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JUL 22 2008

BUREAU OF AIR REGULATION

July 21, 2008

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)] x 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 NOx 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 YYYY. 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 YYYY 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

B. EMISSIONS UNIT CAPACITY INFORMATION

(Optional for unregulated emissions units.)

Emissions Unit Operating Capacity and Schedule

1. Maximum Process or Throughput Rate:		
2. Maximum Production Rate:		
3. Maximum Heat Input Rate: 1,830 million Btu/hr		
4. Maximum Incineration Rate:	pounds/hr tons/day	
5. Requested Maximum Operating Schedule:	24 hours/day 52 weeks/year	7 days/week 5,000 hours/year
6. Operating Capacity/Schedule Comment: **Maximum heat input rates: Natural gas firing - 1,623 MMBtu/CT/hr Distillate fuel oil firing - 1,830 MMBtu/CT/hr** **Maximum heat input rates are based on lower heating value of each fuel at ambient conditions of 59 degree F, 60 percent RH, 100 percent load, and 14.7 psi pressure.** **Fuel oil firing limited to an average of 750 hours/CT/year. ~~Fuel oil firing limited to an average of 1,000 hr/CT/yr.~~ Annual operation limited to an average of 3,390 hr/CT/yr. No single CT is permitted to operate more than 5,000 hr/yr.**		

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/ft^3.** **Maximum hourly rate = 1,623 MMBtu/hr /933 MMBtu/MM ft^3 = 1.739 MM ft^3/CT/hr** **Maximum annual rate = 1.739 MM ft^3/hr x 3,390 hr/yr = 5,897.8 MM ft^3/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: **~~13,863.6~~10,397.7**	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 = 10,397,700 gallons/yr.~~Maximum annual rate = 13,863.6 gal/hr x 1,000 hr/yr = 13,863,600 gal/CT/yr~~**		

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 ~~19.3~~18.3 tons/year	4. Synthetically Limited? ☒ Yes ☐ 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: ☐ 5 years ☐ 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 = (17.0 lb/hr x 750 hrs/yr + 9 lb/hr x 2,640 hrs/yr) x ton/2,000 lb = 18.255 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 TPY~~/CT**	
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: **9.0 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~~ 6.4tons/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):	

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_{10}**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **17.0** lb/hour ~~19.3~~18.3 tons/year	4. Synthetically Limited? ☒ Yes ☐ 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: ☐ 5 years ☐ 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 = (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** ~~Annual emissions based on 1,000 hr/yr of distillate oil firing and 2,390 hr/yr of natural gas firing. 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~~	
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: **9.0 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):	

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: ~~66.2~~44.7 lb/hour ~~68.6~~45.1 tons/year	4. Synthetically Limited? ☒ Yes ☐ 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: ☐ 5 years ☐ 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.**	

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: **~~29.7~~21.5** lb/hour **~~50.3~~36.4** 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 ppmvd~~20 ppmvd~~**	4. Equivalent Allowable Emissions: **~~66.2~~ 44.7** lb/hour **~~33.1~~16.8** 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 ~~7.34~~6.8 tons/year	4. Synthetically Limited? ☒ Yes ☐ 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: ☐ 5 years ☐ 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 = (7.5 lb/hr x 750 hrs/yr + 3.0 lb/hr x 2,640 hrs/yr) x ton/2,000 lb = 6.77 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 TPY~~/CT**	
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: **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 **~~3.75~~2.8** 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: **SO_2**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **3.~~0~~1** lb/hour **~~13.3~~14.9** tons/year	4. Synthetically Limited? ☒ Yes ☐ 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: ☐ 5 years ☐ 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 = (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~~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**	
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: **2 grains/ 100 cf**	4. Equivalent Allowable Emissions: **~~9.9~~10.4** lb/hour **~~16.8~~17.6** 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.~~0~~1** lb/hour **1.~~5~~2** 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? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: 42 ppmvd at 15 percent O_2 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: ☐ 5 years ☐ 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 = (323.0 lb/hr x 750 hrs/yr + 59 lb/hr x 2,640 hrs/yr) x ton/2,000 lb = 199.0 TPY ~~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	
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 O_2.**	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 O_2.**	4. Equivalent Allowable Emissions: **323** lb/hour ~~161.5~~121.1 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
Combustion Turbine Performance			
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
CT Exhaust Flow			
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
Fuel Usage			
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
Stack			
Stack Height (ft)	75	75	75
Stack Diameter (ft)	18	18	18
Stack Flow Conditions			
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 Case 1	59 °F Case 2	95 °F Case 3
Particulate Matter (Front-half only)			
Particulate from CT- provided	9.0	9.0	9.0
Sulfur Dioxide			
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
Nitrogen Oxides			
NOx (lb/hr) = NOx (ppm actual) x Volume flow (acfm) x			
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
Carbon Monoxide			
CO (lb/hr) = CO (ppm actual) x Volume flow (acfm) x			
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 Case 1	 59 °F Case 2	 95 °F Case 3
Volatile Organic Compounds			
VOC (lb/hr) = VOC (ppm actual) x Volume flow (acfm) x			
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
Sulfuric Acid Mist			
Total Sulfuric Acid Mist (SAM) (lb/hr) = SAM Formed in the CT			
	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
Lead			
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
Combustion Turbine Performance			
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
CT Exhaust Flow			
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
Fuel Usage			
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
Stack			
Stack Height (ft)	75	75	75
Stack Diameter (ft)	18	18	18
Stack Flow Conditions			
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
Particulate Matter (Front-half only)			
Particulate from CT- provided	9.0	9.0	9.0
Sulfur Dioxide			
Fuel use (cf/hr)	1,612,040	1,489,784	1,376,156
Sulfur content (grains/ 100 cf)	2	2	2
	2	2	2
CT Stack emission rate (lb/hr)- calculated	9.2	8.5	7.9
Nitrogen Oxides			
NOx (lb/hr) = NOx (ppm actual) x Volume flow (acfm) x			
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
Carbon Monoxide			
CO (lb/hr) = CO (ppm actual) x Volume flow (acfm) x			
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
Volatile Organic Compounds			
VOC (lb/hr) = VOC (ppm actual) x Volume flow (acfm) x			
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
Sulfuric Acid Mist			
Total Sulfuric Acid Mist (SAM) (lb/hr)= SAM Formed in the CT	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
Lead			
Lead (lb/hr) = NA			
Emission Rate Basis	NA	NA	NA
HRSG 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
Combustion Turbine Performance			
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
CT Exhaust Flow			
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
Fuel Usage			
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
Stack			
Stack Height (ft)	75	75	75
Stack Diameter (ft)	18	18	18
Stack Flow Conditions			
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 Case 7	59 °F Case 8	95 °F Case 9
Particulate Matter (Front-half only)			
Particulate from CT- provided	9.0	9.0	9.0
Sulfur Dioxide			
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
Nitrogen Oxides			
NOx (lb/hr) = NOx (ppm actual) x Volume flow (acfm) x			
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
Carbon Monoxide			
CO (lb/hr) = CO (ppm actual) x Volume flow (acfm) x			
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 Case 7	59 °F Case 8	95 °F Case 9
Volatile Organic Compounds			
VOC (lb/hr) = VOC (ppm actual) x Volume flow (acfm) x			
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
Sulfuric Acid Mist			
Total Sulfuric Acid Mist (SAM) (lb/hr)= SAM Formed in the CT			
	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
Lead			
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
Combustion Turbine Performance			
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
CT Exhaust Flow			
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
Fuel Usage			
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
Stack			
Stack Height (ft)	75	75	75
Diameter (ft)	18	18	18
HRSG Stack Flow Conditions			
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; Golder, 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
Particulate Matter (Front-half only)			
Particulate from CT- provided	17.0	17.0	17.0
Sulfur Dioxide			
Fuel oil use (lb/hr)	109,721	103,222	93,061
Fuel oil Sulfur Content	0.0015%	0.0015%	0.0015%
lb SO2 / lb S (64/32)	2	2	2
Stack emission rate (lb/hr)- calculated	3.3	3.1	2.8
Nitrogen Oxides			
NOx (lb/hr) = NOx (ppm actual) x Volume flow (acfm) x			
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
Carbon Monoxide			
CO (lb/hr) = CO (ppm actual) x Volume flow (acfm) x			
Basis, ppmvd - provided	13.5	13.5	13.5
Basis, ppmvd @ 15% O2 - 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
Volatile Organic Compounds			
VOC (lb/hr) = VOC (ppm actual) x Volume flow (acfm) x			
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
Sulfuric Acid Mist			
Total Sulfuric Acid Mist (SAM) (lb/hr)= SAM Formed in the CT			
	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
Lead			
	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
Combustion Turbine Performance			
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
CT Exhaust Flow			
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
Fuel Usage			
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
HRSG Stack			
HRSG - Stack Height (ft)	75	75	75
Diameter (ft)	18	18	18
Stack Flow Conditions			
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
Particulate Matter (Front-half only)			
Particulate from CT- provided	17.0	17.0	17.0
Sulfur Dioxide			
Fuel oil Sulfur Content	0.0015%	0.0015%	0.0015%
Fuel oil use (lb/hr)	89,805	84,326	76,670
lb SO2 / lb S (64/32)	2	2	2
Stack emission rate (lb/hr)- calculated	2.7	2.5	2.3
Nitrogen Oxides			
NOx (lb/hr) = NOx (ppm actual) x Volume flow (acfm) x			
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
Carbon Monoxide			
CO (lb/hr) = CO (ppm actual) x Volume flow (acfm) x			
Basis, ppmvd - provided	13.5	13.5	13.5
Basis, ppmvd @ 15% O2 - 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**
Volatile Organic Compounds			
VOC (lb/hr) = VOC (ppm actual) x Volume flow (acfm) x			
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
Sulfuric Acid Mist			
Total Sulfuric Acid Mist (SAM) (lb/hr)= SAM Formed in the CT			
	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
Lead			
	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
Combustion Turbine Performance			
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
CT Exhaust Flow			
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
Fuel Usage			
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
HRSG Stack			
HRSG - Stack Height (ft)	75	75	75
Diameter (ft)	18	18	18
Stack Flow Conditions			
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
Particulate Matter (Front-half only)			
Particulate from CT- provided	17.0	17.0	17.0
Sulfur Dioxide			
Fuel oil Sulfur Content	0.0015%	0.0015%	0.0015%
Fuel oil use (lb/hr)	69,454	65,826	59,897
lb SO2 / lb S (64/32)	2	2	2
Stack emission rate (lb/hr)- calculated	2.1	2.0	1.8
Nitrogen Oxides			
NOx (lb/hr) = NOx (ppm actual) x Volume flow (acfm) x			
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
Carbon Monoxide			
CO (lb/hr) = CO (ppm actual) x Volume flow (acfm) x			
Basis, ppmvd - provided	13.5	13.5	13.5
Basis, ppmvd @ 15% O2 - 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
Volatile Organic Compounds			
VOC (lb/hr) = VOC (ppm actual) x Volume flow (acfm) x			
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
Sulfuric Acid Mist			
Total Sulfuric Acid Mist (SAM) (lb/hr)= SAM Formed in the CT			
	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
Lead			
	14	14	14
Stack emission rate (lb/hr)- calculated	0.0178	0.0169	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	59 °F
			1	2
HIR (MMBtu/hr):		1,892	CT	CTs
Sulfuric acid mist		1.60	2.7	5.4
HAPs (Section 112(b) of Clean Air Act)				
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
Formadehyde		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:

Emission Factors		Value	Reference
Sulfuric acid mist		10	
1,3-Butadiene	(a)	0.43	
Acetaldehyde		40	
Acrolein		6.4	
Benzene		12	
Ethylbenzene		32	
Formadehyde		0.091	ppmvd @15% O2 (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 NOx COMBUSTOR, NATURAL GAS, BASE LOAD

Parameter	CT Only Turbine Inlet Temperature 20 °F Case 1	 59 °F Case 2	 95 °F Case 3
Formaldehyde (CH_2O) MW = 30			
CH_2O (lb/hr) = CH_2O (ppm actual) x Volume flow (acfm) x 46 (mole. wgt NOx) x 2116.8 lb/ft2 (pressure) / [1545.7 (gas constant, R) x Actual Temp. (°R)] x 60 min/hr			
CH_2O (ppm actual) = CH_2O (ppmd @ 15%O_2) x [(20.9 - O_2 dry)/(20.9 - 15)]			
Oxygen (%, dry)(O_2 dry) = Oxygen (%)/(1-Moisure (%))			
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; O_2= 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) Firing Distillate Fuel Oil (1)	Maximum Annual Emissions (TPY)			
	Base Load	Distillate Fuel Oil (2)		Natural Gas (4)	Natural Gas and Fuel Oil (5)
	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
Formadehyde	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	
Formadehyde		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 anni 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 NOx COMBUSTOR, DISTILLATE OIL, BASE LOAD

Parameter	CT Only Turbine Inlet Temperature 20 °F Case 10	59 °F Case 11	95 °F Case 12
Formaldehyde (CH_2O) MW = 30			
CH_2O (lb/hr) = CH_2O (ppm actual) x Volume flow (acfm) x 46 (mole. wgt NOx) x 2116.8 lb/ft2 (pressure) /			
[1545.7 (gas constant, R) x Actual Temp. (°R)] x 60 min/hr			
CH_2O (ppm actual) = CH_2O (ppmd @ 15%O_2) x [(20.9 - O_2 dry)/(20.9 - 15)]			
Oxygen (%, dry)(O_2 dry) = Oxygen (%)/(1-Moisture (%))			
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

		Operating and Emission Data[a] for Ambient Temperature		
		Combustion Turbine		
Parameter		20 °F	59 °F	95 °F
CT Stack Data (ft)				
Height		75	75	75
Diameter		18.0	18.0	18.0
100 Percent Load				
		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
75 Percent Load				
		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
50 Percent Load				
		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

		Operating and Emission Data[a] for Ambient Temperature		
		Combustion Turbine		
Parameter		20 °F	59 °F	95 °F
CT/HRSG Stack Data (ft)				
Height		75	75	75
Diameter		18	18	18
100 Percent Load				
		1,053	1,093	1,143
Velocity (ft/sec)		172.4	164.7	154.8
Maximum Hourly Emissions per Unit				
SO_2	lb/hr	3.3	3.1	2.8
PM/PM_{10}	lb/hr	17.0	17.0	17.0
NO_x	lb/hr	345.9	322.3	293.5
CO	lb/hr	48.0	44.7	40.9
VOC (as methane)	lb/hr	8.2	7.5	6.7
Lead	lb/hr	0.028	0.026	0.024
Sulfuric Acid Mist	lb/hr	0.50	0.47	0.43
75 Percent Load				
		1,196	1,200	1,200
Velocity (ft/sec)		139.4	135.6	130.7
Maximum Hourly Emissions per Unit				
SO_2	lb/hr	2.7	2.5	2.3
PM/PM_{10}	lb/hr	17.0	17.0	17.0
NO_x	lb/hr	280.4	263.3	239.2
CO	lb/hr	35.2	34.1	32.6
VOC (as methane)	lb/hr	6.0	5.8	5.5
Lead	lb/hr	0.023	0.022	0.020
Sulfuric Acid Mist	lb/hr	0.41	0.39	0.35
50 Percent Load				
		1,196	1,200	1,200
Velocity (ft/sec)		116.0	114.5	110.2
Maximum Hourly Emissions per Unit				
SO_2	lb/hr	2.1	2.0	1.8
PM/PM_{10}	lb/hr	17.0	17.0	17.0
NO_x	lb/hr	214.9	203.6	185.2
CO	lb/hr	29.8	29.3	27.9
VOC (as methane)	lb/hr	5.0	5.0	4.7
Lead	lb/hr	0.018	0.017	0.015
Sulfuric Acid Mist	lb/hr	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

	Maximum Hourly Emissions (lb/hr)[a] Simple Cycle (SC)		Maximum Emissions (tons/year)		
			Operating Scenario	Operating Hours	
Fuel:	NG	Oil	SC/ NG 100 % Load	3,390	2,640
Temp & Load:	59 °F, 100%	59 °F, 100%	SC/ OIL 100 % Load	0	750
Pollutant			TOTAL	3,390	3,390
One Combustion Turbine					
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
Two Combustion Turbines					
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) 2 CTs	Emergency Generator	Natural Gas Heater	TOTAL	PSD Significant Emission Rate (tons/year)	PSD Review Required?
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
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 2,640 hr/yr Gas Firing and 750 hr/yr Oil Firing

Cost Component	Costs	Basis of Cost Component
Direct Annual Costs		
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	
Energy Costs		
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	
Indirect Annual Costs		
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--NOx 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 Primary	Secondary	Total
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	-89.66
Carbon Dioxide (additonal 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
Direct Annual Costs		
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	
Energy Costs		
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	
Indirect Annual Costs		
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.

	Incremental Emissions (tons/year) of SCR		
Pollutants	Primary	Secondary	Total
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	6.61	-103.39
Carbon Dioxide (additonal 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
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 5000 hr/yr gas firing only.

Cost Component	Costs	Basis of Cost Component
Direct Annual Costs		
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	
Energy Costs		
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	
Indirect Annual Costs		
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	$1,381,547	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--NOx 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:	-44.00	6.61	-37.39
Carbon Dioxide (additonal 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 you 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

[redacted] [redacted]

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

YEAR	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.		
	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		

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

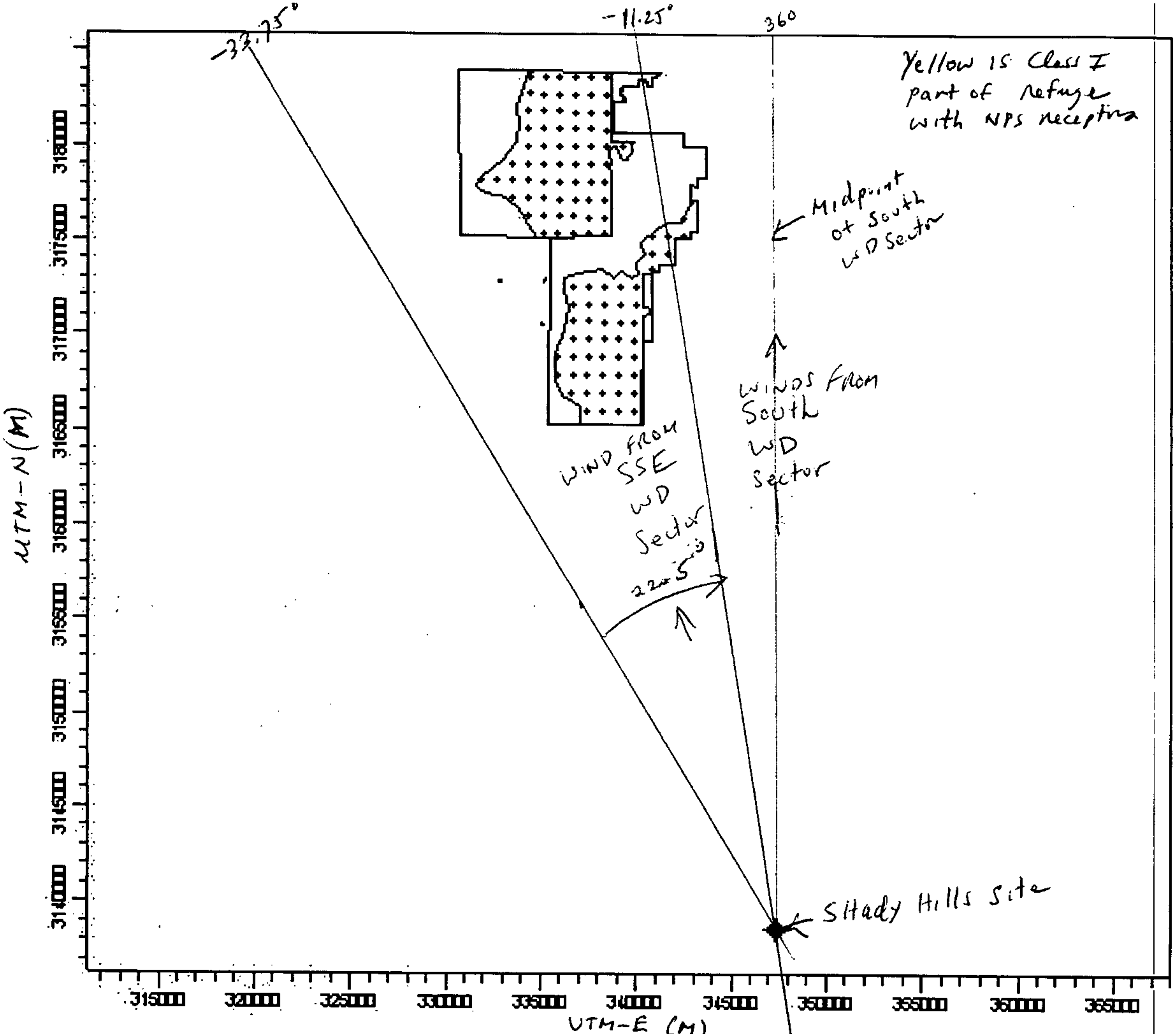
-33.75°
-11.25°
360
Yellow is Class I part of Refuge with NPS receptors
Midpoint of South WD Sector
WINDS FROM South WD Sector
WIND FROM SSE WD Sector
22.5°
Shady Hills Site
UTM-N (M)
UTM-E (M)
315000
320000
325000
330000
335000
340000
345000
350000
355000
360000
365000
3140000
3145000
3150000
3155000
3160000
3165000
3170000
3175000
3180000

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
                                    Delta E       Contrast
                                  ===========   ============
Backgrnd Theta Azi Distance Alpha 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
                                    Delta E       Contrast
                                  ===========   ============
Backgrnd Theta Azi Distance Alpha 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 Crit	Delta E Plume	Contrast Crit	Contrast 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 Crit	Delta E Plume	Contrast Crit	Contrast 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
                                         Delta E       Contrast
                                       ===========   ============
Backgrnd Theta Azi Distance Alpha 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
                                         Delta E       Contrast
                                       ===========   ============
Backgrnd Theta Azi Distance Alpha 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
                                            Delta E       Contrast
                                          ===========   ============
Backgrnd Theta Azi Distance Alpha 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
                                            Delta E       Contrast
                                          ===========   ============
Backgrnd Theta Azi Distance Alpha 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       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       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
                                   Delta E       Contrast
                                 ===========   ===========
Backgrnd Theta Azi Distance Alpha 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
                                   Delta E       Contrast
                                 ===========   ===========
Backgrnd Theta Azi Distance Alpha 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

Dispersion Conditions						Transport	Frequency of Occurrence (percent) of Dispersion Conditions[c]			
Stability		Wind Speed	Dispersion Parameter		Sigma Y x Sigma Z x Wind Speed	Time to Class I Area	7 a.m. to 1 p.m.		1 p.m. to 7 p.m.	
Category	Name	(m/s)	Horizontal (sigma Y (m))	Vertical (sigma Z (m))	(m^3/s)	(hours)[a]	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