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ORIGINAL

TAMPA ELECTRIC

Tampa Electric Company
Determination of Need for
Electrical Power: Polk Unit 6

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I. EXECUTIVE SUMMARY

Tampa Electric has determined through its integrated resource planning process ("IRP") a need to construct Polk Unit 6, a 632 MW (annual nominal) integrated gasification combined cycle ("IGCC") unit, with a targeted commercial operation date of January 2013. Combined with Tampa Electric's demand-side management ("DSM") energy efficiency programs and supply-side resources, Polk Unit 6 will provide the most cost-effective, reliable means of serving Tampa Electric's customers' energy and reliability requirements. Tampa Electric's incremental capacity needs are 576 MW and 482 MW in the winter and summer of 2013, respectively. The addition of Polk Unit 6 addresses long term strategic issues including fuel diversity, fuel flexibility, cost stability, and enhanced environmental performance. Polk Unit 6 will also provide the flexibility to modify future operations and accommodate emerging environmental requirements.

Tampa Electric's firm load is expected to grow approximately 2.8 percent annually or 126 MW of firm winter demand per year. Tampa Electric will continue to meet capacity requirements with the most economical combination of DSM, renewable energy, purchased power and generating capacity additions. Besides normal load growth, Tampa Electric's resource requirements will be significantly greater by January 1, 2013 due to the expiration of a firm 441 MW long term purchased power contract in December 31, 2012.

Through its IRP process, Tampa Electric reviewed potential demand and energy reduction programs to determine if it could economically defer the need for additional generating capacity. The company considered a number of potential supply-side technologies and issued a request for proposals ("RFP") for baseload capacity. No responses were received. For supply-side alternatives, the company researched current technologies for the most feasible options. The resulting list of demand- and supply-side resources was screened for technical feasibility, reliability and relative economics. The initial screening resulted in the narrowing of technology alternatives to super critical pulverized coal ("SCPC"), natural gas combined cycle ("NGCC") and IGCC for further detailed analysis.

Tampa Electric evaluated these technologies utilizing standard IRP techniques. Some of the economic and non-economic factors that were considered included resource reliability, efficiency, range of fuel capability and availability, capital and operating costs, ability to meet current and potential future environmental requirements, water use, and overall site benefits. As a result of this detailed analysis, Tampa Electric determined that IGCC technology is the best option to meet the 2013 need for four primary reasons:

1. Polk Unit 6 is the most cost-effective alternative, and the project results a savings of $184 million over NGCC technology and $93 million over SCPC technology.
2. Polk Unit 6 utilizes a proven, reliable, clean coal technology providing low environmental emissions and lower water use requirements compared to other baseload coal technologies.
3. Polk Unit 6 will be able to utilize a wide range of cost-effective fuels providing greater fuel flexibility than other solid fuel or gas technologies while allowing for natural gas as a backup fuel.
4. The existing Polk Station site and supporting infrastructure for both solid fuels and natural gas is uniquely compatible with Polk Unit 6.

After its detailed analysis, Tampa Electric conducted three scenario analyses to assess the recommended Tampa Electric Polk Unit 6 resource plan against potential future price sensitivities. The first scenario analysis tested the sensitivity of the base fuel forecast using both high and low fuel price bands around the base forecast. Tampa Electric's evaluation demonstrated that Polk Unit 6 was the most cost-effective alternative for the base and high delivered fuel price sensitivity. The second scenario analysis assessed the potential cost impacts of potential carbon dioxide ("CO_2") emission restrictions. Tampa Electric evaluated low, medium and high price bands on a cost per ton of CO_2 emitted basis which was applied to the total system CO_2 emissions in each year of the study period. The low and medium price sensitivity bands indicated Polk Unit 6 was still the most cost-effective alternative. The Polk Unit 6 plan was also more cost-effective than the SCPC plan in the high price band sensitivity.

The third scenario analysis assessed lower and higher than expected capital costs for the NGCC, SCPC and IGCC technologies. The results of this analysis demonstrated Polk Unit 6 remained the most cost-effective alternative in the lower capital cost sensitivity and was more cost-effective than the SCPC plan in the high capital cost sensitivity. Based on these three scenario analyses, Polk Unit 6 continued to have the lowest cumulative present worth revenue requirements ("CPWRR") compared to the SCPC plan in all of the seven price sensitivities except for the low fuel price band. The Polk Unit 6 plan was also more cost-effective than the NGCC plan in all of the price sensitivity scenarios except for the low fuel price band, high CO_2 price per ton band and the high capital cost sensitivities.

In summary, Tampa Electric has developed a fully integrated resource plan that achieves reliability and cost-effectiveness objectives and addresses key strategic issues related to potential energy and environmental initiatives. The plan effectively balances both demand- and supply-side resources including demand and energy reduction programs, economic purchased power and construction of Polk Unit 6 at Tampa Electric's existing Polk Station site.

II. INTRODUCTION, PURPOSE AND OVERVIEW

A. Purpose and Overview

This Need Study supports Tampa Electric's petition to the Florida Public Service Commission ("Commission" or "FPSC") for an affirmative determination of need for the proposed Polk Unit 6, a 632 MW (annual nominal) IGCC unit to be constructed at Polk Station. The 900 MW of total capacity at Polk Station consists of one 255 MW IGCC unit and four combustion turbines totaling 645 MW. As required by Rule 25-22.081, F.A.C., Tampa Electric provides the information that will "allow the Commission to take into account the need for electric system reliability and integrity, the need for adequate reasonable cost electricity, the need for fuel diversity and supply reliability, and the need to determine whether the proposed plant is the most cost-effective alternative available." Additionally, the company describes its consideration of environmental factors and fuel diversity issues that further support Tampa Electric's selection of Polk Unit 6 as the most cost-effective, reliable, and fuel diverse option to meet its supply resource need in 2013.

The Need Study is composed of ten major sections. Section I is an executive summary of Tampa Electric's overall IRP process and the results. Section II provides a more detailed explanation of the company's IRP process and an explanation of the specific process used for this Need Study. Section III entitled "Background and Assumptions" provides a description of Tampa Electric's existing generating system and the assumptions, data, and information utilized. This includes demand and energy forecasts, fuel forecasts, environmental assumptions, financial assumptions and technology assumptions. Section IV discusses the calculation of Tampa Electric's 2013 need including the impact of recent DSM and renewable energy initiatives. Section V describes the screening of potential supply-side technologies and results and Section VI includes the detailed economic analysis where the supply-side alternatives were narrowed based on feasibility and evaluated in greater detail. Section VI also includes qualitative factors that were considered in the selection of Polk Unit 6. Section VII describes Polk Unit 6 in detail including design, permitting, location, cost and schedule. Section VIII describes sensitivity cases and results relative to construction costs, fuel pricing variations, and environmental factors. Section IX describes the adverse consequences if Polk Unit 6 is not approved or is delayed. Finally, Section X provides the conclusions of the Need Study.

B. Tampa Electric's Integrated Resource Planning Process

Tampa Electric's IRP process, which is the basis of the selection of Polk Unit 6, is a planning process that determines the timing, type and amount of additional resources required to maintain system reliability in a cost-effective manner. The objective of the IRP process is to evaluate demand- and supply-side resources on a fair and consistent basis to satisfy future demand and energy requirements in a cost-effective and reliable manner. The process used to develop the Polk Unit 6 Need Study was conducted as an integral component of Tampa Electric's ongoing IRP process. The primary steps in the process include:

1. Establish an initial demand and energy forecast;
2. Identify the amount and timing of Tampa Electric's incremental resource needs to maintain system reliability criteria;
3. Identify and screen the types of technologies that have the greatest potential for meeting the required resource need;
4. Conduct an initial detailed economic analysis and consideration of non-economic factors to decide on the best alternative;
5. Evaluate potential demand-side alternatives and select cost-effective alternatives to reduce demand and energy requirements;
6. Reforecast demand and energy considering additional demand-side alternatives to be implemented;

7. Conduct final detailed economic analysis and consideration of non-economic factors to decide on the best supply-side alternatives;
8. Conduct sensitivity analyses to further ensure the alternative remains the best option in future scenarios; and
9. Conduct an RFP process and/or business plan development as required based on the recommended resource plan.

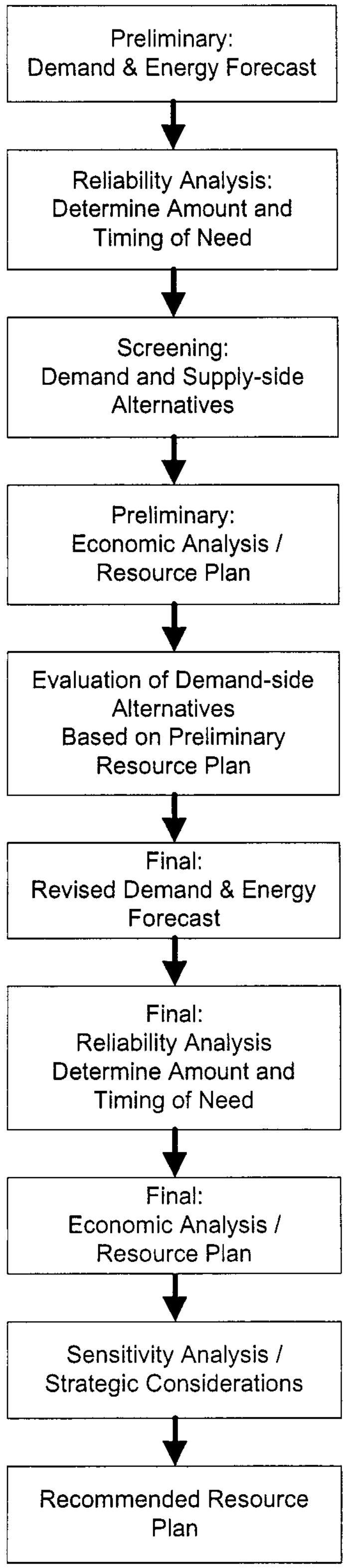
This process is illustrated in Figure 1 and described in further detail below. This process was utilized during the 2006 and 2007 timeframe to determine the Polk Unit 6 resource plan.

As a first step in the process, Tampa Electric established its demand and energy forecast in June 2006. The primary objective of this procedure is to blend proven statistical techniques with practical forecasting experience to provide a 20-year projection of future system demand and energy requirements.

Utilizing the 2006 Tampa Electric demand and energy forecast, a reliability analysis determined the amount of any incremental resources needed to maintain a 20 percent margin above the winter and summer system firm peaks. The seasonal system firm peaks include firm retail load and firm wholesale load and exclude all non-firm retail load and as-available wholesale load. The minimum reserve margin for each year is calculated by multiplying the seasonal system firm peak by 20 percent. The net available capacity is determined by combining all installed generating capacity and firm power purchases less the seasonal system firm peak. If the net available capacity is less than the firm reserve margin in any year, incremental capacity is added in that year to achieve the minimum reserve margin requirement. Incremental capacity identified in a given year is included in subsequent years in order to determine the discrete incremental capacity required in each subsequent year.

Next, Tampa Electric identified the demand- and supply-side alternatives available to meet the system incremental resource requirement. Demand-side alternatives are discussed in Section III.F.(1). Three groups of supply-side alternatives were considered: natural gas fired, solid fuel fired and other. Tampa Electric screened the supply-side alternatives based on economic screening curves and considered qualitative factors such as ability to site the generating technology, technological feasibility, and commercial availability. This screening analysis resulted in the selection of the three most viable alternatives for baseload requirements: SCPC, NGCC and IGCC and natural gas combustion turbines for peaking requirements.

Figure 1: Evaluation Methodology



Next, Tampa Electric conducted a detailed economic analysis and qualitative evaluation of the competing alternatives. The detailed economic analysis captured cost differences between the competing resource plans as further described in Section VI. The analysis conducted in 2006 demonstrated that IGCC technology was the most cost-effective alternative over SCPC and NGCC to meet the baseload capacity need in 2013.

In February 2007, Tampa Electric issued an RFP for its 2013 baseload capacity needs with the assistance of an independent consultant experienced in RFP development and bid evaluation to identify third party supply-side alternatives. The company did not receive any responses to the RFP.

As a result of the revised expansion plan that included Polk Unit 6, Tampa Electric's evaluation of DSM programs resulted in the company's 2007 proposal of additional cost-effective programs and increases in DSM goals. These additional programs and increased DSM goals are before this Commission in Docket No. 070375-EG and 070056-EG.

The additional DSM programs and increased goals along with the appliance efficiency standards mandated by the Energy Policy Act of 2005 (EPACT) reduced the 2007 firm system demand and energy projections. Tampa Electric incorporated the new demand and energy forecast, updated IGCC, SCPC, NGCC technology costs and existing system operating parameters, and updated fuel forecasts and financial assumptions. The results of the 2007 detailed economic analysis continued to demonstrate that IGCC technology is the most cost-effective option for Tampa Electric.

Since IGCC was the most cost-effective supply alternative using the most probable base forecasts, Tampa Electric conducted scenario analyses to evaluate price sensitivities related to capital costs, fuel and CO_2 emissions for each of the resource plans based on either IGCC, NGCC or SCPC technologies. Based on these scenario analyses, IGCC remained the most cost-effective alternative in most of the price sensitivities.

In conclusion, Polk Unit 6 is the best option for Tampa Electric to cost-effectively maintain system reliability and enhance fuel diversity. The results of the company's analysis detailed in this Need Study demonstrate that Polk Unit 6 is also the best alternative to address technological, environmental and other strategic factors that affect Tampa Electric and its customers.

III. BACKGROUND AND ASSUMPTIONS

A. Description of Tampa Electric's System

Tampa Electric, an investor-owned electric utility, is the largest subsidiary under the TECO Energy holding company. The service area for Tampa Electric spans approximately 2,000 square miles and consists of Hillsborough County, western Polk County and parts of Pasco and Pinellas counties. Tampa Electric serves approximately 654,000 customers. Tampa Electric has five generating stations that include fossil steam units, combined cycle units, combustion turbine peaking units, an integrated coal gasification combined cycle unit and internal combustion diesel units.

Big Bend Station: The station contains four pulverized coal fired steam units equipped with de-sulfurization scrubbers, electrostatic precipitators and three distillate fueled combustion turbines. The coal units are currently undergoing the addition of air pollution control systems called selective catalytic reduction ("SCR"). This work is scheduled to be completed in 2010.

H.L. Culbreath Bayside Station: The station contains two natural gas-fired combined cycle units. Bayside Unit 1 utilizes three combustion turbines, three heat recovery steam generators ("HRSG") and one steam turbine. Bayside Unit 2 utilizes four combustion turbines, four HRSGs and one steam turbine.

Polk Station: The station is presently comprised of five generating units. Polk Unit 1 is an IGCC unit fired with synthetic gas produced from gasified coal and other carbonaceous fuels with distillate oil as a secondary fuel. Polk Units 2 through 5 are combustion turbines. Polk Units 2 and 3 are fueled primarily with natural gas with distillate oil as a backup fuel. Polk Unit 4, which was placed in service March 2007, is fueled with natural gas. Polk Unit 5, which was placed in service April 2007, is also fueled with natural gas.

Other Facilities: Partnership Station is comprised of two diesel engines converted to use natural gas. This project was developed in partnership with Tampa Electric and the City of Tampa. Phillips Station is comprised of two residual or distillate oil fired diesel engines.

The following table lists Tampa Electric's generating assets as of June 1, 2007.

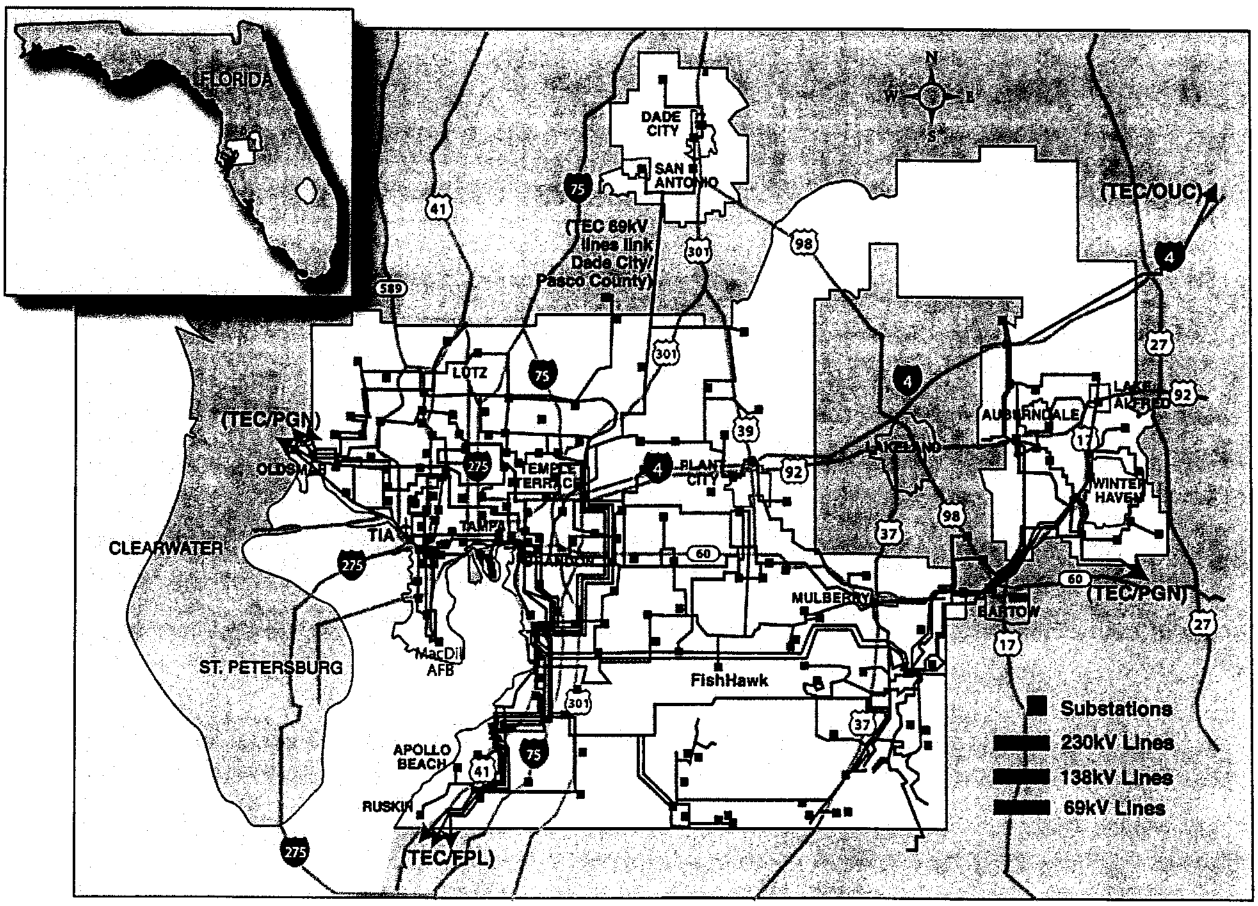
Table 1: Tampa Electric System Installed Capacity

Plant Name	Number of Units	Summer Net MW	Winter Net MW
Big Bend Station	7	1,728	1,779
Bayside Power Station	2	1,632	1,841
Polk Station	5	900	988
Phillips Station	2	34	36
Partnership Station	2	6	6
TOTAL	**18**	**4,300**	**4,650**

1. Transmission and Distribution

Tampa Electric's transmission and distribution system, which is depicted in Figure 2 below, is comprised of 171 substations, 1,200 miles of transmission and 13,431 miles of distribution lines. Tampa Electric's transmission system is interconnected to the Florida transmission grid through ties with Lakeland Electric, Florida Power & Light, Orlando Utilities Commission and Progress Energy Florida ("PEF").

Figure 2: Tampa Electric's Transmission System and Service Territory



2. Firm Purchased Power Capacity

Tampa Electric has entered into a number of firm purchased power agreements ("PPA") with cogeneration facilities, other investor-owned utilities and merchant power providers. Tampa Electric has a 441 MW long term PPA for capacity and energy from Invenergy's Hardee Station which expires December 31, 2012. The contract is a shared-capacity agreement with Seminole Electric Cooperative.

Tampa Electric has an existing firm PPA with PEF for up to 75 MW through November 2007. The company also has an agreement with Calpine Energy Services for 170 MW through April 30, 2011. Tampa Electric is close to finalizing a PPA with Pasco Cogen for the purchase of 115 MW to cover the January 1, 2009 through December 31, 2018 period.

Tampa Electric expects 427 MW of cogeneration capacity in its service area in 2007. Self-service capacity of 212 MW is used by cogenerators to serve internal load requirements, 64 MW are purchased by Tampa Electric on a firm contract basis, and 14 MW are purchased on a non-firm, as-available basis. The remaining 136 MW of cogeneration capacity is exported out of Tampa Electric's system.

3. Demand-Side Management and Renewable Energy

DSM is the planning, development, implementation, monitoring and evaluation of conservation and load management programs designed to cost-effectively reduce customers' peak demand and overall energy consumption on the company's system. Tampa Electric measures the cost-effectiveness of DSM programs by using its Commission-approved methodology. The methodology consists of three tests: the Rate Impact Measure ("RIM") Test, the Participants' Test and the Total Resource Cost ("TRC") Test.

Tampa Electric offers DSM programs that achieve a cost-benefit-ratio ("CBR") greater than 1.0 for each test. Programs that have a CBR greater than 1.0 under the RIM Test provide lower rates for all customers by the deferral or avoidance of new capacity. The Participants' Test ensures that the programs are economical for the customers who participate in the programs. The TRC Test ensures that society as a whole is not harmed by the transfer of costs between individuals.

Tampa Electric has long been a leader in offering its customers cost-effective DSM programs coupled with a comprehensive educational emphasis on the wise use of energy. This effort began in the mid-1970s when Tampa Electric offered its first DSM program, the Energy Answer Home, to curb heating and air-conditioning requirements in new homes by encouraging the use of high-efficiency heat pumps instead of conventional air-conditioning with resistance heating. Within two years, the company introduced a computer-based home energy audit well in advance of the legislation that ultimately required this level of home energy analysis.

In 1980, the Florida Energy Efficiency Conservation Act ("FEECA") was passed by the Florida legislature. In response to that legislation, Tampa Electric filed its DSM plans with the Commission and became the first Florida utility to have its DSM programs for both residential and commercial customers approved. Subsequent to that first DSM plan, Tampa Electric has filed and gained Commission approval of numerous DSM programs designed to promote new energy efficient technologies to encourage energy savings. Additionally, the company has modified existing DSM programs over time to promote new technologies and maintain program cost-effectiveness.

Tampa Electric's successful DSM initiatives have achieved 659 MW of winter demand reduction, 222 MW of summer demand reduction and 600 GWH of cumulative energy savings as of December 31, 2006. Peak load reduction has eliminated the need for the equivalent of more than three 180 MW power plants and this accomplishment was achieved without subsidies from customers who were not participants. Tampa Electric achieved this level of reduction by offering only those DSM programs that reduce rates for all customers, both DSM participants and non-participants alike.

Furthermore, Tampa Electric's DSM program results compare quite favorably to other utilities across the nation. The Energy Information Administration ("EIA") of the United States Department of Energy ("DOE") reports annually on the effectiveness of utility DSM initiatives. Based on national data reported for the 2001 through 2005 period, Tampa Electric ranked as high as the 96th percentile for cumulative conservation and the 90th percentile for load management achievements.

4. Renewable Energy Initiative

Tampa Electric continues to be active in supporting the development of renewable energy resources. The company recognizes renewable energy will advance the utilization of a diverse fuel mix for the production of electricity and demonstrates sound environmental stewardship. Currently, Tampa Electric secures approximately 2.5 percent of its net energy for load from renewable energy resources such as municipal solid waste ("MSW") facilities, waste heat production facilities, biomass generation, landfill gas and ("PV") photovoltaic arrays.

Some of Tampa Electric's initial work in the area of renewable energy utilized PV arrays to charge batteries that power parking lot lighting. A research and development ("R&D") effort was also undertaken to evaluate the use of PV arrays to provide emergency lighting at a strategic storm shelter.

In the mid 1990s, Tampa Electric partnered with the City of Tampa transit authority to install PV arrays to recharge batteries for the transit authority's electric bus fleet. Although the electric bus fleet failed to materialize, the large PV array supplies energy to Tampa Electric's grid and is an integral resource for the company's renewable energy program.

Tampa Electric's commitment to a more formalized renewable energy program began in 2001. The company implemented a pilot renewable energy program with the following goals: 1) determine the level of program interest among customers and their willingness to pay a higher cost for renewable energy; 2) examine marketing methods to identify the most cost-effective manner to secure residential and commercial program participants; 3) determine the longevity of customer participation; 4) determine the functionality of certain renewable generation; and 5) determine the sustainability of renewable fuel resources.

Due to the pilot program R&D efforts Tampa Electric currently offers a permanent renewable energy program for which participation of residential and commercial customers is growing steadily. The program continues to offer incremental renewable energy that is produced locally and within the state so the environmental benefits accrue to the citizens of Florida.

Another key area of renewable energy activity centers on the Solar for Schools initiative advanced by the Florida Solar Energy Center ("FSEC"). Tampa Electric has been a participant with FSEC and the Hillsborough County School District in the deployment of PV arrays on schools where science students can engage in studies of renewable energy production and technology reliability. Recently, Tampa Electric unveiled a 10 kW array, the largest PV system installed to date in the Solar for Schools program. Tampa Electric also owns smaller PV arrays scattered throughout its service area.

Tampa Electric engages in a number of other renewable energy activities aimed at increasing the amount of clean, renewable energy on its system. Annually, the company purchases over 125,000 MWh of renewable energy produced from the waste heat of phosphate production. Tampa Electric also has 42 MW of firm capacity under contract from the MSW industry. Discussions concerning the expansion of an existing MSW facility in the service area are ongoing.

Tampa Electric recently gained Commission approval of its renewable standard offer contract ("SOC"). The renewable SOC includes the following features: 1) the customer can select any of the fossil fuel generating units in the company's 10-year expansion plan; 2) the renewable SOC will be continuously available; 3) the subscription limit has been removed; 4) the renewable generator can select the term of the contract; and 5) flexibility on capacity and energy payments to the customer now exist.

Tampa Electric recognizes the growing importance of renewable energy as a vital component of its resources to meet customer load. Recently, the company issued an RFP for renewable energy that includes new or existing generating sources on a firm or as-available basis. The type of renewable energy being sought is consistent with the definition found in the Florida Statutes. In order to maximize the number of potential bidders, the company has not placed limits on the size of the proposals, and proposals may originate inside or outside the company's service area.

5. Tampa Electric's Current Energy Mix by Fuel Type

The energy mix for Tampa Electric's generation can significantly affect the cost of electricity. Too much reliance on energy sources with volatile fuel prices can result in significant volatility in the ultimate cost of electricity. Tampa Electric's fuel source mix to meet system energy requirements for

2007 is projected to be 49 percent solid fuel, 45 percent natural gas and 6 percent fuel oil and other sources including a system power purchase and cogeneration purchases. The projected energy mix in 2013 with the addition of Polk Unit 6 is forecasted to be 64 percent solid fuel, 34 percent natural gas and 2 percent fuel oil and other sources. These energy mix percentages are shown in Table 2 below.

Table 2: Tampa Electric's Energy Mix by Fuel Type

Total System	2007	2013
Solid Fuel	49%	64%
Natural Gas	45%	34%
Fuel Oil / Other	6%	2%
System Net Energy for Load (GWH)	20,724	24,405

B. Demand and Energy Forecasts

During the analysis that resulted in the selection of Polk Unit 6, Tampa Electric utilized two demand and energy forecasts. A 2006 forecast was used for the preliminary screening and economic analysis. In 2007, an updated forecast which incorporated additional DSM reductions and EPACT impacts was used for Tampa Electric's final detailed economic analysis.

The customer, demand and energy forecast is the foundation of the integrated resource plan. Tampa Electric utilizes multiple databases and sophisticated analytical tools and methods to develop the forecast. The primary objective of this procedure is to blend proven statistical techniques with practical forecasting experience to develop the most probable demand and energy forecast over a 20-year planning period.

1. Forecast Assumptions

The economic assumptions used in the forecast models are derived from forecasts from Economy.com and the University of Florida's Bureau of Economic and Business Research ("BEBR"). Numerous assumptions are input to the MetrixND models, an advanced statistics program for analysis and forecasting, of which the more significant ones are listed below.

Population and Households

The state population forecast is the starting point for developing the customer and energy projections. BEBR and Economy.com supply population projections for Hillsborough County and Florida. The population forecast is based upon the projections of BEBR in the short term and a blend of BEBR and Economy.com in the long term. Through 2016, the average annual population growth rate in both Hillsborough County and Florida is expected to be 2.0 percent. In addition, Economy.com provides household data as an input to the residential average use model.

Commercial, Industrial and Governmental Employment

Commercial and industrial employment assumptions are utilized in computing the number of customers in their respective sectors. Over the next ten years, commercial employment is provided to rise at a 3.3 percent average annual rate and industrial employment is projected to decline slowly at an annual rate of -0.2 percent. Government employment is used in combination with government output to estimate energy sales to public authorities. Economy.com projects government employment to rise at a 1.0 percent average annual rate.

Commercial, Industrial and Governmental Output

In addition to employment, output in terms of real gross domestic product by employment sector is utilized in computing energy usage by sector. Over the next ten years Economy.com projects output for the entire employment sector to rise at a 4.8 percent average annual rate.

Real Household Income

Economy.com supplies the assumptions for Hillsborough County's real household income growth. During 2007-2016, real household income for Hillsborough County is expected to increase at a 1.6 percent average annual rate.

Price of Electricity

Forecasts for the price of electricity by customer class are supplied by Tampa Electric's Regulatory Affairs department. The price of electricity is included in each per-customer consumption model. The price variable was primarily used to capture long term impacts of the real price of electricity. Recent increases in the real price of electricity have resulted in reduced growth in residential and commercial sales in the short term and increased growth as the price moderates. Due to atypical recent price volatility, a smoothed trend of the real price of electricity was used in the residential and commercial models. This change affects sales growth for the first few years of the forecast; long term results are not affected. Energy sales for the remaining sectors were not as sensitive to the changes in the real price of electricity.

Appliance Efficiency Standards

Another factor influencing energy consumption is the movement toward more efficient appliances. The forces behind this development include market pressures for more energy-saving devices and the appliance efficiency standards enacted by the state and federal governments.

Also influencing energy consumption is the saturation levels of appliances. The saturation trend for heating appliances is increasing through time; however, overall electricity consumption actually declines over time as less efficient heating technologies such as room heating and furnaces are replaced with more efficient technologies such as heat pumps. Similarly, cooling equipment saturation will continue to increase, but is offset by central air conditioning efficiency gains.

Improvements in the efficiency of other non-weather related appliances also helps to lower electricity growth; however, any efficiency gains are offset by the increasing saturation trend of electronic equipment and appliances.

Weather

Since weather is the most difficult input to project, historical data is the major determinant in developing temperature profiles. Monthly profiles used in calculating energy consumption are based on twenty years of historical data. In addition, the temperature profiles used in projecting the winter and summer system peak are based on an examination of the minimum and maximum temperatures for the past twenty years and the temperatures on peak days for the past twenty years.

2. Forecast Methodology

MetrixND was used to develop customer, demand and energy forecasts. This software provides a platform for the development of more dynamic and fully integrated models. The phosphate demand and energy is forecasted separately and then combined in the total forecast. Likewise, the effect of Tampa Electric's conservation, load management, and cogeneration programs is incorporated into the process by subtracting the expected reduction in demand and energy from the forecast.

Customer Forecast Models

The customer multi-regression forecasting model is an eight-equation model. The equations forecast the number of customers by eight major categories.

Residential Customer Model

Customer projections are a function of Florida's population. Since a strong correlation exists between historical changes in customers and historical changes in Florida's population, Florida population estimates for 2007-2026 were used to forecast the future growth patterns in residential customers.

Commercial Customer Model

Total commercial customers include commercial customers and temporary service customers (temporary poles on construction sites); therefore, two models are used to forecast total commercial customers. The Commercial Customer Model is a function of residential customers. An increase in the number of households provides the need for additional services, restaurants, and retail establishments. The amount of residential activity also plays a part in the attractiveness of the Tampa Bay area as a place to relocate or start a new business. Projections of employment in the construction sector are a good indicator of expected increases and decreases in local construction activity. Therefore, the Temporary Service model projects the number of commercial customers as a function of construction employment.

Industrial General Service Customer Model

Industrial customers include three rate classes that have been modeled individually: General Service ("GS"), General Service Demand ("GSD") and General Service Large Demand ("GSLD"). The GS customer model is a function of Hillsborough County commercial employment.

Industrial GSD Customer Model

The industrial GSD customer model is a function of Hillsborough County commercial employment. Since the structure of the local industrial sector has been shifting from an energy-intense manufacturing sector to a non-energy intense manufacturing sector, the type of customers in this sector have qualities of large scale commercial customers.

Industrial GSLD Customer Model

The industrial GSLD Customer Model is a function of Hillsborough County manufacturing employment.

Public Authority Customer Model

Customer projections are a function of Florida's population. The need for public services will depend on the number of people in the region; therefore, consistent with the residential customer model, Florida's population projections are used to determine future growth in the public authorities sector.

Street & Highway Lighting Customer Model

As the number of commercial customers increases so does the need for infrastructure expansion such as street and highway lighting. Therefore, the commercial customer forecast is the basis for the Street & Highway Lighting customer model.

3. Energy Forecast Models

There are a total of eight energy models. All of these models represent average usage per customer (kWh/customer), except for the Temporary Services Model which represents total kWh sales. The average usage models interact with the customer models to arrive at total sales for each class.

The energy models are based on an approach known as Statistically Adjusted Engineering ("SAE"). SAE entails specifying end-use variables, such as heating, cooling and base use appliance/equipment and incorporating these variables into regression models. This approach allows the models to capture long term structural changes that end-use models are known for, while also performing well in the short term, as do econometric regression models.

Residential Energy Model

The residential forecast model is made up of three major components: (1) the end-use equipment index variables, which capture the long term net effect of equipment saturation and equipment efficiency improvements; (2) the second component serves to capture changes in the economy such as household income, household size, and the price of electricity; and (3) the third component is made up of weather variables, which serve to allocate the seasonal impacts of weather throughout the year.

Commercial Energy Model

The model framework for the commercial sector is the same as the residential model; it also has three major components and utilizes the SAE model framework. The differences lie in the type of end-use equipment and in the economic variables used. The end-use equipment variables are based on commercial appliance/equipment saturation and efficiency assumptions. The economic drivers in the commercial model are commercial productivity measured in terms of dollar output and the price of electricity for the commercial sector. The third component, weather variables, is the same as in the residential model.

Temporary Service Energy Model

The model is a subset of the total commercial sector and is a rather small percentage of the total commercial sector. Although small in nature, it is still a component that needs to be included. A simple regression model is used with the primary drivers being the construction sector's productivity and heating and cooling degree days.

Industrial-GS Energy Model

Industrial energy forecasts include three rate classes that have been modeled individually: GS, GSD and GSLD. The Industrial-GS energy model has two major components. Utilizing the SAE model framework, the first component, economic index variables, includes estimates for manufacturing output and the price of electricity in the industrial sector. The second component is a cooling degree-day variable. Unlike the previous models discussed, heating load does not impact the industrial sector.

Industrial-GSD Energy Model

The GSD is modeled like the GS energy model.

Industrial-GSLD Energy Model

The GSLD model is based on an Industrial Production Manufacturing Index and a cooling degree day variable.

Public Authority Sector Model

Within this model, the equipment index is based on the same commercial equipment saturation and efficiency assumptions used in the commercial model. The economic component is based on government sector productivity and the price of electricity in this sector. Weather variables are consistent with the residential and commercial models.

Street & Highway Lighting Sector Model

The street and highway lighting sector is not impacted by weather; therefore; it is a rather simple model and the SAE modeling approach does not apply. The model is a linear regression model where street & highway lighting energy consumption is a function of the number of billing days in the cycle, and the number of daylight hours in a day for each month.

The eight energy models described above plus an exogenous interruptible and phosphate forecast are added together to arrive at the total retail energy sales forecast.

4. Demand Forecast Models

After the total retail energy sales forecast is complete, it is integrated into the peak demand model as an independent variable along with weather variables. The energy variable represents the long term economic and appliance trend impacts. The volatility of the phosphate load is removed to stabilize the peak demand data series and improve model accuracy. To further stabilize the data, the peak demand models project on a per customer basis.

The weather variables provide the monthly seasonality to the peaks. The weather variables used are heating and cooling degree days for both the temperature at the time of the peak and the 24-hour average on the day of the peak. By incorporating both temperatures, the model is accounting for the fact that cold/heat buildup contributes to determining the peak day.

The non-phosphate per customer kW forecast is multiplied by the final customer forecast. This result is then aggregated with a phosphate coincident peak forecast to arrive at the final projected peak demand.

Phosphate Demand and Energy Forecasts

Because Tampa Electric's phosphate customers are relatively few in number, each customer's energy consumption is forecasted individually based on historical usage patterns and detailed information obtained by customer surveys. The Commercial/Industrial Customer Service department's familiarity with industry dynamics, their close working relationship with phosphate company representatives and the surveys are used to determine future energy and demand requirements. This survey is the foundation upon which the phosphate forecast is based, and further inputs are provided by trend analysis of historical usage patterns.

Demand-Side Management and Cogeneration Forecasts

Tampa Electric incorporates the impacts of conservation, load management and cogeneration programs into the demand and energy forecasts. This is done by reducing the forecasts by the incremental annual savings associated with conservation and load management programs. In addition, demand and energy projections are adjusted for any projected incremental changes in cogeneration programs that impact the amount of electricity Tampa Electric provides to these customers.

Wholesale Load

Tampa Electric's long term firm sales are served through contracts with the Cities of Wauchula, Fort Meade, St. Cloud and other entities including PEF and Reedy Creek Improvement District. A multiple regression approach similar to that used for forecasting Tampa Electric's retail load has been utilized since Tampa Electric's sales to Wauchula and Fort Meade will vary over time based on the strength of the local economies. Under this methodology, two equations have been developed for each municipality for forecasting energy and peaks. Tampa Electric will continue to serve the City of Fort Meade's electric load through December 31, 2008. For the remaining wholesale customers, future sales for a given year are based on the specific terms of their contracts with Tampa Electric. In 2013, Tampa Electric expects to serve the City of Wauchula 12 MW and Reedy Creek Improvement District as much as 77 MW of firm capacity.

5. Load Forecasts

The analysis that resulted on the selection of Polk Unit 6 incorporated two demand and energy forecasts.

Customer Forecasts

Based on the forecast used in the 2006 analysis, Tampa Electric is projecting an annual average increase of 16,393 new customers over the next ten years from 2007-2016. This average annual increase of 2.2 percent is slightly lower than the average annual growth rate of 2.6 percent during the past ten years from 1997-2006.

Retail Energy Sales Forecasts

The primary driver behind the increase in the energy sales forecast is the average annual increase in customers of 2.2 percent. In addition, average per-customer consumption is expected to increase at an average annual rate of 0.5 percent. Combining the growth in customers and per-customer consumption, retail energy sales are expected to increase at an average annual rate of 2.8 percent. Excluding the phosphate sector, which has recently been declining, retail energy sales are expected to increase at an average annual rate of 2.9 percent. The number of retail customers and retail energy sales by customer class are shown in Appendix C and D, respectively.

Retail Total and Firm Peak Demand Forecasts

Summer and winter retail peak usage per-customer is projected to increase at an average annual rate of 0.6 percent, which is consistent with historical growth rates as well as per-customer energy consumption. The increase in customers and the increase in per-customer demand results in an average annual growth rate of 2.8 percent for the winter peak and a 2.9 percent growth rate for the summer peak. Total peak demand for the summer 2007 is forecasted to be 4,113 MW and increase to 5,300 MW in 2016, an average increase of 132 MW per year. The 2007 winter peak was forecasted to be 4,364 MW and increase to 5,602 MW in 2016, an average increase of 138 MW per year. Winter and summer total and firm peak demands are shown in Appendix E.

6. Updates to Customer Demand and Energy Forecast

Since the initial detailed economic analysis, a new customer peak demand and energy forecast was developed as part Tampa Electric's annual business planning process. The new forecast included updated economic assumptions, the company's proposed new and modified DSM programs and more efficient appliance trends associated with EPACT. Retail energy sales and peak demand growth have moderated in the new forecasts due to increased conservation levels. Summer firm peak demand growth from summer 2007 to 2013 is 698 MW, compared to 748 MW in the initial forecast.

Summer and winter retail total peak usage per-customer is projected to increase at an average annual rate of 0.5 percent. The increase in customers and the increase in per-customer demand results in an average annual growth rate of 2.7 percent for the winter peak and a 2.8 percent growth rate for the summer peak. Total peak demand for the summer 2007 is forecasted to be 4,083 MW, increasing to 5,252 MW in 2016, an average increase of 130 MW per year. The 2007 total winter peak is forecasted to be 4,344 MW, increasing to 5,543 MW in 2016, an average increase of 133 MW per year. Updated forecast information including winter and summer total and firm peak demands are shown in Appendices F, G and H.

C. Fuel Forecast

Current fuel price forecasts in 2006 were used to analyze supply-side alternatives for the 2013 need. The coal, petroleum coke ("pet coke") and natural gas forecasts are provided in Appendix I. In 2007, forecasts were updated to reflect current market conditions. The coal, pet coke and natural gas forecasts used in Tampa Electric's 2007 analysis are provided in Appendix J, and the IGCC blended fuel price is in Appendix M. Due to the tax credit requirements described below, IGCC blended fuel is 80 percent coal and 20 percent pet coke in the first five years of operations. For the remaining years, the blend will be 80 percent pet coke and 20 percent coal. These fuel price forecasts were utilized in the final detailed economic analysis. Tampa Electric also prepared low and high price forecasts for the sensitivity analyses which are provided in Appendices K and L.

Tampa Electric developed a 30-year fuel price forecast utilizing fuel price forecasts prepared by well respected, independent energy consultants. These forecasts are thorough and unbiased. Market analysis and projections from PIRA Energy Consultants form the basis for the fuel oil and natural gas price forecasts. Tampa Electric utilized Hill & Associates' projections as the basis of the solid fuel price forecasts including domestic coal, imported coal and pet coke.

Where necessary, appropriate refinements were made to align the forecasts to Tampa Electric's physical delivery requirements. For example, most natural gas forecasts are based on the Henry Hub, a recognized market center for trading natural gas. Since much of the natural gas Tampa Electric purchases is delivered into Zone 3 of the Florida Gas Transmission ("FGT") pipeline, Tampa Electric's natural gas price reflects the typical price difference between Henry Hub and FGT Zone 3.

1. Solid Fuels

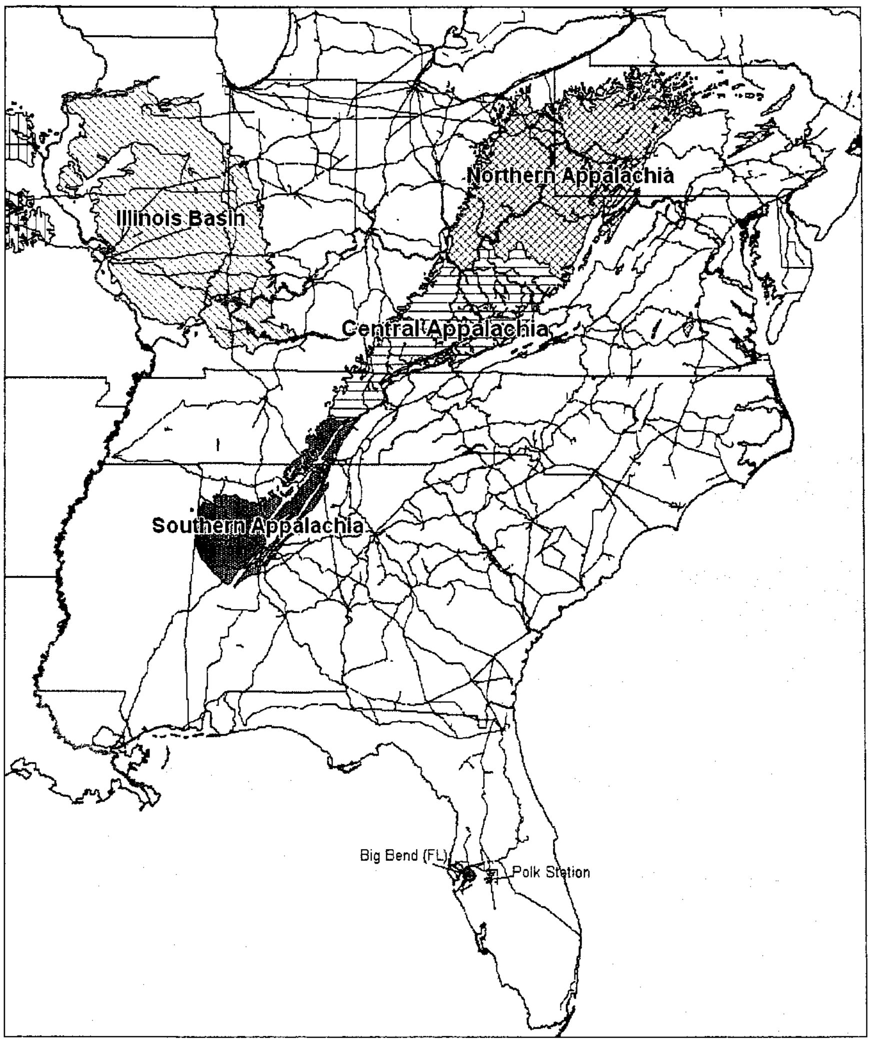
Coal is an abundant fossil fuel. The EIA indicates there are over 200 years of coal reserves in the United States. Beyond the U.S., Russia, Australia, Colombia, Indonesia, China and Canada all have large coal reserves.

Recent development in China, India and other countries has placed a large demand on coal supply which has affected availability and pricing. In addition, the Clean Air Interstate Rule ("CAIR") has caused utilities to reassess their compliance strategies and fuel mix, especially with respect to coal. Coal users are deciding whether to switch to lower sulfur coal, add environmental control equipment or switch to a different fuel altogether. Combined with high oil and natural gas prices, these factors have encouraged new coal production projects both domestically and internationally. These forces will have influences on the supply and demand of coal over the next decade.

Pet coke, a byproduct of the oil refining process, is an attractive fuel source due to its typically low cost and high Btu/lb content. Several new refining projects have been announced which will increase the supply of pet coke in the market.

Utilities that have fuel supply options and transportation flexibility will have a competitive advantage. Polk Unit 6 is capable of burning a wide variety of coals and pet coke. Given the location of Polk Unit 6, fuel delivery options include rail and a combination of waterborne and short rail or truck. This fuel sourcing and delivery flexibility provides reliability advantages. In addition, biomass can be used in a blended fuel for IGCC technology.

Figure 3: Eastern U. S. Coal Sources



2. Natural Gas

Considerable amounts of natural gas are expected to be available to the U.S. energy market. Based on statistics from EIA on proven reserves and current demand, as much as 40 to 50 years of natural gas reserves exist in the U.S. Beyond the U.S., significant quantities of natural gas exist in Russia, Australia, North Africa, the Middle East and Indonesia. A liquefied natural gas ("LNG") supply chain will need to evolve to add these natural gas volumes to the world market.

Despite the available reserves, natural gas has experienced dramatic price swings for nearly a decade. Recently, U.S. utilities have predominantly built natural gas-fired generation to meet customer needs. This has placed a significant demand on natural gas resources and contributed to producers using more expensive sources to meet the growing demand. From a supply perspective, large incremental volumes of LNG are expected to be needed to meet growing U.S. demand and will influence natural gas prices over the next 30 years. In the short term, natural gas prices react quickly and dramatically to weather events such as hurricanes and geopolitical instability. As utilities continue to add significant amounts of natural gas generation to their fleets, natural gas prices are likely to remain volatile as supply and demand fluctuate.

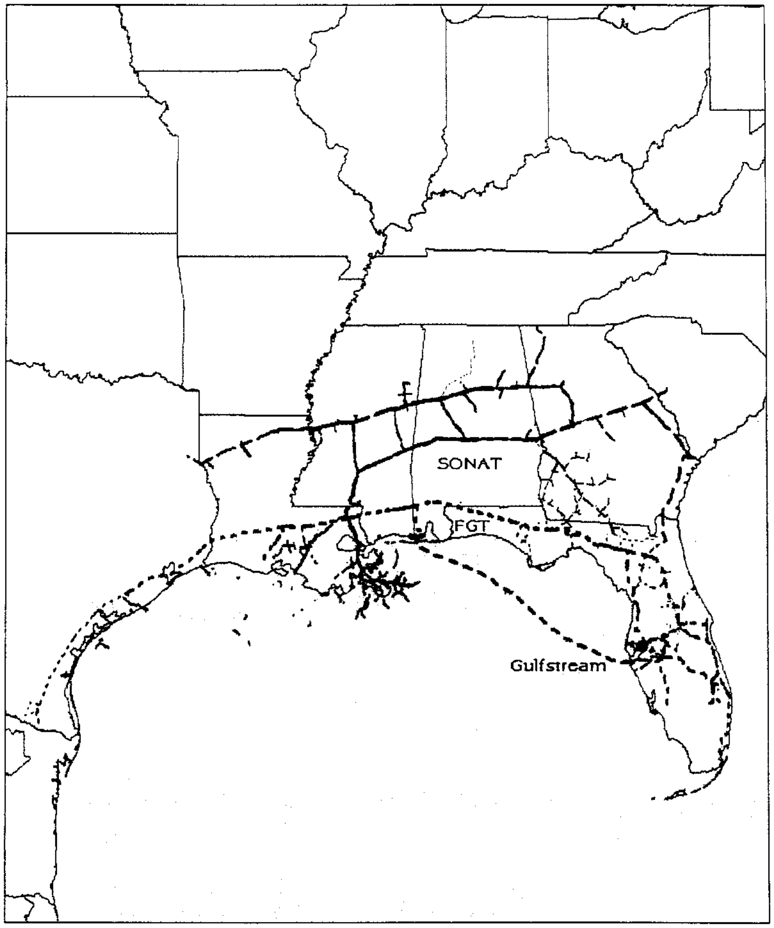
Polk Unit 6 has unique fuel flexibility in addition to its flexibility in solid fuel varieties. Natural gas is the backup fuel for Polk Unit 6. In the event that deliveries of coal are interrupted or gasifier maintenance occurs, the unit's availability is not affected. This unique fuel flexibility provides Polk Unit 6 with strong reliability and economic advantages.

3. Transportation

Consistent with Polk Unit 6's varied fuel sourcing options are its varied transportation methods. These methods include waterborne, truck and direct rail. Tampa Electric expects this transportation optionality will yield competitive transportation pricing for Polk Unit 6. Polk Station is located approximately 35 miles east of Tampa Bay. Currently, Tampa Electric trucks coal to Polk and stores coal for Polk Station at Big Bend Station. The design of Polk Unit 6 includes a yard to hold up to 225,000 tons of inventory. It also includes blending and rail facilities. For the solid fuels, transportation costs are modeled consistently with current transportation costs.

For transportation of natural gas, Tampa Electric and other Florida utilities are dependent upon interstate pipelines to deliver their gas needs. FGT, Gulfstream Natural Gas Company ("Gulfstream") and SONAT interstate pipelines serve the state, with FGT and Gulfstream being the primary pipelines. Despite the maturing of the interstate pipeline system in Florida, it is still a constrained system. FGT and Gulfstream are expected to be fully subscribed by 2009. Therefore, any additional natural gas demand will require pipeline expansions.

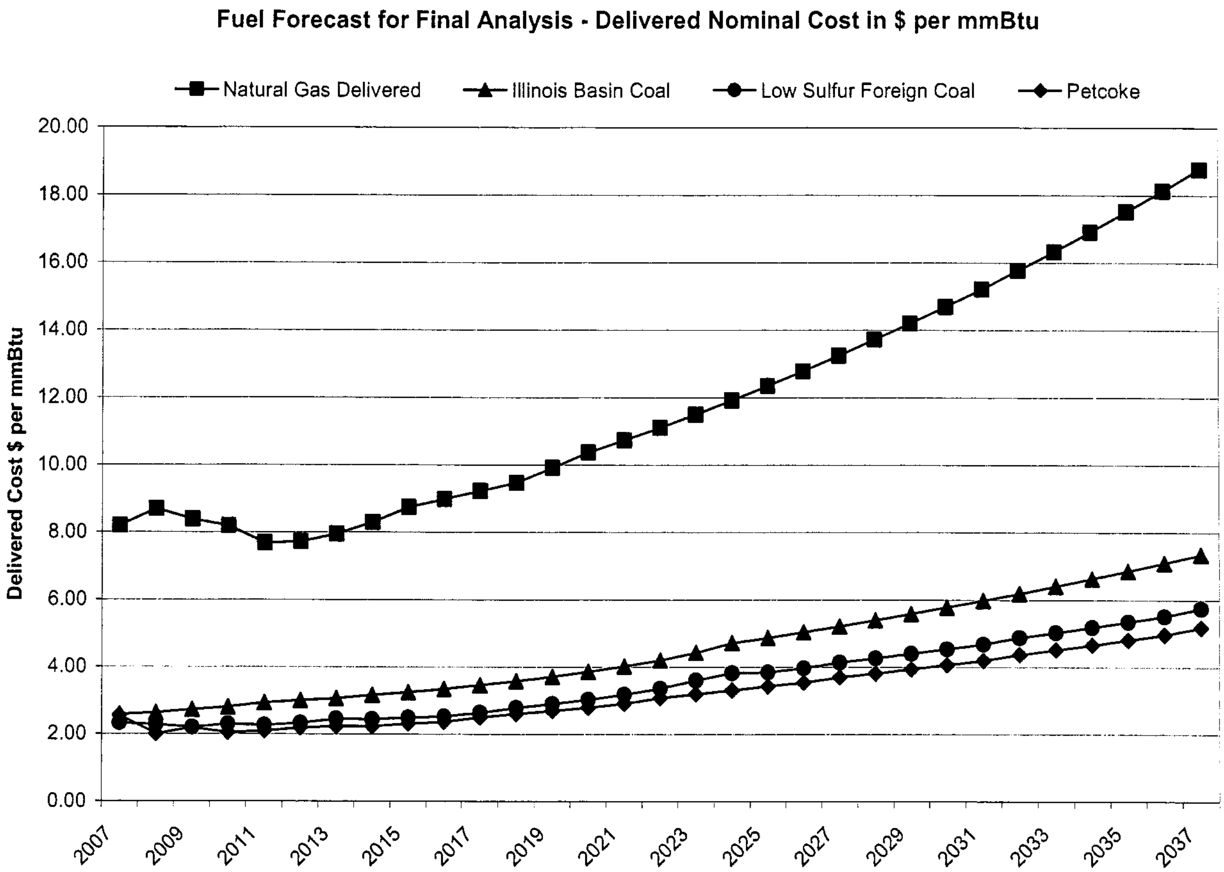
Figure 4: Natural Gas Pipelines



4. Fuel Price Forecasts

As part of the 2007 evaluation of the company's fuel forecast, an updated forecast was developed. Figure 5 depicts natural gas, coal and pet coke delivered fuel prices. Appendices I and J contain in tabular form the fuel forecast used in the initial and final analysis.

Figure 5: Fuel Forecast for Final Analysis



D. Environmental

Environmental requirements considered in Tampa Electric's analysis of supply-side alternatives include environmental permitting requirements which are defined by current environmental regulations and planning for future environmental requirements. Environmental permitting requirements are often well established by the permitting of similar units and/or through interpretation of existing regulations. An example is the expected Polk Unit 6 environmental permitting requirements discussed in Section VII.C.

Future environmental requirements include currently promulgated rules that have future requirements defined, currently promulgated rules that have future requirements undefined and potential environmental requirements that are currently being considered in federal and/or state legislature. The primary requirements considered by Tampa Electric in this study include the CAIR and the Clean Air Mercury Rule ("CAMR"). These regulations are currently promulgated but have some level of uncertainty because final allocation of emission allowances has not occurred due to litigation.

Clean Air Interstate Rule

Due to the repowering of Gannon Station, early implementation of nitrogen oxides ("NO_x") control equipment at Big Bend Station, and Florida's allocation system, Tampa Electric is expected to have a surplus of NO_x allowances that can be banked and used to cover Polk Unit 6 emissions during the first year of operation and beyond. The system that the Florida Department of Environmental Protection ("FDEP") has adopted, pending EPA expected approval, allocates NO_x allowances to Polk Unit 6 for both the annual and ozone season allocation program after completing one year of operation. Therefore, Polk Unit 6 will begin qualifying for its own allowance allocation beginning in 2014.

The sulfur dioxide ("SO_2") allowance allocation will remain the same under the current EPA Acid Rain Program. Due to the Consent Decree agreement between Tampa Electric, the U.S. Department of Justice, and EPA, Tampa Electric may use Gannon Station allowances to cover the Tampa Electric system, including Polk Unit 6 emissions. Tampa Electric is projected to have enough SO_2 allowances to cover emissions from Polk Unit 6, even as CAIR requires the surrender of two allowances for every ton of emissions from 2010 through 2014 and the surrender of three allowances for every ton emitted beginning in 2015. Tampa Electric's current SO_2 allocation is expected to cover emissions beyond 2015 and into the foreseeable future.

Clean Air Mercury Rule

Due to the repowering of Gannon Station, early implementation of NO_x control equipment at Big Bend Station with the co-benefit of enhanced mercury removal, and the Florida allocation system, Tampa Electric is expected to have a surplus of mercury allowances that can be banked and used to cover Polk Unit 6 emissions during the first year of operation and beyond. Similar to CAIR, the system that FDEP has adopted, pending expected EPA approval, allocates mercury allowances to Polk Unit 6 after completing one year of operation. Therefore, Polk Unit 6 will begin qualifying for its own mercury allowance allocation beginning in 2014. Tampa Electric is expected to have sufficient allowances to cover Polk Unit 6 mercury emissions into the foreseeable future.

Carbon Dioxide

Tampa Electric made environmental strides long before the focus on global climate change and greenhouse gas ("GHG") emissions became prominent. As a result of the company's overall environmental improvement program, Tampa Electric's current carbon dioxide ("CO_2") emissions are 20 percent lower than in 2000. While there are no state or federal CO_2 regulations currently, discussions continue at the federal level regarding GHG reduction legislation. Tampa Electric believes that any legislation addressing GHG emission should apply to all industries, while ensuring implementation does not economically disadvantage the United States. Furthermore, the legislation should encourage technology development to address reductions with tax incentives, give credit to companies who have taken early actions, maintains fuel diversity and support a realistic timeframe for addressing climate change.

Given the on-going national debate regarding CO_2 emissions, Tampa Electric conducted a CO_2 emissions sensitivity analysis based on three price signals for CO_2 reductions as discussed in Section VIII.

E. General Financial Assumptions

In addition to the fuel, load, environmental and other assumptions described, Tampa Electric utilized certain financial assumptions to conduct its initial and final detailed economic analysis. Major financial assumptions used in the 2007 analysis include:

- Discount rate of 7.88 percent;
- Tax rate of 38.575 percent;
- Property tax and insurance rate of 2.4 percent;
- Escalation rate for capital expenditures of 2.3 percent;
- Escalation rate for fixed and variable O&M of 2.3 percent; and
- AFUDC rate of 7.79 percent.

1. Section 48 Tax Credit

EPACT authorized the United States Department of the Treasury ("DOT") to allocate tax credits as incentives to move advanced generation technologies into the marketplace, including certain coal technologies. The coal technologies fall under two different tax credit programs: one for "Qualifying Advanced Coal Projects," under Internal Revenue Code Section 48A, and another for "Qualifying Gasification Projects," under Internal Revenue Code Section 48B. Congress authorized a total of $1.65 billion in tax credits for advanced clean coal projects, including $350 million in tax credits for advanced gasification projects.

In June 2006, Tampa Electric filed two applications with DOT and DOE describing the Polk Unit 6 project and requesting the maximum amount of credits available to an applicant under both Section 48A and 48B. Taxpayers could qualify for either the Section 48A credit or the Section 48B credit but not both at the same time. The maximum allowable credit to a single applicant under Section 48A was $133.5 million and under Section 48B was $130 million.

In November 2006, Tampa Electric was awarded the maximum Section 48A tax credits of $133.5 million dollars for Polk Unit 6, its proposed IGCC project. Tampa Electric's planned Polk Unit 6 was one of nine projects awarded the credits out of a total of 49 applicants. The tax credits will be earned during the construction phase when money is spent on "eligible property". "Eligible property" as defined by the provisions of EPACT is essentially the gasification system construction expenditures excluding the power block, which exceeds approximately 50 percent of the total construction cost of Polk Unit 6. Current estimates indicate that the full $133.5 million credit will be generated during the first four years of construction.

Additionally, the gasifiers in Polk Unit 6 must burn more than 50 percent bituminous coal, and at least 75 percent coal for five years after the facility is placed in service. If these conditions are violated, the credits are subject to recapture, and Tampa Electric would lose all or a percentage of the credit depending upon when the violations occur.

2. Tax Credit Requirements

No later than November 2008, Tampa Electric is required to have 1) secured all federal and state environmental authorizations or reviews necessary to commence construction of Polk Unit 6; 2) purchased or entered into binding contracts to purchase the main steam turbines; and 3) submitted required documentation to the IRS for certification. Additionally, to be eligible for the tax credits, Polk Unit 6 must be placed in service within five years of the date of the issuance of the IRS certification. The in-service deadline is expected to be November 2013. Failure to meet any of these deadlines means the tax credits must be forfeited in their entirety.

3. Financial Impact of the Tax Credit

Tampa Electric's tax obligation and payments are reduced as the credits are earned. The reduced tax payments will increase Tampa Electric's available cash to construct Polk Unit 6. Tampa Electric customers benefit by lower revenue requirements as the tax credits are amortized over the 25 year life of the gasifier beginning in 2013. The deferral and amortization over the depreciable life of the asset is an IRS prescribed treatment and is consistent with prior FPSC regulatory policy and determinations for similar tax credits. The amortization to the income statement effectively lowers the CPWRR for the new IGCC unit by approximately $63 million.

4. Advanced Recovery of Carrying Costs During Construction

House Bill ("HB") 549 was signed into law June 12, 2007. The law expands the statute created in 2006 that authorized advanced cost recovery for nuclear power to include IGCC technology. Stemming from legislative and executive branch concerns over the growing dependency on natural gas fired electric generation in Florida, the statute expressly states that the intent is to "promote" and "encourage" investor owned utility investment in nuclear power and IGCC technology.

Though the legislation itself does not contain environmental standards, there was public discussion and support for the legislation in both 2006 and 2007 that involved the environmental characteristics of the two technologies. Nuclear power has no air or mercury emissions, and releases no greenhouse gases. IGCC, among solid fuel technologies, has the lowest air emissions profile, and uses less water and produces less solid waste. In addition, IGCC is considered by many to be the best technology platform for capturing CO_2 if required in the future. The law also contains an important new provision that requires utilization of renewable energy sources and conservation measures by utilities prior to building any type of new power plant.

5. Impact of Advanced Recovery of Carrying Costs

The law allows for advanced recovery of prudently incurred carrying costs during plant construction for a nuclear or IGCC plant prior to its commercial in-service date. Carrying costs are normally added to the total plant in-service costs. These costs are recovered from customers through base rate charges once a plant has been placed into service. The law allows these funds to be collected during construction of the unit resulting in lower customer rate impacts when the unit is placed in-service. This treatment actually lowers the CPWRR of the installed plant. Once the Commission has granted a petition for determination of need for a nuclear or IGCC power plant, the utility must petition the Commission to receive the advanced cost recovery. On an annual basis, the utility is required to report to the Commission the estimated and actual costs.

F. Technology Assumptions

1. Demand-Side Alternatives

Tampa Electric's current DSM plan consists of 16 comprehensive residential and commercial programs which provide customers with a variety of program offerings to better manage their energy consumption. Tampa Electric reviews its existing DSM programs for cost-effectiveness and examines the potential for new offerings and program modifications on an annual basis.

When Tampa Electric updated its demand and energy forecast in 2007 and included Polk Unit 6 in its resource expansion plan, updated avoided cost parameters were developed. These avoided cost parameters were higher than the previous avoided cost parameters. Tampa Electric incorporated the higher avoided costs in its 2007 analysis of DSM programs. The increase provided the opportunity to develop new programs and modify existing programs. Additionally, the company completed its R&D work associated with its pilot residential demand response program and the results indicated a permanent program could be offered. In Docket Nos. 070056-EG and 070375-EG, the company has requested approval of these changes to its DSM plan. Appendices A and B contain a listing of Tampa Electric's current and proposed residential and commercial DSM programs.

2. Supply-Side Technologies

Solid Fuel Technologies

In the screening process, Tampa Electric considered all feasible technologies including SCPC, atmospheric fluidized bed combustion ("AFBC"), and IGCC technologies. SCPC is similar to the technology used at Big Bend Station with the primary difference being that the units operate at higher steam cycle operating pressures and steam temperatures. While SCPC boilers like the Big Bend units operate at steam pressures under 3,208 psi and have a temperature of 1,000 degrees Fahrenheit, supercritical boilers operate at pressures between 3,208 psi and 4,500 psi and at temperatures of approximately 1,050 degrees Fahrenheit or greater.

AFBC boilers are designed and operate in a significantly different manner. In a AFBC boiler, a portion of the combustion air is introduced through the bottom of the furnace. This air is spread evenly across the bottom of the furnace to produce a bed of air with entrained fuel. This process of entrainment of the fuel in air is called fluidization, thus the name "fluidized bed". Combustion of the fuel occurs in the fluidized bed of fuel. In addition to solid fuel, limestone and other agents may be added to control SO_2 emissions.

IGCC technology uses a gasification process conducted at high pressures utilizing pure oxygen instead of air to convert solid fuels such as coal, pet coke, and biomass into synthesis gas that is used to fuel a combined cycle unit. The gasification process allows for synthesis gas to be cleaned of impurities prior to being used as a fuel.

Natural Gas Fired Technologies

Tampa Electric considered simple cycle gas-fired technologies including LM 6000, 7FA and 7E. Tampa Electric also considered combined cycle using 7FA and LMS100. In comparison to other generating technologies, NGCC technologies are typically characterized by relatively low capital costs, low heat rates and low environmental emissions. The same combustion turbines implemented in simple cycle configurations are characterized by lower capital costs, higher heat rates and typically higher emission rates. The primary reason for the differences between combined cycle and simple cycle efficiencies is the recovery of exhaust heat from the combustion turbine in the combined cycle configuration.

Other Technologies

Tampa Electric considered renewable technologies such as solid biomass fired technologies, biogas, waste to energy, wind, solar, geothermal, hydroelectric and ocean energy, and advanced technologies such as fuel cells.

Tampa Electric's supply-side analysis was conducted first through a qualitative and quantitative screening followed by updated economic analysis. The screening step is intended to narrow the range of alternatives to focus the most viable options. Based on updated information, Tampa Electric conducted another detailed analysis to reconfirm that the selection of Polk Unit 6 remained the most cost-effective option.

IV. NEED FOR CAPACITY IN 2013

A. Reliability Assessment

Based on the Commission requirement to maintain a 20 percent reserve margin requirement, Tampa Electric determined through its IRP process that new baseload power would be necessary in 2013. In addition to the 20 percent reserve margin criteria, Tampa Electric also maintains a seven percent minimum summer supply-side reserve margin criteria, a voluntary but important qualitative component for reliability purposes. Reserve requirements can be met through load reductions, new generating capacity and purchased power.

Tampa Electric conducted two reliability assessments. The first assessment was the basis for the company's 2007 Ten-Year Site Plan which identified a need for peaking resources in 2008 through 2012, a large baseload unit in 2013 and additional peaking resources in 2014 through 2016. In mid-2007, an updated load forecast was prepared that incorporated demand and energy reductions due to the implementation of new and modified DSM programs as well as EPACT impacts. Other assumptions, as described below, were also updated and utilized in the final reliability assessment.

1. Request for Proposal (RFP) for Capacity

On February 7, 2007, Tampa Electric issued an RFP for supply resources. Tampa Electric provided information about its Polk Unit 6 option as required by Commission rule, Selection of Generating Capacity ("Bid Rule"). The RFP provided a detailed description of the Polk Unit 6 site, fuel types and costs, estimated costs of the proposed project, and other major financial assumptions. The minimum RFP requirements, such as the requirement for firm capacity and energy, were included in the document. The RFP also described the company's intention to maintain a balanced generation mix. Tampa Electric hired Alan S. Taylor of Sedway Consulting to assist with the development of the RFP and evaluation of the responses.

The company notified the market of the RFP by publishing notices in the Wall Street Journal, the Tampa Tribune and other energy industry publications. Two informational meetings were held at Tampa Electric's headquarters to describe the RFP and the process and to encourage offers and proposals in response to the RFP. The first meeting was held on January 31, 2007 prior to the release of the RFP to discuss the process and how potential bidders could obtain a copy of the RFP. The second meeting was held two weeks after the issuance of the RFP on February 21, 2007 to provide a more in-depth review of the RFP and to answer questions. Lastly, Tampa Electric established a web site that granted access to the RFP documents and allowed potential bidders to submit questions. Tampa Electric did not receive any bids in response to the RFP.

2. Demand-Side Management and Renewable Energy

Tampa Electric conducted an extensive evaluation of all conservation measures reasonably available. The company's current 2005-2014 DSM goals were established utilizing a comprehensive set of DSM measures. Through the company's efforts, these goals are being met. Additionally, the company has proposed additional and modified DSM programs commensurate with increases in DSM goals, which are before this Commission in Docket Nos. 070375-EG and 070056-EG.

Tampa Electric has identified all reasonably achievable DSM demand and energy reductions in its Need Study analysis. Even with the additional proposed summer and winter reduction of 41 MW and 48 MW, respectively, the company will not be able to meet the capacity identified in the Need Study. Therefore, Tampa Electric's evaluation of future generating capacity has already captured all cost-effective DSM measures available and there are no DSM alternatives that will defer the need for additional generating capacity in 2013.

Tampa Electric has engaged in several activities aimed at increasing the amount of renewable energy on its system. These activities include 1) developing and implementing a renewable energy program utilizing resources native to the state such as biomass, landfill gas and PV arrays for energy production; 2) securing MSW under firm contracts and participating in current discussions aimed at increasing that capacity; 3) purchasing as-available energy produced from waste heat; and 4) issuing a renewable energy RFP. Although the response to the RFP is unknown at this time, Tampa Electric does not anticipate renewable offerings large enough to alter the company's 2013 need for baseload capacity.

B. Tampa Electric's Reliability Assessment Results

The results of the 2007 final reliability assessment indicate that Tampa Electric will continue to need peaking and baseload resources and have a winter and summer 2013 need for 576 MW and 482 MW, respectively. Table 3 identifies the firm peak requirement of 4,831 MW and 4,627 MW in the winter and summer of 2013, respectively.

Table 3: 2013 Firm Peak Requirements

	Winter 2013 (MW)	Summer 2013 (MW)
Firm Retail	4,742	4,539
Firm Wholesale	89	89
Total Firm Peak[1]	**4,831**	**4,627**

Table 4 illustrates the addition of the 20 percent reserve margin requirement to the firm peak to determine the total firm capacity requirement. Tampa Electric's 2013 total firm capacity requirement is 5,797 MW and 5,553 MW in winter and summer, respectively. Tampa Electric's net available firm capacity is subtracted from the total firm capacity requirement to determine the winter and summer 2013 incremental capacity need of 576 MW and 482 MW, respectively. Detailed calculations for each year are shown in Appendix N.

Table 4: 2013 Capacity Requirements

	Winter 2013 (MW)	Summer 2013 (MW)
Total Firm Capacity Required	5,797	5,553
Net Available Firm Capacity	5,221	5,071
Incremental Capacity Needed	**576**	**482**

[1] May not add due to rounding

V. SCREENING OF POTENTIAL TECHNOLOGIES

A. Preliminary Screening

Electric utilities have a wide range of potential supply-side technologies which may be considered for future load requirements. Tampa Electric conducted an initial screening of potential supply-side technologies including SCPC, AFBC, IGCC, nuclear and NGCC based on economic viability and qualitative factors such as technical feasibility, commercial availability and construction timing.

The objective of the screening was to determine the most viable and applicable technologies for further analysis. The first step in the screening process was a qualitative screening which relied on widely accepted information sources such as the DOE and trade publications along with engineering judgment to assess the viability of various technologies. Further screening was conducted using quantitative screening methods using a comparison of the levelized total cost ($/kW-yr) for technologies not screened out in the qualitative analysis. This financial parameter considers fuel costs, heat rates, outage rates, and capacity of the generating unit to calculate the nominal cost per unit of capacity for a given operating capacity factor. The primary technology assumptions are shown in Appendix O.

This preliminary screening eliminated certain SCPC and nuclear technologies. Supercritical units operating at extreme steam temperature and pressures termed "ultra-supercritical" were excluded because operating under extreme conditions imposes additional demands on system components which increases cost and may reduce reliability. Also this technology has unproven domestic use and lacks operating experience. Nuclear technology was eliminated because its minimum cost-effective size would exceed Tampa Electric's need and could not be constructed in the desired timeframe.

B. Qualitative Screening – Renewable Technologies

Besides traditional technologies, renewable technologies including wind power, solar, geothermal, biomass and other advanced technologies such as ocean thermal and tidal were included in the initial screening. Tampa Electric has utilized biomass for fuel in the past at Gannon Station and Polk Station.

Wind power is a potentially viable alternative in areas with high sustained winds. Even the coastal areas in Florida, where the highest winds potentials are located, are considered marginal in regard to being a viable location for wind power. The siting of wind turbines on the coast may also be difficult due to negative impacts on tourism and environmental impacts to birds. For example, 200 MW of capacity would require one hundred 2 MW wind turbines with a blade sweep area of 64 meters. In addition to the siting difficulty, this would not meet the requirement of firm capacity. Therefore, Tampa Electric did not find the use of wind power viable.

Tampa Electric currently employs the use of solar power at a number of sites in the Tampa Electric service territory. Solar power production on a scale sufficient to offset any significant portion of the 2013 capacity need would be technically infeasible due to the area required to site the solar cells. Solar cells average power output is up to 200 watts per square meter. A 200 MW solar plant would occupy approximately 200 million square meters (approximately 50,000 acres) of area.

Tampa Electric periodically purchases renewable energy from biomass energy producers in support of its renewable energy program. Tampa Electric secures renewable energy from technologies such as landfill gas generation and energy from the waste of exothermic processes. Tampa Electric also encourages additional renewable energy through its renewable SOC approved by the Commission.

Other technologies such as ocean thermal and tidal are not considered commercially available. There are no significant geothermal sources in Florida. There are no fuel cells of sufficient size commercially available to offset the 2013 need.

C. Quantitative Screening

After the preliminary screening process, Tampa Electric performed a more detailed quantification. In this step of Tampa Electric's analysis, the levelized annual cost of each viable technology was calculated and compared at various capacity factors. The screening curves below illustrate the cost of these technologies over a range of capacity factors. Figure 6 illustrates a comparison of combined cycle and simple cycle technologies from a zero to 40 percent capacity factor. The figure illustrates the cost of the technology at the capacity factor that the technology may be dispatched. The conclusion was that 7F and LMS100 units were the most cost-effective at capacity factors lower than 15 percent. At capacity factors between 15 and 40 percent 7FA combined cycle and LMS100 were the most cost-effective technologies.

Figure 6: Low Capacity Factor Technology Screen Curve

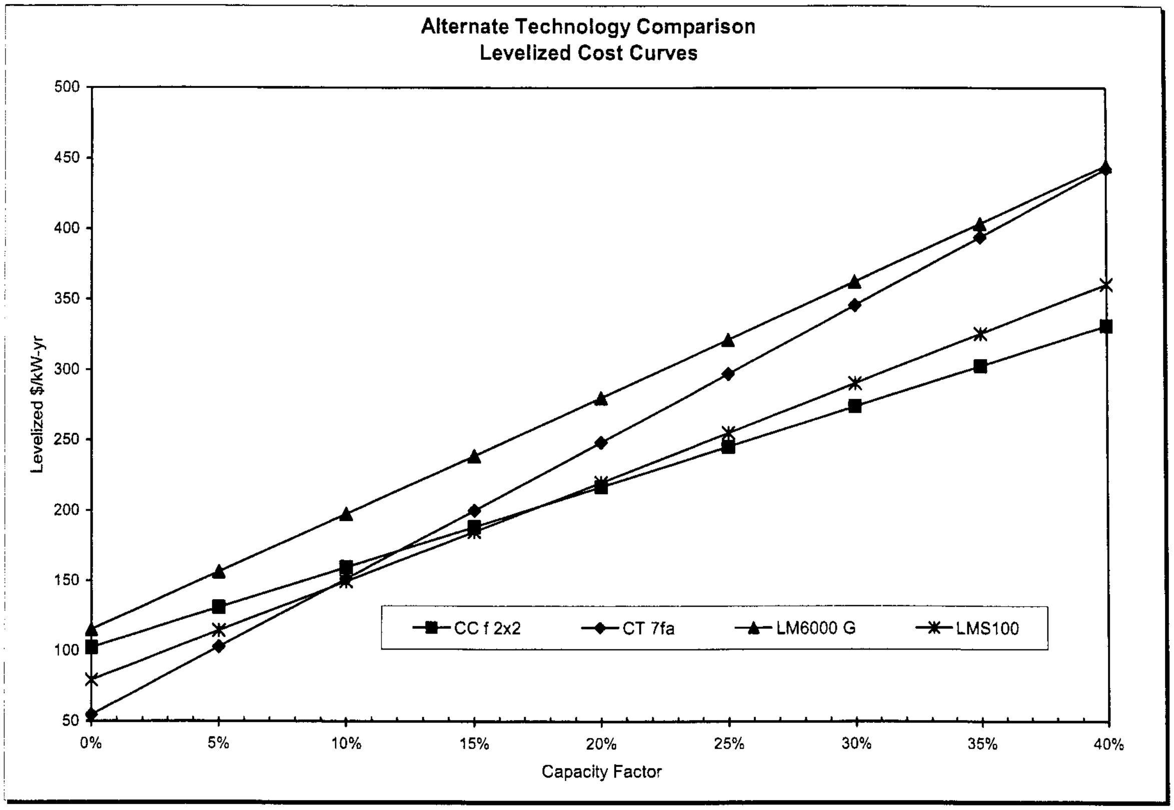
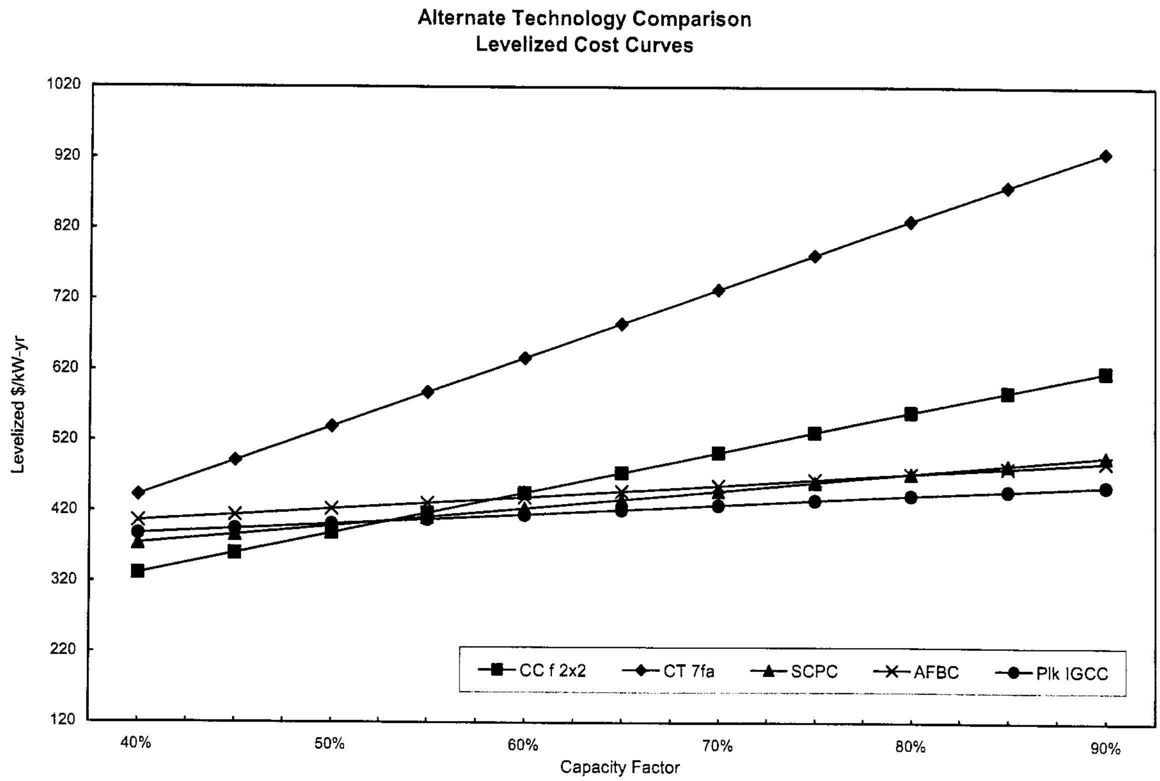


Figure 7 continues the capacity factor evaluation by comparing simple cycle and combined cycle 7FA, SCPC, AFBC and IGCC at capacity factors from 40 to 90 percent. At capacity factors greater than 60 percent, solid fuel technologies are demonstrated to be the lowest cost alternatives and natural gas combined cycle is the next best alternative.

Figure 7: High Capacity Factor Screening Curve



This analysis indicates that the levelized cost of the AFBC plant was greater than any other solid fuel plant until it exceeded an 80 percent capacity factor. Since AFBC technology is designed in relatively small increments of capacity, scale up requires a larger footprint. Additionally, AFBC technology creates a non-marketable combustion byproduct resulting in incremental waste handling issues and therefore dropped from further economic analysis.

As a result of the screening analysis, Tampa Electric concluded that SCPC, NGCC and IGCC were the most viable technologies for further consideration of the company's 2013 baseload need.

VI. DETAILED ECONOMIC ANALYSIS

A. Description of Analysis

Tampa Electric conducted detailed economic analysis of the leading supply-side alternatives in 2006 and updated the analysis in 2007 to reflect its updated demand and energy forecast. The detailed analysis involved the development of a resource plan for each technology case that was evaluated. In the construction of resource plans for each technology case, new units were added to each case to maintain a 20 percent reserve margin. The results of the detailed production costing analyses were combined with the capital revenue requirements to produce CPWRR results. The various resource plans that were the most cost-effective are shown in Table 5.

Table 5: 2007 Detailed Economic Analysis Resource Plan

	IGCC	SCPC	NGCC
2008	Peaking Need	Peaking Need	Peaking Need
2009	Peaking Need	Peaking Need	Peaking Need
2010	Peaking Need	Peaking Need	Peaking Need
2011	Peaking Need	Peaking Need	Peaking Need
2012	Peaking Need	Peaking Need	Peaking Need
2013	Polk IGCC	SCPC	NGCC and NGCT
2014	Peaking Need	Peaking Need	Peaking Need
2015	Peaking Need	Peaking Need	Peaking Need
2016	Peaking Need	Peaking Need	Peaking Need

B. Final Economic Analysis Results

As discussed in previous sections, changes in financial assumptions, demand and energy forecasts updated capital forecast and fuel costs were included in the 2007 economic analysis. Tampa Electric's 2007 economic analysis considered SCPC, NGCC and IGCC located at the Polk Station. The results of the analysis are illustrated in Table 6 below. Polk Unit 6 provides a CPWRR savings of $184 million over NGCC and $93 million over SCPC.

Table 6: Results of Final Economic Analysis
Total System Costs[1]
(2007 $M)

IGCC	SCPC	NGCC	Delta SCPC	Delta NGCC
$ 24,622	$ 24,715	$ 24,806	$ 93	$ 184

1. Tampa Electric Selected Alternative

Tampa Electric selected IGCC technology as the best supply-side alternative to meet its 2013 need based on the results of the economic analysis and consideration of other qualitative factors. Qualitative factors not assigned a specific economic value that were considered in the selection of IGCC included reliability enhancements due to the number of fuel types and availabilities, backup fuel capabilities, low environmental emissions, byproduct production and reuse/sale, low water use requirements, potential to cost-effectively meet future environmental and renewable requirements, and infrastructure and operational synergies with Polk Unit 1.

2. Qualitative Factors and Benefits of the Selected Alternative

Polk Unit 6's fuel benefits over other coal and natural gas technologies are the primary driver in the cost-effectiveness. Due to its use of gasification technology, Polk Unit 6 will have the capability to run on a wide range of fuels

[1] Total system costs include system fuel and purchased power, system O&M and incremental capital and O&M annual revenue requirements associated with new unit additions over a 30-year study period and shown on a cumulative present worth basis in 2007 dollars.

including pet coke. Polk Unit 6 will be designed for bituminous coals which are readily available domestically and internationally.

Polk Unit 6 will also have the capability to burn natural gas as a backup fuel, thereby enhancing operational flexibility and ensuring the capability to meet Tampa Electric's demand requirements. Polk Unit 6 will have the capability to run its combustion turbines and associated HRSG and steam turbine independent of the gasification process, giving Polk Unit 6 the highest availability of new solid fuel technologies. The resulting availability is expected to be 95 percent. IGCC technology will accommodate the gasification of biomass as a portion of the feedstock which will position Tampa Electric for using renewable sources.

The use of gasification technology also facilitates its low environmental emissions. Unlike combustion technologies like SCPC where environmental controls treat a large volume of exhaust gases, IGCC primary environmental controls treat a much smaller volume of pre-combustion gases, which reduces the size and expense of the treatment equipment. The resulting clean synthesis gas ("syngas") is combusted in the same manner that natural gas combined cycles utilizes natural gas. The result is lower environmental emissions and the potential to retrofit for future environmental requirements at a lower cost than other technologies. Polk Unit 6 will have lower emissions than any other currently proposed solid fuel fired unit in the state of Florida.

The use of solid fuels for Polk Unit 6 will ensure a diverse energy mix for Tampa Electric and its customers. With Polk Unit 6, Tampa Electric's energy mix by fuel type will be 64 percent solid fuel and 34 percent natural gas in 2013. If this need was met with a natural gas unit, Tampa Electric would rely on natural gas for 51 percent of its energy requirements.

Polk Unit 6 will produce more marketable byproducts than any other solid fuel alternative, which will reduce operating costs and minimize environmental impacts. Polk Unit 6 will convert sulfur contained in the fuel to sulfuric acid for sale in the sulfuric acid market. Polk Unit 6 will also produce a saleable slag byproduct.

Because a significant portion of the energy in the coal is converted to syngas which is then burned in combustion turbines, Polk Unit 6 relies on a steam system that operates at lower pressures and is of smaller size than comparable SCPC technologies resulting in lower water use. Water use is a critical factor in the state and is a constraint for all power plant site permitting including Polk Station.

Finally, Tampa Electric has more than a decade of experience with IGCC technology and the existing infrastructure at the Polk Station will provide design and operational synergies and maximize the effectiveness of Polk Unit 6. Some of these synergies are discussed in Section VII. B.

3. Consistency with Florida Needs

Tampa Electric's need for additional solid fuel capacity in January 2013 is consistent with the Peninsular Florida energy mix of 25.8 percent coal-fired generation to meet the Peninsular Florida net energy for load of 284,886 GWH in 2013, as identified by the Florida Reliability Coordinating Council ("FRCC") and reported in the FRCC 2007 Regional Load and Resource Plan. The FRCC 2007 plan uses Tampa Electric specific data in conjunction with similar information from other Florida electric utilities. Polk Unit 6 is consistent with state policy actions that encourage fuel diversity and avoid the reliance on any single fuel.

VII. TAMPA ELECTRIC'S PROPOSED UNIT

A. Overview

Polk Unit 6 is an IGCC unit with an annual nominal rating of 632 MW. Polk Unit 6 will be constructed at Polk Station and is planned to be in service by January 2013. The total in-service cost of the project is expected to be $2.013 billion. This includes the direct overnight engineering and procurement costs for the project of $1.614 billion. It also includes transmission costs, owner's costs, contingency and escalation.

B. Description

Tampa Electric plans to make use of its extensive experience with IGCC technology to construct Polk Unit 6, a second IGCC power plant at Polk Station. Polk Station occupies over 2,800 acres on State Road 37 in Polk County, Florida, approximately 40 miles southeast of Tampa and about 60 miles southwest of Orlando. Feedstock for Polk Unit 6 will be bituminous coal with the capability of gasifying up to 100 percent pet coke. Polk Unit 6 will also be capable of gasifying renewable biomass as a portion of the feedstock.

To qualify for federal tax credits that encourage the construction of IGCC technology, Polk Unit 6 must burn at least 75 percent coal for the first five years of service. After the first five years, the unit will have the flexibility to burn the most cost-effective fuel blends to minimize fuel cost. Polk Unit 6 is expected to generate a net 647 MW of electricity in winter at 32 degrees Fahrenheit and 610 MW in the summer at 92 degrees Fahrenheit. The average annual net heat rate, higher heating value is expected to be about 9,111 Btu/kWh.

Tampa Electric will use technology for Polk Unit 6 that builds on the company's experience with Polk Unit 1. Tampa Electric will utilize GE gasification and power generation technologies. Coal, pet coke and biomass will be delivered to

Polk Station via direct rail, or waterborne with truck or short haul rail. The fuel constituents will be individually stored on-site and then blended in the desired ratio using weigh feeders as they are reclaimed from storage.

Fuel and process water will be ground in rod mills to produce a slurry, which will be stored in tanks. A pump will deliver the slurry to the gasifier's feed injector. Main air compressors and extraction air from the two combustion turbines will feed a distillation column, which separates oxygen from nitrogen. Oxygen compressors or pumps will transfer oxygen to the gasifiers, and diluent nitrogen compressors will supply the combustion turbines with nitrogen for NO_x suppression and power augmentation. Two GE gasifiers of the same size as Polk Unit 1 each will operate at 650 psi. A radiant syngas cooler for each gasifier will cool the syngas and make steam, while removing most of the ash particles from the syngas. For each gasifier train, a single water/gas scrubber with multiple steps of water/gas contact will be installed to remove the remaining ash particles.

Several stages of heat recovery followed by a trim cooler will be provided in low temperature syngas cooling. An activated carbon bed will remove mercury from the syngas. The system will include two carbonyl sulfide ("COS") hydrolysis systems, one for each gasification train, each consisting of one superheater followed by a COS hydrolysis reactor. A Selexol acid gas removal system will provide high sulfur removal rates. An acid plant will produce 700 to 800 tons per day of commercial grade sulfuric acid for sale into the market. A single saturator column will add water vapor to the syngas for supplemental NO_x suppression. Two 232 MW General Electric ("GE") 7FB combustion turbines, each with a HRSG, and a single 325 MW steam turbine will produce the electrical power.

Make-up water to the plant will be provided by on-site wells. The existing 750 acre cooling reservoir, along with a supplemental cooling tower will provide cooling for the various heat exchangers in the system.

1. Location

By co-locating Polk Unit 6 at Polk Station, there are numerous benefits:

- A 750 acre cooling reservoir exists at the site has the capacity to handle a large portion of the cooling needs for Polk Unit 6.
- The site is currently served by four 230 kV volt transmission circuits with the capacity to be upgraded to handle the additional output of Polk Unit 6. The existing on-site substation can be readily expanded to accommodate switching for the unit.
- The site has good access to paved roads for truck and other vehicle traffic.
- The site has an existing rail line that is used for large equipment deliveries via the CSX rail network. The design of Polk Unit 6 includes facilities to unload rail cars and a coal storage yard.
- The site is served by a natural gas pipeline owned by FGT that can provide fuel for gasifier start-up and operation of the power block up to full load output. Additionally, the Gulfstream natural gas pipeline could potentially be extended to the site.
- The site has an existing administration building, control room, warehouse, maintenance shop, construction management building, first aid building and laboratory that can be modified to serve Polk Unit 6.
- The site has in excess of 40 acres of space immediately adjacent to the footprint for Polk Unit 6 that can be used for new equipment deliveries and construction staging.
- Over 100 personnel, including Tampa Electric employees and subcontractors, regularly work at this site providing operations and

maintenance services to Polk Unit 1, the company's existing IGCC unit. The skills are directly applicable to Polk Unit 6.

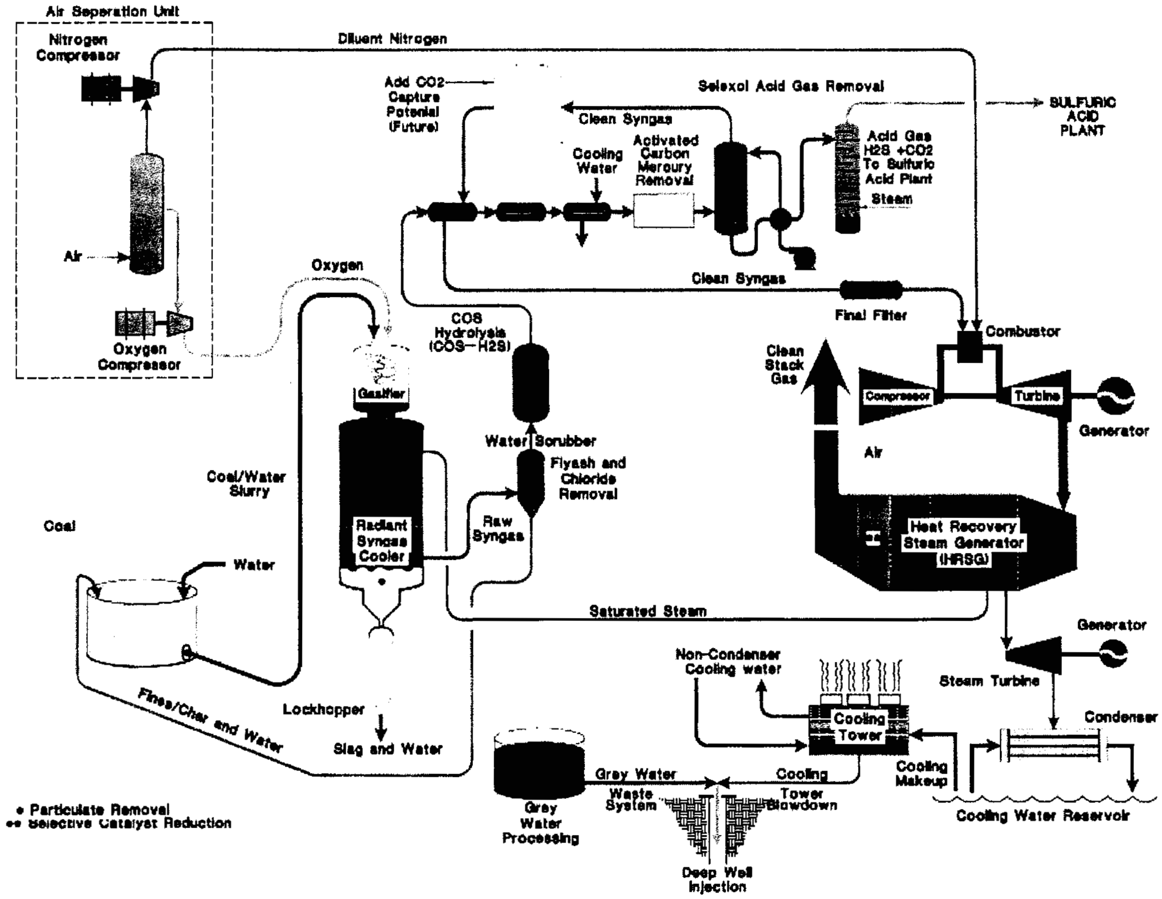
- Tampa Electric has established relationships with dozens of service providers and specialty contractors located in the immediate area surrounding the site. This network has been established specifically to service the needs of Polk Unit 1 and will be available for Polk Unit 6.

Appendix Q provides an overview of the proposed site plot plan.

2. Design

Tampa Electric is currently in the Front End Engineering Design ("FEED") stage of design for Polk Unit 6. At this stage of the project a preliminary concept of the plant has been developed. This preliminary conceptual design provides sufficient information for estimation of the expected performance, and general arrangement of the plant and high level estimates of the projects schedules and costs. The plant can be broken down into several sections, as described in the following sections. A process diagram is provided in Figure 8 below.

Figure 8: Polk Unit 6 Overall Process



POLK 6 PROCESS

3. Systems

Coal Receiving and Storage

Most solid fuel will be delivered via rail, water or a combination of the two methods. Rail and rail unloading equipment will be added to allow delivery of coal and pet coke. Conveyors will transport fuel from the rail car unloader to an active fuel storage area. The active fuel storage area will have two areas: one for coal and the other for pet coke. This area will also have two reclaimers to transport fuel from the active storage area to fuel blending bins. The blending bins will allow the company to combine coal and pet coke in appropriate ratios for use in the gasifiers. Two conveyors will allow transport of the blended fuel to the slurry preparation buildings. The long term fuel storage area may contain up to 225,000 tons of fuel storage.

Slurry Preparation

The slurry preparation area will contain two rod mills which will grind the fuel and mix it with water to make slurry for injection into the gasifiers. Two slurry tanks provide a few hours of storage of the slurry. Slurry pumps, one per gasifier, will pump the slurry to the feed injector in each gasifier.

Air Separation Plant

An air separation plant will separate air into its primary components; nitrogen and oxygen. The air plant will include main air compressors, heat exchanger filters, and nitrogen and oxygen compressors or pumps.

Gasification

There will be two gasification trains. Each gasifier will sit on top of a radiant syngas cooler. The radiant syngas cooler will cool the syngas generated in the gasifier, produce steam in the process, and separate most of the ash (slag) from the syngas. Slag will be removed from each radiant syngas cooler through lock hoppers located at the bottom of each cooler.

Slag Removal and Handling

The slag exiting the lock hoppers will travel across screens where it is washed to remove fines which contain carbon that can be reused to enhance efficiency. The slag will continue along conveyors to bins where the material is tested before removal for sale to various industrial users. Fines containing high amounts of carbon will be transported to the slag storage area for later reuse in the system, alternative sales, or long term storage.

Syngas Scrubbing (Particulate Removal)

The cooled syngas leaving the radiant syngas cooler will go to scrubbers which wash out any remaining particulate matter from the gas. The particulate matter, mixed with water, will be returned to the slurry preparation equipment to be re-gasified for recovery of the remaining carbon. The scrubbed gas continues on to low temperature gas cooling.

Low Temperature Gas Cooling

Low temperature gas cooling is a series of heat exchangers that will cool the syngas further, recovering more of the heat from the syngas for use in other portions of the process to improve overall efficiency.

Mercury Removal

A sorbent bed will be included which will remove mercury from the syngas prior to going to the combustion turbines. Approximately 90 percent of the mercury is expected to be removed.

COS Hydrolysis

Equipment will be installed which will convert COS to hydrogen sulfide, which will increase the amount of sulfur removed from the syngas prior to going to the combustion turbines.

Acid Gas Removal

A Selexol acid gas removal system will be included. This equipment will remove sulfur compounds from the syngas prior to it going to the combustion turbines. The resultant acid gas will go to a sulfuric acid plant.

Sulfur Recovery

Sulfur recovery equipment will take the acid gas from the acid gas removal system and convert it to sulfuric acid. The resultant sulfuric acid byproduct will be sold into the sulfuric acid market.

Syngas Saturator

A syngas saturator will add moisture to the syngas prior to its use in the combustion turbine. This saturation step will help to lower NO_x emissions from the combustion turbine/HRSG stacks.

Water Use

Water is recycled to the maximum extent practical to minimize groundwater use. For instance, the water required for slurry preparation is derived from internal streams from water recycled from low-temperature cooling. In addition, water will be used for make up to the cooling reservoir to replace water evaporated from the reservoir and cooling tower.

Cooling Water

Cooling water pumps will take water from the cooling reservoir and route it to the steam turbine condensers. The cooling water from the condensers returns to the discharge portion of the reservoir. This heated water travels a very long route, cooling off in the process, before arriving back at the intake structure where it is used again. Other pumps will also take water from the reservoir and provide make-up water to the new cooling tower basin. This make-up water will replace water evaporated from the cooling tower and water that is discharged to control the quality of the cooling tower basin. Cooling water pumps will take water from the cooling tower basin and route it to various heat exchangers throughout the plant.

Process Water Treatment

Water used throughout the gasification and gas clean up systems will concentrate impurities due to the evaporation or decomposition of water in these processes. To keep these process waters from becoming too concentrated, a stream from these systems is treated and will be injected into deep waste water wells located at the site.

Power Block

There will be two combustion turbines with connected electric generators, two HRSG's, and one steam turbine with a connected generator. The combustion turbines will burn the syngas to produce electricity. The hot exhaust gas from the combustion turbines will flow through the HRSG's producing steam. The cooled exhaust gas will exit through a stack on each HRSG. The steam produced in the HRSG's produces electricity in the steam turbine.

The expected Equivalent Availability Factor for Polk Unit 6 is 95 percent. Availability of Polk Unit 6 is expected to be greater than that of Polk Unit 1. Design changes, such as elimination of the convective syngas coolers contribute heavily to this increase. In addition, having two gasifiers and two combustion turbines will mean that a single gasifier or combustion turbine outage will reduce output to about half, rather than the full reduction. The ability to utilize natural gas as a backup fuel during gasifier outages will also enhance the availability of the unit.

C. Environmental

1. Environmental Requirements

Tampa Electric is required to obtain federal, state, and regional environmental approvals and permits. The principal environmental approval is Certification under Florida's Electrical Power Plant Siting Act ("PPSA") codified in 403.500 Florida Statutes. This is a comprehensive review of all environmental aspects of Polk 6 Unit, coordinated through the FDEP and involving all state and regional agencies with environmental responsibility and those potentially affected by Polk Unit 6.

Polk Unit 6 will require federal and federally delegated permits. This includes an approval by the U.S. Army Corp of Engineers ("ACOE") for impacts to wetlands, a Prevention of Significant Deterioration ("PSD")/Air Construction Permit by the FDEP, a National Pollutant Discharge Elimination System ("NPDES") and an Underground Injection Control ("UIC") Permit from FDEP.

The ACOE permit is required under Section 404 of the Clean Water Act and includes a demonstration that impacts to wetlands have been minimized and compensatory wetland mitigation has been provided as needed. Since Polk Unit 6 will be located at the existing site of Polk Unit 1, minimal impacts to wetlands will occur. Appendix S contains a detailed list of environmental permitting activities that are currently in process by Tampa Electric for Polk Unit 6.

Under the federally authorized PSD program, Polk Unit 6 will be required to install Best Available Control Technology ("BACT") and demonstrate that the project will comply with all air quality standards including those applicable to the PSD Class I Areas. FDEP PSD rules are codified in Rule 62-212 F.A.C. An important aspect of PSD review is the determination of BACT.

The Polk Unit 6 site was selected at a location that provides the needed infrastructure and minimizes environmental impacts. The Polk Station site includes sufficient land area, which has been previously certified to minimize any additional environmental impacts. Water use will be minimized by using storm water from on site collection, maximizing the reuse of existing industrial waste water, and lower-quality water from the Upper Floridian Aquifer. Water will be recycled as much as possible and released using UIC wells. Polk Unit 6 is being designed to minimize existing NPDES water discharges to surface waters or groundwater that can potentially impact the environment. Byproducts will be recycled to the greatest extent practicable. Byproducts that cannot be recycled will be placed in an area designed to have minimal impacts to the environment. Air emissions from Polk Station will be minimized by use of the Selexol Acid Removal system and SCR and installation of state-of-the-art air pollution control equipment.

2. Environmental Controls

Tampa Electric based the CO_2 emissions sensitivity on three price signals for CO_2 reductions. The three price signals used were $5, $15 and $30 per ton of CO_2 with a five percent yearly escalation starting in 2010. The forecasted price used in the analysis including the high and low sensitivities is provided in Appendix P.

These three price signals were incorporated in the CPWRR calculations of the base fuel NGCC and IGCC cases to calculate the environmental case CPWRR results. Because the exact detail of any future CO_2 emission policy is unknown at this time, this wide range of $5 to $30 was selected for the CO_2, sensitivity analysis in an effort to encompass the potential impacts of the various policy proposals such as a market-based cap-and-trade program, a specific tax or technology mandates.

D. Transmission Facilities

Polk Unit 6 will require the construction of transmission infrastructure. This infrastructure/facilities includes:

1. Three 230 kV onsite transmission lines to interconnect the Polk 6 combustion turbines and steam turbine to the Polk Power Substation.
2. Three new bays and six new 230 kV Circuit Breakers at the Polk Power Substation to terminate the three new 230 kV onsite transmission lines.
3. The upgrade of two parallel 230 kV lines that connect Polk Power Substation to Pebbledale Substation. These two lines, 230605 and 230606, are approximately 10 miles and 14 miles respectively.

The total project costs are approximately $25 million. The Polk interconnection work would begin December 2010 and would be completed by September 2011. This will allow time for testing of the unit and associated IGCC equipment prior to its commercial date. The Polk Power Substation to Pebbledale line construction must begin by September 2010 with an in-service date of March 2012. This also ensures that all transmission facilities are in-service prior to any testing of Polk Unit 6.

Polk Unit 6 will be interconnected with Tampa Electric with three new 230 kV lines connecting three new Polk Unit 6 generator step-up transformers ("GSU") to the existing Polk Power Substation. The Polk Power Substation is connected to the Tampa Electric bulk electric system through four 230 kV lines, two to Pebbledale Substation, one to Mines Substation and one line to the Hardee Power Station. The three GSU will be located near the combustion turbines, steam turbine and associated IGCC equipment. A 0.7 mile double circuit 230kV line will be built from two of the GSU to two new termination positions at the Polk Power Substation. A second 0.7 mile 230kV line will be built from the remaining GSU to another new termination position at the Polk Power Substation. Polk Power Substation will have three new bay positions and six new circuit breakers.

E. Cost

The overall direct overnight construction cost for Polk Unit 6 is $1.614 billion. The estimate represents overnight construction costs in January 2007 dollars for all direct work at Polk Unit 6. The primary components are the gasification area and the balance of plant and power block. The estimate includes all engineering, procurement, construction, startup and commissioning costs associated with the completion of activities required to construct Polk Unit 6.

The total in-service cost estimate for Polk Unit 6 is $2.013 billion, which includes the aforementioned overnight construction costs as well as owner's costs, transmission costs and contingency and escalation. Owner's costs include project development costs such as technology development and environmental permitting, project management and operational support and training, legal and other professional services costs, and insurance. Tampa Electric estimated the owner's costs for Polk Unit 6 based on its experience developing and constructing generating units in Florida.

F. Schedule

Conceptual design began in 2006, and the preliminary engineering package development began in the second quarter 2007 and is expected to be completed in the second quarter 2008. The Site Certification Application will be filed with the FDEP in August 2007. The detailed design and procurement will begin second quarter 2008, starting with the engineering for the gasification process and the combined cycle equipment. Detailed design and procurement activities are expected to continue through second quarter 2011. Construction activities are expected to begin in first quarter 2009 with general site work. Field construction will start in the second quarter 2009 and continue second quarter 2012. Startup and commission will occur in parallel with the end of construction starting in fourth quarter 2010 through fourth quarter 2012. The unit will begin commercial operation in 2013.

Tampa Electric has entered into a contract with GE and Bechtel to prepare a preliminary basis for design, block flow diagram, layout drawing and performance and emissions data in support of project development. Both companies continue to support Tampa Electric in the preparation of permit application documents. Tampa Electric has engaged the services of an environmental consultant to prepare air modeling studies and other evaluations, as well as prepare the permit application documents.

The preliminary project schedule is shown in Appendix R.

VIII. SCENARIO ANALYSIS

A. Approach

As the final step of Tampa Electric's IRP process, the company conducted three scenario analyses to assess the recommended Polk Unit 6 resource plan against potential price sensitivities. The scenarios included price bands around the base fuel forecasts, potential cost impacts of CO_2 emissions restrictions and lower and higher than expected capital costs for the NGCC, SCPC and IGCC technologies.

B. Results of Scenario Analyses

The results of the fuel and environmental sensitivities are presented in CPWRR for NGCC, SCPC and IGCC. The results of all the scenario analyses demonstrated the IGCC technology, or Polk Unit 6, remained the most cost-effective alternative for most of the price sensitivities. The exceptions were the low fuel price band, high capital cost estimate and high CO_2 price band sensitivities when compared to the NGCC plan. The IGCC plan was more cost-effective than the SCPC plan in all of the scenarios except for the low fuel price band sensitivity.

1. Fuel Scenario

To evaluate price fluctuations, Tampa Electric prepared high and low price forecasts for natural gas and coal. The price ranges for the high and low price scenarios are derived from the level of change in annualized prices of each commodity during the past five years. In the case of solid fuel, the same percentage change was utilized for all solid fuel types. Appendices K and L include the low and high fuel forecasts, respectively. The high case for natural gas is 42 percent higher than the base case and the low case is 49 percent lower than the base case. Coal commodity is 17 percent higher and 22 percent lower than the base case, respectively. The results of the fuel price sensitivities are provided in Table 7 below:

Table 7: Results of Fuel Pricing Sensitivities
Total System Costs[1]
(2007 $M)

	IGCC	SCPC	NGCC	Delta SCPC	Delta NGCC
Low Fuel	$ 18,673	$ 18,553	$ 17,507	$ (120)	$ (1,167)
Base Fuel	$ 24,622	$ 24,715	$ 24,806	$ 93	$ 184
High Fuel	$ 30,435	$ 30,659	$ 31,577	$ 224	$ 1,142

2. Environmental Scenario

Tampa Electric based the CO_2 emissions sensitivity on three price bands for CO_2 reductions. The three price bands used were $5, $15 and $30 per ton of CO_2 with a five percent yearly escalation starting in 2010. The forecasted price used in the analysis including the high and low sensitivities is provided in Appendix P.

[1] Total system costs include system fuel and purchased power, system O&M and incremental capital and O&M annual revenue requirements associated with new unit additions over a 30-year study period and shown on a cumulative present worth basis in 2007 dollars.

These three price bands were incorporated in the CPWRR calculations of the base fuel NGCC, SCPC and IGCC cases to calculate the environmental case CPWRR results. Because the exact detail of any future CO_2 emission policy is unknown at this time, this wide range of $5 to $30 was selected for the CO_2, price sensitivity analysis in an effort to encompass the potential impacts of the various policy proposals such as a market-based cap-and-trade program, a specific tax or technology mandates. The IGCC plan resulted in a savings in comparison to NGCC and SCPC in all sensitivities except for the NGCC high price band sensitivity. The results of the environmental sensitivities are provided in Table 8 below:

Table 8: Results of Environmental Sensitivities
Total System Costs[1]
(2007 $M)

	IGCC	SCPC	NGCC	Delta SCPC	Delta NGCC
Low Price Band	$ 26,224	$ 26,312	$ 26,348	$ 88	$ 125
Medium Price Band	$ 29,426	$ 29,505	$ 29,432	$ 79	$ 5
High Price Band	$ 34,231	$ 34,295	$ 34,057	$ 64	$ (173)

3. Capital Cost Scenario

Recognizing that the estimated in-service costs for Polk Unit 6 are based on preliminary estimates, capital cost sensitivities were analyzed. The high and low cases were established utilizing 15 percent higher and lower in-service costs. The IGCC plan resulted in a savings in comparison to NGCC and SCPC plans in all of the capital cost price bands except for the NGCC high

[1] Total system costs include system fuel and purchased power, system O&M and incremental capital and O&M annual revenue requirements associated with new unit additions over a 30-year study period and shown on a cumulative present worth basis in 2007 dollars.

capital cost sensitivity. The results of the capital cost sensitivities are provided in Table 9 below:

Table 9: Results of Capital Cost Sensitivities
Total System Costs[1]
(2007 $M)

	IGCC	SCPC	NGCC	Delta SCPC	Delta NGCC
Low Capital Cost	$ 24,245	$ 24,401	$ 24,715	$ 156	$ 470
High Capital Cost	$ 24,999	$ 25,030	$ 24,898	$ 31	$ (102)

IX. ADVERSE CONSEQUENCES IF POLK UNIT 6 IS DELAYED OR DENIED

In the event that Polk Unit 6 is delayed by one year, Tampa Electric would have to forfeit the DOE advanced coal project tax credits of $133.5 million and project costs would increase. The company would need to purchase more expensive replacement power purchases. It is likely that the purchases would come from natural gas fired generators in Florida, resulting in a higher dependence on natural gas and a greater exposure to the associated risk of supply disruptions and price volatility associated with this fuel. A delay would, therefore, result in higher costs for Tampa Electric's customers.

If Tampa Electric's proposed Polk Unit 6 were denied, the company would construct a NGCC unit or SCPC unit in 2013. This would result in a cost increase to customers of $184 million or $93 million, respectively, compared to the IGCC unit on a CPWRR basis. Florida's policy on fuel diversity and single fuel reliance would not be accomplished due to the company's added reliance on

[1] Total system costs include system fuel and purchased power, system O&M and incremental capital and O&M annual revenue requirements associated with new unit additions over a 30-year study period and shown on a cumulative present worth basis in 2007 dollars.

natural gas. In fact, Tampa Electric's energy mix by fuel type would consist of 51 percent natural gas.

X. CONCLUSION

Tampa Electric, through its IRP process, determined that there is a 2013 summer need of 482 MW and a winter need of 576 MW in order to meet the Commission mandated 20 percent reserve margin criteria. Tampa Electric considered DSM and renewable energy programs and supply-side alternatives to mitigate the need. Despite Tampa Electric's recently proposed new and modified DSM programs and the associated increase in load reductions, the company will not be able to defer its need.

Tampa Electric conducted a detailed evaluation of various supply-side alternatives. Both gas fired and solid fuel fired alternatives were considered. After an initial screening process of a variety of viable technologies, a detailed economic analysis of NGCC, SCPC and IGCC technologies demonstrated that Polk Unit 6 is the most cost-effective means of meeting Tampa Electric's 2013 need. Tampa Electric's analysis demonstrated Polk Unit 6 provides $184 million in savings compared to NGCC technology and $93 million in savings compared to SCPC technology.

The use of solid fuels for Polk Unit 6 will ensure a diverse energy mix for Tampa Electric and its customers. With Polk Unit 6, Tampa Electric's energy mix by fuel type will be 64 percent solid fuel and 34 percent natural gas in 2013. If this need was met with a natural gas unit, Tampa Electric would rely on natural gas for 51 percent of its energy requirements.

Besides quantitative analyses, Tampa Electric evaluated qualitative factors such as environmental emissions, water use and byproduct production. Polk Unit 6 will have significantly lower emission rates than any currently proposed solid fuel fired power plant in Florida. Tampa Electric is designing the unit with consideration of potential future CO_2 emission regulations. The design provides space for commercially available and technically proven carbon control equipment to be added should future legislation be passed.

Polk Unit 6 will produce more marketable byproducts than any other solid fuel alternative, which will reduce costs and impacts to the environment. Polk Unit 6 will convert sulfur contained in the fuel to sulfuric acid for sale in the sulfuric acid market. Polk Unit 6 will also produce a saleable slag byproduct.

Because a significant portion of the energy in the coal is converted to syngas which is then burned in combustion turbines, Polk Unit 6 relies on a steam system that operates at lower pressures and is of smaller size than comparable SCPC technologies resulting in lower water use. Water use is a critical factor in the state and is a constraint for all power plant site permitting including Polk Station. Finally, Tampa Electric has more than a decade of experience with IGCC technology and the existing infrastructure at the Polk Station will provide design and operational synergies and maximize the effectiveness of Polk Unit 6.

After its detailed analysis, Tampa Electric conducted three scenario analyses to test the results of Tampa Electric's supply-side evaluation against potential future price sensitivities. The first scenario analysis tested the base fuel forecast results against high and low fuel price bands. Polk Unit 6 was the most cost-effective alternative compared to the NGCC and SCPC plans except for the low fuel price sensitivity. The second scenario tested the effects of potential CO_2 requirements. Tampa Electric evaluated low, medium and high CO_2 emission prices as scenarios for potential CO_2 regulation. Polk Unit 6 was the most cost-effective alternative except for the NGCC plan under the high price band sensitivity. The third scenario analysis tested lower and higher than expected capital costs for NGCC, SCPC and IGCC technologies. The results of this analysis demonstrated the IGCC remained the most cost-effective alternative except for the high capital cost sensitivity. Based on these scenario analyses, IGCC remains the most cost-effective alternative compared to the SCPC and NGCC resource plans.

In conclusion, Polk Unit 6 is the best option for Tampa Electric to cost-effectively maintain system reliability and enhance fuel diversity. Based on the details of this Need Study, Polk Unit 6 is also the best alternative to address technological, environmental and other strategic factors that affect Tampa Electric and its customers.

XI. APPENDICES

Appendix A: Residential DSM

Appendix B: Commercial DSM Programs

Appendix C: Retail Customers by Customer Class

Appendix D: Retail Energy Sales by Customers

Appendix E: Retail Peak Demand Forecast

Appendix F: Updated Demand and Energy Forecast – Retail Customers

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Appendix I: Fuel Forecast for Initial Economic Analysis

Appendix J: Fuel Forecast for Final Economic Analysis

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Appendix N: Final Reliability Analysis

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Appendix P: Carbon Dioxide Allowance Forecast ($ per Ton)

Appendix Q: Polk Unit 6 Conceptual Plot Plan

Appendix R: Polk Unit 6 Preliminary Project Schedule

Appendix S: Polk Unit 6 Environmental Permit Requirements

Appendix A: Residential DSM

SUMMARY OF MODIFICATIONS AND ADDITIONS TO TAMPA ELECTRIC'S RESIDENTIAL DSM PLAN

Residential Programs	Measures	Brief Description
Walk-Through Audit		**Modified** - Customer will be given six compact fluorescent lamps during audit
On-Line Audit		**No Changes**
Telephone Audit		**New** - This audit will be added to the Customer Assisted Audit Portfolio
Energy Awareness (Pilot)	School Program	**New** - This partneship with service area schools at the eight grade level supports
		the science curriculumn through a professionally written play using interactive
		theater and classroom guides to teach students the benefits of energy efficiency.
		On-line or telephone audits of the students homes will be performed for extra
		class credit.
Heating & Cooling Program	High Efficiency Cooling With Natural Gas Heating	**Modified** - to include all residential structures. Incentive will increase from $250
	High Efficiency Heat Pumps	**to $275 for heat pumps replacing strip heat and from $100 to $125 for heat**
		heat pumps replacing heat pumps.
Duct Repair	Duct Repair	**Modified** - Customer costs to participate will be reduced from $79 to $50.
Residential Building Envelope Improvement	Window Replacement	**New** - Will pay up to $350 for Energy Efficient Windows
	Window Film	**New** - Will pay up to $1 per sq. ft. for Energy Efficient Window film
	Ceiling Insulation	**Modified** - Will pay up to $200 for ceiling insulation (based on sq. ft. of home)
	Wall Insulation	**New** - Will pay up to $200 for Wall insulation
New Construction Program	Duct Sealing With Mastic	**Modified** - This measure went from a prerequisite to a $50 incentive
	High Efficiency Cooling With Natural Gas Heating	**No Changes**
	High Efficiency Heat Pumps	**No Changes**
	Ceiling Insulation Upgrades	**Modified** - Incentive reduced from $100 to $75 to maintain cost-effectiveness
	Window Upgrades	**New** - Will pay up to $350 for Energy Efficient Windows
	Alternate Water Heating Upgrades	**No Changes**
	Certification	**New** - Will pay $75 for Energy Star Certification
Residential Low Income		**New** - Program aimed at low-income customers. The company will provide at
		no cost items to reduce energy and demand. The following items are available:
		Six compact fluorescents lamps
		One water heater wrap
		Three Low flow faucet aerators and two showerheads
		Window HVAC weather stripping kit (up to two)
		Wall plate thermometer (where applicable)
		HVAC Filters (where applicable)
		Weather stripping and caulking
		Ceiling insulation (up to R-19)
Renewable Energy Initiative	Customer Purchases of Renewable Energy	**No Changes**
Prime Time	Heating Control Cyclic	
	Heating Control Extended	**Requesting that the FPSC allow Tampa Electric to continue Prime Time to new**
	Cooling Control Cyclic	**customers where existing equipment is already in place.**
	Cooling Control Extended	
	Water Heating	
	Pool Pumps	
9 Programs	33 Measures	
Energy Planner	Price Responsive Load Management*	**New - Pricing schedule combined with programmable thermostat designed to**
		reduce weather sensitive peak loads.

Appendix B: Commercial DSM Programs

Commercial Programs	Measures	Comments
Commercial/Industrial Audit (free)		**No Changes**
Commercial/Industrial Audit (paid)		**No Changes**
Commercial Duct Repair	Duct Repair	**New** - Will provide $200.00 incentive for duct repair
Commercial Building Envelope Improvement	Window Film	**New** - Will provide $200.00 incentive for duct repair
	Ceiling Insulation	**New** - Will provide $0.05 per sq. ft. incentive for ceiling insulation
	Wall Insulation	**New** - Will provide $0.20 per sq. ft. incentive for wall insulation
Energy Efficient Motors	Motor Upgrades	**New** - Will provide $2.50 per HP incentive for energy efficient motor upgrades.
Commercial Load Management	Load Reduction	**Modified** - Will increase cyclic incentive $1.00/kW to $2.50/kW
Industrial Load Management	Load Reduction	**No Changes**
Commercial Demand Response	Price Responsive Load Management	**New** - Turn key program providing price incentives for demand reduction.
Commercial Cooling	Direct Expansion Air Conditioners	**Modified** - Increased participation to include units larger than 20 tons, increased
		incentive per btu from $25 to 30/ton
	PTAC Units	**New** - Will provide incentive per btu for energy efficiency room units (approx $30/ton)
Commercial Chillers	Air and Water Cooled Chillers	**New** - Will provide $100/ton for energy efficient chillers.
Commercial Lighting	Lighting Upgrades In Conditioned Spaces	**Modified** - Will increase incentive for energy efficient lighting from $100/kW to $150/kW
	Lighting Upgrades In Un-Conditioned Spaces	**New** - Will provide $150/kW incentive for energy efficient lighting.
Commercial Lighting Occupancy Sensors	Load Reduction Through Occupancy Sensors	**New** - Will provide $75/kW of lighting load controlled.
Standby Generator	Load Reduction through Emer. Generation	**Modified** - Will increase incentive $3.00/kW to $3.50/kW
Commercial Refrigeration	Anti-Condensate Heat Control	**New** - Will provide $135/kW for controls to reduce demand of refrigeration strip heaters.
Commercial Water Heating	Heat Recovery Units	**New** - Will provide $58/per ton incentive for waste heat recovery and heat pump water
	Heat Pump Water Heaters	heaters.
Conservation Value	Customer Specific Measures > 5 kW Average	**Modified** - Will increase incentive $200/kW to $250/kW
Cogeneration	On-Site Generation by existing Processes	**No Changes**
Renewable Energy Initiative	*Customer Purchases of Renewable Energy*	***No Changes***

Appendix C: Retail Customers by Customer Class

Tampa Electric Company
Retail Customers

	Residential	Commercial	Industrial	Other	Total
1997	456,175	56,981	628	4,583	518,367
1998	466,189	58,542	681	4,839	530,251
1999	477,533	60,089	740	5,299	543,660
2000	491,925	61,986	776	5,497	560,184
2001	505,964	63,316	850	5,650	575,780
2002	518,554	64,665	948	6,032	590,199
2003	531,257	66,041	1,204	6,398	604,901
2004	544,313	67,488	1,299	6,435	619,536
2005	558,601	69,027	1,337	6,656	635,621
2006	575,111	70,205	1,485	6,905	653,706
2007	589,307	71,900	1,441	7,002	669,650
2008	603,394	73,327	1,479	7,166	685,366
2009	617,561	74,753	1,532	7,332	701,178
2010	631,430	76,153	1,589	7,494	716,666
2011	645,029	77,530	1,647	7,653	731,859
2012	659,079	78,927	1,706	7,816	747,528
2013	673,981	80,367	1,768	7,989	764,104
2014	689,615	81,842	1,835	8,169	781,462
2015	705,667	83,335	1,907	8,354	799,264
2016	721,830	84,830	1,983	8,540	817,184
1997-2006	2.6%	2.3%	10.0%	4.7%	2.6%
2007-2016	2.3%	1.9%	3.6%	2.2%	2.2%

Appendix D: Retail Energy Sales by Customers

Tampa Electric Company
Retail Energy Sales
(GWH)

	Residential GWH	Commercial GWH	Industrial GWH	Other GWH	Total GWH
1997	6,500	4,902	2,465	1,223	15,090
1998	7,050	5,173	2,520	1,285	16,027
1999	6,967	5,337	2,223	1,278	15,805
2000	7,369	5,541	2,390	1,338	16,638
2001	7,594	5,685	2,329	1,368	16,976
2002	8,046	5,832	2,612	1,435	17,925
2003	8,265	5,843	2,579	1,538	18,230
2004	8,293	5,988	2,556	1,600	18,437
2005	8,558	6,233	2,478	1,642	18,911
2006	8,721	6,357	2,279	1,668	19,025
2007	9,277	6,619	2,323	1,753	19,972
2008	9,570	6,800	2,359	1,806	20,536
2009	9,881	6,993	2,394	1,862	21,130
2010	10,192	7,189	2,429	1,911	21,722
2011	10,505	7,389	2,461	1,958	22,313
2012	10,829	7,592	2,494	2,006	22,921
2013	11,174	7,812	2,525	2,057	23,568
2014	11,525	8,040	2,557	2,112	24,234
2015	11,871	8,270	2,589	2,169	24,900
2016	12,240	8,504	2,623	2,226	25,593
1997-2006	3.3%	2.9%	-0.9%	3.5%	2.6%
2007-2016	3.1%	2.8%	1.4%	2.7%	2.8%

Appendix E: Retail Peak Demand Forecast

Tampa Electric Company
Peak Demand
(MW)

	Total Winter Peak Demand MW	Total Summer Peak Demand MW	Firm Winter Peak Demand MW	Firm Summer Peak Demand[1] MW
1997	3118	3001	2719	2677
1998	2710	3266	2332	2945
1999	3409	3372	2990	3069
2000	3435	3303	3009	3028
2001	3801	3448	3407	3165
2002	3612	3634	3259	3318
2003	3881	3623	3455	3351
2004	3344	3737	2936	3445
2005	3686	3968	3287	3725
2006	3736	4010	3523	3769
2007	4364	4113	4046	3872
2008	4488	4229	4178	3991
2009	4615	4350	4308	4113
2010	4745	4472	4440	4235
2011	4872	4593	4568	4357
2012	5003	4719	4700	4484
2013	5141	4855	4839	4620
2014	5289	4998	4988	4765
2015	5444	5148	5143	4915
2016	5602	5300	5304	5068
1997-2006	2.0%	3.3%	2.9%	3.9%
2007-2016	2.8%	2.9%	3.1%	3.0%

[1] Firm summer peak is not coincident with the total summer peak demand.

Appendix F: Updated Demand and Energy Forecast – Retail Customers

Updated 2007 Forecast
Tampa Electric Company
Retail Customers

	Residential	Commercial	Industrial	Other	Total
1997	456,175	56,981	628	4,583	518,367
1998	466,189	58,542	681	4,839	530,251
1999	477,533	60,089	740	5,299	543,660
2000	491,925	61,986	776	5,497	560,184
2001	505,964	63,316	850	5,650	575,780
2002	518,554	64,665	948	6,032	590,199
2003	531,257	66,041	1,204	6,398	604,901
2004	544,313	67,488	1,299	6,435	619,536
2005	558,601	69,027	1,337	6,656	635,621
2006	575,111	70,205	1,485	6,905	653,706
2007	588,870	71,206	1,534	7,176	668,786
2008	603,130	72,730	1,507	7,338	684,705
2009	617,613	74,255	1,546	7,495	700,909
2010	631,760	75,762	1,591	7,646	716,759
2011	646,226	77,284	1,639	7,800	732,949
2012	661,399	78,873	1,687	7,960	749,919
2013	677,052	80,525	1,737	8,125	767,439
2014	692,827	82,202	1,792	8,291	785,112
2015	708,889	83,919	1,851	8,459	803,118
2016	725,023	85,634	1,914	8,627	821,198
1997-2006	2.6%	2.3%	10.0%	4.7%	2.6%
2007-2016	2.3%	2.1%	2.5%	2.1%	2.3%

Appendix G: Updated Demand and Energy Forecast – Retail Energy Sales

Updated 2007 Forecast
Tampa Electric Company
Retail Energy Sales
(GWH)

	Residential GWH	Commercial GWH	Industrial GWH	Other GWH	Total GWH
1997	6,500	4,902	2,466	1,223	15,090
1998	7,050	5,173	2,520	1,285	16,027
1999	6,967	5,336	2,223	1,278	15,805
2000	7,369	5,541	2,390	1,338	16,638
2001	7,594	5,685	2,329	1,368	16,976
2002	8,046	5,832	2,612	1,435	17,925
2003	8,265	5,848	2,579	1,538	18,230
2004	8,293	5,988	2,556	1,600	18,437
2005	8,558	6,233	2,478	1,642	18,911
2006	8,711	6,379	2,279	1,669	19,037
2007	9,085	6,614	2,414	1,724	19,837
2008	9,358	6,738	2,497	1,757	20,350
2009	9,630	6,936	2,537	1,805	20,908
2010	9,918	7,063	2,576	1,839	21,396
2011	10,196	7,226	2,613	1,875	21,909
2012	10,503	7,434	2,646	1,917	22,500
2013	10,777	7,658	2,679	1,963	23,077
2014	11,073	7,894	2,714	2,011	23,692
2015	11,394	8,066	2,753	2,050	24,264
2016	11,738	8,239	2,796	2,090	24,863
1997-2006	3.3%	3.0%	-0.9%	3.5%	2.6%
2007-2016	2.9%	2.5%	1.6%	2.2%	2.5%

Appendix H: Updated Demand and Energy Forecast – Peak Demand

Updated 2007 Forecast
Tampa Electric Company
Peak Demand
(MW)

	Total Winter Peak Demand MW	Total Summer Peak Demand MW	Firm Winter Peak Demand MW	Firm Summer Peak Demand[1] MW
1997	3,118	3,001	2,719	2,677
1998	2,710	3,266	2,332	2,945
1999	3,409	3,372	2,990	3,069
2000	3,435	3,303	3,009	3,028
2001	3,801	3,448	3,407	3,165
2002	3,612	3,634	3,259	3,318
2003	3,881	3,623	3,455	3,351
2004	3,344	3,737	2,936	3,445
2005	3,686	3,968	3,287	3,725
2006	3,736	4,010	3,523	3,769
2007	4,344	4,083	4,022	3,841
2008	4,457	4,213	4,130	3,963
2009	4,582	4,331	4,250	4,069
2010	4,708	4,448	4,370	4,179
2011	4,831	4,566	4,486	4,291
2012	4,962	4,696	4,610	4,415
2013	5,103	4,830	4,742	4,539
2014	5,246	4,969	4,876	4,670
2015	5,395	5,109	5,016	4,803
2016	5,543	5,252	5,159	4,942
1997-2006	2.0%	3.3%	2.9%	3.9%
2007-2016	2.7%	2.8%	2.8%	2.8%

[1] Firm summer peak is not coincident with the total summer peak demand.

Appendix I: Fuel Forecast Used in 2006 Economic Analysis

Year	Natural Gas Delivered ($/MMBtu)	Illinois Basin Coal ($/MMBtu)	Low Sulfur Foreign Coal ($/MMBtu)	Pet coke ($/MMBtu)
2006	7.91	2.80	3.11	1.41
2007	8.69	2.64	2.79	1.17
2008	8.11	2.65	2.24	1.09
2009	7.27	2.73	2.68	1.12
2010	6.43	2.80	2.92	1.29
2011	6.41	2.90	2.87	1.45
2012	6.54	2.99	2.95	1.39
2013	6.74	3.04	3.11	1.33
2014	6.97	3.15	3.13	1.25
2015	7.28	3.23	3.25	1.39
2016	7.89	3.33	3.31	1.57
2017	8.52	3.45	3.44	1.81
2018	9.03	3.57	3.61	1.68
2019	9.72	3.69	3.77	1.59
2020	10.24	3.86	3.97	1.87
2021	10.68	4.05	4.18	2.11
2022	11.14	4.22	4.41	2.04
2023	11.62	4.46	4.70	1.96
2024	12.12	4.76	4.95	1.87
2025	12.64	4.96	5.10	2.07
2026	13.19	5.18	5.34	2.31
2027	13.75	5.40	5.59	2.62
2028	14.34	5.63	5.85	2.45
2029	14.96	5.88	6.12	2.34
2030	15.60	6.13	6.40	2.72
2031	16.26	6.40	6.70	3.04
2032	16.97	6.68	7.02	2.97
2033	17.70	6.98	7.34	2.88
2034	18.45	7.28	7.69	2.77
2035	19.24	7.60	8.05	3.04
2036	20.07	7.94	8.42	3.37

Appendix J: Fuel Forecast Used in 2007 Economic Analysis

Year	Natural Gas Delivered ($/MMBtu)	Illinois Basin Coal ($/MMBtu)	Low Sulfur Foreign Coal ($/MMBtu)	Pet coke ($/MMBtu)
2007	8.20	2.58	2.33	2.55
2008	8.70	2.64	2.28	2.00
2009	8.39	2.73	2.20	2.19
2010	8.19	2.80	2.30	2.04
2011	7.69	2.93	2.26	2.09
2012	7.72	3.00	2.33	2.18
2013	7.95	3.06	2.45	2.23
2014	8.30	3.16	2.44	2.23
2015	8.75	3.25	2.49	2.31
2016	8.99	3.34	2.53	2.37
2017	9.23	3.46	2.64	2.50
2018	9.47	3.58	2.78	2.60
2019	9.92	3.71	2.90	2.70
2020	10.38	3.86	3.02	2.79
2021	10.74	4.02	3.18	2.91
2022	11.11	4.20	3.36	3.08
2023	11.50	4.42	3.60	3.19
2024	11.92	4.71	3.82	3.31
2025	12.35	4.87	3.85	3.43
2026	12.79	5.04	3.97	3.54
2027	13.25	5.21	4.13	3.69
2028	13.72	5.39	4.26	3.81
2029	14.20	5.58	4.40	3.93
2030	14.70	5.78	4.53	4.06
2031	15.22	5.98	4.68	4.19
2032	15.77	6.19	4.88	4.37
2033	16.33	6.40	5.03	4.51
2034	16.91	6.63	5.18	4.66
2035	17.51	6.86	5.35	4.81
2036	18.13	7.10	5.51	4.96
2037	18.77	7.35	5.75	5.18

Appendix K: Low Fuel Forecast Used in Scenario Analysis

Year	Natural Gas Delivered ($/MMBtu)	Illinois Basin Coal ($/MMBtu)	Low Sulfur Foreign Coal ($/MMBtu)	Pet coke ($/MMBtu)
2007	4.19	2.58	2.33	2.56
2008	4.44	2.50	2.10	1.81
2009	4.28	2.58	2.06	1.98
2010	4.18	2.65	2.13	2.05
2011	3.93	2.76	2.11	2.08
2012	3.94	2.83	2.16	2.17
2013	4.06	2.89	2.27	2.22
2014	4.24	2.98	2.26	2.23
2015	4.47	3.07	2.31	2.30
2016	4.59	3.18	2.35	2.36
2017	4.71	3.30	2.47	2.50
2018	4.83	3.43	2.59	2.60
2019	5.06	3.57	2.71	2.69
2020	5.30	3.73	2.82	2.79
2021	5.48	3.88	2.96	2.90
2022	5.67	4.05	3.12	3.07
2023	5.87	4.25	3.32	3.17
2024	6.08	4.50	3.51	3.28
2025	6.30	4.66	3.54	3.39
2026	6.53	4.83	3.64	3.49
2027	6.76	5.00	3.80	3.65
2028	7.00	5.18	3.91	3.76
2029	7.25	5.36	4.03	3.87
2030	7.50	5.55	4.15	3.99
2031	7.77	5.75	4.27	4.11
2032	8.05	5.96	4.45	4.30
2033	8.33	6.17	4.59	4.43
2034	8.63	6.39	4.72	4.56
2035	8.94	6.62	4.86	4.70
2036	9.25	6.86	5.01	4.84
2037	9.58	7.10	5.22	5.06

Appendix L: High Fuel Forecast Used in Scenario Analysis

Year	Natural Gas Delivered ($/MMBtu)	Illinois Basin Coal ($/MMBtu)	Low Sulfur Foreign Coal ($/MMBtu)	Pet coke ($/MMBtu)
2007	11.64	2.58	2.33	2.56
2008	12.35	3.02	2.70	2.31
2009	11.91	3.13	2.61	2.53
2010	11.63	3.21	2.72	2.62
2011	10.92	3.36	2.67	2.68
2012	10.96	3.45	2.73	2.79
2013	11.29	3.51	2.88	2.85
2014	11.78	3.62	2.87	2.85
2015	12.43	3.73	2.92	2.95
2016	12.77	3.85	2.97	3.02
2017	13.10	3.99	3.11	3.19
2018	13.44	4.15	3.27	3.33
2019	14.08	4.31	3.42	3.45
2020	14.73	4.49	3.56	3.58
2021	15.24	4.69	3.76	3.73
2022	15.78	4.90	3.96	3.94
2023	16.33	5.16	4.25	4.08
2024	16.92	5.50	4.50	4.22
2025	17.53	5.70	4.53	4.37
2026	18.16	5.90	4.67	4.51
2027	18.81	6.11	4.86	4.70
2028	19.48	6.33	5.01	4.85
2029	20.17	6.56	5.17	5.00
2030	20.87	6.79	5.33	5.16
2031	21.61	7.04	5.50	5.32
2032	22.39	7.29	5.72	5.55
2033	23.19	7.55	5.90	5.73
2034	24.01	7.82	6.09	5.91
2035	24.86	8.11	6.28	6.09
2036	25.74	8.40	6.47	6.28
2037	26.65	8.70	6.74	6.56

Appendix M: Blended Fuel Forecast Used in Final Economic Analysis

Year	Natural Gas Delivered ($/MMBtu)	SCPC Blended Fuel ($/MMBtu)	IGCC Blended Fuel ($/MMBtu)
2007	8.20	2.48	2.38
2008	8.70	2.35	2.21
2009	8.39	2.40	2.20
2010	8.19	2.43	2.24
2011	7.69	2.48	2.22
2012	7.72	2.55	2.29
2013	7.95	2.64	2.40
2014	8.30	2.67	2.39
2015	8.75	2.74	2.45
2016	8.99	2.80	2.49
2017	9.23	2.92	2.61
2018	9.47	3.05	2.63
2019	9.92	3.17	2.73
2020	10.38	3.29	2.83
2021	10.74	3.44	2.96
2022	11.11	3.62	3.13
2023	11.50	3.82	3.26
2024	11.92	4.04	3.40
2025	12.35	4.14	3.50
2026	12.79	4.28	3.61
2027	13.25	4.45	3.77
2028	13.72	4.59	3.89
2029	14.20	4.74	4.01
2030	14.70	4.42	4.14
2031	15.22	4.56	4.27
2032	15.77	4.76	4.46
2033	16.33	4.91	4.60
2034	16.91	5.06	4.75
2035	17.51	5.22	4.90
2036	18.13	5.38	5.06
2037	18.77	5.61	5.27

Final Reliability Analysis

Minimum Capacity Needed to Maintain Summer 20% Reserve Margin

Year	Total Installed Capacity MW	Incremental Capacity for 20% Res Margin MW	Firm Capacity Import MW	QF MW	Total Capacity Available MW	Retail Firm Summer Peak Demand MW	Whls Firm Summer Peak Demand MW	System Firm Summer Peak Demand MW	Reserve Margin MW	Reserve Margin % of Peak
2008	4,255	134	526	64	4,979	3,963	186	4,149	830	20%
2009	4,379	125	526	64	5,093	4,069	176	4,244	849	20%
2010	4,509	151	526	40	5,226	4,179	175	4,355	871	20%
2011	4,664	222	356	32	5,274	4,291	104	4,395	879	20%
2012	4,886	157	356	23	5,422	4,415	104	4,519	904	20%
2013	5,048	482	0	23	5,553	4,539	89	4,627	925	20%
2014	5,530	143	0	23	5,696	4,670	77	4,747	949	20%
2015	5,570	263	0	23	5,856	4,803	77	4,880	976	20%
2016	5,833	189	0	0	6,022	4,942	77	5,018	1,004	20%

Final Reliability Analysis

Minimum Capacity Needed to Maintain Winter 20% Reserve Margin

Year	Total Installed Capacity MW	Incremental Capacity for 20% Res Margin MW	Firm Capacity Import MW	QF MW	Total Capacity Available MW	Retail Firm Winter Peak Demand MW	Whls Firm Winter Peak Demand MW	System Firm Winter Peak Demand MW	Reserve Margin MW	Reserve Margin % of Peak
2007-08	4,650	0	611	64	5,325	4,130	188	4,318	1,006	23%
2008-09	4,610	42	611	64	5,326	4,250	188	4,438	888	20%
2009-10	4,662	119	611	64	5,455	4,370	176	4,546	909	20%
2010-11	4,785	166	611	32	5,594	4,486	176	4,662	932	20%
2011-12	4,951	242	441	23	5,657	4,610	104	4,714	943	20%
2012-13	5,198	576	0	23	5,797	4,742	89	4,831	966	20%
2013-14	5,774	146	0	23	5,944	4,876	77	4,953	991	20%
2014-15	5,786	302	0	23	6,112	5,016	77	5,093	1,019	20%
2015-16	6,089	194	0	0	6,283	5,159	77	5,236	1,047	20%

Appendix O: Technology Assumptions

Screening Data

Category	Units	AFBC	IGCC	SCPC	NGCC	LM6000	7FA	LMS100
Overnight Cost	($)	699,559,085	874,514,757	772,228,306	279,552,445	27,984,000	53,069,237	41,710,000
Installed Cost (Net)	($/KW)	1,730	1,498	1,381	557	596	295	430
Fixed O&M	($/KW)	26.65	37.79	24.05	4.18	8.66	2.50	3.61
Variable O&M	($/MWH)	2.91	2.42	1.73	1.87	2.65	9.00	3.18
Capacity Gross	(KW)	450,000	662,000	600,000	509,600	49,367	182,000	100,000
Capacity Net	(KW)	404,430	583,781	559,129	501,970	46,967	180,000	97,000
Heat Rate (Net)	(BTU/KWH HHV,MDC)	9,584	8,800	8,982	6,850	9,736	10,500	8,000

Fuel	Units	AFBC	IGCC	SCPC	NGCC	LM6000	7FA	LMS100
Natural Gas	(%)	0	0	0	100	100	100	100
Low Sulfur Foreign Coal	(%)	0	20	0	0	0	0	0
Illinois Basin Coal	(%)	15	0	85	0	0	0	0
Pet Coke	(%)	85	80	15	0	0	0	0

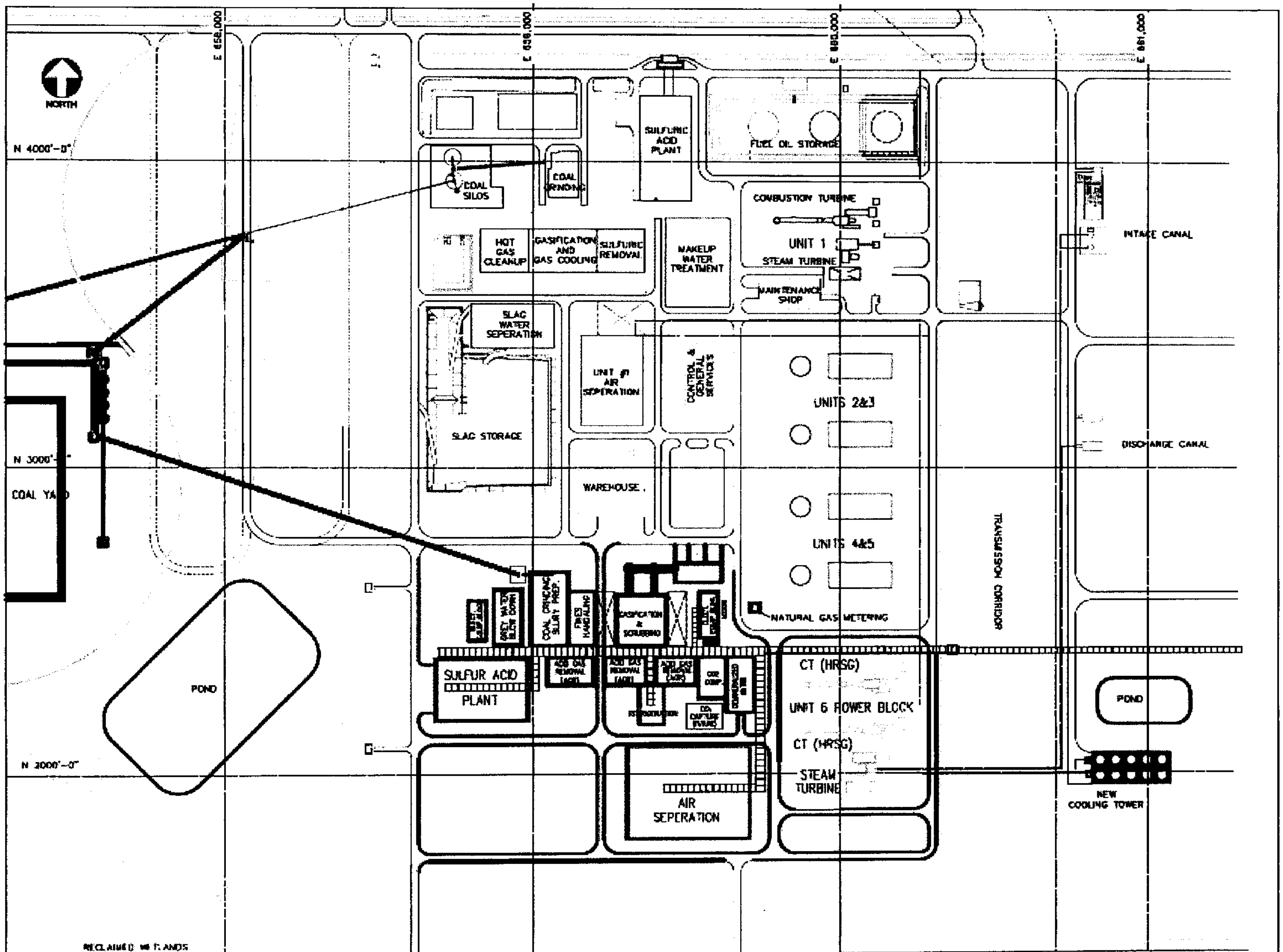
Final Analysis Data

Category	Units	IGCC	SCPC	NGCC
Overnight Cost	($)	1,875,565,000	1,542,937,035	458,177,592
Installed Cost (Net)	($/KW)	2,899	2,509	913
Fixed O&M	($/KW)	30.9	25.9	6.6
Variable O&M	($/MWH)	1.15	1.86	2.84
Capacity Gross	(KW)			
Capacity Net	(KW)	646,900	615,000	502,000
Heat Rate (Net)	(BTU/KWH HHV,MDC)	9,111	9,431	7,400

Fuel	Units	IGCC	SCPC	NGCC
Natural Gas	(%)	0	0	100
Low Sulfur Foreign Coal	(%)	20	40	0
Illinois Basin Coal	(%)	0	40	0
Pet Coke	(%)	80	20	0

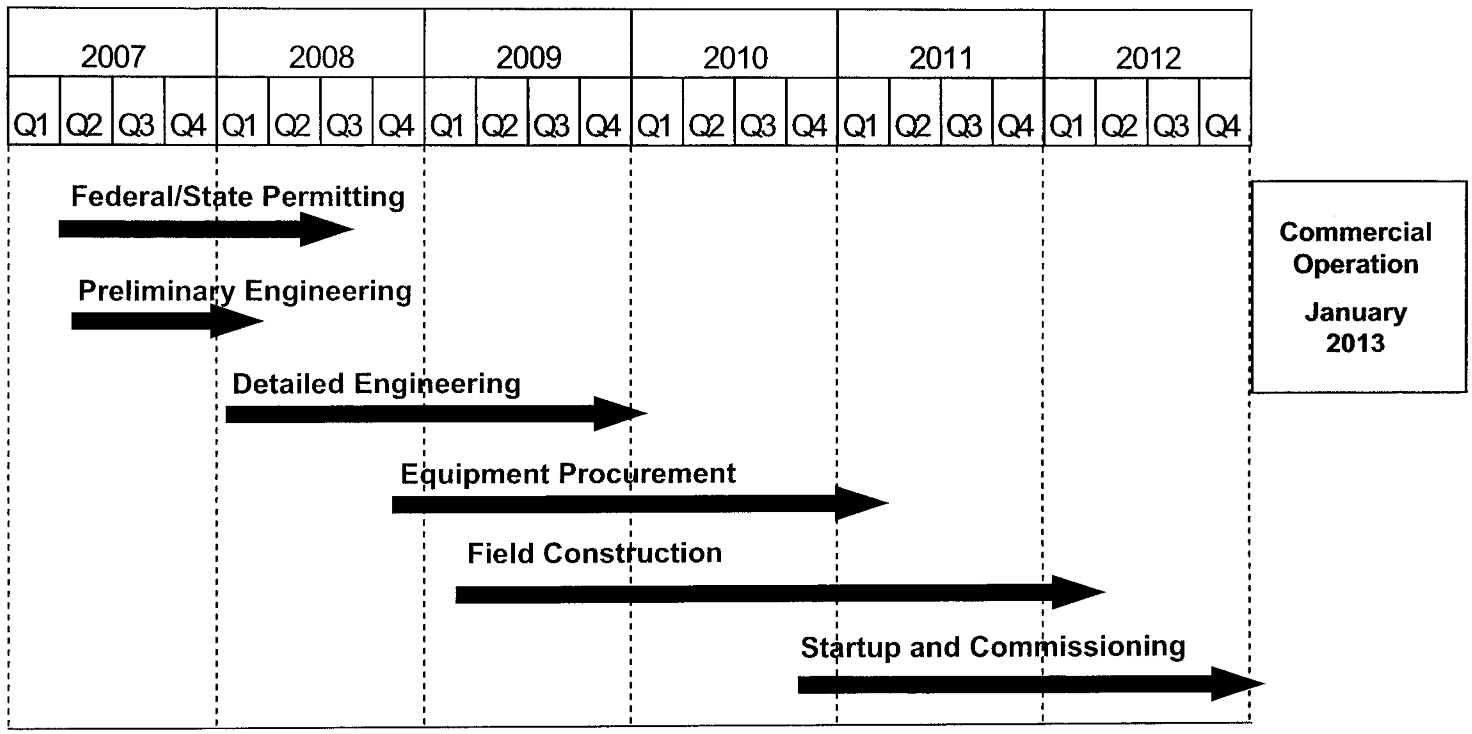
Appendix P: Carbon Dioxide (CO_2) ($ per Ton)

	Low Band	Medium Band	High Band
2007	$ -	$ -	$ -
2008	$ -	$ -	$ -
2009	$ -	$ -	$ -
2010	$ 5.00	$ 15.00	$ 30.00
2011	$ 5.25	$ 15.75	$ 31.50
2012	$ 5.51	$ 16.54	$ 33.08
2013	$ 5.79	$ 17.36	$ 34.73
2014	$ 6.08	$ 18.23	$ 36.47
2015	$ 6.38	$ 19.14	$ 38.29
2016	$ 6.70	$ 20.10	$ 40.20
2017	$ 7.04	$ 21.11	$ 42.21
2018	$ 7.39	$ 22.16	$ 44.32
2019	$ 7.76	$ 23.27	$ 46.54
2020	$ 8.14	$ 24.43	$ 48.87
2021	$ 8.55	$ 25.66	$ 51.31
2022	$ 8.98	$ 26.94	$ 53.88
2023	$ 9.43	$ 28.28	$ 56.57
2024	$ 9.90	$ 29.70	$ 59.40
2025	$ 10.39	$ 31.18	$ 62.37
2026	$ 10.91	$ 32.74	$ 65.49
2027	$ 11.46	$ 34.38	$ 68.76
2028	$ 12.03	$ 36.10	$ 72.20
2029	$ 12.63	$ 37.90	$ 75.81
2030	$ 13.27	$ 39.80	$ 79.60
2031	$ 13.93	$ 41.79	$ 83.58
2032	$ 14.63	$ 43.88	$ 87.76
2033	$ 15.36	$ 46.07	$ 92.15
2034	$ 16.13	$ 48.38	$ 96.75
2035	$ 16.93	$ 50.80	$ 101.59
2036	$ 17.78	$ 53.34	$ 106.67



PROPOSED PLOT PLAN OF POLK UNIT 6

Polk Unit 6 Project Execution Plan



Appendix S: Polk Unit 6 Environmental Permit Requirements

Permit	Review/ Approval Agencies	Status/Comments
• Florida Electrical Power Plant Siting Act (PPSA)	FDEP/Affected Agencies/Siting Board	Supplemental site certification application submitted and approved prior to commencing construction of proposed electrical generation and associated facilities.
o PSD air construction permit	FDEP	The PSD permit application will be reviewed concurrently with the supplemental site certification application process. Separate PSD permit issued 30 to 45 days after issuance of certification by Siting Board (new procedures could modify this step).
o NPDES industrial wastewater treatment permit	FDEP	The existing NPDES permit will be reviewed concurrently with the supplemental site certification application process. Separate NPDES permit issued 30 to 40 days after issuance of certification by Siting Board (new procedures could modify this step).
• Ground water discharge permit	FDEP	The existing permit will be will be reviewed and any modifications approved as part of the supplemental site certification application process.
• Consumptive water use permit	SWFWMD	The existing permit will be will be reviewed and any modifications approved as part of the supplemental site certification application process.
o Section 404 dredge-and-fill permit	USACE/ FDEP	Will be reviewed concurrently with the supplemental site certification application process. Separate permit issued 30 to 45 days after issuance of certification.
o Section 10 permit	USACE	Will be reviewed concurrently with the supplemental site certification application process. Separate permit issued 30 to 45 days after issuance of certification.
o Endangered/threatened species review	USFWS/ FFWCC	Will be reviewed and approved as part of the supplemental site certification application and Section 404 processes.

Permit	Review/ Approval Agencies	Status/Comments
• Section 401 water quality certification	FDEP	Will be reviewed and approved as part of the supplemental site certification application process.
• Environmental resource permit/storm water management	FDEP	Will be reviewed and approved as part of the supplemental site certification application process.
• Water well construction permit	FDEP	Will be reviewed and approved as part of the supplemental site certification application process.
• Non-transient, non-community water system permit	FDEP	The existing permit will be will be reviewed and any modifications approved as part of the supplemental site certification application process.
• Domestic septic system permit	Polk County	The existing permit will be will be reviewed and any modifications approved as part of the supplemental site certification application process.
• NPDES storm water permit NOI associated with industrial activity	FDEP	The existing permit will be will be reviewed and any modifications approved as part of the supplemental site certification application process.
• Solid waste management facilities permit	FDEP	Will be reviewed and approved as part of the supplemental site certification application process.
Determination of need	FPSC	Needed for new electrical generating facilities subject to PPSA. Required within 150 days after site certification application filed.
○ NPDES general permit NOI for storm water for construction sites	EPA	Will be submitted prior to start of construction
✦ Phase II Title IV acid rain permit	FDEP/EPA	The existing permit will be modified to add the Project. Application required 24 months prior to start of operations.

Permit	Review/ Approval Agencies	Status/Comments
✦ Title V air emissions operation permit	FDEP	The existing permit will be modified to add the Project. Application required 24 months prior to start of operations.
• Construction dewatering permit	SWFWMD	Required for temporary dewatering activities for construction
✦ Hazardous waste generator registration	EPA/ FDEP	Existing registration, no additional approvals necessary
Notice of construction in navigable aerospace	FAA	Construction of tall exhaust stacks.
✦ Aboveground storage tank (AST) registration	FDEP	Needed for ASTs for petroleum products.
✦ Spill prevention, control, and countermeasure plan	EPA	Existing SPCC plan will be modified as needed.
✦ Facility response plan	EPA/FDEP	Existing FRP will be modified as needed.
• Zoning/local comprehensive plan	Polk County	Already consistent with zoning for Power Plant use.

- • Reviewed and approved as part of the PPSA process; required prior to start of construction.
- ○ Reviewed concurrently with the PPSA process with separate permit issued 30 to 45 days after issuance of certification by Siting Board; required prior to start of construction.
- ✦ Not required prior to start of construction.

Note: EPA = U.S. Environmental Protection Agency.

FAA = Federal Aviation Administration.

FDEP	=	Florida Department of Environmental Protection.
FFWCC	=	Florida Fish and Wildlife Conservation Commission.
FPSC	=	Florida Public Service Commission.
USACE	=	U.S. Army Corps of Engineers
SWFWMD	=	Southwest Florida Water Management District.