TECHNICAL EVALUATION
&
PRELIMINARY DETERMINATION

APPLICANT

Duke Energy Florida, Inc. (DEF)

7700 County Line Rd. 555
Bartow, Florida 33830

Hines Energy Complex
Facility ID No. 1050234

PROJECT

Project No. 1050234-021-AC
Application for Minor Source Air Construction Permit
Installation of Inlet Air Chillers on the Combustion Turbines

COUNTY

Polk County, Florida

PERMITTING AUTHORITY

Florida Department of Environmental Protection
Division of Air Resource Management
Office of permitting and Compliance
2600 Blair Stone Road, MS#5505
Tallahassee, Florida 32399-2400

December 12, 2014

1. GENERAL PROJECT INFORMATION

1.1. Air Pollution Regulations

Projects at stationary sources with the potential to emit air pollution are subject to the applicable environmental laws specified in Section 403 of the Florida Statutes (F.S.). The statutes authorize the Department of Environmental Protection (Department) to establish regulations regarding air quality as part of the Florida Administrative Code (F.A.C.), which includes the following applicable chapters: 62-4 (Permits); 62-204 (Air Pollution Control – General Provisions); 62-210 (Stationary Sources – General Requirements); 62-212 (Stationary Sources – Preconstruction Review); 62-213 (Operation Permits for Major Sources of Air Pollution); 62-296 (Stationary Sources - Emission Standards); and 62-297 (Stationary Sources – Emissions Monitoring). Specifically, air construction permits are required pursuant to Chapters 62-4, 62-210 and 62-212, F.A.C.

In addition, the U. S. Environmental Protection Agency (EPA) establishes air quality regulations in Title 40 of the Code of Federal Regulations (CFR). Part 60 specifies New Source Performance Standards (NSPS) for numerous industrial categories. Part 61 specifies National Emission Standards for Hazardous Air Pollutants (NESHAP) based on specific pollutants. Part 63 specifies NESHAP based on the Maximum Achievable Control Technology (MACT) for numerous industrial categories. The Department adopts these federal regulations in Rule 62-204.800, F.A.C.

1.2. Facility Description and Location

Duke Energy Florida, Inc. (DEF) operates the Hines Energy Complex, which is an existing power plant (SIC No. 4911). The plant is located on an approximate 8,000-acre site in southwest Polk County that was previously a phosphate mine. The address is 7700 County Road 555, Bartow, Florida. The location with respect to other DEF (formerly PEF) facilities in Florida is shown in **Figure 1**. **Figure 2** contains the location of the plant with respect to CR 555 and the immediate environs.

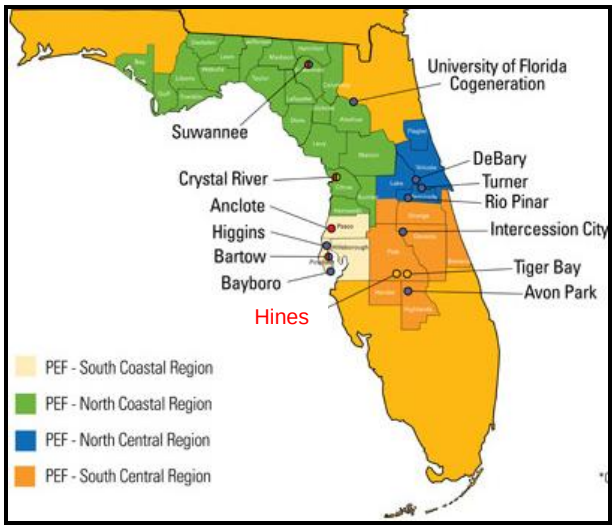


Figure 1. Hines Energy Complex in DEF System. Figure 2. Hines Energy Complex Location, Environs.

The plant is located approximately 118 km south-southeast of the PSD Class I Chassahowitzka National Wilderness Area. The approximate facility UTM coordinates are: Zone 17, 414.4 km East and 3073.9 km North. According to the facility Title V Air Operating Permit, the Hines Energy Complex is comprised of the following four power blocks. Link to Hines Title V Permit

Power Block 1 consists of a "two-on-one" combined cycle unit with a nominal capacity of 500 megawatts (MW); a 99 million Btu per hour (MMBtu/hour) auxiliary boiler; and a 97,570 barrel fuel oil storage tank.

Power Blocks 2, 3 and 4 are also "two-on-one" combined cycle units, each with a nominal capacity of 530 MW. Emissions from each CT and HRSG combination are vented through a single stack.

1.3. Facility Regulatory Categories

- The facility is a major source of hazardous air pollutants (HAP).
- The facility is a Title V major source of air pollution in accordance with Chapter 213, F.A.C.
- The facility is a major stationary source (PSD-major source) in accordance with Rule 62-212.400, F.A.C.
- The facility operates units subject to the Standards of Performance for New Stationary Sources (NSPS) pursuant to 40 Code of Federal Regulations (CFR) Part 60.
- The facility operates units subject to the National Emissions Standards for Hazardous Air Pollutants (NESHAP) pursuant to 40 CFR Part 63.
- The facility operates units subject to the Acid Rain provisions of the Clean Air Act.
- The facility is located in an area that is designated as "attainment", "maintenance", or "unclassifiable" for each pollutant subject to a National Ambient Air Quality Standard pursuant to Rule 62-204.340, F.A.C.
- The facility was certified pursuant to Siting under 403.501-519, F.S. and Chapter 62-17, F.A.C.

1.4. Process Description and Emissions

Figure 3 is an aerial photograph of the DEF Hines Energy Complex. Each "two-on-one" power block includes two combustion turbine-electrical generators (CTGs), two heat recover steam generators (HRSGs) and one steam turbine-electric generator (STG). The eight exhaust stacks (one per HRSG) are visible in the lower part of the picture.

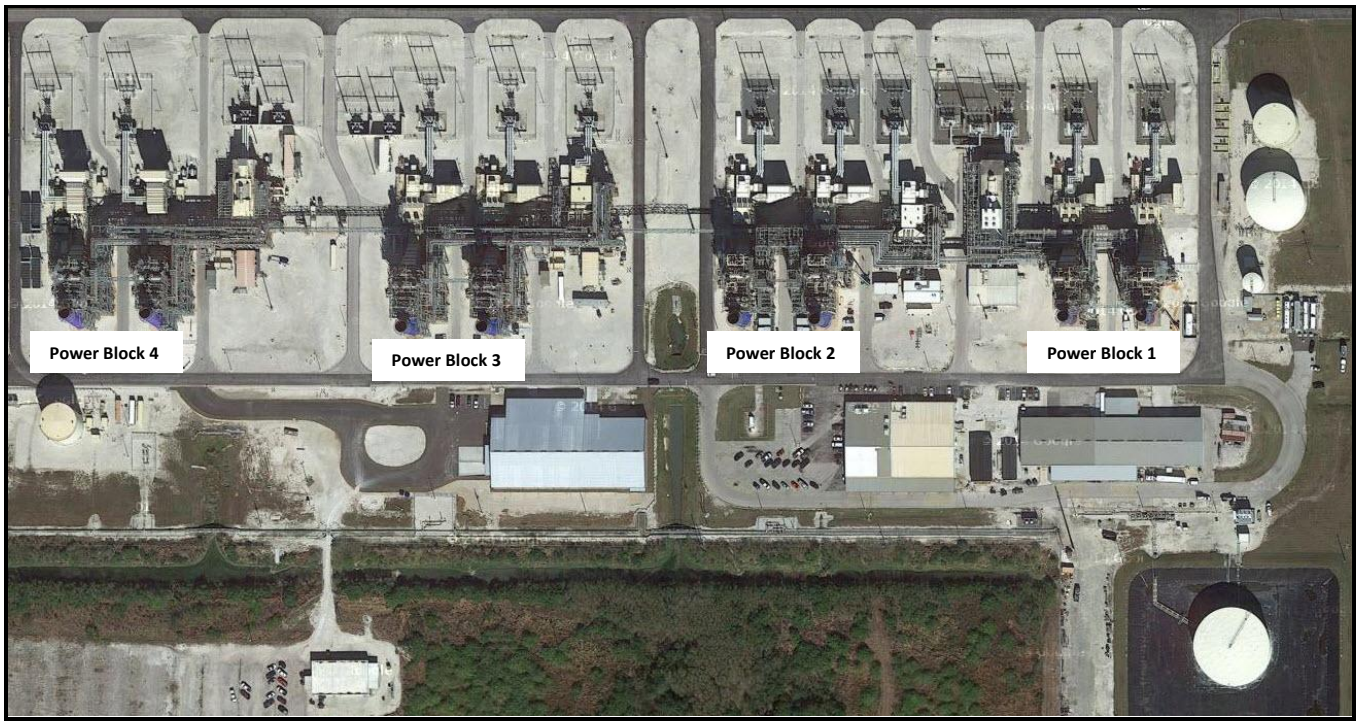


Figure 3. DEF Hines Energy Complex, Four Combined Cycle Units (~2,090 MW)

Figure 4 is a simplified process flow diagram of a single power block; i.e. a "two-on-one" combined cycle unit. Fuel is burned in the two CTGs. The mechanical energy produced operates the compressor section of each CTG and also drives an electric generator. Each CTG is rated at approximately 170 MW. The generation capacity is highly dependent upon ambient conditions. The turbine exhaust gas (TEG) exits the CTGs at temperatures in the range of 1,000 to 1,100 degrees Fahrenheit (°F). The heat contained in the TEG is used to produce steam in each HRSG. The steam from the two HRSGs (per block) drives a single, separate STG (per block), thus producing additional electrical power.

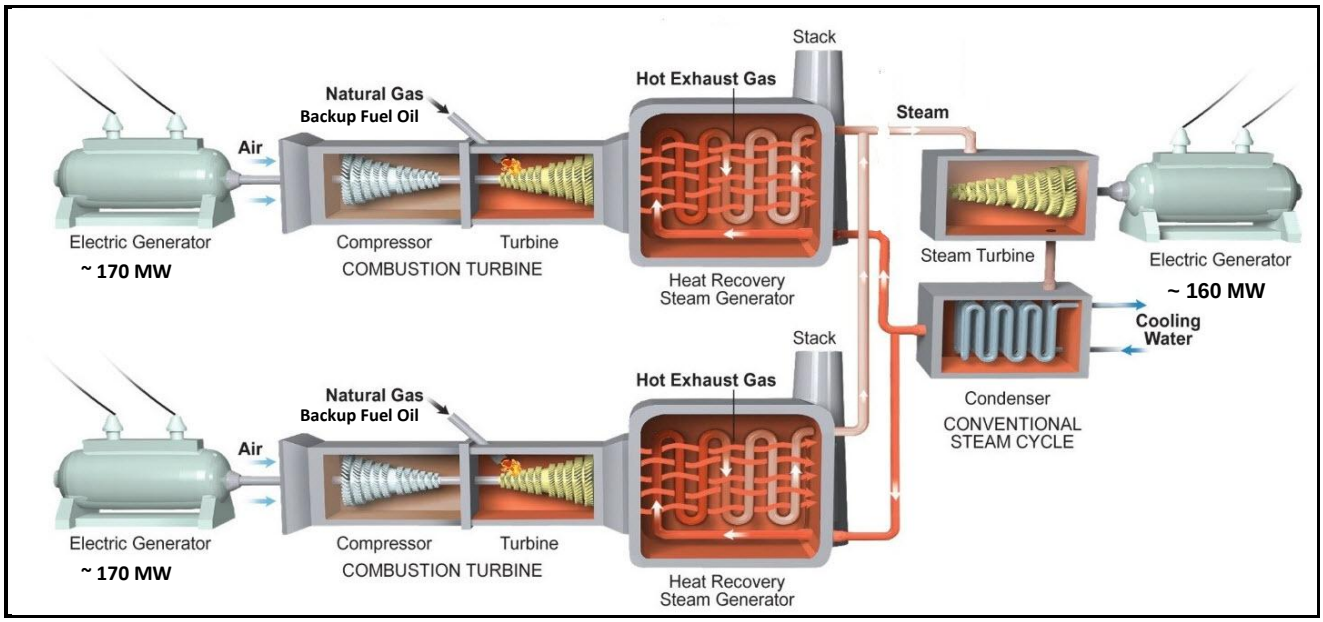


Figure 4. A 500 MW "Two-on-One" Natural Gas-Fueled Combined Cycle Unit (With Backup Fuel Oil).

Figure 5 (from Nooter-Eriksen) below is a diagram of a HRSG, which is a type of waste heat boiler. The TEG enters the HRSG via the duct work (Component 1) and exits via the stack (Component 14). The key pollution control equipment is the selective catalytic reduction (SCR) system used to control nitrogen oxides (NO_X). Components 10 represents the SCR reactor and Component 21 is the ammonia (NH_3) injection grid that supplies reagent to the SCR system. The SCR system lies between low and high-pressure steam systems where the temperature requirements for conventional SCR can be met.

Figure 6 is a photograph of the DEF Hines Energy Complex, Power Block 1 HRSGs and stacks. The external lines to the NH_3 injection grid are easily visible. The magnitude of the installation can be appreciated when compared with nearby individuals and vehicles.

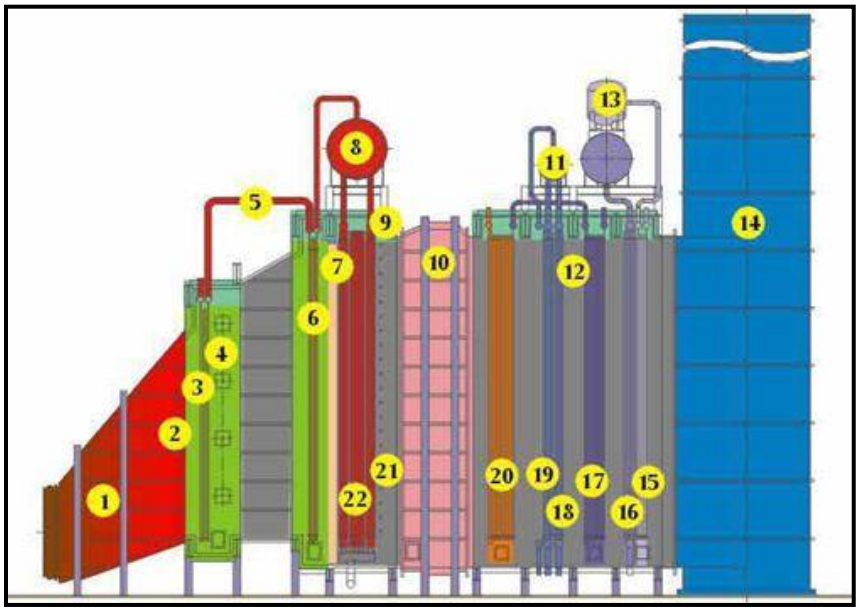


Figure 5. Key HRSG Components (10 is SCR)

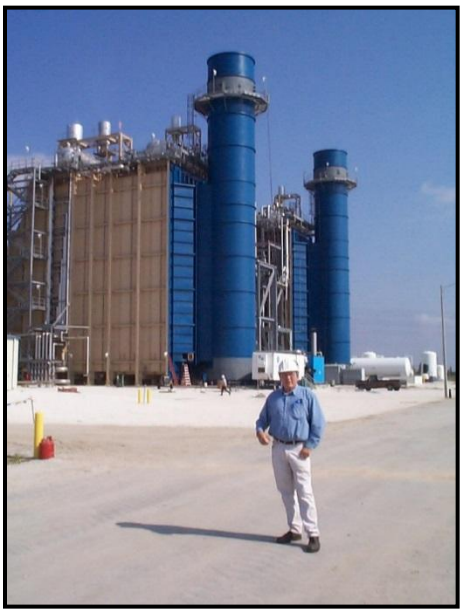


Figure 6. Block 1 HRSGs and Stacks.

1.5. Hines Energy Complex Power Ratings

CTG electric power ratings are usually specified at standard conditions. A common basis is known at ISO standard conditions, which are 15°C (59°F), 60 percent (%) relative humidity and the ambient pressure at sea level. As ambient temperature increases (or if sited at a high elevation), the density of air entering the CTG compressor section decreases. This results in a reduction of mass flow through the compressor and consequently less thrust and less energy production.

In Florida, maximum demand is typically during the hot summer air conditioning season, which is precisely when the greatest power production penalty occurs. For this reason, summer power ratings are different than winter ratings, notwithstanding the nominal ratings of Power Blocks 1-4 given in **Section 1.2** above.

Table 1 contains various capacity ratings for the DEF Hines Energy Complex Power Blocks 1-4. The values were taken from the 2014 DEF 10-year Site Plan submitted to the Florida PSC or facility air permits.
DEF 10-year Site Plan

Table 1. Capacity Ratings (MW) of DEF Hines Energy Complex Power Blocks 1-4. [1]

Power Block	Generator Max. Nameplate	Summer Net Capability	Winter Net Capability	Nominal [2]
1	546.50	462	528	500
2	548.25	490	563	530
3	561.00	488	564	530
4	610.00	472	544	530
Total	2,265.75	1,912	2,199	2,090

1. Nameplate, summer, Winter Net Capabilities as presented by DEF in 10-year Site Plan submitted to the Florida PSC April 1, 2014.
2. Nominal Ratings were developed during project permitting and are included in the facility air construction and operating permits.

Refer to **Figure 7** from TAS Energy. According to the diagram, a CTG rated at 100 MW at 59°F will only produce about 81 MW when the compressor inlet temperature is 100°F. Conversely, the same CTG will produce 104 MW at a compressor inlet temperature of 40°F. Link to TAS Energy

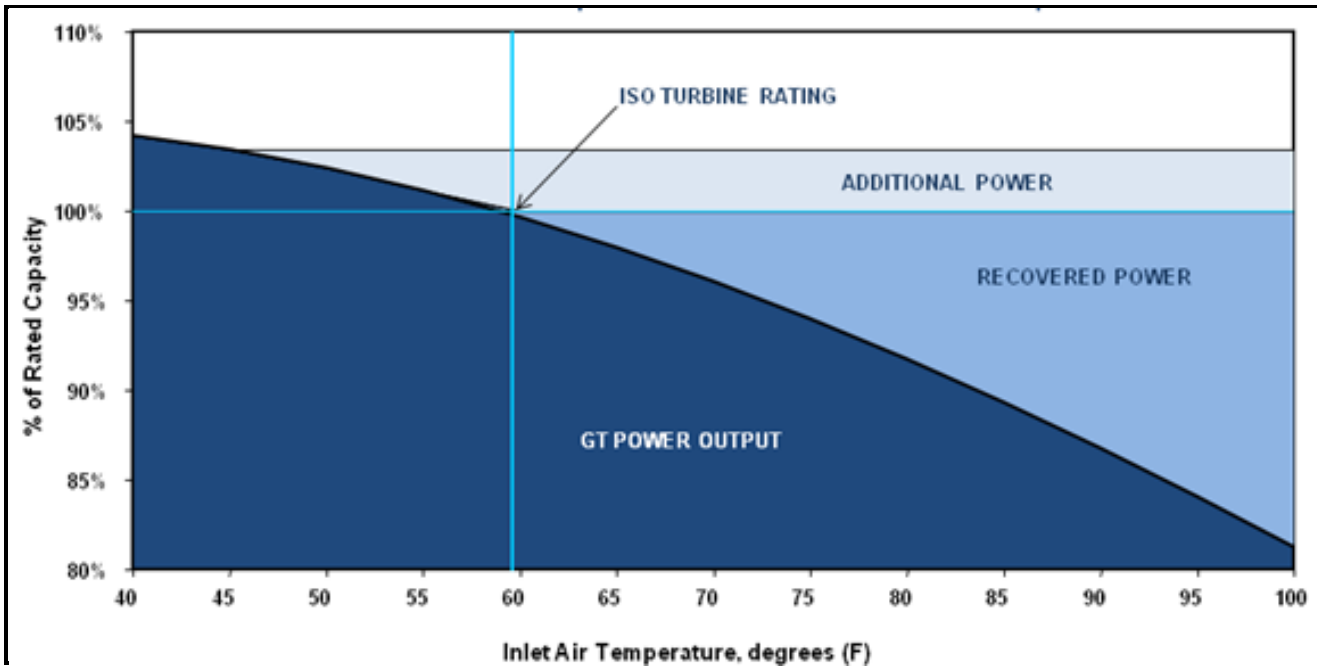


Figure 7. Effect of Compressor Inlet Air Temperature on CTG Power Output.

Chiller systems can cool the inlet air, thus increasing its density and energy production at the given ambient temperature. The cooling is accomplished by drawing CTG inlet air across cooling coils, in which chilled water is circulated. The additional power at a given *ambient temperature* does not change the maximum power that is possible at a given *compressor inlet temperature*. The net effect is to generate spring/fall or winter conditions, thus resulting in greater power production during the middle of summer (or whenever the ambient temperature is high).

1.6. DEF Hines Energy Complex Proposed Chiller Project

Refer to **Figure 8**. DEF will install water-cooled inlet air chillers on all eight CTGs to decrease the compressor inlet temperature during high ambient temperature days. Link to Application The method primarily uses less-expensive off-peak power at night to generate the chilled water for inlet air cooling during peak demand periods during the day. The four blocks of chillers will come into service in alignment with future plant outages. All systems will be in service by the summer of 2017. According to the Florida PSC approval, the project will add 220 MW of summer capacity and cost of about $160 million. Link to PSC Order

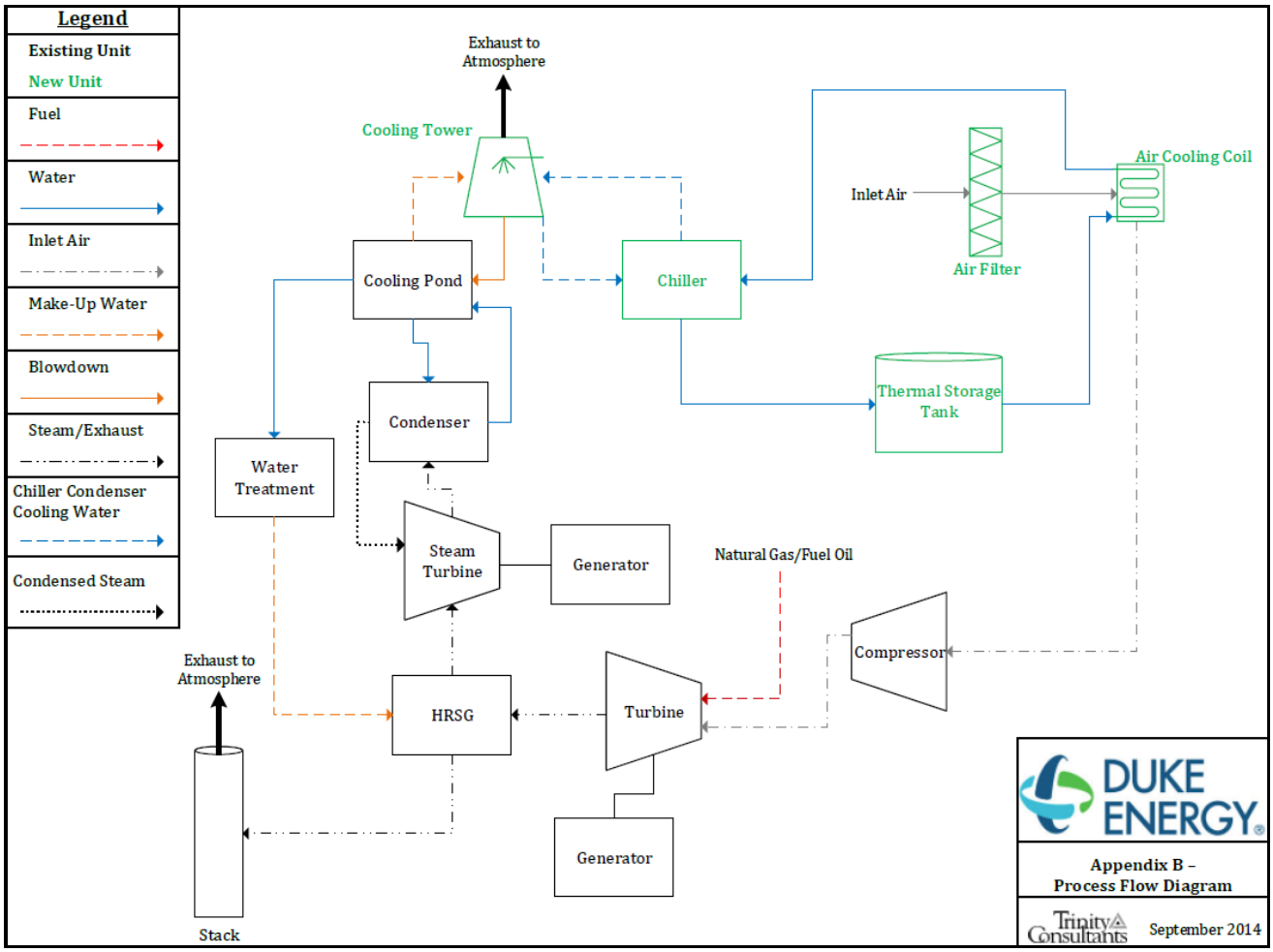
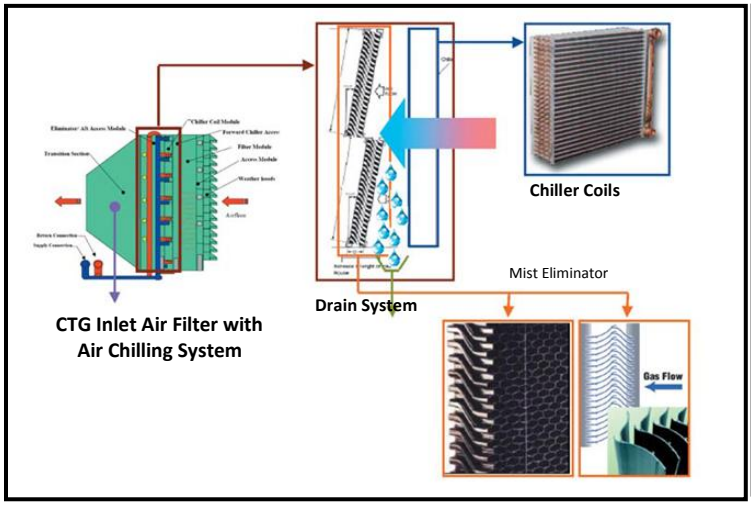


Figure 8. Process flow Diagram for Mechanical Water Chiller and CTG Inlet Air Chillers.

At night, the mechanical chillers will be used to chill the water in a 13 million gallon thermal energy storage (TES) tank. The chilled water will absorb heat from ambient air in the compressor inlet duct. During the day when ambient inlet air temperatures exceed 60 °F, the chilled water from the tank, will be combined with chilled water from the chillers, and circulated through heat exchangers (air cooling coil) mounted on each CTG air inlet filter in order to chill the compressor inlet air to 50 °F. The warmed water will return to the chillers to expel the absorbed heat to the atmosphere via a cooling tower that will use water from the existing facility cooling pond.

Figure 9 is a diagram from a General Electric brochure that contains the key chiller components located at the CTG air inlet location. **Figure 10** is a picture from the same brochure a CTG inlet air filtration that incorporates inlet air chilling. The chilled water supply and return piping is a prominent feature. Link to GE Brochure



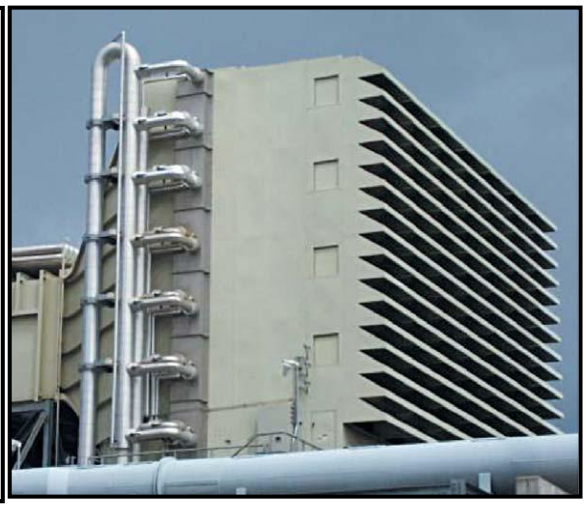


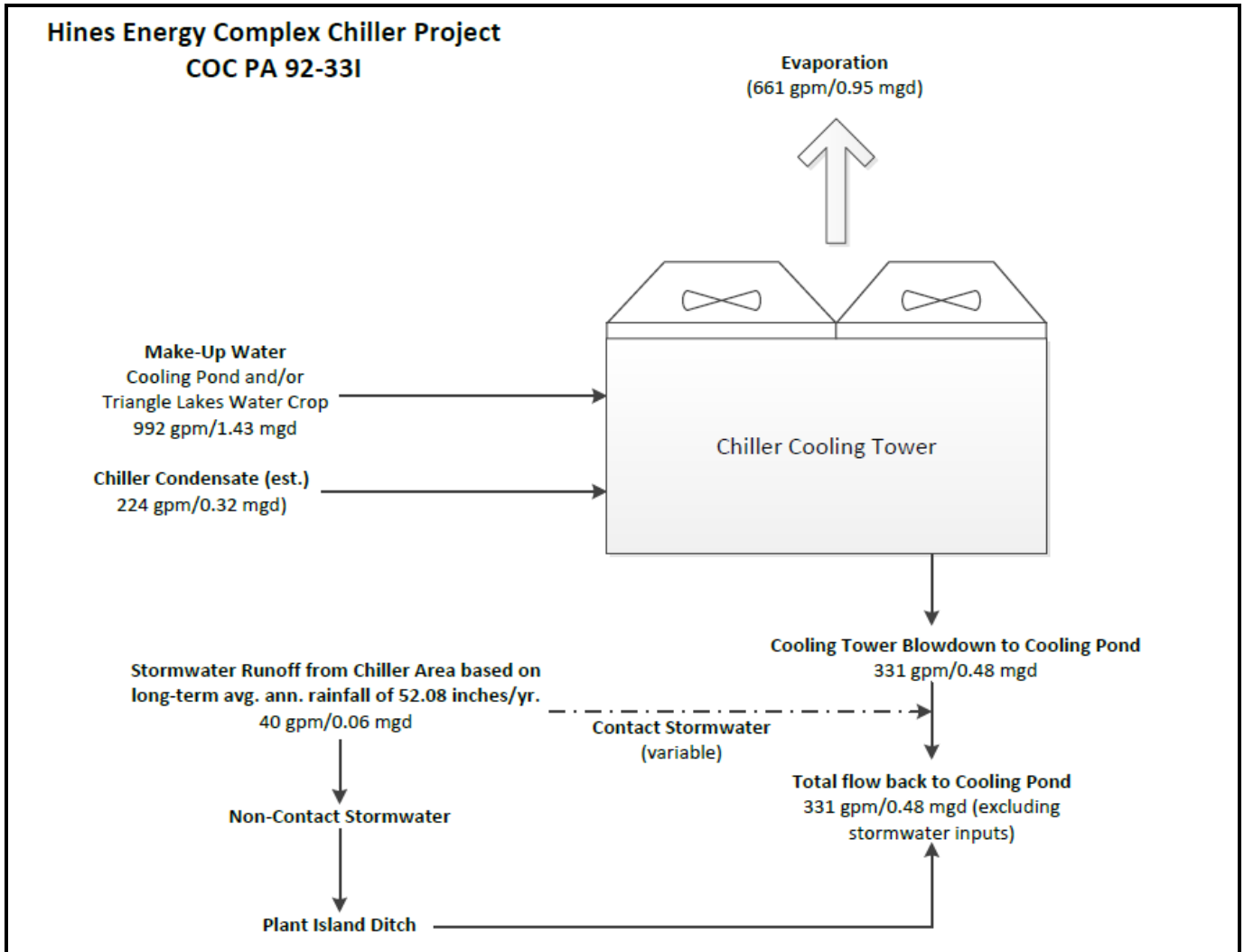
Figure 9. Main Components of Chilling System at CTG. **Figure 10. Chilled Water Supply/Return.**

Figure 11 is a picture of a thermal storage tank, chillers and cooling tower that comprise the chilled water supply system at a TAS Energy-designed project.

Figure 11. Chilled Water Supply and Thermal Energy Storage Systems at a TAS Energy Project.

Figure 12 is a conceptual water flow schematic for the water chilling operation as pending final design. Evaporative losses from the cooling tower will be partially off-set by the generation of condensate, which will be directed back into the cooling tower basin.

The current plan is to install a single three-cell cooling tower servicing all the chillers. The total maximum makeup flow rate for the cooling tower is projected to be 1,216 gallons per minute (gpm) and the maximum cooling tower recirculation flow rate is projected to be 44,000 gpm. Regardless of the ultimate number of cooling towers or cooling tower cells constructed, the maximum makeup flow rate and maximum cooling tower recirculation flow rate will be as described in the diagram.



1. Make up, chiller condensate, evaporation and cooling tower blowdown only occur during times of chiller operation. The chillers will be capable of operating anytime during the year whenever ambient air temperatures are > approx. 50o F, but are expected to be operated predominantly during warmer time periods from April through October.
2. Diagram is conceptual. Actual line routing and process flow locations are subject to change.
3. Flows based on ambient conditions equal to 95o F temperature and 48% relative humidity.
4. Make-up flow values exclude chiller condensate quantities. Chiller condensate expected to off-set make-up supplies one for one.
5. CT blowdown flows will be augmented by a portion of total stormwater runoff ("contact" stormwater) from the developed chiller site. The remaining stormwater will be directed to the Plant Island Ditch (PID) system, which serves as an alternative water supply source to the Cooling Pond.

Figure 12. Water Flow Schematic for Water Chilling Operation at Hines Energy Complex

Refer to **Figure 13**, which contains the planned physical locations of the key chiller components within the DEF Hines Energy Complex.

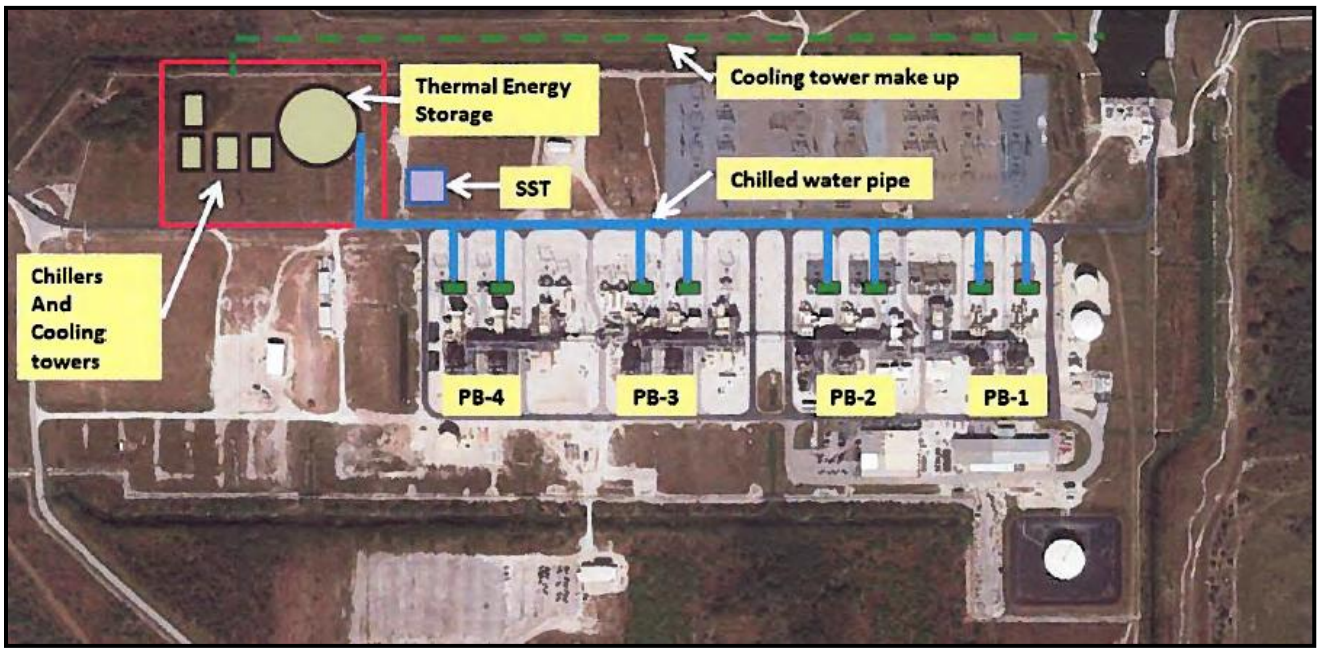


Figure 13. Proposed Chilling Equipment on General Layout of DEF Hines Energy Complex.

1.7. Processing Schedule

11/17/2014: Department received complete application for an air construction permit.

12/12/2014: Distributed Intent to Issue Air Permit package.

2. PSD APPLICABILITY REVIEW

2.1. General PSD Applicability

The Department regulates major stationary sources in accordance with Florida's PSD program pursuant to Rule 62-212.400, F.A.C. PSD preconstruction review is required in areas that are currently in attainment with the state and federal ambient air quality standards (AAQS) or areas designated as "unclassifiable" for these regulated pollutants. The project is located in Polk, which is in an area that is currently designated in attainment with each State AAQS and NAAQS or not classified.

The key requirements of a PSD review include: employment of Best Available Control Technology (BACT); a demonstration that the project will not cause or contribute to a violation of a state of federal AAQS or increment; and a demonstration that the project will not cause adverse impacts to Air Quality Related Values (AQRVs) such as visibility, soils and vegetation.

Commonly addressed PSD pollutants include: carbon monoxide (CO), nitrogen oxides (NO_X) PM, PM with a mean diameter of 10 microns or less (PM_{10}), PM with a mean diameter of 2.5 microns or less ($PM_{2.5}$), sulfuric acid mist (SAM), sulfur dioxide (SO_2), volatile organic compounds (VOC), lead (Pb), fluorides (F), and mercury (Hg). Additional PSD pollutants that are more common to certain other industries include: hydrogen sulfide (H_2S), TRS including H_2S, reduced sulfur compounds (RSC) including H_2S, municipal waste combustor (MWC) organics measured as total tetra- through octa-chlorinated dibenzo-p-dioxins and dibenzofurans (dioxin/furan), MWC metals measured as PM, MWC acid gases measured as SO_2 and HCl, and municipal solid waste (MSW) landfill emissions as non-methane organic compounds (NMOC).

Greenhouse gases (GHGs) is another PSD pollutant. GHGs is defined at section 40 CFR 86.1818-12(a) as the aggregate group of gases including carbon dioxide (CO_2) nitrous oxide (N_2O), methane (CH_4), hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), and sulfur hexafluoride (SF_6). GHGs is expressed as CO_2-equivalent (CO_2e). In making the CO_2e calculation, the values listed in 40 CFR 98, Subpart A, Table A-1 are used to weight emissions by their respective Global Warming Potential (GWP). E.g., the current GWP factors for four of the GHGs are: $CO_2 = 1$; $CH_4 = 25$; $N_2O = 298$ and $SF_6 = 22{,}800$. Link to 40 CFR 98, Subpart A

2.2. Definition of a Major Stationary Source

As defined in Rule 62-210.200(Definitions), F.A.C., a stationary source is a "major stationary source" (major PSD source) if it emits or has the potential to emit (PTE):

- 250 tons per year (tons/year) or more of any PSD pollutant; or
- 100 tons/year or more of any PSD pollutant and the facility belongs to one of the 28 listed PSD major facility categories.

According to a recent Supreme Court Opinion and EPA Implementation Guidance, a stationary source is not a major stationary source subject to PSD if only its GHGs emissions exceed the values listed above. [1]

The listed PSD major facility categories includes "fossil fuel-fired steam electric plants of more than 250 million British thermal units per hour heat input". The given category applies to the DEF Hines Energy Complex. The Hines Energy Complex is a major stationary source based on actual emissions of and potential to emit 100 tons/year or more of several individual PSD pollutants.

Once a new facility is considered a major stationary source based on one PSD pollutant, then other PSD pollutants are reviewed for PSD applicability based on the respective Significant Emission Rate (SER) defined and specified in Rule 62-210.200, F.A.C. Each pollutant projected to be emitted at a rate equal to or greater than its respective SER is also considered to be "*significant*" and subject to PSD preconstruction review, including a BACT determination.

Refer to **Table 2**. Although a new stationary source may be "major" for a single PSD pollutant, the project must include BACT controls for any PSD pollutant that exceeds the corresponding SERs listed in the table below.

Table 2. List of Significant Emission Rates (SERs) by PSD-Pollutant. [1]

Pollutant	SER (tons/year)	Pollutant	SER (tons/year) [4]
CO	100	NO_X	40
$PM/PM_{10}/PM_{2.5}$	25/15/10	Ozone (VOC) [2]	40
$PM_{2.5}$ (NO_X)	40	$PM_{2.5}$ (SO_2)	40
Ozone (NO_X) [2]	40	SAM	7
SO_2	40	Pb	0.6
Hg	0.1	GHGs	> 75,000 (CO_2e) and > 0 (mass) [3]

1. Excluding fluoride and pollutants specific to the Pulp and Paper industry, MWCs, MSW landfills.
2. Ozone (O_3) is regulated by its precursors (VOC and NO_X). PSD for $PM_{2.5}$ can be triggered by its precursors (NO_X and SO_2).
3. Pursuant to 40 CFR 52.21(b)(23)(ii), pollutants with no SER listed at 40 CFR 52.21(b)(23)(i) have a SER of zero (0) tons/year.
4. SER also means any emissions rate or any net emissions increase associated with a major stationary source or major modification which would construct within 10 km of a Class I area and have an impact on such area equal to or greater than 1 $\mu g/m^3$, 24-hour average.

2.3. Definition of Major Modification

"Major modifications" at major stationary sources are also subject to PSD review. According to Rule 62-210.200(Definitions), F.A.C., Major Modification (of a Major Stationary Source) is defined as follows:

[1] U.S. Supreme Court opinion dated June 23, 2014. Link to Supreme Court Opinion EPA guidance dated July 24, 2014. Link to EPA Guidance

(a) Any physical change in or change in the method of operation of a major stationary source that would result in a significant emissions increase of a PSD pollutant ***and*** a significant net emissions increase of that pollutant from the major stationary source. (Refer to SERs in **Table 2** above)

(b) Any significant emissions increase from any emissions units or net emissions increase at a major stationary source that is significant for volatile organic compounds or nitrogen oxides shall be considered significant for ozone. (Refer to SERs in **Table 2** above)

(c) through (d). These paragraphs are not relevant to this review.

For a major modification of an existing major stationary source, the review must include a BACT determination for any PSD pollutant that exceeds the respective SER. The review must include demonstrations that the project will not cause or contribute to a violation of an AAQS or increment and that the project will not adversely affect AQRVs.

GHGs becomes subject to regulation at a major modification if project emissions as CO_2e are greater than 75,000 tons/year and mass GHGs exceed zero tons/year. Consistent with the previously mentioned Supreme Court Opinion and EPA Implementation Guidance, if a project does not trigger PSD for pollutants other than GHGs then PSD is not triggered by GHGs regardless of emissions or emission increases.

2.4. Definitions of Baseline Actual Emissions and Projected Actual Emissions

To determine whether the project causes net emissions increases equal to or greater than the respective SER (triggering PSD) requires a comparison of recent "baseline actual emissions" with future "projected actual emissions". According to Rule 62-210.200(Definitions), F.A.C., as applicable to an existing electric steam generating unit:

"Baseline Actual Emissions" means, for any existing electric utility steam generating unit, the average rate, in tons per year, at which the unit actually emitted the pollutant during any consecutive 24-month period selected by the owner or operator within the 5-year period immediately preceding the date a complete permit application is received by the Department. The Department shall allow the use of a different time period upon a determination that it is more representative of normal source operation.

*"Projected Actual Emissions" means the maximum annual rate, in tons/year, at which an existing emissions unit is projected to emit a PSD pollutant in **any one** of the 5 years following the date the unit resumes regular operation after the project, or in **any one** of the 10 years following that date, if the project involves increasing the emissions unit's design capacity or its potential to emit that PSD pollutant and full utilization of the unit would result in a significant emissions increase or a significant net emissions increase at the major stationary source. One year is one 12-month period. In determining the projected actual emissions, the Department:*

(a) Shall consider all relevant information, including historical operational data, the company's own representations, the company's expected business activity and the company's highest projections of business activity, the company's filings with the State or Federal regulatory authorities, and compliance plans or orders, including consent orders; and

(b) Shall include fugitive emissions to the extent quantifiable and emissions associated with startups and shutdowns; and

(c) Shall exclude that portion of the unit's emissions following the project that an existing unit could have accommodated during the consecutive 24-month period used to establish the baseline actual emissions and that are also unrelated to the particular project including any increased utilization due to product demand growth; or

(d) In lieu of using the method set out in paragraphs (a) through (c) above, may be directed by the owner or operator to use the emissions unit's potential to emit, in tons per year.

2.5. Emission Calculations Submitted by DEF

Refer to **Table 3**, which is a summary of three tables contained in the application submitted by DEF.
Link to Application

Table 3. DEF's Estimates of Baseline and Projected Actual Emissions and Emissions Increases.

Parameter	Projected Actual Emissions (tons/year) [1]	New Cooling Tower (tons/year) [2]	Baseline Actual Emissions (tons/year) [3]	Project Emissions Increase (tons/year) [4]
NO_X	622.95	N/A	662.13	0
CO	565.95	N/A	626.56	0
VOC	25.97	N/A	27.96	0
SO_2	25.75	N/A	27.43	0
PM	224.71	0.03	242.65	0.03
PM_{10}	77.78	0.03	83.38	0.03
$PM_{2.5}$	77.78	0.03	83.38	0.03
SAM	1.97	N/A	2.10	0
CO_2e	4,956,619	N/A	5,336,386	0

1. Projected Actual Emissions (PAE) excluding the cooling tower.
2. Potential to Emit (PTE) of the cooling tower.
3. Baseline Actual Emissions (BAE) for period 12/2011 to 11/2013 for all parameters except CO, VOC and PM. BAE for CO (1/2010-12/2011), VOC (4/2012-3/2014) and PM (2/2012-1/2014)
4. Project Emissions Increase (PEI) = PTE (new) + Max [0, PAE (existing) – BAE (existing)]

Baseline actual emissions (BAEs) were calculated by DEF as follows:

- NO_X emissions were calculated using the continuous emissions monitoring systems (CEMS) data reported to U.S. EPA's Clean Air Markets Division (CAMD).
- SO_2 emissions were obtained from the CAMD website.
- CO emissions were based on actual CEMS data for Power Blocks 2-4. CO emissions from Power Block 1 were estimated factors developed from Power Blocks 2-4 and the heat input data reported to CAMD.
- VOC emissions were based on actual stack test data.
- $PM/PM_{10}/PM_{2.5}$ emissions were calculated using the 2013 Annual Operating Report emission factors and unit specific heat input from CAMD.
- SAM emissions were calculated assuming that 5% of SO_2 converts to SAM.
- GHGs as CO_2e were calculated based on a combination of CO_2 data submitted to CAMD, AP-42 emission factors for CH_4 and N_2O using the GWPs given in 40 CFR Part 98.

DEF selected the consecutive 24-month periods indicated in **footnote** 3 of **Table 3** and calculated the average annualized rate at which the four units unit actually emitted each of the pollutants listed in the table.

DEF uses models for business planning that incorporate all of the unit characteristics, outages, fuel prices and volatilities to forecast a run profile for each unit in the portfolio. This system-wide model calculates changes to expected utilization based on all relevant factors. DEF calculated projected actual emissions (PAEs) as follows:

- The Ventex System Optimizer and PROSYM were used, along with models to predict demand, load growth and penetration of energy efficiency programs through Duke Energy Florida's fleet.
- These models were used to predict total generation for the Hines Energy Complex for the five years following the proposed project.
- Once total monthly generation is determined, PAEs were calculated by multiplying the highest projected heat input, in MMBtu/year with their relevant emission factor, in lb/MMBtu, for each emission unit and pollutant.

The models indicate PAEs are less than BAEs with or without the project. In other words, emissions are expected to decrease at the Hines Energy Complex in future years with the project, but not because of the project. DEF did not exclude future emissions due to demand growth because a contraction of demand is projected compared with the baseline period.

In cases where emissions of pollutants are expected to decrease, DEF used an estimate of zero (0) as the project emission increase (PEI). DEF nevertheless provided PEI estimates of 0.3 tons/year of $PM/PM_{10}/PM_{2.5}$ to reflect the emissions from the new cooling tower.

Table 4 is a summary of future PAEs with and without the chiller project.

Table 4 DEF's Projections of Future Heat Input and PAEs With and Without Chiller Project

Project Status	Heat Input [1] (MMBtu)	NO_X (tons)	SO_2 (tons)	PM (tons)	PM_{10} (tons)	$PM_{2.5}$ (tons)	CO (tons)	VOC (tons)	SAM (tons)	CO_2e (tons)
Without the Project	82,403,947	626.76	25.49	220.74	75.95	75.95	555.78	25.46	1.95	4,907,743
With the Project	81,583,987	622.95	25.75	224.71	77.78	77.78	565.95	25.97	1.97	4,956,618

1. For reference, the average annual heat during the period of baseline emissions was 88,962,185 MMBtu.

According to the analysis prepared by DEF the project does not constitute a Major Modification as defined in Rule 62-210.200(Definitions), F.A.C. and does not trigger PSD.

2.6. Further Evaluation by the Department

Emissions are projected by DEF to decrease in the future despite execution of a project that constitutes an increase of summer net capability. To test this conclusion, the Department conducted additional technical analysis and examined recent company representations submitted to the Florida PSC.

Figure 14 (from a GE CTG performance document) is a diagram of the relation between compressor inlet temperature and the power output, heat rate, heat consumption, and exhaust flow of a single-shaft GE 7FA.03. For reference, this is the model used in Hines Power Block 4. GE CTG Performance

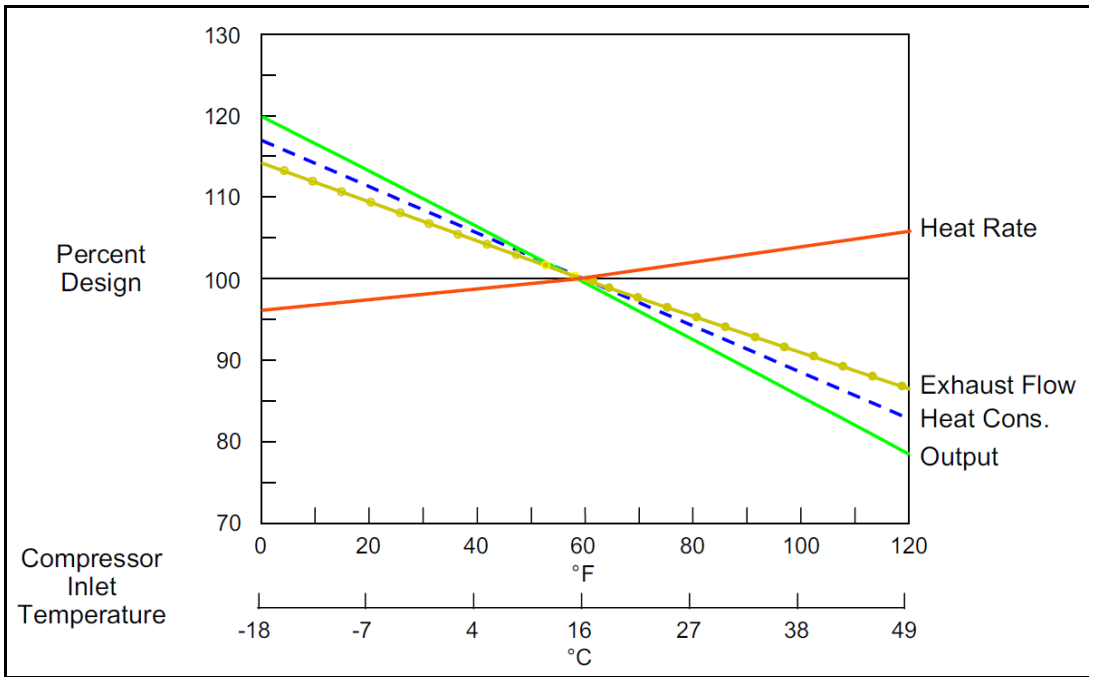


Figure 14. Inlet Temperature vs. Power Output, Heat Rate, Heat Input, Exhaust Flow.

In addition to significantly increasing power output, heat rate is improved (i.e. fuel use per kilowatt-hour of energy is less) when operating at a lower compressor inlet temperature. This tends to reduce emissions per unit of electrical energy generated; by ~5% if generating at 50°F rather than 100°F. However, this reduction does not completely defray all of additional emissions that occur due to 20% greater power output at 50°F versus 100°F.

DEF's recent (2012-2013) and projected (2014-2020) electrical energy sources are presented in **Table 5** by fuel type, generator type and (as applicable) outside sources. The source of the information is the DEF 10-year Site Plan submitted to the Florida PSC in April 2014. Link to DEF 10-year Site Plan

Table 5. DEF Recent and Projected Energy Electrical Sources (GW-hours) 2012-2020.

Energy Sources	Type	2012[1]	2013[1]	2014	2015	2016	2017	2018	2019	2020
Annual Firm Interchange [2]		1,558	1,409	709	854	989	578	577	529	495
Coal	Steam Units	10,003	10,577	9,816	11,072	10,078	11,776	10,826	9,272	6,772
Residual Oil	Steam Units	46	127	0	0	0	0	0	0	0
Distillate	Steam Units	63	58	0	0	0	0	0	0	0
	Comb. Cycle	1	7	0	0	0	0	0	0	0
	CT (Peakers)	39	28	27	35	43	27	35	23	27
	Total	104	93	27	35	43	27	35	23	27
Natural Gas	Steam Units	2,175	1,951	2,738	3,349	3,264	2,235	2,159	2,240	2,006
	Comb. Cycle	**21,469**	**20,893**	**21,037**	**19,641**	**20,183**	**21,038**	**22,732**	**25,465**	**29,061**
	CT (Peakers)	353	217	562	631	927	921	927	763	788
	Total	23,997	23,061	24,337	23,621	24,374	24,194	25,818	28,468	31,855
Other [3]	QF purchases	2,767	2,886	1,421	1,444	1,529	1,527	1,533	1,526	1,506
	Renewables	1,183	1,132	1,301	1,260	1,277	1,279	1,285	1,280	1,254
	Import [4]	1,559	1,546	2,191	2,203	2,809	1,995	1,921	1,915	2,089
	Export [4]	-4	-59	0	0	0	0	0	0	0
Net Energy for Load		41,213	40,772	39,801	40,490	41,098	41,375	41,995	43,013	43,998

1. Actual values during 2012 and 2013. Values for 2014-2020 are forecasts as of April 2014.
2. Net Energy Purchased (+) or Sold (-) Within the FRCC Region.
3. Net Energy Purchased (+) or Sold (-)
4. Import (from out-of-state), Export (to out-of-state)

Natural gas consumption was greater in 2012 at the DEF combined cycle units than in 2013 or the projections through 2017. In addition to the Hines Energy Complex, DEF operates the nominal 1,133 MW Bartow Power Combined Cycle Plant in Pinellas County and the 205 MW Tiger Bay Plan in Polk County. Link to Bartow Plant Link to Tiger Bay Plant

Among the reasons for the lower future natural gas use projections is lower demand growth and generally increasing natural gas prices compared with 2012. **Figure 15** is a chart of Henry Hub spot natural gas prices from 2007 to the present. It was obtained from the Department of Energy (DOE), Energy Information Agency (EIA) website. Link to DOE/EIA Gas Prices According to the EIA, price increases in the near term are driven by faster growth of consumption in the industrial and electric power sectors and, later, due to growing demand for export at LNG facilities.

In 2013 DEF completed the conversion of the nominal 1,100 MW Anclote Power Plant (conventional steam units) to exclusive natural gas service. Link to Anclote Plant According to discussions with company representatives, reductions in future emissions from Hines are related to changes in the operating dispatch order, particularly following the construction of the Citrus Combined-Cycle Plant and the increases natural gas prices that are projected for the future.

DEF System-wide combined cycle natural gas supply and use will significantly increase by 2019-2020 when the nominal 1,640 MW Citrus Combined Cycle Project displaces production from two conventional coal-fueled units at the DEF Crystal River Energy Complex. Link to Citrus Combined Cycle Project Link to Sabal Trail Project

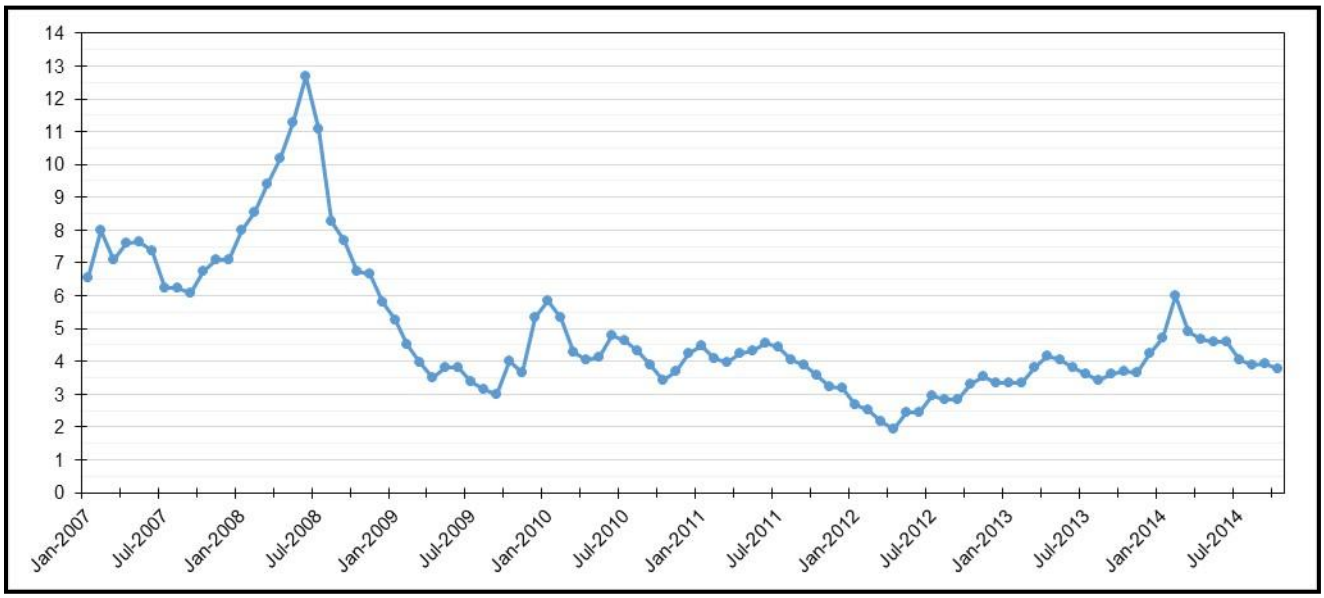


Figure 15. Henry Hub Natural Gas Spot Price ($/MMBtu). Source DOE/EIA.

Figure 16 is a chart of historical gross generation and NO_X emissions from the DEF Hines Energy Complex during the period 2007-2013. For reference, 2008 was the first full year that Power Block 4 operated.

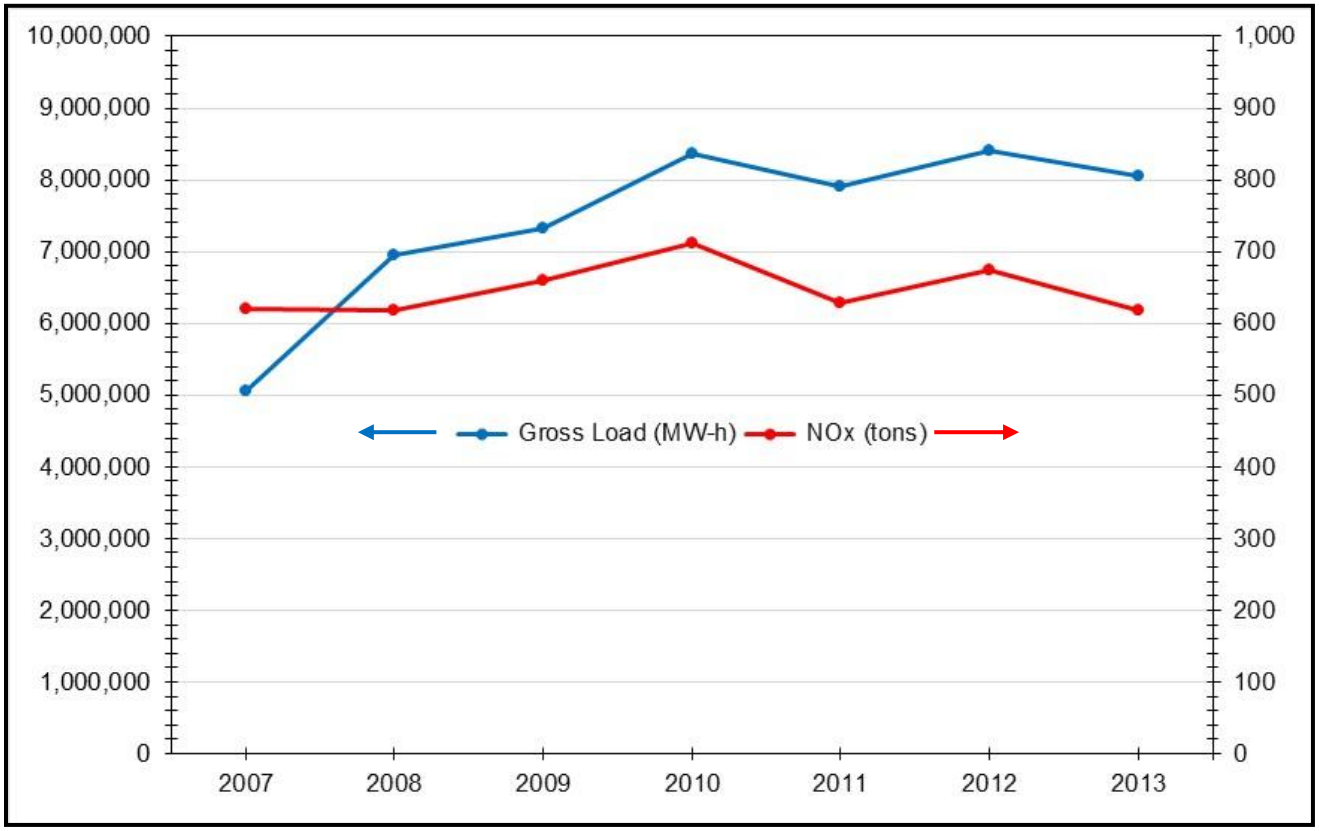


Figure 16. Historical Generation and NO_X Emissions from the DEF Hines Energy Complex (2007-2013).

The 10-year Site Plan submitted to the Florida PSC includes all of the mentioned projects including the chiller project at the Hines Energy Complex. Overall, the heat input and emissions projections submitted to the Department by DEF for the Hines Energy Complex chiller project are consistent with the generation and fuel use projections submitted to the Florida PSC and with the natural gas price trends reported by DOE.

The Department examined data contained in the EPA eGRID system related to annual generation and nameplate capacity. Link to EPA eGrid Although the 2012 data have not yet been uploaded to the site, the Department obtained them from EPA. For the purposes of this analysis, capacity factor is calculated as the net electrical energy generation divided by the nameplate capacity as reported to eGRID. During 2012, the Hines Energy Complex operated at a capacity factor of 65.6%.

If the chiller project stimulated additional generation and ***caused*** a (very unlikely) relative increase of 10% in the annual capacity factor to 71.2%, then emissions of NO_X (partly defrayed by a 2% relative improvement in heat rate) would increase by 8% or approximately 53 tons/year. A more likely reason for increases the annual capacity factors would be system-wide demand growth, lower natural gas prices or shifting of dispatch for regulatory reasons. In such a case, DEF can subtract the emissions caused by demand growth from its PAE estimates.

Notwithstanding the low probability of a significant increase in NO_X emissions, the Department will require that DEF report annual emissions of NO_X in accordance with the provisions in Section 62-212.300(1)(e), F.A.C.

3. PRELIMINARY DETERMINATION

The Department makes a preliminary determination that the project is not a major modification and that it will comply with all applicable state and federal air pollution regulations as conditioned by the draft permit. This determination is based on a technical review of the complete application, reasonable assurances provided by the applicant or otherwise obtained by the Department, and the conditions specified in the draft permit. No air quality modeling analysis is required because the project does not result in a significant increase in emissions. Al Linero is the project engineer responsible for reviewing the application and drafting the air construction permit revision. Additional details of this analysis may be obtained by contacting the project engineer at the Department's Office of Permitting and Compliance at Mail Station #5505, 2600 Blair Stone Road, Tallahassee, Florida 32399-2400.