Appendix 5.1D
Criteria Pollutant and Greenhouse BACT Analysis

BACT Determination for the Redondo Beach Energy Project

Prepared for

AES Southland Development, LLC

Submitted to

South Coast Air Quality Management District
EPA Region IX

November 2012

CH2MHILL®

Contents

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
CO_2e	carbon dioxide equivalent
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 gas(es)
GWh	gigawatt-hour(s)
H_2	hydrogen
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
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
RBEP	Redondo Beach Energy Project
RCEC	Russell City Energy Center
RPS	renewable portfolio standard
SAAT	site ambient average temperature
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 Redondo Beach Energy Project (RBEP) at the existing AES-SLD Redondo Beach Generating Station site at 1100 North Harbor Drive, Redondo Beach, CA 90277. The RBEP is a combined-cycle power plant with a net generating capacity of 496 megawatts (MW)[1] and gross generating capacity of 511 MW. The RBEP will consist of one 3-on-1 combined-cycle power block. The power block will consist of three Mitsubishi Power Systems Americas (MPSA) 501DA combustion turbine generators (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 oxides of nitrogen (NO_x) (DLN) burners and selective catalytic reduction (SCR) to limit NO_x 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) will be limited to 1 ppmv through the use of best combustion practices and an oxidation catalyst. Best combustion practices and the use of pipeline-quality natural gas will minimize emissions of the remaining pollutants.

Two electric fire pumps connected to two independent power feeds from the Southern California Edison distribution system will be used to provide onsite fire protection. Because the electric fire pumps will not be a source of air emissions, they were not included in this best available control technology (BACT) analysis for RBEP.

Authorization for the construction and operation of RBEP will be through the California Energy Commission (CEC) Application for Certification (AFC) licensing process and the South Coast Air Quality Management District (SCAQMD) New Source Review/Prevention of Significant Deterioration (NSR/PSD) permitting process. Because RBEP 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. The existing Redondo Beach Generating Station currently has four operating generating units (Units 5–8) and one auxiliary boiler (Boiler No. 17). The operating units, the retired units 1–4, auxiliary boiler No. 17, and the main administrative building will be demolished as part of the project. Because the existing Redondo Beach Generating Station units will be retired and removed as part of the project, the maximum 2-year historical past actual emissions from these units between calendar years 2007 and 2011 have been subtracted from the PTE for RBEP.

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. Because SCAQMD has also been delegated partial PSD permitting authority,[2] the PSD BACT analysis is also being submitted to SCAQMD as part of the permitting process.

1.2 Project Objectives

The key design objective of RBEP is to provide up to 496 MW of environmentally responsible, cost-effective, operationally flexible, and efficient generating capacity to the Los Angeles Basin Local Reliability Area in general, and specifically to the western Los Angeles Basin sub-area[3]. The project would provide local capacity for reliability needs, serve peak southern California energy demands, and provide controllable generation to allow the

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[1] The net generating capacity including auxiliary load is 496 MW; gross output as measured at the generator terminals is 511 MW, referenced to site ambient average temperature (SAAT) conditions of 63.3 degrees Fahrenheit (°F) dry bulb and 58.5°F wet bulb temperature.

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

[3] As defined by the California Independent System Operator's (CAISO) "Local Capacity Technical Study Overview and Results" reported dated April 17, 2012.

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 it has been designed to start and stop very quickly and frequently and to be able to quickly ramp up and down through a wide range of electrical output. As more renewable electrical resources are brought online as a result of electric utilities meeting California's renewable portfolio standard (RPS), projects strategically located within load centers and designed for fast starts and ramp-up and -down capability, such as RBEP, will be critical in supporting local electrical reliability and grid stability.

Consistent with the Energy Action Plan as drafted by the CEC and the California Public Utilities Commission (CPUC), RBEP will assist in meeting the state's goal of ensuring that electric energy in the state is "adequate, affordable, technologically advanced, and environmentally sound." RBEP will also assist in meeting greenhouse gas reduction targets under the Global Warming Solutions Act of 2006 (AB-32), and will help utilities integrate renewable energy into their systems as required under the state's RPS. RBEP will also provide needed electric generation capacity with improved efficiency and operational flexibility to help meet southern California's long-term electricity needs. CAISO has identified a need for new power generation facilities in the western sub-area of the 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) *Statewide Water Quality Control Policy on the Use of Coastal and Estuarine Waters for Power Plant Cooling* (CAISO, 2012; SWRCB, 2010). The case study results from CAISO's year 2021 long-term Local Capacity Requirement proceeding estimates that most aligned with predicted commercial interests are that between 2,370 and 3,741 MW of new generation is required to replace the OTC generating plants in the Los Angeles Basin to meet the future needs of the area. 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).

The project objectives are consistent with SCAQMD Air Quality-Related Energy Policy and Rule 1304(a)(2), which encourages and facilitates the replacement of older, less-efficient electric utility steam boilers with gas turbine-based generation technologies equipped with BACT.

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

- Provide the most efficient, reliable, and predictable generating capacity 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 Local Reliability Area; and be consistent with SCAQMD Rule 1304(a)(2).
- Develop a 496 MW project that provides efficient operational flexibility with rapid-start and steep ramping capability to allow for the efficient integration of renewable energy sources into the California electrical grid.
- Serve southern California energy demand with efficient and competitively priced electrical generation.
- Develop on a brownfield site of sufficient size and reuse existing offsite electrical, water, wastewater, natural gas infrastructure and land to minimize terrestrial resource impacts.
- Site the project to serve the western Los Angeles Basin load center without constructing new transmission facilities.
- Assist in developing increased local generation projects, thereby reducing dependence on imported power and associated transmission infrastructure.
- Ensure that potential environmental impacts can be avoided, eliminated, or mitigated to less-than-significant levels.

Locating the project on an existing power plant site avoids the need to construct new offsite linear facilities, including gas and water supply lines, discharge lines, and transmission interconnections. This reduces potential offsite environmental impacts, as well as the cost of construction. Additionally, as demonstrated by the analyses contained in this AFC, the project would not result in significant environmental impacts, and the proposed RBEP site meets all project siting objectives.

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), 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 Prevention of Significant Deterioration and Title V Greenhouse Gas Tailoring Rule (GHG Tailoring Rule). The GHG BACT analysis is included in Section 3.

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 RBEP emission limits are presented in Table 2-1.

TABLE 2-1
Proposed Emission Limits for the Redondo 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 criteria pollutant BACT levels for RBEP (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 RBEP

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 RBEP is based on the EPA's top-down analysis method; the following 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 November 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 RBEP, as set forth in Table 2-1. If the emission limits at other facilities were lower 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 RBEP, then the proposed emission limits for the RBEP 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.

2.2.1.1.1 NOx 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 expenses 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 processes: (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 using 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 by incorporating post-combustion pollution control technologies.

2.2.1.1.2 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; the system 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 that is not consumed in the reaction 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[4]. 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

2.2.1.2.1 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 RBEP. 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; however, 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 RBEP.

2.2.1.2.2 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, 2011a). 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 RBEP NO_x limit of 2.0 ppm NO_x.

[4] 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 RBEP.

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 RBEP. 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 RBEP'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)
Channel Energy Center	TX-0618	2.0 ppm (3-hour)
Deer Park Energy Center	TX-0619	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)

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
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)
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 lower than the proposed BACT emission limit for the RBEP 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 RBEP 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 RBEP 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 RBEP.

2.2.2.1.1 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 (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.

2.2.2.1.2 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 RBEP.

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 lower than the proposed RBEP 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 RBEP. However, three projects have CO emission rates that are lower than the CO emission rate proposed for the RBEP. These projects are discussed following Table 2-3.

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)

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
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)
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 lower 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)

2.2.2.3.1 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 publicly 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.

2.2.2.3.2 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 to have been achieved in practice at this time.

2.2.2.3.3 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 RBEP 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 RBEP 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 RBEP 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 RBEP 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 NO_x BACT analysis, the EMx and XONON technologies were determined to not be feasible for RBEP.

2.2.3.1.1 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 VOCs 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.

2.2.3.1.2 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 RBEP.

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 lower than the proposed RBEP 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
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 lower 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 RBEP. However, the following projects have VOC emission rates that are lower than the VOC emission rate proposed for the RBEP:

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

2.2.3.3.1 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 RBEP 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 achieved in practice.

2.2.3.3.2 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 publicly 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.

2.2.3.3.3 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; rather, the permit 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 RBEP maximum VOC emission rate is 0.0012 lb/MMBtu. Therefore, RBEP's VOC emission rate is lower than the Chouteau Power Plant permit value defined in units of lb/MMBtu.

2.2.3.3.4 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 RBEP 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 RBEP 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 RBEP 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 composed of hydrocarbons of larger molecular weight that are not fully combusted (EPA, 2006). Because the PM is less than 2.5 microns in diameter, the BACT control technology discussion assumes that 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

2.2.4.1.1 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 NO_x 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, thereby 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.

2.2.4.1.2 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 RBEP.

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 to 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 to 9.5 lb/hr with duct burners is consistent with BACT at 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 RBEP 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 to 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 CPUC pipeline-quality natural gas with a sulfur content of less than 1 grain of sulfur per 100 scf. The RBEP 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 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 RBEP. 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 RBEP 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 RBEP 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; however, they involve NO_x, CO, and VOC emissions rates that are highly variable and greater than emissions during steady-state operation[5]. 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

[5] 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 because less fuel is consumed as compared to during full load operations.

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 shutdown events are outlined below.

2.2.6.2 Determination of BACT Emissions Limit for Startups and Shutdowns

2.2.6.2.1 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 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	115.9	27.9	25.4	113.9	27.3	90
Warm	16.6	46.0	21.0	23.1	50.0	22.1	32.5
Hot	16.6	33.6	20.4	23.1	37.6	21.5	32.5

2.2.6.2.2 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, with the SCR and oxidation remaining 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	32.5	10

2.2.6.3 Summary of the Proposed BACT for Startups and Shutdowns

The project owner proposes to limit individual startup 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 RBEP, and the evaluation follows EPA regulations and guidance for BACT analyses as well as 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 RBEP process, the fossil fuel burned will be pipeline-quality natural gas, which is the lowest GHG-emitting fossil fuel available. The RBEP 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 a 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 carbon dioxide equivalent [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, effective July 1, 2011, new sources with a GHG PTE equal to or greater than 100,000 tpy of CO_2e are considered a major source and are required to undergo PSD permitting, including preparation of a BACT analysis for GHG emissions. Modifications to existing major sources (with a 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, then 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 therefore emphasizes the importance of energy efficiency in BACT reviews. Specifically, EPA states the following:

> *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 may be 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-efficiency 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 RBEP 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 are 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 RBEP GHG emissions inventory, the estimated N_2O emissions total only 26.4 metric tons per year. Therefore, even if an order-of-magnitude increase in N_2O occurred as a result of the SCR, the impact to CO_2e emissions would be insignificant as compared to total estimated RBEP CO_2 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. Even if carried forward through the GHG BACT analysis, the controls 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 RBEP 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 1 percent of facility GHG CO_2e emissions. RBEP 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 the most-effective controls and document the 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 November 2012.
- 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 RBEP combined-cycle equipment:

- Carbon capture and storage (CCS)
- Thermal efficiency

The proposed RBEP design and operation will consist of one 3-by-1 combined-cycle generating power block, 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 of this document. Several of the primary objectives of the RBEP 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.

Because other potentially lower emitting renewable generation technologies would change the fundamental business purpose of the RBEP, they were not evaluated in this BACT analysis. 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… (*EPA, 2011b*)*

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

3.2.2.1.1 Carbon Capture and Storage

CCS technology is composed of three main components: (1) CO_2 capture and 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, depleted coal seam, or ocean site, or the CO_2 would be 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 streams 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, incorporation of CO_2 compression equipment will require the installation of specialized equipment with high operating energy requirements.

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 oceangoing 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 as0_2, N_2, CH_4, 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.

With geologic sequestration, a suitable geological formation is identified close to the proposed project, and the CO_2 captured 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 the Atlas 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.

3.2.2.1.2 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 0.50 ton) CO_2 per megawatt-hour (MWh). This emission standard corresponds to a heat rate of approximately 9,450 British thermal units per kilowatt-hour (Btu/kWh on a higher heating value [HHV] basis) (CEC, 2006).

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.

3.2.2.2.1 Carbon Capture and Storage

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. As such, 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. For comparison, the RBEP facility could produce CO_2 up to approximately 1.5 million metric tpy or 7,613 metric tons per day.

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 reviewing 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 considered 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, which is in the range of the power pilot tests noted above. Therefore, a scale-up involving a substantial increase in size from pilot scale to commercial scale would represent a significant technical risk, and full-scale capture of power plant CO_2 has not yet been accomplished anywhere in the world. Therefore, 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 RBEP, as follows:

- No full-scale systems for solvent-based carbon capture are currently in operation to capture CO_2 from dilute exhaust streams such as those from natural-gas-fired electrical generation systems at the scale proposed for the RBEP. As a result, the ability for electric utilities to contract for turn-key CCS systems simply does not exist at this time.
- 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 RBEP to undertake. Oil and gas production in the vicinity of RBEP 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.
- 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 entity 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 viable.

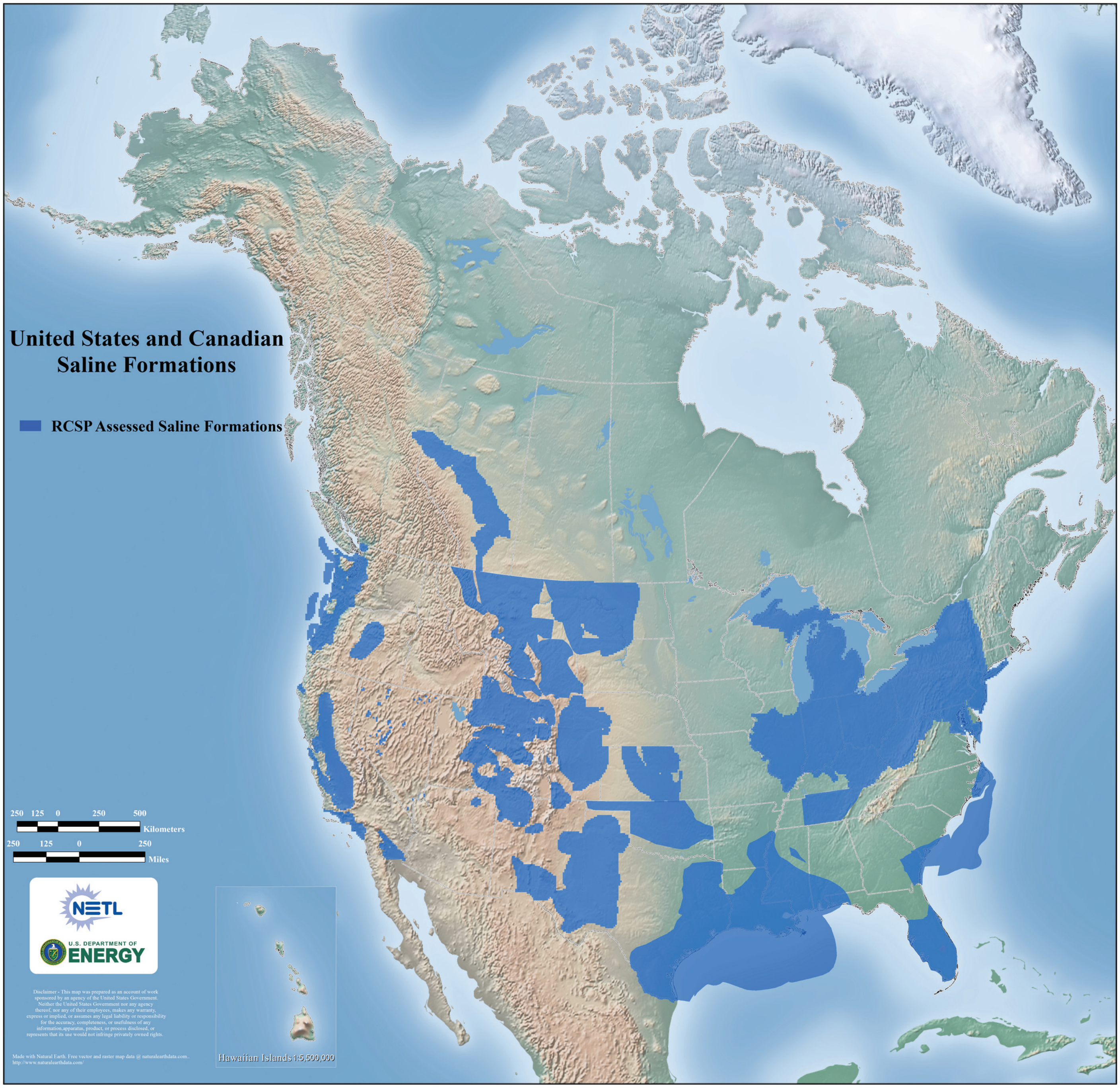


FIGURE 1
United States and Canadian Saline Formations
AES Redondo Beach Energy Project
Redondo Beach, California

CH2MHILL®

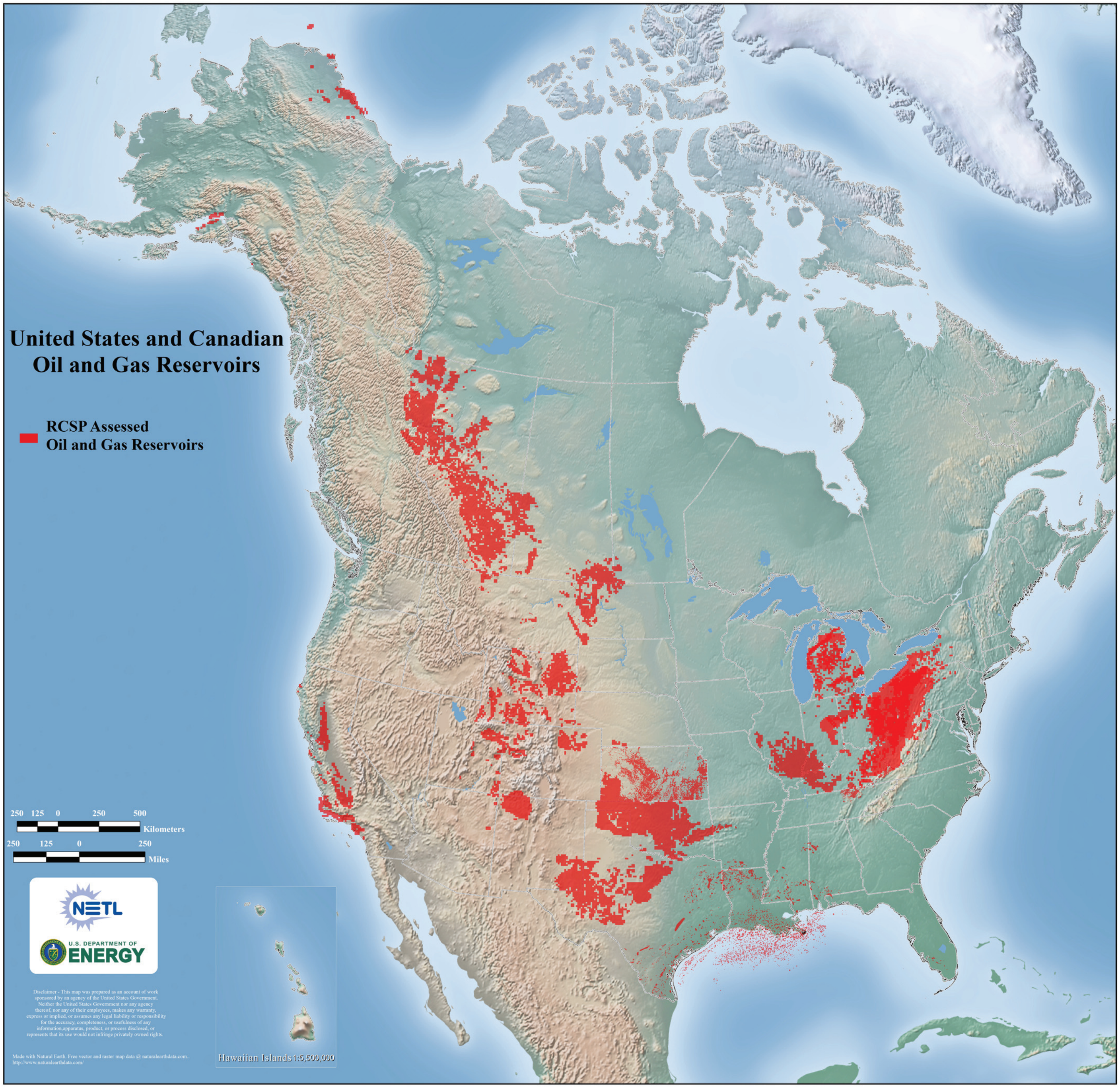


FIGURE 2
United States and Canadian Oil and Gas Reservoirs
AES Redondo Beach Energy Project
Redondo Beach, California

- Significant legal uncertainties continue to exist regarding the relationship between land surface ownership rights and subsurface (pore space) ownership, as well as 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 RBEP 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 RBEP facility are designed to accommodate rapidly fluctuating power and steam demands from renewable electrical generation sources.

The following discussion provides some additional background information regarding the bulleted items above.

As suggested in the *EPA's New Source Review Workshop Manual* (EPA, 1990), 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." As discussed in the following paragraphs, 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 on the scale of RBEP.

Carbon Capture. Three fundamental types of carbon capture systems are employed throughout various process and energy industries: sorbent adsorption, physical absorption, and chemical absorption.

Sorbent Adsorption. 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_4 reforming 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, 2011), 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."

Physical Absorption. 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).

Chemical Absorption. 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 RBEP facility. To date, a chemical solvent technology has not been demonstrated at the operating scale proposed.

Carbon Storage. The following section provides additional details on the potential use of deep saline aquifers, compressed CO_2 to enhance oil recovery in crude oil production operations, and ocean sequestration as potential options for the storage of captured CO_2.

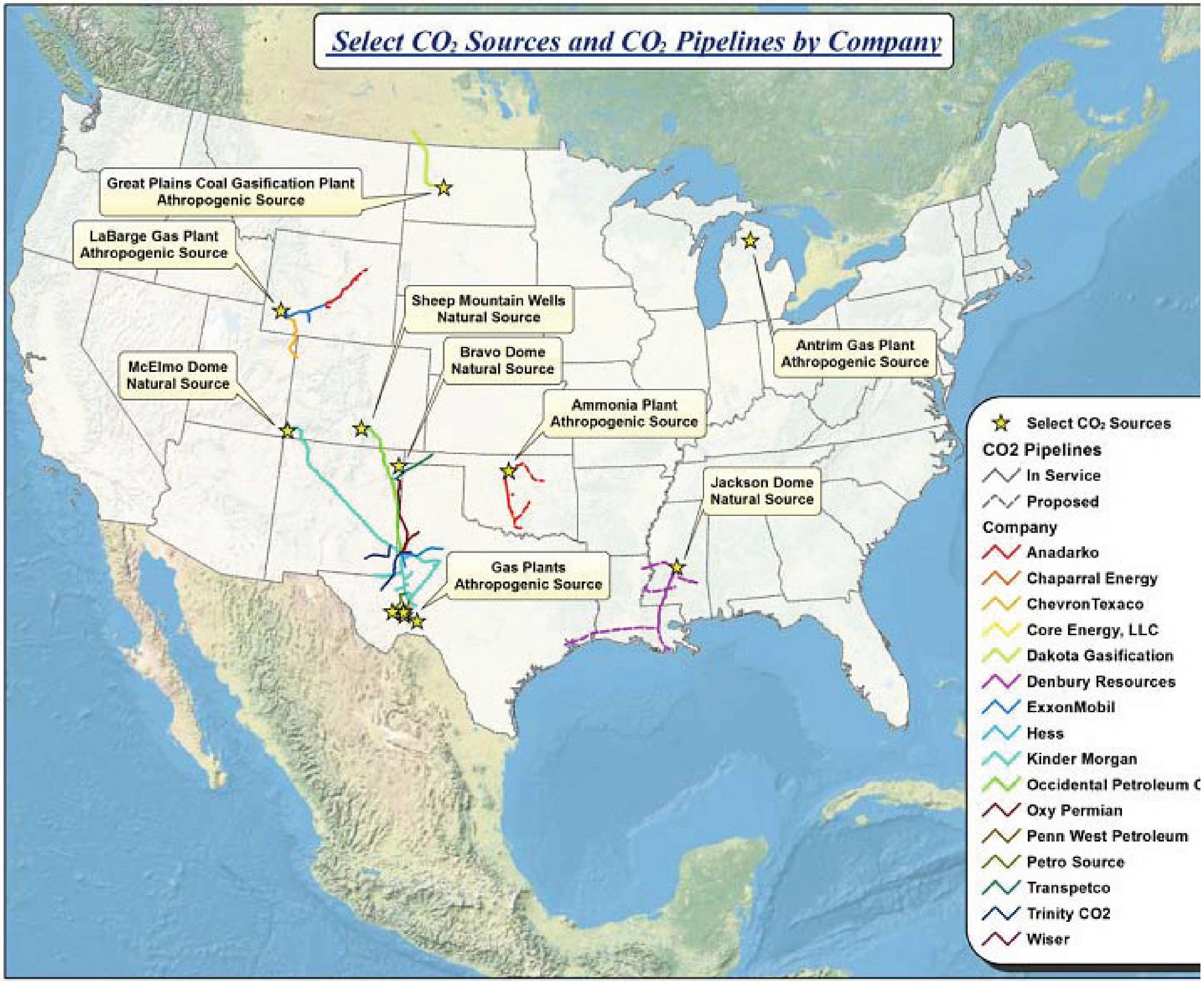
Enhanced Oil Recovery. Use of captured CO_2 for EOR is widely believed to represent the practical first opportunity for CCS deployment. During a study to evaluate the "future oil recovery potential in the major oil basins and large oil fields in California," the DOE concluded that a number of oil fields in the Los Angeles Basin are "amendable to miscible CO_2-EOR." (DOE, 2005) Two of those oil fields, the Santa Fe Springs and Dominquez fields, are located approximately 20 miles and 2 miles, respectively, from the RBEP facility. Although the CO_2 could be used for EOR applications in the vicinity of RBEP, only pilot-scale projects are known in the region, and only estimates are available on the capacity of these miscible oil fields. Therefore, 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. Furthermore, 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.

Finally, the potential to sell CO_2 to industrial or oil and gas operations is infeasible for an operation such as RBEP, where daily operation 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.

Deep Saline Aquifer. 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.

Figure 3 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.



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

FIGURE 3
Existing and Planned CO2 Pipelines in the United States with Sources
AES Redondo Beach Energy Project
Redondo Beach, California

CH2MHILL.

Ocean Sequestration. 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 this time. The feasibility of implementing a commercially available sequestration approach is further brought into question, with the IPCC stating as follows:

> *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).

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

3.2.2.2.2 Carbon Capture and Storage Conclusion

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 RBEP. 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 purpose of the AEP Mountaineer site (AEP is 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 the 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.

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). The following is noted on page 36 of this guidance:

> *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 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 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)

Based on the preceding discussion, it is concluded that the CCS alternative is not considered technically feasible for the RBEP, and this alternative 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.

3.2.2.2.3 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 RBEP 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 RBEP.

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.

As demonstrated in Step 2, CCS is not a technically feasible alternative for the RBEP. It is suggested on page 42 of the EPA PSD and Title V Permitting Guidance (EPA, 2011b) 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 evaluation of the economic impacts of GHG 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.

The guidance document also acknowledges the current high costs of CCS technology (EPA, 2011b):

> *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.*

Nonetheless, at the suggestion of the EPA team members on other recent projects, economic feasibility of CCS technology is reviewed in this step. Therefore, control options considered in this step include application of CCS technology and plant energy thermal efficiency.

3.2.2.4.1 Carbon Capture and Sequestration

As demonstrated below, CCS is clearly not economically feasible for the RBEP. 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 to lower costs, compared to “pure” sequestration in deep saline aquifers, or through deep ocean storage, additional costs to RBEP would include the following:

- Licensing of scrubber technology, and procurement and construction of carbon capture systems
- Significant reduction of 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 of 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] natural gas combined-cycle (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 RBEP is estimated as at least $319 million. Based on an estimated RBEP capital cost of $250 million to $275 million for the plant and equipment, the capital costs for the capture system alone would 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 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 RBEP, the most realistic scenario could be to construct a pipeline from the Redondo 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 could be obtained and there is an active EOR operation in this location. As noted above, the approximate distance of the pipeline to the Santa Fe Springs or Dominquez fields is approximately 20 miles and 2 miles, respectively. 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 $13.2 million assuming pipelines would be built to access both fields. Therefore, the pipeline alone would represent an additional 4 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 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. 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. Therefore, not only is CCS technically infeasible at this project scale, as the above discussion demonstrates, it is clearly also economically infeasible for natural-gas-fired turbines at this time.

3.2.2.4.2 Thermal Efficiency

Because CCS is not technically or economically feasible, thermal efficiency remains the most effective, technically feasible, and economically feasible GHG control technology for the RBEP. A search of the EPA's RACT/BACT/LAER Clearinghouse was performed for NGCC projects. GHG permit information was found for two sources that were issued permits in December 2011: Westlake Vinyls Company LP Cogeneration Plant (LA-0256) and Sabine Pass LNG, LP & Sabine Pass Liquefaction, LL Sabine Pass LNG Terminal (LA-0257). The record for the Westlake Vinyls facility includes only hourly and annual CO_2e emission limitations; no information regarding estimated costs were provided. The Sabine Pass facility record includes only an annual CO_2e emission limitation; no information regarding estimated costs was provided. Although the details of the Louisiana projects are limited, recent GHG determinations were completed for the Russell City Energy Center, the Watson Cogeneration, and the Palmdale Hybrid Power Project in California. Each of the projects proposed the use of combined-cycle configurations to produce commercial power, and the BACT analyses for each of the projects concluded that plant efficiency was the only feasible combustion control technology. However, it is worth noting that the Palmdale project also includes a 251-acre solar thermal field that generates up to 50 MW during sunny days, which reduces the project's overall heat rate. A comparison of the existing heat rates and GHG performance values for local generation resources in the Los Angeles Basin and the Big Creek/Ventura LSA is presented in Table 3-1. The information in Table 3-1 was extracted from the tables compiled by the CEC during the license proceedings for the Palmdale Hybrid Power Project (CEC, 2011).

With the adoption of Senate Bill 2 on April 12, 2011, California's RPS requirement was increased from 20 percent by 2010 to 33 percent by 2020. 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 RBEP will aid in the effort to meet California's RPS standard because a significant attribute of the RBEP is that the combined-cycle facility can operate similarly to a peaking plant but at higher thermal efficiency. The addition of the high thermal efficiency of the RBEP's generation to the state's electricity system will also facilitate the integration of renewable resources in California's generation supply and will displace other less-efficient, higher GHG-emitting generation. This allows an increased use of wind power and other renewable energy sources, with backup power available from the RBEP.

TABLE 3-1
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.
Notes:
GWh = gigawatt-hour(s)
$MTCO_2$/MWh = metric tons of carbon dioxide per megawatt-hour

In addition to supporting the effort to meet the RPS requirement, the project owner has developed a highly efficient multiple-staged generator project that incorporates fast start, a high degree of turndown, and ramping capability consistent with the project objectives outlined in Section 1.2 of this document. As presented in Figure 4, all combustion turbines in the power block can be started and taken from ignition to full load in a 10-minute period. The RBEP HRSG operation will be integrated into the startup sequence, and full steam turbine generator output can be expected in approximately 35 minutes after fuel ignition for a hot or warm startup scenario.

Based on proprietary design and operational adjustments, the RBEP 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 5, the RBEP 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

RBEP 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.

The RBEP 3-on-1 power island will be dispatched remotely by a centralized control center over an anticipated load range of approximately 160 to 530 MW. 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 per minute. Therefore, the operationally flexible turbine class and steam cycle designs selected for the RBEP are the most thermally efficient for the project design objectives, operating at the projected annual capacity factor of approximately 20 percent.

As shown in Table 3-2, when comparing the RBEP heat rate and GHG performance values for other recently permitted facilities, the RBEP heat rate is greater than that of other recent projects. However, the RBEP operating configuration and project goals are different than those of other recently permitted projects. For instance, 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. The Palmdale project was designed for ramping operations (15 MW/minute) and is described as being designed as a base load project. As previously noted, the RBEP 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 RBEP should be made with simple cycle or peaking units instead of combined-cycle or more base-loaded units.

TABLE 3-2
Comparison of Heat Rates and GHG Performance Values of Recently Permitted Projects

Plant Performance Variable	Heat Rate (Btu/kWh)	GHG Performance ($MTCO_2$/MWh)
Redondo Beach Energy Project	8,352[a]	0.398[b]
Watson Cogeneration Project[c]	5,027 to 6,357	0.219 to 0.318
Palmdale Hybrid Power Project	6,970[d]	0.370[d]
Russell City Energy Project	7,730[e]	0.403[e]

[a] Calculated HHV net heat rate at 63.3°F at site elevation, relative humidity of 75.2 percent, with no inlet air cooling. Heat rate varies over the anticipated load dispatch range.

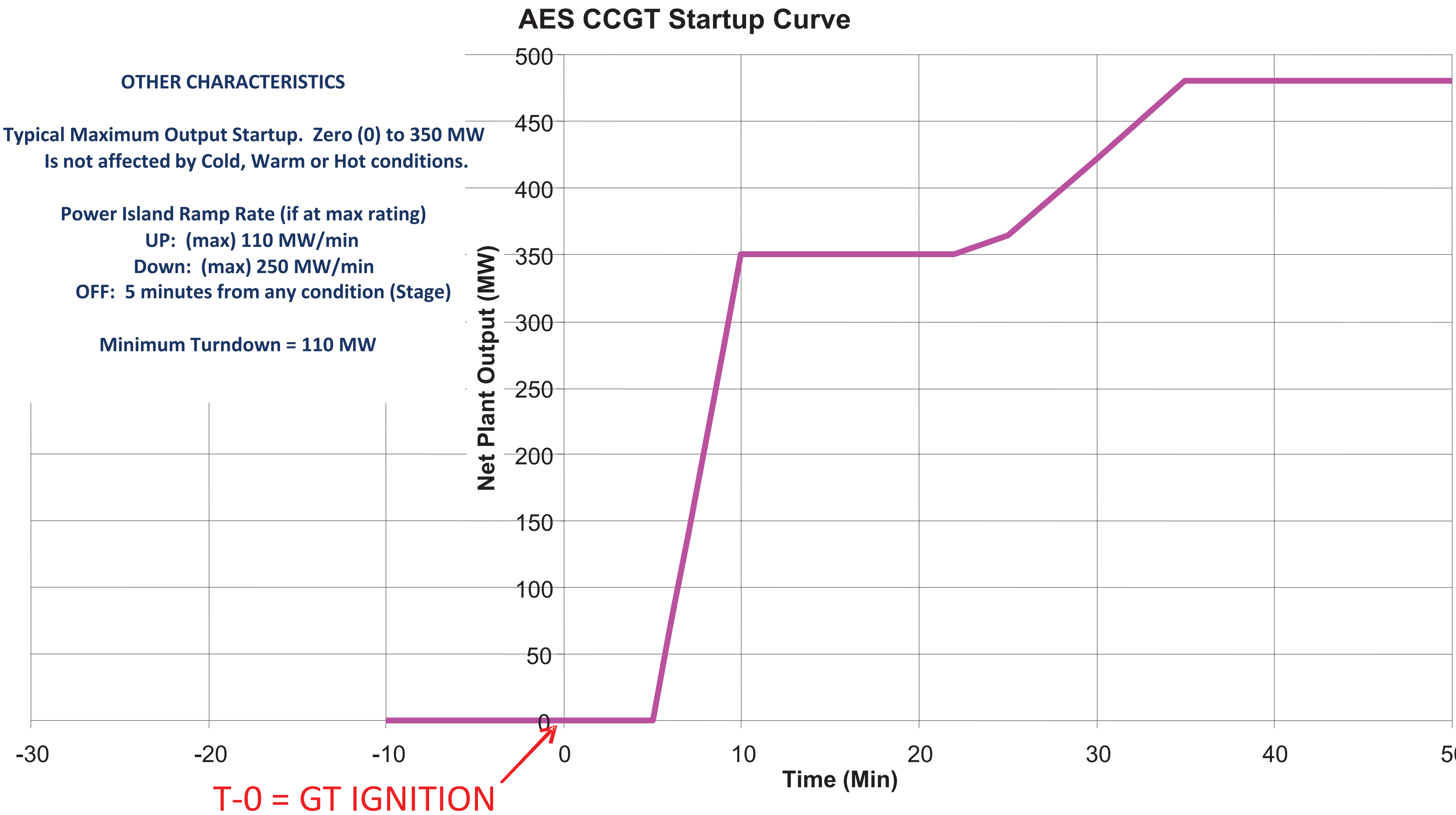
[b] Calculated CO_2 emissions at conditions in footnote “a” above are 144,644 lb/hr with 162.2 MW net generation.

[c] From Watson Cogeneration Project Commission Final Decision.

[d] From Greenhouse Gas Tables 4 and 5 of the Palmdale Hybrid Power Project Final Staff Assessment (CEC, 2010). Does not include effect of solar facility operation.

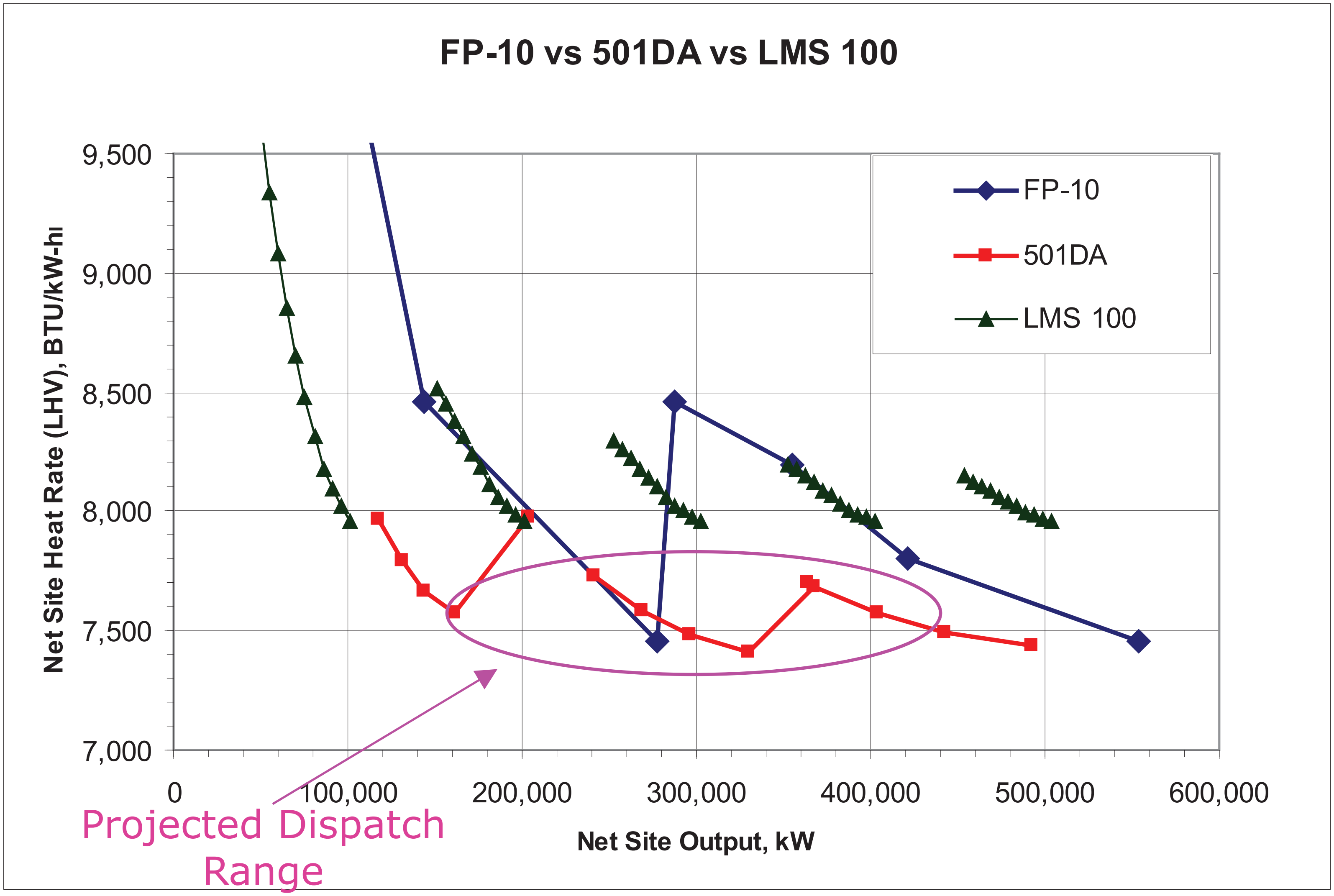
[e] The degraded heat rate included in the PSD Permit is 7,730 Btu/kWh (BAAQMD, 2010a). The net design heat rate for clean and new conditions with no duct burners is 6,852 Btu/kWh (BAAQMD, 2010b and Calpine, 2010). Based on the PSD permit, the facility will generate 600 MW of electricity with a 1-hour CO_2 limit of 242 $MTCO_2$/hr, which yields a GHG performance value of 0.403 $MTCO_2$/MWh.

Comparing the thermal efficiency of the RBEP to other projects in Tables 3-1 and 3-2 demonstrates that incorporating 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. Furthermore, the ability to produce fast-ramping power to augment renewable power sources to the grid makes the RBEP a highly energy-efficient system. Therefore, based on the flexible operating characteristics, having the ability to operate over a wide MW production range with an overall high thermal efficiency, having the ability to respond to the fast-changing load demands and changes necessitated by renewable energy generation swings, and having favorable energy and thermal efficiencies as compared with other comparable peaking gas turbine projects, the RBEP thermal efficiency of the Mitsubishi 501DA turbine, HRSG, and duct burner configuration is considered BACT for GHGs.



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

FIGURE 4
RBEP Startup Curve
AES Redondo Beach Energy Project
Redondo Beach, California



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

FIGURE 5
Comparison of RBEP and Alternative Design Heat Rates
AES Redondo Beach Energy Project
Redondo Beach, California

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 compares favorably with other comparable turbines operating in a peaking capacity. The RBEP 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. However, it is also worth noting that plant operating rates are dictated by the California Independent System Operator (CAISO) to ensure that reliable, cost-effective, and environmentally sound electricity is provided to the electrical control region, and that the project owner only controls operation of the plant for environmental testing and maintenance purposes. 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 RBEP 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 RBEP. Therefore, the proposed RBEP BACT for GHG emissions is an emission rate of 1,082 pounds CO_2/MWhr of gross energy output, and a facility-wide annual CO_2 emissions limit of 1,564,548 metric tons per year. Degradation over time, turndowns, startup, and shutdown are incorporated into these proposed BACT limits.

SECTION 4

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