Statement of Basis
Draft Greenhouse Gas Prevention of Significant Deterioration Preconstruction Permit
for the Victoria WLE, LP

Permit Number: PSD-TX-1348-GHG

August 2014

This document serves as the statement of basis 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 February 13, 2013, Victoria WLE, LP submitted to EPA Region 6 a Prevention of Significant Deterioration (PSD) permit application for Greenhouse Gas (GHG) emissions for a proposed construction project at the Victoria Power Station (VPS). In connection with the same proposed project, Victoria submitted a PSD permit application for non-GHG pollutants to the Texas Commission on Environmental Quality (TCEQ) on February 13, 2013. The project would constitute a PSD major modification to the VPS, an existing major source located in Victoria, Victoria County, Texas. The existing VPS is a natural gas-fired combined cycle base load power generating station that currently operates in a 1 by 1 by 1 (1 x 1 x 1) configuration with a combustion turbine (M501F), heat recovery steam generator (HRSG) equipped with duct burners and a steam generator (General Electric D5). The project contemplates two new operating configurations through the addition of a new combustion turbine (GE 7FA.04 or equivalent) and a new HRSG equipped with duct burners that would be linked to the existing steam generator. The proposed permit would authorize emissions from the new emission units in a 1 x 1 x 1 combined cycle configuration, as well as in a 2 x 2 x1 configuration that utilizes the existing non-modified M501F combustion turbine and HRSG. The VPS plant retains the ability to operate in its original configuration. The terms and conditions of the draft permit would not apply to this operating mode because those emissions are solely attributable to existing, unmodified emissions units. 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 VPS.

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 source, the applicable air requirements, and an analysis showing how the applicant complied with the requirements.

EPA Region 6 concludes that VPS'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 provided by Victoria at EPA's request, and EPA's own technical analysis. EPA is making all this information available as part of the public record.

II. Applicant

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Victoria Power Station
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Victoria, TX 77901

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III. Permitting Authority

On May 3, 2011, EPA published a federal implementation plan that makes EPA Region 6 the PSD permitting authority for the pollutant GHGs. 75 FR 25178 (promulgating 40 CFR § 52.2305). Texas still retains approval of its plan and PSD program for pollutants that were subject to regulation before January 2, 2011, i.e., regulated NSR pollutants other than GHGs.

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:
Melanie Magee
Air Permitting Section (6PD-R)
1445 Ross Avenue
Dallas, TX 75202
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IV. Facility Location

VPS will be located in Victoria County, Texas and this area is currently designated "attainment" for all criteria pollutants. The nearest Class 1 area is the Caney Creek Wilderness area in Arkansas, which is located over 300 miles from the site. The geographic coordinates for this facility are planned to be as follows:

Latitude: 28° 47’ 14”
Longitude: 97° 00’ 36”

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

Figure 1. Victoria Power Station 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. On June 23, 2014, the United States Supreme Court issued a decision addressing the application of stationary source permitting requirements to greenhouse gases (GHG). *Utility Air Regulatory Group (UARG) v. Environmental Protection Agency* (EPA) (No. 12-1146). The Supreme Court said that the EPA may not treat greenhouse gases as an air pollutant for purposes of determining whether a source is a major source required to obtain a PSD or title V permit. However, the Court also said that the EPA could continue to require that PSD permits, otherwise required based on emissions of conventional pollutants, contain limitations on GHG emissions based on the application of Best Available Control Technology (BACT). Pending further EPA engagement in the ongoing judicial process before the District of Columbia Circuit Court of Appeals, the EPA is proposing to issue this permit consistent with EPA's understanding of the Court's decision.

The source is a major source because the existing facility has the potential to emit CO and NOx above the applicable 100 tpy threshold. In this case, the applicant represents that TCEQ, the permitting authority for regulated NSR pollutants other than GHGs, has determined the project is subject to PSD review for the conventional regulated NSR pollutants CO, NOx, PM/PM2.5/PM10.

The applicant also estimates that this same project will result in a GHG emissions increase and a net GHG emissions increase of 1,072,498 tpy CO_2e and greater than zero tons per year mass basis, which well exceeds the GHG thresholds in EPA regulations. 40 C.F.R § 52.21(b)(49)(iv); see also, *PSD and Title V Permitting Guidance for Greenhouse Gases* (March 2011) at 12-13). Since the Supreme Court recognized EPA's authority to limit application of BACT to sources that emit GHGs in greater than *de minimis* amounts, EPA believes it may apply the 75,000 tons per year threshold in existing regulations at this time to determine whether BACT applies to GHGs at this facility.

Accordingly, this project continues to require a PSD permit that includes limitations on GHG emissions based on application of BACT. The Supreme Court's decision does not limit the FIP authority and responsibility of Region 6 with regard to this particular permitting action. 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]

VI. Project Description

Victoria proposes to install an additional natural gas-fired combustion turbine and HRSG with duct burners at the existing VPS in Victoria, Victoria County, Texas. The resulting new base-load power generating capacity may utilize the new combined cycle generating unit (GE.7FA.04 or equivalent) in a 2 x 2 x 1 configuration that utilizes both new and existing emissions units, as well as a 1 x 1 x 1 configuration that utilizes only new emissions units with the existing steam turbine. The existing steam turbine is not a source of emissions, although its use for overall power generation will be maximized due to utilization of orphaned capacity. The proposed combustion turbine and duct burners will fire natural gas exclusively. Operation of the existing unit will continue to be in the original 1 x1 x 1 combined cycle configuration until the new combustion turbine and HRSG construction is completed. Following startup of the new combustion turbine and HRSG, the source will have the capability of operating either the existing combustion turbine or the new combustion turbine in a 1 x 1 x 1 combined cycle mode.

In the context of a modification, GHG BACT applies only to an emissions unit that has been modified or added to an existing facility. *See* GHG Guidance at 23. Accordingly, GHG BACT review here does not apply to the existing emissions units or the emissions from the existing 1 x 1 x 1 configuration, because the existing combustion turbine, HRSG, and steam turbine will not be modified under this project.[2] Emission rate increases associated with the installation and operation of the proposed new units and affected existing units were included in the application. The existing combustion turbine will not operate or be capable of operating at rates higher than it is currently capable of and authorized for under currently permitted non-GHG allowable emission levels.

[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.

The proposed GHG PSD permit, if finalized, would authorize a major modification at the combined cycle electric generating facility, increasing the total gross design capacity of the plant from 290 MW to 545 MW. The operations of VPS covered by the GHG BACT requirements of the proposed permit will consist of the following sources of GHG emissions:

- Natural Gas-Fired Combined Cycle Combustion Turbine (GE.7FA.04 or equivalent). The combustion turbine is equipped with a HRSG and duct burners, a dry low NO_X (DLN) combustion system, and selective catalytic reduction (SCR), and oxidation catalyst;
- Process Fugitives; and
- Electrical equipment insulated with sulfur hexafluoride (SF_6).

<u>Combustion Turbine Generator</u>

In general, the main components of a combustion turbine are 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 CTG and is routed to the HRSG for steam production.

The new facility will consist of a new natural gas-fired General Electric 7FA.04 (GE.7FA.04) CTG or equivalent. The GE.7FA.04 or equivalent combustion turbine will have a maximum heat consumption of approximately 1,816 MMBtu/hr (HHV) and a nominal capacity of up to 177.3 MW of power. The proposed CTG will be equipped with lube oil vents, an inlet chiller, rotor air cooling fans, and totally enclosed water to air cooled (TEWAC) generators.

<u>HRSG with Duct Burners</u>

Heat recovered in the HRSG will be utilized to produce steam. Steam generated by the HRSG will drive the existing steam turbine and associated electrical generator. The new HRSG will be equipped with natural gas-fired duct burners to provide additional steam to the existing steam turbine. The new HRSG will be a natural circulation-type unit similar to the existing HRSG. The duct burners will be capable of a maximum natural-gas firing rate of up to 483 MMBtu/hr (HHV). The duct burners’ total annual firing will not exceed the equivalent of 4,375 hours at maximum capacity per duct burner. The combined exhaust stream from the new combustion turbine and duct burners will be emitted to the atmosphere through one common dedicated stack.

<u>Inlet Air Cooling</u>

The inlet air to the new combustion turbine will be cooled during high ambient temperature conditions through the use of chillers. Cooling of the inlet air will increase output of the combustion turbines while lowering the heat rate.

Generation Capacity Overall

Depending on the operational configuration, steam produced by the new and/or existing HRSGs will be routed to the existing steam turbine. The new and existing CTGs and one existing steam turbine will be coupled to electric generators to produce electricity for sale to the Electric Reliability Council of Texas (ERCOT) power grid. With this proposed project, the base-load gross electric power output will be increased from 290 MW to 545 MW. The maximum design gross power output of the new CTG is approximately 177.3 MW and the maximum electric power output from the existing steam turbine is anticipated to increase by approximately 60 MW. The new facility may operate at reduced load to respond to changes in system power requirements and/or stability.

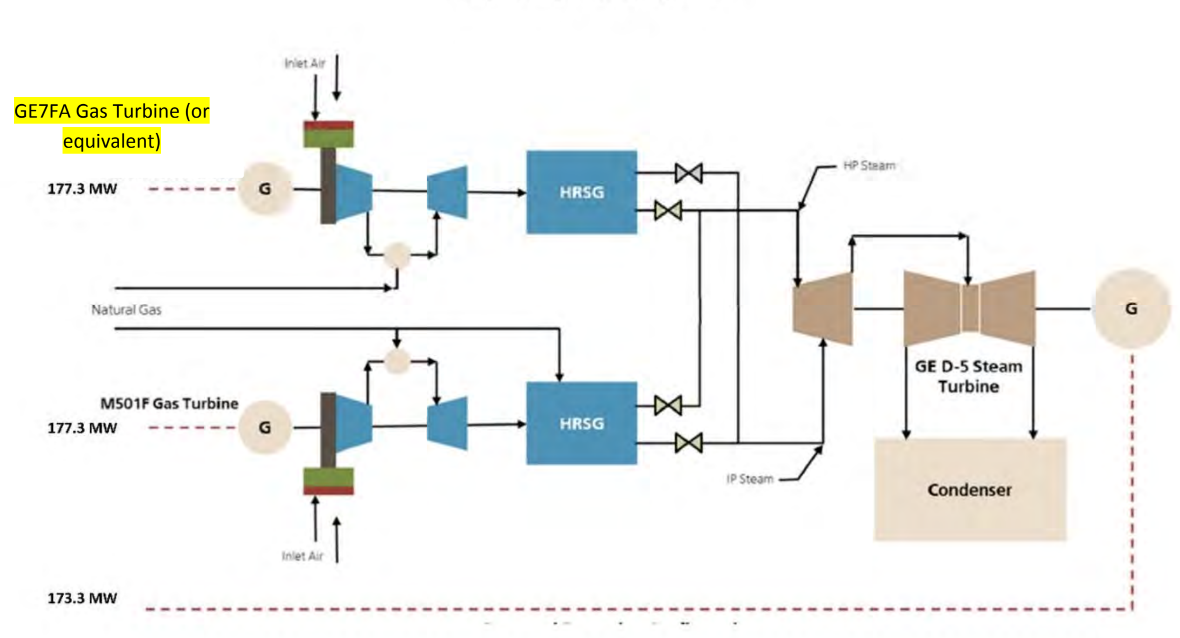
Electrical Equipment Insulated with Sulfur Hexafluoride (SF_6)

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 total capacity of the circuit breakers associated with the proposed facility is currently estimated to be approximately 23 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.

Process Description and Process Flow

The following presents a process flow diagram for the new combined cycle combustion turbines at VPS.

Proposed Expansion Configuration



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 turbine and duct burners). The project will have fugitive emissions from piping components that will account for 445 tpy of CO_2e, or less than 0.04% of the project's total CO_2e emissions. Stationary combustion sources primarily emit CO_2 and small amounts of N_2O, CH_4, and SF_6. The following equipment is included in this proposed GHG PSD permit:

- Combined Cycle Combustion Turbine (VIC10)
- Natural-Gas Process Fugitives (VIC10-FUG-NGAS)
- SF_6-Insulated Electrical Equipment (VIC10-INS-SF6)

IX. Combined Cycle Combustion Turbine equipped with HRSG and Duct Burners

The GE.7FA.04 or equivalent natural gas-fired combined cycle combustion turbine, including the HRSG and duct burners, will be used for electric power generation. The BACT analysis for the combustion turbine 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 (CCS).

As part of the PSD review, VPS provided in the GHG permit application a five-step top-down BACT analysis for the combustion turbine. EPA has reviewed VPS's BACT analysis for the combustion turbine, 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* – Good turbine design maximizes thermal efficiency. Combustion turbines operate at high temperatures. Heat radiated by the hot turbine components is lost to the surrounding atmosphere. To minimize this heat loss, turbines can be wrapped with insulating blankets so that more of the heat is retained in the hot gases for recovery of useful energy.
- *Periodic Maintenance and Tune-Up* – After several months of continuous operation of the combustion turbine, fouling and degradation contribute to a loss of thermal efficiency. A periodic maintenance program consisting of inspection and cleaning of key equipment components and tuning of the combustion system will minimize performance degradation and recover thermal efficiency to the maximum extent possible. Regularly scheduled combustion inspections involving tuning of the combustors are used to maintain optimal thermal efficiency and performance.
- *Reduction in Heat Loss* – Insulation blankets are applied to the combustion turbine casing to minimize heat loss to the environment. These blankets minimize the heat loss through the combustion turbine shell and help improve the overall efficiency of the machine.
- *Instrumentation and Controls* – Proper instrumentation ensures efficient turbine operation to minimize fuel consumption and resulting GHG emissions. Distributed digital system controls are used to automate processes for optimal operation.

Heat Recovery Steam Generator:

- *Heat Exchanger Design Considerations* - Efficient design of the HRSG improves overall thermal efficiency. This includes the following: finned tube, modular type heat recovery surfaces for efficient, economical heat recovery; use of an economizer, which is a heat exchanger that recovers heat from the exhaust gas to preheat incoming HRSG boiler feedwater to attain industry standard performance (ISO) for thermal efficiency; use of a heat exchanger to recover heat from HRSG blowdown to preheat feedwater; use of hot condensate as feedwater which results in less heat required to produce steam in the HRSG, thus improving thermal efficiency; and application of insulation to HRSG surfaces and steam and water lines to minimize heat loss from radiation.
- *Insulation* – The use of insulation prevents heat loss.
- *Minimizing Fouling of Heat Exchange Surfaces* - Fouling of interior and exterior surfaces of the heat exchanger tubes hinders the transfer of heat from the hot combustion gases to the boiler feedwater. This fouling occurs from contaminants in the turbine inlet air and in the feedwater. Fouling is minimized by inlet air filtration, maintaining proper feed water chemistry, and periodic maintenance, including cleaning the tube surfaces as needed during scheduled equipment outages.
- *Minimizing Vented Steam and Repair of Steam Leaks* – Steam loss through venting and leakage reduces the efficiency of the heat exchanger. Restricting the venting outlets is used to maximize steam retention for power generation.

Other Plant-wide Energy Efficiency Features

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

- *Multiple Trains* - Use of multiple turbine/HRSG trains allows one or more train to be shut down while maintaining the remaining unit(s) at or near full load where maximum efficiency is achieved rather than operating a single unit at lower less efficient loads. The proposed unit in combination with the existing combined cycle unit will provide this flexibility.
- *Cooling Towers* – A closed-loop design, which includes a cooling tower to cool the water, will be utilized for the project.
- *Use of Low Carbon Fuel (other than natural gas)* - Natural gas is the lowest carbon fossil fuel that exists. Fuel gases that contain significant amounts of hydrogen and produce no CO_2 when burned, can be burned in turbines and duct burners if available. Use of fuel gas is an effective means of reducing GHG emissions in such situations.

2. Carbon Capture and Storage (CCS)

CCS is classified as an add-on pollution control technology, which involves the separation and capture of CO_2 from flue gas, pressurizing of the captured CO_2 into a pipeline for transport, and injection/storage within a geologic formation. CCS is general "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)."

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 natural-gas combined cycle facility. The third approach, post-combustion capture, is an available control option for combustion 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).

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 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 for a partial stream capture of 365 tons per day of CO_2 from the exhaust of a natural gas combined cycle plant previously owned by Florida Power and Light (Bellingham Energy Center), currently owned by NEXTera Energy Resources of which Florida Power and Light is a subsidiary. The CO_2 capture plant was maintained in continuous operation from 1991 to 2005 (Reddy, Scherffius, Freguia, & Roberts, 2003). The CO_2 capture operation was discontinued in 2005 due to a change in operations from a baseload unit to a peak load shaving unit, which created technical impediments to continuing to operate the system.

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.

Step 2 – Elimination of Technically Infeasible Alternatives

VPS's application examines the technical feasibility of CCS for this project and concludes that:

The combustion of natural gas at the proposed new unit (VIC10) will produce an exhaust gas with a maximum concentration of approximately 4 percent by volume, dry. This low concentration stream will require that a very high volume of gas be treated so that the CO_2 may be captured effectively. As discussed in the "Report of the Interagency Task Force on Carbon Capture and Storage" (August 2010)[3], current industrial processes are designed for streams with 25 percent or higher CO_2 concentrations. The lower CO_2 concentration in the exhaust gases will imply a scale up of existing process, which incorporates a significant technical challenge and a potential barrier to widespread commercial deployment in the near term. VPS Response to Comments dated December 13, 2013, Question 10.

EPA's recent proposed rule addressing Standards of Performance for Greenhouse Gas Emissions from New Stationary Sources: Electric Utility Generating Units concluded that CCS was not the best system of emission reduction for a nation-wide standard for natural gas combined cycle (NGCC) turbines based on questions about whether full or partial capture CCS is technically feasible for the NGCC source category. 79 Fed. Reg. at 1485 (Jan. 8, 2014). Considering this, EPA is evaluating whether there is sufficient information to conclude that CCS is technically feasible at this specific NGCC source and will consider public comments on this issue. However, because the applicant has provided a basis to eliminate CCS on other grounds, we have assumed, for purposes of this specific permitting action, that

[3] http://www.epa.gov/climatechange/Downloads/ccs/CCS-Task-Force-Report-2010.pdf

the potential technical or logistical barriers do not make CCS technically infeasible for this project. We therefore are evaluating the economic, energy, and environmental impacts of CCS in Step 4 of the BACT analysis in order to assess whether CCS is BACT for this project.

The other control options identified in Step 1 are also considered technically feasible for this project.

Step 3 – Ranking of Remaining Technologies Based on Effectiveness

Energy efficiency processes, practices, and designs are all considered effective and have a range of efficiency improvements which cannot be directly quantified, and therefore, ranking them is not possible. In assessing CO_2 emission reduction from CCS, it has been reported that CCS could enable large reductions (85-90 percent) reduction of CO_2 emissions from fossil fuel combustion.

Step 4 – Evaluation of Control Technologies in Order of Most Effective to Least Effective

An evaluation of each technically feasible combustion turbine control option follows in order of descending GHG-reduction effectiveness.

Carbon Capture and Storage (CCS)

VPS developed an initial cost analysis for CCS that estimated the total estimated capital cost for CCS to be $187 million and stated that this would result in an approximate 100% increase in the total capital cost of the proposed project. Based on these costs, VPS maintains that CCS is not economically feasible. VPS submitted information to support the underlying bases for this cost estimation, and we have additionally reviewed whether these cost assertions are in line with cost estimates for similar facility types developed for other recent GHG permitting actions.

Capital costs associated with CCS fall into two primary areas – CO_2 capture and compression equipment and CO_2 transport. The capture and compression equipment associated with CCS would have cost impacts based on the installation of the additional process equipment (e.g., amine units, cryogenic units, dehydration units, and compression facilities), while transport costs are associated with construction of a pipeline to transport the captured CO_2. VPS conducted an analysis of the capital cost impact of CCS capture and compression equipment on the VPS by using project specific data along with the information provided in the "Report of the Interagency Task Force on Carbon Capture" (August 2010). These costs have been prepared based upon project specific criteria and have been presented as an annualized cost based on a seven-percent interest rate and 20-year equipment-life annuity. The estimated capital cost for post-combustion CO_2 capture and compression equipment was estimated to be $170 million. For transportation costs, VPS identified that the closest site to the proposed project with a demonstrated capacity for geological storage of CO_2 is the Scurry Area Canyon Reef Operators (SACROC) oilfield that is over 359 miles from the project site. Several other candidate storage reservoirs exist within 10 to 50 miles from the project site, but none of these storage reservoirs have been demonstrated to be commercially available for large scale CO_2 storage. However, as a conservative estimate of the capital cost to transport the captured CO_2, VPS chose to rely on a ten mile distance to the nearest potential storage site. Using a 24-inch diameter pipe, VPS has estimated that the total capital cost of CCS transportation is $17 million. Accordingly, VPS's total estimated capital cost for CCS at this facility is approximately $187 million.

Examining other recent and similar permitting actions in the general area, EPA Region 6 estimates that a conservative capital cost of CCS for EOR purposes would be approximately $182 million. Our estimate supports VPS's assertion that adding CCS to the proposed facility would increase the total capital cost of the proposed project by more than 100%.

Based on the control cost, the comparison of total capital cost of control to the project cost, and the decrease in net power output due to the additional power requirements for CCS, VPS maintains that CCS is not economically feasible. EPA has reviewed VPS's estimated CCS cost projections. Based upon the potential volume of CO_2 emissions from the project that would be available for capture and the current estimates of CCS costs that would be associated with a similar project, we believe that VPS's estimated costs to install CCS at the facility are credible. EPA concludes that such costs would render the project economically unfeasible for VPS, and we are eliminating CCS as BACT for this proposed project.

Energy Efficiency Processes, Practices, and Design

There are no known adverse economic, energy, or environmental impacts associated with the control technologies and techniques identified in Step 1 for energy efficiency process, practices, and design. All of these options are proposed for the facility.

Other Plant-wide Energy Efficiency Features

There are no known adverse economic, energy, or environmental impacts associated with the control technologies and techniques identified in Step 1 for other plant-wide energy efficiency features. All of these options are proposed for the facility.

Step 5 – Selection of BACT

EPA proposes the following BACT control technologies and techniques for the VPS's combustion 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
  - Design HRSG to recover heat from exhaust and blowdown for pre-heating of fuel and boiler feedwater
- Install instrumentation and control package, including:
  - Fuel-gas flow and usage;
  - Exhaust-gas temperature monitoring;
  - Pressure monitoring around the turbine package;
  - Temperature monitoring around the turbine package;
  - Vibration monitoring;
  - Air/fuel ratio monitoring; and
  - HRSG temperature and pressure monitoring
- Plant-wide energy efficiency processes, practices, and design
  - Multiple combustion turbine/HRSG trains
  - Closed-loop cooling towers

BACT Limits and Compliance:

To determine the appropriate output-based limit, VPS started with annual average firing rate from the new combustion turbine and duct burners and then calculated a compliance margin based upon reasonable degradation factors that may foreseeably reduce efficiency under real-world conditions. The following table summarizes VPS's proposed efficiency standards based on their permit application.

Combustion Turbine Model	Gross Heat Rate (HHV) (Btu/kWhr)	Combustion Turbine Annual Average Firing Rate[1] (HHV) (MMBtu/hr)	Duct Burners Annual Average Firing Rate[1] (HHV) (MMBtu/hr)	Output-Based Emission Limit, Gross Basis[2] (lb CO_2/MWh)	MSS Emission BACT Limit[2,3] (tons CO_2/hr)
GE.7FA.04 or equivalent (unfired)	7,480	1,816	--	889	108
GE.7FA.04 or equivalent (fired)	8,240	1,816	483	979	

[1] Limits are based on a 12-month rolling average.
[2] These limits apply with and without duct burner firing. The output-based emission limit is based on normal operation.
[3] Limit is based on a 12-month rolling total.

These rates reflect the facility's "gross" power production, meaning the amount of power provided to the grid, and operation in a 2 x 2 x 1 operational configuration. To be consistent with other recent GHG BACT determinations, the annual average firing rate with and without duct burner firing is used to calculate the heat-input efficiency limit. From the VPS permit application, a comparison of VPS's proposed efficiency standard and other recent permitting actions was provided. VPS's proposed standard appears to be within the same range of the other permitting actions.

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

- 2.0% added for variations between as built and design conditions (design margins), including periods of operation at part load conditions,
- 5.0% for efficiency loss due to equipment degradation (performance margin), and
- 3.0% for variations in operation of ancillary plant facilities (degradation margin)

Design Margin - 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. Based on other GHG permits and permit application reviews by EPA Region 6, most combined cycle power plants have a design margin up to 5% for the guaranteed net MW output and net heat rate. This is the condition for which the contractor has a "make right" obligation to continue tuning the facility's performance to achieve this minimum value. Therefore, the contractor must deliver a facility that is capable of generating 95% of the guaranteed MW and must have a heat rate that is no more than 105% of the guaranteed heat rate. With VPS's expertise and experience with combined cycle power plant construction, VPS has elected to reduce the 5% design margin to 2.0%.

Performance Margin on Combustion Turbine and Steam Turbine Generators - The performance margin for equipment degradation relates to the combustion turbine and steam turbine generators. 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 project 5% degradation rate represents the average, and not the maximum or guaranteed, rate of degradation for the gas turbine. Therefore, VPS proposes on previous GHG permitting actions a 20-year degradation of 5%. This degradation rate is comparable to the rates estimated by other natural gas fired power plants that have received a GHG PSD permit.

Degradation Margin for the Auxiliary Plant Equipment - The degradation margin for the auxiliary plant equipment encompasses the HRSGs. This margin accounts for the scaling and corrosion of the boiler tubes over time, as well as minor potential fouling of the heating surface of the tubes. Similar to the HRSGs, scaling and corrosion of the condenser tubes will also degrade the heat transfer characteristics, thus degrading the performance of the steam turbine generator. Because combustion turbine degradation accounts for the majority of the performance loss, as well as the large variation in operating parameters (fuels, temperatures, water treatment, cycling conditions, etc.), little operating data has been gathered and published that illustrate a clear performance degradation characteristic for this auxiliary plant equipment. This degradation rate is comparable to the rates estimated by other natural gas fired power plants that have received a GHG PSD permit.

EPA is proposing the following BACT limits for the VPS project:

Turbine Model	Combustion Turbine Annual Firing Rate[1] (mmBtu/hr) (HHV)	Duct Burners Annual Firing Rate[1] (mmBtu/hr) (HHV)	Output Based Emission Limit, gross (lb CO_2/MWh)[2]	MSS Emission BACT Limit[2,3] (tons CO_2/hr)
GE.7FA.04 or equivalent	1,816	483	940	108

[1] The Firing Rates are based on a 12-month rolling average.
[2] The output based emission limit applies with or without duct burner firing. The output based emission limit is based on normal operation.
[3] Limit is based on a 12-month rolling total.

The calculation of the lb CO_2/MWh and CO_2e is in the supplemental information that was provided by VPS on July 22, 2014 The output based limit of 940 lb CO_2/MWh is based on EPA Region 6 calculation of the estimated CO_2 emissions, MW output of the plant over the course of a year, and applying a 1% correction factor to accommodate emission fluctuations during startup and shutdown. The BACT limit will apply to the combustion turbine during normal operational conditions, with and without duct burner firing. VPS shall meet the BACT limit on a 12-month rolling average. The BACT limit for MSS is 108 tons CO_2 per hour and the start-up and shut down events are limited to 1,000 hours per year. MSS events are estimated as follows:

- Cold Startup: is a startup after an extended CT shutdown of greater than 64 hours. A cold startup event shall not exceed 10 hours.
- Warm Startup: is a startup after a CT shutdown of 16 to 64 hours. A planned warm startup event shall not exceed 4 hours.

- Hot Startup: is a startup after a CT shutdown of less than 16 hours A planned hot startup event shall not exceed 2.5 hours.
- Shutdown of the CT: is limited to 60 minutes per event.

A startup of EPN: VIC10 is initiated when the Data Acquisition and Handling System (DAHS) detects a flame signal (or equivalent signal) and ends when the permissives for the emission control system are met (i.e., steady state emissions compliance is achieved). A startup for the combustion turbine is limited to 10 hours (cold startup) per event. A shutdown of EPN: VIC10 begins when the load drops to the point at which steady state emissions compliance can no longer be assured and ends when a flame-off signal is detected. A shutdown for the combustion turbine is limited to 60 minutes per event.

VPS requested that the BACT limit be 940 lb CO_2/MWh based on a limit of 4,375 hours of duct burning firing per year and 108 tons per hour of CO_2 for 1,000 hours of start-up and shutdown per year. The proposed BACT limits are similar to or lower than the range of other BACT limits established for natural gas fired combustion turbines with duct burning. The existing, non-modified steam turbine proposed to be used with this project is a General Electric, Model D5 tandem compound, reheat steam turbine that was originally installed in 1963. The steam turbine was designed for normal inlet throttle steam conditions of 1,800 psia and 1,000°F and had a design rating of 160 MW. The steam turbine is coupled with a 60 Hz, hydrogen-cooled generator rated at 212 MVA. Steam turbines of this vintage were very robust and conservatively designed with multiple inner casings and thick sections. Newer steam turbines combine highly developed steam path technology, advanced sealing features, compact turbine sections and a broad portfolio of last-stage buckets. Because newer units have less mass to warm during the startup process, they are able to come up to full load more quickly than the Victoria steam turbine. The startup process for any steam turbine cold-cold start is necessarily long and highly controlled to avoid damage to the equipment. Start times for the Victoria steam turbine are constrained by the gas turbine start and initial loading, HRSG and steam line warm-up and various OEM constraints.

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
FGE Power, LLC Westbrook, TX	1,620 MW Combined cycle	Energy Efficiency Good Design & Combustion Practices	899 lb CO_2/MWh (gross) Startup Emissions- 48 tons CO_2/hr per turbine and 1,735 lb CH4/event per turbine Shutdown Emission 192 tons CO_2/hr per turbine and 510 lb CH_4/event per turbine	2014	PSD-TX-1364-GHG
La Paloma Energy Center Harlingen, TX	637 - 735 MW depending on turbine model selected Combined cycle	Energy Efficiency Good Design & Combustion Practices	Annual Heat Input – 7,861-7,679 Btu/kWh depending on turbine model selected 934-909 lb CO_2/MWh depending on turbine model selected	2013	PSD-TX-1288-GHG

Company / Location	Process Description	Control Device	BACT Emission Limit / Requirements	Year Issued	Reference
Calpine Deer Park Energy Center Deer Park, TX	168 MW/180 MW Combined cycle with Duct Burner	Energy Efficiency Good Design & Combustion Practices	Annual Heat Input – 7,730 But/kWh 920 lb CO_2/MWh	2012	PSD-TX-979-GHG
Calpine Channel Energy Center Pasadena, TX	168 MW/180 MW Combined cycle with Duct Burner	Energy Efficiency Good Design & Combustion Practices	Annual Heat Input – 7,730 Btu/kWh 920 lb CO_2/MWh	2012	PSD-TX-955-GHG
Pioneer Valley Energy Center Westfield, MA	431 MW Combined cycle	Energy Efficiency Good Design & Combustion Practices	825 lb CO_2e/MWh_{grid} (initial performance test) 895 lb CO_2e/MWh_{grid} on a 365-day rolling average	2012	052-042-MA15
LCRA Thomas C. Ferguson Plant Horseshoe Bay, TX	195 MW Combined Cycle	Energy Efficiency Good Design & Combustion Practices	Annual Heat Rate - 7,720 Btu/kWh 920 lb CO_2/MWh	2011	PSD-TX-1244-GHG
Palmdale Hybrid Power Plant Project Palmdale, CA	195 MW Combined cycle with Duct Burning	Energy Efficiency Good Design & Combustion Practices	Annual Heat Rate - 7,319 Btu/kWh 774 lb CO_2/MWh	2011**	SE 09-01
PacifiCorp Energy - Lake Side Power Plant Vineyard, UT	629 MW Combined cycle	Energy Efficiency Good Design & Combustion Practices	950 lb CO_2e/MWh (gross)	2011	DAQE-AN0130310010-11
Calpine Russell City Energy Hayward, CA	600 MW Combined cycle	Energy Efficiency/ Good Design & Combustion Practices	Combustion Turbine Operational limit of 2,038.6 MMBtu/kWh	2011	15487
Pinecrest Energy Center Lufkin, TX	637-735 MW depending on turbine model selected	Energy Efficiency Good Design &	909.2-942.0 lb CO_2/MWh depending on turbine model selected	2014	PSD-TX-1298-GHG

Company / Location	Process Description	Control Device	BACT Emission Limit / Requirements	Year Issued	Reference
	Combined-cycle with Duct Burner	Combustion Practices			

***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.*

On January 8, 2014, EPA proposed New Source Performance Standard (NSPS) 40 CFR Part 60 Subpart TTTT (Standards of Performance for Greenhouse Gas Emissions for New Stationary Sources: Electric Utility Generating Units, 77 FR 22392) that would control CO_2 emissions from new electric generating units (EGUs). The proposed rule would apply to fossil fuel fired EGUs that generate electricity for sale and are larger than 25 MW. EPA proposed that large, natural gas combined cycle EGUs must meet an annual average output-based standard of 1,000 lb CO_2/MWh, on a gross basis. The proposed emission rate for the VPS combustion turbine, on a gross electrical output basis, is 940 lb CO_2/MWh, with or without duct burner firing. The proposed CO_2 emission rate for the VPS combustion turbine is therefore less than the emission limit proposed in the NSPS at 40 CFR Part 60 Subpart TTTT.

VPS will demonstrate compliance with the CO_2 limit established as BACT by calculating the CO_2 value based on equation G-4 of 40 CFR 75, Appendix G. The calculated CO_2 emission value is divided by the summed amount of the combustion turbine's gross output and the apportioned steam turbine's gross output (MW). The resulting quotient is then converted to lb CO_2/MWh and compared to the BACT limit of 940 lb CO_2/MWhr on a 12-month rolling average basis. To determine the apportioned steam turbine gross output, a plan shall be submitted to demonstrate the apportionment of the gross electric output within 60 days after achieving the maximum production rate at which the affected facility will be operated, but not later than 180 days from the date of initial startup of the combustion turbine. This plan will detail how the apportionment will be determined, and a monitoring strategy to demonstrate the apportionment will be included.

As an alternative to calculating emissions under equation G-4, VPS may choose to install and operate a CO_2 continuous emission monitoring system (CEMS) to determine the amount of CO_2 from combustion. If the CO_2 CEMS is selected, the measured hourly CO_2 emissions are divided by the net hourly energy output and averaged daily. For any period of time that the CO_2 CEMS is nonfunctional, VPS shall use the methods and procedures outlined in the Missing Data Substitution Procedures as specified in 40 CFR Part 75, Subpart D.

To determine compliance with the CO_2e annual emission limit, VPS shall calculate the emission values for CO_2, CH_4 and N_2O based on equation G-4 of 40 CFR 75, Appendix G, emission factors provided in 40 CFR Part 98, Subpart C, Table C-2, fuel usage, and the actual heat input (HHV). 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 shall be required to be kept to demonstrate compliance with the emission limits on a 12-month rolling total basis.

VPS will determine a site-specific Fc factor using the ultimate analysis and GCV in equation F-7b of 40 CFR Part 75, Appendix F. The site-specific Fc factor will be re-determined annually in accordance with 40 CFR Part 75, Appendix F § 3.3.6.

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

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

This approach is consistent with the CO_2 reporting requirements of 40 CFR Part 98, Subpart D (Mandatory GHG Reporting Rule for Electricity Generation). The CO_2 monitoring method proposed by VPS is consistent with the recently proposed NSPS, Subpart TTTT (40 CFR 60.5535(c)), which allows for EGUs firing gaseous fuel to determine CO_2 mass emissions by monitoring fuel combusted in the affected EGU and using a site specific Fc factor determined in accordance to 40 CFR Part 75, Appendix F.

An initial stack test demonstration will be required for CO_2 emissions from EPN: VIC10. VPS proposes to demonstrate compliance with the proposed heat rate with an initial compliance test at or above 90% load (corrected to ISO conditions) and subsequent annual testing. The conditions of the performance demonstration tests shall be conducted under such conditions to ensure representative performance of the affected facility and shall be recorded and made available for review upon request. VPS will demonstrate compliance with the proposed heat rate with an annual compliance test at or above 90 percent load, corrected to ISO conditions. An initial stack test demonstration for CH_4 and N_2O emissions is not required because the CH_4 and N_2O emissions comprise approximately 0.01% of the total CO_2e emissions from the combustion turbines.

IX. Process Fugitives

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 estimated to be 445 tpy as CO_2e. VPS 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.

Step 1 – Identification of Potential Control Technologies

- *Leakless/Sealless Technology*
- *Instrument Leak Detection and Repair (LDAR) Programs*
- *Remote Sensing*
- *Auditory/Visual/ Olfactory (AVO) Monitoring*
- *Use of High Quality Components and Materials*

Step 2 – Elimination of Technically Infeasible Alternatives

All options identified in Step 1 are considered technically feasible.

Step 3 – Ranking of Remaining Technologies Based on Effectiveness

Leakless technologies are effective in eliminating fugitive emissions from valve stems and flanges, though there are still some areas where fugitive emissions can occur (e.g., relief valves). Instrument monitoring (LDAR) is effective for identifying leaking components and is an accepted practice by EPA. Quarterly monitoring with an instrument and a leak definition of 500 ppm is assigned as a control effectiveness of 97%. The Texas Commission on Environmental Quality's LDAR program, 28LAER, provides for 97% control credit for valves, flanges, and connectors. Remote sensing using infrared imaging has proven effective in identifying leaks, especially for components in difficult to monitor areas. LDAR programs and remote sensing using an infrared camera have been determined by EPA to be equivalent methods of piping fugitive controls. AVO monitoring is effective due to the frequency of observation opportunities, but it is not very effective for low leak rates. It is not preferred for identifying large leaks of odorless gases such as methane. However, since pipeline natural gas is odorized with very small quantities of mercaptan, AVO 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, AVO observations of potential fugitive leaks are likewise moderately effective. The use of high quality components is also effective relative to the use of lower quality components.

Step 4 – Evaluation of Control Technologies in Order of Most Effective to Least Effective

Although the use of leakless components, instrument LDAR and/or remote sensing of piping fugitive emission in natural gas service may be somewhat more effective than as-observed AVO methods, the incremental GHG emissions controlled by implementation of the TCEQ 28 LAER LDAR program or a comparable remote sensing program is considered a de minimis level in comparison to 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. Given that GHG fugitives are conservatively estimated to be less than 18 tons per year CH_4 (0.04 percent of the total project), there is, in any case, a negligible difference in emissions between the considered control alternatives.

Step 5 – Selection of BACT

Based on the economic impracticability of instrument monitoring and remote sensing for natural gas piping components, EPA 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.

X. SF_6 Emissions from Electrical Equipment Insulation Leaks

The generator circuit breakers associated with the proposed unit will be insulated with SF_6. The capacity of the circuit breakers associated with the proposed plant is currently estimated to be 23 lb of SF_6.

Step 1 – Identification of Potential Control Technologies for GHGs

Circuit Breaker Design Efficiency - 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.

Alternative Dielectric Material – Because SF_6 has a high GWP, 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. The alternatives considered include mixtures of SF_6 and nitrogen, gases and mixtures and potential gases for which little experimental data are available

Step 2 – Elimination of Technically Infeasible Alternatives

Circuit Breaker Design Efficiency – Considered technically feasible and is carried forward for Step 3 analysis.

Alternative Dielectric Material - According to the report NIST Technical Note 1425, among the alternatives examined in the report, 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 "…various gas mixtures show considerable promise for use in new equipment, particularly if the equipment is designed specifically for use with a gas mixture." The mixture of SF_6 and nitrogen is noted to need further development and may only be applicable in limited installations. This alternative has not been demonstrated in practice for this project's design installation. The second alternative of various gases and mixtures has not been demonstrated in practice, and needs additional systematic study before this alternative could be considered technically feasible. The third alternative of potential gases has not been demonstrated in practice, and there is little experimental data available.

Additional studies are needed before this alternative would be considered feasible. Based on the information contained in this report, "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, because the alternative dielectric material options have not been demonstrated in practice for this project's proposed design application and are not commercially available, this alternative is considered technically infeasible.

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

Since the only remaining control option is circuit breaker design efficiency, and since that option is selected as BACT, a Step 4 evaluation of the most effective controls is not necessary.

Step 5 – Selection of BACT

Circuit breaker design efficiency is selected as BACT. Specifically, state-of-the-art enclosed-pressure SF_6 circuit breakers with leak detection are the BACT control technology option selected. The circuit breakers will be designed to meet the latest of the American National Standards Institute (ANSI) C37.06 and C37.010 standard for high voltage circuit breakers. The proposed circuit breaker at the generator output will have a low density alarm and a low density 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.

VPS will monitor emissions annually in accordance with the requirements of the Mandatory Greenhouse Gas Reporting Rules for Electrical Transmissions and Distribution Equipment Use.[4] Annual SF_6 emissions will be calculated according to the mass balance approach in Equation DD-1 of 40 CFR Part 98, Subpart DD.

VPS will implement the following work practices as SF_6 BACT:

- Use of state-of-the-art circuit breakers that are gas-tight and guaranteed to achieve a leak rate of 0.5% by year by weight or less (the current maximum leak rate standard established by the International Electrotechnical Commission);
- An LDAR program to identify and repair leaks and leaking equipment as quickly as possible;

[4] See 40 CFR Part 98 Subpart DD.

- Systematic operations tracking, including cylinder management and SF_6 gas recycling cart use; and
- Educating and training employees with proper SF_6 handling methods and maintenance operations.

XI. 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, Victoria Power Station ("Victoria"), and its consultant, Whitenton Group, LLC ("Whitenton"), thoroughly reviewed and adopted by EPA.

The draft BA identifies five (5) species as federally endangered or threatened in Brazoria County, Texas:

Federally Listed Species for Brazoria County by the U.S. Fish and Wildlife Service (USFWS) and the Texas Parks and Wildlife Department (TPWD)	**Scientific Name**
Birds	
Attwater's Greater Prairie Chicken	*Tympanuchus cupido attwateri*
Whooping crane	*Grus americana*
Interior least tern	*Sterna antillarum athalassos*
Mammals	
Louisiana Black Bear	*Ursus americanus luteolus*
Red Wolf	*Canis rufus*

EPA has determined that issuance of the proposed permit to Victoria will have no effect on four of the five listed species, specifically Attwater's prairie chicken (*Tympanuchus cupido attwateri*), interior least tern (*Sterna antillarum athalassos*), Louisiana black bear (*Ursus americanus luteolus*), and red wolf (*Canis rufus*) as there are no records of occurrence, no designated critical habitat, nor potential suitable habitat for any of these species within the action area.

However, the whooping crane (*Grus americana*) is a species that may be present in the action area during migration as the proposed project is approximately 33 miles north of whooping crane critical habitat, Aransas National Wild Refuge, and located directly within its migratory path. Information in the BA indicates that there is no known or potential habitat for the cranes within the action area. However, because the use of certain construction equipment poses a possible but unlikely risk of bird strikes during flyovers, Victoria engaged in informal consultation with the USFWS's Southwest Region, Clear Lake Texas Ecological Services Field Office. Following discussions with USFWS, Victoria has agreed to implement measures to minimize any potential adverse effects the project may have on the whooping crane, as indicated in their Biological Assessment.

EPA submitted the final draft BA to the Southwest Region, Corpus Christi, Texas Ecological Services Field Office of the USFWS on June 26, 2014, and requested concurrence from USFWS that issuance of the permit may affect, but is not likely to adversely affect the whooping crane. USFWS provided concurrence and agreed with EPA's determination on August 4, 2014.

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.

XII. National Historic Preservation Act (NHPA)

Section 106 of the NHPA requires EPA to consider the effects of this permit action on properties 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 (Horizon) on behalf of Whitenton Group, a contractor to Victoria and the EPA.

For purposes of the NHPA review, the Area of Potential Effect (APE) was determined to be approximately 7.4 acres of land that contains the construction footprint of the project. Horizon performed a field survey of the property and a desktop review on the archaeological background and historical records within a one-mile radius of the APE. The desktop review included an archaeological background and historical records review using 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 for the site, four previously recorded archeological sites, 95 historic properties listed on the National Register of Historic Places (NRHP), and one historic district listed on the NRHP are present within a one-mile radius of the existing Victoria Power Station complex; however, they are all outside the APE .

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

On March 7, 2014, 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 submitted a copy of the final draft of the cultural report to the State Historic Preservation Officer (SHPO) for consultation and requested concurrence with its determination on June 3, 2014. SHPO provided concurrence and agreed with EPA's determination on July 17, 2014. 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.

XIII. 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 GHG. 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.

XIV. Conclusion and Proposed Action

Based on the information supplied by Victoria, our review of the analyses contained in 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 Victoria 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

Table 1. Annual Emission Limits[1]

Annual emissions, in tons per year (TPY) on a 12-month, rolling total, shall not exceed the following:

FIN	EPN	Description	GHG Mass Basis		TPY CO_2e[2,3]	BACT Requirements
				TPY		
VIC10	VIC10	Natural Gas-Fired Combined Cycle Combustion Turbine (GE.7FA.04)	CO_2	1,070,879.0	1,072,053	940 lb CO_2/MWh (gross) on a 12-month rolling average. Start-up and Shutdown emissions limited to 1,000 hours per year. MSS emissions are limited to 108 tons CO_2/hr. See Special Conditions IV.A.1. and Table 2.
			CH_4	23		
			N_2O	2		
VIC10-FUG-NGAS	VIC10-FUG-NGAS	Process Fugitives	CH_4	No Emission Limit Established[5]	No Emission Limit Established[5]	
VIC10-INS-SF6	VIC10-INS-SF6	SF_6 Insulated Electrical Equipment	SF_6	No Emission Limit Established[6]	No Emission Limit Established[6]	
Totals[7]			**CO_2**	**1,070,879**	**1,072,498**	
			CH_4	**41**		
			N_2O	**2**		
			SF_6	**0.000056**		

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. This total is rounded off for estimation purposes to two significant figures.
3. Global Warming Potentials (GWP): CO_2 =1, CH_4 = 25, N_2O = 298, SF_6 = 22,800
4. Includes emissions during all operational modes, including purging venting associated with the CT and DB shutdown and maintenance events. CH_4 is vented via an automatic double block and bleed at the CTG during each shutdown event. Additionally, CH_4 is vented from the duct burner system each time the ducts are shutdown. Annual emissions for these activities are included in the annual CO_2e limit for VIC10.
5. Fugitive process emissions from EPN VIC10-FUG-NGAS are estimated to be 17.8 TPY CH_4, and 445 TPY CO_2e. Fugitive process emission totals are for information only and do not constitute an emission limit. The emission limit will be a design/work practice standard as specified in the permit.
6. SF_6 emissions from EPA VIC10-INS-SF6 are estimated to be 0.000056 tpy SF_6 and 1.28 tpy CO_2e. Fugitive process emission totals are for information only and do not constitute an emission limit. The emission limit will be a design/work practice standard as specified in the permit.
7. Totals are given for informational purposes only and do not constitute emission limits.

Nuria de las Casas

From:	Nuria de las Casas
Sent:	Monday, July 14, 2014 2:28 PM
To:	Magee, Melanie; Robinson, Jeffrey
Cc:	Marc Sturdivant (Marc.Sturdivant@tceq.texas.gov); Gary Clark; Matthew Lindsey; Jeff Martin; Mona Johnson (mjohnson@camsesparc.com)
Subject:	RE: Opportunity to Review Draft Permit for Victoria Power
Attachments:	2014-07-14 Statement of Basis Victoria 060514.docx; 2014-07-14 Unit 10 (VIC10) GHG Emission Rate Calcs.pdf; 2014-07-14 Victoria Draft Permit 060514.docx; 2014-07-14 Victoria Post Submittal Perform Std.pdf
Categories:	Victoria

Melanie,

Thank you for the additional time to review and provide comments on the draft permit and statement of basis. Following our discussions last week, we have reviewed Victoria's proposed output-based emission rate limit for full load operation and incorporated a BACT emission rate limit applicable during MSS events. In addition, during our call with Ms. Wilson, she requested we provided detailed calculations of the maintenance and shutdown methane purging that had been added to the total Unit 10 GHG calculations.

In order to provide clarification on both aspects I'm attaching to this email the following documentation:

1. 2014-07-14 Unit 10 (VIC10) GHG Emission Rate Calcs.pdf → detailed emission rate calculation for VIC10 including detailed MSS emission rate calculations.
2. 2014-07-14 Victoria Post Submittal Perform Std.pdf → description of the proposed performance standards calculation and compliance methodology.
3. 2014-07-14 Statement of Basis Victoria 060514.doc → reviewed and marked-up SOB.
4. 2014-07-14 Victoria Draft Permit 060514.doc → reviewed and marked-up Draft Permit.

Although we have provided the above requested updates to the draft permit and SOB, we would appreciate an explanation as to how the recent Supreme Court ruling is going to impact this permit and in particular the proposed limits to be imposed for CO2-related emission rates. Please let me know what will be the best timing for you to schedule a call and discuss the impacts of this ruling on our application and the eventual permit issuance.

Shall you need any additional clarification, don't hesitate to contact me at 617-599-0303 or at ndelascasas@camsesparc.com

Thank you

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B-1 Combustion Turbine/Duct Burner Emissions Calculations - Unit 10 (VIC10)

EPN:	VIC10	Turbine:	GE 7FA

Specifications			
Parameter		**Value**	**Unit**
Fuel Type : Natural Gas			
		1,024	Btu/scf
Annual Average Firing Rate:	Turbine	1,816	mmBtu/hr (HHV)
	Duct Burners	483	mmBtu/hr (HHV)
	Factor Basis	**Emission Factor**	
CO2 Emission Factor	Part 75 App G	118.9	lb/mmBtu
CH4 Emission Factor	Part 98, App C	0.001	kg/mmBtu
N2O Emission Factor	Part 98, App C	0.0001	kg/mmBtu
Operating Hours	Turbine Full Load	7,760	hr/yr
	Duct Burners	4,375	hr/yr
	MSS	1,000	hr/yr

Note: All mmBtu values are HHV

Emission Rates			
Pollutant	**tpy**	**GWP* Factor**	**CO_2e tpy**
Full Load			
CO2	962,956	1	962,956
CH4	18	25	447
N20	2	298	532
Total CO2e	N/A	N/A	**963,935**
MSS			
CO2	107,924	1	107,924
CH4	5	25	135
N20	0.2	298	60
Total CO2e	N/A	N/A	**108,118**
Total VIC10			
CO2	1,070,879	1	1,070,879
CH4	23	25	581
N20	2	298	592
Total CO2e	N/A	N/A	**1,072,053**

* Table A-1 to Subpart A of Part 98–Global Warming Potentials

Sample Calculations:

CO2 emission factor calculated from constants in Section 2.3 of Appendix G to 40 CFR Part 75 as follows:

CO2 (lb/mmBtu) = 1040 scf/mmbtu x 1 mole/385 scf x 44 lb CO2/mole = 118.9 lb/mmBtu

CO2 (Full Load) = (1,816 mmBtu/hr * 7,760 hr/yr + 483 mmBtu/hr * 4,375 hr/yr) * 118.9 lb/mmBtu * 1ton/2000lb = 962,956 tpy

CO2 (MSS) = 1,816 mmBtu/hr * 1,000 hr/yr * 118.9 lb/mmBtu * 1ton/2000lb = 107,924 tpy

CO2 (Total) = 962,956 tpy + 107,924 tpy = 1,070,879 tpy

CH4 (Full Load) = (1,816 mmBtu/hr * 7,760 hr/yr + 483 mmBtu/hr * 4,375 hr/yr) * 0.001 kg/mmBtu * 1000g/kg * 1lb/453.6g * 1ton/2000lb = 18 tpy

CH4 (MSS) = 3.4 tpy + (1,816 mmBtu/hr * 1,000 hr/yr * 0.001 kg/mmBtu * 1000g/kg * 1lb/453.6g * 1ton/2000lb) = 5 tpy (includes shutdown and maintenance purging)

CH4 (Total) = 18 tpy + 5 tpy = 23 tpy

N2O (Full Load) = (1,816 mmBtu/hr * 7,760 hr/yr + 483 mmBtu/hr * 4,375 hr/yr) * 0.0001 kg/mmBtu * 1000g/kg * 1lb/453.6g * 1ton/2000lb = 2 tpy

N2O (MSS) = 1,816.0 mmBtu/hr * 1,000 hr/yr * 0.0001 kg/mmBtu * 1000g/kg * 1lb/453.6g * 1ton/2000lb = 0.2 tpy

N2O (Total) = 2 tpy + 0.2 tpy = 2 tpy

Total CO2e = 1,070,879 tpy * 1 + 23 tpy * 25 + 2 tpy * 298 = 1,072,053 tpy

Summary of CH_4 Purging Emissions

Purging Event	GHG Annual Emission Rate (tpy)	CO_2e Annual Emission Rate (tpy)
Shutdown CH_4 Purging [1]	2.9	73.0
Maintenance CH_4 Purging [2]	0.5	11.6
Total	**3.4**	**84.6**

Notes:
(1) Shutdown process requires limited amounts of CH_4 to be purged via an automatic double block and bleed valve at the CTG and DB System
(2) Prior to any maintenance event at the CT, the CT and DB lines are vented to the atmosphere, and consequently CH_4 is released.

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July 14, 2014

Ms. Melanie Magee
EPA Region 6
magee.melanie@epa.gov

Re: Victoria Power Station
Victoria WLE LP
Application for Greenhouse Gas
Prevention of Significant Deterioration Permit

Dear Ms. Magee,

By means of this letter, we would like to update the Victoria Power Station proposed performance standards as provided on June 20, 2014. The previously submitted standards did not include periods of startup and shutdown of the unit. Following our discussions and the review of similar facilities that are being authorized under EPA Region 6 (e.g. Pinecrest Energy Center, LLC), Victoria would like to update its proposed standards.

The proposed initial and continued compliance demonstration methodology with the limits on a 12-month rolling average remains unchanged from our proposal on May 15, 2014. The following table summarizes Victoria's proposed BACT limits.

Combustion Turbine Model	Combustion Turbine Annual Firing Rate (mmBtu/hr) (HHV)	Duct Burners Annual Firing Rate (mmBtu/hr) (HHV)	Heat Rate, Gross basis (Btu/kWh) (HHV)	Output Based Emission Limit, Gross Basis (lb CO_2/MWh)	MSS Emission Limit (ton_{CO2}/hr)
GE.7FA.04 or equivalent	1,816	483	8,074	960	108

* The lb/MWh BACT limit applies for full load operation with and without supplemental duct burner firing and does not apply during MSS.

Proposed Heat Rate (Btu/kWh)

Victoria proposes a heat rate of **8,074 Btu/kWh (HHV)** for VIC10 at full load on a 12-month rolling average and gross basis. The proposed heat rate accounts for the power generation of the new unit

Victoria Power Station
Proposed Standards VIC10

Victoria will operate with the existing unit (VIC7), the new unit (VIC10), and the existing ST in a 2x2x1 configuration. Both CTs (VIC7 and VIC10) will supply steam to the ST. Victoria could also potentially operate in a 1x1x1 configuration with either CT (VIC7 or VIC10) in combination with the existing ST. Because only one CT will contribute to steam production, the ST will not be able to achieve its full capacity in a 1x1x1 configuration. Since VIC7 is an existing unit, it is not subject to a CO_2 output-base emission rate; therefore, this analysis is required only for VIC10. During operation in the 2x2x1 configuration, it is necessary to separate the emissions and power generation contribution of VIC10 from that of VIC7 to obtain a VIC10-specific output-based emission rate.

Compliance with the proposed CO2 output-based BACT emission rate limit (940 lbCO2/MWh) will be demonstrated on a 12-month rolling average and gross basis. This limit applies only during full load with and without supplemental duct burning. The lb/MWh BACT limit does not apply during part load maintenance, startup or shutdown (MSS) periods. VIC10 MSS emissions will be limited to 108 ton CO2/hr on a 12-month rolling average basis.

Proposed Output-Based Emission Rate (Full Load)

Parameter	Units	VIC10 (Full Load, Gross Basis)		
		Unfired	Fired	Proposed
VIC10 CTG Nominal Gross Output (1)	MW	177.3	177.3	
STG Gross Output attributed to VIC10 (2)	MW	89.8	101.5	
Max. Heat Input (HHV) (3)	MMBtu/hr (HHV)	1,816	2,088	
Compliance Margin (4)	%	10.0%	10.0%	
Annual Hours of Operation (5)	hr/yr	3,385	4,375	7,760
Heat Rate, Gross Basis (6), (7)	Btu/kWh (HHV)	7,480	8,240	7,908
CO_2 Emission Factor (8)	lb_{CO2}/MMBtu (HHV)	118.9	118.9	118.9
CO_2 Output-Based Emission Rate, Gross Basis (9)	lb_{CO2}/MWh	889	979	940

<u>Notes:</u>

(1) Estimated units output per vendor and actual data. Final values may vary depending on final design and ambient temperatures:

Mitsubishi 501F (VIC7) = 177.3 MW
General Electric 7FA.04 or equivalent (VIC10) = 177.3 MW
General Electric D5 Steam Turbine Unfired (ST) = 173.3 MW
Duct Fired Capacity (total both units) = 11.7 MW

(2) ST Gross Output attributed to VIC10 has been estimated based on VIC10 Gross Output and 2012 actual heat balance data for current configuration with VIC7.

	VIC7 CT	ST (operating with VIC7)
Avg. Gross Capacity CY 2012	165.3 MW	83.7 MW

ST Gross Output attributed to VIC10 (Unfired) = ST Gross Output operating with VIC7 * VIC 10 Gross Output / VIC7 Gross Output
ST Capacity Operating with VIC10 (Unfired) = 83.7 MW * 177.3 MW / 165.3 MW = 89.8 MW
ST Gross Output attributed to VIC10 (Fired) = ST Gross Output operating with VIC7 * VIC 10 Gross Output / VIC7 Gross Output + DB Gross Output
ST Capacity Operating with VIC10 (Fired) = 83.7 MW * 177.3 MW / 165.3 MW + 11.7 MW = 101.5 MW

(3) Maximum Heat Input:

CT Heat Input (HHV) = 1,816 MMBtu/hr (manufacturer data)
DB Heat Input (HHV) = 483 MMBtu/hr (manufacturer data)

Max. Heat Input (HHV) (Fired) = CT Heat Input * Unfired Hours of Operation + (CT + DB) Heat Input * Fired Hours of Operation / Total Hours of Operation
Max. Heat Input (HHV) (Fired) = [1,816 MMBtu/hr * 3,385 hr/yr + (1,816 MMBtu/hr + 483 MMBtu/hr) * 4,375 hr/yr] / [3,385 hr/yr unfired + 4,375 hr/yr fired] = 2,088 MMBtu/hr

(4) Compliance margin is an adjustment factor to the design rates to arrive at the proposed efficiency standards.
It includes a margin to reflect actual vs. design differences, degradation between maintenance overhauls, and degradation of plant auxiliary equipment.

Design Margin = 2.0%
Performance Margin on CTG and STG = 5.0%
Degradation Margin for the Auxiliary Plant Equipment = 3.0%

(5) Estimated annual hours of operation are based on engineering knowledge of the plant performance but are not intended to contractually limit Victoria operation. Victoria will meet the proposed output-based CO_2 emission rate on a 12-month rolling average and gross basis, independently of the final hours running in each of the operational modes.

Annual Hours of Operation Unfired = 3,385 hr/yr
Annual Hours of Operation Fired = 4,375 hr/yr
Annual Startup Hours = 1,000 hr/yr

(6) Heat Rate (Btu/kWh) = Heat Input (MMBtu/hr) * 1,000,000 Btu/MMBtu / (VIC10 Output + STG Output attributed to VIC10) (MW) * 1 MW / 1,000 kW * Comp. Margin

Heat Rate (Unfired), Gross Basis = 1,816 MMBtu/hr * 1,000,000 Btu/MMBtu / (177.3 MW + 89.8 MW) * 1 MW / 1,000 kW * 1.10 = 7,480 Btu/kWh (HHV)
Heat Rate (Fired), Gross Basis = 2,088 MMBtu/hr * 1,000,000 Btu/MMBtu / (177.3 MW + 101.5 MW) * 1 MW / 1,000 kW * 1.10 = 8,240 Btu/kWh (HHV)

(7) Proposed Heat Rate (Btu/kWh) = [[HR (Btu/kWh) * Annual Op (hr/yr)]$_{Unfired}$ + [HR (Btu/kWh) * Annual Op (hr/yr)]$_{Fired}$] / [Annual Op (hr/yr)$_{Unfired}$ + Annual Op (hr/yr)$_{Fired}$]

Proposed Heat Rate = [7,480 Btu/kWh * 3,385 hr/yr + 8,240 Btu/kWh * 4,375 hr/yr] / 7,760 hr/yr = 7,908 Btu/kWh

(8) CO_2 emission factor calculated per 40 CFR Part 75, Appendix G, Equation G-4, as referenced in §98.43(a), where:

Carbon based F-factor, F_C:	1,040	scf/MMBtu
Standard Molar Volume:	385	scf/lbmole
Molecular Weight CO_2, MW_{CO2}:	44	lb/lbmole

CO2 Emission Factor = 1,040 scf/MMBtu / 385scf/lbmole * 44lb/lbmole = 118.9 lb/MMBtu

(9) CO_2 Emission Limit (lb_{CO2}/MWh) = Heat Rate (Btu/kWh) * 1MMBtu/1,000,000 Btu * CO_2 Emission Factor (lb_{CO2}/MMBtu) * 1,000 kW/MW

CO2 Output-Based Emission Rate (Unfired), Gross Basis = 7,480 Btu/kWh * 1 MMBtu/1,000,000 Btu * 118.9 lbCO2/MMBtu * 1,000 kW/MW = 889 lbCO2/MWh
CO2 Output-Based Emission Rate (Fired), Gross Basis = 8,240 Btu/kWh * 1 MMBtu/1,000,000 Btu * 118.9 lbCO2/MMBtu * 1,000 kW/MW = 979 lbCO2/MWh
CO2 Output-Based Emission Rate (Fired), Gross Basis = 7,908 Btu/kWh * 1 MMBtu/1,000,000 Btu * 118.9 lbCO2/MMBtu * 1,000 kW/MW = 940 lbCO2/MWh

Nuria de las Casas

From:	Nuria de las Casas
Sent:	Tuesday, July 22, 2014 9:45 AM
To:	'Magee, Melanie'
Cc:	Mona Johnson (mjohnson@camsesparc.com); Gary Clark; Matthew Lindsey (mlindsey@camstex.com)
Subject:	Victoria Power Station GHG PSD Permit Application Update
Attachments:	2014-07-18 Victoria Expansion GHG Perform Rvw.pdf
Categories:	Victoria

Good morning Melanie,

Thank you for your time in reviewing the Victoria Power Station application. I am attaching to this email the revised calculations using a compliance margin of 10% instead of 12.3%. The 12.3% margin that we used in developing our application was consistent with the guidance provided by our consultant, based on other applications that they reviewed at the time of application submittal. Therefore, we assumed this was an industry standard. However, in order for the Victoria project to meet an output based CO_2 limit closer to which Austin Energy has agreed, we will have to apply the 10% compliance margin as proposed by them.

Victoria's steam turbine is a General Electric, Model D5 tandem compound, reheat steam turbine that was originally installed in 1963. The STG was designed for normal inlet throttle steam conditions of 1,800 psia and 1,000 °F and had a design rating of 160 MW. The steam turbine is coupled with a 60 Hz, hydrogen-cooled generator rated at 212 MVA.

Steam turbines of this vintage were very robust and conservatively designed with multiple inner casings and thick sections. Newer steam turbines combine highly developed steam path technology, advanced sealing features, compact turbine sections and a broad portfolio of last-stage buckets. Because newer units have less mass to warm during the startup process, they are able to come up to full load more quickly than the Victoria steam turbine. The startup process for any steam turbine cold-cold start is necessarily long and highly controlled to avoid damage to the equipment. Start times for the Victoria steam turbine are constrained by the elements shown in the table below. The time required for each of these elements varies with the length of time from the previous shutdown and with ambient temperature conditions which determine the amount of cooling (a cold-cold start in the winter takes longer than a summer cold-cold start). Typical starting and warming times for a cold-cold start are shown below.

Gas turbine start and initial loading	0.5 hours
HRSG & steam line warm-up	1.5 hours
Steam turbine pre-warm (OEM constraints)	4.0 hours
Steam turbine heat-soak (OEM constraints)	2.0 hours
Steam turbine loading (OEM constraints)	1.5 hours

As noted, Original Equipment Manufacturer (OEM) operating instructions are the major time constraints during startup and are directed at minimizing thermal stresses on the rotor as well as other conditions that may lead to destructive vibrations and rubs due to shell/rotor misalignment caused by differential heating of the casing and differential expansion between the casing and the rotor. In addition to the immediate effects of improper warmup, rotor life can be significantly shortened by failure to maintain temperature rise to within OEM recommended guidelines.

I hope this information is sufficient and resolves all open issues. Please let me know should you need additional clarification.

Thank you

Mona Johnson

From: Mona Johnson
Sent: Wednesday, May 14, 2014 1:19 PM
To: Magee, Melanie
Subject: Victoria GHG Permit [capital cost CCS]

Melanie:

Please see responses to your email request below. We will separately forward the information related to the proposed out-based limit for Victoria. Let me know if this is sufficient.

-Mona

From: Magee, Melanie [mailto:Magee.Melanie@epa.gov]
Sent: Tuesday, May 13, 2014 1:03 PM
To: Mona Johnson
Subject: RE: Victoria GHG Permit

Hi Mona. I hope all is going well. I am continuing to work on your statement of basis and have run across another piece of information that we are going to need. In your permit application and response to comments, the CCS cost estimate is provided in an annualized cost amount. I need to understand how you derived the initial capital cost of your CCS system. Could you provide me with the specifics on the equipment used in the estimate and the initial capital cost?

Our CCS cost estimate was based on information provided in the "Report of the Interagency Task Force on Carbon Capture" (August 2010) data, which provides a methodology to estimate the total annualized costs for CO_2 capture and compression facilities. This methodology aligns well with our goal of developing a cost per ton of reduction. This same report also makes reference to the expected total capital cost to add CCS to a combined cycle natural gas facility. According to this report, DOE analyses indicate that for a new 550 MW net output power plant, the addition of post-combustion CO_2 capture will increase the capital cost of the project by $340 million (Section III.A.4 CO_2 Capture Cost).

The VIC10 addition will result in approximately half this amount of additional output. Therefore, we are assuming a capital cost of $170 million for CCS on the new unit (if it were technically feasible). Additionally, the capital costs for CO_2 transportation facilities need to be addressed. Table 6-2 of our GHG application (attached) provides the $17 million capital cost for a 10 mile pipeline with 24-inch diameter, estimated using DOE/NETL calculation methodology. Therefore, we would be looking at a total capital cost of about $187 million.

Also, I have included a placeholder for your numeric output based limit for EPN:VIC10, so if you can just send that to me I will add it to my drafts. I have been following the requirements in Subpart Da to use as a guideline for the monitoring strategy.

We will send this information separately.

Thanks, Melanie