Environmental Consulting & Technology, Inc.

June 12, 2013
ECT No. 120468-0200

Mr. David Garcia, Acting Director
Multimedia Planning and Permitting Division
U.S. Environmental Protection Agency, Region 6
1445 Ross Avenue, Suite 1200
Dallas, Texas 75202-2733

Re: Guadalupe Power Partners, LP
Guadalupe Generating Station
Guadalupe County, Marion, Texas

Dear Mr. Garcia:

On behalf of Guadalupe Power Partners, LP, Environmental Consulting & Technology, Inc. (ECT), is submitting the following response to your completeness determination letter for the greenhouse gas (GHG) Prevention of Significant Deterioration (PSD) permit application for the proposed construction and operation of two simple-cycle combustion turbines at the existing Guadalupe Generating Station located in Marion, Texas.

We trust that these responses satisfy the additional information requested by EPA Region 6 and that the GHG PSD permit application can be deemed complete. If you should have additional questions or require additional information, please contact me at 352/248-3313 or e-mail at bkarl@ectinc.com, or Mr. Chandler Morris at 281/252-5210 or e-mail at cmorris@navasotaenergy.com.

Sincerely,

ENVIRONMENTAL CONSULTING & TECHNOLOGY, INC.

William F. Karl, P.E.
Senior Engineer

WFK/dlm

cc: M. Magee, EPA
C. Morris, Guadalupe Power Partners, LP

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GUADALUPE POWER PARTNERS LP RESPONSE TO EPA INFORMATION REQUEST

Guadalupe Power Partners LP – Guadalupe Generating Station Application for Greenhouse Gas Prevention of Significant Deterioration Permit

1. Page 2-1 of the permit application, includes a list of four simple cycle combustion turbines that are currently being evaluated and considered for this project. Please provide supplemental data that includes production output, gross heat rate and percent efficiency of each model currently being considered and please provide this data for similarly designed combustion turbines that have been recently permitted by air permitting authorities nationwide (this information may be represented graphically in load/efficiency curves).

<u>Response:</u>

Table 1 provides the gross heat rates, design margin, performance margin, and resulting proposed gross heat rates for the four proposed simple-cycle combustion turbine models for Guadalupe Generating Station (GGS).

GPP has performed a search of other similarly designed combustion turbines that have been recently permitted by air permitting authorities nationwide. GPP searched U.S. Environmental Protection Agency's (EPA's) Reasonably Available Control Technology (RACT)/Best Available Control Technology (BACT)/Lowest Achievable Emissions Rate (LAER) Clearinghouse (RBLC) database for carbon dioxide equivalent (CO_2e) draft and final determinations since January 1, 2003, for natural gas-fired large (greater than 25 megawatts [MW]) simple-cycle combustion turbines. This search resulted in the following three facilities:

- Montana-Dakota Utilities Company, R.M. Heskett Station located in Morton County, North Dakota.
- Pio Pico Energy Center, LLC, located in Otay Mesa County, California.
- Sabine Pass Liquefaction, LLC, located in Cameron County, Louisiana.

These three facilities are proposing combustion turbine manufacturers and models other than those proposed for GGS and, therefore, cannot be used for comparative purposes.

Table 1. GGS Heat Rates and Design and Performance Margins

Turbine Model	Design Heat Rate* (HHV) (Btu/kWh)	Design Margin (%)	Performance Margin (%)	Proposed GHG Heat Rate† (HHV) (Btu/kWh)
GE 7FA.03	10,175	3.3	6.0	11,121
GE 7FA.04	9,904	3.3	6.0	10,826
GE 7FA.05	9,765	3.3	6.0	10,673
SW 5000F	10,482	3.3	6.0	11,456

Note: Btu/kWh = British thermal unit per kilowatt-hour.
HHV = higher heating value.

*Gross heat rate based on base load at International Organization for Standardization (ISO) conditions.
†The design margin and performance margin were applied separately to the design gross heat rate.

Sources: General Electric (GE), 2013.
Siemens Westinghouse (SW), 2013.
Environmental Consulting & Technology, Inc. (ECT), 2013.

(Montana-Dakota Utilities Company is proposing General Electric [GE] 7EA combustion turbines, Pio Pico Energy Center is proposing GE LMS100 aero-derivative combustion turbines, and Sabine Pass Liquefaction is proposing GE LM2500 combustion turbines.)

GPP searched other databases for permit determinations as well as proposed greenhouse gas (GHG) BACT limits contained in recently submitted permit applications. GPP researched the California Energy Commission Website for power plant projects filed since 1996, EPA Regions 4 and 6 Websites, and other sources of proposed GHG BACT limits. Table 2 provides a summary of final, draft, and proposed GHG BACT limits.

The GHG heat rates shown in Table 1 for the four combustion turbine manufacturers and models proposed for GGS are less than the comparable heat rates shown for NRG Texas Power, Cedar Bayou, and S.R. Bertron, which have proposed comparable combustion turbine manufacturers and models.

2. Beginning on page 4-14, Guadalupe has proposed a ton per year emissions and heat rate cap limit. EPA will issue an output-based BACT emissions limit (e.g., lb/MWh) or a combination of an output- and input-based limit, where feasible and appropriate. For the four turbine models under consideration for this project, please propose an output-based or efficiency based limits for each combustion turbine train to be constructed. Please provide an analysis that substantiates any reasons for infeasibility of a numerical emissions limitation. For the emissions sources where numerical emissions limitations are infeasible, please propose an operating work practice standard that can be practically enforceable.

Response

Table 3 provides output-based GHG BACT limits for all four proposed combustion turbine manufacturers and models.

Table 2. Recently Proposed GHG BACT Limits and Permit Determinations for Natural Gas-Fired Simple-Cycle Combustion Turbines

Project	County	State	Turbine Manufacturer and Model	Basis	Heat Rate (Btu/kWh)	GHG BACT limit (lb CO_2e/MWh)
Cheyenne Prairie Generating Station	Cheyenne	WY	GE LM6000PF	Final		1,600 (gross)
El Paso Electric, Montana Power Station	El Paso	TX	GE LMS100	Draft		1,194 (net)
NRG Texas Power, Cedar Bayou 5	Chambers	TX	SW F5 or MHI 501GAC or GE 7FA.05	Proposed	11,500 (net)	
NRG Texas Power, S.R. Bertron 5	Harris	TX	SW F5 or MHI 501GAC or GE 7FA.05	Proposed	11,500 (net)	
Golden Spread Electric Co-op, Antelope Station	Hale	TX	GE 7F 5-Series	Proposed		1,217 (gross) at maximum load; 1,514 (gross) at 50 to 100-percent load
Golden Spread Electric Co-op, Floydada Station	Floyd	TX	GE 7F 5-Series	Proposed		1,217 (gross) at maximum load; 1,514 (gross) at 50 to 100-percent load

Note: Btu/kWh = British thermal unit per kilowatt-hour.
lb CO_2e/MWh = pound of carbon dioxide equivalent per megawatt-hour.

Source: ECT, 2013.

Table 3. Equivalent Output-Based GHG BACT Emissions Limits

Turbine Model	Proposed GHG Heat Rate* (HHV) (Btu/kWh)	Emissions Factors and Global Warming Potential (GWP): Carbon Dioxide Emissions Factor† (kg/MMBtu)	Carbon Dioxide GWP	Methane Emissions Factor† (kg/MMBtu)	Methane GWP	Nitrous Oxide Emissions Factor† (kg/MMBtu)	Nitrous Oxide GWP	Equivalent Output-Based GHG BACT Emissions Limit (lb CO_2e/MWh)
GE 7FA.03	11,121	53.06	1	1.0 E-03	25	1.0 E-04	298	1,302
GE 7FA.04	10,826	53.06	1	1.0 E-03	25	1.0 E-04	298	1,268
GE 7FA.05	10,673	53.06	1	1.0 E-03	25	1.0 E-04	298	1,250
SW 5000F	11,456	53.06	1	1.0 E-03	25	1.0 E-04	298	1,342

Note: Btu/kWh = British thermal unit per kilowatt-hour.
GWP = global warming potential.
HHV = higher heating value.
kg/MMBtu = kilogram per million British thermal units.
lb CO_2e/MWh = pound of carbon dioxide equivalent per megawatt-hour.

*Gross heat rate based on base load at International Organization for Standardization (ISO) conditions.
†EPA proposed emissions factors, Federal Register, Volume 78, No. 63, April 2, 2013.

Sources: EPA, 2013.
ECT, 2013.

3.	***Beginning on page 4-3 of the permit application, the BACT discussion includes an evaluation of a combined cycle combustion turbine for this project. It is stated on page 4-9 that there are some combined cycle combustion turbine power plant designs that propose the use of fast or rapid start combustion turbines. Also on page 4-9 of the permit application, it is stated that the peaker plant must also be able to shut down quickly and be able to restart in response to the electrical demand. How many startups and shutdowns are anticipated for the proposed Guadalupe project? Also, include the rationale for the number of proposed startup and shutdowns. Please specify if these are cold or hot standby startups.***

Response

A maximum of 450 startups and shutdowns (SUSDs) per year have been assumed. This is the maximum anticipated number of SUSDs per year that have been assumed and used in the calculation of other Prevention of Significant Deterioration (PSD) pollutants, such as oxides of nitrogen (NO_x) and carbon monoxide (CO), since emissions rates for these pollutants are higher during SUSD as compared to normal operation. GHG emissions are based solely on heat input or fuel consumption and are not higher during SUSD. It is anticipated that these units will actually startup and shutdown in the range of 250 to 350 times per year. The maximum number of SUSDs has been projected based on the anticipated dispatch of the simple-cycle combustion turbines from the Electric Reliability Council of Texas (ERCOT).

Cold, warm, and hot startups are only associated with the operation of combined-cycle combustion turbines and are based on the amount of turbine downtime between normal operation. This is due to prevent thermal shock damage to the heat recovery steam generators (HRSGs) associated with combined-cycle units. The concept of a hot or cold start is not relevant for the proposed GGS simple-cycle combustion turbines.

4.	***On page 4-5 of permit application, it states that for burner maintenance "there are three basic maintenance levels: combustion inspections, hot gas path inspections, and major overhauls." Please provide supplemental details about each maintenance level such as what it involves, how often, monitoring and recordkeeping requirements.***

Response

Periodic inspections are a vital part of maintaining the efficiency of combustion turbine operation. The three typical types of inspections performed on a combustion turbine are combustion inspection, hot gas path inspection, and major overhauls where the entire combustion turbine is inspected. The combustion inspection consists of a relatively short disassembly shutdown inspection of the fuel nozzles, liners, transition pieces, crossfire tubes and retainers, spark plug assemblies, flame detectors, and combustor flow sleeves. The hot gas path inspection involves the examination of those parts exposed to high temperatures from the hot gases discharged from the combustion process. In addition to the items included in a combustion inspection, the hot gas inspection includes detailed inspection of the combustion turbine nozzles, stationary stator shrouds, and combustion turbine buckets. This inspection also requires that the top half of the combustion turbine shell be removed, as well as any associated piping, etc. The major overhaul involves the inspection of all of the internal rotating and stationary components from the inlet through to the exhaust portion of the combustion turbine.

The frequency of inspections is determined by several factors, including combustion turbine manufacturer and model, fuel(s), base load operating hours, hours at peak load, hours with evaporative cooling, number of SUSDs, number of trips, etc. As an example, typical information from GE on turbine maintenance indicates that a heavy-duty machine, such as an F-class natural gas-fired combustion turbine, might require combustion inspections at approximately 8,000 hours of operation and/or 450 starts. The hot gas path inspections may occur after 24,000 hours and/or 900 starts, and a major overhaul may occur following 48,000 hours of operation and/or 2,400 starts. Inspections may also occur if unusual degradation or change in turbine performance is noticed. Of course detailed records are kept of every inspection or any action taken, such as the replacement of parts. Also, various combustion turbine parameters are constantly monitored, e.g., temperatures, vibration, fuel flow, etc., so that corrective action may be taken if necessary. These are all standard operating procedures and are performed to maintain the turbines at the highest efficiency possible, as well as to avoid any unnecessary maintenance issues.

5. On page 4-6 of the permit application, it states that "F-class combustion turbines have sophisticated instrumentation and controls to automatically control the operation of 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-emissions performance under all operating cases." Please provide more information pertaining to the automation of the combustion turbine operation that will ensure optimal fuel combustion. Please provide supplemental information that discusses details of what operating parameters will be monitored and how will it be used to determine that the turbines are operating at optimal efficiency and fuel combustion is occurring such as temperature, pressure, etc. How will proper air/fuel ratios be assured? What type of analyzers will be utilized? Will these analyzers provide continuous monitoring? Will there be manual overrides and alarms to alert on-site personnel to operating abnormalities? What is the company's proposed monitoring strategy (e.g. CEMs)?

Response

The combustion turbine models being considered for the GGS simple-cycle combustion turbine project are the same in every aspect as those that would be installed for a combined-cycle plant. The combustion turbines are the major component of both simple- and combined-cycle facilities. Combustion turbines at simple-cycle facilities are supplied with the same instrumentation and combustion/emissions controls as an identical combustion turbine at a combined-cycle facility. Although similar in many respects, these systems are specific to each model and manufacturer and are designed by the manufacturer to ensure that their performance guarantees can be met for the service life of the machine. Since the owner/operator does not have any input into the design of these systems, the details of their operation are somewhat irrelevant. However, GPP will ensure that the selected combustion turbine manufacturer and model will be operated in accordance with the manufacturer's recommendations and specifications.

Continuous emissions monitoring systems are not provided by the combustion turbine manufacturer and are dependent on the final PSD permit conditions and must comply with all applicable state and federal regulations.

> ***6. Please provide site-specific facility information to evaluate and eliminate CCS from consideration. This information should contain detailed information on the quantity and concentration of CO_2 that is in the waste stream and the equipment for capture, storage and transportation. Please include cost of construction, operation and maintenance, cost per pound of CO_2 removed by the technologies evaluated and include the feasibility and cost analysis for storage or transportation for these options. Please discuss in detail any site specific safety or environmental impacts associated with such a removal system.***

<u>Response</u>

Quantity and Concentration of Carbon Dioxide in the Waste Stream

Carbon dioxide (CO_2) concentrations in the exhaust gas range from 3.5 to 3.9 percent by volume for all four combustion turbine models and normal operating ranges. The higher CO_2 concentrations are generally at base load operation, which is anticipated to occur most of the time. The total maximum CO_2 emissions rates range from approximately 200 tons per hour for the GE 7FA.03 to 275 tons per hour for the Siemens-Westinghouse (SW) 5000F.

Equipment for Capture, Storage, and Transportation

The main components of a typical postcombustion CO_2 capture system consist of a scrubber and regeneration column. The system uses a chemical absorbent to attach to the CO_2. The CO_2 is driven off when heated in the regeneration column. The absorbent is then reused in the scrubber section. Amines are generally used as the absorbent. The CO_2 stream is dried and compressed, usually in several stages, before introducing it to the pipeline. This type of operation is suited for continual operation, and it is uncertain as to the feasibility or efficiency of carbon capture technology to the intermittent operation typical for a simple-cycle combustion turbine facility.

Currently, the largest number of CO_2 pipelines in the state is concentrated in West Texas. This area is approximately 250 miles from the GGS site. The Green Pipeline from Louisiana to Alvin, Texas, southeast of Houston was constructed to transport CO_2 to the Hastings oil field. Alvin is approximately 175 miles from the GGS site. The cost for constructing a pipeline to tie into either of these systems may be cost prohibitive. It was reported that the Green Pipeline was constructed at an average cost of more than $2,000,000 per mile.

Cost of Construction, Operation and Maintenance, Cost per Pound for CO_2 Removed by Technologies Evaluated

The combined-cycle generating station located in Bellingham, Massachusetts, has been cited as the basis for concluding that carbon capture and sequestration (CCS) is technically feasible for combustion turbine sources. The Bellingham Energy Center is a nominal 300-MW combined-cycle combustion turbine power plant comprised of two SW W501D5 dual fuel (natural gas and distillate fuel oil) combustion turbines, two unfired HRSGs, and one steam turbine. From 1991 through 2005, Fluor Econamine FG^{SM} CO_2 capture technology was used at the Bellingham Energy Center to process a 15-percent slip stream of the combined cycle units exhaust gas to recover 360 tons per day (tpd) of CO_2. The captured CO_2 was not sequestered but instead used for beverage carbonation. The Fluor CO_2 capture technology has not been in use at the Bellingham Energy Center since 2005.

The Bellingham Energy Center CO_2 capture technology is not considered technically feasible for the GGS project, since only a small fraction (i.e., 15 percent) of the Bellingham Energy Center combined-cycle units exhaust gas was processed for CO_2 capture, resulting in a recovery rate of 360 tpd. The estimated daily CO_2 emissions rate for the two GGS simple-cycle units will be at least four to five times that of the Bellingham facility. Assuming 85-percent capture, the Fluor Econamine FG^{SM} CO_2 capture technology equipment would need to be four to five times larger for the GGS units. The technical issues associated with such a large scale-up are unknown. As stated in the Obama Administration's Interagency Task Force on Carbon Capture and Storage August 2010 report:

> "Since the CO_2 capture capacities used in current industrial processes are generally much smaller than the capacity required for GHG emissions mitigation at a typical power plant, there is considerable uncertainty associated with capacities at volumes necessary for commercial deployment."

There has been no full-scale application of CO_2 capture technology to a simple-cycle combustion turbine power plant to date. Fluor's Website regarding worldwide experience of their Econamine FG^{SM} CO_2 capture technology shows one gas turbine exhaust installation: the Bellingham Energy Center project. As noted herein, the CO_2 technology at the Bellingham Energy Center did not include carbon sequestration and is no longer in use. Another major developer of CO_2 capture technology, Alstom, currently states the following on their website:

> "We're continuing our significant R&D efforts in CCS and are validating the technologies at a number of pilot and demonstration projects around the world. We're working closely with our partners towards **full-scale commercialization that will be available on the market around 2015**."

Alstom does not indicate the scale of their future full-scale commercial offerings.

The amine-based systems for capturing CO_2 require that the temperature of the column be maintained at 135 to 140°F for optimal CO_2 solubility. Current carbon capture systems have been designed for combined-cycle and IGCC units. For IGCCs, the process is operated under pressure (500+ pounds per square inch), and the hot syngas from the gasifier is initially cooled through a waste heat boiler and then quenched by direct contact with water to a temperature that the amine scrubber can handle (130 to 150°F). The higher process pressure allows for higher acid gas solubility (Henry's Law) in the amine scrubbing solution while using smaller sized equipment. Combined-cycle units have much lower exhaust temperatures (i.e., approximately 200°F), which is closer to the temperatures required by the CO_2 capture equipment, while simple-cycle units have exhaust temperatures that are typically at 1,000°F and higher. In addition, simple-cycle combustion turbines do not operate under pressure, nor do they have an outside source of heating or cooling to reduce the gas temperature to a level suitable for the CO_2 capture and recovery process. For the proposed GGS units, it would require more than 2,000 gallons per minute for per turbine to quench the hot flue gas from 1,100°F to the 130 to 150°F range. To apply current carbon capture technology to simple-cycle turbines would require an inordinate amount of energy just to cool the large amount of exhaust gas to the proper temperature for the carbon capture equipment to work properly. The energy and equipment costs just to cool the exhaust gas would be impractical, as well as cost-prohibitive.

Based on the lack of commercial availability of a CCS system for a full-scale power plant in conjunction with the challenges of applying this technology to the intermittent operation and high exhaust temperatures of a simple-cycle combustion turbine power plant, GPP considers CCS to be technically infeasible for the GGS Project.

Although full-scale CO_2 capture for a simple-cycle combustion turbine power plant is not yet commercially available, numerous projects have made efforts to estimate the cost of CCS technology using various U.S. Department of Energy (DOE) and EPA procedures, should full-scale carbon capture technology become commercially available in the future. The conclusion from these evaluations is that the cost of applying CCS technology to a combined-cycle power plant is prohibitively expensive and would result in cancellation of the power plant project if required. Excessive costs are projected due to the large volume of exhaust gas associated with combined-cycle power plants, the low concentration of CO_2 in these exhaust gases, and the substantial energy penalty associated with CO_2 absorption, stripping, and compression.

This economic feasibility for a simple-cycle combustion turbine facility would be much worse as due to the intermittent operation of a simple-cycle combustion turbine facility operate intermittently.

The Obama Administration's Interagency Task Force published a report on carbon capture and storage in August 2010. This report cites an estimated annual cost of $103 per ton of CO_2 avoided for the CO_2 capture and compression components of a CCS system for a natural gas-fired combined cycle facility. As previously stated, this cost would be higher for a simple-cycle combustion turbine facility as proposed for GGS. The annual costs for each of the turbine options assuming 85-percent capture of CO_2 and $103 per ton of CO_2 controlled are shown in the following table. The annual costs range from

$44.7 to $59.6 million, which is well above the level that would make the GGS project economically infeasible:

Turbine Model	Maximum Annual Combustion Turbine CO_2 Emissions (tons)	Maximum Annual Captured CO_2* (tpy)	Annual Cost of CCS System ($ per year)
GE 7FA.03	510,878	434,246	$44,727,338
GE 7FA.04	522,210	443,879	$45,719,537
GE 7FA.05	600,880	510,748	$52,607,044
SW 5000F	681,172	578,996	$59,636,588

Note: tpy = ton per year.

*Based on an 85-percent CO_2 capture efficiency.

Feasibility and Cost Analysis for Storage or Transportation for Evaluated Options

The combustion turbines will operate in simple-cycle mode for a maximum of 2,500 hours per year (hr/yr) per turbine. The combustion turbine may start up, operate for several hours during peak periods of demand, then shut down. The proposed simple-cycle combustion turbines can start up in approximately 10 minutes. This type of operation would be inefficient for operation of a CCS system, since it would need to be kept on standby so it could quickly begin to process the exhaust gas stream when the turbines become operational. This will also result in additional energy use to keep the CCS system at operating conditions between periods of turbine operation. There may also be a period needed to stabilize the CO_2 stream to assure sufficient quality before it can be sent to the CCS system, during which time the CO_2 will need to be vented to the atmosphere.

The cost for transportation and storage of the captured CO_2 can be estimated for each of the four proposed combustion turbine models using cost estimated from the Interagency Task Force for Carbon Capture and Storage, as shown in the following table:

Turbine Model	Maximum Annual Combustion Turbine CO_2 Emissions (tons)	Maximum Annual Captured CO_2* (tpy)	Annual Cost of CCS Storage and Transportation System ($ per year)
GE 7FA.03	510,878	434,246	$4,802,761
GE 7FA.04	522,210	443,879	$4,909,302
GE 7FA.05	600,880	510,748	$5,648,873
SW 5000F	681,172	578,996	$6,403,696

Note: tpy = ton per year.

*Based on 85-percent CO_2 capture efficiency.
†Based on $11.06 per ton for transportation and storage from Interagency Task Force on Carbon Capture and Storage, August 2010. Median of ranges for transportation and storage costs was used.

It should also be noted that there is an amount of uncertainty in these costs estimates. The Interagency Task Force Report on Carbon Capture and Storage states:

> "Estimates vary depending on numerous factors, including type of reservoir, existing information/infrastructure for the site, onshore versus offshore storage, extent of monitoring, regional factors, etc. Costs may vary regionally and could affect "dispatching" of geologic storage options, which, in turn, would affect strategies for development of any pipeline networks. Costs may vary over time as earlier operations exploit more certain and lower-cost storage sites."

Site-Specific Safety or Environmental Impacts Associated with the Removal System

CO_2 acts as both a toxic substance and an asphyxiant. High concentrations (e.g., above 3 percent) can have serious physical consequences. Higher concentrations can lead to physical impairment and death. Any routine venting of high concentrations will have to be assessed to ensure that the CO_2 poses no threat to workers or offsite populations. It may be possible to vent most routine releases back through the exhaust stack. This may have adverse affects on the performance of the turbines, and special accommodations may need to be made.

In addition to routine venting of CO_2, accidental releases are a concern. Large amounts of CO_2 can be released from breaks in pipelines or onsite storage tanks. Risk to workers and the surrounding population are of concern. Since CO_2 is heavier than air, it will fall to the ground and may build up to dangerous levels in low-lying areas.

7. Please provide supplemental data to the 5-step BACT analysis for fugitives that include a comprehensive evaluation of the technologies considered to reduce fugitive emissions and a basis for elimination. The technologies could include, but are not limited to, the following:

- ***Installing leakless technology components to eliminate fugitive emissions sources;***
- ***Implementing an alternative monitoring program using a remote sensing technology such as infrared camera monitoring;***
- ***Designing and constructing facilities with high quality components and materials of construction compatible with the process known as the Enhanced LDAR standards;***
- ***Monitoring of flanges for leaks;***
- ***Using a lower leak detection level for components; and***
- ***Implementing an audio/visual/olfactory (AVO) monitoring program for compounds.***

<u>Response</u>

Natural gas will be supplied to the new simple-cycle combustion turbines through a newly installed piping system that contains various connection components, such as valves, flanges, relief valves, etc. These piping components are potential sources of minor natural gas leaks.

Step 1—Identify All Available Control Technologies

The following list contains control options for controlling fugitive emissions from natural gas piping components:

- Implementation of leak detection and repair (LDAR) program involving monitoring systems using handheld monitors.

- Implementation of LDAR using remote sensing equipment.
- Implementation of an audio/visual/olfactory (AVO) leak detection program.

Step 2—Eliminate Technically Infeasible Options

An LDAR program using either handheld or remote sensing is technically feasible for this project. Also, an AVO leak detection program is feasible, since the natural gas will be treated with an odorant.

Step 3—Rank Remaining Control Technologies

In their table of control efficiencies for Texas Commission on Environmental Quality (TCEQ) LDAR programs, AVO is listed as 97-percent effective for gas/vapor for valves, flanges/connectors, and relief valves (APDG 6129v2, revised July 2011). This control efficiency is equal to or higher than any other of the TCEQ LDAR programs.

Step 4—Evaluate Most Effective Controls and Document Results

Because of the low odor threshold of mercaptans in natural gas, AVO inspections are an effective means of detecting natural gas leaks, and an AVO detection program is equivalent to other LDAR programs. In addition, it has been estimated that GHG emissions from the newly installed natural gas piping components will constitute less than 0.01 percent of the total GHG emissions from the proposed simple-cycle combustion turbines.

Step 5—Select BACT

Based on the high efficiency of an AVO leak detection program and the relatively small amount of GHG emissions anticipated from natural gas piping components, an AVO leak detection performed on a regular basis is selected as BACT for fugitive emissions from natural gas piping components for the GGS project.

8. *Please provide emissions point numbers (EPNs) for the fugitive emissions and SF6 circuit breaker and confirm the EPN for the diesel-fuel fire water pump engine to be FWP-2. Please supplement the process flow diagram with a representation of these GHG sources and associated EPNs.*

Response

The emissions point numbers for the sulfur hexafluoride (SF_6) circuit breaker and the new firewater pump engine will be SF6-1 and FWP-3, respectively. In addition, the fugitive natural gas emissions point number will be NG-1. A modified process flow diagram showing the additional emissions point numbers is attached.

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Jun 10, 2013 - 2:48pm by jroberts

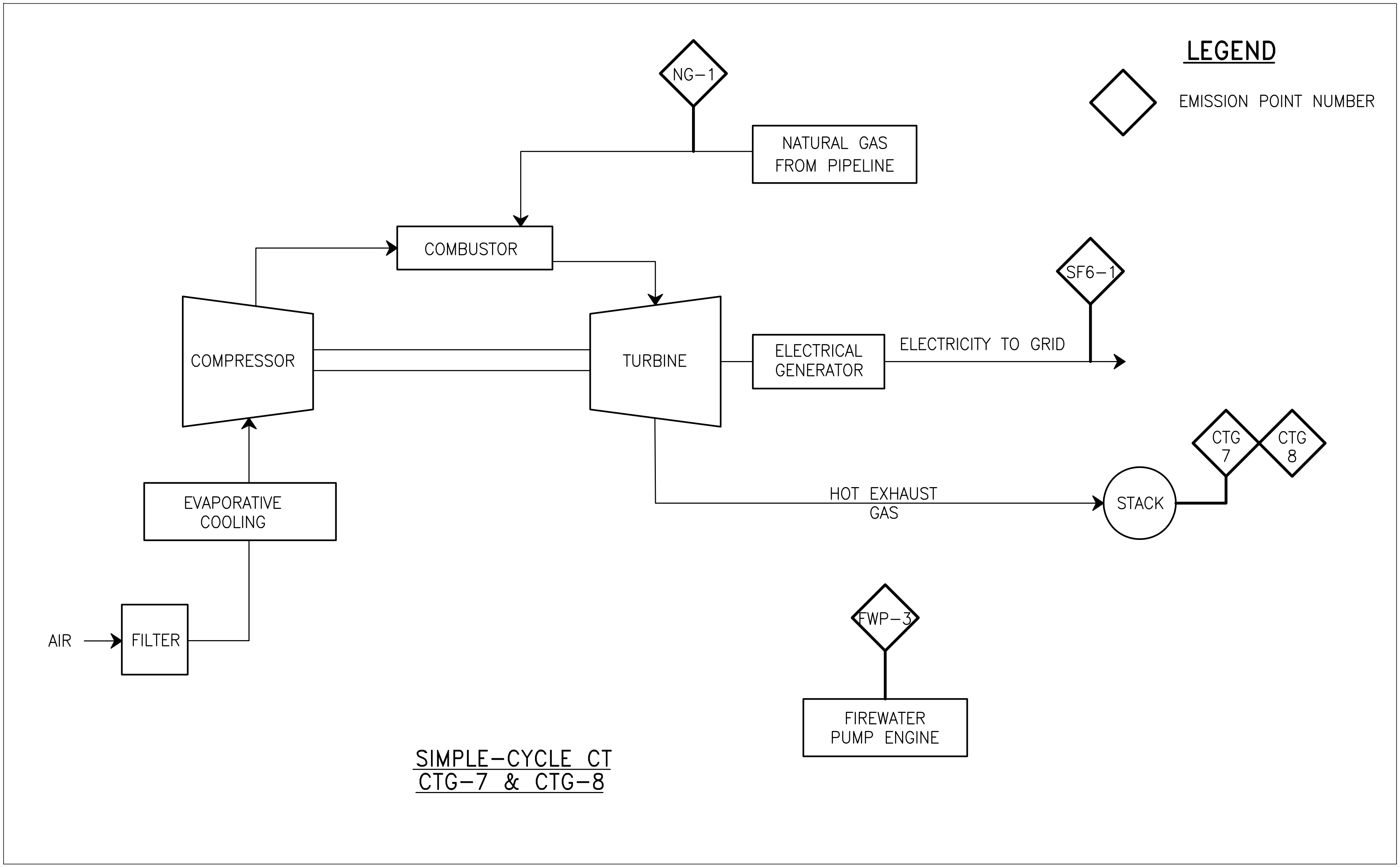

FIGURE 2-3.

SIMPLIFIED PROCESS FLOW DIAGRAM OF A BASIC SIMPLE-CYCLE CT

Source: ECT, 2013.

Environmental Consulting & Technology, Inc.