TECHNICAL EVALUATION

&

PRELIMINARY DETERMINATION

APPLICANT

Florida Power Corporation d/b/a
Progress Energy Florida, Inc. (PEF)
1729 Baillies Bluff Road
Holiday, Florida

Anclote Power Generating Facility
ARMS Facility ID No. 1010017

PROJECT

Natural Gas Fuel Conversion
Fossil Fuel Fired Steam Generator Units 1 and 2
File No. 1010017-013-AC (PSD-FL-419)

COUNTY

Pasco 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

July 30, 2012

1. GENERAL PROJECT INFORMATION

1.1. Facility Description and Location

Florida Power Corporation d/b/a Progress Energy Florida, Inc. (PEF), an indirect subsidiary of Duke Energy Corporation, operates the Anclote Power Generating Facility (the Anclote Plant). The facility is an electrical power generating plant with a Standard Industrial Classification Code of SIC No. 4911. Refer to Figures 1 and 2 below. The facility is located at 1729 Baillies Bluff Road, Holiday, Pasco County; UTM Coordinates: Zone 17, 324.4 km East and 3118.7 km North.

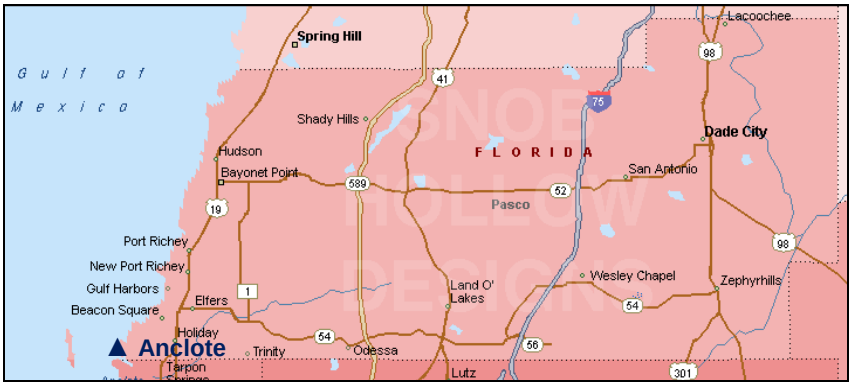

Figure 1 – Pasco County, FL **Figure 2 – Anclote Plant Location**

The existing Anclote Plant includes:

- Two fuel oil and natural gas fueled steam generators, Unit Nos. 1 and 2;
- A common stack 499 foot stack;
- Two, 12-cell mechanical draft helper cooling towers; and
- Fuel oil storage tanks, diesel engines and other ancillary equipment.

The following list of emissions units (E.U.) is from the Anclote Facility Title V Air Operation Permit. Link to Anclote Title V Permit

Table 2. List of Emissions Units located at the Anclote Plant

E.U. ID No.	Brief Description
Regulated Emissions Units	
001	Fossil Fuel Fired Steam Generator Unit No. 1
002	Fossil Fuel Fired Steam Generator Unit No. 2
007	Two, 12-cell Mechanical Draft Helper Cooling Towers
008	Relocatable Diesel Fired Engine Driven Generator(s)
009	Two, 16.5 million Btu/hour Natural Gas Fuel Heaters
Unregulated Emissions Units and/or Activities	
003	Surface Coating Operations
005	Emergency Diesel Generator
006	Diesel Air Compressor

1.2. Primary Regulatory Categories

- The existing facility is a major stationary source in accordance with Rule 62-212.400, F.A.C. for the Prevention of Significant Deterioration (PSD) of Air Quality and Rule 62-210.200 (Definitions), F.A.C.
- The existing facility is a major source of hazardous air pollutants (HAP).
- According to the applicant, after the project the facility will not be a major source of HAP.
- The existing facility has units regulated under Clean Air Act, Title IV, Acid Rain provisions, Phase II.
- The existing facility is a Title V major source of air pollution in accordance with Chapter 62-213, F.A.C.

1.3. Project Description

This air construction permit application is to convert Anclote Units 1 and 2 (E.U. 001 and 002) and associated equipment from present use of heavy fuel oil and natural gas to exclusive use of natural gas. PEF has determined the change in fuels is needed to exempt the units from the new Mercury and Air Toxics Standard (MATS) limits promulgated by the U.S. EPA.

Briefly, the project will include:

- Addition of three levels of natural gas burners to the existing natural gas burners on Units 1 and 2;
- Addition of two fuel gas heaters;
- Modifications to the natural gas delivery systems;
- Replacement of the existing natural gas metering and regulating station;
- Superheater surface area reductions;
- Disabling of residual fuel oil firing capability;
- Upgrade of superheater metallurgy; and
- Upgrade of the burner control and management system.

The applicant also requests a change in the allowable hours of operation for the two cooling towers (E.U. 007) from 4,500 hours/year/individual tower to an average of 4,500 hours/year/tower (i.e. 9,000 hours/year for the two towers combined).

1.4. Processing Schedule

June 18, 2012	The Department received the application for the Anclote Gas Natural Conversion Project. Link to Anclote Application
July 3, 2012	The Department issued a request for additional information (RAI) related primarily to the calculation of projected actual emissions and the emissions-versus-load characteristics of the natural gas burners.
July 27, 2012	Department received additional information.
July 30, 2012	The Department distributed the Intent to Issue Air Permit package.

2. AIR POLLUTION REGULATIONS AND APPLICABILITY DETERMINATIONS

2.1. Department 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.). The key rules are listed in Table 2.

2.2. Federal Regulations

The U.S. Environmental Protection Agency (EPA) establishes air quality regulations in 40 Code of Federal Regulations, Part 60 (40 CFR 60) that identify New Source Performance Standards (NSPS) for a variety of industrial activities.

Table 2. Applicable Air-Related Rules from the Florida Administrative Code

Chapter	Description
62-4	Permits
62-17	Power Plant Siting (not applicable to this project)
62-204	Air Pollution Control – General Provisions
62-210	Stationary Sources of Air Pollution – General Requirements
62-212	Stationary Sources – Preconstruction Review
62-213	Operation Permits for Major Sources (Title V) of Air Pollution
62-296	Stationary Sources – Emission Standards
62-297	Stationary Sources – Emissions Monitoring

40 CFR 61 generally specifies National Emission Standards for Hazardous Air Pollutants (NESHAP). 40 CFR 63 generally specifies NESHAP provisions based on the Maximum Achievable Control Technology (MACT) for given source categories. Federal regulations adopted by reference are given in Rule 62-204.800, F.A.C. State regulations approved by EPA are given in 40 CFR 52, Subpart K – Florida; also known as the State Implementation Plan (SIP) for Florida. Link to 40 CFR 52, Subpart K

2.3. General PSD Major Stationary Source 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.

Commonly addressed PSD pollutants include: carbon monoxide (CO), nitrogen oxides (NO_X) particulate matter (PM), PM smaller than 10 micrometers (µm) (PM_{10}), PM smaller than 2.5 µm ($PM_{2.5}$), sulfur dioxide (SO_2), volatile organic compounds (VOC), sulfuric acid mist (SAM), lead (Pb), fluorides (F), and mercury (Hg).

Additional PSD pollutants that are more common to certain other industries include: municipal waste combustor organics (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 hydrogen chloride (HCl), hydrogen sulfide (H_2S), total reduced sulfide (TRS including H_2S), reduced sulfur compounds (RSC including H_2S), and municipal solid waste (MSW) landfill emissions as non-methane organic compounds (NMOC).

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; <u>or</u>
- 100 tons/year or more of any PSD pollutant <u>and</u> the facility belongs to one of the 28 listed PSD major facility categories.

The list given in the citation includes the category of "fossil fuel-fired steam electric plants of more than 250 million British thermal units per hour heat input (MMBtu/hour)". The Anclote Plant is a major stationary source based on actual emissions of and potential to emit 100 tons/year or more of several individual PSD pollutants.

For major stationary sources such as the Anclote Plant, PSD applicability for modification projects is based on thresholds known as the significant emission rates (SER) as defined in Rule 62-210.200

(Definitions), F.A.C. Any "net emissions increase" as defined in Rule 62-210.200 (Definitions), F.A.C. of a PSD pollutant from the project that equals or exceeds the respective SER is considered "significant". SER also means any emissions rate or any net emissions increase of a PSD pollutant 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 gram per cubic meter, 24-hour average.

Although a facility may be "major" (i.e. emits or has the potential to emit 100 or 250 TPY as applicable) for only one PSD pollutant, a project must include Best Available Control Technology (BACT) proposals for any PSD pollutant that exceeds the corresponding significant emission rates given in Table 4.

Table 4. List of Significant Emission Rates by PSD-Pollutant Relevant to the Facility [2]

Pollutant	SER (tons/year)	Pollutant	SER (tons/year)
PM	25	PM_{10}	15
$PM_{2.5}$	10	MWC metals as PM	15
$PM_{2.5}$ (NO_X)	40	$PM_{2.5}$ (SO_2)	40
CO	100	NO_X	40
Ozone (NO_X) [1]	40	Ozone (VOC) [1]	40
SO_2	40	MWC acid gases as HCl and SO_2	40
fluoride	3	lead	0.6
mercury	0.1	Sulfuric acid mist (SAM)	7
MWC organics as dioxin/furan	3.5×10^{-6}	MSW Landfill Emissions as NMOC	50

1. $PM_{2.5}$ is also regulated through precursors (NO_X and SO_2); Ozone (O_3) is regulated through precursors (VOC and NO_X).
2. There is federal SER of 75,000 tons/year for Greenhouse Gases (GHG) as carbon dioxide equivalent (CO_2e) that has not been incorporated into Department rules.

According to 40 CFR 52.21, six greenhouse gases (GHG), are also be subject to regulation at new stationary sources that will emit or have the potential to emit 100,000 tons/year (SER equal to 75,000 tons/year) expressed as the carbon dioxide equivalent emissions (CO_2e). This requirement has not been incorporated into Department rules but is a separate requirement of the EPA.

2.4. Methodology to Determine Net Emissions Increase

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".

Calculation Methodology of Baseline Actual Emissions

According to Rule 62-210.200(Definitions), F.A.C., "Baseline Actual Emissions" is the rate of emissions, in tons/year, of a PSD pollutants.

(a) For any existing electric utility steam generating unit, baseline actual emissions means the average rate, in tons/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.***

1. *The average rate shall include fugitive emissions to the extent quantifiable, and emissions associated with startups and shutdowns.*
2. *The average rate shall be adjusted downward to exclude any non-compliant emissions that occurred while the source was operating above any emission limitation that was legally enforceable during the consecutive 24-month period.*
3. *For a PSD pollutant, when a project involves multiple emissions units, only one consecutive 24-month period must be used to determine the baseline actual emissions for the emissions units being changed. A different consecutive 24-month period can be used for each PSD pollutant.*

4. *The average rate shall not be based on any consecutive 24-month period for which there is inadequate information for determining annual emissions, in tons/year, and for adjusting this amount if required by subparagraph (a)2. above.*

Calculation Methodology of Projected Actual Emissions

According to Rule 62-210.200(Definitions), F.A.C., "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. Applicant's Determination of Net Emissions Increases

PEF included estimates of baseline actual emissions for Units 1 and 2 in a table on page 5 of the application. These estimates were termed "highest two-year average emissions". The applicant also included estimates of future emissions which were termed "maximum potential emissions from the project" as Table 1 of the application. The Department consolidated the table as Table 5 below.

Table 5. Summary of the Applicant's Emissions Estimates and PSD Applicability

Pollutant	24-Month Baseline Period Selected (Years)	Applicant Baseline Actual Emissions (tons/year) [1]	Applicant Projected Actual Emissions (tons/year) [3]	Projected Increase (tons/year) [4]	≥ PSD SER? (tons/year) Yes/No
CO	2006 – 2007	506	3,945	+3,439	≥ 100? **Yes**
VOC	2006 – 2007	78	118	+40	≥ 40? **Yes**
NO_X [2]	2006 – 2007	6,540	6,573	+33	≥ 40? No
SO_2 [2]	2006 – 2007	25,273	60	-25,213	≥ 40? No
PM	2006 – 2007	805	548	-257	≥ 25? No
PM_{10}	2006 – 2007	572	411	-161	≥ 15? No
$PM_{2.5}$	2006 – 2007	193	137	-56	≥ 10? No
$PM_{2.5}$ precursors	2008 – 2009	25,272/6,541 (SO_2/NO_X)	60/6,573 (SO_2/NO_X)	-25,213/+33	≥ 40? No
Lead	2009 – 2010	0.72	0.01	-0.71	≥ 0.60? No
GHG (CO_2e) [2]	2006 – 2007	2,517,405	2,530,141	+12,736	≥ 75,000? No

1. Baseline actual emissions based on company submitted annual operating reports (AOR), except NO_X, SO_2, CO_2 and $PM_{2.5}$.
2. NO_X, SO_2, CO_2 were derived from EPA Air Markets Program Data. See link: http://ampd.epa.gov/ampd/QueryToolie.html .
3. Applicant calculated "maximum potential emissions" when limited by 3,980 hour/year/unit. The Department recalculated projected actual emissions further below.
4. Estimate of projected net emissions increases for comparison with respective SER.

The Department summed the contributions of each unit as they are virtually identical in physical and operational terms as well as dispatching. Also, given a pollutant, the applicant selected the same 24-month period for calculating baseline actual emissions for both units. The Department also applied the correct nomenclature of baseline actual emissions and projected actual emissions.

Use of the correct terms and calculation techniques would be a benefit to PEF. For example, use of the term "maximum potential emissions" or "maximum two-year average" (as given in application Table 1) implies that the applicant has determined that projected actual emissions shall be calculated in accordance with paragraph (d) of the definition of projected actual emissions. The applicant made the future calculation based upon 3,980 "maximum hours of usage per year per unit". Yet the applicant stated they did not want the basis of the calculation to actually be used as a limitation to avoid triggering PSD. According to the application:

"PEF has conducted future operating projections for the Anclote Plant, both with and without the natural gas conversion, and the projections do not reflect any significant differences as a result of the conversion of these units to natural gas. Therefore, PEF's position is that there is not a causal relationship between the Project and future actual utilization and emission increases in these pollutants (in fact, hourly emission rates of NO_X and GHGs will decrease as a result of the fuel conversion). In other words, future actual annual emissions of NO_X and GHGs may be greater than past actual emissions, by a significant amount, but, if so, would be a reflection of system wide demand increase. Such an increase in emissions due to a demand increase unrelated to the Project would be excluded from the determination of regulatory applicability."

The Department does not disagree with the conclusions. However, adherence to the definition and the described procedure for determining future actual emissions provides for a clearer path to the conclusion and avoids misunderstandings in the future. Finally, there is no need to try to estimate usage such that (unadjusted) emissions increases for certain pollutants will be just less than the amount that would trigger PSD.

2.6. Applicant's Filings with the Florida Public Service Commission (PSC)

On April 18, 2012 PEF submitted a petition to the Florida PSC to modify the scope of its previously approved Integrated Clean Air Compliance Program (ICACP) to encompass additional activities such that the costs associated with such activities may be recovered through the Environmental Cost Recovery Clause. Link to Petition

Accordingly, the Florida PSC opened Docket No. 120103-E1, which contains several key documents about the projected future operation of the Anclote Plant. Link to Docket 120103-E1

The filing is premised on the requirement to comply with the EPA Mercury and Air Toxics Standards (MATS) at 40 CFR 63, Subpart UUUUU, published in the Federal register on February 16, 2012. Link to MATS PEF considered three options, including:

- Install electrostatic precipitators (ESP) to comply with the MATS requirements and Low NO_X burners(LNB) to comply with various other EPA regulations targeting NO_X;
- Convert Units 1 and 2 to 100% natural gas capability; or
- Discontinue heavy fuel oil use without completing full conversion to natural gas (effectively derating the units to their present 40% natural gas based capability).

The capital cost of the company's proposed natural gas conversion is of approximately $79,000,000. According to a PEF filing dated June 4, 2012, the company expects fuel savings of approximately $50,000,000 at the Anclote Plant and $268,000,000 over the entire PEF system between 2013 and 2018. According to the filing, the opportunity to operate the Anclote units more efficiently reduces the need to operate other units which are either less efficient, or had been projected to operate in less efficient ways (e.g. at partial loads or making extra starts). The same document had a likely dispatch scenario which is provided in Table 6 below. Link to June 4 2012 Submittal

Table 6. PEF Analysis for 2013 – 2018. Anclote Capacity Factors, Heat Rates, System Fuel Savings

Year	Anclote Unit 1		Anclote Unit 2		System [2]
	Capacity Factor (%)	Heat Rate (Btu/kWH) [1]	Capacity Factor (%)	Heat Rate (Btu/kWH)	Fuel Savings ($)
2013	28.4	11,228	29.6	10,802	14,868,000
2014	29.7	11,196	39.1	10,735	45,326,000
2015	23.3	11,372	30.8	10,886	35,323,000
2016	25.8	11,256	35.5	10,822	55,115,000
2017	26.4	11,267	36.1	10,815	54,192,000
2018	26.9	11,241	36.2	10,808	63,629,000

1. Btu/kWH = Btu per kilowatt-hours. 1,000 kWH = 1 megawatt-hour (MWH). 1,000 MWH = 1 gigawatt-hour (GWH).
2. The fuel savings at the Anclote Plant alone are expected to be $50,000,000 over the same period.

Basically, capacity factor is the annual net electrical generation in megawatt-hours (MWH) divided by the MWH that could have been generated at full load and continuous operation. Although the name plate rating is 556 MW/unit, the present net capability is approximately 510 MW/unit. It is not yet certain whether the natural gas conversion will change capability. Removing the fuel oil handling will decrease parasitic load. However significant physical changes are required in the boilers to maintain their present capabilities when firing only natural gas.

Per the table the highest capacity factor will occur in 2014. Electrical generation is estimated as follows:

[(0.297) + (0.391)]x(510 MW)]x(8,760 H) = <u>3,073,709 MWH</u> = 3,074 gigawatt-hours (GWH)

Heat input is estimated as follows:

[(0.297)x(11,196 Btu/kWH) + (0.391)x(10,735 Btu/kWH)]x[(510 MW)x(8,760 H)x (1,000 kWH/MWH)x(MMBtu/1,000,000 Btu)] = <u>33,607,954 MMBtu</u>

These two estimates form a reasonable estimate of future production and bases for projecting actual emissions. This does not materially limit the ability of PEF to change the production estimates in the future based on changes in utilization and demand based on the economy, changes in the 10-year plans submitted to the PSC, shut downs or modifications of other units due to regulations.

2.7. Historical Emissions and Generation Information for the Anclote Plant

The Department obtained data from the EPA Air Markets website and the Department of Energy website for electric power production. Figure 3 is a summary of annual emissions (tons/year), energy use (MMBtu/year) and gross electric generation (MWH) for the Anclote Plant (Units 1 and 2 combined) for the calendar years 1997 through 2011. Energy use and electric generation have declined by approximately two-thirds (from 50% to 18%) since the recent historically highest values achieved in 2004. Emissions have decreased by 90 to 95% during the same period.

Figure 4 is a summary of emission factors and capacity factors developed from the EPA and DOE data that can be used to explain the disproportionate emissions decreases (compared with generation decreases). During the period 2004-2006, the fraction of natural gas used compared with all fuels (including residual fuel oil) was 1%. In 2011, the fraction of natural used compared with all fuels was 0.89 (i.e. 89% of fuel use). There have been no pollution control projects conducted at the plant in recent years. Increased natural gas use and lower utilization of the units account for the emissions decreases.

For reference, reductions in generation disproportionately reduce NO_X emissions because thermal NO_X is reduced (thus a lower lb/MMBtu value) and mass flow is reduced. The SO_2 emission reductions are in direct proportion to the utilization of natural gas and to the lower annual generation.

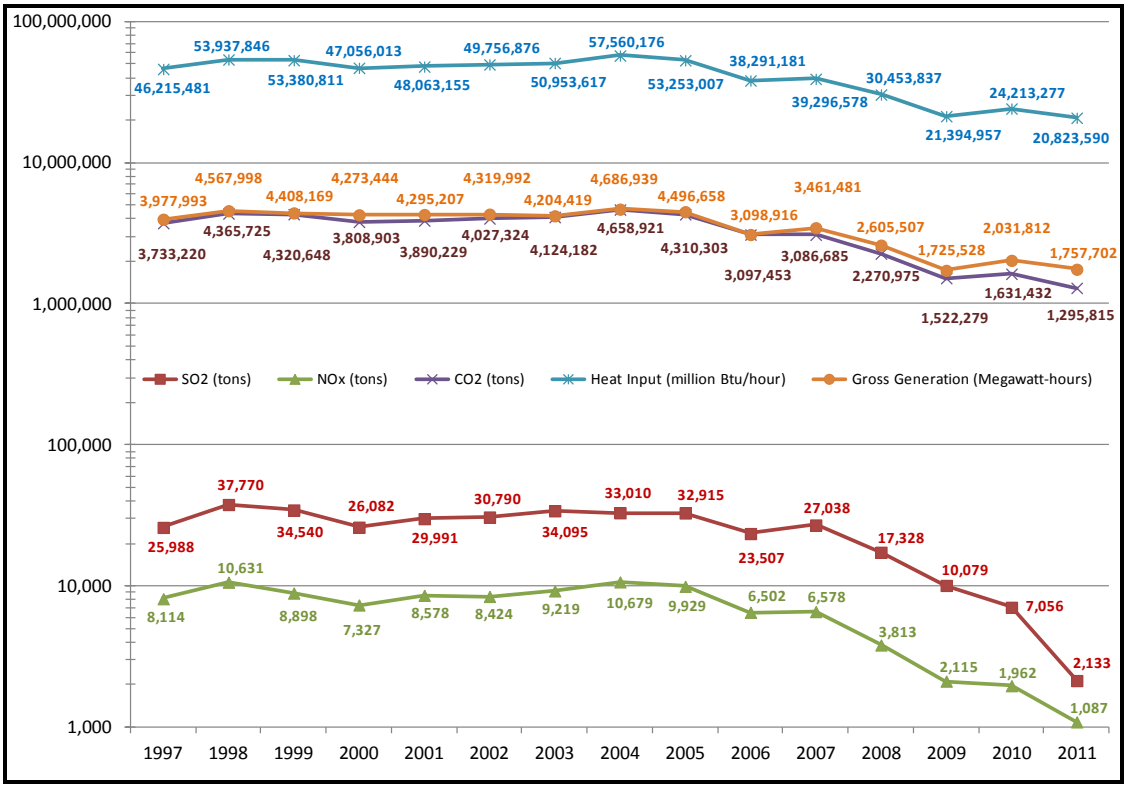

Figure 3. Annual Emissions, Energy Use, Electric Generation – Anclote Plant (1997-2011)

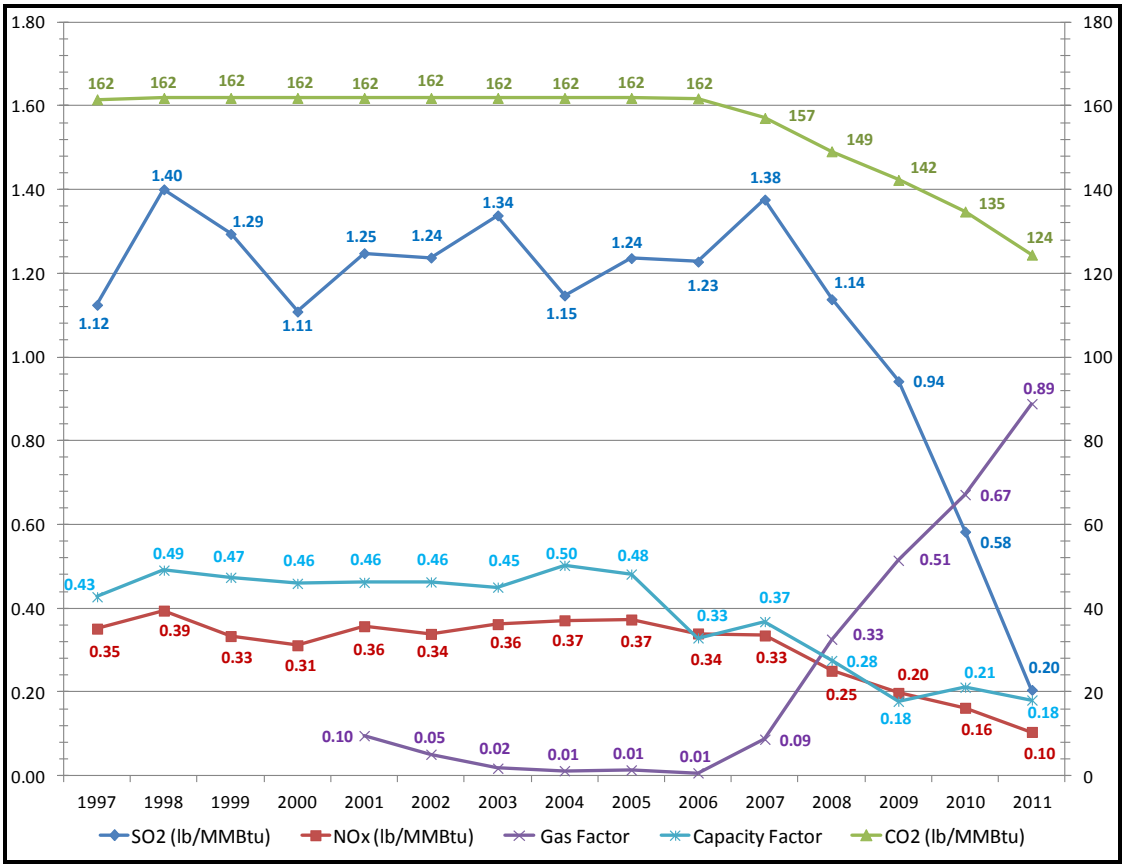

Figure 4. Annual Emissions, Energy Use, Electric Generation – Anclote Plant (1997-2011)

The applicant selected 2006-2007 as the baseline years. During those years, the plant capacity factor was approximately 35% averaged over the two years and over the two units. One of the years (2006) is outside of the most recent 5-year window (2007-2011) normally used for determining baseline actual emissions. The Department accepts the two year selected (2006-2007) as provided by paragraph (a) of the definition of baseline actual emissions. These two years are somewhat more representative (than 2007-2008) considering the 14 year time series shown in the Figures 3 and 4.

The selection of 2006-2007 versus 2007-2008 makes no material difference for this project regarding PSD applicability because there will be a reduction in future emission factors (lb/MMBtu) for key pollutants (NO_X, SO_2 and CO_2). Selection of the earlier 2-year period simply reduces the amount of excludable emissions due to future demand growth/utilization when determining PSD applicability.

Thus, based on the PSC filing, the applicant projects that future demand/utilization will be approximately equal to past demand/utilization. According to Figure 4, the emission factor for GHG/CO_2 has been substantially reduced (from 162 to 124 lb/MMBtu) as the gas factor has increased. This trend will be even more pronounced once the Anclote Plant is fully converted to natural gas usage and fuel oil use is excluded. Similarly the SO_2 emissions factor will be nearly zero after the complete conversion to natural gas.

It is clear that at equal demand/utilization in the future that SO_2 and CO_2 emissions will be much less than they were during the baseline years.

The NO_X emission factor was much less in 2011 (0.10 lb/MMBtu) than during the 2006-2007 baseline years (0.33-0.34 lb NO_X/MMBtu). The main reason is that the units were typically operated at low load and produced much less thermal NO_X per unit of fuel burned. The emission factor and annual emissions will increase (compared with 2011, but not compared with 2006-2007) based on the projected demand/utilization as provided to the PSC.

The applicant has proposed a limit of 0.3 lb NO_X/MMBtu. This insures that in the future at equal demand/utilization to the baseline years, annual NO_X emissions will always be less than during the baseline years. If the emission characteristics of the burners are included as a limit (e.g. 0.30 lb/MMBtu on a 12-month averaging time), then the Department will have reasonable assurance that the project (after correcting for demand/utilization changes) will not (and cannot) cause a net emissions increase equal to or greater than the NO_X SER of 40 tons/year regardless of future demand/utilization.

The applicant can legitimately operate the units at even greater utilization based on system-wide demand. Any such related future emissions increases would be excludable because the units could have accommodated the additional demand/utilization and the additional emissions during the baseline years.

The applicant has projected that the emission factor for CO and VOC emissions will be greater than during the baseline periods. They provided minimal data to support that assertion. It is possible that the goal of minimizing NO_X emissions necessarily increases CO emissions. The units did not have CO and VOC limits or test requirements. However, <u>based on the application</u>, future CO emissions will increase due to the project even if the capacity factor remains as low as it was in 2011. The project will certainly result in a significant net emissions increase under any reasonable future demand/utilization scenario.

The cases of PM, PM_{10}, $PM_{2.5}$ and lead (Pb) are trivial due to the inherently low emissions caused by combustion of natural gas in lieu of residual fuel oil. There is no need to estimate future actual emissions of these pollutants.

2.8. Department's Calculation of Projected Actual Emissions

Based on the foregoing, the Department recalculated baseline and future actual emissions based upon the future capacity factors and heat rate estimates submitted to the PSC for the Anclote Plant. NO_X emissions from Unit 1 and 2 combined are equal to the projected 2014 heat input as estimated above and the future emission factor (guarantee) as follows:

(0.3 lb NO_X/MMBtu)x(33,607,954 MMBtu)x(ton/2,000 lb) = 5,041 tons

The Department believes that emissions will be much less than projected by the applicant because the effective emission factor averaged over all loads will be closer to 0.20 rather than 0.30 lb/MMBtu following conversion to exclusive use of natural gas. Figure 5 is a graph of the SO_2 and NO_X emission factors with respect to gross load throughout January 13, 2011 for Unit 1. On that date, the unit was fired almost exclusively with fuel oil as evidenced by the high SO_2 factor as load varied in response to demand throughout the day.

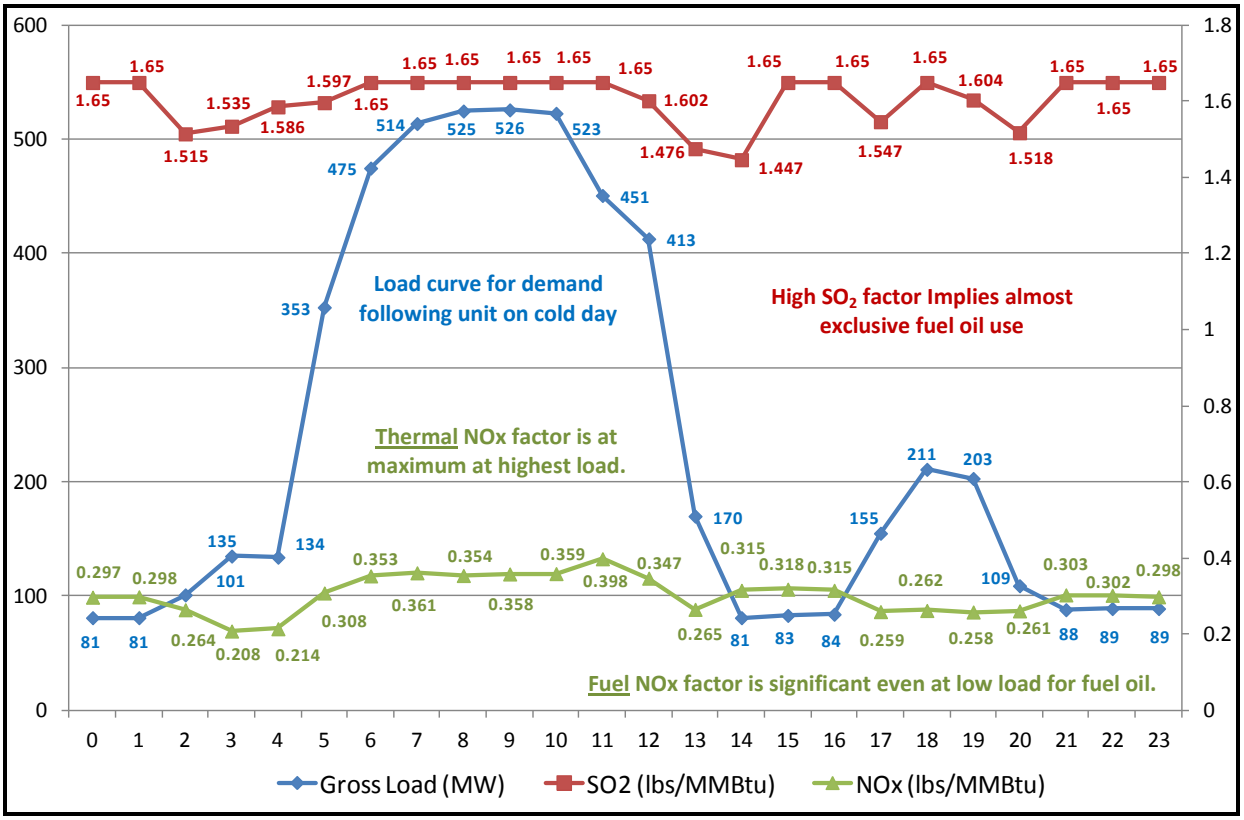

Figure 5. Unit 1 Gross Load, NO_X Emission Factor and SO_2 Emission Factor on January 13, 2011

While burning residual fuel oil (almost exclusively), the NO_X emission factor varied from around 0.20 lb/MMBtu at low load to 0.40 lb/MMBtu at peak load. This kind of load-following scenario is what is envisioned in the future. Without the project a future emission factor of 0.30 lb/MMBtu would be accurate for continued fuel oil firing if little natural gas is used.

Figure 6 is a graph of the SO_2 and NO_X emission factors with respect to gross load throughout January 19, 2011 for Unit 1. On that date, the unit was fired almost exclusively with natural gas when operating at low loads (between 80 and 200 MW). Fuel oil was used to augment natural gas and by the middle of the morning comprised about 60% of the fuel used at the highest load of the day. Under this particular scenario (combined natural gas and residual fuel oil use), the NO_X emission factor varied from 0.06 lb/MMBtu at low load to 0.25 lb/MMBtu at peak load.

The future operating scenario after conversion to exclusive natural gas use and operating at the envisioned annual capacity factors of 30 to 40% suggests that the units will continue to be load following with daily curves similar to those given in Figures 5 and 6. Figure 7 contains curves that describe the expected characteristics of the natural gas burners. The <u>peak</u> NO_X factor <u>at full load</u> will be 0.30 lb/MMBtu with a <u>full load mean</u> of approximately 0.25 lb/MMBtu. At the lower loads, characteristic of most of the hours of the year, the factor will be between 0.15 and 0.25 lb NO_X/MMBtu (and probably lower).

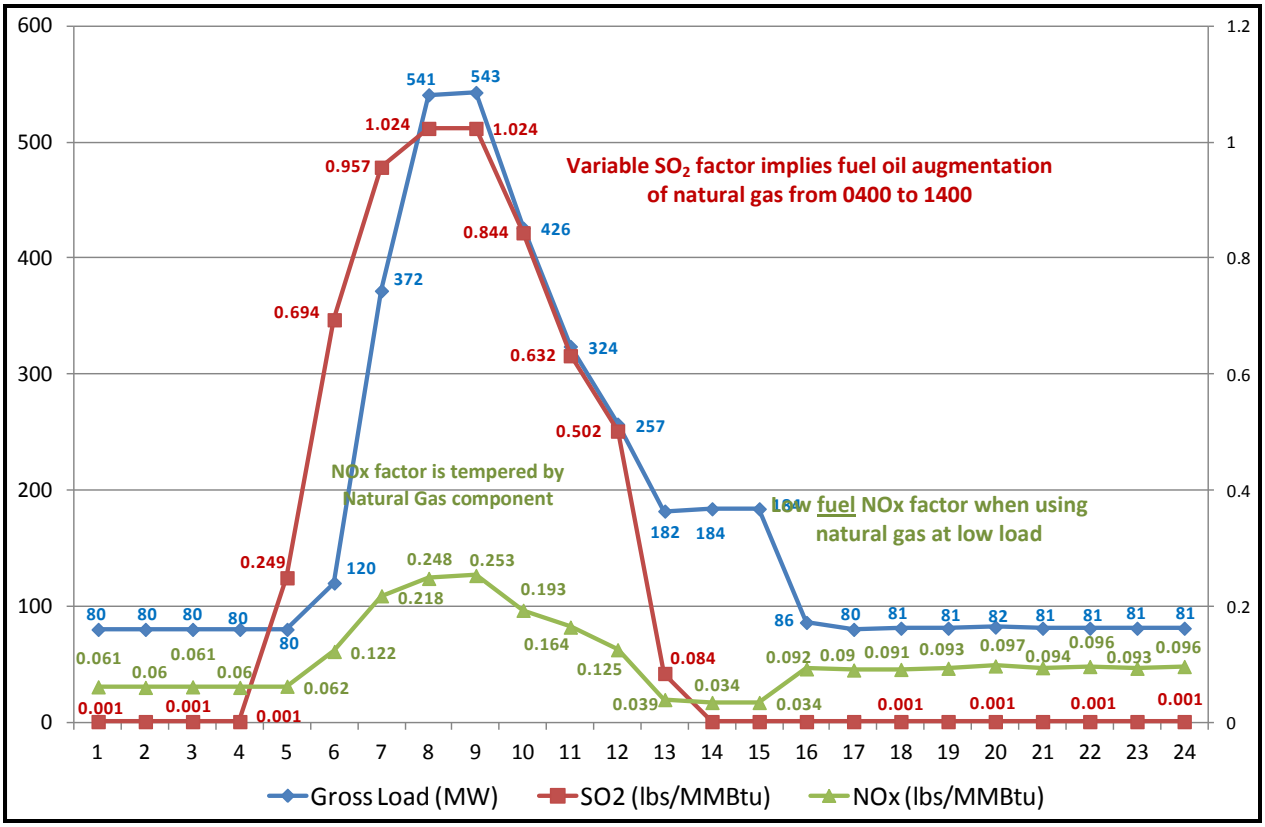

Figure 6. Unit 2 Gross Load and NO_X and SO_2 Emission Factors on January 19, 2011

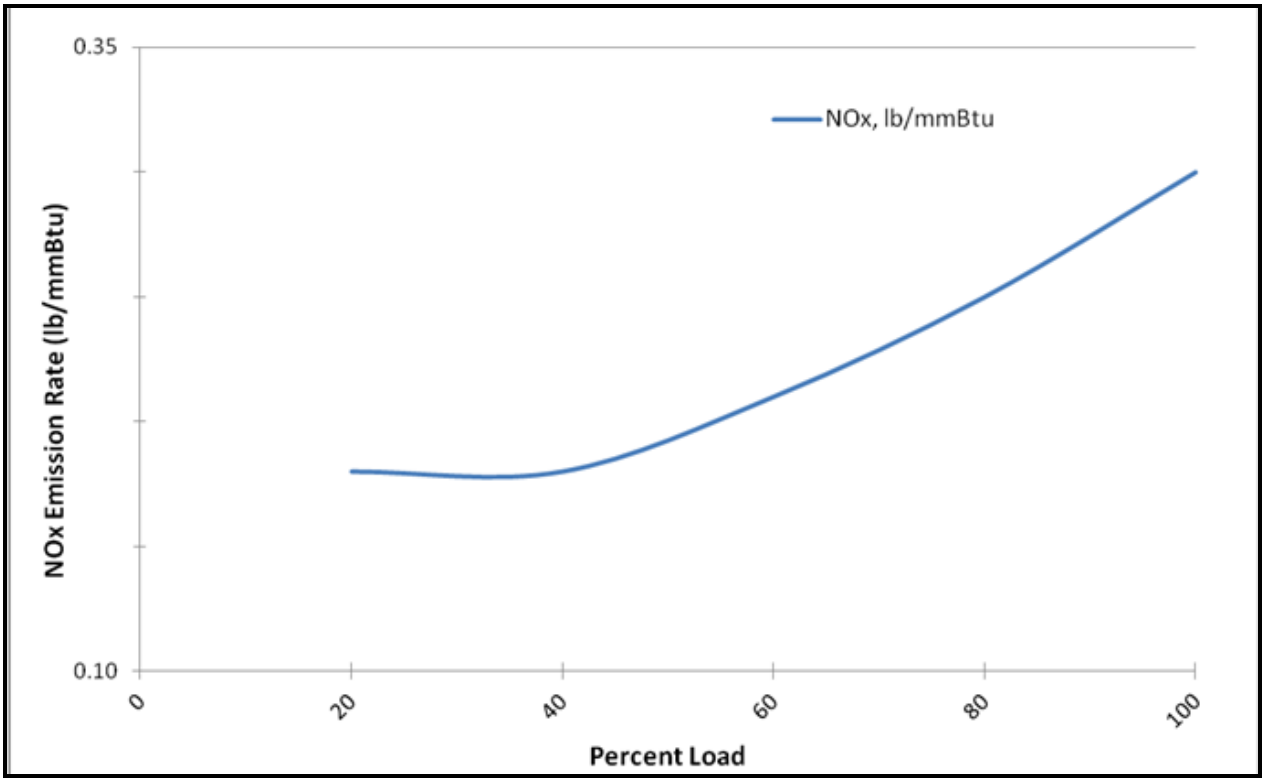

Figure 7. Approximate Expected NO_X Emissions vs. % Load after Conversion Project

The Department's estimate of projected actual emissions using the forecasted heat rate and capacity factors submitted to the Florida PSC and weighted for peak/mean and low/high load operation for 2014 is calculated as follows:

(0.225 lb NO_X/MMBtu)x(33,607,954 MMBtu)x(ton/2,000 lb) = 3,781 tons

This value is much less than the value projected in the application of 6,573 tons/year. It is noted that the Anclote Plant will, after the project, have the following potential to emit (PTE) based on 0.30 lb/MMBtu (the peak emission factor at full load), 8,760 hours of operation, 510 MW (net)/unit and a full load heat rate of approximately 10,750 Btu/kWH of:

(0.30 lb NO_X/MMBtu)x(510 MW)x(10,750 Btu/kWH)x(1,000 kW/MW)x(2 units)x (8,760 H)(MMBtu/1,000,000 Btu)x(ton NO_X/2,000 lb NO_X) = 14,409 tons NO_X/year

The future PTE to emit value is about twice the applicant estimate of projected actual emissions and about four times the Department's estimate. However the future value is actually available to the applicant for future demand/utilization. This future PTE value is actually less than what could have been accommodated (the present PTE) under the present configuration because at continuous full load and using residual fuel oil, the emission factor is actually closer to 0.40 lb NO_X/MMBtu. The Department will include the future emission factor limit of 0.30 lb/MMBtu in the permit.

GHG CO_2 emissions are calculated as follows based on the standard emissions factor of 116.4 lb/MMBtu:

(116.4 lb CO_2/MMBtu) x(33,607,954 MMBtu)x(ton/2,000 lb) = 1,955,983 tons

This represents a reduction in GHG emissions. The main reason is that during the past, the CO_2 emission factor was approximately 160 lb/MMBtu due to much greater fuel oil use. During the baseline years, the Anclote Plant used more than 90% fuel oil, whereas in the future the Anclote Plant will use 100% natural gas.

CO emissions are calculated using the applicant's CO BACT proposal of 0.18 lb/MMBtu and the capacity factors and heat rates from the submittal to the Florida PSC as:

(0.18 lb CO/MMBtu)x(33,607,954 MMBtu)x(ton/2,000 lb) = 3,025 tons/year

For reference, the PTE of CO emissions is calculated using the applicant's CO BACT proposal of 0.18 lb/MMBtu and assuming continuous operation (8,760 hours/year) at full load (i.e. potential to emit):

(0.18 lb CO/MMBtu)x(5,500 MMBtu/hour/unit)x(2 units)x(8,760 hours) = 8,672 tons/year

VOC emissions are calculated using the applicant's VOC BACT proposal of 0.005 lb/MMBtu and assuming continuous operation (8,760 hours/year) at full load (i.e. potential to emit):

(0.005 lb VOC/MMBtu)x(5,500 MMBtu/hour/unit)x(2 units)x(8,760 hours) = 241 tons/year.

For reference, using the average capacity factors from the submittal to the Florida PSC, projected actual emissions of VOC are calculated as:

(0.005 lb VOC/MMBtu)x(33,607,954 MMBtu)x(ton/2,000 lb) = 84 tons/year

Using the updated capacity factors and heat rates from the submittals to the Florida PSC, the Department concludes that PSD will not be triggered for VOC. Furthermore it is illogical to conclude that burning natural gas, comprised primarily of methane (CH_4), will cause as much or more VOC emissions when combusted than residual fuel oil, which is comprised of chained organic molecules. Even unburned CH_4 and ethane (C_2H_6 – another constituent of natural gas) are not considered VOC. Confusion often occurs because CH_4 and C_2H_6 contribute to unburned hydrocarbons (UHC) that are sometimes used as a first estimate or testing surrogate of VOC.

The Department accepts the applicant's estimate of future SO_2 emissions at 60 tons/year.

Table 7 is a summary of emission estimates and PSD applicability following the Department's adjustments as discussed above.

Table 7. Summary of the Applicant's Emissions Estimates and PSD Applicability

Pollutant	24-Month Baseline Period Selected (Years)	Applicant Baseline Actual Emissions (tons/year) [1]	Revised Projected Actual Emissions (tons/year)	Projected Increase (tons/year) [7]	≥ PSD SER? (tons/year) Yes/No
CO	2006 – 2007	506	3,025 [3]	2,519	≥ 100? **Yes**
VOC	2006 – 2007	78	84	+6	≥ 40? No
NO_X	2006 – 2007	6,540 [2]	3,781 [4]	-2,759	≥ 40? No
SO_2	2006 – 2007	25,273 [2]	60	-25,213	≥ 40? No
GHG (CO_2e)	2006 – 2007	2,517,405 [2]	1,955,983 [5]	-541,422	≥ 75,000? No
Heat Input	2006 - 2007	38,793,879 [2]	33,607,954 [6]	-5,185,925	Not Applicable

1. Baseline actual emissions based on company submitted annual operating reports (AOR), except NO_X, SO_2, CO_2 and $PM_{2.5}$.
2. NO_X, SO_2, CO_2 were derived from EPA Air Markets Program Data. See link: http://ampd.epa.gov/ampd/QueryToolie.html .
3. The Department estimates 3,025 tons/year based on capacity factors and heat rates for 2014 in company submittals to Florida PSC. The Department estimates 8,673 tons/year as the PTE.
4. Projected actual NO_X emissions were calculated at an estimated future emission factor weighted over all loads of 0.225 lb NO_X/MMBtu and the projected capacity factors and heat rates for 2014 in company submittals to Florida PSC. The PTE is 14,409 tons/year when based on continuous operation and an emission factor of 0.30 lb NO_X/MMBtu.
5. Projected actual GHG emissions were calculated at an estimated future emission factor of 116.4 lb CO_2/MMBtu and the projected capacity factors and heat rates for 2014 in company submittals to Florida PSC.
6. Heat input is expected to decrease in the future compared with the baseline years of 2006-2007, although heat input will be substantially greater than realized during the most recent years (e.g. 2010-2011).
7. Estimate of projected net emissions increases for comparison with respective SER.

The Department concludes that PSD review and a BACT determination are required only for CO.

3. REQUIREMENTS FOR PROJECTS SUBJECT TO PSD

In accordance with Rule 62-212.400(4), F.A.C., for the construction of any new "major stationary source" or the major "modification" of any existing major stationary source, the applicant must provide the following information:

(a) A description of the nature, location, design capacity, and typical operating schedule of the source or modification, including specifications and drawings showing its design and plant layout;

(b) A detailed schedule for construction of the source or modification;

(c) A detailed description as to what system of continuous emission reduction is planned for the source or modification, emission estimates, and any other information necessary to determine best available control technology (BACT) including a proposed BACT;

(d) The air quality impact of the source or modification, including meteorological and topographical data necessary to estimate such impact and an analysis of "good engineering practice" stack height; and

(e) The air quality impacts, and the nature and extent of any or all general commercial, residential, industrial, and other growth which has occurred since August 7, 1977, in the area the source or modification would affect.

The application adequately describes the project. The conversion is scheduled to occur in the second half of 2012 and through 2013. The BACT proposal is described in the application and evaluated in Section 4 below. The air quality impacts of the CO increases are evaluated in Section 5 below. Growth related impacts are also described in the application and Section 5 below.

4. BEST AVAILABLE CONTROL TECHNOLOGY (BACT) – DRAFT DETERMINATIONS

4.1. Definitions and Requirements Related to BACT

"Best Available Control Technology" or "BACT" is defined in Rule 62-210.200(Definitions), F.A.C. as:

(a) An emission limitation, including a visible emissions standard, based on the maximum degree of reduction of each pollutant emitted which the Department, on a case by case basis, taking into account:

1. *Energy, environmental and economic impacts, and other costs,*
2. *All scientific, engineering, and technical material and other information available to the Department; and*
3. *The emission limiting standards or BACT determinations of Florida and any other state; determines is achievable through application of production processes and available methods, systems and techniques (including fuel cleaning or treatment or innovative fuel combustion techniques) for control of each such pollutant.*

(b) If the Department determines that technological or economic limitations on the application of measurement methodology to a particular part of an emissions unit or facility would make the imposition of an emission standard infeasible, a design, equipment, work practice, operational standard or combination thereof, may be prescribed instead to satisfy the requirement for eh application of BACT. Such standard shall, to the degree possible, set forth the emissions reductions achievable by implementation of such design, equipment, work practice or operation.

(c) Each BACT determination shall include applicable test methods or shall provide for determining compliance with the standard(s) by means which achieve equivalent results.

(d) In no event shall application of BACT result in emissions of any pollutant which would exceed the emissions allowed by any applicable standard under 40 CFR Parts 60, 61, and 63.

4.2. Requirements of 40 CFR Parts 60 and 63 on the Natural Gas Conversion Project

As stated in the definition of BACT given above, *"in no event shall application of BACT result in emissions of any pollutant which would exceed the emissions allowed by any applicable standard under 40 CFR Parts 60, 61, and 63 (i.e. the NSPS or NESHAP)"*. The company "commenced construction" on the units as defined in NSPS, Subpart A before the applicability dates contained in 40 CFR 60 Subparts D – Standards of Performance for Fossil Fuel Fired Steam generators and Da - Standards of Performance for Electric Utility Steam Generating Units.

The project is not a modification as defined in NSPS Subpart A. The only pollutant expected to increase is CO, for which no emission standard applies under the potentially relevant NSPS Subpart D and Da. The project does not constitute reconstruction as defined in NSPS, Subpart A, because the cost is less than $40,000,000 per unit whereas the cost to construct entirely new like-kind units would be an order of magnitude greater.

The units are presently subject to NESHAP, Subpart UUUUU, also known as the MATS. This Subpart will not apply if the units are converted to natural gas prior to the initial compliance deadline date of April 16, 2015. NESHAP, Subpart DDDDD - Industrial, Commercial, and Institutional Boilers and Process Heaters, does not regulate electric utility steam generating units. NESHAP Subpart JJJJJJ - Industrial, Commercial, and Institutional Boilers Area Sources, does not regulate natural gas boilers.

The Department concludes that no standards from 40 CFR 60, 61 or 63 apply to this project or as factors when conducting a BACT determination.

4.3. CO BACT Determination for Natural Gas Conversion of Units 1 and 2

CO Formation and Combustion Controls

CO is a product of incomplete combustion of carbon-containing fuels such as natural gas and fuel oil. Factors adversely affecting the combustion process are low temperatures, insufficient turbulence and residence times, and inadequate amounts of excess air. Control of CO by combustion controls is typically called Good Combustion Practices (GCP). Primary control of NO_X is also accomplished by GCP. When no add-on or post-combustion controls are included, the control of NO_X and CO involves optimization to insure that efforts to control one pollutant do not cause unacceptable increases in the other.

Combustion controls reduce the level of NO_X emissions by altering or modifying the firing conditions under which combustion is achieved. Each of the combustion control technologies are based on achieving one or more of three primary objectives: 1) lower the flame temperature; 2) create a fuel rich condition at the maximum flame temperature; or 3) lower the residence time under which oxidizing conditions exist. The efficiency of the combustion process and CO emissions are often affected by the implementation of combustion controls. Link to NOx Reduction White Paper

Table 8 is a summary of meaningful NO_X combustion control technologies for boilers.

Table 8. Summary of Combustion Control Technologies (Excludes trim technologies)

NO_X Emissions Control Technology	Application	NO_X Reduction (%)
Low NO_X Burners (LNB) – Oil & Gas	Boilers/Process Heaters	40-60
Close coupled overfire air (CCOFA)	Boilers	30-50
Separate overfire air (SOFA)	Boilers	40-60
Induced Flue Gas Recirculation (FGR)	Boilers/Process Heaters (Internal)	30-40
Forced FGR (requires additional fan)	Boilers	40-50
Water/Steam Injection	Boilers/Process Heaters	20-25

Of particular interest are the SOFA and CCOFA concepts shown in Figures 8 and 9, respectively.

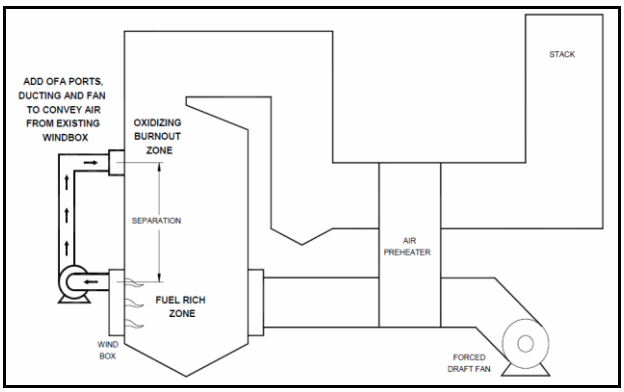

Figure 8. SOFA System for NO_X Control

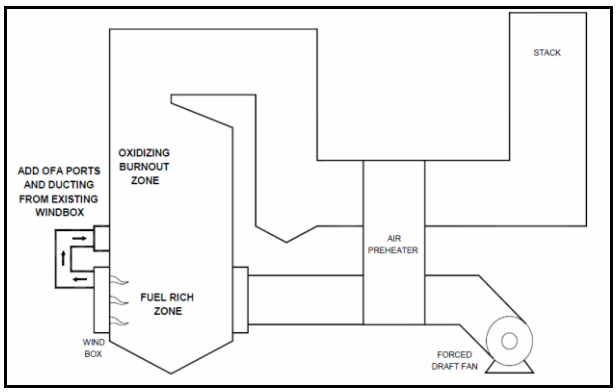

Figure 9. CCOFA System for NO_X Control

The clearest difference between the two options is that the CCOFA system promptly adds the necessary oxygen to promote rapid burnout and lower CO (and consequently less aggressive NO_X control).

Another factor is that fuel oil combustion occurs in distinct physical heterogeneous stages involving atomization, mixing, release of volatile compounds, combustion and burnout of char. Natural gas combustion occurs as homogeneous phase combustion.

Applicant's CO BACT Proposal

The applicant will remove four levels of residual fuel oil burners and an igniter level while adding three levels of natural gas burners in combination with the existing natural gas burners to provide full output on 100 percent natural gas. BACT is not required for NO_X. The project will be designed to minimize NO_X emissions by CCOFA as clarified by electronic communication from Golder Associates on July 25, 2012.

According to the applicant, GCP are the only technically feasible method of controlling CO emissions and have been identified as BACT for CO control for every major fossil fuel-fired boiler identified in the EPA's clearinghouse database. Furthermore, design of a boiler and combustion air system to efficiently burn the natural gas represents BACT for control of CO emissions. According to the applicant, there are no other control devices demonstrated that are available or feasible for the project.

According to the applicant, CO emissions can be reduced by passing the flue gas (leaving the furnace) over an oxidation catalyst (Ox-cat) at a suitable temperature (900 to 1,000^{o}F). The applicant rejected this post-combustion control and provided the following reasons:

- No utility fossil fuel-fired boilers are operating with catalytic CO control systems and it would be difficult to retrofit an oxidation catalyst in the proper temperature zone downstream of the boiler.
- Catalyst converts up to 70 percent of SO_2 to SO_3.
- There is a lack of experience with large-scale operation of this technology using particulate-laden gases from fossil fuel-fired boilers. Catalysts can be easily eroded and fouled by silica and trace metals in the flue gas.
- The temperature profile of the flue gas does not match the temperature requirements of typical catalysts.
- Use of an undemonstrated catalyst technology would reduce the availability and reliability of the plant (e.g., catalyst plugging).
- The high costs to install and operate the system (additional pressure drop, catalyst replacement and disposal, etc.) are without corresponding demonstrated needs or benefits. Design and operation of the boiler to efficiently combust the fuel will minimize CO emissions. The additional costs to further lower emissions are not justified.

The applicant proposes a CO BACT limit of 0.18 lb/MMBtu and claims the value is within the range of emission rates recently established as BACT for new units. According to the application, the value is equal based on vendor data that specifies 200 parts per million, by volume, dry at 3% oxygen (ppmvd@3% O_2). According to the applicant, lower furnace temperatures at low loads can result in elevated CO emissions in terms of lb/MMBtu (and ppmvd). However, the applicant believes that overall mass emission rate is relatively constant over the entire boiler operating range from initial ignition at startup to full load and proposes a mass CO emission limit of 990 lb/hour applicable at all loads.

In summary the applicant proposes the following as CO BACT:

- CO emissions shall be controlled using GCP; and
- CO emissions shall be limited to the higher of 0.18 lb/MMBtu or 990 lb/hour, based on a three-hour test average, whichever is greater.

Department's Assessment of Applicant's CO BACT Proposal

The Department does not dispute the applicant's assertion that GCP (and not Ox-cat) has been identified as BACT for all (large) fossil fuel-fired boiler projects. The Department disagrees with the rationale provided in support of the claim that Ox-cat is not technically feasible.

Refer to Figure 10. The information in the curves from catalyst providers, Süd-Chemie and Johnson-Matthey, conclusively show that Ox-cat is effective for CO removal at temperatures as low as 300 °F.

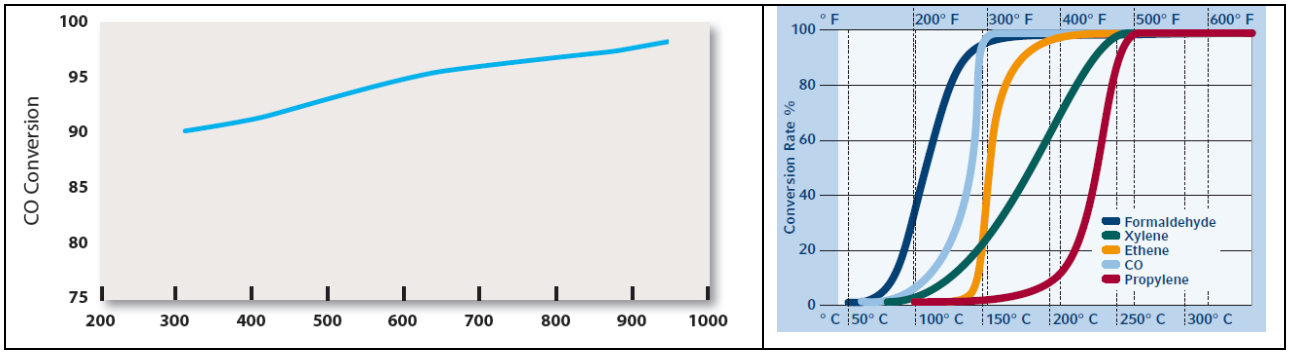

Figure 10. Ox-cat Performance vs. Temperature (^{o}F) Ox-cat Performance vs. Temperature (^{o}C)

For reference, Süd-Chemie supplies catalyst for more difficult application such as biomass-fueled power projects. Johnson-Matthey tends to avoid biomass application, but clearly offers Ox-cat for use in natural gas-fired boilers. Link to Johnson-Matthey Catalyst Presentation According Johnson-Matthey, *"CO oxidation catalyst is suitable for gas-firing and low/no sulfur fuels"*. Clearly all of the reasons provided by the applicant (other than economic) refer to coal-fired boilers and are irrelevant to gas-fired boilers.

As proposed, the technology-based emission standard 0.18 lb CO/MMBtu citation as BACT is superfluous because the alternative 990 lb/hour limit will always be the "higher of" the two except at full load - in which case they are equal. The Department does not agree with the statement that *"overall mass emission rate is relatively constant over the entire boiler operating range"*. No information was provided to support the statement. However, the Department has information suggesting that CO mass emissions are actually low at low loads for an analogous situation occurring at a coal-fired unit with NO_X and CO limits based on combustion controls.

As a comparison, the coal-fired OUC Stanton Unit 1 has a net capacity of approximately 440 MW, while the Anclote units are each rated at approximately 510 MW (net). The Department set a BACT limit of 0.18 lb CO/MMBtu on a 30-day basis for OUC Unit 1 in conjunction with a NO_X control project, including Low NO_X Burners (LNB) and overfire air (OFA). The unit has no post combustion controls such as selective catalytic reduction or Ox-cat.

Refer to Figures 11. The data are represent all of the hourly observations recorded during a single month by the CO and NO_X continuous emission monitoring systems (CEMS) on the OUC Stanton Unit 1. The CO and NO_X plots and data points are organized based on the concurrent heat input rate, which is ordered from the lowest to highest hourly heat input measured during the month (over 740 readings).

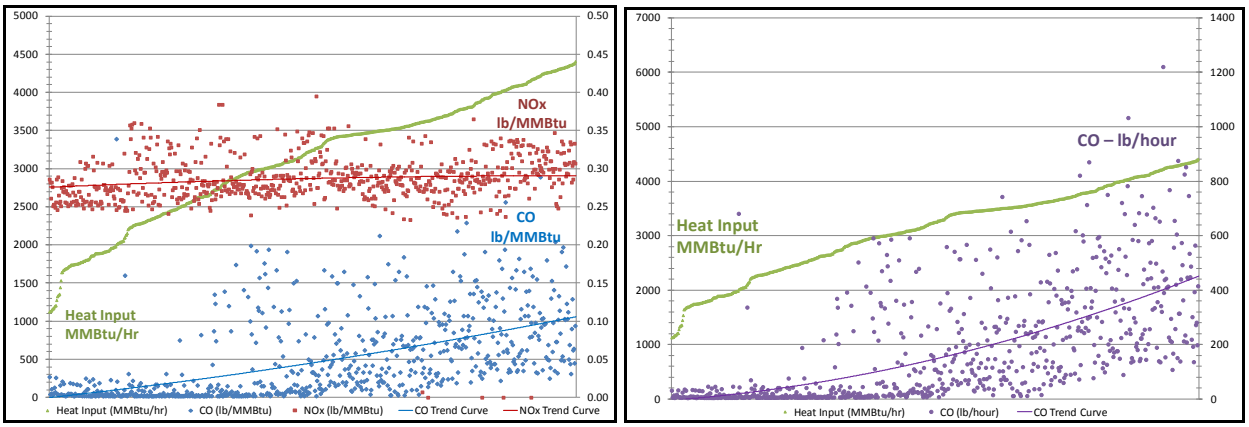

Figure 11. OUC Unit 1 NO_X, CO, Heat Input; Relation of CO Hourly Emissions vs. Hourly Heat Input

The data on the left side of Figure 11 and the trend line through the data indicate that hourly NO_X concentrations, expressed as lb/MMBtu, are fairly even for OUC Unit 1 with respect to heat input measured as MMBtu/hour. Interestingly, the average NO_X emissions are a little less than 0.30 lb/MMBtu and roughly equal to the target for Anclote Units 1 and 2.

Hourly CO concentrations increase with respect to heat input as indicated by the trend line. Individual hourly measurements are almost always less than the 30-day BACT emission standard of 0.18 lb/MMBtu. The hourly CO mass emission rates and the trend line on the right side of Figure 11 very clearly suggest strong correlation with hourly heat input.

The LNB and OFA systems on OUC Unit 1 are optimized to maintain a low NO_X value. Without these controls, NO_X concentrations would be much greater. The CO BACT concentration limit of 0.18 lb/MMBtu was set high enough to accommodate the low NO_X objectives of the OUC LNB and OFA project. By comparison, the natural gas conversion project at Anclote seeks more modest NO_X reductions. The Anclote gas conversion places fewer constraints on achievement of low CO emissions compared with the OUC Unit 1 project (which fires fuel with inherently greater CO emissions).

By comparison, the Department establishes permit conditions for municipal waste combustors (MWC), including limits of 100 ppmvd CO @7% O_2 on a 4-hour block average. The equivalent value at power plant reference conditions would be 78 ppmvd @3% O_2 and 0.14 lb/MMBtu. These are low emission rates for a wet, heterogeneous and lumpy fuel such as municipal solid waste. Like the fossil fuel plants, such MWC units have substantial NO_X combustion controls that incorporate optimization with CO.

In the future the PTE of CO from the Anclote Plant will be 8,673 tons/year at 990 lb/hour/unit. If, e.g., CO were valued at just $100/ton removed, then annualized capital and operating costs of $434,000 would be justified to remove 50% of the CO. If CO were valued at $1,000/ton removed, annualized capital and operational expenditures of $4,340,000 would be justifiable. Even Ox-cat would appear cost-effective.

Department's CO BACT Determination

The Department believes that a relatively modest investment in automated controls cost to further optimize NO_X and CO emissions (in a manner analogous to that achieved at the OUC Stanton Unit 1) will be cost-effective (without installing Ox-cat). The project includes an upgrade of the burner control and management system and this upgrade can include tools to achieve the CO BACT determination.

In general structural changes can also be made to increase the residence time following the OFA system and before some of the convective passes. Those changes are not indicated for this project given that the CCOFA system is selected as in most Alstom gas conversion projects. The Department does not necessarily rule out consideration of greater residence times or Ox-cat on modifications in general or on new units.

The Department will set a BACT limit of 0.15 lb CO/MMBtu for Units 1 and 2 on a 30-day basis. According to the Department's calculations, this value is equal to the 200 ppmvd @3% O_2 value cited as "vendor data" in the application form (page 21). This value can be achieved by GCP within the constraints of the multi-pollutant controls (NO_X and CO) on the units. The Department will require installation of a CO-CEMS. CEMS have been used throughout the industry as a cost-effective means for documenting compliance with BACT limits and were required in conjunction with similar projects at OUC, Lakeland Utilities and Tampa Electric Big Bend. There will be a requirement for the CEMS to be installed and certified by December 31, 2013 for Unit 1 and June 30, 2014 for Unit 2.

4.4. Draft BACT Determination for the Natural Gas Process Gas Heater

The Project will also require the addition of two fuel gas heaters, one for each of the units. The natural gas heaters will utilize a heat transfer fluid for heating the natural gas and be fired with only natural gas. The application described the specifications for the gas heaters as follows:

- Usage of 3,390 hours/year/unit;
- Heat input rate of 16.5 MMBtu/hour/unit;
- CO emissions of 0.081 lb/MMBtu; and
- Annual CO emissions of 2.7 tons/year/unit

However, the applicant's scenario was marked to future expected operation of Units 1 and 2 and not intended as requests to limit operation of the gas heaters.

The requirements of NSPS Subpart Dc - Small Industrial-Commercial-Institutional Steam Generating Units are given at: Link to NSPS Subpart Dc . NSPS Subpart Dc does not address NO_X or CO. Also it does not set emission standards for PM or SO_2 from units exclusively fueled by natural gas.

No major source NESHAP apply to this project because the facility is an area source of HAP. The requirements of NESHAP Subpart JJJJJJ - Industrial, Commercial, and Institutional Boilers Area Sources are given at Link to NESHAP Subpart JJJJJJ . Unlike the NSPS Subpart Dc, the NESHAP JJJJJJ excludes natural gas –fueled units. Unlike the major source NESHAP Subpart DDDDD, the area source NESHAP excludes process heaters.

The applicant estimated CO emission concentrations of 0.081 lb/MMBtu based on GCP. The Department will specify the use of natural gas as BACT for these relatively small gas heaters. This determination does not necessarily apply to future projects with numerous or larger gas heaters.

4.5. Visible Emissions BACT Determination for Natural Gas Conversion of Units 1 and 2

In accordance with the definition of BACT (including a visible emissions standard) the Department will specify a limit of 15% opacity. Normally there should be minimal visible emissions when combusting natural gas. However it is possible to experience some visible emissions related to the NO_X emissions and also, for a time, re-entrained condensed sulfur compounds and particles from the years of residual fuel oil firing. As part of the project, there will undoubtedly be surface cleaning and slag removal and over time, visible emissions should settle down into a more familiar range of 10% opacity or less.

5. UNIT 1 AND 2 HEAT INPUT REQUIREMENTS

The steam turbine electrical-generators each have a name plate of 556.2 MW (gross). The summer capabilities of Units 1 and 2 as presently configured are 501 and 510 MW (net), respectively. The winter capabilities of Units 1 and 2 are 517 and 530 MW (net), respectively. PEF 10-year Site Plan

The Title V Air Operation Permit describes the units as follows:

*"**Unit No. 1**, a fossil fuel fired steam generator, consists of a Combustion Engineering, Inc., Controlled Circulation, Radiant Reheat (CCRR) type boiler/steam generator and steam turbine which drives a generator with a nameplate rating of 535 (summer)/540 (winter) megawatts (MW) (electric).*

"This unit is authorized to fire fuel oil Nos. 1 through 6, and on-specification used oil, with a nominal maximum heat input of 4,964 MMBtu per hour. Pipeline quality natural gas may be fired alone or co-fired with fuel oil and shall be limited to a nominal maximum heat input of 2300 MMBtu per hour.

*"Unit No. 1 is authorized to co-fire natural gas with fuel oil Nos. 1 through 6, and on-specification used oil, with a nominal maximum heat input of **5,073** MMBtu per hour."*

*"**Unit No. 2**, a fossil fuel fired steam generator, consists of a Combustion Engineering, Inc., CCRR type boiler/steam generator and steam turbine which drives a generator with a nameplate rating of 525 (summer)/530 (winter) MW (electric).*

"This unit is authorized to fire fuel oil Nos. 1 through 6, and on-specification used oil, with a nominal maximum heat input of 4850 MMBtu per hour. Pipeline quality natural gas may be fired alone or co-fired with fuel oil and shall be limited to a nominal maximum heat input rate of 2300 MMBtu per hour.

*"Unit No. 2 is authorized to co-fire natural gas with fuel oil Nos. 1 through 6, and on-specification used oil, with a nominal maximum heat input of **4,957** MMBtu per hour. Fuel additives, typically of a magnesium oxide, hydroxide or sulfonate, or calcium nitrate origin, are used to enhance combustion and/or control acidity. Fossil fuel fired steam generator Unit No. 2 began commercial operation on October 31, 1978."*

In the present application, the applicant provided the maximum heat input rate of each unit as **5,500** MMBtu/hour, or an increase of approximately 10% compared with the present "nominal maximum heat input ratings". Boiler efficiency is reduced when using natural gas. For example, a fuel oil to natural gas conversion at a 565 MW unit at the Boston Edison, Mystic Plant in Massachusetts resulted in an efficiency drop of 5-6%. Link to Natural Gas Document No derating of the unit occurred. Therefore it would require a greater heat input to maintain the pre-conversion rating.

For the same rating, fuel oil units are generally larger and can accommodate the needs of natural gas conversion. With some physical rearrangements, such conversions can accommodate the additional heat input required to maintain rated capacity. Figure 12 is a graphical depiction of this concept. The larger oil furnace provides for additional heat input when burning natural gas and provides the opportunity to generate enough steam to actually achieve the gross nameplate capacity of the steam generators.

The conversion to natural gas at Anclote Power Plant will remove the auxiliary loads required for oil heating and circulation. This reduction and some additional heat input beyond that required to maintain the present furnace rating will result in greater net winter/summer capabilities of Units 1 and 2 and take maximum advantage of the steam generator capacities.

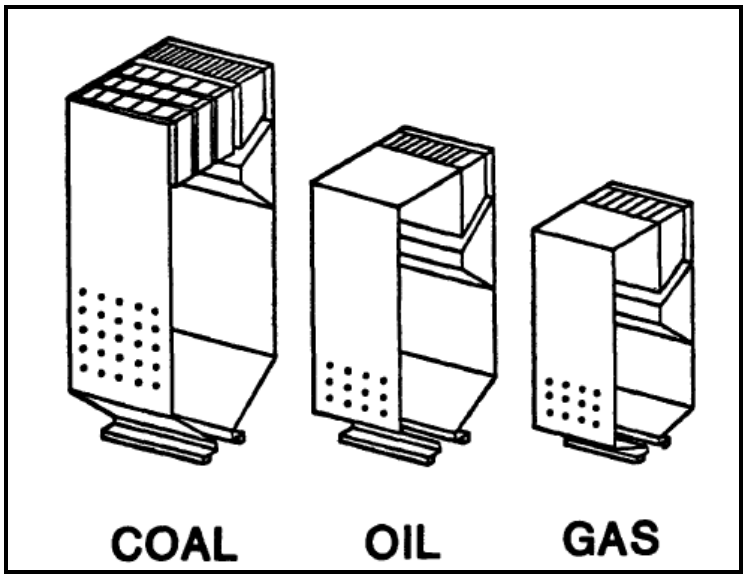

Figure 12. Relative Sizes of Coal, Oil, Gas Fired Boilers of Equal Maximum Continuous Rating

Although the heat input capacity will increase, projected demand utilization estimates were made only 5 years into the future (2013-2018). According to PEF submittals to the Florida PSC, there is a *"recognition that PEF may elect to pursue a combined cycle conversion of the facility later in the decade to meet future system power needs"*. Link to July 5, 2012 Submittal

In any event, the nature of the present conversion to an inherently cleaner fuel and the federally enforceable limits on NO_X insure that even well into the future, any net emissions increases as defined in the Department's rules cannot possibly exceed the relevant significant emission rates. The only exception is CO and that pollutant was addressed by this BACT determination. The Department will, therefore, reference a new design heat input of 5,500 MMBtu/hour/unit in the permit.

6. HELPER COOLING TOWERS

The Anclote Power Plant has two 12-cell mechanical "helper cooling towers". These are used within a once-through cooling water arrangement to reject a portion of the circulating water heat load to the atmosphere rather than to the water body that supplies the once-through cooling water. Figure 13 is an aerial photograph of the Anclote Power Plant. The once-through cooling water canal and helper cooling towers are clearly visible.

The Department issued Air Permit No. 1010017-007-AC (PSD-FL-379) on October 20, 2006 to replace the existing helper cooling towers. Link to Permit PSD-FL-379 PSD was triggered for PM only and a BACT determination was conducted that limited the drift rate to 0.0005%. The permit limited the operation of each cooling tower to 4,500 hour/year/tower.

The applicant requests a change in the operational limits contained in the original PSD permit and the present Title V Air Operation Permit as follows:

Hours of Operation. ~~Each~~ Both cooling towers shall not operate more than ~~4,500~~ 9,000 hours in total per calendar year. This equates to an average of 4,500 hours/year/cooling tower.
[Rule 62-210.200 (Definitions – Potential to Emit (PTE), F.A.C.; and, PSD-FL-379/Air Construction Permit No. 1010017-007-AC.]

The request is acceptable and will be incorporated into the present permitting action. The change will not cause a significant increase PM emissions and the PM_{10} emissions from these units are very low (0.9 tons/year). Any conceivable increases would be easily offset by the permanent PM and PM_{10} reduction at Units 1 and 2 due to the natural gas conversion project.

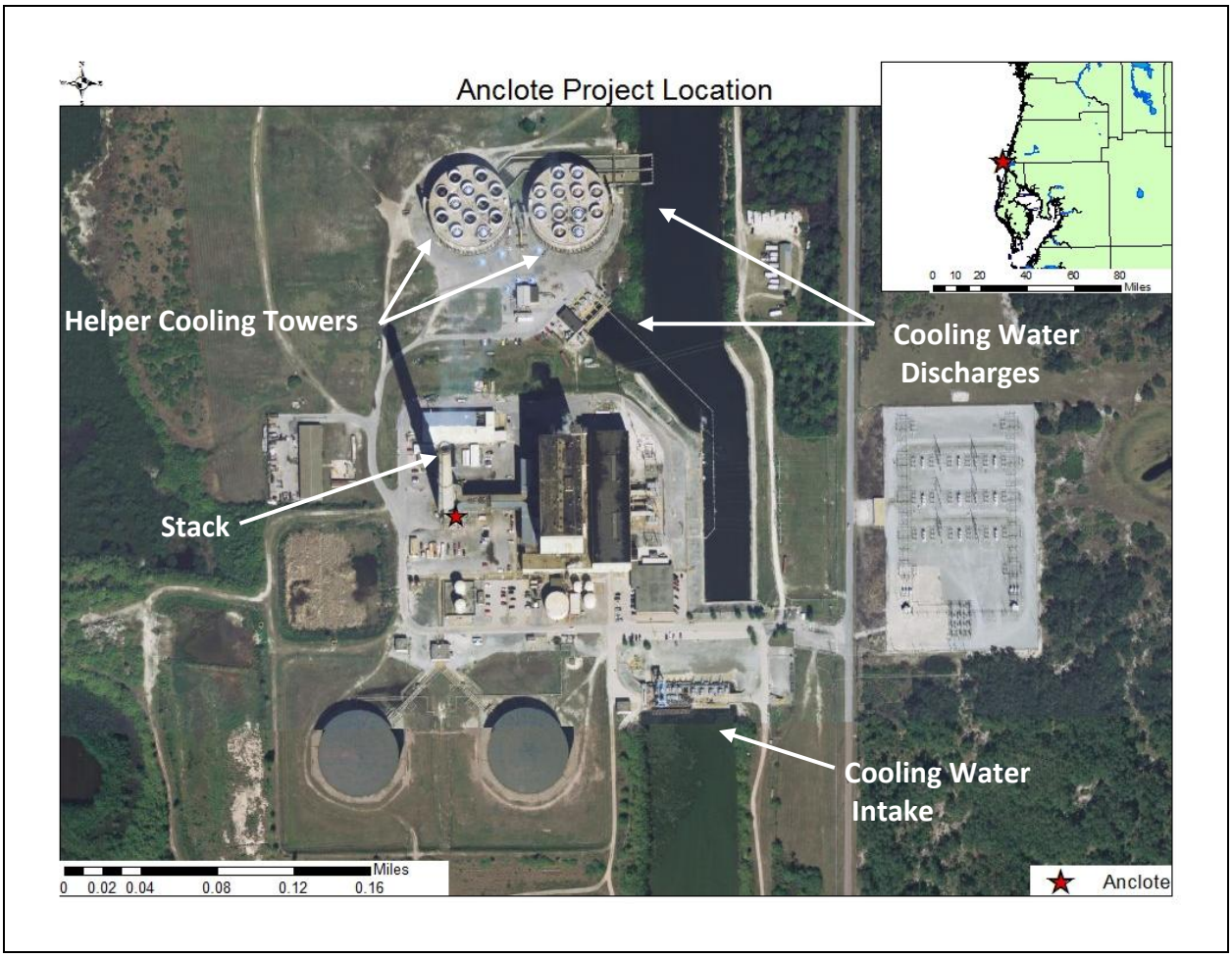

Figure 13. Location of Anclote Plant and Orientations of Stack, Cooling Canal and Cooling Towers

7. AMBIENT AIR QUALITY

7.1. Introduction

The proposed project will increase CO emissions at levels in excess of the PSD SER. The applicant must provide a demonstration using approved air quality models that project emissions of CO will not cause or contribute to a violation of an ambient air quality standard (AAQS) or PSD increment for the pollutants

where they apply. CO has defined national and state AAQS. In addition, significant impact levels (SIL) and de minimis monitoring levels are defined for CO and are used to determine the scope of the modeling analysis and the need for additional ambient air monitoring data.

7.2. Major Stationary Sources Nearest to the Project

Tables 9 lists the largest sources of the pollutants across West-Central Florida (near the project site) per annual operating reports (AOR) filed with the Department in 2011. The values include the contributions of the existing Anclote Power Plant. Facilities have been arranged from greatest to least 2011 emissions.

Table 9 - Largest Sources of CO Nearest to the Project in tons/year

Owner	Site Name	County	Year 2011
TECO	Big Bend Generating Station	Hillsborough	9,168*
Progress Energy	Bartow Plant	Pinellas	466
Cemex and Arroyo Energy	Brooksville South Facility	Hernando	370
EnviroFocus	EnviroFocus Lead Battery Recycling	Hillsborough	350*
TECO	Bayside Power Station	Hillsborough	266
Progress Energy	**Anclote Power Plant**	**Pasco**	**257**
Pinellas Co RRF	Pinellas Co RRF	Pinellas	193
Hillsborough Co Solid Waste	Southeast Landfill	Hillsborough	180

7.3. Ambient Air Quality Monitoring

The state ambient air monitoring network operated by the Department and its partners includes more than 23 monitors at 11 sites. These monitors measure NO_2, SO_2, PM_{10}, $PM_{2.5}$ and ozone (O_3). The 2012 monitoring network is shown below in Figure 14.

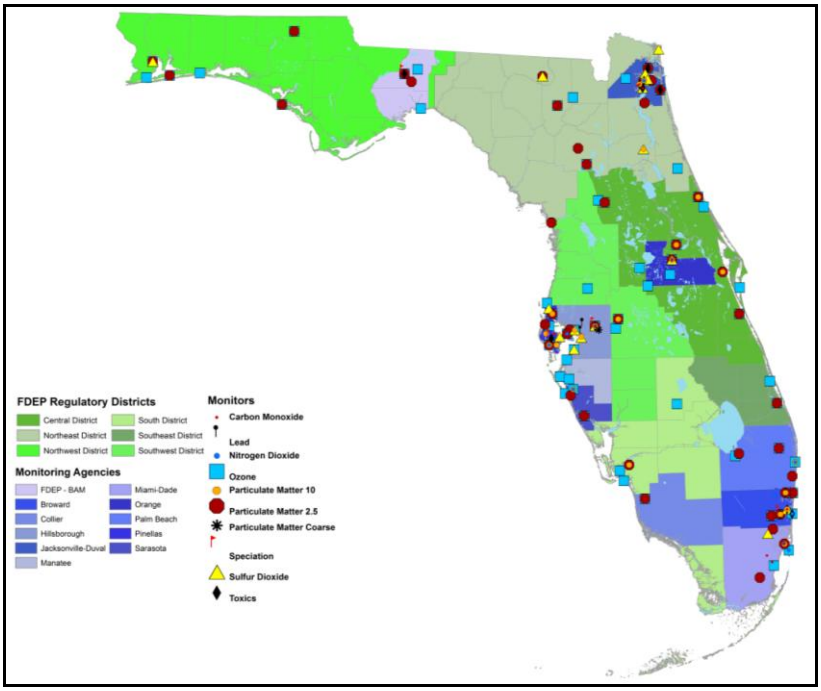

Figure 14. Florida 2012 Ambient Air Monitoring Network

A close up of just the most representative CO monitor, which is in adjacent Pinellas County is shown in Figure 15. This monitor is used to estimate the existing background CO concentration nearest to the Anclote Power Plant.

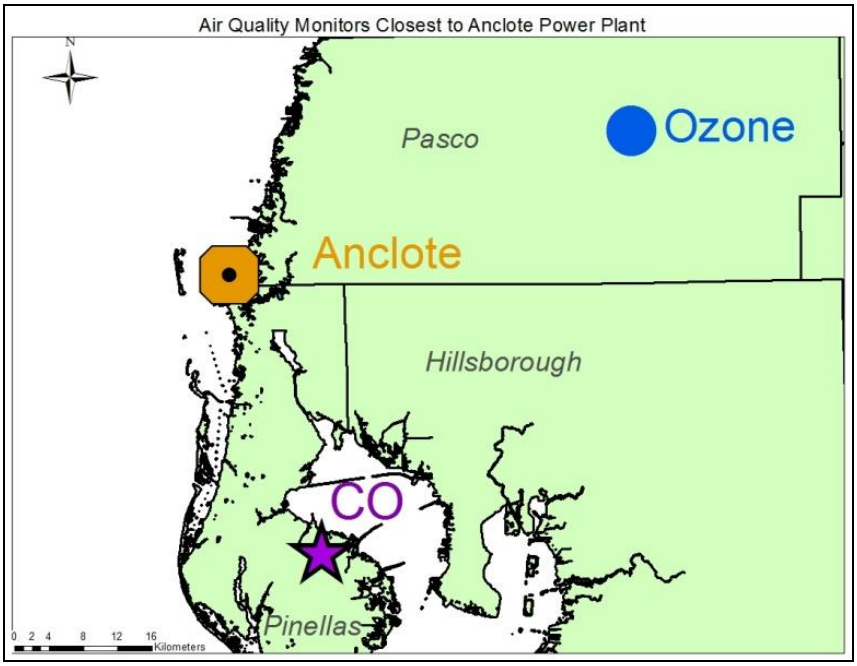

Figure 15 – Representative Monitors of PEF Anclote Site

Air quality measurements from these monitors are summarized below in Table 10 and compared with the National and State Ambient Air Quality Standards (AAQS). Currently, all monitors in Florida indicate attainment with the relevant AAQS.

The existing monitoring data show no violations of any ambient air quality standards. The Department determines that the data collected from these monitors is representative of the air quality in the vicinity of the project and may be used to satisfy the preconstruction monitoring requirements for CO. As necessary, the below ambient concentrations will be used as the ambient background concentrations for any required AAQS analysis.

Table 10 - Ambient Air Quality Based on Most Representative Monitors near the Project Site

Pollutant	County (Site No.)	Averaging Period	Ambient Concentration			
			Compliance Period	Value	Standard [b]	Units [a]
CO	Pinellas (L1032008)	1-hour	2011	1.5	35	ppm
		8-hour		1	9	ppm

a. Units are in parts per million (ppm).
b. Not to be exceeded more than once per year.

7.4. Ambient CO Air Quality Impact Analysis

This section provides a general overview of the modeling analyses required for PSD preconstruction review followed by the specific analyses required for this project.

Preconstruction Ambient Monitoring Procedure

Generally, the first step is to determine whether the Department will require preconstruction ambient air quality monitoring. Using an EPA-approved air quality model, the applicant must determine the predicted maximum ambient concentrations and compare the results with regulatory thresholds for preconstruction ambient monitoring, known as de minimis air quality levels. The de minimus air quality level for CO is 575 $\mu g/m^3$ for an 8-hour averaging period. As shown later in Table 11, the maximum impact from the Anclote modification for this averaging period is only 31 $\mu g/m^3$. Therefore, preconstruction monitoring for this proposed project is not required.

PSD Class II Area Model, Class I Model for sources where all of the Class I area is < 50 km from source

The EPA-approved American Meteorological Society and EPA Regulatory Model (AERMOD) dispersion model is used to evaluate short range impacts from the proposed project and other existing major sources. In November of 2005, the EPA promulgated AERMOD as the preferred regulatory model for predicting pollutant concentrations within 50 kilometers of a source. The AERMOD is a replacement for the Industrial Source Complex Short-Term model (ISCST3). The AERMOD calculates hourly concentrations based on hourly meteorological data. The model can predict pollutant concentrations for annual, 24-hour, 8-hour, 3-hour and 1-hour averaging periods. In addition to the PSD Class II modeling, it is also used to model the predicted impacts for comparison with the de minimis ambient air quality levels when determining preconstruction monitoring requirements.

For evaluating plume behavior within the building wake of structures, the AERMOD incorporates the Plume Rise Enhancement (PRIME) downwash algorithm developed by the Electric Power Research Institute (EPRI). A series of specific model features recommended by the EPA are referred to as the regulatory options. The applicant used the EPA-recommended regulatory options in each modeling scenario and building downwash effects were evaluated for stacks below the good engineering practice (GEP) stack heights.

Meteorological data used in the AERMOD model consisted of a concurrent five-year period of hourly surface weather observations from the National Weather Service office located at Tampa International Airport and twice-daily upper air soundings from Ruskin. The five-year period of meteorological data was from 2006 through 2010. These stations were selected for use in the evaluation because they are the closest primary weather stations to the project area and are most representative of the project site.

Stack Height Considerations

GEP stack height means the greater of 65 meters (213 feet) or the maximum nearby building height plus 1.5 times the building height or width, whichever is less. Where the affected stacks did not meet the requirements for GEP stack height, building downwash was considered in the modeling analyses. Based on a review of this application, the Department determines that the project complies with the applicable provisions of the stack height regulations as revised by EPA on July 8, 1985 (50 FR 27892). Portions of the regulations have been remanded by a panel of the U.S. Court of Appeals for the D.C. Circuit in NRDC v. Thomas, 838 F. 2d 1224 (D.C. Cir. 1988). Consequently, this permit may be subject to modification if and when EPA revises the regulation in response to the court decision. This may result in revised emission limitations or may affect other actions taken by the source owners or operators.

Source Impact Analysis for PSD Class I Areas

No Class I standards exist for CO or VOC. Therefore, a significant impact assessment was not preformed for a Class I area.

Source Impact Analysis for PSD Class II Areas

For the preliminary significant impact analysis, the highest short-term predicted concentrations will be compared to the respective significant impact levels. Since five years of data are available, the highest-second-high (HSH) short-term predicted concentrations will be used for any required AAQS and PSD Class II increment analysis with regard to short-term averages. However, for annual averages, the highest predicted annual average will be compared with the corresponding annual level. The following table shows the results of the preliminary PSD Class II significant impact analysis.

Table 11 - Significant Impact Analysis for PSD Class II Areas (Vicinity of Facility)

Pollutant	Averaging Time	Maximum Predicted Impact (µg/m^3)	Significant Impact Level (µg/m^3)	Significant Impact (SI)?	SI Radius (km)
CO	8-hour	31	500	NO	NONE
	1-hour	164	2000	NO	NONE

As shown above, the maximum predicted impacts are below the PSD Class II significant impact level. Therefore, no further modeling is required.

7.5. Additional Impact Analysis

The applicant has modeled to show that the proposed modification will not violate AAQS. However, PSD regulations require additional analyses of air quality impacts to sensitive types of vegetation and soil, air quality impacts related to growth, and visibility in the affected Class I areas.

Impacts on Soils, Vegetation and Wildlife

The maximum predicted ground-level concentrations of CO from the proposed project and all other nearby sources are very much less than the corresponding AAQS. CO concentrations on the order of AAQS have not been shown to have a harmful impact on soils, vegetation, and wildlife.

According to a literature search for a different project near the area (PEF Bartow), plant species most sensitive to CO showed cellular damage when exposed to 685,000 $\mu g/m^3$ of CO. The applicant's maximum modeled impacts are three orders of magnitude less than this level.

Air Quality Impacts Related to Growth

The proposed modification will not change employment, population, housing, commercial development, or industrial development in the area to the extent that significant air quality impact will result.

7.6. Conclusion on Air Quality Impacts

The Department has reasonable assurance that the proposed project will not cause, or significantly contribute to, a violation of any AAQS or PSD increment.

8. PRELIMINARY DETERMINATION

The Department makes a preliminary determination that the project 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 application, the reasonable assurances provided by the applicant, and the conditions specified in the Draft permit.

Melody Lovin is the meteorologist responsible for reviewing and preparing the ambient air quality analyses. Alvaro Linero, P.E. is the project engineer responsible for preparing the draft permit and BACT determination. Details of the analyses may be obtained by contacting Ms. Lovin at melody.lovin@dep.state.fl.us or Mr. Linero at alvaro.linero@dep.state.fl.us .