DOCKETED

Docket Number:	13-AFC-01
Project Title:	Alamitos Energy Center
TN #:	201620-44
Document Title:	AEC AFC Appendix 5.1D BACT Analysis
Description:	Previously TN# 201493-17
Filer:	Tiffani Winter
Organization:	CH2M Hill
Submitter Role:	Applicant Consultant
Submission Date:	2/3/2014 12:47:11 PM
Docketed Date:	2/3/2014

Appendix 5.1D
Criteria Pollutant and Greenhouse Gas BACT Analysis

BACT Determination for the Alamitos Energy Center

Prepared for

AES Alamitos, LLC

Submitted to

South Coast Air Quality Management District
EPA Region IX

December 2013

CH2MHILL®

Contents

Acronyms and Abbreviations

°F	degree(s) Fahrenheit
AB	Assembly Bill
AEC	Alamitos Energy Center
AES-SLD	AES Southland Development, LLC
AFC	Application for Certification
ARB	California Air Resources Board
BAAQMD	Bay Area Air Quality Management District
BACT	best available control technology
Btu/kWh	British thermal unit(s) per kilowatt-hour
CAISO	California Independent System Operator
CCS	carbon capture and storage
CEC	California Energy Commission
CFR	Code of Federal Regulations
CH_4	methane
CHP	combined heating and power
CO	carbon monoxide
CO_2	carbon dioxide
CO_2e	carbon dioxide equivalents
CPUC	California Public Utilities Commission
CPV	Competitive Power Ventures
CTG	combustion turbine generator
DLN	dry low NO_x
DOE	U.S. Department of Energy
EPA	U.S. Environmental Protection Agency
GHG	greenhouse gas
GHG Tailoring Rule	Prevention of Significant Deterioration and Title V Greenhouse Gas Tailoring Rule
GWh	gigawatt-hour(s)
HBEP	Huntington Beach Energy Project
HFC	hydrofluorocarbon
HHV	higher heating value
HRSG	heat recovery steam generator
IPCC	Intergovernmental Panel on Climate Change
kV	kilovolt
LAER	Lowest Achievable Emission Rate
lb/hr	pound(s) per hour
lb/MMBtu	pound(s) per million British thermal unit
LBWD	City of Long Beach Water Department
LCR	Local Capacity Requirement
LHV	lower heating value
LSIP	large-scale integrated carbon capture and storage project
Mandatory Reporting Rule	EPA Final Mandatory Reporting of Greenhouse Gases Rule
MMBtu/hr	million British thermal unit(s) per hour
MPSA	Mitsubishi Power Systems Americas
MSG	multi-stage generating
MT CO_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-fired combined-cycle
NO	nitric oxide
NO_2	nitrogen dioxide
NO_x	oxides of nitrogen
NSR	New Source Review
O_2	oxygen
O&M	Operations and Maintenance
OTC	once-through cooling
PFC	perfluorocarbons
PM_{10}	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
ppmvd	part(s) per million dry volume
PSA	pressure swing adsorption
PSD	Prevention of Significant Deterioration
psig	pound(s) of force per square inch gauge
PTE	Potential to Emit
RACT	Retrofit Available Control Technology
RCEC	Russell City Energy Center
RPS	Renewable Portfolio Standard
SCAQMD	South Coast Air Quality Management District
SCE	Southern California Edison
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	oxides of sulfur
STG	steam turbine generator
SWRCB	State Water Resources Control Board
tpy	ton(s) per year
TSP	Total Suspended Particulates
VOC	volatile organic compound
WestCarb	West Coast Regional Carbon Sequestration Partnership

SECTION 1

Project Description

1.1 Project Overview

AES Southland Develoment, LLC (AES-SLD) proposes to construct, own, and operate a new electrical generating plant in Long Beach, Los Angeles County, California. The proposed Alamitos Energy Center (AEC) is a natural-gas-fired, air-cooled, combined-cycle electrical generating facility with a net generating capacity of 1,936 megawatts (MW) and gross generating capacity of 1,995 MW.[1] The AEC will replace and be constructed on the site of the existing Alamitos Generating Station.

The AEC will consist of four 3-on-1 combined-cycle gas turbine power blocks with twelve natural-gas-fired combustion turbine generators (CTG), twelve heat recovery steam generators (HRSG), four steam turbine generators (STG), four air-cooled condensers, and related ancillary equipment. The AEC will use air-cooled condensers for cooling, completely eliminating the existing ocean water once-through-cooling system. The AEC will use potable water provided by the City of Long Beach Water Department (LBWD) for construction, operational process, and sanitary uses but at substantially lower volumes than the existing Alamitos Generating Station has historically used. This water will be supplied through existing onsite potable water lines.

The AEC will interconnect to the existing Southern California Edison (SCE) 230-kilovolt (kV) switchyard adjacent to the north side of the property. Natural gas will be supplied to the AEC via the existing offsite 30-inch-diameter pipeline owned and operated by Southern California Gas Company that currently serves the Alamitos Generating Station. Natural gas compressors, water treatment facilities, emergency services, and administration and maintenance buildings will be constructed within the existing Alamitos Generating Station site footprint. Stormwater will be discharged to two retention basins and then ultimately to the San Gabriel River via existing stormwater outfalls.

The AEC will include a new 1,000-foot process/sanitary wastewater pipeline to the first point of interconnection with the existing LBWD sewer system and will eliminate the current practice of treatment and discharge of process/sanitary wastewater to the San Gabriel River. The project may also require upgrading approximately 4,000 feet of the existing offsite LBWD sewer line downstream of the first point of interconnection, therefore, this possible offsite improvement to the LBWD system is also analyzed in the Application for Certification (AFC). The total length of the new pipeline (1,000 feet) and the upgraded pipeline (4,000 feet) is approximately 5,000 feet.

To provide fast-starting and stopping, flexible generating resources, the AEC will be configured and deployed as a multi-stage generating (MSG) facility. The MSG configuration will allow the AEC to generate power across a wide and flexible operating range. The AEC can serve both peak and intermediate loads with the added capabilities of rapid startup, significant turndown capability (ability to turn down to a low load), and fast ramp rates (30 percent per minute when operating above minimum gas turbine turndown capacity). As California’s intermittent renewable energy portfolio continues to grow, operating in either load following or partial shutdown mode will become more necessary to maintain electrical grid reliability, thus placing an increased importance upon the rapid startup, high turndown, steep ramp rate, and superior heat rate of the MSG configuration employed at the AEC.

By using proven combined-cycle technology, the AEC can also run as a baseload facility, if needed, providing greater reliability to meet resource adequacy needs for the southern California electrical system. As an in-basin generating asset, the AEC will provide local generating capacity, voltage support, and reactive power that are essential for transmission system reliability. The AEC will be able to provide system stability by providing reactive power, voltage support, frequency stability, and rotating mass in the heart of the critical Western Los Angeles local reliability area. By being in the load center, the AEC also helps to avoid potential transmission line overloads and can provide reliable local energy supplies when electricity from more distant generating resources is unavailable.

[1] Referenced to site ambient average temperature conditions of 65.3 degrees Fahrenheit (°F) dry bulb and 62.7°F wet bulb temperature without evaporative cooler operation.

The AEC's combustion turbines and associated equipment will include the use of best available control technology (BACT) to limit emissions of criteria pollutants and hazardous air pollutants. By being able to deliver flexible operating characteristics across a wide range of generating capacity, at a relatively consistent and superior heat rate, the AEC will help lower the overall greenhouse gas (GHG) emissions resulting from electrical generation in southern California and allow for smoother integration of intermittent renewable resources.

Existing Alamitos Generating Station Units 1–6 are currently in operation. All six operating units and retired Unit 7 will be demolished as part of the proposed project. Construction and demolition activities at the project site are anticipated to last 139 months, from first quarter 2016 until third quarter 2027. The project will commence with the demolition of retired Unit 7 and other ancillary structures to make room for the construction of AEC Blocks 1 and 2. The demolition of Unit 7 will commence in the first quarter of 2016. The construction of Block 1 is scheduled to commence in the third quarter of 2016 and construction of Block 2 is scheduled to commence in the fourth quarter of 2016. The demolition of existing Units 5 and 6 will make space for the construction of AEC Block 3. AEC Block 3 construction is scheduled to commence in the first quarter of 2020 and will be completed in the second quarter of 2022. The demolition of existing Units 3 and 4 will make space for the construction of AEC Block 4. AEC Block 4 construction is scheduled to commence in the second quarter of 2023 and will be completed in the fourth quarter of 2025. The demolition of remaining existing units is scheduled to commence in the third quarter of 2025.

Construction of the AEC will require the use of onsite laydown areas (approximately 8 acres dispersed throughout the existing site) and a 16-acre laydown area located adjacent to the existing site. The adjacent 16-acre laydown area will be shared with another project being developed by the Applicant (Huntington Beach Energy Project [HBEP] 12-AFC-02). Due to the timing for commencement of construction for these two projects, the adjacent laydown area will already be in use for equipment storage before AEC construction begins.

1.2 Project Objectives

The key objective of AEC is to provide up to 1,936 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.[2] The project will provide local capacity for reliability needs, serve peak southern California energy demand, and provide controllable generation to allow integration of the ever-increasing contribution of variable renewable energy into the electrical grid. As a MSG facility, the project will displace older and less efficient generation in southern California, and has been designed to start and stop very quickly and frequently and be able to quickly ramp up and down through a wide range of electrical output. As more renewable electrical resources are brought on line 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/ramp-down capability, such as AEC, will be critical in supporting local electrical reliability and grid stability.

Consistent with the Energy Action Plan, as drafted by the California Energy Commission (CEC) and the California Public Utilities Commission (CPUC), AEC will assist in meeting the state's goal of ensuring that electric energy in the state is "adequate, affordable, technologically advanced, and environmentally sound." It will also assist in meeting GHG reduction targets under the Global Warming Solutions Act of 2006 (Assembly Bill [AB] 32) and will help utilities integrate renewable energy into their systems, as required under the state's RPS. AEC will also provide needed electric generation capacity with improved efficiency and operational flexibility to help meet southern California's long-term electricity needs and Clean Air objectives.

The California Independent System Operator (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) *Water Quality Control Policy on the Use of Coastal and Estuarine Waters for Power Plant Cooling (OTC Policy)* (CAISO, 2012a; SWRCB, 2010). The results from CAISO's year 2021 long-term Local Capacity Requirement

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

(LCR) study estimates that between 2,370 and 3,741 MW[3] of replacement OTC generation is required 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, along with other long-term transmission planning assumptions, is also confirmed in CAISO's Once-Through Cooling and AB 1318 Study Results presented on December 8, 2011 (CAISO, 2011). CAISO also notes that many of the OTC facilities are in locations critical to local electrical reliability and that repowered or replacement generating capacity, with characteristics that support renewable integration in these same locations, would provide both local capacity for reliability and essential grid support for a future with ever-increasing amounts of variable renewable energy, thereby reducing the number of total MW required compared to new generation developed elsewhere (CAISO, 2012b).

The CPUC confirmed the need for new generation in the Los Angeles Basin in a decision authorizing procurement of between 1,400 and 1,800 MWs of new electrical capacity in the western Los Angeles sub-area to meet long-term local capacity requirements by 2021 and that at least 1,000 but no more than 1,200 MWs must be from conventional gas-fired resources (including combined heat and power resources). Further, CPUC found the following: a significant need for LCR resources to replace retiring OTC plants in the Los Angeles basin local area under every scenario analyzed by CAISO; that a significant amount of the 1,400 to 1,800 MW procurement must be met through conventional gas-fired resources in order to ensure LCR needs are met; and that gas-fired resources at current OTC sites meet CAISO's criteria for meeting LCR needs and that other resources are also capable of meeting or reducing LCR needs, but may not be as effective (CPUC, 2013).

The project objectives also include using qualifying technology under the South Coast Air Quality Management District's (SCAQMD) Rule 1304(a)(2) that allows for the replacement of older, less efficient electric utility steam boilers with specific new generation technologies on a MW to MW basis (that is, the replacement MW are equal or less than the MW from the electric utility steam boilers). Rule 1304(a)(2) requires that the electric utility steam boiler be replaced with one of several specific technologies, including the combined-cycle configuration used in the AEC design.

AEC 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 1,936-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 onsite electrical, water, 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, thus reducing dependence on imported power and associated transmission infrastructure.
- Ensure 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 many new linear offsite facilities, including gas and water supply lines, and transmission interconnections. This reduces potential offsite environmental impacts, and the cost of construction. Additionally, as demonstrated by the analyses contained in the AFC, the project will not result in any significant environmental impacts.

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[3] This range of OTC replacement capacity corresponds to the CAISO "Trajectory" planning scenario, which has been defined as the most likely planning scenario.

SECTION 2

Criteria Pollutant BACT Analysis

Based on the SCAQMD's BACT definition and major source thresholds (SCAQMD Rules 1302 and 1303), a BACT analysis is required for the uncontrolled emissions of oxides of nitrogen (NO_x), volatile organic compounds (VOC), carbon monoxide (CO), oxides of sulfur (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 Prevention of Significant Deterioration (PSD) permit application required under the EPA's "Prevention of Significant Deterioration and Title V Greenhouse Gas Tailoring Rule" (GHG Tailoring Rule). The GHG BACT analysis is included in Section 3.

The criteria and GHG BACT analyses were completed only for the combustion turbine emissions, and do not include emissions from worker commutes and material delivery vehicles. These mobile source emissions will not be new for the AEC, as they presently occur with the operation of the existing Alamitos Generating Station.

AES-SLD plans to rely on the response characteristics of the Mitsubishi Power Systems Americas (MPSA) 501DA CTGs 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 AEC emission limits are presented in Table 2-1.

TABLE 2-1
Proposed Emission Limits for the Alamitos Energy Center

Pollutant	Emission Limit (at 15 percent O_2)
NO_x	2 ppmvd (averaged over 1 hour)
CO	2 ppmvd (averaged over 1 hour)
VOC	1 ppmvd (averaged over 1 hour)
PM_{10}	4.5 lb/hr
$PM_{2.5}$	4.5 lb/hr
SO_x	<0.75 grain of sulfur/100 scf of natural gas

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

The following discussion presents an assessment of the BACT for AEC and includes the following components:

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

2.1 Methodology for Evaluating the Criteria Pollutant BACT Emission Levels

The NO_x, CO, VOC, PM_{10}, $PM_{2.5}$,[4] and SO_x BACT analyses for the AEC is based on the EPA's top-down analysis method. The following top-down analysis steps are listed in the EPA's *New Source Review Workshop Manual* (EPA, 1990):

- Step 1: Identify all control technologies
- Step 2: Eliminate technically infeasible options

[4] For the AEC, PM_{10} and PM $_{2.5}$ emissions comprise Total Suspended Particulates (TSP).

- 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 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, 2013):**
  - Search included the NO_x, CO, VOC, PM_{10}, $PM_{2.5}$, and sulfur dioxide (SO_2) BACT/LAER determinations for combined-cycle and cogeneration, large combustion turbines (greater than 25 MW) with permit dates between 2000 and August 2013.
- **California Air Pollution Control Officers Association/California Air Resources Board (ARB) BACT Clearinghouse (ARB, 2013):**
  - Search included the BACT determinations listed in ARB's BACT clearinghouse for combined-cycle turbines from all California air districts.
- **Local Air Pollution Control Districts BACT Guidelines/Clearinghouses:**
  - **SCAQMD BACT Guidelines (SCAQMD, 2013):**
    - 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, 2013):**
    - 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, 2013):**
    - 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, 2013):**
  - 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 AEC, as set forth in Table 2-1. If the emission limits at other facilities were less than the values in Table 2-1, additional research was conducted to find which turbine technology had been selected and whether the facilities had been constructed (Step 3). If it could be demonstrated that other units with lower emission rates either had not yet been built or used a different turbine technology than that selected for the AEC, the proposed emission limits for the AEC were determined to be BACT (Step 5).

2.2 Combustion Turbine 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 oxygen (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 combustion turbines:

NO_x Combustion Control Technologies. The two combustion controls for combustion turbines are (1) the use of water or steam injection, and (2) dry low NO_x (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 steam injection can achieve a NO_x emission level of 25 part(s) per million dry volume (ppmvd) at 15 percent O_2, but with the added economic, energy, and environmental expense of using water.

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

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

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

Post-combustion NO_x Control Technologies. Three post-combustion controls are available for combustion turbines: (1) selective catalytic reduction (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 ppmvd for combined-cycle gas turbines. EMx uses a hydrogen regeneration gas to convert the NO_x to elemental N_2 and water. SNCR also uses ammonia to control NO_x emissions, but without a catalyst.

Selective Catalytic Reduction. SCR is a post-combustion control technology designed to control NO_x emissions from gas turbines. The SCR system is placed inside the exhaust ductwork and consists of a catalyst bed with an ammonia injection grid located upstream of the catalyst. The ammonia reacts with the NO_x and O_2 in the presence of a catalyst to form N_2 and water. The catalyst consists of a support system with a catalyst coating typically of titanium dioxide, vanadium pentoxide, or zeolite. A small amount of ammonia is not consumed in the reaction and is emitted in the exhaust stream; this is referred to as “ammonia slip.”

EMx System. The EMx system uses a single catalyst to remove NO_x emissions in the turbine exhaust gas by oxidizing NO to NO_2 and then absorbing NO_2 onto the catalytic surface using a potassium carbonate absorber coating. The potassium carbonate coating reacts with NO_2 to form potassium nitrites and nitrates, which are deposited onto the catalyst surface. The optimal temperature window for operation of the EMx catalyst is from 300 to 700 degrees Fahrenheit (°F). EMx does not use ammonia, so there are no ammonia emissions from this catalyst system (ARB, 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 (ARB, 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.[5] This technology is not available for combustion turbines because gas turbine exhaust temperatures are below the minimum temperature required of 1,600°F.

2.2.1.2 Eliminate Technically Infeasible Options – Step 2

Pre-combustion NO_x Control Technologies

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

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

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

Post-combustion NO_x Control Technologies

Selective Catalytic Reduction. The use of SCR, with an ammonia slip of less than 5 ppmvd corrected to 15 percent O_2, 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 ppmvd 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 AEC NO_x limit of 2 ppmvd NO_x.

[5] 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 AEC.

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 AEC. DLN combustors were selected because these allow for a 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 AEC's water consumption. When used in combination with SCR, these technologies will control NO_x emissions to 2 ppmvd (1-hour average).

Applicable BACT clearinghouse determinations and the BAAQMD, ARB, 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 are presented in Table 2-2.

TABLE 2-2
Summary of NO_x Emission Limits for Combined-cycle 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
Black Hills Power, Inc./Cheyenne	WY-0070	3.0 ppm (1-hour)
Mirant Gastonia Power Facility	NC-0095	2.5 ppm (24-hour) for first 500 hours; 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
NRG Energy Center Dover, LLC.	DE-0023	2.5 ppm (1-hour)
Empire Power Plant	NY-0100	2.0 ppm (3-hour) without duct burners; 3.0 ppm (3-hour) with duct burners
Tracy Substation Expansion Project	NV-0035	2.0 ppm (3-hour)
Langley Gulch Power Plant	ID-0018	2.0 ppm (3-hour)
Palomar Escondido – SDG&E	2001-AFC-24	2.0 ppm (1-hour); 2.0 ppm (3-hour) with duct burners or transient hour of +25 MW
Warren County Facility	VA-0308	2.0 ppm with or without duct burners
Ivanpah Energy Center, L.P.	NV-0038	2.0 ppm (1-hour) without duct burners; 13.96 lb/hr with duct burners
Gila Bend Power Generating Station	AZ-0038	2.0 ppm (1-hour)
Duke Energy Arlington Valley	AZ-0043	2.0 ppm (1-hour)
Colusa II Generation Station	2006-AFC-9	2.0 ppm (1-hour)
Avenal Energy – Avenal Power Center, LLC	2008-AFC-1	2.0 ppm (1-hour)
Russell City Energy Center	2001-AFC-7	2.0 ppm (1-hour)

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

Facility	Facility ID Number	NO_x Emission Limit at 15 percent O_2
CPV Warren	VA-0291	2.0 ppm (1-hour)
IDC Bellingham	CA-1050	2.0 ppm/1.5 ppm (1-hour)
Oakley Generating Station	2009-AFC-4	2.0 ppm (1-hour)
GWF Tracy Combined-cycle Project	2008-AFC-7	2.0 ppm (1-hour)
Watson Cogeneration Project	2009-AFC-1	2.0 ppm (1-hour)
Garrison Energy Center, LLC/Calpine Corporation	DE-0024	2.0 ppm
Moxie Energy, LLC	PA-0286	2.0 ppm
Channel Energy Center, LLC	TX-0618	2.0 ppm (3-hour)
Deer Park Energy Center, LLC	TX-0619	2.0 ppm (3-hour)
Calhoun Port Authority	TX-0620	2.0 ppm (3-hour)

* 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.

ppm = part(s) per million

Sources: EPA, 2013 and CEC, 2013

The review of these recent determinations identified only the IDC Bellingham Project as having emission limits less than the proposed BACT emission limit for the AEC of 2 ppmvd NO_x. Based on the Final Determination of Compliance for the Oakley Generating Station Project, BAAQMD noted that the IDC Bellingham facility was permitted with a two-tiered NO_x emission limit that imposed an absolute not-to-exceed limit of 2.0 part(s) per million (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 ppmvd (1-hour average) for AEC 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 rate of 2 ppmvd (1-hour average) is the lowest NO_x emission rate 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 AEC is the use of DLN combustors with SCR to control NO_x emissions to 2 ppmvd (1-hour average).

2.2.2 Carbon Monoxide

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 AEC.

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

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

2.2.2.2 Eliminate Technically Infeasible Options – Step 2

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

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 ppmvd (1-hour average).

Applicable BACT clearinghouse determinations and the SCAQMD, EPA, BAAQMD, ARB, and SJVAPCD BACT determinations were reviewed to determine whether CO emission rates less than the proposed AEC level 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 AEC. However, three projects have CO emission rates that are lower than the CO emission rate proposed for the AEC. These projects are discussed below.

TABLE 2-3
Summary of CO Emission Limits for Combined-cycle Combustion Turbines*
Emission Control Ranking for Turbines With and Without Duct Burning

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)

TABLE 2-3
Summary of CO Emission Limits for Combined-cycle Combustion Turbines*
Emission Control Ranking for Turbines With and Without Duct Burning

Facility	Facility ID Number	CO Emission Limit at 15 percent O_2
Wallula Power Plant	WA-0291	2.0 ppm (3-hour)
Duke Energy Arlington Valley (AVEFII)	AZ-0043	2.0 ppm (3-hour)
Wanapa Energy Center	OR-0041	2.0 ppm (3-hour)
Vernon City Light and Power	CA-1096	2.0 ppm (3-hour)
Mariposa Energy Project	2009-AFC-3	2.0 ppm (3-hour)
Palmdale Hybrid Power Plant Project	08-AFC-9	2.0 ppm without duct burners (1-hour); 3.0 ppm with duct burners (1-hour)
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)
Moxie Energy, LLC	PA-0286	2.0 ppm
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)

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

Sources: EPA, 2013 and CEC, 2013

Competitive Power Ventures (CPV) Warren and Warren County Facilities. A new PSD permit application was submitted in April 2010 (AECOM, 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 firing, respectively. Based on publically available information, Dominion expects commercial operation of the Warren facility to occur in late 2014 or early 2015. Therefore, this level of control has not been demonstrated in practice on a long-term basis with a short (1-hour) averaging period.

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

Conclusion. As shown in Table 2-3, the proposed CO emission rate of 2 ppmvd (1-hour average) for the AEC 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 ppmvd (1-hour average) for the AEC 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 AEC is good combustion design and the installation of an oxidation catalyst system to control CO emissions to 2 ppmvd (1-hour average).

2.2.3 Volatile Organic Compoundss

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 AEC 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 AEC.

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

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

2.2.3.2 Eliminate Technically Infeasible Options – Step 2

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

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 ppmvd (1-hour average).

Applicable BACT clearinghouse determinations and the SCAQMD, EPA, BAAQMD, ARB, and SJVAPCD BACT determinations were reviewed to determine whether VOC emission rates less than the proposed AEC level 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 ppm 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 ppm 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 without duct burners; 1.5 ppm 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)
Moxie Energy, LLC	PA-0286	1.0 ppm without 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 ppm without duct burners (3-hour); 1.6 ppm with duct burners (3-hour)
Warren County Facility	VA-0308	0.7 ppm without duct burners; 1.0 ppm with duct burners
Chouteau Power Plant	OK-0129	0.3 ppm (3-hour) with duct burners

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

Sources: EPA, 2013 and CEC, 2013

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

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

Russell City Energy Center (RCEC). The RCEC has a VOC permit limit of 1.0 ppmvd at 15 percent O_2 with 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 AEC limit of 1 ppmvd at 15 percent O_2 averaged over a 1-hour period without duct burners, construction of the RCEC has not been completed. Therefore, long-term demonstration of compliance with the proposed emission rate and averaging period has not been demonstrated in practice.

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

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

Conclusion. As shown in Table 2-4, the proposed VOC emission rate of 1 ppmvd (1-hour average) without duct burner firing for the AEC 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 ppmvd (1-hour average) for the AEC 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 AEC is good combustion design and the installation of an oxidation catalyst system to control VOC emissions to 1 ppmvd (1-hour average).

2.2.4 Particulate Matter

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

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

Pre-combustion Particulate Control Technologies. The major sources of PM_{10} and $PM_{2.5}$ emissions from a natural-gas-fired combustion 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 particulate matter in the exhaust stack; and (3) particulate matter in the ambient air entering the gas turbine through the inlet air filtration system, and the aqueous ammonia dilution air. Therefore, the use of clean-burning, low-sulfur fuels such as natural gas will result in minimal formation of PM_{10} and $PM_{2.5}$ during combustion. Best combustion practices will ensure proper air/fuel mixing ratios to achieve complete combustion, minimizing emissions of unburned hydrocarbons that can lead to formation of particulate matter at the stack. In addition to good combustion, use of high-efficiency filtration on the inlet air system will minimize the entrainment of particulate matter into the exhaust stream.

Post-combustion Particulate Control Technologies. Two post-combustion control technologies designed to reduce particulate matter emissions from industrial sources are electrostatic precipitators and baghouses. However, neither of these control technologies is appropriate for use on natural-gas-fired combustion turbines because of the very low levels and small aerodynamic diameter of particulate matter 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 particulate matter emission concentrations, and are not used in natural-gas-fired applications, which have inherently low particulate matter 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 AEC.

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 combustion turbine control technologies proposed by the project owner to control total PM_{10} and $PM_{2.5}$ emissions to 4.5 lb/hr (front and back-half catch). Furthermore, because no add-on control devices are technically feasible to control particulate matter emissions from natural-gas-fired combustion turbines, there would be little an applicant could do beyond using best combustion practices and using clean-burning fuels and inlet air filtration to control particulate matter 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 practices, pipeline-quality natural gas, and inlet air filtration to control both PM_{10} and $PM_{2.5}$ emissions to 4.5 lb/hr is consistent with BACT at other similar sources. Therefore, an assessment of the economic and environmental impacts is not necessary.

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

The BACT for PM_{10} and $PM_{2.5}$ emissions from the AEC is using good combustion practices, pipeline-quality natural gas, and inlet air filtration to control both PM_{10} and $PM_{2.5}$ emissions to 4.5 lb/hr.

2.2.5 Sulfur Dioxide

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

There are two principal types of post-combustion control technologies for SO_2—wet scrubbing and dry scrubbing. Wet scrubbers use an alkaline solution to remove the SO_2 from the exhaust gases. Dry scrubbers use an SO_2 sorbent injected as powder or slurry to remove the SO_2 from the exhaust stream. However, the SO_2 concentrations in the natural gas exhaust gases are too low for the scrubbing technologies to work effectively or to be technically feasible.

2.2.5.2 Eliminate Technically Infeasible Options – Step 2

Use of pipeline-quality natural gas with very low sulfur content is technically feasible for the AEC. However, because sulfur emissions from natural-gas-fired combustion turbines are extremely low when using pipeline-quality natural gas, the two post-combustion SO_2 controls for natural-gas fired combustion 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 combustion turbines, and it is the most effective SO_2 control technology used by all other natural-gas-fired combustion 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 AEC 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 sulfur content 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 AEC is use of pipeline-quality natural gas with a sulfur content of less than 0.75 grain of sulfur per 100 scf of natural gas.

2.2.6 BACT for Startups and Shutdowns

Startup and shutdown events are a normal part of the power plant operation, but they involve NO_x, CO, and VOC emissions rates that are highly variable and greater than emissions during steady-state operation[6]. This is because emission control systems are not fully functional during these events. In the case of the DLN combustors, the turbines must achieve a minimum operating rate before these systems are functional. Likewise, the SCR and oxidation catalyst systems must be heated to a specific minimum temperature before the catalyst systems become effective. Furthermore, startup and shutdown emissions are dependent on a number of project-specific factors; therefore, permitted startup and shutdown emission limits are highly variable. For these reasons, BACT for startup and shutdown will consider only the duration of these events.

2.2.6.1 Control Devices and Techniques to Limit Startup and Shutdown Emissions

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

2.2.6.2 Determination of BACT Emissions Limit for Startups and Shutdowns

Startups. The combustion turbine vendor (MPSA) has determined a turbine startup period of 10 minutes from first fire to full load operation. This startup period does not include the warm-up time required by the SCR and oxidation catalyst systems, which is affected by the length of time the system has been inactive. The length of

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

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	116	27.9	25.5	114	27.3	90
Warm	16.6	46.0	21.0	21.5	49.0	21.9	32.5
Hot	16.6	33.6	20.4	21.5	36.6	21.3	32.5

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

TABLE 2-6
Facility Shutdown Emission Rates Per Turbine

	NO_x (lb/event)	CO (lb/event)	VOC (lb/event)	NO_x (lb/hr)	CO (lb/hr)	VOC (lb/hr)	Duration (minutes/event)
Shutdown	9.0	45.3	31.0	18.0	50.8	32.6	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.

2.3 Oil-Water Separator BACT Analysis

2.3.1 Volatile Organic Compounds

The AEC will install three 3,000-gallon capacity oil-water separators for the project, rated at 300 gallons per minute. The oil-water separators have the potential of releasing VOCs from the volatilization of the oily surface of the collected water. Control technologies for reducing VOC emissions include: (1) installation of a cover on oil-water separator, and (2) utilization of vapor loss control devices.

The AEC oil-water separators will include a cover and vapor loss controls, with a minimum VOC control efficiency of 90 percent. VOC emissions from the three AEC oil-water separators are estimated at 90 pound(s) per year (lb/yr). Therefore, BACT for oil-water separators is utilization of covers and vapor loss controls, with 90 percent VOC emissions control.

SECTION 3

GHG BACT Analysis

3.1 Introduction

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

3.1.1 Regulatory Overview

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

3.1.2 BACT Evaluation Overview

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

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

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

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

1. Identify available control technologies.
2. Eliminate technically infeasible options.
3. Rank remaining technologies.
4. Evaluate remaining technologies (in terms of economic, energy, and environmental impacts).
5. Select BACT (the most effective control technology and lowest consistently achievable emission limit) that has not been eliminated for economic, energy, or environmental impact reasons.

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

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

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

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

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

3.2 GHG BACT Analysis

3.2.1 Assumptions

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

- The AEC 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 Code of Federal Regulations [CFR] 98) factors for estimating CO_2e emissions from natural gas combustion assume complete combustion of the fuel. While the oxidation catalyst has the potential of incrementally increasing CO_2 emissions, these emissions are already accounted for in the Mandatory Reporting Rule factors and included in the CO_2e totals.

- Similarly, the SCR catalyst may result in an increase in N_2O emissions. Although quantifying the increase is difficult, it is generally estimated to be very small or negligible. From the AEC GHG emissions inventory, the estimated N_2O emissions only total 171 metric tons per year. Therefore, even if there were an order-of-magnitude increase in N_2O as a result of the SCR, the impact to CO_2e emissions would be insignificant as compared to total estimated AEC CO_2e emissions.

- AEC plans to install twenty (20) electric breakers containing SF_6, and estimates a total of approximately 1,248 pounds of SF_6 will be contained within the electrical circuit breakers. With an assumed annual leak rate of 0.1 percent per year, the AEC estimates that SF_6 emissions would be 1.248 pounds per year or 13.5 metric tons of CO_2e per year (assuming a global warming potential for SF_6 of 23,900), which is insignificant as compared to total estimated AEC CO_2e emissions.

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

3.2.2 BACT Determination

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

The primary GHG of concern for AEC is CO_2. This analysis primarily presents the GHG BACT analysis for CO_2 emissions because CH_4 and N_2O CO_2e emissions are insignificant, at approximately 1.6 percent of facility GHG CO_2e emissions. Similarly, SF_6 CO_2e emissions from electrical switchgear are also insignificant, at approximately 0.0004 percent of facility GHG CO_2e emissions. Therefore, the primary sources of GHG emissions would be the natural-gas-fired combustion turbines.

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

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

Each of these steps, described in the following sections, was conducted for GHG emissions from the CTGs and HRSGs. 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, 2013):**
  - 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 August 2013.
- **BACT Analyses for Recently Permitted Combined-cycle CEC Projects (CEC, 2013):**
  - 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 AEC combined-cycle equipment:

- Carbon capture and storage (CCS)
- Thermal efficiency

The proposed AEC design and operation will consist of four 3-on-1 combined-cycle generating power blocks, each including three natural-gas-fired MPSA 501DA CTGs with unfired HRSGs, and one STG. AES-SLD has determined that this configuration is the only alternative that meets all of the project objectives as further detailed in Section 1.2. Several of the primary objectives of the AEC are to backstop variable renewable resources with a MSG project that incorporates fast-start capability, a high degree of turndown, fast ramping capability, and a high thermal efficiency. Therefore, and to avoid changing the fundamental business purpose of the AEC, other potentially lower-emitting renewable generation technologies were not evaluated in this BACT analysis.

This is consistent with EPA's March 2011 GHG Tailoring Rule, which states:

> *EPA has recognized that a Step 1 list of options need not necessarily include inherently lower polluting processes that would fundamentally redefine the nature of the source proposed by the permit applicant…", and "…the permitting authority should keep in mind that BACT, in most cases, should not regulate the applicant's purpose or objective for the proposed facility… (p. 26).*

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

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

CO_2 Capture and Compression.

The capture of CO_2 from industrial gas streams has occurred for decades using several processes to separate CO_2 from other gases. These processes have been used in energy production and to produce food- and chemical-grade CO_2. In the middle of the century, gas adsorption technologies were developed at refineries for hydrogen production.[7] Three capture technologies are primarily being considered for CCS: pre-combustion, post-combustion, and oxy-combustion. Pre-combustion capture refers to a process in which a hydrocarbon fuel is gasified to form a synthetic mixture of hydrogen and CO. The CO is converted to CO_2, using shift reactors, and captured before combusting the hydrogen-based fuel. The post-combustion capture technologies include the three methods identified by the SCAQMD, namely sorbent adsorption, physical adsorption, and chemical absorption. Oxy-combustion technology uses air separators to remove the N_2 from combustion air so that the combustion products are almost exclusively CO_2, thereby reducing the volume of exhaust gases needed to be treated by the carbon capture system. Of these technologies, the post-combustion technology is most applicable to the AEC.

Once the CO_2 is captured, the concentrated CO_2 is 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 is then transported to an appropriate location for underground injection into a suitable geological storage reservoir, such as a deep saline aquifer, or depleted coal seam, ocean storage site, or used in crude oil production for enhanced oil recovery.

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

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[7] Report of the Interagency Task Force on Carbon Capture and Storage, United States Department of Energy, August 2010. http://www.fe.doe.gov/programs/sequestration/ccstf/CCSTaskForceReport2010.pdf

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 and specialized equipment are required, and operating energy requirements are very high.

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

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

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

The U.S. Department of Energy (DOE) National Energy Technology Laboratory (NETL), via the West Coast Regional Carbon Sequestration Partnership (WestCarb), has researched potential geologic storage locations, including those in southern California. This information has been presented in NETL’s 2012 U.S. *Carbon Utilization and Storage Atlas-Fourth Edition* (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), Southern California Carbon Sequestration Research Consortium’s (SoCalCarb) Carbon Atlas (http://socalcarb.org/atlas.html), and WESTCARB’s Carbon Atlas (http://westcarb.org/carbonatlas.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 has been identified.

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

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

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

The AEC is an efficient MSG project that incorporates a high degree of turndown, fast-start, and ramping capability that will support grid reliability as renewable generating sources comprise a larger share of California's energy production. This allows an increased use of wind power and other renewable energy sources, with backup power available from the AEC. A natural-gas-fired plant such as the AEC uses a relatively small amount of electricity to operate the facility compared to the energy in the fossil fuel combusted. Therefore, minimal benefit occurs in terms of energy efficiency and GHG emission reductions of the facility associated with lowering electricity usage at the facility compared to increasing the thermal efficiency of the process.

The addition of the high thermal efficiency of the AEC's generation to the state's electricity system will facilitate the integration of renewable resources into California's generation supply and will displace other less-efficient, higher GHG-emitting generation.

California's RPS requirement was increased from 20 percent by 2010 to 33 percent by 2020, with the adoption of Senate Bill 2 on April 12, 2011. To meet the new RPS requirements, the amount of dispatchable, high-efficiency, natural gas generation used as regulation resources, fast-ramping resources, or load-following or supplemental energy dispatches will have to be significantly increased. The AEC will aid in the effort to meet California's RPS requirement, because a significant attribute of the AEC is that the combined-cycle facility can operate similarly to a peaking plant but at higher thermal efficiency.

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

The AEC MPSA 501DA CTGs allow for a unique operating configuration when integrated with the HRSG operation. Over the anticipated projected load dispatch range presented in Figure 4, the AEC 3-on-1 configuration maintains an efficient heat rate over almost the entire load range. Note that Figure 4 compares the combined-cycle AEC combustion turbines operating similar to peaker units, with other combustion turbines operating in a similar peaker configuration. Operation within this high efficiency band is maintained through operational changes by the combustion turbine and HRSG/STG. These operational adjustments allow efficient operation over most of the project operating range.

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

3.2.2.2 Eliminate Technically Infeasible Options – Step 2

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

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

- No full-scale systems for solvent-based carbon capture are currently in operation to capture CO_2 from dilute exhaust steams, such as those from natural-gas-fired electrical generation systems at the scale proposed for the AEC.
- Use of captured CO_2 for enhanced oil recovery 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 AEC to undertake. Oil and gas production in the vicinity of AEC is available for enhanced oil recovery; however, only pilot-scale projects are known in the region and only estimates are available on the capacity of these miscible oil fields.

Figure 1. U.S. and Canadian Saline Formations

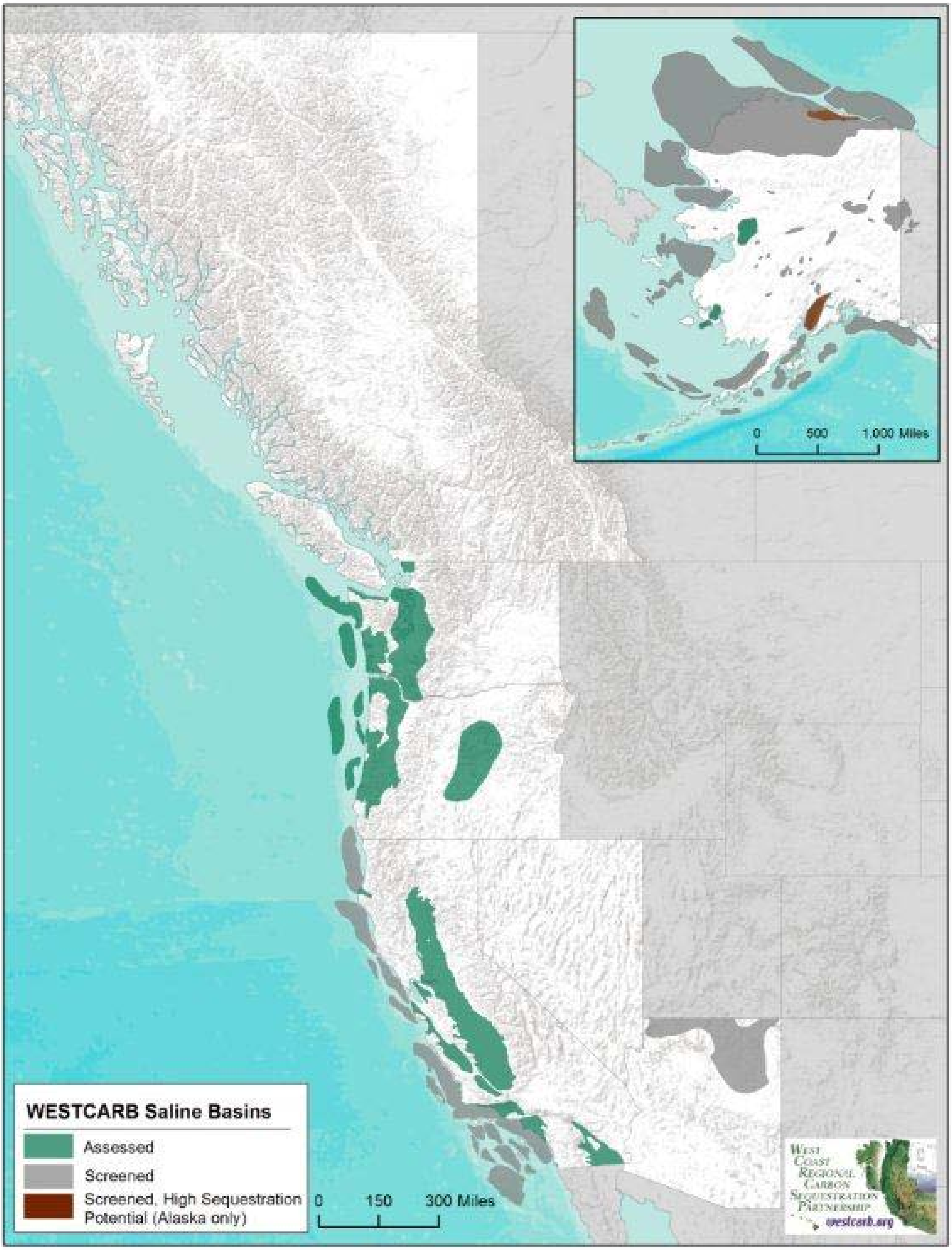


Figure 2. U.S. and Canadian Oil and Gas Reserves

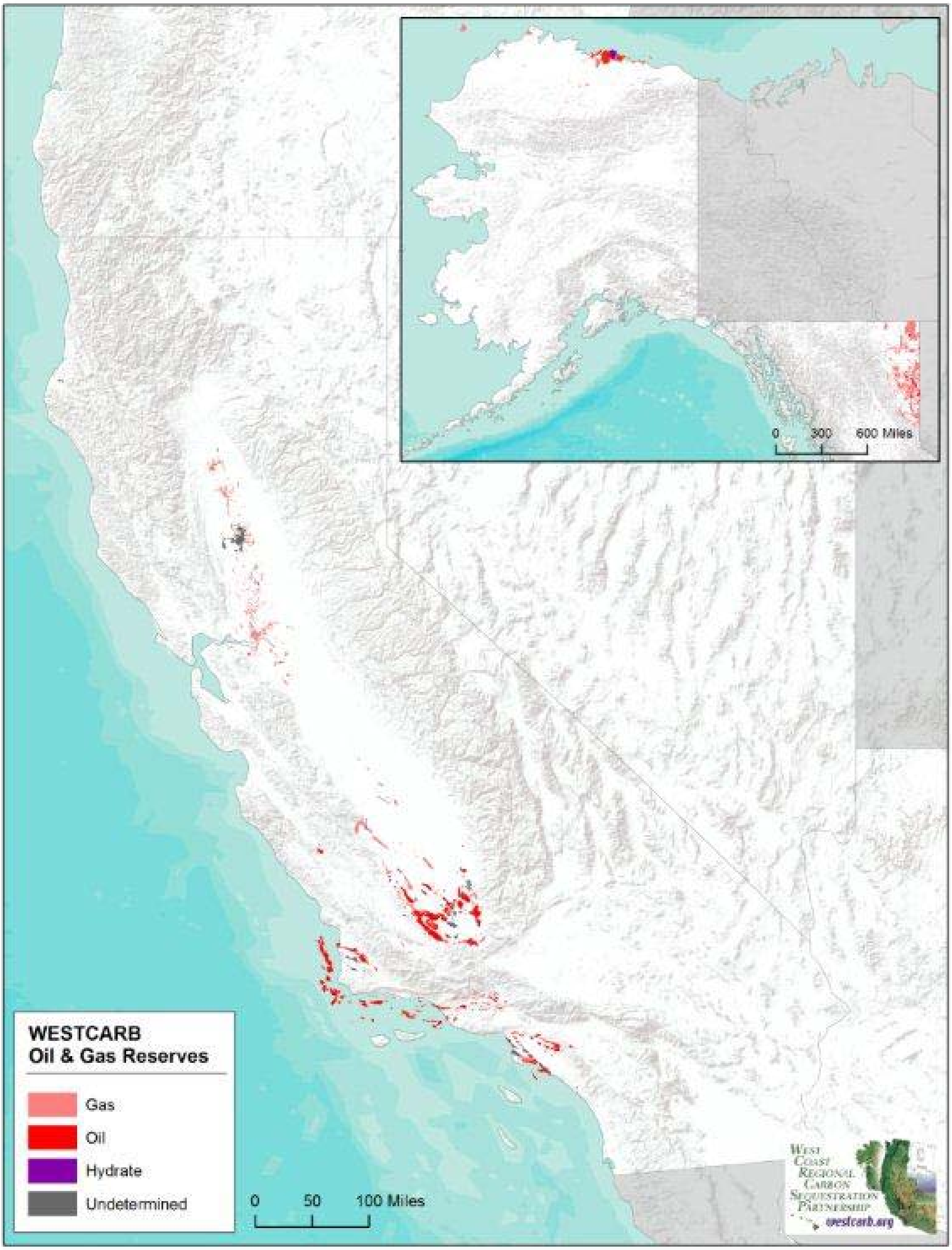


Figure 3. AEC Startup Curve

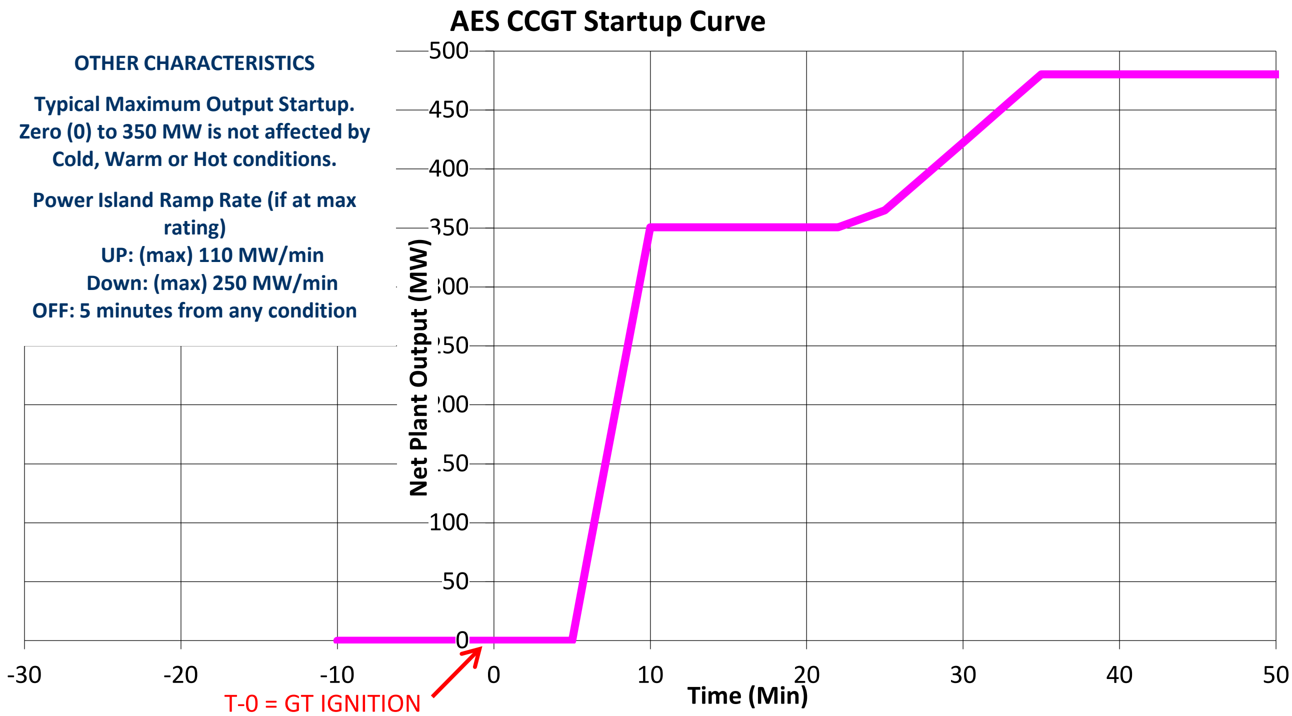
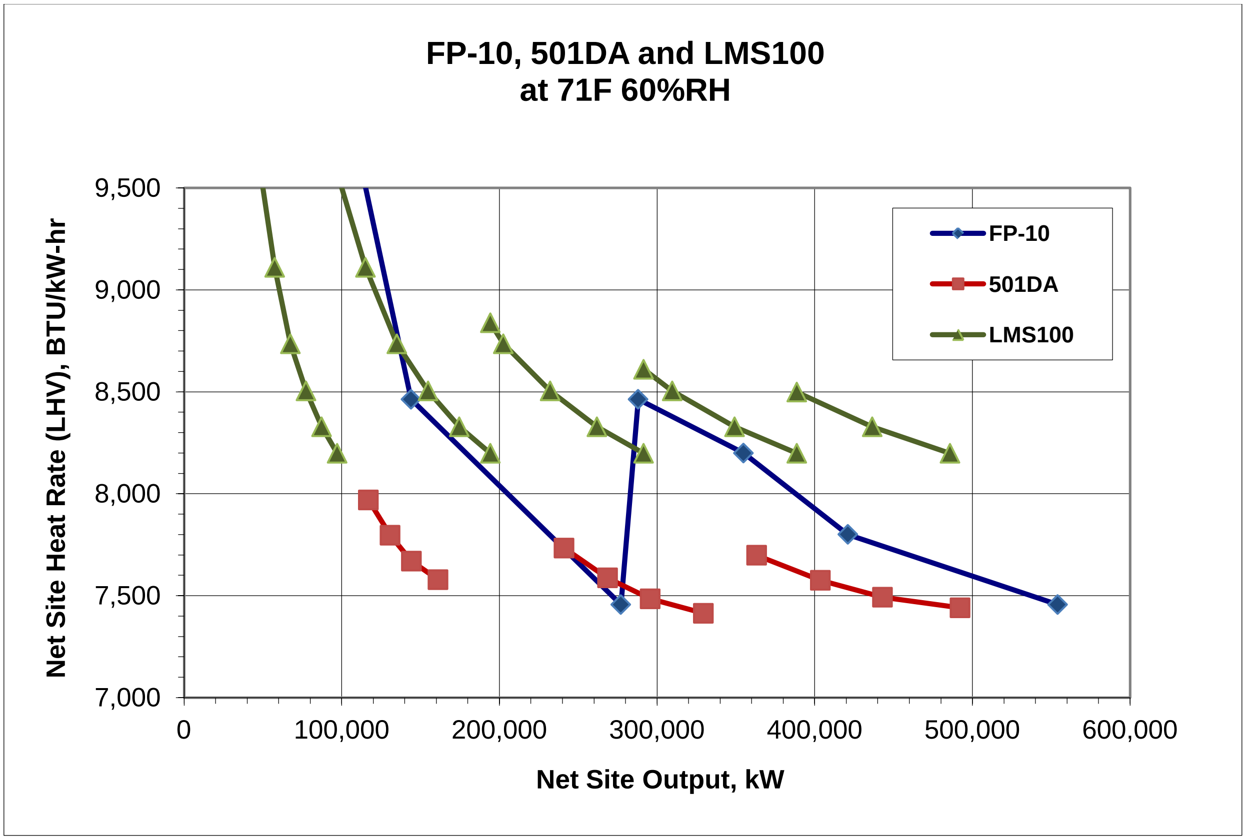


Figure 4. Comparison of AEC and Alternative Design Heat Rates



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

These issues are discussed in more detail below.

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

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

For example, CO_2 is separated from petroleum in refinery hydrogen plants in a number of locations, but this is typically accomplished on the product gas from a steam CH_4 reforming process that contains primarily hydrogen, 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 *DOE/NETL Advanced Carbon Dioxide Capture R&D Program: Technology Update*, NETL notes the different applications for chemical solvent absorption, physical solvent absorption, and sorbent adsorption processes. As noted in Section 4.B, “When the fluid component has a high concentration in the feed stream (for example, 10 percent or more), a PSA mechanism is more appropriate” (NETL, 2011).

In another example, at the Dakota Gasification Company’s Great Plains Synfuels Plant in North Dakota, CO_2 is separated from intermediate fuel streams produced from gasification of coal. The gas from which the CO_2 is separated is a mixture of primarily hydrogen, CH_4, and 30 to 35 percent CO_2; a physical absorption process

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

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

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

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

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

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

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

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

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

> *than the capacity required for the purposes of GHG emissions mitigation at a typical power plant, there is considerable uncertainty associated with capacities at volumes necessary for commercial deployment.* (DOE and EPA, 2010)

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

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

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

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

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

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

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

The effectiveness of ocean sequestration as a full-scale method for CO_2 capture and storage is unclear given the limited availability of injection pilot tests and the ecological impacts to shallow and deep ocean ecosystems. Ocean sequestration is conducted by injecting supercritical liquid CO_2 from either a stationary or towed pipeline at targeted depth interval, typically below 3,000 feet. CO_2 is injected below the thermocline, creating either a rising droplet or a dense phase plume and sinking bottom gravity current. Through NETL, extensive research is being conducted by the Monterey Bay Aquarium Research Institute on the behavior of CO_2 hydrates and dispersion of these hydrates within the various depth horizons of the marine environment; however, the experiments are small in scale and the results may not be applicable to larger-scale injection projects in the near future. Long-term effects on the marine environment, including pH excursions, are ongoing, making the use of ocean sequestration technically infeasible at the current time. The feasibility of implementing a commercially available sequestration approach is further brought into question, with the IPCC stating:

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

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

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

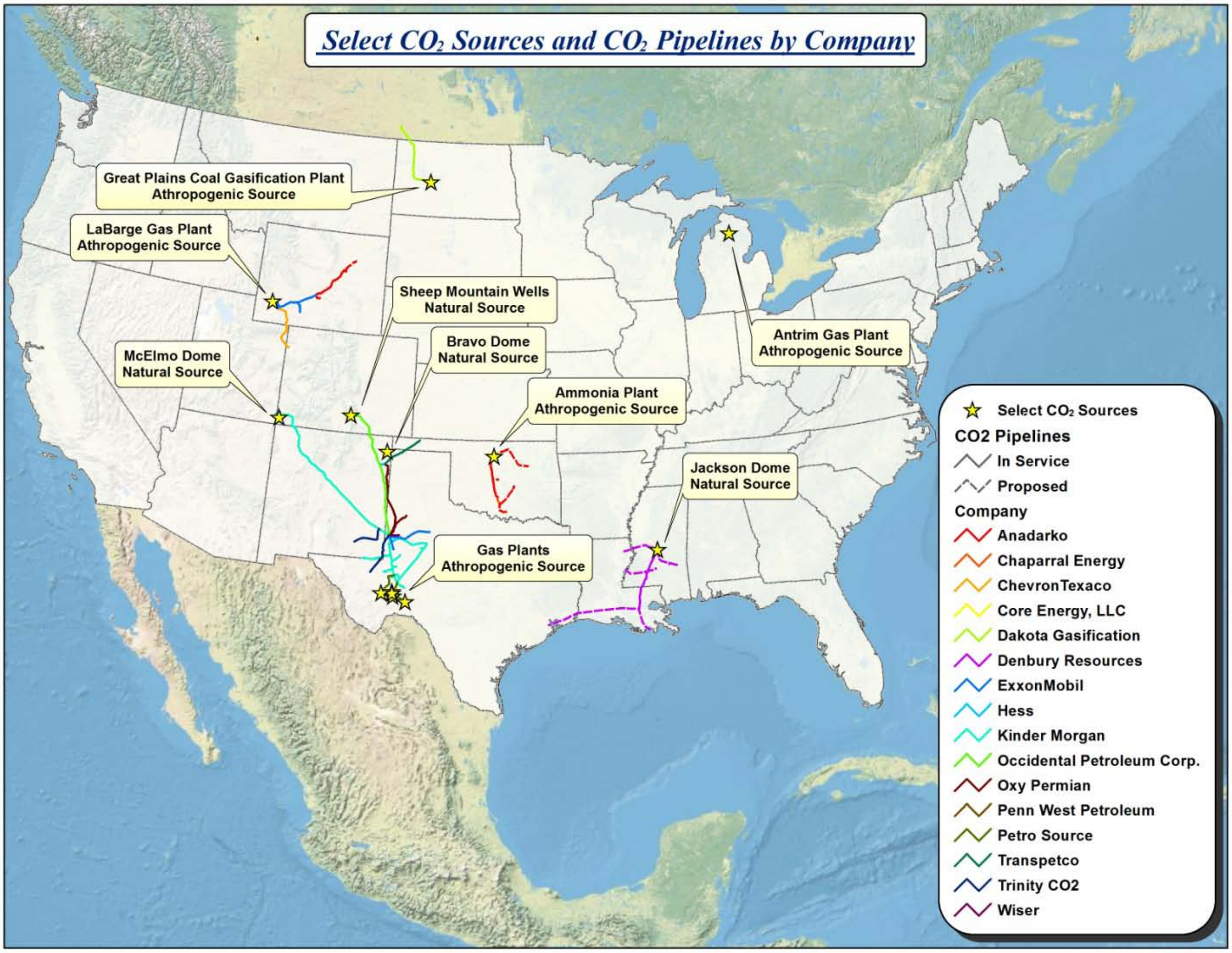
Most current carbon capture systems are based on amine or chilled ammonia technology, which are chemical absorption processes. Although capture system startup and shutdown time of vendor processes could not be confirmed within this BACT analysis, clearly both types of processes would require durations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

Finally, the potential to sell CO_2 to industrial or oil and gas operations is infeasible for an operation such as this, where daily operation of AEC depends on grid dispatch needs, particularly to offset reductions from renewable energy sources. Even if a potential enhanced oil recovery 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 enhanced oil recovery option unviable. Therefore, CCS technology would be better suited for applications with low variability in operating conditions.

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

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

Figure 5. Existing and Planned CO_2 Pipelines in the U.S. with Sources



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

The CCS alternative is not considered technically feasible for the AEC, and it should therefore be eliminated from further consideration in Step 2. However, from recommendations made on other recent projects, economic feasibility issues will be discussed in Step 4.

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

3.2.2.3 Combustion Turbine GHG Control Technology Ranking – Step 3

Because CCS is not technically feasible, the only remaining technically feasible GHG control technology for the AEC 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 AEC.

3.2.2.4 Evaluate Most Effective Controls – Step 4

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

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

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

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

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

> *EPA recognizes that at present CCS is an expensive technology, largely because of the costs associated with CO_2 capture and compression, and these costs will generally make the price of electricity from power plants with CCS uncompetitive compared to electricity from plants with other GHG controls. Even if not eliminated in Step 2 of the technical feasibility of the BACT analysis, on the basis of the current costs of CCS, we expect that CCS will often be eliminated from consideration in Step 4 of the economical feasibility of the BACT analysis, even in some cases where underground storage of the captured CO_2 near the power plant is feasible.* (EPA, 2011b)

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

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

A 2009 review of available CO_2 capture technologies identified 17 facilities worldwide currently in operation, including four natural gas processing facilities and a synthetic gas facility with capture levels exceeding 1 million tons of CO_2 per year (the capture level applicable to power plant emissions). The integration of these existing technologies with power plants represents significant cost and operating issues that need to be addressed in order to facilitate cost-effective deployment of CO_2 capture technologies.[8]

To this end, AEC explored the status of CCS development and, based on the Global Carbon Capture and Storage Institute's January 2013 CCS status report,[9] determined that there are a total of 72 large-scale integrated CCS projects (LSIP) in various stages of development worldwide, with four in operation in the U.S., two in Europe, and one each in Canada and Africa. Of the other LSIPs, only eight are at a development stage where final design or contract execution is being considered. The remaining 56 projects are in the identification, evaluation, and project definition stage. Of the 72 projects, 39 are power generation projects with four of these projects developing CCS technologies at natural-gas-fired power plants. Thus far, a majority of the CCS work has been focused on solid fuel power generation, primarily with integrated gasifier combined cycle designs and oxy-fuel designs.

Given that CCS is being currently employed on electrical generating units regardless of fuel type, the SCAQMD has requested a more detailed economic evaluation of CCS technology for the AEC. During a recent meeting with the SCAQMD, they indicated that AEC could use indicative pricing to define the CCS costs for AEC. After researching indicative CCS costing data, a DOE February 2012 Cost and Performance report[10] shows the cost for installing and operating a CCS system on a natural-gas-fired combined-cycle (NGCC) combustion turbine project. Therefore, these data are being used to determine the cost of applying CCS to AEC.

The DOE report determined the cost for developing a 615 MW NGCC project based on two General Electric Frame 7FA turbines (or equivalent), two HRSGs, a single reheat steam turbine, a wet mechanical cooling tower, and emission controls for NO_x and CO with CCS. Table 3-1 presents the installation and operating costs for the above NGCC project with CCS and comparative cost for AEC.

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8 ibid

9 http://www.globalccsinstitute.com/publications/global-status-ccs-update-january-2013

10 http://bv.com/docs/reports-studies/nrel-cost-report.pdf

TABLE 3-1
Cost for a NGCC Power Plant with and without Carbon Capture and Sequestration

Technology	Capital Cost [a] ($/kW)	Variable O&M Cost ($/MWh)	Fixed O&M Cost ($/kW-year)
NGCC	1,230	3.67	6.31
NGCC with CCS [b]	3,750	10	18.4
AEC – Base Case	>1,000	< 1.00	~ 6.00

[a] AEC capital cost calculated based on $2,000 million/1,995,000 kW gross excluding land value, taxes, and insurance.
[b] NGCC with CCS assumes 85 percent carbon capture.

kW = kilowatt
O&M = Operations and Maintenance

As shown in Table 3-1, the expected costs of deploying CCS on AEC would be prohibitive, resulting in over 3 times the AEC base case capital costs. Additionally, operational variable and fixed costs would increase by a factor of 10 and 3, respectively. Based on the DOE report, the heat rate for the NGCC plant without CCS was estimated at 6,705 Btu/kWh, whereas the heat rate for the NGCC plant with CCS was estimated at 10,080 Btu/kWh.[11] This degradation in heat rate is due to the additional electrical load required to operate the CCS system, resulting in a 33 percent reduction in performance. AEC believes that the CCS heat rate degradation would push AEC's heat rate (reported as 7,547 Btu/kWh-lower heating value [LHV]) to over 11,000 Btu/kWh-LHV.

Based on the results of CCS data presented in Table 3-1, an estimate of the costs for incorporating CCS on the AEC is presented in Table 3-2. These costs assumed that carbon capture systems are currently available, that nearby CO_2 sequestration sites are readily available, and that regulatory/land use issues regarding the siting of a high-pressure CO_2 pipeline and legal issues addressing sequestration are resolved.

TABLE 3-2
Cost Comparison for AEC with and without Carbon Capture and Sequestration

Technology	Capital Cost ($/kW)	Capital Cost ($)	Variable O&M Cost [a] ($/year)	Fixed O&M Cost [a] ($/year)	Total Annual O&M Cost ($/year)
AEC	>1,000	2,000,000,000	7,340,000	11,970,000	19,310,000
AEC with CCS [b]	3,520	7,022,400,000	73,400,000	36,708,000	110,108,000
Incremental Cost of CCS [c]	2,520	5,022,400,000	66,060,000	24,738,000	90,798,000

[a] AEC variable and fixed O&M costs are based on Table 3-1 costs, assuming 7,340,000 MWh and 1,995,000 kW. Based on a 42% AEC capacity factor.
[b] AEC with CCS capital cost calculated as $3,750/kW - $1,230/kW + $1,000/kW.
[c] Cost of CCS is the difference between AEC with CCS and AEC.

It is clear that based on the DOE study, deploying CCS at AEC does not appear to be cost effective. It should be noted that the DOE report assumes the NGCC units have a capacity factor (ratio of actual MW produced in a year divided by theoretical MW possible in a year) of 85 percent. AEC expects the capacity factor of AEC to be approximately 42 percent with approximately 495 startups and shutdowns per year. The intermittent operation of AEC is not factored into the above cost estimate, but is expected to both reduce the efficiency of the CCS system and increase costs on a dollars per kilowatt (kW) basis.

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 enhanced oil recovery 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

[11] http://bv.com/docs/reports-studies/nrel-cost-report.pdf, pages 14 and 16.

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 AEC, the most realistic scenario could be to construct a pipeline from the Long Beach area to either the Santa Fe Springs or Dominquez oil fields near Los Angeles for enhanced oil recovery, assuming that permits and right-of-way agreements are obtained and there is an active enhanced oil recovery operation in this location. As noted above, the approximate distance of a pipeline from AEC to either of these two fields is within 20 miles. From the *Carbon Management GIS: CO2 Pipeline Transportation Cost Estimate, MIT, June 2009*, a 12-inch pipeline would likely be required for the AEC project. From this document, the estimated cost per mile is approximately $500,000 per mile for baseline construction case with no obstructions. For the Long Beach area, which is highly populated, the costs are adjusted by an estimated construction factor of 15, or a resultant $7.5 million per mile or $150 million for a 20-mile pipeline. Therefore, the pipeline alone would represent nearly an additional 12 percent increase to the estimated $1.3 billion capital cost, assuming that the enhanced oil recovery opportunities could be realized; however, costs could be substantially higher to transport CO_2 to deep saline aquifer or ocean storage locations.

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

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

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

Because CCS is not technically or economically feasible, thermal efficiency remains the most effective, technically feasible, and economically feasible GHG control technology for the AEC. The operationally-flexible turbine class and steam cycle designs selected for the AEC are the most thermally efficient for the project design objectives, operating at the projected annual capacity factor of approximately 42 percent. Table 3-3 compares the AEC heat rate with that of other recent projects.

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

Plant Performance Variable	Heat Rate (Btu/kWh)	GHG Performance (MT CO_2/MWh)
Alamitos Energy Center	8,302 [g]	0.420 [h]
Huntington Beach Energy Project	8,236 [a]	0.479 [b]
Watson Cogeneration Project [c]	5,027 to 6,327	0.219 to 0.318
Palmdale Hybrid Power Project	6,970 [d]	0.370 [d]
Russell City Energy Project	6,852 [e]	0.371 [f]

[a] Calculated HHV net heat rate at 65.8°F at site elevation, relative humidity of 58.32 percent, no inlet air cooling, and without duct burners. Heat rate varies over the anticipated load dispatch range.
[b] Calculated CO_2 emissions at conditions in footnote a above are 163,658 lb/hr with 166.3 combined MW (generation from both CTG and STG).
[c] From Watson Cogeneration Project Commission Final Decision.
[d] From Tables 3 and 4 of the Palmdale Hybrid Power Project Commission Decision, 2011.
[e] Net design heat rate with no duct burners, from "GHG BACT Analysis Case Study," Russell City Energy Center; November 2009, updated February 3, 2010.
[f] From Russell City total heat input of 4,477 MMBtu/hr (from PSD Permit), generation of 653 MW was calculated utilizing design heat rate of 6,852 Btu/kwh. From reference document in footnote e above, 1-hour CO_2 limit is 242 MT CO_2 per hour, which yields 0.371 MT CO_2/MWh.
[g] Based on LHV net heat rate of 7,547 Btu/KWh at 87°F at site elevation, relative humidity of 47 percent, without duct burners, and calculated HHV of 1.1 times LHV. Heat rate varies over the anticipated load dispatch range.
[h] Calculated CO_2 emissions at conditions of 273,745 MT CO_2 per year and 176.9 MW per turbine, and 3,686 operating hours per year.

MT CO_2/MWh = metric ton(s) of carbon dioxide per megawatt-hour

As shown in Table 3-3, when comparing the AEC heat rate and GHG performance values for other recently permitted facilities, the AEC heat rate is greater than that of other recent projects. However, the AEC operating configuration and project goals are different than those of other recently permitted projects. The Watson Cogeneration project is a combined heating and power (CHP) project, and it is designed for base load operation and not for flexible, dispatchable, or fast-ramping capability. As a CHP project, the heat rate for the Watson Cogeneration project was calculated based on steam conversion factor and, therefore, is not directly comparable to the AEC heat rate. While the Palmdale project was designed for fast ramping operation (15 MW per minute), the project is described as being designed as a base load project. The AEC's design objectives are to be able to operate over a wide MW production range with an overall high thermal efficiency, in order to respond to the fast changing load demands and changes necessitated by renewable energy generation swings. At maximum firing rate, the maximum power island ramp rate is 110 MW per minute for increasing in load and 250 MW per minute for decreasing load. At other load points, the load ramp rate is 30 percent. The AEC start time to 67 percent load of the power island is 10 minutes, and it is projected that the project will operate at an approximate 42 percent annual capacity factor.

The AEC 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 configuration. Therefore, comparison of operating efficiency and heat rate of the AEC should be made with simple-cycle or peaking units instead of combined-cycle or more base-loaded units. Table 3-4 shows that the AEC compares very favorably to the peaker units listed.

TABLE 3-4
Generation Heat Rates and 2008 Energy Outputs [a]

Plant Name	Heat Rate (Btu/kWh) [b]	2008 Energy Output (GWh)	GHG Performance (MT CO_2/MWh)
La Paloma Generating	7,172	6,185	0.392
Pastoria Energy Facility L.L.C.	7,025	4,905	0.384
Sunrise Power	7,266	3,605	0.397
Elk Hills Power, LLC	7,048	3,552	0.374
Sycamore Cogeneration Co	12,398	2,096	0.677
Midway-Sunset Cogeneration	11,805	1,941	0.645
Kern River Cogeneration Co	13,934	1,258	0.761
Ormond Beach Generating Station	10,656	783	0.582
Mandalay Generating Station	10,082	597	0.551
McKittrick Cogeneration Plant	7,732	592	0.422
Mt Poso Cogeneration (coal/pet. coke)	9,934	410	0.930
South Belridge Cogeneration Facility	11,452	409	0.625
McKittrick Cogeneration	9,037	378	0.494
KRCD Malaga Peaking Plant[c]	9,957	151	0.528
Henrietta Peaker[c]	10,351	48	0.549
CalPeak Power – Panoche	10,376	7	0.550
Wellhead Power Gates, LLC[c]	12,305	5	0.652
Wellhead Power Panoche, LLC[c]	13,716	3	0.727
MMC Mid-Sun, LLC[c]	12,738	1.4	0.675
Fresno Cogeneration Partners, LP PKR [c]	16,898	0.8	0.896
Palmdale Hybrid Power Project (PHPP)	6,970	4,993 [d]	0.370

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

GWh = gigawatt-hour(s)

The AEC will be dispatched remotely by a centralized control center over an anticipated load range of approximately 117 to 493 net MW for each 3-on-1 power island. Over this load range, the AEC anticipated heat rate is estimated at approximately 7,400 to 8,000 Btu/kWh LHV (~ 8,140 to 8,800 Btu/kWh HHV). The AEC will be able to start and provide 67 percent of the power island load in 10 minutes and provide 110 MW per minute of upward ramp and 250 MW per minute of downward ramp capability. Comparing the thermal efficiency of the AEC to other recently permitted California projects demonstrates that the AEC is more thermally efficient than other similar projects that are designed to operate as a peaker unit. Based both on its flexible operating characteristics and favorable energy and thermal efficiencies, as compared with other comparable peaking gas turbine projects, the AEC thermal efficiency is BACT for GHGs.

3.2.2.5 GHG BACT Selection – Step 5

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

As shown above, the MPSA 501DA combustion turbines operating in a MSG combined-cycle operating configuration compare favorably with other comparable turbines operating in a peaking capacity. The AEC turbines 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 operational combinations. Finally, annual metrics for output-based limits on GHG emissions are affected by startup and shutdown periods because fuel is combusted before useful output of energy or steam. Therefore, the annual average efficiency of any turbine operating over the entire load range, including startups and shutdowns, will be lower than the 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 AEC 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 AEC. The AEC has concluded that the combustion turbine BACT for GHG emissions is an emission rate of 1,089 pounds CO_2 per MWh of gross energy output, based on 5 percent degradation in turbine performance. The total AEC facility annual CO_2e PTE emissions is 3,284,950 metric tons per year. Degradation over time and turndowns, startup, and shutdown are incorporated into these limits.

SECTION 4
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