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JUL 22 2008

July 21, 2008

BUREAU OF AIR REGULATION

Via Federal Express

Jeffery F. Koerner
New Source Review Section
Florida Department of Environmental Protection
Bob Martinez Center
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Re: Request for Additional Information Regarding the Site Expansion – Addition of Two 170 MW Simple Cycle Combustion Turbines – for the Shady Hills Generating Station; Project No. 1010373-007-AC (PSD-FL-402)

Dear Mr. Koerner:

Shady Hills Power Company, LLC (Shady Hills) is in receipt of the Department's June 11, 2008 request for additional information (RAI) related to the May 13, 2008, air construction permit to construct and install two simple cycle GE 7FA combustion turbines at the existing Shady Hills Generating Station. The following responses are provided to the comments in the order in which they were received.

1. Section 2-3 of the Prevention of Significant Deterioration (PSD) report provided with the application identifies the potential emissions of carbon monoxide (CO) for natural gas and distillate oil from the two simple cycle GE 7FA combustion turbines. The report states that CO for natural gas has the potential to emit 9 ppmvd and distillate oil has the potential to emit 20 ppmvd. These emissions are based on a 59°F turbine inlet air condition and a baseload of 2,390 hours/year for natural gas and 1,000 hours/year for distillate oil. Actual CO emissions data for installed units indicate levels of 1-2 ppmvd @ 15% oxygen for gas and oil firing. Please discuss the rationale for the requested higher CO emission rates. Recent PSD permits issued by the Department for the GE 7FA combustion turbines specify CO standards at 4.1 and 8.0 ppmvd @ 15% oxygen for gas and oil firing, respectively. In addition, General Electric offers a guaranteed CO emission rate of 4.1 ppmvd @ 15% oxygen. At these levels, it may be possible for the project to escape PSD review for CO emissions. Please comment.

Response: Shady Hills has re-evaluated the emission levels for carbon monoxide (CO) for the GE 7FA combustion turbines and at this time is requesting permit limits for CO as follows:

- Natural Gas Combustion, 6.5 ppmvd; and
- Distillate Oil Combustion, 13.5 ppmvd.

Based on these concentrations, the maximum annual CO emissions for the Project are 98 tons per year (TPY) assuming an average of 750 hours per year per CT, rather than the 1,000 hours per year per CT initially requested. This annual emission level is below the PSD review threshold for CO of 100 TPY. Updated emission tables are provided in Attachment A.

2. Please describe the evaporative cooling equipment that will be installed on the simple cycle units. What is the expected maximum temperature reduction from the evaporative cooling equipment?

Response: A number of components make up the evaporative cooling system. The main components are briefly described below:

- **Evaporative Media Blocks** – The media blocks are direct contact, irrigated media utilizing cross-fluted cellulose blocks which are impregnated with insoluble anti-rot salts and rigidifying saturants. These blocks are retained in place by facing plates within the cooler section. Air entering the cooler and passing through the water saturated media is cooled through adiabatic exchange of heat.
- **Mist Eliminator Panels** – Mist eliminator blocks are installed directly downstream of the cooler media blocks. These panels protect the turbine from water droplets that may be pulled from the evaporative media blocks. Water separated out of the air stream by the mist eliminator blocks drains forward by gravity into the bottom of the cooler into a sump.
- **Distribution Pads** – Located on top of the media at each water distribution manifold, these pads ensure that the water is evenly distributed across the top of the media.

The evaporative cooler is used where significant operation of the turbine occurs in the warm months and where low relative humidities are common. The cooler air, being denser, gives the machine a higher mass-flow rate and pressure ratio, resulting in an increase in turbine output and efficiency. In addition to achieving extra power, the use of an evaporative cooler increases water vapor in the inlet air, thereby lowering the amount of nitrogen oxides produced in the combustion process.

The evaporative cooler design specifications are as follows (note that these values are design estimates, provided for informational purposes only):

Component/Condition	Setting
Air Flow	772,027 cfm
Evaporative Cooler Air Pressure Drop	0.28 in. w.g.
Drift Eliminator Media Air Pressure Drop	0.03 in. w.g.
Evaporative Cooler Media Velocity (ISO)	538 fpm
Estimated Saturation Efficiency	88 percent

Component/Condition	Setting
Relative Humidity	64%
Entering Conditions	
Dry Bulb Temperature	95 F
Wet Bulb Temperature	84.3 F
Water Conditions	
Evaporation Rate	16 gpm
Maximum Blow Down Rate	16 gpm
Make up water Rate	32 gpm

The temperature reduction is not a design requirement for the cooler. Instead the design specification identifies that the cooler has a saturation efficiency of a minimum of 85 percent. Saturation efficiency is defined as follows:

$$SE\% = [(DBE-DBL)/(DBE-WBE)] \times 100$$

DBE = Dry Bulb Entering Temperature
DBL = Dry Bulb Leaving Temperature
WBE = Wet Bulb Entering Temperature

Accordingly, the maximum temperature decrease really depends on the condition of the incoming air (the wet and dry bulb temperatures) which is basically the humidity of the incoming air.

3. Please provide a discussion of the expected combustion turbine maintenance schedules and compare natural gas and oil.

Response: Combustion maintenance scheduling is based on independent counts of fired starts and fired hours (whichever occurs first). For a peaking plant, as in our case, combustion maintenance scheduling is "starts-based" and fuel type does not change the planned maintenance interval. A base loaded plant will be "hours-based" and fuel type does have an effect. For a base loaded plant, the distillate fuel type has an hours factor of 1.5 compared to 1.0 for gas fuel.

4. See Table B-4 of the application. This table identifies a cost associated with a "selective catalytic reduction bypass duct and stack". Please explain.

Response: Table B-4 has been updated and the bypass duct and stack have been removed. See Attachment B.

5. Were the acid rain forms provided in the application sent to Region 4 of the Environmental Protection Agency (EPA)?

Response: The Acid Rain application forms were only provided initially to the Department, however, the U.S. EPA has since been provided with copies of these application forms.

6. The application requests an average operation of 3,390 hours/year/unit with no single unit operating more than 5,000 hours/year. As requested by EPA Region 4 in the past, please revise the control equipment cost estimates for "5,000" hours/year of operation. In addition, please revise the control equipment estimates for the following items:

- An equipment life of 20 years;
- Zero indirect costs for overhead, property taxes, and insurance (see page 2-48 of EPA's OAQPS manual);
- Exclude the "MW loss and Heat Rate Penalty" cost (the table references EPA, page 6-20, but there is no page 6-20 in EPA's OAQPS cost manual);
- For the oxidation catalyst, assume replacement every 5 years or provide vendor data to support replacement every 3 years for 4,000 hours/year on natural gas or 1,000 hours/year on ultra low sulfur distillate oil; and
- Do not double count catalysts costs (see page 2-33 and 2-46 of EPA's OAQPS cost manual).

Please provide the vendor quote for the selective catalytic reduction (SCR) and oxidation catalyst equipment costs.

Response: The NO_x control cost analysis has been updated and is included as Attachment B. The control costs are based on vendor quotes from 2003 and scaled up to 2008 cost based on ENR's

Construction Cost Index included as Attachment B. The following changes have been made for the cost analysis:

- Equipment life of 20 years and associated Capital Recovery Factor of 9.44%;
- Per OAQPS page 2-48, indirect costs for overhead, property taxes, and insurance have all been set equal to zero;
- MW loss and Heat Rate Penalty is from EPA 1993 Alternative Control Techniques Document--NOx Emissions from Stationary Gas Turbines, Page 6-20. These losses are associated with the addition of SCR and have been included and accepted by the State in previous BACT cost analysis for SCR control of combustion turbines. As such no changes have been made other than clarification of reference to the EPA 1993 Alternative Control Techniques Document--NOx Emissions from Stationary Gas Turbines.
- CO oxidation catalyst costs have not been updated since CO is no longer subject to PSD review per RAI response No. 1; and
- To prevent double counting of SCR catalyst in the cost analysis, the cost of the catalyst has been removed from the capital cost of the system.

In addition to the changes noted above, additional cost analyses are provided assuming that a single CT could operate up to 5,000 hrs/yr. A summary of the resulting cost-effectiveness evaluation is as follows:

Scenario	Cost Effectiveness (\$/ton)
2,640 hr/y gas and 750 hr/yr oil	9,640
4,250 hr/yr gas and 750 hr/yr oil	8,407
5,000 hr/yr gas only	14,050

7. For the facility, the existing combustion turbines have operated at the following maximum rates over the last seven years:

- Less than 1,500 hours/year/combustion turbine total (2002/2003); and
- Less than 325 hours/year/combustion turbine on oil (2002/2003).

Please explain why the proposed peaking units will operate a maximum of:

- 5,000 hours/year/combustion turbine (total);
- 1,000 hours/year/combustion turbine on oil; and
- An average of 3,390 hours/year/combustion turbine.

Response: GE has revised the permit request for oil combustion to an average of 750 hours/year/CT. However, the total maximum requested hours of operation (i.e., gas and oil-firing combined) of an average of 3,390 hours per year per CT is based on anticipated demand and the parameters of the Power Purchase Agreement (PPA). During 2007, Shady Hills experienced a demand of 2,448 total operating hours for CT1, 2,223 total hours for CT2 and 2,502 total hours for CT3. Of these totals, oil firing ranged from ~ 55 to 75 hours annually per CT. The units continue to be dispatched more frequently in 2008 than in previous years, with January through June operating hours totaling 1,414 for CT1, 1,390 for CT2 and 1,413 for CT3. If these actual operating hours were doubled to estimate operating hours for the full 2008 calendar year, it's evident that an upward trend in demand is continuing.

Therefore, regarding the above-requested operating hours, Shady Hills believes an average of 3,390 total operating hours per CT is justified based on past operating history, the anticipated annual growth in energy demand and the obligations under the PPA which require this type of operating flexibility. The request for up to a maximum of 5,000 hours per year of operation for an individual CT, again, is necessary in the event other CTs are not operational or otherwise unavailable. The total operating hours among the two CTs would not increase, however, the maximum hours on an individual CT could. At the Department's request, the response to Comment 6 above provided a revised cost-effectiveness determination based on the ability of an individual CT to operate up to 5,000 hours per year. Finally, as stated above, Shady Hills has revised the requested oil-firing hours to an average of 750 hours per CT, rather than the 1,000 hours per CT initially requested. Shady Hills requires this operational flexibility in order to comply with power demand obligations in the event of a natural gas curtailment. Further, it's anticipated that a certain amount of the oil-firing may entail the use of biofuels, which would be important in attaining any future renewable portfolio standards.

8. Does the facility have a firm contract for the primary fuel of natural gas?

Response: GE will obtain a contract for primary fuel upon development of a Power Purchase Agreement for the project. However, the parameters of the fuel procurement contract will be reflective of the assumptions provided in other associated responses.

9. The application indicates that the facility will become a major source of hazardous air pollutants (HAP) with the additional units. Therefore, the combustion turbines will be subject to the provisions of National Emissions Standards for Hazardous Air Pollutants (NESHAP) Subpart YYYYY. Since this regulation has been stayed, currently the only requirement is to notify the Department that the facility is a major source of HAP and the affected units. Please revise the application pages accordingly.

Response: The application incorrectly indicated that the facility will become a major source of hazardous air pollutants. As indicated on Page 2-5,

“The MACT standard in 40 CFR, Subpart YYYYY is potentially applicable to the Project. However, Shady Hills Generating Station will not be a major source of HAP emissions since emissions are projected to be below 10 tons per year (TPY) of a single HAP and less than 25 TPY for all HAPs. “

10. A Level 2 VISCREEN analysis was performed which showed potential impacts over the threshold screening level outside the Chassahowitzka PSD Class I area. In addition, the 4.4 m/s wind speed associated with this analysis seemed high. A lower wind speed may result in impacts over the threshold level inside the Class I area. Please provide further detailed justification for this value in order to evaluate whether a PLUVUE analysis should be required.

Response: The Stability Array (STAR) program that was used to compute the wind speed and stability class frequencies was modified. The original STAR wind speed frequencies of 0-3, 4-6, 7-10, 11-16, 17-21 and GT 21 knots were replaced with the following wind speed categories: 0-2, 3-4, 5-6, 7-8, 9-10 and GT10 knots. The first 5 wind speed categories equate closely to 0-1, 1-2, 2-3, 3-4, and 4-5 m/s. The revised STAR frequencies for the south-southeast (SSE), south (S) and the average of the two wind direction sectors is summarized in Table 7-4 Rev. Based on the revised combined wind direction (WD) sector wind speed frequencies, the realistic meteorological condition for VISCREEN Level 2 was D stability and 4.0 m/s. VISCREEN modeling output for natural gas and oil firing are summarized in Figures 7-19 rev and 7-20 rev. The air modeling results vary slightly from the results in the original application which were based on D stability and a wind speed of 4.4 m/s.

Supplement Information: Individual WD Sector Analyses:

The original Level 2 analysis was based on the average wind frequencies from combining both the SSE and S wind direction sectors and assumed a fixed nearest receptors distance of 28 km. These two assumptions produced very conservative plume impacts. Figure 1 shows that over 95 percent of Chassahowitka NWA lies within the SSE sector. The small section that lies within the S wind direction sector is at a minimum distance from the Shady Hills plant of 35 km and a maximum distance of 36 km from the plant. For the SSE wind direction, the actual wind frequencies are so low that the cumulative frequency never reaches 1.0 (see Table 7-4 rev) through the last listed condition of D stability and 5 m/s. As such, D stability and 6 m/s wind speed were assumed as the realistic Level 2 meteorological conditions for the SSE wind direction sector. Similarly, from Table 7-4 rev, D stability and 3 m/s wind speed were assumed as the realistic Level 2 meteorological conditions for the S wind direction sector.

The results for natural gas and fuel oil-firing for the SSE wind direction sector are shown in Figures 7-21 and 7-22, respectively. The results for natural gas and fuel oil-firing for the S wind direction sector are shown in Figures 7-23 and 7-24, respectively. The revised tables and figures referred to in this response are included as Attachment C.

As these responses are providing additional information of an engineering nature, a State of Florida professional engineering certification has also been provided, in accordance with Rule 62-4.050(3), F.A.C. In addition, the appropriate Responsible Official certification page has been signed and included in this submittal.


Should you have any question regarding these responses or need additional information, please contact the undersigned at (813) 287-1717 or Roy Belden at 203-357-6820.

Sincerely,

GOLDER ASSOCIATES INC.



David Larocca
Senior Project Engineer



Scott Osbourn, P.E.
Senior Consultant

Attachments

cc: Mara Nasca, Southwest District Office (Mara.Nasca@dep.state.fl.us)
Roy S. Belden, GE Energy Financial Services
William Stevens, GE Energy Financial Services
Rick Waggoner, Compliance Opportunities Group

ATTACHMENT A

UPDATED FDEP APPLICATION FORMS

UPDATED PSD APPLICATION EMISSION CALCULATIONS

EMISSIONS UNIT INFORMATION

Section [1] of [3]
Simple-Cycle Combustion Turbine

D. SEGMENT (PROCESS/FUEL) INFORMATION

Segment Description and Rate: Segment 1 of 2

1. Segment Description (Process/Fuel Type): Internal Combustion Engines; Electric Generation; Natural-Gas Firing		
2. Source Classification Code (SCC): 2-01-002-01		3. SCC Units: Million cubic feet natural gas burned
4. Maximum Hourly Rate: 1.74	5. Maximum Annual Rate: 5,897.8	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit: 933
10. Segment Comment: Based on natural gas lower heating value (LHV) of 933 Btu/ft³. Maximum hourly rate = 1,623 MMBtu/hr /933 MMBtu/MM ft³ = 1.739 MM ft³/CT/hr Maximum annual rate = 1.739 MM ft³/hr x 3,390 hr/yr = 5,897.8 MM ft³/CT/yr		

Segment Description and Rate: Segment 2 of 2

1. Segment Description (Process/Fuel Type): Internal Combustion Engines; Electric Generation; Distillate Oil Firing		
2. Source Classification Code (SCC): 2-01-001-01		3. SCC Units: 1,000 Gallons burned
4. Maximum Hourly Rate: 13.9	5. Maximum Annual Rate: 13,863.610,397.7	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur: 0.0015	8. Maximum % Ash:	9. Million Btu per SCC Unit: 132
10. Segment Comment: Based on distillate oil LHV of 132 MMBtu/1,000 gal Maximum hourly rate = 1,830 MMBtu/hr /132 MMBtu/1,000 gal = 13,863.6 gal/CT/hr Maximum annual rate = 13,863 gallons/hr x 750 hr/yr = 10,397,250 gallons/yr. Maximum annual rate = 13,863.6 gal/hr x 1,000 hr/yr = 13,863,600 gal/CT/yr		

EMISSIONS UNIT INFORMATION

Section [1] of [3]
Simple-Cycle Combustion Turbine

POLLUTANT DETAIL INFORMATION

Page [1] of [6]
Total Particulate Matter - PM

**F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION –
POTENTIAL/ESTIMATED FUGITIVE EMISSIONS**

(Optional for unregulated emissions units.)

Complete a Subsection F1 for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V operation permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

Potential, Estimated Fugitive and Baseline & Projected Actual Emissions

1. Pollutant Emitted: PM		2. Total Percent Efficiency of Control:	
3. Potential Emissions: 17.0 lb/hour 19.318.3 tons/year		4. Synthetically Limited? <input checked="" type="checkbox"/> Yes <input type="checkbox"/> No	
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year			
6. Emission Factor: 17.0 lb/hr Reference: Vendor Data		7. Emissions Method Code: 0	
8.a. Baseline Actual Emissions (if required): tons/year		8.b. Baseline 24-month Period: From: To:	
9.a. Projected Actual Emissions (if required): tons/year		9.b. Projected Monitoring Period: <input type="checkbox"/> 5 years <input type="checkbox"/> 10 years	
10. Calculation of Emissions: <u>Annual emissions based on 750 hrs/yr of distillate oil firing and 2,640 hrs/yr of natural gas firing. Annual emissions based on 1,000 hr/yr of distillate oil firing and 2,390 hr/yr of natural gas firing.</u> <u>Annual emissions = (17.0 lb/hr x 750 hrs/yr + 9 lb/hr x 2,640 hrs/yr) x ton/2,000 lb = 18.255</u> <u>TPY Annual emissions = (17.0 lb/hr x 1,000 hr/yr + 9 lb/hr x 2,390 hr/yr) x ton/2,000 lb = 19.255</u> <u>TPY/CT</u>			
11. Potential, Fugitive, and Actual Emissions Comment: Hourly emissions based on distillate oil firing.			

EMISSIONS UNIT INFORMATION

Section [1] of [3]
Simple-Cycle Combustion Turbine

POLLUTANT DETAIL INFORMATION

Page [1] of [6]
Total Particulate Matter - PM

**F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION -
ALLOWABLE EMISSIONS**

Complete Subsection F2 if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions 1 of 2

1. Basis for Allowable Emissions Code: OTHER	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: 9.0 lb/hr	4. Equivalent Allowable Emissions: 9.0 lb/hour 15.3 tons/year
5. Method of Compliance: VE Test using EPA Method 9	
6. Allowable Emissions Comment (Description of Operating Method): Allowable emissions based on natural gas firing.	

Allowable Emissions Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: OTHER	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: 17.0 lb/hr	4. Equivalent Allowable Emissions: 17.0 lb/hour 8.5-6.4 tons/year
5. Method of Compliance: VE Test using EPA Method 9	
6. Allowable Emissions Comment (Description of Operating Method): Allowable emissions based on distillate oil firing.	

Allowable Emissions Allowable Emissions ____ of ____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

EMISSIONS UNIT INFORMATION

POLLUTANT DETAIL INFORMATION

Section [1] of [3]
Simple-Cycle Combustion Turbine

Page [2] of [6]
Particulate Matter - PM₁₀

**F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION –
POTENTIAL/ESTIMATED FUGITIVE EMISSIONS**

(Optional for unregulated emissions units.)

Complete a Subsection F1 for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V operation permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

Potential, Estimated Fugitive and Baseline & Projected Actual Emissions

1. Pollutant Emitted: PM₁₀		2. Total Percent Efficiency of Control:	
3. Potential Emissions: 17.0 lb/hour 19.318.3 tons/year		4. Synthetically Limited? <input checked="" type="checkbox"/> Yes <input type="checkbox"/> No	
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year			
6. Emission Factor: 17.0 lb/hr Reference: Vendor Data		7. Emissions Method Code: 0	
8.a. Baseline Actual Emissions (if required): tons/year		8.b. Baseline 24-month Period: From: To:	
9.a. Projected Actual Emissions (if required): tons/year		9.b. Projected Monitoring Period: <input type="checkbox"/> 5 years <input type="checkbox"/> 10 years	
10. Calculation of Emissions: <u>Annual emissions based on 750 hrs/yr of distillate oil firing and 2,640 hrs/yr of natural gas firing.</u> <u>Annual emissions = (17.0 lb/hr x 750 hrs/yr + 9 lb/hr x 2,640 hrs/yr) x ton/2,000 lb = 18.255 TPY/CT</u> <u>Annual emissions based on 1,000 hr/yr of distillate oil firing and 2,390 hr/yr of natural gas firing.</u> <u>Annual emissions = (17.0 lb/hr x 1,000 hr/yr + 9 lb/hr x 2,390 hr/yr) x ton/2,000 lb = 19.255</u>			
11. Potential, Fugitive, and Actual Emissions Comment: Hourly emissions based on distillate oil firing.			

EMISSIONS UNIT INFORMATION

POLLUTANT DETAIL INFORMATION

Section [1] of [3]
Simple-Cycle Combustion Turbine

Page [2] of [6]
Particulate Matter - PM₁₀

**F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION -
ALLOWABLE EMISSIONS**

Complete Subsection F2 if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions 1 of 2

1. Basis for Allowable Emissions Code: OTHER	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: 9.0 lb/hr	4. Equivalent Allowable Emissions: 9.0 lb/hour 15.3 tons/year
5. Method of Compliance: VE Test using EPA Method 9	
6. Allowable Emissions Comment (Description of Operating Method): Allowable emissions based on natural gas firing.	

Allowable Emissions Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: OTHER	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: 17.0 lb/hr	4. Equivalent Allowable Emissions: 17.0 lb/hour 8.5 6.4 tons/year
5. Method of Compliance: VE Test using EPA Method 9	
6. Allowable Emissions Comment (Description of Operating Method): Allowable emissions based on distillate oil firing.	

Allowable Emissions Allowable Emissions ____ of ____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

EMISSIONS UNIT INFORMATION

POLLUTANT DETAIL INFORMATION

Section [1] of [3]
Simple-Cycle Combustion Turbine

Page [3] of [6]
Carbon Monoxide - CO

**F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION –
POTENTIAL/ESTIMATED FUGITIVE EMISSIONS**

(Optional for unregulated emissions units.)

Complete a Subsection F1 for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V operation permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

Potential, Estimated Fugitive and Baseline & Projected Actual Emissions

1. Pollutant Emitted: CO		2. Total Percent Efficiency of Control:	
3. Potential Emissions: 66,244.7 lb/hour 68,645.1 tons/year		4. Synthetically Limited? <input checked="" type="checkbox"/> Yes <input type="checkbox"/> No	
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year			
6. Emission Factor: 20-13.5 ppmvd Reference: Vendor Data		7. Emissions Method Code: 0	
8.a. Baseline Actual Emissions (if required): tons/year		8.b. Baseline 24-month Period: From: To:	
9.a. Projected Actual Emissions (if required): tons/year		9.b. Projected Monitoring Period: <input type="checkbox"/> 5 years <input type="checkbox"/> 10 years	
10. Calculation of Emissions: Annual emissions based on 750 hrs/yr of distillate oil firing and 2,640 hrs/yr of natural gas firing. Annual emissions based on 1,000 hr/yr of distillate oil firing and 2,390 hr/yr of natural gas firing. Annual emissions = (44.7 lb/hr x 750 hrs/yr + 21.5 lb/hr x 2,640 hrs/yr) x ton/2,000 lb = 45.1 TPY Annual emissions = (66.2 lb/hr x 1,000 hr/yr + 29.7 lb/hr x 2,390 hr/yr) x ton/2,000 lb = 68.59 TPY/CT			
11. Potential, Fugitive, and Actual Emissions Comment: Hourly emissions and ppm concentration based on distillate oil firing.			

EMISSIONS UNIT INFORMATION

Section [1] of [3]
Simple-Cycle Combustion Turbine

POLLUTANT DETAIL INFORMATION

Page [3] of [6]
Carbon Monoxide - CO

**F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION -
ALLOWABLE EMISSIONS**

Complete Subsection F2 if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions 1 of 2

1. Basis for Allowable Emissions Code: OTHER	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: 9-6.5 ppmvd	4. Equivalent Allowable Emissions: 29-721.5 lb/hour 50-336.4 tons/year
5. Method of Compliance: Annual testing using using EPA Method 10.	
6. Allowable Emissions Comment (Description of Operating Method): Allowable emissions based on natural gas firing.	

Allowable Emissions Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: OTHER	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: 13.5 ppmvd20-ppmvd	4. Equivalent Allowable Emissions: 66.2-44.7 lb/hour 33-416.8 tons/year
5. Method of Compliance: Annual testing using using EPA Method 10.	
6. Allowable Emissions Comment (Description of Operating Method): Allowable emissions based on distillate oil firing.	

Allowable Emissions Allowable Emissions ____ of ____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	

**F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION –
POTENTIAL/ESTIMATED FUGITIVE EMISSIONS**

(Optional for unregulated emissions units.)

Complete a Subsection F1 for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V operation permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

Potential, Estimated Fugitive and Baseline & Projected Actual Emissions

1. Pollutant Emitted: VOC		2. Total Percent Efficiency of Control:	
3. Potential Emissions: 7.5 lb/hour 7.346.8 tons/year		4. Synthetically Limited? <input checked="" type="checkbox"/> Yes <input type="checkbox"/> No	
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year			
6. Emission Factor: 4 ppmvd Reference: Vendor Data		7. Emissions Method Code: 0	
8.a. Baseline Actual Emissions (if required): tons/year		8.b. Baseline 24-month Period: From: To:	
9.a. Projected Actual Emissions (if required): tons/year		9.b. Projected Monitoring Period: <input type="checkbox"/> 5 years <input type="checkbox"/> 10 years	
10. Calculation of Emissions: <u>Annual emissions based on 750 hrs/yr of distillate oil firing and 2,640 hrs/yr of natural gas firing. Annual emissions based on 1,000 hr/yr of distillate oil firing and 2,390 hr/yr of natural gas firing.</u> <u>Annual emissions = (7.5 lb/hr x 750 hrs/yr + 3.0 lb/hr x 2,640 hrs/yr) x ton/2,000 lb = 6.77</u> <u>TPY Annual emissions = (7.5 lb/hr x 1,000 hr/yr + 3.0 lb/hr x 2,390 hr/yr) x ton/2,000 lb = 7.34</u> <u>TPY/CT</u>			
11. Potential, Fugitive, and Actual Emissions Comment: Hourly emissions based on distillate oil firing.			

EMISSIONS UNIT INFORMATION

Section [1] of [3]
Simple-Cycle Combustion Turbine

POLLUTANT DETAIL INFORMATION

Page [4] of [6]
Volatile Organic Compounds - VOC

**F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION -
ALLOWABLE EMISSIONS**

Complete Subsection F2 if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions 1 of 2

1. Basis for Allowable Emissions Code: OTHER	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: 1.6 ppmvd	4. Equivalent Allowable Emissions: 3.0 lb/hour 5.1 tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method): Allowable emissions based on natural gas firing.	

Allowable Emissions Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: OTHER	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: 4.0 ppmvd	4. Equivalent Allowable Emissions: 7.5 lb/hour 3.752.8 tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method): Allowable emissions based on distillate oil firing.	

Allowable Emissions Allowable Emissions ____ of ____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

**F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION –
POTENTIAL/ESTIMATED FUGITIVE EMISSIONS**

(Optional for unregulated emissions units.)

Complete a Subsection F1 for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V operation permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

Potential, Estimated Fugitive and Baseline & Projected Actual Emissions

1. Pollutant Emitted: SO₂		2. Total Percent Efficiency of Control:	
3. Potential Emissions: 3.01 lb/hour 13.314.9 tons/year		4. Synthetically Limited? <input checked="" type="checkbox"/> Yes <input type="checkbox"/> No	
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year			
6. Emission Factor: 0.0015 % S Reference: Vendor Data		7. Emissions Method Code: 0	
8.a. Baseline Actual Emissions (if required): tons/year		8.b. Baseline 24-month Period: From: To:	
9.a. Projected Actual Emissions (if required): tons/year		9.b. Projected Monitoring Period: <input type="checkbox"/> 5 years <input type="checkbox"/> 10 years	
10. Calculation of Emissions: <u>Annual emissions based on 750 hrs/yr of distillate oil firing and 2,640 hrs/yr of natural gas firing. Annual emissions based on 1,000 hr/yr of distillate oil firing and 2,390 hr/yr of natural gas firing.</u> <u>Annual emissions = (3.1 lb/hr x 750 hrs/yr + 10.4 lb/hr x 2,640 hrs/yr) x ton/2,000 lb = 14.89 TPY</u> <u>Annual emissions = (3.0 lb/hr x 1,000 hr/yr + 9.9 lb/hr x 2,390 hr/yr) x ton/2,000 lb = 13.3 TPY/CT</u>			
11. Potential, Fugitive, and Actual Emissions Comment: Hourly emissions based on distillate oil firing.			

EMISSIONS UNIT INFORMATION

Section [1] of [3]
Simple-Cycle Combustion Turbine

POLLUTANT DETAIL INFORMATION

Page [5] of [6]
Sulfur Dioxide – SO₂

**F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION -
ALLOWABLE EMISSIONS**

Complete Subsection F2 if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions 1 of 2

1. Basis for Allowable Emissions Code: OTHER	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: 2 grains/ 100 cf	4. Equivalent Allowable Emissions: 9.910.4 lb/hour 46.817.6 tons/year
5. Method of Compliance: Use of pipeline natural gas (sulfur content 2grains/100 ft^3).	
6. Allowable Emissions Comment (Description of Operating Method): Allowable emissions based on natural gas firing.	

Allowable Emissions Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: OTHER	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: 0.0015 % S	4. Equivalent Allowable Emissions: 3.01 lb/hour 1.52 tons/year
5. Method of Compliance: Use of distillate oil with a maximum of 0.0015 percent sulfur. Fuel sampling.	
6. Allowable Emissions Comment (Description of Operating Method): Allowable emissions based on distillate oil firing.	

Allowable Emissions Allowable Emissions ____ of ____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

**F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION –
POTENTIAL/ESTIMATED FUGITIVE EMISSIONS**

(Optional for unregulated emissions units.)

Complete a Subsection F1 for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V operation permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

Potential, Estimated Fugitive and Baseline & Projected Actual Emissions

1. Pollutant Emitted: NO_x		2. Total Percent Efficiency of Control:	
3. Potential Emissions: 323 lb/hour 232-199 tons/year		4. Synthetically Limited? <input checked="" type="checkbox"/> Yes <input type="checkbox"/> No	
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year			
6. Emission Factor: 42 ppmvd at 15 percent O₂ Reference: Vendor Data		7. Emissions Method Code: 0	
8.a. Baseline Actual Emissions (if required): tons/year		8.b. Baseline 24-month Period: From: To:	
9.a. Projected Actual Emissions (if required): tons/year		9.b. Projected Monitoring Period: <input type="checkbox"/> 5 years <input type="checkbox"/> 10 years	
10. Calculation of Emissions: <u>Annual emissions based on 750 hrs/yr of distillate oil firing and 2,640 hrs/yr of natural gas firing. Annual emissions based on 1,000 hr/yr of distillate oil firing and 2,390 hr/yr of natural gas firing.</u> <u>Annual emissions = (323.0 lb/hr x 750 hrs/yr + 59 lb/hr x 2,640 hrs/yr) x ton/2,000 lb = 199.0 TPY</u> <u>Annual emissions = (323.0 lb/hr x 1,000 hr/yr + 59 lb/hr x 2,390 hr/yr) x ton/2,000 lb = 232.005 TPY/CT</u>			
11. Potential, Fugitive, and Actual Emissions Comment: Hourly emissions based on distillate oil firing.			

**F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION -
ALLOWABLE EMISSIONS**

Complete Subsection F2 if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions 1 of 2

1. Basis for Allowable Emissions Code: OTHER	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: 9 ppmvd at 15 percent O₂.	4. Equivalent Allowable Emissions: 59 lb/hour 100 tons/year
5. Method of Compliance: CEM Data (24-hour block average)	
6. Allowable Emissions Comment (Description of Operating Method): Allowable emissions based on natural gas firing.	

Allowable Emissions Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: OTHER	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: 42 ppmvd at 15 percent O₂.	4. Equivalent Allowable Emissions: 323 lb/hour 161.5121.1 tons/year
5. Method of Compliance: CEM Data (3-hour average)	
6. Allowable Emissions Comment (Description of Operating Method): Allowable emissions based on distillate oil firing.	

Allowable Emissions Allowable Emissions of

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

TABLE A-1
DESIGN INFORMATION AND STACK PARAMETERS FOR THE SHADY HILLS ENERGY CENTER PROJECT
GE7FA, NATURAL GAS, BASE LOAD

Parameter	CT Only		
	Turbine Inlet Temperature		
	20 °F Case 1	59 °F Case 2	95 °F Case 3
<u>Combustion Turbine Performance</u>			
Net power output (MW)	201.803	181.599	161.722
Net heat rate (Btu/kWh, LHV)	9,080	9,385	9,596
(Btu/kWh, HHV)	10,078	10,418	10,652
Heat Input (MMBtu/hr, LHV)	1,832.3	1,704.4	1,551.9
(MMBtu/hr, HHV)	2,033.8	1,891.9	1,722.6
Relative Humidity (%)	80	60	64
Fuel heating value (Btu/lb, LHV)	20,825	20,825	20,825
(Btu/lb, HHV)	23,116	23,116	23,116
(HHV/LHV)	1.110	1.110	1.110
<u>CT Exhaust Flow</u>			
Mass Flow (lb/hr)- provided	3,929,264	3,650,916	3,333,093
- provided	NA	NA	NA
Temperature (°F) - provided	1,074	1,113	1,154
Moisture (% Vol.)	7.55	8.37	9.88
Oxygen (% Vol.)	12.75	12.57	12.34
Molecular Weight	28.48	28.38	28.22
<u>Fuel Usage</u>			
Fuel usage (lb/hr) = Heat Input (MMBtu/hr) x 1,000,000 Btu/MMBtu (Fuel Heat Content, Btu/lb (LHV))			
Heat input (MMBtu/hr, LHV)	1,832.3	1,704.4	1,551.9
Heat content (Btu/lb, LHV)	20,825	20,825	20,825
Fuel usage (lb/hr)- calculated	87,985	81,843	74,520
Heat content (Btu/cf, LHV)- assumed	933	933	933
	0.0448	0.0448	0.0448
Fuel usage (cf/hr)- calculated	1,963,009	1,825,979	1,662,601
<u>Stack</u>			
Stack Height (ft)	75	75	75
Stack Diameter (ft)	18	18	18
<u>Stack Flow Conditions</u>			
Velocity (ft/sec) = Volume flow (acfm) / [((diameter) ² / 4) x 3.14159] / 60 sec/min			
Mass flow (lb/hr)	3,929,264	3,650,916	3,333,093
	1,074	1,113	1,154
Molecular weight	28.48	28.38	28.22
Volume flow (acfm)	2,575,419	2,462,317	2,320,037
Diameter (ft)	18	18	18
Velocity (ft/sec)- calculated	168.7	161.3	152.0

Source: GE, 2007- CT Performance Data; Goler, 2008

**TABLE A-2
MAXIMUM EMISSIONS FOR CRITERIA POLLUTANTS FOR THE SHADY HILLS ENERGY CENTER PROJECT
GE7FA, NATURAL GAS, BASE LOAD**

Parameter	CT Only		
	Turbine Inlet Temperature		
	20 °F	59 °F	95 °F
	Case 1	Case 2	Case 3
<u>Particulate Matter (Front-half only)</u>			
Particulate from CT- provided	9.0	9.0	9.0
<u>Sulfur Dioxide</u>			
Fuel use (cf/hr)	1,963,009	1,825,979	1,662,601
Sulfur content (grains/ 100 cf)	2	2	2
	2	2	2
CT emission rate (lb/hr) - calculated	11.2	10.4	9.5
<u>Nitrogen Oxides</u>			
<i>NOx (lb/hr) = NOx (ppm actual) x Volume flow (acfm) x</i>			
Basis, ppmvd - calculated	10.8	11.0	11.0
	9	9	9
Moisture (%)	7.55	8.37	9.88
Oxygen (%)	12.75	12.57	12.34
Oxygen (%) dry	13.79	13.72	13.69
Turbine Flow (acfm)	2,575,419	2,462,317	2,320,037
Turbine Flow (acfm, dry)	2,380,975	2,256,221	2,090,818
Turbine Exhaust Temperature (°F)	1,074	1,113	1,154
CT emission rate (lb/hr) - calculated	63.6	59.4	53.8
CT Emission rate (lb/hr) - provided	63.0	59.0	53.0
<u>Carbon Monoxide</u>			
<i>CO (lb/hr) = CO (ppm actual) x Volume flow (acfm) x</i>			
Basis, ppmvd - provided	6.5	6.5	6.5
Basis, ppmvd @ 15% O2 - calculated	5.4	5.3	5.3
Moisture (%)	7.55	8.37	9.88
Oxygen (%)	12.75	12.57	12.34
Oxygen (%) dry	13.79	13.72	13.69
Turbine Flow (acfm)	2,575,419	2,462,317	2,320,037
Turbine Flow (acfm, dry)	2,380,975	2,256,221	2,090,818
Turbine Exhaust Temperature (°F)	1,074	1,113	1,154
CT emission rate (lb/hr) - calculated	23.2	21.5	19.4
CT Emission rate (lb/hr) - provided	32.0	29.0	26.0

**TABLE A-2
MAXIMUM EMISSIONS FOR CRITERIA POLLUTANTS FOR THE SHADY HILLS ENERGY CENTER PROJECT
GE7FA, NATURAL GAS, BASE LOAD**

Parameter	CT Only		
	Turbine Inlet Temperature		
	20 °F	59 °F	95 °F
	Case 1	Case 2	Case 3
<u>Volatile Organic Compounds</u>			
<i>VOC (lb/hr) = VOC (ppm actual) x Volume flow (acfm) x</i>			
Basis, ppmvd - provided	1.6	1.6	1.6
Basis, ppmvd @ 15% O2 - calculated	1.3	1.3	1.3
Moisture (%)	7.55	8.37	9.88
Oxygen (%) wet	12.75	12.57	12.34
Oxygen (%) dry	13.79	13.72	13.69
Turbine Flow (acfm)	2,575,419	2,462,317	2,320,037
Turbine Flow (acfm, dry)	2,380,975	2,256,221	2,090,818
Turbine Exhaust Temperature (°F)	1,074	1,113	1,154
CT emission rate (lb/hr) - calculated	3.26	3.02	2.72
CT Emission rate (lb/hr) - provided	3.00	2.80	2.60
<u>Sulfuric Acid Mist</u>			
<i>Total Sulfuric Acid Mist (SAM) (lb/hr) = SAM Formed in the CT</i>			
	11.2	10.4	9.5
	10	10	10
Stack emission rate (lb/hr)- calculated	1.72	1.60	1.45
- provided	NA	NA	NA
<u>Lead</u>			
Emission Rate Basis	NA	NA	NA
Emission rate (lb/hr)	NA	NA	NA

Source: GE, 2007- CT Performance Data; Goler, 2008

TABLE A-3
DESIGN INFORMATION AND STACK PARAMETERS FOR THE SHADY HILLS ENERGY CENTER PROJECT
GE7FA, NATURAL GAS, 75% LOAD

Parameter	CT Only		
	Turbine Inlet Temperature		
	20 °F Case 4	59 °F Case 5	95 °F Case 6
<u>Combustion Turbine Performance</u>			
Net power output (MW)	151.348	138.128	121.310
Net heat rate (Btu/kWh, LHV)	9,942	10,067	10,589
(Btu/kWh, HHV)	11,036	11,175	11,753
Heat Input (MMBtu/hr, LHV)	1,504.7	1,390.6	1,284.5
(MMBtu/hr, HHV)	1,670.2	1,543.5	1,425.8
Relative Humidity (%)	80	60	64
Fuel heating value (Btu/lb, LHV)	20,825	20,825	20,825
(Btu/lb, HHV)	23,116	23,116	23,116
(HHV/LHV)	1.110	1.110	1.110
<u>CT Exhaust Flow</u>			
Mass flow (lb/hr)- provided	2,956,564	2,941,381	2,762,226
- provided	NA	NA	NA
Temperature (°F) - provided	1,200	1,159	1,190
Moisture (% Vol.)	8.13	8.26	9.80
Oxygen (% Vol.)	12.11	12.60	12.43
Molecular Weight	28.44	28.41	28.22
<u>Fuel Usage</u>			
Fuel usage (lb/hr) = Heat Input (MMBtu/hr) x 1,000,000 Btu/MMBtu (Fuel Heat Content, Btu/lb (LHV))			
Heat input (MMBtu/hr, LHV)	1,505	1,391	1,285
Heat content (Btu/lb, LHV)	20,825	20,825	20,825
Fuel usage (lb/hr)- calculated	72,254	66,774	61,681
Heat content (Btu/cf, LHV)- assumed	933	933	933
	0.0448	0.0448	0.0448
Fuel usage (cf/hr)- calculated	1,612,040	1,489,784	1,376,156
<u>Stack</u>			
Stack Height (ft)	75	75	75
Stack Diameter (ft)	18	18	18
<u>Stack Flow Conditions</u>			
Velocity (ft/sec) = Volume flow (acfm) / [((diameter) ² / 4) x 3.14159] / 60 sec/min			
Mass flow (lb/hr)	2,956,564	2,941,381	2,762,226
	1,200	1,159	1,190
Molecular weight	28.44	28.41	28.22
Volume flow (acfm)	2,100,040	2,040,226	1,965,203
Diameter (ft)	18	18	18
Velocity (ft/sec)- calculated	137.5	133.6	128.7

Source: GE, 2007- CT Performance Data; Goler, 2008

**TABLE A-4
MAXIMUM EMISSIONS FOR CRITERIA POLLUTANTS FOR THE SHADY HILLS ENERGY CENTER PROJECT
GE7FA, NATURAL GAS, 75% LOAD**

Parameter	Turbine Inlet Temperature		
	20 °F Case 4	59 °F Case 5	95 °F Case 6
<u>Particulate Matter (Front-half only)</u>			
Particulate from CT- provided	9.0	9.0	9.0
<u>Sulfur Dioxide</u>			
Fuel use (cf/hr)	1,612,040	1,489,784	1,376,156
Sulfur content (grains/ 100 cf)	2	2	2
CT Stack emission rate (lb/hr)- calculated	9.2	8.5	7.9
<u>Nitrogen Oxides</u>			
<i>NOx (lb/hr) = NOx (ppm actual) x Volume flow (acfm) x</i>			
Basis, ppmvd - calculated	11.8	10.9	10.9
	9	9	9
Moisture (%)	8.13	8.26	9.8
Oxygen (%)	12.11	12.60	12.43
Oxygen (%) dry	13.18	13.73	13.78
Turbine Flow (acfm)	2,100,040	2,040,226	1,965,203
Turbine Flow (acfm, dry)	1,929,307	1,871,704	1,772,613
Turbine Exhaust Temperature (°F)	1,200	1,159	1,190
CT Emission rate (lb/hr) - calculated	51.7	47.8	44.1
CT Emission rate (lb/hr) - provided	51.0	47.0	44.0
<u>Carbon Monoxide</u>			
<i>CO (lb/hr) = CO (ppm actual) x Volume flow (acfm) x</i>			
Basis, ppmvd - provided	6.5	6.5	6.5
Basis, ppmvd @ 15% O2 - calculated	5.0	5.4	5.4
Moisture (%)	8.13	8.26	9.8
Oxygen (%)	12.11	12.60	12.43
Oxygen (%) dry	13.18	13.73	13.78
Turbine Flow (acfm)	2,100,040	2,040,226	1,965,203
Turbine Flow (acfm, dry)	1,929,307	1,871,704	1,772,613
Turbine Exhaust Temperature (°F)	1,200	1,159	1,190
CT Emission rate (lb/hr) - calculated	17.4	17.3	16.1
CT Emission rate (lb/hr) - provided	24.0	24.0	22.0

TABLE A-4
MAXIMUM EMISSIONS FOR CRITERIA POLLUTANTS FOR THE SHADY HILLS ENERGY CENTER PROJECT
GE7FA, NATURAL GAS, 75% LOAD

Parameter	Turbine Inlet Temperature		
	20 °F Case 4	59 °F Case 5	95 °F Case 6
<u>Volatile Organic Compounds</u>			
<i>VOC (lb/hr) = VOC (ppm actual) x Volume flow (acfm) x</i>			
Basis, ppmvd - provided	1.6	1.6	1.6
Basis, ppmvd @ 15% O2 - calculated	1.2	1.3	1.3
Moisture (%)	8.13	8.26	9.8
Oxygen (%)	12.11	12.60	12.43
Oxygen (%) dry	13.18	13.73	13.78
Turbine Flow (acfm)	2,100,040	2,040,226	1,965,203
Turbine Flow (acfm, dry)	1,929,307	1,871,704	1,772,613
Turbine Exhaust Temperature (°F)	1,200	1,159	1,190
CT Emission rate (lb/hr) - calculated	2.44	2.43	2.26
CT Emission rate (lb/hr) - provided	2.40	2.20	2.20
<u>Sulfuric Acid Mist</u>			
<i>Total Sulfuric Acid Mist (SAM) (lb/hr) = SAM Formed in the CT</i>			
	9.2	8.5	7.9
	10	10	10
Stack emission rate (lb/hr)- calculated	1.41	1.30	1.20
- provided	NA	NA	NA
<u>Lead</u>			
Lead (lb/hr) = NA			
Emission Rate Basis	NA	NA	NA
HRS Stack emission rate (lb/hr)	NA	NA	NA

**TABLE A-5
DESIGN INFORMATION AND STACK PARAMETERS FOR THE SHADY HILLS ENERGY CENTER PROJECT
GE7FA, NATURAL GAS, 50% LOAD**

Parameter	CT Only		
	Turbine Inlet Temperature		
	20 °F Case 7	59 °F Case 8	95 °F Case 9
<u>Combustion Turbine Performance</u>			
Net power output (MW)	100.897	92.126	80.909
Net heat rate (Btu/kWh, LHV)	11,762	12,083	12,654
(Btu/kWh, HHV)	13,056	13,412	14,046
Heat Input (MMBtu/hr, LHV)	1,186.7	1,113.1	1,023.8
(MMBtu/hr, HHV)	1,317.3	1,235.6	1,136.5
Relative Humidity (%)	80	60	64
Fuel heating value (Btu/lb, LHV)	20,825	20,825	20,825
(Btu/lb, HHV)	23,116	23,116	23,116
(HHV/LHV)	1.110	1.110	1.110
<u>CT Exhaust Flow</u>			
Mass flow (lb/hr)- provided	2,498,048	2,433,269	2,325,978
- provided	NA	NA	NA
Temperature (°F) - provided	1,200	1,200	1,200
Moisture (% Vol.)	7.54	7.96	9.37
Oxygen (% Vol.)	12.77	12.94	12.92
Molecular Weight	28.48	28.42	28.25
<u>Fuel Usage</u>			
Fuel usage (lb/hr) = Heat Input (MMBtu/hr) x 1,000,000 Btu/MMBtu (Fuel Heat Content, Btu/lb (LHV))			
Heat input (MMBtu/hr, LHV)	1,187	1,113	1,024
Heat content (Btu/lb, LHV)	20,825	20,825	20,825
Fuel usage (lb/hr)- calculated	56,986	53,452	49,164
Heat content (Btu/cf, LHV)- assumed	933	933	933
	0.0448	0.0448	0.0448
Fuel usage (cf/hr)- calculated	1,271,405	1,192,548	1,096,884
<u>Stack</u>			
Stack Height (ft)	75	75	75
Stack Diameter (ft)	18	18	18
<u>Stack Flow Conditions</u>			
Velocity (ft/sec) = Volume flow (acfm) / [((diameter) ² / 4) x 3.14159] / 60 sec/min			
Mass flow (lb/hr)	2,498,048	2,433,269	2,325,978
	1,200	1,200	1,200
Molecular weight	28.48	28.42	28.25
Volume flow (acfm)	1,771,785	1,729,434	1,663,345
Diameter (ft)	18	18	18
Velocity (ft/sec)- calculated	116.0	113.3	108.9

Source: GE, 2007- CT Performance Data; Goler, 2008

**TABLE A-6
MAXIMUM EMISSIONS FOR CRITERIA POLLUTANTS FOR THE SHADY HILLS ENERGY CENTER PROJECT
GE7FA, NATURAL GAS, 50% LOAD**

Parameter	Turbine Inlet Temperature		
	20 °F	59 °F	95 °F
	Case 7	Case 8	Case 9
<u>Particulate Matter (Front-half only)</u>			
Particulate from CT- provided	9.0	9.0	9.0
<u>Sulfur Dioxide</u>			
Fuel use (cf/hr)	1,271,405	1,192,548	1,096,884
Sulfur content (grains/ 100 cf)	2	2	2
	2	2	2
CT Stack emission rate (lb/hr)- calculated	7.3	6.8	6.3
<u>Nitrogen Oxides</u>			
<i>NOx (lb/hr) = NOx (ppm actual) x Volume flow (acfm) x</i>			
Basis, ppmvd - calculated	10.8	10.4	10.1
	9	9	9
Moisture (%)	7.54	7.96	9.37
Oxygen (%)	12.77	12.94	12.92
Oxygen (%) dry	13.81	14.06	14.26
Turbine Flow (acfm)	1,771,785	1,729,434	1,663,345
Turbine Flow (acfm, dry)	1,638,192	1,591,771	1,507,489
Turbine Exhaust Temperature (°F)	1,200	1,200	1,200
CT Emission rate (lb/hr) - calculated	40.3	37.8	34.8
CT Emission rate (lb/hr) - provided	40.0	37.0	34.0
<u>Carbon Monoxide</u>			
<i>CO (lb/hr) = CO (ppm actual) x Volume flow (acfm) x</i>			
Basis, ppmvd - provided	6.5	6.5	6.5
Basis, ppmvd @ 15% O2 - calculated	5.4	5.6	5.8
Moisture (%)	7.54	7.96	9.37
Oxygen (%)	12.77	12.94	12.92
Oxygen (%) dry	13.81	14.06	14.26
Turbine Flow (acfm)	1,771,785	1,729,434	1,663,345
Turbine Flow (acfm, dry)	1,638,192	1,591,771	1,507,489
Turbine Exhaust Temperature (°F)	1,200	1,200	1,200
CT Emission rate (lb/hr) - calculated	14.8	14.3	13.6
CT Emission rate (lb/hr) - provided	20.0	20.0	19.0

TABLE A-6
MAXIMUM EMISSIONS FOR CRITERIA POLLUTANTS FOR THE SHADY HILLS ENERGY CENTER PROJECT
GE7FA, NATURAL GAS, 50% LOAD

Parameter	Turbine Inlet Temperature		
	20 °F	59 °F	95 °F
	Case 7	Case 8	Case 9
<u>Volatile Organic Compounds</u>			
<i>VOC (lb/hr) = VOC (ppm actual) x Volume flow (acfm) x</i>			
Basis, ppmvd - provided	1.6	1.6	1.6
Basis, ppmvd @ 15% O2 - calculated	1.3	1.4	1.4
Moisture (%)	7.54	7.96	9.37
Oxygen (%)	12.77	12.94	12.92
Oxygen (%) dry	13.81	14.06	14.26
Turbine Flow (acfm)	1,771,785	1,729,434	1,663,345
Turbine Flow (acfm, dry)	1,638,192	1,591,771	1,507,489
Turbine Exhaust Temperature (°F)	1,200	1,200	1,200
CT Emission rate (lb/hr) - calculated	2.08	2.02	1.91
CT Emission rate (lb/hr) - provided	2.00	1.80	1.80
<u>Sulfuric Acid Mist</u>			
<i>Total Sulfuric Acid Mist (SAM) (lb/hr) = SAM Formed in the CT</i>			
	7.3	6.8	6.3
	10	10	10
Stack emission rate (lb/hr)- calculated	1.11	1.04	0.96
- provided	NA	NA	NA
<u>Lead</u>			
Lead (lb/hr) = NA			
Emission Rate Basis	NA	NA	NA
HRSG Stack emission rate (lb/hr)	NA	NA	NA

Source: GE, 2007- CT Performance Data; Goler, 2008

**TABLE A-7
DESIGN INFORMATION AND STACK PARAMETERS FOR THE SHADY HILLS ENERGY CENTER PROJECT
GE7FA, DISTILLATE OIL, BASE LOAD**

Parameter	CT Only		
	Turbine Inlet Temperature		
	20 °F Case 10	59 °F Case 11	95 °F Case 12
<u>Combustion Turbine Performance</u>			
Net power output (MW)	199.791	187.397	164.066
Net heat rate (Btu/kWh, LHV)	10,050	10,080	10,380
(Btu/kWh, HHV)	10,653	10,685	11,003
Heat Input (MMBtu/hr, LHV)	2,007.9	1,888.96	1,703.0
(MMBtu/hr, HHV)	2,128.4	2,002.3	1,805.2
Relative Humidity (%)	80	60	64
Fuel heating value (Btu/lb, LHV)	18,300	18,300	18,300
(Btu/lb, HHV)	19,398	19,398	19,398
(HHV/LHV)	1.060	1.060	1.060
<u>CT Exhaust Flow</u>			
Mass Flow (lb/hr)- provided	4,055,000	3,766,000	3,407,000
Temperature (°F) - provided	1,053	1,093	1,143
Moisture (% Vol.)	10.87	11.46	13.07
Oxygen (% Vol.)	11.24	11.11	10.77
Molecular Weight	28.36	28.30	28.12
<u>Fuel Usage</u>			
Fuel usage (lb/hr) = Heat Input (MMBtu/hr) x 1,000,000 Btu/MMBtu (Fuel Heat Content, Btu/lb (LHV))			
Heat input (MMBtu/hr, LHV)	2,007.9	1,889.0	1,703.0
Heat content (Btu/lb, LHV)	18,300	18,300	18,300
Fuel usage (lb/hr)- calculated	109,721	103,222	93,061
<u>Stack</u>			
Stack Height (ft)	75	75	75
Diameter (ft)	18	18	18
<u>HRSG Stack Flow Conditions</u>			
Velocity (ft/sec) = Volume flow (acfm) / [((diameter) ² / 4) x 3.14159] / 60 sec/min			
Mass flow (lb/hr) - provided	4,055,000	3,766,000	3,407,000
	1,053	1,093	1,143
Molecular weight	28.36	28.30	28.12
CT volume flow (acfm)	2,632,958	2,515,327	2,363,790
	43,883	41,922	39,397
Diameter (ft)	18	18	18
Velocity (ft/sec)- calculated	172.4	164.7	154.8

Source: GE, 2007- CT Performance Data; Goler, 2008

**TABLE A-8
MAXIMUM EMISSIONS FOR CRITERIA POLLUTANTS FOR THE SHADY HILLS ENERGY CENTER PROJECT
GE7FA, DISTILLATE OIL, BASE LOAD**

Parameter	Turbine Inlet Temperature		
	20 °F Case 10	59 °F Case 11	95 °F Case 12
<u>Particulate Matter (Front-half only)</u>			
Particulate from CT- provided	17.0	17.0	17.0
<u>Sulfur Dioxide</u>			
Fuel oil use (lb/hr)	109,721	103,222	93,061
Fuel oil Sulfur Content	0.0015%	0.0015%	0.0015%
lb SO ₂ / lb S (64/32)	2	2	2
Stack emission rate (lb/hr)- calculated	3.3	3.1	2.8
<u>Nitrogen Oxides</u>			
<i>NO_x (lb/hr) = NO_x (ppm actual) x Volume flow (acfm) x</i>			
Basis, ppmvd - calculated	59.0	59.5	60.6
	42	42	42
Moisture (%)	10.87	11.46	13.07
Oxygen (%)	11.24	11.11	10.77
Oxygen (%) dry	12.61	12.55	12.39
Turbine Flow (acfm)	2,632,958	2,515,327	2,363,790
Turbine Flow (acfm, dry)	2,346,756	2,227,070	2,054,843
Turbine Exhaust Temperature (°F)	1,053	1,093	1,143
CT emission rate (lb/hr) - calculated	345.9	322.3	293.5
CT Emission rate (lb/hr) - provided	345.0	323.0	293.0
<u>Carbon Monoxide</u>			
<i>CO (lb/hr) = CO (ppm actual) x Volume flow (acfm) x</i>			
Basis, ppmvd - provided	13.5	13.5	13.5
Basis, ppmvd @ 15% O ₂ - calculated	9.6	9.5	9.4
Moisture (%)	10.87	11.46	13.07
Oxygen (%)	11.24	11.11	10.77
Oxygen (%) dry	12.61	12.55	12.39
Turbine Flow (acfm)	2,632,958	2,515,327	2,363,790
Turbine Flow (acfm, dry)	2,337,014	2,235,874	2,109,210
Turbine Exhaust Temperature (°F)	1,053	1,093	1,143
CT emission rate (lb/hr) - calculated	48.0	44.7	40.9
CT Emission rate (lb/hr) - provided	71.0	66.0	59.0

**TABLE A-8
MAXIMUM EMISSIONS FOR CRITERIA POLLUTANTS FOR THE SHADY HILLS ENERGY CENTER PROJECT
GE7FA, DISTILLATE OIL, BASE LOAD**

Parameter	Turbine Inlet Temperature		
	20 °F Case 10	59 °F Case 11	95 °F Case 12
<u>Volatile Organic Compounds</u>			
<i>VOC (lb/hr) = VOC (ppm actual) x Volume flow (acfm) x</i>			
Basis, ppmvd - provided	4.0	4.0	4.0
Basis, ppmvd @ 15% O2 - calculated	2.8	2.8	2.8
Moisture (%)	10.87	11.46	13.07
Oxygen (%)	11.24	11.11	10.77
Oxygen (%) dry	12.61	12.55	12.39
Turbine Flow (acfm)	2,632,958	2,515,327	2,363,790
Turbine Flow (acfm, dry)	2,346,756	2,227,070	2,054,843
Turbine Exhaust Temperature (°F)	1,053	1,093	1,143
CT emission rate (lb/hr) - calculated	8.2	7.5	6.7
CT Emission rate (lb/hr) - provided	8.0	7.5	7.0
<u>Sulfuric Acid Mist</u>			
<i>Total Sulfuric Acid Mist (SAM) (lb/hr)= SAM Formed in the CT</i>			
	3.3	3.1	2.8
	10	10	10
Stack emission rate (lb/hr)- calculated	0.50	0.47	0.43
- provided	NA	NA	NA
<u>Lead</u>			
	14	14	14
Stack emission rate (lb/hr)- calculated	0.0281	0.0264	0.0238

Source: GE, 2007- CT Performance Data; Goler, 2008

**TABLE A-9
DESIGN INFORMATION AND STACK PARAMETERS FOR THE SHADY HILLS ENERGY CENTER PROJECT
GE7FA, DISTILLATE OIL, 75% LOAD**

Parameter	CT Only		
	Turbine Inlet Temperature		
	20 °F Case 13	59 °F Case 14	95 °F Case 15
<u>Combustion Turbine Performance</u>			
Net power output (MW)	149.812	139.907	123.076
Net heat rate (Btu/kWh, LHV)	10,970	11,030	11,400
(Btu/kWh, HHV)	11,628	11,692	12,084
Heat Input (MMBtu/hr, LHV)	1,643.4	1,543.2	1,403.1
(MMBtu/hr, HHV)	1,742.0	1,635.8	1,487.3
Relative Humidity (%)	80	60	64
Fuel heating value (Btu/lb, LHV)	18,300	18,300	18,300
(Btu/lb, HHV)	19,398	19,398	19,398
(HHV/LHV)	1.060	1.060	1.060
<u>CT Exhaust Flow</u>			
Mass Flow (lb/hr)- with no margin	2,991,000	2,898,000	2,783,000
- provided	NA	NA	NA
Temperature (°F) - provided	1,196	1,200	1,200
Moisture (% Vol.)	11.72	11.85	12.65
Oxygen (% Vol.)	10.34	10.57	10.86
Molecular Weight	28.32	28.29	28.16
<u>Fuel Usage</u>			
Fuel usage (lb/hr) = Heat Input (MMBtu/hr) x 1,000,000 Btu/MMBtu (Fuel Heat Content, Btu/lb (LHV))			
Heat input (MMBtu/hr, LHV)	1,643.4	1,543.2	1,403.1
Heat content (Btu/lb, LHV)	18,300	18,300	18,300
Fuel usage (lb/hr)- calculated	89,805	84,326	76,670
<u>HRSG Stack</u>			
HRSG - Stack Height (ft)	75	75	75
Diameter (ft)	18	18	18
<u>Stack Flow Conditions</u>			
Velocity (ft/sec) = Volume flow (acfm) / [((diameter) ² / 4) x 3.14159] / 60 sec/min			
Mass flow (lb/hr)	2,991,000	2,898,000	2,783,000
	1,196	1,200	1,200
Molecular weight	28.32	28.29	28.16
CT volume flow (acfm)	2,128,442	2,069,745	1,996,279
	35,474	34,496	33,271
Diameter (ft)	18	18	18
Velocity (ft/sec)- calculated	139.4	135.6	130.7

Source: GE, 2007- CT Performance Data; Goler, 2008

**TABLE A-10
MAXIMUM EMISSIONS FOR CRITERIA POLLUTANTS FOR THE SHADY HILLS ENERGY CENTER PROJECT
GE 7FA, DISTILLATE OIL, 75% LOAD**

Parameter	Turbine Inlet Temperature		
	20 °F Case 13	59 °F Case 14	95 °F Case 15
<u>Particulate Matter (Front-half only)</u>			
Particulate from CT- provided	17.0	17.0	17.0
<u>Sulfur Dioxide</u>			
Fuel oil Sulfur Content	0.0015%	0.0015%	0.0015%
Fuel oil use (lb/hr)	89,805	84,326	76,670
lb SO ₂ / lb S (64/32)	2	2	2
Stack emission rate (lb/hr)- calculated	2.7	2.5	2.3
<u>Nitrogen Oxides</u>			
<i>NO_x (lb/hr) = NO_x (ppm actual) x Volume flow (acfm) x</i>			
Basis, ppmvd - calculated	65.4	63.4	60.3
	42	42	42
Moisture (%)	11.72	11.85	12.65
Oxygen (%)	10.34	10.57	10.86
Oxygen (%) dry	11.71	11.99	12.43
Turbine Flow (acfm)	2,127,478	2,068,807	1,995,375
Turbine Flow (acfm, dry)	1,878,138	1,823,654	1,742,960
Turbine Exhaust Temperature (°F)	1,196	1,200	1,200
CT emission rate (lb/hr) - calculated	280.4	263.3	239.2
CT Emission rate (lb/hr) - provided	280.0	263.0	239.0
<u>Carbon Monoxide</u>			
<i>CO (lb/hr) = CO (ppm actual) x Volume flow (acfm) x</i>			
Basis, ppmvd - provided	13.5	13.5	13.5
Basis, ppmvd @ 15% O ₂ - calculated	8.7	8.9	9.4
Moisture (%)	11.72	11.85	12.65
Oxygen (%)	10.34	10.57	10.86
Oxygen (%) dry	11.71	11.99	12.43
Turbine Flow (acfm)	2,127,478	2,068,807	1,995,375
Turbine Flow (acfm, dry)	1,878,138	1,823,654	1,742,960
Turbine Exhaust Temperature (°F)	1,196	1,200	1,200
CT emission rate (lb/hr) - calculated	35.2	34.1	32.6
CT Emission rate (lb/hr) - provided	52.0	51.0	48.0

**TABLE A-10
MAXIMUM EMISSIONS FOR CRITERIA POLLUTANTS FOR THE SHADY HILLS ENERGY CENTER PROJECT
GE 7FA, DISTILLATE OIL, 75% LOAD**

Parameter	Turbine Inlet Temperature		
	20 °F Case 13	59 °F Case 14	95 °F Case 15
<u>Volatile Organic Compounds</u>			
<i>VOC (lb/hr) = VOC (ppm actual) x Volume flow (acfm) x</i>			
Basis, ppmvd - provided	4.0	4.0	4.0
Basis, ppmvd @ 15% O2 - calculated	2.6	2.6	2.8
Moisture (%)	11.72	11.85	12.65
Oxygen (%)	10.34	10.57	10.86
Oxygen (%) dry	11.71	11.99	12.43
Turbine Flow (acfm)	2,127,478	2,068,807	1,995,375
Turbine Flow (acfm, dry)	1,878,138	1,823,654	1,742,960
Turbine Exhaust Temperature (°F)	1,196	1,200	1,200
CT emission rate (lb/hr) - calculated	6.0	5.8	5.5
CT Emission rate (lb/hr) - provided	6.0	5.5	5.5
<u>Sulfuric Acid Mist</u>			
<i>Total Sulfuric Acid Mist (SAM) (lb/hr) = SAM Formed in the CT</i>			
	2.7	2.5	2.3
	10	10	10
Stack emission rate (lb/hr)- calculated	0.41	0.39	0.35
- provided	NA	NA	NA
<u>Lead</u>			
	14	14	14
Stack emission rate (lb/hr)- calculated	0.0230	0.0216	0.0196

Note: ppmvd= parts per million, volume dry; O2= oxygen.

Source: GE, 2007- CT Performance Data; Goler, 2008

**TABLE A-11
DESIGN INFORMATION AND STACK PARAMETERS FOR THE SHADY HILLS ENERGY CENTER PROJECT
GE7FA, DISTILLATE OIL, 50% LOAD**

Parameter	CT Only		
	Turbine Inlet Temperature		
	20 °F Case 16	59 °F Case 17	95 °F Case 18
<u>Combustion Turbine Performance</u>			
Net power output (MW)	99.844	93.237	81.983
Net heat rate (Btu/kWh, LHV)	12,730	12,920	13,370
(Btu/kWh, HHV)	13,494	13,695	14,172
Heat Input (MMBtu/hr, LHV)	1,271.0	1,204.6	1,096.1
(MMBtu/hr, HHV)	1,347.3	1,276.9	1,161.9
Relative Humidity (%)	80	60	64
Fuel heating value (Btu/lb, LHV)	18,300	18,300	18,300
(Btu/lb, HHV)	19,398	19,398	19,398
(HHV/LHV)	1.060	1.060	1.060
<u>CT Exhaust Flow</u>			
Mass Flow (lb/hr)- with no margin	2,499,000	2,457,000	2,353,000
- provided	NA	NA	NA
Temperature (°F) - provided	1,196	1,200	1,200
Moisture (% Vol.)	10.19	10.38	11.37
Oxygen (% Vol.)	11.30	11.54	11.73
Molecular Weight	28.44	28.40	28.26
<u>Fuel Usage</u>			
Fuel usage (lb/hr) = Heat Input (MMBtu/hr) x 1,000,000 Btu/MMBtu (Fuel Heat Content, Btu/lb (LHV))			
Heat input (MMBtu/hr, LHV)	1,271.0	1,204.6	1,096.1
Heat content (Btu/lb, LHV)	18,300	18,300	18,300
Fuel usage (lb/hr)- calculated	69,454	65,826	59,897
<u>HRSG Stack</u>			
HRSG - Stack Height (ft)	75	75	75
Diameter (ft)	18	18	18
<u>Stack Flow Conditions</u>			
Velocity (ft/sec) = Volume flow (acfm) / [((diameter) ² / 4) x 3.14159] / 60 sec/min			
Mass flow (lb/hr)	2,499,000	2,457,000	2,353,000
	1,196	1,200	1,200
Molecular weight	28.44	28.40	28.26
CT volume flow (acfm)	1,770,922	1,748,009	1,682,253
	29,515	29,133	28,038
Diameter (ft)	18	18	18
Velocity (ft/sec)- calculated	116.0	114.5	110.2

Source: GE, 2007- CT Performance Data; Goler, 2008

**TABLE A-12
MAXIMUM EMISSIONS FOR CRITERIA POLLUTANTS FOR THE SHADY HILLS ENERGY CENTER PROJECT
GE 7FA, DISTILLATE OIL, 50% LOAD**

Parameter	Turbine Inlet Temperature		
	20 °F Case 16	59 °F Case 17	95 °F Case 18
<u>Particulate Matter (Front-half only)</u>			
Particulate from CT- provided	17.0	17.0	17.0
<u>Sulfur Dioxide</u>			
Fuel oil Sulfur Content	0.0015%	0.0015%	0.0015%
Fuel oil use (lb/hr)	69,454	65,826	59,897
lb SO ₂ / lb S (64/32)	2	2	2
Stack emission rate (lb/hr)- calculated	2.1	2.0	1.8
<u>Nitrogen Oxides</u>			
$NO_x \text{ (lb/hr)} = NO_x \text{ (ppm actual)} \times \text{Volume flow (acfm)} \times$			
Basis, ppmvd - calculated	59.2	57.1	54.6
	42	42	42
Moisture (%)	10.19	10.38	11.37
Oxygen (%)	11.30	11.54	11.73
Oxygen (%) dry	12.58	12.88	13.23
Turbine Flow (acfm)	1,770,120	1,747,217	1,681,491
Turbine Flow (acfm, dry)	1,589,745	1,565,856	1,490,306
Turbine Exhaust Temperature (°F)	1,196	1,200	1,200
CT emission rate (lb/hr) - calculated	214.9	203.6	185.2
CT Emission rate (lb/hr) - provided	215.0	203.0	185.0
<u>Carbon Monoxide</u>			
$CO \text{ (lb/hr)} = CO \text{ (ppm actual)} \times \text{Volume flow (acfm)} \times$			
Basis, ppmvd - provided	13.5	13.5	13.5
Basis, ppmvd @ 15% O ₂ - calculated	9.6	9.9	10.4
Moisture (%)	10.19	10.38	11.37
Oxygen (%)	11.30	11.54	11.73
Oxygen (%) dry	12.58	12.88	13.23
Turbine Flow (acfm)	1,770,120	1,747,217	1,681,491
Turbine Flow (acfm, dry)	1,589,745	1,565,856	1,490,306
Turbine Exhaust Temperature (°F)	1,196	1,200	1,200
CT emission rate (lb/hr) - calculated	29.8	29.3	27.9
CT Emission rate (lb/hr) - provided	44.0	43.0	41.0

**TABLE A-12
MAXIMUM EMISSIONS FOR CRITERIA POLLUTANTS FOR THE SHADY HILLS ENERGY CENTER PROJECT
GE 7FA, DISTILLATE OIL, 50% LOAD**

Parameter	Turbine Inlet Temperature		
	20 °F Case 16	59 °F Case 17	95 °F Case 18
<u>Volatile Organic Compounds</u>			
<i>VOC (lb/hr) = VOC (ppm actual) x Volume flow (acfm) x</i>			
Basis, ppmvd - provided	4.0	4.0	4.0
Basis, ppmvd @ 15% O2 - calculated	2.8	2.9	3.1
Moisture (%)	10.19	10.38	11.37
Oxygen (%)	11.30	11.54	11.73
Oxygen (%) dry	12.58	12.88	13.23
Turbine Flow (acfm)	1,770,120	1,747,217	1,681,491
Turbine Flow (acfm, dry)	1,589,745	1,565,856	1,490,306
Turbine Exhaust Temperature (°F)	1,196	1,200	1,200
CT emission rate (lb/hr) - calculated	5.0	5.0	4.7
CT Emission rate (lb/hr) - provided	5.0	5.0	4.5
<u>Sulfuric Acid Mist</u>			
<i>Total Sulfuric Acid Mist (SAM) (lb/hr) = SAM Formed in the CT</i>			
	2.1	2.0	1.8
	10	10	10
Stack emission rate (lb/hr)- calculated	0.32	0.30	0.28
- provided	NA	NA	NA
<u>Lead</u>			
Stack emission rate (lb/hr)- calculated	14 0.0178	14 0.0169	14 0.0153

Note: ppmvd= parts per million, volume dry; O2= oxygen.

Source: GE, 2007- CT Performance Data; Goler, 2008

**TABLE A-13
REGULATED AND HAZARDOUS AIR POLLUTANT EMISSION FACTORS AND EMISSIONS
WHEN FIRING NATURAL GAS, GE7FA CT**

Parameter	Emission Rate (lb/hr) firing Natural Gas for Operating Conditions of Base Load (1)	Natural Gas Maximum Annual Emissions (TPY) (2)	
		59 °F	59 °F
		1 CT	2 CTs
HIR (MMBtu/hr):	1,892		
Sulfuric acid mist	1.60	2.7	5.4
<u>HAPs (Section 112(b) of Clean Air Act)</u>			
1,3-Butadiene	0.000814	0.001	0.003
Acetaldehyde	0.0757	0.128	0.257
Acrolein	0.0121	0.021	0.041
Benzene	0.0227	0.038	0.077
Ethylbenzene	0.0605	0.103	0.205
Formaldehyde	0.392	0.664	1.328
Naphthalene	0.00246	0.004	0.008
Polycyclic Aromatic Hydrocarbons (PAH) (3)	0.00416	0.007	0.014
Propylene Oxide	0.0549	0.093	0.186
Toluene	0.0624	0.106	0.212
Xylene	0.121	0.205	0.410
Antimony	0.0	0.0	0.00
Arsenic	0.0	0.0	0.00
Beryllium	0.0	0.0	0.00
Cadmium	0.0	0.0	0.00
Chromium	0.0	0.0	0.00
Lead	0.0	0.0	0.00
Manganese	0.0	0.0	0.00
Mercury	1.89E-06	0.0	6.41E-06
Nickel	0.0	0.0	0.00
Selenium	0.0	0.0	0.00
HAPs (Total)	0.808	1.4	2.7

(1) Emissions based on the following emission factors and conversion factors for firing natural gas:

<u>Emission Factors</u>	<u>Value</u>	<u>Reference</u>
Sulfuric acid mist	10	
1,3-Butadiene (a)	0.43	
Acetaldehyde	40	
Acrolein	6.4	
Benzene	12	
Ethylbenzene	32	
Formaldehyde	0.091 ppmvd @15% O ₂ (see Table 9a)	
Naphthalene	1.3	
Polycyclic Aromatic Hydrocarbons (PAH)	2.2	
Propylene Oxide (a)	29	
Toluene	33	
Xylene	64	
Antimony	0.00E+00	
Arsenic	0.00E+00	
Beryllium	0.00E+00	
Cadmium	0.00E+00	
Chromium	0.00E+00	
Lead	0.00E+00	
Manganese	0.00E+00	
Mercury	1.00E-03	
Nickel	0.00E+00	
Selenium	0.00E+00	

(a) Based on 1/2 the detection limit; expected emissions are lower.

3390 CT
0 CT/DB

(3) Assumed to be representative of Polycyclic Organic Matter (POM) emissions, a regulated HAP.

TABLE A-13a
MAXIMUM FORMALDEHYDE EMISSIONS
FOR THE SHADY HILLS ENERGY CENTER PROJECT
GE7FA, DRY LOW NO_x COMBUSTOR, NATURAL GAS, BASE LOAD

Parameter	CT Only		
	Turbine Inlet Temperature		
	20 °F Case 1	59 °F Case 2	95 °F Case 3
<u>Formaldehyde (CH₂O) MW = 30</u>			
<i>CH₂O (lb/hr) = CH₂O (ppm actual) x Volume flow (acfm) x 46 (mole. wgt NO_x) x 2116.8 lb/ft² (pressure) / [1545.7 (gas constant, R) x Actual Temp. (°R)] x 60 min/hr</i>			
<i>CH₂O (ppm actual) = CH₂O (ppmd @ 15%O₂) x [(20.9 - O₂ dry)/(20.9 - 15)]</i>			
<i>Oxygen (% dry)(O₂ dry) = Oxygen %/(1-Moisture (%))</i>			
Basis, ppmvd - calculated	0.110	0.111	0.111
	0.091	0.091	0.091
Moisture (%)	7.55	8.37	9.88
Oxygen (%)	12.75	12.57	12.34
Oxygen (%) dry	13.79	13.72	13.69
Exhaust Flow (acfm)	2,575,419	2,462,317	2,320,037
Exhaust Flow (acfm, dry)	2,380,975	2,256,221	2,090,818
Exhaust Temperature (°F)	1,074	1,113	1,154
CT Emission rate (lb/hr)	0.420	0.392	0.355
	206.3	207.0	206.1

Note: ppmvd= parts per million, volume dry; O₂= oxygen.

Source: GE, 2007- CT Performance Data; Goler, 2008

**TABLE A-14
REGULATED AND HAZARDOUS AIR POLLUTANT EMISSION FACTORS AND EMISSIONS
WHEN FIRING DISTILLATE FUEL OIL, GE 7FA CTS**

Parameter	Emission Rate (lb/hr)	Maximum Annual Emissions (TPY)			
	Firing Distillate Fuel Oil (1)	Distillate Fuel Oil (2)		Natural Gas (4)	Natural Gas and Fuel Oil (5)
	Base Load 59 °F	1 CT	2 CTs	2 CTs	2 CTs
HIR (MMBtu/hr):	2,002				
Sulfuric acid mist	0.47	0.24	0.5	5.4	5.3
HAPs (Section 112(b) of Clean Air Act)					
1,3-Butadiene	0.0320	0.0160	0.0320	0.0028	0.034
Acetaldehyde	0.00	0.00	0.00	0.26	0.2
Acrolein	0.00	0.00	0.00	0.041	0.04
Benzene	0.110	0.0551	0.1101	0.077	0.18
Ethylbenzene	0.00	0.00	0.00	0.205	0.18
Formaldehyde	0.455	0.228	0.4554	1.33	1.6
Naphthalene	0.0701	0.0350	0.0701	0.0083	0.077
Polycyclic Aromatic Hy(3)	0.0801	0.0400	0.0801	0.0141	0.09
Propylene Oxide	0.00	0.00	0.00	0.186	0.16
Toluene	0.00	0.00	0.00	0.21	0.2
Xylene	0.00	0.00	0.00	0.41	0.4
Antimony	0.00	0.00	0.00	0.00	0.0
Arsenic	0.0220	0.01101	0.02203	0.00	0.022
Beryllium	0.000621	0.000310	0.000621	0.00	0.00062
Cadmium	0.00961	0.00481	0.00961	0.00	0.0096
Chromium	0.0220	0.01101	0.02203	0.00	0.022
Lead	0.0280	0.01402	0.02803	0.00	0.028
Manganese	1.58	0.791	1.582	0.00	1.6
Mercury	0.00240	0.001201	0.002403	0.00	0.0024
Nickel	0.00921	0.00461	0.00921	0.00	0.0092
Selenium	0.0501	0.0250	0.0501	0.00	0.050
HAPs (Total)	2.47	1.24	2.47	2.7	4.9

(1) Emissions based on the following emission factors and conversion factors for firing distillate fuel oil:

Emission Factors	Value	Reference
Sulfuric acid mist	5	
1,3-Butadiene	(a) 16	
Acetaldehyde	0.0	
Acrolein	0.0	
Benzene	55	
Ethylbenzene	0.0	
Formaldehyde	0.091 ppmvd @15% O2 (see Table 10a)	
Naphthalene	35	
Polycyclic Aromatic Hydrocarbons (40	
Propylene Oxide	0.0	
Toluene	0.0	
Xylene	0.0	
Antimony	0.0	
Arsenic	(a) 11	
Beryllium	(a) 0.31	
Cadmium	4.8	
Chromium	11	
Lead	14	
Manganese	790	
Mercury	1.2	
Nickel	(a) 4.6	
Selenium	(a) 25	

(a) Based on 1/2 the detection limit, expected emissions are lower.

1,000 hours

(3) Assumed to be representative of Polycyclic Organic Matter (POM) emissions, a regulated HAP.

(4) Annual emissions based on maximum emissions presented for natural gas-firing.

(5) Maximum total annual 1,000 hours of firing fuel and remaining hours firing natural gas.

TABLE A-14a
MAXIMUM FORMALDEHYDE EMISSIONS
FOR THE SHADY HILLS ENERGY CENTER PROJECT
GE 7FA CT, DRY LOW NO_x COMBUSTOR, DISTILLATE OIL, BASE LOAD

Parameter	CT Only		
	Turbine Inlet Temperature		
	20 °F Case 10	59 °F Case 11	95 °F Case 12
Formaldehyde (CH₂O) MW = 30			
<i>CH₂O (lb/hr) = CH₂O (ppm actual) x Volume flow (acfm) x 46 (mole. wgt NO_x) x 2116.8 lb/ft² (pressure) / [1545.7 (gas constant, R) x Actual Temp. (°R)] x 60 min/hr</i>			
<i>CH₂O (ppm actual) = CH₂O (ppmd @ 15%O₂) x [(20.9 - O₂ dry)/(20.9 - 15)]</i>			
<i>Oxygen (% dry)(O₂ dry) = Oxygen (%) / (1 - Moisture (%))</i>			
Basis, ppmvd - calculated	0.128	0.129	0.131
	0.091	0.091	0.091
Moisture (%)	10.87	11.46	13.07
Oxygen (%)	11.24	11.11	10.77
Oxygen (%) dry	12.61	12.55	12.39
Exhaust Flow (acfm)	2,632,958	2,515,327	2,363,790
Exhaust Flow (acfm, dry)	2,346,756	2,227,070	2,054,843
Exhaust Temperature (°F)	1,053	1,093	1,143
CT Emission rate (lb/hr)	0.489	0.455	0.415
	229.7	227.4	229.8

Note: ppmvd= parts per million, volume dry; O₂= oxygen.

Source: GE, 2007- CT Performance Data; Goler, 2008

**TABLE 2-1
STACK, OPERATING, AND EMISSION DATA FOR THE COMBUSTION TURBINES FOR SIMPLE CYCLE
OPERATION - NATURAL GAS COMBUSTION**

Parameter	Operating and Emission Data ^a for Ambient Temperature			
	Combustion Turbine			
	20 °F	59 °F	95 °F	
<u>CT Stack Data (ft)</u>				
Height	75	75	75	
Diameter	18.0	18.0	18.0	
<u>100 Percent Load</u>				
Velocity (ft/sec)	1,074	1,113	1,154	
Velocity (ft/sec)	168.7	161.3	152.0	
Maximum Hourly Emissions per Unit				
SO ₂	lb/hr	11.2	10.4	9.5
PM/PM ₁₀	lb/hr	9.0	9.0	9.0
NO _x	lb/hr	63.6	59.4	53.8
CO	lb/hr	23.2	21.5	19.4
VOC (as methane)	lb/hr	3.3	3.0	2.7
Sulfuric Acid Mist	lb/hr	1.7	1.6	1.5
<u>75 Percent Load</u>				
Velocity (ft/sec)	1,200	1,159	1,190	
Velocity (ft/sec)	137.5	133.6	128.7	
Maximum Hourly Emissions per Unit				
SO ₂	lb/hr	9.2	8.5	7.9
PM/PM ₁₀	lb/hr	9.0	9.0	9.0
NO _x	lb/hr	51.7	47.8	44.1
CO	lb/hr	17.4	17.3	16.1
VOC (as methane)	lb/hr	2.4	2.4	2.3
Sulfuric Acid Mist	lb/hr	1.41	1.30	1.20
<u>50 Percent Load</u>				
Velocity (ft/sec)	1,200	1,200	1,200	
Velocity (ft/sec)	116.0	113.3	108.9	
Maximum Hourly Emissions per Unit				
SO ₂	lb/hr	7.3	6.8	6.3
PM/PM ₁₀	lb/hr	9.0	9.0	9.0
NO _x	lb/hr	40.3	37.8	34.8
CO	lb/hr	14.8	14.3	13.6
VOC (as methane)	lb/hr	2.1	2.0	1.9
Sulfuric Acid Mist	lb/hr	1.11	1.04	0.96

^a Refer to Appendix A for detailed information on basis of pollutant emission rates and operating data.
Source: GE, 2007- CT Performance Data; Goler, 2008

**TABLE 2-2
STACK, OPERATING, AND EMISSION DATA FOR THE COMBUSTION TURBINES FOR SIMPLE
CYCLE OPERATION - ULTRA LOW-SULFUR LIGHT OIL COMBUSTION**

Parameter	Operating and Emission Data ^a for Ambient Temperature		
	Combustion Turbine		
	20 °F	59 °F	95 °F
<u>CT/HRSG Stack Data (ft)</u>			
Height	75	75	75
Diameter	18	18	18
<u>100 Percent Load</u>			
Velocity (ft/sec)	1,053	1,093	1,143
Maximum Hourly Emissions per Unit			
SO ₂	3.3	3.1	2.8
PM/PM ₁₀	17.0	17.0	17.0
NO _x	345.9	322.3	293.5
CO	48.0	44.7	40.9
VOC (as methane)	8.2	7.5	6.7
Lead	0.028	0.026	0.024
Sulfuric Acid Mist	0.50	0.47	0.43
<u>75 Percent Load</u>			
Velocity (ft/sec)	1,196	1,200	1,200
Maximum Hourly Emissions per Unit			
SO ₂	2.7	2.5	2.3
PM/PM ₁₀	17.0	17.0	17.0
NO _x	280.4	263.3	239.2
CO	35.2	34.1	32.6
VOC (as methane)	6.0	5.8	5.5
Lead	0.023	0.022	0.020
Sulfuric Acid Mist	0.41	0.39	0.35
<u>50 Percent Load</u>			
Velocity (ft/sec)	1,196	1,200	1,200
Maximum Hourly Emissions per Unit			
SO ₂	2.1	2.0	1.8
PM/PM ₁₀	17.0	17.0	17.0
NO _x	214.9	203.6	185.2
CO	29.8	29.3	27.9
VOC (as methane)	5.0	5.0	4.7
Lead	0.018	0.017	0.015
Sulfuric Acid Mist	0.32	0.30	0.28

^a Refer to Appendix A for detailed information on basis of pollutant emission rates and operating data.

Source: GE, 2007- CT Performance Data; Goler, 2008

TABLE 2-3

SUMMARY OF MAXIMUM POTENTIAL ANNUAL EMISSIONS FOR THE CTS IN SIMPLE CYCLE OPERATIONS

Pollutant	Maximum Hourly Emissions (lb/hr) ^a		Maximum Emissions (tons/year)	
	Simple Cycle (SC)		Operating Scenario	Operating Hours
	Fuel:	Temp & Load:	SC/ NG 100 % Load	SC/ OIL 100 % Load
	NG	Oil	3,390	2,640
	59 °F, 100%	59 °F, 100%	0	750
			TOTAL	3,390
				3,390
<u>One Combustion Turbine</u>				
SO ₂	10.4	3.1	17.7	14.9
PM/PM ₁₀	9.0	17.0	15.3	18.3
NO _x	59.4	322.3	100.7	199.2
CO	21.5	44.7	36.4	45.1
VOC (as methane)	3.0	7.5	5.1	6.8
Sulfuric Acid Mist	1.6	0.5	2.7	2.3
HAPs	0.81	2.47	1.4	2.0
Lead	0.00	0.026	0.0	0.010
<u>Two Combustion Turbines</u>				
SO ₂	20.9	6.2	35.4	29.9
PM/PM ₁₀	18.0	34.0	30.5	36.5
NO _x	118.8	644.5	201.3	398.5
CO	42.9	89.4	72.7	90.2
VOC (as methane)	6.0	15.1	10.2	13.6
Sulfuric Acid Mist	3.2	0.9	5.4	4.6
HAPs	1.6	4.9	2.7	4.0
Lead	0.0	0.1	0.0	0.020

^a Based on 59 °F ambient inlet air temperature

Source: GE, 2007- CT Performance Data; Goler, 2008

TABLE 2-6

SUMMARY OF MAXIMUM POTENTIAL ANNUAL EMISSIONS FOR THE SHADY HILLS GENERATING STATION PROJECT

Pollutant	Annual Emissions (tons/year)				PSD Significant Emission Rate (tons/year)	PSD Review Required?
	2 CTs	Emergency Generator	Natural Gas Heater	TOTAL		
SO ₂	35.4	0.0082	0.24	36	40	No
PM	36.5	0.13	0.08	37	25	Yes
PM ₁₀	36.5	0.13	0.08	37	15	Yes
NO _x	398.5	6.65	4.15	409	40	Yes
CO	90.2	4.60	3.49	98	100	No
VOC (as methane)	13.6	1.76	0.23	16	40	No
Sulfuric Acid Mist	5.4	NA	NA	5.42	7	No
Lead	0.020	NA	NA	0.02	0.6	No

Source: Golder, 2008.

ATTACHMENT B

UPDATED BACT CALCULATIONS AND SUPPORTING INFORMATION

Table B-4. Capital Cost for Selective Catalytic Reduction for General Electric Frame 7F Simple Cycle Combustion Turbine
Based on 2,640 hr/yr Gas Firing and 750 hr/yr Oil Firing

Cost Component	Costs	Basis of Cost Component
<u>Direct Capital Costs</u>		
SCR Associated Equipment	5,243,333.33	Vendor Estimate; Includes Cooling System
Ammonia Storage Tank	included	Vendor Estimate
Flue Gas Ductwork	included	Vendor Estimate
Instrumentation	included	Vendor Estimate
Emission Monitoring	\$262,167	5% of SCR Associated Equipment
Freight	\$262,167	5% of SCR Associated Equipment
Total Direct Capital Costs (TDCC)	\$5,767,667	
<u>Direct Installation Costs</u>		
Foundation and supports	\$461,413	8% of TDCC and RCC; OAQPS Cost Control Manual
Handling & Erection	\$807,473	14% of TDCC and RCC; OAQPS Cost Control Manual
Electrical	\$230,707	4% of TDCC and RCC; OAQPS Cost Control Manual
Piping (Ammonia Injection Grid)	included	Vendor Estimate
Insulation for ductwork	\$57,677	1% of TDCC and RCC; OAQPS Cost Control Manual
Painting	\$57,677	1% of TDCC and RCC; OAQPS Cost Control Manual
Site Preparation (General Facilities)	\$288,383	5% of TDCC and RCC; OAQPS Cost Control Manual
Project Contingencies	\$576,767	10% of TDCC and RCC; OAQPS Cost Control Manual
Total Direct Installation Costs (TDIC)	\$2,480,097	
Total Capital Costs (TCC)	\$8,247,763	Sum of TDCC and TDIC
<u>Indirect Costs</u>		
Engineering	included	Vendor Estimate
PSM/RMP Plan	\$50,000	Engineering Estimate
Construction and Field Expense	\$412,388	5% of Total Capital Costs; OAQPS Cost Control Manual
Contractor Fees	\$824,776	10% of Total Capital Costs; OAQPS Cost Control Manual
Start-up	\$164,955	2% of Total Capital Costs; OAQPS Cost Control Manual
Performance Tests	\$82,478	1% of Total Capital Costs; OAQPS Cost Control Manual
Total Indirect Capital Cost (TInCC)	\$1,534,597	
Total Direct, Indirect and Capital Costs (TDICC)	\$9,782,361	Sum of TCC and TInCC

Table B-5. Annualized Cost for Selective Catalytic Reduction for General Electric Frame 7F Simple Cycle Operation
Based on 2,640 hr/yr Gas Firing and 750 hr/yr Oil Firing

Cost Component	Costs	Basis of Cost Component
<u>Direct Annual Costs</u>		
Operating Personnel	\$21,840	28 hours/week at \$15/hr
Supervision	\$3,276	15% of Operating Personnel; OAQPS Cost Control Manual
Ammonia	\$52,545	\$500 per ton for Aqueous NH ₃ , 62 lb/hr, 3,390 hr/year
PSM/RMP Update	\$25,000	Engineering Estimate
Inventory Cost	\$9,519	Capital Recovery (9.44%) for 1/3 catalyst for SCR
Catalyst Cost	\$75,625	4 years catalyst life; Based on Vendor Budget Estimate
Contingency	\$5,634	3% of Direct Annual Costs
Total Direct Annual Costs (TDAC)	\$193,439	
<u>Energy Costs</u>		
Electrical (SCR and Cooling)	\$44,748	330kW/h for SCR system @ \$0.04/kWh, 3,390 hr/yr
MW Loss and Heat Rate Penalty	\$117,260	0.5% of MW output; EPA, 1993 (Page 6-20) ^a
Total Energy Costs (TEC)	\$162,008	
<u>Indirect Annual Costs</u>		
Overhead	\$0	0% of Operating/Supervision Labor and Ammonia
Property Taxes	\$0	0% of Total Capital Costs
Insurance	\$0	0% of Total Capital Costs
Annualized Total Direct Capital	\$923,455	9.44% Capital Recovery Factor of 7% over 20 years times sum c of TDICC
Total Indirect Annual Costs (TIAC)	\$923,455	
Total Annualized Costs	\$1,278,902	Sum of TDAC, TEC and TIAC
Incremental Cost Effectiveness(9 to 3 ppmvd)	\$9,640	NO _x Reduction Only
	\$14,264	Net Emission Reduction

^a Alternative Control Techniques Document--NO_x Emissions from Stationary Gas Turbines, Page 6-20.

Table B-6. Maximum Potential Incremental Emissions (TPY) with Selective Catalytic Reduction
Based on 2,640 hr/yr Gas Firing and 750 hr/yr Oil Firing

Pollutants	Incremental Emissions (tons/year) of SCR		Total
	Primary	Secondary	
Particulate	5.24	0.14	5.38
Sulfur Dioxide		0.05	0.05
Nitrogen Oxides	-132.67	2.62	-130.05
Carbon Monoxide		1.57	1.57
Volatile Organic Compounds		0.10	0.10
Ammonia	33.29		
	Total:	-94.14	4.48
Carbon Dioxide (additional from gas firing)		2,484.33	2,484.33

Basis:

Lost Energy (mmBtu/year) 39,226

Secondary Emissions (lb/mmBtu): Assumes natural gas firing in NO_x controlled steam unit.

Particulate 0.0072

Sulfur Dioxide 0.0027

Nitrogen Oxides w/LNB 0.1333

Carbon Monoxide 0.0800

Volatile Organic Compounds 0.0052

Reference: Table 1.4-1 and 1.4-2, AP-42, Version 2/98

Table B-4. Capital Cost for Selective Catalytic Reduction for General Electric Frame 7F Simple Cycle Combustion Turbine
Based on 4,250 hr/yr Gas Firing and 750 hr/yr Oil Firing.

Cost Component	Costs	Basis of Cost Component
Direct Capital Costs		
SCR Associated Equipment	5,243,333.33	Vendor Estimate; Includes Cooling System
Ammonia Storage Tank	included	Vendor Estimate
Flue Gas Ductwork	included	Vendor Estimate
Instrumentation	included	Vendor Estimate
Emission Monitoring	\$262,167	5% of SCR Associated Equipment
Freight	\$262,167	5% of SCR Associated Equipment
Total Direct Capital Costs (TDCC)	\$5,767,667	
Direct Installation Costs		
Foundation and supports	\$461,413	8% of TDCC and RCC; OAQPS Cost Control Manual
Handling & Erection	\$807,473	14% of TDCC and RCC; OAQPS Cost Control Manual
Electrical	\$230,707	4% of TDCC and RCC; OAQPS Cost Control Manual
Piping (Ammonia Injection Grid)	included	Vendor Estimate
Insulation for ductwork	\$57,677	1% of TDCC and RCC; OAQPS Cost Control Manual
Painting	\$57,677	1% of TDCC and RCC; OAQPS Cost Control Manual
Site Preparation (General Facilities)	\$288,383	5% of TDCC and RCC; OAQPS Cost Control Manual
Project Contingencies	\$576,767	10% of TDCC and RCC; OAQPS Cost Control Manual
Total Direct Installation Costs (TDIC)	\$2,480,097	
Total Capital Costs (TCC)	\$8,247,763	Sum of TDCC and TDIC
Indirect Costs		
Engineering	included	Vendor Estimate
PSM/RMP Plan	\$50,000	Engineering Estimate
Construction and Field Expense	\$412,388	5% of Total Capital Costs; OAQPS Cost Control Manual
Contractor Fees	\$824,776	10% of Total Capital Costs; OAQPS Cost Control Manual
Start-up	\$164,955	2% of Total Capital Costs; OAQPS Cost Control Manual
Performance Tests	\$82,478	1% of Total Capital Costs; OAQPS Cost Control Manual
Total Indirect Capital Cost (TInCC)	\$1,534,597	
Total Direct, Indirect and Capital Costs (TDICC)	\$9,782,361	Sum of TCC and TInCC

Table B-5. Annualized Cost for Selective Catalytic Reduction for General Electric Frame 7F Simple Cycle Operation
Based on 4,250 hr/yr Gas Firing and 750 hr/yr Oil Firing.

Cost Component	Costs	Basis of Cost Component
<u>Direct Annual Costs</u>		
Operating Personnel	\$21,840	28 hours/week at \$15/hr
Supervision	\$3,276	15% of Operating Personnel; OAQPS Cost Control Manual
Ammonia	\$77,500	\$500 per ton for Aqueous NH ₃ , 62 lb/hr, 3,390 hr/year
PSM/RMP Update	\$25,000	Engineering Estimate
Inventory Cost	\$9,519	Capital Recovery (9.44%) for 1/3 catalyst for SCR
Catalyst Cost	\$75,625	4 years catalyst life; Based on Vendor Budget Estimate
Contingency	\$6,383	3% of Direct Annual Costs
Total Direct Annual Costs (TDAC)	\$219,142	
<u>Energy Costs</u>		
Electrical (SCR and Cooling)	\$66,000	330kW/h for SCR system @ \$0.04/kWh, 3,390 hr/yr
MW Loss and Heat Rate Penalty	\$172,950	0.5% of MW output; EPA, 1993 (Page 6-20) ^a
Total Energy Costs (TEC)	\$238,950	
<u>Indirect Annual Costs</u>		
Overhead	\$0	0% of Operating/Supervision Labor and Ammonia
Property Taxes	\$0	0% of Total Capital Costs
Insurance	\$0	0% of Total Capital Costs
Annualized Total Direct Capital	\$923,455	9.44% Capital Recovery Factor of 7% over 20 years times sum of TDICC of TDICC
Total Indirect Annual Costs (TIAC)	\$923,455	
Total Annualized Costs	\$1,381,547	Sum of TDAC, TEC and TIAC
Incremental Cost Effectiveness(9 to 3 ppmvd)	\$8,407	NO _x Reduction Only
	\$13,363	Net Emission Reduction

Table B-6. Maximum Potential Incremental Emissions (TPY) with Selective Catalytic Reduction
Based on 4,250 hr/yr Gas Firing and 750 hr/yr Oil Firing.

Pollutants	Incremental Emissions (tons/year) of SCR		Total
	Primary	Secondary	
Particulate	5.24	0.21	5.45
Sulfur Dioxide		0.08	0.08
Nitrogen Oxides	-164.33	3.86	-160.48
Carbon Monoxide		2.31	2.31
Volatile Organic Compounds		0.15	0.15
Ammonia	49.10		
	Total:	-110.00	-103.39
Carbon Dioxide (additional from gas firing)		3,664.20	3,664.20

Basis:

Lost Energy (mmBtu/year)

57,856

Secondary Emissions (lb/mmBtu): Assumes natural gas firing in NO_x controlled steam unit.

Particulate

0.0072

Sulfur Dioxide

0.0027

Nitrogen Oxides w/LNB

0.1333

Carbon Monoxide

0.0800

Volatile Organic Compounds

0.0052

Reference: Table 1.4-1 and 1.4-2, AP-42, Version 2/98

Table B-4. Capital Cost for Selective Catalytic Reduction for General Electric Frame 7F Simple Cycle Combustion Turbine
Based on 5000 hr/yr gas firing only.

Cost Component	Costs	Basis of Cost Component
<u>Direct Capital Costs</u>		
SCR Associated Equipment	5,243,333.33	Vendor Estimate; Includes Cooling System
Ammonia Storage Tank	included	Vendor Estimate
Flue Gas Ductwork	included	Vendor Estimate
Instrumentation	included	Vendor Estimate
Emission Monitoring	\$262,167	5% of SCR Associated Equipment
Freight	\$262,167	5% of SCR Associated Equipment
Total Direct Capital Costs (TDCC)	\$5,767,667	
<u>Direct Installation Costs</u>		
Foundation and supports	\$461,413	8% of TDCC and RCC; OAQPS Cost Control Manual
Handling & Erection	\$807,473	14% of TDCC and RCC; OAQPS Cost Control Manual
Electrical	\$230,707	4% of TDCC and RCC; OAQPS Cost Control Manual
Piping (Ammonia Injection Grid)	included	Vendor Estimate
Insulation for ductwork	\$57,677	1% of TDCC and RCC; OAQPS Cost Control Manual
Painting	\$57,677	1% of TDCC and RCC; OAQPS Cost Control Manual
Site Preparation (General Facilities)	\$288,383	5% of TDCC and RCC; OAQPS Cost Control Manual
Project Contingencies	\$576,767	10% of TDCC and RCC; OAQPS Cost Control Manual
Total Direct Installation Costs (TDIC)	\$2,480,097	
Total Capital Costs (TCC)	\$8,247,763	Sum of TDCC and TDIC
<u>Indirect Costs</u>		
Engineering	included	Vendor Estimate
PSM/RMP Plan	\$50,000	Engineering Estimate
Construction and Field Expense	\$412,388	5% of Total Capital Costs; OAQPS Cost Control Manual
Contractor Fees	\$824,776	10% of Total Capital Costs; OAQPS Cost Control Manual
Start-up	\$164,955	2% of Total Capital Costs; OAQPS Cost Control Manual
Performance Tests	\$82,478	1% of Total Capital Costs; OAQPS Cost Control Manual
Total Indirect Capital Cost (TInCC)	\$1,534,597	
Total Direct, Indirect and Capital Costs (TDICC)	\$9,782,361	Sum of TCC and TInCC

Table B-5. Annualized Cost for Selective Catalytic Reduction for General Electric Frame 7F Simple Cycle Operation
Based on 5000 hr/yr gas firing only.

Cost Component	Costs	Basis of Cost Component
<u>Direct Annual Costs</u>		
Operating Personnel	\$21,840	28 hours/week at \$15/hr
Supervision	\$3,276	15% of Operating Personnel; OAQPS Cost Control Manual
Ammonia	\$77,500	\$500 per ton for Aqueous NH ₃ , 62 lb/hr, 3,390 hr/year
PSM/RMP Update	\$25,000	Engineering Estimate
Inventory Cost	\$9,519	Capital Recovery (9.44%) for 1/3 catalyst for SCR
Catalyst Cost	\$75,625	4 years catalyst life; Based on Vendor Budget Estimate
Contingency	\$6,383	3% of Direct Annual Costs
Total Direct Annual Costs (TDAC)	\$219,142	
<u>Energy Costs</u>		
Electrical (SCR and Cooling)	\$66,000	330kW/h for SCR system @ \$0.04/kWh, 3,390 hr/yr
MW Loss and Heat Rate Penalty	\$172,950	0.5% of MW output; EPA, 1993 (Page 6-20) ^a
Total Energy Costs (TEC)	\$238,950	
<u>Indirect Annual Costs</u>		
Overhead	\$0	0% of Operating/Supervision Labor and Ammonia
Property Taxes	\$0	0% of Total Capital Costs
Insurance	\$0	0% of Total Capital Costs
Annualized Total Direct Capital	\$923,455	9.44% Capital Recovery Factor of 7% over 20 years times sum of TDICC
Total Indirect Annual Costs (TIAC)	\$923,455	
Total Annualized Costs	\$1,381,547	Sum of TDAC, TEC and TIAC
Incremental Cost Effectiveness(9 to 3 ppmvd)	\$14,050	NO _x Reduction Only
	\$36,953	Net Emission Reduction

^a Alternative Control Techniques Document--NO_x Emissions from Stationary Gas Turbines, Page 6-20.

Table B-6. Maximum Potential Incremental Emissions (TPY) with Selective Catalytic Reduction
Based on 5000 hr/yr gas firing only.

Pollutants	Incremental Emissions (tons/year) of SCR		Total
	Primary	Secondary	
Particulate	5.24	0.21	5.45
Sulfur Dioxide		0.08	0.08
Nitrogen Oxides	-98.33	3.86	-94.48
Carbon Monoxide		2.31	2.31
Volatile Organic Compounds		0.15	0.15
Ammonia	49.10		
	Total:	6.61	-37.39
Carbon Dioxide (additional from gas firing)		3,664.20	3,664.20

Basis:

Lost Energy (mmBtu/year)

57,856

Secondary Emissions (lb/mmBtu): Assumes natural gas firing in NO_x controlled steam unit.

Particulate

0.0072

Sulfur Dioxide

0.0027

Nitrogen Oxides w/LNB

0.1333

Carbon Monoxide

0.0800

Volatile Organic Compounds

0.0052

Reference: Table 1.4-1 and 1.4-2, AP-42, Version 2/98



E-MAIL COMMUNICATION

TO:

CC:

FROM:

PHONE:

FAX:

DATE: June 10, 2003

SUBJECT: Frame 7FA SCR Systems

Based on your inquiry we propose to furnish six (6) Simple Cycle SCR systems for use with six (6) GE Frame 7FA combustion gas turbine generators for the budgetary selling price of \$27,500,000.00 FOB point of manufacture. Estimated shipping weight is approximately 10,500,000 lb. total. Based on the availability of material and present shop loading conditions delivery is estimated to be approximately one year after receipt of an order and complete release to purchase materials.

Our scope of supply includes the following components:

- Ductwork and catalyst housings
- Exhaust stack
- Ammonia injection grid (AIG)
- AIG piping
- Ammonia/air dilution skid
- SCR catalyst
- Controls
- Walkways and ladders
- Fluid cooling system including:
 - Exhaust gas cooler
 - Air cooled heat exchanger
 - Redundant circulating pumps
 - Expansion/storage tank
 - Interconnecting piping
 - Associated trim and trim piping

Warranted SCR catalyst life is three years based on combustion gas turbine operation of less than 3800 hours per year and operation on fuel oil of less than 720 hours per year. Expected catalyst life is four years under the aforementioned operating conditions. Replacement catalyst cost is \$250,000.00 per unit based on current pricing. Ammonia consumption is approximately 325 lb/hr based on 19% aqueous ammonia. Estimated electrical loads for operating the system are listed below.

Ambient Temp - F	20	59	100
Load, SCR Operating (Fuel Oil) – kW	215	330	385
Load, SCR not Operating (Natural Gas) - kW	140	255	310

We request the opportunity to work with you on this project. Please contact us if you need additional information.

Regards,
David R. Logeais
Sr. Product Manager

	PPPI (Producer Prices Paid Index) 1.	PPRI (Producer Prices Received Index) 1.	PPPI (Producer Prices Paid Index) 1.	PPRI (Producer Prices Received Index) 1.	CCI (ENR's Construction Cost Index) 2.	CPI (Consumer Price Index) 3.	Water Resource Discount Rate 4.	OMB 10Y A-76 Nominal Discount Rate 5.		
YEAR	1977 Index	1977 Index	1990-92 Index	1990-92 Index	1913 Index					
1908					97.00					
1909					91.00					
1910					96.00					
1911					93.00					
1912					91.00					
1913					100.00	9.90				
1914					89.00	10.00				
1915					93.00	10.10				
1916					130.00	10.90				
1917					181.00	12.80				
1918					189.00	15.10				
1919					198.00	17.30				
1920					251.00	20.00				
1921					202.00	17.90				
1922					174.00	16.80				
1923					214.00	17.10				
1924					215.00	17.10				
1925					207.00	17.50				
1926					208.00	17.70				
1927					206.00	17.40				
1928					207.00	17.10				
1929					207.00	17.10				
1930					203.00	16.70				
1931					181.00	15.20				
1932					157.00	13.70				
1933					170.00	13.00				
1934					198.00	13.40				
1935					196.00	13.70				
1936					206.00	13.90				
1937					235.00	14.40				
1938					236.00	14.10				
1939					236.00	13.90				
1940					242.00	14.00				
1941					258.00	14.70				
1942					276.00	16.30				
1943					290.00	17.30				
1944					299.00	17.60				
1945					308.00	18.00				
1946					346.00	19.50				
1947					413.00	22.30				

1948					461.00	24.10		
1949					477.00	23.80		
1950					510.00	24.10		
1951					543.00	26.00		
1952					569.00	26.50		
1953					600.00	26.70		
1954	44.50	54.00	25.57	37.24	628.00	26.90		
1955	43.50	51.00	25.00	35.17	660.00	26.80		
1956	43.50	50.00	25.00	34.48	692.00	27.20		
1957	45.00	51.00	25.86	35.17	724.00	28.10	2.500	
1958	46.00	55.00	26.44	37.93	759.00	28.90	2.500	
1959	46.50	53.00	26.72	36.55	797.00	29.10	2.500	
1960	46.00	52.00	26.44	35.86	824.00	29.60	2.500	
1961	46.50	53.00	26.72	36.55	847.00	29.90	2.625	
1962	47.00	53.00	27.01	36.55	872.00	30.20	2.625	
1963	47.50	53.00	27.30	36.55	901.00	30.60	2.875	
1964	47.00	52.00	27.01	35.86	936.00	31.00	3.000	
1965	48.00	54.00	27.59	37.24	971.00	31.50	3.125	
1966	49.50	58.00	28.45	40.00	1019.00	32.40	3.125	
1967	50.00	55.00	28.74	37.93	1074.00	33.40	3.125	
1968	50.00	56.00	28.74	38.62	1155.00	34.80	3.250	
1969	52.00	59.00	29.89	40.69	1269.00	36.70	4.625	
1970	54.00	60.00	31.03	41.38	1381.00	38.80	4.875	
1971	56.50	62.00	32.47	42.76	1581.00	40.50	5.125	
1972	61.00	69.00	35.06	47.59	1753.00	41.80	5.375	
1973	73.00	98.00	41.95	67.59	1895.00	44.40	5.500	
1974	83.00	105.00	47.70	72.41	2020.00	49.30	5.625	
1975	91.00	101.00	52.30	69.66	2212.00	53.80	5.875	
1976	97.00	102.00	55.75	70.34	2401.00	56.90	6.125	
1977	100.00	100.00	57.47	68.97	2576.00	60.60	6.375	
1978	108.00	115.00	62.07	79.31	2776.00	65.20	6.625	
1979	125.00	132.00	71.84	91.03	3003.00	72.60	6.875	9.000
1980	138.00	134.00	79.31	92.41	3237.00	82.40	7.125	10.600
1981	148.00	138.00	85.06	95.17	3535.00	90.90	7.375	12.200
1982	153.00	133.00	87.93	91.72	3825.00	96.50	7.625	13.300
1983	152.00	135.00	87.36	93.10	4066.00	99.60	7.875	10.200
1984	155.00	142.00	89.08	97.93	4146.00	103.90	8.125	10.300
1985	151.00	128.00	86.78	88.28	4195.00	107.60	8.375	11.000
1986	144.00	123.00	82.76	84.83	4295.00	109.60	8.625	8.900
1987	147.00	127.00	84.48	87.59	4406.00	113.60	8.875	6.700
1988	157.00	138.00	90.23	95.17	4519.00	118.30	8.625	8.000
1989	167.00	147.00	95.98	101.38	4615.00	124.00	8.875	8.300
1990	171.00	149.00	99.00	104.00	4732.00	130.70	8.875	7.700
1991	174.00	145.00	100.00	100.00	4835.00	136.20	8.750	7.500
1992	174.00	140.00	101.00	98.00	4985.00	140.30	8.500	7.000
1993	181.00	143.00	104.00	101.00	5210.00	144.50	8.250	6.700
1994	183.40	144.70	106.00	100.00	5408.00	148.20	8.000	5.700
1995	201.70	147.60	109.00	102.00	5471.00	152.40	7.750	7.900
1996	210.90	162.00	115.00	112.00	5620.00	156.90	7.625	5.600

CCI

1997	216.40	154.77	118.00	107.00	5826.00	160.50	7.375	6.100	
1998	210.90	147.54	115.00	102.00	5920.00	163.00	7.125	5.900	
1999	210.90	137.41	115.00	95.00	6059.00	166.60	6.875	4.900	
2000	220.07	138.86	120.00	96.00	6221.00	172.20	6.625	6.100	
2001	225.57	147.54	123.00	102.00	6334.00	177.07	6.375	5.400	
2002	227.41	141.75	124.00	98.00	6538.00	179.88	6.125	5.100	
2003	234.74	154.77	128.00	107.00	6694.64	183.96	5.875	4.200	
2004	243.91	160.55	133.00	111.00	7114.89	188.90	5.625	4.600	
2005	262.25	164.89	143.00	114.00	7445.98	195.30	5.375	4.600	
2006	271.42	175.02	148.00	121.00	7887.62	201.60	5.125	5.000	
2007	289.76	199.61	158.00	138.00	8089.45	207.342	4.875	5.000	
2008	308.10	216.96	168.00	150.00	8094.28	210.036	4.875	4.600	1.2091
Report Dates	Jan. 2008	Jan. 2008	Jan. 2008	Jan. 2008	Feb.2008	Dec, 2007	As of FY2008	For FY 2008	
Data Sources:									
1. Prices paid and Received by Farmers, ERS/NASS data provided through Cornell University. http://usda.mannlib.cornell.edu/MannUsda/viewDocumentInfo.do?documentID=1002									
2. Engineering News Review, Construction Cost Index History http://www.enr.com/ The ENR website only provides the current month CCI. History of CCI available to members.									
3. Consumer Price Index-All Urban Consumers http://inflationdata.com/Inflation/Consumer_Price_Index/CurrentCPI.asp									
4. FY Plan Formulation Rate For Federal Water Projects http://www.economics.nrcs.usda.gov/cost/priceindexes/rates.html									
5. OMB Circ. A-94 10-Year Nominal Discount Rate http://www.whitehouse.gov/omb/circulars/a094/a094.html									
Updated since 1997 by David Buland Update dates given at the bottom of the column. Format Created by Madalene Ransom, 1996, Updated 2007									

ATTACHMENT C
UPDATED VISCREEN ANALYSIS

UTM-N (M)

314000 314500 315000 315500 316000 316500 317000 317500 318000

31500 32000 32500 33000 33500 34000 34500 35000 35500 36000 36500

UTM-E (M)

Steady Hills site

WIND from
W D
SSE
Sector
22.5°

WINDS from
South
Sector

Midpoint
of S of Sector

Yellow is Class I
part of Refugae
with NPS receptors

33.75°

-11.25°

360

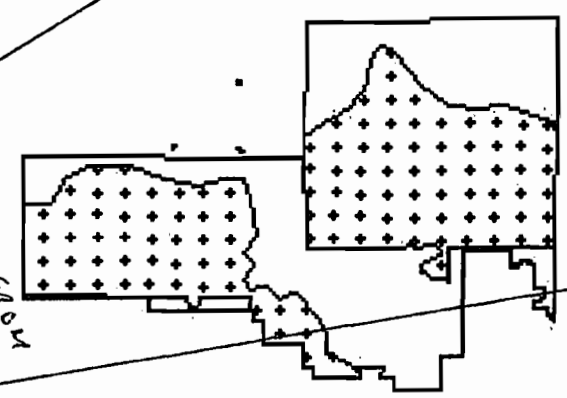


Figure 7-19 Level 2 Screening Analysis of Visual Effects due to the Project Firing Natural Gas Predicted at the Chassahowitzka NWA – Average of SSE and S WD Sectors (revised 07/08)

*** User-selected Screening Scenario Results ***

Input Emissions for

Particulates	18.00	LB /HR
NOx (as NO2)	129.10	LB /HR
Primary NO2	.00	LB /HR
Soot	.00	LB /HR
Primary SO4	3.28	LB /HR

Transport Scenario Specifications:

Background Ozone:	.04	ppm
Background Visual Range:	177.80	km
Source-Observer Distance:	28.00	km
Min. Source-Class I Distance:	28.00	km
Max. Source-Class I Distance:	46.00	km
Plume-Source-Observer Angle:	11.25	degrees
Stability:	4	
Wind Speed:	4.00	m/s

R E S U L T S

Asterisks (*) indicate plume impacts that exceed screening criteria

Maximum Visual Impacts INSIDE Class I Area
Screening Criteria ARE NOT Exceeded

Backgrnd	Theta	Azi	Distance	Alpha	Delta E		Contrast	
					Crit	Plume	Crit	Plume
SKY	10.	152.	46.0	16.	2.00	.319	.05	.003
SKY	140.	152.	46.0	16.	2.00	.219	.05	-.004

Maximum Visual Impacts OUTSIDE Class I Area
Screening Criteria ARE Exceeded

Backgrnd	Theta	Azi	Distance	Alpha	Delta E		Contrast	
					Crit	Plume	Crit	Plume
SKY	10.	0.	1.0	168.	2.00	3.102*	.05	.044
SKY	140.	0.	1.0	168.	2.00	1.443	.05	-.041

**Figure 7-20 Level 2 Screening Analysis of Visual Effects due to the Project Firing Fuel Oil
 Predicted at the Chassahowitzka NWA – Average of SSE and S WD Sectors (revised 07/08)**

*** User-selected Screening Scenario Results ***

Input Emissions for

Particulates	34.00	LB /HR
NOx (as NO2)	693.70	LB /HR
Primary NO2	.00	LB /HR
Soot	.00	LB /HR
Primary SO4	.98	LB /HR

Transport Scenario Specifications:

Background Ozone:	.04	ppm
Background Visual Range:	177.80	km
Source-Observer Distance:	28.00	km
Min. Source-Class I Distance:	28.00	km
Max. Source-Class I Distance:	46.00	km
Plume-Source-Observer Angle:	11.25	degrees
Stability:	4	
Wind Speed:	4.00	m/s

R E S U L T S

Asterisks (*) indicate plume impacts that exceed screening criteria

Maximum Visual Impacts INSIDE Class I Area
 Screening Criteria ARE NOT Exceeded

Backgrnd	Theta	Azi	Distance	Alpha	Delta E		Contrast	
					Crit	Plume	Crit	Plume
SKY	10.	152.	46.0	16.	2.00	1.692	.05	-.002
SKY	140.	152.	46.0	16.	2.00	1.059	.05	-.012

Maximum Visual Impacts OUTSIDE Class I Area
 Screening Criteria ARE Exceeded

Backgrnd	Theta	Azi	Distance	Alpha	Delta E		Contrast	
					Crit	Plume	Crit	Plume
SKY	10.	0.	1.0	168.	2.00	5.246*	.05	.061*
SKY	140.	0.	1.0	168.	2.00	2.089*	.05	-.054*

Note: The results with Theta equal to 10 degrees are unrealistic because the plume is assumed to be between the observer and the sun which is located at an angle of 10 degrees above the horizon in a direction to the southeast or southwest of the observer. In reality, such a sun angle and direction are not likely to occur for any given line of sight from the Class I area to the project. By limiting the southward extent of sun's location to the east-southeast or west-southwest directions and to a 10-degree angle above the horizon, the Delta E for the project is estimated to be less than the criterion of 2.0.

Figure 21. Level 2 Screening Analysis of Visual Effects due to the Project Firing Natural Gas Predicted at the Chassahowitzka NWA – SSE WD Sector Only

*** User-selected Screening Scenario Results ***

Input Emissions for

Particulates	18.00	LB /HR
NOx (as NO2)	129.10	LB /HR
Primary NO2	.00	LB /HR
Soot	.00	LB /HR
Primary SO4	3.28	LB /HR

Transport Scenario Specifications:

Background Ozone:	.04	ppm
Background Visual Range:	177.80	km
Source-Observer Distance:	28.00	km
Min. Source-Class I Distance:	28.00	km
Max. Source-Class I Distance:	46.00	km
Plume-Source-Observer Angle:	11.25	degrees
Stability:	4	
Wind Speed:	6.00	m/s

R E S U L T S

Asterisks (*) indicate plume impacts that exceed screening criteria

Maximum Visual Impacts INSIDE Class I Area
Screening Criteria ARE NOT Exceeded

Backgrnd	Theta	Azi	Distance	Alpha	Delta E		Contrast	
					Crit	Plume	Crit	Plume
SKY	10.	152.	46.0	16.	2.00	.213	.05	.002
SKY	140.	152.	46.0	16.	2.00	.146	.05	-.003

Maximum Visual Impacts OUTSIDE Class I Area
Screening Criteria ARE Exceeded

Backgrnd	Theta	Azi	Distance	Alpha	Delta E		Contrast	
					Crit	Plume	Crit	Plume
SKY	10.	0.	1.0	168.	2.00	2.380*	.05	.026
SKY	140.	0.	1.0	168.	2.00	1.286	.05	-.031

Figure 22. Level 2 Screening Analysis of Visual Effects due to the Project Firing Fuel Oil Predicted at the Chassahowitzka NWA – SSE WD Sector Only

*** User-selected Screening Scenario Results ***

Input Emissions for

Particulates	34.00	LB /HR
NOx (as NO2)	693.70	LB /HR
Primary NO2	.00	LB /HR
Soot	.00	LB /HR
Primary SO4	.98	LB /HR

Transport Scenario Specifications:

Background Ozone:	.04	ppm
Background Visual Range:	177.80	km
Source-Observer Distance:	28.00	km
Min. Source-Class I Distance:	28.00	km
Max. Source-Class I Distance:	46.00	km
Plume-Source-Observer Angle:	11.25	degrees
Stability:	4	
Wind Speed:	6.00	m/s

R E S U L T S

Asterisks (*) indicate plume impacts that exceed screening criteria

Maximum Visual Impacts INSIDE Class I Area
Screening Criteria ARE NOT Exceeded

Backgrnd	Theta	Azi	Distance	Alpha	Delta E		Contrast	
					Crit	Plume	Crit	Plume
SKY	10.	152.	46.0	16.	2.00	1.139	.05	-.001
SKY	140.	152.	46.0	16.	2.00	.714	.05	-.008

Maximum Visual Impacts OUTSIDE Class I Area
Screening Criteria ARE Exceeded

Backgrnd	Theta	Azi	Distance	Alpha	Delta E		Contrast	
					Crit	Plume	Crit	Plume
SKY	10.	0.	1.0	168.	2.00	3.906*	.05	.038
SKY	140.	0.	1.0	168.	2.00	1.744	.05	-.040

Figure 23. Level 2 Screening Analysis of Visual Effects due to the Project Firing Natural Gas Predicted at the Chassahowitzka NWA – South WD Sector Only

*** User-selected Screening Scenario Results ***

Input Emissions for

Particulates	18.00	LB /HR
NOx (as NO2)	129.10	LB /HR
Primary NO2	.00	LB /HR
Soot	.00	LB /HR
Primary SO4	3.28	LB /HR

PARTICLE CHARACTERISTICS

	Density	Diameter
	=====	=====
Primary Part.	2.5	6
Soot	2.0	1
Sulfate	1.5	4

Transport Scenario Specifications:

Background Ozone:	.04 ppm
Background Visual Range:	177.80 km
Source-Observer Distance:	35.00 km
Min. Source-Class I Distance:	35.00 km
Max. Source-Class I Distance:	36.00 km
Plume-Source-Observer Angle:	11.25 degrees
Stability:	4
Wind Speed:	3.00 m/s

R E S U L T S

Asterisks (*) indicate plume impacts that exceed screening criteria

Maximum Visual Impacts INSIDE Class I Area
Screening Criteria ARE NOT Exceeded

					Delta E	Plume	Contrast	
					=====	=====	=====	=====
Backgrnd	Theta	Azi	Distance	Alpha	Crit	Plume	Crit	Plume
=====	=====	=====	=====	=====	=====	=====	=====	=====
SKY	10.	93.	36.0	76.	2.98	.183	.06	.002
SKY	140.	93.	36.0	76.	2.00	.170	.06	-.002

Maximum Visual Impacts OUTSIDE Class I Area
Screening Criteria ARE Exceeded

					Delta E	Plume	Contrast	
					=====	=====	=====	=====
Backgrnd	Theta	Azi	Distance	Alpha	Crit	Plume	Crit	Plume
=====	=====	=====	=====	=====	=====	=====	=====	=====
SKY	10.	0.	1.0	168.	2.00	3.539*	.05	.054*
SKY	140.	0.	1.0	168.	2.00	1.263	.05	-.043

Figure 24. Level 2 Screening Analysis of Visual Effects due to the Project Firing Fuel Oil Predicted at the Chassahowitzka NWA – South WD Sector Only

*** User-selected Screening Scenario Results ***

Input Emissions for

Particulates	34.00	LB /HR
NOx (as NO2)	693.70	LB /HR
Primary NO2	.00	LB /HR
Soot	.00	LB /HR
Primary SO4	.98	LB /HR

Transport Scenario Specifications:

Background Ozone:	.04	ppm
Background Visual Range:	177.80	km
Source-Observer Distance:	35.00	km
Min. Source-Class I Distance:	35.00	km
Max. Source-Class I Distance:	36.00	km
Plume-Source-Observer Angle:	11.25	degrees
Stability:	4	
Wind Speed:	3.00	m/s

R E S U L T S

Asterisks (*) indicate plume impacts that exceed screening criteria

Maximum Visual Impacts INSIDE Class I Area
Screening Criteria ARE NOT Exceeded

Backgrnd	Theta	Azi	Distance	Alpha	Delta E		Contrast	
					Crit	Plume	Crit	Plume
SKY	10.	93.	36.0	76.	2.98	1.245	.06	-.001
SKY	140.	93.	36.0	76.	2.00	.825	.06	-.007

Maximum Visual Impacts OUTSIDE Class I Area
Screening Criteria ARE Exceeded

Backgrnd	Theta	Azi	Distance	Alpha	Delta E		Contrast	
					Crit	Plume	Crit	Plume
SKY	10.	0.	1.0	168.	2.00	5.851*	.05	.072*
SKY	140.	0.	1.0	168.	2.00	1.834	.05	-.058*

TABLE 7-4
 PLUME VISUAL IMPACT ANALYSIS - SCREENING LEVEL 2 - IDENTIFICATION OF WORSE-CASE METEOROLOGICAL CONDITIONS

Category	Stability	Name	Dispersion Conditions			Sigma Y x Sigma Z x Wind Speed (m ³ /s)	Transport Time to Class I Area (hours) ^a	Frequency of Occurrence (percent)			
			Wind Speed (m/s)	Dispersion Parameter				of Dispersion Conditions ^c			
				Horizontal (sigma Y (m))	Vertical (sigma Z (m))			7 a.m. to 1 p.m.		1 p.m. to 7 p.m.	
						f ^b	cf ^b	f ^b	cf ^b		
Combined South-southeast to South Wind Direction Sector^d											
F	Moderately Stable	1	673.6	67.3	45,333	7.8	0.00	0.00	0.00	0.00	
F	Moderately Stable	2	673.6	67.3	90,667	3.9	0.01	0.01	0.00	0.00	
E	Slightly Stable	1	1011.5	124.1	125,473	7.8	0.02	0.03	0.15	0.16	
F	Moderately Stable	3	673.6	67.3	136,000	2.6	0.02	0.05	0.08	0.23	
E	Slightly Stable	2	1011.5	124.1	250,946	3.9	0.00	0.06	0.06	0.30	
D	Neutral	1	1350.7	241.5	326,253	7.8	0.00	0.06	0.05	0.28	
E	Slightly Stable	3	1011.5	124.1	376,419	2.6	0.00	0.06	0.05	0.33	
E	Slightly Stable	4	1011.5	124.1	501,892	1.9	0.00	0.06	0.05	0.38	
E	Slightly Stable	5	1011.5	124.1	627,365	1.6	0.00	0.06	0.17	0.55	
D	Neutral	2	1350.7	241.5	652,506	3.9	0.14	0.20	0.08	0.63	
D	Neutral	3	1350.7	241.5	978,758	2.6	0.31	0.51	0.22	0.85	
D	Neutral	4	1350.7	241.5	1,305,011	1.9	0.31	0.82	0.22	1.07	
D	Neutral	5	1350.7	241.5	1,631,264	1.6	0.31	1.13	0.22	1.29	
South-southeast Wind Direction Sector Only											
F	Moderately Stable	1	673.6	67.3	45,333	7.8	0.00	0.00	0.00	0.00	
F	Moderately Stable	2	673.6	67.3	90,667	3.9	0.03	0.03	0.01	0.01	
E	Slightly Stable	1	1011.5	124.1	125,473	7.8	0.00	0.03	0.00	0.01	
F	Moderately Stable	3	673.6	67.3	136,000	2.6	0.03	0.05	0.04	0.05	
E	Slightly Stable	2	1011.5	124.1	250,946	3.9	0.01	0.06	0.04	0.08	
D	Neutral	1	1350.7	241.5	326,253	7.8	0.00	0.03	0.00	0.01	
E	Slightly Stable	3	1011.5	124.1	376,419	2.6	0.01	0.04	0.11	0.12	
E	Slightly Stable	4	1011.5	124.1	501,892	1.9	0.00	0.04	0.00	0.12	
E	Slightly Stable	5	1011.5	124.1	627,365	1.6	0.00	0.04	0.00	0.12	
D	Neutral	2	1350.7	241.5	652,506	3.9	0.10	0.14	0.06	0.18	
D	Neutral	3	1350.7	241.5	978,758	2.6	0.24	0.37	0.10	0.28	
D	Neutral	4	1350.7	241.5	1,305,011	1.9	0.24	0.61	0.10	0.38	
D	Neutral	5	1350.7	241.5	1,631,264	1.6	0.24	0.85	0.10	0.48	
South Wind Direction Sector Only											
F	Moderately Stable	1	673.6	67.3	45,333	7.8	0.00	0.00	0.00	0.00	
F	Moderately Stable	2	673.6	67.3	90,667	3.9	0.00	0.00	0.00	0.00	
E	Slightly Stable	1	1011.5	124.1	125,473	7.8	0.04	0.04	0.30	0.30	
F	Moderately Stable	3	673.6	67.3	136,000	2.6	0.02	0.05	0.12	0.42	
E	Slightly Stable	2	1011.5	124.1	250,946	3.9	0.00	0.05	0.09	0.51	
D	Neutral	1	1350.7	241.5	326,253	7.8	0.00	0.05	0.09	0.60	
E	Slightly Stable	3	1011.5	124.1	376,419	2.6	0.00	0.05	0.00	0.42	
E	Slightly Stable	4	1011.5	124.1	501,892	1.9	0.00	0.05	0.09	0.51	
E	Slightly Stable	5	1011.5	124.1	627,365	1.6	0.00	0.05	0.35	0.86	
D	Neutral	2	1350.7	241.5	652,506	3.9	0.17	0.23	0.09	0.95	
D	Neutral	3	1350.7	241.5	978,758	2.6	0.38	0.61	0.34	1.29	
D	Neutral	4	1350.7	241.5	1,305,011	1.9	0.38	0.99	0.34	1.62	
D	Neutral	5	1350.7	241.5	1,631,264	1.6	0.38	1.38	0.34	1.96	

^a Proposed project location is approximately 28.0 km from closest boundary of Class I area.

^b f= frequency for given meteorological condition; cf= cumulative frequency up to and including condition.

^c Based on surface meteorological data for 2001 to 2005 from the National Weather Service (NWS) station at the Tampa International Airport.

^d Approximately 95 percent of the Chassahowitzka NWA is downwind of the proposed project with a south-southeast wind direction.