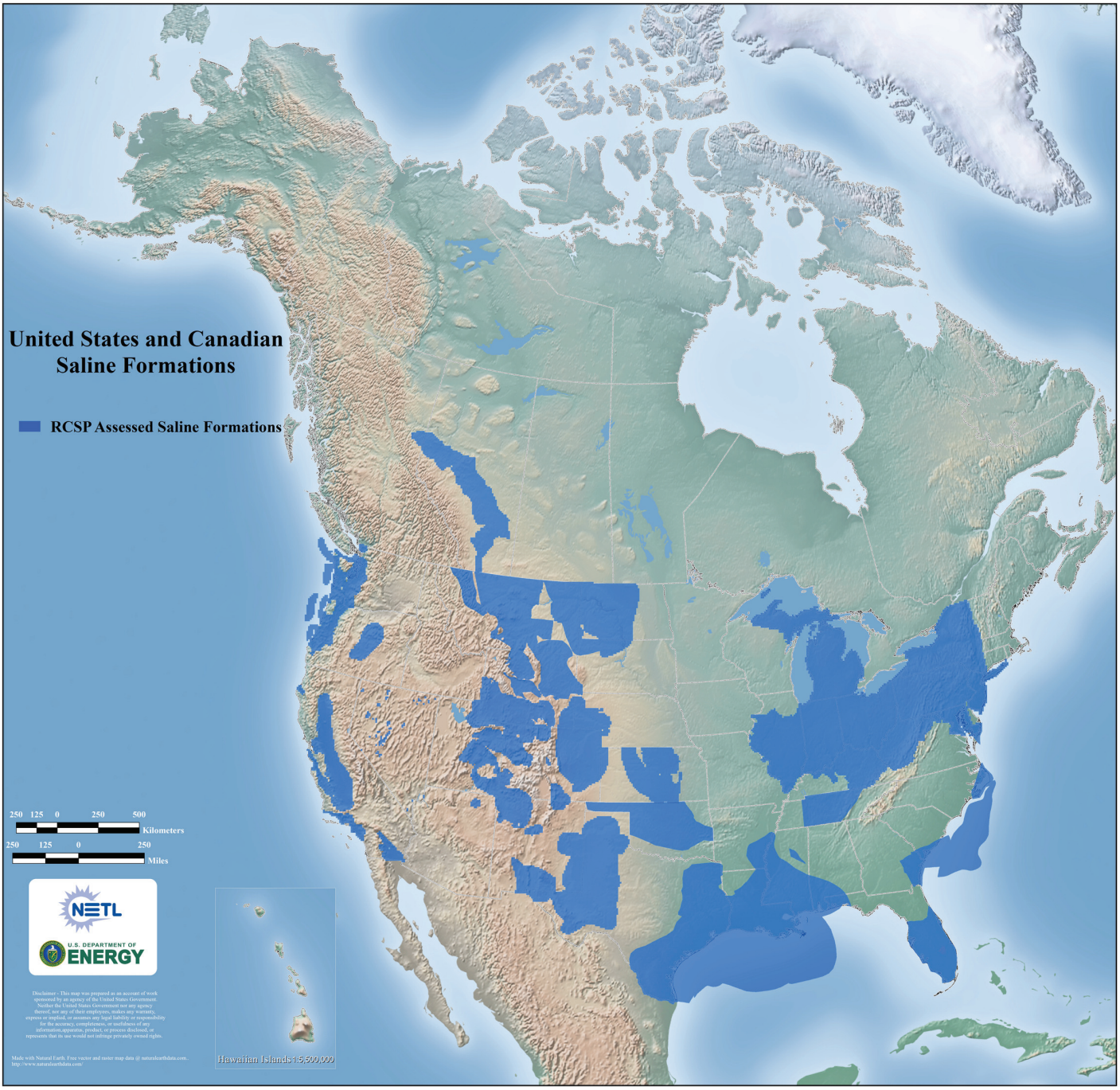


FIGURE 1
United States and Canadian Saline Formations
AES Huntington Beach Energy Project
Huntington Beach, California

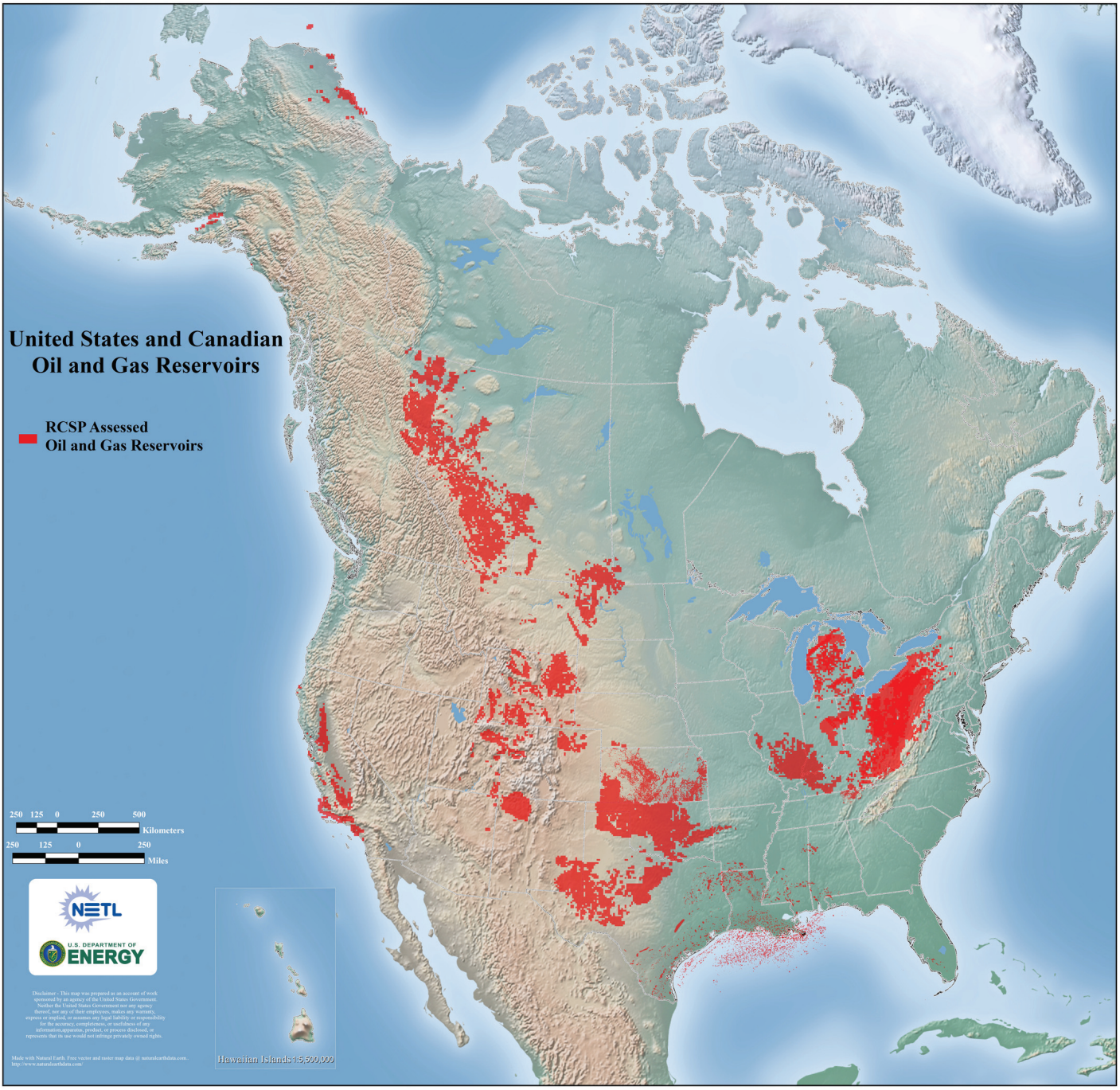
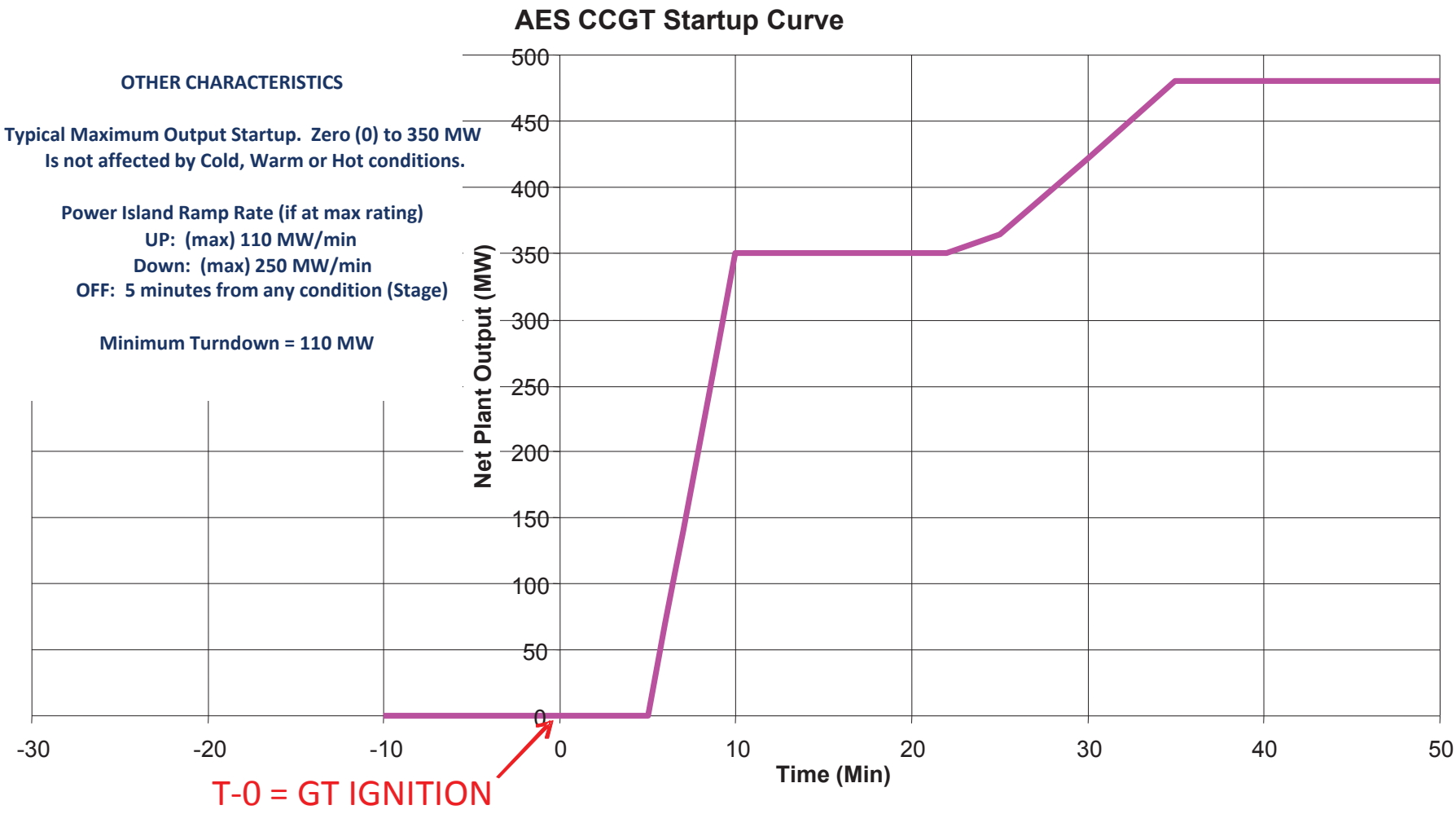
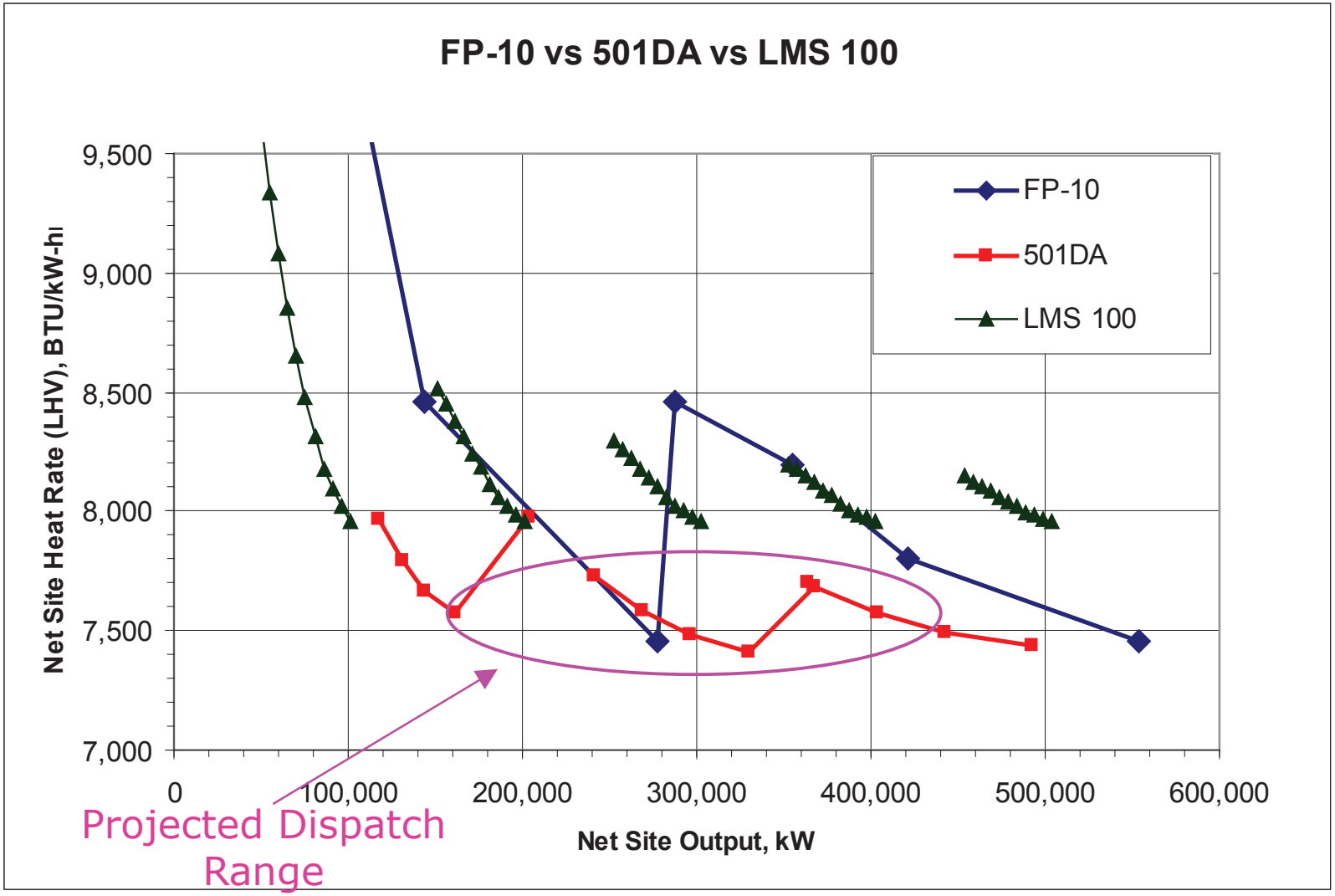


FIGURE 2
United States and Canadian Oil and Gas Reservoirs
AES Huntington Beach Energy Project
Huntington Beach, California



Source: AES Southland Development, LLC, as presented to the South Coast Air Quality Management District on April 19, 2012

FIGURE 3
HBEP Startup Curve
AES Huntington Beach Energy Project
Huntington Beach, California



Source: AES Southland Development, LLC, as presented to the South Coast Air Quality Management District on April 19, 2012

FIGURE 4
Comparison of HBEP and Alternative Design Heat Rates
AES Huntington Beach Energy Project
Huntington Beach, California

- Little experience exists with other types of storage systems, such as deep saline aquifers (geological sequestration) or ocean systems (ocean sequestration). These storage systems are not commercially available technology.
- Because of the developmental nature of CCS technology, vendors and contractors do not provide turnkey offerings; separate contracting would be required for capture system design and construction; compression and pipeline system routing, siting and licensing, engineering and construction; and geologic storage system design, deployment, operations, and monitoring. Because no individual facility could be expected to take on all of these requirements to implement a control technology, this demonstrates that the technology as a whole is not yet commercially available.
- Significant legal uncertainties continue to exist regarding relationship between land surface ownership rights and subsurface (pore space) ownership, and potential conflicts with other uses of land such as exploitation of mineral rights, management of risks and liabilities, and so on.
- The potential for frequent startup and shutdown, as well as intended rapid load fluctuations, of generation units at the HBEP facility makes CCS impractical for two reasons – inability of capture systems to start up in the same short time frame as combustion turbines, and infeasibility for potential users of the CO_2 such as EOR systems to use uncertain and intermittent flows. As described above, the units at the HBEP facility are designed to accommodate rapidly fluctuating power and steam demands from renewable electrical generation sources.

These issues are discussed in more detail below.

As suggested in the *EPA New Source Review Workshop Manual*, control technologies should be demonstrated in practice on full-scale operations to be considered available within a BACT analysis: "Technologies which have not yet been applied to (or permitted for) full scale operations need not be considered available; an applicant should be able to purchase or construct a process or control device that has already been demonstrated in practice" (EPA, 1990). As discussed in more detail below, carbon capture technology has not been demonstrated in practice in power plant applications. Other process industries do have carbon capture systems that are demonstrated in practice; however, the technology used for these processes cannot be applied to power plants at the scale of HBEP.

Three fundamental types of carbon capture systems are employed throughout various process and energy industries: sorbent adsorption, physical absorption, and chemical absorption. Use of carbon capture systems on power plant exhaust is inherently different from other commercial-scale systems currently in operation, mainly because of the concentration of CO_2 and other constituents in the gas streams.

For example, CO_2 is separated from petroleum in refinery hydrogen plants in a number of locations, but this is typically accomplished on the product gas from a steam CH_4reforming process that contains primarily hydrogen (H_2), unreacted CH_4, and CO_2. Based on the stoichiometry of the reforming process, the CO_2 concentration is approximately 80 percent by weight, and the gas pressure is approximately 350 pounds of force per square inch gauge (psig). Because of the high concentration and high pressure, a pressure swing adsorption (PSA) process is used for the separation. In the PSA process, all non-hydrogen components, including CO_2 and CH_4, are adsorbed onto the solid media under high pressure; after the sorbent becomes saturated, the pressure is reduced to near atmospheric conditions to desorb these components. The CO_2/CH_4 mixture in the PSA tail gas is then typically recycled to the reformer process boilers to recover the heating value; however, where the CO_2 is to be sold, an additional amine absorption process would be required to separate the CO_2 from CH_4. In its May 2011 *Department of Energy's (DOE)/NETL Advanced Carbon Dioxide Capture R&D Program: Technology Update*, NETL notes the different applications for chemical solvent absorption, physical solvent absorption, and sorbent adsorption processes. As noted in Section 4.B, "When the fluid component has a high concentration in the feed stream (for example, 10 percent or more), a PSA mechanism is more appropriate" (NETL, 2011).

In another example, at the Dakota Gasification Company's Great Plains Synfuels Plant in North Dakota, CO_2 is separated from intermediate fuel streams produced from gasification of coal. The gas from which the CO_2 is

separated is a mixture of primarily H_2, CH_4, and 30 to 35 percent CO_2; a physical absorption process (Rectisol) is used. In contrast, as noted on page 29 of the *Report of the Interagency Task Force on Carbon Capture and Storage* (DOE and EPA, 2010), CO_2 concentrations for natural-gas-fired systems are in the range of 3 to 5 percent. This adds significant technical challenges to separation of CO_2 from natural-gas-fired power plant exhaust as compared to other systems.

In Section 4.A of the above-referenced technology update, NETL notes this difference between pre-combustion CO_2 capture such as that from the North Dakota plant versus the post-combustion capture such as that required from a natural-gas-fired power plant: "Physical solvents are well suited for pre-combustion capture of CO_2 from syngas at elevated pressures; whereas, chemical solvents are more attractive for CO_2 capture from dilute low-pressure post-combustion flue gas" (NETL, 2011).

In the 2010 report noted above, the task force discusses four currently operating post-combustion CO_2 capture systems associated with power production. All four are on coal-based power plants where CO_2 concentrations are higher (typically 12 to 15 percent), with none noted for natural gas-based power plants (typically 3 to 5 percent).

The DOE/NETL is a key player in the nation's efforts to realize commercial deployment of CCS technology. A downloadable database of worldwide CCS projects is available on the NETL website (http://www.netl.doe.gov/technologies/carbon_seq/global/database/index.html). Filtering this database for projects that involve both capture and storage, which are based on post-combustion capture technology (the only technology applicable to natural gas turbine systems) and are shown as "active" with "injection ongoing" or "plant in operation," yields four projects. Three projects, one of which is a pilot-scale process noted in the interagency task force report as described above, are listed at a capacity of 274 tons per day (100,000 tpy), and the fourth has a capacity of only 50 tons per day. Post-combustion CCS has not been accomplished on a scale of the HEBP facility, which could produce up to approximately 3.2 million tpy or 8,662 tons per day CO_2e. Furthermore, scale-up involving a substantial increase in size from pilot scale to commercial scale is unusual in chemical processes and would represent significant technical risk.

A chemical solvent CCS approach would be required to capture the approximate 3 to 5 percent CO_2 emitted from the flue gas generated from the natural-gas-fired systems (combined-cycle) used at the HEPB facility. To date, a chemical solvent technology has not been demonstrated at the operating scale proposed.

As detailed in the August 2010 report, one goal of the task force is to bring 5 to 10 commercial demonstration projects online by 2016. With demonstration projects still years away, clearly the technology is not currently commercially available at the scale necessary to operate the HEBP facility. It is notable that several projects, including those with DOE funding or loan guarantees, were cancelled in 2011, making it further unlikely that technical information required to scale up these processes can be accomplished in the near future. For example, the AEP Mountaineer site (AEP; a former DOE demonstration commercial-scale project) was to expand capture capacity to 100,000 tpy; however, to date only the "Project Validation Facility" was completed and only accomplished capture of a total of 50,000 metric tons and storage of 37,000 metric tons of CO_2. AEP recently announced that the larger project will be cancelled after completion of the front-end engineering design because of uncertain economic and policy conditions.

EPA's Fact Sheet and Ambient Air Quality Impact Report for the Palmdale project states that "commercial CO_2 recovery plants have been in existence since the late 1970s, with at least one plant capturing CO_2 from gas turbines". However, on review of the fact sheet referenced for the gas turbine project (http://www.powermag.com/coal/2064.html), it is notable that the referenced project is not a commercial-scale operation; rather, it is a pilot study at a commercial power plant. The pilot system captured 365 tons per day of CO_2 from the power plant, in the range of the power pilot tests noted above. Full-scale capture of power plant CO_2 has not yet been accomplished anywhere in the world.

The interagency task force report notes the lack of demonstration in practice:

> *Current technologies could be used to capture CO_2 from new and existing fossil energy power plants; however, they are not ready for widespread implementation primarily because they have not been demonstrated at the scale necessary to establish confidence for power plant application.*

> *Since the CO_2 capture capacities used in current industrial processes are generally much smaller than the capacity required for the purposes of GHG emissions mitigation at a typical power plant, there is considerable uncertainty associated with capacities at volumes necessary for commercial deployment.* (DOE and EPA, 2010)

The ability to inject into deep saline aquifers as an alternative to EOR reservoirs is a major focus of the NETL research program. Although it is believed that saline aquifers are a viable opportunity, there are many uncertainties. Risk of mobilization of natural elements such as manganese, cobalt, nickel, iron, uranium, and barium into potable aquifers is of concern. Technical considerations for site selection include geologic siting, monitoring and verification programs, post-injection site care, long-term stewardship, property rights, and other issues.

At least one planned saline aquifer pilot project is underway in the Lower San Joaquin Valley near Bakersfield, California (the Kimberlina Saline Formation), that may act as a possible candidate location for geologic sequestration and storage. According to WestCarb, a pilot project plant operated by Clean Energy Systems is targeting the Vedder Sandstone formation at a depth of approximately 8,000 feet, where there is a beaded stream unit of saline formation that may be favorable for CO_2 storage. It is unclear when the project is planned for full scale testing, and no plans are currently available to build a pipeline within the area to transport CO_2 to the test site. As noted above, the Wilmington Graben project is a large-scale study of the potential for geologic storage in offshore formations near Los Angeles; however, no indications of near-term plans for pilot testing were noted in NETL or SoCalCarb's websites.

As noted above, presumably the CO_2 could be used for EOR applications within the Los Angeles and Ventura Basins, but the exact location, time frame, and needed flow rates for those existing or future EORs are unclear because this information is typically treated as being a trade secret. During a study to evaluate the "future oil recovery potential in the major oil basins and large oil fields in California," the DOE concluded that a number of oil fields in the Los Angeles Basin are "amendable to miscible CO_2-EOR." Two of those oil fields, the Santa Fe Springs and Dominquez fields, are located approximately 30 miles from the HEBP facility. However, the feasibility of obtaining the necessary permits to build infrastructure and a pipeline to transport CO_2 to these fields through a densely urbanized area is uncertain.

Figure 5 from the Interagency Task Force report shows that no existing CO_2 pipelines are shown in California. The report does note that nationally there are "many smaller pipelines connecting sources with specific customers"; however, based on lack of natural or captured CO_2 sources in Southern California, it is assumed that no pipelines exist. The SoCalCarb carbon atlas shows a number of existing pipelines in the region; however, these are petroleum product pipelines. As noted above, because of high pressures, potential for propagation facture, and other issues, CO_2 pipeline design is highly specialized, and product pipelines would not be suitable for re-use of CO_2 transport.

Regarding CO_2 storage security, the CCS task force report (DOE and EPA, 2010) notes such uncertainties:

> *"The technical community believes that many aspects of the science related to geologic storage security are relatively well understood. For example, the Intergovernmental Panel on Climate Change (IPCC) concluded that "it is considered likely that 99 percent or more of the injected CO_2 will be retained for 1,000 years" (IPCC, 2005). However, additional information (including data from large-scale field projects, such as the Kimberlina project, with comprehensive monitoring) is needed to confirm predictions of the behavior of natural systems in response to introduced CO_2 and to quantify rates for long-term processes that contribute to trapping and, therefore, risk profiles (IPCC, 2005). "*

Field data from the Kimberlina CCS pilot project will provide additional information regarding storage security for that and other locations. Meanwhile, some uncertainties will remain regarding safety and permanence aspects of storage in these types of formations.

The effectiveness of ocean sequestration as a full-scale method for CO_2 capture and storage is unclear given the limited availability of injection pilot tests and the ecological impacts to shallow and deep ocean ecosystems. Ocean sequestration is conducted by injecting supercritical liquid CO_2 from either a stationary or towed pipeline at

targeted depth interval, typically below 3,000 feet. CO_2 is injected below the thermocline, creating either a rising droplet or a dense phase plume and sinking bottom gravity current. Through NETL, extensive research is being conducted by the Monterey Bay Aquarium Research Institute on the behavior of CO_2 hydrates and dispersion of these hydrates within the various depth horizons of the marine environment; however, the experiments are small in scale and the results may not be applicable to larger-scale injection projects in the near future. Long-term effects on the marine environment, including pH excursions, are ongoing, making the use of ocean sequestration technically infeasible at the current time. The feasibility of implementing a commercially available sequestration approach is further brought into question, with the IPCC stating:

> *Ocean storage, however, is in the research phase and will not retain CO_2 permanently as the CO_2 will re-equilibrate with the atmosphere over the course of several centuries…Before the option of ocean injection can be deployed, significant research is needed into its potential biological impacts to clarify the nature and scope of environmental consequences, especially in the longer term…Clarification of the nature and scope of long-term environmental consequences of ocean storage requires further research.* (IPCC, 2005).

Questions may also arise regarding the international legal implications of injecting industrial generated CO_2 into the ocean, which may eventually migrate to other international waters.

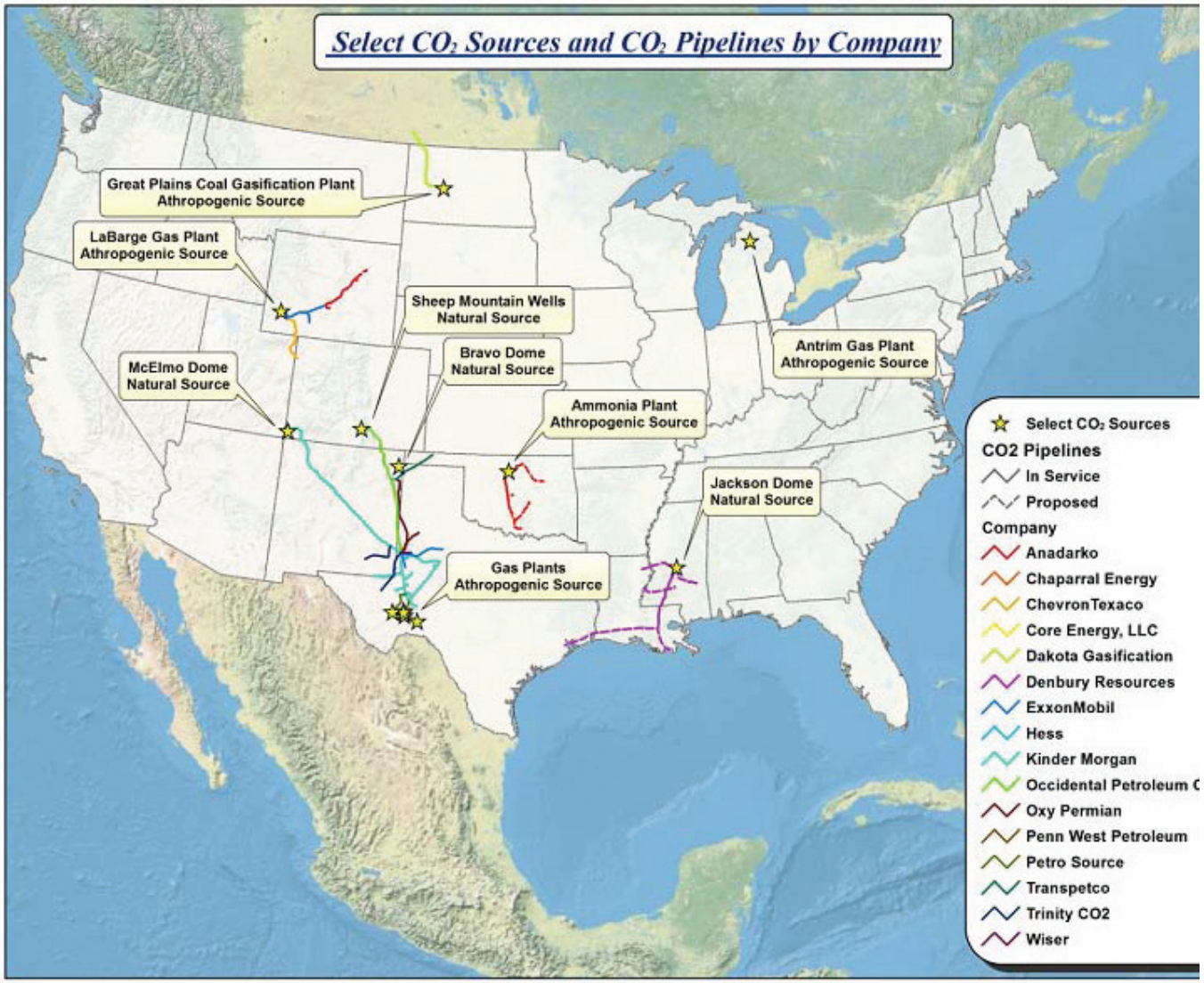
CCS technology development is dominated by vendors that are attempting to commercialize carbon capture technologies and by academia-led teams (largely funded by DOE) that are leading research into the geologic systems. The ability for electric utilities to contract for turn-key CCS systems simply does not exist at this time.

Most current carbon capture systems are based on amine or chilled ammonia technology, which are chemical absorption processes. Although capture system startup and shutdown time of vendor processes could not be confirmed within this BACT analysis, clearly both types of processes would require durations that exceed the time required for HBEP turbine startup or load response. As described above, HEBP may start or stop turbines and duct burners, and it may adjust the load on the operating turbines rapidly to meet grid reliability demands. In contrast, both amine and chilled ammonia systems require startup of countercurrent liquid-gas absorption towers and either chilling of the ammonia solution or heating of regeneration columns for the amine systems. It is technically infeasible for the carbon capture systems to start up and shut down or to make large adjustments in gas volume in the time frames required to serve this type of operation effectively; this means that portions of the HBEP operation would run without CO_2 capture even with implementation of a CCS system. Alternatively, the CCS system could be operated at a minimum load during periods of expected operation. However, this approach would consume energy, offsetting some of the benefit.

Finally, the potential to sell CO_2 to industrial or oil and gas operations is infeasible for an operation such as this, where daily operation of HBEP depends on grid dispatch needs, particularly to offset reductions from renewable energy sources. Even if a potential EOR opportunity could be identified, such an operation would typically need a steady supply of CO_2. Intermittent CO_2 supply from potentially short duration with uncertain daily operation would be virtually impossible to sell on the market, making the EOR option unviable. Therefore, CCS technology would be better suited for applications with low variability in operating conditions.

In the EPA PSD and Title V GHG permitting guidance, the issues noted above are summarized: "A number of ongoing research, development, and demonstration projects may make CCS technologies more widely applicable *in the future*" (EPA, 2011b; italics added). From page 36 of this guidance, it is noted:

> *While CCS is a promising technology, EPA does not believe that at this time CCS will be a technically feasible BACT option in certain cases. As noted above, to establish that an option is technically infeasible, the permitting record should show that an available control option has neither been demonstrated in practice nor is available and applicable to the source type under review. EPA recognizes the significant logistical hurdles that the installation and operation of a CCS system presents and that sets it apart from other add-on controls that are typically used to reduce emissions of other regulated pollutants and already have an existing reasonably accessible infrastructure in place to address waste disposal and other offsite needs. Logistical hurdles for CCS may include obtaining contracts for offsite land acquisition (including the availability of land), the*



Source: Figure B-1 from the "Report of the Interagency Task Force on Carbon Capture and Storage", August 2010.

FIGURE 5
Existing and Planned CO2 Pipelines in the United States with Sources
AES Huntington Beach Energy Project
Huntington Beach, California

CH2MHILL.

> *need for funding (including, for example, government subsidies), timing of available transportation infrastructure, and developing a site for secure long-term storage. Not every source has the resources to overcome the offsite logistical barriers necessary to apply CCS technology to its operations, and smaller sources will likely be more constrained in this regard.* (EPA, 2011b)

The CCS alternative is not considered technically feasible for the HEBP, and it should therefore be eliminated from further consideration in Step 2. However, at the suggestion of EPA team members on other recent projects, economic feasibility issues will be discussed in Step 4.

Thermal Efficiency. Thermal efficiency is a standard measurement metric for combined-cycle facilities; therefore, it is technically feasible as a control technology for BACT consideration.

3.2.2.3 Combustion Turbine GHG Control Technology Ranking – Step 3

Because CCS is not technically feasible, the only remaining technically feasible GHG control technology for the HEBP is thermal efficiency. While CCS will be discussed further in Step 4, and if it were technically feasible would rank higher than thermal efficiency for GHG control, thermal efficiency is the only technically feasible control technology that is commercially available and applicable for the HEBP.

3.2.2.4 Evaluate Most Effective Controls – Step 4

Step 4 of the BACT analysis is to evaluate the remaining technically feasible controls and consider whether energy, environmental, and/or economic impacts associated with the remaining control technologies would justify selection of a less-effective control technology. The top-down approach specifies that the evaluation begin with the most-effective technology.

Carbon Capture and Sequestration. As demonstrated in Step 2, CCS is not a technically feasible alternative for the HEBP. Nonetheless, at the suggestion of the EPA team members on other recent projects, economic feasibility of CCS technology is reviewed in this step. Control options considered in this step therefore include application of CCS technology and plant energy thermal efficiency. As demonstrated below, CCS is clearly not economically feasible for the HEBP.

On page 42 of the EPA PSD and Title V Permitting Guidance, it is suggested that detailed cost estimates and vendor quotes should not be required where it can be determined from a qualitative standpoint that a control strategy would not be cost effective:

> *With respect to the valuation of the economic impacts of [AES] control strategies, it may be appropriate in some cases to assess the cost effectiveness of a control option in a less detailed quantitative (or even qualitative) manner. For instance, when evaluating the cost effectiveness of CCS as a GHG control option, if the cost of building a new pipeline to transport the CO_2 is extraordinarily high and by itself would be considered cost prohibitive, it would not be necessary for the applicant to obtain a vendor quote and evaluate the cost effectiveness of a CO_2 capture system.* (EPA, 2011b)

The guidance document also acknowledges the current high costs of CCS technology:

> *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 technical feasibility 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 economical feasibility of the BACT analysis, even in some cases where underground storage of the captured CO_2 near the power plant is feasible.*(EPA, 2011b)

The costs of constructing and operating CCS technology are indeed extraordinarily high, based on current technology. Even with the optimistic assumption that appropriate EOR opportunities could be identified in order to lower costs, compared to "pure" sequestration in deep saline aquifers, or through deep ocean storage, additional costs to HBEP would include the following:

- Licensing of scrubber technology and construction of carbon capture systems
- Significant reduction to plant output due to the high energy consumption of capture and compression systems
- Identification of oil and gas companies holding depleted oil reservoirs with appropriate characteristics for effective use of CO_2 for tertiary oil recovery, and negotiation with those parties for long-term contracts for CO_2 purchases
- Construction of compression systems and pipelines to deliver CO_2 to EOR or storage locations
- Hiring of labor to operate, maintain, and monitor the capture, compression, and transport systems
- Resolving issues regarding project risk that would jeopardize the ability to finance construction

The interagency task force report provides an estimate of capital and operating costs for carbon capture from natural gas systems: "For a [550-MWe net output] NGCC plant, the capital cost would increase by $340 million and an energy penalty of 15 percent would result from the inclusion of CO_2 capture" (DOE and EPA, 2010). Using the "Capacity Factor Method" for prorating capital costs for similar systems of different sizes as suggested by the Association for the Advancement of Cost Engineering and other organizations, the CO_2 capture system capital cost for the HEBP is estimated as at least $467 million. Based on an estimated HBEP capital cost of $500 million to $550 million for the plant and equipment, the capture system alone would nearly double the cost of the overall plant equipment capital cost.

As noted above, the effort required to identify and negotiate with oil and gas companies that may be able to utilize the CO_2 would be substantial. Prospective EOR oil fields are located within the area, but no active commercial facilities exist within the Los Angeles Basin, making predictions for CO_2 demand generated by CCS difficult. And, because of the patchwork of oil well ownership, many parties could potentially be involved in negotiations over CO_2 value.

Because of the extremely high pressures required to transport and inject CO_2 under supercritical conditions, the compressors required are highly specialized. For example, the compressors for the Dakota Gasification Company system are of a unique eight-stage design. It is unclear whether the Task Force natural gas combined-cycle (NGCC) cost estimate noted above includes the required compression systems; if not, then this represents another substantial capital cost.

Pipelines must be designed to withstand the very high pressures (over 2,000 psig) and the potential for corrosion if any water is introduced into the system. As noted above, if CCS were otherwise technically and economically feasible for the HEBP, the most realistic scenario could be to construct a pipeline from the Huntington Beach area to either the Santa Fe Springs or Dominquez oil fields near Los Angeles for EOR, assuming that permits and right-of-way agreements are obtained and there is an active EOR operation in this location. As noted above, the approximate distance of the pipeline to either of these two fields is approximately 30 miles. Based on engineering analysis by the designers of the Denbury CO_2 pipeline in Wyoming, costs for an 8-inch CO_2 pipeline are estimated at $600,000 per mile, for a total cost of $18 million. Therefore, the pipeline alone would represent an additional 3 percent increase to the capital cost assuming that the EOR opportunities could be realized; however, costs could be substantially higher to transport CO_2 to deep saline aquifer or ocean storage locations.

It is unlikely that financing could be approved for a project that combines CCS with generation, given the technical and financial risks. Also, as evidenced with utilities' inability to obtain CPUC approval for integrated gasification / combined-cycle projects because of their unacceptable cost and risk to ratepayers (such as Wisconsin's disapproval of the Wisconsin Electric Energy project), it is reasonable to assume that the same issues would apply in this case before the CEC.

In summary, capital costs for capture system and pipeline construction alone would almost double the project capital cost, and lost power sales resulting from the CCS system energy penalty would represent another major impact to the project financials and a multi-fold increase to project capital costs. Other costs, such as identification, negotiation, permitting studies, and engineering of EOR opportunities; operating labor and maintenance costs for capture, compression, and pipeline systems; uncertain financing terms or inability to finance; and difficulty in obtaining CEC approval would also impact the project also, it is unclear whether compression systems are included in the task force estimate of capture system costs. Not only is CCS not technically feasible at this project scale, as the above discussion demonstrates, but CCS is clearly not economically feasible for natural-gas-fired turbines at this time.

Thermal Efficiency. A search of the EPA's RACT/BACT/LAER Clearinghouse was performed for NGCC projects. GHG permit information was found for one source—Westlake Vinyls Company LP Cogeneration Plant (LA-0256)—which was issued a permit in December 2011. The record for this source includes only hourly and annual CO_2e emission limitations and no information of costs estimated performed for the GHG BACT determination. Recent GHG determinations were completed for the Russell City Energy Center and the Palmdale Hybrid Power Project in California. Both projects proposed the use of combined-cycle configurations to produce commercial power, and the BACT analyses for both projects concluded that plant efficiency was the only feasible combustion control technology. However, the Palmdale project includes a 251-acre solar thermal field that generates up to 50 MWs during sunny days, which reduces the project's overall heat rate.

Because CCS is not technically or economically feasible, thermal efficiency remains the most effective, technically feasible, and economically feasible GHG control technology for the HBEP. The operationally flexible turbine class and steam cycle designs selected for the HBEP are the most thermally efficient for the project design objectives, operating at the projected annual capacity factor of approximately 40 percent. Table 3-1 compares the HBEP heat rate with that of other recent projects.

TABLE 3-1
Comparison of Heat Rates and GHG Performance Values of Recently Permitted Projects

Plant Performance Variable	Heat Rate (Btu/kWh)	GHG Performance ($MTCO_2$/MWh)
Huntington Beach Energy Project	8,236[a]	0.479[b]
Watson Cogeneration Project[c]	5,027 to 6,327	0.219 to 0.318
Palmdale Hybrid Power Project	6,970[d]	0.370[d]
Russell City Energy Project	6,852[e]	0.371[f]

[a] Calculated higher heating value (HHV) net heat rate at 65.8°F at site elevation, relative humidity of 58.32 percent, no inlet air cooling, without duct burners. Heat rate varies over the anticipated load dispatch range.
[b] Calculated CO_2 emissions at conditions in footnote a above are 163,658 lb/hr with 166.3 combined MW (both combustion turbine and steam turbine generation)
[c] From Watson Cogeneration Project Commission Final Decision
[d] From Tables 3 and 4 of the Palmdale Hybrid Power Project Greenhouse Gas BACT Analysis (AECOM, 2011)
[e] Net design heat rate with no duct burners, from "GHG BACT Analysis Case Study, Russell City Energy Center; November 2009, updated February 3, 2010.
[f] From Russell City total heat input of 4,477 MMBtu/hr (from PSD Permit), generation of 653 MW was calculated utilizing design heat rate of 6,852 Btu/kwh. From reference document in footnote d above, 1-hour CO_2 limit is 242 $MTCO_2$/hr, which yields 0.371 $MTCO_2$/MWh.

Note:

$MTCO_2$/MWh = metric tons of carbon dioxide per megawatt-hour

As shown in Table 3-1, when comparing the HBEP heat rate and GHG performance values for other recently permitted facilities, the HBEP heat rate is greater than that of other recent projects. However, the HBEP operating configuration and project goals are different than those of other recently permitted projects. The Watson Cogeneration project is a combined heating and power project, and it is designed for base load operation and not for flexible, dispatchable, or fast ramping capability. While the Palmdale project was designed for fast ramping

operation (15 MW/minute), the project is described as being designed as a base load project. The HBEP's design objectives are to be able to operate over a wide MW production range with an overall high thermal efficiency, in order to respond to the fast changing load demands and changes necessitated by renewable energy generation swings. This rapid response is accomplished by utilizing fast start/stop and ramping capability and the use of the duct burners to bridge the MW production when additional combustion turbines are started (as opposed to the duct burner's traditional roll of providing peaking power during periods of high electrical demand). At maximum firing rate, the maximum power island ramp rate is 110 MW/minute for increasing in load and 250 MW/minute for decreasing load. At other load points, the load ramp rate is 30 percent. The HBEP start time to 67 percent load of the power island is 10 minutes, and it is projected that the project will operate at an approximate 40 percent annual capacity factor.

The HBEP offers the flexibility of fast start and ramping capability of a simple-cycle configuration, as well as the high efficiency associated with a combined cycle. Therefore, comparison of operating efficiency and heat rate of the HBEP should be made with simple cycle or peaking units instead of combined-cycle or more base-loaded units. Table 3-2 shows that the HBEP compares very favorably to the peaker units listed.

TABLE 3-2
Generation Heat Rates and 2008 Energy Outputs[a]

Plant Name	Heat Rate (Btu/kWh)[b]	2008 Energy Output (GWh)	GHG Performance ($MTCO_2$/MWh)
La Paloma Generating	7,172	6,185	0.392
Pastoria Energy Facility L.L.C.	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 Cogeneration Facility	11,452	409	0.625
McKittrick Cogeneration	9,037	378	0.494
KRCD Malaga Peaking Plant[c]	9,957	151	0.528
Henrietta Peaker[c]	10,351	48	0.549
CalPeak Power – Panoche	10,376	7	0.550
Wellhead Power Gates, LLC[c]	12,305	5	0.652
Wellhead Power Panoche, LLC[c]	13,716	3	0.727
MMC Mid-Sun, LLC[c]	12,738	1.4	0.675
Fresno Cogeneration Partners, LP PKR[c]	16,898	0.8	0.896
Palmdale Hybrid Power Project (PHPP)	6,970	4,993 [d]	0.370

[a] Reference: From the Palmdale Hybrid Power Project AFC Final Decision, Page 6.1-14, Table 4 (CEC, 2011)
[b] Based on the HHV of the fuel.
[c] Peaker facilities.
[d] Based on continuous operation at peak capacity.

GWh = gigawatt-hour(s)

The HBEP will be dispatched remotely by a centralized control center over an anticipated load range of approximately 160 to 528 MW for each 3-by-1 power island. Over this load range, the HBEP anticipated heat rate is estimated at approximately 7,400 to 8,000 Btu/kWh lower heating value (LHV) (~ 8,140 to 8,800 Btu/kWh HHV). The HBEP will be able to start and provide 67 percent of the power island load in 10 minutes and provide 110 MW/min of upward ramp and 250 MW/min of downward ramp capability. Comparing the thermal efficiency of the HBEP to other recently permitted California projects demonstrates that the HBEP is more thermally efficient than other similar projects that are designed to operate as a peaker unit. Based both on its flexible operating characteristics and favorable energy and thermal efficiencies as compared with other comparable peaking gas turbine projects, the HBEP thermal efficiency is BACT for GHGs.

3.2.2.5 GHG BACT Selection – Step 5

Based on the above analysis, the only remaining feasible and cost-effective option is the “Thermal Efficiency” option, which therefore is selected as the BACT.

As shown above, the Mitsubishi 501DA combustion turbines operating in a multistage generator combined-cycle operating configuration compare favorably with other comparable turbines operating in a peaking capacity. The HBEP turbines and duct burners will combust natural gas to generate electricity from both the CTG and STG units. Therefore, the thermal efficiency for the project is best measured in terms of pounds of CO_2 per MWh.

The performance of all CTGs degrades over time. Typically, turbine degradation at the time of recommended routine maintenance is up to 10 percent. Additionally, thermal efficiency can vary significantly with combustion turbine turndown and steam turbine/duct burning combinations. Finally, annual metrics for output-based limits on GHG emissions are affected by startup and shutdown periods because fuel is combusted before useful output of energy or steam. Therefore, the annual average thermal efficiency performance of any turbine will be greater than the optimal efficiency of a new turbine operating continuously at peak load over the lifetime of the turbine.

Based on the projected annual operating profile and equipment design specification provided by the project owner, the GHG BACT calculation for the HBEP was determined in pounds of CO_2 per MWh of energy output (on a gross basis). Included in this calculation is the inherent degradation in turbine performance over the lifetime of the HBEP. The HBEP has concluded that the BACT for GHG emissions is an emission rate of 1,082 pounds CO_2/MWhr of gross energy output, and a total annual CO_2 emissions limit of 3,161,785 metric tons per year. Degradation over time and turndowns, startup, and shutdown are incorporated into these limits.

SECTION 4

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