EXHIBIT AA

Statement of Basis

Draft Greenhouse Gas Prevention of Significant Deterioration Preconstruction Permit for the La Paloma Energy Center, LLC

Permit Number: PSD-TX-1288-GHG

March 2013

This document serves as the Statement of Basis (SOB) for the above-referenced draft permit, as required by 40 CFR 124.7. This document sets forth the legal and factual basis for the draft permit conditions and provides references to the statutory or regulatory provisions, including provisions under 40 CFR 52.21, that would apply if the permit is finalized. This document is intended for use by all parties interested in the permit.

I. Executive Summary

On April 30, 2012, La Paloma Energy Center, LLC (La Paloma), submitted to EPA Region 6 a Prevention of Significant Deterioration (PSD) permit application for Greenhouse Gas (GHG) emissions for a proposed construction project. On July 17, 2012 and August 6, 2012, La Paloma submitted additional information for inclusion into the application. In connection with the same proposed construction project, La Paloma submitted an application for a PSD Permit for non-GHG pollutants to the Texas Commission on Environmental Quality (TCEQ) on March 15, 2012. The project proposes to construct a new natural gas fired combined cycle electric generating plant, La Paloma Energy Center (LPEC), to be located near Harlingen, Cameron County, Texas. The LPEC will consist of two natural gas fired combustion turbines, each exhausting to a heat recovery steam generator (HRSG) to produce steam to drive a shared steam turbine. After reviewing the application, EPA Region 6 has prepared the following SOB and draft air permit to authorize construction of air emission sources at the La Paloma Energy Center.

This SOB documents the information and analysis EPA used to support the decisions EPA made in drafting the air permit. It includes a description of the proposed facility, the applicable air permit requirements, and an analysis showing how the applicant complied with the requirements.

EPA Region 6 concludes that La Paloma’s application is complete and provides the necessary information to demonstrate that the proposed project meets the applicable air permit regulations. EPA's conclusions rely upon information provided in the permit application, supplemental information requested by EPA and provided by La Paloma, and EPA's own technical analysis. EPA is making all this information available as part of the public record.

II. Applicant

La Paloma Energy Center, LLC
4011 West Plano Parkway
Suite 128
Plano, TX 75093

Facility Physical Address:
24684 FM 1595
Harlingen, TX 78550

Contact:
Kathleen Smith
President
La Paloma Energy Center, LLC
(281) 253-4385

III. Permitting Authority

On May 3, 2011, EPA published a federal implementation plan (FIP) that makes EPA Region 6 the PSD permitting authority for the pollutant GHGs. See 75 FR 25178 (promulgating 40 CFR § 52.2305).

The GHG PSD Permitting Authority for the State of Texas is:

EPA, Region 6
1445 Ross Avenue
Dallas, TX 75202

The EPA, Region 6 Permit Writer is:
Aimee Wilson
Air Permitting Section (6PD-R)
(214) 665-7596

The Non-GHG PSD Permitting Authority for the State of Texas is:

Air Permits Division (MC-163)
TCEQ
P.O. Box 13087
Austin, TX 78711-3087

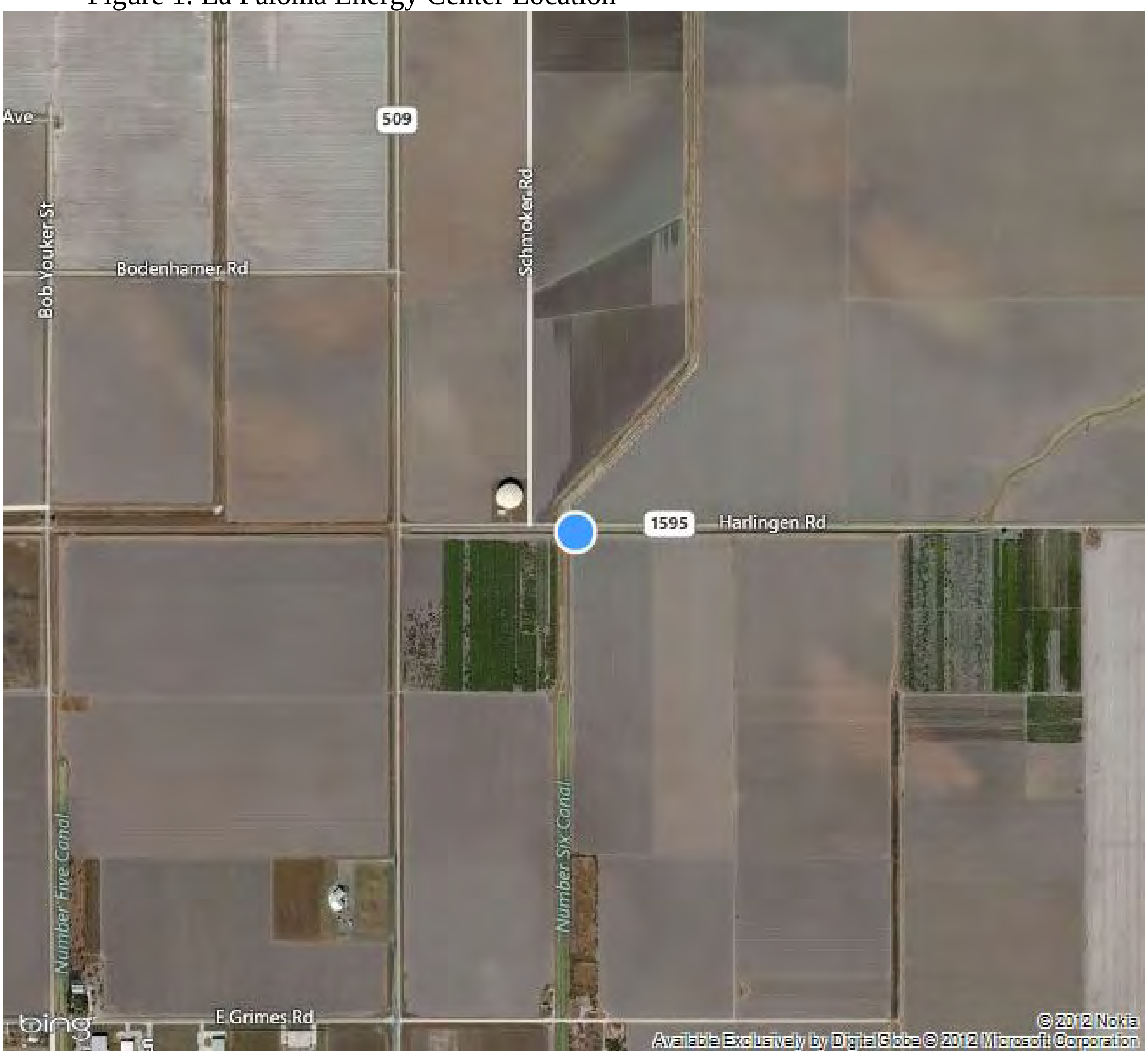
IV. Facility Location

The La Paloma Energy Center (LPEC) will be located in Cameron County, Texas, and this area is currently designated "attainment" for all criteria pollutants. The nearest Class 1 area is the Big Bend National Park, which is located well over 100 miles from the site. The geographic coordinates for this proposed facility site are as follows:

Latitude: 26º 12' 58.9" North
Longitude: -97º 37'41.02" West

Below, Figure 1 illustrates the proposed facility location for this draft permit.

Figure 1. La Paloma Energy Center Location



V. Applicability of Prevention of Significant Deterioration (PSD) Regulations

EPA Region 6 implements a GHG PSD FIP for the State of Texas under the provisions of 40 CFR 52.21 (except paragraph (a)(1)). See 40 CFR § 52.2305. For the proposed construction project, La Paloma estimates potential GHG emissions of 3,292,862 tons per year (tpy) of CO_2e. Since the proposed project's GHG emissions would make LPEC a major stationary source for pursuant to 40 CFR 52.21(b)(1)(i) and (b)(49)(iv), EPA concludes that La Paloma's application is subject to PSD review for GHG.

La Paloma represents that TCEQ, the permitting authority for regulated NSR pollutants other than GHGs, will determine that LPEC is also subject to PSD review for VOC, NOx, CO, PM, PM_{10}, $PM_{2.5}$, and H_2SO_4. Accordingly, under the circumstances of this project, the TCEQ will issue the non-GHG portion of the permit and EPA will issue the GHG portion.[1]

EPA Region 6 applies the policies and practices reflected in EPA's *PSD and Title V Permitting Guidance for Greenhouse Gases* (March 2011). Consistent with that guidance, we have not required the applicant to model or conduct ambient monitoring for GHGs, nor have we required any assessment of impacts of GHGs in the context of the additional impacts analysis or Class I area provisions. Instead, EPA has determined that compliance with the BACT analysis is the best technique that can be employed at present to satisfy the additional impacts analysis and Class I area requirements of the rules related to GHGs. We note again, however, that the project has regulated NSR pollutants that are non-GHG pollutants, which are addressed by the PSD permit to be issued by TCEQ.

VI. Project Description

The proposed GHG PSD permit, if finalized, would authorize La Paloma Energy Center to construct a new combined cycle electric generating plant (LPEC) in Cameron County, Texas. LPEC will generate 637 - 735 megawatts (MW) of gross electrical power near the City of Harlingen. The gross electrical power output is based on two turbines rated between 183 and 232 MW each and the steam from the HRSGs driving a third electric generator with an electricity output capacity of 271 MW. The LPEC will consist of the following sources of GHG emissions:

- Two natural gas-fired combustion turbines equipped with lean pre-mix low-NOx combustors;
- Two natural gas-fired duct burner system equipped Heat Recovery Steam Generators (HRSG);
- Natural gas piping and metering;

[1] *See* EPA, Question and Answer Document: Issuing Permits for Sources with Dual PSD Permitting Authorities, April 19, 2011, http://www.epa.gov/nsr/ghgdocs/ghgissuedualpermitting.pdf

- One diesel fuel-fired emergency electrical generator engine;
- One diesel fuel-fired fire water pump engine;
- One natural gas-fired auxiliary boiler; and
- Electrical equipment insulated with sulfur hexafluoride (SF_6).

Combustion Turbine Generator

The plant will consist of two identical natural gas-fired combustion turbines (CTGs). There are three models being considered by LPEC: the General Electric 7FA, the Siemens SGT6-5000F(4), and the Siemens SGT6-5000F(5). The final selection of the combustion turbine model to be used at the plant will likely be made after the permit is issued. Each combustion turbine will exhaust to a heat recovery steam generator (HRSG). As explained below, the final permit will include BACT limits and related conditions specific to each of the possible turbine models. If a final selection of combustion turbine is made after the public notice begins, and before the issuance of the final permit, EPA will issue a final permit including only the limits for the selected turbine.

The combustion turbine will burn pipeline natural gas to rotate an electrical generator to generate electricity. The main components of a combustion turbine generator consist of a compressor, combustor, turbine, and generator. The compressor pressurizes combustion air to the combustor where the fuel is mixed with the combustion air and burned. Hot exhaust gases then enter the turbine where the gases expand across the turbine blades, driving a shaft to power an electric generator. The exhaust gas will exit the combustion turbine and be routed to the HRSG for steam production.

Heat Recovery Steam Generator with Duct Burners

Heat recovered in the HRSG will be utilized to produce steam. Steam generated within the HRSG will be utilized to drive a steam turbine and associated electrical generator. The HRSG will be equipped with duct burners for supplemental steam production. The duct burners will be fired with pipeline quality natural gas. The duct burners have a maximum heat input capacity of 750 MMBtu/hr per unit. The exhaust gases from the unit, including emissions from the CT and the duct burners, will exit through a stack to the atmosphere.

The normal duct burner operation will vary from 0 to 100 percent of the maximum capacity. Duct burners will be located in the HRSG prior to the selective catalytic reduction (SCR) system.

Generators Overall

Steam produced by each of the two HRSGs will be routed to the steam turbine. The two combustion turbines and one steam turbine will be coupled to electric generators to produce electricity for sale to the Electric Reliability Council of Texas (ERCOT) power grid. Each combustion turbine model has an approximate maximum base-load electric power output as follows: GE 7FA output of 183 MW, the Siemens SGT6-5000F(4) output of 205 MW, and the Siemens SGT6-5000F(5) output of 232 MW. The maximum electric power output from the steam turbine is approximately 271 MW for both the GE and Siemens configurations. The units may operate at reduced load to respond to changes in system power requirements and/or stability.

Auxiliary Boiler

One auxiliary boiler will be available to facilitate startup of the combined cycle turbine units. The auxiliary boiler will have a maximum heat input of 150 MMBtu/hr and will burn pipeline natural gas. The auxiliary boiler is proposed to be permitted to operate up to 876 hours per year.

Emergency Equipment

The site will be equipped with one nominally rated 1,072-hp diesel-fired emergency generator to provide electricity to the facility in case of power failure. A nominally rated 500-hp diesel-fired pump will be installed at the site to provide water in the event of a fire. Each emergency engine will be limited to 100 hours of operation per year for purposes of maintenance checks and readiness testing.

Electrical Equipment Insulated with Sulfur Hexafluoride (SF_6)

The generator circuit breakers associated with the proposed units will be insulated with SF_6. SF_6 is a colorless, odorless, non-flammable, and non-toxic synthetic gas. It is a fluorinated compound that has an extremely stable molecular structure. The unique chemical properties of SF_6 make it an efficient electrical insulator. The gas is used for electrical insulation, arc quenching, and current interruption in high-voltage electrical equipment. SF_6 is only used in sealed and safe systems which under normal circumstances do not leak gas. The capacity of the circuit breakers associated with the proposed plant is currently estimated to be 400 lbs of SF_6. The proposed circuit breaker at the generator output will have a low pressure alarm and a low pressure lockout. The alarm will alert personnel of any leakage in the system and the lockout prevents any operation of the breaker due to lack of “quenching and cooling” of SF_6 gas.

VII. General Format of the BACT Analysis

The BACT analyses for this draft permit were conducted in accordance with EPA’s *PSD and Title V Permitting Guidance for Greenhouse Gases* (March 2011), which outlines the steps for conducting a “top-down” BACT analysis. Those steps are listed below.

(1) Identify all available control options;
(2) Eliminate technically infeasible control options;
(3) Rank remaining control options;
(4) Evaluate the most effective controls (taking into account the energy, environmental, and economic impacts) and document the results; and
(5) Select BACT.

VIII. Applicable Emission Units for BACT Analysis

The majority of the GHGs associated with the project are from emissions at combustion sources (i.e., combined cycle combustion turbines, auxiliary boiler, emergency engine, and fire water pump). The project will have fugitive emissions from piping components which will account for 423 TPY of CO_2e, or less than 0.01% of the project's total CO_2e emissions. Stationary combustion sources primarily emit CO_2, and small amounts of N_2O and CH_4. The following equipment is included in this proposed GHG PSD permit:

- Combined Cycle Combustion Turbines (U1-STK and U2-STK)
- Auxiliary Boiler (AUXBLR)
- Emergency Generator (EMGEN1-STK)
- Fire Water Pump (FWP1-STK)
- Natural Gas Fugitives (NG-FUG)
- SF_6 Insulated Equipment (SF6-FUG)
- Gaseous Fuel Venting (TRB-MSS)

IX. Combined Cycle Combustion Turbines (U1-STK and U2-STK)

There will be two new natural gas fired combined cycle combustion turbines (U1-STK and U2-STK) used for power generation. La Paloma is evaluating three combustion turbines for this project: General Electric 7FA, Siemens SGT6-5000F(4), and Siemens SGT6-5000F(5). The BACT analysis for the turbines considered two types of GHG emission reduction alternatives: (1) energy efficiency processes, practices, and designs for the turbines and other facility components; and (2) carbon capture and storage/sequestration (CCS). The proposed energy efficiency processes, practices, and designs discussed in Step 1 will be the same for the three models being considered. The proposed BACT limits listed in Step 5 section are specific to each turbine model.

As part of the PSD review, La Paloma provided in the GHG permit application a 5-step top-down BACT analysis for the combustion turbines. EPA has reviewed La Paloma's BACT analysis for the combustion turbines, which is part of the record for this permit (including this

Statement of Basis), and we also provide our own analysis in setting forth BACT for this proposed permit, as summarized below.

Step 1 – Identify All Available Control Options

(1) **Energy Efficiency Processes, Practices, and Design**

Combustion Turbine:

- *Combustion Turbine Design* – The most efficient way to generate electricity from a natural gas fuel source is the use of a combined cycle combustion turbine. Furthermore, the three turbine models under consideration for the LPEC facility are highly efficient turbines, in terms of their heat rate (expressed as number of BTUs of heat energy required to produce a kilowatt-hour of electricity), which is a measure that reflects how efficiently a generator uses heat energy.
- *Periodic Burner Tuning* – Periodic combustion inspections involving tuning of the combustors to restore highly efficient low-emission operation.
- *Reduction in Heat Loss* – Insulation blankets are applied to the combustion turbine casing. These blankets minimize the heat loss through the combustion turbine shell and help improve the overall efficiency of the machine.
- *Instrumentation and Controls*– The control system is a digital type supplied with the combustion turbine. The control system monitors the operation of the unit and modulates the fuel flow and turbine operation to achieve optimal high-efficiency low-emission performance for full load and part-load conditions.

Heat Recovery Steam Generator:

- *Heat Exchanger Design Considerations* – The HRSG's are designed with multiple pressure levels. Each pressure level incorporates an economizer section(s), evaporator section, and superheater section(s). These heat transfer sections are made up of many thin-walled tubes to provide surface area to maximize the transfer of heat to the working fluid.
- *Insulation* – Insulation minimizes heat loss to the surrounding air thereby improving the overall efficiency of the HRSG. Insulation is applied to the HRSG panels that make up the shell of the unit, to the high-temperature steam and water lines, and typically to the bottom portion of the stack.
- *Minimizing Fouling of Heat Exchange Surfaces* – Filtration of the inlet air to the combustion turbine is performed to minimize fouling. Additionally, cleaning of the tubes is performed during periodic outages. By reducing the fouling, the efficiency of the unit is maintained.
- *Minimizing Vented Steam and Repair of Steam Leaks* – Steam is vented from the system from deaerator vents, blowdown tank vents, and vacuum pumps/steam jet air ejectors. These

vents are necessary to improve the overall heat transfer within the HRSG and condenser by removing solids and air that potentially blankets the heat transfer surfaces lowering the equipment's performance. Steam leaks are repaired as soon as possible to maintain facility performance.

Steam Turbine:

- *Use of Reheat Cycles* – Reheat cycles are employed to minimize the moisture content of the exhaust steam. This cycle reheats partially expanded steam from the steam turbine.
- *Use of Exhaust Steam Condenser* – The exhaust steam is saturated under vacuum condition by the use of a condenser. The condensing steam creates a vacuum in the condenser, which increases steam turbine efficiency.
- *Efficient Blading Design and Turbine Seals* – Blade design has evolved for high-efficiency transfer of the energy in the steam to power generation. Blade materials are also important components in blade design, which allow for high-temperature and large exhaust areas to improve performance. The steam turbines have a multiple steam seal design to obtain the highest efficiency from the steam turbine.
- *Efficient Steam Turbine Generator Design* – The generator for modern steam turbines are cooled allowing for the highest efficiency of the generator, resulting in an overall high-efficiency steam turbine. The cooling method for the LPEC steam turbine will be either totally enclosed water to air cooling or hydrogen cooling.

Other Plant-wide Energy Efficiency Features

La Paloma has proposed a number of other measures that help improve overall energy efficiency of the facility (and thereby reducing GHG emissions from the emission units), including:

- *Fuel Gas Preheating* – The overall efficiency of the combustion turbine is increased with increased fuel inlet temperatures.
- *Drain Operation* – Drains are required to allow for draining the equipment for maintenance, and also allow condensate to be removed from steam piping and drains for operation. Closing the drains as soon as the appropriate steam conditions are achieved will minimize the loss of energy from the cycle.
- *Multiple Combustion Turbine/HRSG Trains* – Multiple trains allow the unit to achieve higher overall plant part-load efficiency by shutting down a train operating at less efficient part-load conditions and ramping up the remaining train to high-efficiency full-load operation.
- *Boiler Feed Pump Variable Speed Drives* – To minimize the power consumption at part-loads, the use of variable speed drives will be used improving the facility's overall efficiency.

(2) **Carbon Capture and Sequestration (CCS)**

Carbon capture and storage is a GHG control process that can be used by "facilities emitting CO_2 in large concentrations, including fossil fuel-fired power plants, and for industrial facilities with high-purity CO_2 streams (e.g., hydrogen production, ammonia production, natural gas processing, ethanol production, ethylene oxide production, cement production, and iron and steel manufacturing)."[2] CCS systems involve the use of adsorption or absorption processes to remove CO_2 from flue gas, with subsequent desorption to produce a concentrated CO_2 stream. The three main capture technologies for CCS are pre-combustion capture, post-combustion capture, and oxyfuel combustion (IPCC, 2005). Of these approaches, pre-combustion capture is applicable primarily to gasification plants, where solid fuel such as coal is converted into gaseous components by applying heat under pressure in the presence of steam and oxygen (U.S. Department of Energy, 2011). At this time, oxyfuel combustion has not yet reached a commercial stage of deployment for gas turbine applications and still requires the development of oxy-fuel combustors and other components with higher temperature tolerances (IPCC, 2005). Accordingly, pre-combustion capture and oxyfuel combustion are not considered available control options for this proposed gas turbine facility; the third approach, post-combustion capture, is applicable to gas turbines.

With respect to post-combustion capture, a number of methods may potentially be used for separating the CO_2 from the exhaust gas stream, including adsorption, physical absorption, chemical absorption, cryogenic separation, and membrane separation (Wang et al., 2011). Many of these methods are either still in development or are not suitable for treating power plant flue gas due to the characteristics of the exhaust stream (Wang, 2011; IPCC, 2005). Of the potentially applicable technologies, post-combustion capture with an amine solvent such as monoethanolamine (MEA) is currently the preferred option because it is the most mature and well-documented technology (Kvamsdal et al., 2011), and because it offers high capture efficiency, high selectivity, and the lowest energy use compared to the other existing processes (IPCC, 2005). Post-combustion capture using MEA is also the only process known to have been previously demonstrated in practice on gas turbines (Reddy, Scherffius, Freguia, & Roberts, 2003). As such, post-combustion capture is the sole carbon capture technology considered in this BACT analysis.

In a typical MEA absorption process, the flue gas is cooled before it is contacted counter-currently with the lean solvent in a reactor vessel. The scrubbed flue gas is cleaned of solvent and vented to the atmosphere while the rich solvent is sent to a separate stripper where it is regenerated at elevated temperatures and then returned to the absorber for re-use. Fluor's

[2]U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards, *PSD and Title V Permitting Guidance for Greenhouse Gases*, March 2011, <http:/www.epa.gov/nsr/ghgdocs/ghgpermittingguidance.pdf> (March 2011)

Econamine FG Plus process operates in this manner, and it uses an MEA-based solvent that has been specially designed to recover CO_2 from oxygen-containing streams with low CO_2 concentrations typical of gas turbine exhaust (Fluor, 2009). This process has been used successfully to capture 365 tons per day of CO_2 from the exhaust of a natural gas combined-cycle plant owned by Florida Power and Light in Bellingham, Massachusetts. The CO_2 capture plant was maintained in continuous operation from 1991 to 2005 (Reddy, Scherffius, Freguia, & Roberts, 2003). As this technology is commercially available and has been demonstrated in practice on a combined-cycle plant, EPA generally considers it to be technically feasible for natural gas combined cycle turbines.

Once CO_2 is captured from the flue gas, the captured CO_2 is compressed to 100 atmospheres (atm) or higher for ease of transport (usually by pipeline). The CO_2 would then be transported to an appropriate location for underground injection into a suitable geological storage reservoir, such as a deep saline aquifer or depleted coal seam, or used in crude oil production for enhanced oil recovery (EOR). There is a large body of ongoing research and field studies focused on developing better understanding of the science and technologies for CO_2 storage.[3]

Step 2 – Elimination of Technically Infeasible Alternatives

All options identified in Step 1 are considered technically feasible for this project.[4]

Step 3 – Ranking of Remaining Technologies Based on Effectiveness

Since all of the energy efficiency processes, practices, and designs discussed in Step 1, are proposed for this project, we will rank CCS and the suite of energy efficiency measures in BACT Step 4.

Step 4 – Evaluation of Control Options in Order of Most Effective to Least Effective, with Consideration of Economic, Energy, and Environmental Impacts

Carbon Capture and Storage

La Paloma developed a cost analysis for CCS. The estimated total annual cost of CCS would be $271,000,000 per year. The estimated plant construction cost with CCS is approximately $974,000,000. EPA Region 6 reviewed La Paloma's CCS cost estimate and believes it

[3] U.S. Department of Energy, Office of Fossil Energy, National Energy Technology Laboratory *Carbon Sequestration Program: Technology Program Plan*, <http://www.netl.doe.gov/technologies/carbon_seq/refshelf/2011_Sequestration_Program_Plan.pdf>, February 2011

[4] Based on the information provided by La Paloma and reviewed by EPA for this BACT analysis, while there are some portions of CCS that may be technically infeasible for this project, EPA has determined that overall Carbon Capture and Storage (CCS) technology is technologically feasible at this source.

adequately approximates the cost of a CCS control for this project and demonstrates those costs are high in relation to the overall cost of the proposed project without CCS, which is estimated at $443,800,000.

Furthermore, the recovery and purification of CO_2 from the stack gases would necessitate significant additional processing, including energy, and environmental/air quality penalties, to achieve the necessary CO_2 concentration for effective sequestration. The additional process equipment required to separate, cool, and compress the CO_2, would require a significant additional water and power expenditure. This equipment would include amine scrubber vessels, CO_2 strippers, amine transfer pumps, flue gas fans, an amine storage tank, and CO_2 gas compressors. The LPEC will utilize the effluent discharge from the local waste water treatment facility to provide both the cooling water and the boiler make-up water requirements. The local waste treatment facility currently processes and discharges a daily average of seven million gallons of effluent. This volume of effluent cannot support the daily water requirements of an F-class natural gas fired combined cycle facility if equipped with CCS. The water use for a combined cycle plant with CCS would be 7.6 - 9.5 million gallons per day. The additional GHG emissions resulting from additional fuel combustion would either further increase the cost of the CCS system, if the emissions were also captured for sequestration, or reduce the net amount GHG emission reduction, making CCS even less cost effective than expected.

Therefore, since the cost of CCS would more than double the cost of the current project, and considering the adverse energy and environmental impacts of CCS, CCS has been eliminated as BACT for this project.

Energy Efficiency Measures

None of the Energy Efficiency Measures have been eliminated from the BACT review based on adverse economic, environmental, or energy impacts. As noted above, the three turbine models under consideration are some of the most efficient combined cycle turbines, based on their lower heat rate in comparison to other combustion turbine models. From a GHG perspective, these factors may make IC engines the preferred generation alternative in some situations. Furthermore, the other energy efficiency measures proposed by La Paloma make the suite of Energy Efficiency options the preferred option for BACT.

Step 5 – Selection of BACT

To date, other similar facilities with a GHG BACT limit are summarized in the table below:

Company / Location	Process Description	Control Device	BACT Emission Limit / Requirements	Year Issued	Reference
Lower Colorado River Authority (LCRA), Thomas C. Ferguson Plant Horseshoe Bay, TX	590 MW combined cycle combustion turbine and heat recovery steam generator	Energy Efficiency/ Good Design & Combustion Practices	Combustion turbine annual net heat rate limited to 7,720 Btu/kWh (HHV) GHG BACT limit of 0.459 tons CO_2/MWh (net) without duct burning. 365-day average, rolling daily for the combustion turbine unit	2011	PSD-TX-1244-GHG
Palmdale Hybrid Power Plant Project Palmdale, CA	570 MW combined cycle combustion turbine and heat recovery steam generator and 50 MW Solar-Thermal Plant	Energy Efficiency/ Good Design & Combustion Practices	Combustion turbine annual net heat rate limited to 7,319 Btu/kWh (HHV) GHG BACT limit of 0.387 tons CO_2/MWh (net)* 365-day average, rolling daily for the combustion turbine unit	2011	SE 09-01
Calpine Russell City Energy Hayward, CA	600 MW combined cycle power plant	Energy Efficiency/ Good Design & Combustion Practices	Combustion Turbine Operational limit of 2,038.6 MMBtu/kWh	2011	15487
PacifiCorp Energy - Lake Side Power Plant Vineyard, UT	629 MW (without duct burning) combined cycle turbine	Energy Efficiency/ Good Design & Combustion Practices	Combustion turbine BACT limit of 950 lb CO_2e/MWh (gross) on a 12-month rolling average basis	2011	DAQE-AN0130310010-11
Kennecott Utah Copper-Repowering South Jordan, UT	275 MW combined combustion	Energy Efficiency/ Good Design & Combustion Practices	Combustion turbine BACT limit of 1,162,552 tpy CO_2e rolling 12-month period	2011	DAQE-IN105720026-11

Company / Location	Process Description	Control Device	BACT Emission Limit / Requirements	Year Issued	Reference
Pioneer Valley Energy Center Westfield, MA	431 MW combined cycle turbine generator	Energy Efficiency/ Good Design & Combustion Practices	825 lbs CO_2e/MWh_{grid} (initial performance test) 895 lb CO_2e/MWh_{grid} on a 365-day rolling average	2012	052-042-MA15
Calpine Deer Park Energy Center Deer Park, TX	168 MW/180 MW combustion turbine generator with heat recovery steam generator	Energy Efficiency/ Good Design & Combustion Practices	0.460 tons CO_2/MWh on a 30 day rolling average without duct burning.	2012	PSD-TX-979-GHG
Calpine Channel Energy Center Pasadena, TX	168 MW/180 MW combustion turbine generator with heat recovery steam generator	Energy Efficiency/ Good Design & Combustion Practices	0.460 tons CO_2/MWh on a 30 day rolling average without duct burning.	2012	PSD-TX-955-GHG

*The Palmdale facility BACT limit is reduced due to the offset of emissions from the use of a 50 MW Solar-Thermal Plant that was part of the permitted project.

The following specific BACT practices are proposed for the turbines:

- Use of Combined Cycle Power Generation Technology
- Combustion Turbine Energy Efficiency Processes, Practices, and Design
    - Highly Efficient Turbine Design
    - Turbine Inlet Air Cooling
    - Periodic Turbine Burner Tuning
    - Reduction in Heat Loss
    - Instrumentation and Controls
- HRSG Energy Efficiency Processes, Practices, and Design
    - Efficient Heat Exchanger Design
    - Insulation of HRSG
    - Minimizing Fouling of Heat Exchange Surfaces
    - Minimizing Vented Steam and Repair of Steam Leaks
- Steam Turbine Energy Efficiency Processes, Practices, and Design
    - Use of Reheat Cycles
    - Use of Exhaust Steam Condenser
    - Efficient Blading Design
    - Efficient Generator Design

- Plant-wide Energy Efficiency Processes, Practices, and Design
    - Fuel Gas Preheating
    - Drain Operation
    - Multiple Combustion Turbine/HRSG Trains
    - Boiler Feed Pump Fluid Drive Design

BACT Limits and Compliance:

To determine the appropriate heat-input efficiency limit, LPEC started with the turbine's design base load net heat rate for combined cycle operation and then calculated a compliance margin based upon reasonable degradation factors that may foreseeably reduce efficiency under real-world conditions. The design base load net heat rates for the combustion turbines being considered for this project are as follows:

- General Electric 7FA
    - 6674 Btu/kWhr (HHV) without duct burner firing
    - 7051 Btu/kWhr (HHV) with duct burner firing
- Siemens SGT6-5000F(4)
    - 6782 Btu/kWhr (HHV) without duct burner firing
    - 7045 Btu/kWhr (HHV) with duct burner firing
- Siemens SGT6-5000F(5)
    - 6891 Btu/kWhr (HHV) without duct burner firing
    - 7204 Btu/kWhr (HHV) with duct burner firing

These rates reflect the facility's "net" power production, meaning the amount of power provided to the grid; it does not reflect the total amount of energy produced by the plant, which also includes auxiliary load consumed by operation of the plant. To be consistent with other recent GHG BACT determinations, the net heat rate without duct burner firing is used to calculate the heat-input efficiency limit.

To determine an appropriate heat rate limit for the permit, the following compliance margins are added to the base heat rate limit:

- A 3.3% design margin reflecting the possibility that the constructed facility will not be able to achieve the design heat rate.
- A 6% performance margin reflecting efficiency losses due to equipment degradation prior to maintenance overhauls.
- A 3% degradation margin reflecting the variability in operation of auxiliary plant equipment due to use over time.

Design and construction of a combined-cycle power plant involves many assumptions about anticipated performance of the many elements of the plant, which are often imprecise or not reflective of conditions once installed at the site. As a consequence, the facility also calculates an "Installed Base Heat Rate," which represents a design margin of 3.3% to address such items as equipment underperformance and short-term degradation.

To establish an enforceable BACT condition that can be achieved over the life of the facility, the permit limit must also account for anticipated degradation of the equipment over time between regular maintenance cycles. The manufacturer's degradation curves project anticipated degradation rates of 5% within the first 48,000 hours of the gas turbine's useful life; they do not reflect any potential increase in this rate which might be expected after the first major overhaul and/or as the equipment approaches the end of its useful life. Further, the projected 5% degradation rate represents the average, and not the maximum or guaranteed, rate of degradation for the gas turbines. Therefore, LPEC proposes that, for purposes of deriving an enforceable BACT limitation on the proposed facility's heat rate, gas turbine degradation may reasonably be estimated at 6% of the facility's heat rate. This degradation rate is comparable to the rates estimated by other natural gas fired power plants that have received a GHG PSD permit.

Finally, in addition to the heat rate degradation from normal wear and tear on the combustion turbines, LPEC is also providing a reasonable compliance margin based on potential degradation in other elements of the combined cycle plant that would cause the overall plant heat rate to rise (i.e., cause efficiency to fall). Degradation in the performance of the heat recovery steam generator, steam turbine, heat transfer, cooling tower, and ancillary equipment such as pumps and motors is also expected to occur over the course of a major maintenance cycle.

The following BACT limits are proposed:

Turbine Model	Gross Heat Rate, with duct burner firing (Btu/kWh) (HHV)	Output Based Emission Limit (lb CO_2/MWh) gross with duct burning
General Electric 7FA	7,861.8	934.5
Siemens SGT6-5000F(4)	7,649.0	909.2
Siemens SGT6-5000F(5)	7,679.0	912.7

The calculation of the gross heat rate and the equivalent lb CO_2/MWh is provided in Tables 5-1, 5-2, and 5-3 of the application. There is a 2.6% variation from the lowest proposed BACT limit to the highest proposed BACT limit. The BACT limit will not apply during startup conditions, shutdown, or during periods of maintenance (MSS will account for no more than 500 hours of operation a year). The turbines will comply with the BACT limit during all operational conditions, with and without duct burner firing. While energy efficiency will be a consideration for final selection of a turbine, other considerations will include the capacity of the turbine, cost, reliability, and predicted longevity of the turbines. Since the plant heat rate varies according to turbine operating load and amount of duct burner firing, LPEC proposes to demonstrate compliance with the proposed heat rate with an annual compliance test, at 100% load, corrected to ISO conditions.

LPEC requested the BACT limit to be expressed in lbs CO_2/MWh. When converting the BACT limits to tons CO_2/MWh gives a range of 0.455 tons CO_2/MWh to 0.467 tons CO_2/MWh with duct burning. When compared to other BACT limits established for other combined cycle/heat recovery steam generating units, the proposed limits for LPEC are comparable to the limits established for LCRA, Calpine Deer Park, Calpine Channel Energy Center, Pioneer Valley Energy Center, and PacifiCorp Energy Lake Side Power Plant. The differences in BACT between La Paloma and LCRA and Cricket Valley Energy Center (CVEC) are related to the net heat rate for the turbines. The net heat rate of the turbines proposed by LPEC are higher than those at LCRA and CVEC. The BACT limit proposed for LPEC is higher than the limit proposed for Pioneer Valley Energy Center (PVEC). PVEC is more likely to operate at base load conditions, whereas LPEC will operate as a load cycling unit. The BACT for LPEC (without duct burner firing is 0.437 to 0.443 tons CO_2e/MWh) is less than that established for both Calpine facilities (0.46 tons CO_2e/MWh).

On March 27, 2012, the EPA proposed New Source Performance Standard (NSPS), 40 CFR Part 60 Subpart TTTT, that would control CO_2 emissions from new electric generating units (EGUs).[5] The proposed rule would apply to fossil-fuel fired EGUs that generate electricity for sale and are larger than 25 MW. The EPA proposed that new EGUs meet an annual average output based standard of 1,000 lb CO_2/MWh, on a gross basis. The proposed emission rate for the LPEC turbines on a gross electrical output basis ranges from 909.2 to 934.5 lb/MWh with maximum duct burner firing. The proposed CO_2 emission rates from the LPEC combined cycle turbines are well within the emission limit proposed in the NSPS at 40 CFR §60 Subpart TTTT.

LPEC shall meet the BACT limit, for the chosen combustion turbine, on a 12-month rolling average.

For all combustion turbines considered, the combined cycle combustion turbine unit will be designed with a number of features to improve the overall efficiency. The additional combustion turbine design features include:

- Inlet evaporative cooling to utilize water to cool the inlet air and thereby increasing the turbine’s efficiency;
- Periodic burner tuning as part of a regularly scheduled maintenance program to help ensure a more reliable operation of the unit and maintain optimal efficiency;

[5] Standards of Performance for Greenhouse Gas Emissions for New Stationary Sources: Electric Utility Generating Units, 77 Fed Reg 22392, April 13, 2012. Available at http://www.epa.gov/ttn/atw/nsps/electric/fr13ap12.pdf

- A Distributed Control System (DCS) will control all aspects of the turbine's operation, including fuel feed and burner operations, to achieve optimal high-efficiency low-emission performance for full-load and partial-load conditions;
- Insulation blankets are utilized to minimize the heat loss through the combustion turbine shell and help improve the overall efficiency of the machine; and
- Totally enclosed water to air cooling or hydrogen cooling will be used to cool the generators resulting in a lower electrical loss and higher unit efficiency.

The Heat Recovery Steam Generator (HRSG) energy efficiency processes, practices and designs considered include:

- Energy efficient heat exchanger design. In this design, each pressure level incorporates an economizer section(s), evaporator section, and superheater section(s);
- Addition of insulation to the HRSG panels, high-temperature steam and water lines and to the bottom portion of the stack;
- Filtration of the inlet air to the combustion turbine and periodic cleaning of the tubes (performed at least every 18 months) is performed to minimize fouling; and
- Minimization of steam vents and repairs of steam leaks.

Within the combined-cycle power plant, several plant-wide, overall energy efficiency processes, practices and designs are included as BACT requirements because the additional operating conditions/practices help maintain the efficiency of the turbine. The requirements include:

- Fuel gas preheating. For the F-class combustion turbine based combined-cycle, the fuel gas is pre-heated to temperature of approximately 300^{o}F with high temperature water from the HRSG;
- Drain operation. Operation drains are controlled to minimize the loss of energy from the cycle but closing the drains as soon as the appropriate steam conditions are achieved;
- Multiple combustion turbine/HRSG trains. Multiple combustion turbine/HRSG trains help with part-load operation. A higher overall plant part-load efficiency is achieved by shutting down trains operating at less efficient part-load conditions and ramping up the remaining train(s) to high-efficiency full-load operation; and
- Boiler feed pump fluid drives. To minimize the power consumption at part-loads, the use of fluid drives or variable-frequency drives are used to minimize the power consumption at part-load conditions

La Paloma will demonstrate compliance with the CO_2 limit established as BACT by using fuel flow meters to monitor the quantity of fuel combusted in the electric generating unit and performing periodic scheduled fuel sampling pursuant to 40 CFR 75.10(3)(ii) and the procedures listed in 40 CFR 75, Appendix G. Results of the fuel sampling will be used to calculate a site-specific Fc factor, and that factor will be used in the equation below to calculated CO_2 mass

emissions. The proposed permit also includes an alternative compliance demonstration method in which LPEC may install, calibrate, and operate a CO_2 CEMS and volumetric stack gas flow monitoring system with an automated data acquisition and handling system for measuring and recording CO_2 emissions. To demonstrate compliance with the CO_2 BACT limit using CO_2 CEMS, the measured hourly CO_2 emissions are divided by the net hourly energy output and averaged daily.
La Paloma proposes to determine a site-specific Fc factor using the ultimate analysis and GCV in equation F-7b of 40 CFR 75, Appendix F. The site-specific Fc factor will be re-determined annually in accordance with 40 CFR 75, Appendix F, §3.3.6.

The equation for estimating CO_2 emissions as specified in 40 CFR 75.10(3)(ii) is as follows:

$$W_{CO_2} = (Fc \times H \times Uf \times MW_{CO_2})/2000$$

Where:

W_{CO2} = CO_2 emitted from combustion, tons/hour
MW_{CO2} = molecular weight of CO_2, 44.0 lbs/mole
Fc = Carbon-based Fc-Factor, 1040 scf/MMBtu for natural gas or site-specific Fc factor
H = hourly heat input in MMBtu, as calculated using the procedure in 40 CFR 75, Appendix F, §5
Uf = 1/385 scf CO_2/lb-mole at 14.7 psia and 68°F

La Paloma is subject to all applicable requirements for fuel flow monitoring and quality assurance pursuant to 40 CFR 75, Appendix D, which include:

- Fuel flow meter- meets an accuracy of 2.0%, required to be tested once each calendar quarter pursuant to 40 CFR 75, Appendix D, §2.1.5 and §2.1.6(a))
- Gross Calorific Value (GCV)- determine the GCV of pipeline natural gas at least once per calendar month pursuant to 40 CFR 75, Appendix D, §2.3.4.1

Additionally, this approach is consistent with the CO_2 reporting requirements of 40 CFR 98, Subpart D- GHG Mandatory Reporting Rule for Electricity Generation. Furthermore, La Paloma proposed CO_2 monitoring method is consistent with the recently proposed New Source Performance Standards, Subpart TTTT- Standards of Performance for Greenhouse Gas Emissions for Electric Utility Generating Units (40 CFR 60.5535(c)) which allows for electric generating units firing gaseous fuel to determine CO_2 mass emissions by monitoring fuel combusted in the affected electric generating unit and using a site specific Fc factor determined in accordance to 40 CFR 75, Appendix F.

If La Paloma chooses to install and operate the CO_2 CEMS equipped with a volumetric stack gas monitoring system, the applicant shall rely on the data from the CO_2 CEMS for compliance purposes.

The emission limits associated with CH_4 and N_2O are calculated based on emission factors provided in 40 CFR Part 98, Table C-2 and the actual heat input (HHV). Comparatively, the emissions from CO_2 contribute the most (greater than 99%) to the overall emissions from the combined cycle combustion turbines and; therefore, additional analysis is not required for CH_4 and N_2O. To calculate the CO_2e emissions, the draft permit requires calculation of the emissions based on the procedures and Global Warming Potentials (GWP) contained in the Greenhouse Gas Regulations, 40 CFR Part 98, Subpart A, Table A-1. Records of the calculations would be required to be kept to demonstrate compliance with the emission limits on a 12-month, rolling average.

An initial stack test demonstration will be required for CO_2 emissions from U1-STK and U2-STK. La Paloma also proposes to demonstrate compliance with the proposed heat rate with an annual compliance test, at 100% load, corrected to ISO conditions. An initial stack test demonstration for CH_4 and N_2O emissions are not required because the CH_4 and N_2O emission are approximately 0.01% of the total CO_2e emissions from the combustion turbines.

X. Auxiliary Boiler (AUXBLR)

One nominally rated 150 MMBtu/hr auxiliary boiler (EPN AUXBLR) will be utilized to facilitate startup of the combined cycle units. The auxiliary boiler will be limited to 876 hours of operation per year.

Step 1 – Identification of Potential Control Technologies for GHGs

- *Use of Low Carbon Fuels* – Fuels vary in the amount of carbon per Btu, which in turn affects the quantity of CO_2 emissions generated per unit of heat input. Selecting low carbon fuels is a viable method of reducing GHG emissions. Natural gas is the lowest carbon fuel available at LPEC.
- *Use of Good Operating and Maintenance Practices* – Following the manufacturer's recommended operating and maintenance procedures; maintaining good fuel mixing in the combustion zone; and maintain the proper air/fuel ratio so that sufficient oxygen is provided to provide complete combustion of fuel while at the same time preventing introduction of more air than is necessary into the boiler.
- *Energy Efficient Design* – The auxiliary boiler is designed for a thermal efficiency of approximately 80%. The energy efficient design includes insulation to retain heat within the

boiler and a computerized process control system that will optimize the fuel/air mixture and limit excess air in the boiler.

- *Low Annual Capacity* – The auxiliary boiler will be used to facilitate the startup of the two combustion turbines and the annual hours of operation will be limited to 876 hours per year.

Step 2 – Elimination of Technically Infeasible Alternatives

All options identified in Step 1 are technically feasible.

Step 3 – Ranking of Remaining Technologies Based on Effectiveness

All of the energy efficiency related processes, practices, and designs discussed in Step 1 are being proposed. Therefore, a ranking of the control technologies is not necessary.

Step 4 – Evaluation of Control Technologies in Order of Most Effective to Least Effective, with Consideration of Economic, Energy, and Environmental Impacts

As all of the energy efficiency related processes, practices, and designs discussed in Step 1 are being proposed for this project, an examination of the energy, environmental, and economic impacts of the efficiency designs is not necessary.

Step 5 – Selection of BACT

La Paloma proposes to use natural gas as a low carbon fuel; good operation and maintenance practices; energy efficient design, and low annual capacity as BACT for the auxiliary boiler. The following specific BACT practices are proposed for the heaters:

- Use of low carbon fuel (natural gas). Natural gas will be the only fuel fired in the proposed auxiliary boiler. It is the lowest carbon fuel available for use at LPEC.
- Good operation and maintenance practices will include following the manufacturer's recommended operating and maintenance procedures; maintaining good fuel mixing, and limiting the amount of excess air in the combustion chamber to maximize thermal efficiency.
- Energy efficient design will incorporate insulation to retain heat within the boiler.
- The auxiliary boiler will be limited to 876 hours of operation a year.

Use of these practices corresponds with a permit limit of 7,687 tpy CO_2e for the auxiliary boiler. Compliance will be determined by the number of hours of operation and the calculated emissions using Equation C-1 from 40 CFR Part 98 Subpart C which is based on metered fuel usage and the emission factor for natural gas.

XI. Emergency Engines (EMGEN1-STK and FWP1-STK)

The LPEC site will be equipped with one nominally rated 1,072-hp diesel-fired emergency generator to provide electricity to the facility in the case of power failure and one nominally rated 500-hp diesel-fired pump to provide water in the event of a fire.

Step 1 – Identification of Potential Control Technologies

- *Low Carbon Fuels* – Engine options includes engines powered by electricity, natural gas, or liquid fuel, such as gasoline or fuel oil.
- *Good Combustion Practices and Maintenance* – Good combustion practices include appropriate maintenance of equipment, such as periodic readiness testing, and operating within the recommended air to fuel ratio recommended by the manufacturer.
- *Low Annual Capacity Factor* – Limiting the hours of operation reduces the emissions produced. Each emergency engine will be limited to 100 hours of operation per year for purposes of maintenance checks and readiness testing.

Step 2 – Elimination of Technically Infeasible Alternatives

- *Low Carbon Fuels* – The purpose of the engines is to provide a power source during emergencies, which includes outages of the combustion turbines, natural gas supply outages, and natural disasters. Electricity and natural gas may not be available during an emergency and therefore cannot be used as an energy source for the emergency engines and are eliminated as technically infeasible for this facility. The engines must be powered by a liquid fuel that can be stored on-site in a tank and supplied to the engines on demand, such as gasoline or diesel. Gasoline fuel has a much higher volatility than diesel, and is thus less safe for use in an emergency situation, and it cannot be stored for long periods of time, which may be necessary for emergency use. Therefore, gasoline is eliminated as infeasible for these emergency engines.
- *Good Combustion Practices and Maintenance* – Is considered technically feasible
- *Low Annual Capacity Factor* – Is considered technically feasible since the engines will only be operated either for readiness testing or for actual emergencies.

Step 3 – Ranking of Remaining Technologies Based on Effectiveness

Since the remaining technically feasible processes, practices, and designs in Step 1 are being proposed for the engines, a ranking of the control technologies is not necessary.

Step 4 – Evaluation of Control Technologies in Order of Most Effective to Least Effective, with Consideration of Economic, Energy, and Environmental Impacts

Since the remaining technically feasible processes, practices, and designs in Step 1 are being proposed for the engines, an evaluation of the most effective controls is not necessary.

Step 5 – Selection of BACT

The following specific BACT practices are proposed for the diesel-fired emergency generators:

- *Good Combustion Practices and Maintenance* – Good combustion practices for compression ignition engines include appropriate maintenance of equipment, periodic testing conducted weekly, and operating within the recommended air to fuel ratio, as specified by its design.
- *Low Annual Capacity Factor* – The emergency engines will not be operated more than 100 hours per year each. They will only be operated for maintenance and readiness testing, and in actual emergency operation.

Using the BACT practices identified above results in a BACT limit of 65 tpy CO_2e for the Emergency Generator (EMGEN1-STK) and 28 tpy CO_2e for the Fire Water Pump (FWP1-STK). La Paloma will demonstrate compliance with the CO_2 emission limit using the default emission factor and default high heating value for diesel fuel from 40 CFR Part 98 Subpart C, Table C-1. The equation for estimating CO_2 emissions as specified in 40 CFR 98.33(a)(3)(iii) is as follows:

$$CO_2 = 1 \times 10^{-3} * Fuel * HHV * EF * 1.102311$$

Where:
CO_2 = Annual CO_2 mass emissions from combustion of diesel fuel (short tons)
Fuel = Mass or volume of fuel combusted per year, from company records.
HHV = Defaullt high heat value of the fuel, from Table C-1 of 40 CFR Part 98 Subpart C.
EF = Fuel specific default CO_2 emission factor, from Table C-1 of 40 CFR Part 98 Subpart C.
1×10^{-3} = Conversion of kg to metric tons.
1.102311 = Conversion of metric tons to short tons.

The emission limits associated with CH_4 and N_2O are calculated based on emission factors provided in 40 CFR Part 98, Table C-2, site specific analysis of process fuel gas, and the actual heat input (HHV).

XII. Natural Gas Fugitive Emissions (NG-FUG)

The proposed project will include natural gas piping components. These components are potential sources of methane and CO_2 emissions due to emissions from rotary shaft seals, connection interfaces, valve stems, and similar points. The additional methane and CO_2 emissions from process fugitives have been conservatively estimated to be 423 tpy as CO_2e. Fugitive emissions are negligible, and account for less than 0.01% of the project's total CO_2e emissions.

Step 1 – Identification of Potential Control Technologies for GHGs

- *Implementing a leak detection and repair (LDAR) program using a handheld analyzer;*
- *Implement alternative monitoring using a remote sensing technology such as infrared camera monitoring; and*
- *Implementing an auditory/visual/olfactory (AVO) monitoring program.*

Step 2 – Elimination of Technically Infeasible Alternatives

LDAR programs are a technically feasible option for controlling process fugitive GHG emissions.

Step 3 – Ranking of Remaining Technologies Based on Effectiveness

Instrument LDAR programs and remote sensing using an infrared camera have been determined by EPA to be equivalent methods of piping fugitive controls.[6] The most stringent LDAR program potentially applicable to this facility is TCEQ's 28LAER, which provides for 97% control credit for valves, flanges, and connectors.

As-observed audio, visual, and olfactory (AVO) observation methods are generally somewhat less effective than instrument LDAR and remote sensing, since they are not conducted at specific intervals. However, since pipeline natural gas is odorized with very small quantities of mercaptan, as-observed olfactory observation is a very effective method for identifying and correcting leaks in natural gas systems. Due to the pressure and other physical properties of plant fuel gas, as-observed audio and visual observations of potential fugitive leaks are likewise moderately effective.

[6] 73 FR 78199-78219, December 22, 2008.

Step 4 – Evaluation of Control Technologies in Order of Most Effective to Least Effective, with Consideration of Economic, Energy, and Environmental Impacts

Although instrument LDAR and/or remote sensing of piping fugitive emissions in natural gas service may be somewhat more effective than as-observed AVO methods, the incremental GHG emissions controlled by implementation of the TCEQ 28LAER LDAR program or a comparable remote sensing program is less than 0.05% of the total project's proposed CO_2e emissions. Accordingly, given the costs of implementing 28LAER or a comparable remote sensing program when not otherwise required, these methods are not economically practicable for GHG control from components in natural gas service.

Step 5 – Selection of BACT

Based on the economic impracticability of instrument monitoring and remote sensing for natural gas piping components, La Paloma proposes to incorporate as-observed AVO as BACT for the piping components in the new combined cycle power plant in natural gas service. The proposed permit contains a condition to implement AVO inspections on a daily basis.

XIII. SF_6 Insulated Electrical Equipment (SF6-FUG)

The generator circuit breakers associated with the proposed units will be insulated with SF_6. The capacity of the circuit breakers associated with the proposed plant is currently estimated to be 400 lb of SF_6.

Step 1 – Identification of Potential Control Technologies for GHGs

In comparison to older SF_6 circuit breakers, modern circuit breakers are designed as a totally enclosed-pressure system with far lower potential for SF_6 emissions. In addition, the effectiveness of leak-tight closed systems can be enhanced by equipping them with a density alarm that provides a warning when 10% of the SF_6 (by weight) has escaped. The use of an alarm identifies potential leak problems before the bulk of the SF_6 has escaped, so that it can be addressed proactively in order to prevent further release of the gas.

One alternative considered in this analysis is to substitute another non-GHG substance for SF_6 as the dielectric material in the breakers. Potential alternatives to SF_6 were addressed in the National Institute of Standards and Technology (NIST) Technical note 1425, *Gases for*

Electrical Insulation and Arc Interruption: Possible Present and Future Alternatives to Pure SF_6.[7]

Step 2 – Elimination of Technically Infeasible Alternatives

According to the report NIST Technical Note 1425, SF_6 is a superior dielectric gas for nearly all high voltage applications. It is easy to use, exhibits exceptional insulation and arc-interruption properties, and has proven its performance by many years of use and investigation. It is clearly superior in performance to the air and oil insulated equipment used prior to the development of SF_6 insulated equipment. The report concluded that although "…various gas mixtures show considerable promise for use in new equipment, particularly if the equipment is designed specifically for use with a gas mixture…it is clear that a significant amount of research must be performed for any new gas or gas mixture to be used in electrical equipment". Therefore, there are currently no technically feasible options besides the use of SF_6.

Step 3 – Ranking of Remaining Technologies Based on Effectiveness

The use of state-of-the-art SF_6 technology with leak detection to limit fugitive emissions is the highest ranked control technology that is feasible for this application.

Step 4 – Evaluation of Control Technologies in Order of Most Effective to Least Effective, with Consideration of Economic, Energy, and Environmental Impacts

Energy, environmental, or economic impacts are not addressed because the use of alternative, non-greenhouse gas substance for SF_6 as the dielectric material in the breakers is not technically feasible.

Step 5 – Selection of BACT

La Paloma concludes that using state-of-the-art enclosed-pressure SF_6 circuit breakers with leak detection as the BACT control technology option. The circuit breakers will be designed to meet the latest of the American National Standards Institute (ANSI) C37.013 standard for high voltage circuit breakers.[8] The proposed circuit breaker at the generator output will have a low pressure alarm and a low pressure lockout. This alarm will function as an early leak detector that will bring potential fugitive SF_6 emissions problems to light before a substantial portion of the SF_6 escapes. The lockout prevents any operation of the breaker due to the lack of "quenching and cooling" SF_6 gas.

[7] Christophorous, L.G., J.K. Olthoff, and D.S. Green, *Gases for Electrical Insulation and Arc Interruption: Possible Present and Future Alternatives to Pure SF_6.* NIST Technical Note 1425, Nov. 1997. Available at http://www.epa.gov/electricpower-sf6/documents/new_report_final.pdf
[8] ANSI Standard C37.013, *Standard for AC High-Voltage Generator Circuit Breakers on a Symmetrical Current*.

LPEC will monitor emissions annually in accordance with the requirements of the Mandatory Greenhouse Gas Reporting rules for Electrical Transmissions and Distribution Equipment Use.[9] Annual SF_6 emissions will be calculated according to the mass balance approach in Equation DD-1 of Subpart DD.

XIV. Gaseous Venting (TRB-MSS)

LPEC will have small amounts of GHGs emitted from gaseous fuel venting during turbine shutdown and maintenance from the fuel lines being cleared of fuel. They will also have small amounts of GHGs emitted from the repair and replacement of small equipment and fugitive components. The GHG emissions from these activities account for less than 0.0001% of the total project GHG emissions. Due to the infrequent nature of these activities and small quantity of GHG emissions, a BACT analysis is not warranted.

XV. Endangered Species Act

Pursuant to Section 7(a)(2) of the Endangered Species Act (ESA) (16 U.S.C. 1536) and its implementing regulations at 50 CFR Part 402, EPA is required to insure that any action authorized, funded, or carried out by EPA is not likely to jeopardize the continued existence of any federally-listed endangered or threatened species or result in the destruction or adverse modification of such species' designated critical habitat.

To meet the requirements of Section 7, EPA is relying on a Biological Assessment (BA) prepared by the applicant and adopted by EPA. Further, EPA designated La Paloma Energy Center, LLC ("La Paloma") and its consultant, Zephyr Environmental Corporation ("Zephyr"), as non-federal representatives for purposes of preparation of the BA.

A draft BA has identified eighteen (18) species listed as federally endangered or threatened in Cameron County, Texas:

Federally Listed Species for Cameron County by the U.S. Fish and Wildlife Service (USFWS), National Marine Fisheries Service (NMFS) and the Texas Parks and Wildlife Department (TPWD)	Scientific Name
Birds	
Piping Plover	*Charadrius melodus*
Eskimo Curlew	*Numenius borealis*
Northern Aplomado Falcon	*Falco femoralis septentrionalis*
Interior Least Tern	*Sterna antillarum athalassos*

[9] See 40 CFR Part 98 Subpart DD.

Federally Listed Species for Cameron County by the U.S. Fish and Wildlife Service (USFWS), National Marine Fisheries Service (NMFS) and the Texas Parks and Wildlife Department (TPWD)	Scientific Name
Fish	
Smalltooth Sawfish	*Pristis pectinata*
Rio Grande Silvery Minnow	*Hybognathus amarus*
Mammals	
Gulf Coast Jaguarundi	*Herpailurus yaguarondi*
Ocelot	*Leopardus pardalis*
Jaguar	*Panthera onca*
West Indian Manatee	*Trichechus manatus*
Plant	
South Texas ambrosia	*Ambrosia cheiranthifolia*
Star cactus	*Astrophytum asterias*
Texas ayenia	*Ayenia limitaris*
Reptiles	
Green Sea Turtle	*Chelonia mydas*
Kemp's Ridley Sea Turtle	*Lepidochelys kempii*
Leatherback Sea Turtle	*Dermochelys coriacea*
Loggerhead Sea Turtle	*Caretta caretta*
Atlantic Hawksbill Sea Turtle	*Eretmochelys imbricata*

Based on the information provided in the BA, EPA determines that issuance of the proposed PSD permit allowing La Paloma to construct two natural gas-fired combustion turbines will have no effect on 15 species because there are no records of occurrence, no designated critical habitat, nor potential suitable habitat for any of these species within the action area. Those fifteen species include: piping plover, Eskimo curlew, interior least tern, smalltooth sawfish, Rio Grande silvery minnow, jaguar, West Indian manatee, South Texas ambrosia, star cactus, Texas ayenia, green sea turtle, Kemp's ridley sea turtle, leatherback sea turtle, loggerhead sea turtle, and Atlantic hawksbill sea turtle.

However, based on the information provided in the BA and by the USFWS, EPA determines that the issuance of the permit may affect, but is not likely to adversely affect, the Northern Aplomado falcon, Gulf Coast jaguarundi and the ocelot. EPA and La Paloma (as EPA's designated non-federal representative) engaged in informal consultation with the USFWS's Southwest Region, Corpus Christi, Texas Ecological Services Field Office and the sub-office in Alamo, Texas. During consultation, USFWS indicated that they have recently released Northern Aplomado falcons in Cameron County, outside of the action area, and that there is potential that the falcon could forage within the action area or perch on transmission lines being constructed for this project. The USFWS also indicated that an irrigation canal located adjacent to the facility as well as other vegetated areas within the action area may provide travel or migration corridors for the ocelot or jaguarundi. USFWS provided recommendations for additional protections of all of these species, which La Paloma has committed to implement. By letter dated March 7, 2013, EPA requested USFWS's written concurrence with EPA's "may effect" determination.

Any interested party is welcome to bring particular concerns or information to our attention regarding this project's potential effect on listed species. The final draft biological assessment can be found at EPA's Region 6 Air Permits website at http://yosemite.epa.gov/r6/Apermit.nsf/AirP.

XVI. National Historic Preservation Act (NHPA)

Section 106 of the NHPA requires EPA to consider the effects of this permit action on properties on or eligible for inclusion in the National Register of Historic Places. To make this determination, EPA relied on and adopted a cultural resource report prepared by Horizon Environmental Services, Inc. ("Horizon") on behalf of Zephyr submitted on December 19, 2012.

For purposes of the NHPA review, the Area of Potential Effect (APE) was determined to be approximately 78 acres of land within and adjacent to the construction footprint of the existing facility. Horizon conducted a field survey of the property and a desktop review on the archaeological background and historical records within a 1-mile radius area of potential effect (APE) which included a review of the Texas Historical Commission's online Texas Archaeological Site Atlas (TASA) and the National Park Service's National Register of Historic Places (NRHP). Based on the results of the field survey, no archaeological resources or historic structures were found within the APE. Based on the desktop review, one archaeological site was located 0.7 miles from the APE but was not recommended to be eligible to be listed on the National Register.

EPA Region 6 determines that because no historic properties are located within the APE and that a potential for the location of archaeological resources within the construction footprint itself is low, issuance of the permit to La Paloma will not affect properties potentially eligible for listing on the National Register.

On January 10, 2013, EPA sent letters to Indian tribes identified by the Texas Historical Commission as having historical interests in Texas to inquire if any of the tribes have historical interest in the particular location of the project and to inquire whether any of the tribes wished to consult with EPA in the Section 106 process. EPA received no requests from any tribe to consult on this proposed permit. EPA will provide a copy of the report to the State Historic Preservation Officer for consultation and concurrence with its determination. Any interested party is welcome to bring particular concerns or information to our attention regarding this project's potential effect on historic properties. A copy of the report may be found at http://yosemite.epa.gov/r6/Apermit.nsf/AirP.

XVII. Environmental Justice (EJ)

Executive Order (EO) 12898 (59 FR 7629 (Feb. 16, 1994)) establishes federal executive branch policy on environmental justice. Based on this Executive Order, the EPA's Environmental Appeals Board (EAB) has held that environmental justice issues must be considered in connection with the issuance of federal Prevention of Significant Deterioration (PSD) permits issued by EPA Regional Offices [See, e.g., *In re Prairie State Generating Company*, 13 E.A.D. 1, 123 (EAB 2006); *In re Knauf Fiber Glass*, Gmbh, 8 E.A.D. 121, 174-75 (EAB 1999)]. This permitting action, if finalized, authorizes emissions of GHG, controlled by what we have determined is the Best Available Control Technology for those emissions. It does not select environmental controls for any other pollutants. Unlike the criteria pollutants for which EPA has historically issued PSD permits, there is no National Ambient Air Quality Standard (NAAQS) for GHGs. The global climate-change inducing effects of GHG emissions, according to the "Endangerment and Cause or Contribute Finding", are far-reaching and multi-dimensional (75 FR 66497). Climate change modeling and evaluations of risks and impacts are typically conducted for changes in emissions that are orders of magnitude larger than the emissions from individual projects that might be analyzed in PSD permit reviews. Quantifying the exact impacts attributable to a specific GHG source obtaining a permit in specific places and points would not be possible [PSD and Title V Permitting Guidance for GHGs at 48]. Thus, we conclude it would not be meaningful to evaluate impacts of GHG emissions on a local community in the context of a single permit. Accordingly, we have determined an environmental justice analysis is not necessary for the permitting record.

XVIII. Conclusion and Proposed Action

Based on the information supplied by La Paloma, our review of the analyses contained the TCEQ PSD Permit Application and the GHG PSD Permit Application, and our independent evaluation of the information contained in our Administrative Record, it is our determination that the proposed facility would employ BACT for GHGs under the terms contained in the draft permit. Therefore, EPA is proposing to issue La Paloma a PSD permit for GHGs for the facility, subject to the PSD permit conditions specified therein. This permit is subject to review and comments. A final decision on issuance of the permit will be made by EPA after considering comments received during the public comment period.

APPENDIX

Annual Facility Emission Limits

Three models being considered by LPEC: the General Electric 7FA, the Siemens SGT6-5000F(4), and the Siemens SGT6-5000F(5). The final selection of the combustion turbine model to be used at the plant will likely be made after the permit is issued. Accordingly, this action proposes to issue a final permit that will include BACT limits and related conditions specific to each of the possible turbine models, and EPA will require the applicant to amend the permit after it has made a final turbine selection to remove the turbine options not selected.

Annual emissions, in tons per year (TPY) on a 12-month, rolling average, shall not exceed the following if the General Electric 7FA is selected as the combustion turbine model:

Table 1A. Annual Emission Limits[1] - General Electric 7FA

FIN	EPN	Description	GHG Mass Basis		TPY CO_2e[2,3]	BACT Requirements
				TPY[2]		
U1-STK	U1-STK	Combined Cycle Combustion Turbine/Heat Recovery Steam Generator[4]	CO_2	1,261,820	1,263,055	934.5 lb CO_2/MWh (gross) with duct burning[5]. See Special Conditions III.A.1.
			CH_4	23.4		
			N_2O	2.4		
U2-STK	U2-STK	Combined Cycle Combustion Turbine/Heat Recovery Steam Generator[4]	CO_2	1,261,820	1,263,055	934.5 lb CO_2/MWh (gross) with duct burning[5]. See Special Conditions III.A.1.
			CH_4	23.4		
			N_2O	2.4		
AUXBLR	AUXBLR	Auxiliary Boiler	CO_2	7,680	7,687	Good Combustion and Operating Practices. Limit to 876 hours of operation per year. See Special Conditions III.B.
			CH_4	0.14		
			N_2O	0.01		
EMGEN1-STK	EMGEN1-STK	Emergency Generator	CO_2	64	64	Good Combustion and Operating Practices. Limit to 100 hours of operation per year. See Special Conditions III.C.
			CH_4	No Numerical Limit Established[6]		
			N_2O	No Numerical Limit Established[6]		

FIN	EPN	Description	GHG Mass Basis		TPY CO_2e[2,3]	BACT Requirements
				TPY[2]		
FWP1-STK	FWP1-STK	Fire Water Pump	CO_2	28	28	Good Combustion and Operating Practices. Limit to 100 hours of operation per year. See Special Conditions III.C.
			CH_4	No Numerical Limit Established[6]		
			N_2O	No Numerical Limit Established[6]		
TRB-MSS	TRB-MSS	Maintenance , Startup, and Shutdown	CO_2	No Numerical Limit Established[6]	2.2	Negligible emissions, EPA verified the provided analysis.
			CH_4	0.106		
NG-FUG	NG-FUG	Natural Gas Fugitives	CO_2	Not Applicable	Not Applicable	Implementation of AVO Monitoring. See Special Condition III.D.
			CH_4	Not Applicable		
SF6-FUG	SF6-FUG	SF_6 Insulated Equipment	SF_6	No Numerical Limit Established[6]	23.9	Instrumented monitoring and alarm. See Special condition III.D.
Totals[7]			**CO_2**	**2,531,413**	**CO_2e 2,534,338**	
			CH_4	**67**		
			N_2O	**4.8**		

1. Compliance with the annual emission limits (tons per year) is based on a 12 month rolling average.
2. The TPY emission limits specified in this table are not to be exceeded for this facility and include emissions from the facility during all operations and include MSS activities.
3. Global Warming Potentials (GWP): CH_4 = 21, N_2O = 310
4. The annual emissions limit for the combustion turbines is based on operating at maximum duct burner firing for 8,260 hours per year, and operating during startup, shutdown, and maintenance (MSS) for 500 hours per year.
5. The BACT limit for the combustion turbine does not apply during MSS.
6. All values indicated as “No Numerical Limit Established” are less than 0.01 TPY with appropriate rounding. The emission limit will be a design/work practice standard as specified in the permit.
7. The total emissions for CH_4 and CO_2e include the PTE for process fugitive emissions of CH_4. Total emissions are for information only and do not constitute an emission limit.

Annual emissions, in tons per year (TPY) on a 12-month, rolling average, shall not exceed the following if the Siemens SGT6-5000F(4) is selected as the combustion turbine model:

Table 1B. Annual Emission Limits[1] - Siemens SGT6-5000F(4)

FIN	EPN	Description	GHG Mass Basis		TPY CO_2e[2,3]	BACT Requirements
				TPY[2]		
U1-STK	U1-STK	Combined Cycle Combustion Turbine/Heat Recovery Steam Generator[4]	CO_2	1,415,907	1,417,263	909.2 lb CO_2/MWh (gross) with duct burning[5]. See Special Conditions III.A.1.
			CH_4	26.2		
			N_2O	2.6		
U2-STK	U2-STK	Combined Cycle Combustion Turbine/Heat Recovery Steam Generator[4]	CO_2	1,415,907	1,417,263	909. 2 lb CO_2/MWh (gross) with duct burning[5]. See Special Conditions III.A.1.
			CH_4	26.2		
			N_2O	2.6		
AUXBLR	AUXBLR	Auxiliary Boiler	CO_2	7,680	7,687	Good Combustion and Operating Practices. Limit to 876 hours of operation per year. See Special Conditions III.B.
			CH_4	0.14		
			N_2O	0.01		
EMGEN1-STK	EMGEN1-STK	Emergency Generator	CO_2	64	64	Good Combustion and Operating Practices. Limit to 100 hours of operation per year. See Special Conditions III.C.
			CH_4	No Numerical Limit Established[6]		
			N_2O	No Numerical Limit Established[6]		
FWP1-STK	FWP1-STK	Fire Water Pump	CO_2	28	28	Good Combustion and Operating Practices. Limit to 100 hours of operation per year. See Special Conditions III.C.
			CH_4	No Numerical Limit Established[6]		
			N_2O	No Numerical Limit Established[6]		
TRB-MSS	TRB-MSS	Maintenance , Startup, and Shutdown	CO_2	No Numerical Limit Established[6]	2.2	Negligible emissions, EPA verified the provided analysis.
			CH_4	0.106		

FIN	EPN	Description	GHG Mass Basis		TPY CO_2e[2,3]	BACT Requirements
				TPY[2]		
NG-FUG	NG-FUG	Natural Gas Fugitives	CO_2	Not Applicable	Not Applicable	Implementation of AVO Monitoring. See Special Condition III.D.
			CH_4	Not Applicable		
SF6-FUG	SF6-FUG	SF_6 Insulated Equipment	SF_6	No Numerical Limit Established[6]	23.9	Instrumented monitoring and alarm. See Special condition III.D.
Totals[7]			**CO_2**	**2,839,587**	**CO_2e 2,842,754**	
			CH_4	**73**		
			N_2O	**5.2**		

1. Compliance with the annual emission limits (tons per year) is based on a 12 month rolling average.
2. The TPY emission limits specified in this table are not to be exceeded for this facility and include emissions from the facility during all operations and include MSS activities.
3. Global Warming Potentials (GWP): CH_4 = 21, N_2O = 310
4. The annual emissions limit for the combustion turbines is based on operating at maximum duct burner firing for 8,260 hours per year, and operating during startup, shutdown, and maintenance (MSS) for 500 hours per year.
5. The BACT limit for the combustion turbine does not apply during MSS.
6. All values indicated as “No Numerical Limit Established” are less than 0.01 TPY with appropriate rounding. The emission limit will be a design/work practice standard as specified in the permit.
7. The total emissions for CH_4 and CO_2e include the PTE for process fugitive emissions of CH_4. Total emissions are for information only and do not constitute an emission limit.

Annual emissions, in tons per year (TPY) on a 12-month, rolling average, shall not exceed the following if the Siemens SGT6-5000F(5) is selected as the combustion turbine model:

Table 1C. Annual Emission Limits[1] - Siemens SGT6-5000F(5)

FIN	EPN	Description	GHG Mass Basis		TPY CO_2e[2,3]	BACT Requirements
				TPY[2]		
U1-STK	U1-STK	Combined Cycle Combustion Turbine/Heat Recovery Steam Generator[4]	CO_2	1,594,162	1,595,712	912.7 lb CO_2/MWh (gross) with duct burning[5]. See Special Conditions III.A.1.
			CH_4	29.5		
			N_2O	3		
U2-STK	U2-STK	Combined Cycle Combustion Turbine/Heat Recovery Steam Generator[4]	CO_2	1,594,162	1,595,712	912.7 lb CO_2/MWh (gross) with duct burning[5]. See Special Conditions III.A.1.
			CH_4	29.5		
			N_2O	3		
AUXBLR	AUXBLR	Auxiliary Boiler	CO_2	7,680	7,687	Good Combustion and Operating Practices. Limit to 876 hours of operation per year. See Special Conditions III.B.
			CH_4	0.14		
			N_2O	0.01		
EMGEN1-STK	EMGEN1-STK	Emergency Generator	CO_2	64	64	Good Combustion and Operating Practices. Limit to 100 hours of operation per year. See Special Conditions III.C.
			CH_4	No Numerical Limit Established[6]		
			N_2O	No Numerical Limit Established[6]		
FWP1-STK	FWP1-STK	Fire Water Pump	CO_2	28	28	Good Combustion and Operating Practices. Limit to 100 hours of operation per year. See Special Conditions III.C.
			CH_4	No Numerical Limit Established[6]		
			N_2O	No Numerical Limit Established[6]		

FIN	EPN	Description	GHG Mass Basis		TPY CO_2e[2,3]	BACT Requirements
				TPY[2]		
TRB-MSS	TRB-MSS	Maintenance , Startup, and Shutdown	CO_2	No Numerical Limit Established[6]	2.2	Negligible emissions, EPA verified the provided analysis.
			CH_4	0.106		
NG-FUG	NG-FUG	Natural Gas Fugitives	CO_2	Not Applicable	Not Applicable	Implementation of AVO Monitoring. See Special Condition III.D.
			CH_4	Not Applicable		
SF6-FUG	SF6-FUG	SF_6 Insulated Equipment	SF_6	No Numerical Limit Established[6]	23.9	Instrumented monitoring and alarm. See Special condition III.D.
Totals[7]			**CO_2**	**3,196,097**	**CO_2e 3,199,650**	
			CH_4	**80**		
			N_2O	**6**		

1. Compliance with the annual emission limits (tons per year) is based on a 12 month rolling average.
2. The TPY emission limits specified in this table are not to be exceeded for this facility and include emissions from the facility during all operations and include MSS activities.
3. Global Warming Potentials (GWP): CH_4 = 21, N_2O = 310
4. The annual emissions limit for the combustion turbines is based on operating at maximum duct burner firing for 8,260 hours per year, and operating during startup, shutdown, and maintenance (MSS) for 500 hours per year.
5. The BACT limit for the combustion turbine does not apply during MSS.
6. All values indicated as "No Numerical Limit Established" are less than 0.01 TPY with appropriate rounding. The emission limit will be a design/work practice standard as specified in the permit.
7. The total emissions for CH_4 and CO_2e include the PTE for process fugitive emissions of CH_4. Total emissions are for information only and do not constitute an emission limit.

EXHIBIT BB

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION 6
1445 ROSS AVENUE, SUITE 1200
DALLAS, TX 75202-2733

AUG 2 2 2012

Ms. Kathleen Smith
President
La Paloma Energy Center, LLC
4011 West Plano Parkway, Suite 128
Plano, TX 75093

Subject: Completeness Determination for the La Paloma Energy Center (LPEC) Greenhouse Gas Prevention of Significant Deterioration (PSD) Permit Application

Dear Ms. Smith:

This letter is in response to your application received by this office on April 26, 2012 for a Greenhouse Gas (GHG) Prevention of Significant Deterioration (PSD) permit. After our initial review of the application, we determined that additional information was necessary in order to continue the processing of the permit. Accordingly, we sent notification that the application was determined to be incomplete on May 29, 2012. Based on our review of your response and the supplemental information provided on July 17, 2012, and on August 6, 2012, we have determined that your application is complete pursuant to 40 CFR 124.3(c).

We are drafting a proposed determination on the issuance of a GHG PSD permit. EPA will publish a public notice of that proposed determination and allow for at a minimum a 30-day public comment period. In addition, documents important to the proposed determination such as the draft permit will be made available for review by the public during the public comment period. EPA will consider and respond to all significant comments in making the final decision on the application and keep a record of the persons commenting and the issues being raised during the public participation process. As we develop our proposed determination, it may be necessary for EPA to request additional clarifying or supporting information. If the supporting information substantially changes the original scope of the permit application, an amendment or new application may be required.

Although not required as a part of our completeness determination, the EPA may not issue a final permit without determining its action will have no effect on threatened or endangered species and their designated critical habitat or until it has completed consultation under Section 7 of the Endangered Species Act (16 USC 1536). In addition, the EPA must undergo consultation pursuant to Section 106 of the National Historic Preservation Act (16 USC 470f). To expedite these consultations, the EPA requests that permit applicants provide a Biological Assessment and a cultural resources report covering the project and action area to the EPA.

If you have any questions regarding the review of your permit application, please contact Aimee Wilson of my staff at (214) 665-7596 or wilson.aimee@epa.gov.

Sincerely yours,

for Carl E. Edlund, P.E.
Director
Multimedia Planning and
Permitting Division

cc: Mr. Mike Wilson, P.E., Director
Air Permits Division
Texas Commission on Environmental Quality

EXHIBIT CC

Declaration of Kathleen Smith
President, La Paloma Energy Center, LLC

In Support of Response from La Paloma Energy Center, LLC to the
Petition for Review of the Prevention of Significant Deterioration Permit
Issued by Region VI for La Paloma Energy Center, Harlingen, Texas

I, Kathleen Smith, declare under penalty of perjury under the laws of the United States of America that the following is true and correct to the best of my knowledge, information and belief:

1. I am the President of La Paloma Energy Center, LLC ("LPEC"), with responsibility since August, 2011for managing the development of the La Paloma power plant. Since its inception I have also been the President of Coronado Power Ventures, LLC ("Coronado") where I am responsible for managing the various power projects in which Coronado is involved. Coronado is a founding partner of LPEC.

2. I make this declaration in support of the Response referenced above. I have personal knowledge of the issues and activities referred to herein, except where stated on information and belief. If called upon to testify, I could and would testify truthfully thereto.

3. LPEC is a single purpose entity with a sole purpose of developing a gas-fired generating unit in the Electric Reliability Council of Texas ("ERCOT") market. Coronado is an independent power producer focused on domestic greenfield power development. Coronado and LPEC are not in the business of developing renewable energy.

4. Since August, 2011, LPEC has been planning and working on the development of a new natural gas-fired electric generating facility located in Harlingen, Texas. This project has been carefully sited to take advantage of nearby natural gas pipelines and easy access to electrical transmission lines.

5. A project developer such as LPEC must undertake many actions before it may commence construction of a new power plant. Only one of those activities is beginning the long process of applying to obtain a preconstruction Clean Air Act permit that allows construction to commence. Additionally, the developer must begin working on a parallel timeline on the

development of the project. Among other things, this entails hiring engineering consultants to determine potential designs for the project, evaluating what equipment may meet the project goals and business purpose, and considering availability of transmission lines and fuel sources. Securing financing for the project is contingent upon successfully obtaining all of the requisite permits. Many projects have flexibility that enables the project developer to assess the improvements and status of performance and commercial factors during the permitting process. Where the project developer has such flexibility, that developer pursues the procurement process after the permitting authority has issued the necessary permits for the project. Once the project developer knows the parameters within which the facility can be constructed and operated, the project developer can obtain guarantees from equipment vendors to ensure that the equipment selected will be able to comply with the permits. After undertaking all of these steps, the developer is finally in a position to present the project to investors and lenders to obtain financing. This entire process takes years.

6. As the project developer is moving through the lengthy and complex design and permitting process, turbine availability and technology does not stay stagnant. Vendors are continually striving to develop the most cost effective and efficient turbines to maintain a competitive position and make their particular turbine models more appealing to potential customers. Given these considerations, it is uncommon for project developers to select the actual turbine model that will be installed until they are within a few months of commencing construction – approximately 12-18 months after the permit applications have been submitted. Retaining flexibility as to when the turbine is selected is imperative so that the developer may purchase the turbine that is best suited to the project at the time of construction – meaning it meets the permit emissions limits and lowers the cost of generation because it is more fuel efficient. Forcing the project developer to lock in its selection of a given turbine before the permits are final would empower the turbine vendor to dictate the terms of the purchase agreement, including price, the delivery schedule, and emissions guarantees, such that those terms might be unacceptable to the project developer, investors, and lenders.

7. LPEC listed three turbines in the air permit application it filed with EPA Region 6: General Electric 7FA, Siemens SGT6-5000F(4), and Siemens SGT6-5000F(5). These turbines were selected by LPEC based upon not only their efficiency in reducing emissions, but also based upon LPEC's business objectives. When selecting a turbine, LPEC considers many

factors, including whether the equipment will be able to reliably meet the State's short- and long-term energy needs. At this time, there is a need for additional baseload generation in Texas; therefore, LPEC took that supply/demand imbalance into consideration when considering what turbines to include in its application. Furthermore, LPEC was aware that these three turbines had been selected for installation in other projects that have been recently proposed throughout the U.S. Overall, the three turbines listed in the permit are some of the leading turbines sold in the U.S. market: they are known for having good reliability, performance, and efficiency.

8. LPEC did not consider including solar preheat in its project because the project purpose was to construct a gas-fired electric generating unit – not to construct a renewable project or project that contained a renewable component. Furthermore, Coronado and LPEC are not in the business of developing renewable projects.

9. The project has been specifically sited to supply power to the ERCOT market. As the U.S. Department of Energy's National Renewable Energy Laboratory recognizes, this area is not well-suited to solar. *See* Ex. CC-1. Harlingen, Texas is located in the heart of the Rio Grande Valley in south Texas and is approximately 30 miles from the Gulf Coast. It experiences high humidity, as well as hurricane-force winds. The nearest high solar potential field for industrial purposes is not even located in Texas and, therefore, does not serve the ERCOT market that LPEC expressly seeks to serve. *See* Ex. CC-1. Moreover, based upon information and belief, there is not room to install solar at the chosen project location. After constructing the planned La Paloma project, there would be approximately 20 acres available for further development. Based upon information and belief, this limited space is not sufficient to support the installation of solar preheat for this project in any significant amount. Given the poor solar availability at the proposed location, based upon information and belief, any solar field that could be installed for this project would generate much less than 1% of the plant thermal energy. Furthermore, Texas does not have incentives like other markets to subsidize solar projects; therefore, adding solar preheat to this project would increase the cost of electricity produced by the project, impacting its ability to compete in the Texas market.

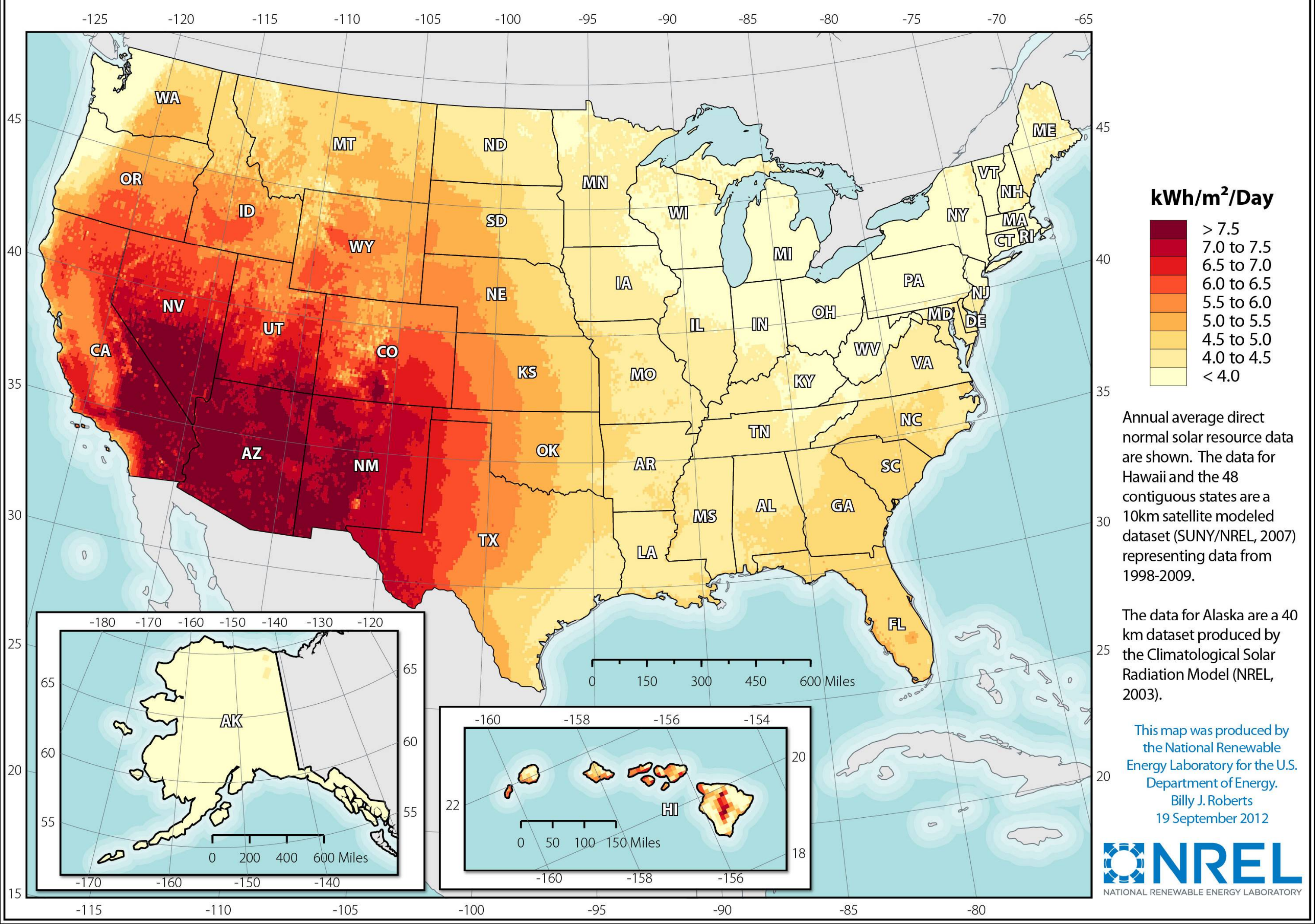
Dated: December 27, 2013

K Smith

Kathleen Smith
President, La Paloma Energy Center, LLC
115 Bella Strada Cove
Austin, TX 78734

EXHIBIT CC-1

Concentrating Solar Resource of the United States



Annual average direct normal solar resource data are shown. The data for Hawaii and the 48 contiguous states are a 10km satellite modeled dataset (SUNY/NREL, 2007) representing data from 1998-2009.

The data for Alaska are a 40 km dataset produced by the Climatological Solar Radiation Model (NREL, 2003).

This map was produced by the National Renewable Energy Laboratory for the U.S. Department of Energy.
Billy J. Roberts
19 September 2012

NREL
NATIONAL RENEWABLE ENERGY LABORATORY

EXHIBIT DD

PSD and Title V Permitting Guidance for Greenhouse Gases

EPA-457/B-11-001
March 2011

PSD and Title V Permitting Guidance for Greenhouse Gases

U.S. Environmental Protection Agency
Office of Air Quality Planning and Standards
Air Quality Policy Division
Research Triangle Park, NC

Disclaimer

This document explains the requirements of EPA regulations, describes EPA policies, and recommends procedures for permitting authorities to use to ensure that permitting decisions are consistent with applicable regulations. This document is not a rule or regulation, and the guidance it contains may not apply to a particular situation based upon the individual facts and circumstances. This guidance does not change or substitute for any law, regulation, or any other legally binding requirement and is not legally enforceable. The use of non-mandatory language such as "guidance," "recommend," "may," "should," and "can," is intended to describe EPA policies and recommendations. Mandatory terminology such as "must" and "required" are intended to describe controlling requirements under the terms of the Clean Air Act and EPA regulations, but this document does not establish legally binding requirements in and of itself.

Table of Contents

I. INTRODUCTION 1
II. PSD APPLICABILITY 6
A. CALCULATING GHG MASS-BASED AND CO_2E-BASED EMISSIONS 11
B. PSD APPLICABILITY FOR GHGS - NEW SOURCES 12
C. PSD APPLICABILITY FOR GHGS - MODIFIED SOURCES 13
1. General Requirements 13
2. Contemporaneous Netting 15
III. BACT ANALYSIS 17
A. DETERMINING THE SCOPE OF THE BACT ANALYSES 22
B. BACT STEP 1 – IDENTIFY ALL AVAILABLE CONTROL OPTIONS 24
C. BACT STEP 2 – ELIMINATE TECHNICALLY INFEASIBLE OPTIONS 33
D. BACT STEP 3 – RANKING OF CONTROLS 37
E. BACT STEP 4 – ECONOMIC, ENERGY, AND ENVIRONMENTAL IMPACTS 38
F. BACT STEP 5 – SELECTING BACT 44
IV. OTHER PSD REQUIREMENTS 47
V. TITLE V CONSIDERATIONS 50
A. GENERAL CONCEPTS AND TITLE V REQUIREMENTS 50
B. TITLE V APPLICABILITY REQUIREMENTS AND GHGS 51
C. PERMITTING REQUIREMENTS 52
D. TITLE V FEES 55
E. FLEXIBLE PERMITS 55
VI. APPENDICES 57

List of Appendices

Appendix A. GHG Applicability Flow Chart – New Sources
(January 2, 2011, through June 30, 2011)

Appendix B. GHG Applicability Flow Chart – New Sources
(On or after July 1, 2011)

Appendix C. GHG Applicability Flow Chart – Modified Sources
(January 2, 2011, through June 30, 2011)

Appendix D. GHG Applicability Flow Chart – Modified Sources
(On or after July 1, 2011)

Appendix E. Example of PSD Applicability for a Modified Source

Appendix F. BACT Example – Natural Gas Boiler

Appendix G. BACT Example – Municipal Solid Waste Landfill

Appendix H. BACT Example – Petroleum Refinery Hydrogen Plant

Appendix I. Resources for GHG Emission Estimation

Appendix J. Resources for GHG Control Measures

Appendix K. Calculating Cost Effectiveness for BACT
(Excerpt from Draft 1990 New Source Review Workshop Manual)

I. Introduction

EPA is issuing this guidance document to assist permit writers and permit applicants in addressing the prevention of significant deterioration (PSD) and title V permitting requirements[1] for greenhouse gases (GHGs) that begin to apply on January 2, 2011. This document: (1) describes, in general terms and through examples, the requirements of the PSD and title V permit regulations; (2) reiterates and emphasizes relevant past EPA guidance on the PSD and title V review processes for other regulated air pollutants;[2] and (3) provides additional recommendations and suggested methods for meeting the permitting requirements for GHGs, which are illustrated in many cases by examples. We believe this guidance is necessary to respond to inquiries from permitting authorities and other stakeholders regarding how these permitting programs will apply to greenhouse gas (GHG) emissions.

This document is organized into sections with supporting appendices. Section I describes the purpose of this document, describes the actions that led to the permitting of sources of GHGs, and provides a general background for the permitting of major stationary sources. Section II describes PSD applicability criteria and how to determine if a proposed new or modified stationary source is required to obtain a PSD permit for GHGs. Section III discusses the process that EPA recommends following to determine best available control technology (BACT) for GHGs for new sources and modified emissions units. Section IV discusses how other PSD permitting requirements are generally inapplicable or have limited relevance to GHGs. Section V describes considerations for permitting of GHGs under title V of the Clean Air Act (CAA or Act). The appendices located at the end of this document include PSD applicability flowcharts for new and modified sources of GHGs, an example PSD applicability analysis for a modified source, example BACT analyses, compilations of resources for estimating emissions of GHGs and for finding control measures for sources of GHGs, and cost effectiveness calculation methodology.

EPA initially issued this GHG permitting guidance in November 2010. This version reflects a limited number of clarifying edits to the November 2010 guidance and replaces it.

---

[1] Such requirements are reflected in provisions of the Clean Air Act, EPA rules, and approved State Implementation Plans. See 75 FR 17004 (Apr. 2, 2010).

[2] Collections of past EPA guidance on the PSD and title V review processes include:

- EPA websites listing some existing guidance documents for NSR (including PSD) (http://www.epa.gov/nsr/guidance.html) and title V (http://www.epa.gov/ttn/oarpg/t5pgm.html);
- Environmental Appeals Board (EAB) decisions on PSD permitting (http://yosemite.epa.gov/oa/EAB_Web_Docket.nsf/PSD+Permit+Appeals+(CAA)?OpenView) and title V permitting (http://yosemite.epa.gov/oa/EAB_Web_Docket.nsf/Title+V+Permit+Appeals?OpenView); and
- EPA Region 7's online searchable database of many PSD and title V guidance documents issued by EPA headquarters offices and EPA Regions (http://www.epa.gov/region07/air/policy/search.htm).

Most of the EPA documents cited in this document can be found in one of these locations. To the extent this guidance relies on a document that is not located in one of the above collections, we have attempted to provide a website link or other relevant information to help locate the document.

Relevant Background

New major stationary sources and major modifications at existing major stationary sources are required by the CAA to, among other things, obtain an air pollution permit before commencing construction. This permitting process for major stationary sources is called new source review (NSR) and is required whether the major source or major modification is planned for an area where the national ambient air quality standards (NAAQS) are exceeded (nonattainment areas) or an area where the NAAQS have not been exceeded (attainment and unclassifiable areas). In general, permits for sources in attainment areas and for other pollutants regulated under the major source program are referred to as prevention of significant deterioration (PSD) permits, while permits for major sources emitting nonattainment pollutants and located in nonattainment areas are referred to as nonattainment NSR (NNSR) permits. The entire preconstruction permitting program, including both the PSD and NNSR permitting programs, is referred to as the NSR program. Since EPA has not established a NAAQS for GHGs, the nonattainment component of the NSR program does not apply. Thus, the NSR portions of this guidance focus on the PSD requirements that apply once GHGs become a regulated NSR pollutant.

Major stationary sources and certain other sources are also required by the CAA to obtain title V operating permits. While title V permits generally do not establish new emissions limits, they consolidate requirements under the CAA, including applicable GHG requirements, into a comprehensive air permit.

Over the past year, EPA has taken several actions regarding GHGs under the CAA. The result of these EPA actions, explained in more detail below, is that certain PSD permits and certain title V permits issued on or after January 2, 2011, must address emissions of GHGs. These actions included new rules that established a common sense approach to phase in permitting requirements for GHG emissions from stationary sources, beginning with large industrial sources that are already subject to PSD and title V permitting requirements.

On December 15, 2009, EPA found that elevated atmospheric concentrations of six well-mixed GHGs, taken in combination, endanger both public health and welfare ("the endangerment finding"), and that the combined emissions of these GHGs from new motor vehicles cause and contribute to the air pollution that endangers public health and welfare ("the cause and contribute finding").[3] These findings did not themselves impose any requirements to control GHG emissions, but they were a prerequisite to finalizing GHG standards for vehicles under title II of the Act. Thereafter, on May 7, 2010, EPA issued a final rule – the Light-Duty Vehicle Rule (LDVR) – establishing national GHG emissions standards for vehicles under the CAA.[4] The new LDVR standards apply to new passenger cars, light-duty trucks, and medium-duty passenger vehicles, starting with model year 2012.

[3] 74 FR 66496 (Dec. 15, 2009).

[4] 75 FR 25324 (May 7, 2010). As part of this joint rulemaking, the Department of Transportation's National Highway Traffic Safety Administration (NHTSA) issued Corporate Average Fuel Economy (CAFE) standards for these vehicles under the Energy Policy and Conservation Act, as amended.

For stationary sources, on March 29, 2010, EPA made a final decision to continue applying (with one refinement) the Agency's existing interpretation regarding when a pollutant becomes "subject to regulation" under the Act, and thus covered under the PSD and title V permitting programs applicable to such sources. EPA published notice of this decision on April 2, 2010.[5] Under EPA's final interpretation, a pollutant becomes "subject to regulation" on the date that a requirement in the CAA or a rule adopted by EPA under the Act to actually control emissions of that pollutant "takes effect" or becomes applicable to the regulated activity (rather than upon promulgation or the legal effective date of the rule containing such a requirement). EPA's April 2, 2010 notice also explained that, based on the anticipated promulgation of the LDVR, the GHG requirements of the LDVR would take effect on January 2, 2011, if the LDVR was finalized as proposed for model year 2012 vehicles. Thus, under EPA's interpretation of the Act and applicable rules, construction permits issued[6] under the PSD program on or after January 2, 2011, must contain conditions addressing GHG emissions.

With respect to title V operating permits, the April 2, 2010 notice reiterated EPA's interpretation that the 100 tons per year (TPY) major source threshold for title V operating permits is triggered only by pollutants "subject to regulation" under the Act. EPA also explained that the Agency interprets "subject to regulation" for title V purposes in the same way it interprets that term for PSD purposes (*i.e.,* a pollutant is subject to regulation when an actual control requirement under the Act takes effect).

On June 3, 2010, EPA issued a final rule that "tailors" the applicability provisions of the PSD and title V programs to enable EPA and states to phase in permitting requirements for GHGs in a common sense manner ("Tailoring Rule").[7] The Tailoring Rule focuses on first applying the CAA permitting requirements for GHG emissions to the largest sources with the most CAA permitting experience. Under the Tailoring Rule, facilities responsible for nearly 70 percent of the national GHG emissions from stationary sources are subject to permitting requirements beginning in 2011, including the nation's largest GHG emitters (*i.e.,* power plants, refineries, and cement production facilities). Emissions from small farms, churches, restaurants,

---

[5] 75 FR 17004 (April 2, 2010).

[6] Consistent with its regulations in 40 CFR Part 124, EPA uses the term "issued" to describe the time when a permitting authority issues a PSD permit after public comment on a draft permit or preliminary determination to issue a PSD permit. Depending on the applicable administrative procedures, the date a permit is issued is not necessarily the same as the date the permit becomes effective or final agency action for purposes of judicial review. Under EPA's procedural regulations, a permit is "issued" when the Regional Office makes a final decision to grant the application, not when the permit becomes effective or final agency action. 40 CFR 124.15; 40 CFR 124.19(f). EPA generally applies the requirements in effect at the time a permit is issued by a Regional office unless the Agency has expressed an intent when adopting a new requirement that the requirement apply to permits that were issued earlier but not yet effective or final agency action by the time the new requirement takes effect. *In re: Dominion Energy Brayton Point, L.L.C.*, 12 E.A.D. 490, 616 (EAB 2006). In its actions discussing the January 2, 2011 date when GHGs will become a regulated NSR pollutant, EPA did not indicate that GHG requirements should apply to any permits issued before January 2, 2011. Thus, EPA does not intend to require PSD permits that are issued (as described in 40 CFR 124.15) prior to January 2, 2011 to address GHGs, even if the permit is not effective until after January 2, 2011 by virtue of a delayed effective date or an appeal to the Environmental Appeals Board. See, 40 CFR 124.15(b); 40 CFR 124.19(f). A similar approach may be appropriate in states with approved PSD programs that have analogous administrative procedures.

[7] 75 FR 31514 (June 3, 2010).

and small commercial facilities are examples of source types that are not likely to be covered by these programs under the Tailoring Rule. The rule then expands to cover the largest sources of GHGs that may not have been previously covered by the CAA for other pollutants.

As discussed in detail below, under the Tailoring Rule, application of PSD to GHGs will be implemented in multiple steps, which we refer to in this document as "Tailoring Rule Steps" to avoid confusion with the five steps for implementing the "top down" best available control technology (BACT) analysis and the two steps of the applicability procedures for modifications. The first Tailoring Rule step begins on January 2, 2011, and ends on June 30, 2011, and this step covers what EPA has called "anyway sources" and "anyway modifications" that would be subject to PSD "anyway" based on emissions of pollutants other than GHGs. The second step begins on July 1, 2011, and continues thereafter to cover both anyway sources and certain other large emitters of GHGs. EPA has committed to completing another rulemaking no later than July 1, 2012, to solicit comments on whether to take a third step of the implementation process to apply the permitting programs to additional sources. EPA has also committed to undertaking another rulemaking after 2012. Sources subject to the permitting programs under the first two steps will remain subject to these programs through any future steps. Future steps are not discussed further in this guidance document, since the outcomes of those rulemaking efforts are not yet known. Under the Tailoring Rule, in no event are sources with a potential to emit (PTE) less than 50,000 TPY of CO_2 equivalent (CO_2e) subject to PSD or title V permitting for GHG emissions before 2016. For additional information regarding the steps of the PSD and title V implementation processes for GHGs, please refer to the preamble of the Tailoring Rule.[8]

This guidance does not reiterate all the provisions of the Tailoring Rule or other EPA rules; rather, it takes the applicable provisions and lays them out in a way designed to explain and simplify the procedures for applicants and other stakeholders going through the PSD and title V permitting processes. Should there be any inconsistency between this document and the rules, the rules shall govern.

The fundamental aspects of the PSD and title V permitting programs are generally not affected by the integration of GHGs into these programs. Therefore, this document does not elaborate on topics such as public notice requirements, aggregation of related physical or operational changes, the definition of a stationary source, debottlenecking, treatment of fugitive emissions, determining creditable emissions reductions, or routine maintenance, repair and replacement. Readers that are interested in understanding these aspects of the federal program should rely on current EPA rules and guidance when permitting GHGs.

EPA Regional Offices should apply the policies and practices reflected in this document when issuing permits under the federal PSD and title V permitting programs, unless the facts and the record in an individual case demonstrate grounds to approach the subjects discussed in a different manner. State, local and tribal permitting authorities that issue permits under a delegation of federal authority from EPA Regional Offices should do likewise. EPA also recommends that permitting authorities with approved PSD or title V permit programs apply the guidance reflected in this document, but these permitting authorities have the discretion to apply alternative approaches that comply with state and/or local laws and the requirements of the CAA

[8] 75 FR at 31522-525.

and approved state, local or tribal programs. As is always the case, permitting authorities have the discretion to establish requirements in their permits that are more stringent than those suggested in this guidance or prescribed by EPA regulations.[9]

[9] 42 USC 7416.

II. PSD Applicability

General Concepts

Under the CAA, new major stationary sources of certain air pollutants, defined as "regulated NSR pollutants," and major modifications to existing major sources are required to, among other things, obtain a PSD permit prior to construction or major modification. We refer to the set of requirements that determine which sources and modifications are subject to PSD as the "applicability" requirements. Once major sources become subject to PSD, these sources must, in order to obtain a PSD permit, meet the various PSD requirements. For example, they must apply BACT, demonstrate compliance with air quality related values and PSD increments, address impacts on special Class I areas (*e.g.,* some national parks and wilderness areas), and assess impacts on soils, vegetation, and visibility. These PSD requirements are the subject of Sections III and IV of this document.

In this section, we discuss how the CAA and relevant EPA regulations describe the PSD applicability requirements. The CAA applies the PSD requirements to any "major emitting facility" that constructs (if the facility is new) or undertakes a modification (if the facility is an existing source).[10] The term "major emitting facility" is defined as a stationary source that emits, or has a PTE of, at least 100 TPY, if the source is in one of 28 listed source categories, or, if the source is not, then at least 250 TPY, of "any air pollutant."[11] For existing facilities, the CAA adds a definition of modification, which, in general, is any physical or operational change that "increases the amount" of any air pollutant emitted by the source.[12]

EPA's regulations implement these PSD applicability requirements through use of different terminology, and, in the case of GHGs, with additional limitations. Specifically, the regulations apply the PSD requirements to any major stationary source that begins actual construction[13] (if the source is new) or that undertakes a major modification (if the source is existing).[14] The term major stationary source is defined as a stationary source that emits, or has a PTE of, at least 100 TPY if the source is in one of 28 listed source categories, or, if the source is not, then at least 250 TPY, of regulated NSR pollutants.[15] We refer to these 100- or 250-TPY amounts as the major source limits or thresholds.

A major modification is defined as "any physical change in or change in the method of operation of a major stationary source that would result in: a significant emissions increase [ ] of a regulated NSR pollutant [ ]; and a significant net emissions increase of that pollutant from the major stationary source."[16] EPA rules specify what amount of emissions increase is "significant" for listed regulated NSR pollutants (*e.g.,* 40 TPY for sulfur dioxide, 100 TPY for carbon

[10] 42 USC 7475(a), 7479(1).
[11] 42 USC 7479(1).
[12] 42 USC 7479(1), 7411(a)(4).
[13] 40 CFR 52.21(b)(11).
[14] 40 CFR 52.21(a)(2).
[15] 40 CFR 52.21(b)(1)(i).
[16] 40 CFR 52.21(b)(2)(i) and the term "net emissions increase" as defined at 40 CFR 52.21(b)(3).

monoxide), but for any regulated NSR pollutant that is not listed in the regulations, any increase is significant.[17]

A pollutant is a "regulated NSR pollutant" if it meets at least one of four requirements, which are, in general, any pollutant for which EPA has promulgated a NAAQS or a new source performance standard (NSPS), certain ozone depleting substances, and "[a]ny pollutant that otherwise is subject to regulation under the Act."[18] PSD applies on a regulated-NSR-pollutant-by-regulated-NSR-pollutant basis. The PSD requirements do not apply to regulated NSR pollutants for which the area is designated as nonattainment. Further, some modifications are exempt from PSD review (*e.g.,* routine maintenance, repair and replacement).[19]

For proposed modifications at existing major sources, PSD applies to each regulated NSR pollutant for which the proposed emissions increase resulting from the modification both is significant and results in a significant net emissions increase. This is true even if the increased pollutant is different than the pollutant for which the source is major. Thus, the regulations quoted above require a two-step applicability process for modifications. Step 1 involves determining if the modification by itself results in a significant increase. No emissions decreases are considered in Step 1.[20] If there is no significant increase in Step 1, then PSD does not apply. If there is a significant increase in Step 1, then Step 2 applies, which involves determining if the modification results in a significant net emissions increase. The Step 2 calculation includes creditable emissions increases and decreases from the modification by itself and also includes creditable emissions increases and decreases at the existing source over a "contemporaneous period." This period is defined in the federal regulations as the period that extends back 5 years prior to the date that construction commences on the modification and forward to the date that the increase from the modification occurs.

To determine PSD applicability of an existing stationary source, an owner or operator may use one of two tests to determine the emissions increase from an existing emissions unit: the actual-to-projected-actual" emissions test or the "actual-to-potential" emissions test.[21] If the emissions unit at an existing source is new, the owner or operator must use the "actual-to-potential" emissions test to calculate emissions increases. Also, the "baseline actual emissions" for existing emissions units are generally the actual emissions in TPY from the unit for any consecutive 24-month period (selected by the applicant) in the prior 10 years, or 5 years if the source is an Electric Generating Unit (EGU).[22] Assuming a source applies the actual-to-projected-actual applicability test for its modifications, it should be noted that some projects that sources undertake to improve the energy or process efficiency of their operations may not be subject to PSD review. This is because the increased efficiency of the project can translate into less raw material and/or fuel consumption for the same amount of output of product. Consequently, as long as the output from the affected unit(s) is not reasonably expected to increase, the projected actual annual emissions for all of the pollutants emitted from the process

[17] 40 CFR 52.21(b)(23)(i)-(ii).
[18] 40 CFR 52.21(b)(50).
[19] 40 CFR 52.21(b)(2)(iii).
[20] Letter from Barbara A. Finazzo, Region II, to Kathleen Antoine, HOVENZA LLC (March 30, 2010).
[21] 40 CFR 52.21(b)(41).
[22] 40 CFR 52.21(b)(48).

is likely be less than the baseline actual emissions, resulting in a no emission increase for the change in emissions of the pollutants using the actual-to-projected-actual applicability test.[23] Of course, other factors must be considered as well when calculating the projected actual annual emissions resulting from a modification (*e.g.,* whether the projected actual emissions increase could have been accommodated at the changed emissions unit(s) and is also unrelated to the particular project). These and other factors may influence whether a modification involving an energy or process efficiency improvement is subject to PSD.

Before beginning actual construction, a source may limit its PTE to avoid application of the PSD permitting program. To appropriately limit PTE, a source's permit must contain a production or operational limitation in addition to the unit-specific emissions limitation in cases where the emissions limitation does not reflect the maximum emissions of the source operating at full design capacity. Restrictions on production or operation that limit a source's PTE include limitations on quantities of raw materials consumed, fuel combusted, hours of operation, or conditions which specify that the source must install, operate, and maintain controls that reduce emissions to a specified emission rate or to a specified control efficiency. Production and operational limits must be stated as conditions that can be enforced independently of one another. For example, restrictions on fuel that relate to both type and amount of fuel combusted should state each as an independent condition in the permit. This is necessary to make the PTE restrictions enforceable as a practical matter.[24]

As an alternative applicability procedure, applicants may secure an enforceable plantwide applicability limit (PAL) in TPY at existing major stationary sources for one or more regulated NSR pollutants prior to any modification.[25] Once properly established in the source's permit, subsequent modifications to existing emissions units, or the addition of new emissions units, are not subject to PSD for the PAL pollutant if the emissions of all emissions units under the PAL remain below the PAL limit and all other PAL requirements are met.

GHG-Specific Considerations

Beginning on January 2, 2011, GHGs are a regulated NSR pollutant under the PSD major source permitting program when they are emitted by new sources or modifications in amounts that meet the Tailoring Rule's set of applicability thresholds, which phase in over time. For PSD purposes, GHGs are a single air pollutant defined[26] as the aggregate group of the following six gases:

- carbon dioxide (CO_2)
- nitrous oxide (N_2O)
- methane (CH_4)
- hydrofluorocarbons (HFCs)

---

[23] The source must be able to substantiate its projections, and if it fails to do so or if it fails to operate its unit in accordance with their projection, PSD may apply.

[24] *See, generally,* EPA Guidance on Limiting Potential to Emit (PTE) in New Source Permitting (June 13, 1989), available at http://www.epa.gov/reg3artd/permitting/t5_epa_guidance.htm.

[25] 40 CFR 52.21(a)(2)(v), (b)(2)(iv) and (aa)(1)(ii).

[26] 40 CFR 52.21(b)(49)(i).

- perfluorocarbons (PFCs)
- sulfur hexafluoride (SF_6)

Specifically, in Tailoring Rule Step 1, beginning on January 2, 2011, and continuing through June 30, 2011, GHGs that are emitted in at least specified threshold amounts from a new source that is subject to PSD anyway, due to emissions of another regulated NSR pollutant, are subject to regulation and therefore a regulated NSR pollutant from that source. By the same token, when an existing major source undertakes a physical or operational change that would be subject to PSD anyway due to emissions of another regulated NSR pollutant and increases its emissions of GHGs by at least the specified threshold amounts, the GHGs are treated as subject to regulation and therefore as a regulated NSR pollutant from that source. (We call such a modification an "anyway modification.") In Tailoring Rule Step 2, beginning on July 1, 2011, and continuing thereafter, GHGs emitted by anyway sources and anyway modifications remain a regulated NSR pollutant in the same manner as under Step 1. In addition, for new sources that are not anyway sources and for modifications that are not anyway modifications, emissions of GHGs in at least specified threshold amounts are also treated as subject to regulation and therefore as a regulated NSR pollutant.

For GHGs, the Tailoring Rule does not change the basic PSD applicability process for evaluating whether there is a new major source or modification. However, due to the nature of GHGs and their incorporation into the definition of regulated NSR pollutant, the process for determining whether a source is emitting GHGs in an amount that would make the GHGs a regulated NSR pollutant, includes a calculation of, and applicability threshold for, the source based on CO_2 equivalent (CO_2e) emissions as well as its GHG mass emissions. Consequently, when determining the applicability of PSD to GHGs, there is a two-part applicability process that evaluates both:[27]

- the sum of the CO_2e emissions in TPY of the six GHGs, in order to determine whether the source's emissions are a regulated NSR pollutant; and, if so

- the sum of the mass emissions in TPY of the six GHGs, in order to determine if there is a major source or major modification of such emissions.

This applicability process is laid out in more detail in Sections II.B through D of this guidance, as well as in flowcharts in Appendices A through D.

CO_2e emissions are defined as the sum of the mass emissions of each individual GHG adjusted for its global warming potential (GWP). Since GWP values may vary, applicants should use the GWP values in Table A-1 of the Greenhouse Gas Reporting Program (GHGRP) (40 CFR Part 98, Subpart A, Table A-1). Note that the GHGRP does not require reporting of all emissions and emission sources that may be subject to a PSD applicability analysis.

---

[27] As we explained in the Tailoring Rule preamble, while evaluation of the mass-based thresholds is technically the second step in the PSD applicability analysis, we understand that most sources are likely to treat this mass-based evaluation as an initial screen from a practical standpoint, since they would not proceed to calculate emissions on a CO_2e basis if they do not trigger PSD or title V on a mass basis. See 75 FR at 31522.

In the annual US inventory of GHG emissions and sinks, EPA has reported that the Land-Use, Land-Use Change, and Forestry (LULUCF) sector (including those stationary sources using biomass for energy) in the United States is a net carbon sink, taking into account the carbon gains (*e.g.,* terrestrial sequestration) and losses (*e.g.,* emissions or harvesting) from that sector.[28] On the basis of the inventory results and other considerations, numerous stakeholders requested that EPA exclude, either partially or wholly, emissions of GHG from bioenergy and other biogenic sources for the purposes of the BACT analysis and the PSD program based on the view that the biomass used to produce bioenergy feedstocks can also be a carbon sink and, therefore, management of that biomass can play a role in reducing GHGs.[29] EPA plans to provide further guidance on how to consider the unique GHG attributes of biomass as fuel. Specifically, the EPA Administrator recently announced that EPA will complete a rulemaking by July 1, 2011 to defer for three years PSD applicability for biomass and other biogenic CO_2 emissions. The 3-year deferral will give EPA time to examine the science associated with biogenic CO_2 emissions and to consider the technical issues that the Agency must resolve in order to account for biogenic CO_2 emissions for PSD applicability purposes.[30] EPA published the proposed deferral rule on March 21, 2011 (76 FR 15249).

Before this rule becomes final, however, permitting authorities may consider, when carrying out their BACT analyses for GHG, the environmental, energy, and economic benefits that may accrue from the use of certain types of biomass and other biogenic sources (*e.g.,* biogas from landfills) for energy generation, consistent with existing air quality standards. In particular, a variety of federal and state policies have recognized that some types of biomass can be part of a national strategy to reduce dependence on fossil fuels and to reduce emissions of GHGs. Federal and state policies, along with a number of state and regional efforts, are currently under way to foster the expansion of renewable resources and promote biomass as a way of addressing climate change and enhancing forest-management. EPA believes that it is appropriate for permitting authorities to account for both existing federal and state policies and their underlying objectives in evaluating the environmental, energy, and economic benefits of biomass fuel. Based on these considerations, permitting authorities might determine that, with respect to the biomass component of a facility's fuel stream, certain types of biomass by themselves are BACT for GHGs.

To assist permitting authorities further in considering these factors, as well as to provide a measure of national consistency and certainty, in March 2011 EPA issued guidance that provides a suggested framework for undertaking an analysis of the environmental, energy, and economic benefits of biomass in Step 4 of the top-down BACT process, that, as a result, may enable permitting authorities to simplify and streamline BACT determinations with respect to certain types of biomass used in energy generation.[31] The guidance includes qualitative information on useful issues to consider with respect to biomass combustion. While the guidance does not provide a final determination of BACT for a particular source, since such determinations can only be made by individual permitting authorities on a case-by-case basis, EPA believes the

[28] 2010 US Inventory Report at http://epa.gov/climatechange/emissions/usinventoryreport.html.
[29] GHG emissions from bioenergy and other biogenic sources are generated during combustion or decomposition of biologically-based material, and include sources such as utilization of forest or agricultural products for energy, wastewater treatment and livestock management facilities, and fermentation processes for ethanol production.
[30] Letter from Lisa P. Jackson, EPA Administrator, to Senator Max Baucus (January 12, 2011).
[31] http://www.epa.gov/nsr/ghgdocs/bioenergyguidance.pdf

analysis provided in the guidance will be sufficient in most cases, during the interim period until the biomass deferral rulemaking is finalized and incorporated into applicable implementation plans to support the conclusion that utilization of biomass fuel alone is BACT for a bioenergy facility.

A. Calculating GHG Mass-Based and CO_2e-Based Emissions

For any source, since GHG emissions may be a mixture of up to six compounds, the amount of GHG emissions calculated for the PSD applicability analysis is a sum of the compounds emitted at the emissions unit. The following example illustrates the method to calculate GHG emissions on both a mass basis and CO_2e basis.

A proposed emissions unit emits five of the six GHG compounds in the following amounts:

50,000 TPY of CO_2
60 TPY of methane
1 TPY of nitrous oxide
5 TPY of HFC-32 (a hydrofluorocarbon)
3 TPY of PFC-14 (a perfluorocarbon)

The GWP for each of the GHGs used in this example are:

GHG	GWP*
Carbon Dioxide	1
Nitrous Oxide	310
Methane	21
HFC-32	650
PFC-14	6,500

** as of the date of this document (see 40 CFR Part 98, Subpart A, Table A-1)*

The ***GHGs mass-based emissions*** of the unit are calculated as follows:

50,000 TPY + 60 TPY + 1 TPY + 5 TPY + 3TPY = 50,069 TPY of GHGs

The ***CO_2e-based emissions*** of the unit are calculated as follows:

(50,000 TPY x 1) + (60 TPY x 21) + (1 TPY x 310) + (5 TPY x 650) + (3 TPY x 6,500)

= 50,000 + 1,260 + 310 + 3,250 + 19,500 = 74,320 TPY CO_2e

Note: Short tons (2,000 lbs), not long or metric tons, are used in PSD applicability calculations.[32]

[32] Metric tonnes (*i.e.*, 1,000 kg) are used in the GHG reporting rule.

B. PSD Applicability for GHGs - New Sources

1. *Tailoring Rule Step 1 - PSD Applicability Test for GHGs in PSD Permits Issued from January 2, 2011, to June 30, 2011*

PSD applies to the GHG emissions from a proposed new source if ***both*** of the following are true:[33]

- Not considering its emissions of GHGs, the new source is considered a major source for PSD applicability and is required to obtain a PSD permit (called an "anyway source"), ***and***

- The potential emissions of GHGs from the new source would be equal to or greater than 75,000 TPY on a CO_2e basis.

2. *Tailoring Rule Step 2 - PSD Applicability Test for GHGs in PSD Permits Issued on or after July 1, 2011*

PSD applies to the GHG emissions from a proposed new source if ***either*** of the following is true:

- PSD for GHGs would be required under Tailoring Rule Step 1, ***or***

- The potential emissions of GHGs from the new source would be equal to or greater than 100,000 TPY CO_2e basis ***and*** equal to or greater than the applicable major source threshold (*i.e.,* 100 or 250 TPY, depending on the source category[34]) on a mass basis for GHGs.

In addition, as noted in the Tailoring Rule, if a minor source construction permit is issued to a source before July 1, 2011, and that permit does not contain synthetic minor limitations on GHG emissions, and the source has a PTE of GHG emissions that would trigger PSD on or after July 1, 2011, then the source must either (1) begin actual construction before July 1, 2011, or (2) seek a permit revision to include a minor source limit for the GHG emissions. If neither (1) nor (2) occurs, the source must obtain a PSD permit for GHGs.[35]

The PSD applicability criteria discussed above for new sources are summarized in Table II-A below. Flowcharts for applicability determinations for new sources in each of the two Tailoring Rule steps are presented in Appendices A and B, respectively.

---

[33] While the Tailoring Rule specified that potential emissions calculations for GHG applicability determinations would also involve a finding that potential emissions would be equal to or greater than the applicable significant emission rate on a mass basis, in the interest of clarity and simplicity, this guidance does not discuss this requirement with regard to new sources, because the lack of a netting analysis in a new source determination means that any new source that meets the 75,000 TPY CO_2e requirements would automatically exceed the applicable significant emissions rate for GHGs, which is 0 TPY on a mass basis.

[34] 42 USC 7479(1) (providing list of 100 TPY sources).

[35] 75 FR at 31527.

Table II-A. Summary of PSD Applicability Criteria for New Sources of GHGs

Permits issued from January 2, 2011, to June 30, 2011 (Step 1 of the Tailoring Rule)	Permits issued on or after July 1, 2011 (Step 2 of the Tailoring Rule)
PSD applies to GHGs, if: • The source is otherwise subject to PSD (for another regulated NSR pollutant), **and** • The source has a GHG PTE equal to or greater than: o 75,000 TPY CO_2e	**PSD applies to GHGs, if:** • The source is otherwise subject to PSD (for another regulated NSR pollutant), **and** • The source has a GHG PTE equal to or greater than: o 75,000 TPY CO_2e **OR** • Source has a GHG PTE equal to or greater than: o 100,000 TPY CO_2e, **and** o 100/250 TPY mass basis

C. PSD Applicability for GHGs - Modified Sources

1. General Requirements

a. *Tailoring Rule Step 1 - PSD Applicability Test for GHGs in PSD Permits Issued from January 2, 2011, to June 30, 2011*

PSD applies to the GHG emissions from a proposed modification to an existing major source if ***both*** of the following are true:

- Not considering its emissions of GHGs, the modification would be considered a major modification anyway and therefore would be required to obtain a PSD permit (called an "anyway modification"), ***and***

- The emissions increase ***and*** the **net** emissions increase of GHGs from the modification would be equal to or greater than 75,000 TPY on a CO_2e basis ***and*** greater than zero TPY on a mass basis.

b. *Tailoring Rule Step 2 - PSD Applicability Test for GHGs in PSD Permits Issued on or after July 1, 2011*

PSD applies to the GHG emissions from a proposed modification to an existing source if any of the following is true:

- PSD for GHGs would be required under Tailoring Rule Step 1.

OR BOTH:

- The existing source's PTE for GHGs is equal to or greater than 100,000 TPY on a CO_2e basis ***and*** is equal to or greater than 100/250 TPY (depending on the source category) on a mass basis,[36] ***and***

- The emissions increase ***and*** the **net** emissions increase of GHGs from the modification would be equal to or greater than 75,000 TPY on a CO_2e basis ***and*** greater than zero TPY on a mass basis.

OR BOTH:

- The existing source is minor[37] for PSD (including GHGs) before the modification, ***and***

- The actual or potential emissions of GHGs from the modification *alone* would be equal to or greater than 100,000 TPY on a CO_2e basis ***and*** equal to or greater than the applicable major source threshold of 100/250 TPY on a mass basis. Note that minor PSD sources cannot "net" out of PSD review.

The PSD applicability criteria for modified existing sources discussed above are summarized in Table II-B below. Flowcharts for applicability determinations for existing sources in each of the two Tailoring Rule steps are presented in Appendices C and D, respectively.

[36] The mass basis calculation for the amount of GHGs determines whether the GHGs are emitted at the major source level, so that GHGs are considered to be emitted at the major source level if they are emitted in an amount that is equals to or greater than 100/250 TPY (depending on the source category) on a mass basis. In contrast, the CO_2e basis calculation for the amount of GHGs is relevant for determining whether the GHGs are subject to regulation as a regulated NSR pollutant, but not for determining whether GHGs are emitted at the major source level.

[37] A source is considered minor for PSD if it does not emit any regulated NSR pollutants in amounts that equal or exceed 100/250 TPY (depending on the source category).

Table II-B. Summary PSD Applicability Criteria for Modified Sources of GHGs

Permits issued from January 2, 2011, to June 30, 2011 (Step 1 of the Tailoring Rule)	**Permits issued on or after July 1, 2011 (Step 2 of the Tailoring Rule)**
PSD applies to GHGs, if: • Modification is otherwise subject to PSD (for another regulated NSR pollutant), and has a GHG emissions increase and net emissions increase: o Equal to or greater than 75,000 TPY CO_2e, **and** o Greater than -0- TPY mass basis,	**PSD applies to GHGs, if:** • Modification is otherwise subject to PSD (for another regulated NSR pollutant), and has a GHG emissions increase and net emissions increase: o Equal to or greater than 75,000 TPY CO_2e, **and** o Greater than -0- TPY mass basis **OR BOTH:** • The existing source has a PTE equal to or greater than: o 100,000 TPY CO_2e **and** o 100/250 TPY mass basis • Modification has a GHG emissions increase and net emissions increase: o Equal to or greater than 75,000 TPY CO_2e, **and** o Greater than -0- TPY mass basis **OR BOTH:** • The source is an existing minor source for PSD, **and** • Modification alone has actual or potential GHG emissions equal to or greater than: o 100,000 TPY CO_2e, **and** o 100/250 TPY mass basis

2. Contemporaneous Netting

As noted above, assessing PSD applicability for a modification at an existing major stationary source against the GHG emissions thresholds is a two-step process. Step 1 of the applicability analysis considers only the emissions increases from the proposed modification itself. Step 2 of the applicability analysis, which is often referred to as "contemporaneous netting," considers all creditable emissions increases and decreases (including decreases resulting from the proposed modification) occurring at the source during the "contemporaneous period." The federal "contemporaneous period" for GHG emissions is no different than the federal contemporaneous period for other regulated NSR pollutants, which covers the period beginning 5 years before construction of the proposed modification through the date that the increase from the modification occurs.

It should be noted that both the contemporaneous period and the baseline period will, at least for a while, require reference to emissions prior to the January 2, 2011 date that PSD applies to GHG-emitting sources. That is, because the contemporaneous period includes a five-year "look back," for several years after January 2, 2011, the contemporaneous period for netting of GHG emissions includes periods before January 2, 2011. By the same token, when calculating the "baseline actual emissions" for existing units included in PSD applicability calculations, the selected 24-month time period for determining actual emissions may include time periods that begin before January 2, 2011.

Because PSD applicability for modifications at existing sources requires a two-step analysis, and because, for GHGs, each step requires a mass-based calculation and a CO_2e-based calculation, a total of four applicability conditions must be met in order for modifications involving GHG emissions at existing major sources to be subject to PSD. These four conditions are summarized below.[38]

1) The CO_2e emissions increase resulting from the modification, calculated as the sum of the six GHGs on a CO_2e basis (*i.e.,* with GWPs applied) is equal to or greater than 75,000 TPY CO_2e. No emissions decreases are considered in this calculation (*i.e.,* if the sum of the change in the six GHGs on a CO_2e basis from an emissions unit included in the modification results in a negative number, that negative sum is not included in this calculation to offset increases at other emissions units).

2) The "net emissions increase" of CO_2e over the contemporaneous period is equal to or greater than 75,000 TPY.

3) The GHG emissions increase resulting from the modification, calculated as the sum of the six GHGs on a mass basis (*i.e.,* with no GWPs applied) is greater than zero TPY. No emissions decreases are considered in this calculation (*i.e.,* if the sum of the change in the six GHGs on a mass basis from an emissions unit included in the modification results in a negative number, that negative sum is not included in this calculation to offset increases at other emissions units).

4) The "net emissions increase" of GHGs (on a mass basis) over the contemporaneous period is greater than zero TPY.

Flowcharts of the above four-part PSD applicability test for modified sources of GHGs are presented in Appendices C and D. Appendix E provides a detailed example of the application of the test to a modified existing major source.

[38] In addition, as discussed above, either the modification must be an "anyway" modification or the source must emit, prior to the modification, GHGs in the amount of 100,000 TPY CO_2e and 100/250 TPY mass basis.

III. BACT Analysis

Under the CAA and applicable regulations, a PSD permit must contain emissions limitations based on application of BACT for each regulated NSR pollutant. A determination of BACT for GHGs should be conducted in the same manner as it is done for any other PSD regulated pollutant.

The BACT requirement is set forth in section 165(a)(4) of the CAA, in federal regulations at 40 CFR 52.21(j), in rules setting forth the requirements for approval of a state implementation plan (SIP) for a State PSD program at 40 CFR 51.166(j), and in the specific SIPs of the various states at 40 CFR Part 52, Subpart A - Subpart FFF. CAA § 169(3) defines BACT as:

> an emissions limitation (including a visible emission standard) based on the maximum degree of reduction for each pollutant subject to regulation under the Clean Air Act which would be emitted from any proposed major stationary source or major modification which the Administrator, 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….

Each new source or modified emission unit subject to PSD is required to undergo a BACT review.

The CAA and corresponding implementing regulations require that a permitting authority conduct a BACT analysis on a case-by-case basis, and the permitting authority must evaluate the amount of emissions reductions that each available emissions-reducing technology or technique would achieve, as well as the energy, environmental, economic and other costs associated with each technology or technique. Based on this assessment, the permitting authority must establish a numeric emissions limitation that reflects the maximum degree of reduction achievable for each pollutant subject to BACT through the application of the selected technology or technique. However, if the permitting authority determines that technical or economic limitations on the application of a measurement methodology would make a numerical emissions standard infeasible for one or more pollutants, it may establish design, equipment, work practices or operational standards to satisfy the BACT requirement.[39]

<u>Top-Down BACT Process</u>

EPA recommends that permitting authorities continue to use the Agency's five-step "top-down" BACT process to determine BACT for GHGs.[40] In brief, the top-down process calls for

[39] 40 CFR 51.166(b)(12); 40 CFR 52.21(b)(12).
[40] The Clean Air Act Advisory Committee (CAAAC) recognized that the top-down framework is the "predominant method for determining BACT" and recommended that permitting authorities continue to use their existing BACT determinations process, such as the top-down framework, in conducting BACT analyses for GHGs. CAAAC, *Interim Phase I Report of the Climate Change Work Group of the Permits, New Source Review and Toxics*

all available control technologies for a given pollutant to be identified and ranked in descending order of control effectiveness. The permit applicant should first examine the highest-ranked ("top") option. The top-ranked options should be established as BACT unless the permit applicant demonstrates to the satisfaction of the permitting authority that technical considerations, or energy, environmental, or economic impacts justify a conclusion that the top-ranked technology is not "achievable" in that case. If the most effective control strategy is eliminated in this fashion, then the next most effective alternative should be evaluated, and so on, until an option is selected as BACT.[41]

EPA has broken down this analytical process into the following five steps, which are each discussed in detail later in this section.

Step 1: Identify all available control technologies.

Step 2: Eliminate technically infeasible options.

Step 3: Rank remaining control technologies.

Step 4: Evaluate most effective controls and document results.

Step 5: Select the BACT.

To illustrate how the analysis proceeds through these steps, assume at Step 1 that the permit applicant and permitting authority identify four control strategies that may be applicable to the particular source under review. At the second step of the process, assume that one of these four options is demonstrated to be technically infeasible for the source and is eliminated from further consideration. The remaining three pollution control options should then be ranked from the most to the least effective at the third step of the process. In the fourth step, the permit applicant and permitting authority should begin by evaluating the energy, environmental, and economic impacts of the top-ranked option. If these considerations do not justify eliminating the top-ranked option, it should be selected as BACT at the fifth step. However, if the energy, environmental, or economic impacts of the top-ranked option demonstrate that this option is not achievable, then the evaluation remains in Step 4 of the process and continues with an examination of the energy, environmental, and economic impacts of the second-ranked option. This Step 4 assessment should continue until an achievable option is identified for each source. The highest-ranked option that cannot be eliminated is selected as BACT at Step 5, which includes the development of an emissions limitation that is achievable by the particular source using the selected control strategy. Thus, the inclusion and evaluation of an option as part of a top-down BACT analysis for a particular source does not necessarily mean that option will ultimately be required as BACT for that source.

Subcommittee (Feb. 3, 2010) at 16 and 18, *available at* http://www.epa.gov/oar/caaac/climate/2010_02_InterimPhaseIReport.pdf.

[41] 1990 Workshop Manual at B.2.

EPA developed the top-down process in order to improve the application of the BACT selection criteria and provide consistency.[42] For over 20 years, EPA has applied and recommended that permitting authorities apply the top-down approach to ensure compliance with the BACT criteria in the CAA and applicable regulations. EPA Regional Offices that implement the federal PSD program (through Federal Implementation Plans (FIPs)) and state permitting authorities that implement the federal program through a delegation of federal authority from an EPA Regional Office should apply the top-down BACT process in accordance with EPA policies and interpretations articulated in this document and others that are referenced. However, EPA has not established the top-down BACT process as a binding requirement through rule.[43] Thus, permitting authorities that implement an EPA-approved PSD permitting program contained in their State Implementation Plans (SIPs) may use another process for determining BACT in permits they issue, including BACT for GHGs, so long as that process (and each BACT determination made through that process) complies with the relevant statutory and regulatory requirements.[44] EPA does not require states to apply the top-down process in order to obtain EPA approval of a PSD program, but EPA regulations do require that each state program apply the applicable criteria in the definition of BACT.[45] Furthermore, EPA has certain oversight responsibilities with respect to the issuance of PSD permits under state permitting programs. In that capacity, EPA does not seek to substitute its judgment for state permitting authorities in BACT determinations, but EPA does seek to ensure that individual BACT determinations by states with approved programs are reasoned and faithful to the requirements of the CAA and the approved state program regulations.[46]

The discussion that follows in Section III provides an overview of the top-down BACT process, with discussion of how each step may apply to the aspects that are unique to GHGs. In addition, Appendices F, G, and H to this document provide illustrative examples of the application of the top-down BACT process to emissions of GHGs. These examples provide only basic illustrations of the concepts discussed in this document. A successful BACT analysis requires a more detailed record (that is, case- and fact-specific) to justify the conclusions reached by the permitting authority than can be provided in this guidance.

The most comprehensive discussion of the five-step top-down BACT process can be found in EPA's 1990 Draft New Source Review Workshop Manual ("1990 Workshop Manual"),[47] and the method has been progressively refined through federal permitting decisions by EPA, orders on title V permitting decisions, and opinions of the EPA Environmental Appeals Board (EAB) that have adopted many of the principles from the 1990 Workshop Manual and

---

[42] Memorandum from Craig Potter, EPA Assistant Administrator for Air and Radiation, to Regional Administrators, *Improving New Source Review Implementation* (Dec. 1, 1987); Memorandum from John Calcagni, EPA Air Quality Management Division, *Transmittal of Background Statement on "Top-Down" Best Available Control Technology (BACT)* (June 13, 1989).

[43] *Alaska Department of Environmental Conservation v. EPA*, 124 S.Ct. 983, 995 n. 7 (2004).

[44] *In re Cardinal FG Company*, 12 E.A.D. 153, 162 (EAB 2005) and cases cited therein.

[45] 40 CFR 51.166(b)(12); 40 CFR 51.166(j).

[46] *Alaska Department of Environmental Conservation v. EPA*, 124 S.Ct. 983 (2004); *In the Matter of Cash Creek Generation, LLC*, Petition Nos. IV-2008-1 & IV-2008-2 (Order on Petition) (December 15, 2009).

[47] A copy of the 1990 Workshop Manual is available at http://www.epa.gov/ttn/nsr/gen/wkshpman.pdf. There is another draft version of the 1990 Workshop Manual that has jigsaw puzzle pieces on the cover, is not available online, and has some minor differences from the online version. For ease of reference, any citations to the 1990 Workshop Manual in this document refer to the version that is available at the link provided above.

expanded upon them. Thus, EPA recommends that permitting authorities seeking more detailed guidance on particular aspects of the top-down BACT process take care to consider more recent EPA actions (many of which are referenced in this document) in addition to the discussions in the 1990 Workshop Manual.[48]

Since the BACT provisions in the CAA and EPA's rules provide discretion to permitting authorities, a critical and essential component of a successful BACT analysis (whether it follows the top-down process or another approach) is the record supporting the decisions reached by the permitting authority. Permitting authorities should ensure that the BACT requirements contained in the final PSD permit are supported and justified by the information and analysis presented in a thorough and complete permit record. The record should clearly explain the reasons for selection or rejection of possible control and emissions reductions options and include appropriate supporting analysis.[49] In accordance with relevant statutory and regulatory requirements, the permitting authority must also provide notice of its preliminary decision on a source's application for a PSD permit and an opportunity for the public to comment on that preliminary decision. Thus, the record must also reflect careful consideration and response to each significant consideration raised in public comments. Each BACT analysis must be supported by a complete permitting record that shows consideration of all the relevant factors.

This guidance (including the appendices) provides some preliminary EPA views on some key issues that may arise in a BACT analysis for GHGs. It is important to recognize that this document does not provide any final determination of BACT for a particular source, since such determinations can only be made by individual permitting authorities on a case-by-case basis after consideration of the record in each case. Upon considering the record in an individual case, if a permitting authority has a reasoned basis to address particular issues discussed in this document in a different manner than EPA recommends here, permitting authorities (including EPA) have the discretion to do so in decisions on individual permit applications consistent with the relevant requirements in the CAA and regulations. Thus, depending on the relevant facts and circumstances, permitting authorities have the discretion to establish BACT limitations that are more or less stringent than levels that might appear to result if one were to follow the recommendations in this guidance.

Relationship of BACT and New Source Performance Standards (NSPS)

The CAA specifies that BACT cannot be less stringent than any applicable standard of performance under the New Source Performance Standards (NSPS).[50] As of the date of this guidance, EPA has not promulgated any NSPS that contain emissions limits for GHGs. EPA has developed this permitting guidance and associated technical "white papers"[51] to support initial

[48] See the collections of PSD guidance provided in footnote 2, *supra*.
[49] *In re Knauf Fiber Glass, GmbH*, 8 E.A.D. 121, 131 (EAB 1999) ("The BACT analysis is one of the most critical elements of the PSD permitting process. As such, it should be well documented in the administrative record."); *In re Steel Dynamics, Inc.*, 9 E.A.D. 165, 224-25 (EAB 2000) (remanding BACT limitation where permit issuer failed to provide adequate explanation for why limits deviated from those of other facilities).
[50] 42 USC 7479(3).
[51] These technical "white papers", targeting specific industrial sectors, provide basic information on GHG control options to assist states and local air pollution control agencies, tribal authorities and regulated entities implementing measures to reduce GHG, particularly in the assessment of best available control technology (BACT) under the PSD

BACT determinations for GHGs that will need to be made without the benefit of having an NSPS and supporting technical documents to inform the evaluation of the performance of available control systems and techniques.

To the extent EPA completes an NSPS for a relevant source category, BACT determinations that follow will need to consider the levels of the GHG standards and the supporting rationale for the NSPS. The process of developing NSPS and considering public input on proposed standards will advance the technical record on GHG control strategies and may reflect advances in control technology or reductions in the costs or other impacts of using particular control strategies. Thus, the guidance in this document should be viewed taking into consideration the potential development of an NSPS for a particular source category. In addition, the fact that a NSPS for a source category does not require a more stringent level of control does not preclude its consideration in a top-down BACT analysis.

Importance of Energy Efficiency

As discussed in greater detail below, EPA believes that it is important in BACT reviews for permitting authorities to consider options that improve the overall energy efficiency of the source or modification – through technologies, processes and practices at the emitting unit. In general, a more energy efficient technology burns less fuel than a less energy efficient technology on a per unit of output basis. For example, coal-fired boilers operating at supercritical steam conditions consume approximately 5 percent less fuel per megawatt hour produced than boilers operating at subcritical steam conditions.[52] Thus, considering the most energy efficient technologies in the BACT analysis helps reduce the products of combustion, which includes not only GHGs but other regulated NSR pollutants (*e.g.,* NO_X, SO_2, $PM/PM_{10}/PM_{2.5}$, CO, etc.). Thus, it is also important to emphasize that energy efficiency should be considered in BACT determinations for all regulated NSR pollutants (not just GHGs). Additional considerations concerning energy efficiency in the determination of BACT for GHGs are discussed in more detail below.

An available tool that is particularly useful when assessing energy efficiency opportunities and options is performance benchmarking. Performance benchmarking information, to the extent it is specific and relevant to the source in question, may provide useful information regarding energy efficient technologies and processes for consideration in the BACT assessment. Comparison of the unit's or source's energy performance with a benchmark may highlight the need to assess additional energy efficiency possibilities. To the extent that benchmarking an emissions unit or source shows it to be a poor-to-average performer, the permitting authority may need to document and evaluate whether greater efficiencies are achievable. To ensure that the source is constructed and operated in a manner consistent with achieving the energy efficiency goals determined to be BACT, consideration should be given to

---

permitting program. These papers provide basic technical information that may be useful in a BACT analysis but they do not define BACT for each sector.

[52] U.S. Department of Energy, *Cost and Performance Baseline for Fossil Energy Plants - Volume 1: Bituminous Coal and Natural Gas to Electricity*, DOE/NETL-2007/1281, Final Report, Revision 1 (August 2007) at 6 (finding that the absolute efficiency difference between supercritical and subcritical boilers is 2.3% (39.1% compared to 36.8%), which is equivalent to a 5.9% reduction in fuel use), *available at* http://www.netl.doe.gov/energy-analyses/pubs/Bituminous%20Baseline_Final%20Report.pdf.

the individual and overall impact of the various measures under consideration. For example, in the case of numerous small energy saving measures, the intended effect of such measures could be reflected in projecting the GHG emissions limit or output-based standard for the emissions unit. On the other hand, it may be appropriate to include specific energy efficiency measures or techniques in the permit (as well as reflected in the GHG emissions limit) where such measures would clearly have a noticeable effect on energy savings.

There are a number of resources available for benchmarking facilities. For example, EPA's ENERGY STAR program for industrial sources offers several resources that can assist with performance benchmarking. To evaluate the energy performance of an entire facility,[53] ENERGY STAR developed sector-specific benchmarking tools called plant Energy Performance Indicators (EPIs).[54] For sectors where an EPI has been developed, these tools may be used to assess a plant's performance compared to the industry. At a unit and process level, ENERGY STAR has developed sector-specific Energy Guides for a number of industries. These Energy Guides discuss in detail processes and technologies that a permit applicant or permitting authority may wish to consider. This type of information may be particularly useful at the initial stages of the GHG BACT permitting process as the RACT/BACT/LAER clearinghouse (RBLC) is populated and updated with case-specific information.[55] Additional resources can be found in Appendix J of this document.

A. Determining the Scope of the BACT Analyses

General Concepts

An initial consideration that is not directly covered in the five steps of the top-down BACT process is the scope of the entity or equipment to which a top-down BACT analysis is applied. EPA has generally recommended that permit applicants and permitting authorities conduct a separate BACT analysis for each emissions unit[56] at a facility and has also encouraged applicants and permitting authorities to consider logical groupings of emissions units as appropriate on a case-by-case basis.[57]

---

[53] For PSD applicability, the scope of the "major stationary source" is determined by the definition in 40 CFR 52.21(b)(1), and the title V "major source" is defined in 40 CFR 70.2. The PSD and title V regulations distinguish between a "facility" and a "stationary source"; in fact, the regulations include a facility as type of stationary source. 40 CFR 52.21(b)(5)-(6), 40 CFR 71.2. However, in this guidance, source and facility are used interchangeably to generally designate pollutant emitting structures and do not designate official positions regarding applicability unless otherwise noted.
[54] Current ENERGY STAR industrial sector EPIs can be found at http://www.energystar.gov/EPIS.
[55] The RBLC provides access to information and decisions about pollution control measures required by air pollution emission permits issued by state and local permitting agencies so that the information is accessible to all permitting authorities working on similar projects. The expanded RBLC includes GHG control and test data, and a GHG message board for permitting authorities.
[56] 40 CFR 52.21(b)(7).
[57] 1990 Workshop Manual at B.10; *In re General Motors, Inc.*, 10 E.A.D. 360, 382 (EAB 2002). EPA has also supported grouping emissions units in the similar context of evaluating options for meeting the technology-based LAER standards under the nonattainment NSR program. Memorandum from John Calcagni, Air Quality

For new sources triggering PSD review, the CAA and EPA rules provide discretion for permitting authorities to evaluate BACT on a facility-wide basis by taking into account operations and equipment which affect the environmental performance of the overall facility. The term "facility" and "source" used in applicable provisions of the CAA and EPA rules encompass the entire facility and are not limited to individual emissions units.[58]

For existing sources triggering PSD review, EPA rules are more explicit that BACT applies to those emission units at which a net emissions increase would occur at the source[59] as a result of a physical change or change in the method of operation.[60] EPA has interpreted these provisions to mean that BACT applies in the context of a modification to only an emissions unit that has been modified or added to an existing facility.[61]

<u>GHG-Specific Considerations</u>

The application of BACT to GHGs has the potential to place greater importance on determining the scope of the entity or equipment to which BACT applies. Under existing rules, a permitting authority evaluating applications to construct new sources has the flexibility to consider source-wide energy efficiency strategies (over an entire production process or across multiple production process) to reduce GHG emissions from the proposed new source. EPA interprets the language of the BACT definition in CAA §169, which requires consideration of "production processes and available methods, systems, and techniques ... for control of [each] pollutant," to include control methods that can be used facility-wide. As noted above, for a

---

Management Division to David Kee, Region V, *Transfer of Technology in Determining Lowest Achievable Emissions Rate (LAER)* (Aug. 29, 1988).

[58] 42 USC 7479(1) and (3); 40 CFR 52.21(b)(1) and (5).

[59] For the purposes of determining whether a PSD permit is required (applicability of PSD), EPA requires a permitting authority to look beyond the emissions unit that is modified (across the entire source) to determine the extent of emissions increases that result from the modification. Thus, EPA has considered downstream and upstream emissions increases and decreases from emissions units that are not physically or operationally changed when determining the level of emissions increase that results from a modification. This concept is frequently described as "debottlenecking" because the upstream or downstream emission increases that are accounted for in the analysis are often the result of increased throughput across the source resulting from the removal of a bottleneck in the equipment that is physically changed. 1990 Workshop Manual at A.46; Letter from Kathleen Henry, Region III to John M. Daniel, Virginia DEQ (Oct. 23, 1998) (Intermet Archer Creek Facility). In 2006, EPA proposed potential changes to its approach to debottlenecking based on an analysis that the agency had flexibility to define the causation of an increase. 71 FR 54235 (Sept. 14, 2006). However, that proposal was not adopted by the Agency and explicitly withdrawn. The discussion of this concept in this note is intended solely to provide context for the BACT requirement. This note is in no way intended to modify the Agency's approach to this aspect of PSD applicability, as applied prior the 2006 proposal referenced above and continuing to this day.

[60] 40 CFR 52.21(j)(3).

[61] In the preamble for the 1980 rule that established the current version of 40 CFR 52.21(j)(3), EPA explained that "BACT applies only to the units actually modified." 45 FR 52676, 52681 (Aug. 7, 1980). Later in this preamble, EPA elaborated as follows with a specific example:

> The proposal required BACT for the new or modified emissions units which were associated with the modification and not for those unchanged emissions units at the same source. Thus, if an existing boiler at a source were modified or a new boiler added in such a way as to significantly increase particulate emissions, only that boiler would be subject to BACT, not the other emissions units at the source.

Id. at 52722. *See also* Letter from Robert Miller, EPA Region 5 to Lloyd Eagan, Wisconsin DNR (Feb. 8, 2000) (PSD applicability for debottlenecked source).

modification of an existing facility, EPA's existing regulations state that BACT only applies to emission units that are physically or operationally changed.[62]

EPA has historically interpreted the BACT requirement to be inapplicable to secondary emissions, which are defined to include emissions that may occur as a result of the construction or operation of a major stationary source but do not come from the source itself.[63] Thus, under this interpretation of EPA rules, a BACT analysis should not include (in Step 1 of the process) energy efficient options that may achieve reductions in a facility's demand for energy from the electric grid but that cannot be demonstrated to achieve reduction in emissions released from the stationary source (*e.g.,* within the property boundary). Nevertheless, as discussed in more detail below, EPA recommends that permitting authorities consider in a portion of the BACT analysis (Step 4) how available strategies for reducing GHG emissions from a stationary source may affect the level of GHG emissions from offsite locations.

B. BACT Step 1 – Identify All Available Control Options

General Concepts

The first step in the top-down BACT process is to identify all "available" control options. Available control options are those air pollution control technologies or techniques (including lower-emitting processes and practices) that have the potential for practical application to the emissions unit and the regulated pollutant under evaluation. To satisfy the statutory requirements of BACT, EPA believes that the applicant must focus on technologies that have been demonstrated to achieve the highest levels of control for the pollutant in question, regardless of the source type in which the demonstration has occurred.

Air pollution control technologies and techniques include the application of alternative production processes, methods, systems, and techniques, including clean fuels or treatment or innovative fuel combustion techniques for control of the affected pollutant. In some circumstances, inherently lower-polluting processes are appropriate for consideration as available control alternatives. The control options should include not only existing controls for the source category in question, but also controls determined through "technology transfer" that are applied to source categories with exhaust streams that are similar to the source category in question. The 1990 Workshop Manual provides useful guidelines for issues related to technology transfer among process applications. Primary factors that should be considered are the characteristics of the gas stream to be controlled, the comparability of the production processes (*e.g.,* batch versus continuous operation, frequency of process interruptions, special product quality concerns, etc.), and the potential impacts on other emission points within the source. Also, technologies in application outside the United States should be considered to the extent that the technologies have been successfully demonstrated in practice. In general, if a control option has been demonstrated in practice on a range of exhaust gases with similar physical and chemical characteristics and does not have a significant negative impact on process

[62] 40 CFR 52.21(j)(3).
[63] 44 FR 51924, 51947 (Sept. 5, 1979); 40 CFR 52.21(b)(18).

operations, product quality, or the control of other emissions, it may be considered as potentially feasible for application to another process.

Technologies that formed the basis for an applicable NSPS (if any) should, in most circumstances, be included in the analysis, as BACT cannot be set at an emission control level that is less stringent than that required by the NSPS.[64] In cases where a NSPS is proposed, the NSPS will not be controlling for BACT purposes since it is not a final action and the proposed standard may change, but the record of the proposed standard (including any significant public comments on EPA's evaluation) should be weighed when considering available control strategies and achievable emission levels for BACT determinations made that are completed before a final standard is set by EPA. However, even though a proposed NSPS is not a controlling floor for BACT, the NSPS is an independent requirement that will apply to an NSPS source that commences construction after an NSPS is proposed and carries with it a strong presumption as to what level of control is achievable. This is not intended to limit available options to only those considered in the development of the NSPS. For example, in addition to considering controls addressed in an NSPS rulemaking, controls selected in lowest achievable emission rate (LAER) determinations are available for BACT purposes, should be included as control alternatives included in BACT Step 1, and may frequently be found to represent the top control alternative at later steps in the BACT analysis.[65]

EPA has placed potentially applicable control alternatives identified and evaluated in the BACT analysis into the following three categories:

- ***Inherently Lower-Emitting Processes/Practices/Designs,***[66]
- ***Add-on Controls*, and**
- ***Combinations of Inherently Lower Emitting Processes/Practices/Designs and Add-on Controls*.**

The BACT analysis should consider potentially applicable control techniques from all of the above three categories. Lower-polluting processes (including design considerations) should be considered based on demonstrations made on the basis of manufacturing identical or similar products from identical or similar raw materials or fuels. Add-on controls, on the other hand, should be considered based on the physical and chemical characteristics of the pollutant-bearing emission stream.

---

[64] 40 CFR 52.21(b)(12). While this guidance is being issued at a time when no NSPS have been established for GHGs, permitting authorities must consider any applicable NSPS as a controlling floor in determining BACT once any such standards are final.

[65] EPA has stated that technologies designated as meeting lowest achievable emission rate (LAER) – which are required in NSR permits issues to sources in non-attainment areas – are available for BACT purposes, must be included in the list of control alternatives in step 1, and will usually represent the top control alternative. 1990 Workshop Manual at B.5.

[66] While the 1990 Workshop Manual generally refers to "Inherently Lower Polluting Processes/Practices," the discussion contained in that portion of the Manual makes it clear that lower emitting *designs* may also be considered in Step 1 of the top-down analysis. See 1990 Workshop Manual at B.14 (stating that "the ability of design considerations to make the process inherently less polluting must be considered as a control alternative for the source").

As explained later in this guidance, in the course of the BACT analysis, one or more of the available options may be eliminated from consideration because they are demonstrated to be technically infeasible or have unacceptable energy, economic, and environmental impacts on a case- and fact-specific basis. However, such options should still be included in Step 1 of the BACT process, since the purpose of Step 1 of the process is to cast a wide net and identify all control options with potential application to the emissions unit under review that should be subject to scrutiny under later steps of the process.

While Step 1 is intended to capture a broad array of potential options for pollution control, this step of the process is not without limits. EPA has recognized that a Step 1 list of options need not necessarily include inherently lower polluting processes that would fundamentally redefine the nature of the source proposed by the permit applicant.[67] BACT should generally not be applied to regulate the applicant's purpose or objective for the proposed facility.

In assessing whether an option would fundamentally redefine a proposed source, EPA recommends that permitting authorities apply the analytical framework recently articulated by the Environmental Appeals Board.[68] Under this framework, a permitting authority should look first at the administrative record to see how the applicant defined its goal, objectives, purpose or basic design for the proposed facility in its application. The underlying record will be an essential component of a supportable BACT determination that a proposed control technology redefines the source.[69] The permitting authority should then take a "hard look" at the applicant's proposed design in order to discern which design elements are inherent for the applicant's purpose and which design elements may be changed to achieve pollutant emissions reductions without disrupting the applicant's basic business purpose for the proposed facility. In doing so, the permitting authority should keep in mind that BACT, in most cases, should not be applied to regulate the applicant's purpose or objective for the proposed facility.[70] This approach does not preclude a permitting authority from considering options that would change aspects (either minor or significant) of an applicants' proposed facility design in order to achieve pollutant reductions

---

[67] *In re Prairie State Generating Company*, 13 E.A.D. 1, 23 (EAB 2006).

[68] *See, generally, In the Matter of American Electric Power Service Corporation, Southwest Electric Power Company, John W. Turk Plant*, Petition No. VI-2008-01 (Order on Petition) (December 15, 2009) (title V order referencing and applying framework developed by the EAB) ; *In the Matter of Cash Creek Generation, LLC*, Petition Nos. IV-2008-1 & IV-2008-2 (Order on Petition) (December 15, 2009) (same).

[69] *In re Desert Rock Energy Company*, PSD Appeal No. 08-03 et al. (EAB Sept. 24, 2009), slip op. at 65, 76.

[70] The EPA Environmental Appeals Board has applied this framework for evaluating redefining the source questions in three cases involving coal-fired power plants. *In re Desert Rock Energy Company*, PSD Appeal No. 08-03 et al. (EAB Sept. 24, 2009); *In re Northern Michigan University*, PSD Appeal No. 08-02 (EAB Feb. 18, 2009); *In re Prairie State Generating Company*, 13 E.A.D. 1 (EAB 2006). For additional examples of how EPA approached the redefining the source issue in the context of power plants prior to developing this analytical framework, see the following decisions. *In re Old Dominion Electric Cooperative*, 3 E.A.D. 779 (Adm'r 1992); *In re Hawaiian Commercial & Sugar Co.*, 4 E.A.D. 95 (EAB 1992); *In re SEI Birchwood Inc.*, 5 E.A.D. 25 (EAB 1994). EPA also considered this issue in the context of waste incinerators prior to developing the recommended analytical framework. *In re Pennsauken*, 2 E.A.D. 667 (Adm'r 1988); *In the Matter of Spokane Regional Waste-to-Energy Facility*, 2 E.A.D. 809 (Adm'r 1989); *In the Matter of Brooklyn Navy Yard Resource Recovery Facility*, 3 E.A.D. 867 (EAB 1992); *In re Hillman Power Co., LLC*, 10 E.A.D. 673, 684 (EAB 2002). In another case, EPA considered this question in the context of a conversion of a natural-gas fired taconite ore facility to a petcoke fuel. *In re Hibbing Taconite Co*., 2 E.A.D. 838 (Adm'r 1989). For an example of the application of this concept to a fiberglass manufacturing facility, see *In re Knauf Fiber Glass*, 8 E.A.D 121 (EAB 1998).

that may or may not be deemed achievable after further evaluation at later steps of the process. EPA does not interpret the CAA to prohibit fundamentally redefining the source and has recognized that permitting authorities have the discretion to conduct a broader BACT analysis if they desire.[71] The "redefining the source" issue is ultimately a question of degree that is within the discretion of the permitting authority. However, any decision to exclude an option on "redefining the source" grounds must be explained and documented in the permit record, especially where such an option has been identified as significant in public comments.[72]

In circumstances where there are varying configurations for a particular type of source, the applicant should include in the application a discussion of the reasons why that particular configuration is necessary to achieve the fundamental business objective for the proposed construction project. The permitting authority should determine the applicant's basic or fundamental business purpose or objective based on the record in each individual case. For example, the permitting authority can consider the intended function of an electric generating facility as a baseload or peaking unit in assessing the fundamental business purpose of a permit applicant.[73] However, a factor that might be considered at later steps of the top-down BACT process, such as whether a process or technology can be applied on a specific type of source (Step 2) or the cost of constructing a source with particular characteristics (Step 4), should not be used as a justification for eliminating an option in Step 1 of the BACT analysis. Thus, cost savings and avoiding the risk of an apparently achievable technology transfer are not appropriately considered to be a part of the applicant's basic design or fundamental business purpose or objective.[74] Since BACT Step 4 also includes consideration of "energy" impacts from the control options under consideration, such impacts should not be used to justify excluding an option in Step 1 of a top-down BACT analysis.

The CAA includes "clean fuels" in the definition of BACT.[75] Thus, clean fuels which would reduce GHG emissions should be considered, but EPA has recognized that the initial list of control options for a BACT analysis does not need to include "clean fuel" options that would fundamentally redefine the source. Such options include those that would require a permit applicant to switch to a primary fuel type (*i.e.,* coal, natural gas, or biomass) other than the type of fuel that an applicant proposes to use for its primary combustion process. For example, when an applicant proposes to construct a coal-fired steam electric generating unit, EPA continues to believe that permitting authorities can show in most cases that the option of using natural gas as a primary fuel would fundamentally redefine a coal-fired electric generating unit.[76] Ultimately,

---

[71] *In re Hawaiian Commercial & Sugar Co.*, 4 E.A.D. at 100; *In re Knauf Fiber Glass*, 8 E.A.D. at 136.

[72] *In re Desert Rock Energy Company*, slip op. at 70-71, 76-77; *In the Matter of Cash Creek Generation*, Order at 7-10.

[73] *In re Prairie State Generating Company*, 13 E.A.D. at 25 (recognizing distinction between sources designed to provide base load power and those designed to function as peaking facilities).

[74] *In re Prairie State Generating Company*, 13 E.A.D. at 23, n.23.

[75] 42 USC 7579(3). EPA has not yet updated the definition of BACT in the PSD regulations to reflect the addition of the "clean fuels" language that occurred in the 1990 amendments to the Clean Air Act. 40 CFR 52.21(b)(12); 40 CFR 51.166(b)(12). Nevertheless, EPA reads and applies its regulations consistent with the terms of the Clean Air Act.

[76] *See, e.g.,* 1990 Workshop Manual at B.13; *In re Old Dominion Electric Cooperative*, 3 E.A.D. at 793-94; *In re SEI Birchwood Inc.*, 5 E.A.D. at 28, n. 8. *But see In re Hibbing Taconite Co.,* 2 E.A.D. 838, 843(Adm'r 1989) (finding it reasonable to consider burning natural gas instead of or in combination with coal where the plant at issue was already equipped to burn natural gas).

however, a permitting authority retains the discretion to conduct a broader BACT analysis and to consider changes in the primary fuel in Step 1 of the analysis. EPA does not classify the option of using a cleaner form of the same type of fuel that a permit applicant proposes to use as a change in primary fuel, so these types of options should be assessed in a top-down BACT analysis in most cases.[77] For example, a permitting authority may consider that some types of coal can have lower emissions of GHG than other forms of coal, and they may insist that the lower emitting coal be evaluated in the BACT review. Furthermore, when a permit applicant has incorporated a particular fuel into one aspect of the project design (such as startup or auxiliary applications), this suggests that a fuel is "available" to a permit applicant. In such circumstances, greater utilization of a fuel that the applicant is already proposing to use in some aspect of the project design should be listed as an option in Step 1 unless it can be demonstrated that such an option would disrupt the applicant's basic business purpose for the proposed facility.[78]

Although not required in Step 1 of the BACT process, the applicant may also evaluate and propose to apply innovative technologies that qualify for coverage under the innovative control technology waiver in EPA rules.[79] Under this waiver, a source is allowed an extended period of time to bring innovative technology into compliance with the required performance level. To be considered "innovative," a control technique must meet the provisions of 40 CFR 52.21(b)(19) or, where appropriate, the applicable definition in a state SIP. In the early 1990s, EPA did not consider it appropriate to grant applications for this waiver for proposed projects that were the same as or similar to projects for which the waiver had previously been granted.[80] However, in 1996, EPA said that it was inclined to allow additional waivers if the criteria in the CAA for such a waiver under the NSPS program were met. EPA proposed revisions to this provision in the PSD rules to incorporate the statutory criteria from the NSPS program, which specifies that such waivers may not exceed the number the administrator finds necessary to ascertain whether the criteria for issuing a waiver are met.[81] Though the 1996 proposal was never issued as final policy, EPA continues to adhere to the view expressed in that 1996 proposal and will consider approving more than one waiver under these conditions.

GHG-Specific Considerations

Permit applicants and permitting authorities should identify all "available" GHG control options that have the potential for practical application to the source under consideration. The application of BACT to GHGs does not affect the discretion of a permitting authority to exclude options that would fundamentally redefine a proposed source. GHG control technologies are

---

[77] *See In re Old Dominion Electric Cooperative*, 3 E.A.D. at 793 (stating that the BACT analysis includes consideration of fuels cleaner than that proposed by the applicant); *In re Inter-Power of New York,* 5 E.A.D. 130, 145-150 (EAB 1994) (upholding permitting authorities BACT analysis involving coals with different sulfur contents). *But see In re Prairie State Generating Company*, 13 E.A.D. at 27-28 (finding the permitting authority properly excluded consideration of lower sulfur coal as redefining the source since the power plant at issue was co-located with a mine and designed to burn the coal from that mine) .

[78] *In the Matter of Cash Creek Generation*, Order at 7-10.

[79] 40 CFR 52.21(v); 40 CFR 51.166(s).

[80] 1990 Workshop Manual at B.13; Memo from Ed Lillis, Chief, Permits Program Branch, to Kenneth Eng, Chief, Air Compliance Branch, *Kamine Development Corporation's (KDC) Request for a Prevention of Significant Deterioration (PSD) Innovative Control Technology Waiver* (August 20, 1991).

[81] 61 FR 38250, 38281 (July 23, 1996).

likely to vary based on the type of facility, processes involved, and GHGs being addressed. The discussion below is focused on energy efficiency and carbon capture and storage (CCS) because these control approaches may be applicable to a wide range of facilities that emit large amounts of CO_2. Information on other technologies and mitigation approaches to control CO_2 as well as the other GHGs (*e.g.,* methane) is found in Appendix J.

The application of methods, systems, or techniques to increase energy efficiency is a key GHG-reducing opportunity that falls under the category of "lower-polluting processes/practices." Use of inherently lower-emitting technologies, including energy efficiency measures, represents an opportunity for GHG reductions in these BACT reviews. In some cases, a more energy efficient process or project design may be used effectively alone; whereas in other cases, an energy efficient measure may be used effectively in tandem with end-of-stack controls to achieve additional control of criteria pollutants. Applying the most energy efficient technologies at a source should in most cases translate into fewer overall emissions of all air pollutants per unit of energy produced. Selecting technologies, measures and options that are energy efficient translates not only in the reduction of emissions of the particular regulated NSR air pollutant undergoing BACT review, but it also may achieve collateral reductions of emissions of other pollutants, as well as GHGs.

For these reasons, EPA encourages permitting authorities to use the discretion available under the PSD program to include as available technologies in Step 1 the most energy efficient options in BACT analyses for both GHG and non-GHG regulated NSR pollutants. While energy efficiency can reduce emissions of all combustion-related emissions, it is a particularly important consideration for GHGs since the use of add-on controls to reduce GHG emissions is not as well-advanced as it is for most combustion-derived pollutants. Initially, in many instances energy efficient measures may serve as the foundation for a BACT analysis for GHGs, with add-on pollution control technology and other strategies added as they become more available. Energy efficient options that should be considered in Step 1 of a BACT analysis for GHGs can be classified in two categories.

The first category of energy efficiency improvement options includes technologies or processes that maximize the energy efficiency of the individual emissions unit. For example, the processes that may be used in electric generating facilities have varying levels of energy efficiency, measured in terms of amount of heat input that is used in the process or in terms of per unit of the amount of electricity that is produced. When a permit applicant proposes to construct a facility using a less efficient boiler design, such as a pulverized coal (PC) or circulating fluidized bed (CFB) boiler using subcritical steam pressure, a BACT analysis for this source should include more efficient options such as boilers with supercritical and ultra-supercritical steam pressures.[82] Furthermore, combined cycle combustion turbines, which generally have higher efficiencies than simple cycle turbines, should be listed as options when an applicant proposes to construct a natural gas-fired facility. In coal-fired permit applications,

[82] "Supercritical EGUs typically use steam pressures of 3,500 psi (24 MPa) and steam temperatures of 1,075°F (580°C). However, supercritical boilers can be designed to operate at steam pressures as high as 3,600 psi (25 MPa) and steam temperatures as high as 1,100°F (590°C). Above this temperature and pressure the steam is sometimes called 'ultra-supercritcal'[*sic*]." EPA Office of Air and Radiation, *Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from Coal-fired Electric Generating Units* (October 2010) at 27.

EPA believes that integrated gasification combined cycle (IGCC) should also be listed for consideration when it is more efficient than the proposed technology.[83] However, these options may be evaluated under the redefining the source framework described above and excluded from consideration at Step 1 of a top-down analysis on a case-by-case basis if it can be shown that application of such a control strategy would disrupt the applicant's basic or fundamental business purpose for the proposed facility.

The second category of energy efficiency improvements includes options that could reduce emissions from a new greenfield facility by improving the utilization of thermal energy and electricity that is generated and used on site. As noted previously, BACT reviews for modified units at existing sources should focus on the emitting unit that is being physically or operationally changed. However, when reviewing a PSD permit application for the construction of a new facility that creates its own energy (thermal or electric) for its own use, EPA recommends that permitting authorities consider technologies or processes that not only maximize the energy efficiency of the individual emitting units, but also process improvements that impact the facility's energy utilization assuming it can be shown that efficiencies in energy use by the facility's higher-energy-using equipment, processes or operations could lead to reductions in emissions from the facility. EPA has long recognized that "a control option [considered in the BACT analysis] may be an 'add-on' air pollution control technology that removes pollutants from a facility's emissions stream, or an 'inherently lower-polluting process/practice' that prevents emissions from being generated in the first instance."[84]

---

[83] EPA no longer subscribes to the reasoning used by the Agency in a 2005 letter to justify excluding IGCC from consideration in all cases on redefining the source grounds. Letter from Stephen Page, EPA OAQPS to Paul Plath, E3 Consulting, *Best Available Control Technology Requirements for Proposed Coal-Fired Power Plant Projects* (Dec. 13, 2005) (last paragraph on page 2). The Environmental Appeals Board subsequently rejected the application of this reasoning in an individual permit decision, where the record did not demonstrate that IGCC was inconsistent with the fundamental objectives of the permit applicant or distinguish between prior permit decisions that evaluated the technology in more detail. *In re Desert Rock Energy Company*, Slip. Op. at 68-69. Based on this decision, EPA also concluded that a state permit decision following substantially the same reasoning lacked a reasoned basis for excluding further consideration of IGCC. *In the Matter of: American Electric Power Service Corporation,* Order at 8-12. However, EPA continues to interpret the relevant provisions of the CAA, as described in the 2005 letter (pages 1-2), to provide discretion for permitting authorities to exclude options that would fundamentally redefine a proposed source, provided the record includes an appropriate justification in each case *In re Desert Rock Energy Company*, Slip. Op. at 76. Thus, IGCC should not be categorically excluded from a BACT analysis for a coal fired electric generating unit, and this technology should not be excluded on redefining the source grounds at Step 1 of a BACT analysis in any particular case unless the record clearly demonstrates why the permit applicant's basic or fundamental business purpose would be frustrated by application of this process.

[84] *In re Knauf Fiberglass, GMBH*, 8 EAD 121, 129 (EAB 1999) (citing 1990 NSR Workshop Manual at B.10, B.13). In *Knauf Fiberglass* the EPA's Environmental Appeals Board observed that "[t]he permitting authority may require consideration of alternative production processes in the BACT analysis when appropriate." *Id.* at 136. The EAB remanded a PSD permit for a facility that manufactured fiberglass insulation because of several deficiencies in the BACT analysis for the source. One of these deficiencies noted by the Board was the failure to sufficiently consider the possibility of applying an alternative process for producing the fiberglass that was used by another facility in the industry that had lower levels of PM10 emissions using the same add on controls. The source argued that it was unable to reduce its PM10 emissions to levels similar to its competitor because the competitor used a different production process that enabled it to achieve lower PM10 emissions levels. The EAB acknowledged that if the competitor's process was a proprietary trade secret, then such an option might be technically infeasible (not commercially available) for the source under evaluation, but called for the permit record to document this fact and for the applicant to seriously consider pollution control designs for other facilities that were a matter of public record. 8 EAD at 139-144. After the initial remand in 1999, the EAB later upheld a revised permit that was based

For example, an applicant proposing to build a new facility that will generate its own energy with a boiler could also consider ways to optimize the thermal efficiency of a new heat exchanger that uses the steam from the new boiler. Moreover, the design, operation, and maintenance of a steam distribution and utilization system may influence how much steam is needed to complete a specific task. If the steam distribution and utilization is optimized, less steam may be needed. In many cases, lower steam demand could result in lower fuel use and lower emissions at a new facility. Since lower-emitting processes should be considered in BACT reviews, opportunities to utilize energy more efficiently and therefore to produce less of it are appropriate considerations in a BACT review for a new facility. As discussed in the previous section, the evaluation of options in this second category can be facilitated by defining, in the case of new sources, the entity subject to BACT on a basis that encompasses the significant energy-using equipment, processes or operations of the facility.

For the first category of energy efficiency options described above, the number of options available for a given type of emissions unit at an existing or new source will generally be limited in number and not significantly expand the number of options that have traditionally been considered in BACT analyses for previously regulated NSR pollutants. However, the second category of options appropriate for consideration at a new greenfield facility may include equipment or processes that have the effect of lowering emissions because their efficient use of energy means that the facility's energy-producing emitting unit can produce less energy. Evaluation of options in this second category need not include an assessment of each and every conceivable improvement that could marginally improve the energy efficiency of the new facility as a whole (*e.g.,* installing more efficient light bulbs in the facility's cafeteria), since the burden of this level of review would likely outweigh any gain in emissions reduction achieved.[85] EPA instead recommends that the BACT analyses for units at a new facility concentrate on the energy efficiency of equipment that uses the largest amounts of energy, since energy efficient options for such units and equipment (*e.g.,* induced draft fans, electric water pumps) will have a larger impact on reducing the facility's emissions. EPA also recommends that permit applicants at new sources propose options that are defined as an overall category or suite of techniques to yield levels of energy utilization that could then be evaluated and judged by the permitting authority and the public against established benchmarks. Comparing the proposed suite of techniques to such benchmarks, which represent a high level of performance within an industry, would demonstrate that the new facility will achieve commensurate levels of energy efficiency using the proposed methods. Such an approach would leave some flexibility for the permit applicant to suggest the precise mix of measures that would meet the desired benchmark, and avoid including in a permit review an assessment of a large number of different combinations of technology choices for smaller pieces of equipment.

While engineering calculations and results from similar equipment demonstrations can often enable the permit applicant or engineer to closely estimate the energy efficiency of a unit,

---

on the conclusion that it was not technically feasible for this source to use the lower-polluting process used by its competitor because the process was proprietary and not commercially available to Knauf. *In re Knauf Fiberglass, GMBH*, 9 EAD 1 (EAB 2000).

[85] One federal court has recognized the undesirability of making the BACT analysis into a "Sisyphean labor where there was always one more option to consider." *Sierra Club v. EPA*, 499 F.3d 653, 655 (7th Cir. 2007).

we recognize that, in some cases, it may be more difficult to fully and accurately predict the energy efficiency of a unit for BACT purposes. Commonly, the responsible design engineers or vendors will provide both estimated "expected" results and "guaranteed" results. Such estimates can be provided for the permitting authority's consideration. The difference between expected and guaranteed results gives some indication of the uncertainty and risk tolerances included in the guaranteed value. Still, in some cases, the ultimate energy efficiency of the unit may not be accurately known without testing the installed equipment, especially if multiple vendors or multiple design engineers are involved. Of course, this is substantially similar to many current permitting situations, such as when combustion enhancements are installed for controlling emissions of criteria pollutants and the exact effect on energy efficiency is somewhat uncertain until it is operationally tested. Thus, where there is some reasonable uncertainty regarding performance of specified energy efficiency measures, or the combination of measures, the permit can be written to acknowledge that uncertainty. As in the past, based on the particular circumstances addressed in the permitting record, the permitting authority has the discretion to set a permit limit informed by engineering estimates, or to set permit conditions that make allowance for adjustments of the BACT limits based on operational experience.

For the purposes of a BACT analysis for GHGs, EPA classifies CCS as an add-on pollution control technology[86] that is "available"[87] for facilities emitting CO_2 in large amounts, including fossil fuel-fired power plants, and for industrial facilities with high-purity CO_2 streams (*e.g.,* hydrogen production, ammonia production, natural gas processing, ethanol production, ethylene oxide production, cement production, and iron and steel manufacturing). For these types of facilities, CCS should be listed in Step 1 of a top-down BACT analysis for GHGs. This does not necessarily mean CCS should be selected as BACT for such sources. Many other case-specific factors, such as the technical feasibility and cost of CCS technology for the specific application, size of the facility, proposed location of the source, and availability and access to transportation and storage opportunities, should be assessed at later steps of a top-down BACT analysis. However, for these types of facilities and particularly for new facilities, CCS is an

---

[86] EPA recognizes that CCS systems may have some unique aspects that differentiate them from the types of equipment that have the traditionally been classified as add-on pollution controls (*i.e.,* scrubbers, fabric filters, electrostatic precipitators). However, since CCS systems have more similarities to such devices than inherently lower-polluting processes, EPA believes that CCS systems are best classified as add-on controls for purposes of a top-down BACT analysis.

[87] As noted above, a control option is "available" if it has a potential for practical application to the emissions unit and the regulated pollutant under evaluation. Thus, even technologies that are in the initial stages of full development and deployment for an industry, such as CCS, can be considered "available" as that term is used for the specific purposes of a BACT analysis under the PSD program. In 2010, the Interagency Task Force on Carbon Capture and Storage was established to develop a comprehensive and coordinated federal strategy to speed the commercial development and deployment of this clean coal technology. As part of its work, the Task Force prepared a report that summarizes the state of CCS and identified technical and non-technical challenges to implementation. EPA, which participated in the Interagency Task Force, supports the Task Force's recommendations concerning ongoing investment in demonstrations of the CCS technologies based on the report's conclusion that: "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." See Report of the Interagency Task Force on Carbon Capture and Storage, p.50 (http://www.epa.gov/climatechange/policy/ccs_task_force.html).

option that merits initial consideration and, if the permitting authority eliminates this option at some later point in the top-down BACT process, the grounds for doing so should be reflected in the record with an appropriate level of detail.

In identifying control technologies in BACT Step 1, the applicant needs to survey the range of potentially available control options. EPA recognizes that dissemination of data and information detailing the function of the proposed control equipment or process is essential if permitting agencies are to reach consistent conclusions on the availability of GHG technology across industries. In the initial phase of PSD permit reviews for GHGs, background information about certain emission control strategies may be limited and technologies may still be under development. For example, alternative technologies are being developed for reusing carbon or sequestering carbon in a form or location other than through injection into underground formations. When these technologies are more developed, they could be included in Step 1 of the top-down BACT process. EPA will add information to the RBLC as it becomes available and supplement the information in the GHG Mitigation Measures Database.[88] EPA may also issue additional white papers for selected stationary source sectors in the future.

C. BACT Step 2 – Eliminate Technically Infeasible Options

General Concepts

Under the second step of the top-down BACT analysis, an available control technique listed in Step 1 may be eliminated from further consideration if it is not technically feasible for the specific source under review. A demonstration of technical infeasibility should be clearly documented and should show, based on physical, chemical, or engineering principles, that technical difficulties would preclude the successful use of the control option on the emissions unit under review.

EPA generally considers a technology to be technically feasible if it: (1) has been demonstrated and operated successfully on the same type of source under review, or (2) is available and applicable to the source type under review. If a technology has been operated on the same type of source, it is presumed to be technically feasible. An available technology from Step 1, however, cannot be eliminated as infeasible simply because it has not been used on the same type of source that is under review. If the technology has not been operated successfully on the type of source under review, then questions regarding "availability" and "applicability" to the particular source type under review should be considered in order for the technology to be eliminated as technically infeasible.[89]

[88] EPA has developed a new online tool (GHG Mitigation Measures Database) that includes specific performance and cost data on current and developing GHG control measures. It also provides available data on other potential environmental impacts a GHG control measure may have. Currently, the database includes information on GHG controls for electric generating and cement production. This database can be found on EPA's website at http://www.epa.gov/nsr/ghgpermitting.html

[89] *In re Cardinal FG Company*, 12 E.A.D. 153, 166 (EAB 2005); *In re Steel Dynamics, Inc.*, 9 E.A.D. 165, 199 (EAB 2000).

In the context of a technical feasibility analysis, the terms "availability" and "applicability" relate to the use of technology in a situation that appears similar even if it has not been used in the same industry. Specifically, EPA considers a technology to be "available" where it can be obtained through commercial channels or is otherwise available within the common meaning of the term.[90] EPA considers an available technology to be "applicable" if it can reasonably be installed and operated on the source type under consideration. Where a control technology has been applied on one type of source, this is largely a question of the transferability of the technology to another source type. A control technique should remain under consideration if it has been applied to a pollutant-bearing gas stream with similar chemical and physical characteristics. The control technology would not be applicable if it can be shown that there are significant differences that preclude the successful operation of the control device. For example, the temperature, pressure, pollutant concentration, or volume of the gas stream to be controlled, may differ so significantly from previous applications that it is uncertain the control device will work in the situation currently undergoing review.

Evaluations of technical feasibility should consider all characteristics of a technology option, including its development stage, commercial applications, scope of installations, and performance data. The applicant is responsible for providing evidence that an available control measure is technically infeasible. However, the permitting authority is responsible for deciding technical feasibility. The permitting authority may require the applicant to address the availability and applicability of a new or emerging technology based on information that becomes available during the consideration of the permit application.

Information regarding what vendors will guarantee should be considered in the BACT selection process with all the other relevant factors, such as BACT emission rates for other recently permitted sources, projected cost and effectiveness of controls, and experience with the technology on similar gas streams. Commercial guarantees are a contract between the permit applicant and the vendor to establish the risk of non-performance the vendor is willing to accept, and they typically establish the remedy for failure to perform and the test methods for acceptance. A permit applicant uses these guarantees to provide its investors and lenders with reasonable assurances that the proposed facility will reliably perform its intended function and consistently meet the proposed permit limits. While permit applicants use these guarantees as protection from overly optimistic vendor claims for new technologies, experience demonstrates that these terms and conditions can also be customized for each circumstance to imply greater or lesser performance, depending on the stringency of the guarantees and associated penalties for nonperformance. The willingness of vendors to provide guarantees and the limits of these guarantees can be an important factor in determining the level of performance specified in a PSD permit. A vendor guarantee of a certain level of performance may be considered by the permitting authority later in the BACT process when proposing a specific emissions limit or level of performance in the PSD permit. However, a control technology should not be eliminated in Step 2 of the top-down BACT process based solely on the inability to obtain a commercial guarantee from a vendor on the application of technology to a source type.

[90] *In re Cardinal FG Company*, 12 E.A.D. at 14; *In re Steel Dynamics, Inc.*, 9 E.A.D. at 199.

Further, a technology should not be eliminated as technically infeasible due to costs. Where the resolution of technical difficulties is a matter of cost, this analysis should occur in BACT Step 4.

GHG-Specific Considerations

EPA's historic approach to assessing technical feasibility that is summarized above and described in the 1990 Workshop Manual and subsequent actions such as EAB decisions is generally applicable to GHGs. The nature of the concerns and remedies arising from identification of available technologies is well-explained in the 1990 Workshop Manual and other referenced documents. However, technologies available for controlling traditional pollutants were, in many cases, well-developed at the time that the 1990 Workshop Manual was drafted. Similarly, we expect the commercial availability of different GHG controls to increase in the coming years. Permitting authorities need to make sure that their decisions regarding technical infeasibility are well-explained and supported in their permitting record, paying particular attention to the most recent information from the commercial sector and other recently-issued permits.

This guidance is being issued at a time when add-on control technologies for certain GHGs or emissions sources may be limited in number and in various stages of development and commercialization. A number of ongoing research, development, and demonstration programs may make CCS technologies more widely applicable in the future.[91] These facts are important to BACT Step 2, wherein technically infeasible control options are eliminated from further consideration. When considering the guidance provided below, permitting authorities should be aware of the changing status of various control options for GHG emissions when determining BACT.

In the early years of GHG control strategies, consideration of commercial guarantees is likely to be involved in the BACT determination process. This type of guarantee may be more relevant for certain GHG controls because, unlike other pollutants with available, proven control technologies, some GHG controls may have a greater uncertainty regarding their expected performance. As noted above, the lack of availability of a commercial guarantee, by itself, is not a sufficient basis to classify a technology as "technologically infeasible" for BACT evaluation purposes, even for GHG control determinations.

As discussed earlier, although CCS is not in widespread use at this time, EPA generally considers CCS to be an "available" add-on pollution control technology for facilities emitting CO_2 in large amounts and industrial facilities with high-purity CO_2 streams. Assuming CCS has been included in Step 1 of the top-down BACT process for such sources, it now must be evaluated for technical feasibility in Step 2. CCS is composed of three main components: CO_2 capture and/or compression, transport, and storage. CCS may be eliminated from a BACT analysis in Step 2 if it can be shown that there are significant differences pertinent to the successful operation for each of these three main components from what has already been applied to a differing source type. For example, the temperature, pressure, pollutant

[91] For example, the U.S. Department of Energy has a robust CCS research, development, and demonstration program supported by annual appropriations and $3.4B of Recovery Act funds. See www.fe.doe.gov.

concentration, or volume of the gas stream to be controlled, may differ so significantly from previous applications that it is uncertain the control device will work in the situation currently undergoing review. Furthermore, CCS may be eliminated from a BACT analysis in Step 2 if the three components working together are deemed technically infeasible for the proposed source, taking into account the integration of the CCS components with the base facility and site-specific considerations (*e.g.,* space for CO_2 capture equipment at an existing facility, right-of-ways to build a pipeline or access to an existing pipeline, access to suitable geologic reservoirs for sequestration, or other storage options).

While CCS is a promising technology, EPA does not believe that at this time CCS will be a technically feasible BACT option in certain cases. As noted above, to establish that an option is technically infeasible, the permitting record should show that an available control option has neither been demonstrated in practice nor is available and applicable to the source type under review. EPA recognizes the significant logistical hurdles that the installation and operation of a CCS system presents and that sets it apart from other add-on controls that are typically used to reduce emissions of other regulated pollutants and already have an existing reasonably accessible infrastructure in place to address waste disposal and other offsite needs. Logistical hurdles for CCS may include obtaining contracts for offsite land acquisition (including the availability of land), the need for funding (including, for example, government subsidies), timing of available transportation infrastructure, and developing a site for secure long term storage. Not every source has the resources to overcome the offsite logistical barriers necessary to apply CCS technology to its operations, and smaller sources will likely be more constrained in this regard. Based on these considerations, a permitting authority may conclude that CCS is not applicable to a particular source, and consequently not technically feasible, even if the type of equipment needed to accomplish the compression, capture, and storage of GHGs are determined to be generally available from commercial vendors.

The level of detail supporting the justification for the removal of CCS in Step 2 will vary depending on the nature of the source under review and the opportunities for CO_2 transport and storage. As with all top-down BACT analyses, cost considerations should not be included in Step 2 of the analysis, but can be considered in Step 4. In circumstances where CO_2 transportation and sequestration opportunities already exist in the area where the source is, or will be, located, or in circumstances where other sources in the same source category have applied CCS in practice, the project would clearly warrant a comprehensive consideration of CCS. In these cases, a fairly detailed case-specific analysis would likely be needed to dismiss CCS. However, in cases where it is clear that there are significant and overwhelming technical (including logistical) issues associated with the application of CCS for the type of source under review (*e.g.,* sources that emit CO_2 in amounts just over the relevant GHG thresholds and produce a low purity CO_2 stream) a much less detailed justification may be appropriate and acceptable for the source. In addition, a permitting authority may make a determination to dismiss CCS for a small natural gas-fired package boiler, for example, on grounds that no reasonable opportunity exists for the capture and long-term storage or reuse of captured CO_2 given the nature of the project. That finding may be sufficient to dismiss CCS for similar units in subsequent BACT reviews, provided the facts upon which the original finding was made also apply to the subsequent units and are still valid.

D. BACT Step 3 – Ranking of Controls

General Concepts

After the list of all available controls is winnowed down to a list of the technically feasible control technologies in Step 2, Step 3 of the top-down BACT process calls for the remaining control technologies to be listed in order of overall control effectiveness for the regulated NSR pollutant under review. The most effective control alternative (*i.e.,* the option that achieves the lowest emissions level) should be listed at the top and the remaining technologies ranked in descending order of control effectiveness. The ranking of control options in Step 3 determines where to start the top-down BACT selection process in Step 4.[92]

In determining and ranking technologies based on control effectiveness, applicants and permitting authorities should include information on each technology's control efficiency (*e.g.,* percent pollutant removed, emissions per unit product), expected emission rate (*e.g.,* tons per year, pounds per hour, pounds per unit of product, pounds per unit of input, parts per million), and expected emissions reduction (*e.g.,* tons per year). The metrics chosen for ranking should best represent the array of control technology alternatives under consideration. While input-based metrics have traditionally been the preferred ranking format for many BACT analyses, for some source types, particularly combustion sources, it may be more appropriate to rank control options based on output-based metrics that would fully consider the thermal efficiency of the options when determining control effectiveness. In particular, where the output of the facility or the affected source is relatively homogeneous, an output-based standard (*e.g.,* pounds per megawatt hour of electricity, pounds per ton of cement, etc.) may best present the overall emissions control of an array of control options. Where appropriate, net output-based standards provide a direct measure of the energy efficiency of an operation's emission-reducing efforts. However, in the simple case of a new or modified fuel-fired unit, the thermal efficiency of the unit can be a useful ranking metric. Furthermore, when the output of the facility is a changing mix of products, an output-based standard may not be appropriate.

GHG-Specific Considerations

As discussed in earlier sections, the options considered in a BACT analysis for GHG emissions will likely include, but not necessarily be limited to, control options that result in energy efficiency measures to achieve the lowest possible emission level. Where plant-wide measures to reduce emissions are being considered as GHG control techniques, the concept of overall control effectiveness will need to be refined to ensure the suite of measures with the lowest net emissions from the facility is the top-ranked measure. Ranking control options based on their net output-based emissions ensures that the thermal efficiency of the control option, as well as the power demand of that control measure, is fully considered when comparing options in Step 3 of the BACT analysis.

[92] EPA has previously recommended that Step 3 of a BACT analysis include an assessment of the energy, environmental, and economic impacts of each remaining option on the list. See 1990 Workshop Manual at B.25. However, the energy, environmental, and economic impacts of the control options are not actually compared until Step 4 of the process. See 1990 Workshop Manual at B.26. Thus, the compilation of this information can be accomplished in either Step 3 or Step 4 of the process.

Finally, to best reflect the impact on the environment, the ranking of control options should be based on the total CO_2e rather than total mass or mass for the individual GHGs. As explained in the Tailoring Rule, the CO_2e metric will "enable the implementation of flexible approaches to design and implement mitigation and control strategies that look across all six of the constituent gases comprising the air pollutant (*e.g.,* flexibility to account for the benefits of certain CH_4 control options, even though those options may increase CO_2).[93]

E. BACT Step 4 – Economic, Energy, and Environmental Impacts

General Concepts

Under Step 4 of the top-down BACT analysis, permitting authorities must consider the economic, energy, and environmental impacts arising from each option remaining under consideration. Accordingly, after all available and technically feasible control options have been ranked in terms of control effectiveness (BACT Step 3), the permitting authority should consider any specific energy, environmental, and economic impacts identified with those technologies to either confirm that the top control alternative is appropriate or determine it to be inappropriate. The "top" control option should be established as BACT unless the applicant demonstrates, and the permitting authority agrees, that the energy, environmental, or economic impacts justify a conclusion that the most stringent technology is not "achievable" in that case. If the most stringent technology is eliminated in this fashion, then the next most stringent alternative is considered, and so on.

In BACT Step 4, the applicant and permitting authority should consider both direct and indirect impacts of the emissions control option or strategy being evaluated. EPA has previously referred to BACT Step 4 as the "collateral impacts analysis,"[94] but this term is primarily applicable only to the environmental impact analysis. Overall, the Step 4 analysis is more accurately described as an environmental, economic, and energy impacts analysis that includes both direct and indirect (*i.e.,* collateral) considerations.

The economic impacts component of the analysis should focus on direct economic impacts calculated in terms of cost effectiveness (dollars per ton of pollutant emission reduced). Cost effectiveness should be addressed on both an average basis for each measure and combination of measures, and on an incremental basis comparing the costs and emissions performance level of a control option to the cost and performance of the next most stringent control option.[95] The emphasis should be on the cost of control relative to the amount of pollutant removed, rather than economic parameters that provide an indication of the general affordability of the control alternative relative to the source. To justify elimination of an option on economic grounds, the permit applicant should demonstrate that the costs of pollutant

---

[93] 75 FR at 31531-2.
[94] *In re Hillman Power,* 10 E.A.D. at 683; *In the Matter of Columbia Gulf Transmission Co*., 2 E.A.D. 824, 828 n. 5 (Adm'r 1989); *In re Kawaihae Cogeneration Project*, 7 E.A.D. 107, 116-17 (EAB 1997).
[95] 1990 Workshop Manual, Section IV.D.2.b (B.36 – B.44).

removal for that option are disproportionately high.[96] Appendix K provides further direction on determining and considering cost effectiveness of control options. As noted in Appendix K, cost estimates used in BACT are typically accurate to within ± 20 to 30 percent.

EPA has traditionally called for the energy impacts analysis to consider only direct energy consumption and not indirect energy impacts, such as the energy required to produce raw materials for construction of control equipment.[97] Direct energy consumption impacts include the consumption of fuel and the consumption of electrical or thermal energy. This energy impacts analysis should include an assessment of demand for both electricity that is generated onsite and power obtained from the electrical grid, and may include an evaluation of impacts on fuel scarcity or a locally desired fuel mix in a particular area. Applicants and permitting authorities should examine whether the energy requirements for each control option result in any significant or unusual energy penalties or benefits.[98] The costs associated with direct energy impacts should be calculated and included in the economic impacts analysis (*i.e.,* cost analysis).[99]

Since a BACT limitation must reflect the maximum degree of reduction achievable for each regulated pollutant, the environmental impacts analysis in Step 4 should concentrate on impacts other than direct impacts due to emissions of the regulated pollutant in question. EPA has previously recommended focusing the BACT environmental impacts analysis in this manner to avoid confusion with the separate air quality impact analysis required under the CAA and PSD regulations for primarily the pollutants that are covered by NAAQS.[100] However, focusing Step 4 of the BACT analysis on increases in emissions of pollutants other than those the technology was designed to control is also justified because the essential purpose of BACT requirement is to achieve the maximum degree of reduction of the particular pollutant under evaluation. In this context, it is generally unnecessary to explicitly consider or justify the environmental benefits of reducing the pollutant subject to the BACT analysis, since these benefits are presumed under the CAA's mandate to reduce emissions of each regulated pollutant to the maximum degree achievable, considering energy, environmental, and economic impacts. Thus, in this context, it is reasonable to interpret the "environmental impact" component of the BACT requirement to focus on the indirect or collateral environmental impacts that may result from selection of control options that achieve the maximum degree of reduction for the pollutant under evaluation.

EPA has recognized that consideration of a wide variety of environmental impacts is appropriate in BACT Step 4, such as solid or hazardous waste generation, discharges of polluted water from a control device, visibility impacts, demand on local water resources, and emissions of other pollutants subject to NSR or pollutants not regulated under NSR such as air toxics.[101] EPA has also recognized that the environmental impacts analysis may examine trade-offs

[96] 1990 Workshop Manual at B.31-32.
[97] *In re Power Holdings*, PSD Appeal No. 09-04 (EAB Aug. 13, 2010), slip op. at 22, n.17 (citing 1990 Workshop Manual at B.30).
[98] 1990 Workshop Manual at B.29.
[99] 1990 Workshop Manual at B.30.
[100] 1990 Workshop Manual at B.46.
[101] 1990 Workshop Manual at B.46; *In the Matter of North County Resource Recovery Assoc.*, 2 E.A.D. 229, 230 (Adm'r 1986).; *In the Matter of Columbia Gulf Transmission Co.*, 2 E.A.D. at 828.

between emissions of various pollutants resulting from the application of a specific control technique.[102] For instance, in selecting the BACT limit for carbon monoxide (CO) for a facility in an area that is nonattainment for ozone, a permitting authority may need to assess whether it is more important to select a less stringent control for CO emissions to avoid an unacceptable increase in NO_X emissions associated with the CO control technology. EPA has generally not attempted to place specific limits on the scope of the Step 4 environmental impacts analysis, but has focused on "any significant or unusual environmental impacts."[103]

To date, the environmental impacts analysis has not been a pivotal consideration when making BACT determinations in most cases.[104] Typically, applicants and permitting authorities focus on direct economic impacts (*i.e.,* cost effectiveness as measured in annualized cost per tons of pollutant removed by that control) as the reason for not selecting the top-ranked control option as BACT; however, there have been instances where environmental impacts have been a deciding factor in selecting a specific control technology as BACT (*i.e.,* water usage for scrubbers).[105]

Because the Step 4 impacts analysis is intended to help the permitting authority identify and weigh the various beneficial and detrimental impacts of the emissions control option or strategy being evaluated, EPA has recognized that permitting authorities have flexibility in deciding how to weigh the trade-offs associated with emissions control options. However, inherent with the flexibility is the responsibility of the permitting authority to develop a full permit record that explains those decisions given the specific facts of the facility at issue.[106]

GHG-Specific Considerations

There are compelling public health and welfare reasons for BACT to require all GHG reductions that are achievable, considering economic impacts and the other listed statutory factors. As a key step in the process of making GHGs a regulated pollutant, EPA has considered scientific literature on impacts of GHG emissions and has made a final determination that emissions of six GHGs endanger both the public health and the public welfare of current and future generations.[107] Among the public health impacts and risks that EPA cited are anticipated increases in ambient ozone and serious ozone-related health effects, increased likelihood of heat

[102] 1990 Workshop Manual at B.49.
[103] *In re Hillman Power* 10 E.A.D. at 684 (internal quotations omitted).
[104] 1990 Workshop Manual at B.49-50; *In the Matter of Columbia Gulf Transmission Co.*, 2 E.A.D. at 828; *In re Hillman Power*, 10 E.A.D. at 688; *In re Kawaihae Cogeneration*, 7 E.A.D. at 117.
[105] Wyoming Dept. of Environmental Quality, Basin Electric Power Cooperative – Dry Fork Station, Permit Application Analysis NSR-AP-3546 (Feb. 5, 2007) at 11 (selecting a dry scrubber as BACT based, in part, on the "negative environmental impact" of the higher water use associated with the wet scrubber); *cf. In re Kawaihae Cogeneration Project*, 7 E.A.D. at 114-119 (upholding permitting decision in which the permitting authority considered the environmental impacts of ammonia used for SCR technology but found the increase in ammonia emissions were not significant enough to warrant use of less stringent NOx control technology)
[106] 1990 Workshop Manual at B.8-9. *See also Alaska Dept. of Environmental Conservation v. EPA*, 540 U.S. 461, 485-495 (2004) (finding EPA has the authority to review state BACT decisions to determine whether they complied with the CAA and upholding EPA's right to issue stop construction orders upon finding a state permitting authority's BACT determination was unreasonable).
[107] *Endangerment and Cause or Contribute Findings for Greenhouse Gases Under Section 202(a) of the Clean Air Act; Final Rule*, 74 FR 66496, December 15, 2009.

waves affecting mortality and morbidity, risk of increased intensity of hurricanes and floods, and increased severity of coastal storm events due to rising sea levels. With respect to public welfare, EPA cited numerous and far-ranging risks to food production and agriculture, forestry, water resources, sea level rise and coastal areas, energy, infrastructure, and settlements, and ecosystems and wildlife. The potentially serious adverse impacts of extreme events such as wildfires, flooding, drought and extreme weather conditions also supported EPA's finding.

The energy, environmental, and economic impacts discussed in the section above should be considered for each GHG control technology when conducting a top-down analysis. In conducting the energy, environmental and economic impacts analysis, permitting authorities have "a great deal of discretion" in deciding the specific form of the BACT analysis and the weight to be given to the particular impacts under consideration.[108] EPA and other permitting authorities have most often used this analysis to eliminate more stringent control technologies with significant or unusual effects that are unacceptable in favor of the less stringent technologies with more acceptable collateral environmental effects. However, EPA has also interpreted the BACT requirements to allow for a more stringent technology to remain in consideration as BACT if the collateral environmental benefits of choosing such a technology outweigh the economic or energy costs of that selection.[109] In other words, the permitting authority is not limited to evaluating the impacts of only the "top" or most effective technology but can assess the impacts of all technologies under consideration.[110] The same principle applies when assessing technologies for controlling GHGs.

When conducting a BACT analysis for GHGs, the environmental impact analysis should continue to concentrate on impacts other than the direct impacts due to emissions of the regulated pollutant in question. Where GHG control strategies affect emissions of other regulated pollutants, applicants and permitting authorities should consider the potential trade-offs of selecting particular GHG control strategies. Likewise, when conducting a BACT analysis for other regulated NSR pollutants, applicants and permitting authorities should take care to consider how the control strategies under consideration may affect GHG emissions. For example, controlling volatile organic compound (VOC) emissions with a catalytic oxidation system creates GHG emissions in the form of CO_2. Permitting authorities have flexibility when evaluating the trade-offs associated with decreasing one pollutant at the cost of increasing another, and the specific considerations made will depend on the facts of the specific permit at issue. For options that involve improvements in the energy efficiency of a source, EPA does not expect there to be significant trade-offs in emissions of regulated pollutants since energy efficiency improvements should generally reduce emissions of all pollutants resulting from combustion processes.

When weighing any trade-offs between emissions of GHGs and emissions of other regulated NSR pollutants, EPA recommends that permitting authorities focus on the relative levels of GHG emissions rather than the endpoint impacts of GHGs. As a general matter, GHG emissions contribute to global warming and other climate changes that result in impacts on the environment and society. However, due to the global scope of the problem, climate change

[108] *In re Hillman Power*, 10 E.A.D. at 684.
[109] *In the Matter of North County Resource Recovery Assoc.*, 2 E.A.D. at 230-31.
[110] *In re Knauf Fiber Glass,* 8 E.A.D. at 131 n. 15.

modeling and evaluations of risks and impacts of GHG emissions currently is typically conducted for changes in emissions orders of magnitude larger than the emissions from individual projects that might be analyzed in PSD permit reviews. Quantifying these exact impacts attributable to the specific GHG source obtaining a permit in specific places is not currently possible with climate change modeling. Given these considerations, an assessment of the potential increase or decrease in the overall level of GHG emissions from a source would serve as the more appropriate and credible metric for assessing the relative environmental impact of a given control strategy. Thus, when considering the trade-offs between the environmental impacts of a particular level of GHG reduction and a collateral increase in another regulated NSR pollutant, rather than attempting to determine or characterize specific environmental impacts from GHGs emitted at particular locations, EPA recommends that permitting authorities focus on the amount of GHG emission reductions that may be gained or lost by employing a particular control strategy and how that compares to the environmental or other impacts resulting from the collateral emissions increase of other regulated NSR pollutants.

In determining how to value or weigh any trade-offs in emissions for regulated pollutants (including GHGs), permitting authorities should continue to focus on "significant or unusual environmental impacts that have the potential to affect the selection or elimination of a control alternative."[111] Relatively small collateral increases of another pollutant need not be of concern, unless even that small increase would be significant, such as a situation where an area is close to exceeding a NAAQS or PSD increment and the additional increase could push the area into nonattainment. Thus, to assess the significance of an emissions increase or decrease, a permitting authority should give some consideration to the impacts of a given amount of emissions. However, permitting authorities need not consider every possible environmental endpoint impact of every conceivable technology. The top-down BACT process calls for evaluating only those control alternatives that remain under consideration at BACT Step 4 of the analysis. Thus, when a trade-off is present, permitting authorities may limit their consideration of environmental impacts to only to those control options in which the comparison of GHG emissions to other regulated NSR pollutants might actually lead to a different selection of BACT for that facility.

With respect to the evaluation of the economic impacts of GHG control strategies, it may be appropriate in some cases to assess the cost effectiveness of a control option in a less detailed quantitative (or even qualitative) manner. For instance, when evaluating the cost effectiveness of CCS as a GHG control option, if the cost of building a new pipeline to transport the CO_2 is extraordinarily high and by itself would be considered cost prohibitive, it would not be necessary for the applicant to obtain a vendor quote and evaluate the cost effectiveness of a CO_2 capture system. As with all evaluations of economics, a permitting authority should explain its decisions in a well-documented permitting record.

EPA recognizes that at present CCS is an expensive technology, largely because of the costs associated with CO_2 capture and compression, and these costs will generally make the price of electricity from power plants with CCS uncompetitive compared to electricity from plants with other GHG controls. Even if not eliminated in Step 2 of the BACT analysis, on the basis of the current costs of CCS, we expect that CCS will often be eliminated from consideration in

[111] *In re Hillman Power*, 10 E.A.D. at 684.

Step 4 of the BACT analysis, even in some cases where underground storage of the captured CO_2 near the power plant is feasible. However, there may be cases at present where the economics of CCS are more favorable (for example, where the captured CO_2 could be readily sold for enhanced oil recovery), making CCS a more viable option under Step 4. In addition, as a result of the ongoing research and development described in the Interagency Task Force Report noted above, CCS may become less costly and warrant greater consideration in Step 4 of the BACT analysis in the future.

As in the past for criteria pollutant BACT determinations, the final decision regarding the reasonableness of calculated cost effectiveness values will be made by the permitting authority. This decision is typically made by considering previous regulatory and permitting decisions for similar sources. As noted above, to justify elimination of a control option on economic grounds, the permit applicant should demonstrate that the costs of pollutant removal for the particular option are disproportionately high. However, given that there is little history of BACT analyses for GHG at this time, there is not a wealth of GHG cost effectiveness data from prior permitting actions for a permitting authority to review and rely upon when determining what cost level is considered acceptable for GHG BACT. As the permitting of sources of GHG progresses and more experience is gained, additional data to determine what is cost effective in the context of individual permitting actions will become known and should be included in the RBLC. We note, however, that when looking at pollutants historically regulated under the PSD Program, such as criteria pollutants, the cost effectiveness of a control device is based on a significantly lower volume of emissions than the amount of emissions that are emitted by most sources of GHGs. For example, a new boiler that is subject to the NSPS and emits 250 TPY of NO_X will emit well above 100,000 TPY of CO_2e. As a result, even taking account of the current limited data and consequent uncertainty concerning the costs of GHG BACT, it is reasonable to anticipate that the cost effectiveness numbers (in $/ton of CO_2e) for the control of GHGs will be significantly lower than those of the cost effectiveness values for controls of criteria pollutants that have evolved over time.[112]

With respect to energy impacts in a BACT analysis for GHGs, the relative energy demands of the options under consideration for reducing emissions from the facility obtaining a permit should be considered when weighing options for reducing direct emissions of GHGs in Step 4 of the analysis, regardless of the location where the thermal or electrical energy for the facility is produced. This analysis should include an assessment of how particular control options for GHGs may impact the amount of energy that must be produced at an offsite location to support the operation of the facility obtaining the permit. Given the potential emissions from generation of electricity, such impacts may also be considered in the context of environmental impacts.[113]

Permitting authorities also have flexibility when evaluating the trade-offs between energy, environmental, and economic impacts. In selecting a technology for GHG control, a

---

[112] For consistency purposes, cost effectiveness for GHG control options should be based on dollars per ton of CO_2e removed, rather than total mass or mass for the individual GHGs.

[113] As discussed above in the section on Step 1, energy efficiency improvements that only function to reduce the secondary emissions associated with offsite combustion to produce energy at another location should not be considered as options in the BACT analysis under existing EPA interpretations of its regulations.

permitting authority may find that while a control option with high overall energy efficiency has higher economic costs, those costs are outweighed by the overall reduction of emissions of all pollutants that comes from that higher efficiency. There are no "right" answers to these permitting decisions that can be described in this general guidance, because permitting authorities have a wide range of discretion in their consideration of the various direct and indirect economic, energy, and environmental impacts that might be informative to the top-down BACT analysis for GHG emissions, as well as the BACT determinations for other pollutants. Given the case-by-case nature of the BACT analysis and the importance of considering impacts on the local environment and community (*e.g.,* job loss and the potential movement of production overseas), EPA still believes this flexibility provided for deciding how best to weigh the trade-offs associated with a particular emissions control option continues to be appropriate when evaluating BACT for GHGs. The exact scope and detail of that consideration – including the final decision regarding various trade-offs that may arise in a permitting decision – is dependent on many factors, including the specific facts of the proposed facility, local interests and concerns, and the nature of issues raised in public comments. Accordingly, permitting authorities must ensure that their impacts analysis fully considers the relevant facts and concerns for the facility at issue and that the support for the environmental, economic, and energy choices made during the impacts analysis of the BACT determination is well-documented in the permit record. In so doing, we encourage permitting authorities to use their discretion to consider the full range of impacts from the various controls that could result in facilities that are energy efficient and that lower the overall impact of the GHG emissions from those facilities, while maintaining relatively high levels of controls of other pollutants.

F. BACT Step 5 – Selecting BACT

General Concepts

In Step 5 of the BACT determination process, the most effective control option not eliminated in Step 4 should be selected as BACT for the pollutant and emissions unit under review and included in the permit. During Step 3, permitting authorities often consider control alternatives that have a range of potential effectiveness for reducing the pollutant emissions at issue, and thus they must identify an expected emissions reduction range for each technology. In setting the BACT limit in Step 5, the permitting authority should look at the range of performance identified previously and determine a specific limit to include in the final permit. In determining the appropriate limit, the permitting authority can consider a range of factors, including the ability of the control option to consistently achieve a certain emissions rate, available data on past performance of the selected technology, and special circumstances at the specific source under review which might affect the range of performance.[114] In setting BACT limits, permitting authorities have the discretion to select limits that do not necessarily reflect the highest possible control efficiencies but that will allow compliance on a consistent basis based on the particular circumstances of the technology and facility at issue, and thus may consider safety factors unique to those circumstances in setting the limits.[115] EPA has also recognized that in

[114] *In re Prairie State Generating Company*, 13 E.A.D. at 67-71.
[115] *In re Prairie State Generating Company*, 13 E.A.D. at 71, 73 (and cases cited therein).

some circumstances, it may be acceptable to establish BACT limits that can be adjusted or optimized as the performance of a technology becomes clearer after a period of operation.[116]

The permitting authority is also responsible for defining the form of the BACT limits, and making them enforceable as a practical matter.[117] In determining the form of the limit, the permitting authority should consider issues such as averaging times and units of measurement. For example, a final permit may include a limit based on pounds of emissions on a 24-hour rolling average or a limit representing a percentage of pollutant per weight allowed in the fuel. When making sure the limit is practically enforceable, the permitting authority must include information regarding the methods that will be used for determining compliance with the limits (such as operational parameters, timing, testing methods, etc.) and ensure that there is no ambiguity in the permit terms themselves.[118]

Finally, the permitting authority bears the responsibility in Step 5 to fully justify the BACT decision in the permit record. Regardless of the control level proposed by the applicant as BACT, the ultimate determination of BACT is made by the permitting authority after public review is complete. The applicant's role is primarily to provide information on the various control options and, when it proposes a less stringent control option, provide a detailed rationale and supporting documentation for eliminating the more stringent options. It is the responsibility of the permitting authority to review the documentation and rationale presented in order to: (1) ensure that the applicant has addressed all of the most effective control options that could be applied and; (2) determine that the applicant has adequately demonstrated that energy, environmental, or economic impacts justify any proposal to eliminate the more effective control options. Where the permitting authority does not accept the basis for the proposed elimination of a control option, the permitting authority may inform the applicant of the need for more information regarding the control option. However, the BACT selection essentially should default to the highest level of control for which the applicant could not adequately justify its elimination based on energy, environmental and economic impacts. If the applicant is unable to provide to the permitting authority's satisfaction an adequate demonstration for one or more control alternatives, the permitting authority should proceed to establish BACT and prepare a draft permit based on the most effective control option for which an adequate justification for rejection was not provided.

GHG-Specific Considerations

We expect many permits issued after January 2, 2011, to initially place more of an emphasis on energy efficiency, given the role it plays in affecting emissions of GHGs. For energy producing sources, as noted above, one way to incorporate the energy efficiency of a process unit into the BACT analysis is to compare control effectiveness in BACT Step 3 based on output-based emissions of each of the control options. Even in cases where another metric is used in Step 3 to compare options, once an option is selected in Step 5, permitting authorities

[116] *In re AES Puerto Rico, L.P.*, 8 E.A.D. 324, 348-50 (EAB 1999), *In re Hadson Power 14-Buena Vista*, 4 E.A.D. 258, 291 (EAB 1992).
[117] *See generally* EPA Guidance on Limiting Potential to Emit (PTE) in New Source Permitting (June 13, 1989), *available at* http://www.epa.gov/reg3artd/permitting/t5_epa_guidance.htm.
[118] *In re Prairie State Generating Company*, 13 E.A.D. at 83, 120.

may consider converting the BACT emissions limit to a net output basis for the permitted emissions limit. EPA encourages permitting authorities to consider establishing an output-based BACT emissions limit, or a combination of output- and input-based limits, wherever feasible and appropriate to ensure that BACT is complied with at all levels of operation. Although developed as part of a voluntary program, EPA believes the draft handbook entitled *Output-Based Regulations: A Handbook for Air Regulators* (August 2004) may provide relevant information to assist permitting authorities in establishing limits based on output.[119] Furthermore, since the environmental concern with GHGs is with their cumulative impact in the environment, metrics should focus on longer-term averages (*e.g.,* 30- or 365-day rolling average) rather than short-term averages (*e.g.,* 3- or 24-hr rolling average).

In addition to a permit containing specific numerical emissions limits established in a BACT analysis, a permit can also include conditions requiring the use of a work practice such as an Environmental Management System (EMS) focused on energy efficiency as part of that BACT analysis. The ENERGY STAR program provides useful guidance on the elements of an energy management program. The inclusion of such a requirement would be appropriate where it is technically impractical to measure emissions and/or energy use from all of the equipment and processes of the plant and apply an output-based standard to each of them. For example, a candidate might be a factory with many different pieces of equipment and processes that use energy. In addition to a BACT emissions limit on the boiler providing energy, the permit could also lay out a requirement to implement an EMS along with a requirement that all suggested actions that result in net savings have to be implemented. Consequently, the plant will operate in the most efficient manner through gradual achievable improvements. However, design, equipment, or work practice standards may not be used in lieu of a numerical emissions limitation(s) unless there is a demonstration in the record that the criteria for applying such a standard are satisfied.

[119] *Output-Based Regulations: A Handbook for Air Regulators* (Draft Final Report) (August 2004), *available at* http://www.epa.gov/chp/documents/obr_final_9105.pdf.

IV. Other PSD Requirements

General Concepts

The PSD requirements include several provisions requiring new and modified major stationary sources to conduct air quality analyses that may involve air quality modeling and ambient monitoring. The applicant must demonstrate that the emissions of any regulated NSR pollutant do not cause or contribute to a violation of any NAAQS or PSD increments.[120] Several months of ambient air quality data must also be collected in some circumstances to support this analysis.[121] In addition, as part of the "additional impacts analysis," the applicant must provide an analysis of the air quality impact of the source or modification, including an analysis of the impairment to visibility, soils, and vegetation (but not vegetation with no significant commercial or recreational value) that would occur as a result of the source or modification and general commercial, residential, industrial, and other growth associated with the source or modification.[122] Under the federal PSD rules, this analysis may also include monitoring of visibility in any Federal Class I area near the source or modification "for such purposes and by such means as the Administrator deems necessary and appropriate."[123] A demonstration must be made that emissions will not cause or contribute to a violation of any Class I increment and will not have an adverse impact on any air quality related value (AQRV), as defined by the Federal Land Manager, in such area.[124] Under PSD, if a source's proposed project may impact a Class I area, the Federal Land Manager must be notified so this office may fulfill its responsibility for evaluating a source's projected impact on the AQRVs and recommending either approval or disapproval of the source's permit application based on anticipated impacts.

GHG-Specific Considerations

The Tailoring Rule includes the following statement with respect to these requirements:

> "There are currently no NAAQS or PSD increments established for GHGs, and therefore these PSD requirements would not apply for GHGs, even when PSD is triggered for GHGs. However, if PSD is triggered for a GHG emissions source, all regulated NSR pollutants which the new source emits in significant amounts would be subject to PSD requirements. Therefore, if a facility triggers review for regulated NSR pollutants that are non-GHG pollutants for which there are established NAAQS or increments, the air quality, additional impacts, and Class I requirements would apply to those pollutants."[125]

Since there are no NAAQS or PSD increments for GHGs,[126] the requirements in sections 52.21(k) and 51.166(k) of EPA's regulations to demonstrate that a source does not cause or

[120] 42 USC 7475(a)(3); 40 CFR 52.21(k); 40 CFR 51.166(k).
[121] 40 CFR 52.21(m); 40 CFR 51.166(m); 40 CFR 52.21(i)(5); 40 CFR 51.166(i)(5).
[122] 40 CFR 52.21(o); 40 CFR 51.166(o).
[123] 40 CFR 52.21(o)(3).
[124] 40 CFR 52.21(p); 40 CFR 51.166(p).
[125] 75 FR at 31520.
[126] In addition, GHGS have not been designated as a precursor for any criteria pollutant under section 302(g) of the Clean Air Act or in EPA's PSD rules.

contribute to a violation of the NAAQS is not applicable to GHGs. Thus, we do not recommend that PSD applicants be required to model or conduct ambient monitoring for CO_2 or GHGs.

Monitoring for GHGs is not required because EPA regulations provide an exemption in sections 52.21(i)(5)(iii) and 51.166(i)(5)(iii) for pollutants that are not listed in the appropriate section of the regulations, and GHGs are not currently included in that list. However, it should be noted that sections 52.21(m)(1)(ii) and 51.166(m)(1)(ii) of EPA's regulations apply to pollutants for which no NAAQS exists. These provisions call for collection of air quality monitoring data "as the Administrator determines is necessary to assess ambient air quality for that pollutant in any (or the) area that the emissions of that pollutant would affect." In the case of GHGs, the exemption in sections 52.21(i)(5)(iii) and 51.166(i)(5)(iii) is controlling since GHGs are not currently listed in the relevant paragraph. Nevertheless, EPA does not consider it necessary for applicants to gather monitoring data to assess ambient air quality for GHGs under section 52.21(m)(1)(ii), section 51.166(m)(1)(ii), or similar provisions that may be contained in state rules based on EPA's rules. GHGs do not affect "ambient air quality" in the sense that EPA intended when these parts of EPA's rules were initially drafted. Considering the nature of GHG emissions and their global impacts, EPA does not believe it is practical or appropriate to expect permitting authorities to collect monitoring data for purpose of assessing ambient air impacts of GHGs.

Furthermore, consistent with EPA's statement in the Tailoring Rule, EPA believes it is not necessary for applicants or permitting authorities to assess impacts from GHGs in the context of the additional impacts analysis or Class I area provisions of the PSD regulations for the following policy reasons. Although it is clear that GHG emissions contribute to global warming and other climate changes that result in impacts on the environment, including impacts on Class I areas and soils and vegetation due to the global scope of the problem, climate change modeling and evaluations of risks and impacts of GHG emissions is typically conducted for changes in emissions orders of magnitude larger than the emissions from individual projects that might be analyzed in PSD permit reviews. Quantifying the exact impacts attributable to a specific GHG source obtaining a permit in specific places and points would not be possible with current climate change modeling. Given these considerations, GHG emissions would serve as the more appropriate and credible proxy for assessing the impact of a given facility. Thus, EPA believes that the most practical way to address the considerations reflected in the Class I area and additional impacts analysis is to focus on reducing GHG emissions to the maximum extent. In light of these analytical challenges, compliance with the BACT analysis is the best technique that can be employed at present to satisfy the additional impacts analysis and Class I area requirements of the rules related to GHGs.

Applicants and permitting authorities should note that, while we are not recommending these analyses for GHG emissions, the incorporation of GHGs into the PSD program does not change the need for sources and permitting authorities to address these requirements for other regulated NSR pollutants. Accordingly, if PSD is triggered for a GHG emissions source, all regulated NSR pollutants which the source emits in significant amounts would be subject to these other PSD requirements. Therefore, if a facility triggers review for regulated NSR pollutants that are non-GHG pollutants for which there are established NAAQS or increments, the air quality, additional impacts, and Class I requirements must be satisfied for those pollutants and the applicant and permitting authority are required to conduct the necessary analysis.

V. Title V Considerations

A. General Concepts and Title V Requirements

Under the CAA, major sources (and certain other sources) must apply for, and operate in accordance with, an operating permit that contains conditions necessary to assure compliance with all CAA requirements applicable to the source.[127] The operating permit requirements under title V are intended to improve sources' compliance with other CAA requirements. Title V generally does not add new pollution control requirements, but it does require that each permit contain all air quality control requirements or "applicable requirements" required under the CAA (*e.g.,* NSPS and SIP requirements, including PSD), and it requires that certain procedural requirements be followed, especially with respect to compliance with these requirements. "Applicable requirements" for title V purposes include stationary source requirements, but do not include mobile source requirements. Procedural requirements include providing review of permits by EPA, states, and the public, requiring permit holders to track, report, and annually certify their compliance status with respect to their permit requirements, and otherwise ensuring that permits contain conditions to assure compliance with applicable requirements.

This section discusses title V requirements as they pertain to GHGs. These include the applicability requirement for title V permitting due to GHG emissions (*e.g.*, when a source will become subject to title V for the first time due to its GHG emissions), and requirements for permit applications and permit content. Under Step 1 of the Tailoring Rule, no sources become major sources requiring a title V permit solely as a result of GHG emissions. Sources must address GHGs in a title V permit only if they must address GHGs in their PSD permit (thus, they are a PSD "anyway source" or undergo an "anyway modification"). Beginning in Step 2 of the Tailoring Rule, a stationary source may be a major source subject to title V permitting requirements solely on the basis of its GHG emissions, provided the source exceeds the thresholds established in the Tailoring Rule (discussed below).

Under both Step 1 and Step 2 of the Tailoring Rule, when a source is required to address GHGs in their title V permit, the permit needs to meet the generally applicable title V application and permitting requirements for GHGs, such as describing emissions of GHGs and including in the permit any applicable requirements for GHGs established under other CAA programs (*e.g.*, the PSD program). The source's operating permit application generally must contain emissions-related information for: (1) all pollutants for which the source is major (see the definition of "major stationary source" in 40 CFR 70.2, which incorporates the requirements that a pollutant be subject to regulation, and an emissions threshold for GHG); and (2) all emissions of "regulated air pollutants" (which, under 40 CFR 70.2, includes criteria pollutants, VOCs, and pollutants regulated under CAA Section 111 or 112 standards, but does not currently include GHGs). In addition, the permitting authority shall require sources to provide additional emissions information sufficient to verify which requirements are applicable to the source and

[127] Details of the title V program are addressed in rules promulgated by EPA – 40 CFR 70 addresses programs implemented by state and local agencies and tribes, and 40 CFR 71 addresses programs generally implemented by EPA.

other specific information that may be necessary to implement and enforce other applicable requirements of the CAA or to determine the applicability of such requirements.[128]

Since the Tailoring Rule establishes a phased applicability approach under title V, the pertinent requirements vary somewhat between the first two steps of the Tailoring Rule. The following is a summary of the key requirements and some general examples with respect to title V applicability and title V permitting requirements (including permit application and permit content) with respect to GHGs under Steps 1 and 2 of the Tailoring Rule.

B. *Title V Applicability Requirements and GHGs*

Applicability requirements for title V permitting as they apply to GHG emissions are summarized in the following table and explained in more detail in subsections V.B.1 and V.B.2 following the table:

Table V-A. Summary of Title V Applicability Criteria for Sources of GHGs

January 2, 2011, to June 30, 2011 (Step 1 of the Tailoring Rule)	**On or after July 1, 2011 (Step 2 of the Tailoring Rule)**
No sources are subject to title V permitting solely as a result of their emissions of GHGs. (Thus, no new title V sources come into the title V program as a result of GHG emissions.) [However, for sources subject to, or that become newly subject to, title V for non-GHG pollutants (*i.e.*, PSD "anyway sources"), sources and permitting authorities need to meet the generally applicable title V application and permitting requirements as necessary to address GHGs, such as including in the permit any applicable requirements for GHGs established under other CAA programs.]*	The following sources are subject to title V permitting requirements as a result of their GHG emissions: • Existing or newly constructed GHG emission sources (not already subject to title V) that emit or have a PTE equal to or greater than: o 100,000 TPY CO_2e, **and** o 100 TPY GHGs mass basis [As with Step 1, for all PSD "anyway sources" subject to title V in Step 2, sources and permitting authorities need to meet the generally applicable title V application and permitting requirements as necessary to address GHGs, such as including in the permit any applicable requirements for GHGs established under other CAA programs]*

* It is expected, at least at the outset, that this will consist primarily of meeting application and permitting requirements necessary to assure compliance with PSD permitting requirements for GHGs. See accompanying text in Section V.C of this guidance for further discussion and examples.

1. *Applicability under Tailoring Rule Step* 1

Under Step 1, no sources are subject to title V permitting solely as a result of their emissions of GHGs. Thus no new title V sources come into the title V program solely as a result of GHG emissions. However, sources required to have title V permits because they are PSD "anyway sources" or undergo PSD "anyway modifications" will be required to address GHGs as

---

[128] 40 CFR 70.5.

part of their title V permitting to the extent necessary to assure compliance with GHG applicable requirements established under other CAA programs. Section C below describes how sources and permitting authorities should consider addressing GHG requirements in permitting actions.

2. *Applicability under Tailoring Rule Step 2*

Beginning in Step 2 of the Tailoring Rule, a stationary source may be a major source subject to title V permitting requirements solely on the basis of its GHG emissions, provided the source exceeds the thresholds established in the Tailoring Rule. GHG emission sources that emit or have the PTE at least 100,000 TPY CO_2e, and also emit or have the PTE 100 TPY of GHGs on a mass basis will be required to obtain a title V permit if they do not already have one. It is important to note that the requirement to obtain a title V permit will not, by itself, result in the triggering of additional substantive requirements for control of GHG. Rather, these new title V permits will simply incorporate whatever applicable CAA requirements, if any, apply to the source being permitted.

Both of the following conditions need to be met in order for title V to apply under Step 2 of the Tailoring Rule to a GHG emission source:

(1) An existing or newly constructed source emits or has the PTE GHGs in amounts that equal or exceed 100 TPY calculated as the sum of the six well-mixed GHGs on a mass basis (no GWPs applied).

(2) An existing or newly constructed source emits or has the PTE GHGs in amounts that equal or exceed 100,000 TPY calculated as the sum of the six well-mixed GHGs on a CO_2e basis (GWPs applied).

In Step 2, as under Step 1, for all sources otherwise subject to title V for non-GHG pollutants (*i.e.,* anyway sources), sources and permitting authorities will need to meet the generally applicable title V application and permitting requirements as they pertain to GHG applicable requirements established under other CAA programs (*e.g.,* the PSD program). See Section C below for further discussion of permitting requirements.

C. Permitting Requirements

Under both Steps 1 and 2 of the Tailoring Rule, as with other applicable requirements related to non-GHG pollutants, any applicable requirement for GHGs must be addressed in the title V permit (*i.e.,* the permit must contain conditions necessary to assure compliance with applicable requirements for GHGs). EPA anticipates that the initial applicable requirements for GHGs will be in the form of GHG control requirements resulting from PSD permitting actions. It is important to note that GHG reporting requirements for sources established under EPA's final rule for the mandatory reporting of GHGs (40 CFR Part 98: Mandatory Greenhouse Gas Reporting, hereafter referred to as the "GHG reporting rule") are currently not included in the definition of applicable requirement in 40 CFR 70.2 and 71.2. Although the requirements contained in the GHG reporting rule currently are not considered applicable requirements under the title V regulations, the source is not relieved from the requirement to comply with the GHG reporting rule separately from compliance with their title V operating permit. It is the responsibility of each source to determine the applicability of the GHG reporting rule and to comply with it, as necessary. However, since the requirements of the GHG reporting rule are not considered applicable requirements under title V, they do not need to be included in the title V permit.

Under both Steps 1 and 2 of the Tailoring Rule, sources will need to include in their title V permit applications, among other things: citation and descriptions of any applicable requirements for GHGs (*e.g.,* GHG BACT requirements resulting from a PSD review process), information pertaining to any associated monitoring and other compliance activities, and any other information considered necessary to determine the applicability of, and impose, any applicable requirements for GHGs. This is the same application information required under title V for applicable requirements pertaining to conventional pollutants.

As a general matter, all title V permits issued by permitting authorities must contain, among other things, emissions limitations and standards necessary to assure compliance with all applicable requirements for GHGs, all monitoring and testing required by applicable requirements for GHGs, and additional compliance certification, testing, monitoring, reporting, and recordkeeping requirements sufficient to assure compliance with GHG-related terms and conditions of the permit. Permitting authorities will also need to request from sources any information deemed necessary to determine or impose GHG applicable requirements.

It is possible that some sources will need to address GHG-related information in their applications even if they will ultimately not have any GHG-specific applicable requirements (such as a PSD-related BACT requirement for GHGs) included in their permit. This is because, as noted above, permitting authorities would need to request information related to identifying GHG emission sources and other information if they determine such information is necessary to determine applicable requirements. Following is an explanation of the basis for requesting this information and some examples of these types of scenarios under Steps 1 and 2 of the Tailoring Rule.

Under Step 1 of the Tailoring Rule, no source can be major for purposes of title V solely on the basis of its GHG emissions, so the requirement set forth in 40 CFR 70.5 for the source to provide emissions-related information for pollutants for which the source is major does not apply. In addition, as GHGs are not currently considered regulated air pollutants under the title V regulations, the requirement to provide emissions-related information for regulated air pollutants does not apply. However, consistent with the requirements set forth in 40 CFR 70.5, permitting authorities will need to ask for any emissions or other information they deem necessary to determine applicability of, or impose, a CAA requirement.[129] Therefore, during Step 1 of the Tailoring Rule, any source going through a title V permitting action (*i.e.,* applying for a title V operating permit or undergoing a permit revision, reopening or renewal) would need

[129] Note that the phrase "subject to regulation" in the definition of major source in the title V regulations affects when a source may be a major source subject to title V as a result of emissions of a pollutant. If a source is already subject to title V, its application must include any information considered necessary to determine or impose a GHG applicable requirement – this is true even before GHGs become "subject to regulation" for major sources purposes.

to provide GHG emissions or other information if a permitting authority needs the information to determine applicability of a CAA requirement (*e.g.*, PSD).[130] The following is an example of where this request for information might occur:

> *An existing title V source is making a physical change that triggers PSD for NO_X. This change will result in additional applicable requirements for NO_X emissions controls but, according to the applicant, does not trigger BACT review for GHGs. In this case, as part of its analysis of the application for permit revision under its title V program, the permitting authority may determine it necessary to verify that the project did not trigger BACT requirements for GHG emissions, and therefore may need to request the applicant to submit GHG emissions information related to the project sufficient for the permitting authority to determine that PSD did not apply for GHG emissions from the project. This information could include such items as identification and descriptions of any GHG emission units and estimates of GHG emissions associated with the modification project.*

Under Step 2 of the Tailoring Rule, beginning July 1, 2011, a stationary source may be subject to title V permitting requirements solely on the basis of its GHG emissions, provided the source is equal to or greater than the 100,000 TPY CO_2e subject to regulation threshold (as well as the 100 TPY major source mass-based threshold) on a PTE basis. As noted above, sources generally must provide information regarding all emissions of pollutants for which they are major. In many cases, particularly where the source has no applicable requirements for GHGs, emissions descriptions (instead of estimates) may be sufficient. For sources subject to the GHG reporting rule, the emissions description requirements in the title V rules will generally be satisfied by information provided under the reporting rule. Further elaboration on the requirement for emissions data is provided in the White Paper 1 guidance on title V.[131] The following is an example of a permitting scenario under title V during Step 2 of the Tailoring Rule:

> *As of July 1, 2011, an existing facility not previously subject to title V has a GHG PTE over 100,000 TPY CO_2e and over 100 TPY on a mass basis. Therefore, according to the Tailoring Rule applicability criteria for GHG sources, this source becomes subject to title V solely based on its GHG emissions as of July 1, 2011. First, it will need to apply for a title V permit within 12 months of July 1, 2011 (unless an earlier date has been established by the permitting authority). Second, assuming that the facility does not have any applicable requirements for GHG emissions (such as a GHG BACT requirement resulting from a PSD review), the permitting authority may deem it sufficient that the facility simply provide a description of the GHG emission sources at the facility that cause the facility to exceed the applicability criteria threshold for GHGs under title V, rather than a detailed quantification of its GHG emission sources. Lastly, the source would also need to provide other emissions information as necessary for non-GHG emission sources (e.g., information on emissions of regulated air pollutants, information for fee calculation, etc.)*

[130] 40 CFR 70.5(c)(5).
[131] Office of Air Quality Planning and Standards, *White Paper for Streamlined Development of Part 70 Permit Applications* (July 10, 1995).

It is also important to note that sources that are newly subject to title V solely as a result of their GHG emissions will also need to provide in their title V permit applications required information regarding all other applicable requirements that apply to it under the Act (*e.g.,* SIP regulations). The following is an example of this permitting scenario under Step 2 of the Tailoring Rule:

> *A facility becomes subject to title V permitting requirements solely on the basis of its GHG emissions on July 2, 2011, and, therefore, must apply for a title V permit. The facility has an applicable requirement, such as a SIP requirement imposing an opacity limit on fuel-burning equipment that lacks periodic monitoring and monitoring sufficient to assure compliance. Even if the newly subject title V source did not have any specific GHG-related requirements to include in the title V permit, under this scenario, the facility must propose appropriate monitoring, recordkeeping and reporting (MRR) to assure compliance with the opacity standard in its permit application and the permitting authority must add appropriate MRR to the operating permit for that opacity standard (which may be the MRR proposed by the facility or other requirements) under the authority of the Act.*

D. Title V Fees

EPA rules currently do not require sources to pay any title V fees based on GHG emissions or to otherwise quantify GHG emissions strictly for title V fee purposes. However, throughout Steps 1 and 2 of the Tailoring Rule, the statutory and regulatory requirement to collect fees sufficient to cover all reasonable (direct and indirect) costs required to develop and administer title V programs still applies.[132] Permitting authorities need to review resource needs for GHG-emitting sources and determine if their existing fee structure is adequate. If not, permitting authorities would need to raise fees to cover the direct and indirect costs of the program or develop alternative approaches. EPA will work with permitting authorities that request assistance concerning establishing title V fees related to GHG emissions.

E. Flexible Permits

The final Flexible Air Permitting Rule (74 FR 51418), promulgated on October 6, 2009, reflects EPA's policy and rules governing the use of flexible air permits. A flexible air permit (FAP) is a title V operating permit that by its design authorizes the source owner to make certain types or categories of physical and/or operational changes without further review or approval of the individual changes by the permitting authority. Flexible air permits cannot circumvent, modify, or contravene any applicable requirement and, instead, by their design must assure compliance with each one. Based on our evaluation of State FAP pilots in addition to providing greater operational flexibility, FAPs can result in greater environmental protection, lower administrative costs, pollution prevention and increased energy efficiency.

---

[132] 42 USC 7661a(b)(3)(B); 40 CFR 70.9.

FAP approaches can significantly reduce the administrative resources associated with CAA permitting requirements and provide a streamlined path for installing new energy-efficient equipment at industrial facilities. While many energy-efficient equipment upgrades may not trigger air permitting requirements, some changes have the potential to trigger permitting actions or applicability determination activities. The combination of plantwide emissions limits, alternative operating scenarios, and/or advance approvals of categories of operational changes can eliminate the need for case-by-case evaluation (under title V and PSD/NSR) for future energy-efficient equipment upgrades, thereby reducing time delays, uncertainty, and transaction costs in making these changes. In the absence of FAP approaches, air permitting considerations may cause a facility to forego or delay energy-efficient equipment upgrades that have potential to trigger air permitting requirements. FAP approaches can be used to accommodate these types of changes in a streamlined manner that addresses all applicable regulatory requirements up-front.

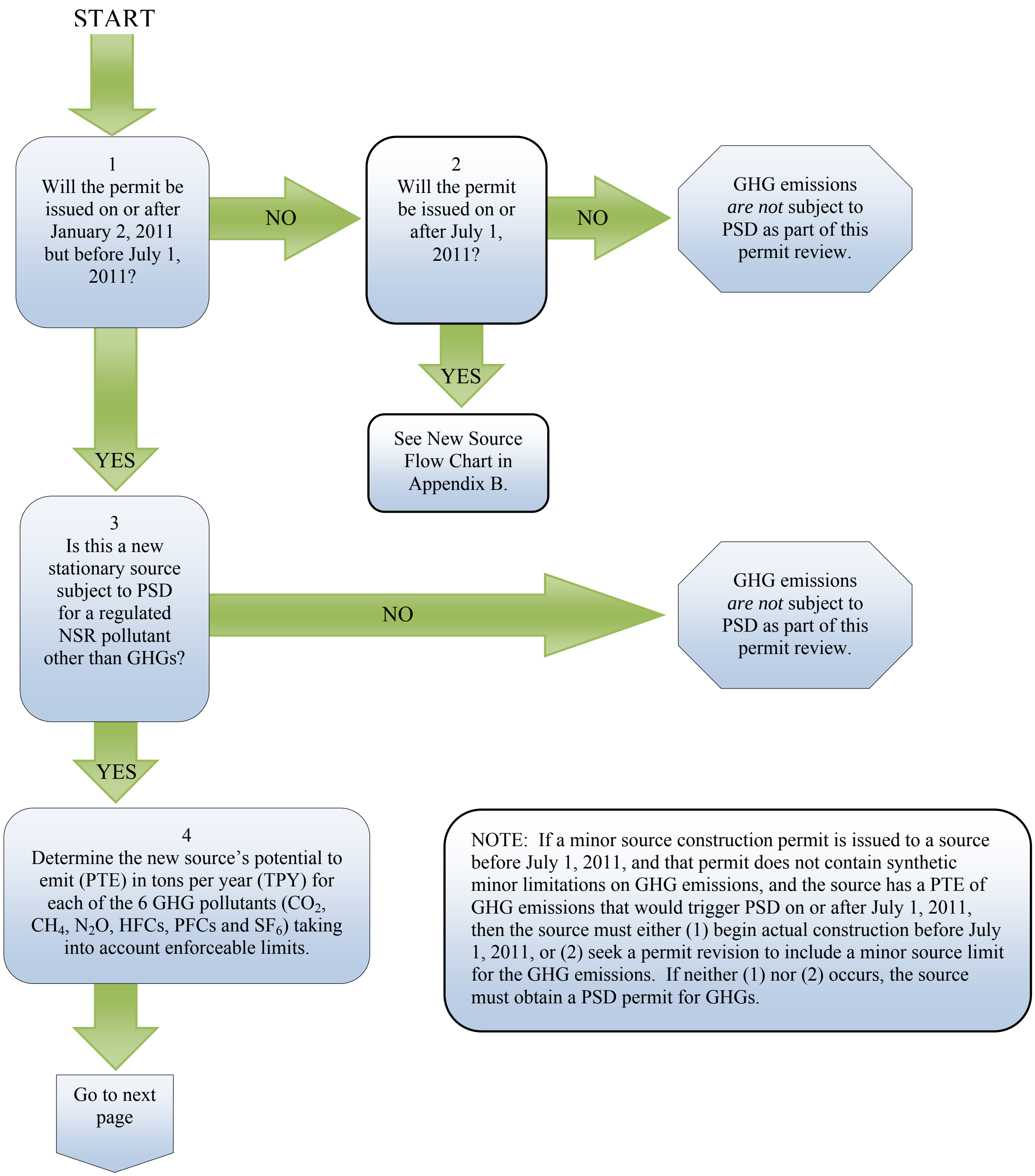
EPA encourages permitting authorities and sources to consider FAPs, particularly in situations where a source is planning to implement an ongoing program designed to improve energy efficiency and reduce GHG over time.

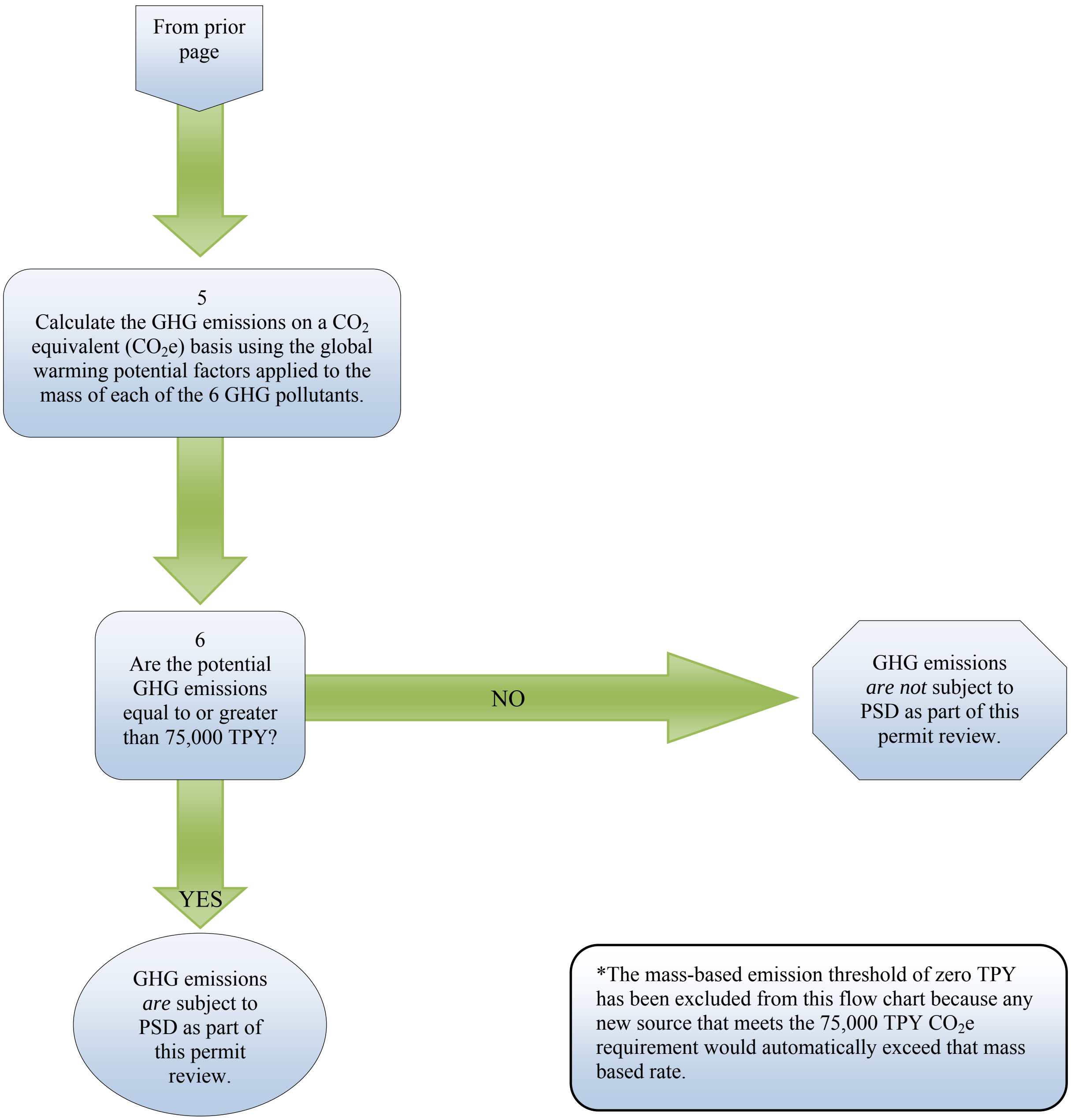
VI. Appendices

Note: The regulatory changes implemented in the Tailoring Rule set forth a two-part applicability process determining the applicability of PSD to GHGs, which first evaluates the sum of the GHG emissions on a CO_2e basis in order to determine whether the source's emissions are a regulated NSR pollutant, and, if so, then evaluates the sum of the GHG emissions on a mass basis in order to determine if there is a major source or major modification of such emissions. However, we noted in the Tailoring Rule preamble that most sources are likely to treat the mass-based analysis as an initial screen from a practical standpoint, since they would not proceed to calculate emissions on a CO_2e basis if they would not trigger PSD or title V on a mass basis.[133] Accordingly, the examples provided in the attached appendices take a variety of approaches for undertaking the required CO_2e and mass-based calculations, and permit applicants and permitting authorities may use the processes identified in this guidance or another process for determining applicability of PSD to GHGs in permits they issue, so long as their process complies with the relevant statutory and regulatory requirements.

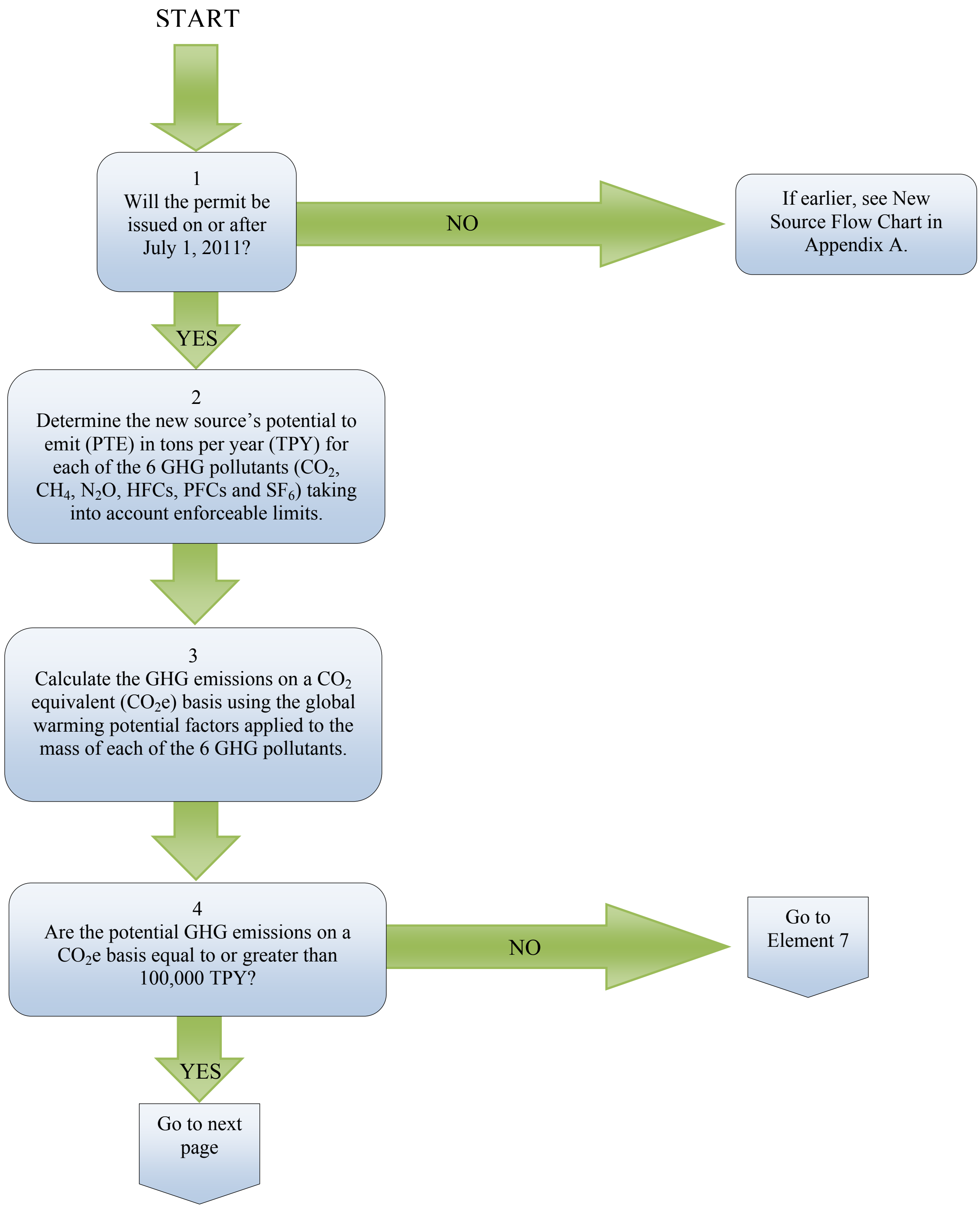
[133] 75 FR 31514, 31522 (June 3, 2010).

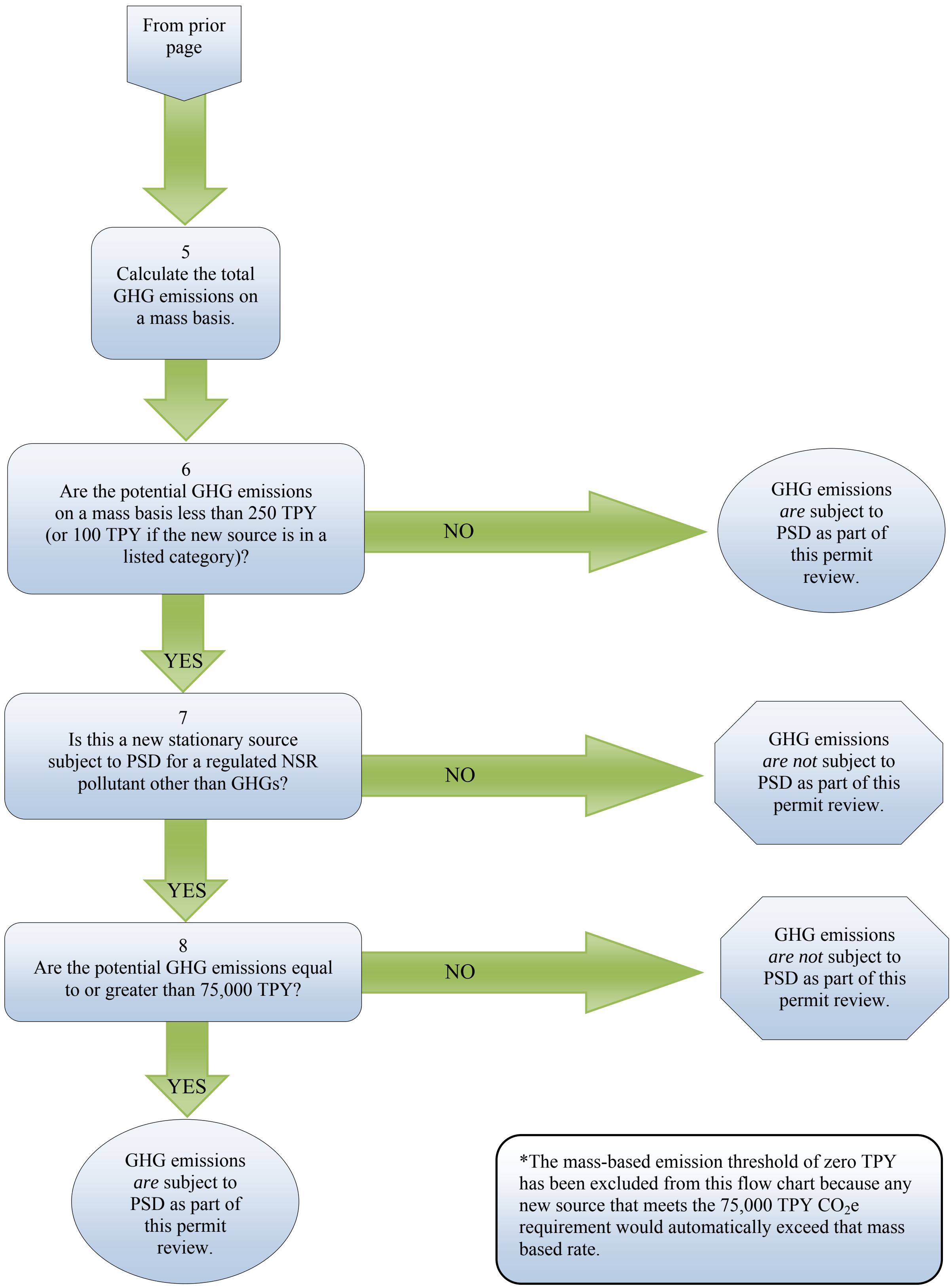
Appendix A. GHG Applicability Flow Chart – New Sources (January 2, 2011, through June 30, 2011)



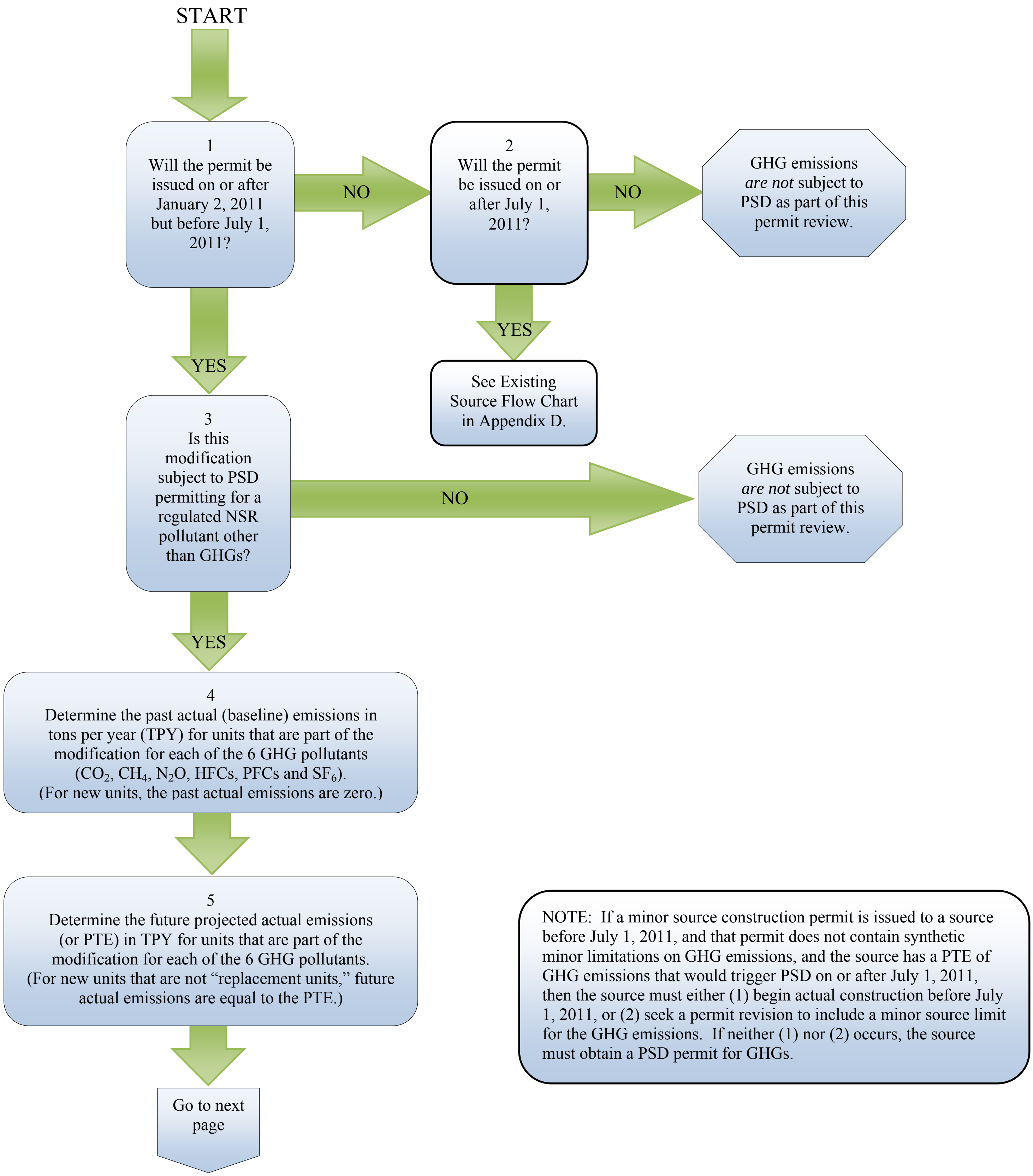

From prior page
5
Calculate the GHG emissions on a CO_2 equivalent (CO_2e) basis using the global warming potential factors applied to the mass of each of the 6 GHG pollutants.
6
Are the potential GHG emissions equal to or greater than 75,000 TPY?
NO
GHG emissions *are not* subject to PSD as part of this permit review.
YES
GHG emissions *are* subject to PSD as part of this permit review.
*The mass-based emission threshold of zero TPY has been excluded from this flow chart because any new source that meets the 75,000 TPY CO_2e requirement would automatically exceed that mass based rate.

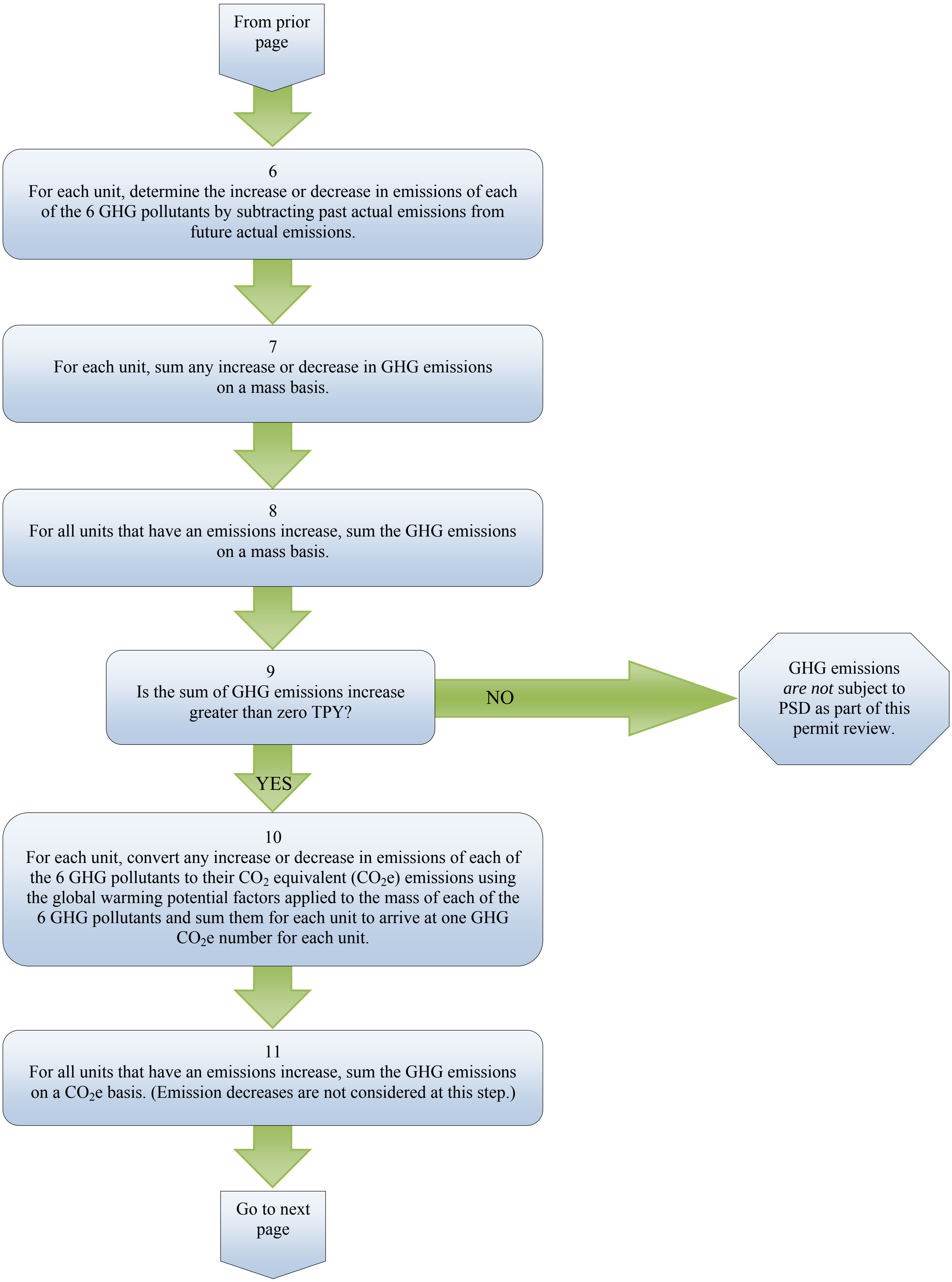
Appendix B. GHG Applicability Flow Chart – New Sources (On or after July 1, 2011)

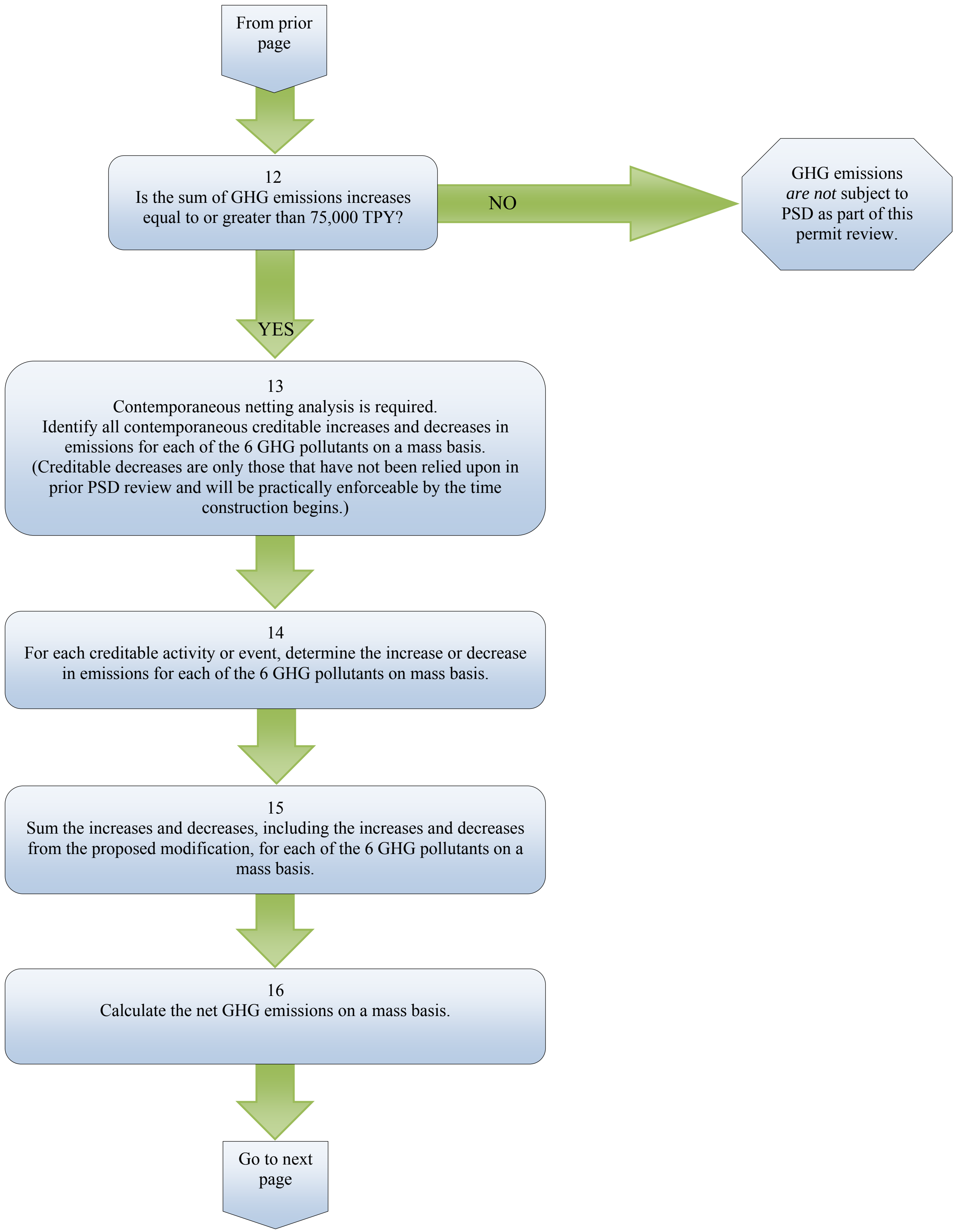


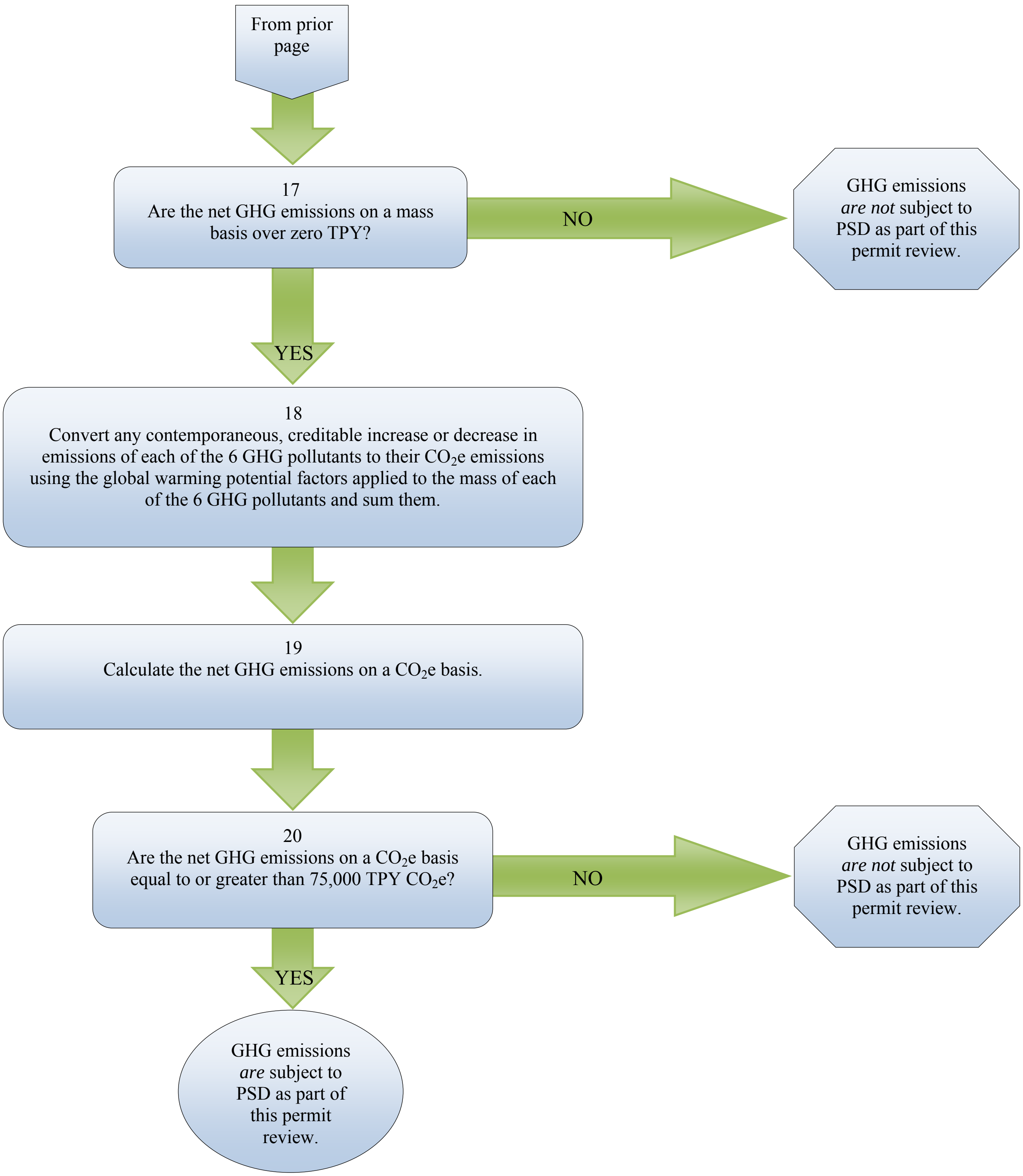

From prior page
5
Calculate the total GHG emissions on a mass basis.
6
Are the potential GHG emissions on a mass basis less than 250 TPY (or 100 TPY if the new source is in a listed category)?
NO
GHG emissions *are* subject to PSD as part of this permit review.
YES
7
Is this a new stationary source subject to PSD for a regulated NSR pollutant other than GHGs?
NO
GHG emissions *are not* subject to PSD as part of this permit review.
YES
8
Are the potential GHG emissions equal to or greater than 75,000 TPY?
NO
GHG emissions *are not* subject to PSD as part of this permit review.
YES
GHG emissions *are* subject to PSD as part of this permit review.
*The mass-based emission threshold of zero TPY has been excluded from this flow chart because any new source that meets the 75,000 TPY CO_2e requirement would automatically exceed that mass based rate.

Appendix C. GHG Applicability Flow Chart – Modified Sources
(January 2, 2011, through June 30, 2011)

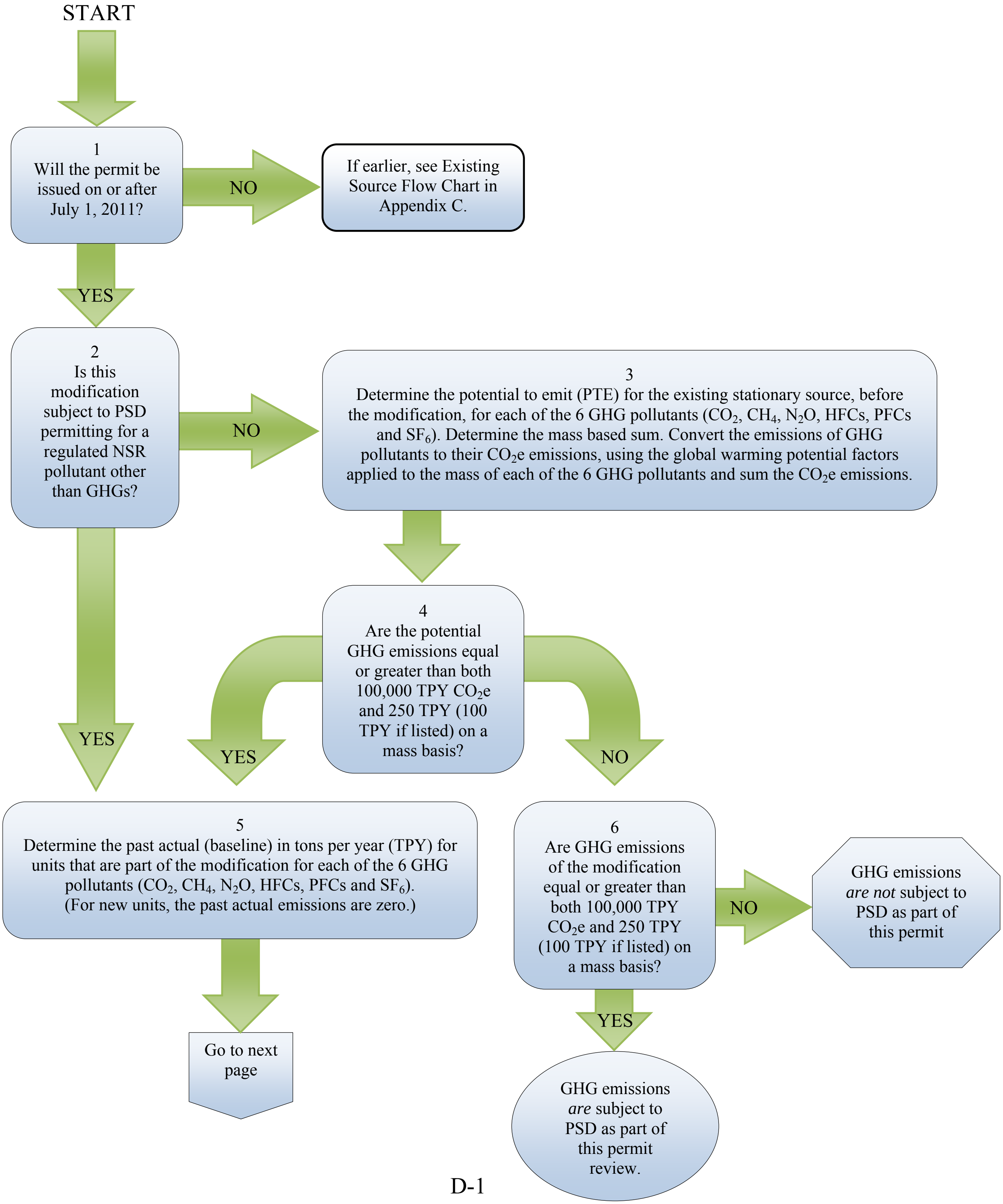


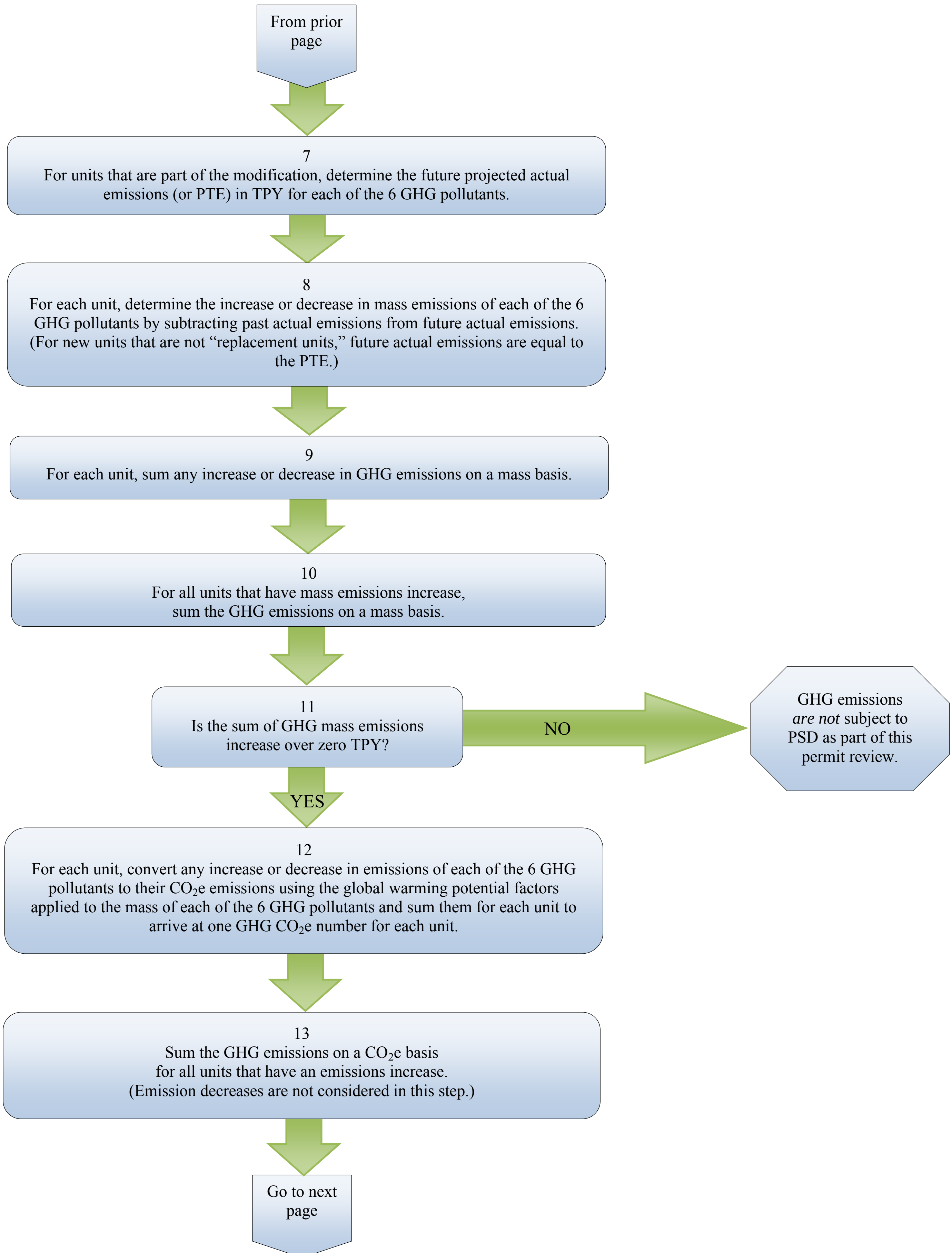

From prior page
6
For each unit, determine the increase or decrease in emissions of each of the 6 GHG pollutants by subtracting past actual emissions from future actual emissions.
7
For each unit, sum any increase or decrease in GHG emissions on a mass basis.
8
For all units that have an emissions increase, sum the GHG emissions on a mass basis.
9
Is the sum of GHG emissions increase greater than zero TPY?
NO
GHG emissions *are not* subject to PSD as part of this permit review.
YES
10
For each unit, convert any increase or decrease in emissions of each of the 6 GHG pollutants to their CO_2 equivalent (CO_2e) emissions using the global warming potential factors applied to the mass of each of the 6 GHG pollutants and sum them for each unit to arrive at one GHG CO_2e number for each unit.
11
For all units that have an emissions increase, sum the GHG emissions on a CO_2e basis. (Emission decreases are not considered at this step.)
Go to next page

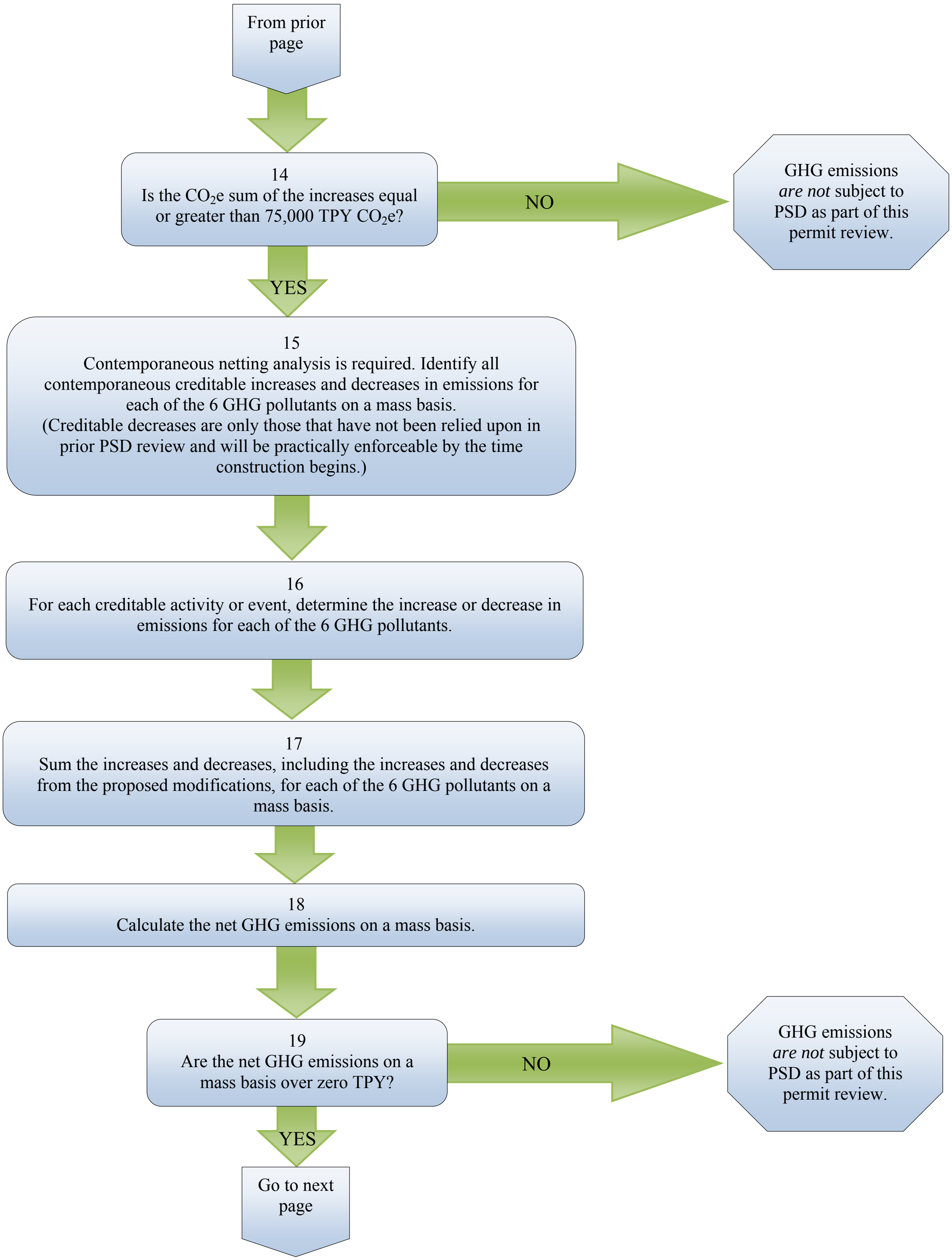

From prior page
12
Is the sum of GHG emissions increases equal to or greater than 75,000 TPY?
NO
GHG emissions *are not* subject to PSD as part of this permit review.
YES
13
Contemporaneous netting analysis is required.
Identify all contemporaneous creditable increases and decreases in emissions for each of the 6 GHG pollutants on a mass basis.
(Creditable decreases are only those that have not been relied upon in prior PSD review and will be practically enforceable by the time construction begins.)
14
For each creditable activity or event, determine the increase or decrease in emissions for each of the 6 GHG pollutants on mass basis.
15
Sum the increases and decreases, including the increases and decreases from the proposed modification, for each of the 6 GHG pollutants on a mass basis.
16
Calculate the net GHG emissions on a mass basis.
Go to next page

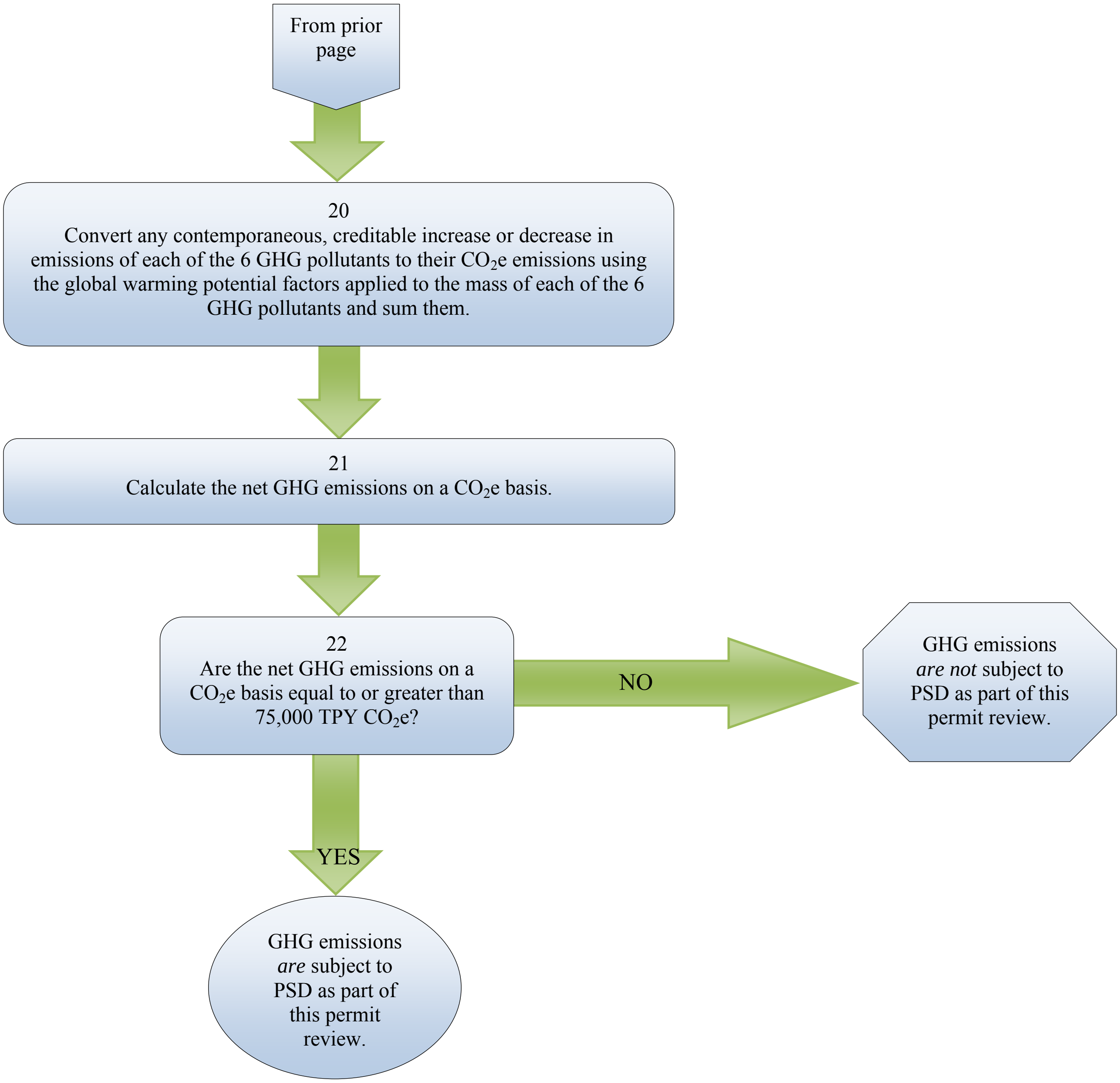

From prior page
17
Are the net GHG emissions on a mass basis over zero TPY?
NO
GHG emissions *are not* subject to PSD as part of this permit review.
YES
18
Convert any contemporaneous, creditable increase or decrease in emissions of each of the 6 GHG pollutants to their CO_2e emissions using the global warming potential factors applied to the mass of each of the 6 GHG pollutants and sum them.
19
Calculate the net GHG emissions on a CO_2e basis.
20
Are the net GHG emissions on a CO_2e basis equal to or greater than 75,000 TPY CO_2e?
NO
GHG emissions *are not* subject to PSD as part of this permit review.
YES
GHG emissions *are* subject to PSD as part of this permit review.

Appendix D. GHG Applicability Flowchart – Modified Sources (On or after July 1, 2011)




From prior page
7
For units that are part of the modification, determine the future projected actual emissions (or PTE) in TPY for each of the 6 GHG pollutants.
8
For each unit, determine the increase or decrease in mass emissions of each of the 6 GHG pollutants by subtracting past actual emissions from future actual emissions. (For new units that are not "replacement units," future actual emissions are equal to the PTE.)
9
For each unit, sum any increase or decrease in GHG emissions on a mass basis.
10
For all units that have mass emissions increase, sum the GHG emissions on a mass basis.
11
Is the sum of GHG mass emissions increase over zero TPY?
NO
GHG emissions *are not* subject to PSD as part of this permit review.
YES
12
For each unit, convert any increase or decrease in emissions of each of the 6 GHG pollutants to their CO_2e emissions using the global warming potential factors applied to the mass of each of the 6 GHG pollutants and sum them for each unit to arrive at one GHG CO_2e number for each unit.
13
Sum the GHG emissions on a CO_2e basis for all units that have an emissions increase. (Emission decreases are not considered in this step.)
Go to next page


From prior page
14
Is the CO_2e sum of the increases equal or greater than 75,000 TPY CO_2e?
NO
GHG emissions *are not* subject to PSD as part of this permit review.
YES
15
Contemporaneous netting analysis is required. Identify all contemporaneous creditable increases and decreases in emissions for each of the 6 GHG pollutants on a mass basis.
(Creditable decreases are only those that have not been relied upon in prior PSD review and will be practically enforceable by the time construction begins.)
16
For each creditable activity or event, determine the increase or decrease in emissions for each of the 6 GHG pollutants.
17
Sum the increases and decreases, including the increases and decreases from the proposed modifications, for each of the 6 GHG pollutants on a mass basis.
18
Calculate the net GHG emissions on a mass basis.
19
Are the net GHG emissions on a mass basis over zero TPY?
NO
GHG emissions *are not* subject to PSD as part of this permit review.
YES
Go to next page


From prior page
20
Convert any contemporaneous, creditable increase or decrease in emissions of each of the 6 GHG pollutants to their CO_2e emissions using the global warming potential factors applied to the mass of each of the 6 GHG pollutants and sum them.
21
Calculate the net GHG emissions on a CO_2e basis.
22
Are the net GHG emissions on a CO_2e basis equal to or greater than 75,000 TPY CO_2e?
NO
GHG emissions *are not* subject to PSD as part of this permit review.
YES
GHG emissions *are* subject to PSD as part of this permit review.

Appendix E. Example of PSD Applicability for a Modified Source

<u>Example Scenario:</u>

- An existing stationary source is major for PSD and modifications involving GHGs may be major and possibly subject to PSD.
- The proposed modification consists of the addition of a new emissions unit (Unit #2) and a modification to existing emissions unit (Unit #1). Both units emit one or more compounds identified as a GHG.
- Emissions Unit A was added at the source 3 years ago.
- The GHG emissions used in PSD applicability analyses is a sum of the compounds emitted at the emission unit.

Unit #2 A new emissions unit with a proposed emissions **increase** of 77,000 TPY of CO_2 (1 x 77,000 TPY CO_2 = 77,000 TPY CO_2e).[134]

Unit #1 The modified existing Unit #1 will result in a CO_2 emissions **increase** of 50 TPY (1 x 50 TPY = 50 TPY CO_2e) and a CH_4 emissions **decrease** of 90 TPY (21 x 90 TPY CH_4 = 1890 TPY CO_2e). The pre- and post-change emissions are:

- Baseline actual GHG mass emissions are 400 TPY of CO_2 and 100 TPY of CH_4, which is a total of 500 TPY of GHGs on a mass basis.
- Proposed GHG emissions after the change are 460 TPY (450 TPY from CO_2, 10 TPY from CH_4), which is a 40 TPY decrease from baseline actual emissions on a mass basis.
- Baseline actual CO_2e emissions are 400 TPY CO_2e (1 x 400 TPY of CO_2) plus 2,100 TPY of CO_2e (21 x 100 TPY of CH_4) = 2500 TPY of CO_2e.
- Proposed CO_2e emissions after the change are 450 TPY of CO_2e (1 x 450 TPY of CO_2) plus 210 TPY of CO_2e (21 x 10 TPY of CH_4) = 660 TPY of CO_2e.

Unit A Three years ago, during the contemporaneous period, there was an emissions increase of 10,000 TPY CO_2 (10,000 TPY CO_2e) from the addition of a new emissions unit (Unit A) at the source. There are no other creditable emissions increases or decreases during the contemporaneous period.

Note: The source must calculate emissions changes from existing emissions units being modified (e.g., Unit #1) and in preparing that calculation, the source must compare the emission unit's baseline actual emissions to either (1) a projection of its future actual emissions; or (2) its potential to emit (PTE). See 40 CFR 52.21(b)(41)(ii). Any creditable emissions decreases from existing emissions units must be decreases in baseline actual emissions. The requirements of the PSD rules apply to these calculations and determinations as applicable.

Mass-Based Calculations

(Step 1) *In this step, only consider emissions increases of GHGs from the proposed modification.*

Unit #2 77,000 TPY mass emissions **increase** of GHGs.

---

[134] For the purposes of this example, the Global Warming Potential values are from the 40 CFR Part 98 Table A-1, as of the date of this document.

Unit #1 The proposed GHG emissions are 460 TPY, which is a 40 TPY GHG mass emissions **decrease** from the baseline actual emissions of 500 TPY. The change at Unit #1 results in a **decrease** in GHG emissions and is therefore not considered in Step 1.

Increases = 77,000 TPY GHG mass emissions increase from Unit #2 is greater than zero TPY, so

Go to Step 2 and conduct contemporaneous netting

(Step 2) *In this step, include the emissions increases and decreases of GHGs from the project and all other contemporaneous and creditable emissions increases and decreases of GHGs.*

Net emissions increase = 77,000 TPY GHG mass emissions from Unit #2 minus a 40 TPY GHG decrease from Unit #1 plus a 10,000 TPY GHG increase from Unit A equals 86,960 TPY GHG mass emissions. This net emissions increase is greater than zero TPY, so

Go to the CO_2e*-based calculations*

CO_2e-Based Calculations

(Step 1) *In this step, only consider CO_2e emissions increases from the modification.*

Unit #2 77,000 TPY CO_2e emissions **increase**

Unit #1 The proposed CO_2e emissions after the modification are 660 TPY CO_2e, which is a 1,840 TPY CO_2e **decrease** from baseline actual emissions of 2,500 TPY CO_2e. Since it is a decrease, ignore the change in CO_2e emissions.

Increases = 77,000 TPY CO_2e emissions increase from Unit #2 is equal to or greater than 75,000 TPY CO_2e, so

Go to Step 2 and conduct contemporaneous netting

(Step 2) *In this step, consider all emissions increases and decreases of CO_2e from the proposed project and all other contemporaneous and creditable emissions increases and decreases of CO_2e.*

Net emissions increase = 77,000 TPY CO_2e emissions increase from Unit #2 minus 1,840 TPY CO_2e emissions decrease from Unit #1 plus a 10,000 TPY CO_2e emissions increase from Unit A equals 85,160 TPY CO_2e emissions. This net emissions increase is equal to or greater than 75,000 TPY CO_2e.

Results: The modification is both a "significant emissions increase" (Step 1) and a "significant net emissions increase" (Step 2) in both the mass and CO_2e-based calculations; therefore, the modification as proposed is major and subject to PSD for GHGs.

Appendix F. BACT Example – Natural Gas Boiler

[Disclaimer: The control options listed here and the outcomes of this example are presented for illustrative purposes only. They do not represent any specific guidance or direction from EPA relative to a BACT determination for this type of source.]

Project Scope: The permit applicant is proposing to install, at an existing PSD major source, a new 250 MMBtu/hour natural gas-fired boiler. The project's emissions increase is in excess of 75,000 TPY CO_2e and the permit will be issued in March 2011, so the project is subject to BACT for GHGs under Step 1 of the Tailoring Rule. For the sake of simplicity, this example focuses on the section of the BACT analysis for GHG emissions from the project.

The top-down BACT determination is carried out in the following five steps:

Step 1: Identifying all available controls

For purposes of this example, assume that the permit application listed the following available controls in the GHG BACT analysis:

- Boiler Annual Tune-up – Once a year the boiler is tuned for optimal thermal efficiency.
- Boiler Oxygen Trim Control – Stack oxygen level is monitored and the inlet air flow is adjusted for optimal thermal efficiency.
- Use of an Economizer – A heat exchanger is used to transfer some of the heat from the boiler exhaust gas to the incoming boiler feedwater. Preheating the feedwater in this way reduces boiler heating load, increases its thermal efficiency and reduces emissions.
- Boiler Blowdown Heat Recovery – Periodically or continuously, some water in the boiler is removed as a means of avoiding the build-up of water impurities in the boiler. A heat exchanger is used to transfer some of the heat in the hot blowdown water for preheating feedwater. This increases the boiler's thermal efficiency.
- Condensate Recovery – As the boiler steam is used in the heat exchanger, it condenses. When hot condensate is returned to the boiler as feedwater, the boiler heating load is reduced and the thermal efficiency increases.

As would be appropriate under EPA's guidelines for Step 1 of the BACT process, the permitting authority asked the applicant to expand the analysis to consider an air preheater (which recovers heat in the boiler exhaust gas to preheat combustion air). Accordingly, at this stage in this example, the permit applicant and permitting authority identified six control measures.

Further, a public comment was received arguing that the analysis should include a combined cycle natural gas-fired turbine that is more efficient than the proposed boiler. Since the application explains that a boiler is necessary to fulfill the fundamental business purpose of providing process steam (and not generating electricity) and because a varying steam demand requires the ability to startup and shutdown the boiler quickly (due to the fluctuating operational demands of the facility, as substantiated in the application), the permitting authority declined to list the option in Step 1 of the BACT analysis on the grounds it would redefine the source. The permitting authority thoroughly documented this decision in its response to comments.

Step 2: Eliminating technically infeasible options

At this stage of the review, the permit applicant and the permitting authority examine all options for technical feasibility. For this example, the permitting authority determined that the seven controls identified are technically feasible because nothing in the record showed that any of these options was not demonstrated or available or applicable to this type of source.

Step 3: Evaluation and ranking of controls by their effectiveness.

At this step, the permit applicant and permitting authority need to select a measure of effectiveness to compare and rank the options. Assume in this example that the applicant ranked control measures for the boiler based on their impact on the thermal efficiency of the boiler, after finding that thermal efficiency was a useful indicator of CO_2 control efficiency because fuel use is directly related to CO_2 emissions for the boiler and the impact of control measures.

The permit applicant completed the control effectiveness analysis showing that the most effective single measure is oxygen trim control. The applicant's analysis also showed that the use of an air preheater was no more effective than an economizer in recovering exhaust heat, and so the applicant narrowed the review to the economizer only. In this example, the applicant's analysis next considered the effectiveness of the boiler controls in combinations and found that the most effective combination of measures is the use of four measures – oxygen trim control, an economizer, condensate recovery and blowdown heat recovery – which was approved by the permitting authority.

Step 4:   Evaluating the most effective controls and documenting results

In this step, the permit applicant completed an analysis of the cost effectiveness of measures and combinations of measures, expressed as $/ton of GHG reduced, as well as an incremental cost effectiveness analysis. In this example, the applicant found that, given the size and other characteristics of this facility, the packages including boiler blowdown heat recovery was not cost effective (as an incremental measure compared to cost born by similar facilities) and the next most effective combination of measures for the boiler was the use of oxygen trim control, an economizer and condensate recovery. The applicant documented this decision in the permitting record and the permitting authority agreed.

Significant energy and environmental impacts are also considered in this step. In this example, the record also showed that the recovery and reuse of condensate would reduce the use of boiler treatment chemicals and the generation of related waste and thus would reduce the amount of water going to wastewater treatment at the site. Since condensate recovery was still in consideration, this information provided additional record support continuing to consider condensate recovery part of the technology option.

Step 5: Selecting BACT

With the analysis and record complete, the permitting authority determines BACT in this last step. In this example, the permitting authority determined, and the record showed, that BACT for GHGs from the proposed facility was the combination of oxygen trim control, an economizer and condensate recovery for the boiler, along with a high transfer efficiency design for the heat exchanger. Accordingly, the permitting authority included the following permit terms in the permit:

- Emission limit expressed in lbs of CO_2e emissions per pound of steam produced, averaged over 30 day rolling periods;
- CO_2e emissions are to be determined based on metered natural gas use and the application of standard emission factors;
- Steam production determined from a gauge on the outlet of the boiler;
- In addition, there would be a requirement to install the boiler as described in the application and BACT determination;
- There would be a requirement to implement a preventive maintenance program for the air to fuel ratio controller of the boiler; and
- A requirement for periodic maintenance and calibration of the natural gas meter and the steam flow analyzer.

Appendix G. BACT Example – Municipal Solid Waste Landfill

[Disclaimer: The control options listed here and the outcomes of this example are presented for illustrative purposes only. They do not represent any specific guidance or direction from EPA relative to a BACT determination for this type of source.]

Project Scope: The permit applicant proposes to build a new, large municipal solid waste landfill. As the solid waste in a landfill decomposes, landfill gas (composed of methane, carbon dioxide, and trace amounts of organic compounds) is formed. The application shows that the PTE of the landfill expressed as CO_2e emissions is in excess of 100,000 TPY. The permit will be issued after June 2011, so BACT will apply to the GHG emissions under Step 2 of the Tailoring Rule. For the sake of simplicity, this example focuses on the section of the BACT analysis for the capture and control of the landfill gas from the project.

The permit applicant and reviewing authority conduct their BACT determination using the five steps of the top-down processes as follows:

Step 1: Identifying all available controls

The permit applicant and permitting authority agree that the BACT review for a landfill logically has two elements: the capture of the landfill gas and the control of emissions of that gas. In this example, there is an existing NSPS (Part 60 Subpart WWW) applicable to non-methane organic compounds (NMOC) emissions from Municipal Solid Waste (MSW) landfills, which addresses the capture and control of landfill gas. While the NSPS addresses a different component of the emissions than GHGs, the permit applicant and the permitting authority determine that the NSPS is a useful starting point for a GHG BACT determination since it has detailed requirements for the design and operation of the gas collection system.

For capture of the landfill gas, the application uses compliance with the NSPS as the starting point. For control, the applicant identified the following three NSPS options as a starting point for the BACT determination:

- venting to an on-site flare,
- use of the gas in on-site internal combustion engines to generate electricity, or
- treatment of the gas for delivery to a natural gas pipeline.

The applicant did not identify or propose any alternative control options in the application, and none were suggested in public comments. However, the permitting authority did ask the applicant to expand the review to consider two other control measures: (1) a requirement to collect and control landfill gas earlier in the life of the landfill than is specified in the NSPS, and (2) the use of a gas turbine to generate power rather than internal combustion engines.

At this stage, there are two control measures listed for gas capture (NSPS compliant system and a NSPS system with earlier gas collection and treatment) and four control options listed for the control of the landfill gas that is collected (flaring, fueling engines, fueling a gas turbine, and treatment and routing of the gas to a pipeline).

Step 2: Eliminating technically infeasible options

At this stage of the review, the applicant and permitting authority assess the technical feasibility of each option. In this example, the applicant demonstrated that the volume of gas from the proposed facility would be inadequate to fuel a commercially available gas turbine. The permitting authority reviewed the record regarding the technical infeasibility for the gas turbine option, found it was adequate, and accepted elimination of that option from further consideration.

Step 3: Evaluation and ranking of controls by their effectiveness

At this step, the permit applicant and permitting authority need to determine a metric for ranking the control effectiveness of the options under consideration. In this case, the application used total CO_2e emissions over the life of the landfill, based on the current business plan and design, as the effectiveness indicator. The applicant explained that the CO_2e emissions estimates in their application reflected the direct emissions of GHGs and the CO_2 produced for the options where that gas was combusted on site. The application also considered combinations of capture systems and controls for overall effectiveness. The record showed that early capture of gas and conversion of the gas to pipeline quality for export were likely to be the most effective combination, from a PSD perspective, given that the maximum amount of gas would be captured and most of the gas would not be combusted on site. The record also showed that flaring and the use of engines were similar in their control of overall on-site GHG emissions, with both controls reducing methane emissions significantly while generating relatively small on-site CO_2 emissions in the process.

Step 4: Evaluating the most effective controls and documenting results

In this step, the applicant completed an analysis of the cost effectiveness of control measures, expressed as $/ton of GHG reduced, and also determined the incremental cost effectiveness. In this example, the applicant's analysis first found that conversion of gas to pipeline quality was not cost effective, explaining that this control option would more than double the overall cost of the project since the landfill was far from an existing pipeline, and the permitting authority agreed that it should be eliminated for further consideration in the BACT analysis. The record also showed that the NSPS system with early collection was cost effective in both the flare and the engines case. There was also evidence in the record showing that the flare was more cost effective because revenue from the sale of power from use of engines was too little to offset the added cost of the engines and a power transmission line.

The applicant and permitting authority also considered the collateral energy and environmental impacts of the options. In this example, the application noted that there was a positive environmental impact from the use of a flare because NO_X emissions for a flare would be lower than those for the engines. Some public comments identified positive energy and environmental offsite impacts arising from the fact that using landfill gas to generate electricity would displace some other offsite energy generation and associated emissions. In responding to the comments, the permitting authority determined that this benefit outweighed the lower NO_X emissions from the flare. The permit record also demonstrated that the use of engines or a flare would have nearly equal CO_2e control effectiveness. Accordingly, the permitting authority found that the environmental benefits arising from the engines-based system outweighed the flare's cost effectiveness and environmental benefits of lower NO_X emissions.

Step 5: Selecting BACT

The permitting authority determines BACT in this last step. In this example, the permitting authority determined that BACT for the proposed facility was NSPS compliance with early implementation of the capture and control system with engines combusting the landfill gas to generate electricity. Accordingly, the permitting authority included the following permit terms in the permit:

- Compliance with the landfill design and operation requirements of the applicable NSPS with a revised condition for earlier capture and control of the gas.
- A requirement to combust the collected gas in engines with the creation and use of an O&M plan for the engines to assure that they operate efficiently.

Appendix H. BACT Example – Petroleum Refinery Hydrogen Plant

[Disclaimer: The control options listed here and the outcomes of this example are presented for illustrative purposes only. They do not represent any specific guidance or direction from EPA relative to a BACT determination for this type of source.]

Project Scope:
Petroleum refineries produce and utilize hydrogen in order to convert crude oil to finished products. In this example, a permit applicant proposes a modification project to expand the hydrogen production and hydrotreating capacity of an existing major source refinery. The application submitted by the permit applicant shows that the project has a significant emissions increase and a significant net emissions increase on both a CO_2e basis and a mass basis. The permitting authority will issue the permit in October 2011, so PSD is triggered for GHGs in Step 2 of the Tailoring Rule. For simplicity, this example addresses the GHG BACT analysis for the new hydrogen plant only.

Accordingly to the application, the proposed project utilizes the most common method of producing hydrogen at a refinery, the steam methane reforming (SMR) process. In SMR, methane and steam are reacted via a catalyst to produce hydrogen and CO. The reaction is endothermic and the necessary heat is provided in a gas-fired reformer furnace. The CO generated by the initial SMR reaction further reacts with the steam to generate hydrogen and CO_2. The hydrogen is then separated from the CO_2 and other impurities. In this example, the application shows that the purification is done using a Pressure Swing Adsorption Unit. The permit applicant proposes to use the offgas from that step (containing some hydrogen, CO_2, and other gases) as part of the fuel for the reformer furnace.

The top-down BACT determination is carried out in the following five steps:

Step 1: Identifying all available controls

Assume for purposes of this example that the permit application lists the following control options for GHG emissions:

- Furnace Air/Fuel Control – An oxygen sensor in the furnace exhaust is to be used to control the air and fuel ratio in the furnace on a continuous basis for optimal energy efficiency.
- Waste Heat Recovery – The overall thermal efficiency is to be optimized through the recovery of heat from both the furnace exhaust and the process streams to preheat the furnace combustion air, to preheat the feed to the furnace and to produce steam for use in the process and elsewhere in the refinery.
- CO_2 Capture and Storage – Capture and compression, transport, and geologic storage of the CO_2. (Some refineries isolate hydrogen reformer CO_2 for sale but that is not a part of this example project.)

The permitting authority did not require the applicant to identify any alternative control options beyond those in the application, and none were suggested in public comments.

Step 2: Eliminating technically infeasible options

At this stage of the review, the permit applicant and the permitting authority examine the control options for technical feasibility. In this example, the permitting record shows that all three controls are technically feasible because there is no evidence that any of these options are not demonstrated or available or applicable to this type of source.

Step 3: Evaluation and ranking of controls by their effectiveness.

At this step, the permit applicant and permitting authority need to select a measure of effectiveness to compare and rank the options. In this example, the applicant ranked control measures for the hydrogen plant based on the GHG emissions per unit of hydrogen produced. The applicant and the permitting authority agreed that such an output-based indicator was a good way to capture the overall effect of multiple energy efficiency measures used in the design of a complex process such as this.

The permit applicant then completed a control effectiveness analysis, in which benchmarking data on the energy efficiency and GHG emissions of recently installed hydrogen plants was provided. The applicant showed that by incorporating various heat recovery measures this hydrogen plant would be a lower emitter (on an output basis) than similar new plants, and the permitting authority concurred in that determination. The applicant's analysis considered the effectiveness of each individual measure and combinations of measures. In this case, the applicant determined that the most effective combination was one in which all three options were included.

Step 4: Evaluating the most effective controls and documenting results

In this step, the permit applicant completed an analysis of the cost effectiveness of measures and combinations of measures, expressed as $/ton of GHG reduced. The applicant also determined the incremental cost effectiveness. In this example, the information supplied by the applicant demonstrated that the transport and sequestration of CO_2 would not be cost effective because the nearest prospective location for sequestration was more than 500 miles away and there was not an existing pipeline or other suitable method for CO_2 transport between the refinery and the sequestration location. Accordingly, the record showed that the cost of transport was significant in comparison to the amount of CO_2 to be sequestered and the cost of the project overall. Although the permitting authority affirmed this determination, in responding to public comments on the issue, the permitting authority did note that in circumstances in which a refinery was located near an oil field that used CO_2 injection for enhanced recovery, the cost for transport and sequestration would likely be in a range that would not exclude the transport control option from the list of technologies that would continue to be considered in the BACT analysis.

Permit applicants and permitting authorities also consider other significant energy and environmental impacts in this step. In this case, none were presented in the application, and the only significant public comment on the issue was addressed by the permitting authority, as noted above.

Step 5: Selecting BACT

With the analysis and record complete, the permitting authority determines BACT. In this example, the permitting authority determined that BACT was a combination of furnace combustion control and integrated waste heat recovery. Accordingly, the permitting authority included the following permit terms in the permit:

- Emission limit in pounds of CO_2e emitted per pound of hydrogen produced, averaged over rolling 30-day periods.
- CO_2e emissions would be determined by metering natural gas sent to the hydrogen plant. With prior approval of the permitting authority, the emissions could be adjusted for excess fuel gas sent to other parts of the refinery. A separate meter and fuel analysis would be needed to get that credit.
- Hydrogen production would be metered.
- The heat recovery systems would need to be installed as described in the application.
- There would need to be a written program for calibration and maintenance of meters.

Appendix I. Resources for GHG Emission Estimation

The following are a number of methods that are traditionally used to estimate PTE from sources and relevant emissions units:

- Federally enforceable operational limits, including the effect of pollution control equipment;
- Performance test data on similar units;
- Equipment vendor emissions data and guarantees;
- Test data from EPA documents, including background information documents for new source performance standards, national emissions standards for hazardous air pollutants, and Section 111(d) standards for designated pollutants;
- AP-42 Emission Factors;
- Emission factors from technical literature; and
- State emission inventory questionnaires for comparable sources.

These approaches remain relevant for GHG emissions calculations and serve as the fundamental approaches to estimating emissions for permitting applications. For example, direct measurements methods such as continuous emissions monitors (CEMs) would continue to be a preferred means to form the starting point basis for estimating emissions from GHG emissions units. However, because GHG emissions historically have not been subject to regulation under air permitting programs, and there are unique GHG emission source categories, there is not as widespread representation or long-term experience with GHG estimation techniques and measurement methods as there is for conventional pollutants under the above approaches. The purpose of this section is to identify additional references and resources that may be useful when evaluating GHG emission sources and deciding which estimation methods to use.[135]

Mandatory Reporting of Greenhouse Gases. This final rule was issued on October 30, 2009 (74 FR 56260), and established GHG reporting requirements for all sectors of the economy and should be considered a primary reference for sources and permitting authorities in estimating GHG emissions and establishing measurement techniques when preparing or processing permit applications. The rule includes procedures for estimating GHG emissions from the source categories that are responsible for the majority of stationary source GHG emissions in the U.S. The procedures identify where applications of direct measurement techniques are viable and describes emission factor and mass-balance based approaches where direct measurement techniques are not applicable or available.

[135] The exclusion of a source or emission unit category from these sources does not imply that such sources or emissions units are excluded from permitting requirements. For example, as of the date of this publication CO_2 from biomass combustion is not included in determining applicability under the mandatory reporting rule, but is included in determining applicability under both PSD and title V programs as described in the Tailoring Rule. Also, there are not methods identified for all possible GHG emitting sources and units in the current mandatory reporting rule.

While the GHG reporting rule is focused on estimating and reporting *actual* emissions from source categories, the basic approaches can be used to estimate a source's PTE when correctly adjusted to reflect future conditions and operating parameters. Since many of the affected GHG source categories and emissions units have been or will be subject to permitting requirements for conventional, non-GHG pollutants, sources should use similar adjustments to fuel throughput, activity data, and emissions for determining PTE for GHG that have been used in existing PSD and title V guidance for those units and which are applied on a case-by-case basis depending on specific operating parameters for the affected sources.

Other reference sources that may prove useful to sources and permitting authorities in identifying, characterizing and estimating emissions from GHG emission sources include the following:

- **ENERGY STAR Industrial Sector Energy Guides and Plant Energy Performance Indicators (benchmarks)**
  http://www.energystar.gov/epis

- **US EPA National Greenhouse Gas Inventory**
  http://epa.gov/climatechange/emissions/usinventoryreport.html

- **EPA's Climate Leaders Protocols**
  http://www.epa.gov/stateply/index.html

- **EPA's Voluntary Partnerships for GHG Reductions:**
  - Landfill Methane Outreach Program (http://www.epa.gov/lmop/)
  - CHP Partnership Program (http://www.epa.gov/chp)
  - Green Power Partnership (http://www.epa.gov/greenpower)
  - Coalbed Methane Outreach Program (http://www.epa.gov/cmop/index.html)
  - Natural Gas STAR Program (http://www.epa.gov/gasstar/index.html)
  - Voluntary Aluminum Industrial Partnership:
    http://www.epa.gov/highgwp/aluminum-pfc/index.html

- **SF Emission Reduction Partnership for the Magnesium Industry**
  http://www.epa.gov/highgwp/magnesium-sf6/index.html

- **PFC Reduction/Climate Partnership for the Semiconductor Industry**
  http://www.epa.gov/highgwp/semiconductor-pfc/index.html

- **Landfill Gas Emissions Model**
  User's Guide: http://www.epa.gov/ttncatc1/dir1/landgem-v302-guide.pdf

- **Estimation Methodologies for Biogenic Emissions from Solid Waste Disposal, Wastewater Treatment, and Ethanol Fermentation**
  http://www.epa.gov/ttn/chief/efpac/ghg/GHG_Biogenic_Report_revised_Dec1410.pdf

Appendix J. Resources for GHG Control Measures

The following are several information sources to consider when looking for available GHG control measures when conducting a BACT analysis.

- **EPA's GHG Mitigation Measures Database**
  http://www.epa.gov/nsr/ghgpermitting.html

- **EPA's Sector GHG Control White Papers**
  http://www.epa.gov/nsr/ghgpermitting.html

- **EPA's RACT/BACT/LAER Clearinghouse (RBLC)**
  http://cfpub.epa.gov/rblc/

- **ENERGY STAR Guidelines for Energy Management**
  http://www.energystar.gov/guidelines

- **ENERGY STAR Industrial Sector Energy Guides**
  http://www.energystar.gov/epis

- **EPA's Climate Leaders Protocols**
  http://www.epa.gov/stateply/index.html

- **Report of the Interagency Task Force on Carbon Capture and Storage**
  http://www.epa.gov/climatechange/policy/ccs_task_force.html

- **EPA's Lean and Energy Toolkit**
  http://www.epa.gov/lean/toolkit/LeanEnergyToolkit.pdf

- **EPA's Voluntary Partnerships for GHG Reductions:**
  - Landfill Methane Outreach Program (http://www.epa.gov/lmop/)
  - CHP Partnership Program (http://www.epa.gov/chp)
  - Green Power Partnership (http://www.epa.gov/greenpower)
  - Coalbed Methane Outreach Program (http://www.epa.gov/cmop/index.html)
  - Natural Gas STAR Program (http://www.epa.gov/gasstar/index.html)
  - Voluntary Aluminum Industrial Partnership:
    http://www.epa.gov/highgwp/aluminum-pfc/index.html

- **SF Emission Reduction Partnership for the Magnesium Industry**
  http://www.epa.gov/highgwp/magnesium-sf6/index.html

- **PFC Reduction/Climate Partnership for the Semiconductor Industry**
  http://www.epa.gov/highgwp/semiconductor-pfc/index.html

- **DOE's Industrial Technologies Program (Best Practices)**
  http://www1.eere.energy.gov/industry/bestpractices/

Additionally, the following are several information sources that may be helpful when including benchmarking as part of a BACT analysis.

- **EPA Energy Star Industrial Energy Management Information Center**
  http://www.energystar.gov/index.cfm?c=industry.bus_industry_info_center

- **DOE Industrial Technologies Program**
  http://www1.eere.energy.gov/industry/

- **Lawrence Berkeley National Laboratory Industrial Energy Analysis Program**
  http://industrial-energy.lbl.gov/

- **European Union Energy Efficiency Benchmarks**
  http://ec.europa.eu/environment/climat/emission/benchmarking_en.htm

In addition to the above sources of information, once permitting authorities gain experience with GHG BACT determinations, useful information on GHG permitting decisions will be present in EPA's RBLC and Control Technology Center.

Appendix K. Calculating Cost Effectiveness for BACT

The following excerpt is from the Draft 1990 NSR Workshop Manual (pages B.36-B.44)

IV.D.2.b. COST EFFECTIVENESS

Cost effectiveness is the economic criterion used to assess the potential for achieving an objective at least cost. Effectiveness is measured in terms of tons of pollutant emissions removed. Cost is measured in terms of annualized control costs.

Cost effectiveness calculations can be conducted on an average, or incremental basis. The resultant dollar figures are sensitive to the number of alternatives costed as well as the underlying engineering and cost parameters. There are limits to the use of cost-effectiveness analysis. For example, cost-effectiveness analysis should not be used to set the environmental objective. Second, cost-effectiveness should, in and of itself, not be construed as a measure of adverse economic impacts. There are two measures of cost-effectiveness that will be discussed in this section: (1) average cost-effectiveness, and (2) incremental cost-effectiveness.

Average Cost Effectiveness

Average cost effectiveness (total annualized costs of control divided by annual emission reductions, or the difference between the baseline emission rate and the controlled emission rate) is a way to present the costs of control. Average cost effectiveness is calculated as shown by the following formula:

$$\text{Average Cost Effectiveness (dollars per ton removed)} = \frac{\text{Control option annualized cost}}{\text{Baseline emissions rate - Control option emissions rate}}$$

Costs are calculated in (annualized) dollars per year ($/yr) and emissions rates are calculated in tons per year (tons/yr). The result is a cost effectiveness number in (annualized) dollars per ton ($/ton) of pollutant removed.

Calculating Baseline Emissions

The baseline emissions rate represents a realistic scenario of upper boundary uncontrolled emissions for the source. The NSPS/NESHAP requirements or the application of controls, including other controls necessary to comply with State or local air pollution regulations, are not considered in calculating the baseline emissions. In other words, baseline emissions are essentially uncontrolled emissions, calculated using realistic upper boundary operating assumptions. When calculating the cost effectiveness of adding post process emissions controls to certain inherently lower polluting processes, baseline emissions may be assumed to be the emissions from the lower polluting process itself. In other words, emission reduction credit can be taken for use of inherently lower polluting processes.

Estimating realistic upper-bound case scenario does not mean that the source operates in an absolute worst case manner all the time. For example, in developing a realistic upper boundary case, baseline emissions calculations can also consider inherent physical or operational constraints on the source. Such constraints should accurately reflect the true upper boundary of the source's ability to physically operate and the applicant should submit documentation to verify these constraints. If the applicant does not adequately verify these constraints, then the reviewing agency should not be compelled to consider these constraints in calculating baseline emissions. In addition, the reviewing agency may require the applicant to calculate cost effectiveness based on values exceeding the upper boundary assumptions to determine whether or not the assumptions have a deciding role in the BACT determination. If the assumptions have a deciding role in the BACT determination, the reviewing agency should include enforceable conditions in the permit to assure that the upper bound assumptions are not exceeded.

For example, VOC emissions from a storage tank might vary significantly with temperature, volatility of liquid stored, and throughput. In this case, potential emissions would be overestimated if annual VOC emissions were estimated by extrapolating over the course of a year VOC emissions based solely on the hottest summer day. Instead, the range of expected temperatures should be considered in determining annual baseline emissions. Likewise, potential emissions would be overestimated if one assumed that gasoline would be stored in a storage tank being built to feed an oil-fired power boiler or such a tank will be continually filled and emptied. On the other hand, an upper bound case for a storage tank being constructed to store and transfer liquid fuels at a marine terminal should consider emissions based on the most volatile liquids at a high annual throughput level since it would not be unrealistic for the tank to operate in such a manner.

In addition, historic upper bound operating data, typical for the source or industry, may be used in defining baseline emissions in evaluating the cost effectiveness of a control option for a specific source. For example, if for a source or industry, historical upper bound operations call for two shifts a day, it is not necessary to assume full time (8760 hours) operation on an annual basis in calculating baseline emissions. For comparing cost effectiveness, the same realistic upper boundary assumptions must, however, be used for both the source in question and other sources (or source categories) that will later be compared during the BACT analysis.

For example, suppose (based on verified historic data regarding the industry in question) a given source can be expected to utilize numerous colored inks over the course of a year. Each color ink has a different VOC content ranging from a high VOC content to a relatively low VOC content. The source verifies that its operation will indeed call for the application of numerous color inks. In this case, it is more realistic for the baseline emission calculation for the source (and other similar sources) to be based on the expected mix of inks that would be expected to result in an upper boundary case annual VOC emissions rather than an assumption that only one color (*i.e.,* the ink with the highest VOC content) will be applied exclusively during the whole year.

In another example, suppose sources in a particular industry historically operate at most at 85 percent capacity. For BACT cost effectiveness purposes (but **not** for applicability), an applicant may calculate cost effectiveness using 85 percent capacity. However, in comparing costs with similar sources, the applicant must consistently use an 85 percent capacity factor for the cost effectiveness of controls on those other sources.

Although permit conditions are normally used to make operating assumptions enforceable, the use of “standard industry practice” parameters for cost effectiveness calculations (but **not** applicability determinations) can be acceptable without permit conditions. However, when a source projects operating parameters (*e.g.*, limited hours of operation or capacity utilization, type of fuel, raw materials or product mix or type) that are lower than standard industry practice or which have a deciding role in the BACT determination, then these parameters or assumptions must be made enforceable with permit conditions. If the applicant will not accept enforceable permit conditions, then the reviewing agency should use the absolute worst case uncontrolled emissions in calculating baseline emissions. This is necessary to ensure that the permit reflects the conditions under which the source intends to operate.

For example, the baseline emissions calculation for an emergency standby generator may consider the fact that the source does not intend to operate more than 2 weeks a year. On the other hand, baseline emissions associated with a base-loaded turbine would not consider limited hours of operation. This produces a significantly higher level of baseline emissions than in the case of the emergency/standby unit and results in more cost effective controls. As a consequence of the dissimilar baseline emissions, BACT for the two cases could be very different. Therefore, it is important that the applicant confirm that the operational assumptions used to define the source’s baseline emissions (and BACT) are genuine. As previously mentioned, this is usually done through enforceable permit conditions which reflect limits on the source’s operation which were used to calculate baseline emissions.

In certain cases, such explicit permit conditions may not be necessary. For example, a source for which continuous operation would be a physical impossibility (by virtue of its design) may consider this limitation in estimating baseline emissions, without a direct permit limit on operations. However, the permit agency has the responsibility to verify that the source is constructed and operated consistent with the information and design specifications contained in the permit application.

For some sources it may be more difficult to define what emissions level actually represents uncontrolled emissions in calculating baseline emissions. For example, uncontrolled emissions could theoretically be defined for a spray coating operation as the maximum VOC content coating at the highest possible rate of application that the spray equipment could physically process, (even though use of such a coating or application rate would be unrealistic for the source). Assuming use of a coating with a VOC content and application rate greater than expected is unrealistic and would result in an overestimate in the amount of emissions reductions to be achieved by the installation of various control options. Likewise, the cost effectiveness of the options could consequently be greatly underestimated. To avoid these problems, uncontrolled emission factors should be represented by the highest realistic VOC content of the types of coatings and highest realistic application rates that would be used by the source, rather than by highest VOC based coating materials or rate of application in general.

Conversely, if uncontrolled emissions are underestimated, emissions reductions to be achieved by the various control options would also be underestimated and their cost effectiveness overestimated. For example, this type of situation occurs in the previous example if the baseline for the above coating operation was based on a VOC content coating or application rate that is too low [when the source had the ability and intent to utilize (even infrequently) a higher VOC content coating or application rate].

Incremental Cost Effectiveness

In addition to the average cost effectiveness of a control option, incremental cost effectiveness between control options should also be calculated. The incremental cost effectiveness should be examined in combination with the total cost effectiveness in order to justify elimination of a control option. The incremental cost effectiveness calculation compares the costs and emissions performance level of a control option to those of the next most stringent option, as shown in the following formula:

$$\text{Incremental Cost (dollars per incremental ton removed)} = \frac{\text{Total costs (annualized) of control option - Total costs (annualized) of next control option}}{\text{Next control option emission rate - Control option emissions rate}}$$

Care should be exercised in deriving incremental costs of candidate control options. Incremental cost-effectiveness comparisons should focus on annualized cost and emission reduction differences between **dominant** alternatives. Dominant set of control alternatives are determined by generating what is called the envelope of least-cost alternatives. This is a graphical plot of total annualized costs for a total emissions reductions for all control alternatives identified in the BACT analysis (see Figure B-1).

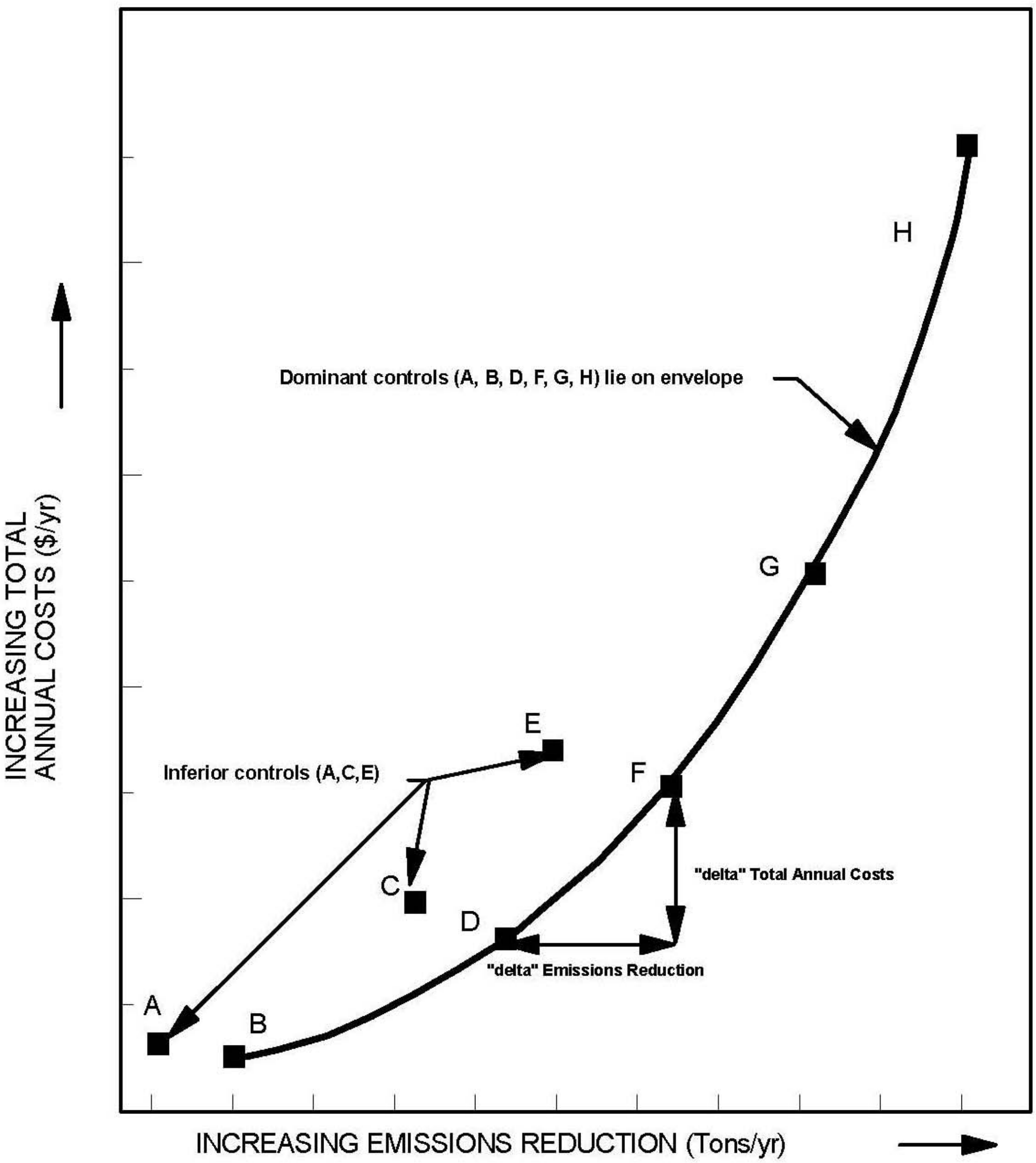


Figure B-1. LEAST-COST ENVELOPE

For example, assume that eight technically available control options for analysis are listed in the BACT hierarchy. These are represented as A through H in Figure B-1. In calculating incremental costs, the analysis should only be conducted for control options that are dominant among all possible options. In Figure B-1, the dominant set of control options, A, B, D, F, G, and H, represent the least-cost envelope depicted by the curvilinear line connecting them. Points C and E are inferior options and should not be considered in the derivation of incremental cost effectiveness. Points A, C and E represent inferior controls because B will buy more emissions reduction for less money than A; and similarly, D and F will by more reductions for less money than E, respectively.

Consequently, care should be taken in selecting the dominant set of controls when calculating incremental costs. First, the control options need to be rank ordered in ascending order of annualized total costs. Then, as Figure B-1 illustrates, the most reasonable smooth curve of the control options is plotted. The incremental cost effectiveness is then determined by the difference in total annual costs between two contiguous options divided by the difference in emissions reduction. An example is illustrated in Figure B-1 for the incremental cost effectiveness for control option F. The vertical distance, “delta” Total Costs Annualized, divided by the horizontal distance, “delta” Emissions Reduced (TPY), would be the measure of the incremental cost effectiveness for option F.

A comparison of incremental costs can also be useful in evaluating the economic viability of a specific control option over a range of efficiencies. For example, depending on the capital and operational cost of a control device, total and incremental cost may vary significantly (either increasing or decreasing) over the operation range of a control device.

As a precaution, differences in incremental costs among dominant alternatives cannot be used by itself to argue one dominant alternative is preferred to another. For example, suppose dominant alternative is preferred to another. For example, suppose dominant alternatives B, D and F on the least-cost envelope (see Figure B-1) are identified as alternatives for a BACT analysis. We may observe the incremental cost effectiveness between dominant alternative B and D is $500 per ton whereas between dominant alternative D and F is $1000 per ton. Alternative D does <u>not</u> dominate alternative F. Both alternatives are dominant and hence on the least cost envelope. Alternative D cannot legitimately be preferred to F on grounds of incremental cost effectiveness.

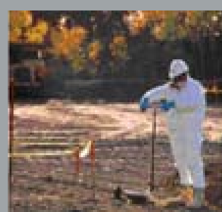
In addition, when evaluating the total or incremental cost effectiveness of a control alternative, reasonable and supportable assumptions regarding control efficiencies should be made. An unrealistically low assessment of the emission reduction potential of a certain technology could result in inflated cost effectiveness figures.

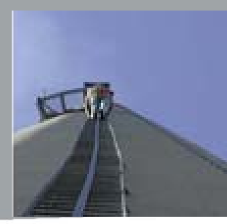
The final decision regarding the reasonableness of calculated cost effectiveness values will be made by the review authority considering previous regulatory decisions. Study cost estimates used in BACT are typically accurate to ± 20 to 30 percent. Therefore, control cost options which are within ± 20 to 30 percent of each other should generally be considered to be indistinguishable when comparing options.

United States Environmental Protection Agency	Office of Air Quality Planning and Standards Air Quality Policy Division Research Triangle Park, NC	Publication No. EPA-457/B-11-001 March 2011

EXHIBIT EE

Prepared for:
City of Victorville and Inland Energy, Inc.




Application for Prevention of Significant Deterioration Permit for Victorville 2 Hybrid Power Project

ENSR Corporation
April 2007
Document No.: 10855-001-040a

Prepared for:
City of Victorville and Inland Energy, Inc.

Application for Prevention of Significant Deterioration Permit for Victorville 2 Hybrid Power Project

Prepared By

Reviewed By

ENSR Corporation
April 2007
Document No.: 10855-001-040a

Contents

1.0 Introduction ... 1-1

1.1 Project Overview ... 1-1

1.2 PSD Applicability ... 1-1

1.3 Application Contacts ... 1-2

1.4 Application Contents ... 1-2

2.0 Proposed Project ... 2-1

2.1 Overview ... 2-1

2.2 Location of Facilities ... 2-1

2.3 Generating Facility Description ... 2-5

2.3.1 Site Arrangement ... 2-5

2.3.2 Process Description ... 2-6

2.3.3 Energy Conversion Facilities Description ... 2-7

2.3.4 Plant Auxiliary Systems and Process Descriptions ... 2-11

2.4 Project Construction and Operating Schedule ... 2-14

2.4.1 Project Construction ... 2-14

2.4.2 Facility Operation ... 2-15

3.0 Regulatory Setting ... 3-1

3.1 Ambient Air Quality Standards ... 3-1

3.2 Applicable Rules and Regulations ... 3-2

3.2.1 New Source Review ... 3-2

3.2.2 Prevention of Significant Deterioration ... 3-3

3.2.3 Title V – Federal Operating Permits Program ... 3-4

3.2.4 Title IV – Acid Rain Program ... 3-4

3.2.5 New Source Performance Standards (NSPS) ... 3-4

3.2.6 Compliance Assurance Monitoring (CAM) Rule ... 3-5

3.2.7 Toxic Chemical Release Inventory Program ... 3-6

4.0 Control Technology Evaluation ... 4-1

4.1 Combustion Turbines and Heat Recovery Steam Generators ... 4-1

4.1.1 LAER for NO_x ... 4-1

4.1.2 BACT for CO ... 4-4

4.2 Auxiliary Boiler and HTF Heater ... 4-5

4.2.1 LAER for NO_x ... 4-5

4.2.2 BACT for CO ... 4-6

4.3 Emergency Diesel Generator and Fire-Water Pump Engines....................4-8
4.3.1 LAER for NO_x....................4-8
4.3.2 BACT for CO....................4-8
4.4 Evaporative Mechanical Draft Cooling Tower....................4-8
4.5 Summary of BACT/LAER Emission Rates....................4-9

5.0 Emission Calculations....................5-1
5.1 Criteria Pollutant Emissions....................5-1
5.1.1 Combustion Turbines and Duct Burners....................5-1
5.1.2 Auxiliary Boiler and HTF Heater....................5-2
5.1.3 Emergency Diesel Generator and Fire-Water Pump Engine....................5-3
5.1.4 PSD Emissions Summary....................5-3
5.2 Hazardous Air Pollutant Emissions....................5-4
5.2.1 Combustion Turbines....................5-4
5.2.2 Auxiliary Boiler and HTF Heater....................5-4
5.2.3 Cooling Towers....................5-5
5.2.4 HAP Emissions Summary....................5-5

6.0 Air Quality Impact Analysis....................6-1
6.1 Class II Area Impact Assessment....................6-1
6.1.1 Modeling Methodology....................6-2
6.1.2 Modeling Results....................6-7
6.2 PSD Class I Analysis....................6-9
6.2.1 PSD Class I Area CALPUFF Analyses....................6-11
6.2.2 VISCREEN Plume Blight Impact Analysis....................6-12
6.3 Other Related Analyses....................6-15
6.3.1 Vegetation and Soils....................6-15
6.3.2 Growth Analysis....................6-16

7.0 References....................7-1

List of Appendices

Appendix A Facility Diagrams

Appendix B Control Technology Listings

Appendix C Emissions Data

Appendix D Modeling Archive

List of Tables

Table 1-1 PSD Applicability Thresholds For the VV2 Project....1-2
Table 2-1 Time (Minutes) to Full Load With and Without GE "Rapid Start Process" 2-9
Table 2-2 Typical Natural Gas Composition 2-12
Table 2-3 Equipment Sizes and Maximum Natural Gas Usage (Per Unit)....2-12
Table 3-1 National Ambient Air Quality Standards 3-1
Table 3-2 Attainment Status for City of Victorville, San Bernardino County 3-2
Table 3-3 Summary of Federal Air Quality Regulations Applicable to the VV2 Project 3-3
Table 4-1 Summary of BACT/LAER Emissions Rates for the VV2 Project....4-9
Table 5-1 Maximum Annual Emissions from Combustion Turbines 5-2
Table 5-2 Maximum Hourly Emissions from Two Combustion Turbines....5-2
Table 5-3 Maximum Hourly and Annual Auxiliary Boiler Emissions 5-2
Table 5-4 Maximum Hourly and Annual HTF Heater Emissions....5-3
Table 5-5 Maximum Hourly and Annual Emergency Diesel Generator Emissions 5-3
Table 5-6 Maximum Hourly and Annual Emergency Diesel Fire-water Pump Emission 5-3
Table 5-7 Total Annual Potential Emissions, Normal Operation 5-4
Table 6-1 Maximum Concentrations From 2003 – 2005 6-2
Table 6-2 Ambient Air Quality Impact Criteria ($\mu g/m^3$)....6-3
Table 6-3 Stack Parameters and Emissions Data for the Combustion Turbines 6-4
Table 6-4 Stack Parameters and Emissions Data for the Ancillary Equipment....6-4
Table 6-5 Summary of GEP Analysis....6-5
Table 6-6 Maximum Modeled Concentrations for VV2 Project Normal Operations 6-7
Table 6-7 NAAQS Analysis for Project Normal Operations....6-8
Table 6-8 Maximum Modeled CO Concentrations for Project Startup/Shutdown Operations 6-9
Table 6-9 Class I Area NO_2 PSD Increment CALPUFF Modeling Result....6-11
Table 6-10 Class I Area Regional Haze CALPUFF Modeling Results....6-12
Table 6-11 Class I Area Nitrogen Deposition CALPUFF Modeling Results 6-12
Table 6-12: Dispersion Condition Frequency Analysis....6-14
Table 6-13 VISCREEN Model Results....6-15
Table 6-14 Soils and Vegetation Analysis....6-15

List of Figures

Figure 2-1: Regional and Vicinity Map 2-2
Figure 2-2: Project Site and Surrounding Area 2-3
Figure 2-3: Aerial View with Simulated Project Facilities....................2-3
Figure 6-1: Locations of Stacks and Buildings for the GEP Analysis....................6-6
Figure 6-2: Location of PSD Class I Areas Relative to the VV2 Project 6-10

1.0 Introduction

1.1 Project Overview

The City of Victorville (City), a municipal corporation in the State of California, submits this Application for a Prevention of Significant Deterioration (PSD) Permit for the Victorville 2 Hybrid Power Project (referred to as the VV2 Project or Project). The Project will feature a 2 on 1 combined-cycle configuration with two GE 7FA gas turbines and one steam turbine producing a nominal electrical output of 570 megawatts (MW) along with a 250-acre solar thermal collection field, capable of producing 50 MW. The hybrid power plant will be owned by the City of Victorville, and the City has contracted with Inland Energy, Inc., to develop the Project. The combustion turbine trains will include heat recovery steam generators and will be fueled with natural gas only. In addition to the combustion turbines, the facility will contain ancillary combustion equipment including a natural gas-fired auxiliary boiler, a natural gas-fired heat transfer fluid (HTF) heater, a diesel-fired emergency generator, and a diesel-fired fire water pump engine. The facility will also include a wet mechanical draft cooling tower. Commercial operation is planned for the summer of 2010.

The VV2 Project is expected to supply power to the rapidly growing Southern California market while also supplying power locally to the City of Victorville's municipal power company, Victorville Municipal Utility Services (VMUS).

1.2 PSD Applicability

The VV2 Project will be located in an area that is designated federal non-attainment for respirable particulate matter (PM10) and ozone (O_3), and attainment or unclassified for sulfur dioxide (SO_2), nitrogen dioxide (NO_2), carbon monoxide (CO), and fine particulate matter (PM2.5). Based on an estimate of preliminary facility air emissions, the Project will be a major source with respect to New Source Review (NSR) regulations, will trigger Prevention Significant Deterioration (PSD) review for NO_2 and CO, and will be subject to non-attainment new source review (NANSR) for PM10 and ozone precursors NO_x and volatile organic compounds (VOC). The Project will be a minor source of SO_x, lead, and other PSD pollutants. Table 1-1 provides a summary of the emissions in tons per year (tpy) and PSD applicability for this Project.

This application for a PSD permit is being submitted to the U.S. Environmental Protection Agency (EPA), which administers the PSD program in this area. The Mojave Desert Air Quality Management District (MDAQMD) manages the local NANSR program, and an application has also been submitted to the MDAQMD and the California Energy Commission (CEC). Although this area is attainment for PM2.5, the implementation rule for PM2.5 is not yet finalized. PSD therefore does not yet apply to this pollutant. However, the Application for Certification (AFC) submitted to the CEC does fully analyze the impacts from the VV2 Project on PM2.5, and the Project was shown to not cause or contribute to an exceedance of the National Ambient Air Quality Standards for PM2.5 (see 6.03 Air Quality.pdf under Applicant's Documents at http://www.energy.ca.gov/sitingcases/victorville2/documents/index.html). This AFC document includes a control technology review for PM10 emissions (the controls applicable to PM2.5 would be the same as those for PM10), as well as precursor emissions such as NO_2 and SO_2. The AFC also contains an alternatives analysis, including cooling technologies, in Section 5.

Table 1-1
PSD Applicability Thresholds For the VV2 Project

Pollutant	PSD Facility Applicability Level (tpy)	Facility Emissions (tpy)	PSD Applies
NO_x	100	111.9	Yes
SO_2	100	8.3	No
PM10 [a]	N/A	120.9	No
CO	100	257.3	Yes
VOC	N/A	34.6	No

N/A – Not Applicable as the pollutant is classified as nonattainment or as a nonattainment precursor pollutant.

a. PM2-5 emissions conservatively assumed to be equal to PM10.

1.3 Application Contacts

The following persons can be contracted for information regarding this application

Jon B. Roberts, City Manager, City of Victorville
14343 Civic Drive / PO Box 5001, Victorville, CA 92393
760-955-5000

Tom Barnett, Senior Vice President, Inland Energy, Inc.
South Tower, Suite 606, 3501 Jamboree Road, Newport Beach, CA 92660
949-856-2200, tbarnett@inlandenergy.com

Sara Head, Vice President, ENSR
1220 Avenida Acaso, Camarillo, CA 93012
805-388-3775, shead@ensr.aecom.com

1.4 Application Contents

Section 2 of this PSD application contains a description of the Project, including a description of the equipment that is proposed. Section 3 provides a regulatory analysis. An evaluation of the control technology requirements is provided in Section 4 and the emissions summaries are contained in Section 5. Section 6 describes the modeling analyses performed for both the Class II area in the vicinity of the project and the Class I areas within 100 kilometers (km). References are given in Section 7. Appendices contain additional information on the control technology listings, emissions calculations, and modeling files.

2.0 Proposed Project

2.1 Overview

The proposed VV2 Project consists of a hybrid of natural gas-fired combined-cycle generating equipment integrated with solar thermal generating equipment. The combined-cycle equipment will utilize two natural gas-fired combustion turbine generators (CTG), two heat recovery steam generators (HRSG), and one steam turbine generator (STG). The solar thermal equipment will utilize arrays of parabolic collectors that heat a working fluid that is then used to generate steam. The combined-cycle equipment is integrated thermally with the solar equipment in that both utilize the single STG that is part of the VV2 Project.

The Project will have a nominal electrical output of 570 MW and commercial operation is planned for the summer of 2010. The solar thermal input will provide approximately 10 percent of the peak power generated by the plant during the most energy demanding time of the day.

The Project will employ several technologies and approaches to reduce air emissions. The combined-cycle units will use selective catalytic reduction (SCR) and oxidation catalyst equipment to control air emissions. The combustion turbines will also be equipped with GE's Rapid Start Process technology and the facility will include an auxiliary boiler to decrease emissions during startups. The cooling tower will have a high efficiency drift eliminator. The primary fuel for the facility will be pipeline quality natural gas.

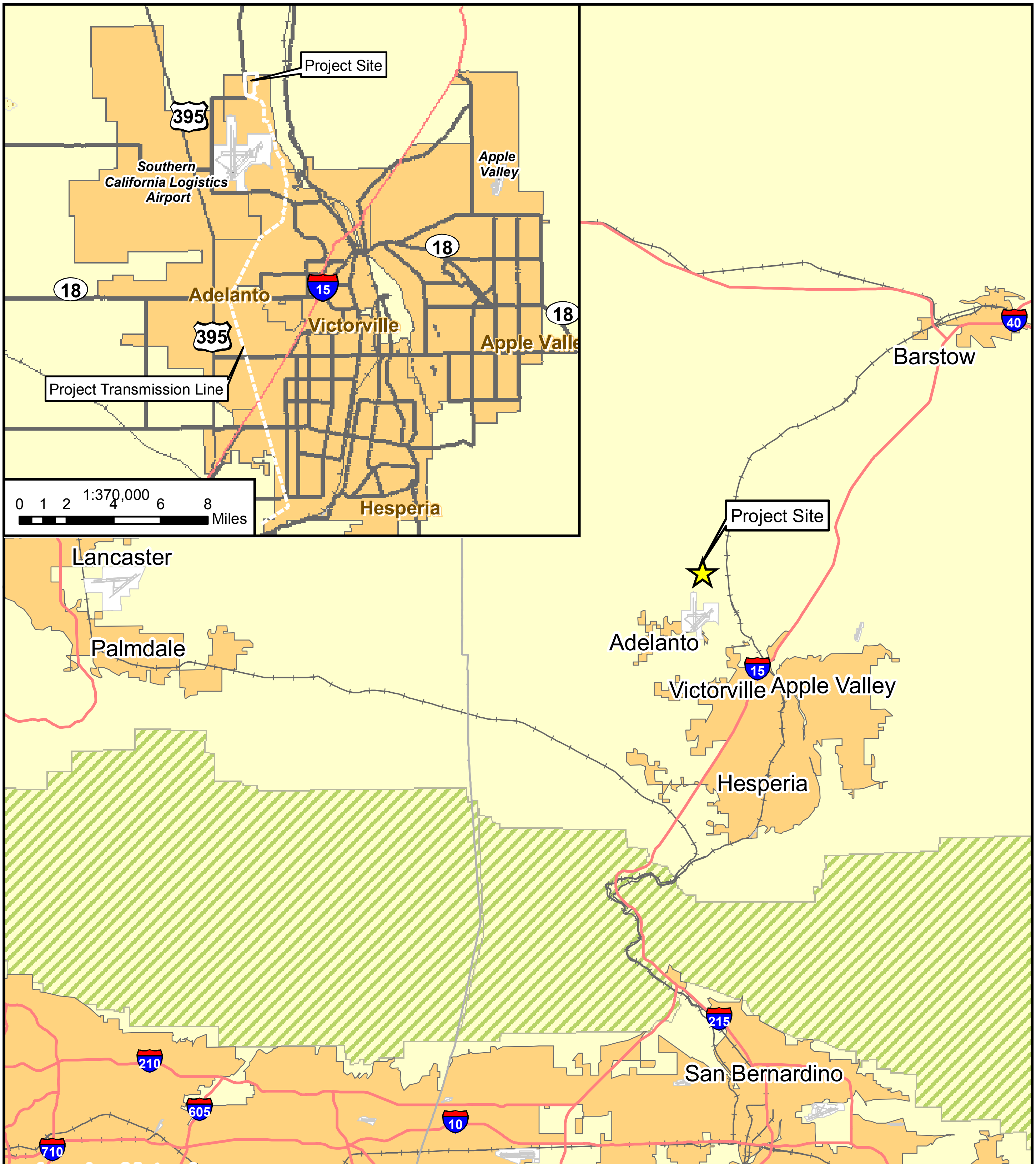
The Project will be fueled with natural gas delivered via an existing natural gas pipeline that supplies the High Desert Power Project (HDPP) located approximately three miles south of the VV2 Project site; this pipeline has sufficient capacity to serve both the VV2 Project and HDPP and is located adjacent to the western boundary of the Project site.

The proposed interconnection point for the VV2 Project with the SCE electrical transmission system is at SCE's existing Victor Substation, approximately 10 miles south-southwest of the Project site.

Reclaimed water for the VV2 Project cooling tower makeup and other industrial uses will be supplied from the nearby Victor Valley Wastewater Reclamation Authority (VVWRA) treatment plant via a new approximately 1.5-mile pipeline. Except for sanitary wastewater that will be disposed through a new approximately 1.25-mile pipeline to an existing sewer interceptor near the VVWRA plant, the Project will be a zero liquid discharge (ZLD) design. Brine (cooling water blowdown) from the Project will be processed to solid waste and disposed at an appropriately permitted offsite disposal facility. The Project's backup cooling water supply will be through a connection to an existing City of Victorville pipeline adjacent to the western boundary of the site that carries State Water Project water. This backup will be used only if there are extended outages in the reclaimed water supply system.

2.2 Location of Facilities

As shown on Figures 2-1 and 2-2, the VV2 Project site is located north of the Southern California Logistics Airport (SCLA), the former George Air Force Base, in the City of Victorville, San Bernardino County, California. The site lies approximately 3.5 miles east of U.S. Highway 395 and approximately 0.5 mile west of the Mojave River (see Figure 2-1). An aerial view of the Project Site with simulated Project facilities is shown in Figure 2-3.



Locus Map

Regional and Vicinity Map

Victorville 2 Hybrid Power Project

Legend

Urban Areas

National Forests

Freeway System

1:600,000

0 2.5 5 10 15 20 Miles

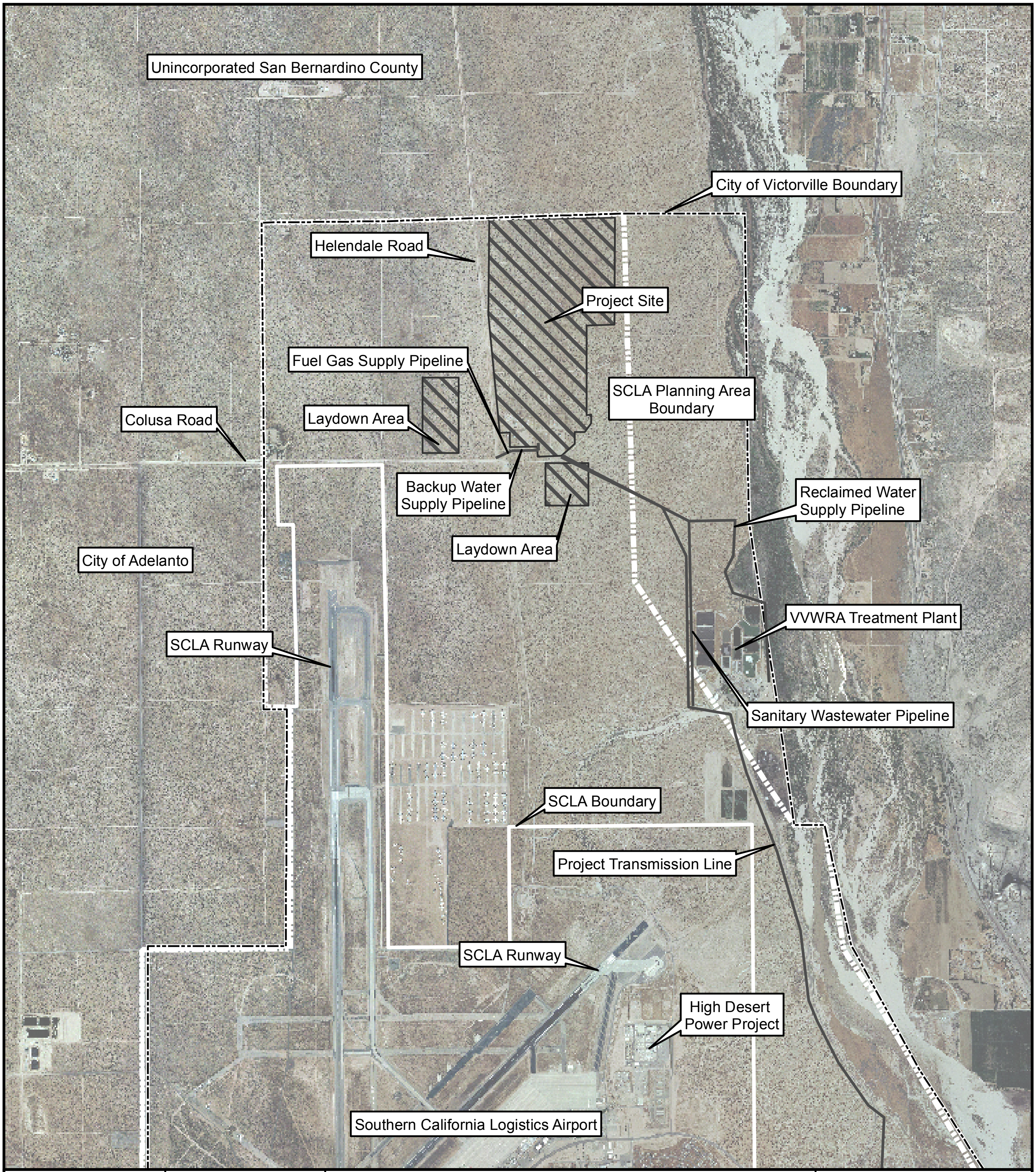
Inland Energy, Inc.

ENSR | AECOM

Figure 2-1

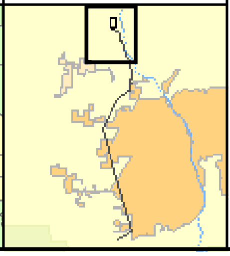
Date: April 2007

Y:\Projects\InlandEnergy\Victorville\MXD\PSD_Application\Figure_2-1_Regional_Vicinity_Map.mxd



Locus Map

Index Map



Project Site and Surrounding Area

Victorville 2 Hybrid Power Project

Source: MapMart Aerial Imagery .61 Meter Resolution Circa 2004

Scale: 1:36,000

0 2,000 4,000 6,000 8,000 Feet

Inland Energy, Inc.

ENSR | AECOM

Figure: 2-2

Date: April 2007

Y:\Projects\InlandEnergy\Victorville\MXD\PSD_Application\Figure_2-2_Project_Site.mxd

Figure 2-3 Aerial View of Project Site with Simulated Project Facilities

Figure 2-2 illustrates the location of the Project power plant site and two adjacent construction laydown areas, as well as the routes of the Project's reclaimed water supply, fuel gas supply, sanitary wastewater disposal, backup water supply, and natural gas pipelines and its transmission lines. The southwest corner of the site is located just north of the intersection of Colusa Road and Helendale Road, approximately one mile northeast of the end of the SCLA north-south runway. Roadway access to the Project site will be from the south along what currently is called Helendale Road. This section of Helendale Road is currently unpaved but will be improved (and renamed Perimeter Road) by the City of Victorville as part of infrastructure upgrades to support planned future development at SCLA and its adjoining planning area (which includes the VV2 Project site).

The legal description of the VV2 Project site is as follows: a portion of Section 2, Township 6 North, Range 5 West, (San Bernardino Base and Meridian), located within the northwest corner of the City of Victorville, California. A new parcel will be created that corresponds with the roughly 275-acre Project site. The power plant site is largely vacant land and consists of primarily five-acre parcels, which are either already under City control or are in the process of being acquired. The City of Victorville is currently acquiring approximately 375 acres for this and other projects, of which a 275-acre subset will be separated and used to construct the VV2 Project.

The existing condition of the Project site is mostly undisturbed land and is surrounded by vacant, undisturbed land. The site is largely flat, with elevations ranging from approximately 2,780 to 2,820 feet above mean sea level (amsl), although at the eastern perimeter of the site and further to the east, topography slopes down to the Mojave River.

2.3 Generating Facility Description

The following sections describe the VV2 Project site arrangement and the processes, systems, and equipment that constitute the proposed power plant. All Project facilities will be designed, constructed and operated in accordance with applicable laws, ordinances, regulations and standards.

2.3.1 Site Arrangement

Facility Diagrams are provided in Appendix A. The Site Plan shows the layout of Project facilities including:

- Plant site, including both the combined-cycle power block and the solar arrays
- Laydown areas
- Fuel gas supply
- Reclaimed water supply
- Sanitary wastewater disposal,
- Backup water supply pipelines, and
- First portion of the Project transmission line

The plot plan of the Project's combined-cycle power block includes the following major components of the Project:

- Two combustion turbine generators (CTGs), each with a heat recovery steam generator (HRSG),
- One steam turbine generator (STG),
- Approximately 250 acres of solar-thermal collectors with associated heat transfer equipment,
- One wet cooling tower,
- An Operations building that incorporates control, maintenance, and administrative functions, and

- A 230-kV switchyard.

An elevation drawing for the power block is also included in Appendix A.

2.3.2 Process Description

This section describes the power generation process and thermodynamic cycle employed by the VV2 Project. The power plant consists of:

- Two CTGs equipped with dry low NO_x combustors and evaporative inlet air coolers,
- Two HRSGs equipped with duct burners,
- One STG, and
- An approximately 250-acre solar thermal collection field with a solar steam boiler and associated auxiliary systems and equipment.

The CTGs and duct burners are fueled exclusively with natural gas. The duct burners enable the HRSGs to produce extra steam in order to obtain peaking output from the STG.

During periods when the solar collectors are in use (i.e., daytime when the sun is shining on the site), the solar field will provide heat directly to the HRSGs to produce more steam, which will allow the facility to reduce firing of the duct burners. This design feature enhances the Project's ability to respond to the energy markets by providing peak power during peak demand periods (e.g., hot summer afternoons) while consuming less natural gas fuel.

At full load, each CTG generates approximately 154 MW (gross) at average ambient conditions. Heat from the CTG exhausts is used in the HRSGs to generate steam and to reheat steam. With the CTGs at full load and the duct burners and solar field out-of-service, the HRSGs produce sufficient steam for operation of the STG at an output of 169 MW (gross) at average ambient conditions, which results in an overall plant gross output of approximately 477 MW (gross). With the CTGs at full load and the duct burners in-service, the HRSGs produce sufficient steam for operation of the STG at its peaking output of 267 MW (gross) at average ambient conditions, which results in an overall plant gross output of approximately 563 MW (net). At full load solar operation, the heat from the solar field can replace the equivalent of approximately 50 MW of duct firing, thereby improving the Project's overall heat rate and reducing air emissions.

Overall, annual availability of the VV2 facility is expected to be in the range of 90 to 95 percent. The plant's capacity factor will depend on the provisions of bilateral power sales contracts as well as market prices for electricity, ancillary services, and natural gas. The design of the power plant provides for operating flexibility (i.e., ability to rapidly start up, shut down, turn down, and provide peaking output), so that operations may be readily adapted to changing market conditions. Included in this flexibility is the ability of the plant to start up the combined-cycle system in slightly over one-half the industry standard for combined-cycle plants it the United States.

The "Rapid Start Process" (RSP) offered by General Electric Power Systems (GE), the supplier of the Project's combustion equipment, allows for faster starting of the gas turbines by mitigating the restrictions of former HRSG designs. Traditionally, the CTGs are brought to full load slowly to limit combined stresses in the high pressure steam drum of the HRSG due to the exhaust temperature of the CTGs. The new GE design eliminates this restriction by modifying the steam drum design. Additional equipment to support the

RSP includes an auxiliary boiler supplying a sealing steam header to allow startup of the steam turbine to follow shortly after the gas turbines.

The following provides a brief description of the combined-cycle equipment's thermodynamic cycle (a combination of the Brayton and Rankine cycles). Air flows through the inlet air filter, evaporative cooler, and associated inlet air ductwork of each CTG and is then compressed in the CTG compressor. Compressed air exiting the compressor flows to the CTG combustors. Natural gas fuel is then injected into the combustors and ignited. The hot combustion gases expand through the CTG's turbine to drive the entire CTG, including the compressor and the electric generator which share a common shaft with the turbine. The hot combustion gases exit the turbine and enter the HRSG dedicated to that CTG. Duct burners installed in each HRSG further heat the CTG exhausts at times when peaking output is desired.

In the HRSGs, heat from the CTG exhausts is transferred to water pumped into the HRSG pressure parts (economizers, evaporators, drums, etc.). The water is converted to superheated steam and is delivered to the STG at three pressures, high pressure (HP), intermediate pressure (IP), and low pressure (LP). The use of multiple steam delivery pressures provides an increase in cycle efficiency. HP steam from the HRSG is admitted to the HP section of the STG, expands through the HP section to drive the STG, and exits the HP section as 'cold reheat' steam. The cold reheat steam is combined with IP steam from the HRSG and delivered to the HRSG reheater. 'Hot reheat' steam leaving the reheater is admitted to the IP section of the STG and expands through the IP and LP sections to further drive the STG. LP steam from the HRSG is admitted to the LP section of the STG and expands through the LP section to also further drive the STG.

Steam leaving the LP section of the STG enters a surface condenser, gives up its latent heat to circulating water, and is condensed to liquid. The circulating water flows through a wet cooling tower where the waste heat is rejected to the atmosphere and the circulating water is then pumped back to the surface condenser.

The cycle described above does not change with the addition of the solar hybrid concept. The solar field circulates a heat transfer fluid (HTF) from the solar boiler and heat exchangers to the solar field. Light from the sun reflects off the solar collector's parabolic troughs and is concentrated on the HTF, which flows in tubes at the focal point of the parabolic troughs. The concentrated sunlight heats the HTF and the heated HTF flows to the solar boiler. Steam from the solar boiler is then fed into the HRSG's high-pressure steam drum to add heat to the steam cycle. This addition reduces the need for duct burning to meet peak power demands.

The HTF planned for use is Therminol™ VP-1, a high temperature, low-pressure oil widely used in solar thermal and other heat transfer applications. The HTF is a low vapor-pressure fluid that allows the solar system to remain at low pressure, thereby enhancing safety by reducing the likelihood of leaks.

2.3.3 Energy Conversion Facilities Description

This section describes the major energy conversion components of the proposed VV2 Project including the CTGs, HRSGs, STG, and solar system.

2.3.3.1 Combustion Turbine-Generators (CTG)

Thermal energy is produced in each of the two CTGs through the combustion of natural gas, and the thermal energy is converted into mechanical energy by the CTG turbine that drives the CTG compressor and electric generator. The CTGs proposed for the VV2 Project employ 'F' technology and are supplied by GE Power Systems. Each CTG consists of a heavy duty, single shaft, combustion turbine-generator and associated auxiliary equipment. The CTGs are equipped with dry low NO_x combustors designed for natural gas. Procurement of the CTGs is based on functional performance criteria, including the following:

- Air emissions at the gas turbine exhaust shall not exceed specified levels.
- Noise emissions shall not exceed specified near-field and property line levels.
- Each CTG shall be capable of operation at 50 percent to 100 percent load while meeting specified air emissions performance criteria.
- Each CTG shall be capable of a specified number of startups per year.

The CTGs are equipped with accessories required to provide efficient, safe and reliable operation, including the following:

- Inlet air filters and on-line filter cleaning system,
- Evaporative inlet air coolers,
- On-line and off-line compressor wash system,
- Fire detection and protection system,
- Lubrication oil system including oil coolers and filters,
- Generator coolers,
- Starting system, auxiliary power system, and control system, and
- Metal acoustical enclosures designed for outdoor service.

2.3.3.2 Heat Recovery Steam Generators (HRSG) and Steam Cycle

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

Each HRSG is a horizontal, natural circulation type unit with three pressure levels of steam generation and reheat loop. High-pressure steam at 1,800 pounds per square inch gage (psig) and 1,050°F is produced in the HRSG and flows to the steam turbine throttle inlet. The exhausted cold reheat steam is mixed with intermediate pressure steam and reintroduced into the HRSG through the reheat loop. The hot reheat steam flows to the intermediate-pressure section of the STG and then to the low-pressure section of the STG. Low-pressure steam from the HRSG also flows to the low-pressure section of the STG. The STG drives an electric generator to produce electricity.

In the proposed hybrid configuration with the solar thermal component integrated into the VV2 Project, additional HP steam is produced during daylight hours from heat collected via the solar array. The solar array heats a working fluid that is used to produce HP steam in a heat exchanger. This HP steam is re-introduced into the combined-cycle system via injection of the solar-generated saturated HP steam into the HP drum of the HRSG. This steam is then superheated in the HRSG superheaters along with the HP steam produced within the HRSG evaporator itself. The STG exhaust steam is condensed in the de-aerating surface condenser with water from a multi-cell wet cooling tower.

Make-up water to the cooling tower will be tertiary treated water from the VVWRA reclaimed water production system brought to the site by a new 1.5-mile pipeline. Blowdown from the cooling tower will be processed in the ZLD system.

GE "Rapid Start Process" (RSP). As noted earlier, the VV2 Project is designed with GE's RSP, which will allow the CTG to reach base load more quickly, reducing startup emissions (emission rates are higher during startup than during normal steady-state operations) and thereby facilitating Project compliance with air emission requirements. Table 2-1 shows the RSP startup rates and startup rates without the RSP. As shown in the table, the RSP reduces CTG startup rates most substantially (by more than 50 percent) during cold starts, with smaller reductions in startup time during warm and hot starts; the RSP does not affect STG startup times.

To facilitate the RSP approach, the HRSGs will be of a modified design. Typical HRSG designs limit the CTG start rate due to the exhaust temperature heating the steam drum too quickly. This limitation is caused by thermal stress limitations on the high-pressure steam drum due to the shell thickness. To avoid this limitation, a modified drum design will be used that allows for thinner wall thickness; this is achieved by elongating the steam drum and reducing its diameter, which allows the steam drum volume to remain relatively unchanged.

Table 2-1
Time (Minutes) to Full Load With and Without GE "Rapid Start Process"

Component	Cold	Warm	Hot
GT1 (Typical)	210	102	62
GT1 (RSP)	70	40	40
GT2 (Typical)	240	124	83
GT2 (RSP)	103	71	71
STG (Typical/RSP)	240	130	130

An alternative approach was considered to reduce combined-cycle system startup times. This alternative included a "once-through" boiler that controls feed water by rate control, which removes the high-pressure steam drum as the limiting component by eliminating it all together. However, the modified drum design described above provides equivalent rapid startup capability without the increased sensitivity to water purity and the need for additional purification equipment associated with the once-through boiler. The once-through boiler approach also removes the planned solar heat input location (high-pressure steam drum), which complicates the Project's hybrid approach (integrated combined-cycle and solar equipment).

2.3.3.3 Auxiliary Boiler

Another limiting factor for startup of combined-cycle equipment is the ability to draw a vacuum on the condenser allowing STG startup to commence. The VV2 Project will use an auxiliary boiler to facilitate rapid startup by providing STG sealing steam prior to CTG startup, thereby allowing the condenser vacuum to be established and the condenser be in a condition ready to accept steam as soon as it is needed. This also avoids the need to vent considerable steam to the atmosphere while waiting for condenser vacuum to be established following CTG start and the beginning of steam generation within the HRSG.

2.3.3.4 Steam Turbine-Generator (STG)

As described earlier, steam from the HRSGs is sent to the STG. The steam expands through the STG turbine blades to drive the steam turbine, which in turn drives the generator. The VV2 Project's STG is of the reheat type and is equipped with accessories required to provide efficient, safe, and reliable operation, including the following:

- Governor system,
- Steam admission system,
- Gland seal system,
- Lubrication oil system including oil coolers and filters,
- Generator coolers, and
- Metal acoustical enclosures designed for outdoor service.

2.3.3.5 Solar Thermal Field System Description

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

The collectors track the sun from east to west during the diurnal cycle to ensure that the sun is continuously focused on the linear receiver. The heat transfer fluid (HTF) is heated up to approximately 740° F as it circulates through the receiver and returns to a series of heat exchangers where the fluid is used to generate high-pressure steam. At the VV2 Project, these heat exchangers are located in the combined-cycle power block (the area where the CTGs, HRSGs, and STG are located). To integrate the solar and combined-cycle Project components, the solar-generated high-pressure steam is then sent to the HP steam section of an on-site HRSG, and thereby contributes to the output of the Project's STG.

Parabolic trough solar technology is the most proven and lowest cost large-scale solar power technology available today, primarily because of the nine commercial-scale solar electric generating station (SEGS) facilities that are operating in the Mojave at Harper Lake, Kramer Junction, and Daggett. More than 2,000,000 m^2 of parabolic trough collector technology have been operating daily for 15+ years, and have accumulated over 175 "plant years" of operational experience. Although no new solar electric generating plants have been built since 1990, significant advancements in collector and plant design have been made possible by the efforts of the SEGS operators, the parabolic trough industry, and solar research laboratories around the world. These improvements include advancements in mirror durability in high winds, receiver efficiency, structural design, cost reduction and system control.

2.3.3.6 Emergency Generator

The emergency diesel generator will supply electrical power to the power plant critical services in the event of a total power outage of switchyard and the plant. The plant critical services will include battery chargers, turning gear, lubricating oil systems, DCS/PLC controls and critical lighting. The generator will be designed, tested, rated, assembled and installed in accordance with all the applicable standards. The equipment shall meet the requirements of NEC and all applicable codes and regulation.

The generator will be Standby rated at 700 kW, 875 KVA, 1,800 RPM, at 0.8 power factor, 480 VAC, 3 phase, 4 wire, 60 hertz, 480/277 VAC, wyes connected to a high resistance grounded system, including radiator fan and all parasitic loads. The diesel generator will have auto-sync capabilities.

The emergency diesel generator will be installed in a dedicated area in the combined-cycle area of the plant site and will include the following major components:

- Diesel Engine,
- Governor,
- Lubricating System,
- Fuel System,
- Generator,
- Exciter,
- Voltage Regulator,
- Remote Synchronizing Panel, including protective relaying and metering,
- Generator Mounted Control Panel,
- Cooling System,
- Fuel Piping and 24 hours Fuel Tank,
- Exhaust System,
- Starting System including Batteries and Batteries Charger, and
- Weather Protective Enclosure.

The plant critical or essential auxiliary electric loads will be served by the normal plant auxiliary power system at 480V or less except when the normal source of power is interrupted or in the case of complete power shutdown at the plant. The emergency generator power system and the critical equipment system will be designed and arranged so that, in the event of failure of the normal auxiliary power, the emergency diesel generator will be automatically connected within 10 seconds to the essential loads and the switching devices (time delay or non-automatic) that are supplying the critical/essential loads.

When the normal plant auxiliary power source is restored, and after a time delay, the automatic transfer switch will disconnect the emergency power source and connect the load to the normal power source. The emergency diesel generator will be periodically tested to confirm its mechanical, electrical and control equipment integrity. The emergency generator system will be synchronized with the normal auxiliary power system from time to time to test its total output power into the system.

2.3.4 Plant Auxiliary Systems and Process Descriptions

The following subsections describe the various plant auxiliary systems (fuel supply, water supply, water treatment, cooling systems, air emissions control, waste management, etc.) associated with the VV2 Project.

2.3.4.1 Fuel Supply and Use

The CTGs and duct burners are designed to burn natural gas. The fuel requirement for base load operation at average ambient conditions is approximately 69.1 MMscfd. The fuel requirement for peaking operation at 77°F/40%RH ambient conditions is approximately 87.5 MMscfd without solar and 78.3 MMscfd with full solar.

Natural gas for the duct burner systems branches off and is regulated to a lower pressure. Safety pressure relief valves are provided downstream of pressure regulation valves. The CTG systems include a natural gas preheater and flow modulation equipment; the duct burner systems also have flow modulation equipment. Table 2-2 shows the typical composition of the natural gas that will fuel the VV2 Project. Table 2-3 shows the maximum natural gas usage for each combustion unit.

Table 2-2
Typical Natural Gas Composition

Component	**Molar %**
Methane, CH_4	95.13
Ethane, C_2H_6	2.66
Propane, C_3H_8	0.35
Butane, C_4H_{10}	0.08
Pentane, C_5H_{12}	0.02
Hexane, C_6H_{14}	0.01
Carbon Dioxide, CO_2	0.72
Nitrogen, N_2	1.03
Total	**100.00**
Sulfur (grains per 100 scf)	0.20
Lower Heating Value (Btu/lb)	20,669
Natural Gas Ratio (HHV/LHV)	1.109

Table 2-3
Equipment Sizes and Maximum Natural Gas Usage (Per Unit)

Component	No. of Units	Maximum Heat Input (MMBtu/hr)[a]	Maximum Annual Usage (hours/year)	Maximum Fuel Usage (MMscf/year)
GE 7FA CTG	2	1,736.4	8,760	14,854
HRSG Duct Burner	2	424.3	8,760	3,630
Auxiliary Boiler	1	35	500	17.1
HTF Heater	1	40	1,000	39.1[b]

a. Higher Heating Value, based on 1,024 Btu/scf

b. Most of the HTF heater fuel usage will be in the months of Nov. through Feb.

2.3.4.2 Cooling Systems

The power plant includes two cooling systems; 1) the steam cycle heat rejection system (e.g., cooling tower) and, 2) the closed cooling water system (equipment cooling), each of which is discussed below.

Steam Cycle Heat Rejection System. The cooling system for heat rejection from the steam cycle consists of a surface condenser, circulating water system, and a wet cooling tower. The surface condenser receives exhaust steam from the LP section of the STG and condenses it to liquid for return to the HRSGs. The surface condenser is a shell-and-tube heat exchanger with wet, saturated steam condensing on the shell side and circulating water flowing through the tubes to provide cooling.

The shell side of the condenser is designed to operate under a vacuum. For example, during base load (unfired) operation at average ambient conditions (77°F/40 percent RH), the condenser is expected to operate at pressure of 1.80 in HgA. Under these conditions, the condenser duty is approximately 975 MMBtu/hr. The auxiliary cooling water system contributes 60 MMBtu/hr of that total duty. This heat is absorbed by the circulating water from the tower, which warms by approximately 17°F (27°F at peak load). The warmed circulating water exits the condenser and flows to the cooling tower.

The circulating water is distributed among multiple cells of the cooling tower, where it cascades downward through each cell and then collects in the cooling tower basin. The mechanical draft cooling tower employs electric motor-driven fans to move air through each cooling tower cell. The cascading circulating water is partially evaporated, and the evaporated water is dispersed to the atmosphere as part of the moist air leaving each cooling tower cell. As discussed in Sections 6.3, Air Quality and 6.15, Visual Resources, because of climatic conditions at the site, visible moisture plumes are expected to occur relatively infrequently and largely in winter months, and no need is expected for a plume-abated cooling tower.

The circulating water is cooled primarily through its partial evaporation and secondarily through heat transfer with the air. The cooled circulating water is pumped from the cooling tower basin back to the surface condenser.

Closed Cooling Water System. The closed cooling water system is filled with a coolant such as a mixture of glycol and water. This coolant is pumped in a closed loop for the purpose of cooling equipment including the CTG and STG lubrication oil coolers, the CTG and STG generator coolers, air compressor aftercoolers, steam cycle sample coolers, etc. The coolant picks up heat from the various equipment items being cooled and the coolant itself is then cooled by non-contact heat exchange with a branch of the circulating water system.

2.3.4.3 Air Emissions Control and Monitoring

Air emissions from the combustion of natural gas in the CTGs and duct burners are controlled by state-of-the-art systems. Emissions that are controlled with control equipment are NO_x, CO, VOC. Particulates (PM10 and PM2.5) and SO_2 are minimized by burning low-sulfur natural gas. Continuous emissions monitoring for NO_x and CO is performed to ensure that the control systems perform correctly and to provide compliance documentation. All emissions values stated in this application are based on parts per million by volume, dry basis (ppmvd) corrected to 15% oxygen (O_2). An evaluation of the control system selection is provided in Section 4 and a summary of emission rates from the proposed equipment is provided in Section 5. A brief description of planned air emissions control methods is provided in the following paragraphs.

Nitrogen Oxides Emissions Control. Stack emissions of NO_x will be controlled by use of dry low-NO_x (DLN) combustors in the CTGs followed by selective catalytic reduction (SCR) in the HRSGs. The DLN combustors control NO_x emissions at the CTG exhausts by pre-mixing fuel and air immediately prior to combustion. Pre-mixing inhibits NO_x formation by minimizing both the flame temperature and the concentration of oxygen at the flame front.

The SCR process uses aqueous ammonia (NH_4OH) as a reagent. Stack emissions of ammonia, referred to as 'ammonia slip,' could be up to 10 ppmvd. The SCR system includes a catalyst bed located within each HRSG, ammonia storage system, and ammonia injection system. The catalyst bed is located in a temperature zone of the HRSG where the catalyst is most effective over the range of loads at which the plant will operate. The ammonia injection grid is located upstream of the catalyst bed. The plant ammonia consumption rate is approximately 266 lb/hr at base load (77ºF/40% RH unfired) conditions and 571 lb/hr at maximum load (18ºF/60% RH fired). A 30,000-gallon aqueous ammonia storage tank located on the VV2 Project site provides sufficient capacity for more than 14 days of continuous operation.

Other Pollutant Emissions Control. Emissions of CO and VOC will be controlled with oxidation catalyst systems located within each HRSG. The oxidation catalyst will also reduce the emissions of hazardous air pollutants.

Fine particulate emissions are controlled by inlet air filtration and by the use of natural gas fuel, which contains essentially no particulate matter. Stack emissions of PM10 consist primarily of hydrocarbon particles formed during combustion. Sulfur dioxide emissions are controlled by the use of natural gas fuel, which contains only trace quantities of sulfur.

Continuous Emissions Monitoring System (CEMS). The Project's CEMS will sample, analyze, and record NO_x, CO, and O_2 concentrations in the stack exhaust. The CEMS will generate a log of emissions data for compliance documentation and activate an alarm in the plant control room when stack emissions exceed specified limits.

2.4 Project Construction and Operating Schedule

2.4.1 Project Construction

The planned VV2 Project construction schedule is as follows:

- Initiation of construction — Summer 2008
- Initial start-up — Late Spring 2010
- Full-scale operations — Late Summer 2010

The construction workforce will peak at 767 during Month 12 of the construction schedule; over the entire construction period, there will be an average workforce of approximately 360. The on-site workforce will consist of laborers, craftsmen, supervisory personnel, support personnel, and construction management personnel. Temporary construction laydown and parking areas will be provided south and west of the power plant site (see Figure 2-3).

The construction sequence for power plant construction includes the following general steps:

- Site Preparation: this includes detailed construction surveys, demolition of existing structures, grading, and preparation of drainage features. It is expected that the combined-cycle area will be prepared first followed by the solar field.

- Foundations: this includes excavations for large equipment (CTGs, STG, HRSG, etc.) and footings for the solar field. This work will begin on the combined-cycle plant and then move to the solar field.
- Major Equipment Installation: once the foundations are complete the larger equipment will be installed. The solar field will be assembled on-site once the foundations are installed.
- Balance of Plant (BOP): with the major equipment in place, the remaining field work will be piping, electrical, and smaller component installations.
- Testing and Commissioning: testing of subsystems will be done as they are completed. Major equipment will be tested once all supporting subsystems are installed and tested.

Construction of the Project transmission system will begin in the third month of the overall construction schedule with work on Segment 3, the southernmost segment furthest from the plant site. Transmission line construction then will proceed northward to Segment 2 and then Segment 1. Construction of the various Project pipelines will begin in the seventh month of the construction schedule.

Equipment and materials will be delivered to the Project site by truck; large components (e.g., CTG) will be brought to the Victorville area by rail and brought to the site by special transporter trucks designed for large loads.

2.4.2 Facility Operation

The VV2 Project will have a small workforce during operation. Actual power plant operations will be controlled by two or three individuals during each operating shift. Additional maintenance and supervisory personnel will be present during the day shift and, as required by specific operations or maintenance activities, during evening and night shifts. The Project is expected to employ 36 full-time personnel.

The power plant will be operated up to 7 days per week, 24 hours per day. When the plant is not operating, personnel will be present as necessary for maintenance, to prepare the plant for startup, and/or for site security.

3.0 Regulatory Setting

3.1 Ambient Air Quality Standards

The EPA has established NAAQS pursuant to the Clean Air Act. The NAAQS include both primary and secondary standards for several "criteria pollutants". The primary standards are designed to protect human health with an adequate margin of safety. The secondary standards are designed to protect property and ecosystems from effects of air pollution. NAAQS have been established for ozone, CO, NO_2, SO_2, PM10, PM2.5, and lead. Table 3-1 presents the NAAQS. Table 3-2 shows the attainment status for the Project area.

Table 3-1
National Ambient Air Quality Standards

Pollutant	Averaging Time	National Standard [1,2]	
		Primary [3]	Secondary [4]
Ozone	8-hour	0.08 ppm (157 $\mu g/m^3$)	Same
CO	8-hour	9 ppm (10 mg/m^3)	Same
	1-hour	35 ppm (40 mg/m^3)	Same
NO_2	Annual Average	0.053 ppm (100 $\mu g/m^3$)	Same
SO_2	Annual Average	0.03 ppm (80 $\mu g/m^3$)	None
	24-hour	0.14 ppm (365 $\mu g/m^3$)	None
	3-hour	None	0.5 ppm (1,300 $\mu g/m^3$)
PM10	24-hour	150 $\mu g/m^3$	Same
PM2.5	Annual	15 $\mu g/m^3$	Same
	24-hour	35 $\mu g/m^3$	Same
Lead	Quarterly	1.5 $\mu g/m^3$	Same

$\mu g/m^3$ = Micrograms per cubic meter.
mg/m^3 = Milligrams per cubic meter.
ppm = parts per million by volume
(1): National standards, other than ozone and those based on annual averages or annual arithmetic means, are not to be exceeded more than once a year. The ozone standard is attained when the expected number of days per calendar year with maximum hourly average concentrations above the standard is equal to or less than one.
(2): Equivalent units given in parentheses are based on a reference temperature of 25ºC and a reference pressure of 760 mm of mercury. All measurements of air quality are to be collected at a reference temperature of 25ºC and a reference pressure of 760 mm of mercury (1,013.2 millibars).
(3): National Primary Standards: The levels of air quality necessary, with an adequate margin of safety to protect the public health. Each state must attain the primary standards no later than three years after that state's implementation plan is approved by the EPA.
(4): National Secondary Standards: The levels of air quality necessary to protect the public welfare from any known or anticipated adverse effects of a pollutant Each state must attain the secondary standards within a 'reasonable time' after implementation plan is approved by the EPA.
(5): The annual PM10 NAAQS of 50 $\mu g/m^3$ was revoked by EPA on September 21st, 2006. FR Vol. 71 Number 200 10/17/2006.

Table 3-2
Attainment Status for City of Victorville, San Bernardino County

Pollutant	Federal
Ozone	Non-attainment (Moderate) for the 8-Hour standard
CO	Unclassified/Attainment
NO_2	Unclassified/Attainment
SO_2	Unclassified
PM10	Non-attainment (Moderate)
PM2.5	Attainment
Lead	Attainment

3.2 Applicable Rules and Regulations

This section describes the regulations and standards that apply to sources of air pollution relevant to the VV2 Project. The focus is on "criteria" pollutant emissions, i.e., those pollutants for which there are ambient air quality standards set to protect health and the environment. The VV2 Project will emit negligible amounts of lead, and hence it is not discussed further.

The EPA is responsible for establishing the NAAQS and enforcing the Federal Clean Air Act (CAA). Various Federal programs have been developed to regulate sources of air pollutants, including stationary, mobile and area sources. These programs include New Source Review (NSR) and other permitting requirements, as well as emissions standards for new and modified sources, and compliance monitoring. The Federal Programs applicable to the VV2 Project are summarized in Table 3-3. Most of these Federal programs, except for PSD, have been delegated to the MDAQMD for implementation in the local area.

3.2.1 New Source Review

The Federal CAA requires any new major stationary sources of air pollution, and any major modifications to existing major stationary sources, to obtain a construction permit before commencing construction. This process is known as New Source Review (NSR). NSR refers to the pre-construction review and permitting programs under CAA Title I, Parts C and D, that must be satisfied before new construction or major modifications can begin on major sources. The Prevention of Significant Deterioration (PSD) program (CAA Title I, Part C) is EPA's NSR permitting program for sources located in areas that attain the NAAQS (attainment areas) and in areas for which there is insufficient information to determine status (unclassified areas). Its counterpart, (CAA Title I, Part D), is for sources located in areas that do not attain the NAAQS (non-attainment areas), and is often called the non-attainment NSR (NNSR) program. EPA Region IX currently issues PSD permits to applicable sources within the MDAQMD, but the non-attainment NSR program is administered by the MDAQMD.

Table 3-3
Summary of Federal Air Quality Regulations Applicable to the VV2 Project

Regulation	Applicability
Prevention of Significant Deterioration (PSD) Clean Air Act (CAA) §160-169A, 42 USC §7470-7491, 40CFR Parts 51 and 52.	Requires PSD review, facility permitting, Best Available Control Technology (BACT) and increment consumption analysis for significant emissions from new major sources
CAA, Sections 171 – 193, 42 USC, Section 7501	Requires NSR facility permitting for construction or modification of specified stationary sources. NSR applies to pollutants for which area is designated non-attainment for NAAQS
CAA, Section 401 (Title IV), 42 USC, Section 7651	Requires reductions in NO_x and SO_2 emissions to reduce acid deposition
CAA, Section 501 (Title V), 42 USC, Section 7661	Establishes a comprehensive permit program for major stationary sources
CAA, Section 111, 42 USC, Section 7411, (Title 40 CFR, Part 60)	Establishes national performance standards for new stationary sources
CAA, Section 114, 42 USC, Section 7414, (Title 40 CFR Part 64)	Requires the operation, maintenance and monitoring of emission control systems
Emergency Planning and Community Right-to-Know Act, 42 USC Chapter 116	Requires reporting of releases of toxic materials to the environment if the facility manufactures, processes or otherwise uses more than specified quantities of toxics

3.2.2 Prevention of Significant Deterioration

The PSD regulations, which can be found at 40 CFR § 52.21, apply to the construction of major sources in areas that are currently in attainment or unclassified for the NAAQS. A major source is defined as a facility with potential to emit equal to or greater than 250 tons per year (tpy) of any criteria pollutant. In addition, the rules provide a list of 28 major facility categories that are subject to the PSD provisions if they have the potential to emit greater than 100 tpy. The VV2 Project power plant is included in the list of 28 major facility categories (fossil-fuel fired, steam electric generating facility).

The PSD program is designed to prevent further significant deterioration of areas that are currently in attainment or unclassified. The PSD regulations accomplish this goal by imposition of Best Available Control Technology (BACT) and dispersion modeling analyses to ensure that allowable increments of degradation will not be exceeded.

The Project area attains the NAAQS for NO_x and CO, but does not attain the national standards for ozone or PM10. Total emissions for the Project will be greater than the 100-tons per year PSD major source threshold for NO_x and CO. Therefore, the PSD program major source requirements apply to emissions of these two pollutants.

3.2.3 Title V – Federal Operating Permits Program

Title V of the CAA Amendments of 1990 requires a Federal Operating Permit for major sources of criteria pollutants and a compliance plan for meeting applicable regulatory requirements. Covered major sources must submit an annual compliance certification and must renew the Title V permit every five years. Requirements for State/locally administered Title V programs are outlined in 40 CFR Part 70. The MDAQMD maintains its own set of regulations (i.e., District Regulation XII) applicable to Federal Operating Permits. Emissions thresholds for Title V applicability vary depending on the attainment status of the area. A Title V permit contains all of the requirements specified in different air quality regulations that affect an individual facility or project. The VV2 Project will be subject to the Title V program and will be required to obtain a Title V permit from the MDAQMD in a timely manner.

3.2.4 Title IV – Acid Rain Program

Title IV of the CAA Amendments of 1990 requires implementation of an acid rain permit program (42 USC §7651; 40 CFR Part 72). These regulations require reductions in emissions of sulfur dioxide and nitrogen oxides from subject facilities in order to reduce the adverse effects of acid deposition. Under this program, the VV2 Project must obtain emission allowances for SO_x emissions and meet monitoring requirements for NO_x. MDAQMD has been delegated by EPA to implement the Title IV program with EPA Region IX oversight. The requirements for this program are contained in MDAQMD Rule 1210.

3.2.5 New Source Performance Standards (NSPS)

The VV2 Project is also subject to specific New Source Performance Standards (NSPS). Enforcement of the NSPS has been delegated to the MDAQMD.

NSPS are Federal standards promulgated for new and modified sources in designated categories codified in 40 CFR Part 60. NSPS are emission standards that are progressively tightened over time in order to achieve on-going air quality improvement without unreasonable economic disruption. The NSPS impose uniform requirements on new and modified sources throughout the nation. These standards are based on the best demonstrated technology (BDT) for emission control. BDT refers to the best system of continuous emissions reduction that has been demonstrated to work in a given industry, considering economic costs and other factors, such as energy use. In other words, a new source of air pollution must install the best control system currently in use within that industry.

The format of the standard can vary from source to source. It can be a numerical emission limit, a design standard, an equipment standard, or a work practice standard. Primary enforcement responsibility of the NSPS rests with EPA, but this authority can be delegated to the States or local air districts. States can adopt an NSPS or impose limitations of their own, as long as the State requirements are at least as stringent as the Federal requirements. The NSPS potentially applicable to the proposed VV2 Project are summarized below.

Subpart A – General Provisions. – Any source subject to an applicable standard under 40 CFR Part 60 is also subject to the general provisions of Subpart A. Because the proposed Project is potentially subject to Subpart KKKK – NO_x Emission Limits for New Stationary Combustion Turbines, the requirements of Subpart A will also apply. The VV2 Project operator will comply with the applicable notifications, performance testing, recordkeeping and reporting outlined in Subpart A.

Subpart KKKK – NOx Emission Limits for New Stationary Combustion Turbines. The proposed combined-cycle hybrid power plant must comply with the requirements of NSPS Subparts KKKK.[1] MDAQMD emission limitations based on BACT requirements are, however, more restrictive than these NSPS requirements.

The NO_x standard for units firing natural gas, and rated at greater than 850 MMBtu/hr heat input, is 15 ppm at 15 percent O_2 (or 54 ng/J of useful output or 0.43 lb/MW-hr). Compliance is determined on a 30-unit-operating-day rolling average, where "unit operating day," is defined as a 24-hour period between 12:00 midnight and the following midnight during which any fuel is combusted in the unit.

The SO_2 standard is 110 ng/J (or 0.9 lb/MW-hr) gross output. Operators can also comply with an alternative standard, limiting potential sulfur emissions to below 26 ng/J (0.06 lb/MMBtu) heat input. Fuel sulfur monitoring is required each unit operating day. However, options are available to reduce frequency or entirely avoid the necessity to monitor (e.g., representative sampling according to the schedule in Part 75, Appendix D or tariff sheet attesting that sulfur content is < 0.05 percent by weight).

At the 2 ppm level required by BACT, the VV2 Project NO_x emissions will meet the NSPS limit and CEMS will be used to ensure compliance. Pipeline quality natural gas will ensure compliance with the SO_2 standard.

Subpart IIII—Standards of Performance for Stationary Compression Ignition Internal Combustion Engines (CI ICE) – Owners and operators of emergency fire-water pump engines with a displacement of less than 30 liters per cylinder must comply with the emission standards in table 4 to this subpart, for all pollutants.

Owners and operators of emergency stationary CI ICE that are not fire-water pumps and with a displacement of less than 30 liters per cylinder and a maximum engine power less than 2,237 kW must comply with the off-road emission standards specified in 40 CFR Part 89.112 and 40 CFR Part 89.113.

Owners and operators of emergency stationary CI ICE with a displacement of greater than or equal to 30 liters per cylinder must meet the following requirements: (1) reduce NO_x emissions by 90 percent or more, or limit the emissions of NO_x in the stationary CI ICE exhaust to 1.6 grams per kW-hr (1.2 grams per horsepower-hour (hp-hr); and (2) reduce particulate matter (PM) emissions by 60 percent or more, or limit the emissions of PM in the stationary CI ICE exhaust to 0.15 g/kW-hr (0.11 g/hp-hr).

If non-emergency use of the engines is restricted to less than 50 hours or as required by fire safety testing, then the above limits do not apply. The VV2 Project will comply with this NSPS by restricting the use of the engines to emergency situations and limiting non-emergency testing to less than 50 hours per year.

3.2.6 Compliance Assurance Monitoring (CAM) Rule

The CAM Rule (40 CFR Part 64) requires facilities to monitor the operation and maintenance of emissions control and report any control system malfunctions to the appropriate regulatory agency. If the emission control system is not working properly, the CAM Rule also requires action to correct the control system malfunction. The CAM Rule applies to units that employ an active control device with uncontrolled potential to emit levels greater than applicable major source thresholds. Emission units governed by Title V operating

---

[1] With the promulgation of 40 CFR Part 60 Subpart KKKK in July 2006, requirements of Subparts GG and Da are superseded by this new regulation.

permits that require continuous compliance determination methods are generally compliant with the CAM Rule.

The pollutant specific emission units (PSEU) at the VV2 Project include the combustion turbines controlled with SCR systems to control NO_x emissions and oxidation catalysts to control CO and VOC. However, these PSEUs are not subject to the CAM Rule because the NO_x emissions are subject to the Acid Rain program, the CO will be continuously monitored as required by a Title V permit, and the catalyst can be shown to be working by the CO continuous emissions monitoring system (CEMS). The dry low-NO_x burners employed by the auxiliary boiler and heater and the drift eliminator installed on the cooling tower are not considered to be “active” control devices, and hence these PSEUs are exempt from the CAM Rule.

3.2.7 Toxic Chemical Release Inventory Program

The Emergency Planning and Community Right-to-Know Act (EPCRA), through the Toxic Chemical Release Inventory (TRI) program, establishes reporting requirements for toxic releases to the environment if the facility: (1) produces more than 25,000 pounds of a listed chemical per year; (2) processes more than 25,000 pounds of a listed chemical per year; or (3) uses more than 10,000 pounds of a listed chemical per year. Electric utilities, in Standard Industrial Classification (SIC) Codes 4911, 4931, and 4939, that combust coal and/or oil for the purpose of generating electricity for distribution in commerce must report under this regulation. The VV2 Project falls under SIC Code 4911, which covers establishments engaged in the generation, transmission, and/or distribution of electric energy for sale. However, the Project will not combust coal and/or oil for the purpose of generating electricity for the distribution in commerce. The VV2 Project will use ammonia, a listed chemical, so it will need to report if it uses more than 10,000 pounds of ammonia in a year.

4.0 Control Technology Evaluation

One of the substantive requirements of the PSD program is that major sources of attainment pollutants must apply BACT. As discussed previously, the Victorville area in the MDAQMD is designated as non-attainment for the NAAQS for ozone and PM10 and attainment for the NAAQS for CO, NO_2 and SO_2. Because the proposed VV2 Project has the potential to emit significant levels of NO_x and CO, BACT must be implemented for these pollutants. Emissions of SO_2 will be below the PSD significance level of 40 tpy, hence BACT is not required for this pollutant under PSD. Because NOx is a precursor to ozone, the control technology for NOx must also meet the more stringent requirements for Lowest Achievable Emission Rate (LAER).

This section evaluates NOx and CO control technology for each proposed emission unit that emits these pollutants. Several agencies, including the EPA, California Air Resources Board (ARB) and several air districts including the South Coast Air Quality Management District (SCAQMD) maintain data bases of control technology determinations. The SCAQMD has published BACT guidelines applicable to the types of equipment found at power generation facilities. While Victorville is within the MDAQMD, and thus outside SCAQMD jurisdiction, the SCAQMD guidelines were used as an additional resource for the determination of BACT/LAER emission levels for the proposed Project. SCAQMD no longer publishes “presumptive” BACT/LAER emission levels, but rather includes examples of recent BACT/LAER determinations as input to future case-by-case BACT/LAER decisions. This control technology evaluation for the VV2 Project includes a summary of previous BACT/LAER determinations from the SCAQMD’s BACT Guidelines and EPA’s RACT/BACT/LAER Clearinghouse (RBLC), as well as recent or pending decisions by the California Energy Commission.

EPA guidance recommends that control technology reviews be performed on a “top down” basis, that is, starting with the top level of control that has been demonstrated in practice on a similar emission source. If the top level of control is selected, no further analysis is required. The following BACT/LAER analysis follows the top-down methodology – however, the top level of control is proposed for each pollutant subject to control technology requirements.

4.1 Combustion Turbines and Heat Recovery Steam Generators

The proposed CTGs will operate in combined-cycle mode. In a combined cycle, hot exhaust from the CTG is ducted through a HRSG, which may also be fired, to drive a steam turbine generator. The VV2 Project will supplement steam produced in the HRSG with steam generation from a solar array. Since the CTG and HRSG are coupled together in a combined-cycle configuration, and exhaust through a single stack, they are considered to be one combustion train for purposes of the evaluation of BACT/LAER emissions control.

4.1.1 LAER for NO_x

4.1.1.1 Top-down Ranking of Achievable Control Levels

The most recent listings for combined-cycle combustion turbines in this size range provided in Part B of the SCAQMD BACT guidance include:

- Magnolia Power Project, Burbank, California – 2004; NO_x = 2 parts per million (ppm), 3-hr average
- Vernon City Power & Light, Vernon, California – 2004; NO_x = 2 ppm, 1-hr average

The Guidance also references several large combined-cycle projects operating in Massachusetts with NO_x limits of 2 ppm, including ANP Blackstone, IDC Bellingham and Sithe Mystic.

EPA's RBLC shows additional projects permitted in recent years at the 2 ppm NO_x emission rate, including:

- Duke Energy Arlington Valley Energy Facility, Maricopa County, Arizona – 2003
- Sacramento Municipal Utility District Cosumnes Plant, Sacramento County, California – 2003
- Salt River Project Santan Generating Station, Maricopa County, Arizona – 2003

The CEC shows additional projects approved or pending approval at the 2 ppm NO_x emission rate, including:

- Roseville Energy Park, Placer County, California – 2005
- El Centro Unit 3 Repower Project, Imperial County, California – 2007
- Blythe Energy Project II, Riverside County, California – 2005
- Los Esteros Critical Energy Facility, Phase II, Santa Clara County, California – 2006
- South Bay Replacement Project, San Diego County, California – pending

All of the combined-cycle combustion turbine projects listed above employ SCR for NO_x control. The basis for the emission rates for the two SCAQMD plants was LAER. See Appendix B for listings of RBLC entries and other projects in the previous four years for NO_x.

4.1.1.2 Ammonia Slip Associated with SCR

The emission of unreacted ammonia (NH_3), or "ammonia slip," is a necessary collateral emission impact of the operation of SCR, especially when NO_x is being controlled to LAER levels. Ammonia is a potential contributor to formation of particulate matter in the atmosphere by reaction with gaseous nitric acid or sulfuric acid, although most such reactions are not ammonia-limited due the consistent presence of naturally occurring ammonia in the atmosphere. A trade-off exists between the minimization of NO_x and the minimization of ammonia slip when SCR is used to control NO_x. Even though NH_3 is not a BACT/LAER applicable criteria air pollutant, regulatory agencies routinely limit NH_3 slip emissions in new permits for combined-cycle facilities.

Information from recent permits in the SCAQMD BACT Guidelines provides the following limits for NH_3:

- Magnolia Power Project, Burbank, California; NH_3 = 5 ppm
- Vernon City Power & Light, Vernon, California; NH_3 = 5 ppm

Four facilities in Massachusetts are listed in the RBLC as being permitted at 2 ppm @ 15% O_2 for ammonia slip:

- ANP Blackstone Energy Company, Worcester, Massachusetts – 1999
- ANP Bellingham Energy Company, Norfolk, Massachusetts – 1999
- Cabot Power Corporation, Suffolk, Massachusetts – 2000
- Sithe Mystic Development, Suffolk, Massachusetts – 1999

None of these facilities, however, are equipped with duct burners. Duct burners add to the total stack emissions of NO_x from a combined-cycle system, and complicate the constant temperature window needed to optimize SCR performance in the heat recovery steam generator. Five ppm is determined to be the lowest NH_3 slip level permitted for combined-cycle turbines with duct burners that seek to reduce NO_x to 2 ppm.

The CEC has approved or is pending approval of several projects at an NH_3 emission rate of 10 ppm, including:

- Roseville Energy Park, Placer County, California – 2005
- Blythe Energy Project II, Riverside County, California – 2005

- Los Esteros Critical Energy Facility, Phase II, Santa Clara County, California – 2006

The El Centro Unit 3 Repower Project, Imperial County, California has a 5 ppm NH_3 emission rate that was proposed by the applicant and is expected to be required by the local air pollution control agency. All these facilities will be equipped with duct burners.

Since ammonia is not a criteria air pollutant subject to BACT/LAER, and since the VV2 Project must minimize emissions of NO_x from both the combustion turbines and fired heat recovery steam generators, ammonia slip emissions of up to 5 ppm are proposed.

4.1.1.3 NO_x LAER Determination for Normal Operation

The VV2 Project proposes a BACT/LAER emission limit of 2.0 ppmvd (15% O_2) NO_x on a 1-hour averaging time using SCR, and an ammonia slip limit of 5 ppmvd (15% O_2) during steady-state, normal operating conditions. Normal operating conditions exclude periods of startup, shutdown and malfunction. The same aggressive limit is proposed when duct burners are also firing in the HRSG.

4.1.1.4 NO_x LAER Determination for Startup and Shutdown

The use of SCR to control NO_x is not technically feasible when the surface of the SCR catalyst is outside of the manufacturer's recommended operating temperature range. Outside of these temperatures, NH_3 cannot be introduced to control NO_x, since the NH_3 will not react with the NO_x completely. Therefore, SCR cannot be used to control NO_x emissions during gas turbine startup or shutdown, when the SCR catalyst temperature is below the minimum operating temperature.

NO_x is emitted in diffusion flame mode in the turbine combustor during the first phases of startup, albeit at low fuel input rates. When turbine load reaches conditions that are predetermined by the turbine control system, the combustors switch to dry low-NO_x (lean pre-mix DLN) operation, and NO_x emissions are controlled with the DLN combustion system of the combustion turbine. Once conditions reach minimum temperature at which NH_3 injection can be initiated, normal operation of the SCR system is rapidly achieved.

The VV2 Project is proposing to permit a gas-fired auxiliary boiler and solar array that will be used to preheat the combined-cycle systems' steam seals and piping, as well as a novel heat recovery steam generator that is designed to enable faster startups. This technology is referred to by the manufacturer (GE) as their "Rapid Start Process" or RSP, and is expected to reduce the duration of startups compared with conventional combined-cycle units. By shortening the duration of startup times, the RSP technology may be capable of reducing total startup emissions on the order of 50 percent.

There are no other technically feasible control techniques to further reduce emissions of NO_x during startup and shutdown. Mass emission rate limits, in pounds per event, proposed during startup and shutdown and the specification of GE's RSP technology therefore represent LAER for emissions of NO_x during the short-term startup and shutdown events. The following emission rate limits during these periods are proposed:

Hot/warm Startup:	40.0 lb/event per turbine
Cold Startup:	96 lb/event per turbine
Shutdown:	57 lb/event per turbine

4.1.2 BACT for CO

CO is formed as a result of incomplete combustion of fuel within the gas turbine generating systems.

4.1.2.1 Top-down Ranking of Achievable Control Levels

In the last four years, projects have been permitted for CO levels ranging from 2.0 to 4.0 ppm. For example, CO listed for similar combined-cycle turbines in the SCAQMD BACT Guidelines include:

- Magnolia Power, Burbank, California, 2004; CO = 2.0 ppm, 1-hr average
- Vernon City Power & Light, Vernon, California, 2004; CO = 2.0 ppm, 3-hr average

Many facilities are listed in the RBLC since 2002 with CO permit limits of 2 ppm @ 15% O_2. Among the most recent projects listed are:

- COB Energy Facility, Klamath, OR – 2003
- Sumas Energy 2 Generation Facility, Whatcom, WA – 2003

The CEC also has a pending approval at the 2 ppm CO emission rate for the South Bay Replacement Project, San Diego County, California.

Duct burners will emit additional CO, which will increase the uncontrolled emission levels entering the oxidation catalyst. Several recent projects, including the Duke Energy Arlington Valley Energy Facility, Maricopa County, AZ and Copper Mountain Power, Clark County, NV have CO permit limits of 3.0 ppm when duct firing and 2.0 ppm when not. A complete listing of RBLC projects, as well as others, is included in Appendix B.

4.1.2.2 CO BACT Determination for Normal Operation

The VV2 Project proposes CO BACT emission limits of 2.0 ppmvd (corrected to 15% O_2) over a one-hour averaging time without duct burners, and 3.0 ppmvd (corrected to 15% O_2) over a one-hour averaging time when duct burners are firing. These emission limits will be achieved with use of an oxidation catalyst.

4.1.2.3 CO BACT Determination for Startup and Shutdown

CO emissions during startup and shutdown are controlled to a lesser extent than during normal operation because the oxidation catalyst is below its normal operating temperature range. Similar to the emissions of other pollutants, the RSP technology may be capable of reducing total startup CO emissions on the order of 50 percent.

There are no other technically feasible control techniques to further reduce emissions of CO during startup and shutdown. The mass emission rate limits, in pounds per event, proposed to limit CO emissions during startup and shutdown therefore represent LAER, which goes beyond the BACT levels required for this Project.

The following CO emission rate limits during these periods are proposed:

Hot/warm Startup:	329.0 lb/event per turbine
Cold Startup:	410.0 lb/event per turbine
Shutdown:	337.0 lb/event per turbine

4.2 Auxiliary Boiler and HTF Heater

The VV2 Project will include a 35 MMBtu/hr auxiliary boiler and a 40 MMBtu/hr Heat Transfer Fluid (HTF) heater. Both will be fired by pipeline quality natural gas. The auxiliary boiler will operate a maximum of 500 hours per year and the HTF heater will operate no more than 1,000 hours per year. The auxiliary boiler is primarily designed to shorten the duration of startups as part of GE's RSP technology; therefore, the boiler itself is control technology designed to minimize emissions during startup.

4.2.1 LAER for NO_x

NO_x is primarily formed within a natural gas combustion process in two ways: (1) the oxidation (within the high temperature environment of the flame) of elemental nitrogen contained in the combustion air (this is referred to as thermal NO_x); and (2) the oxidation of nitrogen contained in the fuel (referred to as fuel NO_x). The rate of formation of thermal NO_x is a function of residence time and free oxygen, and is exponential with peak flame temperature. For conventional boilers fired exclusively with natural gas, it is generally assumed that fuel NO_x formation is of a minimal magnitude.

In general, alternative approaches to minimizing NO_x emissions from a natural gas-fired unit are as follows:

- Combustion modifications / combustion-based control systems
- Flue gas treatment

Combustion-based ("front-end") control mechanisms available for reducing the formation of thermal NO_x emissions include: (1) reduction of local nitrogen concentrations at peak temperature, (2) reduction of local oxygen concentrations at peak temperature, (3) reduction of residence time at peak temperature, and (4) reduction of peak temperature. Because it is quite difficult to reduce nitrogen levels, most front-end NO_x control techniques have focused on the other three mechanisms.

4.2.1.1 Available Control Technologies for NO_x

The primary front-end combustion controls for small scale natural gas combustion sources include low-NO_x burners (LNBs), flue gas recirculation (FGR), and reburn technology (which provides an additional level of staged combustion). All burner manufacturers now offer standard LNBs that limit NO_x formation to a range of approximately 0.035 to 0.05 pounds per million Btu heat input (lb/MMBtu) when firing natural gas. New state-of-the-art LNBs, commonly referred to as 9 ppm ultra low-NO_x "California" burners, can achieve NO_x emission rates in the range of what may be achieved through application of flue gas treatment (SCR). Candidate control technologies that were evaluated are summarized in the following sections.

Selective Catalytic Reduction: The key limitation relative to the technical feasibility of SCR for the proposed auxiliary boiler or HTF heater is that the temperature of the exhaust gas will be below the low end of the proper temperature range for the SCR catalyst. More specifically, it is expected that the temperature of the boiler or heater exhaust gas will be on the order of 350°F while the minimum temperature for effective NO_x reduction with SCR is approximately 600°F. Because the temperature of the exhaust gas exiting the units will be well below the low end of the proper SCR temperature range and the auxiliary units will operate only for a limited number of hours per year, and then primarily to shorten the duration of combined-cycle startups as part of an overall LAER control strategy, SCR has never been attempted or considered on any similar unit. It is doubtful that the proposed auxiliary units would even operate at steady-state conditions long enough to introduce NH_3 to an SCR system. This technology is therefore technically infeasible for application to the proposed auxiliary boiler or HTF heater.

Ultra Low-NO_x Burners with Internal Flue Gas Recirculation: Low-NO_x burners that incorporate internal flue gas recirculation are well established for application to industrial-sized package boilers and heaters.

Commercially available ultra LNBs are now considered technically feasible, and are capable of limiting NO_x emissions to 9 ppm, which is considered to represent LAER in this type of application.

Reburn Technology: Reburn technology involves staging combustion through the combustion of fuel through a second elevation of burners, which limits the formation of thermal NO_x. Package boilers and heaters do not have the required vertical space or furnace volume for the addition of a second burner, and thus NO_x control through the use of reburn technology is not considered to be technically feasible for a package boiler application.

4.2.1.2 Top-down Ranking of Achievable Control Levels

MDAQMD and EPA do not dictate a specific control technology that must be used to achieve established LAER emission rates, and encourage selection of the qualifying technology with the least adverse collateral impacts. For operation of natural gas-fired auxiliary units that will operate very few hours per year, and especially for units that are themselves emission control equipment, the best technology selection to achieve LAER is the 9 ppm ultra-low NO_x burner.

The most recent listings for gas-fired boilers in this size range provided in Part B of the SCAQMD BACT guidance include:

- Los Angeles County Internal Services, Los Angeles, California, 2004; NO_x = 9 ppm
- Clayton Industries, Chatsworth, California, 2002; NO_x = 9 ppm

Several natural gas-fired industrial boilers have also been permitted in Massachusetts with 9 ppm "California Burners" as BACT. The proposed auxiliary boiler will operate to reduce startup duration, and the boiler and heater will operate for very limited hours per year. No similar sources were identified in EPA's RBLC with NO_x emission limits less than 9 ppm.

4.2.1.3 NO_x LAER Determination for Normal Operation

The application of 9 ppm "California" ultra low NO_x burner technology with limited hours of operation and exclusive use of pipeline quality natural gas represents LAER for the proposed auxiliary boiler and HTF heater. The auxiliary boiler will be equipped with LNBs (9 ppm @ 3% O_2) and will have a NO_x emission rate of 0.011 lb/MMBtu. The HTF heater will also emit less than 0.011 lb/MMBtu of NO_x. The use of low NO_x burners and the emission limit of 0.011 lb/MMBtu represent LAER for the proposed auxiliary boiler and HTF heater.

4.2.2 BACT for CO

CO emissions in a natural gas burner result from incomplete combustion of organic compounds contained in the gas being burned. Three principal factors contribute to the failure to achieve completion of combustion: (1) insufficient air supply; (2) insufficient residence time; and (3) thermal quenching of the combustion products.

The minimization of CO emissions from a natural gas-fired unit is accomplished by combustion design, including furnace design and instrumentation, and operational techniques that ensure complete combustion. Effective design of the unit to achieve the lowest possible CO emissions involves the minimization of the three factors cited above. A major issue, however, in the design of an emissions control system is that there exists a tradeoff between NO_x emissions and CO emissions. The mechanisms by which NO_x emissions are minimized tend to result in an increase in the generation of CO emissions.

Fuels require a minimum level of air input to the combustion zone to allow for completion of combustion. Because of the dynamics of the combustion process and the chemical composition of both air and fuel, this minimum level is above the stoichiometric level (i.e., the level at which there is just sufficient oxygen for the elements of the fuel to burn). For natural gas burners, at least 20 percent excess air is typically needed for completion of combustion. The level of excess air is site-specific and can only be established by field tests of the unit. To complete combustion, therefore, the auxiliary boiler must be designed to provide more than 20 percent excess air. LNBs are intended, however, to operate at very low excess air levels (10 percent to 15 percent excess air). Therefore, the system must be designed to maintain excess air within these levels to keep an appropriate balance between control of NO_x and CO. Sufficient time must be provided for the mixing and combustion to take place. A residence time of at least 0.5 seconds in the upper section of the combustion zone is typically required to complete combustion. The system design must take into account both furnace volume and flow mechanics to provide at least this much time. Incomplete combustion can also occur due to the impingement of a flame onto a cold surface. This most often involves the impingement of the flame onto cold furnace walls. Premature quenching of the flame will release CO into the stack gases. The temperature of the gas stream is lowered sufficiently to freeze intermediate combustion products, including CO. The problems with flame impingement are acute with LNBs. Flame lengths with LNBs are longer due to the delayed mixing of air into the flames. It is necessary, therefore, to carefully size the burners to account for the added length of an LNB flame. The control technology alternatives that were considered include combustion control and oxidation catalyst.

4.2.2.1 Available Control Technologies for CO

Similar to SCR technology, oxidation catalyst technology is not technically feasible for application to small auxiliary package boilers or heaters, especially units that will operate relatively few hours per year, and then primarily as part of GE's RSP technology designed to minimize emissions from the combined-cycle systems during startup. Good combustion control, as achieved with state-of-the-art "California" burners, thus represents the only technically feasible CO control technology applicable to the VV2 Project's proposed small auxiliary package boiler and HTF heater.

4.2.2.2 Top-down Ranking of Achievable Control Levels

The most recent listings for gas-fired boilers in this size range provided in Part B of the SCAQMD BACT guidance include:

- Los Angeles County Internal Services, Los Angeles, California, 2004; CO = 100 ppm
- Clayton Industries, Chatsworth, California, 2002; CO = 100 ppm

The proposed auxiliary boiler and HTF heater will each operate for a very limited number of hours per year. No similar sources were identified in EPA's RBLC with emission limits less than 100 ppm.

4.2.2.3 CO BACT Determination for Operation

The application of 100 ppm "California" ultra LNB technology with limited hours of operation and exclusive use of pipeline quality natural gas represents BACT for CO for the proposed auxiliary boiler and the HTF heater. CO emissions from the auxiliary boiler and HTF heater will be minimized by maintaining sufficient oxygen supply and residence time in the combustion chamber, thus allowing complete combustion of the natural gas fuel. Each unit will emit less than 0.074 lb/MMBtu of CO. BACT will be met through effective equipment design and good combustion practices.

4.3 Emergency Diesel Generator and Fire-Water Pump Engines

The VV2 Project will include an emergency diesel generator sized at approximately 2,000 kW and a diesel fire-water pump rated at approximately 135 kW. These emergency diesel engines will each operate for a maximum of 50 hours per year for testing (or as required by fire safety regulations).

New Source Performance Standards (40 CFR 60 Subpart IIII) were promulgated July 11, 2006 (71 FR 39154) by EPA for stationary diesel engines. The new MACT standard (40 CFR 63 Subpart ZZZZ - National Emission Standards for Hazardous Air Pollutant for Stationary Reciprocating Internal Combustion Engines) would not apply to the VV2 Project since the facility will not be a major source of HAP.

Title 17, CCR Section 93115, which is an air toxics control measure, requires new stationary emergency standby diesel-fueled engines to meet the following standards: $\leq$0.15 g PM/bhp-hr (0.20 g/kW-hr), compliance with the appropriate California off-road engine certification standards for hydrocarbons, NO_x and CO as the same model year and horsepower rating, as specified in 13 CCR Section 2423, and a limit of 50 hours/year for maintenance and testing. New stationary emergency standby engines that operate more than 50 hours/year are required to meet a PM emission limit of 0.01 g/bhp-hr (0.0134 g/kW-hr). Annual emissions from the emergency diesel generator and fire-water pump engines have been calculated based on a limitation of 50 hours/year for maintenance and testing.

The California emission standards specified in 13 CCR Section 2423 and the PM emission limits specified in 17 CCR Section 93115 are at least as stringent as the Federal New Source Performance Standards in 40 CFR 60 Subpart IIII. Therefore, compliance with the California emission standards and limits constitutes LAER for the emergency diesel generator and fire-water pump engines.

4.3.1 LAER for NO_x

The emergency diesel generator engine will meet the California Tier 2 limit of 6.4 g/kW-hr of NO_x + NMHC for 2006-2010 model year diesel engines above 560 kW. The fire-water pump engine will meet the California Tier 3 limit of 4.0 g/kW-hr for NO_x + NMHC emissions for 2006-2010 model year diesel engines between 130 and 224 kW. Use of engines that comply with these emission limits plus an enforceable operating restriction of 50 hours per year for non-emergency use such as maintenance and testing constitutes LAER for NO_x emissions for both the emergency generator and the fire-water pump engines.

4.3.2 BACT for CO

The emergency diesel generator engine will meet the California Tier 2 limit of 3.5 g/kW-hr of CO for 2006-2010 model year diesel engines above 560 kW. The fire-water pump engine will meet the California Tier 3 limit of 3.5 g/kW-hr for CO emissions for 2006-2010 model year diesel engines between 130 and 224 kW. Use of engines that comply with these emission limits plus an enforceable operating restriction of 50 hours per year for maintenance and testing constitutes LAER for CO emissions for both the emergency generator and the fire-water pump engines.

4.4 Evaporative Mechanical Draft Cooling Tower

The VV2 Project will utilize reclaimed water from the nearby VVWRA wastewater treatment facility for steam turbine condenser cooling and will employ a ten cell evaporative (wet) cooling tower. Cooling towers emit trace amounts of solid particulate matter due to release of the dissolved solids (salts) in small droplets that escape the mist eliminator at the top of the tower, referred to as cooling tower drift. In theory, these small droplets may evaporate (rather than falling back to earth as liquid droplets), thus releasing dissolved salts as solid particulate matter. PM10/PM2.5 is the only pollutant of concern from wet cooling towers, and hence is not addressed in this BACT/LAER evaluation for NO_x and CO.

4.5 Summary of BACT/LAER Emission Rates

A summary of the BACT/LAER emission rates proposed for the VV2 Project based on the above evaluation are provided in Table 4-1.

Table 4-1
Summary of BACT/LAER Emissions Rates for the VV2 Project

Source	NO_x	CO
Combined-Cycle Units (Gas Turbines and HRSGs)	2.0 ppm, 1-hr avg	3.0 ppm, 1-hr avg
Auxiliary Boiler and HTF Heater	0.011 lb/MMBtu	0.074 lb/MMBtu
Emergency diesel generator	6.4 g/kW-hr NO_x +NMHC	3.5 g/kW-hr
Emergency fire-water pump engine	4.0 g/kW-hr NO_x +NMHC	3.5 g/kW-hr
Cooling Tower	n/a	n/a

5.0 Emission Calculations

5.1 Criteria Pollutant Emissions

This section provides a discussion of the NO_x and CO emissions calculated for the VV2 Project during normal operations. Appendix C provides the calculation of all criteria pollutant emissions for the project.

5.1.1 Combustion Turbines and Duct Burners

Emissions from the VV2 Project combustion turbine units were based on emission guarantees from GE and process information provided by Bibb and Associates, Inc. Annual emissions were calculated for two scenarios: (1) continuous operation of both combustion turbines throughout the year (i.e., no startups, shutdowns or offline periods); and (2) annual operations that include the maximum anticipated number of startups and shutdowns, offline periods prior to each startup, and continuous operation for the rest of the year.

Emissions for continuous operation throughout the year were based on both combustion turbines operating at full load for 8,760 hours per year with 2,000 hours of duct burning at the annual average temperature of 77 °F.

Annual emissions accounting for startups, shutdowns, and offline periods prior to startups were based on:

- Hot Start and Warm Start - 80 minute startup duration with 260 hot/warm startups per unit per year (total of 346.7 hours per year for hot or warm starts). For each hot or warm start the turbines are assumed to be offline for an average of 6 hours prior to the startup (total of 1,560 hours per year offline prior to hot or warm starts).
- Cold Start - 110 minute startup duration with 50 cold startups per unit per year (total of 91.7 hours per year for cold starts). For each cold start, the turbines are assumed to be offline for an average of 48 hours (total of 2,400 hours per year offline prior to cold starts).
- Shutdown - 30 minute shutdown duration with 310 shutdowns per unit per year (total of 155 hours per year for shutdowns).
- Continuous Operation with Duct Burning - 2,000 hours per year.
- Continuous Operation without Duct Burning - 2,207 hours per year.

Emissions for both cases and the higher emissions for the two cases are summarized in Table 5-1. Maximum hourly emissions from the two turbines are shown in Table 5-2. As seen in the table, maximum emissions for NO_x occur when there are continuous operations. It is unusual that NO_x would not be higher when accounting for startup and shutdown events. The VV2 Project is unusual in this regard because of the GE Rapid Start Process option, which reduces the time needed in startup mode. CO emissions are greatest when startups and shutdowns are included even with the Rapid Start option since these emissions are so much greater during startup before the oxidation catalyst is fully functional. Details of the operation emission calculations for the turbines and duct burners are in Appendix C.

Table 5-1
Maximum Annual Emissions from Combustion Turbines

Operating Scenario	NO_x (tpy)	CO (tpy)
Continuous Operation all Year	107.4	74.3
Operation with Startup/Shutdown and Offline Periods	87.6	253
Maximum Annual Emissions [a]	**107.4**	**253**
a. "Maximum Annual Emissions" is the largest total in either the first or second line of this table.		

Table 5-2
Maximum Hourly Emissions from Two Combustion Turbines

Operating Mode	NO_x (lb/hr)	CO (lb/hr)
Full Load Operations		
Without duct firing	23.1	15.3
With duct firing	29.2	26.7
Startup [a]	105.0	494
Shutdown [a]	228.0	1,348
a. Maximum hourly emissions for startup and shutdown were used for modeling of short-term NAAQS. However, the lb/event values given in Section 4.1 are proposed for permit limits.		

5.1.2 Auxiliary Boiler and HTF Heater

The VV2 Project will include a natural gas-fired auxiliary boiler in order to facilitate rapid startup of the gas turbines. It will operate a maximum of 500 hours per year and will have a heat input of 35 MMBtu/hr. NO_x emissions are based on 9 ppmvd @ 3% O_2 and CO emissions are based on 100 ppmvd @ 3%. Auxiliary boiler emissions are presented in Table 5-3**.**

The HTF heater will operate a maximum of 1,000 hours per year and will have a heat input of 40 MMBtu/hr. NO_x emissions are based on 9 ppmvd @ 3% O_2 and CO emissions are based on 100 ppmvd @ 3% O_2. HTF heater emissions are presented in Table 5-4.

Table 5-3
Maximum Hourly and Annual Auxiliary Boiler Emissions

Pollutant	Emission Factor (lb/MMBtu)	Hourly Emission Rate (lb/hr)	Annual Emissions (tpy)
NO_x	0.011	0.38	0.1
CO	0.074	2.59	0.65

Table 5-4
Maximum Hourly and Annual HTF Heater Emissions

Pollutant	Emission Factor (lb/MMBtu)	Hourly Emission Rate (lb/hr)	Annual Emissions (tpy)
NO_x	0.011	0.44	0.22
CO	0.072	2.88	1.44

5.1.3 Emergency Diesel Generator and Fire-Water Pump Engine

The VV2 Project's emergency diesel generator will operate a maximum of 300 hours per year and will have an output of 2 MW. NO_x and CO emission factors were set equal to the California Tier 2 emission limits, with the assumption that 95 percent of the emission limit for NO_x + NMHC is NO_x. Emergency diesel generator emissions are presented in Table 5-5.

The emergency diesel firewater pump engine will operate a maximum of 300 hours per year and will have an output of 182 hp. NO_x and CO emission factors were set equal to the California Tier 3 emission limits, with the assumption that 95 percent of the emission limit for NO_x + NMHC is NO_x. Emergency diesel fire-water pump engine emissions are presented in Table 5-6.

Details of the emergency diesel generator and fire-water pump emission calculations are in Appendix C.

Table 5-5
Maximum Hourly and Annual Emergency Diesel Generator Emissions

Pollutant	Emission Factor (g/hp-hr)	Hourly Emission Rate (lb/hr)	Annual Emissions (tpy)
NO_x	4.53	26.79	4.02
CO	2.61	15.42	2.31

Table 5-6
Maximum Hourly and Annual Emergency Diesel Fire-water Pump Emission

Pollutant	Emission Factor (g/hp-hr)	Hourly Emission Rate (lb/hr)	Annual Emissions (tpy)
NO_x	2.83	1.14	0.17
CO	2.61	1.05	0.16

5.1.4 PSD Emissions Summary

Table 5-7 shows the annual potential to emit for the VV2 Project for the PSD pollutants. The VV2 Project will be a major source (more than 100 tpy) of NO_x and CO.

Table 5-7
Total Annual Potential Emissions, Normal Operation

Source	NO_x (tpy)	CO (tpy)
Gas Turbines and HRSGs	107.4	252.7
Auxiliary Boiler	0.10	0.63
HTF Heater	0.22	1.44
Emergency Generator	4.02	2.31
Fire-Water Pump Engine	0.17	0.16
Total	111.9	257.3

5.2 Hazardous Air Pollutant Emissions

Emissions of hazardous air pollutants (HAP) that may be associated with the VV2 Project include combined-cycle combustion turbines, auxiliary boiler, heat transfer fluid (HTF) heater, and cooling tower. No appreciable quantity of HAP emissions are expected to be emitted from operation of the emergency engines, solar field array, oil/water separator, or emergency fire-water pump fuel tank. Detailed calculations in support of HAP emissions discussed below are provided in Appendix C.

5.2.1 Combustion Turbines

All combustion-related HAP emissions associated with the combustion of natural gas in the turbine generators were calculated using emission factors from AP-42, Section 3.1, Stationary Gas Turbines (EPA, 2000a). Although the oxidation catalyst will reduce the emissions of most HAPs, the exact control efficiency is unknown. EPA found that formaldehyde emissions will be reduced by a 90% control factor due to installation a catalytic oxidation system, so this reduction was applied to the uncontrolled AP-42 emission factor for this individual HAP (EPA, 2000b).

For the purposes of determining the potential maximum ambient concentrations of chemical substances emitted by the combustion turbines, the turbines were assumed to operate at base load conditions with a higher heating value (HHV) and an ambient temperature of 65°F. For annual emissions, the annual average natural gas consumption rate of 1.7 MMscf per hour per turbine plus 0.54 MMscf per hour per duct burner (2.25 MMscf per hour combined) was used, assuming that the continuous operation of both gas turbine/burner units. Duct burner fuel usage was incorporated into the emission estimates assuming 8,760 hours of turbine operations and 5,000 hours of duct burner operations per year at the maximum firing rate.

5.2.2 Auxiliary Boiler and HTF Heater

The VV2 Project will include an auxiliary boiler unit that will be used to provide sealing steam earlier in the start process, and a heater used to increase the temperature of the heat transfer fluid (HTF) received from the solar field to approximately 740° F as it circulates through the receiver and returns to a series of heat exchangers in the power block where the fluid is used to generate high-pressure steam. Both the HTF heater and auxiliary boiler will fire exclusively on natural gas. Emissions for these units were based on operating conditions that represent the maximum emissions profile used for the VV2 Project. The emissions from the boiler were based on an assumed maximum of 500 hours per year of operation, and 1,000 hour per year for operation of the HTF heater.

5.2.3 Cooling Towers

Concentrations of toxics present in the cooling tower make-up water were obtained from an effluent water quality analyses from the Victor Valley Water Reclamation Authority (VVWRA), which will provide reclaimed water for the VV2 Project. Emission rates were calculated from the effluent water analysis, re-circulation rate, drift control efficiency, and maximum expected total dissolved solids (TDS) concentration. Hourly and annual emissions rates for sources were converted to a modeled emission rate in pounds per year (lb/year) for use in evaluating long-term risks, and pounds per hour (lb/hour) for use in short-term health impact modeling.

The emission estimates assumed the cooling tower was operated at the maximum recirculation rate for 8,760 hours per year. Cooling tower emissions were estimated based on a mass balance technique using the water supply quality, cooling tower maximum cycles of concentration(s), water recirculation rate (gallons per minute, gpm), and mist eliminator drift rate (0.0005%). Potential emissions from the cooling tower were identified based on an effluent water quality analysis of reclaimed water from the VVWRA for the years 2004-2005.

5.2.4 HAP Emissions Summary

The VV2 Project will not be a major source of HAP emissions. The emissions inventory (Appendix C) shows total HAP emissions of 7.8 tons per year (tpy). The primary contributor to emissions is toluene with a HAP emission of 2.6 tpy, or 33% of total HAP emissions for the VV2 Project. Regulatory major source thresholds are 10 tpy for any single HAP and 25 tpy for total HAP emissions. The VV2 Project is therefore 74% and 69% below major source thresholds for single and total HAP emissions, respectively.

6.0 Air Quality Impact Analysis

Under the PSD program, sensitive areas such as national parks and wilderness areas over a certain size have been designated as Class I areas. As such, they receive additional protection of the air quality and air quality related values in these areas. All others areas of the U.S. have been designated Class II. The air quality impact assessment (AQIA) for the VV2 Project has been divided into two parts: 1) the Class II area AQIA and 2) the Class I area AQIA.

6.1 Class II Area Impact Assessment

The detailed methodology for the Class II area AQIA is documented in the modeling protocol, "Class II Area Dispersion Modeling Protocol for the Proposed Victorville 2 Hybrid Power Project". A copy of this protocol was submitted to the CEC, EPA and MDAQMD on January 17, 2007. As of April 2007, no comments have been received on this protocol from these three agencies. The analyses were conducted in accordance with the EPA Guideline on Air Quality Models (GAQM; as incorporated in Appendix W of 40 CFR Part 51; EPA, 2005).

The AERMOD model (version 04300) was applied with a three-year sequential hourly meteorological data set, consistent with Appendix B of the CEC's Guidelines (2000). Three years (2002-2004) of wind speed, wind direction and temperature data from the nearby Victorville Park Avenue meteorological station were obtained from MDAQMD. The meteorological tower has an anemometer height of 16.9 meters. The tower data were supplemented with National Weather Service (NWS) data from General William J. Fox Field in Lancaster, CA to fill in missing data and to provide cloud cover and cloud ceiling height data also required for the modeling. Concurrent upper air data from Mercury Desert Rock Airport in Mercury, NV were also used as required for the dispersion modeling. Note that although 2005 meteorological data were available, this year was not used because of the poor data recovery of the upper air data at Mercury Desert Rock Airport during that year. As discussed in the Class II area modeling protocol, the surface and upper air data were processed with the AERMOD meteorological processor, AERMET (version 04300).

A comprehensive Cartesian receptor grid extending to approximately 20 km from the proposed combustion turbine stacks was used in the AERMOD modeling to assess maximum ground-level pollutant concentrations. The 20-km receptor grid was more than sufficient to resolve the maximum impacts and any significant impact area for PM10.

The Cartesian receptor grid consisted of the following receptor spacing:

- Fenceline to 3,000 meters at 100 meter increments
- Beyond 3,000 meters to 5,000 meters at 200 meter increments
- Beyond 5 kilometers to 10 kilometers at 500 meter increments
- Beyond 10 kilometers to 20 kilometers meters at 1,000 meter increments

Discrete receptors were placed approximately every 50 meters along the plant fenceline for increased resolution of impacts along this boundary. Figures that illustrate the receptors are provided in the modeling protocol. Terrain elevations from Digital Elevation Model (DEM) data acquired from USGS were processed with AERMAP (version 02107) to develop the receptor terrain elevations and corresponding hill height scale required by AERMOD. All of the DEM files were for UTM Zone 11 and are referenced to Datum NAD27. The DEM files are included on the modeling archive CD (Appendix D).

The background air quality concentrations used in the National Ambient Air Quality Standards (NAAQS) analysis are given in Table 6-1. In all cases, the maximum concentrations were monitored in 2003.

AERMOD was applied with the EPA recommended default options. Model iterations were conducted for each year of meteorological data to identify the maximum impacts over all 3 years for the pertinent averaging periods.

Table 6-1
Maximum Concentrations From 2003 – 2005

Pollutant	Averaging Period	Yearly Monitored Concentration (μg/m³)		
		2003	2004	2005
NO_2	Annual	41	40	36
CO	1-hour	4,485	2,760	2,875
	8-hour	2,415	1,955	1,840

6.1.1 Modeling Methodology

Air quality modeling during operation was conducted with AERMOD to demonstrate compliance with the NAAQS and PSD increments in the local (Class II) area. The VV2 Project includes the following air emission sources that were included in the modeling analysis:

- Two combined-cycle combustion turbines, each with heat recovery steam generators
- Auxiliary boiler
- Emergency generator engine
- Fire-water pump engine
- Heat transfer fluid heater
- Cooling tower (PM10 only)

EPA has established Significant Impact Levels (SILs) for air quality impacts analyses. A SIL for a given pollutant and averaging period is defined as an ambient concentration produced by a source below which the source is assumed to have an insignificant impact. In accordance with standard modeling procedures for ambient air quality standards compliance analyses, if modeling of VV2 Project sources alone (proposed CTGs/HRSGs and ancillary combustion equipment) indicates that the maximum modeled concentrations for a specific pollutant are below the SILs, no further analysis is required for that pollutant. If modeling indicates that the SIL for any pollutant/averaging period is exceeded, then a cumulative modeling study is required to determine the combined impact of the Project sources plus other major nearby background sources for compliance with the NAAQS and PSD increments. The maximum concentrations determined through cumulative modeling are then summed with representative background concentrations to account for non-modeled source contributions for NAAQS compliance. These criteria for the impact analyses are shown in Table 6-2.

In addition to addressing air quality impacts associated with normal facility operations, modeling was conducted to assess the maximum air quality impacts during startup/shutdown of the combustion turbines.

Table 6-2
Ambient Air Quality Impact Criteria (µg/m^3)

Pollutant	Averaging Period	PSD Class II Significant Impact Levels	PSD Class II Increments	NAAQS	
				Primary	Secondary
NO_2	Annual	1	25	100	100
CO	1-hour	2,000	--	40,000	--
	8-hour	500	--	10,000	--

6.1.1.1 Source Characterization

Air quality modeling for NAAQS and PSD increment compliance during operation was conducted using the AERMOD model (version 04300). The stack parameters and emission rates input to AERMOD for the combustion turbines for normal operations are summarized in Table 6-3. Turbine emission rates and flue gas characteristics were derived for a range of ambient temperatures for natural gas fuel for three operating load points (100 percent, 75 percent and 50 percent) that included variable operating factors such as duct firing, evaporative cooling and solar energy input (See Appendix C). For the dispersion modeling, a worst case composite of emissions and stack data were developed for each of the three load cases to add a measure of conservatism to the analysis. That is, for each load, the highest emission rate and lowest exhaust parameters were identified for the expected range of ambient temperatures and operational cases. Each load was modeled to determine the worst-case for each pollutant to define the turbine stack parameters and emission rates for all Project sources for modeling maximum short-term (≤24-hour) impacts. For modeling annual average impacts for the combustion turbines, stack parameters based on 100 percent load for the representative annual average temperature (77°F) were used as they are most representative of annual average operations.

The stack parameters and emissions data for the ancillary equipment are listed in Table 6-4. These stack parameters are based on operation of the ancillary equipment at 100 percent load. The plot plan for the power block is contained in Appendix A.

Table 6-3
Stack Parameters and Emissions Data for the Combustion Turbines

Parameter		Value		
		Unit 1 (West)		Unit 2 (East)
UTM Coordinate East (meters) [a]		466,040.77		466,080.94
UTM Coordinate North (meters) [a]		3,832,160.30		3,832,159.92
Stack Base Elevation (ft)		2,802		2,802
Stack Height (ft)		145		145
Stack Diameter (inches)		222		222
		Load		
		100% [b]	**75%**	**50%**
Exit Temperature (^{o}F)		174.5 / 174.6	180.1	171.8
Exit Velocity (ft/sec)		58.14 / 60.47	45.75	38.65
Pollutant Emissions Per Combustion Turbine (lb/hr)	NO_x	15.6 / 107.4	10.22	8.12
	CO	14.25 / 252.7	6.22	4.95

a. Coordinates for UTM Zone 11 referenced to Datum NAD27

b. Representative data are provided for worst-case short-term and annual average conditions. Emissions listed are lb/hr and tpy.

Table 6-4
Stack Parameters and Emissions Data for the Ancillary Equipment

Parameter		Auxiliary Boiler	Emergency Generator	Fire-Water Pump	Heater
UTM Coordinate East (m) [1]		466,142.21	466,078.50	466,112.98	466,134.72
UTM Coordinate North (m) [1]		3,832,087.48	3,832,041.01	3,832,164.05	3,832,196.84
Stack Base Elevation (ft)		2802	2802	2802	2802
Stack Height (ft)		30	30	30	30
Stack Diameter (inches)		20.76	21.48	5.64	21
Exit Temperature (^{o}F)		300	761.7	761.7	300
Exit Velocity (ft/sec)		66.6	100	100	74.38
Pollutant Emissions (lb/hr / tpy)	NO_x	0.385 / 0.096	26.79 / 4.02	1.14 / 0.17	0.44 / 0.22
	CO	2.59 / 0.648	15.42 / 2.31	1.05 / 0.16	2.96 / 1.48

[1] Coordinates for UTM Zone 11 referenced to Datum NAD27

6.1.1.2 Good Engineering Practice Analysis

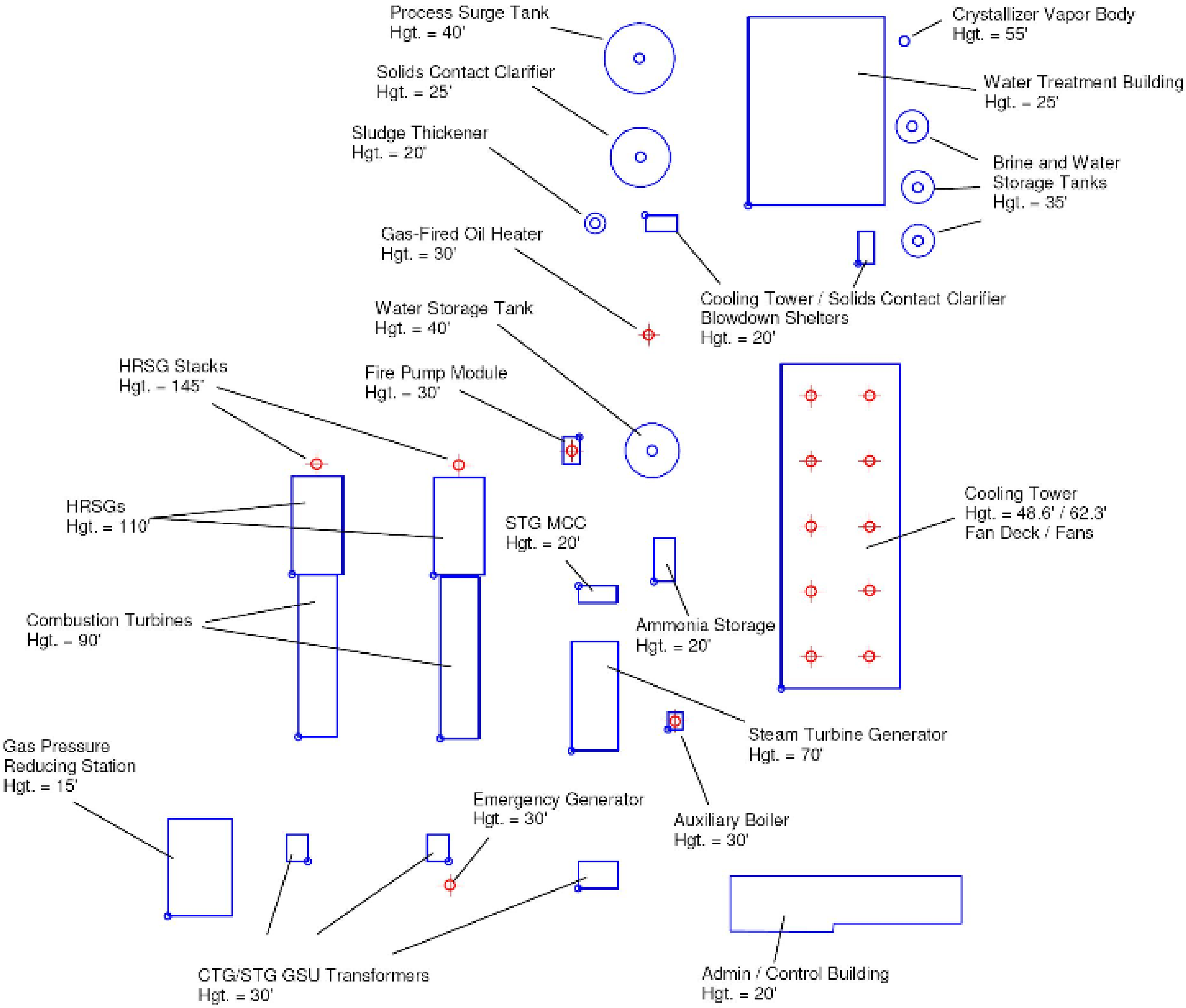
A Good Engineering Practice (GEP) stack height analysis was conducted to evaluate the potential for building downwash. Stacks with heights below GEP are considered to be subject to building downwash and require building dimensions to be input to AERMOD. The GEP stack height analysis was conducted using the EPA Building Profile Input Program (BPIP) (version 04274) that performs the GEP calculation for a multi-building complex on a stack-by-stack basis. The stack locations and buildings included in the GEP analysis are shown in Figure 6-1. A summary of the GEP analysis is provided in Table 6-5. The projected combustion turbine stack height of 145 feet (44 m) is less than GEP, but is more than sufficient to demonstrate compliance with air quality standards as shown below. The stack heights of the ancillary equipment will also be less than their respective GEP formula heights and subject to building downwash. Therefore, building dimensions developed by BPIP for all stacks were input to the dispersion model. The BPIP input and output files are provided on the modeling archive in Appendix D.

Table 6-5
Summary of GEP Analysis

Emission Source	Stack Height (m)	Controlling Buildings or Structures	Building Height (m)	Projected Width (m)	GEP Formula Height (m)
HRSG Stack (West)	44.2	HRSG's #1 and #2	33.53	33.59	83.82
HRSG Stack (East)	44.2	HRSG's #1 and #2	33.53	33.71	83.82
Auxiliary Boiler	9.14	HRSG's #1 and #2	33.53	45.10	83.82
Fire-Water Pump Module	9.14	HRSG's #1 and #2	33.53	33.71	83.82
Gas-Fired HTF Heater	9.14	HRSG's #1 and #2	33.53	46.17	83.82
Emergency Generator	9.15	HRSG #1	33.53	25.36	71.56
Cooling Tower	19.0	HRSG's #1 and #2	33.53	33.59 and 36.13	83.82

6.1.1.3 Ozone Limiting Method

The Ozone Limiting Method (OLM) in AERMOD was used as a refined technique to more accurately model the conversion of NO_x emissions to ambient NO_2 concentrations. The OLM analysis falls under Tier 3 of the U.S. EPA's multi-tiered screening approach for estimating NO_2 sources from point sources as provided in the Guideline on Air Quality Models. In the OLM analysis, 10% of the NO_x emissions from the source are assumed to convert to NO_2 (i.e., fraction associated with thermal conversion) while the remaining fraction of NO_x (90%) is converted based on available ambient ozone (O_3) concentrations. That is, conversion of the remaining 90% of NO_x (to NO_2) is limited based on the availability of ozone and the remaining converted NO_2 is equivalent to the ambient O_3 concentration. These computations are conducted internally in AERMOD on an hourly basis and require representative hourly monitored O_3 that are concurrent to the meteorological data used in the modeling. For this analysis, the 3 concurrent years (2002-2004) of monitored O_3 concentrations from the Victorville Park Avenue monitoring station were used.



Locus Map

Buildings and Sources Used in the GEP Analysis
VV2 Hybrid Power Project

Figure not to scale

Inland Energy, Inc.

ENSR | AECOM

Figure: 6-1

Date: April 2007

6.1.2 Modeling Results

6.1.2.1 Class II Impacts from Project Normal Operations

The modeling of normal VV2 Project operations using AERMOD was done as a multi-step process. First, the worst-case impacts for the combustion turbines (based on different load and temperatures) were identified. The detailed results for the combustion turbine load analysis are provided in Appendix C.

The NAAQS for NO_2 is an Annual Average, while the NAAQS for CO are short-term, 1- and 8-hour averages. Modeling of NO_2 for annual averages was conducted with the annual average operating scenario for the turbines (100% load / 77°F ambient temperature). Since CO is assessed on a short-term basis, operations at different loads could be worst case. The worst-case load for CO was determined to be 100%.

In the next modeling step, the worst-case combustion turbine operating parameters and emissions were combined with normal operations of the facility ancillary sources. Because the emergency generator and fire pump will not be operated for more than one-hour at a time it was assumed that these two sources will operated only from 8 am to 9 am in order to model the likely worst case meteorological conditions (morning stable layer).

The maximum air quality impacts due to emissions from the Project sources are summarized in Table 6-6. Table 6-6 lists the maximum modeled concentrations for all VV2 Project sources for each year of meteorology. The maxima over the three years modeled is noted and compared to the EPA SILs. As shown in Table 6-6, all maximum modeled pollutant concentrations of NO_2 and CO are less than their respective SIL.

Table 6-6
Maximum Modeled Concentrations for VV2 Project Normal Operations

Pollutant	Averaging Period	Maximum AERMOD Concentration ($\mu g/m^3$)			Overall Maximum ($\mu g/m^3$)	EPA SIL ($\mu g/m^3$)	PSD Increment ($\mu g/m^3$)
		2002	2003	2004			
NO_2 [a]	Annual	0.3	0.3	0.3	0.3	1	25
CO	1-hr	215.7	215.8	212.1	215.8	2,000	None
	8-hr	31.0	29.6	31.9	31.9	500	None

a. Modeled NO_2 concentrations as determined with the Ozone Limiting Method.

Since the impacts were below the SILs, no cumulative or NAAQS analysis is required. Although not required, a NAAQS analysis was done and is summarized in Table 6-7. The Project maximum modeled concentrations for NO_2 and CO are summed with ambient background concentrations (from Table 6-1) for comparison to the air standards. As shown in Table 6-7, the total concentrations comprised of maximum modeled plus maximum background are below the NAAQS.

Table 6-7
NAAQS Analysis for Project Normal Operations

Pollutant	Averaging Period	Concentrations ($\mu g/m^3$)			
		AERMOD Result	Ambient Background [b]	Total [c]	NAAQS
NO_2 [a]	Annual	0.3	41	41.3	100
CO	1-hr	215.8	4,485	4,701	40,000
	8-hr	31.9	2,415	2,447	10,000

a. Modeled NO_2 concentrations as determined with the Ozone Limiting Method.
b. Highest value from Table 6-1.
c. Modeled concentration plus ambient background.

6.1.2.2 Impacts from Combustion Turbine Start-up/Shutdown

During startup and shutdown of the combustion turbines, emissions of CO will be higher than normal operations. As such, worst-case startup and shutdown conditions were modeled with AERMOD for comparison to the NAAQS for 1-hour and 8-hour CO. The stack parameters and emissions data required for modeling short-term startup/shutdown are provided in Table 6-8. The stack exhaust parameters correspond to a 20 percent load, assumed to be representative of this operating mode.

Table 6-7
Stack Parameters and Emissions Data for the Combustion Turbines Start-up/Shutdown Modeling

Parameter		Value
Exit Temperature (^{o}F) [a]		173.5
Exit Velocity (ft/sec) [1]		31.76
Pollutant Emissions Per Combustion Turbine (lb/hr)	NO_x	64.8
	CO	344.1

a. Based on 20% load.

Worst case startup/shutdown emissions for modeling were derived from the emissions data in Appendix C. Cold starts, warm starts, hot starts and shutdowns were considered. Based on this analysis, the worst case or maximum emissions are associated with shutdown events. Because shutdowns only require 0.5 hour, maximum 1 hour emissions are conservatively based on 0.5 hour at the maximum normal emission rate plus 0.5 hour in the shutdown mode as shown below:

- Maximum CO emissions = 0.5 x 14.25 lb/hr + 0.5 x 674 lb/hr = 344.1 lb/hr per turbine

The modeling was conducted for the 3-years of meteorological data and assumed simultaneous operation of all ancillary equipment with the two combustion turbines. The results are summarized in Table 6-9. Ambient concentrations are summed with the maxima modeled over the 3 years for comparison to the NAAQS. The total CO concentrations are below the NAAQS.

Table 6-8
Maximum Modeled CO Concentrations for Project Startup/Shutdown Operations

Pollutant	Averaging Period	AERMOD Concentration ($\mu g/m^3$)			Overall Maximum ($\mu g/m^3$)	Total Modeled Plus Background	NAAQS ($\mu g/m^3$)
		2002	2003	2004			
CO	1-hr	635.7	672.5	658.9	672.5	5,157	40,000
	8-hr	301.0	283.7	238.2	301	2,716	10,000

6.2 PSD Class I Analysis

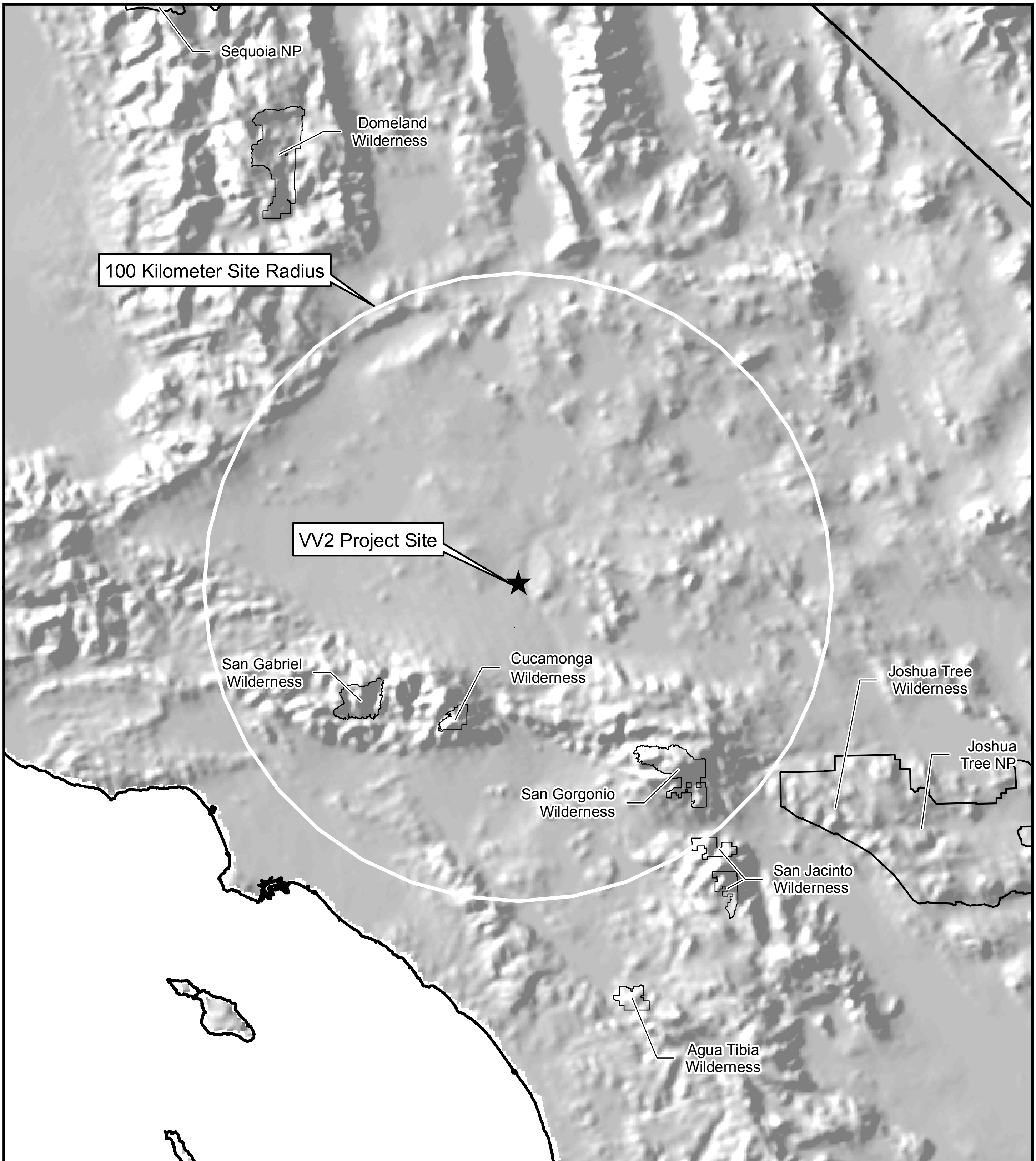
PSD regulations require that facilities within 100 kilometers (km) of a PSD Class I area perform a modeling evaluation of the ambient air quality in terms of Class I PSD Increments and Air Quality Related Values (AQRVs). For the VV2 Project, potential air impacts were addressed at the following Class I areas within 100 km:

- Cucamonga Wilderness Area (WA),
- San Gabriel WA,
- San Gorgonio WA,
- San Jacinto WA, and
- Joshua Tree National Park (NP).

The detailed methodology for the Class I area impact assessment is documented in the modeling protocol, "Class I Area Dispersion Modeling Protocol for the Proposed Victorville 2 Hybrid Power Project. A copy of this protocol was submitted to the CEC, EPA and MDAQMD on January 17, 2007. At EPA's request, a copy of the protocol was also provided to the Federal Land Managers (FLMs) for these areas on January 31, 2007. The National Park Service (NPS) is the FLM for Joshua Tree NP and the U.S. Dept. of Agriculture, Forest Service (USFS) is the FLM for the four Wilderness Areas. On February 1, 2007, the NPS replied "based on the information in the protocol we do not believe the emissions from the proposed Victorville facility will significantly impact resources at Joshua Tree National Park (closest NPS air quality Class I area). Therefore, we will not be providing any comments regarding the protocol." (Morse, 2007) The USFS provided a copy of their draft FLM modeling guidance document (Gebhart, 2005).

Figure 6-2 shows the location of the VV2 Project relative to the nearest PSD Class I areas. Since Joshua Tree NP is the closest National Park Service (NPS) Class I area and it is just on the edge of the 100-km extent from the VV2 Project, it was also included in the Class I impacts analysis.

Since the VV2 Project is located in a designated non-attainment area for PM10, and is not a significant source for SO_2 or H_2SO_4, a Class I increment analysis was conducted only for NO_2 at the Class I areas. Additionally since the VV2 Project is not a significant source for SO_2 or H_2SO_4, a deposition analysis was conducted only for nitrogen compounds which consider primary emissions of NO_X and conversion to nitrate and nitric acid. However, gas turbine emissions of SO_2, H_2SO_4, NO_X, and PM10 were all included in the regional haze analysis for the Class I areas noted above.



Locus Map

Location of Proposed Project Site in Relation to Nearby PSD Class I Areas VV2 Hybrid Power Project

Scale: 1:1,750,000

0 20 40 60 80 100 Miles

Inland Energy, Inc.

ENSR | AECOM

Date: April 2007

Figure: 6-2

Y:\Projects\InlandEnergy\Victorville\MXD\PSD_Application\Figure_6-2_PSD_Class_I_Areas.mxd

6.2.1 PSD Class I Area CALPUFF Analyses

A refined modeling for assessment of PSD Class I increment consumption, regional haze and acid deposition was conducted with the CALPUFF model (Version 5.754) and utilized detailed meteorological data prepared with CALMET, the CALPUFF meteorological pre-processor. The modeling approach is based on requirements outlined in the IWAQM Phase II report (EPA Report EPA-454/R-98-019, 1998; found at http://www.epa.gov/scram001) as well as the Federal Land Managers' Air Quality Related Values Workgroup Phase I Report that was published in December 2000. This document can be found at http://www2.nature.nps.gov/ard/flagfree/index.htm). These guidance documents are provided for suggested modeling approaches by EPA and the FLMs.

6.2.1.1 Class I Area Increment Analysis

The Class I increment modeling results for all areas are summarized in Table 6-10. The maximum annual NO_2 concentrations for each area are below the Class I SIL and therefore also well below the Class I PSD increments.

Table 6-9
Class I Area NO_2 PSD Increment CALPUFF Modeling Result

Class I Area	Averaging Period	Maximum Modeled Concentrations (μg/m³)			Class I SIL[1] (μg/m³)	PSD Class I Increment (μg/m³)
		2001	2002	2003		
Cucamonga WA	Annual	3.29E-03	1.92E-03	2.05E-03	0.1	2.5
Joshua Tree NP	Annual	1.27E-03	9.92E-04	9.32E-04	0.1	2.5
San Gabriel WA	Annual	2.94E-03	9.95E-04	3.12E-03	0.1	2.5
San Gorgonio WA	Annual	8.17E-04	1.23E-04	5.21E-04	0.1	2.5
San Jacinto WA	Annual	3.67E-04	6.85E-05	1.77E-04	0.1	2.5

[1] EPA proposed NSR Reform, FR 7/23/96.

6.2.1.2 Class I Area Regional Haze Analysis

The Class I regional haze modeling results for all areas are summarized in Table 6-11 for the three-years modeled. When a project-related change in extinction is less than five percent of the background extinction, then the project's regional haze impact is defined by EPA to be insignificant and no further modeling is required to demonstrate no adverse impact. As shown in Table 6-11, the maximum modeled change in extinction (Δ B_{ext}) for all years is less than five percent.

Table 6-10
Class I Area Regional Haze CALPUFF Modeling Results

Class I Area	Maximum % Δ B_{ext}			Significance Threshold (Percent Change in Extinction Coefficient)
	2001	2002	2003	
Cucamonga WA	3.80	2.39	3.14	5%
Joshua Tree NP	1.20	1.16	0.95	5%
San Gabriel WA	2.30	2.48	3.56	5%
San Gorgonio WA	1.05	0.78	1.98	5%
San Jacinto WA	0.58	0.56	0.75	5%

6.2.1.3 Class I Area Deposition Analysis

The Class I Area deposition modeling results for all areas are summarized in Table 6-12 for the three-years modeled. The maximum modeled deposition rates for all years modeled are below the Class I Area Deposition Analysis Thresholds.

Table 6-11
Class I Area Nitrogen Deposition CALPUFF Modeling Results

Class I Area	Averaging Period	Maximum Modeled Deposition Results (kg/ha/yr)			Class I Area Nitrogen Deposition Analysis Threshold (kg/ha/yr)
		2001	2002	2003	
Cucamonga WA	Annual	9.96E-04	1.15E-03	6.92E-04	0.005
Joshua Tree NP	Annual	3.23E-04	2.49E-04	2.51E-04	0.005
San Gabriel WA	Annual	1.44E-03	8.57E-04	1.38E-03	0.005
San Gorgonio WA	Annual	3.88E-04	1.99E-04	2.60E-04	0.005
San Jacinto WA	Annual	1.51E-04	7.92E-05	8.60E-05	0.005

6.2.2 VISCREEN Plume Blight Impact Analysis

PSD regulations require an analysis of visibility impairment (i.e., plume blight) at Class I areas within 50 km of a proposed PSD project. Parts of Cucamonga Wilderness Area are located within 50 km of the VV2 Project, therefore in addition to regional haze assessed with CALPUFF, potential VV2 Project visible plume impacts were also addressed for this Class I area.

The plume visibility analysis was conducted with the most current version of EPA's screening model VISCREEN to determine if Project emissions will impair visibility at the Cucamonga WA. VISCREEN was applied with the guidance provided in EPA's Workbook for Plume Visual Impact

Screening and Analysis (Revised, 1992) ("Workbook"). As such, the VISCREEN model was applied to estimate two visual impact parameters, plume perceptibility (ΔE) and plume contrast (Cp). Screening-level guidance indicates that values above 2.0 for ΔE and +/- 0.05 for Cp are considered perceptible. The Workbook offers two levels of analysis. Level 1 screening analysis is the most simplified and conservative approach employing default meteorological data with no site specific conditions. Level 2 analyses takes into account representative meteorological data and site specific conditions such as complex terrain. Initially, the Level 1 analysis was conducted and indicated ΔE and Cp values above the screening thresholds. Therefore, a Level 2 analysis was conducted.

A Level 2 analysis was conducted with the same three-years of meteorological data used in the Class II air quality analysis. The terrain elevation differences between the facility location of more than 600 meters is based on an elevation of the plant site (854 meters above mean sea level [amsl]) and elevation of the Cucamonga WA (1500 - 2600 meters amsl; from receptor elevations provided by NPS.

The source data required by VISCREEN are total NO_x emissions (31.2 lb/hr) and particulate emissions (36.0 lb/hr) for the combustion turbines. The closest distance from the Project to the Cucamonga WA is 40 kilometers. In addition, the 22.5° wind direction sector that would transport emissions from the Project toward the Cucamonga WA located to the south-southwest of the Project location is 11.25° – 33.75°. Based on this information, and the three years of meteorological data, a table of joint frequency of occurrence of wind speed, wind direction, and stability class was developed as outlined in the Workbook. The dispersion conditions, defined by wind speed and stability class, were ranked by evaluating the product of $\sigma_y\sigma_z u$ where σ_y and σ_z are the Pasquill-Gifford horizontal and vertical diffusion coefficients for the given stability class and downwind distance (i.e., 40 km), and u is the wind speed. The dispersion conditions were then ranked in ascending order according to the value of $\sigma_y\sigma_z u$ as shown in Table 6-13.

According to the Workbook, VISCREEN is to be applied with the worst-case meteorological conditions that have a $\sigma_y\sigma_z u$ product with a cumulative probability of 1 percent. That is, the dispersion condition is selected such that the sum of all frequencies of occurrence of conditions worse than this condition totals 1 percent. Note that as is recommended by the Workbook, dispersion conditions that result in greater than 12 hours of plume transport time are discounted from the analysis, since it is unlikely that steady-state plume conditions will persist for more than 12 hours.

According to Table 6-13, the worst-case dispersion conditions with cumulative frequency of 1 percent are D stability, 3 m/sec and occur during daytime hours between 12:00 pm and 6:00 pm (i.e., 1200-1800). Therefore, VISCREEN was applied with C stability, 3 m/sec to account for the complex terrain. As recommended by the FLAG guidance, a visual range of 246 kilometers was used.

The VISCREEN results are summarized in Table 6-14. VISCREEN provides results of plume perceptibility (ΔE) and plume contrast (C_p) for both sky and terrain backgrounds. The results are below the screening criteria thresholds and therefore indicate that the plume would not be perceptible against a sky or terrain background.

Table 6-12: Dispersion Condition Frequency Analysis

Dispersion Condition		$\sigma_y\sigma_z u$	Transport Time	Frequency By Time of Day				Cumulative Frequency By Time of Day			
Stability Class	Wind Speed (m/sec)			0-6	6-12	12-18	18-24	0-6	6-12	12-18	18-24
F	1	68,547	22	0.152	0.000	0.015	0.274	0.000	0.000	0.000	0.000
F	2	137,093	7	0.015	0.000	0.046	0.228	0.015	0.000	0.046	0.228
E	1	196,008	22	0.046	0.015	0.030	0.091	0.015	0.000	0.046	0.228
F	3	205,640	4	0.015	0.015	0.061	0.182	0.030	0.015	0.106	0.411
E	2	392,015	7	0.046	0.030	0.061	0.061	0.076	0.046	0.167	0.471
D	1	536,875	22	0.091	0.228	0.106	0.000	0.076	0.046	0.167	0.471
E	3	588,023	4	0.000	0.000	0.213	0.182	0.076	0.046	0.380	0.654
E	4	784,030	3	0.000	0.015	0.274	0.106	0.076	0.061	0.654	0.760
E	5	980,038	2	0.000	0.000	0.122	0.061	0.076	0.061	0.776	0.821
D	2	1,073,749	7	0.000	0.046	0.122	0.030	0.076	0.106	0.897	0.852
D	3	1,610,624	4	0.000	0.030	0.274	0.015	0.076	0.137	1.171	0.867
D	4	2,147,498	3	0.000	0.061	0.456	0.091	0.076	0.198	1.627	0.958
D	5	2,684,373	2	0.046	0.319	1.414	0.076	0.122	0.517	3.041	1.034
D	6	3,221,247	2	0.015	0.106	0.502	0.030	0.137	0.623	3.543	1.064
D	7	3,758,122	2	0.015	0.152	0.182	0.015	0.152	0.776	3.726	1.080
D	8	4,294,997	1	0.015	0.000	0.030	0.000	0.167	0.776	3.756	1.080

Table 6-13
VISCREEN Model Results

Background	Distance	Plume Perceptibility (ΔE)		Plume Contrast (C_p)	
		VISCREEN	Criteria	VISCREEN	Criteria
Sky	40	0.066	2.00	0.001	0.05
Terrain	40	0.168	2.00	0.001	0.05

6.3 Other Related Analyses

PSD regulations also require that projects conduct analyses to determine the impacts on vegetation and soils, and also from secondary emissions due to growth in the area.

6.3.1 Vegetation and Soils

The VV2 Project site is in an area consisting of desert and desert shrub-land. Criteria for evaluating impacts on soils and vegetation are provided in EPA's A Screening Procedure for the Impacts of Air Pollution Sources on Plants, Soils and Animals (EPA 1980). Table 6-15 lists the EPA suggested criteria for the gaseous pollutants emitted directly from the proposed facility. These criteria are established for sensitive vegetation and crops exposed to the effects of the gaseous pollutants through direct exposure. Adverse impacts on soil systems result more readily from the secondary effects of these pollutants' impacts on the stability of the soil system. These impacts could include increased soil temperature and moisture stress and/or increased runoff and erosion resulting from damage to vegetative cover. In Table 6-15, the total modeled air concentrations for the proposed facility plus ambient background concentrations are compared to these criteria to evaluate impacts on both soils and vegetation. All total concentrations are well below all of the criteria. Therefore, the potential for adverse impacts to either soils or vegetation is negligible.

Table 6-14
Soils and Vegetation Analysis

Pollutant	Averaging Time	Modeled Project Impacts ($\mu g/m^3$)	Ambient Background ($\mu g/m^3$)	Total ($\mu g/m^3$)	Minimum Impact Level for Affects On Sensitive Plants ($\mu g/m^3$)
NO_2	4 hour	239.9	169	409	3,760
	8 hour	239.9	169	409	3,760
	1 month	239.9	169	409	564
	Annual	0.3	41	41.3	94
CO	1 week	31.9	2,415	2,447	1,800,000

6.3.2 Growth Analysis

PSD requires an assessment of the secondary impacts from applicable projects. There will be minimal associated growth expected during VV2 Project construction due to the relatively short-term (27 months) duration and the existence of a large construction labor force in the southern California region. Additionally, no long-term growth (i.e., general commercial, residential, industrial or other secondary growth in the area) is expected during Project operations due to the small labor force (36 employees) that will be required to operate this hybrid power plant. Therefore, no analysis of secondary impacts from associated growth is needed for this Project.

7.0 References

Federal Land Managers' Air Quality Related Values Workgroup Phase I Report, December 2000.

Gebhart, H., 2005. CALPUFF Reviewers Guide, Draft, September. Air Resource Specialists, Fort Collins, CO.

Morse, Dee, 2007. E-mail between Dee Morse, NPS and Sara Head, ENSR. February 1.

National Climatic Data Center, 2006. Integrated Global Radiosonde Archive, WMO site 72387 (Mercury/Desert Rock), http://lwf.ncdc.noaa.gov/oa/climate/igra/index.php

U.S. Environmental Protection Agency (EPA), 2005. Guideline on Air Quality Models (as incorporated in Appendix W of 40 CFR Part 51; EPA, 2005).

U.S. EPA, 2004. Users Guide for the AMS/EPA Regulatory Model – AERMOD. EPA-454/B-03-001. September.

U.S. EPA, 2000a. Compilation of Air Pollutant Emission Factors.

U.S. EPA, 2000b. Regulatory Impact Analysis: Heavy Duty Engine and Vehicle Standards and Highway Diesel Fuel Sulfur Control Requirements, EPA420-R-00-026. December.

U.S. EPA, 1998. IWAQM Phase II report (EPA-454/R-98-019, found at http://www.epa.gov/scram001)

U.S. EPA, 1997. Guideline on Air Quality Models (Revised). EPA-450/2-78-027R-C. OAQPS, Research Triangle Park, NC.

U.S. EPA, 1992. Workbook for Plume Visual Impact Screening and Analysis (Revised).

U.S. EPA, 1980. A Screening Procedure for the Impacts of Air Pollution Sources on Plants, Soils and Animals.