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COMMISSION CLERK

HEARING EXHIBITS FOR THE HEARING HELD on December 12, 2012, in DOCKET No. 120234-EI

Comprehensive Exhibit List for Entry into Hearing Record

Hearing I.D. #	Witness	I.D. # As Filed	Exhibit Description	Entered
STAFF – EXHIBITS				
1	TECO	Exhibit List	Comprehensive Exhibit List	
2	TECO	Staff's Exhibit #2	TECO's Answer to First Set of Interrogatories (Nos. 1-12) of the Florida Public Service Commission *[Bates Nos. 00001-00022]*	**Stipulated**
3	TECO	Staff's Exhibit #3	TECO's Answer to Second Set of Interrogatories (Nos. 13-49, 50 (redacted), 51-60) of the Florida Public Service Commission *[Bates Nos. 00023-00118]* TECO's Answer to Second Set of Interrogatories (No. 50) of the Florida Public Service Commission -**[Confidential FPSC Document No. 07526-12]** *[Bates No. 00119]*	**Stipulated**
4	TECO	Staff's Exhibit #4	TECO's Answer to Third Set of Interrogatories (Nos. 61-68) of the Florida Public Service Commission *[Bates Nos. 00120-00132]*	**Stipulated**

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FPSC-COMMISSION CLERK

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 120234-EI EXHIBIT 1
PARTY Florida Public Service Commission Staff
DESCRIPTION Comprehensive Exhibit List

5	TECO	Staff's Exhibit #5	TECO's Answer to Fourth Set of Interrogatories (Nos. 69-97, 98 (redacted), 99-101) of the Florida Public Service Commission *[Bates Nos. 00133-00182]* TECO's Answer to Fourth Set of Interrogatories (No. 98) of the Florida Public Service Commission -**[Confidential FPSC Document No. 07840-12]** *[Bates No. 00183]*	**Stipulated**
6	TECO	Staff's Exhibit #6	TECO's Answer to Fifth Set of Interrogatories (Nos. 102-105) of the Florida Public Service Commission *[Bates Nos. 00184-00192]*	**Stipulated**
7	TECO	Staff's Exhibit #7	TECO's Answer to First Request for Production of Documents (Nos. 1 *(Bates Stamped Pages (BSP) 4-6)*, 5, 6 (*BSP 2653-2661* redacted), 10 (*BSP 2840-2919*) of the Florida Public Service Commission *[Bates Nos. 00193-00308]* TECO's Answer to First Request for Production of Documents (No. 6 *BSP 2654, 2656, 2658, 2661*) of the Florida Public Service Commission -**[Confidential FPSC Document No. 07114-12]** *[Bates No. 00309]*	**Stipulated**
8	TECO	Staff's Exhibit #8	TECO's Answer to Second Request for Production of Documents (Nos. 19, 20 (NON-CONFIDENTIAL_Source Docs/Non-confidential Early 2012 NG Supply Disposition.pdf -**FPSC Document No. 07212-12**), 22, 23, 24, 25 (*BSP 991-995*) of the	**Stipulated**

			Florida Public Service Commission *[Bates Nos. 00310-00339]* TECO's Answer to Second Request for Production of Documents (No. 20) (CONFIDENTIAL – Work papers /Confidential_2012 GFI NG Base Model Master.xlsx, worksheet entitled "Inputs") of the Florida Public Service Commission -**[Confidential FPSC Document No. 07212-12]** *[Bates No. 00340]*	
9	TECO	Staff's Exhibit #9	TECO's Answer to Third Request for Production of Documents (No. 26) of the Florida Public Service Commission *[Bates Nos. 00341-00344]*	**Stipulated**
10	TECO	Staff's Exhibit #10	TECO's Answer to Fourth Request for Production of Documents (Nos. 27, 28 (redacted), 29 (*BSP 105-108*) of the Florida Public Service Commission *[Bates Nos. 00345-00355]* TECO's Answer to Fourth Request for Production of Documents (No. 28) of the Florida Public Service Commission -**[Confidential FPSC Document No. 07840-12]** *[Bates No. 00356]*	**Stipulated**

TAMPA ELECTRIC COMPANY (TECO) - (DIRECT)				
11	Mark J. Hornick Lorraine L. Cifuentes Howard T. Bryant J. Brent Caldwell David M Lukcic S. Beth Young R. James Rocha		Tampa Electric Company's Determination of Need for Electrical Power: Polk 2-5 Combined Cycle Conversion, filed on September 12, 2012. [FPSC Document No. 06137-12].	
12	Mark J. Hornick	MJH-1	Polk site aerial photograph, process diagram, project schedule and cost estimate	
13	Lorraine L. Cifuentes	LLC-1	Data supporting Tampa Electric's load forecasting process, methodologies and assumptions and load forecasts	
14	Howard T. Bryant	HTB-1	DSM programs and goals and 2010-2019 DSM goals accomplishments	
15	J. Brent Caldwell	JBC-1	Fuel price forecast and fuel price forecast range compared to independent forecasts	
16	S. Beth Young	SBY-1	Polk 2-5 interconnection and integration diagrams; summary of required facilities, ratings and costs and FRCC letter confirming the reliability of the interconnection and integration plan	
17	R. James Rocha	RJR-1	Energy and capacity mix by fuel type, levelized cost screening curves, Tampa Electric and FRCC reliability analyses and sensitivities, planning analyses and supporting documentation, RFP supporting documents, and June 2012 assumptions update	
18	Alan S. Taylor	AST-1	Resume of Alan Taylor and Sedway Consulting's independent evaluation report	
19		TECO	Notice of Hearing & Affidavit of Publication The Ledger, Lakeland, Polk County, Florida.	

20		TECO	Tampa Electric Company's 2017 Power Generation Request for Proposals, dated March 23, 2012.	
21	Hornick/Rocha	DeSoto Generating Co.	Excerpt from Tampa Electric's 2011 FERC Form 1	
22	Hornick/Rocha	DeSoto Generating Co.	Tampa Electric Discount Rate Calculation and Escalation and Escalation Rates – Staff's POD No. 19, BSP 971, 972, 975	
23	Hornick/Rocha	DeSoto Generating Co.	Tampa Electric COG-2 Tariff Sheets 8, 406-8,.424, Effective June 19, 2012	
24	Hornick/Rocha	DeSoto Generating Co.	Excerpt from FPL, 2012 Ten Year Site Plan, Future Combined Cycle /costs, Canaveral, Rivera, and Port Everglades Project	
25	Hornick/Rocha	DeSoto Generating Co.	Excerpts from Tampa Electric 2012 Ten-Year Site Plan	
26	Caldwell	DeSoto Generating Co.	Tampa Electric's Responses to Staff's POD Requests 22, 23, and 24	
27	Caldwell	DeSoto Generating Co.	12/6/2012 Download of 2013 - 2035 NYMEX Henry Hub Natural Gas Price	
28	Caldwell	DeSoto Generating Co.	Table A3, Energy Prices by Sector and Source, U.S. Energy Information Administration, Annual Energy Outlook 2013	
29	Rocha	DeSoto Generating Co.	TECO Need Study, Table 13 and TECO's Answers to Staff's Int. No. 38, (10/23/2012) and Revised (11/27/2012)	

2

TECO's Answer to First Set Of Interrogatories (Nos. 1-12) of the Florida Public Service Commission

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 120234-EI EXHIBIT 2
PARTY Florida Public Service Commission Staff
DESCRIPTION TECO - Staff Exhibit #2
[Bates Nos. 00001-00022]

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition to determine need for Polk 2-5 combined cycle conversion, by Tampa Electric Company	DOCKET NO. 120234-EI FILED: October 18, 2012

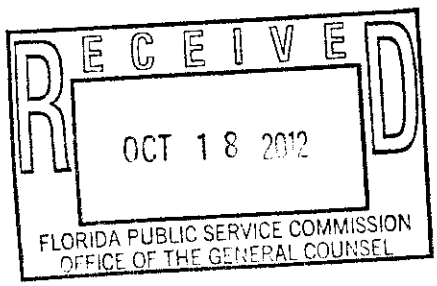
TAMPA ELECTRIC COMPANY'S

ANSWERS TO FIRST SET OF INTERROGATORIES (NOS. 1-12)

OF THE

FLORIDA PUBLIC SERVICE COMMISSION

Tampa Electric files its Answers to Interrogatories (Nos. 1-12) propounded and served on September 28, 2012, by the Florida Public Service Commission.



TAMPA ELECTRIC COMPANY
DOCKET NO. 120234-EI
INDEX TO STAFF'S FIRST SET OF INTERROGATORIES (NOS. 1 – 12)

Number	Witness	Subject	Bates Stamped Page
1	Cifuentes	Why did TECO prepare its per customer energy consumption (kWh/Customer) forecast appearing in witness Cifuentes' direct testimony, Document No. 4 rather than relying upon a per customer energy consumption forecast calculated by dividing TECO's "Total Sales to Ultimate Customers" forecast by "Total Customers" forecast appearing in Schedules 2.2 and 2.3, respectively, of TECO's 2012 Ten Year Site Plan?	1
2	Cifuentes	How did TECO determine the number of "service area households" as referenced in witness Cifuentes'direct testimony, page 4, lines 22-25.	2
3	Cifuentes	When was the load forecast appearing in witness Cifuentes' direct testimony prepared?	3
4	Cifuentes	When was TECO's load forecast appearing in witness Cifuentes' direct testimony approved by TECO executive management and what was the review process?	4
5	Cifuentes	What are the dates and sources of each input data series and assumptions (including projected data) used in the load forecast econometric models, SAE models, and forecasts referenced in witness Cifuentes' direct testimony?	5
6	Cifuentes	What are the energy and demand impacts, dates, and reasons associated with the loss of phosphate load referenced on page 15 of witness Cifuentes's direct testimony at page 15, lines 14-17?	8
7	Cifuentes	Why has TECO's per customer energy consumption and per customer peak demand been declining from 2002 to 2011 and why are those trends expected to continue through the forecast horizon as shown in witness Cifuentes' direct testimony, Documents No. 4 and 6?	9
8	Cifuentes	Which weather station was used to determine 20-year historical weather as referenced in witness Cifuentes' direct testimony, Document No. 2, and how was this weather station selected as representative for the TECO service area?	11
9	Cifuentes	What is the accuracy, stated in percent error terms, of TECO's 2004 through 2006 TYSPs' load forecasts, including Total Customers (Schedule 2.3), Total Sales to Ultimate Customers (Schedule 2.2), and Summer and Winter Peak Demand (Schedules 3.1 and 3.2), for Forecast Year 6 (example: 2006 TYSP forecast of 2011 total customers compared to actual 2011 total customers)?	12
10	Cifuentes	For any percentage forecast error greater than 5 percent identified in TECO's response to Interrogatory No. 9,	13

Number	Witness	Subject	Bates Stamped Page
		above, what are the primary reasons for such error?	
11	Cifuentes	How has TECO's forecasting methods and major assumptions used in developing the 2012 through 2021 load forecasts in Chapter III of TECO's 2012 Ten Year Site Plan changed in the development of TECO's 2012 annual forecast process completed in June 2012, as referenced in witness Cifuentes' direct testimony at page 13, Lines 17-23?	15
12	Cifuentes	If no documents requested in Staff's 1st Request for Production of Documents No. 9 are available, what are the rationale, assumptions, and methods by which the Company integrates its econometric models with statistically adjusted engineering (SAE) models as referenced in witness Cifuentes' direct testimony on page 3, lines 19-22?	17

Lorraine L. Cifuentes
Manager, Load Research and Forecasting

Tampa Electric Company
702 N. Franklin Street
Tampa, FL 33602

1. Why did TECO prepare its per customer energy consumption (kWh/Customer) forecast appearing in witness Cifuentes' direct testimony, Document No. 4 rather than relying upon a per customer energy consumption forecast calculated by dividing TECO's "Total Sales to Ultimate Customers" forecast by "Total Customers" forecast appearing in Schedules 2.2 and 2.3, respectively, of TECO's 2012 Ten Year Site Plan?

A. Tampa Electric utilizes a bottom-up approach to forecasting by preparing per customer energy consumption (kWh/customer) models for its customer classes to capture the differences in weather sensitivity and incorporate changes in energy efficiency improvements by customer class. The average usage models are then used along with the customer models to arrive at total sales for each class. The company's approach is superior to a per customer energy consumption forecast calculated by dividing "Total Sales to Ultimate Customers" forecast by "Total Customers" forecast appearing in Schedules 2.2 and 2.3, respectively, of Tampa Electric's 2012 Ten Year Site Plan, because a total sales model would not be able to reflect changes in average use trends at a customer class level.

2. How did TECO determine the number of "service area households" as referenced in witness Cifuentes' direct testimony, page 4, lines 22-25.

A. "Service area households" as referenced in witness Cifuentes's testimony means the count of residential customers within Tampa Electric's service territory. Once the residential customer forecast is created, it becomes an input to the commercial customer model. The service area households variable is lagged by a year to reflect the trend of new households resulting in a need for additional services, restaurants, and retail establishments in a delayed time frame.

3. When was the load forecast appearing in witness Cifuentes' direct testimony prepared?

A. Tampa Electric's base case long-term load forecasts appearing in witness Cifuentes's testimony were prepared between April and June 2011. The most recent long-term load forecasts were prepared during May and July 2012.

4. When was TECO's load forecast appearing in witness Cifuentes' direct testimony approved by TECO executive management and what was the review process?

A. The base case long-term load forecast review process consisted of a review within the Load Forecasting section, followed by several meetings with Load Forecasting, Regulatory Affairs management and the President of Tampa Electric. Another forecast review meeting was held with Tampa Electric executive management, and the long-term forecasts were approved by Tampa Electric executive management on June 16, 2011.

The most recent forecast review process consisted of an initial review of industry trends and Tampa Electric's forecast methodology by ITRON Corporation, an industry leader in forecasting solutions, which was presented to Tampa Electric executive management on June 6, 2012. As a result of ITRON's review and recommendations, Tampa Electric incorporated minor changes to the company's June 2012 models. The forecasts were reviewed within the Load Forecasting section. Tampa Electric executive management also reviewed the long-term forecasts. The final long-term forecasts were presented to and approved by Tampa Electric executive management on July 18, 2012.

120234 Hearing Exhibits 00008

5. What are the dates and sources of each input data series and assumptions (including projected data) used in the load forecast econometric models, SAE models, and forecasts referenced in witness Cifuentes' direct testimony?

A. The dates and sources of each input data series and assumptions (including projected data) used in the load forecast econometric models, SAE models, and forecasts referenced in witness Cifuentes's direct testimony are shown in the following tables.

Input Data Series: Forecast Prepared Summer 2011	Dates	Sources
Economic Actual and Assumptions	Jan 2001 forward	Moody's Analytics – April 2011 delivery
Population Actual and Assumptions	Jan 2001 forward	Moody's Analytics – April 2011 delivery University of Florida's Bureau of Economic and Business Research (BEBR) – February 2011 projections
Actual Customers and Sales by Customer Class	Jan 2001 – Apr 2011	Tampa Electric
Normal Billing Days	May 2011 forward	Tampa Electric
Actual Hourly Temperatures	Jan 1998-Mar 2011	NOAA's Tampa International Airport ("TIA") weather station
Normal Hourly Temperatures	Apr 2011 forward	Tampa Electric
Actual Calculated Degree Days	Jan 2001-Apr 2011	Tampa Electric calculates based on NOAA's TIA weather station temperatures
Normal Degree Days	May 2011 forward	Tampa Electric
Actual Retail Net Energy for Load and Actual Retail Peak Data	Jan 1998-Mar 2011	Tampa Electric
Normal Peak Weather	April 2011 forward	Tampa Electric
Forecasted Retail Net Energy for Load	Apr 2011 forward	Tampa Electric's MetrixND model output
Actual Phosphate and all other Interruptible Sales	Jan 2001 – Apr 2011	Tampa Electric
Phosphate and all other Interruptible Sales Projections	May 2011 forward	Tampa Electric
Price of Electricity (Actual & Projected)	Jan 2001 forward	Tampa Electric
Commercial appliance saturation and energy efficiency	Jan 2001 forward	Prepared by Tampa Electric incorporating assumptions from Energy Information Administration ("EIA")
Residential appliance saturation and energy efficiency	Jan 2001 forward	Prepared by Tampa Electric incorporating assumptions from EIA

Input Data Series: Forecast Prepared Summer 2012	Dates	Sources
Economic Actual and Assumptions	Jan 2002 forward	Moody's Analytics – March 2012 delivery
Population Actual and Assumptions	Jan 2002 forward	Moody's Analytics – March 2012 delivery University of Florida's BEBR – March 2012 Projections
Actual Customers and Sales by Customer Class	Jan 2002-May 2012	Tampa Electric
Normal Billing Days	Jun 2012 forward	Tampa Electric
Actual Hourly Temperatures	Jan 2002 – Feb 2012	NOAA's TIA weather station
Normal Hourly Temperatures	Mar 2012 forward	Tampa Electric
Actual Calculated Degree Days	Jan 2002 – May 2012	Tampa Electric calculates based on NOAA's TIA weather station temperatures
Normal Degree Days	June 2012 forward	Tampa Electric
Actual Retail Net Energy for Load and actual Retail Peak Data	Jan 2002 – Feb 2012	Tampa Electric
Normal Peak Weather	Mar 2012 forward	Tampa Electric
Forecasted Retail Net Energy for Load	Mar 2012 forward	Tampa Electric's MetrixND model output
Actual Phosphate and all other Interruptible Sales	Jan 2002 – May 2012	Tampa Electric
Phosphate and all other Interruptible Sales Projections	Jun 2012 forward	Tampa Electric
Price of Electricity (Actual & Projected)	Jan 2002 forward	Tampa Electric
Commercial appliance saturation and energy efficiency	Jan 2002 forward	ITRON Corporation
Residential appliance saturation and energy efficiency	Jan 2002 forward	ITRON Corporation

6. What are the energy and demand impacts, dates, and reasons associated with the loss of phosphate load referenced on page 15 of witness Cifuentes's direct testimony at page 15, lines 14-17?

A. The phosphate sector is very volatile from year to year, but there has been a consistent downward trend in energy sales in this sector. The years 2006 and 2011 had more significant drops due to plant or mine closures. Since 2002, phosphate energy sales and coincident peak demands have declined by 647 GWh and 103 MW, respectively.

Although phosphate loads have been declining, the majority of phosphate customers are on interruptible rates. Those non-firm customers' loads do not have any impact on firm peak demand projections, which are the basis for reserve margin calculations.

7. Why has TECO's per customer energy consumption and per customer peak demand been declining from 2002 to 2011 and why are those trends expected to continue through the forecast horizon as shown in witness Cifuentes' direct testimony, Documents No. 4 and 6?

A. There are a number of drivers behind the historical decline in Tampa Electric's per customer energy consumption and per customer peak demand. One is the addition of less energy intense customers in the Industrial sector, which lowers overall per customer consumption and loads. In addition, the Phosphate sector, the company's most energy intense sector, has experienced declining sales as mining slowly moves out of Tampa Electric's service territory.

Another significant driver is the economic downturn that began in 2007. The Industrial sector's sales significantly dropped in 2008 and 2009 as manufacturers of construction products suffered from the housing downturn. Consumption in the Commercial sector also dropped in 2008 and 2009 and has not returned to pre-recession levels. The Residential sector's overall per customer usage began to decline in 2006 as the housing boom left a significant number of vacant homes in Tampa Electric's service territory. In addition to high vacancy levels, many households were financially impacted by the economic downturn and consolidated households or implemented other energy conservation measures to offset rising food and energy costs. In recent years, the multi-family segment has represented a larger share of the customer growth in the Residential sector. These changes all contributed to the declining per customer consumption and peak demands.

The electric industry has undergone significant changes that have put downward pressure on per customer energy consumption and peak demands. Some of these changes include mandated energy efficiency standards for appliance manufacturers, the Energy Independence and Security Act of 2007, the American Recovery and Reinvestment Act of 2009, more stringent building codes for newly constructed homes and buildings, and the new lighting standards that took effect in 2012. All of these changes will continue to reduce upward pressure on future average per customer consumption and peak demand.

In Florida, population is the primary engine for economic growth, and the demographics of the future population migrating to the state will be different than in the past. The Florida Legislature Office of Economic and Demographic Research predicts that the age 60+ population will account for over 55 percent of Florida's future population growth. This segment of the population typically uses less energy,

thus contributing to the downward trend on future per customer consumption and peak demands.

While the company expects this downward trend in per customer consumption to continue, it will be at a diminishing rate. In addition, customer growth is projected to increase at a steady pace through the forecast horizon, which will offset the decline in per customer consumption.

8. Which weather station was used to determine 20-year historical weather as referenced in witness Cifuentes' direct testimony, Document No. 2, and how was this weather station selected as representative for the TECO service area?

A. Tampa Electric uses the weather station located at Tampa International Airport ("TIA") to determine 20-year historical weather. TIA is the primary National Oceanic Atmospheric Administration ("NOAA") station in Tampa Electric's service area. Due to the compact nature of the company's service area, only one weather station is necessary to determine historical weather.

9. What is the accuracy, stated in percent error terms, of TECO's 2004 through 2006 TYSPs' load forecasts, including Total Customers (Schedule 2.3), Total Sales to Ultimate Customers (Schedule 2.2), and Summer and Winter Peak Demand (Schedules 3.1 and 3.2), for Forecast Year 6 (example: 2006 TYSP forecast of 2011 total customers compared to actual 2011 total customers)?

A. The table below shows the accuracy, stated as percent error, of Tampa Electric's 2004 through 2006 TYSP forecasts for Forecast Year 6.

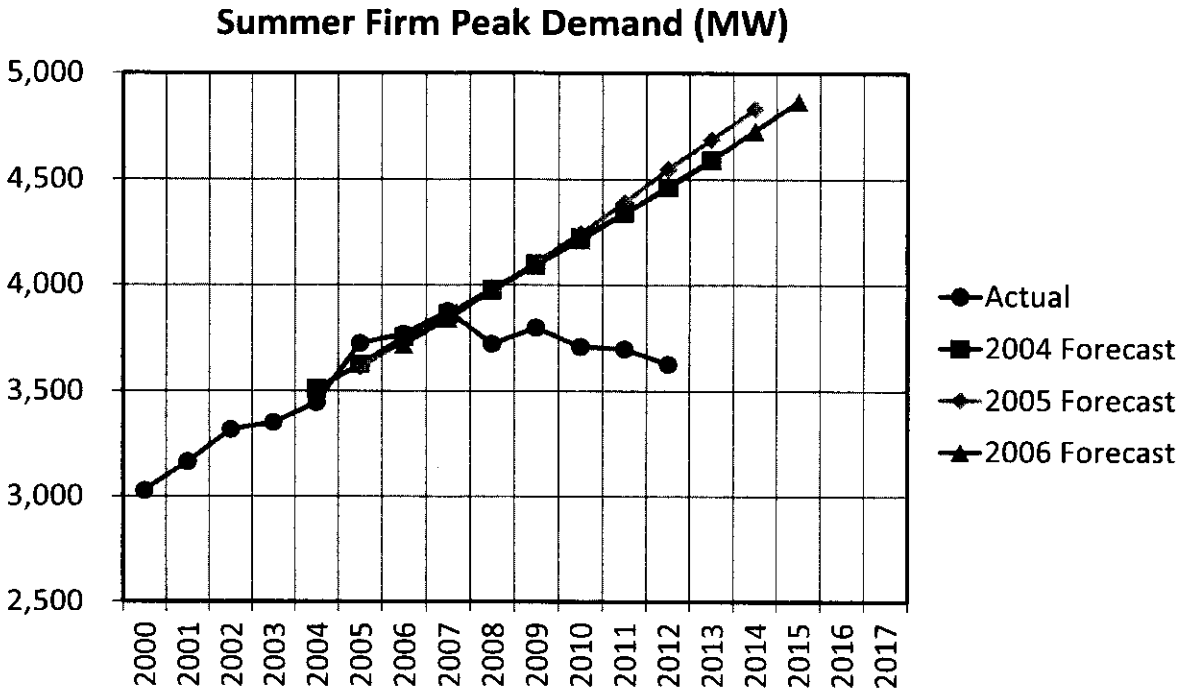
	Total Customers	Total Sales	Summer Firm Pk	Winter Firm Pk
2004 TYSP (for 2009)	3.4%	14.8%	7.9%	14.8%
2005 TYSP (for 2010)	5.7%	14.2%	14.4%	5.2%
2006 TYSP (for 2011)	6.8%	22.0%	17.3%	21.7%

120234 Hearing Exhibits 00016

10. For any percentage forecast error greater than 5 percent identified in TECO's response to Interrogatory No. 9, above, what are the primary reasons for such error?

A. With the exception of the 2004 TYSP customer forecast for 2009, all forecasts have a percentage error greater than five percent. The primary reason for the magnitude of the errors is the timing of when the forecasts were developed. These forecasts were prepared prior to the housing downturn and the recession that began in 2007. (See graph below.) The extent of the sudden, unexpected and sharp decline in customer growth, energy consumption and peak demand that began in 2008 was not foreseeable in 2004 through 2006. The depth and duration of the downturn was also more severe than expected and would have never been projected given historical trends of past recessions. While the economy seemed to be showing signs of a recovery in 2010 and 2011, in reality, average consumption and peak demands continued to decline. This situation was not specific to Tampa Electric, but occurred throughout the state and nationwide.

Tampa Electric believes that its current forecasts are reasonable and appropriate, given the latest economic indicators and recent customer and usage trends.


Summer Firm Peak Demand (MW)
5,000
4,500
4,000
3,500
3,000
2,500
2000
2001
2002
2003
2004
2005
2006
2007
2008
2009
2010
2011
2012
2013
2014
2015
2016
2017
Actual
2004 Forecast
2005 Forecast
2006 Forecast

11. How has TECO's forecasting methods and major assumptions used in developing the 2012 through 2021 load forecasts in Chapter III of TECO's 2012 Ten Year Site Plan changed in the development of TECO's 2012 annual forecast process completed in June 2012, as referenced in witness Cifuentes' direct testimony at page 13, Lines 17-23?

A. In May 2012, ITRON Corporation conducted a review of Tampa Electric's forecasting models and methodologies. As a result of ITRON's recommendations, minor changes to the company's June 2012 models were implemented. In addition, other changes were incorporated as part of the annual forecast process. The differences in Tampa Electric's forecasting methods from the forecasts found in the 2012 Ten Year Site Plan ("2012 TYSP") to the forecasts produced in June 2012 are listed below.

Global Changes to Models

- The estimation period for all of the models listed in the 2012 TYSP start in 2001 while the June 2012 models have an estimation period beginning in 2002.
- All binary variables, a variable with a value of 0 or 1, were reviewed for statistical significance, and variables that were no longer statistically significant were removed, *e.g.* 2004 hurricane impacts, migration between customer classes, data issues, monthly seasonality. In addition, new binary variables were added, as necessary, to capture anomalies in the data and to reflect a permanent step change downward in the data due to the economic downturn.

Changes to the SAE Average Use Models

- The June 2012 appliance efficiency data was provided by ITRON. The prior year, Tampa Electric prepared the appliance efficiency assumptions using data from the Energy Information Administration.

Changes to Population Assumptions

- The June 2012 population assumptions include a revision to history from 2000 through 2010 to incorporate U.S. Census changes.
- The June 2012 population forecast is based on the University of Florida's Bureau of Economic and Business Research's projected Hillsborough County and Florida projected growth rates as well as Hillsborough County projected growth rates from Moody's Analytics. The blending minimizes the risks of uncertainty in the growth rates.

Changes to Household Income Assumptions

- The June 2012 household income assumption is based on Florida and Hillsborough County growth projections from Moody's Analytics. The county level projections increased at a much faster rate than the state projections in 2012. To minimize the risks of uncertainty, the growth rates were averaged.

Changes in Peak Demand Average Use Model

- In the June 2012 model, a summer net energy for load trend variable and lagged heating and cooling degree variables were added.

12. If no documents requested in Staff's 1st Request for Production of Documents No. 9 are available, what are the rationale, assumptions, and methods by which the Company integrates its econometric models with statistically adjusted engineering (SAE) models as referenced in witness Cifuentes' direct testimony on page 3, lines 19-22?

A. All rationale, assumptions, and methods by which Tampa Electric integrates its econometric models with statistically adjusted engineering ("SAE") models as referenced in witness Cifuentes's direct testimony on page 3, lines 19-22 are found in the company's Ten Year Site Plan, dated April 1, 2012, provided in the company's response to Staff's First Request for Production of Documents, No. 1.

A F F I D A V I T

STATE OF FLORIDA)
)
COUNTY OF HILLSBOROUGH)

Before me the undersigned authority personally appeared Lorraine L. Cifuentes who deposed and said that she is Manager – Load Research and Forecasting, Tampa Electric Company, and that the individuals listed in Tampa Electric Company's response to Staff's First Set of Interrogatories, (Nos. 1 - 12) prepared or assisted with the responses to these interrogatories to the best of her information and belief.

Dated at Tampa, Florida this 17 day of October, 2012.

Sworn to and subscribed before me this 17th day of October, 2012.

Cynthia R. Kyle

Notary Public State of Florida
Cynthia R Kyle
My Commission EE052251
Expires 03/01/2015

My Commission expires _____

3

TECO's Answer to Second Set Of Interrogatories (Nos. 13-49, 50 (redacted), 51-60) of the Florida Public Service Commission

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 120234-EI EXHIBIT 3
PARTY Florida Public Service Commission Staff
DESCRIPTION TECO - Staff Exhibit #3 - Confidential
[Bates Nos. 00023-00118] & [Bates No. 00119]

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition to determine need for Polk 2-5 combined cycle conversion, by Tampa Electric Company	**DOCKET NO. 120234-EI** **FILED: October 23, 2012**

REDACTED

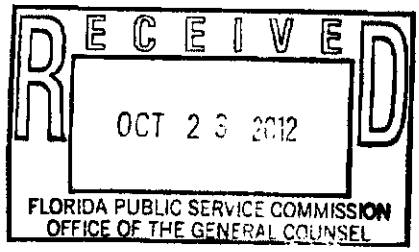
TAMPA ELECTRIC COMPANY'S

ANSWERS TO SECOND SET OF INTERROGATORIES (NOS. 13-60)

OF THE

FLORIDA PUBLIC SERVICE COMMISSION

Tampa Electric files its Answers to Interrogatories (Nos. 13-60) propounded and served on October 3, 2012; by the Florida Public Service Commission.



TAMPA ELECTRIC COMPANY
DOCKET NO. 120234-EI
INDEX TO STAFF'S SECOND SET OF INTERROGATORIES (NOS. 13 – 60)

Number	Witness	Subject	Bates Stamped Page
13	Rosha	Regarding the assumed economic parameters, how did TECO analyze and select the financial assumptions relied upon in its determination that Polk 2-5 combined cycle conversion is the most cost effective alternative for purposes of this proceeding?	1
14	Rosha	In TECO's most cost effective alternative determination, a capital structure was assumed. Please provide the rationale for using this capital structure as assumed.	2
15	Rosha	Please provide the capital components, amounts, relative ratios, and cost rates that produce the weighted average cost of capital and discount rate used in TECO's analysis. For purposes of this response, please show the before-tax and after-tax cost of capital.	3
16	Rosha	Please discuss and list all financial and economic assumptions, not listed on page 28 of the Need Determination Study, used in TECO's economic evaluation of the Polk 2-5 combined cycle conversion. Please include, at a minimum, capital structure and general inflation rate.	4
17	Lukcic	On page 8, lines 19 – 21, of his testimony witness D. Lukcic indicated that "Polk 2-5 will have similar emission rates to recently proposed NGCC projects such as FP&L's modernization of Port Everglades." In the Port Everglades need study, FP&L included the compliance costs for the future EPA regulations and potential GHG/CO2 legislation in its economic analysis. Please explain why TECO did not include the forecasted NOx, SO2, and CO2 air emission compliance costs in its cost analyzing process such as in Section VI, Detailed Economic Analysis, and Section VII, Sensitivity Analysis.	5
18	Lukcic Bryant	Please refer to page 4, lines 1 – 6, of witness D. Lukcic's testimony: a. How many SCRs in total will be installed onto the proposed Polk 2-5 natural gas combined cycle (NGCC) facility? b. What will be the estimated total capital costs associated with the SCRs installation? c. What will be the estimated annual O&M costs associated with the SCRs operation? d. Does TECO intend to recover the costs discussed in Interrogatory No. 18b above through the environmental clause or in its base rates? Please explain.	6

Number	Witness	Subject	Bates Stamped Page
19	Lukcic	Did TECO install a continue emission monitoring system (CEMS) in each of the existing Polk 2-5 Units? a. If yes, will these CEMS be retired after the proposed conversion project? b. If installed and not retired, will they be re-installed onto the new NGCC facility?	7
20	Lukcic	Please refer to page 4, lines 11 – 24, of witness D. Lukcic's testimony: a. What is the current total daily water consummation for the Polk 2-5 Units? b. What will be the total daily water consummation for the proposed NGCC? c. What will be the savings (in dollars) resulting from using the reclaimed water instead of freshwater? d. Does TECO currently use freshwater or reclaimed water for the cooling of the Polk 2-5 Units? e. Witness Lukcic indicated in lines 15 – 17 of his testimony that the City of Lakeland and Polk County will provide reclaimed water for a majority of the water needed for the expansion. (i) Please elaborate on the phrase "a majority" in terms of the percentage of the total water needed for the expansion; and (ii) What will be the source of the rest of the water needed? f. Please refer to lines 13 – 17, of witness D. Lukcic's testimony. (i) Does TECO need to build a piping system from Lakeland reclaim water facility to the Polk Power Station to use the reclaimed water for the new NGCC? (ii) If the answer to Part (f)(i) is yes, what will be the associated costs? (iii) If the answer to part (f)(i) is yes, were these costs identified in part (f)(ii) included in the economic analysis of the need study?	8
21	Lukcic	Please refer to page 8, lines 7 – 12, of witness D. Lukcic's testimony: a. Please elaborate on the phrase "super critical coal technology." (line 9) b. Please provide the emission rates for NOx, SO2, CO2, and mercury, respectively, in the case of the super critical coal technology. c. Please provide the emission rates for NOx, SO2, CO2, and mercury, respectively, in the case of the	11

Number	Witness	Subject	Bates Stamped Page
		proposed NGCC at the Polk Power Station. d. Please explain how TECO obtained the percentage data in witness D. Lukcic's testimony, lines 10 – 11.	
22	Lukcic	Please refer to page 28 of TECO's Determination of Need for Electrical Power, Polk 2-5 Combined Cycle Conversion (Determination of Need Study). a. At the top of the page TECO indicated "[a]n example is the expected Polk 2-5 environmental permitting requirements discussed in Section VII.C." (i) Please identify where the Section VII.C is in the Need Study, and (ii) Please provide the corresponding page number(s). b. TECO indicated in the last sentence of the second paragraph on page 8 that the primary environmental requirements considered by TECO in this study include Green House Gas New Source Performance Standards (GHGNSPS) and [Clean Water Act] 316(b). Please provide detailed explanations concerning how the proposed NGCC conversion project will satisfy these two environmental requirements.	13
23	Hornick	On page 24 of witness Hornick's testimony, the witness stated that Black and Veatch has engineered and constructed numerous similar facilities with a significant amount being in Florida. Please list all projects that are being referenced (with regard to the State of Florida) in this statement.	14
24	Hornick	On page 24 of witness Hornick's testimony, the witness stated that the estimated cost (of the Polk 2-5 Conversion Project) compares favorably to similar projects recently approved. Please provide evidence supporting this claim including, but not limited to, project costs, project capacity, and the name of the project.	15
25	Hornick	Please refer to pages 20-21 of witness Hornick's testimony. Please explain the basis for the high band increase of 6 percent and the low band decrease of 7 percent.	16
26	Hornick	On page 24 of witness Hornick's testimony, the witness stated that the lead times and pricing for HRSGs steam turbines, condensers, and cooling towers are reasonable. What is the current lead times and pricing for the described major equipment?	17
27	Hornick	On page 24 of witness Hornick's testimony, the witness stated that several manufacturers have indicated that they anticipate that the lead times (for major equipment) will	18

Number	Witness	Subject	Bates Stamped Page
		extend in the near future. Please quantify or attempt to quantify the anticipated time extension.	
28	Rocha	Did TECO consider a cost for carbon emissions in its economic analysis of the proposed Polk 2-5 Combined Cycle Conversion? a. If no, why not?	19
29	Rocha	Please complete the table below describing TECO's energy mix by fuel type.	20
30	Rocha	Please describe TECO's efforts to extend the purchased power contracts listed on page 10 of the Determination of Need Study.	21
31	Rocha	On page 24 of witness Rocha's testimony, the witness stated that the cost for converting Units 4 and 5 (to have dual fuel capability) are not included in the construction and operating plan. a. Does this also mean that these costs were not considered in the economic evaluation of the proposed Polk 2-5 Combined Cycle Conversion? b. Why were these costs not included in the construction and operating plan? c. Please quantify (in $2012) the cost of converting Units 4 and 5 to have dual fuel capability.	22
32	Rocha	Did TECO consider a resource plan in which the proposed project was delayed one year?	23
33	Rocha	With respect to the Resource Plans presented in Table 5 of the Determination of Need Study, please provide a similar table detailing unit retirements, expiring PPAs, and any other change in capacity.	24
34	Cifuentes	Please update the tables contained in Appendix E of the Determination of Need Study to include the years 2021 - 2032.	26
35	Cifuentes	Please update the tables contained in Appendix F of the Determination of Need Study to include the years 2021 - 2032.	28
36	Cifuentes	Please update the tables contained in Appendix G of the Determination of Need Study to include the years 2021 - 2032.	30
37	Rocha	Did the high or low peak demand sensitivities cause any changes to the resource plans as they are presented in Table 5 of the Determination of Need Study? a. If yes, please provide the resource plans assuming the high and low sensitivities.	32
38	Rocha	Referencing Table 13, under the column labeled "Proposal B", of the Determination of Need Study, the total value	34

Number	Witness	Subject	Bates Stamped Page
		does not appear to be consistent with the summation of its components (Capital, O&M, Fuel, and Purchased Power). Please reconcile this difference. a. If the total value is incorrect and it should be equal to the summation of the components in that column, how would this impact the conclusion of TECO's economic evaluation?	
39	Rocha	Page 34 of the Determination of Need Study states that TECO conducted an initial screening of potential supply technologies (including solid fuel, natural gas fired, and renewable resources) based on economic viability and qualitative factors such as technical feasibility, commercial availability, construction timing, and environmental impacts and permitting. Please provide a hypothetical timeline for the siting and construction of the solid fuel alternatives evaluated by TECO.	35
40	Hornick	On page 24 of witness Hornick's testimony, the witness stated that "[i]n the late 1990's and early 2000's there was a large spike in demand for gas fired units. This resulted in what was termed a "gas bubble" situation where manufacturers had difficulty meeting demand. The lead time for equipment manufacture increased significantly and prices escalated dramatically." a. Please provide evidence supporting this statement (i.e. lead times and costs for natural gas power plants). b. Additionally, please approximate the increase in lead times and prices experienced during the time period discussed.	36
41	Rocha	Please complete the table below assuming varying configurations of the proposed project.	41
42	Rocha	Page 48 of the Determination of Need Study stated that neither proposal C or D met the 294 MW need in 2017 without the need to add peaking CTs in the 2017 time period. Would this statement remain true assuming the low demand sensitivity or the updated June 2012 demand forecast?	42
43	Young	Please describe how the anticipated capital investment for the transmission projects contained in Exhibit SBY-1, Document No. 3 were developed. a. Please identify any resources or assumptions relied upon in developing the anticipated capital investment.	43
44	Young	Please provide a projected completion date for each project contained in Exhibit SBY-1, Document No. 3.	44
45	Rocha	If TECO were to accept Proposal B as identified in the	46

Number	Witness	Subject	Bates Stamped Page
		Determination of Need Study, would there still be a need for some or all of the projects contained in Exhibit SBY-1, Document No. 3? a. If yes, please list the projects that would still be required and the projected date of completion for each project.	
46	Rocha	Please complete the table below describing the revenue requirements for each resource plan and sensitivity contained in Exhibit RJR-1, Document No. 9. Please provide response in hard copy and in Excel format as available.	47
47	Rocha	Please complete the table below describing the revenue requirements for each resource plan and sensitivity contained in Exhibit RJR-1, Document No. 13. Please provide response in hard copy and in Excel format as available.	66
48	Caldwell	Please refer to TECO's May 1, 2012, response to Staff's Supplemental Data Request, No. 59 in the 2012 Ten Year Site Plan Review. a. Why does the natural gas price forecast in TECO's response vary from the natural gas price forecast appearing in Document No. 1 attached to witness Caldwell's Direct Testimony? b. What are TECO's No. 2 Oil ($/Gallon), Illinois Basin Coal ($/ton), and residual oil price forecasts sponsored by witness Caldwell in this proceeding as provided in $/MMBtu? c. Are TECO's No. 2 Oil, Illinois Basin Coal and residual oil price forecasts stated in $/MMBtu the same price forecasts as appears in TECO's May 1, 2012 response to Staff's Supplemental Data Request, No. 59 in the 2012 Ten Year Site Plan Review? (i) If not, why not?	70
49	Caldwell	Witness Caldwell's Direct Testimony at Page 12, Lines 10-12, indicates that TECO's fuel price forecasts includes both the commodity and delivery prices for the various fuels. a. What does witness Caldwell mean by the term "delivery" for each fuel type? b. For purposes of the fuel price forecasts, where are the origination, transfer, and delivery points for each fuel type?	72
50	Caldwell	What are the commodity, transportation, and delivered prices, in real and nominal terms, for TECO's 2013-2040 delivered fuel price forecast shown in Document No. 1	73

Number	Witness	Subject	Bates Stamped Page
		attached to witness Caldwell's direct testimony and TECO's residual oil price forecast referenced on page 14 of witness Caldwell's direct testimony? a. If transportation price for the various fuels has multiple components (e.g. natural gas "basis" plus additional contract delivery prices), please provide each component price and total transportation price.	
51	Caldwell	What were TECO's 2011 actual prices (commodity and transportation combined, similar to the prices appearing in Document 1 attached to witness Caldwell's direct testimony) for natural gas, No. 2 Oil, residual oil, and Illinois Basin Coal?	74
52	Caldwell	Why did TECO use the Consumer Price Index Less Energy to escalate natural gas, for Years 11 through 30 of its natural gas price forecast, as stated in witness Caldwell's direct testimony at page 13 and 14?	75
53	Caldwell	Refer to witness Caldwell's direct testimony, page 13. a. Is it a correct assumption that TECO used the escalation rates of the NYMEX Natural Gas Futures Contract plus FGT Zone 3 basis to forecast Years 3 through 10 of its distillate oil price forecast? b. If so, why is this method of escalating TECO's distillate oil prices appropriate? c. Is it a correct assumption that TECO used the Consumer Price Index Less Energy to forecast Years 11 through 30 of its distillate oil price forecast? d. If so, why is this method of escalating TECO's distillate oil prices appropriate?	76
54	Caldwell	Referring to witness Caldwell's direct testimony, page 13, what is the method by which TECO has evaluated the historical relationship between its residual oil and distillate oil costs that underpins its residual oil price forecast?	77
55	Caldwell	Why is TECO's coal price forecast based on decreasing market indices percentages until the Wood Mac forecast is 100 percent of TECO's coal price forecast by 2018 as stated in witness Caldwell's direct testimony at page 15?	78
56	Caldwell	Referring to witness Caldwell's direct testimony at page 15, why is TECO's coal price forecast from 2019 through 2040 escalated according to TECO's escalation rates of natural gas, distillate oil, and residual oil?	79
57	Caldwell	What is the name and date of each previous FPSC filing containing TECO's official long-term forecast prepared in the summer of 2011 as referenced in witness Caldwell's direct testimony, page 12?	80

Number	Witness	Subject	Bates Stamped Page
58	Caldwell	Referring to witness Caldwell's direct testimony at page 13, why does TECO base the first 10 years of its natural gas price forecast on the NYMEX price to Henry Hub plus basis cost for delivery to FGT Zone 3 rather than base its forecast on the cost of natural gas delivered to TECO's service area?	81
59	Caldwell	What is the basis for the fuel price sensitivity ranges prepared by TECO (e.g. 35 percent for oil and gas, 20 percent for coal) as stated by witness Caldwell in his direct testimony on page 16?	82
60	Caldwell	For each fuel price forecast prepared by TECO and referenced in witness Caldwell's direct testimony, what are the specific independent forecasts (including forecasted data as well as each forecast's source, date, and forecast description) which TECO used for purposes of comparison to its own fuel price forecast?	83

Howard Bryant
Manager, Rates

Brent Caldwell
Director, Wholesale and Fuels Management

Lori Cifuentes
Manager, Load Research

Mark Hornick
Director, Engineering and Project Management

David Lukcic
Manager, Environmental Health and Safety

Jim Rocha
Director, Planning, Strategy and Compliance

Beth Young
Director, Energy Delivery

Tampa Electric Company
702 N. Franklin Street
Tampa, FL 33602

13. Regarding the assumed economic parameters, how did TECO analyze and select the financial assumptions relied upon in its determination that Polk 2-5 combined cycle conversion is the most cost effective alternative for purposes of this proceeding?

A. Assumptions for economic parameters should reflect forward looking expectations. Tampa Electric targets the capital structure and mid-point return on equity which was approved by the Commission during its most recent base rate case, decided in Docket No. 080317-EI. The Allowance for Funds Used During Construction ("AFUDC") rate was approved in Docket No. 090446-EI and is shown in Order No. PSC-09-0798-PAA-EI, provided in the company's response to Staff's Second Request for Production of Documents, No. 19. Periodically, Tampa Electric's Treasury Department reviews current debt market conditions to determine an appropriate cost of debt for Tampa Electric to use in calculating a weighted average cost of capital. Capital and production escalation rates are derived from market indices such as Handy-Whitman with forward projections, while projections for inflation and non-production escalation rates are based on Consumer Price Index ("CPI") forecasts from the Bureau of Labor Statistics and Moody's Analytics (formerly Economy.com) market research. The escalation and capital structure components were included in Section IV of Tampa Electric's Request for Proposals ("RFP") for power issued March 23, 2012. Other economic parameters are selected based on specific project characteristics. The fuel escalation rates are discussed in witness Caldwell's testimony, as well as in the company's responses to Interrogatory Nos. 49 – 50, 52 – 56, and 58 - 60.

14. In TECO's most cost effective alternative determination, a capital structure was assumed. Please provide the rationale for using this capital structure as assumed.

A. Tampa Electric uses this capital structure as the forward looking target capital structure because this is the one that was approved in the company's most recent base rate proceeding. This was approved as the basis for capital and business determinations made for Tampa Electric and its customers.

15. Please provide the capital components, amounts, relative ratios, and cost rates that produce the weighted average cost of capital and discount rate used in TECO's analysis. For purposes of this response, please show the before-tax and after-tax cost of capital.

A. Please see the table below. The table below is also provided in Tampa Electric's response to Staff's Second Production of Documents, No. 19.

Assumptions	
Mid Point ROE	**11.25%**
Debt Cost [1]	**6.66%**
Targeted Capital Structure	
Debt	**46.04%**
Equity	**53.96%**
Tax Rate	**38.58%**

(1) Debt cost is from Treasury Department

Regulatory ROE =	**11.25%**
PRE-TAX	
[redacted]	
Debt Cost	6.66%
Pre-tax Equity Cost	18.32%
Capital Structure	
Debt Cost	46.04%
Equity	53.96%
Pre-Tax WACC	12.95%
AFTER TAX	
[redacted]	
Debt Cost	6.66%
Equity Cost	11.25%
Capital Structure	
Debt Cost	46.04%
Equity	53.96%
WACC	7.95%

16. Please discuss and list all financial and economic assumptions, not listed on page 28 of the Need Determination Study, used in TECO's economic evaluation of the Polk 2-5 combined cycle conversion. Please include, at a minimum, capital structure and general inflation rate.

A. The requested information is provided in the company's responses to Interrogatory Nos. 13 and 15.

17. On page 8, lines 19 – 21, of his testimony witness D. Lukcic indicated that "Polk 2-5 will have similar emission rates to recently proposed NGCC projects such as FP&L's modernization of Port Everglades." In the Port Everglades need study, FP&L included the compliance costs for the future EPA regulations and potential GHG/CO2 legislation in its economic analysis. Please explain why TECO did not include the forecasted NOx, SO2, and CO2 air emission compliance costs in its cost analyzing process such as in Section VI, Detailed Economic Analysis, and Section VII, Sensitivity Analysis.

A. There were no forecasted NO_x and SO_2 costs because at this time CAIR regulates NO_x and SO_2, under which Tampa Electric has sufficient allowances to meet the requirements on the units. For other proposals, the RFP required each respondent to be responsible for environmental costs. Additionally, all other proposals received in response to the company's RFP offered natural gas as a fuel source where similar compliance costs would be required.

Compliance costs for CO_2 were not included due to the fact that there is too much uncertainty regarding future regulations and legislation and their impacts.

18. Please refer to page 4, lines 1 – 6, of witness D. Lukcic's testimony:

a. How many SCRs in total will be installed onto the proposed Polk 2-5 natural gas combined cycle (NGCC) facility?

b. What will be the estimated total capital costs associated with the SCRs installation?

c. What will be the estimated annual O&M costs associated with the SCRs operation?

d. Does TECO intend to recover the costs discussed in Interrogatory No. 18b above through the environmental clause or in its base rates? Please explain.

A. a. Four SCR's will be installed, one per HRSG and there is one HRSG per combustion turbine.

b. The estimated total capital costs associated with the installation of all four SCR's as well as ammonia storage and handling infrastructure is $9 million.

c. The estimated annual O&M operating costs associated with all four SCR's, based on the expected operating profile and current pricing for anhydrous ammonia, is $96,000.

d. Tampa Electric intends to recover the cost of the SCRs for Polk 2-5 through base rates as part of the overall project cost. There has been no new environmental law promulgated to require utilization of SCRs, thus recovery will occur through base rates.

19. Did TECO install a continue emission monitoring system (CEMS) in each of the existing Polk 2-5 Units?

a. If yes, will these CEMS be retired after the proposed conversion project?

b. If installed and not retired, will they be re-installed onto the new NGCC facility?

A. Yes. CEMS are installed on the existing Polk Units 2-5.

a. The CEMS will not be retired since Tampa Electric plans on maintaining the ability to use the existing stacks in simple cycle bypass mode.

b. The existing CEMS systems will be modified to monitor both the simple cycle (bypass) stacks and the new HRSG stacks.

20. Please refer to page 4, lines 11 – 24, of witness D. Lukcic's testimony:

a. What is the current total daily water consummation for the Polk 2-5 Units?

b. What will be the total daily water consummation for the proposed NGCC?

c. What will be the savings (in dollars) resulting from using the reclaimed water instead of freshwater?

d. Does TECO currently use freshwater or reclaimed water for the cooling of the Polk 2-5 Units?

e. Witness Lukcic indicated in lines 15 – 17 of his testimony that the City of Lakeland and Polk County will provide reclaimed water for a majority of the water needed for the expansion.

(i) Please elaborate on the phrase "a majority" in terms of the percentage of the total water needed for the expansion; and

(ii) What will be the source of the rest of the water needed?

f. Please refer to lines 13 – 17, of witness D. Lukcic's testimony.

(i) Does TECO need to build a piping system from Lakeland reclaim water facility to the Polk Power Station to use the reclaimed water for the new NGCC?

(ii) If the answer to Part (f)(i) is yes, what will be the associated costs?

(iii) If the answer to part (f)(i) is yes, were these costs identified in part (f)(ii) included in the economic analysis of the need study?

A. a. Water consumption varies with the number of hours the generating units operate each day. Maximum use for Polk Units 2-5 in the current simple cycle configuration is approximately 0.1 million gallons per day ("MGD") when firing natural gas and approximately 1.0 MGD when firing fuel oil on Units 2 & 3 due to water injection being used for NO_x control. Actual consumption is much less as these units are typically used in peaking mode.

b. Water consumption for the proposed NGCC will also vary with unit capacity factor. Maximum 24 hour consumption would be 7.6 MGD when firing natural gas and 8.5 MGD when firing fuel oil on Units 2 & 3 due to water injection being used for NO_x control. Maximum use of supplemental firing would require an additional 1.7 MGD. The proposed NGCC is expected to operate as an intermediate load asset with a capacity factor of approximately 60 percent of the unfired capacity. Based on the expected capacity factor, average daily water consumption would be approximately 4.6 MGD.

c. There are no savings associated with the use of reclaimed water. The use of reclaimed water is required to address existing site water quality issues caused by inadequate groundwater availability. Polk is located in the Southern Water Use Caution Area which makes additional groundwater resources difficult or impossible to obtain. Due to this, several companies such as Mosaic have had their consumptive use allotments reduced. The requirements for current and future water needs at Polk Power Station are governed by the Conditions of Certification.

d. Polk Units 2&3 cooling is currently provided by the existing cooling reservoir, while Polk Units 4&5 are air cooled. The make-up water to the existing cooling reservoir is from the on-site consumptive use wells. In 2006, the Regional Reclaimed Water Partnership was initiated to address the existing cooling reservoir water quality issues and allow Polk Power Station to remain viable for future generation expansion.

e. (i) While the total amount of water needed will depend on several factors, including but not limited to annual rainfall, capacity factor, and reclaimed water availability, the phrase "a majority" refers to two-thirds of the total water needed at the site. After expansion, the expected total consumption at the site will be 8.6 MGD, and of that amount an estimated 5.7 MGD will be reclaimed water.

(ii) Additional water will be pumped from existing consumptive use wells.

f. (i) No. The pipeline is being constructed under the Regional Reclaimed Water Partnership. This project was initiated in January of 2006 in order to address existing site water quality concerns and maintain the future viability of the site. In addition, this project

minimizes ground water withdrawals, reduces nutrient loading to Tampa Bay, and half of the project costs are co-funded by Southwest Florida Water Management District through its reclaimed water reuse program.

(ii) This question is not applicable.

(iii) This question is not applicable.

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21. Please refer to page 8, lines 7 – 12, of witness D. Lukcic's testimony:

a. Please elaborate on the phrase "super critical coal technology." (line 9)

b. Please provide the emission rates for NOx, SO2, CO2, and mercury, respectively, in the case of the super critical coal technology.

c. Please provide the emission rates for NOx, SO2, CO2, and mercury, respectively, in the case of the proposed NGCC at the Polk Power Station.

d. Please explain how TECO obtained the percentage data in witness D. Lukcic's testimony, lines 10 – 11.

A. a. Supercritical coal technology refers to a pulverized coal fired generating plant which uses a steam turbine and operates with steam conditions above the critical pressure of water (3200 psia) to increase thermal efficiency.

b.-c. The requested information is provided in the table below.

Comparison of Emission Rates Between Fossil Fuel Generation Alternatives

	Supercritical Coal[1]	Polk 2-5[2]
Emission Rates		
NO_x (lb/MMBtu)	0.07	0.0073
SO_2 (lb/MMBtu)	0.085	0.00058
CO_2 (lb/MMBtu)	203	117*
Mercury (lb/10^{12} Btu)	1.14	N/A

[1]Cost and Performance Baseline for Fossil Energy Plants, Vol. 1, DOE/NETL-2007/1281, May 2007.
[2] B&V values
*Emission rate from GHG MRR for Natural Gas [40 CFR 98 Subpart C; Table C – 1]
The lb/MMBtu emission rates were calculated by dividing the lb/hr emission rate provided from B&V by the heat input at ISO conditions (1,788.3 MMBtu/hr).

d. The percentage data was obtained using the table above. The percent difference reflecting the lower emission rates for Polk Units 2-5 compared to the projected supercritical coal emission rates was calculated using simple arithmetic.

22. Please refer to page 28 of TECO's Determination of Need for Electrical Power, Polk 2-5 Combined Cycle Conversion (Determination of Need Study).

a. At the top of the page TECO indicated "[a]n example is the expected Polk 2-5 environmental permitting requirements discussed in Section VII.C."

(i) Please identify where the Section VII.C is in the Need Study, and

(ii) Please provide the corresponding page number(s).

b. TECO indicated in the last sentence of the second paragraph on page 8 that the primary environmental requirements considered by TECO in this study include Green House Gas New Source Performance Standards (GHGNSPS) and [Clean Water Act] 316(b). Please provide detailed explanations concerning how the proposed NGCC conversion project will satisfy these two environmental requirements.

A. a. As stated in Tampa Electric's revised page 28 of the Determination of Need Study, submitted to the Commission on October 12, 2012, the correct reference is to Section IX.C on pages 56-57.

b. The CO_2 NSPS has been proposed by EPA, and public comments are currently under EPA review. Therefore, it is not a final rule and is likely to change as the rulemaking process progresses. However, based on current NSPS applicability criteria, the Polk 2-5 combustion turbines are existing units and would not be subject to the CO_2 NSPS. The CO_2 NSPS is a consideration for Prevention of Significant Deterioration permitting, and Polk Units 2-5 are expected to meet the applicable GHG Best Available Control Technology standards. These will be determined during the permitting process. Section 316(b) of the Clean Water Act is not applicable to the Polk Units 2-5 conversion because the units do not withdraw water from waters of the state.

23. On page 24 of witness Hornick's testimony, the witness stated that Black and Veatch has engineered and constructed numerous similar facilities with a significant amount being in Florida. Please list all projects that are being referenced (with regard to the State of Florida) in this statement.

A. The referenced projects are listed below.

- Hines Energy Complex Unit 1 – Florida Power (1999)
- Payne Creek (Medulla) Station – Seminole Electric Cooperative (2001)
- Fort Myers Repowering Project – Florida Power & Light (2002)
- Cane Island Unit 3 – Kissimmee Utility Authority (2002)
- Sanford Repowering Project - Florida Power & Light (2002/03)
- Martin Expansion Project - Florida Power & Light (2005)
- Manatee Expansion Project - Florida Power & Light (2005)
- Turkey Point Expansion Project - Florida Power & Light (2007)
- Polk Station Units 4 & 5 – Tampa Electric (2007)
- West County Energy Center – Florida Power & Light (2009-11)

24. On page 24 of witness Hornick's testimony, the witness stated that the estimated cost (of the Polk 2-5 Conversion Project) compares favorably to similar projects recently approved. Please provide evidence supporting this claim including, but not limited to, project costs, project capacity, and the name of the project.

A. To clarify, the testimony states that if the book value of the existing combustion turbine assets are taken into account, the estimated cost compares favorably to similar projects that were recently approved.

Including the book value and capacity of the existing combustion turbines and excluding transmission costs and AFUDC, the estimated cost for the Polk 2-5 Conversion Project equate to $557/kW, based on the Summer rating.

Projects for comparison include FP&L's Port Everglades Project at $815/kW, FP&L's Cape Canaveral Project at $790/kW, and FP&L's Riviera Beach Project at $818/kW. These calculations are based on Summer ratings and excluding transmission and AFUDC.

25. Please refer to pages 20-21 of witness Hornick's testimony. Please explain the basis for the high band increase of 6 percent and the low band decrease of 7 percent.

A. The high band increase of six percent and the low band decrease of seven percent were determined by what the company considered categories of cost and what reasonable increases or decreases were possible for those costs given our knowledge of business conditions and trends. The component variations are shown in the table below.

	LOW BAND	HIGH BAND
MAJOR EQUIPMENT	-5%	+5%
BULKS/COMMODITIES	-1%	+2%
CONSTRUCTION	-14%	+10%
ENGINEERING/CONSTR. MGMT	-10%	n/c
OWNER'S COSTS	n/c	n/c
% OF BASE CASE	92.8%	105.5%

26. On page 24 of witness Hornick's testimony, the witness stated that the lead times and pricing for HRSGs steam turbines, condensers, and cooling towers are reasonable. What is the current lead times and pricing for the described major equipment?

A. The table below provides the requested data, as updated during the estimating process. The lead times are shown as a range since they vary by manufacturer and shop loading.

Equipment Name	Estimated Lead Time	Estimated Cost
HRSGs	16-18 months	$70M
Steam Turbine	18-22 months	$54M
Condenser	12-14 months	$8M
Cooling Tower	8-10 months	$3M

27. On page 24 of witness Hornick's testimony, the witness stated that several manufacturers have indicated that they anticipate that the lead times (for major equipment) will extend in the near future. Please quantify or attempt to quantify the anticipated time extension.

A. This statement was based on conversations with various manufacturers during presentations of their technology and was not specifically quantified. The majority of equipment manufacturers with whom Tampa Electric met stated that the quantity of inquiries had risen dramatically in the recent months due to sustained low natural gas prices combined with increased regulatory pressure related to older coal fired generating units throughout the country.

One steam turbine manufacturer recently stated that their lead time had increased to 28 months, and they will most likely decline to bid since they won't be able to meet the project schedule.

28. Did TECO consider a cost for carbon emissions in its economic analysis of the proposed Polk 2-5 Combined Cycle Conversion?

a. If no, why not?

A. No.

a. The compliance cost for carbon emissions were not included due to the fact that there is too much uncertainty regarding the impacts of future regulations and legislation. Therefore, it is premature to include compliance costs for carbon emissions.

29. Please complete the table below describing TECO's energy mix by fuel type.

	Solid Fuels (%)	Natural Gas (%)	Oil/Other (%)	System Net Energy for Load (GWh)
2011				
2012				
2013				
2014				
2015				
2016				
2017				
2018				
2019				
2020				

A. The requested information is provided in the table below.

	Solid Fuels (%)	Natural Gas (%)	Oil/Other* (%)	System Net Energy for Load (GWh)
2011	56	38	6	19,325
2012	58	37	4	20,080
2013	57	40	3	20,180
2014	58	39	3	20,226
2015	57	40	3	20,358
2016	58	38	3	20,571
2017	59	39	2	20,772
2018	58	40	2	20,991
2019	58	40	2	21,217
2020	58	40	2	21,439

*Oil/Other includes purchased energy.

Values shown may be affected by rounding. The solid fuels column includes coal and petcoke.

30. Please describe TECO's efforts to extend the purchased power contracts listed on page 10 of the Determination of Need Study.

A. Tampa Electric assessed extending the existing purchase power contracts as listed on page 10 of the Determination of Need Study. Since none of the agreements provide Tampa Electric with long term extension rights, the ability to extend contracts is limited, and the corresponding contract terms and conditions would be dependent on negotiations at the time of the extension. Additional details regarding each contract are provided in the table below.

Purchase Power Counterparty	Expiration Date	Extension Status
Hardee Power Partners	December, 2012	Unit committed to another entity beginning 2013 precluding any extension opportunity.
Orange Cogen	December, 2015	No capacity needed in 2016. Also, at only 23 MW, it would not fully displace the reserve margin need.
Southern Power	December, 2015	Has an option to extend through 2017, but at a much higher price. It would also require requesting and contracting for third party transmission capacity.
Auburndale Peaking	December, 2016	The high heat rate makes it sufficient to cover a short term peaking need but would be costly in fuel for a long term need. It would require request and granting of network firm transmission capacity.
Pasco Cogen	December, 2018	Expires after the incremental need for capacity to meet reserve margin needs in 2017.

In addition, each of these entities had the opportunity to bid their generating unit as a power purchase agreement in response to Tampa Electric's Request for Proposals for power issued March 23, 2012.

31. On page 24 of witness Rocha's testimony, the witness stated that the cost for converting Units 4 and 5 (to have dual fuel capability) are not included in the construction and operating plan.

a. Does this also mean that these costs were not considered in the economic evaluation of the proposed Polk 2-5 Combined Cycle Conversion?

b. Why were these costs not included in the construction and operating plan?

c. Please quantify (in $2012) the cost of converting Units 4 and 5 to have dual fuel capability.

A. a. Yes. The costs were not considered in the economic evaluation of the proposed Polk Units 2-5 combined cycle conversion project.

b. These costs were not included in the construction and operating plan because they represent future operational reliability and flexibility benefits. The potential for future dual fuel conversion for Polk Units 4-5 was identified to include in drafting the environmental permit.

c. The costs for converting Units 4 and 5 to have dual fuel capability have not yet been quantified; however, based on costs from other utility projects, the costs of the conversion would be expected to be approximately $15M (2012$).

32. Did TECO consider a resource plan in which the proposed project was delayed one year?

A. Tampa Electric evaluated numerous in-service dates and various combinations of technologies during integrated resource planning. From this evaluation, the top eight (lowest cost) plans and fifteen out of the top twenty plans selected the Polk 2-5 conversion in 2017. Tampa Electric did not perform further evaluations of a one year deferral. However, the company did evaluate the effects if the project were delayed two years, which coincides with Tampa Electric's 2011 Ten Year Site Plan containing an in-service year of 2019. In that case, the result is a higher cost to customers of $65.4 Million on a CPWRR basis.

Additionally, during the company's RFP process, the expansion plan for our system in Proposal B resulted in a delay of the Polk Units 2-5 conversion project by one year, to 2018. The result was a higher cost to customers of $132.4 million on a CPWRR basis.

33. With respect to the Resource Plans presented in Table 5 of the Determination of Need Study, please provide a similar table detailing unit retirements, expiring PPAs, and any other change in capacity.

A. A table detailing expiring PPA's and any other changes in capacity is provided below. The first unit retirements are Big Bend Unit 1 in 2035 and Big Bend Unit 2 in 2038.

Polk 2-5

2012	Hardee (356 MW) Calpine (117 MW) Pasco Cogen (121MW) Reliant (158 MW) Orange Cogen (23 MW)
2013	Calpine (117 MW) Southern (160 MW) Pasco Cogen (121 MW) Orange Cogen (23 MW)
2014	Calpine (117 MW) Southern (160 MW) Pasco Cogen (121 MW) Orange Cogen (23 MW)
2015	Calpine (117 MW) Southern (160 MW) Pasco Cogen (121 MW) Orange Cogen (23 MW)
2016	Calpine (117 MW) Southern (160 MW) Pasco Cogen (121 MW)
2017	Pasco Cogen (121 MW)
2018	Pasco Cogen (121 MW)
2019	
2020	
2021	
2022	

Alternative 1

2012	Hardee (356 MW) Calpine (117 MW) Pasco Cogen (121MW) Reliant (158 MW) Orange Cogen (23 MW)
2013	Calpine (117 MW) Southern (160 MW) Pasco Cogen (121 MW) Orange Cogen (23 MW)
2014	Calpine (117 MW) Southern (160 MW) Pasco Cogen (121 MW) Orange Cogen (23 MW)
2015	Calpine (117 MW) Southern (160 MW) Pasco Cogen (121 MW) Orange Cogen (23 MW)
2016	Calpine (117 MW) Southern (160 MW) Pasco Cogen (121 MW)
2017	Pasco Cogen (121 MW)
2018	Pasco Cogen (121 MW)
2019	
2020	
2021	
2022	

Alternative 2

2012	Hardee (356 MW) Calpine (117 MW) Pasco Cogen (121MW) Reliant (158 MW) Orange Cogen (23 MW)
2013	Calpine (117 MW) Southern (160 MW) Pasco Cogen (121 MW) Orange Cogen (23 MW)
2014	Calpine (117 MW) Southern (160 MW) Pasco Cogen (121 MW) Orange Cogen (23 MW)
2015	Calpine (117 MW) Southern (160 MW) Pasco Cogen (121 MW) Orange Cogen (23 MW)
2016	Calpine (117 MW) Southern (160 MW) Pasco Cogen (121 MW)
2017	Pasco Cogen (121 MW)
2018	Pasco Cogen (121 MW)
2019	
2020	
2021	
2022	

Polk 2-5

2023	
2024	
2025	
2026	
2027	
2028	
2029	
2030	
2031	
2032	
2333	
2034	
2035	BB 1 Retires 10/1/2035
2036	
2037	
2038	BB 2 Retires 4/1/2038

Alternative 1

2023	
2024	
2025	
2026	
2027	
2028	
2029	
2030	
2031	
2032	
2333	
2034	
2035	BB 1 Retires 10/1/2035
2036	
2037	
2038	BB 2 Retires 4/1/2038

Alternative 2

2023	
2024	
2025	
2026	
2027	
2028	
2029	
2030	
2031	
2032	
2333	
2034	
2035	BB 1 Retires 10/1/2035
2036	
2037	
2038	BB 2 Retires 4/1/2038

34. Please update the tables contained in Appendix E of the Determination of Need Study to include the years 2021 -2032.

A. The requested information is provided in the following table.

Tampa Electric Company
Total Retail Peak Demand
(MW)

	Winter	Summer
2002	3612	3634
2003	3881	3623
2004	3344	3737
2005	3686	3968
2006	3736	4010
2007	3398	4123
2008	3709	3952
2009	4080	4015
2010	4512	3917
2011	4037	3976
2012	4081	3993
2013	4112	4023
2014	4141	4049
2015	4180	4082
2016	4224	4125
2017	4269	4165
2018	4315	4207
2019	4361	4250
2020	4408	4292
2021	4453	4331
2022	4494	4369
2023	4534	4405
2024	4574	4441
2025	4613	4475
2026	4650	4509
2027	4687	4542
2028	4723	4575
2029	4761	4611
2030	4800	4645
2031	4836	4676
2032	4870	4705

Average Annual Growth Rates		
2002-2011	1.2%	1.0%
2012-2021	1.0%	0.9%
2022-2032	0.8%	0.7%

Average Absolute Growth		
2002-2011	47	38
2012-2021	41	38
2022-2032	38	34

Tampa Electric Company
Firm Retail Peak Demand
(MW)

	Winter	Summer
2002	3259	3318
2003	3455	3351
2004	2936	3445
2005	3287	3725
2006	3523	3769
2007	3127	3876
2008	3443	3723
2009	3754	3799
2010	4246	3710
2011	3735	3699
2012	3777	3748
2013	3819	3784
2014	3864	3823
2015	3910	3859
2016	3955	3900
2017	4003	3940
2018	4050	3980
2019	4097	4022
2020	4146	4064
2021	4194	4103
2022	4237	4141
2023	4279	4177
2024	4322	4213
2025	4363	4247
2026	4402	4281
2027	4441	4314
2028	4480	4347
2029	4520	4383
2030	4561	4417
2031	4597	4448
2032	4631	4477

Average Annual Growth Rates		
2002-2011	1.5%	1.2%
2012-2021	1.2%	1.0%
2022-2032	0.9%	0.8%

Average Absolute Growth		
2002-2011	53	42
2012-2021	46	39
2022-2032	39	34

120234 Hearing Exhibits 00059

35. Please update the tables contained in Appendix F of the Determination of Need Study to include the years 2021 -2032.

A. The requested information is provided in the following table.

High Load Scenario

Tampa Electric Company
Firm Retail Peak Demand
(MW)

	Winter	Summer
2002	3259	3318
2003	3455	3351
2004	2936	3445
2005	3287	3725
2006	3523	3769
2007	3127	3876
2008	3443	3723
2009	3754	3799
2010	4246	3710
2011	3735	3699
2012	3802	3778
2013	3868	3836
2014	3936	3897
2015	4003	3955
2016	4072	4017
2017	4142	4080
2018	4212	4144
2019	4284	4209
2020	4358	4276
2021	4431	4341
2022	4501	4404
2023	4570	4466
2024	4640	4529
2025	4709	4591
2026	4776	4652
2027	4845	4714
2028	4914	4777
2029	4984	4843
2030	5056	4908
2031	5124	4970
2032	5191	5031

	Average Annual Growth Rates	
2002-2011	1.5%	1.2%
2012-2021	1.7%	1.6%
2022-2032	1.4%	1.3%

	Average Absolute Growth	
2002-2011	53	42
2012-2021	70	63
2022-2032	69	63

Low Load Scenario

Tampa Electric Company
Firm Retail Peak Demand
(MW)

	Winter	Summer
2002	3259	3318
2003	3455	3351
2004	2936	3445
2005	3287	3725
2006	3523	3769
2007	3127	3876
2008	3443	3723
2009	3754	3799
2010	4246	3710
2011	3725	3699
2012	3758	3725
2013	3779	3740
2014	3802	3758
2015	3825	3773
2016	3849	3791
2017	3874	3810
2018	3898	3827
2019	3922	3847
2020	3947	3866
2021	3972	3882
2022	3991	3896
2023	4010	3909
2024	4028	3921
2025	4044	3931
2026	4058	3940
2027	4072	3949
2028	4086	3957
2029	4099	3967
2030	4114	3975
2031	4124	3980
2032	4131	3983

	Average Annual Growth Rates	
2002-2011	1.5%	1.2%
2012-2021	0.6%	0.5%
2022-2032	0.3%	0.2%

	Average Absolute Growth	
2002-2011	52	42
2012-2021	24	17
2022-2032	14	9

120234 Hearing Exhibits 00061

36. Please update the tables contained in Appendix G of the Determination of Need Study to include the years 2021 -2032.

A. The requested information is provided in the following table.

Tampa Electric Company
Total Retail Peak Demand
(MW)

	Winter	Summer
2002	3612	3634
2003	3881	3623
2004	3344	3737
2005	3686	3968
2006	3736	4010
2007	3398	4123
2008	3709	3952
2009	4080	4015
2010	4512	3917
2011	4037	3931
2012	3523	3916
2013	3970	3893
2014	3999	3928
2015	4043	3969
2016	4095	4017
2017	4147	4065
2018	4200	4112
2019	4251	4159
2020	4301	4203
2021	4349	4244
2022	4395	4286
2023	4440	4328
2024	4485	4371
2025	4530	4413
2026	4573	4454
2027	4617	4496
2028	4660	4538
2029	4704	4583
2030	4750	4628
2031	4793	4668
2032	4834	4704

Average Annual Growth Rates		
2002-2011	1.2%	0.9%
2012-2021	1.1%	0.9%
2022-2032	1.0%	0.9%

Average Absolute Growth		
2002-2011	47	33
2012-2021	47	36
2022-2032	44	42

Tampa Electric Company
Firm Retail Peak Demand
(MW)

	Winter	Summer
2002	3259	3318
2003	3455	3351
2004	2936	3445
2005	3287	3725
2006	3523	3769
2007	3127	3876
2008	3443	3723
2009	3754	3799
2010	4246	3710
2011	3725	3699
2012	3237	3677
2013	3699	3667
2014	3731	3701
2015	3778	3741
2016	3832	3788
2017	3887	3835
2018	3941	3881
2019	3993	3927
2020	4045	3971
2021	4095	4012
2022	4144	4054
2023	4191	4096
2024	4238	4139
2025	4285	4181
2026	4331	4222
2027	4377	4264
2028	4423	4306
2029	4469	4351
2030	4517	4395
2031	4560	4435
2032	4601	4471

Average Annual Growth Rates		
2002-2011	1.5%	1.2%
2012-2021	1.3%	1.0%
2022-2032	1.1%	1.0%

Average Absolute Growth		
2002-2011	52	42
2012-2021	50	37
2022-2032	46	42

37. Did the high or low peak demand sensitivities cause any changes to the resource plans as they are presented in Table 5 of the Determination of Need Study?

a. If yes, please provide the resource plans assuming the high and low sensitivities.

A. Yes.

a. The resource plans for both sensitivities are provided below.

Low Load Sensitivity

	Polk 2-5	Alternative 1	Alternative 2
2012	Peaker 117 MW	Peaker 117 MW	Peaker 117 MW
2013	Peaker 117 MW Peaker 160 MW	Peaker 117 MW Peaker 160 MW	Peaker 117 MW Peaker 160 MW
2014	Peaker 117 MW Peaker 160 MW	Peaker 117 MW Peaker 160 MW	Peaker 117 MW Peaker 160 MW
2015	Peaker 117 MW Peaker 160 MW	Peaker 117 MW Peaker 160 MW	Peaker 117 MW Peaker 160 MW
2016	Peaker 117 MW Peaker 160 MW	Peaker 117 MW Peaker 160 MW	Peaker 117 MW Peaker 160 MW
2017	(1) PK 2-5 CC Conversion 463/459 MW - W	(1) 7FA CT 177/149 MW - S	(1) 7FA CT 177/149 MW - S
2018	-	-	-
2019	-	(1) 7FA CT 177/149 MW - S	(1) 7FA CT 177/149 MW - S
2020	-	(1) 7FA CT 177/149 MW - S	(1) PK 2-5 CC Conversion 463/459 MW - S
2021	-	-	-
2022	-	-	-
2023	-	-	-
2024	-	-	-
2025	-	-	-
2026	-	-	-
2027	-	-	-
2028	-	-	-
2029	-	-	-
2030	-	-	-
2031	-	(1) 7FA CT 177/149 MW - S	-
2032	-	-	-

High Load Sensitivity

	Polk 2-5	Alternative 1	Alternative 2
2012	Peaker 117 MW	Peaker 117 MW	Peaker 117 MW
2013	Peaker 117 MW Peaker 160 MW	Peaker 117 MW Peaker 160 MW	Peaker 117 MW Peaker 160 MW
2014	Peaker 117 MW Peaker 160 MW	Peaker 117 MW Peaker 160 MW	Peaker 117 MW Peaker 160 MW
2015	Peaker 117 MW Peaker 160 MW	Peaker 117 MW Peaker 160 MW	Peaker 117 MW Peaker 160 MW
2016	Peaker 117 MW Peaker 160 MW (1) 7FA CT 177/149 MW - S	Peaker 117 MW Peaker 160 MW (1) 7FA CT 177/149 MW - S	Peaker 117 MW Peaker 160 MW (1) 7FA CT 177/149 MW - S
2017	(1) PK 2-5 CC Conversion 463/459 MW - W	(2) 7FA CT 177/149 MW - S	(2) 7FA CT 177/149 MW - S
2018	-	(1) 7FA CT 177/149 MW - S	(1) 7FA CT 177/149 MW - S
2019	(1) 7FA CT 177/149 MW - S	(1) 7FA CT 177/149 MW - S	(1) 7FA CT 177/149 MW - S
2020	(1) 7FA CT 177/149 MW - S	(1) 7FA CT 177/149 MW - S	(1) PK 2-5 CC Conversion 463/459 MW - W
2021	-	-	-
2022	(1) 7FA CT 177/149 MW - S	(1) 7FA CT 177/149 MW - S	
2023	-	-	-
2024	(1) 7FA CT 177/149 MW - S	(1) 7FA CT 177/149 MW - S	
2025	-	-	-
2026	(1) 7FA CT 177/149 MW - S	(1) 7FA CT 177/149 MW - S	(1) 7FA CT 177/149 MW - S
2027	-	-	-
2028	(1) 7FA CT 177/149 MW - S	(1) 7FA CT 177/149 MW - S	(1) 7FA CT 177/149 MW - S
2029	-	-	-
2030	(1) 7FA CT 177/149 MW - S	(1) 7FA CT 177/149 MW - S	(1) 7FA CT 177/149 MW - S
2031	-	-	-
2032	-	-	-

38. Referencing Table 13, under the column labeled "Proposal B", of the Determination of Need Study, the total value does not appear to be consistent with the summation of its components (Capital, O&M, Fuel, and Purchased Power). Please reconcile this difference.

a. If the total value is incorrect and it should be equal to the summation of the components in that column, how would this impact the conclusion of TECO's economic evaluation?

A. For Proposal B, the line item labeled, "Fuel & Purchased Power" was incorrect, due to an incorrect link to a cell that was in the source spreadsheet.

Please note that this error also existed in Exhibit 1, Document 13 of witness Rocha's testimony.

Subsequent to the change identified above, while preparing the response to Staff's 4th set of interrogatories question 75, the company discovered an inadvertent input error in the model that impacts the fuel and purchased power estimated costs of only Proposal B. As such, the original calculated fuel and purchased power costs should have been $13,602.5 million resulting in a total CPWRR of $16,109.6 million and a delta of $75.4 million.

a. The total value has been corrected and does not impact the conclusion of Tampa Electric's economic evaluation.

39. Page 34 of the Determination of Need Study states that TECO conducted an initial screening of potential supply technologies (including solid fuel, natural gas fired, and renewable resources) based on economic viability and qualitative factors such as technical feasibility, commercial availability, construction timing, and environmental impacts and permitting. Please provide a hypothetical timeline for the siting and construction of the solid fuel alternatives evaluated by TECO.

A. Solid fuel alternatives currently have limited appeal because, as the current environmental rules stand, there is no technology available to meet limits on mercury and CO_2. Tampa Electric is aware that the limits are under further review. However, during the initial screening, it was clear that the uncertainty with these regulations is far too great to proceed with a solid fuel alternative technology. Despite these limitations, it is likely that solid fuel unit environmental permitting would require one to three, and construction would take about five to six years.

40. On page 24 of witness Hornick's testimony, the witness stated that "[i]n the late 1990's and early 2000's there was a large spike in demand for gas fired units. This resulted in what was termed a "gas bubble" situation where manufacturers had difficulty meeting demand. The lead time for equipment manufacture increased significantly and prices escalated dramatically."

a. Please provide evidence supporting this statement (i.e. lead times and costs for natural gas power plants).

b. Additionally, please approximate the increase in lead times and prices experienced during the time period discussed.

A. a. The statement was based on personal knowledge and experience with the gas turbine market during that period. The company did procure and construct two simple cycle gas turbines during that period. Polk Unit 2 was ordered in December 1998, and Polk Unit 3 was ordered in June 1999. The purchase price for Polk Unit 2 was $32.7M, and the purchase price for Polk Unit 3 was $35.0M representing an increase of seven percent over a six-month period. In addition, the lead time for Polk Unit 2 was 20 months, compared to 25 months for Polk Unit 3.

In addition, an article that describes the situation during that period is attached.

b. See the company's response to part (a) above. In addition, a major HRSG supplier provided information that over a two-year period costs increased by 20 percent and lead times increased 50 percent, as shown in the attached presentation.

Gas Turbine Orders: 1998 Boom, 2001 Bust, 2004 Rebound?

1.22.04 Mark Axford, Axford Turbine Consultants LLC

Brief History of Gas Turbine Market

Gas turbines were first introduced for industrial and utility service during the 1950s. By 1964, approximately 10gw of gas turbine power had been sold world wide for power generation and mechanical drive. (see Exhibit A). In 1965, a major blackout in the US Northeast left 25 million people, including NY City, in the dark. In some areas, power was not restored for several days. This triggered a buying spree for gas turbines by utilities in North America. They installed gas turbines to provide the capability to "black start" their primary generating stations if they were ever knocked offline again. By 1975, gas turbines were being ordered at a steady 10 -15 GW per year for world wide markets.

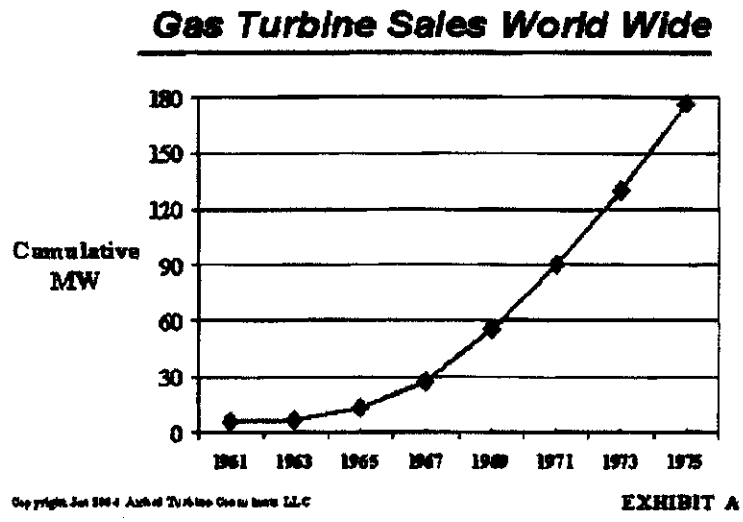

EXHIBIT A

During the 1980s, the worldwide order rate for gas turbines was essentially flat (see Exhibit B) but the US component of total demand grew rapidly. In 1980, approximately 15% of the gas turbine power ordered was for jobsites in the US. By 1989, the US share had risen to approximately 30%. Much of the increase in the US was attributable to the favorable legal and tax treatment of cogeneration. While cogeneration was promoted in the name of energy efficiency, it was in fact the beginning of deregulation of the market for electricity. By 1990, most large US utilities had set up independent deregulated subsidiaries poised to expand

into other regions and internationally.

During the early 1990s, worldwide orders for gas turbines increased to 20-25GW per year. GT orders in Europe rose sharply as the environmental movement took hold. In Asia, gas turbines where the only power generation technology that could be installed quickly enough to match the growing power demand. By 1997, the worldwide order level for GTs was holding steady near 30GW per year and the US component had returned to its historic level of 15% of worldwide orders. **GT Market Bubble 1998 – 2001**

In the summer of 1998, the need for controlled blackouts and brownouts in Alberta and Chicago triggered a market panic, a different type of panic than the 1965 Northeast blackout. Reserve margins throughout North America were at an all time low. Some power marketers who had sold forward electricity were caught short when supply could not meet demand.

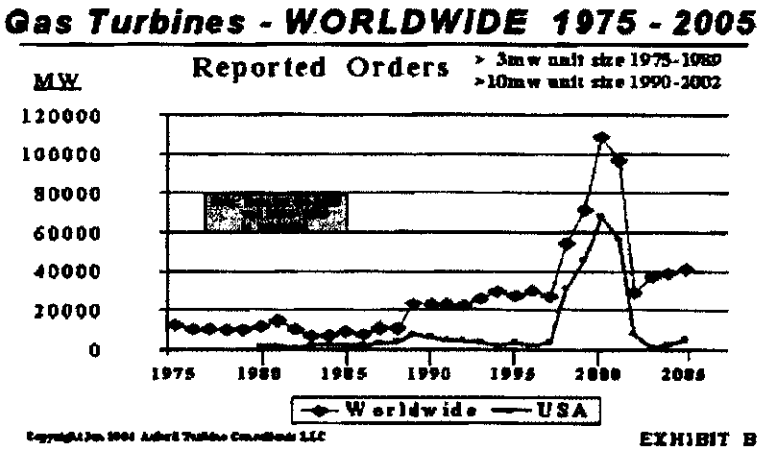

EXHIBIT B All the experts seemed to agree that the shortage of electricity that many had been predicting for several years had suddenly arrived. Utilities and IPPs saw the blackouts as a signal to begin a race to build merchant plants and expand their business nationally and internationally. The two choices seemed to be (1) become a major player with power and gas marketing prowess, or (2) be crushed or acquired by the emerging giants led by Enron. Everybody knows the story of the Enron crash in 2001 but few people outside of the gas turbine business appreciate the magnitude of the demand surge for gas turbine equipment during 1998 -2001.

Gas Turbines became a form of currency. Buyers attempted to buy manufacturing slots from

one another on a secondary market when GT manufacturers could not offer equipment on a timely basis. Between June 1998 and June 2001, approximately 330GW of gas turbine equipment was ordered worldwide....an amount equal to the all of the gas turbines ordered from 1979 - 1997. In short, about 15 years of orders had been jammed into 3 years. !!

GT Market Crashes

The worldwide orders rate for gas turbines peaked in 2000 at 108GW, more than 3.5 times the largest prior year in gas turbine history. During the first 6 months of 2001, the ordering frenzy continued at a pace that would have exceeded 150GW for the full year. Hydro reservoirs in the Pacific Northwest were low. Demand was projected to reach record levels. The experts predicted extensive rolling blackouts in the Western US. The experts were wrong. California braced for the onslaught of hot summer weather and air conditioning load and appealed to residents for conservation. Financial incentives were put into place for customers to reduce consumption. Fortunately for California, the summer of 2001 was mild and demand during peak periods was reduced significantly during the summer months. There were no significant power shortages in the West during the summer of 2001 and trading prices for electricity plummeted. Demand in the rest of the US was also soft as the economic recession took its toll on electric consumption. In October 2001, Enron began to unravel. By year end, Enron had filed for bankruptcy. Their power marketing business model had essentially been destroyed. All of the companies with large trading and marketing businesses fell to the brink of bankruptcy. These were the companies who had bought so many gas turbines that were no longer needed.

During 2002, companies like Williams, Dynegy, Calpine, Duke, NRG, NEG, and Mirant, cancelled a large number of gas turbines placed on order with GE and Siemens Westinghouse. In some instances, partial payments exceeding 25% of the purchase price were abandoned as part of the cancellation terms. In other cases, buyers worked with the manufacturers to delay shipment and payment dates in hope that the market would come back. As turbines rolled off the assembly lines, they were put into warehouses for storage since their project homes had been cancelled. The warehoused supply of 60 hz gas turbine gensets grew to over 20 GW.

GT Market Bottoms in 2003

While year end results for 2003 are not yet finalized, 2003 worldwide orders for gas turbines are projected to exceed 35 GW range, up approximately 30% form 2002. More than 95% of the 2003 orders were for non-US job sites. Another interesting phenomenon in 2003 was

the explosion of orders for steam turbine generator sets during 2003. More than 80 GW of steam turbine generator sets, mostly for coal fired plants, were ordered for China alone during 2003. Deliveries on some steam turbine models have been stretched out to two years. This affects the gas turbine business indirectly since much of the manufacturing of steam turbine generator equipment is done in the same factories that build gas turbine generator sets.

Outlook for 2004

For 2004, another dismal year is expected for gas turbine orders in the US. Aside from Municipals and Cooperatives feeding on fire sale prices from surplus, there are few buyers in North America. GT manufacturers predict the North American market will turn upward during 2005-2006. Meanwhile, the 50hz market for gas turbines and steam turbines remains reasonably firm with a spike of activity in Iraq and the rest of Asia.

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41. Please complete the table below assuming varying configurations of the proposed project.

	3X3X1	2X2X1	1X1X1
MW			
Heat Rate			

A. The requested information is provided in the table below.

	3X3X1	2X2X1	1X1X1
MW*	750	491	234
Heat Rate*	6,894	7,026	7,354

*Average net output of the varying configurations of the proposed Polk Units 2-5 conversion project during average conditions of 73°F and 60% Relative Humidity.

42. Page 48 of the Determination of Need Study stated that neither proposal C or D met the 294 MW need in 2017 without the need to add peaking CTs in the 2017 time period. Would this statement remain true assuming the low demand sensitivity or the updated June 2012 demand forecast?

A. For the low demand sensitivity, proposal C and D would meet the need in 2017 without the need to add peaking CT's until 2019.

For the updated June 2012 demand forecast, neither proposal C or D would need the CT's to meet the 205 MW need in 2017, but each proposal would require CT's beginning in 2018.

43. Please describe how the anticipated capital investment for the transmission projects contained in Exhibit SBY-1, Document No. 3 were developed.

a. Please identify any resources or assumptions relied upon in developing the anticipated capital investment.

A. An estimating team made up of members from Substation Engineering, Transmission Engineering, Real Estate, System Security, Telecommunications, Line Clearance, Community Relations, Project Management, and Environmental Health and Safety reviewed the transmission interconnection and integration requirements to develop a scope of work. This included the review of existing drawings and site visits. Each member, along with an engineering consulting firm, then estimated the costs to complete their scope of work.

a. Each member was responsible for estimating the costs to complete their scope of work, and an engineering consulting firm was used as a resource in developing these cost estimates. All estimates were calculated in 2012 dollars and utilized current material and labor pricing. In addition, an assumed route was selected for the transmission costs. A 5 percent allowance for indeterminates was included in the anticipated transmission capital investment.

44. Please provide a projected completion date for each project contained in Exhibit SBY-1, Document No. 3.

A. The requested information is provided in the following table.

230007	Big Bend to Aspen 230 kV	This circuit will be rerated to a rating of 729.4 MVA.	729.4	$5	JUN 2014
230401	Polk to Aspen 230 kV	The existing circuits from Polk to Mines East and from Mines West to Big Bend will be disconnected from Mines substation and tied together to create the modified circuit 230401. This circuit will be rerated to a rating of 729.4 MVA.	729.4	$10	DEC 2014
230402	Mines West to Aspen 230 kV	This is a new construction of approximately 15 miles circuit with a rating of 1,118.6 MVA.	1,118.6	$30	NOV 2016
230426	Aspen to FishHawk 230 kV	This is a new construction of approximately 6 miles of two circuits with a rating of 1,195.1 MVA.	1,195.1	$13	NOV 2016
230427	Aspen to FishHawk 230 kV	This is a new construction of approximately 6 miles of two circuits with a rating of 1,195.1 MVA.	1,195.1	$13	NOV 2016
230606	Polk to Pebbledale Ckt 1 230 kV	This circuit will be rerouted for approximately 9.8 miles to eliminate a double circuit line with the existing Polk to Mines East line with a rating of 729.4 MVA.	729.4	$20	DEC 2015
230605	Polk to Pebbledale Ckt 2 230 kV	This circuit will be rerated to 729.4 MVA.	729.4	$1	DEC 2015
230635	Polk to Mines East 230 kV	This is a new construction of approximately 12 miles circuit with a rating of 1,118.6 MVA.	1,118.6	$24	NOV 2016
-	Aspen Switching Station	This is a new contruction of the Aspen 230 kV Switching Station along the existing circuits between Mines West and Big Bend.	-	$8	DEC 2014
-	Davis Substation Switched Reactor	A new switchable series reactor will be installed on the Davis to Chapman circuit (230601).	-	$2	JUN 2015
-	FishHawk 230 kV Substation Upgrade	The FishHawk 230 kV Substation will be upgraded as a result of the addional capacity.	-	$1	DEC 2015
-	Mines 230 kV Substation Upgrade	The Mines 230 kV Substation will be upgraded as a result of the addional	-	$2	DEC 2015
-	Polk Steam Turbine Interconnect & Upgrade	The Polk 2-5 Steam Turbine will be interconnected to the existing station and required upgrades.	-	$5	JUN 2016
-	SR 60 North Bus Upgrade	A 3" SPS Al segment will be upgraded to 3000A minimum.	-	$1	JUN 2015
-	Dale Mabry West Bus Upgrade	Upgrade 69kV CB #103 AND 3" sps Al segment to 3000A minimum.		$1	DEC 2015
-	Circuit Breaker Upgrade	There will be 16 breakers that will be upgraded as a result of the additional capacity.	-	$3	DEC 2014
-	-	5% AFI		$7	

* 2012 Dollars

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45. If TECO were to accept Proposal B as identified in the Determination of Need Study, would there still be a need for some or all of the projects contained in Exhibit SBY-1, Document No. 3?

a. If yes, please list the projects that would still be required and the projected date of completion for each project.

A. No. None of the projects contained in Exhibit SBY-1, Document No. 3 would be constructed as they are listed. Work on circuits 230605 and 230606, Polk – Pebbledale, would be required, with a modified scope.

a. The question is not applicable.

46. Please complete the table below describing the revenue requirements for each resource plan and sensitivity contained in Exhibit RJR-1, Document No. 9. Please provide response in hard copy and in Excel format as available.

	Annual Revenue Requirements (Generation Capital) ($millions, 2012 $)	Annual Revenue Requirements (Transmission Capital) ($millions, 2012 $)	Annual Revenue Requirements (O&M) ($millions, 2012 $)	Annual Revenue Requirements (Fuel) ($millions, 2012 $)	Annual Revenue Requirements (Environmental) ($millions, 2012 $)	Total ($millions, 2012 $)	Bill Impact ($/1,000 kWh)
2012							
2013							
2014							
2015							
2016							
2017							
2018							
2019							
2020							
2021							
2022							
2023							
2024							
2025							
2026							
2027							
2028							
2029							
2030							
2031							
2032							
Total							

A. The requested information is provided in the following tables.

Low Cost of Capital: Polk Units 2-5

Year	Annual Revenue Requirements (Generation Capital) ($millions, 2012 $)	Annual Revenue Requirements (Transmission Capital) ($millions, 2012 $)	Annual Revenue Requirements (O&M) ($millions, 2012 $)	Annual Revenue Requirements (Fuel) ($millions, 2012 $)	Annual Revenue Requirements (Environmental) ($millions, 2012 $)	Total ($millions, 2012 $)	Bill Impact (2012 $/1,000 kWh)*
2012	-	-	58.49	891.93	-	950.42	0.00
2013	-	-	56.64	846.43	-	903.08	0.00
2014	-	-	54.01	814.40	-	868.40	0.00
2015	-	-	50.66	787.74	-	838.40	0.00
2016	-	-	49.45	749.39	-	798.84	0.00
2017	58.01	19.98	46.77	672.79	-	797.56	0.00
2018	52.06	17.93	44.06	645.21	-	759.27	0.00
2019	60.48	16.01	43.79	621.53	-	741.80	0.00
2020	55.36	14.29	41.86	603.60	-	715.11	0.00
2021	49.33	12.76	39.67	584.25	-	686.00	0.00
2022	56.13	11.40	38.89	562.41	-	668.83	0.00
2023	51.25	10.18	37.16	541.92	-	640.50	0.00
2024	45.62	9.09	35.28	518.22	-	608.21	0.00
2025	51.16	8.11	34.87	500.58	-	594.73	0.00
2026	46.57	7.23	33.06	478.48	-	565.34	0.00
2027	41.33	6.44	31.42	456.81	-	536.00	0.00
2028	36.65	5.72	30.21	438.75	-	511.33	0.00
2029	41.21	5.08	29.52	422.99	-	498.79	0.00
2030	37.37	4.49	28.04	401.58	-	471.48	0.00
2031	33.00	3.97	26.67	382.12	-	445.76	0.00
2032	29.10	3.50	25.21	362.86	-	420.66	0.00
2033	25.61	3.08	24.14	346.24	-	399.06	0.00
2034	22.51	2.70	22.90	326.94	-	375.05	0.00
2035	19.77	2.36	21.47	311.29	-	354.89	0.00
2036	72.32	2.05	22.82	292.57	-	389.76	0.00
2037	64.46	1.79	21.65	278.00	-	365.90	0.00
2038	57.29	1.59	20.30	264.39	-	343.55	0.00
2039	50.93	1.41	19.38	248.63	-	320.36	0.00
2040	45.27	1.26	18.39	214.67	-	279.59	0.00
2041	40.24	1.11	17.45	199.64	-	258.45	0.00
2042	35.76	0.99	16.60	185.06	-	238.41	0.00
2043	31.76	0.87	15.80	171.56	-	219.98	0.00
2044	27.74	0.77	15.04	159.03	-	202.58	0.00
2045	24.40	0.68	14.33	147.42	-	186.84	0.00
2046	21.61	0.59	13.67	136.66	-	172.54	0.00
Total	1,284.29	177.42	1,099.66	15,566.11	-	18,127.48	

*Assumes Low Cost of Capital is the base case compared to Low Cost of Capital Alternative 1 and Alternative 2.

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Lower Cost of Capital: Alternative 1

Year	Annual Revenue Requirements (Generation Capital) ($millions, 2012 $)	Annual Revenue Requirements (Transmission Capital) ($millions, 2012 $)	Annual Revenue Requirements (O&M) ($millions, 2012 $)	Annual Revenue Requirements (Fuel) ($millions, 2012 $)	Annual Revenue Requirements (Environmental) ($millions, 2012 $)	Total ($millions, 2012 $)	Bill Impact (2012 $/1,000 kWh)*
2012	-	-	58.49	891.93	-	950.42	0.00
2013	-	-	56.64	846.43	-	903.08	0.00
2014	-	-	54.01	814.40	-	868.40	0.00
2015	-	-	50.66	787.74	-	838.40	0.00
2016	-	-	49.47	748.02	-	797.49	(0.07)
2017	30.77	-	49.46	692.17	-	772.41	(0.25)
2018	45.17	-	47.60	664.39	-	757.16	0.75
2019	55.55	-	47.54	646.42	-	749.51	1.12
2020	50.67	-	45.53	630.05	-	726.25	1.18
2021	44.89	-	42.94	604.33	-	692.16	0.86
2022	51.96	-	42.28	585.50	-	679.75	1.02
2023	47.34	-	40.44	565.23	-	653.01	1.02
2024	41.94	-	38.52	542.26	-	622.72	1.06
2025	47.69	-	37.66	520.01	-	605.37	0.83
2026	43.29	-	36.01	500.67	-	579.97	0.96
2027	38.23	-	34.30	479.43	-	551.97	0.98
2028	33.72	-	33.00	462.40	-	529.12	1.02
2029	38.45	-	32.08	443.87	-	514.41	0.89
2030	34.77	-	30.58	420.81	-	486.15	0.82
2031	30.55	-	29.12	401.70	-	461.37	0.84
2032	26.83	-	27.64	383.00	-	437.47	0.87
2033	23.61	-	26.17	360.89	-	410.68	0.63
2034	20.83	-	24.98	341.81	-	387.62	0.65
2035	18.40	-	23.63	330.41	-	372.44	0.85
2036	71.22	-	24.79	300.70	-	396.72	0.38
2037	63.56	-	23.58	284.79	-	371.93	0.33
2038	56.48	-	22.38	274.69	-	353.55	0.49
2039	50.18	-	21.18	259.24	-	330.60	0.50
2040	44.57	-	20.20	224.39	-	289.16	0.46
2041	39.59	-	19.15	208.96	-	267.71	0.44
2042	34.19	-	18.20	194.43	-	246.82	0.40
2043	29.46	-	17.30	180.90	-	227.66	0.37
2044	25.51	-	16.45	168.32	-	210.27	0.36
2045	22.44	-	15.64	156.61	-	194.69	0.37
2046	19.89	-	14.87	145.71	-	180.47	0.37
Total	1,181.79	-	1,172.49	16,062.62	-	18,416.90	

*Assumes Low Cost of Capital is the base case compared to Low Cost of Capital Alternative 1 and Alternative 2.

Lower Cost of Capital: Alternative 2

Year	Annual Revenue Requirements (Generation Capital) ($millions, 2012 $)	Annual Revenue Requirements (Transmission Capital) ($millions, 2012 $)	Annual Revenue Requirements (O&M) ($millions, 2012 $)	Annual Revenue Requirements (Fuel) ($millions, 2012 $)	Annual Revenue Requirements (Environmental) ($millions, 2012 $)	Total ($millions, 2012 $)	Bill Impact (2012 $/1,000 kWh)*
2012	-	-	58.49	891.93	-	950.42	0.00
2013	-	-	56.64	846.43	-	903.08	0.00
2014	-	-	54.01	814.40	-	868.40	0.00
2015	-	-	50.66	787.74	-	838.40	0.00
2016	-	-	49.47	748.02	-	797.49	-0.07
2017	30.77	-	49.46	692.17	-	772.41	-1.21
2018	45.17	-	47.60	664.39	-	757.16	-0.10
2019	55.55	-	47.54	646.42	-	749.51	0.36
2020	50.67	-	45.53	630.05	-	726.25	0.51
2021	44.89	-	42.94	604.33	-	692.16	0.28
2022	51.96	-	42.28	585.50	-	679.75	0.50
2023	47.34	-	40.44	565.23	-	653.01	0.56
2024	41.94	-	38.52	542.26	-	622.72	0.65
2025	76.96	13.72	36.17	499.93	-	626.78	1.43
2026	68.57	12.32	34.35	477.92	-	593.16	1.23
2027	60.88	10.99	32.67	456.98	-	561.52	1.12
2028	54.00	9.81	31.37	438.63	-	533.81	0.98
2029	47.85	8.76	30.03	422.81	-	509.45	0.46
2030	42.35	7.83	28.58	401.40	-	480.16	0.37
2031	37.43	6.99	27.14	381.60	-	453.16	0.32
2032	33.08	6.24	25.67	362.90	-	427.89	0.31
2033	29.28	5.57	24.55	346.05	-	405.45	0.27
2034	25.96	4.97	23.30	326.61	-	380.83	0.25
2035	23.02	4.42	21.83	311.02	-	360.30	0.23
2036	70.17	3.93	23.18	292.32	-	389.59	-0.01
2037	67.61	3.49	22.07	277.95	-	371.12	0.22
2038	60.13	3.09	20.61	263.45	-	347.27	0.15
2039	53.47	2.73	19.68	248.47	-	324.34	0.17
2040	47.51	2.40	18.73	214.79	-	283.44	0.16
2041	42.19	2.11	17.74	199.66	-	261.71	0.14
2042	36.47	1.85	16.88	185.12	-	240.32	0.08
2043	31.46	1.62	16.06	171.64	-	220.78	0.03
2044	27.24	1.41	15.30	159.14	-	203.08	0.02
2045	23.93	1.23	14.58	147.55	-	187.29	0.02
2046	21.22	1.09	13.90	136.80	-	173.01	0.02
Total	1,349.10	116.57	1,137.94	15,741.60	-	18,345.21	

*Assumes Low Cost of Capital is the base case compared to Low Cost of Capital Alternative 1 and Alternative 2.

High Cost of Capital: Polk Units 2-5

Year	Annual Revenue Requirements (Generation Capital) ($millions, 2012 $)	Annual Revenue Requirements (Transmission Capital) ($millions, 2012 $)	Annual Revenue Requirements (O&M) ($millions, 2012 $)	Annual Revenue Requirements (Fuel) ($millions, 2012 $)	Annual Revenue Requirements (Environmental) ($millions, 2012 $)	Total ($millions, 2012 $)	Bill Impact (2012 $/1,000 kWh)*
2012	-	-	58.49	891.93	-	950.42	0.00
2013	-	-	56.64	846.43	-	903.08	0.00
2014	-	-	54.01	814.40	-	868.40	0.00
2015	-	-	50.66	787.74	-	838.40	0.00
2016	-	-	49.45	749.39	-	798.84	0.00
2017	65.98	19.98	46.77	672.79	-	805.52	0.00
2018	59.21	17.93	44.06	645.21	-	766.42	0.00
2019	68.93	16.01	43.79	621.53	-	750.26	0.00
2020	63.12	14.29	41.86	603.60	-	722.87	0.00
2021	56.24	12.76	39.67	584.25	-	692.91	0.00
2022	64.09	11.40	38.89	562.41	-	676.79	0.00
2023	58.52	10.18	37.16	541.92	-	647.77	0.00
2024	52.09	9.09	35.28	518.22	-	614.69	0.00
2025	58.49	8.11	34.87	500.58	-	602.06	0.00
2026	53.24	7.23	33.06	478.48	-	572.01	0.00
2027	47.25	6.44	31.42	456.81	-	541.93	0.00
2028	41.90	5.72	30.21	438.75	-	516.59	0.00
2029	47.16	5.08	29.52	422.99	-	504.74	0.00
2030	42.76	4.49	28.04	401.58	-	476.88	0.00
2031	37.77	3.97	26.67	382.12	-	450.53	0.00
2032	33.30	3.50	25.21	362.86	-	424.86	0.00
2033	29.31	3.08	24.14	346.24	-	402.76	0.00
2034	25.76	2.70	22.90	326.94	-	378.30	0.00
2035	22.63	2.36	21.47	311.29	-	357.74	0.00
2036	82.97	2.05	22.82	292.57	-	400.42	0.00
2037	73.96	1.79	21.65	278.00	-	375.40	0.00
2038	65.73	1.59	20.30	264.39	-	352.00	0.00
2039	58.44	1.41	19.38	248.63	-	327.86	0.00
2040	51.94	1.26	18.39	214.67	-	286.26	0.00
2041	46.17	1.11	17.45	199.64	-	264.38	0.00
2042	41.03	0.99	16.60	185.06	-	243.68	0.00
2043	36.44	0.87	15.80	171.56	-	224.66	0.00
2044	31.83	0.77	15.04	159.03	-	206.67	0.00
2045	28.00	0.68	14.33	147.42	-	190.44	0.00
2046	24.80	0.59	13.67	136.66	-	175.72	0.00
Total	1,469.05	177.42	1,099.66	15,566.11	-	18,312.24	

*Assumes High Cost of Capital is the base case compared to High Cost of Capital Alternative 1 and Alternative 2.

Higher Cost of Capital: Alternative 1

Year	Annual Revenue Requirements (Generation Capital) ($millions, 2012 $)	Annual Revenue Requirements (Transmission Capital) ($millions, 2012 $)	Annual Revenue Requirements (O&M) ($millions, 2012 $)	Annual Revenue Requirements (Fuel) ($millions, 2012 $)	Annual Revenue Requirements (Environmental) ($millions, 2012 $)	Total ($millions, 2012 $)	Bill Impact (2012 $/1,000 kWh)*
2012	-	-	58.49	891.93	-	950.42	0.00
2013	-	-	56.64	846.43	-	903.08	0.00
2014	-	-	54.01	814.40	-	868.40	0.00
2015	-	-	50.66	787.74	-	838.40	0.00
2016	-	-	49.47	748.02	-	797.49	(0.07)
2017	35.34	-	49.46	692.17	-	776.97	(0.42)
2018	51.87	-	47.60	664.39	-	763.85	0.73
2019	63.78	-	47.54	646.42	-	757.74	1.10
2020	58.18	-	45.53	630.05	-	733.76	1.17
2021	51.55	-	42.94	604.33	-	698.81	0.85
2022	59.66	-	42.28	585.50	-	687.45	1.01
2023	54.36	-	40.44	565.23	-	660.02	1.01
2024	48.16	-	38.52	542.26	-	628.94	1.05
2025	54.76	-	37.66	520.01	-	612.44	0.82
2026	49.71	-	36.01	500.67	-	586.39	0.95
2027	43.90	-	34.30	479.43	-	557.64	0.97
2028	38.72	-	33.00	462.40	-	534.12	1.01
2029	44.15	-	32.08	443.87	-	520.11	0.88
2030	39.92	-	30.58	420.81	-	491.31	0.81
2031	35.08	-	29.12	401.70	-	465.90	0.83
2032	30.81	-	27.64	383.00	-	441.44	0.86
2033	27.11	-	26.17	360.89	-	414.18	0.62
2034	23.92	-	24.98	341.81	-	390.71	0.65
2035	21.13	-	23.63	330.41	-	375.17	0.85
2036	81.78	-	24.79	300.70	-	407.27	0.38
2037	72.98	-	23.58	284.79	-	381.35	0.33
2038	64.86	-	22.38	274.69	-	361.92	0.49
2039	57.62	-	21.18	259.24	-	338.04	0.50
2040	51.18	-	20.20	224.39	-	295.77	0.46
2041	45.46	-	19.15	208.96	-	273.57	0.44
2042	39.25	-	18.20	194.43	-	251.88	0.39
2043	33.83	-	17.30	180.90	-	232.03	0.35
2044	29.29	-	16.45	168.32	-	214.05	0.35
2045	25.77	-	15.64	156.61	-	198.01	0.35
2046	22.84	-	14.87	145.71	-	183.42	0.36
Total	1,356.94	-	1,172.49	16,062.62	-	18,592.05	

*Assumes High Cost of Capital is the base case compared to High Cost of Capital Alternative 1 and Alternative 2.

High Cost of Capital: Alternative 2

Year	Annual Revenue Requirements (Generation Capital) ($millions, 2012 $)	Annual Revenue Requirements (Transmission Capital) ($millions, 2012 $)	Annual Revenue Requirements (O&M) ($millions, 2012 $)	Annual Revenue Requirements (Fuel) ($millions, 2012 $)	Annual Revenue Requirements (Environmental) ($millions, 2012 $)	Total ($millions, 2012 $)	Bill Impact (2012 $/1,000 kWh)*
2012	-	-	58.49	891.93	-	950.42	0.00
2013	-	-	56.64	846.43	-	903.08	0.00
2014	-	-	54.01	814.40	-	868.40	0.00
2015	-	-	50.66	787.74	-	838.40	0.00
2016	-	-	49.47	748.02	-	797.49	-0.07
2017	35.34	-	49.46	692.17	-	776.97	-1.37
2018	51.87	-	47.60	664.39	-	763.85	-0.12
2019	63.78	-	47.54	646.42	-	757.74	0.35
2020	58.18	-	45.53	630.05	-	733.76	0.50
2021	51.55	-	42.94	604.33	-	698.81	0.26
2022	59.66	-	42.28	585.50	-	687.45	0.49
2023	54.36	-	40.44	565.23	-	660.02	0.55
2024	48.16	-	38.52	542.26	-	628.94	0.64
2025	87.94	13.72	36.17	499.93	-	637.76	1.59
2026	78.35	12.32	34.35	477.92	-	602.93	1.36
2027	69.55	10.99	32.67	456.98	-	570.20	1.24
2028	61.70	9.81	31.37	438.63	-	541.50	1.08
2029	54.67	8.76	30.03	422.81	-	516.27	0.50
2030	48.38	7.83	28.58	401.40	-	486.19	0.40
2031	42.76	6.99	27.14	381.60	-	458.49	0.34
2032	37.78	6.24	25.67	362.90	-	432.60	0.33
2033	33.44	5.57	24.55	346.05	-	409.61	0.29
2034	29.65	4.97	23.30	326.61	-	384.52	0.27
2035	26.30	4.42	21.83	311.02	-	363.57	0.25
2036	80.45	3.93	23.18	292.32	-	399.87	-0.02
2037	77.52	3.49	22.07	277.95	-	381.03	0.24
2038	68.95	3.09	20.61	263.45	-	356.09	0.17
2039	61.31	2.73	19.68	248.47	-	332.18	0.18
2040	54.48	2.40	18.73	214.79	-	290.41	0.18
2041	48.38	2.11	17.74	199.66	-	267.90	0.15
2042	41.82	1.85	16.88	185.12	-	245.67	0.08
2043	36.07	1.62	16.06	171.64	-	225.39	0.03
2044	31.23	1.41	15.30	159.14	-	207.07	0.02
2045	27.44	1.23	14.58	147.55	-	190.80	0.02
2046	24.33	1.09	13.90	136.80	-	176.12	0.02
Total	1,545.38	116.57	1,137.94	15,741.60	-	18,541.49	

*Assumes High Cost of Capital is the base case compared to High Cost of Capital Alternative 1 and Alternative 2.

Low Load: Polk Units 2-5

Year	Annual Revenue Requirements (Generation Capital) ($millions, 2012 $)	Annual Revenue Requirements (Transmission Capital) ($millions, 2012 $)	Annual Revenue Requirements (O&M) ($millions, 2012 $)	Annual Revenue Requirements (Fuel) ($millions, 2012 $)	Annual Revenue Requirements (Environmental) ($millions, 2012 $)	Total ($millions, 2012 $)	Bill Impact (2012 $/1,000 kWh)*
2012	-	-	58.27	887.51	-	945.78	0.00
2013	-	-	56.16	838.02	-	894.18	0.00
2014	-	-	53.29	802.55	-	855.84	0.00
2015	-	-	49.78	771.23	-	821.01	0.00
2016	-	-	48.45	729.40	-	777.86	0.00
2017	62.53	19.98	45.68	653.56	-	781.74	0.00
2018	56.12	17.93	42.81	622.88	-	739.75	0.00
2019	50.09	16.01	41.46	598.01	-	705.56	0.00
2020	44.71	14.29	39.54	576.53	-	675.07	0.00
2021	39.93	12.76	37.26	554.75	-	644.70	0.00
2022	35.66	11.40	35.63	532.83	-	615.51	0.00
2023	31.85	10.18	33.91	510.65	-	586.58	0.00
2024	28.44	9.09	32.04	485.47	-	555.04	0.00
2025	25.39	8.11	30.91	467.97	-	532.39	0.00
2026	22.63	7.23	29.21	444.09	-	503.17	0.00
2027	20.15	6.44	27.67	422.77	-	477.03	0.00
2028	17.90	5.72	26.47	404.38	-	454.48	0.00
2029	15.88	5.08	25.22	388.26	-	434.44	0.00
2030	14.06	4.49	23.93	365.61	-	408.10	0.00
2031	12.42	3.97	22.76	348.27	-	387.42	0.00
2032	10.95	3.50	21.50	331.24	-	367.19	0.00
2033	9.62	3.08	20.60	316.80	-	350.11	0.00
2034	8.44	2.70	19.55	298.09	-	328.77	0.00
2035	7.37	2.36	18.29	284.54	-	312.56	0.00
2036	66.02	2.05	19.63	267.30	-	355.00	0.00
2037	59.00	1.79	18.71	254.21	-	333.71	0.00
2038	52.53	1.59	17.48	240.84	-	312.42	0.00
2039	46.79	1.41	16.64	226.81	-	291.66	0.00
2040	41.68	1.26	15.80	194.56	-	253.29	0.00
2041	37.11	1.11	14.97	180.91	-	234.10	0.00
2042	33.04	0.99	14.25	167.44	-	215.71	0.00
2043	29.40	0.87	13.58	154.98	-	198.82	0.00
2044	26.14	0.77	12.95	143.44	-	183.30	0.00
2045	23.20	0.68	12.37	132.76	-	169.00	0.00
2046	20.55	0.59	11.82	122.88	-	155.84	0.00
Total	949.58	177.42	1,008.58	14,721.55	-	16,857.13	

*Assumes Low Load is the base case compared to Low Load Alternative 1 and Alternative 2.

Low Load: Alternative 1

Year	Annual Revenue Requirements (Generation Capital) ($millions, 2012 $)	Annual Revenue Requirements (Transmission Capital) ($millions, 2012 $)	Annual Revenue Requirements (O&M) ($millions, 2012 $)	Annual Revenue Requirements (Fuel) ($millions, 2012 $)	Annual Revenue Requirements (Environmental) ($millions, 2012 $)	Total ($millions, 2012 $)	Bill Impact (2012 $/1,000 kWh)*
2012	-	-	58.27	887.51	-	945.78	0.00
2013	-	-	56.16	838.02	-	894.18	0.00
2014	-	-	53.29	802.55	-	855.84	0.00
2015	-	-	49.78	771.23	-	821.01	0.00
2016	-	-	48.45	729.40	-	777.86	0.00
2017	16.68	-	47.42	676.16	-	740.27	(2.01)
2018	16.53	-	44.49	646.56	-	707.58	(1.52)
2019	29.81	-	44.53	626.71	-	701.06	(0.15)
2020	42.49	-	43.41	604.47	-	690.37	0.81
2021	39.16	-	40.58	572.21	-	651.95	0.37
2022	34.69	-	39.00	557.34	-	631.04	0.81
2023	30.75	-	37.22	533.52	-	601.50	0.78
2024	27.25	-	35.24	511.65	-	574.15	1.00
2025	24.14	-	33.75	485.86	-	543.76	0.58
2026	21.36	-	32.13	464.47	-	517.96	0.76
2027	18.86	-	30.49	444.05	-	493.40	0.84
2028	16.62	-	29.26	424.89	-	470.78	0.83
2029	14.60	-	27.84	406.03	-	448.47	0.71
2030	12.79	-	26.35	382.72	-	421.86	0.70
2031	19.81	-	25.69	362.94	-	408.44	1.01
2032	18.30	-	24.41	347.30	-	390.01	1.10
2033	16.08	-	23.04	326.39	-	365.51	0.74
2034	14.16	-	21.96	306.78	-	342.89	0.67
2035	12.50	-	20.91	299.17	-	332.58	0.97
2036	70.69	-	21.94	271.85	-	364.49	0.45
2037	63.23	-	20.87	258.17	-	342.26	0.41
2038	56.28	-	19.83	249.40	-	325.52	0.64
2039	50.08	-	18.81	235.68	-	304.57	0.64
2040	44.55	-	17.90	202.29	-	264.74	0.56
2041	39.61	-	16.99	187.86	-	244.46	0.50
2042	34.67	-	16.16	174.62	-	225.45	0.47
2043	30.57	-	15.38	162.32	-	208.26	0.46
2044	26.65	-	14.63	150.88	-	192.16	0.43
2045	22.95	-	13.92	140.25	-	177.13	0.39
2046	20.12	-	13.25	130.37	-	163.74	0.38
Total	886.01		1,083.37	15,171.63	-	17,141.01	

*Assumes Low Load is the base case compared to Low Load Alternative 1 and Alternative 2.

Low Load: Alternative 2

Year	Annual Revenue Requirements (Generation Capital) ($millions, 2012 $)	Annual Revenue Requirements (Transmission Capital) ($millions, 2012 $)	Annual Revenue Requirements (O&M) ($millions, 2012 $)	Annual Revenue Requirements (Fuel) ($millions, 2012 $)	Annual Revenue Requirements (Environmental) ($millions, 2012 $)	Total ($millions, 2012 $)	Bill Impact (2012 $/1,000 kWh)*
2012	-	-	58.27	887.51	-	945.78	0.00
2013	-	-	56.16	838.02	-	894.18	0.00
2014	-	-	53.29	802.55	-	855.84	0.00
2015	-	-	49.78	771.23	-	821.01	0.00
2016	-	-	48.43	728.56	-	777.00	(0.04)
2017	16.68	-	47.27	668.96	-	732.91	(2.42)
2018	16.53	-	44.31	638.44	-	699.28	(2.00)
2019	29.81	-	44.19	616.03	-	690.03	(0.77)
2020	77.64	15.86	41.85	585.69	-	721.05	2.28
2021	73.80	15.66	39.32	555.93	-	684.72	1.94
2022	65.73	13.98	37.61	534.09	-	651.41	1.73
2023	58.55	12.48	35.85	511.29	-	618.17	1.51
2024	52.16	11.15	33.88	487.38	-	584.57	1.42
2025	46.45	9.96	32.73	468.80	-	557.94	1.21
2026	41.35	8.90	30.89	446.09	-	527.23	1.15
2027	36.78	7.95	29.26	423.80	-	497.79	0.98
2028	32.68	7.10	28.02	404.97	-	472.77	0.86
2029	28.99	6.33	26.72	388.74	-	450.77	0.76
2030	25.66	5.63	25.27	366.43	-	423.00	0.70
2031	22.66	5.01	24.11	349.41	-	401.19	0.64
2032	20.00	4.44	22.81	332.27	-	379.52	0.58
2033	17.64	3.94	21.77	317.73	-	361.07	0.52
2034	15.57	3.48	20.66	300.26	-	339.98	0.54
2035	13.75	3.07	19.44	286.02	-	322.27	0.45
2036	66.08	2.70	20.40	270.28	-	359.46	0.22
2037	64.39	2.37	19.94	254.25	-	340.94	0.34
2038	57.23	2.07	18.62	241.09	-	319.01	0.31
2039	50.85	1.80	17.67	227.02	-	297.34	0.27
2040	45.19	1.58	16.87	194.42	-	258.06	0.22
2041	40.21	1.39	15.98	182.61	-	240.20	0.29
2042	35.27	1.24	15.41	168.96	-	220.88	0.25
2043	31.16	1.11	14.92	156.33	-	203.51	0.23
2044	27.23	0.98	14.49	144.64	-	187.35	0.20
2045	23.98	0.87	14.13	133.83	-	172.81	0.18
2046	21.26	0.77	13.83	123.82	-	159.69	0.19
Total	1,155.29	151.80	1,054.18	14,807.45	-	17,168.71	

*Assumes Low Load is the base case compared to Low Load Alternative 1 and Alternative 2.

High Load: Polk Units 2-5

Year	Annual Revenue Requirements (Generation Capital) ($millions, 2012 $)	Annual Revenue Requirements (Transmission Capital) ($millions, 2012 $)	Annual Revenue Requirements (O&M) ($millions, 2012 $)	Annual Revenue Requirements (Fuel) ($millions, 2012 $)	Annual Revenue Requirements (Environmental) ($millions, 2012 $)	Total ($millions, 2012 $)	Bill Impact (2012 $/1,000 kWh)*
2012	-	-	58.83	897.44	-	956.27	0.00
2013	-	-	57.23	856.50	-	913.73	0.00
2014	-	-	54.83	828.79	-	883.61	0.00
2015	-	-	51.59	806.71	-	858.30	0.00
2016	17	-	51.57	770.75	-	839.80	0.00
2017	79.85	19.98	49.15	693.51	-	842.49	0.00
2018	71.45	17.93	46.36	668.25	-	803.99	0.00
2019	78.85	16.01	46.19	648.42	-	789.47	0.00
2020	86.29	14.29	45.25	633.14	-	778.97	0.00
2021	78.28	12.76	43.04	614.57	-	748.65	0.00
2022	82.82	11.40	42.39	596.28	-	732.89	0.00
2023	75.01	10.18	40.58	575.15	-	700.92	0.00
2024	78.68	9.09	39.47	555.04	-	682.28	0.00
2025	71.14	8.11	38.40	538.88	-	656.53	0.00
2026	74.05	7.23	37.15	517.43	-	635.86	0.00
2027	66.78	6.44	35.46	497.43	-	606.11	0.00
2028	69.07	5.72	34.77	479.72	-	589.28	0.00
2029	62.13	5.08	33.56	466.71	-	567.47	0.00
2030	63.92	4.49	32.51	444.06	-	544.99	0.00
2031	57.38	3.97	30.94	422.98	-	515.27	0.00
2032	50.62	3.50	29.27	401.95	-	485.34	0.00
2033	44.61	3.08	28.06	383.56	-	459.30	0.00
2034	39.25	2.70	26.46	360.33	-	428.74	0.00
2035	34.52	2.36	24.95	344.75	-	406.57	0.00
2036	89.95	2.05	26.19	321.84	-	440.02	0.00
2037	80.07	1.79	24.89	306.00	-	412.75	0.00
2038	71.06	1.59	23.39	290.95	-	386.99	0.00
2039	63.09	1.41	22.28	274.20	-	360.98	0.00
2040	56.00	1.26	21.22	238.92	-	317.40	0.00
2041	49.14	1.11	20.07	221.87	-	292.20	0.00
2042	43.36	0.99	19.08	206.08	-	269.51	0.00
2043	38.47	0.87	18.15	191.41	-	248.89	0.00
2044	33.63	0.77	17.27	177.78	-	229.44	0.00
2045	29.12	0.68	16.44	165.12	-	211.36	0.00
2046	25.58	0.59	15.65	153.37	-	195.19	0.00
Total	1,861.64	177.42	1,202.64	16,549.88	-	19,791.58	

*Assumes High Load is the base case compared to High Load Alternative 1 and Alternative 2.

High load: Alternative 1

Year	Annual Revenue Requirements (Generation Capital) ($millions, 2012 $)	Annual Revenue Requirements (Transmission Capital) ($millions, 2012 $)	Annual Revenue Requirements (O&M) ($millions, 2012 $)	Annual Revenue Requirements (Fuel) ($millions, 2012 $)	Annual Revenue Requirements (Environmental) ($millions, 2012 $)	Total ($millions, 2012 $)	Bill Impact (2012 $/1,000 kWh)*
2012	-	-	58.83	897.44	-	956.27	0.00
2013	-	-	57.23	856.50	-	913.73	0.00
2014	-	-	54.83	828.79	-	883.61	0.00
2015	-	-	51.59	806.71	-	858.30	0.00
2016	17.48	-	51.57	770.75	-	839.80	0.00
2017	50.68	-	52.10	725.45	-	828.23	(0.61)
2018	64.30	-	50.56	695.59	-	810.45	0.32
2019	73.80	-	51.03	683.96	-	808.79	0.90
2020	81.45	-	50.08	668.45	-	799.98	0.95
2021	73.69	-	47.27	644.70	-	765.66	0.76
2022	78.50	-	46.64	633.13	-	758.27	1.15
2023	70.96	-	44.86	612.97	-	728.79	1.25
2024	74.86	-	43.76	589.85	-	708.46	1.12
2025	67.52	-	42.03	570.30	-	679.85	1.01
2026	70.63	-	41.10	550.33	-	662.07	1.09
2027	63.54	-	39.48	531.46	-	634.47	1.16
2028	66.00	-	38.73	516.31	-	621.04	1.29
2029	59.23	-	37.10	497.84	-	594.17	1.08
2030	61.18	-	35.94	472.46	-	569.59	0.96
2031	54.79	-	34.39	452.97	-	542.15	1.05
2032	48.22	-	32.69	431.81	-	512.72	1.07
2033	42.50	-	30.80	405.18	-	478.48	0.75
2034	37.49	-	29.35	382.39	-	449.23	0.80
2035	33.08	-	28.08	372.28	-	433.44	1.05
2036	88.79	-	28.59	335.63	-	453.01	0.51
2037	79.12	-	27.12	316.85	-	423.08	0.40
2038	70.22	-	25.97	307.90	-	404.09	0.67
2039	62.31	-	24.60	291.04	-	377.95	0.66
2040	55.27	-	23.42	254.34	-	333.03	0.61
2041	48.46	-	22.21	236.51	-	307.17	0.59
2042	41.67	-	21.15	220.65	-	283.47	0.55
2043	35.99	-	20.13	205.86	-	261.99	0.51
2044	31.22	-	19.18	192.06	-	242.46	0.51
2045	27.01	-	18.26	179.19	-	224.46	0.51
2046	23.72	-	17.40	167.18	-	208.30	0.51
Total	1,753.69		1,298.07	17,304.81	-	20,356.57	

*Assumes High Load is the base case compared to High Load Alternative 1 and Alternative 2.

High Load: Alternative 2

Year	Annual Revenue Requirements (Generation Capital) ($millions, 2012 $)	Annual Revenue Requirements (Transmission Capital) ($millions, 2012 $)	Annual Revenue Requirements (O&M) ($millions, 2012 $)	Annual Revenue Requirements (Fuel) ($millions, 2012 $)	Annual Revenue Requirements (Environmental) ($millions, 2012 $)	Total ($millions, 2012 $)	Bill Impact (2012 $/1,000 kWh)*
2012	-	-	58.83	897.44	-	956.27	0.00
2013	-	-	57.23	856.50	-	913.73	0.00
2014	-	-	54.83	828.79	-	883.61	0.00
2015	-	-	51.59	806.71	-	858.30	0.00
2016	17.48	-	51.58	769.75	-	838.82	(0.05)
2017	50.68	-	51.83	716.76	-	819.27	(1.08)
2018	64.30	-	50.17	692.48	-	806.95	0.13
2019	73.80	-	50.36	681.10	-	805.26	0.71
2020	120.88	17.36	47.07	631.98	-	817.29	1.70
2021	107.73	15.58	44.78	614.54	-	782.64	1.49
2022	95.80	13.90	43.12	595.90	-	748.72	0.68
2023	85.19	12.41	41.37	575.68	-	714.65	0.59
2024	75.74	11.08	39.48	554.92	-	681.22	(0.04)
2025	67.28	9.90	38.40	538.88	-	654.46	(0.09)
2026	70.63	8.84	37.15	517.43	-	634.04	(0.07)
2027	63.73	7.90	35.46	497.43	-	604.52	(0.06)
2028	66.34	7.05	34.77	479.72	-	587.88	(0.06)
2029	59.67	6.28	33.56	466.71	-	566.23	(0.05)
2030	61.70	5.59	32.51	444.06	-	543.87	(0.04)
2031	55.37	4.97	30.94	422.98	-	514.26	(0.04)
2032	48.85	4.41	29.27	401.95	-	484.48	(0.03)
2033	43.16	3.90	28.06	383.56	-	458.69	(0.02)
2034	38.18	3.45	26.46	360.33	-	428.42	(0.01)
2035	33.77	3.04	24.95	344.75	-	406.51	0.00
2036	89.44	2.67	26.19	321.84	-	440.14	0.00
2037	79.69	2.34	24.89	306.00	-	412.93	0.01
2038	70.69	2.05	23.39	290.95	-	387.07	0.00
2039	62.65	1.78	22.28	274.20	-	360.91	0.00
2040	55.50	1.56	21.22	238.92	-	317.20	(0.01)
2041	48.66	1.38	20.07	221.87	-	291.98	(0.01)
2042	41.87	1.23	19.08	206.08	-	268.26	(0.05)
2043	36.19	1.09	18.15	191.41	-	246.84	(0.08)
2044	31.42	0.97	17.27	177.78	-	227.43	(0.08)
2045	27.66	0.86	16.44	165.12	-	210.07	(0.05)
2046	24.51	0.76	15.65	153.37	-	194.29	(0.04)
Total	1,868.58	152.33	1,218.39	16,627.90	-	19,867.19	

*Assumes High Load is the base case compared to High Load Alternative 1 and Alternative 2.

Low Fuel: Polk Units 2-5

Year	Annual Revenue Requirements (Generation Capital) ($millions, 2012 $)	Annual Revenue Requirements (Transmission Capital) ($millions, 2012 $)	Annual Revenue Requirements (O&M) ($millions, 2012 $)	Annual Revenue Requirements (Fuel) ($millions, 2012 $)	Annual Revenue Requirements (Environmental) ($millions, 2012 $)	Total ($millions, 2012 $)	Bill Impact (2012 $/1,000 kWh)*
2012	-	-	58.51	772.24	-	830.75	0.00
2013	-	-	56.59	679.36	-	735.95	0.00
2014	-	-	53.97	645.03	-	699.00	0.00
2015	-	-	50.65	633.98	-	684.63	0.00
2016	-	-	49.48	598.33	-	647.81	0.00
2017	62.53	19.98	46.78	540.71	-	670.00	0.00
2018	56.12	17.93	44.06	511.13	-	629.24	0.00
2019	65.27	16.01	43.79	500.11	-	625.18	0.00
2020	59.76	14.29	41.87	493.97	-	609.89	0.00
2021	53.24	12.76	39.69	484.56	-	590.25	0.00
2022	60.64	11.40	38.93	475.44	-	586.41	0.00
2023	55.37	10.18	37.20	458.04	-	560.78	0.00
2024	49.29	9.09	35.32	437.16	-	530.85	0.00
2025	55.32	8.11	34.91	421.45	-	519.79	0.00
2026	50.35	7.23	33.08	402.06	-	492.73	0.00
2027	44.69	6.44	31.45	383.71	-	466.28	0.00
2028	39.62	5.72	30.23	368.99	-	444.56	0.00
2029	44.58	5.08	29.53	352.31	-	431.49	0.00
2030	40.43	4.49	28.05	337.81	-	410.78	0.00
2031	35.70	3.97	26.68	320.38	-	386.73	0.00
2032	31.48	3.50	25.21	302.65	-	362.84	0.00
2033	27.70	3.08	24.14	289.99	-	344.91	0.00
2034	24.35	2.70	22.91	275.80	-	325.75	0.00
2035	21.39	2.36	21.47	257.18	-	302.39	0.00
2036	78.36	2.05	22.62	237.17	-	340.19	0.00
2037	69.85	1.79	21.49	225.34	-	318.47	0.00
2038	62.07	1.59	20.25	207.51	-	291.42	0.00
2039	55.18	1.41	19.31	194.10	-	270.01	0.00
2040	49.05	1.26	18.34	184.16	-	252.80	0.00
2041	43.60	1.11	17.40	173.16	-	235.28	0.00
2042	38.75	0.99	16.58	162.62	-	218.93	0.00
2043	34.41	0.87	15.81	152.71	-	203.80	0.00
2044	30.06	0.77	15.08	143.41	-	189.31	0.00
2045	26.44	0.68	14.40	134.67	-	176.19	0.00
2046	23.42	0.59	13.75	126.47	-	164.24	0.00
Total	1,389.01	177.42	1,099.51	12,883.68	-	15,549.62	

*Assumes Low Fuel is the base case compared to Low Fuel Alternative 1 and Alternative 2.

Low Fuel: Alternative 1

Year	Annual Revenue Requirements (Generation Capital) ($millions, 2012 $)	Annual Revenue Requirements (Transmission Capital) ($millions, 2012 $)	Annual Revenue Requirements (O&M) ($millions, 2012 $)	Annual Revenue Requirements (Fuel) ($millions, 2012 $)	Annual Revenue Requirements (Environmental) ($millions, 2012 $)	Total ($millions, 2012 $)	Bill Impact (2012 $/1,000 kWh)*
2012	-	-	58.51	772.24	-	830.75	0.00
2013	-	-	56.59	679.36	-	735.95	0.00
2014	-	-	53.97	645.03	-	699.00	0.00
2015	-	-	50.65	633.98	-	684.63	0.00
2016	-	-	49.49	596.68	-	646.17	(0.08)
2017	33.36	-	49.46	553.10	-	635.92	(1.64)
2018	48.97	-	47.59	523.33	-	619.88	(0.45)
2019	60.21	-	47.53	516.24	-	623.98	(0.06)
2020	54.92	-	45.55	510.70	-	611.17	0.05
2021	48.66	-	42.97	496.80	-	588.43	(0.09)
2022	56.33	-	42.33	489.87	-	588.52	0.09
2023	51.32	-	40.47	472.54	-	564.33	0.15
2024	45.46	-	38.55	452.40	-	536.41	0.25
2025	51.70	-	37.70	433.38	-	522.78	0.13
2026	46.93	-	36.05	416.08	-	499.05	0.28
2027	41.45	-	34.33	398.38	-	474.15	0.35
2028	36.56	-	33.01	384.26	-	453.83	0.40
2029	41.68	-	32.09	365.73	-	439.50	0.35
2030	37.69	-	30.59	349.94	-	418.22	0.32
2031	33.11	-	29.13	332.99	-	395.23	0.36
2032	29.08	-	27.64	315.63	-	372.35	0.41
2033	25.60	-	26.17	299.23	-	351.00	0.26
2034	22.58	-	24.98	285.04	-	332.61	0.29
2035	19.95	-	23.62	269.63	-	313.20	0.46
2036	77.20	-	24.70	242.30	-	344.20	0.17
2037	68.90	-	23.49	229.80	-	322.19	0.16
2038	61.23	-	22.29	214.34	-	297.87	0.27
2039	54.40	-	21.09	201.27	-	276.76	0.29
2040	48.32	-	20.12	190.68	-	259.12	0.27
2041	42.92	-	19.07	179.52	-	241.50	0.27
2042	37.06	-	18.12	169.07	-	224.25	0.23
2043	31.94	-	17.22	159.23	-	208.39	0.20
2044	27.65	-	16.37	149.96	-	193.98	0.20
2045	24.33	-	15.56	141.24	-	181.12	0.21
2046	21.56	-	14.79	133.02	-	169.37	0.22
Total	1,281.05	0.00	1,171.80	13,202.97	-	15,655.82	

*Assumes Low Fuel is the base case compared to Low Fuel Alternative 1 and Alternative 2.

Low Fuel: Alternative 2

Year	Annual Revenue Requirements (Generation Capital) ($millions, 2012 $)	Annual Revenue Requirements (Transmission Capital) ($millions, 2012 $)	Annual Revenue Requirements (O&M) ($millions, 2012 $)	Annual Revenue Requirements (Fuel) ($millions, 2012 $)	Annual Revenue Requirements (Environmental) ($millions, 2012 $)	Total ($millions, 2012 $)	Bill Impact (2012 $/1,000 kWh)*
2012	-	-	58.51	772.24	-	830.75	0.00
2013	-	-	56.59	679.36	-	735.95	0.00
2014	-	-	53.97	645.03	-	699.00	0.00
2015	-	-	50.65	633.98	-	684.63	0.00
2016	-	-	49.49	596.68	-	646.17	-0.08
2017	33.36	-	49.46	553.10	-	635.92	-1.64
2018	48.97	-	47.59	523.33	-	619.88	-0.45
2019	60.21	-	47.53	516.24	-	623.98	-0.06
2020	54.92	-	45.55	510.70	-	611.17	0.05
2021	48.66	-	42.97	496.80	-	588.43	-0.09
2022	56.33	-	42.33	489.87	-	588.52	0.09
2023	51.32	-	40.47	472.54	-	564.33	0.15
2024	45.46	-	38.69	455.99	-	540.15	0.44
2025	83.18	13.72	36.30	420.89	-	554.10	1.53
2026	74.11	12.32	34.41	401.66	-	522.50	1.31
2027	65.79	10.99	32.69	383.64	-	493.12	1.18
2028	58.36	9.81	31.38	368.72	-	468.28	1.03
2029	51.72	8.76	30.07	352.29	-	442.84	0.49
2030	45.77	7.83	28.59	337.61	-	419.79	0.38
2031	40.45	6.99	27.18	320.28	-	394.90	0.35
2032	35.75	6.24	25.73	302.63	-	370.35	0.32
2033	31.64	5.57	24.58	289.70	-	351.49	0.28
2034	28.05	4.97	23.32	275.45	-	331.79	0.26
2035	24.88	4.42	21.87	257.17	-	308.34	0.25
2036	81.65	3.93	22.58	237.42	-	345.58	0.23
2037	72.90	3.49	21.94	225.66	-	323.99	0.24
2038	64.83	3.09	20.61	206.59	-	295.11	0.15
2039	57.63	2.73	19.65	194.73	-	274.75	0.21
2040	51.20	2.40	18.66	184.15	-	256.42	0.15
2041	45.46	2.11	17.67	173.28	-	238.52	0.14
2042	39.28	1.85	16.92	162.71	-	220.77	0.08
2043	33.87	1.62	16.23	152.80	-	204.51	0.03
2044	29.31	1.41	15.60	143.48	-	189.80	0.02
2045	25.75	1.23	15.01	134.73	-	176.72	0.02
2046	22.81	1.09	14.47	126.52	-	164.90	0.03
Total	1,463.63	116.57	1,139.28	12,997.95	-	15,717.43	

*Assumes Low Fuel is the base case compared to Low Fuel Alternative 1 and Alternative 2.

High Fuel: Polk Units 2-5

Year	Annual Revenue Requirements (Generation Capital) ($millions, 2012 $)	Annual Revenue Requirements (Transmission Capital) ($millions, 2012 $)	Annual Revenue Requirements (O&M) ($millions, 2012 $)	Annual Revenue Requirements (Fuel) ($millions, 2012 $)	Annual Revenue Requirements (Environmental) ($millions, 2012 $)	Total ($millions, 2012 $)	Bill Impact (2012 $/1,000 kWh)*
2012	-	-	58.39	993.59	-	1051.98	0.00
2013	-	-	56.57	1013.73	-	1070.30	0.00
2014	-	-	53.96	966.59	-	1020.56	0.00
2015	-	-	50.63	951.72	-	1002.36	0.00
2016	-	-	49.43	900.75	-	950.18	0.00
2017	62.53	19.98	46.77	815.83	-	945.11	0.00
2018	56.12	17.93	44.06	776.58	-	894.69	0.00
2019	65.27	16.01	43.79	758.56	-	883.63	0.00
2020	59.76	14.29	41.86	743.70	-	859.61	0.00
2021	53.24	12.76	39.68	727.28	-	832.97	0.00
2022	60.64	11.40	38.93	705.49	-	816.46	0.00
2023	55.37	10.18	37.18	677.52	-	780.25	0.00
2024	49.29	9.09	35.32	646.93	-	740.63	0.00
2025	55.32	8.11	34.94	623.69	-	722.06	0.00
2026	50.35	7.23	33.09	595.33	-	686.01	0.00
2027	44.69	6.44	31.45	567.18	-	649.76	0.00
2028	39.62	5.72	30.25	542.99	-	618.58	0.00
2029	44.58	5.08	29.60	524.89	-	604.15	0.00
2030	40.43	4.49	28.07	494.83	-	567.83	0.00
2031	35.70	3.97	26.73	470.58	-	536.98	0.00
2032	31.48	3.50	25.24	447.27	-	507.49	0.00
2033	27.70	3.08	24.14	425.01	-	479.93	0.00
2034	24.35	2.70	22.90	398.86	-	448.81	0.00
2035	21.39	2.36	21.47	383.81	-	429.03	0.00
2036	78.36	2.05	23.14	363.95	-	467.49	0.00
2037	69.85	1.79	22.11	345.61	-	439.36	0.00
2038	62.07	1.59	20.69	334.13	-	418.48	0.00
2039	55.18	1.41	19.53	314.84	-	390.97	0.00
2040	49.05	1.26	18.59	297.51	-	366.41	0.00
2041	43.60	1.11	17.60	281.91	-	344.22	0.00
2042	38.75	0.99	16.71	267.88	-	324.32	0.00
2043	34.41	0.87	15.88	254.54	-	305.71	0.00
2044	30.06	0.77	15.09	241.88	-	287.80	0.00
2045	26.44	0.68	14.35	229.84	-	271.31	0.00
2046	23.42	0.59	13.66	218.40	-	256.07	0.00
Total	1,389.01	177.42	1,101.83	19,303.22	-	21,971.48	

*Assumes High Fuel is the base case compared to High Fuel Alternative 1 and Alternative 2.

High Fuel: Alternative 1

Year	Annual Revenue Requirements (Generation Capital) ($millions, 2012 $)	Annual Revenue Requirements (Transmission Capital) ($millions, 2012 $)	Annual Revenue Requirements (O&M) ($millions, 2012 $)	Annual Revenue Requirements (Fuel) ($millions, 2012 $)	Annual Revenue Requirements (Environmental) ($millions, 2012 $)	Total ($millions, 2012 $)	Bill Impact (2012 $/1,000 kWh)*
2012	-	-	58.39	993.59	-	1051.98	0.00
2013	-	-	56.57	1013.73	-	1070.30	0.00
2014	-	-	53.96	966.59	-	1020.56	0.00
2015	-	-	50.63	951.72	-	1002.36	0.00
2016	-	-	49.44	899.71	-	949.15	(0.05)
2017	33.36	-	49.47	842.51	-	925.34	(0.95)
2018	48.97	-	47.60	803.29	-	899.85	0.24
2019	60.21	-	47.56	792.91	-	900.69	0.80
2020	54.92	-	45.56	780.52	-	881.01	0.99
2021	48.66	-	43.22	755.05	-	846.93	0.63
2022	56.33	-	42.63	737.23	-	836.19	0.90
2023	51.32	-	40.80	709.83	-	801.95	0.98
2024	45.46	-	38.87	680.03	-	764.37	1.07
2025	51.70	-	38.01	650.90	-	740.61	0.83
2026	46.93	-	36.36	625.68	-	708.96	1.01
2027	41.45	-	34.69	598.01	-	674.14	1.07
2028	36.56	-	33.37	575.31	-	645.24	1.16
2029	41.68	-	32.47	553.55	-	627.70	1.02
2030	37.69	-	30.90	521.23	-	589.81	0.94
2031	33.11	-	29.47	497.35	-	559.93	0.98
2032	29.08	-	28.01	474.81	-	531.91	1.04
2033	25.60	-	26.21	445.57	-	497.37	0.75
2034	22.58	-	25.00	419.84	-	467.43	0.80
2035	19.95	-	23.70	410.30	-	453.95	1.07
2036	77.20	-	24.82	375.63	-	477.66	0.43
2037	68.90	-	23.59	355.05	-	447.54	0.35
2038	61.23	-	22.40	348.68	-	432.31	0.58
2039	54.40	-	21.21	329.63	-	405.25	0.61
2040	48.32	-	20.23	311.13	-	379.68	0.57
2041	42.92	-	19.18	295.23	-	357.33	0.56
2042	37.06	-	18.23	281.38	-	336.67	0.53
2043	31.94	-	17.33	268.18	-	317.44	0.50
2044	27.65	-	16.48	255.59	-	299.72	0.51
2045	24.33	-	15.66	243.60	-	283.59	0.53
2046	21.56	-	14.90	232.17	-	268.63	0.54
Total	1,281.05	-	1,176.94	19,995.55	-	22,453.54	

*Assumes High Fuel is the base case compared to High Fuel Alternative 1 and Alternative 2.

High Fuel: Alternative 2

Year	Annual Revenue Requirements (Generation Capital) ($millions, 2012 $)	Annual Revenue Requirements (Transmission Capital) ($millions, 2012 $)	Annual Revenue Requirements (O&M) ($millions, 2012 $)	Annual Revenue Requirements (Fuel) ($millions, 2012 $)	Annual Revenue Requirements (Environmental) ($millions, 2012 $)	Total ($millions, 2012 $)	Bill Impact (2012 $/1,000 kWh)*
2012	-	-	58.39	993.59	-	1,051.98	0.00
2013	-	-	56.57	1,013.73	-	1,070.30	0.00
2014	-	-	53.96	966.59	-	1,020.56	0.00
2015	-	-	50.63	951.72	-	1,002.36	0.00
2016	-	-	49.44	899.71	-	949.15	-0.05
2017	33.36	-	49.47	842.51	-	925.34	-0.95
2018	48.97	-	47.60	803.29	-	899.85	0.24
2019	60.21	-	47.56	792.91	-	900.69	0.80
2020	54.92	-	45.56	780.52	-	881.01	0.99
2021	48.66	-	43.22	755.05	-	846.93	0.63
2022	56.33	-	42.63	737.23	-	836.19	0.90
2023	51.32	-	40.80	709.83	-	801.95	0.98
2024	45.46	-	39.05	682.94	-	767.45	1.24
2025	83.18	13.72	36.35	622.93	-	756.19	1.52
2026	74.11	12.32	34.44	595.02	-	715.89	1.32
2027	65.79	10.99	32.70	566.99	-	676.48	1.17
2028	58.36	9.81	31.41	542.80	-	642.39	1.03
2029	51.72	8.76	30.15	525.18	-	615.81	0.50
2030	45.77	7.83	28.62	494.52	-	576.73	0.38
2031	40.45	6.99	27.22	470.39	-	545.05	0.35
2032	35.75	6.24	25.76	447.24	-	514.98	0.32
2033	31.64	5.57	24.58	424.62	-	486.41	0.28
2034	28.05	4.97	23.31	398.55	-	454.88	0.26
2035	24.88	4.42	21.88	384.00	-	435.18	0.26
2036	81.65	3.93	22.81	364.87	-	473.26	0.25
2037	72.90	3.49	22.50	345.95	-	444.83	0.24
2038	64.83	3.09	21.03	333.07	-	422.01	0.14
2039	57.63	2.73	19.87	315.55	-	395.78	0.21
2040	51.20	2.40	18.92	297.53	-	370.06	0.16
2041	45.46	2.11	17.88	281.94	-	347.40	0.14
2042	39.28	1.85	17.13	267.78	-	326.04	0.07
2043	33.87	1.62	16.43	254.33	-	306.25	0.02
2044	29.31	1.41	15.79	241.55	-	288.06	0.01
2045	25.75	1.23	15.20	229.42	-	271.59	0.01
2046	22.81	1.09	14.66	217.89	-	256.45	0.02
Total	1,463.63	116.57	1,143.54	19,551.77	-	22,275.50	

*Assumes High Fuel is the base case compared to High Fuel Alternative 1 and Alternative 2.

47. Please complete the table below describing the revenue requirements for each resource plan and sensitivity contained in Exhibit RJR-1, Document No. 13. Please provide response in hard copy and in Excel format as available.

	Annual Revenue Requirements (Generation Capital) ($millions, 2012 $)	Annual Revenue Requirements (Transmission Capital) ($millions, 2012 $)	Annual Revenue Requirements (O&M) ($millions, 2012 $)	Annual Revenue Requirements (Fuel) ($millions, 2012 $)	Annual Revenue Requirements (Environmental) ($millions, 2012 $)	Total ($millions, 2012 $)	Bill Impact ($/1,000 kWh)
2012							
2013							
2014							
2015							
2016							
2017							
2018							
2019							
2020							
2021							
2022							
2023							
2024							
2025							
2026							
2027							
2028							
2029							
2030							
2031							
2032							
Total							

A. The requested information is provided in the following table.

Polk Units 2-5

Year	Annual Revenue Requirements (Generation Capital) ($millions, 2012 $)	Annual Revenue Requirements (Transmission Capital) ($millions, 2012 $)	Annual Revenue Requirements (O&M) ($millions, 2012 $)	Annual Revenue Requirements (Fuel) ($millions, 2012 $)	Annual Revenue Requirements (Environmental) ($millions, 2012 $)	Total ($millions, 2012 $)	Bill Impact (2012 $/1,000 kWh)*
2012	-	-	55.61	759.59	-	815.20	0.00
2013	-	-	38.24	657.73	-	695.96	0.00
2014	-	-	37.73	640.07	-	677.80	0.00
2015	-	-	35.92	626.37	-	662.29	0.00
2016	-	-	34.92	590.65	-	625.57	0.00
2017	63.52	19.98	32.59	537.61	-	653.70	0.00
2018	57.01	17.93	31.25	517.11	-	623.31	0.00
2019	50.88	16.01	30.20	491.40	-	588.49	0.00
2020	59.91	14.29	29.84	474.50	-	578.55	0.00
2021	54.91	12.76	28.74	455.32	-	551.73	0.00
2022	48.93	11.40	27.61	440.46	-	528.40	0.00
2023	56.19	10.18	27.38	435.37	-	529.12	0.00
2024	51.34	9.09	26.21	423.04	-	509.68	0.00
2025	45.68	8.11	25.47	408.02	-	487.29	0.00
2026	51.55	7.23	24.82	393.23	-	476.84	0.00
2027	46.91	6.44	23.86	385.10	-	462.31	0.00
2028	41.60	5.72	22.89	372.03	-	442.24	0.00
2029	46.35	5.08	22.69	359.73	-	433.85	0.00
2030	42.01	4.49	21.57	348.18	-	416.25	0.00
2031	37.13	3.97	20.87	341.17	-	403.14	0.00
2032	32.77	3.50	19.77	327.61	-	383.65	0.00
2033	28.87	3.08	18.99	315.39	-	366.33	0.00
2034	25.38	2.70	17.77	304.92	-	350.77	0.00
2035	22.28	2.36	17.04	300.88	-	342.55	0.00
2036	79.14	2.05	19.38	290.26	-	390.83	0.00
2037	70.54	1.79	18.47	278.63	-	369.43	0.00
2038	62.66	1.59	17.91	275.72	-	357.88	0.00
2039	55.70	1.41	17.17	268.18	-	342.47	0.00
2040	49.51	1.26	16.29	255.19	-	322.24	0.00
2041	43.98	1.11	15.51	245.63	-	306.24	0.00
2042	39.08	0.99	14.86	237.59	-	292.52	0.00
2043	34.71	0.87	14.25	229.80	-	279.64	0.00
2044	30.81	0.77	13.66	222.28	-	267.52	0.00
2045	26.86	0.68	13.10	215.00	-	255.64	0.00
2046	23.59	0.59	12.57	207.96	-	244.71	0.00
Total	1,379.80	177.42	845.20	13,631.72	-	16,034.14	

*Assumes the Polk 2-5 utilizing June 2012 assumptions is the base case compared to Alternative 2 and Proposal B.

Alternative 2

Year	Annual Revenue Requirements (Generation Capital) ($millions, 2012 $)	Annual Revenue Requirements (Transmission Capital) ($millions, 2012 $)	Annual Revenue Requirements (O&M) ($millions, 2012 $)	Annual Revenue Requirements (Fuel) ($millions, 2012 $)	Annual Revenue Requirements (Environmental) ($millions, 2012 $)	Total ($millions, 2012 $)	Bill Impact (2012 $/1,000 kWh)*
2012	-	-	55.62	759.63	-	815.26	0.00
2013	-	-	38.25	657.80	-	696.05	0.00
2014	-	-	37.73	640.07	-	677.80	0.00
2015	-	-	35.92	626.37	-	662.29	0.00
2016	-	-	34.90	590.77	-	625.67	0.00
2017	33.36	-	35.50	551.19	-	620.05	(1.68)
2018	33.05	-	34.09	530.77	-	597.92	(1.26)
2019	44.44	-	34.20	509.97	-	588.61	0.00
2020	55.45	-	33.65	493.32	-	582.42	0.17
2021	50.65	-	32.27	471.23	-	554.16	0.10
2022	44.88	-	31.17	457.64	-	533.69	0.24
2023	52.37	-	30.64	453.36	-	536.37	0.29
2024	47.72	-	29.53	440.50	-	517.76	0.32
2025	42.25	-	28.34	424.14	-	494.73	0.32
2026	73.82	11.97	26.59	395.99	-	508.37	1.41
2027	68.99	11.81	25.83	400.22	-	506.86	2.05
2028	61.23	10.55	24.75	378.45	-	474.98	1.44
2029	54.30	9.42	23.82	365.20	-	452.73	0.83
2030	48.10	8.41	22.60	352.71	-	431.82	0.67
2031	42.55	7.51	22.06	354.05	-	426.17	1.03
2032	37.64	6.71	20.90	336.64	-	401.89	0.80
2033	33.34	6.00	19.90	319.80	-	379.04	0.54
2034	29.54	5.35	18.63	308.70	-	362.22	0.49
2035	26.19	4.77	18.07	310.59	-	359.62	0.76
2036	77.17	4.25	19.97	303.95	-	405.34	0.67
2037	74.29	3.78	19.29	280.53	-	377.88	0.36
2038	66.07	3.35	18.70	277.62	-	365.74	0.34
2039	58.76	2.97	17.99	271.33	-	351.05	0.36
2040	52.24	2.62	17.02	258.66	-	330.54	0.36
2041	46.42	2.31	16.21	249.68	-	314.62	0.37
2042	40.16	2.03	15.64	240.11	-	297.95	0.25
2043	35.18	1.78	15.12	230.92	-	283.00	0.16
2044	30.71	1.56	14.64	222.07	-	268.98	0.08
2045	26.52	1.36	14.19	213.57	-	255.63	0.01
2046	23.25	1.19	13.79	205.38	-	243.61	(0.03)
Total	1,410.65	109.71	897.55	13,882.92	-	16,300.83	

*Assumes the Polk 2-5 utilizing June 2012 assumptions is the base case compared to Alternative 2 and Proposal B.

Proposal B

Year	Annual Revenue Requirements (Generation Capital) ($millions, 2012 $)	Annual Revenue Requirements (Transmission Capital) ($millions, 2012 $)	Annual Revenue Requirements (O&M) ($millions, 2012 $)	Annual Revenue Requirements (Fuel) ($millions, 2012 $)	Annual Revenue Requirements (Environmental) ($millions, 2012 $)	Total ($millions, 2012 $)	Bill Impact (2012 $/1,000 kWh)*
2012	-	-	55.62	759.63	-	815.26	0.00
2013	13.87	-	38.05	673.24	-	725.16	1.52
2014	14.13	-	37.18	664.79	-	716.11	1.98
2015	12.51	-	35.27	648.63	-	696.41	1.75
2016	11.09	-	34.13	598.58	-	643.80	0.92
2017	9.83	-	32.84	570.54	-	613.21	-2.02
2018	8.72	-	31.43	548.79	-	588.93	-1.70
2019	60.04	16.63	30.48	514.36	-	621.50	1.63
2020	58.48	16.41	28.86	488.06	-	591.81	0.62
2021	52.14	14.65	27.74	468.50	-	563.03	0.53
2022	46.49	13.08	26.62	452.01	-	538.21	0.46
2023	41.45	11.68	25.61	444.28	-	523.03	-0.30
2024	36.95	10.44	24.48	431.20	-	503.06	-0.32
2025	32.93	9.32	23.84	416.91	-	483.00	-0.20
2026	29.34	8.33	22.71	401.84	-	462.21	-0.66
2027	36.54	7.44	22.38	396.28	-	462.63	0.04
2028	33.56	6.63	21.46	379.35	-	441.00	-0.06
2029	39.31	5.90	21.35	366.64	-	433.20	-0.03
2030	35.88	5.25	20.37	354.49	-	416.00	-0.01
2031	31.81	4.66	19.60	346.39	-	402.46	-0.03
2032	28.19	4.13	18.56	332.71	-	383.58	0.00
2033	24.95	3.65	17.83	320.23	-	366.66	0.01
2034	22.06	3.21	16.79	309.48	-	351.53	0.03
2035	19.47	2.83	16.03	304.77	-	343.09	0.02
2036	76.74	2.48	18.58	293.50	-	391.30	0.02
2037	68.44	2.17	17.70	281.90	-	370.21	0.03
2038	60.34	1.89	17.16	278.02	-	357.40	-0.02
2039	53.31	1.65	16.42	270.11	-	341.49	-0.04
2040	47.37	1.46	15.59	257.09	-	321.52	-0.03
2041	42.10	1.30	14.85	247.31	-	305.56	-0.03
2042	37.40	1.16	14.23	239.02	-	291.81	-0.03
2043	33.24	1.03	13.63	230.97	-	278.87	-0.03
2044	29.53	0.91	13.07	223.21	-	266.72	-0.03
2045	26.21	0.81	12.53	215.75	-	255.29	-0.01
2046	23.24	0.71	12.02	208.53	-	244.50	-0.01
Total	1,197.65	159.81	814.99	13,937.11	-	16,109.56	

*Assumes the Polk 2-5 utilizing June 2012 assumptions is the base case compared to Alternative 2 and Proposal B.

48. Please refer to TECO's May 1, 2012, response to Staff's Supplemental Data Request, No. 59 in the 2012 Ten Year Site Plan Review.

a. Why does the natural gas price forecast in TECO's response vary from the natural gas price forecast appearing in Document No. 1 attached to witness Caldwell's Direct Testimony?

b. What are TECO's No. 2 Oil ($/Gallon), Illinois Basin Coal ($/ton), and residual oil price forecasts sponsored by witness Caldwell in this proceeding as provided in $/MMBtu?

c. Are TECO's No. 2 Oil, Illinois Basin Coal and residual oil price forecasts stated in $/MMBtu the same price forecasts as appears in TECO's May 1, 2012 response to Staff's Supplemental Data Request, No. 59 in the 2012 Ten Year Site Plan Review?

(i) If not, why not?

A. a. The natural gas price forecast in Tampa Electric's response to Staff's Supplemental Data Request, No. 59, in the Ten Year Site Plan Review, is the same natural gas price forecast appearing in Document No. 1 of Exhibit JBC-1 to witness Caldwell's direct testimony. The forecast in Document No. 1 is for the fuel commodity only while the forecast in the Supplemental Data request contains the same fuel commodity forecast along with additional transportation costs for delivery of the commodity to the generation station.

b. The requested information is provided in the following table.

$/MMBtu

Year	Natural Gas	No. 2 Oil	Illinois Basin Coal
2013	$5.12	$24.04	$2.42
2014	$5.39	$25.32	$2.45
2015	$5.67	$26.62	$2.56
2016	$5.95	$27.96	$2.41
2017	$6.23	$29.25	$2.40
2018	$6.51	$30.58	$2.27
2019	$6.79	$31.88	$2.43
2020	$7.07	$33.17	$2.59

Year	Natural Gas	No. 2 Oil	Illinois Basin Coal
2021	$7.34	$34.48	$2.75
2022	$7.63	$35.83	$2.90
2023	$7.80	$36.62	$3.01
2024	$7.97	$37.42	$3.11
2025	$8.14	$38.22	$3.22
2026	$8.31	$39.04	$3.32
2027	$8.49	$39.86	$3.43
2028	$8.67	$40.70	$3.54
2029	$8.85	$41.55	$3.65
2030	$9.03	$42.41	$3.76
2031	$9.22	$43.29	$3.87
2032	$9.41	$44.19	$3.99
2033	$9.61	$45.10	$4.11
2034	$9.80	$46.03	$4.23
2035	$10.01	$46.98	$4.35
2036	$10.21	$47.95	$4.48
2037	$10.42	$48.93	$4.61
2038	$10.64	$49.94	$4.74
2039	$10.85	$50.96	$4.87
2040	$11.08	$52.00	$5.01

c. Yes, the forecast fuel prices in Document No. 1 and in Staff's Supplemental Data Request, No. 59, in the 2012 Ten Year Site Plan Review are the same fuel commodity price. The forecasts appear different because the prices in Staff's Supplemental Data Request, No. 59, represent the fully delivered cost including transportation to the generation station. The fuel prices in witness Caldwell's Document No. 1 are fuel commodity only.

(i) This question is not applicable.

49. Witness Caldwell's Direct Testimony at Page 12, Lines 10-12, indicates that TECO's fuel price forecasts includes both the commodity and delivery prices for the various fuels.

a. What does witness Caldwell mean by the term "delivery" for each fuel type?

b. For purposes of the fuel price forecasts, where are the origination, transfer, and delivery points for each fuel type?

A. a. Coal – Delivery means the cost to transport via, as applicable, water, rail, and truck, plus, to the extent applicable, the cost for terminal services and storage of the commodity along that transportation path.

Natural Gas – Delivery means the cost to transport natural gas including fuel, usage and reservation charges for the interstate pipelines used to move the natural gas from the supply point to the generation station.

Oil – Delivery includes the cost to transport the oil from a terminal to the generation station, including applicable taxes.

b. **Coal (and Pet Coke)**

Origination	Various docks and mines in the Illinois Basin, Colorado, Columbia and Gulf Coast refineries
Transfer Points	United Bulk Terminal in Davant, Louisiana, Big Bend Station
Delivery Points	Big Bend Station, Polk Station

Natural Gas

Origination	Gulf Coast and on-shore supply into Florida Gas Transmission and Gulfstream Pipeline
Transfer Points	Not applicable
Delivery Points	Big Bend Station, Polk Station and Bayside Station

Oil

Origination	Gulf Coast refineries
Transfer Points	Tampa Terminal
Delivery Points	Big Bend Station and Polk Station

50. What are the commodity, transportation, and delivered prices, in real and nominal terms, for TECO's 2013-2040 delivered fuel price forecast shown in Document No. 1 attached to witness Caldwell's direct testimony and TECO's residual oil price forecast referenced on page 14 of witness Caldwell's direct testimony?

a. If transportation price for the various fuels has multiple components (e.g. natural gas "basis" plus additional contract delivery prices), please provide each component price and total transportation price.

A. The real and nominal prices for each commodity are shown in the tables below. Please note, Tampa Electric projects the price of residual oil but does not consume any residual oil in its generation units.

a. Please see the attached tables.

REDACTED

TAMPA ELECTRIC COMPANY
DOCKET NO. 120234-EI
STAFF'S SECOND SET OF INTERROGATORIES
INTERROGATORY NO. 50

FILED: OCTOBER 23, 2012
REVISED: OCTOBER 31, 2012

2013-2040 Delivered Price Forecast
$/MMBtu (Nominal Dollars)

	Natural Gas					No. 2 Oil			Illinois Basin Coal		
Year	Commodity*	Basis	Variable Transport	Pipeline Reservation & Storage	Total Delivered Cost	Commodity*	Transportation	Total Delivered Cost	Commodity*	Waterborne Transportation	Total Delivered Cost
2013	$5.12					$24.04			$2.42		
2014	$5.39					$25.32			$2.45		
2015	$5.67					$26.62			$2.56		
2016	$5.95					$27.96			$2.41		
2017	$6.23					$29.25			$2.40		
2018	$6.51					$30.58			$2.27		
2019	$6.79					$31.88			$2.43		
2020	$7.07					$33.17			$2.59		
2021	$7.34					$34.48			$2.75		
2022	$7.63					$35.83			$2.90		
2023	$7.80					$36.62			$3.01		
2024	$7.97					$37.42			$3.11		
2025	$8.14					$38.22			$3.22		
2026	$8.31					$39.04			$3.32		
2027	$8.49					$39.86			$3.43		
2028	$8.67					$40.70			$3.54		
2029	$8.85					$41.55			$3.65		
2030	$9.03					$42.41			$3.76		
2031	$9.22					$43.29			$3.87		
2032	$9.41					$44.19			$3.99		
2033	$9.61					$45.10			$4.11		
2034	$9.80					$46.03			$4.23		
2035	$10.01					$46.98			$4.35		
2036	$10.21					$47.95			$4.48		
2037	$10.42					$48.93			$4.61		
2038	$10.64					$49.94			$4.74		
2039	$10.85					$50.96			$4.87		
2040	$11.08					$52.00			$5.01		

*Commodity Costs are the costs referenced in Document No. 1 of Witness Caldwell's direct testimony

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REDACTED

TAMPA ELECTRIC COMPANY
DOCKET NO. 120234-EI
STAFF'S SECOND SET OF INTERROGATORIES
INTERROGATORY NO. 50

FILED: OCTOBER 23, 2012
REVISED: OCTOBER 31, 2012

2013-2040 Delivered Price Forecast
$/MMBtu (Real Dollars)

	Natural Gas					No. 2 Oil			Illinois Basin Coal		
Year	Commodity*	Basis	Variable Transport	Pipeline Reservation & Storage	Total Delivered Cost	Commodity*	Transportation	Total Delivered Cost	Commodity*	Waterborne Transportation	Total Delivered Cost
2013	$5.05	[redacted]				$23.70			$2.38		
2014	$5.17					$24.29			$2.35		
2015	$5.31					$24.91			$2.40		
2016	$5.46					$25.64			$2.21		
2017	$5.60					$26.29			$2.16		
2018	$5.73					$26.91			$2.00		
2019	$5.85					$27.45			$2.09		
2020	$5.95					$27.94			$2.18		
2021	$6.05					$28.41			$2.26		
2022	$6.15					$28.89			$2.34		
2023	$6.15					$28.89			$2.37		
2024	$6.15					$28.89			$2.40		
2025	$6.15					$28.89			$2.43		
2026	$6.15					$28.89			$2.46		
2027	$6.15					$28.89			$2.48		
2028	$6.15					$28.89			$2.51		
2029	$6.15					$28.89			$2.54		
2030	$6.15					$28.89			$2.56		
2031	$6.15					$28.89			$2.59		
2032	$6.15					$28.89			$2.61		
2033	$6.15					$28.89			$2.63		
2034	$6.15					$28.89			$2.65		
2035	$6.15					$28.89			$2.68		
2036	$6.15					$28.89			$2.70		
2037	$6.15					$28.89			$2.72		
2038	$6.15					$28.89			$2.74		
2039	$6.15					$28.89			$2.76		
2040	$6.15					$28.89			$2.78		

*Commodity Costs are the costs referenced in Document No. 1 of Witness Caldwell's direct testimony.

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51. What were TECO's 2011 actual prices (commodity and transportation combined, similar to the prices appearing in Document 1 attached to witness Caldwell's direct testimony) for natural gas, No. 2 Oil, residual oil, and Illinois Basin Coal?

A. Document No. 1 only contains fuel commodity prices and no associated delivery components. While not directly comparable with the prices shown in Document No. 1, the fully delivered (commodity and transportation combined) prices for 2011 are shown below.

Tampa Electric
A-3 Schedules 2011

	Natural Gas $/MMBtu	No. 2 Oil $/MMBtu	Coal $/MMBtu
January	$6.30	$18.30	$3.18
February	$6.31		$2.99
March	$3.96	$20.57	$3.27
April	$8.76	$19.89	$3.21
May	$6.37	$21.26	$3.28
June	$5.95		$3.34
July	$6.15	$19.69	$3.46
August	$6.11		$3.46
September	$5.67	$20.67	$3.60
October	$5.86		$3.88
November	$6.93	$21.99	$3.53
December	$7.21	$20.56	$3.42
	$6.30	$20.36	$3.38

52. Why did TECO use the Consumer Price Index Less Energy to escalate natural gas, for Years 11 through 30 of its natural gas price forecast, as stated in witness Caldwell's direct testimony at page 13 and 14?

A. Tampa Electric used the Consumer Price Index ("CPI") Less Energy to escalate the price of the natural gas commodity for years 11 through 30 because it represents the projected strength of the U.S. economy and the U.S. dollar. Additionally, it is an accepted and readily available factor. Thus, the CPI Less Energy is a reasonable escalation factor for extending the forecast beyond the NYMEX term.

Tampa Electric considered other escalation factors such as the Gross Domestic Product, the Producer Price Index, and the NYMEX outer years' escalation rate. Tampa Electric selected to use the CPI Less Energy because it reflects the broadest range of economic strength.

53. Refer to witness Caldwell's direct testimony, page 13.

a. Is it a correct assumption that TECO used the escalation rates of the NYMEX Natural Gas Futures Contract plus FGT Zone 3 basis to forecast Years 3 through 10 of its distillate oil price forecast?

b. If so, why is this method of escalating TECO's distillate oil prices appropriate?

c. Is it a correct assumption that TECO used the Consumer Price Index Less Energy to forecast Years 11 through 30 of its distillate oil price forecast?

d. If so, why is this method of escalating TECO's distillate oil prices appropriate?

A. a. Yes.

b. Using the natural gas price changes as the basis for the distillate oil price changes is based on the rationale that natural gas is the marginal fuel for electric generation. As such, it will influence the pricing of competitive electric generation fuels. While there is not a direct correlation, since distillate is used solely as a backup fuel by Tampa Electric, this is a reasonable methodology for escalating distillate oil prices.

c. Yes.

d. This is the same method that Tampa Electric used to escalate those years for the natural gas forecast. Also see the company's response to part (b).

54. Referring to witness Caldwell's direct testimony, page 13, what is the method by which TECO has evaluated the historical relationship between its residual oil and distillate oil costs that underpins its residual oil price forecast?

A. The projection of residual oil pricing is derived by using the actual ratio of residual oil pricing for electric generation to distillate oil pricing for electric generation, as reported by the Energy Information Administration in its 2010 Annual Energy Outlook. This ratio is applied to Tampa Electric's projected distillate oil price forecast to generate the projected residual oil price forecast.

55. Why is TECO's coal price forecast based on decreasing market indices percentages until the Wood Mac forecast is 100 percent of TECO's coal price forecast by 2018 as stated in witness Caldwell's direct testimony at page 15?

A. The published market price indicators for the coal market provide indicative pricing for a couple of years. Tampa Electric uses this market intelligence for the near-term portion of its thirty-year coal price forecast. Tampa Electric also uses long-term coal price forecasts from third party consultants for the mid-term portion of its coal price forecast. To transition between these two sources, Tampa Electric blends the two sources together. A higher weight is given to the market intelligence sources for the first couple years, and then this weight is decreased and a higher weight is given to the long-term consultant forecast for the remaining portion of the transition. For example, the standard low Illinois Basin coal price weights by year are listed below.

Year	%Market Index (Argus)	%Long-term Consultant (WM)
2011	100	0
2012	75	25
2013	50	50
2014+	0	100

56. Referring to witness Caldwell's direct testimony at page 15, why is TECO's coal price forecast from 2019 through 2040 escalated according to TECO's escalation rates of natural gas, distillate oil, and residual oil?

A. Tampa Electric escalates all commodities, including coal, on a consistent basis driven by the change in pricing of natural gas. This escalation methodology is based on the rationale that natural gas is the marginal fuel for electric generation, and other competitive electric generation fuels will reflect the pricing of the marginal fuel. This competitive relationship between coal-fired units and efficient combined cycle natural gas units has been evident in the electric generation market for much of 2012 and is expected to occur periodically in the near future. This methodology also keeps the prices of different commodities from diverging or converging dramatically and, thus, possibly distorting the economic analysis.

57. What is the name and date of each previous FPSC filing containing TECO's official long-term forecast prepared in the summer of 2011 as referenced in witness Caldwell's direct testimony, page 12?

A. Tampa Electric annually prepares a 30-year fuel price forecast each summer in support of the Fuel and Purchased Power Cost Recovery Clause projection filed with the Commission in late August or early September of each year. This annual forecast is then used for all regulatory filings and economic analysis for the subsequent year until a new forecast is prepared the following year.

The long-term fuel price forecast used for the Need Determination was also used in the activities listed below.

- Fuel and Purchased Power Cost Recovery Clause Projection for 2012 filed September 1, 2011
- Request for Proposals for Power issued March 23, 2012
- Ten-Year Site Plan filed April 1, 2012
- Petition for Determination of Need filed September 12, 2012

58. Referring to witness Caldwell's direct testimony at page 13, why does TECO base the first 10 years of its natural gas price forecast on the NYMEX price to Henry Hub plus basis cost for delivery to FGT Zone 3 rather than base its forecast on the cost of natural gas delivered to TECO's service area?

A. Tampa Electric's natural gas forecast includes all costs incurred to deliver the natural gas to its gas-fired generation units. In addition to the commodity cost at the Henry Hub, the delivered cost includes locational basis, which is the cost to get the natural gas to the pipelines on which Tampa Electric holds transportation rights, the variable transportation charges on those pipelines such as usage and fuel, the fixed costs associated with reserving capacity on those pipelines, and the fixed costs associated with underground storage.

Witness Caldwell's testimony focuses primarily on the market price of the natural gas commodity. The testimony discusses the commodity price because the commodity price constitutes the majority, approximately 75 percent, of the total delivered cost and, as a market commodity, is also the most volatile portion of the total delivered cost.

59. What is the basis for the fuel price sensitivity ranges prepared by TECO (e.g. 35 percent for oil and gas, 20 percent for coal) as stated by witness Caldwell in his direct testimony on page 16?

A. The basis of the fuel price sensitivity ranges is the historic annual prices of each commodity for the time period between 2005 and 2010. After examining the range and the standard deviation, a representative sensitivity range was selected. The table below summarizes the data and the sensitivities used.

Summary of Historic Fuel Price Variations
2005 - 2010

2005	$8.62	$1.64	$36.99
2006	$7.23	$1.84	$38.31
2007	$6.86	$2.04	$33.75
2008	$9.03	$2.85	$64.41
2009	$3.99	$1.66	$46.65
2010	$4.39	$2.14	$44.30
Average 2005 - 2010	$6.69	$2.03	$44.07
High 2005 - 2010	$9.03	$2.85	$64.41
Low 2005 - 2010	$3.99	$1.64	$33.75
Range	$5.05	$1.22	$30.66
Half of Range	$2.52	$0.61	$15.33
Standard Deviation 2005 - 2010	$2.10	$0.45	$11.05

60. For each fuel price forecast prepared by TECO and referenced in witness Caldwell's direct testimony, what are the specific independent forecasts (including forecasted data as well as each forecast's source, date, and forecast description) which TECO used for purposes of comparison to its own fuel price forecast?

A. Tampa Electric compared its fuel price forecasts to the Wood Mackenzie long-term price outlooks dated April, 2011 and November, 2011. Tampa Electric also compared its natural gas price forecast to the Energy Information Administration's Annual Energy Outlook, Early Release, dated December, 2011. Tampa Electric reviewed its price forecasts for coal and petroleum coke against the price forecast from JD Energy dated April, 2011. These forecasts are included in the company's response to Staff's Second Request for Production of Documents, No. 20.

AFFIDAVIT

STATE OF FLORIDA)
)
COUNTY OF HILLSBOROUGH)

Before me the undersigned authority personally appeared Carlos Aldazabal who deposed and said that he is a Director, Regulatory Affairs, Tampa Electric Company, and that the individuals listed in Tampa Electric Company's response to Staff's Second Set of Interrogatories, (Nos. 13 - 60) prepared or assisted with the responses to these interrogatories to the best of his information and belief.

Dated at Tampa, Florida this 22nd day of October, 2012.

Carlos Aldazabal

Sworn to and subscribed before me this 22nd day of October, 2012.

Notary Public

My Commission expires

Notary Public State of Florida
Tison C Vega
My Commission EE 165416
Expires 02/01/2016

TECO's Answer to Second Set of Interrogatories (No. 50) of the Florida Public Service Commission

(Confidential FPSC Document No. 07526-12)

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TECO's Answer to Third Set Of Interrogatories (Nos. 61-68) of the Florida Public Service Commission

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 120234-EI EXHIBIT 4
PARTY Florida Public Service Commission Staff
DESCRIPTION TECO - Staff Exhibit #4
[Bates Nos. 00120-00132]

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition to determine need for Polk 2-5 combined cycle conversion, by Tampa Electric Company	DOCKET NO. 120234-EI FILED: November 1, 2012

TAMPA ELECTRIC COMPANY'S

ANSWERS TO THIRD SET OF INTERROGATORIES (NOS. 61-68)

OF THE

FLORIDA PUBLIC SERVICE COMMISSION

Tampa Electric files its Answers to Interrogatories (Nos. 61-68) propounded and served on October 12, 2012, by the Florida Public Service Commission.

RECEIVED
NOV - 1 2012
FLORIDA PUBLIC SERVICE COMMISSION
OFFICE OF THE GENERAL COUNSEL

TAMPA ELECTRIC COMPANY
DOCKET NO. 120234-EI
INDEX TO STAFF'S THIRD SET OF INTERROGATORIES (NOS. 61-68)

Number	Witness	Subject	Bates Stamped Page
61	Caldwell	Please refer to witness Caldwell's direct testimony, Exhibit JBC-1, Document 2, at Page 27. a. Why is TECO's natural gas price forecast for the period 2013 through 2023 significantly higher than the EIA 2012 early release natural gas price forecast? b. Why does the EIA forecast of natural gas prices for the period 2021-2035 show a trend that is at a significantly higher rate than TECO's natural gas price forecast for 2021-2035?	1
62	Caldwell	Please refer to witness Caldwell's direct testimony, Exhibit JBC-1, Document 1, at Page 25 and as referenced at Pages 13-14. What are TECO's assumptions (environmental, economic, technological, political, etc.) supporting its natural gas, No. 2 Oil, Illinois Basin Coal, and distillate oil price forecasts as presented in witness Caldwell's direct testimony?	2
63	Caldwell	Please refer to witness Caldwell's direct testimony, Exhibit JBC-1, Document 2, at Page 27. Are the data series shown in the testimony nominal or real terms?	3
64	Caldwell	Please refer to witness Caldwell's direct testimony, Exhibit JBC-1, Document 2, at Page 27. What deflators or inflators, if any, were applied to TECO's natural gas price forecast or the independent forecasts depicted in the testimony to make the data series consistent with each other?	4
65	Cifuentes	Please refer to witness Cifuentes' direct testimony. As part of TECO's review of the reasonableness of its forecasted energy sales, peak load and energy consumption per customer presented in witness Cifuentes' direct testimony, did TECO compare the average growth in its forecasts from 2012 to 2021 with the forecasted load growth of other large investor-owned utilities in Florida, as may be reflected in the 2012 Ten Year Site Plans? b. If your answer to Interrogatory No. 65a is yes, what did TECO find/conclude? c. If your answer to Interrogatory No. 65a is no, please explain the reason(s) for TECO not comparing the average growth in its forecasts from 2012 to 2021 with the forecasted load growth of other large investor-owned utilities in Florida, as may be reflected in the 2012 Ten Year Site Plans.	5

Number	Witness	Subject	Bates Stamped Page
66	Cifuentes	Please refer to the Direct Testimony of Witness Cifuentes, page 26, Document no. 4. a. Please detail how TECO derived its per customer energy consumption for the period 2012 – 2021. b. If TECO utilized data that is also presented in its 2012 Ten Year Site Plan for derivation of its per customer energy consumption, please detail the source of the information. c. If TECO did not utilize data that is presented in its 2012 Ten Year Site Plan for derivation of its per customer energy consumption, please detail the source of the information.	6
67	Caldwell	Please refer to pages 9 and 10 of witness Caldwell's testimony where the witness indicates that when economics and market operational issues indicate that it is beneficial, the company will eventually connect Polk Power Station to the Gulfstream pipeline. a. Does TECO have an estimate of the cost to connect the Polk Power Station to the Gulfstream pipeline? b. If the answer to Interrogatory No. 67a is yes, please provide the cost estimate.	7
68	Caldwell	Please refer to page 4 of witness Caldwell's testimony where the witness discusses the amount of fuel that will need to be procured if the proposed conversion is constructed. What steps has TECO taken to procure the discussed amount?	8

Brent Caldwell
Director, Wholesale and Fuels Management

Lori Cifuentes
Manager, Load Research

Tampa Electric Company
702 N. Franklin Street
Tampa, FL 33602

61. Please refer to witness Caldwell's direct testimony, Exhibit JBC-1, Document 2, at Page 27.

a. Why is TECO's natural gas price forecast for the period 2013 through 2023 significantly higher than the EIA 2012 early release natural gas price forecast?

b. Why does the EIA forecast of natural gas prices for the period 2021-2035 show a trend that is at a significantly higher rate than TECO's natural gas price forecast for 2021-2035?

A. a. The two forecasts are created on different bases. Tampa Electric's natural gas commodity price forecast for the period 2013 through 2022 is equal to the NYMEX natural gas futures contract prices at the time of preparation of the 2012 Fuel and Purchased Power Cost Recovery Clause Projection Filing, submitted to the Commission on September 1, 2011. By using NYMEX futures prices for the forecast, the prices in the forecast are the prices at which market participants actually execute transactions; and therefore, it is a reasonable basis to represent the future market price. The Energy Information Administration ("EIA") 2012 Annual Energy Outlook ("AEO") Early Release, natural gas price forecast is the result of a pricing model based on forecasted production levels, demand levels, economic assumptions, and competitive alternatives. Tampa Electric's natural gas forecast, based on NYMEX, is a market-based forecast from the summer of 2011, while EIA's 2012 AEO Early Release is a supply and demand model from the winter of 2011/2012.

b. For the period 2021 through 2035, Tampa Electric escalated the nominal price of the natural gas commodity at the same pace as the projected escalation of the Consumer Price Index Less Energy index. This approach effectively assumes that the price of natural gas remains constant in real dollars after 2022. The EIA model contains both an escalation for inflation as well as assumed pricing increase due to underlying supply and demand balances. By holding the real price of natural gas constant after 2022, Tampa Electric de-emphasized the impact of assumed fuel price growth in its long term economic analyses.

62. Please refer to witness Caldwell's direct testimony, Exhibit JBC-1, Document 1, at Page 25 and as referenced at Pages 13-14. What are TECO's assumptions (environmental, economic, technological, political, etc.) supporting its natural gas, No. 2 Oil, Illinois Basin Coal, and distillate oil price forecasts as presented in witness Caldwell's direct testimony?

A. Tampa Electric does not use explicit environmental, economic, technological, or political assumptions in developing the company's fuel price forecast. Instead, Tampa Electric bases its commodity price forecast on actual market transaction activity as reflected in the NYMEX futures contracts or published indexes. These transactions reflect the market balancing point of assumptions between a buyer and a seller that theoretically take into account all the aforementioned assumptions as well as any other market conditions.

When market transaction data is not available (*e.g.*, there is no NYMEX natural gas futures contract data after 2022), Tampa Electric incorporates two key assumptions.

The first key assumption is that the nominal price of natural gas will grow at the same rate as the projected annual change in the overall economy, represented by the Consumer Price Index Less Energy. This assumption has the effect of holding the "real" price of natural gas constant at the level last available in the NYMEX and then adjusting the price to match changes in the value of the dollar. An advantage of this assumption is that it acknowledges the uncertainty of natural gas pricing to be higher or lower in real terms decades into the future. Another advantage is that it diminishes the impact of compounding assumptions of high escalation on the expected commodity prices.

The second key assumption is that natural gas will remain the marginal fuel for electric generation over the thirty-year time horizon. As such, the changes in price for competing electric generation fuels will effectively follow the changes in price for natural gas. Assuming that all fuel commodities escalate at a relatively consistent level limits dramatic divergence or convergence in the price spread between commodities. Dramatic changes in price spread can skew long-term economic analysis while fuel price projections in the outer years have a high level of uncertainty. Therefore, Tampa Electric believes that assuming that fuel commodity prices will escalate in a similar way over the next 30 years results in a reasonable long-term economic analysis.

63. Please refer to witness Caldwell's direct testimony, Exhibit JBC-1, Document 2, at Page 27. Are the data series shown in the testimony nominal or real terms?

A. The data series shown in witness Caldwell's direct testimony, Exhibit JBC-1, Document No. 2, at page 27, is shown in nominal terms.

64. Please refer to witness Caldwell's direct testimony, Exhibit JBC-1, Document 2, at Page 27. What deflators or inflators, if any, were applied to TECO's natural gas price forecast or the independent forecasts depicted in the testimony to make the data series consistent with each other?

A. Tampa Electric did not apply pricing deflators or inflators to the natural gas price forecast or the independent forecasts shown in witness Caldwell's direct testimony, Exhibit JBC-1, Document No. 2, at page 27. All three forecasts are shown in nominal dollars.

65. Please refer to witness Cifuentes' direct testimony. As part of TECO's review of the reasonableness of its forecasted energy sales, peak load and energy consumption per customer presented in witness Cifuentes' direct testimony, did TECO compare the average growth in its forecasts from 2012 to 2021 with the forecasted load growth of other large investor-owned utilities in Florida, as may be reflected in the 2012 Ten Year Site Plans?

b. If your answer to Interrogatory No. 65a is yes, what did TECO find/conclude?

c. If your answer to Interrogatory No. 65a is no, please explain the reason(s) for TECO not comparing the average growth in its forecasts from 2012 to 2021 with the forecasted load growth of other large investor-owned utilities in Florida, as may be reflected in the 2012 Ten Year Site Plans.

A. No. Tampa Electric did not compare the average growth of its forecasted energy sales, peak load and energy consumption per customer presented in witness Cifuentes's direct testimony to the forecasted load growth of other utilities as part of the company's review of the reasonableness of Tampa Electric's forecasts.

b. This question is not applicable.

c. Tampa Electric does not base the reasonableness of its forecasts on other utilities' forecasts.

Although Tampa Electric does not review forecasts from other utilities for purposes of determining the reasonableness of its forecasts or even at the same time as preparing the company's forecasts, the company makes comparisons as part of its participation in the regional Florida Reliability Coordination Council ("FRCC") forecast review, which occurs approximately one year after a particular year's forecast is developed. For example, Tampa Electric's 2012-2021 forecast was prepared in May 2011. In April 2012, the other utilities' forecasts were made available in Ten Year Site Plans, and the FRCC forecast review occurred in May 2012.

The FRCC forecast review that occurred in May 2012 shows Tampa Electric's projected growth rates for residential energy sales are slightly lower than those of the other large investor-owned utilities in Florida, and they are slightly higher than the projected growth rates for the FRCC region.

66. Please refer to the Direct Testimony of Witness Cifuentes, page 26, Document no. 4.

a. Please detail how TECO derived its per customer energy consumption for the period 2012 – 2021.

b. If TECO utilized data that is also presented in its 2012 Ten Year Site Plan for derivation of its per customer energy consumption, please detail the source of the information.

c. If TECO did not utilize data that is presented in its 2012 Ten Year Site Plan for derivation of its per customer energy consumption, please detail the source of the information.

A. a. The requested information was provided in Tampa Electric's response to Staff's First Request for Production of Documents, No. 1, Bates stamp pages 4 through 6, filed in this docket on October 18, 2012.

b. The requested information was provided in Tampa Electric's response to Staff's First Request for Interrogatories, Interrogatory No. 5, Bates stamp page 6, filed in this docket on October 18, 2012.

c. All data utilized to derive per customer energy consumption for the forecast referred to on page 26, Document No. 4 of witness Cifuentes's testimony is presented in the company's 2012 Ten Year Site Plan.

67. Please refer to pages 9 and 10 of witness Caldwell's testimony where the witness indicates that when economics and market operational issues indicate that it is beneficial, the company will eventually connect Polk Power Station to the Gulfstream pipeline.

a. Does TECO have an estimate of the cost to connect the Polk Power Station to the Gulfstream pipeline?

b. If the answer to Interrogatory No. 67a is yes, please provide the cost estimate.

A. a. No, Tampa Electric does not have an estimate of the cost to connect the Polk Power Station to the Gulfstream pipeline. With Tampa Electric's rights under its firm interstate pipeline transportation service agreements, Tampa Electric is able to meet the natural gas supply and delivery requirements of the Polk Units 2-5 conversion project without connecting to a second pipeline. However, Tampa Electric recognizes that access to a second pipeline can provide both reliability and economic benefits. Therefore, Tampa Electric will continue to monitor the market for interstate pipeline capacity and delivered natural gas in Florida to assess when it may become advantageous to connect Polk Station to another interstate pipeline.

b. This question is not applicable.

68. Please refer to page 4 of witness Caldwell's testimony where the witness discusses the amount of fuel that will need to be procured if the proposed conversion is constructed. What steps has TECO taken to procure the discussed amount?

A. Tampa Electric uses a balanced portfolio approach to supply fuel for all of its generation facilities. Tampa Electric secures a portion of its fuel supply under long-term agreements, a portion under medium-term agreements, and a portion under short-term or spot purchases. The conversion of Polk Units 2-5 does not materially change Tampa Electric's fuel supply requirements or planning, so Tampa Electric will continue to supply Polk Units 2-5 using its existing procurement processes.

A F F I D A V I T

STATE OF FLORIDA)
)
COUNTY OF HILLSBOROUGH)

Before me the undersigned authority personally appeared Carlos Aldazabal who deposed and said that he is a Director, Regulatory Affairs, Tampa Electric Company, and that the individuals listed in Tampa Electric Company's response to Staff's Third Set of Interrogatories, (Nos. 61 - 68) prepared or assisted with the responses to these interrogatories to the best of his information and belief.

Dated at Tampa, Florida this 30th day of October, 2012.

Carlos Aldazabal

Sworn to and subscribed before me this 30th day of October, 2012.

Notary Public State of Florida
Tiscon C Vega
My Commission EE 165415
Expires 02/01/2016

My Commission expires _____

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TECO's Answer to Fourth Set Of Interrogatories (Nos. 69-97, 98 (redacted), 99-101) of the Florida Public Service Commission

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 120234-EI EXHIBIT 5
PARTY Florida Public Service Commission Staff
DESCRIPTION TECO - Staff Exhibit #5
[Bates Nos. 00133-00182] & [Bates No. 00183]

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition to determine need for Polk 2-5 combined cycle conversion, by Tampa Electric Company	DOCKET NO. 120234-EI FILED: November 26, 2012

REDACTED

TAMPA ELECTRIC COMPANY'S

ANSWERS TO FOURTH SET OF INTERROGATORIES (NOS. 69-101)

OF THE

FLORIDA PUBLIC SERVICE COMMISSION

Tampa Electric files its Answers to Interrogatories (Nos. 69-101) propounded and served on November 5, 2012, by the Florida Public Service Commission.

TAMPA ELECTRIC COMPANY
DOCKET NO. 120234-EI
INDEX TO STAFF'S FOURTH SET OF INTERROGATORIES (NOS. 69-101)

Number	Witness	Subject	Bates Stamped Page
69	Rocha	Referring to Table 9 on Page 45 of the Need Study, are the resource plans titled "Peaking Only" and "CC Alt" the same as Alternative 1 and Alternative 2? a. If no, please explain where these resource plans are discussed in the Need Study. b. If no, please update Tables 5 through 9 and Table 13 to reflect the "Peaking Only" and "CC Alt" resource plans.	1
70	Rocha	In its response to Staff's Second Set of Interrogatories, No. 17, TECO indicated that "[f]or other proposals, the RFP required each respondent to be responsible for environmental costs." a. Please specify what environmental rules or regulations the above-mentioned environmental costs are intend to address. b. Please clarify whether the above-mentioned environmental costs include potential expenditures associated with CO2 allowances.	2
71	Lukcic	On Page 57, Paragraph 1 of the Need Study, TECO indicated that under the federally authorized PSD program, Polk 2-5 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 Area. a. Apart from the SCRs, are there any other emission controls that will be installed at Polk 2-5 to address the BACT requirement? b. If the response to the above question is yes, please specify what these controls are and what the associated capital costs will be.	3
72	Lukcic	In its response to Staff's Second Set of Interrogatories, No. 22(b), TECO indicated that Section 316(b) of the Clean Water Act is not applicable to the Polk Units 2-5 conversion because the units do not withdraw water from waters of the state. Please explain from whose water body, apart from waters of the state, the converted units will withdraw water for consumption.	4

Number	Witness	Subject	Bates Stamped Page
73	Lukcic	In its response to Staff's Second Set of Interrogatories, No. 20(d), TECO indicated that the make-up water to the existing cooling reservoir (for Polk Units 2&3) is from the on-site consumptive use wells. Are the waters from the wells at the Polk Station defined as waters of the state?	5
74	Lukcic	In its response to Staff's Second Set of Interrogatories, No. 20(e)(i), TECO indicated that after expansion, the expected total consumption at the site will be 8.6 million gallon per day (MGD), and of that amount an estimated 5.7 MGD will be reclaimed water. In its response to Interrogatory No. 20(e)(ii), TECO indicated that the additional water will be pumped from existing consumptive use wells. Please clarify (i) whether the make up water (8.6 - 5.7 = 2.9 MGD) will be withdrawn from existing consumptive use wells; and (ii) whether such fresh water withdrawing will trigger any environmental regulation complying need for the proposed NGCC units.	6
75	Rocha	Please update Table 13 of the Need Study, assuming a Low and High Fuel Cost scenario, based on the "new fuel price forecast" discussed on Page 60 of the Need Study.	7
76	Rocha	Please update Tables 6 and 13 of the Need Study, assuming the environmental compliance costs listed in the table below. The costs in the table below represent the forecasted costs most recently reviewed by the Commission (Docket No. 110309-EI).	8
77	Young	Please describe the responsibilities of each group in the core team as described on Page 7 of witness Young's testimony.	10

Number	Witness	Subject	Bates Stamped Page
78	Young	If TECO did not complete the projects listed in Exhibit SBY-1, Document No. 3, and the proposed conversion was approved, what would be the effect on TECO's bulk electric system?	12
79	Cifuentes	Referring to witness Cifuentes' Direct Testimony, Pages 13 and 14, what is TECO's current forecast of customers and energy sales (completed in June 2012), by customer class and in total?	13
80	Cifuentes	Referring to TECO's response to Staff's 1st Set of Interrogatories, No. 5, why did TECO switch its source of commercial and residential appliance saturation and energy efficiency in its forecast prepared in the summer of 2012 from the Energy Information Administration to ITRON?	14
81	Cifuentes	Referring to TECO's response to Staff's 1st Set of Interrogatories, No. 11, why did TECO add a summer net energy for load trend variable and lagged heating and cooling degree variables in its June 2012 Peak Demand Average Use Model?	15
82	Cifuentes	On Pages 12 and 13 of her direct testimony, witness Cifuentes states that high and low peak demand and energy scenarios include 0.5 percent higher customer and economic growth scenario in the high case and 0.5 percent lower customer and economic growth scenario in the low case. a. How were these percentages of high and low customer and economic growth determined? b. What are the high and low customer and energy forecasts? c. Were the high and low load forecast sensitivities identified on Page 12 and 13 of witness Cifuenties' direct testimony the same sensitivities used to create the load sensitivities appearing in Table 9 of the Need Study (Page 45)?	16

Number	Witness	Subject	Bates Stamped Page
83	Cifuentes	Appendix E of the Need Study (Page 69) shows 2017 firm retail peak winter demand at 4,003 MW. Appendix F of the Need Study (Page 70) shows 2017 firm retail peak winter demand under the high load scenario at 4,142 MW, or 3.5 percent higher than the base case. Also, TECO's response to Staff's 1st Set of Interrogatories, No. 9, indicates the percent error in summer firm peak for Forecast Year 6 ranged from 7.9 percent to 17.3 percent based on the 2004 through 2006 Ten Year Site Plans forecast data. Given this historical forecast accuracy percentage data, are TECO's load sensitivities for customers, energy, and demand in this case broad enough to take into account potential load forecast error throughout the forecast horizon? Why or why not?	17
84	Caldwell	Refer to TECO's response to Staff POD No. 20, file named "Non-confidential_Early 2012 NG Supply Disposition.pdf". This document appears to be a table from the Energy Information Administration's AEO 2012 showing projections of the real Henry Hub spot price of natural gas (2010 dollars) through 2035. The growth in the Henry Hub spot price, in real terms, between 2022 and 2035 is $5.29 to $7.23, or $1.94/MMBtu. Meanwhile, TECO's response to Staff's Second Set of Interrogatories No. 50, as shown on Page 73B under the column titled ""Natural Gas - Commodity", shows TECO's forecast of the commodity price of natural gas (real dollars) unchanged at $6.15 during the period 2022 through 2035. a. What is/are the reason(s) for the difference in the projected growth of the real price of natural gas (commodity) from 2022 through 2035 between TECO and the EIA? b. Why does TECO expect the real price of natural gas to remain unchanged between 2022 and 2035?	18
85	Caldwell	Refer to TECO's response to Staff POD No. 20, file named "Non-confidential_Early 2012 NG Supply Disposition.pdf". This document appears to be a table from the EIA's AEO 2012 showing projections of the nominal Henry Hub spot price through 2035. The percentage growth in nominal price between 2013 and 2035 is 168.2% ($11.48-$4.28)/$4.28). The percentage growth of TECO's nominal natural gas price forecast (commodity) for this same period as shown in witness Caldwell's Direct Testimony, Exhibit	19

Number	Witness	Subject	Bates Stamped Page
		JBC-1, the column titled "Natural Gas $/MMBtu" is 95.5% ($10.01-$5.12)/$5.12). a. What is/are the reason(s) for the difference in projected natural gas price percentage growth between TECO's forecast and EIA's forecast for the period 2013 to 2035? b. Is it correct that the price data in Exhibit JBC-1, Column "Natural Gas $/MMBtu", is inclusive of the Henry Hub commodity costs plus a basis adder to yield FGT Zone 3 natural gas prices?	
86	Caldwell	Refer to TECO's response to Staff's Second Set of Interrogatories, No. 50, Page 85. What is the base year TECO used to determine the real prices shown on this page?	20
87	Caldwell	Refer to TECO's response to Staff POD No. 20, file named "Non-confidential_Early 2012 NG Supply Disposition.pdf". This document shows, at three lines from the bottom of the table, the Energy Information Administration's (EIA's) nominal delivered natural gas price projections for electric power through 2035. The percentage growth in price between 2013 and 2035 is 141.4% ($11.49-$4.76)/$4.76). Consider the percentage growth of TECO's nominal delivered natural gas price forecast for the period 2013 to 2035 calculated based on TECO's response to Staff's Second Set of Interrogatories, No. 50, "Natural Gas – Total Delivered Cost." What are the reasons for the difference in projected nominal natural gas price percentage growth between TECO's forecast and the EIA's forecast for the period 2013 to 2035?	21
88	Caldwell	What is the basis for the difference in the natural gas fuel price forecast shown in Exhibit JBC-1 attached to witness Caldwell's testimony and the natural gas fuel price forecast appearing in Appendix H of the Need Study?	22
89	Caldwell	What is the basis for the difference in the No. 2 oil price forecast shown in response to Staff's Second Set of Interrogatories No. 48 and the No. 2 oil price forecast appearing in Appendix H of the Need Study?	23

Number	Witness	Subject	Bates Stamped Page
90	Caldwell	Why do TECO's low fuel forecasts used in the sensitivity analysis shown in Appendix I of the Need Study and TECO's response to Staff's 2nd Request for PODs, No. 24, show identical prices for coal except the Need Study prices appear to be lagged one year?	24
91	Caldwell	Why do TECO's low fuel forecasts used in the sensitivity analysis shown in Appendix I of the Need Study and TECO's response to Staff's 2nd Request for PODs, No. 24, show dissimilar prices for natural gas and No. 2 oil?	27
92	Caldwell	Why do TECO's high fuel forecasts used in the sensitivity analysis shown in Appendix J of the Need Study and TECO's response to Staff's 2nd Request for PODs, No. 24, show identical prices for coal except the Need Study prices appear to be lagged one year?	28
93	Caldwell	Why do TECO's high fuel forecasts used in the sensitivity analysis shown in Appendix J of the Need Study and TECO's response to Staff's 2nd Request for PODs, No. 24, have dissimilar prices for natural gas and No. 2 oil?	29
94	Caldwell	Please refer to TECO's response to Staff's 1st Production of Documents, No. 20. Where in this response specifically does TECO show how it added "basis" cost to the NYMEX Henry Hub price of natural gas to account for the company receiving its natural gas into FGT Zone 3, as discussed on Pages 12 and 13 of witness Caldwell's direct testimony?	30
95	Caldwell	TECO's response to Staff's Second Set of Interrogatories, No. 48, indicates that Staff's Supplemental Data Request No. 59 in the Ten Year Site Plan Review is the same as the natural gas price forecast appearing as Exhibit JBC-1 in witness Caldwell's testimony, except the supplemental data request prices include additional transportation costs for delivery to the generation station. Why is TECO's delivered natural gas price forecast appearing in Supplemental Data Request No. 59 not the same as the delivered natural gas cost (nominal) shown in TECO's response to Staff's Second Set of Interrogatories No. 50, Page 84 (confidential document), Column "Total Delivered Cost"?	31

Number	Witness	Subject	Bates Stamped Page
96	Caldwell	TECO's response to Staff's 2nd Set of Interrogatories, No. 59, indicates that both range and standard deviation were used as a basis for determining fuel price sensitivities. Why did TECO select a 35% range for No. 2 Oil and a 20% range for Illinois Basin Coal when the response shows the range and the standard deviation percentages were higher for Illinois Basin Coal compared to No. 2 Oil percentages?	32
97	Caldwell	What are the reasons TECO determined to use its 2012 fuel projection forecasts rather than its 2013 fuel projection forecasts as the basis of its Need Study?	33
98	Caldwell	What are the commodity, transportation, and delivered prices, in real and nominal terms, for TECO's 2013 fuel price forecast referenced in witness Caldwell's direct testimony at Page 17, Lines 2-4 for the period 2013-2040? a. If transportation price for the various fuels has multiple components (e.g. natural gas "basis" plus additional contract delivery prices), please provide each component price and total transportation price.	34
99	Caldwell	What are the high and low price forecast sensitivities associated with TECO's 2013 fuel price forecast, based on the methodology described in witness Caldwell's testimony at Page 16, Lines 4 – 9?	37
100	Caldwell	Witness Caldwell indicates that TECO's base forecast is consistent with other independent forecasts available at the time the base forecast was developed. a. What is the source and the date of independent fuel price forecasts TECO use to compare its 2013 fuel price forecasts? b. What did TECO conclude from its comparison of independent fuel price forecasts to its 2013 fuel price forecasts in order to ensure consistency?	38
101	Caldwell	When were TECO's 2012 and 2013 fuel price forecasts developed and when were they approved by TECO's executive management?	39

Brent Caldwell
Director, Wholesale and Fuels Management

Lori Cifuentes
Manager, Load Research

David Lukcic
Manager, Environmental Health and Safety

Jim Rocha
Director, Planning, Strategy and Compliance

Beth Young
Director, Energy Delivery

Tampa Electric Company
702 N. Franklin Street
Tampa, FL 33602

69. Referring to Table 9 on Page 45 of the Need Study, are the resource plans titled "Peaking Only" and "CC Alt" the same as Alternative 1 and Alternative 2?

a. If no, please explain where these resource plans are discussed in the Need Study.

b. If no, please update Tables 5 through 9 and Table 13 to reflect the "Peaking Only" and "CC Alt" resource plans.

A. Yes. The resource plan titled "Peaking Only" should be labeled Alternative 1, and the resource plan titled "CC Alt" should be labeled Alternative 2.

a. This question is not applicable.

b. This question is not applicable.

70. In its response to Staff's Second Set of Interrogatories, No. 17, TECO indicated that "[f]or other proposals, the RFP required each respondent to be responsible for environmental costs."

a. Please specify what environmental rules or regulations the above-mentioned environmental costs are intend to address.

b. Please clarify whether the above-mentioned environmental costs include potential expenditures associated with CO_2 allowances.

A. a. The RFP stated that a respondent's pricing must include any and all environmental costs and expenses that Tampa Electric would be expected to pay to meet environmental requirements that are in effect by the capacity delivery date. Tampa Electric defined these costs to be all equipment, development, design, construction, and commissioning costs as well as all costs of meeting and maintaining compliance with environmental regulations.

b. Each respondent addressed the proposed CO_2 regulations by stating that there are no current regulations for carbon capture and sequestration.

71. On Page 57, Paragraph 1 of the Need Study, TECO indicated that under the federally authorized PSD program, Polk 2-5 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 Area.

a. Apart from the SCRs, are there any other emission controls that will be installed at Polk 2-5 to address the BACT requirement?

b. If the response to the above question is yes, please specify what these controls are and what the associated capital costs will be.

A. a. No. Apart from the SCRs, there are not any other emission controls that will be installed at Polk 2-5 to address the BACT requirement.

b. This question is not applicable.

72. In its response to Staff's Second Set of Interrogatories, No. 22(b), TECO indicated that Section 316(b) of the Clean Water Act is not applicable to the Polk Units 2-5 conversion because the units do not withdraw water from waters of the state. Please explain from whose water body, apart from waters of the state, the converted units will withdraw water for consumption.

A. Cooling for Polk Unit 2-5 will be provided from an existing onsite cooling reservoir and a new auxiliary cooling tower. The water used to make up for evaporation from the reservoir and cooling tower will be provided by the onsite consumptive wells and treated reclaimed water from the City of Lakeland.

73. In its response to Staff's Second Set of Interrogatories, No. 20(d), TECO indicated that the make-up water to the existing cooling reservoir (for Polk Units 2&3) is from the on-site consumptive use wells. Are the waters from the wells at the Polk Station defined as waters of the state?

A. The consumptive use wells withdraw water from the Upper Floridian Aquifer, which are not defined as waters of the state.

74. In its response to Staff's Second Set of Interrogatories, No. 20(e)(i), TECO indicated that after expansion, the expected total consumption at the site will be 8.6 million gallon per day (MGD), and of that amount an estimated 5.7 MGD will be reclaimed water. In its response to Interrogatory No. 20(e)(ii), TECO indicated that the additional water will be pumped from existing consumptive use wells. Please clarify (i) whether the make up water (8.6 - 5.7 = 2.9 MGD) will be withdrawn from existing consumptive use wells; and (ii) whether such fresh water withdrawing will trigger any environmental regulation complying need for the proposed NGCC units.

A. The additional 2.9 MGD of water will be provided from the existing consumptive use wells. These withdrawals will not trigger any environmental regulation, but will require Southwest Florida Water Management District permitting for some additional consumptive use. The original Conditions of Certification for the Polk site included a build-out condition that provides for this additional consumptive use.

75. Please update Table 13 of the Need Study, assuming a Low and High Fuel Cost scenario, based on the "new fuel price forecast" discussed on Page 60 of the Need Study.

A. The requested information is provided in the following tables.

Table 13
Economic Evaluation with Consideration of June 2012 Updated Assumptions
Updated with Low Fuel Forecast

	Polk 2-5		Alternative 2		Proposal B
Capital	$1,557.2		$1,520.4		$1,357.5
O&M	$844.8		$895.6		$814.8
Fuel & Purchased Power	$10,449.9		$10,605.2		$10,771.5
Total	$12,851.9		$13,021.1		$12,943.8
Delta			$169.2		$91.8

Table 13
Economic Evaluation with Consideration of June 2012 Updated Assumptions
Updated with High Fuel Forecast

	Polk 2-5		Alternative 2		Proposal B
Capital	$1,557.2		$1,520.4		$1,357.5
O&M	$847.1		$899.1		$816.8
Fuel & Purchased Power	$16,689.8		$17,007.7		$17,029.4
Total	$19,094.1		$19,427.2		$19,203.7
Delta			$333.1		$109.5

76. Please update Tables 6 and 13 of the Need Study, assuming the environmental compliance costs listed in the table below. The costs in the table below represent the forecasted costs most recently reviewed by the Commission (Docket No. 110309-EI).

$/ton nominal	
	CO2
2013	0
2014	0
2015	0
2016	0
2017	0
2018	27
2019	29
2020	32
2021	34
2022	37
2023	40
2024	44
2025	47
2026	51
2027	55
2028	59
2029	64
2030	68
2031	70
2032	72
2033	74
2034	75
2035	77
2036	79
2037	81
2038	83
2039	85
2040	88
2041	90
2042	92
2043	94
2044	97
2045	99
2046	102

A. The requested information is provided in the following tables.

Table 6: Results of Final Economic Analysis (Including CO_2 Costs)

Total System Costs (2012 $ Million)

	Polk 2-5 Conversion	Alternative 1	Alternative 2
CPWRR	24,995	25,414	25,256
Delta		419	260

Table 13: Economic Evaluation with Consideration of June 2012 Updated Assumptions (Including CO_2 Costs)

	CPWRR ($ million)				
	Polk 2-5		Alternative 2		Proposal B
Capital	$1,557.2		$1,520.4		$1,357.5
O&M	$845.2		$897.5		$815.1
Fuel & Purchased Power	$13,631.7		$13,882.9		$13,937.1
CO2 Costs	$6,647.6		$6,712.6		$6,649.3
Total	$22,681.8		$23,013.5		$22,758.8
Delta			$331.7		$77.1

77. Please describe the responsibilities of each group in the core team as described on Page 7 of witness Young's testimony.

A. The core team was comprised of engineers from System Planning, Environmental, Health and Safety, Substation Engineering, Transmission Engineering, Telecommunications, System Security and staff from Line Clearance, Real Estate, Project Management, and Community Relations.

System Planning developed the power flow models needed to determine the generation addition impact to the state transmission grid. Using those models, the system impact was determined and system improvements evaluated for various generation dispatches. As needed improvements were identified, construction feasibility was reviewed by the various engineering groups and a final plan developed. Once the proposed projects were evaluated by the engineering groups and any required adjustments made, System Planning made the load flow model adjustments, completed the contingency and stability studies requested by the Florida Reliability Coordinating Council Transmission Working Group and provided a Network Resource System Impact Study Report for final approval.

Environmental, Health and Safety was responsible for reviewing environmental concerns for the transmission projects

Substation Engineering was responsible for developing scopes of work and cost estimates for each substation involved in the project based on one-line diagrams provided by System Planning. The estimates were based on the costs of performing similar activities in the past. All equipment and structures selected for use, including circuit breakers, switches, cable and conductors, bus, steel structures, control buildings, instrument transformers and relays are standard items normally used by Tampa Electric.

Transmission Engineering evaluated the proposed system improvements to identify the most cost-effective projects to meet the requirements outlined by System Planning. Using these requirements, such as the starting and ending points required, and capacity and reliability constraints, proposed transmission line designs were developed and ballpark cost estimates produced. In addition to the planning requirements, the proposed line designs addressed engineering criteria including National Electric Safety Code clearances, pole loadings, rights-of-way and electromagnetic field limits.

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Telecommunications was responsible for developing scopes of work and cost estimates for each substation involved in the project based on one-line diagrams provided by System Planning. The estimates were based on the costs of performing similar activities in the past.

System Security was responsible for studying the impact of the proposed transmission projects over Tampa Electric's system in relation to short-circuit levels and circuit breaker interrupting capability as well as system protection requirements. System Security recommended circuit breaker upgrades.

Line Clearance was responsible for assuring proper Right-of-Way and construction requirements were employed to meet North American Electric Reliability Corporation Requirement FAC-003 for the Bulk Electric System. In addition, the Line Clearance team was responsible for providing input into cost estimation, as well as outlining the requirements and specifications for, vegetation clearance, access road construction, culvert locations, gates, fencing, and access road crossings.

Real Estate was responsible for providing information on current company land rights, review of possible routes as to ownerships, land use, and high level estimates of property values to the core team engineering staff and their engineering consultants.

Project Management was responsible for coordinating with the transmission consultant, assisting community relations (and taking input from our communities), and coordinating internal project meetings to ensure open communication between each group to minimize project costs. Project Management also was responsible for managing and executing all engineering contracts.

Community Relations provided input on the project alternatives from a community perspective.

78. If TECO did not complete the projects listed in Exhibit SBY-1, Document No. 3, and the proposed conversion was approved, what would be the effect on TECO's bulk electric system?

A. If Tampa Electric did not complete the projects listed in Exhibit SBY-1, Document No. 3, and the proposed conversion was approved, overloads might occur on the Tampa Electric bulk electric system facilities listed below under certain dispatches.

1. The 230 kV transmission line from Polk Power Substation to Mines Substation
2. The 230 kV transmission line from Pebbledale Substation to FishHawk Substation
3. The two 230 kV transmission lines from Polk Power Substation to Pebbledale Substation

79. Referring to witness Cifuentes' Direct Testimony, Pages 13 and 14, what is TECO's current forecast of customers and energy sales (completed in June 2012), by customer class and in total?

A. Customer and energy sales forecasts by customer class are shown in the following tables.

	Retail Customers						
	Residential	Commercial	Industrial	Phosphate	Public Authorities	Street&Hwy Lighting	Total Retail Sales
2012	603,407	71,115	1,481	27	7,712	210	683,952
2013	610,686	71,930	1,488	27	7,781	213	692,125
2014	618,914	72,886	1,497	27	7,874	217	701,415
2015	628,730	74,034	1,509	27	7,983	221	712,504
2016	639,145	75,264	1,521	27	8,099	225	724,281
2017	649,098	76,388	1,529	27	8,210	229	735,481
2018	658,898	77,477	1,535	27	8,318	234	746,489
2019	668,726	78,568	1,542	27	8,427	238	757,528
2020	678,494	79,662	1,549	27	8,535	243	768,510
2021	687,660	80,691	1,557	27	8,636	248	778,819

	Retail Energy Sales (GWH)						
	Residential	Commercial	Industrial	Phosphate	Public Authorities	Street&Hwy Lighting	Total Retail Sales
2012	8,555	6,253	1,089	821	1,764	75	18,559
2013	8,492	6,197	1,078	609	1,749	77	18,202
2014	8,579	6,264	1,071	616	1,761	79	18,370
2015	8,661	6,344	1,068	616	1,782	81	18,552
2016	8,784	6,430	1,064	622	1,813	82	18,795
2017	8,910	6,525	1,059	611	1,848	84	19,039
2018	9,039	6,614	1,053	611	1,883	86	19,287
2019	9,165	6,704	1,045	611	1,916	87	19,529
2020	9,273	6,790	1,037	611	1,948	89	19,749
2021	9,392	6,864	1,028	611	1,977	91	19,963

80. Referring to TECO's response to Staff's 1st Set of Interrogatories, No. 5, why did TECO switch its source of commercial and residential appliance saturation and energy efficiency in its forecast prepared in the summer of 2012 from the Energy Information Administration to ITRON?

A. The Energy Information Administration ("EIA") is the basis for the energy efficiency assumptions used in the forecasts prepared in 2011 and 2012. The difference lies in the methodology used to calculate the heating, cooling and other appliances units of energy consumption.

In the 2011 forecast, the Tampa Electric's Load Forecasting group used the EIA's appliance saturation and efficiency data to update and maintain the energy efficiency assumptions used in the company's forecast.

In the 2012 forecast, the company purchased ITRON's more updated energy efficiency assumptions, with the latest updates from EIA.

81. Referring to TECO's response to Staff's 1st Set of Interrogatories, No. 11, why did TECO add a summer net energy for load trend variable and lagged heating and cooling degree variables in its June 2012 Peak Demand Average Use Model?

A. Tampa Electric added the new variables based on ITRON's recommendation. The summer net energy for load trend variable was added to differentiate the summer and winter impacts of Net Energy for Load on peak demands. The lagged heating and cooling degree day variables capture cold and heat buildup that is not fully captured in the 24-hour degree day variable. The addition of both new variables improved the model's statistics and performance.

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82. On Pages 12 and 13 of her direct testimony, witness Cifuentes states that high and low peak demand and energy scenarios include 0.5 percent higher customer and economic growth scenario in the high case and 0.5 percent lower customer and economic growth scenario in the low case.

a. How were these percentages of high and low customer and economic growth determined?

b. What are the high and low customer and energy forecasts?

c. Were the high and low load forecast sensitivities identified on Page 12 and 13 of witness Cifuenties' direct testimony the same sensitivities used to create the load sensitivities appearing in Table 9 of the Need Study (Page 45)?

A. a. The percentages used in the high and low economic growth scenarios were determined over 20 years ago, and the company has used them consistently for Ten Year Site Plans. The high and low bands are primarily used to evaluate peak demands. The customer growth rates are the primary driver in sales and peak demand growth, and actual data continues to support the use of the 0.5 percent higher and lower growth rates for the scenarios.

b. High and low customer and energy forecasts are shown in the following tables.

	Customers		
	Low	Base	High
2011	674,622	674,997	675,748
2012	676,613	680,316	685,403
2013	680,649	688,083	697,240
2014	685,665	696,913	709,936
2015	691,372	706,481	723,350
2016	698,014	717,032	737,824
2017	704,373	727,330	752,132
2018	710,467	737,398	766,312
2019	716,492	747,441	780,582
2020	722,328	757,343	794,823
2021	727,579	766,690	808,604

	Energy Sales (MWH)		
	Low	Base	High
2011	18,955,199	18,970,976	18,994,480
2012	18,941,891	19,044,239	19,176,686
2013	18,958,905	19,158,081	19,395,248
2014	18,902,987	19,200,936	19,538,563
2015	18,928,811	19,326,072	19,763,422
2016	19,030,043	19,527,835	20,066,935
2017	19,119,141	19,718,627	20,362,176
2018	19,224,057	19,926,561	20,677,632
2019	19,333,491	20,140,590	21,002,537
2020	19,438,672	20,351,754	21,327,683
2021	19,530,148	20,550,189	21,642,707

c. Yes.

83. Appendix E of the Need Study (Page 69) shows 2017 firm retail peak winter demand at 4,003 MW. Appendix F of the Need Study (Page 70) shows 2017 firm retail peak winter demand under the high load scenario at 4,142 MW, or 3.5 percent higher than the base case. Also, TECO's response to Staff's 1st Set of Interrogatories, No. 9, indicates the percent error in summer firm peak for Forecast Year 6 ranged from 7.9 percent to 17.3 percent based on the 2004 through 2006 Ten Year Site Plans forecast data. Given this historical forecast accuracy percentage data, are TECO's load sensitivities for customers, energy, and demand in this case broad enough to take into account potential load forecast error throughout the forecast horizon? Why or why not?

A. Yes. Absent an unpredictable, infrequent macroeconomic shock such as the economic recession and housing market decline that affected recent years' customer, energy and demand forecasts, including the forecast data shown in the company's 2004 through 2006 Ten Year Site Plans, the high and low bands are broad enough to take into account potential long-term load forecast errors.

An analysis of the customer, energy sales and summer peak demand forecasts produced in the years 1996 through 2002, prior to the recession and housing market decline, show that the Forecast Year 6 projections generally fall within the high and low bands. The years in which forecasts were understated were an average of 3.6 percent lower than actuals. For the years in which forecasts were overstated, they were higher than actuals by an average of 2.9 percent.

84. Refer to TECO's response to Staff POD No. 20, file named "Non-confidential_Early 2012 NG Supply Disposition.pdf". This document appears to be a table from the Energy Information Administration's AEO 2012 showing projections of the real Henry Hub spot price of natural gas (2010 dollars) through 2035. The growth in the Henry Hub spot price, in real terms, between 2022 and 2035 is $5.29 to $7.23, or $1.94/MMBtu. Meanwhile, TECO's response to Staff's Second Set of Interrogatories No. 50, as shown on Page 73B under the column titled ""Natural Gas - Commodity", shows TECO's forecast of the commodity price of natural gas (real dollars) unchanged at $6.15 during the period 2022 through 2035.

a. What is/are the reason(s) for the difference in the projected growth of the real price of natural gas (commodity) from 2022 through 2035 between TECO and the EIA?

b. Why does TECO expect the real price of natural gas to remain unchanged between 2022 and 2035?

A. a. Tampa Electric's natural gas price forecast is held constant in real dollars for the years 2022 through 2035. Thus, the nominal price of natural gas changes annually by the forecasted annual change in inflation. Conversely, the Energy Information Administration uses a model with numerous supply and demand assumptions on both a national and international level to calculate the natural gas price.

b. Tampa Electric holds the real price of natural gas constant for the time period after the NYMEX futures contracts are tradable because of the high level of uncertainty in the level of natural gas prices more than ten years into the future. Instead, Tampa Electric uses the actual market transaction price for the last available trading period posted on NYMEX and combines that with high and low price forecasts. Tampa Electric believes that using a transaction-based base forecast combined with pricing sensitivities provides a robust range of pricing for economic analysis.

85. Refer to TECO's response to Staff POD No. 20, file named "Non-confidential_Early 2012 NG Supply Disposition.pdf". This document appears to be a table from the EIA's AEO 2012 showing projections of the nominal Henry Hub spot price through 2035. The percentage growth in nominal price between 2013 and 2035 is 168.2% ($11.48-$4.28)/$4.28). The percentage growth of TECO's nominal natural gas price forecast (commodity) for this same period as shown in witness Caldwell's Direct Testimony, Exhibit JBC-1, the column titled "Natural Gas $/MMBtu" is 95.5% ($10.01-$5.12)/$5.12).

a. What is/are the reason(s) for the difference in projected natural gas price percentage growth between TECO's forecast and EIA's forecast for the period 2013 to 2035?

b. Is it correct that the price data in Exhibit JBC-1, Column "Natural Gas $/MMBtu", is inclusive of the Henry Hub commodity costs plus a basis adder to yield FGT Zone 3 natural gas prices?

A. a. As described in the company's response to Interrogatory No. 84, Tampa Electric assumed a constant natural gas price, in real terms, following the final posted price available on the NYMEX. This assumption for the outer years yields a lower overall growth rate for natural gas pricing between 2013 and 2035 compared to EIA's modeling assumptions.

b. No. The prices shown in Exhibit JBC-1 do not include basis; the price of natural gas shown in Exhibit JBC-1 is at the Henry Hub, a recognized market trading point for natural gas and the location for NYMEX pricing. The values shown do not include the basis adder to yield the FGT Zone 3 price.

86. Refer to TECO's response to Staff's Second Set of Interrogatories, No. 50, Page 85. What is the base year TECO used to determine the real prices shown on this page?

A. The base year for real prices shown in the company's response to Staff's Second Set of Interrogatories, No. 50, is 2012.

87. Refer to TECO's response to Staff POD No. 20, file named "Non-confidential_Early 2012 NG Supply Disposition.pdf". This document shows, at three lines from the bottom of the table, the Energy Information Administration's (EIA's) nominal delivered natural gas price projections for electric power through 2035. The percentage growth in price between 2013 and 2035 is 141.4% ($11.49-$4.76)/$4.76). Consider the percentage growth of TECO's nominal delivered natural gas price forecast for the period 2013 to 2035 calculated based on TECO's response to Staff's Second Set of Interrogatories, No. 50, "Natural Gas – Total Delivered Cost." What are the reasons for the difference in projected nominal natural gas price percentage growth between TECO's forecast and the EIA's forecast for the period 2013 to 2035?

A. As described in the company's responses to Interrogatory No. 84 and 85, Tampa Electric and EIA have different growth rates for the underlying natural gas commodity price in real terms. This difference in commodity price also causes a difference in the growth rate of the delivered price of natural gas in both real and nominal terms. EIA is also likely to have differing assumptions for natural gas delivery costs in a generic national model than the specific natural gas pipelines serving Florida. Tampa Electric uses more specific information based on its contracts on the Florida gas pipelines, to develop its delivery cost projections.

88. What is the basis for the difference in the natural gas fuel price forecast shown in Exhibit JBC-1 attached to witness Caldwell's testimony and the natural gas fuel price forecast appearing in Appendix H of the Need Study?

A. The natural gas commodity price forecasts shown in Exhibit JBC-1 and Appendix H of the Need Study are the same. The difference is that the natural gas prices shown in Appendix H also include variable delivery costs on the Florida Gas Transmission ("FGT") pipeline to a Tampa Electric generation facility. The sentence above the table in Appendix H, which states that the forecast is at the Henry Hub, should say that the forecast is for prices to the power plant including variable delivery costs.

89. What is the basis for the difference in the No. 2 oil price forecast shown in response to Staff's Second Set of Interrogatories No. 48 and the No. 2 oil price forecast appearing in Appendix H of the Need Study?

A. The values appearing in the company's response to Staff's Second Set of Interrogatories, No. 48, are for commodity only; the values in Appendix H for No. 2 oil include variable delivery costs to a station.

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90. Why do TECO's low fuel forecasts used in the sensitivity analysis shown in Appendix I of the Need Study and TECO's response to Staff's 2nd Request for PODs, No. 24, show identical prices for coal except the Need Study prices appear to be lagged one year?

A. The company's response to Staff's Second request for POD, No. 24 was incorrect. It shows 2011 labeled as 2012 and was reflective of the 2012 High/Low forecast. The corrected tables are provided.

Tampa Electric Fuel Price Forecasts
2011 - 2040
Low Forecast

Year	Natural Gas $/MMBtu	No. 2 Oil $/Gallon	No. 2 Oil $/MMBtu	Illinois Basin Coal $/ton	Illinois Basin Coal $/MMBtu
2012	$ 3.09	$ 2.01	$ 14.52	$ 51.07	$ 2.22
2013	$ 3.33	$ 2.17	$ 15.63	$ 44.46	$ 1.93
2014	$ 3.51	$ 2.28	$ 16.46	$ 45.16	$ 1.96
2015	$ 3.69	$ 2.40	$ 17.30	$ 47.11	$ 2.05
2016	$ 3.87	$ 2.52	$ 18.17	$ 44.39	$ 1.93
2017	$ 4.05	$ 2.64	$ 19.01	$ 44.19	$ 1.92
2018	$ 4.23	$ 2.76	$ 19.88	$ 41.81	$ 1.82
2019	$ 4.41	$ 2.87	$ 20.72	$ 45.40	$ 1.97
2020	$ 4.59	$ 2.99	$ 21.56	$ 49.19	$ 2.14
2021	$ 4.77	$ 3.11	$ 22.42	$ 52.81	$ 2.30
2022	$ 4.96	$ 3.23	$ 23.29	$ 56.54	$ 2.46
2023	$ 5.07	$ 3.30	$ 23.80	$ 58.71	$ 2.55
2024	$ 5.18	$ 3.37	$ 24.32	$ 60.92	$ 2.65
2025	$ 5.29	$ 3.45	$ 24.85	$ 63.15	$ 2.75
2026	$ 5.40	$ 3.52	$ 25.38	$ 65.40	$ 2.84
2027	$ 5.52	$ 3.59	$ 25.91	$ 67.67	$ 2.94
2028	$ 5.63	$ 3.67	$ 26.45	$ 69.98	$ 3.04
2029	$ 5.75	$ 3.75	$ 27.00	$ 72.33	$ 3.14
2030	$ 5.87	$ 3.82	$ 27.57	$ 74.72	$ 3.25
2031	$ 5.99	$ 3.90	$ 28.14	$ 77.16	$ 3.35
2032	$ 6.12	$ 3.98	$ 28.72	$ 79.64	$ 3.46
2033	$ 6.24	$ 4.07	$ 29.32	$ 82.17	$ 3.57
2034	$ 6.37	$ 4.15	$ 29.92	$ 84.74	$ 3.68
2035	$ 6.50	$ 4.24	$ 30.54	$ 87.36	$ 3.80
2036	$ 6.64	$ 4.32	$ 31.17	$ 90.03	$ 3.91
2037	$ 6.77	$ 4.41	$ 31.81	$ 92.76	$ 4.03
2038	$ 6.91	$ 4.50	$ 32.46	$ 95.53	$ 4.15
2039	$ 7.05	$ 4.59	$ 33.12	$ 98.36	$ 4.28
2040	$ 7.20	$ 4.69	$ 33.80	$ 101.24	$ 4.40

Tampa Electric Fuel Price Forecasts
2011 - 2040
High Forecast

	Natural Gas	No. 2 Oil		Illinois Basin Coal	
Year	$/MMBtu	$/Gallon	$/MMBtu	$/ton	$/MMBtu
2012	$ 6.42	$ 4.18	$ 30.15	$ 51.07	$ 2.22
2013	$ 6.91	$ 4.50	$ 32.46	$ 66.69	$ 2.90
2014	$ 7.28	$ 4.74	$ 34.18	$ 67.74	$ 2.95
2015	$ 7.65	$ 4.98	$ 35.93	$ 70.66	$ 3.07
2016	$ 8.04	$ 5.23	$ 37.74	$ 66.58	$ 2.89
2017	$ 8.41	$ 5.48	$ 39.49	$ 66.29	$ 2.88
2018	$ 8.79	$ 5.73	$ 41.28	$ 62.71	$ 2.73
2019	$ 9.17	$ 5.97	$ 43.04	$ 66.91	$ 2.91
2020	$ 9.54	$ 6.21	$ 44.79	$ 71.34	$ 3.10
2021	$ 9.92	$ 6.46	$ 46.55	$ 75.58	$ 3.29
2022	$ 10.30	$ 6.71	$ 48.37	$ 79.94	$ 3.48
2023	$ 10.53	$ 6.86	$ 49.43	$ 82.48	$ 3.59
2024	$ 10.76	$ 7.01	$ 50.51	$ 85.06	$ 3.70
2025	$ 10.99	$ 7.16	$ 51.60	$ 87.68	$ 3.81
2026	$ 11.23	$ 7.31	$ 52.70	$ 90.31	$ 3.93
2027	$ 11.46	$ 7.46	$ 53.81	$ 92.97	$ 4.04
2028	$ 11.70	$ 7.62	$ 54.94	$ 95.67	$ 4.16
2029	$ 11.95	$ 7.78	$ 56.09	$ 98.42	$ 4.28
2030	$ 12.19	$ 7.94	$ 57.25	$ 101.22	$ 4.40
2031	$ 12.45	$ 8.11	$ 58.44	$ 104.07	$ 4.52
2032	$ 12.71	$ 8.27	$ 59.66	$ 106.97	$ 4.65
2033	$ 12.97	$ 8.44	$ 60.89	$ 109.93	$ 4.78
2034	$ 13.24	$ 8.62	$ 62.15	$ 112.94	$ 4.91
2035	$ 13.51	$ 8.80	$ 63.43	$ 116.00	$ 5.04
2036	$ 13.79	$ 8.98	$ 64.73	$ 119.13	$ 5.18
2037	$ 14.07	$ 9.16	$ 66.06	$ 122.31	$ 5.32
2038	$ 14.36	$ 9.35	$ 67.41	$ 125.56	$ 5.46
2039	$ 14.65	$ 9.54	$ 68.79	$ 128.87	$ 5.60
2040	$ 14.95	$ 9.74	$ 70.20	$ 132.24	$ 5.75

91. Why do TECO's low fuel forecasts used in the sensitivity analysis shown in Appendix I of the Need Study and TECO's response to Staff's 2nd Request for PODs, No. 24, show dissimilar prices for natural gas and No. 2 oil?

A. The two forecasts are different because the table filed in the company's response to Staff's Second Request for POD, No. 24, contained a linking error. A corrected table is provided in the company's response to Interrogatory No. 90.

92. Why do TECO's high fuel forecasts used in the sensitivity analysis shown in Appendix J of the Need Study and TECO's response to Staff's 2nd Request for PODs, No. 24, show identical prices for coal except the Need Study prices appear to be lagged one year?

A. The company's response to Staff's Second Request for POD, No. 24, shows 2011 labeled as 2012 and was reflective of the 2012 High/Low forecast. The correct table is provided in Tampa Electric's response to Interrogatory No. 90.

93. Why do TECO's high fuel forecasts used in the sensitivity analysis shown in Appendix J of the Need Study and TECO's response to Staff's 2nd Request for PODs, No. 24, have dissimilar prices for natural gas and No. 2 oil?

A. The two forecasts are different because the table filed in the company's response to Staff's Second Request for POD, No. 24, contained a linking error. A corrected table is provided in the company's response to Interrogatory No. 90.

94. Please refer to TECO's response to Staff's 1st Production of Documents, No. 20. Where in this response specifically does TECO show how it added "basis" cost to the NYMEX Henry Hub price of natural gas to account for the company receiving its natural gas into FGT Zone 3, as discussed on Pages 12 and 13 of witness Caldwell's direct testimony?

A. The majority of Tampa Electric's firm natural gas interstate pipeline capacity has primary receipt in the FGT Zone 3 supply area in and around Mobile Bay, Alabama. The NYMEX prices the natural gas futures contracts at the Henry Hub in Louisiana. There is typically a small price difference between natural gas supplied at the Henry Hub and natural gas supplied into FGT Zone 3. This difference is called basis, and Tampa Electric adds this basis to its forecasted natural gas price. While Tampa Electric intended to include basis in its natural gas price forecast produced for the 2012 Fuel and Purchased Power Cost Recovery Clause Projection Filing, a spreadsheet error inadvertently excluded the basis from the total delivery price. Due to the relatively low value projected for basis in the 2012 forecast, its omission does not make a material impact on any economic analysis.

95. TECO's response to Staff's Second Set of Interrogatories, No. 48, indicates that Staff's Supplemental Data Request No. 59 in the Ten Year Site Plan Review is the same as the natural gas price forecast appearing as Exhibit JBC-1 in witness Caldwell's testimony, except the supplemental data request prices include additional transportation costs for delivery to the generation station. Why is TECO's delivered natural gas price forecast appearing in Supplemental Data Request No. 59 not the same as the delivered natural gas cost (nominal) shown in TECO's response to Staff's Second Set of Interrogatories No. 50, Page 84 (confidential document), Column "Total Delivered Cost"?

A. The values shown in Tampa Electric's response to Staff's Second Set of Interrogatories, No. 50, are correct. Upon examination of the company's response to Staff's Supplemental Data Request, No. 59 in the Ten Year Site Plan Review, the delivered prices reported there are incorrect.

96. TECO's response to Staff's 2nd Set of Interrogatories, No. 59, indicates that both range and standard deviation were used as a basis for determining fuel price sensitivities. Why did TECO select a 35% range for No. 2 Oil and a 20% range for Illinois Basin Coal when the response shows the range and the standard deviation percentages were higher for Illinois Basin Coal compared to No. 2 Oil percentages?

A. Tampa Electric used the +/- 35 percent and +/- 20 percent ranges for No. 2 oil and Illinois Basin Coal fuel sensitivities, respectively, based on the standard deviation and range of historic pricing for each commodity, combined with simplicity of approach and seasoned judgment. The +/- 35 percent range for natural gas was driven primarily by the historic range. Based on the expectation that No. 2 oil pricing for electric generation is influenced by natural gas pricing for electric generation, a similar +/- 35 percent sensitivity was used for No. 2 oil. For the Illinois Basin coal, a lower +/- 20 percent sensitivity value was used. This was driven by the expectation that production costs and market consolidation will limit potential price decreases for Illinois Basin coal and that fuel switching to natural gas combined cycle units will limit the potential for coal price increases.

97. What are the reasons TECO determined to use its 2012 fuel projection forecasts rather than its 2013 fuel projection forecasts as the basis of its Need Study?

A. Tampa Electric produces its annual fuel price forecast during the summer of each year in preparation for the fuel clause projection filing filed around the beginning of September. The determination of Tampa Electric's capacity planning begins early in the year in order to be completed in time to file the Ten Year Site Plan around April 1 of the following year. Therefore, Tampa Electric had not started preparation of its 2013 fuel price forecast at the time that the capacity planning process that led to the Need Study began.

98. What are the commodity, transportation, and delivered prices, in real and nominal terms, for TECO's 2013 fuel price forecast referenced in witness Caldwell's direct testimony at Page 17, Lines 2-4 for the period 2013-2040?

a. If transportation price for the various fuels has multiple components (e.g. natural gas "basis" plus additional contract delivery prices), please provide each component price and total transportation price.

A. a. The requested information is provided in the following tables.

REDACTED

TAMPA ELECTRIC COMPANY
DOCKET NO. 120234-EI
STAFF'S FOURTH SET OF
INTERROGATORIES
INTERROGATORY NO. 98
PAGE 2 OF 3
FILED: NOVEMBER 26, 2012

Tampa Electric Fuel Forecasts
2013 Fuel Projection
$/mmBtu (Nominal)

	Natural Gas					No. 2 Oil			Illinois Basin Coal		
Year	Commodity*	Basis	Variable Transport	Pipeline Reservation and Storage	Total Delivered Cost	Commodity	Transportation	Total Delivered Cost	Commodity	Waterborne Transportation	Total Delivered Cost
2013	$ 4.00					$ 20.53			$ 1.96		
2014	$ 4.23					$ 20.11			$ 2.05		
2015	$ 4.43					$ 19.72			$ 2.09		
2016	$ 4.60					$ 20.32			$ 2.01		
2017	$ 4.78					$ 21.03			$ 2.08		
2018	$ 4.96					$ 21.56			$ 2.10		
2019	$ 5.20					$ 22.10			$ 2.12		
2020	$ 5.45					$ 22.77			$ 2.19		
2021	$ 5.71					$ 23.38			$ 2.21		
2022	$ 6.06					$ 23.98			$ 2.26		
2023	$ 6.40					$ 24.60			$ 2.35		
2024	$ 6.68					$ 25.24			$ 2.42		
2025	$ 7.01					$ 26.05			$ 2.52		
2026	$ 7.32					$ 26.79			$ 2.62		
2027	$ 7.67					$ 27.49			$ 2.71		
2028	$ 7.94					$ 28.28			$ 2.81		
2029	$ 8.27					$ 29.22			$ 2.92		
2030	$ 8.63					$ 30.13			$ 3.03		
2031	$ 9.01					$ 31.51			$ 3.15		
2032	$ 9.44					$ 32.66			$ 3.28		
2033	$ 9.79					$ 32.95			$ 3.39		
2034	$ 10.50					$ 34.02			$ 3.56		
2035	$ 11.19					$ 35.26			$ 3.75		
2036	$ 11.62					$ 36.50			$ 3.91		
2037	$ 12.08					$ 37.78			$ 4.07		
2038	$ 12.56					$ 39.10			$ 4.25		
2039	$ 13.05					$ 40.47			$ 4.42		
2040	$ 13.56					$ 41.88			$ 4.61		

* Commodity costs are the costs referenced at page 17 of witness Caldwell's direct testimony.

REDACTED

TAMPA ELECTRIC COMPANY
DOCKET NO. 120234-EI
STAFF'S FOURTH SET OF
INTERROGATORIES
INTERROGATORY NO. 98
PAGE 3 OF 3
FILED: NOVEMBER 26, 2012

Tampa Electric Fuel Forecasts
2013 Fuel Projection
$/mmBtu (2012$)

	Natural Gas					No. 2 Oil			Illinois Basin Coal		
Year	Commodity*	Basis	Variable Transport	Pipeline Reservation and Storage	Total Delivered Cost	Commodity	Transportation	Total Delivered Cost	Commodity	Waterborne Transportation	Total Delivered Cost
2013	$ 3.94					$ 20.23			$ 1.93		
2014	$ 4.06					$ 19.29			$ 1.96		
2015	$ 4.15					$ 18.46			$ 1.96		
2016	$ 4.22					$ 18.63			$ 1.85		
2017	$ 4.29					$ 18.90			$ 1.87		
2018	$ 4.37					$ 18.97			$ 1.85		
2019	$ 4.47					$ 19.03			$ 1.82		
2020	$ 4.59					$ 19.17			$ 1.84		
2021	$ 4.71					$ 19.26			$ 1.82		
2022	$ 4.89					$ 19.33			$ 1.82		
2023	$ 5.05					$ 19.41			$ 1.85		
2024	$ 5.16					$ 19.49			$ 1.87		
2025	$ 5.30					$ 19.69			$ 1.90		
2026	$ 5.42					$ 19.82			$ 1.94		
2027	$ 5.56					$ 19.92			$ 1.97		
2028	$ 5.64					$ 20.07			$ 1.99		
2029	$ 5.75					$ 20.31			$ 2.03		
2030	$ 5.88					$ 20.52			$ 2.06		
2031	$ 6.01					$ 21.02			$ 2.10		
2032	$ 6.17					$ 21.35			$ 2.14		
2033	$ 6.27					$ 21.10			$ 2.17		
2034	$ 6.59					$ 21.35			$ 2.24		
2035	$ 6.88					$ 21.68			$ 2.31		
2036	$ 7.00					$ 21.99			$ 2.35		
2037	$ 7.13					$ 22.30			$ 2.40		
2038	$ 7.26					$ 22.62			$ 2.46		
2039	$ 7.40					$ 22.94			$ 2.51		
2040	$ 7.53					$ 23.26			$ 2.56		

* Commodity costs are the costs referenced at page 17 of witness Caldwell's direct testimony.

99. What are the high and low price forecast sensitivities associated with TECO's 2013 fuel price forecast, based on the methodology described in witness Caldwell's testimony at Page 16, Lines 4 – 9?

A. Tampa Electric used the same high and low price forecast sensitivity bands for 2013 as were used in 2012. The company used +/- 35 percent for natural gas and No. 2 oil and +/- 20 percent for Illinois Basin coal.

100. Witness Caldwell indicates that TECO's base forecast is consistent with other independent forecasts available at the time the base forecast was developed.

a. What is the source and the date of independent fuel price forecasts TECO use to compare its 2013 fuel price forecasts?

b. What did TECO conclude from its comparison of independent fuel price forecasts to its 2013 fuel price forecasts in order to ensure consistency?

A. a. The sources and dates of the independent fuel price forecasts used to compare to Tampa Electric's fuel price forecasts are listed below.

- Wood Mackenzie, April 2012
- EIA Annual Energy Outlook, June 2012

b. First, because Tampa Electric's fuel price forecast is based on current market transactions, it is consistent with actual fuel costs of Tampa Electric; this provides a high probability of actual fuel clause costs matching the projected costs. Second, Tampa Electric's 2013 fuel price forecast escalates prices in the outer years using the escalation of fuel prices in the EIA Annual Energy Outlook. Therefore, it is implicitly consistent with the EIA forecast. Finally, the Wood Mackenzie and Tampa Electric natural gas price forecasts are similar.

101. When were TECO's 2012 and 2013 fuel price forecasts developed and when were they approved by TECO's executive management?

A. The 2012 fuel price forecast was prepared during the summer of 2011 and approved on August 17, 2011. It was then used for the 2012 Fuel and Purchased Power Cost Recovery Clause Projection Filing filed on September 1, 2011.

The 2013 fuel price forecast was prepared during the summer of 2012 and approved on August 6, 2012. It was then used for the 2013 Fuel and Purchased Power Cost Recovery Clause Projection Filing filed on August 30, 2012 and as a sensitivity in the Need Study filed on September 12, 2012.

AFFIDAVIT

STATE OF FLORIDA)
)
COUNTY OF HILLSBOROUGH)

Before me the undersigned authority personally appeared Carlos Aldazabal who deposed and said that he is a Director, Regulatory Affairs, Tampa Electric Company, and that the individuals listed in Tampa Electric Company's response to Staff's Fourth Set of Interrogatories, (Nos. 69 - 101) prepared or assisted with the responses to these interrogatories to the best of his information and belief.

Dated at Tampa, Florida this 21 day of November, 2012.

Carlos Aldazabal

Sworn to and subscribed before me this 21 day of November, 2012.

Denise Chichetto

Notary Public State of Florida
Denise Chichetto
My Commission EE 161752
Expires 03/21/2016

My Commission expires _____

TECO's Answer to Fourth Set of Interrogatories (No. 98) of the Florida Public Service Commission

(Confidential FPSC Document No. 07840-12)

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TECO's Answer to Fifth Set Of Interrogatories (Nos. 102-105) of the Florida Public Service Commission

FLORIDA PUBLIC SERVICE COMMISSION			
DOCKET NO.	120234-EI	EXHIBIT	6
PARTY	Florida Public Service Commission Staff		
DESCRIPTION	TECO - Staff Exhibit #6		
	[Bates Nos. 00184-00192]		

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition to determine need for Polk 2-5 combined cycle conversion, by Tampa Electric Company	DOCKET NO. 120234-EI FILED: November 26, 2012

TAMPA ELECTRIC COMPANY'S

ANSWERS TO FIFTH SET OF INTERROGATORIES (NOS. 102-105)

OF THE

FLORIDA PUBLIC SERVICE COMMISSION

Tampa Electric files its Answers to Interrogatories (Nos. 102-105) propounded and served on November 6, 2012, by the Florida Public Service Commission.

TAMPA ELECTRIC COMPANY
DOCKET NO. 120234-EI
INDEX TO STAFF'S FIFTH SET OF INTERROGATORIES (NOS. 102-105)

Number	Witness	Subject	Bates Stamped Page
102	Rocha	In response to interrogatory No. 46, TECO provided an analysis through 2046. Why does TECO believe this is a reasonable time frame for evaluating the proposed project?	1
103	Rocha	Please complete the table below summarizing Polk 2-5 assuming the proposed conversion.	2
104	Rocha	Please complete the table below summarizing Polk 2-5 without the proposed conversion.	3
105	Young	On Page 7 of witness S. Beth Young's testimony, the witness states in part that "[a] Tampa Electric core team developed and reviewed potential alternatives and estimated costs." For each alternative mentioned in witness Young's testimony, please provide a table similar to the one contained in Exhibit SBY-1, Document No. 3.	4

Jim Rocha
Director, Planning, Strategy and Compliance

Beth Young
Director, Energy Delivery

Tampa Electric Company
702 N. Franklin Street
Tampa, FL 33602

102. In response to interrogatory No. 46, TECO provided an analysis through 2046. Why does TECO believe this is a reasonable time frame for evaluating the proposed project?

A. All projects were evaluated through 2046 because this time period allows development of full 30-year revenue requirements from the unit's in-service date in January 2017.

103. Please complete the table below summarizing Polk 2-5 assuming the proposed conversion.

Installed Cost ($ Million)	
Fixed O&M ($/kw-yr) 2017$	
Variable O&M ($/MWh) 2017$	
Heat Rate (BTU/kwh)	
Equivalent Availability (%)	
Capacity Factor (%)	

A. The requested information is provided in the following table.

Installed Cost ($ Million)	706.6*
Fixed O&M ($/kW-yr) 2017$	3.21
Variable O&M ($/MWh) 2017$	2.35
Heat Rate (BTU/kWh)	7,000
Equivalent Availability (%)	96.1
Capacity Factor (%)	52.3**

* Includes AFUDC.
** Ten-year average expected output.

104. Please complete the table below summarizing Polk 2-5 without the proposed conversion.

Fixed O&M ($/kw-yr) 2017$	
Variable O&M ($/MWh) 2017$	
Heat Rate (BTU/kwh)	
Equivalent Availability (%)	
Capacity Factor (%)	

A. The requested information is provided in the following table.

Fixed O&M ($/kW-yr) 2017$	0
Variable O&M ($/MWh) 2017$	4.63*
Heat Rate (BTU/kWh)	11,560
Equivalent Availability (%)	97.7
Capacity Factor (%)	4.4

Note: Heat Rate, EAF, and CF are the average results of Polk 2-5 in 2016.
* CT major maintenance modeled as cost per start, then converted to energy basis for presentation.

105. On Page 7 of witness S. Beth Young's testimony, the witness states in part that "[a] Tampa Electric core team developed and reviewed potential alternatives and estimated costs." For each alternative mentioned in witness Young's testimony, please provide a table similar to the one contained in Exhibit SBY-1, Document No. 3.

A. The two alternatives that Tampa Electric initially evaluated are on the following page. While some of the estimated transmission infrastructure and land costs were not part of the initial evaluation or study, they were subsequently updated along with the final transmission path selected.

230626	Pebbledale to Willow Oak 230 kV *	This is a new construction of a 230 kV circuit from Pebbledale to Willow Oak, 230/69 kV Substation with 224 MVA transformer & (2) 69 kV circuits at Willow Oak.	1,118.6	
230428	Willow Oak to Wheeler 230 kV	This is a new construction of a 230 kV circuit from Wheeler Road to Willow Oak Substation and installation of two 230 kV breakers at Willow Oak & Wheeler 230/69 kV transformer.	1,118.6	
-	Wheeler to Thonotossasa 230 kV	This is a new construction of approximately 9 miles circuit with a rating of 1,118.6 MVA, installation of two 230 kV breakers at Wheeler and one at Thonotossasa.	1,118.6	
230606	Polk to Pebbledale Ckt 1 230 kV	This circuit will be rerated to 729.4 MVA.	729.4	
230605	Polk to Pebbledale Ckt 2 230 kV	This circuit will be reconductored to 729.4 MVA.	729.4	
230601	Davis Substation Switched Reactor	A new switchable series reactor will be installed on the Davis to Chapman circuit.	-	
-	S.R. 60 Substation Upgrade	At S.R. 60 substation, North 230/69 kV transformer, upgrade 3'' SPS Al segment to 358.5 MVA.	358.5	$134
-	Dale Mabry Substation Upgrade	At Dale Mabry substation, West 230/69 kV transformer, upgrade the 69 kV circuit breaker #103 and 3'' SPS Al segment to 358.5 MVA.	358.5	
66016	Wheeler-South Seffner 69 kV	This circuit will be rerated to 155.2 MVA.	155.2	
-	Mud Lake Switching Station	Build Mud Lake Rd 230 kV 4-Breaker Ring Bus	-	
230021	FishHawk to Pebbledale 230 kV, #2 Bell Creek to FishHawk 230 kV	The existing line from Bell Creek to Pebbledale will be looped into FishHawk Substation and upgrade two 230 kV breakers.	-	
-	Ariana, Alexander and Wilson Substations	Replace elemetns (breakers, BD, LD, PT, etc) at Ariana, Alexander and Wilson Subtastions.	-	
-	Circuit Breaker Upgrade	There will be breakers that will be upgraded as a result of the additional capacity.	-	
-	Interconnect & Upgrade	Interconnection costs to a TEC existing station and required upgrades.	-	

* Costs for land acquisition are uncertain and could be significantly higher.

230629	FishHawk to Pebbledale 230 kV, #2	The existing line from Bell Creek to Pebbledale will be looped into FishHawk Substation. Rebuild 230 kV circuit from FishHawk to Pebbledale #2 to a rating of 1195.1 MVA.	1,195.1	
230625	FishHawk to Pebbledale 230 kV, #1	Rebuild 230 kV circuit from FishHawk to Pebbledale #1 to a rating of 1195.1 MVA	1,195.1	
230021 REV	Bell Creek to FishHawk 230 kV	Rebuild circuit from Bell Creek to FishHawk to a rating of 1195.1 MVA	1,195.1	
230004	Bell Creek to Gannon 230 kV	This circuit will be upgraded to 1,195.1 MVA.	1,195.1	$169
230005	FishHawk to Gannon 230 kV	This circuit will be upgraded to 1,195.1 MVA.	1,195.1	
-	Circuit Breaker Upgrade	There will be breakers that will be upgraded as a result of the additional capacity.	-	
-	Interconnect & Upgrade	Interconnection costs to a TEC existing station and required upgrades.	-	

A F F I D A V I T

STATE OF FLORIDA)
)
COUNTY OF HILLSBOROUGH)

Before me the undersigned authority personally appeared Carlos Aldazabal who deposed and said that he is a Director, Regulatory Affairs, Tampa Electric Company, and that the individuals listed in Tampa Electric Company's response to Staff's Fifth Set of Interrogatories, (Nos. 102 - 105) prepared or assisted with the responses to these interrogatories to the best of his information and belief.

Dated at Tampa, Florida this 21ST day of November, 2012.

Carlos Aldazabal

Sworn to and subscribed before me this 21ST day of November, 2012.

Tison C Vega

Notary Public State of Florida
Tison C Vega
My Commission EE 165415
Expires 02/01/2016

My Commission expires _____

7

TECO's Answer to First Request for Production of Documents (Nos. 1 *(Bates Stamped Pages (BSP) 4-6)*, 5, 6 (*BSP 2653-2661* redacted), 10 (*BSP 2840-2919*) of the Florida Public Service Commission

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 120234-EI EXHIBIT 7
PARTY Florida Public Service Commission Staff
DESCRIPTION TECO - Staff Exhibit #7 - Confidential
[Bates Nos. 00193-00308] & [Bates No. 00309]

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition to determine need for Polk 2-5 combined cycle conversion, by Tampa Electric Company	**DOCKET NO. 120234-EI** **FILED: October 18, 2012**

REDACTED

TAMPA ELECTRIC COMPANY'S

ANSWERS TO FIRST REQUEST FOR

PRODUCTION OF DOCUMENTS (NOS. 1-11)

OF

FLORIDA PUBLIC SERVICE COMMISSION STAFF

Tampa Electric files this its Answers to Production of Documents (Nos. 1-11) propounded and served on September 28, 2012, by the Florida Public Service Commission Staff.

TAMPA ELECTRIC COMPANY
DOCKET NO. 120234-EI
INDEX TO STAFF'S FIRST REQUEST FOR
PRODUCTION OF DOCUMENTS (NOS. 1-11)

Number	Subject	Bates Stamped Pages
1	Please provide all documents showing the econometric equations used in the preparation of the load forecasts referenced in witness Cifuentes' direct testimony at page 3, lines 19-22.	1 - 15
2	If any of the load forecasts (e.g. total customer forecast) appearing in witness Cifuentes' direct testimony are aggregations of multiple underlying forecasts (e.g. residential, commercial, etc.) based on separate multiregression models, please provide all documents related to each such forecast.	16 - 2377
3	Please provide all documents, in hardcopy and electronic (Excel) format as available, comprising the data used to estimate the econometric equations underlying the preparation of the load forecasts as referenced in witness Cifuentes' direct testimony at page 3, lines 19-22.	2378 - 2633
4	Please provide any documents showing how the blended forecasts discussed in witness Cifuentes' direct testimony were prepared, such as the population forecast referenced in witness Cifuentes' direct testimony at page 4, lines 15-20.	2634
5	Please provide all documentation, in hardcopy and electronic (Excel) format as available, of the statistical output resulting from the estimation of each econometric equation used in the preparation of the load forecasts referenced in witness Cifuentes' direct testimony at page 3, lines 19-22.	2635 – 2652
6	Please provide all documents related to each forecast assumption used to prepare the load forecasts, including each forecast resulting from multiple equation models, as referenced in witness Cifuentes' direct testimony at page 3, lines 19-22.	2653 – 2661
7	Please provide all documentation relating to the calculations and supporting rationale behind any adjustments made to the output of the econometric models relied upon in the load forecasts, including each forecast resulting from multiple equation models, referenced in witness Cifuentes' direct testimony at page 3, lines 19-22.	2662
8	Please provide all documentation relating to the equations, historical data, output, assumptions, and results of each of the statistically adjusted engineering (SAE) models used to develop projections of customer growth, energy consumption, and peak demands as referenced in witness Cifuentes' direct testimony on page 3, lines 19-22, to the extent not already provided in Document Requests No. 1-7 above.	2663 – 2751
9	Please provide all documents related to the rationale, assumptions, and methods by which the Company integrates	2752

Number	Subject	Bates Stamped Pages
	its econometric models with statistically adjusted engineering (SAE) models as referenced in witness Cifuentes' direct testimony on page 3, lines 19-22.	
10	Please provide all portions of TECO's 2011 and 2012 Ten Year Site Plans, and any documents related to the 2012 annual forecast process, which were relied upon by witness Cifuentes' in preparing or comparing her load forecasts as referenced in her direct testimony at page 10, lines 22-25, and page 13, lines 17-23.	2753 – 3124
11	Please provide all documentation related to any sensitivity analyses of TECO's load forecasts as referenced by witness Cifuentes' in her direct testimony at page 12, lines 17-21.	3125 - 3323

TAMPA ELECTRIC COMPANY
DOCKET NO. 120234-EI
STAFF'S FIRST REQUEST FOR
PRODUCTION OF DOCUMENTS
DOCUMENT NO. 1
BATES STAMPED PAGES: 1 - 15
FILED: OCTOBER 18, 2012

1. Please provide all documents showing the econometric equations used in the preparation of the load forecasts referenced in witness Cifuentes' direct testimony at page 3, lines 19-22.

A. Attached is Chapter 3 of Tampa Electric's Ten Year Site Plan, which shows the econometric equations used in the preparation of the company's June 2011 load forecast, referenced in witness Cifuentes's direct testimony at page 3, lines 19-22.

120234 Hearing Exhibits 00197

the sector.

4. *Public Authority Customer Model:* Customer projections are a function of Hillsborough County's population. The need for public services will depend on the number of people in the region; therefore, consistent with the residential customer model, Hillsborough's population projections are used to determine future growth in the public authorities sector.
5. *Street & Highway Lighting Customer Model:* Customer projections are based on the recent growth trend in the sector.

3. ENERGY MULTIREGRESSION MODEL

There are a total of seven 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 time frame, as do econometric regression models.

1. *Residential Energy Model:* The residential forecast model is made up of three major components: (1) end-use equipment index variables, which capture the long-term net effect of equipment saturation and equipment efficiency improvements; (2) changes in the economy such as household income, household size, and the price of electricity; and, (3) weather variables, which serve to allocate the seasonal impacts of weather throughout the year. The SAE model framework begins by defining energy use for an average customer in year (y) and month (m) as the sum of energy used by heating equipment (XHeat y,m), cooling equipment (XCool y,m), and other equipment (XOther y,m). The XHeat, XCool, and XOther variables are defined as a product of an annual equipment index and a monthly usage multiplier.

$$\text{Average Usage}_{y,m} = (\text{XHeat}_{y,m} + \text{XCool}_{y,m} + \text{XOther}_{y,m})$$

Where:

$$\text{XHeat}_{y,m} = \text{HeatEquipIndex}_{y} \times \text{HeatUse}_{y,m}$$
$$\text{XCool}_{y,m} = \text{CoolEquipIndex}_{y} \times \text{CoolUse}_{y,m}$$
$$\text{XOtherUse}_{y,m} = \text{OtherEquipIndex}_{y} \times \text{OtherUse}_{y,m}$$

The annual equipment variables (HeatEquipIndex, CoolEquipIndex, OtherEquipIndex) are defined as a weighted average across equipment types multiplied by equipment saturation levels normalized by operating efficiency levels. Given a set of fixed weights, the index will change over time with changes in equipment saturations and operating efficiencies. The

120234 Hearing Exhibits 00198

weights are defined by the estimated energy use per household for each equipment type in the base year.

Where:

$$\textbf{HeatEquipIndex} = \sum_{Tech.} \text{Weight} \times \left(\frac{\text{Saturation}_{y} \,/\, \text{Efficiency}_{y}}{\text{Saturation}_{\text{base y}} \,/\, \text{Efficiency}_{\text{base y}}} \right)$$

$$\textbf{CoolEquipIndex} = \sum_{Tech.} \text{Weight} \times \left(\frac{\text{Saturation}_{y} \,/\, \text{Efficiency}_{y}}{\text{Saturation}_{\text{base y}} \,/\, \text{Efficiency}_{\text{base y}}} \right)$$

$$\textbf{OtherEquipIndex} = \sum_{Tech.} \text{Weight} \times \left(\frac{\text{Saturation}_{y} \,/\, \text{Efficiency}_{y}}{\text{Saturation}_{\text{base y}} \,/\, \text{Efficiency}_{\text{base y}}} \right)$$

Next, the monthly usage multiplier or utilization variables (HeatUse, CoolUse, OtherUse) are defined using economic and weather variables. A customer's monthly usage level is impacted by several factors, including weather, household size, income levels, electricity prices and the number of days in the billing cycle. The degree day variables serve to allocate the seasonal impacts of weather throughout the year, while the remaining variables serve to capture changes in the economy.

$$\textbf{HeatUse}_{y,m} = \left(\frac{\text{Price}_{y,m}}{\text{Price}_{\text{base y,m}}} \right)^{-.10} \times \left(\frac{\text{HH Income}_{y,m}}{\text{HH Income}_{\text{base y,m}}} \right)^{.10} \times \left(\frac{\text{HH Size}_{y,m}}{\text{HH Size}_{\text{base y,m}}} \right)^{.05} \times \left(\frac{\text{HDD}_{y,m}}{\text{Normal HDD}} \right)$$

$$\textbf{CoolUse}_{y,m} = \left(\frac{\text{Price}_{y,m}}{\text{Price}_{\text{base y,m}}} \right)^{-.10} \times \left(\frac{\text{HH Income}_{y,m}}{\text{HH Income}_{\text{base y,m}}} \right)^{.10} \times \left(\frac{\text{HH Size}_{y,m}}{\text{HH Size}_{\text{base y,m}}} \right)^{.05} \times \left(\frac{\text{CDD}_{y,m}}{\text{Normal CDD}} \right)$$

$$\textbf{OtherUse}_{y,m} = \left(\frac{\text{Price}_{y,m}}{\text{Price}_{\text{base y,m}}} \right)^{-.10} \times \left(\frac{\text{HH Income}_{y,m}}{\text{HH Income}_{\text{base y,m}}} \right)^{.10} \times \left(\frac{\text{HH Size}_{y,m}}{\text{HH Size}_{\text{base y,m}}} \right)^{.05} \times \left(\frac{\text{Billing Days}_{y,m}}{\text{Billing Days}_{\text{base y,m}}} \right)$$

The SAE approach to modeling provides a powerful framework for developing short-term and long-term energy forecasts. This approach reflects changes in equipment saturation and efficiency levels and gives estimates of weather sensitivities that vary over time as well as estimate trend adjustments.

2. *Commercial Energy Models:* total commercial energy sales include commercial sales plus temporary service sales (temporary poles on construction sites); therefore, two models are used to forecast total commercial energy sales.
   a. 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.

b. Temporary Service Energy Model: This 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 driver being temporary service customer growth.

3. *Industrial Energy Model (Non-Phosphate):* Nonphosphate industrial energy includes two rate classes that have been modeled individually: General Service and General Service Demand.
   a. The General Service Energy Model utilizes the same SAE model framework as the commercial energy model. The weather component is consistent with the residential and commercial models.
   b. The General Service Demand Energy Model is based on industrial employment, the price of electricity in the industrial sector, cooling degree-days and number of days billed. Unlike the previous models discussed, heating load does not impact this sector.

4. *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.

5. *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 and 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 five energy models described above, plus an exogenous interruptible and phosphate forecast, are added together to arrive at the total retail energy sales forecast.

In summary, the SAE approach to modeling provides a powerful framework for developing short-term and long-term energy forecasts. This approach reflects changes in equipment saturation and efficiency levels, gives estimates of weather sensitivity that varies over time, as well as estimates trend adjustments.

4. PEAK DEMAND MULTIREGRESSION MODEL

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. To stabilize the peak demand data series and improve model accuracy, the volatility of the phosphate load is removed. To further stabilize the data, the peak demand models project on a per customer basis.

120234 Hearing Exhibits 00200

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5. Please provide all documentation, in hardcopy and electronic (Excel) format as available, of the statistical output resulting from the estimation of each econometric equation used in the preparation of the load forecasts referenced in witness Cifuentes' direct testimony at page 3, lines 19-22.

A. The requested documents are attached.

120234 Hearing Exhibits 00201

Iterations	1
Adjusted Observations	124
Deg. of Freedom for Error	117
R-Squared	0.969
Adjusted R-Squared	0.968
AIC	9.988
BIC	10.147
F-Statistic	612.019
Prob (F-Statistic)	0.0000
Log-Likelihood	-788.20
Model Sum of Squares	75,648,691.05
Sum of Squared Errors	2,410,299.22
Mean Squared Error	20,600.85
Std. Error of Regression	143.53
Mean Abs. Dev. (MAD)	102.11
Mean Abs. % Err. (MAPE)	1.31%
Durbin-Watson Statistic	1.809
Durbin-H Statistic	#NA
Ljung-Box Statistic	25.62
Prob (Ljung-Box)	0.3730
Skewness	0.355
Kurtosis	5.077
Jarque-Bera	24.888
Prob (Jarque-Bera)	0.0000

Forecast Observations	0
Mean Abs. Dev. (MAD)	0.00
Mean Abs. % Err. (MAPE)	0.00%
Avg. Forecast Error	0.00
Mean % Error	0.00%
Root Mean-Square Error	0.00
Theil's Inequality Coefficient	0.0000
-- Bias Proportion	0.00%
-- Variance Proportion	0.00%
-- Covariance Proportion	0.00%

TECOSales Base.NDM
Parameter Tables
Data Tables
Transformation Tables
Models
Simulations
Reports
Graphs
Scatter Plots
Regression Statistics
Iterations 12
Adjusted Observations 123
Deg. of Freedom for Error 109
R-Squared 0.999
Adjusted R-Squared 0.999
AIC 9.362
BIC 9.682
F-Statistic #NA
Prob (F-Statistic) #NA
Log-Likelihood -736.29
Model Sum of Squares 1,215,315,356.28
Sum of Squared Errors 1,139,979.88
Mean Squared Error 10,458.53
Std. Error of Regression 102.27
Mean Abs. Dev. (MAD) 72.31
Mean Abs. % Err. (MAPE) 0.11%
Durbin-Watson Statistic 2.433
Durbin-H Statistic #NA
Ljung-Box Statistic 46.65
Prob (Ljung-Box) 0.0037
Skewness -0.037
Kurtosis 5.360
Jarque-Bera 28.582
Prob (Jarque-Bera) 0.0000
Forecast Observations 0
Mean Abs. Dev. (MAD) 0.00
Mean Abs. % Err. (MAPE) 0.00%
Avg. Forecast Error 0.00
Mean % Error 0.00%
Root Mean-Square Error 0.00
Theil's Inequality Coefficient 0.0000
-- Bias Proportion 0.00%
-- Variance Proportion 0.00%
-- Covariance Proportion 0.00%
MStat
Ready
NUM

2637

| | A | B | C | D | E | F | G | H | I | J | K | L | M | N | O | P | Q | R | S | T | U | V | W | X | Y | Z | AA | AB | AC | AD | AE | AF | AG | AH | AI | AJ | AK | AL | AM | AN | AO | AP | AQ | AR | AS | AT | AU | AV | AW | AX | AY | AZ | BA | BB | BC | BD | BE | BF | BG | BH | BI | BJ | BK | BL | BM | BN | BO | BP | BQ | BR | BS | BT | BU | BV | BW | BX | BY | BZ | CA | CB | CC | CD | CE | CF | CG | CH | CI | CJ | CK | CL | CM | CN | CO | CP | CQ | CR | CS | CT | CU | CV | CW | CX | CY | CZ | DA | DB | DC | DD | DE | DF | DG | DH | DI | DJ | DK | DL | DM | DN | DO | DP | DQ | DR | DS | DT | DU | DV | DW | DX | DY | DZ | EA | EB | EC | ED | EE | EF | EG | EH | EI | EJ | EK | EL | EM | EN | EO | EP | EQ | ER | ES | ET | EU | EV | EW | EX | EY | EZ | FA | FB | FC | FD | FE | FF | FG | FH | FI | FJ | FK | FL | FM | FN | FO | FP | FQ | FR | FS | FT | FU | FV | FW | FX | FY | FZ | GA | GB | GC | GD | GE | GF | GG | GH | GI | GJ | GK | GL | GM | GN | GO | GP | GQ | GR | GS | GT | GU | GV | GW | GX | GY | GZ | HA | HB | HC | HD | HE | HF | HG | HH | HI | HJ | HK | HL | HM | HN | HO | HP | HQ | HR | HS | HT | HU | HV | HW | HX | HY | HZ | IA | IB | IC | ID | IE | IF | IG | IH | II | IJ | IK | IL | IM | IN | IO | IP | IQ | IR | IS | IT | IU | IV | IW | IX | IY | IZ | JA | JB | JC | JD | JE | JF | JG | JH | JI | JJ | JK | JL | JM | JN | JO | JP | JQ | JR | JS | JT | JU | JV | JW | JX | JY | JZ | KA | KB | KC | KD | KE | KF | KG | KH | KI | KJ | KK | KL | KM | KN | KO | KP | KQ | KR | KS | KT | KU | KV | KW | KX | KY | KZ | LA | LB | LC | LD | LE | LF | LG | LH | LI | LJ | LK | LL | LM | LN | LO | LP | LQ | LR | LS | LT | LU | LV | LW | LX | LY | LZ | MA | MB | MC | MD | ME | MF | MG | MH | MI | MJ | MK | ML | MM | MN | MO | MP | MQ | MR | MS | MT | MU | MV | MW | MX | MY | MZ | NA | NB | NC | ND | NE | NF | NG | NH | NI | NJ | NK | NL | NM | NN | NO | NP | NQ | NR | NS | NT | NU | NV | NW | NX | NY | NZ | OA | OB | OC | OD | OE | OF | OG | OH | OI | OJ | OK | OL | OM | ON | OO | OP | OQ | OR | OS | OT | OU | OV | OW | OX | OY | OZ | PA | PB | PC | PD | PE | PF | PG | PH | PI | PJ | PK | PL | PM | PN | PO | PP | PQ | PR | PS | PT | PU | PV | PW | PX | PY | PZ | QA | QB | QC | QD | QE | QF | QG | QH | QI | QJ | QK | QL | QM | QN | QO | QP | QQ | QR | QS | QT | QU | QV | QW | QX | QY | QZ | RA | RB | RC | RD | RE | RF | RG | RH | RI | RJ | RK | RL | RM | RN | RO | RP | RQ | RR | RS | RT | RU | RV | RW | RX | RY | RZ | SA | SB | SC | SD | SE | SF | SG | SH | SI | SJ | SK | SL | SM | SN | SO | SP | SQ | SR | SS | ST | SU | SV | SW | SX | SY | SZ | TA | TB | TC | TD | TE | TF | TG | TH | TI | TJ | TK | TL | TM | TN | TO | TP | TQ | TR | TS | TT | TU | TV | TW | TX | TY | TZ | UA | UB | UC | UD | UE | UF | UG | UH | UI | UJ | UK | UL | UM | UN | UO | UP | UQ | UR | US | UT | UU | UV | UW | UX | UY | UZ | VA | VB | VC | VD | VE | VF | VG | VH | VI | VJ | VK | VL | VM | VN | VO | VP | VQ | VR | VS | VT | VU | VV | VW | VX | VY | VZ | WA | WB | WC | WD | WE | WF | WG | WH | WI | WJ | WK | WL | WM | WN | WO | WP | WQ | WR | WS | WT | WU | WV | WW | WX | WY | WZ | XA | XB | XC | XD | XE | XF | XG | XH | XI | XJ | XK | XL | XM | XN | XO | XP | XQ | XR | XS | XT | XU | XV | XW | XX | XY | XZ | YA | YB | YC | YD | YE | YF | YG | YH | YI | YJ | YK | YL | YM | YN | YO | YP | YQ | YR | YS | YT | YU | YV | YW | YX | YY | YZ | ZA | ZB | ZC | ZD | ZE | ZF | ZG | ZH | ZI | ZJ | ZK | ZL | ZM | ZN | ZO | ZP | ZQ | ZR | ZS | ZT | ZU | ZV | ZW | ZX | ZY | ZZ | AAA | AAB | AAC | AAD | AAE | AAF | AAG | AAH | AAI | AAJ | AAK | AAL | AAM | AAN | AAO | AAP | AAQ | AAR | AAS | AAT | AAU | AAV | AAW | AAX | AAY | AAZ | ABA | ABB | ABC | ABD | ABE | ABF | ABG | ABH | ABI | ABJ | ABK | ABL | ABM | ABN | ABO | ABP | ABQ | ABR | ABS | ABT | ABU | ABV | ABW | ABX | ABY | ABZ | ACA | ACB | ACC | ACD | ACE | ACF | ACG | ACH | ACI | ACJ | ACK | ACL | ACM | ACN | ACO | ACP | ACQ | ACR | ACS | ACT | ACU | ACV | ACW | ACX | ACY | ACZ | ADA | ADB | ADC | ADD | ADE | ADF | ADG | ADH | ADI | ADJ | ADK | ADL | ADM | ADN | ADO | ADP | ADQ | ADR | ADS | ADT | ADU | ADV | ADW | ADX | ADY | ADZ | AEA | AEB | AEC | AED | AEE | AEF | AEG | AEH | AEI | AEJ | AEK | AEL | AEM | AEN | AEO | AEP | AEQ | AER | AES | AET | AEU | AEV | AEW | AEX | AEY | AEZ | AFA | AFB | AFC | AFD | AFE | AFF | AFG | AFH | AFI | AFJ | AFK | AFL | AFM | AFN | AFO | AFP | AFQ | AFR | AFS | AFT | AFU | AFV | AFW | AFX | AFY | AFZ | AGA | AGB | AGC | AGD | AGE | AGF | AGG | AGH | AGI | AGJ | AGK | AGL | AGM | AGN | AGO | AGP | AGQ | AGR | AGS | AGT | AGU | AGV | AGW | AGX | AGY | AGZ | AHA | AHB | AHC | AHD | AHE | AHF | AHG | AHH | AHI | AHJ | AHK | AHL | AHM | AHN | AHO | AHP | AHQ | AHR | AHS | AHT | AHU | AHV | AHW | AHX | AHY | AHZ | AIA | AIB | AIC | AID | AIE | AIF | AIG | AIH | AII | AIJ | AIK | AIL | AIM | AIN | AIO | AIP | AIQ | AIR | AIS | AIT | AIU | AIV | AIW | AIX | AIY | AIZ | AJA | AJB | AJC | AJD | AJE | AJF | AJG | AJH | AJI | AJJ | AJK | AJL | AJM | AJN | AJO | AJP | AJQ | AJR | AJS | AJT | AJU | AJV | AJW | AJX | AJY | AJZ | AKA | AKB | AKC | AKD | AKE | AKF | AKG | AKH | AKI | AKJ | AKK | AKL | AKM | AKN | AKO | AKP | AKQ | AKR | AKS | AKT | AKU | AKV | AKW | AKX | AKY | AKZ | ALA | ALB | ALC | ALD | ALE | ALF | ALG | ALH | ALI | ALJ | ALK | ALL | ALM | ALN | ALO | ALP | ALQ | ALR | ALS | ALT | ALU | ALV | ALW | ALX | ALY | ALZ | AMA | AMB | AMC | AMD | AME | AMF | AMG | AMH | AMI | AMJ | AMK | AML | AMM | AMN | AMO | AMP | AMQ | AMR | AMS | AMT | AMU | AMV | AMW | AMX | AMY | AMZ | ANA | ANB | ANC | AND | ANE | ANF | ANG | ANH | ANI | ANJ | ANK | ANL | ANM | ANN | ANO | ANP | ANQ | ANR | ANS | ANT | ANU | ANV | ANW | ANX | ANY | ANZ | AOA | AOB | AOC | AOD | AOE | AOF | AOG | AOH | AOI | AOJ | AOK | AOL | AOM | AON | AOO | AOP | AOQ | AOR | AOS | AOT | AOU | AOV | AOW | AOX | AOY | AOZ | APA | APB | APC | APD | APE | APF | APG | APH | API | APJ | APK | APL | APM | APN | APO | APP | APQ | APR | APS | APT | APU | APV | APW | APX | APY | APZ | AQA | AQB | AQC | AQD | AQE | AQF | AQG | AQH | AQI | AQJ | AQK | AQL | AQM | AQN | AQO | AQP | AQQ | AQR | AQS | AQT | AQU | AQV | AQW | AQX | AQY | AQZ | ARA | ARB | ARC | ARD | ARE | ARF | ARG | ARH | ARI | ARJ | ARK | ARL | ARM | ARN | ARO | ARP | ARQ | ARR | ARS | ART | ARU | ARV | ARW | ARX | ARY | ARZ | ASA | ASB | ASC | ASD | ASE | ASF | ASG | ASH | ASI | ASJ | ASK | ASL | ASM | ASN | ASO | ASP | ASQ | ASR | ASS | AST | ASU | ASV | ASW | ASX | ASY | ASZ | ATA | ATB | ATC | ATD | ATE | ATF | ATG | ATH | ATI | ATJ | ATK | ATL | ATM | ATN | ATO | ATP | ATQ | ATR | ATS | ATT | ATU | ATV | ATW | ATX | ATY | ATZ | AUA | AUB | AUC | AUD | AUE | AUF | AUG | AUH | AUI | AUJ | AUK | AUL | AUM | AUN | AUO | AUP | AUQ | AUR | AUS | AUT | AUU | AUV | AUW | AUX | AUY | AUZ | AVA | AVB | AVC | AVD | AVE | AVF | AVG | AVH | AVI | AVJ | AVK | AVL | AVM | AVN | AVO | AVP | AVQ | AVR | AVS | AVT | AVU | AVV | AVW | AVX | AVY | AVZ | AWA | AWB | AWC | AWD | AWE | AWF | AWG | AWH | AWI | AWJ | AWK | AWL | AWM | AWN | AWO | AWP | AWQ | AWR | AWS | AWT | AWU | AWV | AWW | AWX | AWY | AWZ | AXA | AXB | AXC | AXD | AXE | AXF | AXG | AXH | AXI | AXJ | AXK | AXL | AXM | AXN | AXO | AXP | AXQ | AXR | AXS | AXT | AXU | AXV | AXW | AXX | AXY | AXZ | AYA | AYB | AYC | AYD | AYE | AYF | AYG | AYH | AYI | AYJ | AYK | AYL | AYM | AYN | AYO | AYP | AYQ | AYR | AYS | AYT | AYU | AYV | AYW | AYX | AYY | AYZ | AZA | AZB | AZC | AZD | AZE | AZF | AZG | AZH | AZI | AZJ | AZK | AZL | AZM | AZN | AZO | AZP | AZQ | AZR | AZS | AZT | AZU | AZV | AZW | AZX | AZY | AZZ | BAA | BAB | BAC | BAD | BAE | BAF | BAG | BAH | BAI | BAJ | BAK | BAL | BAM | BAN | BAO | BAP | BAQ | BAR | BAS | BAT | BAU | BAV | BAW | BAX | BAY | BAZ | BBA | BBB | BBC | BBD | BBE | BBF | BBG | BBH | BBI | BBJ | BBK | BBL | BBM | BBN | BBO | BBP | BBQ | BBR | BBS | BBT | BBU | BBV | BBW | BBX | BBY | BBZ | BCA | BCB | BCC | BCD | BCE | BCF | BCG | BCH | BCI | BCJ | BCK | BCL | BCM | BCN | BCO | BCP | BCQ | BCR | BCS | BCT | BCU | BCV | BCW | BCX | BCY | BCZ | BDA | BDB | BDC | BDD | BDE | BDF | BDG | BDH | BDI | BDJ | BDK | BDL | BDM | BDN | BDO | BDP | BDQ | BDR | BDS | BDT | BDU | BDV | BDW | BDX | BDY | BDZ | BEA | BEB | BEC | BED | BEE | BEF | BEG | BEH | BEI | BEJ | BEK | BEL | BEM | BEN | BEO | BEP | BEQ | BER | BES | BET | BEU | BEV | BEW | BEX | BEY | BEZ | BFA | BFB | BFC | BFD | BFE | BFF | BFG | BFH | BFI | BFJ | BFK | BFL | BFM | BFN | BFO | BFP | BFQ | BFR | BFS | BFT | BFU | BFV | BFW | BFX | BFY | BFZ | BGA | BGB | BGC | BGD | BGE | BGF | BGG | BGH | BGI | BGJ | BGK | BGL | BGM | BGN | BGO | BGP | BGQ | BGR | BGS | BGT | BGU | BGV | BGW | BGX | BGY | BGZ | BHA | BHB | BHC | BHD | BHE | BHF | BHG | BHH | BHI | BHJ | BHK | BHL | BHM | BHN | BHO | BHP | BHQ | BHR | BHS | BHT | BHU | BHV | BHW | BHX | BHY | BHZ | BIA | BIB | BIC | BID | BIE | BIF | BIG | BIH | BII | BIJ | BIK | BIL | BIM | BIN | BIO | BIP | BIQ | BIR | BIS | BIT | BIU | BIV | BIW | BIX | BIY | BIZ | BJA | BJB | BJC | BJD | BJE | BJF | BJG | BJH | BJI | BJJ | BJK | BJL | BJM | BJN | BJO | BJP | BJQ | BJR | BJS | BJT | BJU | BJV | BJW | BJX | BJY | BJZ | BKA | BKB | BKC | BKD | BKE | BKF | BKG | BKH | BKI | BKJ | BKK | BKL | BKM | BKN | BKO | BKP | BKQ | BKR | BKS | BKT | BKU | BKV | BKW | BKX | BKY | BKZ | BLA | BLB | BLC | BLD | BLE | BLF | BLG | BLH | BLI | BLJ | BLK | BLL | BLM | BLN | BLO | BLP | BLQ | BLR | BLS | BLT | BLU | BLV | BLW | BLX | BLY | BLZ | BMA | BMB | BMC | BMD | BME | BMF | BMG | BMH | BMI | BMJ | BMK | BML | BMM | BMN | BMO | BMP | BMQ | BMR | BMS | BMT | BMU | BMV | BMW | BMX | BMY | BMZ | BNA | BNB | BNC | BND | BNE | BNF | BNG | BNH | BNI | BNJ | BNK | BNL | BNM | BNN | BNO | BNP | BNQ | BNR | BNS | BNT | BNU | BNV | BNW | BNX | BNY | BNZ | BOA | BOB | BOC | BOD | BOE | BOF | BOG | BOH | BOI | BOJ | BOK | BOL | BOM | BON | BOO | BOP | BOQ | BOR | BOS | BOT | BOU | BOV | BOW | BOX | BOY | BOZ | BPA | BPB | BPC | BPD | BPE | BPF | BPG | BPH | BPI | BPJ | BPK | BPL | BPM | BPN | BPO | BPP | BPQ | BPR | BPS | BPT | BPU | BPV | BPW | BPX | BPY | BPZ | BQA | BQB | BQC | BQD | BQE | BQF | BQG | BQH | BQI | BQJ | BQK | BQL | BQM | BQN | BQO | BQP | BQQ | BQR | BQS | BQT | BQU | BQV | BQW | BQX | BQY | BQZ | BRA | BRB | BRC | BRD | BRE | BRF | BRG | BRH | BRI | BRJ | BRK | BRL | BRM | BRN | BRO | BRP | BRQ | BRR | BRS | BRT | BRU | BRV | BRW | BRX | BRY | BRZ | BSA | BSB | BSC | BSD | BSE | BSF | BSG | BSH | BSI | BSJ | BSK | BSL | BSM | BSN | BSO | BSP | BSQ | BSR | BSS | BST | BSU | BSV | BSW | BSX | BSY | BSZ | BTA | BTB | BTC | BTD | BTE | BTF | BTG | BTH | BTI | BTJ | BTK | BTL | BTM | BTN | BTO | BTP | BTQ | BTR | BTS | BTT | BTU | BTV | BTW | BTX | BTY | BTZ | BUA | BUB | BUC | BUD | BUE | BUF | BUG | BUH | BUI | BUJ | BUK | BUL | BUM | BUN | BUO | BUP | BUQ | BUR | BUS | BUT | BUU | BUV | BUW | BUX | BUY | BUZ | BVA | BVB | BVC | BVD | BVE | BVF | BVG | BVH | BVI | BVJ | BVK | BVL | BVM | BVN | BVO | BVP | BVQ | BVR | BVS | BVT | BVU | BVV | BVW | BVX | BVY | BVZ | BWA | BWB | BWC | BWD | BWE | BWF | BWG | BWH | BWI | BWJ | BWK | BWL | BWM | BWN | BWO | BWP | BWQ | BWR | BWS | BWT | BWU | BWV | BWW | BWX | BWY | BWZ | BXA | BXB | BXC | BXD | BXE | BXF | BXG | BXH | BXI | BXJ | BXK | BXL | BXM | BXN | BXO | BXP | BXQ | BXR | BXS | BXT | BXU | BXV | BXW | BXX | BXY | BXZ | BYA | BYB | BYC | BYD | BYE | BYF | BYG | BYH | BYI | BYJ | BYK | BYL | BYM | BYN | BYO | BYP | BYQ | BYR | BYS | BYT | BYU | BYV | BYW | BYX | BYY | BYZ | BZA | BZB | BZC | BZD | BZE | BZF | BZG | BZH | BZI | BZJ | BZK | BZL | BZM | BZN | BZO | BZP | BZQ | BZR | BZS | BZT | BZU | BZV | BZW | BZX | BZY | BZZ | CAA | CAB | CAC | CAD | CAE | CAF | CAG | CAH | CAI | CAJ | CAK | CAL | CAM | CAN | CAO | CAP | CAQ | CAR | CAS | CAT | CAU | CAV | CAW | CAX | CAY | CAZ | CBA | CBB | CBC | CBD | CBE | CBF | CBG | CBH | CBI | CBJ | CBK | CBL | CBM | CBN | CBO | CBP | CBQ | CBR | CBS | CBT | CBU | CBV | CBW | CBX | CBY | CBZ | CCA | CCB | CCC | CCD | CCE | CCF | CCG | CCH | CCI | CCJ | CCK | CCL | CCM | CCN | CCO | CCP | CCQ | CCR | CCS | CCT | CCU | CCV | CCW | CCX | CCY | CCZ | CDA | CDB | CDC | CDD | CDE | CDF | CDG | CDH | CDI | CDJ | CDK | CDL | CDM | CDN | CDO | CDP | CDQ | CDR | CDS | CDT | CDU | CDV | CDW | CDX | CDY | CDZ | CEA | CEB | CEC | CED | CEE | CEF | CEG | CEH | CEI | CEJ | CEK | CEL | CEM | CEN | CEO | CEP | CEQ | CER | CES | CET | CEU | CEV | CEW | CEX | CEY | CEZ | CFA | CFB | CFC | CFD | CFE | CFF | CFG | CFH | CFI | CFJ | CFK | CFL | CFM | CFN | CFO | CFP | CFQ | CFR | CFS | CFT | CFU | CFV | CFW | CFX | CFY | CFZ | CGA | CGB | CGC | CGD | CGE | CGF | CGG | CGH | CGI | CGJ | CGK | CGL | CGM | CGN | CGO | CGP | CGQ | CGR | CGS | CGT | CGU | CGV | CGW | CGX | CGY | CGZ | CHA | CHB | CHC | CHD | CHE | CHF | CHG | CHH | CHI | CHJ | CHK | CHL | CHM | CHN | CHO | CHP | CHQ | CHR | CHS | CHT | CHU | CHV | CHW | CHX | CHY | CHZ | CIA | CIB | CIC | CID | CIE | CIF | CIG | CIH | CII | CIJ | CIK | CIL | CIM | CIN | CIO | CIP | CIQ | CIR | CIS | CIT | CIU | CIV | CIW | CIX | CIY | CIZ | CJA | CJB | CJC | CJD | CJE | CJF | CJG | CJH | CJI | CJJ | CJK | CJL | CJM | CJN | CJO | CJP | CJQ | CJR | CJS | CJT | CJU | CJV | CJW | CJX | CJY | CJZ | CKA | CKB | CKC | CKD | CKE | CKF | CKG | CKH | CKI | CKJ | CKK | CKL | CKM | CKN | CKO | CKP | CKQ | CKR | CKS | CKT | CKU | CKV | CKW | CKX | CKY | CKZ | CLA | CLB | CLC | CLD | CLE | CLF | CLG | CLH | CLI | CLJ | CLK | CLL | CLM | CLN | CLO | CLP | CLQ | CLR | CLS | CLT | CLU | CLV | CLW | CLX | CLY | CLZ | CMA | CMB | CMC | CMD | CME | CMF | CMG | CMH | CMI | CMJ | CMK | CML | CMM | CMN | CMO | CMP | CMQ | CMR | CMS | CMT | CMU | CMV | CMW | CMX | CMY | CMZ | CNA | CNB | CNC | CND | CNE | CNF | CNG | CNH | CNI | CNJ | CNK | CNL | CNM | CNN | CNO | CNP | CNQ | CNR | CNS | CNT | CNU | CNV | CNW | CNX | CNY | CNZ | COA | COB | COC | COD | COE | COF | COG | COH | COI | COJ | COK | COL | COM | CON | COO | COP | COQ | COR | COS | COT | COU | COV | COW | COX | COY | COZ | CPA | CPB | CPC | CPD | CPE | CPF | CPG | CPH | CPI | CPJ | CPK | CPL | CPM | CPN | CPO | CPP | CPQ | CPR | CPS | CPT | CPU | CPV | CPW | CPX | CPY | CPZ | CQA | CQB | CQC | CQD | CQE | CQF | CQG | CQH | CQI | CQJ | CQK | CQL | CQM | CQN | CQO | CQP | CQQ | CQR | CQS | CQT | CQU | CQV | CQW | CQX | CQY | CQZ | CRA | CRB | CRC | CRD | CRE | CRF | CRG | CRH | CRI | CRJ | CRK | CRL | CRM | CRN | CRO | CRP | CRQ | CRR | CRS | CRT | CRU | CRV | CRW | CRX | CRY | CRZ | CSA | CSB | CSC | CSD | CSE | CSF | CSG | CSH | CSI | CSJ | CSK | CSL | CSM | CSN | CSO | CSP | CSQ | CSR | CSS | CST | CSU | CSV | CSW | CSX | CSY | CSZ | CTA | CTB | CTC | CTD | CTE | CTF | CTG | CTH | CTI | CTJ | CTK | CTL | CTM | CTN | CTO | CTP | CTQ | CTR | CTS | CTT | CTU | CTV | CTW | CTX | CTY | CTZ | CUA | CUB | CUC | CUD | CUE | CUF | CUG | CUH | CUI | CUJ | CUK | CUL | CUM | CUN | CUO | CUP | CUQ | CUR | CUS | CUT | CUU | CUV | CUW | CUX | CUY | CUZ | CVA | CVB | CVC | CVD | CVE | CVF | CVG | CVH | CVI | CVJ | CVK | CVL | CVM | CVN | CVO | CVP | CVQ | CVR | CVS | CVT | CVU | CVV | CVW | CVX | CVY | CVZ | CWA | CWB | CWC | CWD | CWE | CWF | CWG | CWH | CWI | CWJ | CWK | CWL | CWM | CWN | CWO | CWP | CWQ | CWR | CWS | CWT | CWU | CWV | CWW | CWX | CWY | CWZ | CXA | CXB | CXC | CXD | CXE | CXF | CXG | CXH | CXI | CXJ | CXK | CXL | CXM | CXN | CXO | CXP | CXQ | CXR | CXS | CXT | CXU | CXV | CXW | CXX | CXY | CXZ | CYA | CYB | CYC | CYD | CYE | CYF | CYG | CYH | CYI | CYJ | CYK | CYL | CYM | CYN | CYO | CYP | CYQ | CYR | CYS | CYT | CYU | CYV | CYW | CYX | CYY | CYZ | CZA | CZB | CZC | CZD | CZE | CZF | CZG | CZH | CZI | CZJ | CZK | CZL | CZM | CZN | CZO | CZP | CZQ | CZR | CZS | CZT | CZU | CZV | CZW | CZX | CZY | CZZ | DAA | DAB | DAC | DAD | DAE | DAF | DAG | DAH | DAI | DAJ | DAK | DAL | DAM | DAN | DAO | DAP | DAQ | DAR | DAS | DAT | DAU | DAV | DAW | DAX | DAY | DAZ | DBA | DBB | DBC | DBD | DBE | DBF | DBG | DBH | DBI | DBJ | DBK | DBL | DBM | DBN | DBO | DBP | DBQ | DBR | DBS | DBT | DBU | DBV | DBW | DBX | DBY | DBZ | DCA | DCB | DCC | DCD | DCE | DCF | DCG | DCH | DCI | DCJ | DCK | DCL | DCM | DCN | DCO | DCP | DCQ | DCR | DCS | DCT | DCU | DCV | DCW | DCX | DCY | DCZ | DDA | DDB | DDC | DDD | DDE | DDF | DDG | DDH | DDI | DDJ | DDK | DDL | DDM | DDN | DDO | DDP | DDQ | DDR | DDS | DDT | DDU | DDV | DDW | DDX | DDY | DDZ | DEA | DEB | DEC | DED | DEE | DEF | DEG | DEH | DEI | DEJ | DEK | DEL | DEM | DEN | DEO | DEP | DEQ | DER | DES | DET | DEU | DEV | DEW | DEX | DEY | DEZ | DFA | DFB | DFC | DFD | DFE | DFF | DFG | DFH | DFI | DFJ | DFK | DFL | DFM | DFN | DFO | DFP | DFQ | DFR | DFS | DFT | DFU | DFV | DFW | DFX | DFY | DFZ | DGA | DGB | DGC | DGD | DGE | DGF | DGG | DGH | DGI | DGJ | DGK | DGL | DGM | DGN | DGO | DGP | DGQ | DGR | DGS | DGT | DGU | DGV | DGW | DGX | DGY | DGZ | DHA | DHB | DHC | DHD | DHE | DHF | DHG | DHH | DHI | DHJ | DHK | DHL | DHM | DHN | DHO | DHP | DHQ | DHR | DHS | DHT | DHU | DHV | DHW | DHX | DHY | DHZ | DIA | DIB | DIC | DID | DIE | DIF | DIG | DIH | DII | DIJ | DIK | DIL | DIM | DIN | DIO | DIP | DIQ | DIR | DIS | DIT | DIU | DIV | DIW | DIX | DIY | DIZ | DJA | DJB | DJC | DJD | DJE | DJF | DJG | DJH | DJI | DJJ | DJK | DJL | DJM | DJN | DJO | DJP | DJQ | DJR | DJS | DJT | DJU | DJV | DJW | DJX | DJY | DJZ | DKA | DKB | DKC | DKD | DKE | DKF | DKG | DKH | DKI | DKJ | DKK | DKL | DKM | DKN | DKO | DKP | DKQ | DKR | DKS | DKT | DKU | DKV | DKW | DKX | DKY | DKZ | DLA | DLB | DLC | DLD | DLE | DLF | DLG | DLH | DLI | DLJ | DLK | DLL | DLM | DLN | DLO | DLP | DLQ | DLR | DLS | DLT | DLU | DLV | DLW | DLX | DLY | DLZ | DMA | DMB | DMC | DMD | DME | DMF | DMG | DMH | DMI | DMJ | DMK | DML | DMM | DMN | DMO | DMP | DMQ | DMR | DMS | DMT | DMU | DMV | DMW | DMX | DMY | DMZ | DNA | DNB | DNC | DND | DNE | DNF | DNG | DNH | DNI | DNJ | DNK | DNL | DNM | DNN | DNO | DNP | DNQ | DNR | DNS | DNT | DNU | DNV | DNW | DNX | DNY | DNZ | DOA | DOB | DOC | DOD | DOE | DOF | DOG | DOH | DOI | DOJ | DOK | DOL | DOM | DON | DOO | DOP | DOQ | DOR | DOS | DOT | DOU | DOV | DOW | DOX | DOY | DOZ | DPA | DPB | DPC | DPD | DPE | DPF | DPG | DPH | DPI | DPJ | DPK | DPL | DPM | DPN | DPO | DPP | DPQ | DPR | DPS | DPT | DPU | DPV | DPW | DPX | DPY | DPZ | DQA | DQB | DQC | DQD | DQE | DQF | DQG | DQH | DQI | DQJ | DQK | DQL | DQM | DQN | DQO | DQP | DQQ | DQR | DQS | DQT | DQU | DQV | DQW | DQX | DQY | DQZ | DRA | DRB | DRC | DRD | DRE | DRF | DRG | DRH | DRI | DRJ | DRK | DRL | DRM | DRN | DRO | DRP | DRQ | DRR | DRS | DRT | DRU | DRV | DRW | DRX | DRY | DRZ | DSA | DSB | DSC | DSD | DSE | DSF | DSG | DSH | DSI | DSJ | DSK | DSL | DSM | DSN | DSO | DSP | DSQ | DSR | DSS | DST | DSU | DSV | DSW | DSX | DSY | DSZ | DTA | DTB | DTC | DTD | DTE | DTF | DTG | DTH | DTI | DTJ | DTK | DTL | DTM | DTN | DTO | DTP | DTQ | DTR | DTS | DTT | DTU | DTV | DTW | DTX | DTY | DTZ | DUA | DUB | DUC | DUD | DUE | DUF | DUG | DUH | DUI | DUJ | DUK | DUL | DUM | DUN | DUO | DUP | DUQ | DUR | DUS | DUT | DUU | DUV | DUW | DUX | DUY | DUZ | DVA | DVB | DVC | DVD | DVE | DVF | DVG | DVH | DVI | DVJ | DVK | DVL | DVM | DVN | DVO | DVP | DVQ | DVR | DVS | DVT | DVU | DVV | DVW | DVX | DVY | DVZ | DWA | DWB | DWC | DWD | DWE | DWF | DWG | DWH | DWI | DWJ | DWK | DWL | DWM | DWN | DWO | DWP | DWQ | DWR | DWS | DWT | DWU | DWV | DWW | DWX | DWY | DWZ | DXA | DXB | DXC | DXD | DXE | DXF | DXG | DXH | DXI | DXJ | DXK | DXL | DXM | DXN | DXO | DXP | DXQ | DXR | DXS | DXT | DXU | DXV | DXW | DXX | DXY | DXZ | DYA | DYB | DYC | DYD | DYE | DYF | DYG | DYH | DYI | DYJ | DYK | DYL | DYM | DYN | DYO | DYP | DYQ | DYR | DYS | DYT | DYU | DYV | DYW | DYX | DYY | DYZ | DZA | DZB | DZC | DZD | DZE | DZF | DZG | DZH | DZI | DZJ | DZK | DZL | DZM | DZN | DZO | DZP | DZQ | DZR | DZS | DZT | DZU | DZV | DZW | DZX | DZY | DZZ | EAA | EAB | EAC | EAD | EAE | EAF | EAG | EAH | EAI | EAJ | EAK | EAL | EAM | EAN | EAO | EAP | EAQ | EAR | EAS | EAT | EAU | EAV | EAW | EAX | EAY | EAZ | EBA | EBB | EBC | EBD | EBE | EBF | EBG | EBH | EBI | EBJ | EBK | EBL | EBM | EBN | EBO | EBP | EBQ | EBR | EBS | EBT | EBU | EBV | EBW | EBX | EBY | EBZ | ECA | ECB | ECC | ECD | ECE | ECF | ECG | ECH | ECI | ECJ | ECK | ECL | ECM | ECN | ECO | ECP | ECQ | ECR | ECS | ECT | ECU | ECV | ECW | ECX | ECY | ECZ | EDA | EDB | EDC | EDD | EDE | EDF | EDG | EDH | EDI | EDJ | EDK | EDL | EDM | EDN | EDO | EDP | EDQ | EDR | EDS | EDT | EDU | EDV | EDW | EDX | EDY | EDZ | EEA | EEB | EEC | EED | EEE | EEF | EEG | EEH | EEI | EEJ | EEK | EEL | EEM | EEN | EEO | EEP | EEQ | EER | EES | EET | EEU | EEV | EEW | EEX | EEY | EEZ | EFA | EFB | EFC | EFD | EFE | EFF | EFG | EFH | EFI | EFJ | EFK | EFL | EFM | EFN | EFO | EFP | EFQ | EFR | EFS | EFT | EFU | EFV | EFW | EFX | EFY | EFZ | EGA | EGB | EGC | EGD | EGE | EGF | EGG | EGH | EGI | EGJ | EGK | EGL | EGM | EGN | EGO | EGP | EGQ | EGR | EGS | EGT | EGU | EGV | EGW | EGX | EGY | EGZ | EHA | EHB | EHC | EHD | EHE | EHF | EHG | EHH | EHI | EHJ | EHK | EHL | EHM | EHN | EHO | EHP | EHQ | EHR | EHS | EHT | EHU | EHV | EHW | EHX | EHY | EHZ | EIA | EIB | EIC | EID | EIE | EIF | EIG | EIH | EII | EIJ | EIK | EIL | EIM | EIN | EIO | EIP | EIQ | EIR | EIS | EIT | EIU | EIV | EIW | EIX | EIY | EIZ | EJA | EJB | EJC | EJD | EJE | EJF | EJG | EJH | EJI | EJJ | EJK | EJL | EJM | EJN | EJO | EJP | EJQ | EJR | EJS | EJT | EJU | EJV | EJW | EJX | EJY | EJZ | EKA | EKB | EKC | EKD | EKE | EKF | EKG | EKH | EKI | EKJ | EKK | EKL | EKM | EKN | EKO | EKP | EKQ | EKR | EKS | EKT | EKU | EKV | EKW | EKX | EKY | EKZ | ELA | ELB | ELC | ELD | ELE | ELF | ELG | ELH | ELI | ELJ | ELK | ELL | ELM | ELN | ELO | ELP | ELQ | ELR | ELS | ELT | ELU | ELV | ELW | ELX | ELY | ELZ | EMA | EMB | EMC | EMD | EME | EMF | EMG | EMH | EMI | EMJ | EMK | EML | EMM | EMN | EMO | EMP | EMQ | EMR | EMS | EMT | EMU | EMV | EMW | EMX | EMY | EMZ | ENA | ENB | ENC | END | ENE | ENF | ENG | ENH | ENI | ENJ | ENK | ENL | ENM | ENN | ENO | ENP | ENQ | ENR | ENS | ENT | ENU | ENV | ENW | ENX | ENY | ENZ | EOA | EOB | EOC | EOD | EOE | EOF | EOG | EOH | EOI | EOJ | EOK | EOL | EOM | EON | EOO | EOP | EOQ | EOR | EOS | EOT | EOU | EOV | EOW | EOX | EOY | EOZ | EPA | EPB | EPC | EPD | EPE | EPF | EPG | EPH | EPI | EPJ | EPK | EPL | EPM | EPN | EPO | EPP | EPQ | EPR | EPS | EPT | EPU | EPV | EPW | EPX | EPY | EPZ | EQA | EQB | EQC | EQD | EQE | EQF | EQG | EQH | EQI | EQJ | EQK | EQL | EQM | EQN | EQO | EQP | EQQ | EQR | EQS | EQT | EQU | EQV | EQW | EQX | EQY | EQZ | ERA | ERB | ERC | ERD | ERE | ERF | ERG | ERH | ERI | ERJ | ERK | ERL | ERM | ERN | ERO | ERP | ERQ | ERR | ERS | ERT | ERU | ERV | ERW | ERX | ERY | ERZ | ESA | ESB | ESC | ESD | ESE | ESF | ESG | ESH | ESI | ESJ | ESK | ESL | ESM | ESN | ESO | ESP | ESQ | ESR | ESS | EST | ESU | ESV | ESW | ESX | ESY | ESZ | ETA | ETB | ETC | ETD | ETE | ETF | ETG | ETH | ETI | ETJ | ETK | ETL | ETM | ETN | ETO | ETP | ETQ | ETR | ETS | ETT | ETU | ETV | ETW | ETX | ETY | ETZ | EUA | EUB | EUC | EUD | EUE | EUF | EUG | EUH | EUI | EUJ | EUK | EUL | EUM | EUN | EUO | EUP | EUQ | EUR | EUS | EUT | EUU | EUV | EUW | EUX | EUY | EUZ | EVA | EVB | EVC | EVD | EVE | EVF | EVG | EVH | EVI | EVJ | EVK | EVL | EVM | EVN | EVO | EVP | EVQ | EVR | EVS | EVT | EVU | EVV | EVW | EVX | EVY | EVZ | EWA | EWB | EWC | EWD | EWE | EWF | EWG | EWH | EWI | EWJ | EWK | EWL | EWM | EWN | EWO | EWP | EWQ | EWR | EWS | EWT | EWU | EWV | EWW | EWX | EWY | EWZ | EXA | EXB | EXC | EXD | EXE | EXF | EXG | EXH | EXI | EXJ | EXK | EXL | EXM | EXN | EXO | EXP | EXQ | EXR | EXS | EXT | EXU | EXV | EXW | EXX | EXY | EXZ | EYA | EYB | EYC | EYD | EYE | EYF | EYG | EYH | EYI | EYJ | EYK | EYL | EYM | EYN | EYO | EYP | EYQ | EYR | EYS | EYT | EYU | EYV | EYW | EYX | EYY | EYZ | EZA | EZB | EZC | E

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Iterations 19
Adjusted Observations 123
Deg. of Freedom for Error 109
R-Squared 0.960
Adjusted R-Squared 0.955
AIC 9.832
BIC 10.152
F-Statistic 200.870
Prob (F-Statistic) 0.0000
Log-Likelihood -765.18
Model Sum of Squares 43,687,902.52
Sum of Squared Errors 1,823,600.30
Mean Squared Error 16,730.26
Std. Error of Regression 129.35
Mean Abs. Dev. (MAD) 86.96
Mean Abs. % Err. (MAPE) 2.89%
Durbin-Watson Statistic 1.880
Durbin-H Statistic #NA
Ljung-Box Statistic 26.50
Prob (Ljung-Box) 0.3282
Skewness -0.522
Kurtosis 7.347
Jarque-Bera 102.448
Prob (Jarque-Bera) 0.0000
Forecast Observations 0
Mean Abs. Dev. (MAD) 0.00
Mean Abs. % Err. (MAPE) 0.00%
Avg. Forecast Error 0.00
Mean % Error 0.00%
Root Mean-Square Error 0.00
Theil's Inequality Coefficient 0.0000
-- Bias Proportion 0.00%
-- Variance Proportion 0.00%
-- Covariance Proportion 0.00%
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Statistics	Forecast Observations
Iterations	1
Adjusted Observations	124
Deg. of Freedom for Error	114
R-Squared	0.964
Adjusted R-Squared	0.961
AIC	6.785
BIC	7.012
F-Statistic	#NA
Prob (F-Statistic)	#NA
Log-Likelihood	-586.59
Model Sum of Squares	2,470,564.01
Sum of Squared Errors	93,301.92
Mean Squared Error	818.44
Std. Error of Regression	28.61
Mean Abs. Dev. (MAD)	18.28
Mean Abs. % Err. (MAPE)	4.00%
Durbin-Watson Statistic	0.950
Durbin-H Statistic	#NA
Ljung-Box Statistic	77.05
Prob (Ljung-Box)	0.0000
Skewness	0.211
Kurtosis	7.704
Jarque-Bera	115.234
Prob (Jarque-Bera)	0.0000

	Forecast Observations
Forecast Observations	0
Mean Abs. Dev. (MAD)	0.00
Mean Abs. % Err. (MAPE)	0.00%
Avg. Forecast Error	0.00
Mean % Error	0.00%
Root Mean-Square Error	0.00
Theil's Inequality Coefficient	0.0000
-- Bias Proportion	0.00%
-- Variance Proportion	0.00%
-- Covariance Proportion	0.00%

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Forecast Statistics
Iterations 10
Adjusted Observations 124
Deg. of Freedom for Error 110
R-Squared 0.836
Adjusted R-Squared 0.816
AIC 17.824
BIC 18.143
F-Statistic 43.063
Prob (F-Statistic) 0.0000
Log-Likelihood -1,267.06
Model Sum of Squares 27,734,629,930.63
Sum of Squared Errors 5,449,684,182.18
Mean Squared Error 49,541,674.47
Std. Error of Regression 7,038.58
Mean Abs. Dev. (MAD) 4,538.98
Mean Abs. % Err. (MAPE) 3.88%
Durbin-Watson Statistic 1.955
Durbin-H Statistic #NA
Ljung-Box Statistic 41.02
Prob (Ljung-Box) 0.0166
Skewness 0.074
Kurtosis 11.199
Jarque-Bera 347.459
Prob (Jarque-Bera) 0.0000
Forecast Observations 0
Mean Abs. Dev. (MAD) 0.00
Mean Abs. % Err. (MAPE) 0.00%
Avg. Forecast Error 0.00
Mean % Error 0.00%
Root Mean-Square Error 0.00
Theil's Inequality Coefficient 0.0000
-- Bias Proportion 0.00%
-- Variance Proportion 0.00%
-- Covariance Proportion 0.00%
MStat
Ready
NUM

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Regression Statistics	
Iterations	29
Adjusted Observations	124
Deg. of Freedom for Error	117
R-Squared	-0.716
Adjusted R-Squared	-0.804
AIC	9,738
BIC	9,897
F-Statistic	#NA
Prob (F-Statistic)	#NA
Log-Likelihood	-772.70
Model Sum of Squares	-783,470.98
Sum of Squared Errors	1,877,315.44
Mean Squared Error	16,045.43
Std. Error of Regression	126.67
Mean Abs. Dev. (MAD)	63.78
Mean Abs. % Err. (MAPE)	11.56%
Durbin-Watson Statistic	0.791
Durbin-H Statistic	#NA
Ljung-Box Statistic	274.79
Prob (Ljung-Box)	0.0000
Skewness	1.089
Kurtosis	6.875
Jarque-Bera	102.105
Prob (Jarque-Bera)	0.0000

Forecast Statistics	
Forecast Observations	0
Mean Abs. Dev. (MAD)	0.00
Mean Abs. % Err. (MAPE)	0.00%
Avg. Forecast Error	0.00
Mean % Error	0.00%
Root Mean-Square Error	0.00
Theil's Inequality Coefficient	0.0000
- Bias Proportion	0.00%
- Variance Proportion	0.00%
- Covariance Proportion	0.00%

Iterations	1	Forecast Observations	0
Adjusted Observations	111	Mean Abs. Dev. (MAD)	0.00
Deg. of Freedom for Error	95	Mean Abs. % Err. (MAPE)	0.00%
R-Squared	0.855	Avg. Forecast Error	0.00
Adjusted R-Squared	0.832	Mean % Error	0.00%
AIC	-2.580	Root Mean-Square Error	0.00
BIC	-2.189	Theil's Inequality Coefficient	0.0000
F-Statistic	#NA	- Bias Proportion	0.00%
Prob (F-Statistic)	#NA	- Variance Proportion	0.00%
Log-Likelihood	1.68	- Covariance Proportion	0.00%
Model Sum of Squares	37.11		
Sum of Squared Errors	6.30		
Mean Squared Error	0.07		
Std. Error of Regression	0.26		
Mean Abs. Dev. (MAD)	0.17		
Mean Abs. % Err. (MAPE)	3.43%		
Durbin-Watson Statistic	1.388		
Durbin-H Statistic	#NA		
Ljung-Box Statistic	22.56		
Prob (Ljung-Box)	0.5459		
Skewness	0.253		
Kurtosis	4.558		
Jarque-Bera	12.412		
Prob (Jarque-Bera)	0.0020		

NDM for TECOPeak
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TECOPeak.NDM
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Iterations 1
Adjusted Observations 171
Deg. of Freedom for Error 159
R-Squared 0.621
Adjusted R-Squared 0.595
AIC 6.139
BIC 6.360
F-Statistic 23.695
Prob (F-Statistic) 0.0000
Log-Likelihood -755.53
Model Sum of Squares 112,951.44
Sum of Squared Errors 68,902.24
Mean Squared Error 433.35
Std. Error of Regression 20.82
Mean Abs. Dev. (MAD) 15.96
Mean Abs. % Err. (MAPE) 11.59%
Durbin-Watson Statistic 1.542
Durbin-H Statistic #NA
Ljung-Box Statistic 22.05
Prob (Ljung-Box) 0.5764
Skewness 0.378
Kurtosis 3.109
Jarque-Bera 4.166
Prob (Jarque-Bera) 0.1246
Forecast Observations 0
Mean Abs. Dev. (MAD) 0.00
Mean Abs. % Err. (MAPE) 0.00%
Avg. Forecast Error 0.00
Mean % Error 0.00%
Root Mean-Square Error 0.00
Theil's Inequality Coefficient 0.0000
-- Bias Proportion 0.00%
-- Variance Proportion 0.00%
-- Covariance Proportion 0.00%
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Iterations	1
Adjusted Observations	124
Deg. of Freedom for Error	105
R-Squared	0.983
Adjusted R-Squared	0.980
AIC	7.134
BIC	7.566
F-Statistic	342.186
Prob (F-Statistic)	0.0000
Log-Likelihood	-599.25
Model Sum of Squares	6,712,693.48
Sum of Squared Errors	114,433.04
Mean Squared Error	1,089.84
Std. Error of Regression	33.01
Mean Abs. Dev. (MAD)	24.53
Mean Abs. % Err. (MAPE)	1.98%
Durbin-Watson Statistic	1.670
Durbin-H Statistic	#NA
Ljung-Box Statistic	52.56
Prob (Ljung-Box)	0.0007
Skewness	0.209
Kurtosis	2.830
Jarque-Bera	1.049
Prob (Jarque-Bera)	0.5918

Forecast Observations	0
Mean Abs. Dev. (MAD)	0.00
Mean Abs. % Err. (MAPE)	0.00%
Avg. Forecast Error	0.00
Mean % Error	0.00%
Root Mean-Square Error	0.00
Theil's Inequality Coefficient	0.0000
– Bias Proportion	0.00%
– Variance Proportion	0.00%
– Covariance Proportion	0.00%

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Iterations 18
Adjusted Observations 123
Deg. of Freedom for Error 104
R-Squared 1.000
Adjusted R-Squared 1.000
AIC 11.930
BIC 12.364
F-Statistic #NA
Prob (F-Statistic) #NA
Log-Likelihood -889.21
Model Sum of Squares 112,419,210,156.95
Sum of Squared Errors 13,701,231.07
Mean Squared Error 131,742.61
Std. Error of Regression 362.96
Mean Abs. Dev. (MAD) 259.92
Mean Abs. % Err. (MAPE) 0.05%
Durbin-Watson Statistic 1.868
Durbin-H Statistic #NA
Ljung-Box Statistic 32.02
Prob (Ljung-Box) 0.1265
Skewness -0.217
Kurtosis 3.089
Jarque-Bera 1.008
Prob (Jarque-Bera) 0.6042
Forecast Observations 0
Mean Abs. Dev. (MAD) 0.00
Mean Abs. % Err. (MAPE) 0.00%
Avg. Forecast Error 0.00
Mean % Error 0.00%
Root Mean-Square Error 0.00
Theil's Inequality Coefficient 0.0000
-- Bias Proportion 0.00%
-- Variance Proportion 0.00%
-- Covariance Proportion 0.00%
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Observation Statistics	
Iterations	10
Adjusted Observations	123
Deg. of Freedom for Error	115
R-Squared	0.959
Adjusted R-Squared	0.957
AIC	12.879
BIC	13.062
F-Statistic	384.732
Prob (F-Statistic)	0.0000
Log-Likelihood	-958.62
Model Sum of Squares	991,843,366.62
Sum of Squared Errors	42,353,040.62
Mean Squared Error	368,287.31
Std. Error of Regression	606.87
Mean Abs. Dev. (MAD)	451.52
Mean Abs. % Err. (MAPE)	1.99%
Durbin-Watson Statistic	2.259
Durbin-H Statistic	#NA
Ljung-Box Statistic	39.56
Prob (Ljung-Box)	0.0238
Skewness	0.067
Kurtosis	3.614
Jarque-Bera	2.025
Prob (Jarque-Bera)	0.3633

Observation Statistics	
Forecast Observations	0
Mean Abs. Dev. (MAD)	0.00
Mean Abs. % Err. (MAPE)	0.00%
Avg. Forecast Error	0.00
Mean % Error	0.00%
Root Mean-Square Error	0.00
Theil's Inequality Coefficient	0.0000
- Bias Proportion	0.00%
- Variance Proportion	0.00%
- Covariance Proportion	0.00%

2647

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Iterations	1	Forecast Observations 0
Adjusted Observations	124	Mean Abs. Dev. (MAD) 0.00
Deg. of Freedom for Error	100	Mean Abs. % Err. (MAPE) 0.00%
R-Squared	0.901	Avg. Forecast Error 0.00
Adjusted R-Squared	0.879	Mean % Error 0.00%
AIC	13.042	Root Mean-Square Error 0.00
BIC	13.588	Theil's Inequality Coefficient 0.0000
F-Statistic	39.718	- Bias Proportion 0.00%
Prob (F-Statistic)	0.0000	- Variance Proportion 0.00%
Log-Likelihood	-960.57	- Covariance Proportion 0.00%
Model Sum of Squares	354,977,652.88	
Sum of Squared Errors	38,858,502.50	
Mean Squared Error	388,585.03	
Std. Error of Regression	623.37	
Mean Abs. Dev. (MAD)	446.50	
Mean Abs. % Err. (MAPE)	2.24%	
Durbin-Watson Statistic	1.041	
Durbin-H Statistic	#NA	
Ljung-Box Statistic	115.72	
Prob (Ljung-Box)	0.0000	
Skewness	-0.196	
Kurtosis	2.853	
Jarque-Bera	0.906	
Prob (Jarque-Bera)	0.6358	

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TBDSalesBase.NDM
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Iterations 1
Adjusted Observations 124
Deg. of Freedom for Error 114
R-Squared 0.996
Adjusted R-Squared 0.996
AIC 7.659
BIC 7.886
F-Statistic #NA
Prob (F-Statistic) #NA
Log-Likelihood -640.78
Model Sum of Squares 63,144,649.47
Sum of Squared Errors 223,581.49
Mean Squared Error 1,961.24
Std. Error of Regression 44.29
Mean Abs. Dev. (MAD) 33.42
Mean Abs. % Err. (MAPE) 0.50%
Durbin-Watson Statistic 0.728
Durbin-H Statistic #NA
Ljung-Box Statistic 123.18
Prob (Ljung-Box) 0.0000
Skewness -0.385
Kurtosis 3.265
Jarque-Bera 3.425
Prob (Jarque-Bera) 0.1804
Forecast Observations 0
Mean Abs. Dev. (MAD) 0.00
Mean Abs. % Err. (MAPE) 0.00%
Avg. Forecast Error 0.00
Mean % Error 0.00%
Root Mean-Square Error 0.00
Theil's Inequality Coefficient 0.0000
-- Bias Proportion 0.00%
-- Variance Proportion 0.00%
-- Covariance Proportion 0.00%
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Iterations	1
Adjusted Observations	124
Deg. of Freedom for Error	121
R-Squared	0.919
Adjusted R-Squared	0.916
AIC	11.422
BIC	11.491
F-Statistic	686.312
Prob (F-Statistic)	0.0000
Log-Likelihood	-881.13
Model Sum of Squares	122,416,416.99
Sum of Squared Errors	10,791,299.88
Mean Squared Error	89,184.30
Std. Error of Regression	298.64
Mean Abs. Dev. (MAD)	193.56
Mean Abs. % Err. (MAPE)	6.56%
Durbin-Watson Statistic	0.248
Durbin-H Statistic	#NA
Ljung-Box Statistic	391.08
Prob (Ljung-Box)	0.0000
Skewness	-1.794
Kurtosis	7.046
Jarque-Bera	151.047
Prob (Jarque-Bera)	0.0000

Forecast Observations	0
Mean Abs. Dev. (MAD)	0.00
Mean Abs. % Err. (MAPE)	0.00%
Avg. Forecast Error	0.00
Mean % Error	0.00%
Root Mean-Square Error	0.00
Theil's Inequality Coefficient	0.0000
- Bias Proportion	0.00%
- Variance Proportion	0.00%
- Covariance Proportion	0.00%

Iterations 9
Forecast Observations 0
Adjusted Observations 123 Mean Abs. Dev. (MAD) 0.00
Deg. of Freedom for Error 117 Mean Abs. % Err. (MAPE) 0.00%
R-Squared 0.901 Avg. Forecast Error 0.00
Adjusted R-Squared 0.897 Mean % Error 0.00%
AIC 19.946 Root Mean-Square Error 0.00
BIC 20.083 Theil's Inequality Coefficient 0.0000
F-Statistic 213.683 -- Bias Proportion 0.00%
Prob (F-Statistic) 0.0000 -- Variance Proportion 0.00%
Log-Likelihood -1,395.22 -- Covariance Proportion 0.00%
Model Sum of Squares 468,362,663,944.08
Sum of Squared Errors 51,289,432,214.99
Mean Squared Error 438,371,215.51
Std. Error of Regression 20,937.32
Mean Abs. Dev. (MAD) 15,382.93
Mean Abs. % Err. (MAPE) 5.98%
Durbin-Watson Statistic 2.294
Durbin-H Statistic #NA
Ljung-Box Statistic 44.27
Prob (Ljung-Box) 0.0071
Skewness 0.337
Kurtosis 4.667
Jarque-Bera 16.569
Prob (Jarque-Bera) 0.0003
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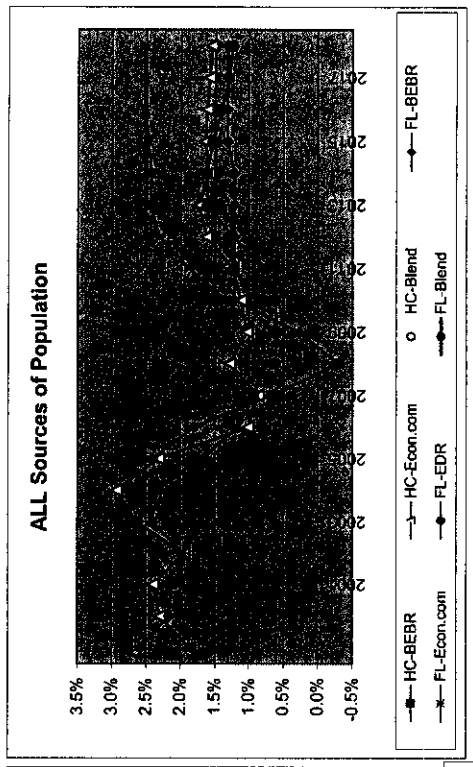
TAMPA ELECTRIC COMPANY
DOCKET NO. 120234-EI
STAFF'S FIRST REQUEST FOR
PRODUCTION OF DOCUMENTS
DOCUMENT NO. 6
BATES STAMPED PAGES: 2653 - 2661
FILED: OCTOBER 18, 2012

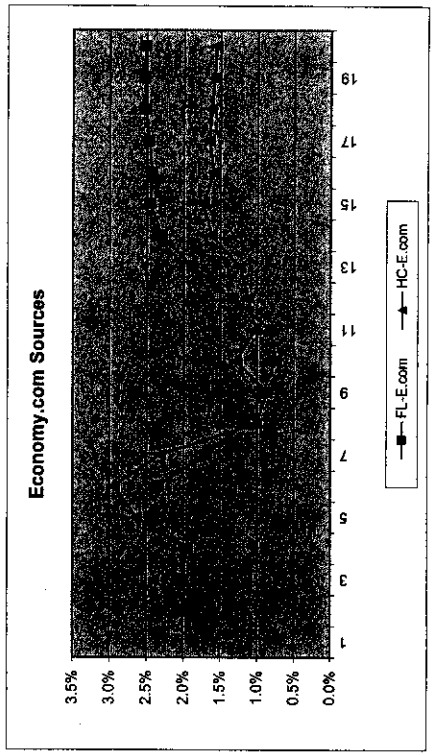
6. Please provide all documents related to each forecast assumption used to prepare the load forecasts, including each forecast resulting from multiple equation models, as referenced in witness Cifuentes' direct testimony at page 3, lines 19-22.

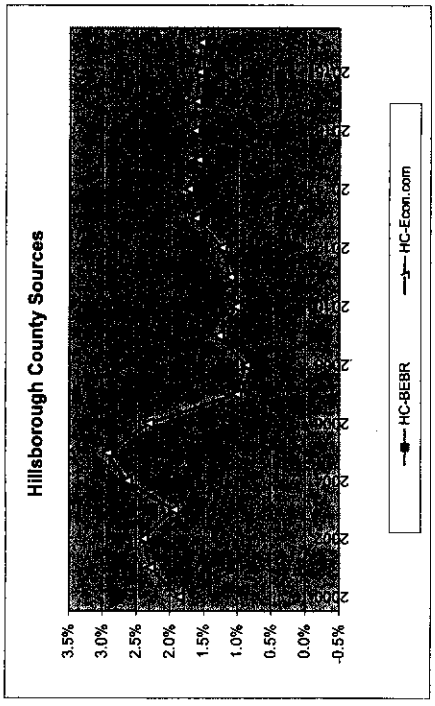
A. The requested documents are attached. Additionally, see the company's response to Staff's First Request for Production of Documents, No. 2, Bates stamped pages 17 through 1187.

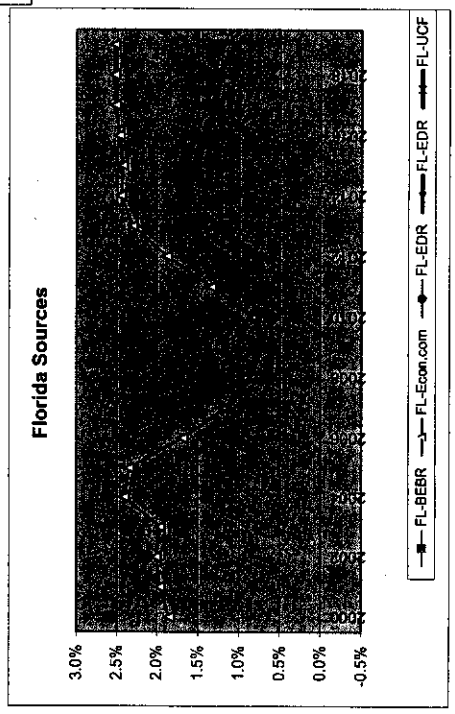
120234 Hearing Exhibits 00219

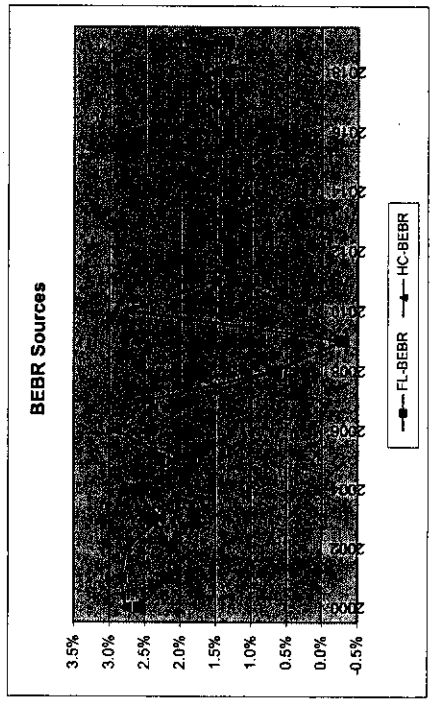
	BEBR			Economy.com			EDR	UCF	EIA	BLENDS	
	Hills.Cty. Population	Florida Population	Hills.Cty. Population	Florida Population	USA Population	Florida Population	Florida Population	USA Population	HC Blend	Florida Blend
1999	972	15,581	985	16,090	279					
2000	999	15,983	1,003	16,388	283					
2001	1,027	16,328	1,026	16,709	285					
2002	1,056	16,675	1,051	17,045	288					
2003	1,080	17,072	1,071	17,379	291		17,497			
2004	1,108	17,517	1,100	17,797	293		17,904			
2005	1,132	17,918	1,132	18,214	296		18,212			
2006	1,164	18,349	1,158	18,523	299		18,419			
2007	1,193	18,680	1,170	18,738	302	18,548	18,580	305		
2008	1,201	18,807	1,180	18,912	305	18,663	18,715	308		
2009	1,197	18,750	1,195	19,052	307	18,773	18,859	311		
2010	1,229	18,801	1,208	19,208	310	18,890	19,030	314		
2011	1,248	19,030	[redacted]			19,030	19,261	317		
2012	1,267	19,262				19,266	19,565	320		
2013	1,286	19,497				19,577	19,936	323		
2014	1,305	19,734				19,895		326		
2015	1,325	19,974				20,201		329		
2016	1,345	20,238				20,484		333		
2017	1,365	20,505				20,751		336		
2018	1,386	20,775				21,008		339		
2019	1,406	21,049				21,263				
						1.3%	-100.0%	1.0%		
2000-2009	2.0%	1.8%	2.0%		0.9%					
2007-2009	0.2%	0.2%	1.1%	0.8%	0.9%	0.6%	0.8%	0.9%		
2010-2019	1.5%	1.3%	1.5%	2.3%	1.0%	1.3%	-100.0%	1.0%		
Difference	1.3%	1.1%	0.4%	1.4%	0.06%	0.7%	-100.8%	0.0%		
2000	2.76%	2.58%	1.86%	1.85%	1.11%					
2001	2.84%	2.16%	2.29%	1.96%	1.02%					
2002	2.76%	2.12%	2.40%	2.01%	0.94%					
2003	2.27%	2.38%	1.95%	1.96%	0.89%					
2004	2.67%	2.61%	2.64%	2.41%	0.93%					
2005	2.09%	2.29%	2.94%	2.35%	0.93%					
2006	2.91%	2.40%	2.32%	1.69%	0.97%					
2007	2.44%	1.81%	1.01%	1.17%	0.99%		1.13%			
2008	0.64%	0.68%	0.87%	0.93%	0.91%	0.62%	0.87%	0.85%		
2009	-0.30%	-0.30%	1.29%	0.74%	0.88%	0.59%	0.73%	0.97%		
2010	2.71%	0.27%	1.03%	0.81%	0.98%	0.62%	0.77%	0.97%		
2011	1.51%	1.22%	1.12%	1.34%	0.97%	0.74%	0.91%	0.99%		
2012	1.51%	1.22%	1.24%	1.88%	0.97%	1.24%	1.21%	0.95%		
2013	1.51%	1.22%	1.63%	2.30%	0.97%	1.61%	1.58%	0.97%		
2014	1.51%	1.22%	1.73%	2.45%	0.97%	1.62%	1.90%	0.99%		
2015	1.51%	1.22%	1.59%	2.42%	0.97%	1.54%		0.95%		
2016	1.51%	1.32%	1.65%	2.47%	0.96%	1.40%		0.97%		
2017	1.51%	1.32%	1.62%	2.52%	0.96%	1.30%		0.93%		
2018	1.51%	1.32%	1.59%	2.53%	0.96%	1.24%		0.95%		
2019	1.51%	1.32%	1.56%	2.52%	0.95%					
									Blend	
Last Year										
2009	0.22%	0.22%	0.59%	0.78%	0.98%	0.26%	0.26%	0.26%	0.22%	0.33%
2010	0.49%	0.45%	-0.11%	0.84%	0.98%	0.40%	0.40%	0.40%	0.36%	0.78%
2011	1.33%	1.17%	0.37%	1.37%	0.97%	0.68%	0.68%	0.68%	0.90%	1.32%


ALL Sources of Population
HC-BEBR
HC-Econ.com
HC-Blend
FL-BEBR
FL-Econ.com
FL-EDR
FL-Blend


Economy.com Sources
FL-E.com
HC-E.com


Hillsborough County Sources
HC-BEBR
HC-Econ.com


Florida Sources
FL-BEBR
FL-Econ.com
FL-EDR
FL-UCF


BEBR Sources
FL-BEBR
HC-BEBR

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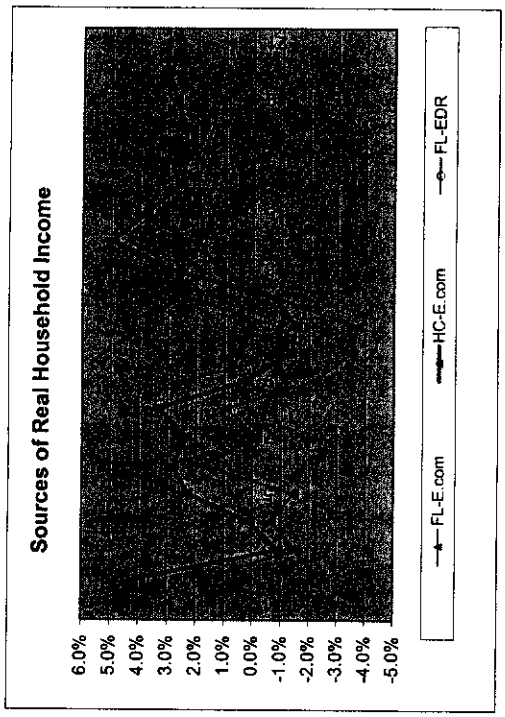
TAMPA ELECTRIC COMPANY
DOCKET NO. 120234-EI
STAFF'S FIRST REQUEST FOR PODS
FILED: OCTOBER 18, 2012

Nominal Personal Income

	Economy.com			UCF	EDR
	Hills.Cty.	Florida	USA	Florida	Florida
1999	26,988	491,654	7,911	-	
2000	29,299	519,761	8,559	-	
2001	30,268	532,849	8,883	-	
2002	31,439	548,225	9,060	-	
2003	33,444	561,372	9,378	-	
2004	36,194	600,102	9,937	600.1	
2005	39,253	633,118	10,486	633.1	
2006	42,669	671,795	11,268	671.8	704,618
2007	44,396	683,048	11,912	682.5	732,976
2008	45,654	677,994	12,391	676.7	729,172
2009	45,512	661,135	12,175	659.9	726,407
2010	46,422	664,483	12,547	664.3	755,475
2011	[redacted]			680.7	785,854
2012				697.3	822,409
2013				722.4	869,941
2014				756.2	925,443
2015				-	982,470
2016				-	1,036,707
2017				-	1,089,727
2018				-	1,144,078
2019				-	1,204,003
2020					
10-2009	5.0%	2.7%	4.0%	#DIV/0!	
17-2009	1.2%	-1.6%	1.1%	-1.7%	-0.4%
10-2019	6.6%	4.3%	5.2%	-100.0%	5.3%
Difference	5.3%	6.0%	4.1%	-98.3%	5.8%
1999					
2000	8.6%	5.7%	8.2%		
2001	3.3%	2.5%	3.8%		
2002	3.9%	2.9%	2.0%		
2003	6.4%	2.4%	3.5%		
2004	8.2%	6.9%	6.0%		
2005	8.5%	5.5%	5.5%	5.5%	
2006	8.7%	6.1%	7.5%	6.1%	
2007	4.0%	1.7%	5.7%	1.6%	4.0%
2008	2.8%	-0.7%	4.0%	-0.8%	-0.5%
2009	-0.3%	-2.5%	-1.7%	-2.5%	-0.4%
2010	2.0%	0.5%	3.1%	0.7%	4.0%
2011	5.9%	3.8%	5.6%	2.5%	4.0%
2012	8.2%	5.6%	6.6%	2.4%	4.7%
2013	8.1%	5.3%	7.7%	3.6%	5.8%
2014	6.6%	3.9%	5.3%	4.7%	6.4%
2015	6.0%	3.8%	4.6%		6.2%
2016	6.0%	3.8%	4.6%		5.5%
2017	6.1%	4.1%	4.3%		5.1%
2018	6.2%	4.4%	4.0%		5.0%
2019	6.2%	4.4%	3.9%		

Real Household Income

	Economy.com			EDR
	Hills.Cty.	Florida	USA	Florida
1999	79,891	90,667	87,776	
2000	83,028	92,137	92,218	
2001	82,290	90,711	90,563	
2002	82,368	90,129	89,993	
2003	84,261	88,823	89,563	
2004	86,614	90,323	91,688	
2005	88,644	90,190	92,516	
2006	91,587	91,047	95,400	91,471
2007	91,788	89,034	96,598	93,599
2008	90,561	85,897	97,704	92,469
2009	89,181	82,692	94,782	91,678
2010	88,504	82,051	96,457	93,764
2011	[redacted]			95,372
2012				96,979
2013				98,800
2014				100,729
2015				102,562
2016				104,056
2017				105,334
2018				106,688
2019				108,558
10-2009	0.8%	-1.2%	0.3%	
17-2009	-1.4%	-3.6%	-0.9%	-1.0%
10-2019	3.1%	0.5%	2.1%	1.6%
Difference	4.5%	4.1%	3.1%	2.7%
1999				
2000	3.9%	1.6%	5.1%	
2001	-0.9%	-1.5%	-1.8%	
2002	0.1%	-0.6%	-0.6%	
2003	2.3%	-1.4%	-0.5%	
2004	2.8%	1.7%	2.4%	
2005	2.3%	-0.1%	0.9%	
2006	3.3%	1.0%	3.1%	
2007	0.2%	-2.2%	1.3%	2.3%
2008	-1.3%	-3.5%	1.1%	-1.2%
2009	-1.5%	-3.7%	-3.0%	-0.9%
2010	-0.8%	-0.8%	1.8%	2.3%
2011	3.0%	1.2%	3.1%	1.7%
2012	4.9%	2.0%	3.2%	1.7%
2013	3.7%	0.4%	3.5%	1.9%
2014	2.6%	-0.8%	1.6%	2.0%
2015	2.4%	-0.3%	1.4%	1.8%
2016	2.4%	-0.2%	1.7%	1.5%
2017	2.7%	0.3%	1.6%	1.2%
2018	3.0%	0.7%	1.5%	1.3%
2019	3.1%	0.9%	1.5%	


Sources of Real Household Income
6.0%
5.0%
4.0%
3.0%
2.0%
1.0%
0.0%
-1.0%
-2.0%
-3.0%
-4.0%
-5.0%
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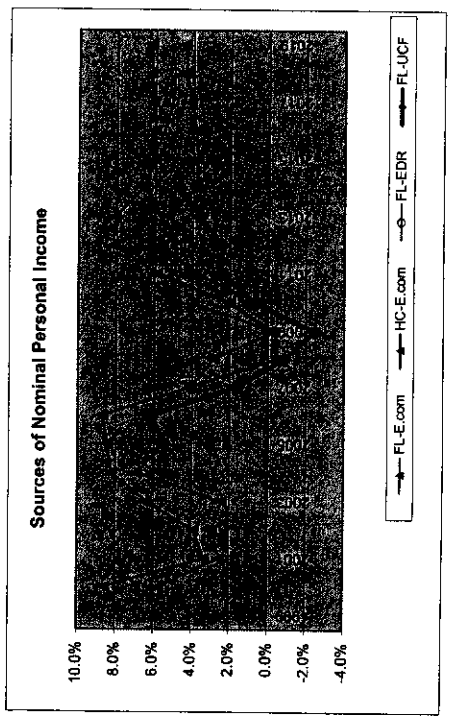
HC-E.com
FL-EDR


Sources of Nominal Personal Income
10.0%
8.0%
6.0%
4.0%
2.0%
0.0%
-2.0%
-4.0%
FL-E.com
HC-E.com
FL-EDR
FL-UCF

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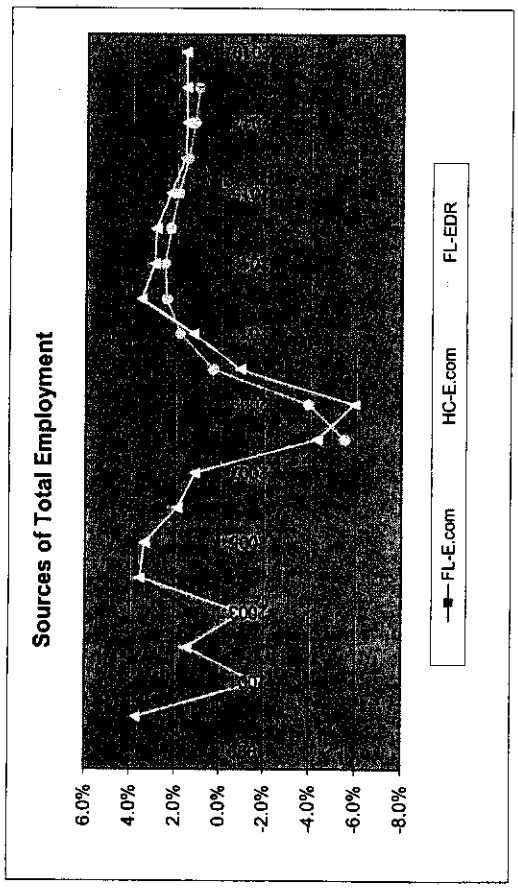
Construction

	Economy.com		EDR
	Hills.Cty.	Florida	USA	Florida
1999	32.91	455.93	6,544.75	
2000	34.28	479.31	6,787.92	
2001	34.03	495.08	6,826.50	
2002	35.27	500.53	6,715.33	
2003	37.02	519.68	6,735.67	
2004	40.99	568.48	6,973.17	
2005	45.51	633.05	7,333.42	
2006	47.25	677.82	7,689.58	659
2007	44.86	618.48	7,627.25	567
2008	39.21	511.52	7,160.92	449
2009	30.55	392.28	6,014.08	361
2010	27.00	346.21	5,526.83	340
2011	[redacted]			351
2012				388
2013				441
2014				485
2015				517
2016				541
2017				561
2018				577
2019				596
00-2009	-1.3%	1.3%	1.0%	
07-2009	-17.5%	-20.4%	-11.2%	-20.2%
10-2019	4.5%	3.8%	2.2%	6.8%
ference	22.0%	24.1%	13.4%	27.1%
1999				
2000	4.2%	5.1%	3.7%	
2001	-0.7%	3.3%	0.6%	
2002	3.7%	1.1%	-1.6%	
2003	4.9%	3.8%	0.3%	
2004	10.7%	9.4%	3.5%	
2005	11.0%	11.4%	5.2%	
2006	3.8%	7.1%	4.9%	
2007	-5.1%	-8.8%	-0.8%	
2008	-12.6%	-17.3%	-6.1%	-20.8%
2009	-22.1%	-23.3%	-16.0%	-19.7%
2010	-11.6%	-11.7%	-8.1%	-5.8%
2011	7.3%	4.4%	1.5%	3.4%
2012	17.3%	12.7%	5.1%	10.6%
2013	4.6%	4.8%	4.0%	13.6%
2014	2.6%	3.1%	3.4%	9.9%
2015	2.6%	2.6%	2.1%	6.7%
2016	1.9%	1.9%	1.0%	4.5%
2017	1.4%	1.5%	1.0%	3.8%
2018	2.0%	1.6%	1.0%	2.9%
2019	2.1%	1.9%	1.1%	

Total Employment

	Hills.Cty.	Economy.com Florida	Economy.com USA	EIA USA	EDR Florida
	581.55	6,814.83	128,991.67		
	603.32	7,070.79	131,793.58		
	593.45	7,160.58	131,829.92		
	602.12	7,170.28	130,340.42		
	596.04	7,249.92	129,996.00		
	617.29	7,498.52	131,419.17		
	638.04	7,799.48	133,694.08		
	650.18	8,003.72	136,091.50		8,045
	657.46	8,019.00	137,587.25		7,913
	629.00	7,735.51	136,778.08	136.7	7,475
	591.64	7,251.78	130,788.83	130.9	7,179
	586.19	7,177.23	129,822.17	130.7	7,200
	[redacted]			133.3	7,329
				134.5	7,505
				138.7	7,690
				140.7	7,861
				142.2	8,009
				143.7	8,127
				145.1	8,222
				146.4	8,304
				147.4	8,403
	0.9%	1.4%	0.7%	#DIV/0!	
	-5.1%	-4.9%	-2.5%	#DIV/0!	-4.7%
	2.1%	2.6%	1.5%	1.3%	1.8%
	7.3%	7.5%	4.0%	#DIV/0!	6.5%
	3.7%	3.8%	2.2%	#DIV/0!	
	-1.6%	1.3%	0.0%	#DIV/0!	
	1.5%	0.1%	-1.1%	#DIV/0!	
	-1.0%	1.1%	-0.3%	#DIV/0!	
	3.6%	3.4%	1.1%	#DIV/0!	
	3.4%	4.0%	1.7%	#DIV/0!	
	1.9%	2.6%	1.8%	#DIV/0!	
	1.1%	0.2%	1.1%	#DIV/0!	
	-4.3%	-3.5%	-0.6%	#DIV/0!	-5.5%
	-5.9%	-6.3%	-4.4%	-4.2%	-4.0%
	-0.9%	-1.0%	-0.7%	-0.2%	0.3%
	1.2%	1.6%	1.3%	2.0%	1.8%
	3.5%	3.8%	2.3%	0.9%	2.4%
	2.9%	3.6%	2.6%	3.1%	2.5%
	2.9%	3.4%	2.7%	1.4%	2.2%
	2.2%	2.7%	1.7%	1.1%	1.9%
	1.6%	2.1%	0.8%	1.1%	1.5%
	1.5%	2.0%	0.6%	1.0%	1.2%
	1.6%	2.1%	0.6%	0.9%	1.0%
	1.6%	2.1%	0.6%	0.7%	


Sources of Total Employment
6.0%
4.0%
2.0%
0.0%
-2.0%
-4.0%
-6.0%
-8.0%
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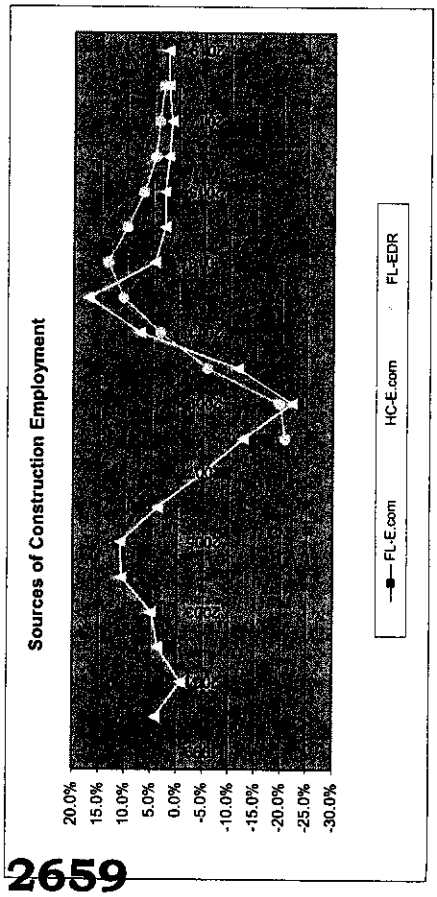
HC-E.com
FL-EDR


Sources of Construction Employment
20.0%
15.0%
10.0%
5.0%
0.0%
-5.0%
-10.0%
-15.0%
-20.0%
-25.0%
-30.0%
FL-E.com
HC-E.com
FL-EDR

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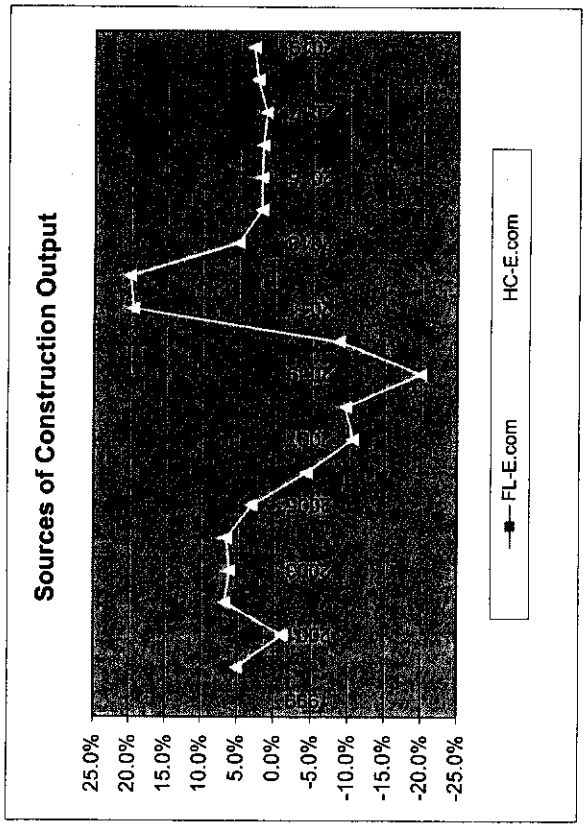
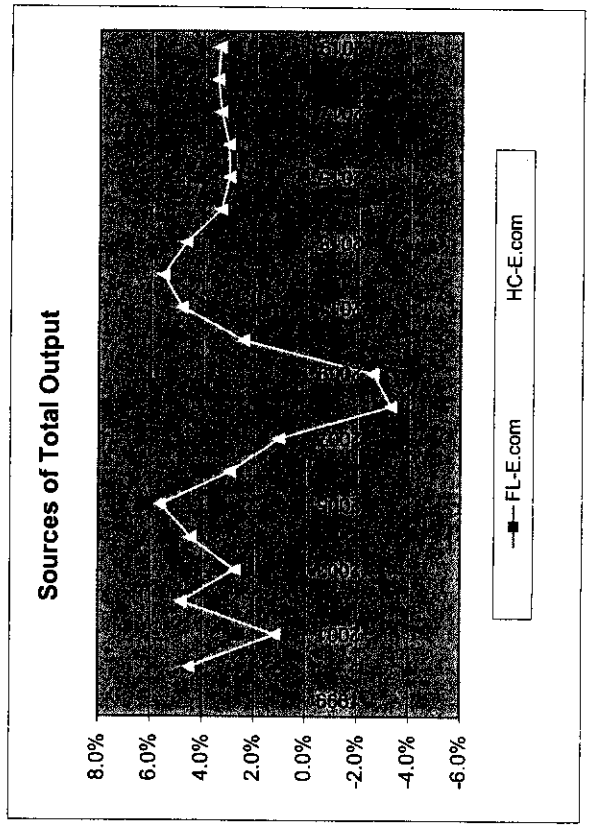

Sources of Construction Output
25.0%
20.0%
15.0%
10.0%
5.0%
0.0%
-5.0%
-10.0%
-15.0%
-20.0%
-25.0%
FL-E.com
HC-E.com


Sources of Total Output
8.0%
6.0%
4.0%
2.0%
0.0%
-2.0%
-4.0%
-6.0%
FL-E.com
HC-E.com

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Output - Construction

	Economy.com		
	Hills.Cty.	Florida	USA
1999	2,951.85	37,882.21	625.97
2000	3,103.14	40,268.01	647.70
2001	3,069.58	41,210.02	632.10
2002	3,277.06	42,999.47	611.47
2003	3,475.77	45,305.69	616.20
2004	3,702.99	48,141.41	617.95
2005	3,815.99	51,064.44	611.63
2006	3,651.53	51,203.95	593.67
2007	3,264.93	44,863.52	569.65
2008	2,951.57	38,609.80	549.85
2009	2,363.48	30,595.67	492.84
2010	2,157.17	27,349.43	466.88
2011	[redacted]		
2012			
2013			
2014			
2015			
2016			
2017			
2018			
2019			
2000-2009	-3.0%	0.2%	-1.4%
2007-2009	-14.9%	-17.4%	-7.0%
2010-2019	6.0%	5.0%	2.0%
Difference	20.9%	22.4%	9.0%

Total Output

	Economy.com		
	Hills.Cty.	Florida	USA
1999	46,810.95	524,943.96	10,778.68
2000	48,921.29	548,764.61	11,225.66
2001	49,492.42	562,883.66	11,346.98
2002	51,871.82	582,602.05	11,552.42
2003	53,295.31	609,504.31	11,839.94
2004	55,670.86	640,934.00	12,263.31
2005	58,799.59	680,196.55	12,637.62
2006	60,524.43	706,560.77	12,975.58
2007	61,143.20	712,636.38	13,228.38
2008	59,119.18	690,086.38	13,229.20
2009	57,583.40	660,978.03	12,880.84
2010	58,976.62	666,289.22	13,247.06
2011	[redacted]		
2012			
2013			
2014			
2015			
2016			
2017			
2018			
2019			
2000-2009	2.6%	3.1%	2.3%
2007-2009	-3.0%	-3.7%	-1.3%
2010-2019	3.8%	3.5%	2.8%
Difference	6.8%	7.2%	4.2%

1999			
2000	5.1%	6.3%	3.5%
2001	-1.1%	2.3%	-2.4%
2002	6.8%	4.3%	-3.3%
2003	6.1%	5.4%	0.8%
2004	6.5%	6.3%	0.3%
2005	3.1%	6.1%	-1.0%
2006	-4.3%	0.3%	-2.9%
2007	-10.6%	-12.4%	-4.0%
2008	-9.6%	-13.9%	-3.5%
2009	-19.9%	-20.8%	-10.4%
2010	-8.7%	-10.6%	-5.3%
2011	19.5%	17.8%	2.2%
2012	20.0%	15.7%	4.7%
2013	5.0%	4.6%	3.8%
2014	1.8%	2.0%	2.7%
2015	1.9%	1.4%	1.3%
2016	1.7%	1.2%	0.7%
2017	1.2%	0.7%	0.8%
2018	2.4%	1.2%	0.9%
2019	2.9%	1.8%	0.9%
	4.5%	4.5%	4.1%
	1.2%	2.6%	1.1%
	4.8%	3.5%	1.8%
	2.7%	4.6%	2.5%
	4.5%	5.2%	3.6%
	5.6%	6.1%	3.1%
	2.9%	3.9%	2.7%
	1.0%	0.9%	1.9%
	-3.3%	-3.2%	0.0%
	-2.6%	-4.2%	-2.6%
	2.4%	0.8%	2.8%
	4.8%	3.6%	3.3%
	5.5%	5.4%	4.3%
	4.7%	4.6%	3.8%
	3.3%	3.2%	3.1%
	3.0%	2.8%	2.3%
	3.0%	2.9%	2.1%
	3.3%	3.1%	2.2%
	3.5%	2.9%	2.2%
	3.4%	2.8%	2.2%

2661

TAMPA ELECTRIC COMPANY
DOCKET NO. 120234-EI
STAFF'S FIRST REQUEST FOR
PRODUCTION OF DOCUMENTS
DOCUMENT NO. 10
BATES STAMPED PAGES: 2753 - 3124
FILED: OCTOBER 18, 2012

10. Please provide all portions of TECO's 2011 and 2012 Ten Year Site Plans, and any documents related to the 2012 annual forecast process, which were relied upon by witness Cifuentes' in preparing or comparing her load forecasts as referenced in her direct testimony at page 10, lines 22-25, and page 13, lines 17-23.

A. The requested documents are attached. They include the data used to estimate the econometric equations of each of the company's forecasting models, as generated by the software package, MetrixND. Additionally, see the company's response to Staff's First Request for Production of Documents, No. 2, Bates stamped pages 1188 through 2377.

120234 Hearing Exhibits 00228

TEN-YEAR SITE PLAN FOR ELECTRICAL GENERATING FACILITIES AND ASSOCIATED TRANSMISSION LINES

January 2012 to December 2021

TAMPA ELECTRIC COMPANY
Tampa, Florida

April 1, 2012

2840

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Glossary of Terms

CODE IDENTIFICATION SHEET

Unit Type:	CC	=	Combined Cycle
	CG	=	Coal Gasifier
	D	=	Diesel
	FS	=	Fossil Steam
	GT	=	Combustion Turbine (includes jet engine design)
	HRSG	=	Heat Recovery Steam Generator
	IC	=	Internal Combustion
	IGCC	=	Integrated Gasification Combined Cycle
	ST	=	Steam Turbine
Unit Status:	LTRS	=	Long Term Reserve Stand-by
	OT	=	Other
	P	=	Planned
	T	=	Regulatory Approval Received
	UC	=	Under Construction
Fuel Type:	BIT	=	Bituminous Coal
	C	=	Coal
	HO	=	Heavy Oil (#6 Oil)
	LO	=	Light Oil (#2 Oil)
	NG	=	Natural Gas
	PC	=	Petroleum Coke
	WH	=	Waste Heat
Environmental:	CL	=	Closed Loop Water Cooled
	CLT	=	Cooling Tower
	EP	=	Electrostatic Precipitator
	FGD	=	Flue Gas Desulfurization
	FQ	=	Fuel Quality
	LS	=	Low Sulfur
	OLS	=	Open Loop Cooling Water System
	OTS	=	Once-Through System
	NR	=	Not Required
Transportation:	PL	=	Pipeline
	RR	=	Railroad
	TK	=	Truck
	WA	=	Water
Other:	N	=	None

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Chapter I

Tampa Electric has five (5) 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.

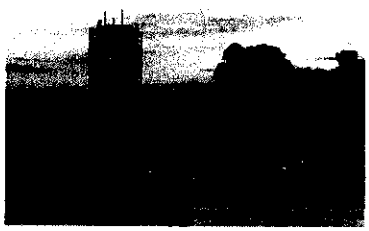
Big Bend Power Station

The station operates four (4) pulverized coal fired steam units equipped with desulfurization scrubbers and electrostatic precipitators. The station's coal-fired units have recently undergone the addition of air pollution control systems called Selective Catalytic Reduction (SCR). The SCR installations occurred from 2007 to the spring of 2010. In addition, the station operates one (1) aero-derivative combustion turbine that entered into service in 2009 and can be fired with natural gas or distillate oil.

H.L. Culbreath Bayside Power Station

The station operates two (2) natural gas fired combined cycle units. Bayside Unit 1 utilizes three (3) combustion turbines, three (3) heat recovery steam generators (HRSGs) and one (1) steam turbine. Bayside Unit 2 utilizes four (4) combustion turbines, four (4) HRSGs and one (1) steam turbine. In addition, the station operates four (4) natural gas fired aero-derivative combustion turbines that were placed into service in 2009.

Polk Power Station



The station operates five (5) generating units. Polk Unit 1 is an integrated gasification combined cycle (IGCC) unit fired with synthetic gas produced from gasified coal and other carbonaceous fuels. This technology integrates state-of-the-art environmental processes to create a clean fuel gas from a variety of feedstock with the efficiency benefits of combined cycle generation equipment. Polk Units 2 through 5 are combustion turbines fired primarily with natural gas. Units 1, 2 and 3 can also be fired with distillate oil.

J.H. Phillips Power Station

The station is comprised of two (2) residual or distillate oil fired diesel engines. The units were placed into long-term reserve standby in 2009.

Partnership Power Station

The station is comprised of two (2) natural gas fired internal combustion engines. This project was developed in partnership with Tampa Electric and the City of Tampa.

120234 Hearing Exhibits 00239

Schedule 1

Existing Generating Facilities
As of December 31, 2011

(1) Plant Name	(2) Unit No.	(3) Location	(4) Unit Type	(5) Fuel Pri	(6) Fuel Alt	(7) Fuel Transport Pri	(8) Fuel Transport Alt	(9) Alt Fuel Days	(10) Commercial In-Service Mo/Yr	(11) Expected Retirement Mo/Yr	(12) Gen. Max. Nameplate KW		(13) Net Capability Summer MW	(14) Net Capability Winter MW
Big Bend		Hillsborough Co. 14/31S/19E									1,892,485		1,608	1,643
	1		ST	BIT	N	WA	N	0	10/70	Unknown	445,500		385	395
	2		ST	BIT	N	WA	N	0	4/73	Unknown	445,500		385	395
	3		ST	BIT	N	WA	N	0	5/76	Unknown	445,500		365	365
	4		ST	BIT	N	WA	N	0	2/85	Unknown	486,000		417	427
	CT 4		GT	NG	LO	PL	TK	0	8/09	Unknown	69,985		56	61
Bayside		Hillsborough Co. 4/30S/19E									2,294,100		1,854	2,083
	1		CC	NG	N	PL	N	0	4/03	Unknown	809,060		701	792
	2		CC	NG	N	PL	N	0	1/04	Unknown	1,205,100		929	1,047
	3		GT	NG	N	PL	N	0	7/09	Unknown	69,985		56	61
	4		GT	NG	N	PL	N	0	7/09	Unknown	69,985		56	61
	5		GT	NG	N	PL	N	0	4/09	Unknown	69,985		56	61
	6		GT	NG	N	PL	N	0	4/09	Unknown	69,985		56	61
Phillips		Highland Co. 12-055									38,430		36 [1]	36 [1]
	1		IC	HO	LO	TK	N	0	6/83	LTRS 9/09	19,215		18 [1]	18 [1]
	2		IC	HO	LO	TK	N	0	6/83	LTRS 9/09	19,215		18 [1]	18 [1]
Polk		Polk Co. 2,3/32S/23E									1,029,379		824	952
	1		IGCC	BIT	LO	WA/TK	TK	0	9/96	Unknown	326,299		220	220
	2		GT	NG	LO	PL	TK	0	7/00	Unknown	175,770	[2]	151	183
	3		GT	NG	LO	PL	TK	0	5/02	Unknown	175,770	[2]	151	183
	4		GT	NG	N	PL	N	0	3/07	Unknown	175,770	[2]	151	183
	5		GT	NG	N	PL	N	0	4/07	Unknown	175,770	[2]	151	183
Partnership		Hillsborough Co. W30/29/19									5,800		6	6
	1		IC	NG	N	PL	N	0	4/01	Unknown	2,900		3	3
	2		IC	NG	N	PL	N	0	4/01	Unknown	2,900		3	3
										TOTAL			4,292	4,684

Notes:
[1] Phillips Units 1 & 2 were placed into long-term reserve standby (LTRS) on September 4, 2009, and net capacities are not included into the system total.
[2] Polk Units 2-5 turbine name plate ratings are based on 59 degrees Fahrenheit. The net capacity of these units vary with ambient air temperature.

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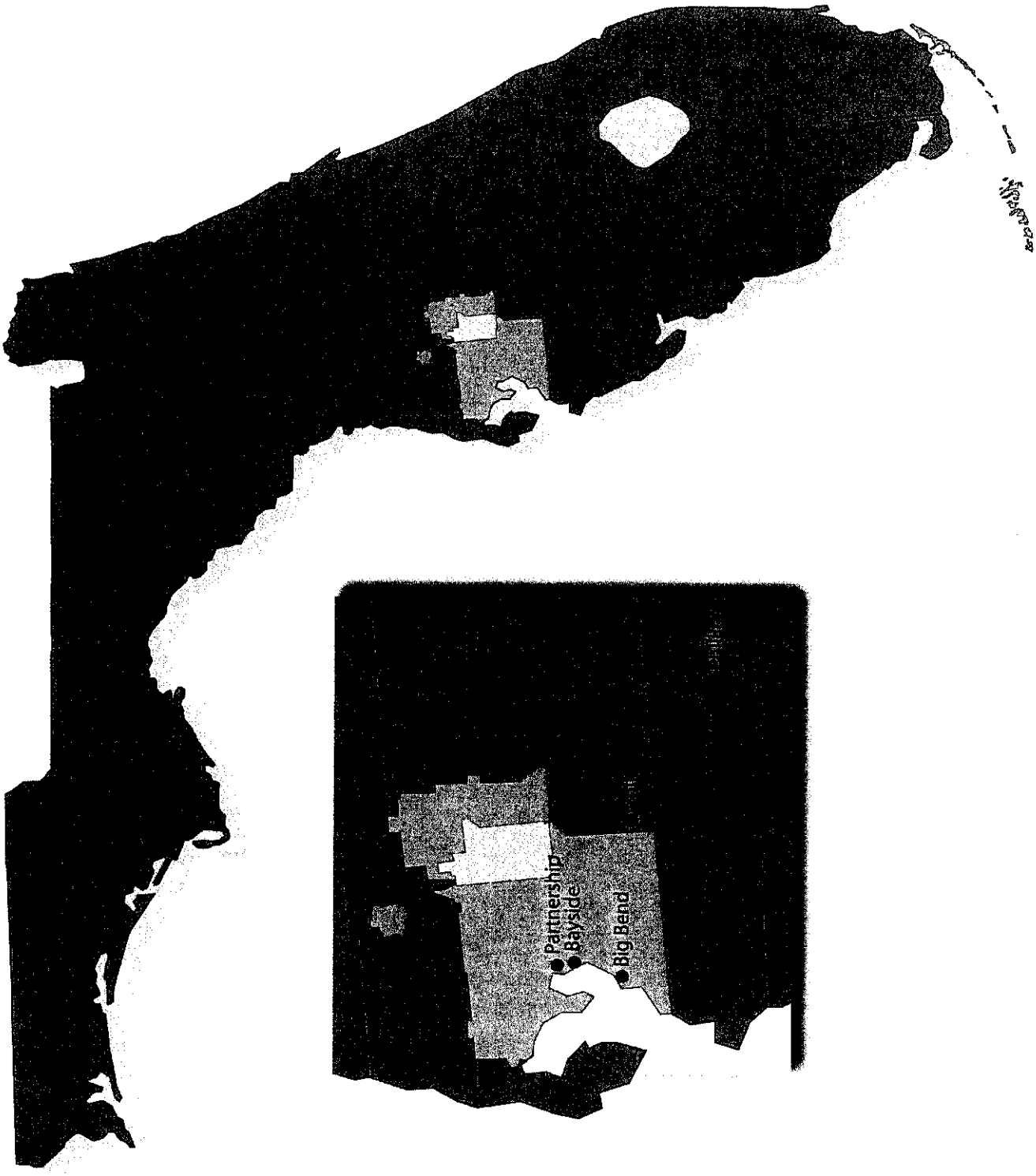
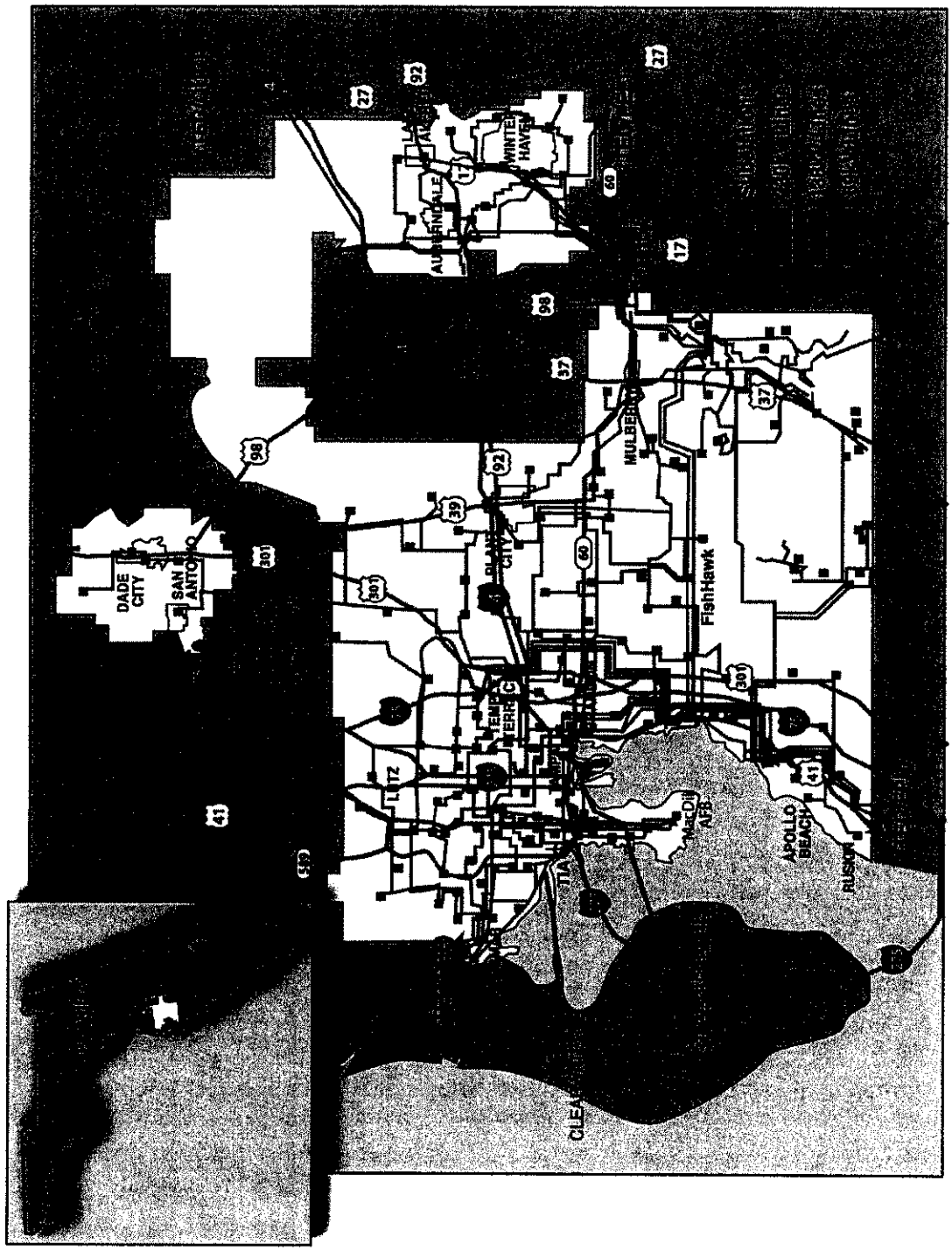
120234 Hearing Exhibits 00241

I.1 Tampa Electric Service Area Map



I.2 Tampa Electric Service Area Transmission Facility



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Chapter II

The Schedule 2 through 4 tables reflect three different levels of load forecasting: base case, high case and low case. The expansion plan is based on the base case of the load forecast and is reflected in Schedules 5 through 9. This forecast band best represents the current economic conditions and the long-term impacts to Tampa Electric's service territory.

Schedule 2.1: History and Forecast of Energy Consumption and Number of Customers by Customer Class (Base, High & Low)

Schedule 2.2: History and Forecast of Energy Consumption and Number of Customers by Customer Class (Base, High & Low)

Schedule 2.3: History and Forecast of Energy Consumption and Number of Customers by Customer Class (Base, High & Low)

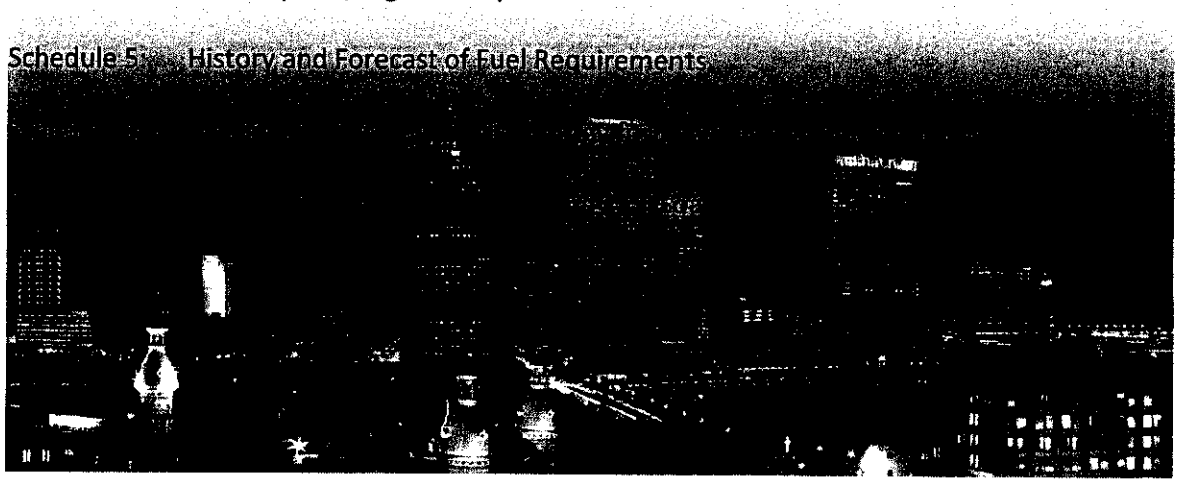
Schedule 3.1: History and Forecast of Summer Peak Demand (Base, High & Low)

Schedule 3.2: History and Forecast of Winter Peak Demand (Base, High & Low)

Schedule 3.3: History and Forecast of Annual Net Energy for Load (Base, High & Low)

Schedule 4: Previous Year and 2-Year Forecast of Peak Demand and Net Energy for Load by Month (Base, High & Low)

Schedule 5: History and Forecast of Fuel Requirements



120234 Hearing Exhibits 00245

Schedule 2.1

History and Forecast of Energy Consumption and Number of Customers by Customer Class
Base Case

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
	Rural and Residential					Commercial		
Year	Hillsborough County Population	Members Per Household	GWH	Customers*	Average KWH Consumption Per Customer	GWH	Customers*	Average KWH Consumption Per Customer
2002	1,053,580	2.6	8,046	518,554	15,516	5,832	64,665	90,188
2003	1,079,491	2.5	8,265	531,257	15,557	5,843	66,041	88,475
2004	1,108,451	2.5	8,293	544,313	15,236	5,988	67,488	88,727
2005	1,138,786	2.5	8,558	558,601	15,320	6,233	69,027	90,298
2006	1,170,851	2.5	8,721	575,111	15,164	6,357	70,205	90,549
2007	1,194,436	2.5	8,871	586,776	15,119	6,542	70,891	92,276
2008	1,206,084	2.5	8,546	587,602	14,545	6,399	70,770	90,415
2009	1,215,216	2.5	8,666	587,396	14,754	6,274	70,182	89,395
2010	1,229,226	2.6	9,185	591,554	15,526	6,221	70,176	88,655
2011	1,236,778	2.6	8,718	595,914	14,630	6,207	70,522	88,009
2012	1,246,939	2.6	8,904	599,454	14,854	6,346	71,418	88,860
2013	1,261,960	2.6	9,003	606,320	14,849	6,412	72,252	88,739
2014	1,278,632	2.6	9,095	614,152	14,809	6,484	73,176	88,608
2015	1,296,480	2.6	9,174	622,637	14,735	6,557	74,183	88,388
2016	1,316,090	2.6	9,272	632,012	14,671	6,640	75,278	88,206
2017	1,335,184	2.6	9,376	641,161	14,624	6,727	76,346	88,107
2018	1,353,814	2.6	9,486	650,099	14,591	6,814	77,398	88,033
2019	1,372,385	2.6	9,600	659,014	14,567	6,901	78,447	87,972
2020	1,390,666	2.6	9,716	667,793	14,550	6,985	79,491	87,868
2021	1,407,907	2.6	9,826	676,073	14,534	7,063	80,484	87,751

December 31, 2011 Status

* Average of end-of-month customers for the calendar year.
Note: Values shown may be affected due to rounding.

Schedule 2.1

History and Forecast of Energy Consumption and
Number of Customers by Customer Class
High Case

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
	Rural and Residential					Commercial		
Year	Hillsborough County Population	Members Per Household	GWH	Customers*	Average KWH Consumption Per Customer	GWH	Customers*	Average KWH Consumption Per Customer
2002	1,053,580	2.6	8,046	518,554	15,516	5,832	64,665	90,188
2003	1,079,491	2.5	8,265	531,257	15,557	5,843	66,041	88,475
2004	1,108,451	2.5	8,293	544,313	15,236	5,988	67,488	88,727
2005	1,138,786	2.5	8,558	558,601	15,320	6,233	69,027	90,298
2006	1,170,851	2.5	8,721	575,111	15,164	6,357	70,205	90,549
2007	1,194,436	2.5	8,871	586,776	15,119	6,542	70,891	92,276
2008	1,206,084	2.5	8,546	587,602	14,545	6,399	70,770	90,415
2009	1,215,216	2.5	8,666	587,396	14,754	6,274	70,182	89,395
2010	1,229,226	2.6	9,185	591,554	15,526	6,221	70,176	88,655
2011	1,236,778	2.6	8,718	595,914	14,630	6,207	70,522	88,009
2012	1,309,286	2.7	8,980	603,999	14,868	6,394	71,935	88,885
2013	1,325,058	2.7	9,137	614,469	14,869	6,498	73,211	88,754
2014	1,342,564	2.7	9,284	625,723	14,837	6,607	74,552	88,623
2015	1,361,304	2.7	9,418	637,612	14,771	6,717	75,973	88,408
2016	1,381,895	2.7	9,572	650,459	14,715	6,837	77,491	88,232
2017	1,401,944	2.7	9,733	663,158	14,676	6,963	78,991	88,144
2018	1,421,505	2.7	9,901	675,735	14,652	7,089	80,486	88,081
2019	1,441,004	2.7	10,076	688,390	14,637	7,218	81,991	88,032
2020	1,460,200	2.7	10,255	701,009	14,629	7,343	83,504	87,941
2021	1,478,302	2.7	10,430	713,212	14,623	7,464	84,976	87,840

December 31, 2011 Status

* Average of end-of-month customers for the calendar year.
Note: Values shown may be affected due to rounding.

120234 Hearing Exhibits 00247

Schedule 2.1

History and Forecast of Energy Consumption and Number of Customers by Customer Class
Low Case

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
	Rural and Residential					Commercial		
Year	Hillsborough County Population	Members Per Household	GWH	Customers*	Average KWH Consumption Per Customer	GWH	Customers*	Average KWH Consumption Per Customer
2002	1,053,580	2.6	8,046	518,554	15,516	5,832	64,665	90,188
2003	1,079,491	2.5	8,265	531,257	15,557	5,843	66,041	88,475
2004	1,108,451	2.5	8,293	544,313	15,236	5,988	67,488	88,727
2005	1,138,786	2.5	8,558	558,601	15,320	6,233	69,027	90,298
2006	1,170,851	2.5	8,721	575,111	15,164	6,357	70,205	90,549
2007	1,194,436	2.5	8,871	586,776	15,119	6,542	70,891	92,276
2008	1,206,084	2.5	8,546	587,602	14,545	6,399	70,770	90,415
2009	1,215,216	2.5	8,666	587,396	14,754	6,274	70,182	89,395
2010	1,229,226	2.6	9,185	591,554	15,526	6,221	70,176	88,655
2011	1,236,778	2.6	8,718	595,914	14,630	6,207	70,522	88,009
2012	1,184,592	2.4	8,847	596,151	14,841	6,310	71,043	88,817
2013	1,198,862	2.4	8,892	599,713	14,828	6,340	71,476	88,700
2014	1,214,700	2.4	8,930	604,166	14,781	6,376	71,989	88,570
2015	1,231,656	2.4	8,955	609,233	14,699	6,412	72,580	88,348
2016	1,250,286	2.4	8,998	615,146	14,627	6,458	73,253	88,161
2017	1,268,425	2.4	9,046	620,808	14,572	6,507	73,898	88,054
2018	1,286,123	2.4	9,099	626,230	14,530	6,556	74,521	87,971
2019	1,303,766	2.4	9,156	631,589	14,497	6,604	75,136	87,898
2020	1,321,133	2.4	9,214	636,771	14,470	6,649	75,742	87,780
2021	1,337,511	2.4	9,265	641,428	14,445	6,687	76,291	87,649

December 31, 2011 Status

* Average of end-of-month customers for the calendar year.
Note: Values shown may be affected due to rounding.

Schedule 2.2

History and Forecast of Energy Consumption and
Number of Customers by Customer Class
Base Case

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
	Industrial						
Year	GWH	Customers*	Average KWH Consumption Per Customer	Railroads and Railways GWH	Street & Highway Lighting GWH	Other Sales to Public Authorities GWH	Total Sales to Ultimate Consumers GWH
2002	2,612	948	2,755,274	0	55	1,380	17,925
2003	2,580	1203	2,144,638	0	57	1,481	18,226
2004	2,556	1299	1,967,667	0	58	1,542	18,437
2005	2,478	1,337	1,853,403	0	60	1,582	18,911
2006	2,279	1,485	1,534,680	0	61	1,607	19,025
2007	2,366	1,494	1,583,695	0	63	1,692	19,533
2008	2,205	1,421	1,551,724	0	64	1,776	18,990
2009	1,995	1,424	1,401,219	0	68	1,771	18,774
2010	2,010	1,434	1,401,767	0	73	1,724	19,213
2011	1,804	1,493	1,207,838	0	74	1,761	18,564
2012	1,897	1496	1,268,116	0	74	1,822	19,044
2013	1,837	1507	1,218,829	0	74	1,833	19,158
2014	1,704	1518	1,122,549	0	75	1,844	19,201
2015	1,663	1526	1,089,778	0	76	1,856	19,326
2016	1,668	1533	1,087,735	0	77	1,871	19,528
2017	1,651	1540	1,071,966	0	77	1,887	19,719
2018	1,646	1548	1,063,502	0	78	1,903	19,927
2019	1,641	1555	1,055,145	0	79	1,919	20,141
2020	1,636	1563	1,046,664	0	80	1,935	20,352
2021	1,631	1571	1,038,255	0	81	1,949	20,550

December 31, 2011 Status

* Average of end-of-month customers for the calendar year.
Note: Values shown may be affected due to rounding.

120234 Hearing Exhibits 00249

Schedule 2.2

History and Forecast of Energy Consumption and Number of Customers by Customer Class
High Case

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
	Industrial						
Year	GWH	Customers*	Average KWH Consumption Per Customer	Railroads and Railways GWH	Street & Highway Lighting GWH	Other Sales to Public Authorities GWH	Total Sales to Ultimate Consumers GWH
2002	2,612	948	2,755,274	0	55	1,380	17,925
2003	2,580	1,203	2,144,638	0	57	1,481	18,226
2004	2,556	1,299	1,967,667	0	58	1,542	18,437
2005	2,478	1,337	1,853,403	0	60	1,582	18,911
2006	2,279	1,485	1,534,680	0	61	1,607	19,025
2007	2,366	1,494	1,583,695	0	63	1,692	19,533
2008	2,205	1,421	1,551,724	0	64	1,776	18,990
2009	1,995	1,424	1,401,219	0	68	1,771	18,774
2010	2,010	1,434	1,401,767	0	73	1,724	19,213
2011	1,804	1,493	1,207,838	0	74	1,761	18,564
2012	1,900	1,498	1,268,509	0	74	1,828	19,177
2013	1,841	1,510	1,219,406	0	74	1,845	19,395
2014	1,710	1,523	1,123,028	0	75	1,862	19,539
2015	1,672	1,534	1,089,914	0	76	1,881	19,763
2016	1,678	1,543	1,087,585	0	77	1,903	20,067
2017	1,663	1,552	1,071,816	0	77	1,926	20,362
2018	1,660	1,562	1,062,775	0	78	1,949	20,678
2019	1,657	1,572	1,053,983	0	79	1,973	21,003
2020	1,653	1,582	1,045,123	0	80	1,996	21,328
2021	1,650	1,592	1,036,283	0	81	2,018	21,643

December 31, 2011 Status

* Average of end-of-month customers for the calendar year.
Note: Values shown may be affected due to rounding.

Schedule 2.2

History and Forecast of Energy Consumption and
Number of Customers by Customer Class
Low Case

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
	Industrial						
Year	GWH	Customers*	Average KWH Consumption Per Customer	Railroads and Railways GWH	Street & Highway Lighting GWH	Other Sales to Public Authorities GWH	Total Sales to Ultimate Consumers GWH
2002	2,612	948	2,755,274	0	55	1,380	17,925
2003	2,580	1,203	2,144,638	0	57	1,481	18,226
2004	2,556	1,299	1,967,667	0	58	1,542	18,437
2005	2,478	1,337	1,853,403	0	60	1,582	18,911
2006	2,279	1,485	1,534,680	0	61	1,607	19,025
2007	2,366	1,494	1,583,695	0	63	1,692	19,533
2008	2,205	1,421	1,551,724	0	64	1,776	18,990
2009	1,995	1,424	1,401,219	0	68	1,771	18,774
2010	2,010	1,434	1,401,767	0	73	1,724	19,213
2011	1,804	1,493	1,207,838	0	74	1,761	18,564
2012	1,895	1,495	1,267,377	0	74	1,816	18,942
2013	1,832	1,503	1,218,786	0	74	1,820	18,959
2014	1,697	1,512	1,122,389	0	75	1,825	18,903
2015	1,655	1,519	1,089,475	0	76	1,831	18,929
2016	1,658	1,524	1,087,699	0	77	1,840	19,030
2017	1,640	1,529	1,072,341	0	77	1,849	19,119
2018	1,633	1,535	1,063,805	0	78	1,858	19,224
2019	1,627	1,540	1,056,218	0	79	1,867	19,333
2020	1,620	1,546	1,047,902	0	80	1,876	19,439
2021	1,614	1,551	1,040,302	0	81	1,884	19,530

December 31, 2011 Status

* Average of end-of-month customers for the calendar year.
Note: Values shown may be affected due to rounding.

120234 Hearing Exhibits 00251

Schedule 2.3

History and Forecast of Energy Consumption and Number of Customers by Customer Class
Base Case

(1)	(2)	(3)	(4)	(5)	(6)
Year	Sales for * Resale GWH	Utility Use ** & Losses GWH	Net Energy *** for Load GWH	Other **** Customers	Total **** Customers
2002	502	935	19,362	6,032	590,199
2003	587	985	19,798	6,399	604,900
2004	589	945	19,971	6,435	619,535
2005	712	952	20,575	6,656	635,621
2006	700	1,000	20,725	6,905	653,706
2007	829	916	21,278	7,193	666,354
2008	752	909	20,650	7,473	667,266
2009	191	978	19,943	7,748	666,750
2010	305	1,149	20,667	7,827	670,991
2011	120	642	19,325	7,869	675,799
2012	20	1,016	20,080	7,947	680,316
2013	0	1,022	20,180	8,004	688,083
2014	0	1,025	20,226	8,067	696,913
2015	0	1,032	20,358	8,135	706,481
2016	0	1,043	20,571	8,210	717,032
2017	0	1,053	20,772	8,283	727,330
2018	0	1,065	20,991	8,354	737,398
2019	0	1,076	21,217	8,425	747,441
2020	0	1,088	21,439	8,495	757,343
2021	0	1,099	21,649	8,561	766,690

December 31, 2011 Status

* Includes sales to Progress Energy Florida, Wauchula, Ft. Meade, St. Cloud and Reedy Creek. Contract ended with Ft. Meade on 12/31/08 and Reedy Creek on 12/31/10.

** Utility Use and Losses include accrued sales.

*** Net Energy for Load includes output to line including energy supplied by purchased cogeneration.

**** Average of end-of-month customers for the calendar year.

Note: Values shown may be affected due to rounding.

Schedule 2.3

History and Forecast of Energy Consumption and Number of Customers by Customer Class
High Case

(1)	(2)	(3)	(4)	(5)	(6)
Year	Sales for * Resale GWH	Utility Use ** & Losses GWH	Net Energy *** for Load GWH	Other **** Customers	Total **** Customers
2002	502	935	19,362	6,032	590,199
2003	587	985	19,798	6,399	604,900
2004	589	945	19,971	6,435	619,535
2005	712	952	20,575	6,656	635,621
2006	700	1,000	20,725	6,905	653,706
2007	829	916	21,278	7,193	666,354
2008	752	909	20,650	7,473	667,266
2009	191	978	19,943	7,748	666,750
2010	305	1,149	20,667	7,827	670,991
2011	120	642	19,325	7,869	675,799
2012	20	1,023	20,220	7,970	685,402
2013	0	1,035	20,430	8,050	697,240
2014	0	1,043	20,582	8,138	709,936
2015	0	1,055	20,819	8,231	723,350
2016	0	1,072	21,139	8,331	737,824
2017	0	1,088	21,450	8,431	752,132
2018	0	1,105	21,783	8,530	766,313
2019	0	1,123	22,125	8,629	780,582
2020	0	1,140	22,468	8,728	794,823
2021	0	1,157	22,800	8,825	808,605

December 31, 2011 Status

* Includes sales to Progress Energy Florida, Wauchula, Ft. Meade, St. Cloud and Reedy Creek. Contract ended with Ft. Meade on 12/31/08 and Reedy Creek on 12/31/10.
** Utility Use and Losses include accrued sales.
*** Net Energy for Load includes output to line including energy supplied by purchased cogeneration.
**** Average of end-of-month customers for the calendar year.
Note: Values shown may be affected due to rounding.

120234 Hearing Exhibits 00253

Schedule 2.3

History and Forecast of Energy Consumption and Number of Customers by Customer Class
Low Case

(1)	(2)	(3)	(4)	(5)	(6)
Year	Sales for * Resale GWH	Utility Use ** & Losses GWH	Net Energy *** for Load GWH	Other **** Customers	Total **** Customers
2002	502	935	19,362	6,032	590,199
2003	587	985	19,798	6,399	604,900
2004	589	945	19,971	6,435	619,535
2005	712	952	20,575	6,656	635,621
2006	700	1,000	20,725	6,905	653,706
2007	829	916	21,278	7,193	666,354
2008	752	909	20,650	7,473	667,266
2009	191	978	19,943	7,748	666,750
2010	305	1,149	20,667	7,827	670,991
2011	120	642	19,325	7,869	675,799
2012	20	1,010	19,972	7,924	676,613
2013	0	1,012	19,971	7,957	680,649
2014	0	1,009	19,912	7,997	685,664
2015	0	1,011	19,939	8,041	691,373
2016	0	1,016	20,046	8,090	698,013
2017	0	1,021	20,140	8,137	704,372
2018	0	1,027	20,251	8,183	710,469
2019	0	1,033	20,367	8,227	716,492
2020	0	1,039	20,477	8,269	722,328
2021	0	1,044	20,574	8,308	727,578

December 31, 2011 Status

* Includes sales to Progress Energy Florida, Wauchula, Ft. Meade, St. Cloud and Reedy Creek. Contract ended with Ft. Meade on 12/31/08 and Reedy Creek on 12/31/10.
** Utility Use and Losses include accrued sales.
*** Net Energy for Load includes output to line including energy supplied by purchased cogeneration.
**** Average of end-of-month customers for the calendar year.
Note: Values shown may be affected due to rounding.

Schedule 3.1

History and Forecast of Summer Peak Demand
Base Case

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	
Year	Total *	Wholesale**	Retail *	Interruptible	Residential Load Management	Residential Conservation	Comm./Ind. Load Management	Comm./Ind. Conservation	Net Firm Demand	
2002	3,869	122	3,747	206	99	60	21	43	3,318	***
2003	3,854	122	3,732	188	63	65	21	44	3,351	
2004	3,974	120	3,854	177	95	70	20	47	3,445	
2005	4,218	128	4,090	144	79	73	19	49	3,725	
2006	4,265	128	4,137	146	77	77	18	50	3,769	
2007	4,428	172	4,256	159	69	80	18	53	3,876	
2008	4,240	148	4,092	143	69	84	18	55	3,723	
2009	4,310	136	4,174	120	56	89	51	59	3,799	
2010	4,134	118	4,016	73	33	95	40	65	3,710	***
2011	4,099	28	4,071	109	48	102	40	73	3,699	
2012	4,324	142	4,182	125	55	108	75	71	3,748	
2013	4,226	0	4,226	118	55	115	77	76	3,784	
2014	4,266	0	4,266	105	56	122	80	80	3,823	
2015	4,313	0	4,313	102	57	130	82	84	3,859	
2016	4,371	0	4,371	103	58	137	85	88	3,900	
2017	4,426	0	4,426	102	59	145	88	93	3,940	
2018	4,483	0	4,483	102	61	153	90	97	3,980	
2019	4,542	0	4,542	102	63	161	93	101	4,022	
2020	4,599	0	4,599	102	65	170	94	104	4,064	
2021	4,653	0	4,653	102	66	178	96	108	4,103	

December 31, 2011 Status

* Includes residential and commercial/industrial conservation.

** Includes sales to Progress Energy Florida, Wauchula, Ft. Meade, St. Cloud, Reedy Creek and Florida Power & Light. Contract ended with Ft. Meade on 12/31/08, Reedy Creek on 12/31/10, Progress Energy Florida on 2/31/11 and Wauchula on 9/31/11.

*** Net Firm Demand is not coincident with system peak.

Note: Values shown may be affected due to rounding.

Schedule 3.1

History and Forecast of Summer Peak Demand
High Case

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	
Year	Total *	Wholesale**	Retail *	Interruptible	Residential Load Management	Residential Conservation	Comm./Ind. Load Management	Comm./Ind. Conservation	Net Firm Demand	
2002	3,869	122	3,747	206	99	60	21	43	3,318	
2003	3,854	122	3,732	188	63	65	21	44	3,351	***
2004	3,974	120	3,854	177	95	70	20	47	3,445	
2005	4,218	128	4,090	144	79	73	19	49	3,725	
2006	4,265	128	4,137	146	77	77	18	50	3,769	
2007	4,428	172	4,256	159	69	80	18	53	3,876	
2008	4,240	148	4,092	143	69	84	18	55	3,723	
2009	4,310	136	4,174	120	56	89	51	59	3,799	
2010	4,134	118	4,016	73	33	95	40	65	3,710	
2011	4,099	28	4,071	109	48	102	40	73	3,699	***
2012	4,354	142	4,212	125	55	108	75	71	3,778	
2013	4,278	0	4,278	118	55	115	77	76	3,836	
2014	4,340	0	4,340	105	56	122	80	80	3,897	
2015	4,409	0	4,409	102	57	130	82	84	3,955	
2016	4,488	0	4,488	103	58	137	85	88	4,017	
2017	4,566	0	4,566	102	59	145	88	93	4,080	
2018	4,647	0	4,647	102	61	153	90	97	4,144	
2019	4,729	0	4,729	102	63	161	93	101	4,209	
2020	4,811	0	4,811	102	65	170	94	104	4,276	
2021	4,891	0	4,891	102	66	178	96	108	4,341	

December 31, 2011 Status

* Includes residential and commercial/industrial conservation.

** Includes sales to Progress Energy Florida, Wauchula, Ft. Meade, St. Cloud, Reedy Creek and Florida Power & Light. Contract ended with Ft. Meade on 12/31/08, Reedy Creek on 12/31/10, Progress Energy Florida on 2/31/11 and Wauchula on 9/31/11.

*** Net Firm Demand is not coincident with system peak.

Note: Values shown may be affected due to rounding.

2867

Schedule 3.1

History and Forecast of Summer Peak Demand
Low Case

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	
Year	Total *	Wholesale**	Retail *	Interruptible	Residential Load Management	Residential Conservation	Comm./Ind. Load Management	Comm./Ind. Conservation	Net Firm Demand	
2002	3,869	122	3,747	206	99	60	21	43	3,318	
2003	3,854	122	3,732	188	63	65	21	44	3,351	***
2004	3,974	120	3,854	177	95	70	20	47	3,445	
2005	4,218	128	4,090	144	79	73	19	49	3,725	
2006	4,265	128	4,137	146	77	77	18	50	3,769	
2007	4,428	172	4,256	159	69	80	18	53	3,876	
2008	4,240	148	4,092	143	69	84	18	55	3,723	
2009	4,310	136	4,174	120	56	89	51	59	3,799	
2010	4,134	118	4,016	73	33	95	40	65	3,710	
2011	4,099	28	4,071	109	48	102	40	73	3,699	***
2012	4,301	142	4,159	125	55	108	75	71	3,725	
2013	4,182	0	4,182	118	55	115	77	76	3,740	
2014	4,201	0	4,201	105	56	122	80	80	3,758	
2015	4,227	0	4,227	102	57	130	82	84	3,773	
2016	4,262	0	4,262	103	58	137	85	88	3,791	
2017	4,296	0	4,296	102	59	145	88	93	3,810	
2018	4,330	0	4,330	102	61	153	90	97	3,827	
2019	4,367	0	4,367	102	63	161	93	101	3,847	
2020	4,401	0	4,401	102	65	170	94	104	3,866	
2021	4,432	0	4,432	102	66	178	96	108	3,882	

December 31, 2011 Status

* Includes residential and commercial/industrial conservation.

** Includes sales to Progress Energy Florida, Wauchula, Ft. Meade, St. Cloud, Reedy Creek and Florida Power & Light. Contract ended with Ft. Meade on 12/31/08, Reedy Creek on 12/31/10, Progress Energy Florida on 2/31/11 and Wauchula on 9/31/11.

*** Net Firm Demand is not coincident with system peak.

Note: Values shown may be affected due to rounding.

120234 Hearing Exhibits 00257

2869

TAMPA ELECTRIC COMPANY
DOCKET NO. 120234-EI
STAFF'S FIRST REQUEST FOR PODS
FILED: OCTOBER 18, 2012

Schedule 3.2

History and Forecast of Winter Peak Demand
Base Case

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
Year	Total *	Wholesale **	Retail *	Interruptible	Residential Load Management	Residential Conservation	Comm./Ind. Load Management	Comm./Ind. Conservation	Net Firm Demand
2001/02	4,217	127	4,090	168	176	419	22	46	3,259
2002/03	4,484	129	4,355	195	210	428	21	46	3,455
2003/04	3,949	120	3,829	254	136	437	18	48	2,936
2004/05	4,308	129	4,179	194	189	444	16	49	3,287
2005/06	4,404	171	4,233	51	144	447	18	50	3,523
2006/07	4,063	162	3,900	157	96	452	18	51	3,127
2007/08	4,369	152	4,217	120	129	456	18	52	3,443
2008/09	4,687	67	4,620	181	120	461	52	52	3,754
2009/10	5,158	122	5,036	117	109	468	40	56	4,246
2010/11	4,694	120	4,574	174	88	477	40	60	3,735
2011/12	4,725	91	4,633	132	111	482	72	58	3,777
2012/13	4,679	0	4,678	125	111	490	73	60	3,819
2013/14	4,720	0	4,719	113	110	497	74	61	3,864
2014/15	4,772	0	4,772	109	110	504	76	63	3,910
2015/16	4,829	0	4,829	110	110	512	77	64	3,955
2016/17	4,888	0	4,888	109	111	520	78	66	4,003
2017/18	4,948	0	4,948	109	113	528	80	67	4,050
2018/19	5,009	0	5,009	109	115	536	82	69	4,097
2019/20	5,070	0	5,070	109	117	544	83	70	4,146
2020/21	5,130	0	5,130	109	119	553	84	72	4,194

December 31, 2011 Status

* Includes residential and commercial/industrial conservation.

** Includes sales to Progress Energy Florida, Wauchula, Ft. Meade, St. Cloud, Reedy Creek and Florida Power & Light. Contract ended with Ft. Meade on 12/31/08, Reedy Creek on 12/31/10, Progress Energy Florida on 2/31/11 and Wauchula on 9/31/11.

Note: Values shown may be affected due to rounding.

120234 Hearing Exhibits 00258

Schedule 3.2

History and Forecast of Winter Peak Demand
High Case

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
Year	Total *	Wholesale **	Retail *	Interruptible	Residential Load Management	Residential Conservation	Comm./Ind. Load Management	Comm./Ind. Conservation	Net Firm Demand
2001/02	4,217	127	4,090	168	176	419	22	46	3,259
2002/03	4,484	129	4,355	195	210	428	21	46	3,455
2003/04	3,949	120	3,829	254	136	437	18	48	2,936
2004/05	4,308	129	4,179	194	189	444	16	49	3,287
2005/06	4,404	171	4,233	51	144	447	18	50	3,523
2006/07	4,063	162	3,900	157	96	452	18	51	3,127
2007/08	4,369	152	4,217	120	129	456	18	52	3,443
2008/09	4,687	67	4,620	181	120	461	52	52	3,754
2009/10	5,158	122	5,036	117	109	468	40	56	4,246
2010/11	4,694	120	4,574	174	88	477	40	60	3,735
2011/12	4,749	91	4,658	132	111	482	72	58	3,802
2012/13	4,727	0	4,727	125	111	490	73	60	3,868
2013/14	4,791	0	4,791	113	110	497	74	61	3,936
2014/15	4,865	0	4,865	109	110	504	76	63	4,003
2015/16	4,946	0	4,946	110	110	512	77	64	4,072
2016/17	5,027	0	5,027	109	111	520	78	66	4,142
2017/18	5,110	0	5,110	109	113	528	80	67	4,212
2018/19	5,196	0	5,196	109	115	536	82	69	4,284
2019/20	5,282	0	5,282	109	117	544	83	70	4,358
2020/21	5,367	0	5,367	109	119	553	84	72	4,431

December 31, 2011 Status

* Includes residential and commercial/industrial conservation.

** Includes sales to Progress Energy Florida, Wauchula, Ft. Meade, St. Cloud, Reedy Creek and Florida Power & Light. Contract ended with Ft. Meade on 12/31/08, Reedy Creek on 12/31/10, Progress Energy Florida on 2/31/11 and Wauchula on 9/31/11.

Note: Values shown may be affected due to rounding.

120234 Hearing Exhibits 00259

Schedule 3.2

History and Forecast of Winter Peak Demand
Low Case

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
Year	Total *	Wholesale **	Retail *	Interruptible	Residential Load Management	Residential Conservation	Comm./Ind. Load Management	Comm./Ind. Conservation	Net Firm Demand
2001/02	4,217	127	4,090	168	176	419	22	46	3,259
2002/03	4,484	129	4,355	195	210	428	21	46	3,455
2003/04	3,949	120	3,829	254	136	437	18	48	2,936
2004/05	4,308	129	4,179	194	189	444	16	49	3,287
2005/06	4,404	171	4,233	51	144	447	18	50	3,523
2006/07	4,063	162	3,900	157	96	452	18	51	3,127
2007/08	4,369	152	4,217	120	129	456	18	52	3,443
2008/09	4,687	67	4,620	181	120	461	52	52	3,754
2009/10	5,158	122	5,036	117	109	468	40	56	4,246
2010/11	4,694	120	4,574	174	88	477	40	60	3,735
2011/12	4,705	91	4,614	132	111	482	72	58	3,758
2012/13	4,638	0	4,638	125	111	490	73	60	3,779
2013/14	4,657	0	4,657	113	110	497	74	61	3,802
2014/15	4,687	0	4,687	109	110	504	76	63	3,825
2015/16	4,723	0	4,723	110	110	512	77	64	3,849
2016/17	4,759	0	4,759	109	111	520	78	66	3,874
2017/18	4,796	0	4,796	109	113	528	80	67	3,898
2018/19	4,834	0	4,834	109	115	536	82	69	3,922
2019/20	4,871	0	4,871	109	117	544	83	70	3,947
2020/21	4,908	0	4,908	109	119	553	84	72	3,972

December 31, 2011 Status

* Includes residential and commercial/industrial conservation.

** Includes sales to Progress Energy Florida, Wauchula, Ft. Meade, St. Cloud, Reedy Creek and Florida Power & Light. Contract ended with Ft. Meade on 12/31/08, Reedy Creek on 12/31/10, Progress Energy Florida on 2/31/11 and Wauchula on 9/31/11.

Note: Values shown may be affected due to rounding.

2871

Schedule 3.3

History and Forecast of Annual Net Energy for Load - GWH
Base Case

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
Year	Total	Residential Conservation	Comm./Ind. Conservation	Retail	Wholesale *	Utility Use & Losses	Net Energy for Load	Load ** Factor %
2002	18,422	361	137	17,925	502	935	19,362	58.9
2003	18,756	378	152	18,226	587	985	19,798	60.3
2004	18,999	394	168	18,437	589	945	19,971	65.6
2005	19,491	404	176	18,911	712	952	20,575	57.3
2006	19,625	412	188	19,025	700	1000	20,725	57.2
2007	20,153	421	200	19,533	829	916	21,279	56.6
2008	19,632	430	212	18,990	752	909	20,650	57.3
2009	19,449	443	231	18,774	191	978	19,943	54.7
2010	19,923	458	251	19,213	305	1149	20,667	50.9
2011	19,324	476	284	18,564	120	642	19,325	53.1
2012	19,831	497	291	19,044	20	1016	20,080	54.6
2013	19,981	513	310	19,158	0	1022	20,180	55.8
2014	20,059	530	328	19,201	0	1025	20,226	55.5
2015	20,221	548	347	19,326	0	1032	20,358	55.3
2016	20,460	565	366	19,528	0	1043	20,571	55.1
2017	20,688	584	386	19,719	0	1053	20,772	55.1
2018	20,933	603	403	19,927	0	1065	20,991	55.1
2019	21,183	622	420	20,141	0	1076	21,217	55.0
2020	21,430	642	436	20,352	0	1088	21,439	54.8
2021	21,664	662	452	20,550	0	1099	21,649	54.9

December 31, 2011 Status

* Includes residential and commercial/industrial conservation.
** Load Factor is the ratio of total system average load to peak demand.
Note: Values shown may be affected due to rounding.

120234 Hearing Exhibits 00261

Schedule 3.3

History and Forecast of Annual Net Energy for Load - GWH
High Case

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
Year	Total	Residential Conservation	Comm./Ind. Conservation	Retail	Wholesale *	Utility Use & Losses	Net Energy for Load	Load ** Factor %
2002	18,422	361	137	17,925	502	935	19,362	58.9
2003	18,756	378	152	18,226	587	985	19,798	60.3
2004	18,999	394	168	18,437	589	945	19,971	65.6
2005	19,491	404	176	18,911	712	952	20,575	57.3
2006	19,625	412	188	19,025	700	1,000	20,725	57.2
2007	20,153	421	200	19,533	829	916	21,279	56.6
2008	19,632	430	212	18,990	752	909	20,650	57.3
2009	19,449	443	231	18,774	191	978	19,943	54.7
2010	19,923	458	251	19,213	305	1,149	20,667	50.9
2011	19,324	476	284	18,564	120	642	19,325	53.1
2012	19,964	497	291	19,177	20	1,021	20,218	54.7
2013	20,218	513	310	19,395	0	1,036	20,431	55.8
2014	20,397	530	328	19,539	0	1,042	20,581	55.5
2015	20,658	548	347	19,763	0	1,057	20,820	55.3
2016	20,999	565	366	20,067	0	1,073	21,140	55.1
2017	21,332	584	386	20,362	0	1,087	21,449	55.1
2018	21,684	603	403	20,678	0	1,106	21,784	55.1
2019	22,045	622	420	21,003	0	1,122	22,125	55.0
2020	22,406	642	436	21,328	0	1,140	22,468	54.8
2021	22,756	662	452	21,643	0	1,157	22,800	54.9

December 31, 2011 Status

* Includes residential and commercial/industrial conservation.
** Load Factor is the ratio of total system average load to peak demand.
Note: Values shown may be affected due to rounding.

Schedule 3.3

History and Forecast of Annual Net Energy for Load - GWH
Low Case

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
Year	Total	Residential Conservation	Comm./Ind. Conservation	Retail	Wholesale *	Utility Use & Losses	Net Energy for Load	Load ** Factor %
2002	18,422	361	137	17,925	502	935	19,362	58.9
2003	18,756	378	152	18,226	587	985	19,798	60.3
2004	18,999	394	168	18,437	589	945	19,971	65.6
2005	19,491	404	176	18,911	712	952	20,575	57.3
2006	19,625	412	188	19,025	700	1,000	20,725	57.2
2007	20,153	421	200	19,533	829	916	21,279	56.6
2008	19,632	430	212	18,990	752	909	20,650	57.3
2009	19,449	443	231	18,774	191	978	19,943	54.7
2010	19,923	458	251	19,213	305	1,149	20,667	50.9
2011	19,324	476	284	18,564	120	642	19,325	53.1
2012	19,729	497	291	18,942	20	1,010	19,972	54.6
2013	19,781	513	310	18,959	0	1,011	19,970	55.8
2014	19,761	530	328	18,903	0	1,007	19,910	55.4
2015	19,824	548	347	18,929	0	1,009	19,938	55.3
2016	19,962	565	366	19,030	0	1,016	20,046	55.0
2017	20,089	584	386	19,119	0	1,022	20,141	55.1
2018	20,230	603	403	19,224	0	1,026	20,250	55.0
2019	20,376	622	420	19,333	0	1,033	20,366	55.0
2020	20,517	642	436	19,439	0	1,039	20,478	54.8
2021	20,644	662	452	19,530	0	1,042	20,572	54.8

December 31, 2011 Status

* Includes residential and commercial/industrial conservation.
** Load Factor is the ratio of total system average load to peak demand.
Note: Values shown may be affected due to rounding.

120234 Hearing Exhibits 00263

Schedule 4
Base Case

Previous Year and 2-Year Forecast of Peak Demand and Net Energy for Load (NEL) by Month

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	2011 Actual		2012 Forecast		2013 Forecast	
Month	Peak Demand * MW	NEL ** GWH	Peak Demand * MW	NEL ** GWH	Peak Demand * MW	NEL ** GWH
January	3,912	1,485	4,172	1,518	4,112	1,519
February	3,036	1,274	3,470	1,332	3,456	1,332
March	2,722	1,385	3,141	1,444	3,126	1,449
April	3,448	1,568	3,372	1,481	3,251	1,488
May	3,600	1,762	3,816	1,776	3,700	1,783
June	3,918	1,897	4,020	1,902	3,905	1,913
July	3,796	1,941	4,132	1,996	4,018	2,008
August	3,960	2,024	4,135	2,056	4,023	2,069
September	3,645	1,821	3,953	1,895	3,840	1,908
October	3,082	1,473	3,684	1,711	3,569	1,723
November	2,833	1,328	3,216	1,455	3,151	1,465
December	2,470	1,367	3,350	1,515	3,285	1,524
TOTAL		19,325		20,080		20,180

December 31, 2011 Status

* Peak demand represents total retail and wholesale demand, excluding conservation impacts.
** Values shown may be affected due to rounding.

Schedule 4
High Case

Previous Year and 2-Year Forecast of Peak Demand and Net Energy for Load (NEL) by Month

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	2011 Actual		2012 Forecast		2013 Forecast	
Month	Peak Demand * MW	NEL ** GWH	Peak Demand * MW	NEL ** GWH	Peak Demand * MW	NEL ** GWH
January	3,912	1,485	4,197	1,525	4,161	1,535
February	3,036	1,274	3,492	1,340	3,498	1,348
March	2,722	1,385	3,162	1,453	3,165	1,466
April	3,448	1,568	3,394	1,490	3,292	1,506
May	3,600	1,762	3,842	1,788	3,747	1,805
June	3,918	1,897	4,048	1,916	3,956	1,937
July	3,796	1,941	4,161	2,010	4,070	2,034
August	3,960	2,024	4,165	2,071	4,075	2,096
September	3,645	1,821	3,982	1,909	3,890	1,932
October	3,082	1,473	3,711	1,724	3,616	1,746
November	2,833	1,328	3,240	1,466	3,192	1,483
December	2,470	1,367	3,376	1,526	3,328	1,543
TOTAL		19,325		20,218		20,431

December 31, 2011 Status

* Peak demand represents total retail and wholesale demand, excluding conservation impacts.
** Values shown may be affected due to rounding.

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Schedule 4
Low Case

Previous Year and 2-Year Forecast of Peak Demand and Net Energy for Load (NEL) by Month

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	2011 Actual		2012 Forecast		2013 Forecast	
Month	Peak Demand * MW	NEL ** GWH	Peak Demand * MW	NEL ** GWH	Peak Demand * MW	NEL ** GWH
January	3,912	1,485	4,153	1,512	4,072	1,506
February	3,036	1,274	3,452	1,325	3,420	1,319
March	2,722	1,385	3,125	1,437	3,094	1,434
April	3,448	1,568	3,355	1,473	3,217	1,473
May	3,600	1,762	3,796	1,766	3,661	1,765
June	3,918	1,897	3,999	1,892	3,864	1,892
July	3,796	1,941	4,110	1,984	3,975	1,986
August	3,960	2,024	4,112	2,044	3,979	2,046
September	3,645	1,821	3,931	1,884	3,798	1,887
October	3,082	1,473	3,664	1,701	3,530	1,705
November	2,833	1,328	3,198	1,447	3,117	1,449
December	2,470	1,367	3,331	1,507	3,249	1,508
TOTAL		19,325		19,973		19,970

December 31, 2011 Status

* Peak demand represents total retail and wholesale demand, excluding conservation impacts.
** Values shown may be affected due to rounding.

Schedule 5

History and Forecast of Fuel Requirements
Base Case Forecast Basis

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
	Fuel Requirements		Unit	Actual 2010	Actual 2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
(1)	Nuclear		Trillion BTU	0	0	0	0	0	0	0	0	0	0	0	0
(2)	Coal		1000 Ton	4,025	4,261	4,717	4,589	4,630	4,640	4,799	4,903	4,900	4,910	4,941	4,902
(3)	Residual	Total	1000 BBL	0	0	0	0	0	0	0	0	0	0	0	0
(4)		Steam	1000 BBL	0	0	0	0	0	0	0	0	0	0	0	0
(5)		CC	1000 BBL	0	0	0	0	0	0	0	0	0	0	0	0
(6)		CT	1000 BBL	0	0	0	0	0	0	0	0	0	0	0	0
(7)		Diesel	(A) 1000 BBL	0	0	0	0	0	0	0	0	0	0	0	0
(8)	Distillate	Total	1000 BBL	82	26	49	56	57	55	57	55	52	55	55	53
(9)		Steam	1000 BBL	0	0	0	0	0	0	0	0	0	0	0	0
(10)		CC	1000 BBL	59	26	49	55	55	52	55	55	52	55	55	52
(11)		CT	1000 BBL	23	0	0	1	2	3	2	0	0	0	0	1
(12)		Diesel	1000 BBL	0	0	0	0	0	0	0	0	0	0	0	0
(13)	Natural Gas	Total	1000 MCF	61,924	55,515	54,996	59,448	59,058	60,136	58,898	56,272	58,246	59,352	60,408	63,044
(14)		Steam	1000 MCF	0	0	0	0	0	0	0	0	0	0	0	0
(15)		CC	1000 MCF	57,625	49,542	52,952	56,489	55,650	56,142	54,778	56,259	58,094	59,225	60,099	62,459
(16)		CT	1000 MCF	4,299	5,973	2,044	2,959	3,408	3,995	4,120	13	152	127	309	585
(17)	Other (Specify)														
(18)	Petroleum Coke		1000 Ton	481	439	297	324	325	310	323	325	309	325	327	311

(A) Data reported as diesel for Phillips Units 1 and 2.
Notes: Values shown may be affected due to rounding.
All values exclude ignition.

Schedule 6.1

History and Forecast of Net Energy for Load by Fuel Source in GWH
Base Case Forecast Basis

(1)	(2)	(3)		(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
	Energy Sources			Unit	Actual 2010	Actual 2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
(1)	Annual Firm Interchange			GWh	864	461	334	99	120	147	212	2	5	0	0	0
(2)	Nuclear			GWh	0	0	0	0	0	0	0	0	0	0	0	0
(3)	Coal			GWh	9,267	9,657	10,933	10,647	10,745	10,761	11,119	11,397	11,386	11,401	11,460	11,396
(4)	Residual	Total		GWh	0	0	0	0	0	0	0	0	0	0	0	0
(5)		Steam		GWh	0	0	0	0	0	0	0	0	0	0	0	0
(6)		CC		GWh	0	0	0	0	0	0	0	0	0	0	0	0
(7)		CT		GWh	0	0	0	0	0	0	0	0	0	0	0	0
(8)		Diesel	(A)	GWh	0	0	0	0	0	0	0	0	0	0	0	0
(9)	Distillate	Total		GWh	49	13	28	32	32	31	32	31	30	31	31	30
(10)		Steam		GWh	0	0	0	0	0	0	0	0	0	0	0	0
(11)		CC		GWh	38	13	28	31	31	30	31	31	30	31	31	30
(12)		CT		GWh	12	0	0	1	1	1	1	0	0	0	0	0
(13)		Diesel		GWh	0	0	0	0	0	0	0	0	0	0	0	0
(14)	Natural Gas	Total		GWh	8,375	7,392	7,456	8,014	7,942	8,075	7,904	8,033	8,304	8,477	8,630	8,949
(15)		Steam		GWh	0	0	0	0	0	0	0	0	0	0	0	0
(16)		CC		GWh	8,004	6,860	7,275	7,754	7,642	7,723	7,540	8,032	8,290	8,466	8,603	8,897
(17)		CT		GWh	371	532	181	260	300	352	364	1	14	11	27	52
(18)	Other (Specify)															
(19)	Petroleum Coke Generation			GWh	1,346	1,231	812	888	895	854	884	893	848	894	899	854
(20)	Net Interchange			GWh	235	177	292	307	308	307	309	305	306	303	308	309
(21)	Purchased Energy from															
(22)	Non-Utility Generators		(B)	GWh	530	393	225	194	184	183	112	111	111	111	112	111
(23)	Net Energy for Load			GWh	20,667	19,325	20,080	20,180	20,226	20,358	20,571	20,772	20,991	21,217	21,439	21,649

(A) Data reported as diesel for Phillips Units 1 and 2.
(B) Line (22) includes energy purchased from Non-Renewable and Renewable resources.
Notes: Values shown may be affected due to rounding.

Schedule 6.2

History and Forecast of Net Energy for Load by Fuel Source as a Percent
Base Case Forecast Basis

(1)	(2)	(3)		(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
	Energy Sources			Unit	Actual 2010	Actual 2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
(1)	Annual Firm Interchange			%	4.2	2.4	1.7	0.5	0.6	0.7	1.0	0.0	0.0	0.0	0.0	0.0
(2)	Nuclear			%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(3)	Coal			%	44.8	50.0	54.4	52.8	53.1	52.9	54.1	54.9	54.2	53.7	53.5	52.6
(4)	Residual	Total		%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(5)		Steam		%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(6)		CC		%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(7)		CT		%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(8)		Diesel	(A)	%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(9)	Distillate	Total		%	0.2	0.1	0.1	0.2	0.2	0.2	0.2	0.1	0.1	0.1	0.1	0.1
(10)		Steam		%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(11)		CC		%	0.2	0.1	0.1	0.2	0.2	0.1	0.2	0.1	0.1	0.1	0.1	0.1
(12)		CT		%	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(13)		Diesel		%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(14)	Natural Gas	Total		%	40.5	38.3	37.1	39.7	39.3	39.7	38.4	38.7	39.6	40.0	40.3	41.3
(15)		Steam		%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(16)		CC		%	38.7	35.5	36.2	38.4	37.8	37.9	36.7	38.7	39.5	39.9	40.1	41.1
(17)		CT		%	1.8	2.8	0.9	1.3	1.5	1.7	1.8	0.0	0.1	0.1	0.1	0.2
(18)	Other (Specify)															
(19)	Petroleum Coke Generation			%	6.5	6.4	4.0	4.4	4.4	4.2	4.3	4.3	4.0	4.2	4.2	3.9
(20)	Net Interchange			%	1.1	0.9	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.4	1.4	1.4
(21)	Purchased Energy from															
(22)	Non-Utility Generators		(B)	%	2.6	2.0	1.1	1.0	0.9	0.9	0.5	0.5	0.5	0.5	0.5	0.5
(23)	Net Energy for Load			%	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0

(A) Data reported as diesel for Phillips Units 1 and 2.
(B) Line (22) includes energy purchased from Non-Renewable and Renewable resources.
Notes: Values shown may be affected due to rounding.

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Chapter III

The Customer, Demand and Energy Forecasts are the foundation from which the integrated resource plan is developed. Recognizing its importance, Tampa Electric employs the necessary methodologies for carrying out this function. The primary objective of this procedure is to blend proven statistical techniques with practical forecasting experience to provide a projection, which represents the highest probability of occurrence.

This chapter is devoted to describing Tampa Electric's forecasting methods and the major assumptions utilized in developing the 2012-2021 forecasts. The data tables in Chapter II outline the expected customer, demand, and energy values for the 2012-2021 time period.

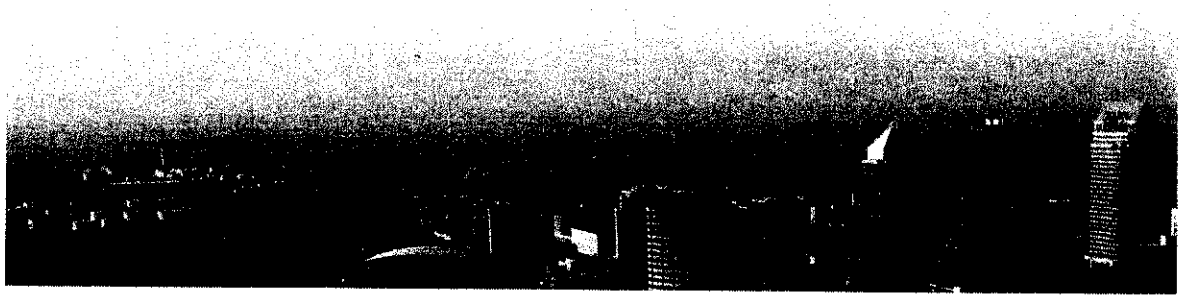
RETAIL LOAD

MetrixND, an advanced statistics program for analysis and forecasting, was used to develop the 2012-2021 Customer, Demand and Energy forecasts. This software allows a platform for the development of more dynamic and fully integrated models.

In addition, Tampa Electric uses MetrixLT, which integrates with MetrixND to develop multiple-year forecasts of energy usage at the hourly level. This tool allows the annual or monthly forecasts in MetrixND to be combined with hourly load shape data to develop a long-term "bottom-up" forecast, which is consistent with short-term statistical forecasts.

Tampa Electric's retail customer, demand and energy forecasts are the result of six separate forecasting analyses:

1. Economic Analysis;
2. Customer Multiregression Model;
3. Energy Multiregression Model;
4. Peak Demand Multiregression Model;
5. Phosphate Demand and Energy Analysis;
6. Conservation, Load Management and Cogeneration Programs.



The MetrixND models are the company's most sophisticated and primary load forecasting models. The phosphate demand and energy is forecasted separately and then combined in the final 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.

1. ECONOMIC ANALYSIS

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).

See the "Base Case Forecast Assumptions" section of this chapter for an explanation of the most significant economic inputs to the MetrixND models.

2. CUSTOMER MULTIREGRESSION MODEL

The customer multiregression forecasting model is a seven-equation model. The equations forecast the number of customers by seven major categories. The primary economic drivers in the customer forecast models are Hillsborough County population estimates, service area households and Hillsborough County employment growth.

1. *Residential Customer Model:* Customer projections are a function of Hillsborough County's population. Since a strong correlation exists between historical changes in service area customers and historical changes in Hillsborough County, the County's population estimates for 2012-2021 were used to forecast the future growth patterns in residential customers.
2. *Commercial Customer Model:* Total commercial customers include commercial customers plus temporary service customers (temporary poles on construction sites); therefore, two models are used to forecast total commercial customers
   a. 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.
   b. 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 customers as a function of construction employment.
3. *Industrial Customer Model (Non-Phosphate):* Non-phosphate industrial customers include two rate classes that have been modeled individually: General Service and General Service Demand.
   a. The General Service Customer Model is a function of Hillsborough County commercial employment.

   b. The General Service Demand Customer Model is based on the recent growth trend in

the sector.

4. *Public Authority Customer Model:* Customer projections are a function of Hillsborough County's population. The need for public services will depend on the number of people in the region; therefore, consistent with the residential customer model, Hillsborough's population projections are used to determine future growth in the public authorities sector.
5. *Street & Highway Lighting Customer Model:* Customer projections are based on the recent growth trend in the sector.

3. ENERGY MULTIREGRESSION MODEL

There are a total of seven 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 time frame, as do econometric regression models.

1. *Residential Energy Model:* The residential forecast model is made up of three major components: (1) end-use equipment index variables, which capture the long-term net effect of equipment saturation and equipment efficiency improvements; (2) changes in the economy such as household income, household size, and the price of electricity; and, (3) weather variables, which serve to allocate the seasonal impacts of weather throughout the year. The SAE model framework begins by defining energy use for an average customer in year (y) and month (m) as the sum of energy used by heating equipment (XHeat y,m), cooling equipment (XCool y,m), and other equipment (XOther y,m). The XHeat, XCool, and XOther variables are defined as a product of an annual equipment index and a monthly usage multiplier.

$$\text{Average Usage}_{y,m} = (\text{XHeat}_{y,m} + \text{XCool}_{y,m} + \text{XOther}_{y,m})$$

Where:

$$\text{XHeat}_{y,m} = \text{HeatEquipIndex}_{y} \times \text{HeatUse}_{y,m}$$
$$\text{XCool}_{y,m} = \text{CoolEquipIndex}_{y} \times \text{CoolUse}_{y,m}$$
$$\text{XOtherUse}_{y,m} = \text{OtherEquipIndex}_{y} \times \text{OtherUse}_{y,m}$$

The annual equipment variables (HeatEquipIndex, CoolEquipIndex, OtherEquipIndex) are defined as a weighted average across equipment types multiplied by equipment saturation levels normalized by operating efficiency levels. Given a set of fixed weights, the index will change over time with changes in equipment saturations and operating efficiencies. The

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weights are defined by the estimated energy use per household for each equipment type in the base year.

Where:

$$\textbf{HeatEquipIndex} = \sum_{Tech.} \text{Weight} \times \left(\frac{\text{Saturation}_{y} \,/\, \text{Efficiency}_{y}}{\text{Saturation}_{\text{base y}} \,/\, \text{Efficiency}_{\text{base y}}} \right)$$

$$\textbf{CoolEquipIndex} = \sum_{Tech.} \text{Weight} \times \left(\frac{\text{Saturation}_{y} \,/\, \text{Efficiency}_{y}}{\text{Saturation}_{\text{base y}} \,/\, \text{Efficiency}_{\text{base y}}} \right)$$

$$\textbf{OtherEquipIndex} = \sum_{Tech.} \text{Weight} \times \left(\frac{\text{Saturation}_{y} \,/\, \text{Efficiency}_{y}}{\text{Saturation}_{\text{base y}} \,/\, \text{Efficiency}_{\text{base y}}} \right)$$

Next, the monthly usage multiplier or utilization variables (HeatUse, CoolUse, OtherUse) are defined using economic and weather variables. A customer's monthly usage level is impacted by several factors, including weather, household size, income levels, electricity prices and the number of days in the billing cycle. The degree day variables serve to allocate the seasonal impacts of weather throughout the year, while the remaining variables serve to capture changes in the economy.

$$\textbf{HeatUse}_{y,m} = \left(\frac{\text{Price}_{y,m}}{\text{Price}_{\text{base y, m}}} \right)^{-.10} \times \left(\frac{\text{HH Income}_{y,m}}{\text{HH Income}_{\text{base y, m}}} \right)^{.10} \times \left(\frac{\text{HH Size}_{y,m}}{\text{HH Size}_{\text{base y, m}}} \right)^{.05} \times \left(\frac{\text{HDD}_{y,m}}{\text{Normal HDD}} \right)$$

$$\textbf{CoolUse}_{y,m} = \left(\frac{\text{Price}_{y,m}}{\text{Price}_{\text{base y, m}}} \right)^{-.10} \times \left(\frac{\text{HH Income}_{y,m}}{\text{HH Income}_{\text{base y, m}}} \right)^{.10} \times \left(\frac{\text{HH Size}_{y,m}}{\text{HH Size}_{\text{base y, m}}} \right)^{.05} \times \left(\frac{\text{CDD}_{y,m}}{\text{Normal CDD}} \right)$$

$$\textbf{OtherUse}_{y,m} = \left(\frac{\text{Price}_{y,m}}{\text{Price}_{\text{base y, m}}} \right)^{-.10} \times \left(\frac{\text{HH Income}_{y,m}}{\text{HH Income}_{\text{base y, m}}} \right)^{.10} \times \left(\frac{\text{HH Size}_{y,m}}{\text{HH Size}_{\text{base y, m}}} \right)^{.05} \times \left(\frac{\text{Billing Days}_{y,m}}{\text{Billing Days}_{\text{base y, m}}} \right)$$

The SAE approach to modeling provides a powerful framework for developing short-term and long-term energy forecasts. This approach reflects changes in equipment saturation and efficiency levels and gives estimates of weather sensitivities that vary over time as well as estimate trend adjustments.

2. *Commercial Energy Models:* total commercial energy sales include commercial sales plus temporary service sales (temporary poles on construction sites); therefore, two models are used to forecast total commercial energy sales.
   a. 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

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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.

b. Temporary Service Energy Model: This 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 driver being temporary service customer growth.

3. *Industrial Energy Model (Non-Phosphate):* Nonphosphate industrial energy includes two rate classes that have been modeled individually: General Service and General Service Demand.
   a. The General Service Energy Model utilizes the same SAE model framework as the commercial energy model. The weather component is consistent with the residential and commercial models.
   b. The General Service Demand Energy Model is based on industrial employment, the price of electricity in the industrial sector, cooling degree-days and number of days billed. Unlike the previous models discussed, heating load does not impact this sector.

4. *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.

5. *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 and 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 five energy models described above, plus an exogenous interruptible and phosphate forecast, are added together to arrive at the total retail energy sales forecast.

In summary, the SAE approach to modeling provides a powerful framework for developing short-term and long-term energy forecasts. This approach reflects changes in equipment saturation and efficiency levels, gives estimates of weather sensitivity that varies over time, as well as estimates trend adjustments.

4. PEAK DEMAND MULTIREGRESSION MODEL

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. To stabilize the peak demand data series and improve model accuracy, the volatility of the phosphate load is removed. To further stabilize the data, the peak demand models project on a per customer basis.

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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.

5. PHOSPHATE DEMAND AND ENERGY ANALYSIS

Tampa Electric's phosphate customers are relatively few in number, which has allowed the company's Commercial/Industrial Customer Service Department to obtain detailed knowledge of industry developments including:

1. knowledge of expansion and close-out plans;
2. familiarity with historical and projected trends;
3. personal contact with industry personnel;
4. governmental legislation;
5. familiarity with worldwide demand for phosphate products.

This department's familiarity with industry dynamics and their close working relationship with phosphate company representatives were used to form the basis for a survey of the phosphate customers to determine their future energy and demand requirements. This survey is the foundation upon which the phosphate forecast is based. Further inputs are provided by individual customer trend analysis and discussions with industry experts.

6. CONSERVATION, LOAD MANAGEMENT AND COGENERATION PROGRAMS

Conservation and Load Management demand and energy savings are forecasted for each individual program. The savings is based on a forecast of the annual number of new participants, estimated annual average energy savings per participant and estimated summer and winter average demand savings per participant. The individual forecasts are aggregated and represent the cumulative amount of Demand Side Management (DSM) savings throughout the forecast horizon.

Tampa Electric's retail demand and energy forecasts are adjusted downward to reflect the incremental demand and energy savings of these DSM programs.

Tampa Electric has developed conservation, load management and cogeneration programs to achieve five major objectives:

1. Defer expansion, particularly production plant construction
2. Reduce marginal fuel cost by managing energy usage during higher fuel cost periods
3. Provide customers with some ability to control energy usage and decrease energy costs
4. Pursue the cost-effective accomplishment of the Florida Public Service Commission (FPSC) ten-year demand and energy goals for the residential and commercial/industrial

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sectors

5. Achieve the comprehensive energy policy objectives as required by the Florida Energy Efficiency Conservation Act

The company's current energy efficiency and conservation plan contains a mix of proven, mature programs along with several newly developed programs that focus on the market place demand for their specific offerings. The following is a list that briefly describes the company's programs:

1. Heating and Cooling - Encourages the installation of high-efficiency residential heating and cooling equipment.

2. Load Management – Encourages residential, commercial and industrial programs to reduce weather-sensitive heating, cooling and water heating through a radio signal control mechanism. However, the residential program is closed to new participation.

3. Energy Audits - a "how to" information and analysis guide for customers. Six types of audits are available to Tampa Electric customers; four types are for residential class customers and two types are for commercial/industrial customers.

4. Residential Building Envelope - An incentive program for existing residential structures which will help to supplement the cost of adding additional ceiling and wall insulation, window film and window upgrades.

5. Commercial Lighting - Encourages investment in more efficient lighting technologies within existing commercial facilities.

6. Standby Generator - A program designed to utilize the emergency generation capacity of commercial/industrial facilities in order to reduce weather sensitive peak demand.

7. Conservation Value - Encourages investments in measures that are not sanctioned by other commercial programs.

8. Residential Duct Repair - An incentive program for existing homeowners which will help to supplement the cost of repairing leaky ductwork of central air-conditioning systems.

9. Cogeneration - A program whereby large industrial customers with waste heat or fuel resources may install electric generating equipment, meet their own electrical requirements and/or sell their surplus to the company.

10. Commercial Cooling - Encourages the installation of high efficiency direct expansion commercial and packaged terminal air conditioning cooling equipment.

11. Commercial Chillers - Encourages the installation of high efficiency chiller equipment.

12. Energy Plus Homes - Encourages the construction of residential dwellings at efficiency

levels greater than current Florida building code baseline practices.

13. Low Income Weatherization - Provides for the installation of energy efficient measures for qualified low-income customers.

14. Energy Planner - Reduces weather-sensitive loads through an innovative rate used to encourage residential customers to make behavioral or equipment usages changes by pre-programming HVAC, water heating and pool pumps.

15. Commercial Duct Repair - An incentive program for existing commercial customers which will help to supplement the cost of repairing leaky ductwork of central air-conditioning systems.

16. Commercial Building Envelope - An incentive program for existing commercial structures which will help to supplement the cost of adding additional ceiling and wall insulation and window film.

17. Energy Efficient Motors - Encourages the installation of high-efficiency motors.

18. Commercial Lighting Occupancy Sensors – Encourages the installation of occupancy sensors for load control in commercial facilities.

19. Commercial Refrigeration (Anti-condensate) – A program to encourage the installation of anti-condensate equipment sensors for load control in commercial facilities.

20. Commercial Water Heating - Encourages the installation of high efficiency water heating systems.

21. Commercial Demand Response - A turn-key program to incent commercial/industrial customers to reduce their demand for electricity in response to market signals.

22. Residential Electronically Commutated Motor - An incentive program designed to help residential customers improve the overall efficiency of their existing HVAC equipment by replacing the existing motor in the air-handler with an Electronically Commutated Motor.

23. Residential HVAC Re-commissioning - An incentive program designed to help residential customers ensure HVAC equipment is operating at optimal efficiency through maintenance and equipment tune-up.

24. Energy Education Outreach - A program designed to establish opportunities for engaging groups of customers and students, in energy-efficiency related discussions in an organized setting. Participants will be provided with energy saving devices and supporting information appropriate for the audience.

25. Commercial Electronically Commutated Motor - An incentive program designed to help commercial customers improve the overall efficiency of their existing HVAC equipment

by replacing the existing HVAC motors with an Electronically Commutated Motor.

26. Commercial HVAC Re-commissioning - An incentive program designed to help commercial customers ensure HVAC equipment is operating at optimal efficiency through maintenance and equipment tune-up.

27. Cool Roof - An incentive program designed to encourage commercial/industrial customers to install a cool roof system above conditioned spaces.

28. Energy Recovery Ventilation - An incentive program designed to help commercial/industrial customers reduce humidity and HVAC loads in buildings.

The programs listed above were developed to meet the FPSC demand and energy goals established in Docket No. 080409-EG, approved on December 30, 2009. The 2011 demand and energy savings achieved by conservation and load management programs are listed in Table III-1.

Tampa Electric developed a Monitoring and Evaluation (M&E) plan in response to requirements filed in Docket No. 941173-EG. The M&E plan was designed to effectively accomplish the required objective with prudent application of resources.

The M&E plan has its focus on two distinct areas: process evaluation and impact evaluation. Process evaluation examines how well a program has been implemented including the efficiency of delivery and customer satisfaction regarding the usefulness and quality of the services delivered. Impact evaluation is an evaluation of the change in demand and energy consumption achieved through program participation. The results of these evaluations give Tampa Electric insight into the direction that should be taken to refine delivery processes, program standards, and overall program cost-effectiveness.

WHOLESALE LOAD

Tampa Electric's firm long-term wholesale sales consist of a contract with the city of St. Cloud. Sales for a given year are based on the specific terms of their contract with Tampa Electric.

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TABLE III-1
Comparison of Achieved MW and GWh Reductions With Florida Public Service Commission Goals
Savings at the Generator

Residential

	Winter Peak MW Reduction			Summer Peak MW Reduction			GWh Energy Reduction		
Year	Total Achieved	Commission Approved Goal	% Variance	Total Achieved	Commission Approved Goal	% Variance	Total Achieved	Commission Approved Goal	% Variance
2010	11.3	6.4	176.6%	8.1	4.6	176.1%	17.3	9.8	176.5%
2011	21.5	14.9	144.3%	16.7	11.2	149.1%	36.5	23.8	153.4%

Commercial/Industrial

	Winter Peak MW Reduction			Summer Peak MW Reduction			GWh Energy Reduction		
Year	Total Achieved	Commission Approved Goal	% Variance	Total Achieved	Commission Approved Goal	% Variance	Total Achieved	Commission Approved Goal	% Variance
2010	7.2	0.9	800.0%	11.1	2.5	444.0%	18.3	6.5	281.5%
2011	19.0	2.0	950.0%	26.4	6.1	432.8%	51.3	17.1	300.0%

Combined Total

	Winter Peak MW Reduction			Summer Peak MW Reduction			GWh Energy Reduction		
Year	Total Achieved	Commission Approved Goal	% Variance	Total Achieved	Commission Approved Goal	% Variance	Total Achieved	Commission Approved Goal	% Variance
2010	18.5	7.3	253.4%	19.2	7.1	270.4%	35.6	16.3	218.4%
2011	59.0	24.2	243.8%	62.3	24.4	255.3%	123.4	57.2	215.7%

BASE CASE FORECAST ASSUMPTIONS

RETAIL LOAD

Numerous assumptions are inputs to the MetrixND models, of which the more significant ones are listed below.

1. Population and Households
2. Commercial, Industrial and Governmental Employment
3. Commercial, Industrial and Governmental Output
4. Real Household Income
5. Price of Electricity
6. Appliance Efficiency Standards
7. Weather

1. POPULATION AND HOUSEHOLDS

Florida and Hillsborough County population forecasts are the starting point for developing the customer and energy projections. Both the University of Florida's Bureau of Economic and Business Research (BEBR) and economy.com supply population projections for Hillsborough County and Florida. The population forecast is based upon a blend of BEBR and economy.com projections. Over the next ten years (2012-2021) the average annual population growth rate in Hillsborough County is expected to be 1.4%. In addition, economy.com provides household data as an input to the residential average use model.

2. COMMERCIAL, INDUSTRIAL AND GOVERNMENTAL EMPLOYMENT

Commercial and industrial employment assumptions are utilized in computing the number of customers in their respective sectors. It is imperative that employment growth be consistent with the expected population expansion and unemployment levels. Over the next ten years, employment is assumed to rise at a 2.0% average annual rate. economy.com supplies employment projections.

3. 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 in their respective sectors. Over the next ten years, output for the entire employment sector is assumed to rise at a 3.4% average annual rate. Economy.com supplies output projections.

4. REAL HOUSEHOLD INCOME

Economy.com supplies the assumptions for Hillsborough County's real household income growth. During 2012-2021, real household income for Hillsborough County is

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expected to increase at a 2.9% average annual rate.

5. PRICE OF ELECTRICITY

Forecasts for the price of electricity by customer class are supplied by Tampa Electric's Regulatory Affairs Department.

6. 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 (room heating and furnaces) are replaced with more efficient technologies (heat pumps). Similarly, cooling equipment saturation will continue to increase, but be offset by heat pump and 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 in households throughout the forecast period.

7. WEATHER

Since weather is the most difficult input to project, historical data is the major determinant in developing temperature profiles. For example, 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 plus the temperatures on peak days for the past twenty years.

HIGH AND LOW SCENARIO FOCUS ASSUMPTIONS

The base case scenario is tested for sensitivity to varying economic conditions and customer growth rates. The high and low peak demand and energy scenarios represent alternatives to the company's base case outlook. Compared to the base case, the expected economic growth rates are 0.5% higher in the high scenario and 0.5% lower in the low scenario.

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HISTORY AND FORECAST OF ENERGY USE

A history and forecast of energy consumption by customer classification are shown in Schedules 2.1 - 2.3.

1. RETAIL ENERGY

For 2012-2021, retail energy sales are projected to rise at a 0.8% annual rate. The major contributor to growth is the residential category, increasing at an annual rate of 1.1%.

2. WHOLESALE ENERGY

Wholesale energy sales to St. Cloud are expected to be 20 GWH in 2012 decline to zero in 2013.

HISTORY AND FORECAST OF PEAK LOADS

Historical, base, high and low scenario forecasts of peak loads for the summer and winter seasons are presented in Schedules 3.1 and 3.2, respectively. For the 2012-2021 period, Tampa Electric's base retail firm peak demand is expected to advance in the winter at an average annual rate of 1.2% and at rate of 1.0% in the summer.

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Chapter IV

The proposed generating facility additions and changes shown in Schedule 8.1 integrate energy efficiency and conservation programs and generating resources to provide economical, reliable service to Tampa Electric's customers. Various energy resource plan alternatives, comprised of a mixture of generating technologies, purchased power, and cost-effective energy efficiency and conservation programs, are developed to determine this plan. These alternatives are combined with existing supply resources and analyzed to determine the energy resource option which best meets Tampa Electric's future system demand and energy requirements. A detailed discussion of Tampa Electric's integrated resource planning process is included in Chapter V.

The results of the integrated resource planning process provide Tampa Electric with a cost-effective plan that maintains system reliability and environmental requirements while considering technology availability and lead times for construction. To meet the expected system demand and energy requirements over the next ten years peaking and intermediate resources are needed. The peaking capacity need will be met by purchase power agreements for peaking capacity secured through 2016. In 2017, Tampa Electric currently expects to meet its intermediate load needs by converting Polk Power Station's simple cycle combustion turbines (Polk Units 2 - 5) to a natural gas combined cycle (NGCC) unit. The operating and cost parameters associated with the capacity additions resulting from the analysis are shown in Schedule 9. Beyond 2017, the company foresees the future needs being that of additional peaking capacity, which it will meet by combustion turbine additions and/or future purchase power agreements.

Tampa Electric will compare viable purchase power options as an alternative and/or enhancement to planned unit additions. At a minimum, the purchase power must have firm transmission service and firm fuel transportation to support firm reserve margin criteria for reliability. Assumptions and information that impact the plan are discussed in the following sections and in Chapter V.

COGENERATION

Tampa Electric plans for a total of 23 MW of firm cogeneration capacity, of which all 23 MW (through December 2015) are imported from outside its service area. In 2012 Tampa Electric plans for 476 MW of cogeneration capacity operating in its service area.

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Cogeneration in Service Area	Capacity (MW)
Self-service	268
Firm to Tampa Electric	23
As-available to Tampa Electric	19
Export to other systems	189
Total	499

Self-service is the capacity and energy cogenerators use to serve their internal load requirements.

FUEL REQUIREMENTS

A forecast of fuel requirements and energy sources is shown in Schedule 5, Schedule 6.1 and Schedule 6.2. Tampa Electric currently uses a generation portfolio consisting of coal and natural gas for its generating requirements. Tampa Electric has firm transportation contracts with the Florida Gas Transmission Company (FGT) and Gulfstream Natural Gas System LLC for delivery of natural gas to the Big Bend Aero, Bayside, and Polk Units. As shown in Schedule 6.2, in 2012 coal and petcoke will fuel 58% of net energy for load and natural gas will fuel 37%. Less than one percent of net energy for load will be fueled by oil. The remaining net energy for load is served by non-utility generators and net interchange purchases. Some on the company's natural gas generating units also have dual-fuel (i.e., natural gas or oil) capability, which adds to system reliability.

ENVIRONMENTAL CONSIDERATIONS

Tampa Electric has always strived to reduce emissions from its generating facilities. Since 1998, Tampa Electric has reduced annual sulfur dioxides (SO_2) by 94%, nitrogen oxides (NOx) by 91%, particulate matter (PM) by 87% and mercury emissions by 85%. These reductions were the result of a December 1999 agreement between the Florida Department of Environmental Protection (DEP) and Tampa Electric. In February 2000, Tampa Electric reached a similar agreement with the U.S. Environmental Protection Agency (EPA) in a Consent Decree (CD).

Tampa Electric's major activities to increase pollution control and decrease emissions include:

- integration of Big Bend Unit 3 into Big Bend Unit 4's existing scrubber in 1995
- installation of flue gas desulfurization (scrubber) systems on Big Bend Units 1 and 2 in 1999
- installation and operation of selective catalytic reduction systems, combustion tuning and optimization projects at Big Bend Station from 2007 to 2010
- repowering of Gannon Station to H.L. Culbreath Bayside Power Station from coal to natural gas optimization from 2003 to 2004
- improvement of the Big Bend electrostatic precipitators

In November 2011, the Chicago Climate Exchange (CCX) applauded Tampa Electric for the

successful completion of the program's Phase II greenhouse gas commitment of a 6% carbon dioxide (CO2) reduction. With an actual reduction of more than 13% in 2010, the company far surpassed the CCX target.

Through a proactive approach, Tampa Electric has achieved significant levels of emission reduction. However, the company recognizes that environmental regulations continue to change. As these regulations evolve, they will impact both cost and operations.

INTERCHANGE SALES AND PURCHASES

Tampa Electric has the following long-term firm sale agreements:

- 15 MW to the City of St. Cloud through December 2012
- 75 MW winter and 125 MW summer to Florida Power & Light through December 2012

Tampa Electric has the following long-term purchase power contracts for capacity and energy:

- 441 MW winter and 356 MW summer from the Hardee Power Station through December 2012
- 117 MW from Calpine Energy Services for the period November 2011 through December 2016
- 158 MW from RRI Energy (previously Reliant Energy Services) through May 2012
- 160 MW from Southern Power Company for the period January 2013 through December 2015 (Tampa Electric has an option to extend this agreement and will compare it to the unspecified purchase power of 160 MW noted in Schedules 7.1 and 7.2 for the period January 2016 through December 2016)
- 121 MW from Pasco Cogen for the period January 2009 through December 2018

The wholesale power sales and purchases are included in Schedules 3.1, 3.2, 3.3, 4, 5, 6.1, 7.1, and 7.2.

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Schedule 7.1

Forecast of Capacity, Demand, and Scheduled Maintenance at Time of Summer Peak

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
Year	Total Installed Capacity MW	Firm Capacity Import MW	Firm Capacity Export MW	QF MW	Total Capacity Available MW	System Firm Summer Peak Demand MW	Reserve Margin Before Maintenance MW	Reserve Margin Before Maintenance % of Peak	Scheduled Maintenance MW	Reserve Margin After Maintenance MW	Reserve Margin After Maintenance % of Peak
2012	4,292	594	0	23	4,909	3,890	1,019	26%	0	1,019	26%
2013	4,312	398	0	23	4,733	3,784	949	25%	0	949	25%
2014	4,312	398	0	23	4,733	3,823	910	24%	0	910	24%
2015	4,312	398	0	23	4,733	3,859	874	23%	0	874	23%
2016	4,312	398	0	0	4,710	3,900	810	21%	0	810	21%
2017	4,771	121	0	0	4,892	3,940	952	24%	0	952	24%
2018	4,771	121	0	0	4,892	3,980	912	23%	0	912	23%
2019	4,920	0	0	0	4,920	4,022	898	22%	0	898	22%
2020	4,920	0	0	0	4,920	4,064	856	21%	0	856	21%
2021	4,920	0	0	0	4,920	4,103	817	20%	0	817	20%

NOTE:
1. Capacity import includes firm purchase power agreements (PPA) with Invenergy of 356 MW through 2012, Calpine of 117 MW through 2016, Reliant of 158 MW through May 2012, Southern of 160 MW through 2015, STC of 15 MW through 2012, Pasco Cogen of 121 MW through 2018, and an unspecified 160 MW in 2016.
2. The QF column accounts for cogeneration that will be purchased under firm contracts, and excludes non-firm purchases.

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Schedule 7.2

Forecast of Capacity, Demand, and Scheduled Maintenance at Time of Winter Peak

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
	Total Installed Capacity	Firm Capacity Import	Firm Capacity Export	QF	Total Capacity Available	System Firm Winter Peak Demand	Reserve Margin Before Maintenance		Scheduled Maintenance	Reserve Margin After Maintenance	
Year	MW	MW	MW	MW	MW	MW	MW	% of Peak	MW	MW	% of Peak
2011-12	4,684	837	0	23	5,544	3,868	1,676	43%	0	1,676	43%
2012-13	4,684	398	0	23	5,105	3,819	1,286	34%	0	1,286	34%
2013-14	4,714	398	0	23	5,135	3,864	1,271	33%	0	1,271	33%
2014-15	4,714	398	0	23	5,135	3,910	1,225	31%	0	1,225	31%
2015-16	4,714	398	0	0	5,112	3,955	1,157	29%	0	1,157	29%
2016-17	5,177	121	0	0	5,298	4,003	1,295	32%	0	1,295	32%
2017-18	5,177	121	0	0	5,298	4,050	1,248	31%	0	1,248	31%
2018-19	5,177	0	0	0	5,177	4,097	1,080	26%	0	1,080	26%
2019-20	5,354	0	0	0	5,354	4,146	1,208	29%	0	1,208	29%
2020-21	5,354	0	0	0	5,354	4,194	1,160	28%	0	1,160	28%

NOTE:
1. Capacity import includes firm purchase power agreements (PPA) with Invenergy of 356 MW through 2012, Calpine of 117 MW through 2016, Reliant of 158 MW through May 2012, Southern of 160 MW through 2015, STC of 15 MW through 2012, Pasco Cogen of 121 MW through 2018, and an unspecified 160 MW in 2016.
2. The QF column accounts for cogeneration that will be purchased under firm contracts, and excludes non-firm purchases.

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Schedule 8.1

Planned and Prospective Generating Facility Additions

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
Plant Name	Unit No.	Location	Unit Type	Fuel Primary	Fuel Alternate	Fuel Trans. Primary	Fuel Trans. Alternate	Const. Start Mo/Yr	Commercial In-Service Mo/Yr	Expected Retirement Mo/Yr	Gen. Max. Nameplate kW	Net Capability Summer MW	Net Capability Winter MW	Status
Polk 2-5 CC	1	Polk	CC	NG	N/A	PL	N/A	10/14	1/17	unknown	unknown	1063*	1195*	P
Future CT	1	unknown	CT	NG	N/A	PL	N/A	9/18	5/19	unknown	unknown	149	177	P

Notes:
* Net capability values shown for the Polk 2-5 CC reflect the conversion of Polk Units 2-5 CTs to a natural gas CC unit in 2017. Incremental capacity gain from the conversion is 459 MW summer and 463 MW winter.

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SCHEDULE 9
(Page 1 of 2)
STATUS REPORT AND SPECIFICATIONS OF PROPOSED GENERATING FACILITIES
UTILITY: TAMPA ELECTRIC COMPANY

(1)	PLANT NAME AND UNIT NUMBER	POLK 2-5 CC CONVERSION
(2)	CAPACITY	
	A. SUMMER	1063
	B. WINTER	1195
(3)	TECHNOLOGY TYPE	COMBINED CYCLE
(4)	ANTICIPATED CONSTRUCTION TIMING	
	A. FIELD CONSTRUCTION START DATE	OCT 2014
	B. COMMERCIAL IN-SERVICE DATE	JAN 2017
(5)	FUEL	
	A. PRIMARY FUEL	NATURAL GAS
	B. ALTERNATE FUEL	DISTILLATE OIL
(6)	AIR POLLUTION CONTROL STRATEGY	SCR, DLN BURNERS
(7)	COOLING METHOD	N/A
(8)	TOTAL SITE AREA	UNDETERMINED
(9)	CONSTRUCTION STATUS	PROPOSED
(10)	CERTIFICATION STATUS	UNDETERMINED
(11)	STATUS WITH FEDERAL AGENCIES	N/A
(12)	PROJECTED UNIT PERFORMANCE DATA	
	PLANNED OUTAGE FACTOR (POF)	3.2
	FORCED OUTAGE RATE (FOR)	0.7
	EQUIVALENT AVAILABILITY FACTOR (EAF)	96.1
	RESULTING CAPACITY FACTOR (2017)	48.2%
	AVERAGE NET OPERATING HEAT RATE (ANOHR) [1]	7,012 Btu/kWh
(13)	PROJECTED UNIT FINANCIAL DATA	
	BOOK LIFE (YEARS)	30
	TOTAL INSTALLED COST (IN-SERVICE YEAR $/kW)	448.01
	DIRECT CONSTRUCTION COST ($/kW)	355.17
	AFUDC AMOUNT ($/kW)	61.34
	ESCALATION ($/kW)	31.51
	FIXED O&M ($/kW – Yr)	1.27
	VARIABLE O&M ($/MWH)	2.43
	K FACTOR	1.5383

[1] BASED ON IN-SERVICE YEAR.

SCHEDULE 9
(Page 2 of 2)
STATUS REPORT AND SPECIFICATIONS OF PROPOSED GENERATING FACILITIES
UTILITY: TAMPA ELECTRIC COMPANY

(1)	PLANT NAME AND UNIT NUMBER	FUTURE CT 1
(2)	CAPACITY	
	A. SUMMER	149
	B. WINTER	177
(3)	TECHNOLOGY TYPE	COMBUSTION TURBINE
(4)	ANTICIPATED CONSTRUCTION TIMING	
	A. FIELD CONSTRUCTION START DATE	SEP 2018
	B. COMMERCIAL IN-SERVICE DATE	MAY 2019
(5)	FUEL	
	A. PRIMARY FUEL	NATURAL GAS
	B. ALTERNATE FUEL	N/A
(6)	AIR POLLUTION CONTROL STRATEGY	WET LOW EMISSION
(7)	COOLING METHOD	N/A
(8)	TOTAL SITE AREA	UNDETERMINED
(9)	CONSTRUCTION STATUS	PROPOSED
(10)	CERTIFICATION STATUS	UNDETERMINED
(11)	STATUS WITH FEDERAL AGENCIES	N/A
(12)	PROJECTED UNIT PERFORMANCE DATA	
	PLANNED OUTAGE FACTOR (POF)	2.6
	FORCED OUTAGE RATE (FOR)	1.0
	EQUIVALENT AVAILABILITY FACTOR (EAF)	95.4
	RESULTING CAPACITY FACTOR (2019)	0.3%
	AVERAGE NET OPERATING HEAT RATE (ANOHR) [1]	11,983 Btu/kWh
(13)	PROJECTED UNIT FINANCIAL DATA	
	BOOK LIFE (YEARS)	25
	TOTAL INSTALLED COST (IN-SERVICE YEAR $/kW)	878.11
	DIRECT CONSTRUCTION COST ($/kW)	689.31
	AFUDC AMOUNT ($/kW)	67.03
	ESCALATION ($/kW)	121.77
	FIXED O&M ($/kW – Yr)	9.67
	VARIABLE O&M ($/MWH)	4.87
	K FACTOR	1.4763

[1] BASED ON IN-SERVICE YEAR.

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Schedule 10

Status Report and Specifications of Proposed Directly Associated Transmission Lines

Units	Point of Origin and Termination	Number of Circuits	Right-of-Way	Circuit Length	Voltage	Anticipated In-Service Date	Anticipated Capital Investment	Substations	Participation with Other Utilities
Polk 2-5 CC	Polk-Aspen-FishHawk	5	ROW issues under-review	62.5 mi	230 kV	January 2017	$140 million	Switching Station	None
Polk 2-5 CC	Davis Substation Switched Reactor	0	ROW issues under-review	0 mi	230 kV	January 2017	$2 million	No new substations	None
Polk 2-5 CC	Polk Steam Turbine Interconnect & Upgrade	1	ROW issues under-review	0 mi	230 kV	January 2017	$5 million	No new substations	None
Future CT 1	Unsited[1]	1	No new ROW required	0 mi	kV	May 2019	$ million	No new substations	None

[1] Note: Specific information related to "Unsited" units unknown at this time.

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Chapter V

TRANSMISSION CONSTRAINTS AND IMPACTS

Based on a variety of assessments and sensitivity studies of the Tampa Electric transmission system using year 2011 Florida Reliability Coordinating Council (FRCC) databank models, no transmission constraints, that violate the criteria stated in the Generation and Transmission Reliability Criteria section of this document, were identified in these studies.

EXPANSION PLAN ECONOMICS AND FUEL FORECAST

The overall economics and cost-effectiveness of the plan were analyzed using Tampa Electric's Integrated Resource Planning process. As part of this process, Tampa Electric evaluated various planning and operating alternatives against expected operations, with the objective to: meet compliance requirements in the most cost-effective and reliable manner, maximize operational flexibility, and minimize total costs.

Early in the study process, many alternatives were screened on a qualitative and quantitative basis to determine the options that were the most feasible overall. Those alternatives that failed to meet the qualitative and quantitative considerations were eliminated. This phase of the study resulted in a set of feasible alternatives that were considered in a more detailed economic analysis.

Tampa Electric forecasts base case natural gas, coal and oil fuel commodity prices by analyzing current market prices and price forecasts obtained from various consultants and agencies. These sources include the New York Mercantile Exchange, Wood Mackenzie Energy Group, Coal Daily, Inside FERC and Platt's Oilgram. For the more volatile natural gas and oil prices, the company produces both high and low fuel price projections, which represent alternative forecasts to the company's base case outlook. The high and low price projections are defined by varying natural gas and oil prices by 35% relative to the base case.

GENERATING UNIT PERFORMANCE ASSUMPTIONS

Tampa Electric's generating unit performance assumptions are used to evaluate long-range system operating costs associated with particular generation expansion plans. Generating units are characterized by several different performance parameters. These parameters include capacity, heat rate, unit derations, planned maintenance days, and unplanned outage rates.

The unit performance projections are based on historical data trends, engineering judgment, time since last planned outage, and recent equipment performance. The first five years of planned outages are based on a forecasted outage schedule, and the planned outages for the balance of the years are based on an average of the first five years.

The five-year forecasted outage schedule is based on unit-specific maintenance needs, material lead-time, labor availability, and the need to supply our customers with power in the most economical manner. Unplanned outage rate projections are based on an average of three years of historical data adjusted, if necessary, to account for current unit conditions.

FINANCIAL ASSUMPTIONS

Tampa Electric makes numerous financial assumptions as part of the preparation for its Ten-Year Site Plan process. These assumptions are based on the current financial status of the company, the market for securities, and the best available forecast of future conditions. The primary financial assumptions include the FPSC-approved Allowance for Funds Used During Construction (AFUDC) rate, capitalization ratios, financing cost rates, tax rates, and FPSC-approved depreciation rates.

- Per the Florida Administrative Code, an amount for AFUDC is recorded by the company during the construction phase of each capital project. This rate is approved by the FPSC and represents the cost of money invested in the applicable project while it is under construction. This cost is capitalized, becomes part of the project investment, and is recovered over the life of the asset. The AFUDC rate assumed in the Ten-Year Site Plan represents the company's currently approved AFUDC rate.
- The capitalization ratios represent the percentages of incremental long-term capital that are expected to be issued to finance the capital projects identified in the Ten-Year Site Plan.
- The financing cost rates reflect the incremental cost of capital associated with each of the sources of long-term financing.
- Tax rates include federal income tax, state income tax, and miscellaneous taxes including property tax.
- Depreciation represents the annual cost to amortize the total original investment in a plant over its useful life less net salvage value. This provides for the recovery of plant investment. The assumed book life for each capital project within the Ten-Year Site Plan represents the average expected life for that type of investment.

INTEGRATED RESOURCE PLANNING PROCESS

Tampa Electric's Integrated Resource Planning process was designed to evaluate demand side and supply side resources on a fair and consistent basis to satisfy future energy requirements in a cost-effective and reliable manner, while considering the interests of utility customers and shareholders.

The process incorporates a reliability analysis to determine timing of future needs and an economic analysis to determine what resource alternatives best meet future system demand and energy requirements. Initially, a demand and energy forecast, which excludes incremental energy efficiency and conservation programs, is developed. Then a supply plan based on the system requirements, which excludes incremental energy efficiency and conservation, is developed. This interim supply plan becomes the basis for potential avoided unit(s) in a comprehensive cost-effective analysis of the energy efficiency and conservation programs. Once the cost-effective energy efficiency and conservation programs are determined, the system demand and energy requirements are revised to include the effects of these programs on reducing system peak and energy requirements. The process is repeated to incorporate the energy efficiency and conservation programs and supply side resources.

The cost-effectiveness of energy efficiency and demand response programs is based on the following standard Commission tests: the Rate Impact Measure (RIM), the Total Resource Cost (TRC), and the participants tests. Using the FPSC's standard cost-effectiveness methodology, each measure is evaluated based on different marketing and incentive assumptions. Utility plant avoidance assumptions for generation, transmission, and distribution are used in this analysis. All measures that pass the RIM, TRC, and participants tests in the energy efficiency and demand response analysis are considered for utility program adoption. Each adopted measure is quantified into annual kW/kWh savings and is reflected in the demand and energy forecast. Measures with the highest RIM values are generally adopted first. Tampa Electric evaluates energy efficiency and demand response measures using a spreadsheet that comports with Rule 25-17.008, F.A.C., the FPSC's prescribed cost-effectiveness methodology.

Generating resources to be considered are determined through an alternative technology screening analysis, which is designed to determine the economic viability of a wide range of generating technologies for the Tampa Electric service area.

The technologies that pass the screening are included in a supply side analysis, which examines various supply side alternatives for meeting future capacity requirements.

Tampa Electric uses the ProView module of Strategist, a computer model developed by Ventyx, to evaluate the supply side resources. ProView uses a dynamic programming approach to develop an estimate of the timing and type of capacity additions which would most economically meet the system demand and energy requirements. Dynamic programming compares all feasible combinations of generating unit additions, which satisfy the specified reliability criteria, and determines the schedule of additions that have the lowest revenue requirements. The model uses production costing analysis and incremental capital and O&M expenses to project the revenue requirements and rank each plan.

A detailed cost analysis for each of the top ranked resource plans is performed using the Capital Expenditure and Recovery module of Strategist and the Planning & Risk (PAR) production cost model. PAR, a computer model developed by Ventyx, replaced ProMod as Tampa Electric's production cost model in 2009. The capital expenditures associated with each capacity addition are obtained based on the type of generating unit, fuel type, capital spending curve, and in-service year. The fixed charges resulting from the capital expenditures are expressed in present worth dollars for comparison. The fuel and the operating and maintenance costs associated with each scenario are projected based on economic dispatch of all the energy resources on our system. The projected operating expense, expressed in present worth dollars, is combined with the fixed charges to obtain the total present worth of revenue requirements for each alternative plan.

STRATEGIC CONCERNS

Strategic concerns affect the type, capacity, and/or timing of future generation resource requirements. Concerns such as competitive pressures, environmental legislation, and plan acceptance are not easily quantified. These strategic concerns are considered within the Integrated Resource Planning process to ensure that an economically viable expansion plan is selected which has the flexibility for the company to respond to future technological and economic changes. The resulting expansion plan may include self-build generation, market purchase options or other viable supply and demand-side alternatives.

The results of the Integrated Resource Planning process provide Tampa Electric with a plan that is cost-effective while maintaining flexibility and adaptability to a dynamic regulatory and competitive environment. The new capacity additions are shown in Schedule 8.1. To meet the expected system demand and energy requirements over the next ten years and cost-effectively maintain system reliability, Tampa Electric is planning the conversion of Polk Units 2-5 to a natural gas combined cycle and the addition of a combustion turbine.

Tampa Electric will continue to assess competitive purchase power agreements that may replace or delay the scheduled new units. Such alternatives would be considered if better suited to the overall objective of providing reliable power in the most cost effective manner.

GENERATION AND TRANSMISSION RELIABILITY CRITERIA

GENERATION

Tampa Electric currently uses two criteria to measure the reliability of its generating system. The company utilizes a minimum 20% reserve margin criteria with a minimum contribution of 7% supply side resources. Tampa Electric's approach to calculating percent reserves are consistent with that outlined in the settlement agreement. The calculation of the minimum 20% reserve margin employs an industry accepted method of using total available generating and firm purchased power capacity (capacity less planned maintenance and contracted unit sales)

and subtracting the annual firm peak load, then dividing by the firm peak load, and multiplying by 100%. Since the reserve margin calculation assumes no forced outages, Tampa Electric includes the purchased power contract with Invenergy for the Hardee Power Station in its available capacity. Contractually, Hardee Power Station is planned to be available to Tampa Electric at the time of system peak. Also, the capacity dedicated to any firm unit or station power sales at the time of system peak is subtracted from Tampa Electric's available capacity.

Tampa Electric's summer supply-side reserve margin is calculated by dividing the difference of projected supply-side resources and projected total peak demand by the forecasted firm peak demand. The total peak demand includes the summer firm peak demand, and interruptible and load management loads.

TRANSMISSION

The following criteria are used as guidelines for proposing system expansion and/or improvement projects. A detailed engineering study must be performed prior to making a prudent decision to initiate a project.

Tampa Electric follows the FRCC planning criteria, as contained in the *FRCC Regional Transmission Planning Process* document. The FRCC planning guide is based on the North American Electric Reliability Council (NERC) Planning Reliability Standards, which are used to measure system adequacy. In general, the NERC standards state that the transmission system will remain stable, within the applicable thermal and voltage rating limits, without cascading outages, under normal, single and multiple contingency conditions.

In addition to FRCC criteria, Tampa Electric utilizes specific criteria for normal system operation and single contingency operation as listed in the Generation and Transmission Reliability Criteria section of this document.

GENERATION DISPATCH MODELED

The generation dispatched in the planning models is dictated on an economic basis and is calculated by the Economic Dispatch (ECDI) function of the PSS/E load flow software. The ECDI activity schedules the unit dispatch so that the total generation cost required to meet the projected load is minimized. This is the generation scenario contained in the power flow cases submitted to fulfill the requirements of FERC Form 715 and the FRCC.

Since varying load levels and unplanned and planned unit outages can result in a system dispatch that varies significantly from a base plan, bulk transmission planners also investigate several scenarios that may stress Tampa Electric's transmission system. These additional generation sensitivities are analyzed to ensure the integrity of the bulk transmission system under maximized bulk power flows.

120234 Hearing Exhibits 00299

TRANSMISSION SYSTEM PLANNING LOADING LIMITS CRITERIA

Tampa Electric follows the FRCC planning criteria as contained in the FRCC Standards Handbook and NERC Standards. In addition to FRCC criteria, Tampa Electric utilizes company-specific planning criteria.

The following table summarizes the thresholds, which alert planners to problematic transmission lines and transformers.

TRANSMISION SYSTEM LOADING LIMITS	
Transmission System Conditions	**Maximum Acceptable Loading Limit for Transformers and Transmission Lines**
All elements in service	100%
Single Contingency (pre-switching)	Emergency Rating*
Single Contingency (post-switching)	100%
Bus Outages (pre-switching)	Emergency Rating*
Bus Outages (post-switching)	100%

* As determined by FAC-009.

The transmission system is planned to allow voltage control on the 13.2 kV distribution buses between 1.023 and 1.043 per unit. For screening purposes, this criterion can be approximated by the following transmission system voltage limits.

TRANSMISION SYSTEM VOLTAGE LIMITS			
Transmission System Conditions	**Industrial Substation Buses at point-of-service**	**69 kV Buses**	**138 kV and 230 kV Buses**
Single Contingency (pre-switching)	0.925 - 1.050 p.u.	0.925 - 1.050 p.u.	0.950 - 1.060 p.u.
Single Contingency (post-switching)	0.925 - 1.050 p.u.	0.925 - 1.050 p.u.	0.950 - 1.060 p.u.
Bus Outages	0.925 - 1.050 p.u.	0.925 - 1.050 p.u.	0.950 - 1.060 p.u.

AVAILABLE TRANSMISSION TRANSFER CAPABILITY (ATC) CRITERIA

Tampa Electric adheres to the FRCC ATC calculation methodology described in the *FRCC ATC Calculation and Coordination Procedures* document, as well as the principles contained in the NERC Reliability Standards relating to ATC calculations.

TRANSMISSION PLANNING ASSESSMENT PRACTICES

BASE CASE OPERATING CONDITIONS

The Transmission Planning department ensures that the Tampa Electric Company transmission system can support peak and off-peak system load levels without violation of the loading and voltage criteria stated in the Generation and Transmission Reliability Criteria section of this document.

SINGLE CONTINGENCY PLANNING CRITERIA

The Tampa Electric Company transmission system is designed such that any single branch (transmission line or autotransformer) can be removed from service up to the forecasted peak load level without any violations of the criteria stated in the Generation and Transmission Reliability Criteria section of this document.

MULTIPLE CONTINGENCY PLANNING CRITERIA

Double contingencies (including FRCC studies of C2, C3, C3Gens, C3Lines, and C5 events) involving two branches or more out of service simultaneously are analyzed at a variety of load levels. The Tampa Electric Company transmission system is designed such that these double contingencies do not cause violation of FRCC criteria.

TRANSMISSION CONSTRUCTION AND UPGRADE PLANS

A specific list of the construction projects can be found in Chapter IV, Schedule 10. This list represents the latest transmission construction related to the generation expansion plan available. However, due to the timing of this document in relationship to the company's internal planning schedule, this plan may change in the near future.

120234 Hearing Exhibits 00301

SUPPLY SIDE RESOURCES PROCUREMENT PROCESS

Tampa Electric will manage the procurement process in accordance with established policies and procedures. Prospective suppliers of supply side resources, as well as suppliers of equipment and services, will be identified using various data base resources and competitive bid evaluations, and will be used in developing award recommendations to management.

This process will allow for future supply side resources to be supplied from self-build, purchase power, or competitively bid third parties. Consistent with company practice, bidders will be encouraged to propose incentive arrangements that promote development and implementation of cost savings and process improvement recommendations.

ENERGY EFFICIENCY AND CONSERVATION AND ENERGY SAVINGS DURABILITY

Tampa Electric verifies the durability of energy savings from its conservation and load management programs by several methods. First, Tampa Electric has established a monitoring and evaluation process where historical analysis validates the energy savings. These include:

1. Periodic system load reduction analyses for residential load management (Prime Time and Energy Planner) to confirm the accuracy of Tampa Electric's load reduction estimation formulas;

2. Billing analysis of various program participants (Energy Planner), compared to control groups to minimize the impact of weather abnormalities;

3. Periodic DOE2 modeling of various program participants such as the Residential and Commercial Building Envelope programs to evaluate savings achieved in residential programs involving building components; components;

4. End-use sampling of building segments to validate savings achieved in Conservation Value and Commercial Indoor Lighting programs; and

5. In commercial programs such as Standby Generator and Commercial Load Management and Commercial Demand Response, the reductions are verified through metering of loads under control to determine the demand and energy savings.

Second, the programs are designed to promote the use of high efficiency equipment having permanent installation characteristics. Specifically, those programs that promote the installation of energy efficient measures or equipment (heat pumps, hard-wired lighting fixtures, ceiling insulation, wall insulation, window replacements, air distribution system repairs, DX commercial cooling units, chiller replacements, water heating replacements and motor upgrades) have program standards that require the new equipment to be installed in a permanent manner thus insuring their durability.

TAMPA ELECTRIC'S RENEWABLE ENERGY PROGRAMS

Tampa Electric offered a pilot Renewable Energy Program for several years. Due to its success, permanent program status was requested by the company and approved by the Commission in Docket No. 060678-EG, Order No. PSC-06-1063-TRF-EG, issued December 26, 2006.

Through December 2011, Tampa Electric's Renewable Energy Program has over 2,400 customers purchasing over 3,500 blocks of renewable energy each month. With the permanent program status effective December 2006, the company doubled the renewable energy block size from 100 to 200 kWh per month. Furthermore, in 2009, Tampa Electric began offering the ability to purchase one-time blocks of renewable energy to power specific events, starting with Super Bowl XLIII.

The company's renewable generation portfolio is a mix of various technologies and renewable fuel sources, including six company owned photovoltaic (PV) arrays totaling 81.7 kW. The PV arrays are installed at the Museum of Science and Industry, Walker Middle and Middleton High schools and Tampa Electric's Manatee Viewing Center. Most recently, systems were installed at Tampa's Lowry Park Zoo and the Florida Aquarium to further educate the public on the benefits of renewable energy. To complement the installations at these facilities throughout the community, interactive displays were built to provide a hands-on experience to engage visitors' interest in solar technology. Program participation has reached a level where it is necessary to supplement the company's renewable resources with incremental purchases from a biomass facility in south Florida. Through December 2011, participating customers have utilized over 47 GWH of renewable energy since the program inception.

In 2011, Tampa Electric also initiated a five-year renewable energy pilot that utilizes rebates and incentives to encourage the following:

1. The installation of solar photovoltaic (PV) and solar water heating (SWH) technologies on existing and new residential and commercial premises;

2. The installation of PV on emergency shelter schools, coupled with an educational component for teachers and students; and

3. The installation of SWH on low income housing done in partnership with local non-profit building organizations.

This pilot has annual funding capped at $1.53 million. Through this initiative Tampa Electric expects an additional 510 kW of customer owned PV to be installed along with 155 residential SWH systems to be added each year of the pilot.

120234 Hearing Exhibits 00303

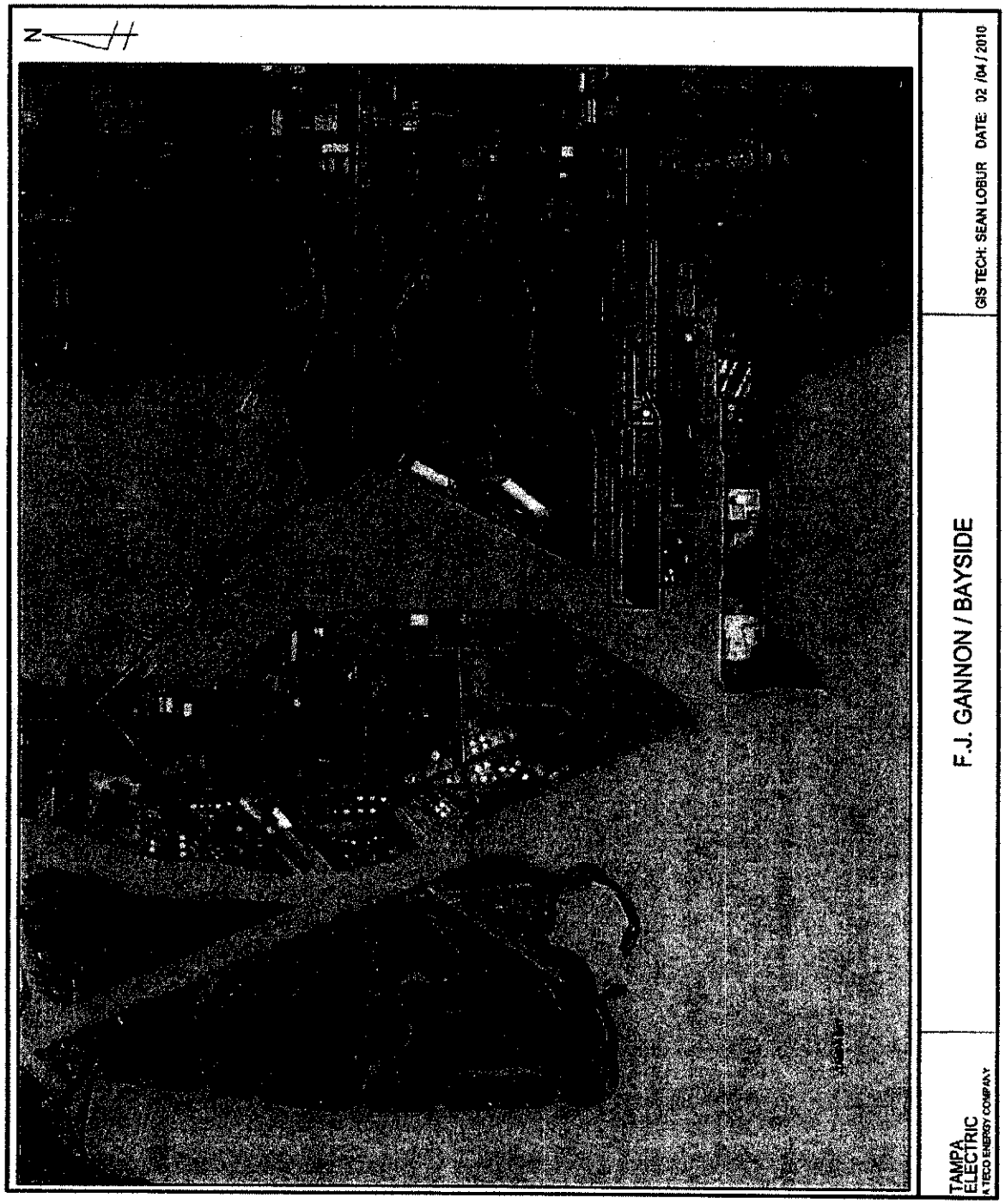
Tampa Electric continually analyzes renewable energy alternatives with the objective to integrate them into our resource portfolio. Specific renewable options for the future are the integration of a 60 MW biomass boiler at Bayside 2 and a possible fuel conversion of Phillips Power Station to bio-diesel as its primary fuel resulting in 32 MW. Solar thermal integration of the new combined cycle conversion at Polk Power Station could result in a 30 MW renewable energy alternative for our customers, as well as additional solar PV arrays at our Manatee Viewing Center. As market conditions continue to change and technology improves in this sector, renewable alternatives, such as solar, become more cost effective to our customers.

Chapter VI

[redacted]

The future generating capacity additions identified in Chapter IV could occur at H.L. Culbreath Bayside Power Station, Polk Power Station, or Big Bend Power Station. The H.L. Culbreath Bayside Power Station site is located in Hillsborough County on Port Sutton Road (See Figure VI-1), Polk Power Station site is located in southwest Polk County close to the Hillsborough and Hardee County lines (See Figure VI-2) and Big Bend Power Station is located in Hillsborough County on Big Bend Road (See Figure VI-3). All facilities are currently permitted as existing power plant sites. Additional land use requirements and/or alternative site locations are not currently under consideration.

Figure VI-1



2917

Figure VI-2

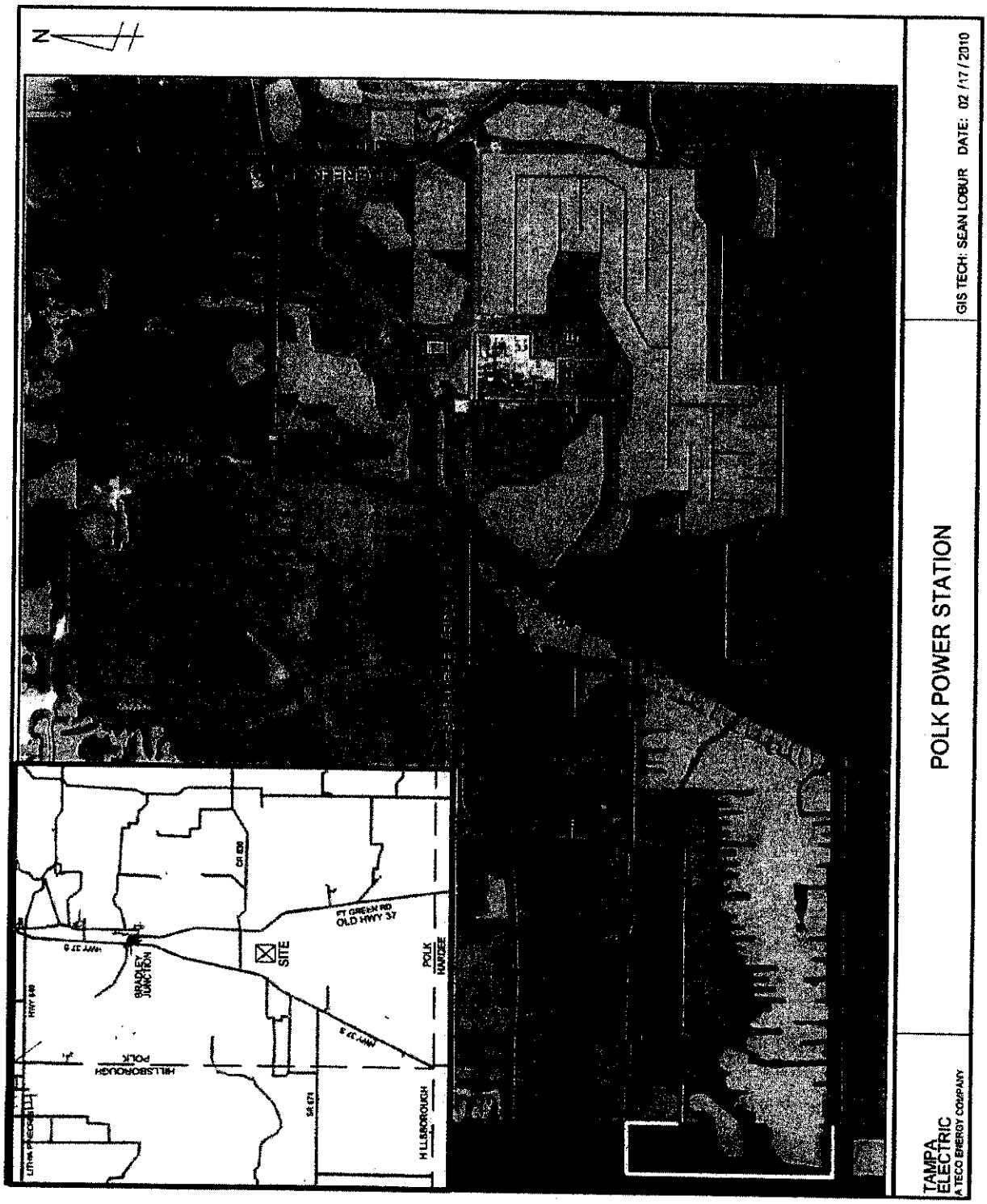
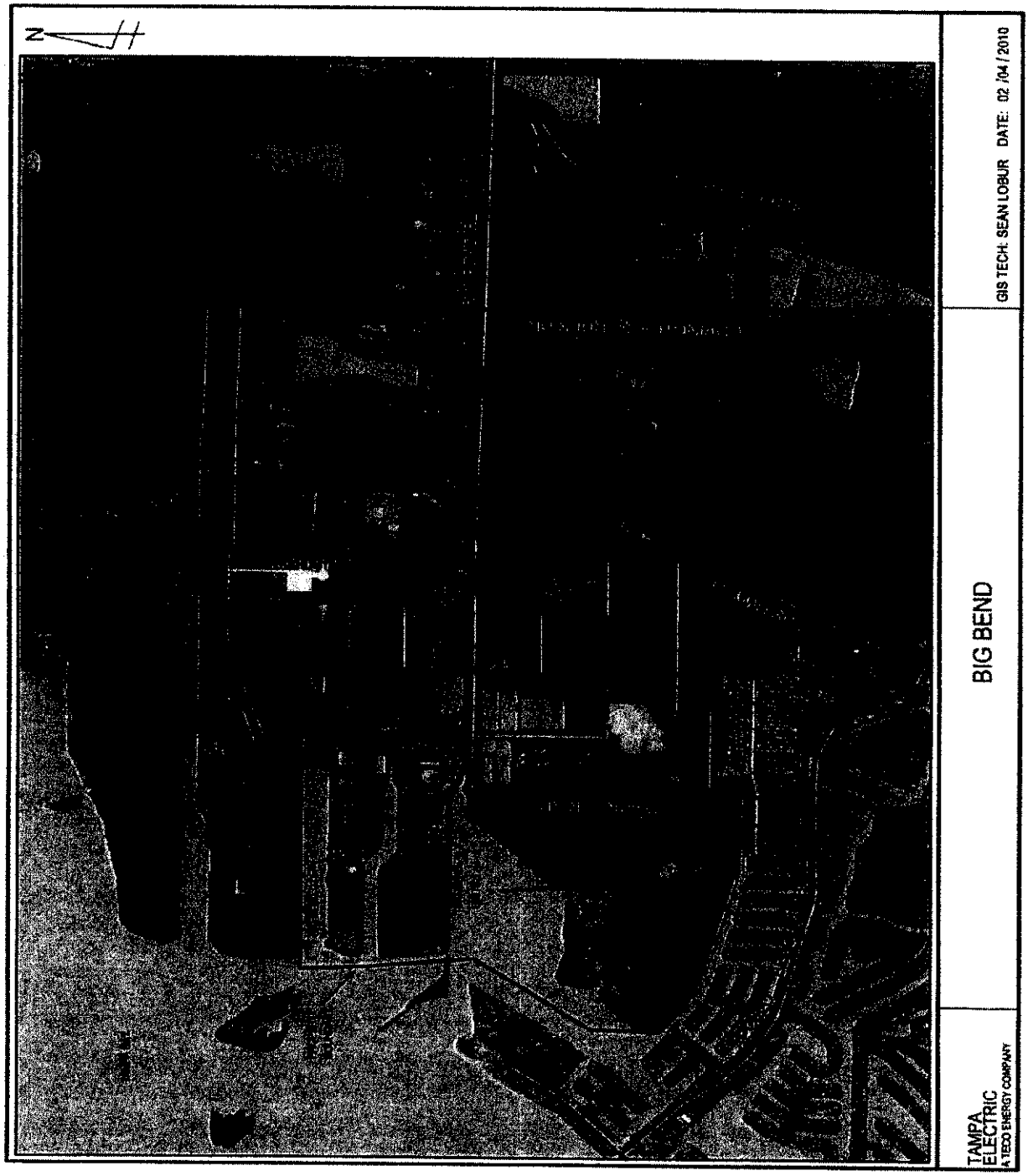

N
POLK POWER STATION
GIS TECH: SEAN LOBUR DATE: 02/17/2010
TAMPA ELECTRIC
A TECO ENERGY COMPANY
SITE
FT GREEN RD
OLD HWY 37
BRADLEY JUNCTION
POLK
HILLSBOROUGH
HWY 37 S
CR 630
SR 674

Figure VI-3



2919

TECO's Answer to First Request for Production of Documents (No. 6 *BSP 2654, 2656, 2658, 2661*) of the Florida Public Service Commission

(Confidential FPSC Document No. 07114-12)

8

TECO's Answer to Second Request for Production of Documents (Nos. 19, 20 (NON-CONFIDENTIAL_Source Docs/Non-confidential Early 2012 NG Supply Disposition.pdf -FPSC Document No. 07212-12), 22, 23, 24, 25 (*BSP 991-995*) of the Florida Public Service Commission

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 120234-EI EXHIBIT 8
PARTY Florida Public Service Commission Staff
DESCRIPTION TECO - Staff Exhibit #8 - Confidential
[Bates Nos. 00310-00339] & [Bates No. 00340]

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition to determine need for Polk 2-5 combined cycle conversion, by Tampa Electric Company	**DOCKET NO. 120234-EI** **FILED: October 23, 2012**

REDACTED

TAMPA ELECTRIC COMPANY'S

ANSWERS TO SECOND REQUEST FOR

PRODUCTION OF DOCUMENTS (NOS. 12-25)

OF

FLORIDA PUBLIC SERVICE COMMISSION STAFF

Tampa Electric files this its Answers to Production of Documents (Nos. 12-25) propounded and served on October 3, 2012, by the Florida Public Service Commission Staff.

TAMPA ELECTRIC COMPANY
DOCKET NO. 120234-EI
INDEX TO STAFF'S SECOND REQUEST FOR
PRODUCTION OF DOCUMENTS (NOS. 12-25)

Number	Subject	Bates Stamped Pages
12	Please provide a copy of the most recent Standard & Poor's credit/bond report and analysis for TECO.	1 - 5
13	Please provide a copy of the most recent Standard & Poor's credit/bond report and analysis for TECO Energy.	6 - 10
14	Please provide a copy of the most recent Moody's Investor Service's credit/bond report and analysis for TECO.	11 - 15
15	Please provide a copy of the most recent Moody's Investor Service's credit/bond report and analysis for TECO Energy.	16 - 21
16	Please provide a copy of the most recent Fitch Rating's credit/bond report and analysis, for TECO.	22 - 28
17	Please provide a copy of the most recent Fitch Rating's credit/bond report and analysis, for TECO Energy.	29 - 35
18	Please provide copies of all investment analyst reports for or by TECO and TECO Energy since January 1, 2011.	36 - 970
19	Regarding the economic parameters in the application, please provide complete copies of all source documents, reports, etc., that support the selection of the capital structure, the assumed escalation rates, the assumed financing rates, the capital structure ratios, the AFUDC rate, and the assumed present worth discount rates.	971 - 981
20	Please provide complete copies of all workpapers and source documents, in hard copy and in Excel format as available, used to support or develop TECO's fuel price forecasts as presented in witness Caldwell's direct testimony, Document No. 1.	982
21	Please provide complete copies of all work papers and source documents, in hard copy and in Excel format as available, used to support or develop TECO's residual oil price forecast as discussed in witness Caldwell's direct testimony at pages 13 and 14.	983
22	Witness Caldwell stated that TECO's fuel price forecast used in the Polk 2-5 economic analyses was the same official long-term forecast prepared in the summer of 2011. Please provide documents containing the full 30-year fuel price forecast TECO prepared in the summer of 2011, inclusive of the years 2011 through 2040.	984 - 985
23	Please provide documents containing TECO's updated 30-year fuel price forecasts for the 2013 fuel and purchased power cost recovery clause projection filing, in hard copy and in Excel format as available, as referenced in witness Caldwell's direct testimony at Page 16, Lines 22-24.	986 - 987

Number	Subject	Bates Stamped Pages
24	Please provide a document containing TECO's high and low price forecasts of natural gas, distillate oil, residential oil, and coal as referenced in witness Caldwell's direct testimony at page 16.	988 - 990
25	Please provide all documents TECO relied upon in the preparation of each high and low price forecast of natural gas, distillate oil, residual oil, and coal as referenced in witness Caldwell's direct testimony at page 16.	991 - 2439

TAMPA ELECTRIC COMPANY
DOCKET NO. 120234-EI
STAFF'S SECOND REQUEST FOR
PRODUCTION OF DOCUMENTS
DOCUMENT NO. 19
BATES STAMPED PAGES: 971 - 981
FILED: OCTOBER 23, 2012

19. Regarding the economic parameters in the application, please provide complete copies of all source documents, reports, etc., that support the selection of the capital structure, the assumed escalation rates, the assumed financing rates, the capital structure ratios, the AFUDC rate, and the assumed present worth discount rates.

A. Please see attached documents.

[redacted]

MEMORANDUM

FROM: Chrys Remmers

DATE: September 30, 2011

SUBJECT: Financial Assumptions for Economic Evaluations and Planning Studies

This memo contains two sets of financial assumptions for engineering economy studies and for the calculation of avoided costs.

1) The first set of costs are for discretionary capital projects and contain a hurtle rate. These assumptions are to be used for internal economic evaluations. The capital structure and incremental costs of capital are:

	Rate	Weight
Debt	6.66%	46.04%
Common Equity	12.25%	53.96%
		100.00%

After tax discount rate for present worth calculations: 8.49%

2) The second set of financial assumptions is to be used for external studies where the costs are to reflect TEC's projected actual costs. The capital structure and incremental costs of capital are:

	Rate	Weight
Debt	6.66%	46.04%
Common Equity	11.25%	53.96%
		100.00%

After tax discount rate for present worth calculations: 7.95%

Common analysis assumptions include:

Property Tax Rate	
Hillsborough	2.00%
Polk	1.60%
Property Insurance Rate	0.15% / $100 of value
Income Tax Rate	38.575%

These are general assumptions to use in project evaluations. Please contact me if you have questions regarding specific assumptions for your project analysis.

TECO ENERGY

Tampa Electric
Cost of Capital
Updated as of 9/26/2011

Assumptions

Mid-Point ROE	**11.25%**
Debt Cost [1]	**6.66%**
Targeted Capital Structure	
Debt	**46.04%**
Equity	53.96%
Tax Rate	**38.575%**

	Regulatory ROE = 10.25%	Regulatory ROE = 11.25%	Regulatory ROE = 12.25%
PRETAX	WACC Calculator Debt Cost 6.66% Pre-tax Equity Cost 16.69% Capital Structure Debt 46.04% Equity 53.96% **Pre-Tax WACC 12.07%**	WACC Calculator Debt Cost 6.66% Pre-tax Equity Cost 18.32% Capital Structure Debt 46.04% Equity 53.96% **Pre-Tax WACC 12.95%**	WACC Calculator Debt Cost 6.66% Pre-tax Equity Cost 19.94% Capital Structure Debt 46.04% Equity 53.96% **Pre-Tax WACC 13.83%**
AFTERTAX	WACC Calculator Debt Cost 6.66% Equity Cost 10.25% Capital Structure Debt 46.04% Equity 53.96% **WACC 7.41%**	WACC Calculator Debt Cost 6.66% Equity Cost 11.25% Capital Structure Debt 46.04% Equity 53.96% **WACC 7.95%**	WACC Calculator Debt Cost 6.66% Equity Cost 12.25% Capital Structure Debt 46.04% Equity 53.96% **WACC 8.49%**

(1) Debt cost is from Treasury Department's per Kim Caruso 09/06/2011

TAMPA ELECTRIC COMPANY
DOCKET NO. 120234-EI
STAFF'S SECOND REQUEST FOR PODS
FILED: OCTOBER 23, 2012

Created/Modified:10/18/2012 3:44 PM
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Interest Rate Assumptions Using 20 Year Historicals
Updated as of 9/6/11

	2012	2013-2022
Short-term taxable rate		
Tampa Electric	1.28	4.54
TECO Energy	2.29	5.56
Long-term taxable rate		
Tampa Electric	4.30	6.66
TECO Energy	4.50	7.13
Short-term tax exempt rate		
Tampa Electric	na	na
TECO Energy	na	na
Long-term tax exempt rate		
Tampa Electric	4.60	6.53
Investment rate (LIBOR - 0.5 excl vol. prem.)	-	3.70

Inputs:		2012 Projected	Historical Average
3 month Libor estimate		0.30	4.10
Short term volatility premium		0.50	-
Total 3 month Libor		0.80	4.10
Fed Funds estimate		0.25	3.82
Short term volatility premium		0.50	-
Total Fed Funds		0.75	3.82
Prime Rate		3.25	6.74
10-Yr Treasury		3.00	5.30
Tampa Electric Spreads:			
Short Term Taxable			
AR Facility (Libor + Program Fee)	85%	0.350	0.350
Fed Funds Rate (FF + spread)	15%	1.250	1.250
Base Rate (Prime Rate)	0%	-	-
Long Term Taxable		1.38	1.27
Long Term Tax Exempt as % of Taxable		107%	95%
Short Term Tax Exempt (spread to LIBOR)		-	-
Remarketing Fee		-	-
Net Short Term Tax Exempt (spread to LIBOR)		-	-
TECO Spreads:			
Short Term Taxable (less than 85% utiliz)			
Libor Rate (Libor + spread)	85%	1.500	1.500
Fed Funds Rate (FF + spread)	15%	1.500	1.500
Base Rate (Prime Rate)	0%	-	-
Long Term Taxable		1.50	1.74

TAMPA ELECTRIC

MEMORANDUM

FROM: Samantha Superville, Load Research & Forecasting

DATE: June 28, 2011

SUBJECT: Escalation Rates

Please use the following escalation rates for this year's budget process.

Consumer Price Index (CPI): Moderate inflation in 2011
The consumer price index in April was up 3.2% from April 2010. Inflation has moderated in recent months primarily due to a slowdown in food and energy price increases. Moody's Economy.com and over 50 economists participating in the Wall Street Journal's forecasting survey (April 2011) predict an inflation rate just under 3.0 percent for 2011. The annual inflation rate for 2012 is projected to be 2.1 percent. Consumer price inflation over the next decade will remain in the 2.0 percent range annually, averaging 2.4 percent each year from 2014 and beyond.

According to the Federal Reserve's FOMC (Federal Open Market Committee), longer-term inflation stayed within the range that has prevailed over the past several years. The Committee said it anticipates long-run inflation to remain stable.

TAMPA ELECTRIC COMPANY
ESCALATION RATES (3)
(Annual Percent Change)

Year	Production HWI (1)	Non-Production CPI (2)
2009	6.0%	-0.4%
2010	5.6%	1.6%
2011	3.6%	2.8%
2012	5.2%	2.1%
2013	2.5%	2.9%
2014 - 2018	2.1%	2.4%

(1) Handy Whitman Index – South Atlantic Region; June 2011 delivery
(2) Consumer Price Index – All Urban Consumers, All Items, NSA; April 2011 delivery
(3) Forecast and commentary provided by Economy.com

Handy-Whitman Index (HWI): Production Inflation Moderating Long-Term
Currently, the inflation rate for electric utility construction costs is 3.6 percent, 2 percentage points lower than in 2010. Production inflation rates are projected to be 5.2 percent in 2012 and drop to the 2 percent range from 2013 and beyond (2.5% in 2013, 2.1% in 2014+).

There was a drop in the 1st Quarter 2011 actual values which drove the forecast down for that year. The rest of the forecast is driven by the cost of industrial goods, specifically machinery and equipment.

cc: TJ Szelistowski, Lori Cifuentes, Stacy Hallman

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Request for approval of change rate used to account for allowance funds used during construction (AFUDC) from 7.79% to 8.17%, effective May 1, 2009, by Tampa Electric Company.	DOCKET NO. 090446-EI ORDER NO. PSC-09-0798-PAA-EI ISSUED: December 2, 2009

The following Commissioners participated in the disposition of this matter:

MATTHEW M. CARTER II, Chairman
LISA POLAK EDGAR
NANCY ARGENZIANO
NATHAN A. SKOP
DAVID E. KLEMENT

NOTICE OF PROPOSED AGENCY ACTION
ORDER APPROVING CHANGE IN RATE FOR ALLOWANCE
FOR FUNDS USED DURING CONSTRUCTION

BY THE COMMISSION:

NOTICE is hereby given by the Florida Public Service Commission that the action discussed herein is preliminary in nature and will become final unless a person whose interests are substantially affected files a petition for a formal proceeding, pursuant to Rule 25-22.029, Florida Administrative Code (F.A.C.).

BACKGROUND

Tampa Electric Company's (TECO or the Company) current Allowance for Funds Used During Construction (AFUDC) rate of 7.79 percent was approved in Order No. PSC-95-1229-FOF-EI, issued October 3, 1995, in Docket No. 950621-EI, In re: Request for approval to change allowance for funds used during construction (AFUDC) from 7.28% to 7.79% effective 1/1/95 by Tampa Electric Company. By letter dated September 10, 2009, TECO requests that its AFUDC rate be increased to reflect its current capital structure and cost rates. We have jurisdiction over this matter pursuant to Chapter 366, Florida Statutes (F.S.), including Sections 366.04, 366.05, and 366.06, F.S.

TECO has requested an increase in its AFUDC rate from 7.79 percent to 8.17 percent. Rule 25-6.0141 Florida Administrative Code (F.A.C.), Allowance for Funds Used During Construction, provides the following guidance:

> (2) The applicable AFUDC rate shall be determined as follows:
> (a) The most recent 13-month average embedded cost of capital, except as noted below, shall be derived using all sources of capital and adjusted using adjustments consistent with those used by the Commission in the utility's last rate case.

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FPSC-COMMISSION CLERK

> (b) The cost rates for the components in the capital structure shall be the midpoint of the last allowed return on common equity, the most recent 13-month average cost of short term debt and customer deposits and a zero cost rate for deferred taxes and all investment tax credits. The cost of long term debt and preferred stock shall be based on end of period cost. The annual percentage rate shall be calculated to two decimal places.

In support of the requested AFUDC rate of 8.17 percent, TECO provided its calculations and capital structure as Schedules A and B attached to its petition. We reviewed these calculations and determined that the requested rate was calculated in accordance with Rule 25-6.0141(2), F.A.C. However, due to a rounding error involving the relative percentage of common equity, the correct AFUDC rate is 8.16 percent as shown on the attached Schedule 1. The primary driver behind the increase in the requested AFUDC rate is an increase in the relative percentage of long-term debt in the capital structure. The factors contributing to the relative increase in the percentage of long-term debt are an increase in the absolute amount of long-term debt and a decrease in the relative percentages of deferred taxes and investment tax credits in the capital structure. In addition, the capital structure relied upon to determine the current AFUDC rate included preferred stock and short-term debt while the capital structure for the requested AFUDC rate includes neither of these relatively lower cost capital components. Finally, the upward pressure on the AFUDC rate due to the factors discussed above is partially offset by a decrease in the cost rates of common equity and long-term debt.

Based on our review, the requested increase in the AFUDC rate from 7.79 percent to 8.17 percent is not appropriate. Instead, we find that 8.16 percent is the appropriate AFUDC rate.

Additionally, TECO has requested a monthly compounding rate of 0.656600 percent to achieve an annual AFUDC rate of 8.17 percent. In support of the requested monthly compounding rate of 0.656600 percent, TECO provided its calculations as Schedule C attached to its request. Rule 25-6.0141(3), F.A.C., provides a formula for discounting the annual AFUDC rate to reflect monthly compounding. The rule also requires that the monthly compounding rate be calculated to six decimal places.

Based on our decision to reduce TECO's requested annual AFUDC rate of 8.17 percent to 8.16 percent, the appropriate monthly compounding rate is 0.655820 percent, as shown on Schedule 2, a copy of which is attached. Therefore, we approve a discounted monthly AFUDC rate of 0.655820 percent.

TECO's proposed AFUDC rate was calculated using a 13-month average capital structure for the period ending April 30, 2009. Rule 25-6.0141(5), F.A.C., provides that:

> The new AFUDC rate shall be effective the month following the end of the 12-month period used to establish that rate and may not be retroactively applied to a previous fiscal year unless authorized by the Commission.

The Company's requested effective date of May 1, 2009, complies with the requirement that the effective date does not precede the period used to calculate the rate. Therefore, we approve it.

Rule 25-6.0423(5)(b)1, F.A.C., Nuclear or Integrated Gasification Combined Cycle Power Plant Cost Recovery, states the following:

> For power plant need petitions submitted on or before December 31, 2010, the associated carrying costs shall be computed based on the pretax AFUDC rate in effect on June 12, 2007.

TECO's current AFUDC rate of 7.79 percent was approved[1] with an effective date of January 1, 1995, and was in effect on June 12, 2007. For the purposes of Rule 25-6.0423, F.A.C., 7.79 percent is the appropriate AFUDC rate to be utilized for computing carrying costs for power plant need petitions submitted on or before December 31, 2010.

Based on the foregoing, it is

ORDERED by the Florida Public Service Commission that Tampa Electric Company's request for an increase in the AFUDC rate is hereby approved effective May 1, 2009. It is further

ORDERED that Tampa Electric Company's AFUDC rate shall be increased from 7.79 percent to 8.16 percent for the reasons set forth herein. It is further

ORDERED that Tampa Electric Company's discounted monthly AFUDC rate shall be changed to 0.655820 percent. It is further

ORDERED that if no person whose substantial interests are affected by the proposed agency action files a protest within 21 days of the issuance of this order, this docket shall be closed upon the issuance of a consummating order.

By ORDER of the Florida Public Service Commission this 2nd day of December, 2009.

Ann Cole

ANN COLE
Commission Clerk

(SEAL)

KY

[1] Order No. PSC-95-1229-FOF-EI, issued October 3, 1995, in Docket No. 950621-EI, In re: Request for approval to change allowance for funds used during construction (AFUDC) from 7.28% to 7.79% effective 1/1/95 by Tampa Electric Company.

NOTICE OF FURTHER PROCEEDINGS OR JUDICIAL REVIEW

The Florida Public Service Commission is required by Section 120.569(1), Florida Statutes, to notify parties of any administrative hearing that is available under Section 120.57, Florida Statutes, as well as the procedures and time limits that apply. This notice should not be construed to mean all requests for an administrative hearing will be granted or result in the relief sought.

Mediation may be available on a case-by-case basis. If mediation is conducted, it does not affect a substantially interested person's right to a hearing.

The action proposed herein is preliminary in nature. Any person whose substantial interests are affected by the action proposed by this order may file a petition for a formal proceeding, in the form provided by Rule 28-106.201, Florida Administrative Code. This petition must be received by the Office of Commission Clerk, 2540 Shumard Oak Boulevard, Tallahassee, Florida 32399-0850, by the close of business on December 23, 2009.

In the absence of such a petition, this order shall become final and effective upon the issuance of a Consummating Order.

Any objection or protest filed in this/these docket(s) before the issuance date of this order is considered abandoned unless it satisfies the foregoing conditions and is renewed within the specified protest period.

TAMPA ELECTRIC COMPANY
DOCKET NO. 090446-EI
BASIS FOR THE REQUESTED AFDUC RATE
FPSC ADJUSTED BASIS
APRIL, 2009

SCHEDULE 1

Company As Filed

CAPITAL COMPONENTS	JURISDICTIONAL AVERAGE	CAPITAL RATIO	COST OF CAPITAL	AFDUC WEIGHTED COMPONENTS
LONG TERM DEBT	$ 1,370,916,433	41.45%	6.81%	2.82%
SHORT TERM DEBT	-	0.000%	2.72% *	0.00%
PREFERRED STOCK	-	0.000%	0.00%	0.00%
CUSTOMER DEPOSITS	94,789,129	2.87%	6.11% *	0.18%
COMMON EQUITY	1,518,259,773	45.92%	11.25%	5.17%
DEFERRED INCOME TAX	313,334,952	9.47%	0.00%	0.00%
INVESTMENT TAX CREDITS	9,718,779	0.29%	0.00%	0.00%
TOTAL	$ 3,307,019,066	100.00%		8.17%

* 13-MONTH AVERAGE

COMMISSION ADJUSTED

CAPITAL COMPONENTS	JURISDICTIONAL AVERAGE	CAPITAL RATIO	COST OF CAPITAL	AFDUC WEIGHTED COMPONENTS
LONG TERM DEBT	$ 1,370,916,433	41.4547%	6.81%	2.823%
SHORT TERM DEBT	-	0.0000%	2.72% *	0.000%
PREFERRED STOCK	-	0.0000%	0.00%	0.000%
CUSTOMER DEPOSITS	94,789,129	2.8663%	6.11% *	0.175%
COMMON EQUITY	1,518,259,773	45.9102%	11.25%	5.165%
DEFERRED INCOME TAX	313,334,952	9.4748%	0.00%	0.000%
INVESTMENT TAX CREDITS	9,718,779	0.2939%	0.00%	0.000%
TOTAL	$ 3,307,019,066	100.00%		8.16%

* 13-MONTH AVERAGE

SCHEDULE 2

TAMPA ELECTRIC COMPANY
DOCKET NO. 090446-EI
METHODOLOGY FOR COMPOUNDING AFUDC RATE

PER TAMPA ELECTRIC COMPANY

Time Period	($) AFUDC Expenditures	($) AFUDC Base	($) Monthly AFUDC	($) Cumulative AFUDC
1	1.0	1.000000	0.0065660	0.0065660
2			0.0066091	0.0131750
3			0.0066525	0.0198275
4			0.0066961	0.0265236
5			0.0067401	0.0332637
6			0.0067844	0.0400481
7			0.0068289	0.0468770
8			0.0068737	0.0537507
9			0.0069189	0.0606696
10			0.0069643	0.0676339
11			0.0070100	0.0746439
12			0.0070561	0.0817000

Annual Rate (R) = .0817
Monthly Rate = ((1 + R)^(1/12)) - 1 = .0065660

COMMISSION ADJUSTED

Time Period	($) AFUDC Expenditures	($) AFUDC Base	($) Monthly AFUDC	($) Cumulative AFUDC
1	1.0	1.000000	0.0065582	0.0065582
2			0.0066012	0.0131594
3			0.0066445	0.0198039
4			0.0066881	0.0264920
5			0.0067319	0.0332239
6			0.0067761	0.0400000
7			0.0068205	0.0468205
8			0.0068653	0.0536858
9			0.0069103	0.0605961
10			0.0069556	0.0675517
11			0.0070012	0.0745529
12			0.0070471	0.0816000

Annual Rate (R) = .0816
Monthly Rate = ((1 + R)^(1/12)) - 1 = .0065582

TAMPA ELECTRIC COMPANY
DOCKET NO. 120234-EI
STAFF'S SECOND REQUEST FOR
PRODUCTION OF DOCUMENTS
DOCUMENT NO. 20
BATES STAMPED PAGE: 982
FILED: OCTOBER 23, 2012

20. Please provide complete copies of all workpapers and source documents, in hard copy and in Excel format as available, used to support or develop TECO's fuel price forecasts as presented in witness Caldwell's direct testimony, Document No. 1.

A. The enclosed CD contains all workpapers and source documents in Excel and Adobe PDF format used to support or develop Tampa Electric's 2012 fuel price forecasts. This electronic response contains both confidential and non-confidential documents.

120234 Hearing Exhibits 00325

Natural Gas Supply, Disposition, and Prices, Reference case
(trillion cubic feet, unless otherwise noted)

Supply, Disposition, and Prices	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	Growth Rate (2010-2035)
Production																												
Dry Gas Production 1/	20.58	21.58	22.97	23.67	22.96	23.24	23.67	24	24.16	24.4	24.77	25.21	25.55	25.82	25.91	26.03	26	26.11	26.11	26.27	26.52	26.79	26.95	27.17	27.44	27.63	27.84	1.00%
Supplemental Natural Gas 2/	0.07	0.07	0.06	0.07	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	-0.20%
Net Imports	**2.68**	**2.58**	**1.89**	**1.68**	**1.59**	**1.72**	**1.7**	**1.35**	**1.12**	**0.96**	**0.69**	**0.29**	**0**	**-0.31**	**-0.57**	**-0.72**	**-0.84**	**-0.9**	**-0.87**	**-0.87**	**-0.91**	**-0.97**	**-0.98**	**-1.03**	**-1.15**	**-1.27**	**-1.45**	- -
Pipeline 3/	2.26	2.21	1.64	1.46	1.46	1.54	1.54	1.44	1.42	1.27	1.21	1.04	0.74	0.44	0.18	0.03	-0.1	-0.16	-0.16	-0.17	-0.2	-0.26	-0.28	-0.32	-0.4	-0.53	-0.68	- -
Liquefied Natural Gas 4/	0.42	0.37	0.25	0.16	0.14	0.18	0.16	-0.08	-0.3	-0.3	-0.52	-0.74	-0.74	-0.74	-0.74	-0.74	-0.74	-0.74	-0.71	-0.7	-0.72	-0.71	-0.7	-0.71	-0.74	-0.74	-0.74	- -
Total Supply	**23.32**	**24.22**	**24.92**	**25.37**	**24.62**	**25.02**	**25.43**	**25.42**	**25.34**	**25.43**	**25.52**	**25.56**	**25.61**	**25.58**	**25.4**	**25.38**	**25.22**	**25.27**	**25.3**	**25.47**	**25.66**	**25.88**	**26.03**	**26.21**	**26.36**	**26.42**	**26.48**	**0.40%**
Consumption by Sector																												
Residential	4.78	4.94	4.92	5.04	4.87	4.88	4.87	4.86	4.85	4.84	4.83	4.82	4.81	4.8	4.78	4.77	4.76	4.75	4.74	4.73	4.73	4.72	4.71	4.69	4.67	4.66	4.65	-0.20%
Commercial	3.12	3.21	3.23	3.32	3.28	3.31	3.33	3.35	3.37	3.38	3.39	3.4	3.4	3.4	3.4	3.4	3.42	3.43	3.43	3.45	3.47	3.49	3.51	3.52	3.53	3.55	3.56	0.40%
Industrial 5/	6.17	6.6	6.78	6.69	6.77	6.9	6.97	7.06	7.15	7.2	7.21	7.23	7.22	7.21	7.17	7.14	7.12	7.08	7.04	7.02	7.01	7	6.99	6.98	6.98	6.97	7	0.20%
Natural Gas-to-Liquids Heat and Power 6/	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0 - -
Natural Gas to Liquids Production 7/	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0 - -
Electric Power 8/	6.87	7.38	7.51	7.82	7.47	7.79	8.09	7.95	7.78	7.81	7.88	7.89	7.93	7.92	7.81	7.82	7.69	7.78	7.86	8.03	8.2	8.4	8.54	8.72	8.86	8.92	8.93	0.80%
Transportation 9/	0.04	0.04	0.04	0.05	0.05	0.05	0.06	0.06	0.07	0.07	0.08	0.08	0.09	0.09	0.1	0.1	0.11	0.12	0.12	0.13	0.13	0.14	0.14	0.15	0.15	0.16	0.16	5.90%
Pipeline Fuel	0.6	0.63	0.65	0.69	0.66	0.67	0.67	0.67	0.67	0.67	0.67	0.67	0.67	0.67	0.67	0.67	0.66	0.66	0.65	0.65	0.65	0.66	0.66	0.66	0.66	0.66	0.66	0.20%
Lease and Plant Fuel 10/	1.28	1.34	1.42	1.46	1.39	1.38	1.39	1.4	1.4	1.41	1.42	1.43	1.44	1.45	1.45	1.44	1.44	1.44	1.43	1.44	1.45	1.46	1.47	1.48	1.49	1.5	1.5	0.50%
Total	**22.85**	**24.13**	**24.55**	**25.07**	**24.48**	**24.97**	**25.38**	**25.37**	**25.29**	**25.38**	**25.48**	**25.52**	**25.57**	**25.54**	**25.37**	**25.35**	**25.2**	**25.25**	**25.28**	**25.45**	**25.65**	**25.87**	**26.02**	**26.2**	**26.35**	**26.42**	**26.48**	**0.40%**
Discrepancy 11/	**0.47**	**0.09**	**0.37**	**0.3**	**0.14**	**0.06**	**0.05**	**0.05**	**0.05**	**0.05**	**0.04**	**0.04**	**0.04**	**0.03**	**0.03**	**0.03**	**0.03**	**0.02**	**0.02**	**0.02**	**0.01**	**0.01**	**0.01**	**0.01**	**0**	**0**	**0** - -
Natural Gas Prices																												
(2010 dollars per million Btu)																												
Henry Hub Spot Price	4	4.39	3.94	3.6	4.11	4.16	4.27	4.3	4.42	4.59	4.72	4.8	5	5.29	5.49	5.64	5.75	5.98	6.17	6.18	6.13	6.19	6.42	6.67	6.83	6.99	7.23	2.00%
Average Lower 48 Wellhead Price 12/	3.75	4.06	3.72	3.34	3.69	3.73	3.83	3.85	3.96	4.1	4.22	4.28	4.46	4.7	4.87	5	5.1	5.3	5.46	5.47	5.42	5.48	5.67	5.89	6.02	6.16	6.36	1.80%
(2010 dollars per thousand cubic feet)																												
Average Lower 48 Wellhead Price 12/	3.85	4.16	3.81	3.42	3.78	3.82	3.92	3.94	4.05	4.2	4.32	4.38	4.56	4.82	4.99	5.12	5.23	5.43	5.59	5.6	5.55	5.61	5.81	6.03	6.17	6.31	6.52	1.80%
Delivered Prices																												
Residential	12.25	11.36	10.66	10.83	10.75	10.37	10.54	10.62	10.79	11.01	11.19	11.33	11.61	11.94	12.16	12.31	12.41	12.64	12.81	12.86	12.87	12.98	13.23	13.49	13.71	13.93	14.21	0.90%
Commercial	10.06	9.32	8.83	8.94	8.92	8.67	8.81	8.85	8.98	9.17	9.32	9.44	9.69	9.99	10.18	10.3	10.38	10.58	10.71	10.74	10.71	10.79	11	11.23	11.41	11.59	11.84	1.00%
Industrial 5/	5.47	5.65	4.97	4.54	4.81	4.86	4.97	4.99	5.09	5.23	5.35	5.44	5.64	5.9	6.07	6.19	6.27	6.47	6.62	6.63	6.58	6.64	6.83	7.06	7.21	7.37	7.59	1.20%
Electric Power 8/	4.97	5.25	4.77	4.47	4.58	4.49	4.64	4.64	4.68	4.83	4.94	5.02	5.2	5.45	5.61	5.74	5.83	6.04	6.19	6.21	6.19	6.27	6.48	6.72	6.87	7.03	7.24	1.30%
Transportation 13/	14.49	13.54	12.86	12.39	12.6	12.6	12.69	12.68	12.74	12.87	12.96	13.01	13.19	13.42	13.54	13.62	13.66	13.81	13.92	13.91	13.86	13.91	14.08	14.28	14.42	14.55	14.75	0.30%
Average 14/	**7.55**	**7.33**	**6.72**	**6.55**	**6.64**	**6.47**	**6.58**	**6.62**	**6.73**	**6.89**	**7.01**	**7.12**	**7.33**	**7.61**	**7.8**	**7.93**	**8.03**	**8.24**	**8.38**	**8.4**	**8.36**	**8.42**	**8.62**	**8.84**	**9**	**9.17**	**9.4**	**1.00%**
(nominal dollars per million Btu)																												
Henry Hub Spot Price	3.95	4.39	4.02	3.7	4.28	4.4	4.61	4.72	4.95	5.24	5.5	5.7	6.06	6.54	6.92	7.26	7.56	8.02	8.44	8.61	8.71	8.98	9.48	10.04	10.46	10.91	11.48	3.90%
Average Lower 48 Wellhead Price 12/	3.71	4.06	3.8	3.44	3.84	3.95	4.13	4.23	4.43	4.68	4.91	5.09	5.4	5.82	6.15	6.45	6.71	7.11	7.47	7.62	7.71	7.94	8.37	8.86	9.23	9.61	10.1	3.70%
(nominal dollars per thousand cubic feet)																												
Average Lower 48 Wellhead Price 12/	3.8	4.16	3.89	3.52	3.93	4.04	4.23	4.33	4.54	4.79	5.03	5.21	5.53	5.96	6.3	6.6	6.87	7.28	7.65	7.81	7.89	8.13	8.57	9.07	9.45	9.84	10.34	3.70%
Delivered Prices																												
Residential	12.11	11.36	10.87	11.15	11.18	10.97	11.36	11.67	12.09	12.57	13.03	13.47	14.08	14.78	15.35	15.86	16.31	16.95	17.52	17.94	18.3	18.81	19.53	20.3	21	21.72	22.55	2.80%
Commercial	9.95	9.32	9.01	9.21	9.28	9.17	9.49	9.73	10.06	10.47	10.85	11.22	11.75	12.36	12.85	13.27	13.64	14.19	14.65	14.97	15.23	15.64	16.24	16.9	17.48	18.08	18.79	2.80%
Industrial 5/	5.4	5.65	5.06	4.67	5.01	5.14	5.36	5.49	5.7	5.97	6.23	6.46	6.84	7.3	7.66	7.97	8.25	8.68	9.06	9.25	9.36	9.62	10.09	10.62	11.04	11.5	12.05	3.10%
Electric Power 8/	4.92	5.25	4.87	4.6	4.76	4.75	5	5.1	5.25	5.51	5.75	5.96	6.31	6.74	7.08	7.39	7.66	8.1	8.47	8.67	8.8	9.08	9.56	10.1	10.53	10.97	11.49	3.20%
Transportation 13/	14.32	13.54	13.12	12.76	13.1	13.33	13.68	13.93	14.28	14.69	15.09	15.46	15.99	16.6	17.09	17.55	17.95	18.52	19.04	19.4	19.71	20.16	20.8	21.48	22.08	22.7	23.41	2.20%
Average 14/	7.46	7.33	6.85	6.75	6.91	6.85	7.1	7.28	7.54	7.87	8.17	8.46	8.89	9.41	9.84	10.21	10.56	11.05	11.47	11.71	11.88	12.2	12.73	13.31	13.78	14.31	14.92	2.90%

1/ Marketed production (wet) minus extraction losses.

2/ Synthetic natural gas, propane air, coke oven gas, refinery gas, biomass gas, air injected for Btu stabilization, and manufactured gas commingled and distributed with natural gas.

3/ Includes any natural gas regasified in the Bahamas and transported via pipeline to Florida, as well as gas from Canada and Mexico.

4/ Includes natural gas used for liquefaction at export terminals.

5/ Includes energy for combined heat and power plants, except those whose primary business is to sell electricity, or electricity and heat, to the public.

6/ Includes any natural gas used in the process of converting natural gas to liquid fuel that is not actually converted.

7/ Includes any natural gas converted into liquid fuel.

8/ Includes consumption of energy by electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public. Includes small power producers and exempt wholesale generators.

9/ Compressed natural gas used as vehicle fuel.

10/ Represents natural gas used in well, field, and lease operations, and in natural gas processing plant machinery.

11/ Balancing item. Natural gas lost as a result of converting flow data measured at varying temperatures and pressures to a standard temperature and pressure and the merger of different data reporting systems which vary in scope, format, definition, and respondent type. In addition, 2009 and 2010 values include net storage injections.

12/ Represents lower 48 onshore and offshore supplies.

13/ Compressed natural gas used as a vehicle fuel. Price includes estimated motor vehicle fuel taxes and estimated dispensing costs or charges.

14/ Weighted average prices. Weights used are the sectoral consumption values excluding lease, plant, and pipeline fuel.

- - = Not applicable.

Note: Totals may not equal sum of components due to independent rounding. Data for 2009 and 2010 are model results and may differ slightly from official EIA data reports.

Sources: 2009 supply values; and lease, plant, and pipeline fuel consumption: Energy Information Administration (EIA), Natural Gas Annual 2009, DOE/EIA-0131(2009) (Washington, DC, December 2010). 2010 supply values; and lease, plant, and pipeline fuel consumption; and wellhead price: EIA, Natural Gas Monthly, DOE/EIA-0130(2011/07) (Washington, DC, July 2011).
Other 2009 and 2010 consumption based on: EIA, Annual Energy Review 2010, DOE/EIA-0384(2010) (Washington, DC, October 2011).
2009 wellhead price: U.S. Department of the Interior, Office of Natural Resources Revenue; and EIA, Natural Gas Annual 2009, DOE/EIA-0131(2009) (Washington, DC, December 2010). 2009 residential and commercial delivered prices: EIA, Natural Gas Annual 2009, DOE/EIA-0131(2009) (Washington, DC, December 2010).
2010 residential and commercial delivered prices: EIA, Natural Gas Monthly, DOE/EIA-0130 (2011/07) (Washington, DC, July 2011). 2009 and 2010 electric power prices: EIA, Electric Power Monthly, DOE/EIA-0226, April 2010 and April 2011, Table 4.13.B, and EIA, State Energy Data System 2009, DOE/EIA-0214(2009) (Washington, DC, June 2011). 2009 and 2010 industrial delivered prices are estimated based on: EIA, Manufacturing Energy Consumption Survey and Industrial and wellhead prices from the Natural Gas Annual 2009, DOE/EIA-0131(2009) (Washington, DC, December 2010) and the Natural Gas Monthly, DOE/EIA-0130(2011/07) (Washington, DC, July 2011). 2009 transportation sector delivered prices are based on: EIA, Natural Gas Annual 2009, DOE/EIA-0131(2009) (Washington, DC, December 2010) and estimated state taxes, federal taxes, and dispensing costs or charges.
2010 transportation sector delivered prices are model results.

120234 Hearing Exhibits 00326

Projections: EIA, AEO2012 National Energy Modeling System.

120234 Hearing Exhibits 00327

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22. Witness Caldwell stated that TECO's fuel price forecast used in the Polk 2-5 economic analyses was the same official long-term forecast prepared in the summer of 2011. Please provide documents containing the full 30-year fuel price forecast TECO prepared in the summer of 2011, inclusive of the years 2011 through 2040.

A. Tampa Electric prepared a 30-year outlook in the summer of 2011 for the 2012 Fuel and Purchase Power Recovery Clause projection. Please see attached document.

120234 Hearing Exhibits 00328

Tampa Electric Fuel Price Forecasts
2011 - 2040

	Natural Gas	No. 2 Oil		Illinois Basin Coal	
Year	$/MMBtu	$/Gallon	$/MMBtu	$/ton	$/MMBtu
2011	$4.30	$3.01	$21.69	$43.79	$1.90
2012	$4.76	$3.10	$22.33	$51.07	$2.22
2013	$5.12	$3.33	$24.04	$55.57	$2.42
2014	$5.39	$3.51	$25.32	$56.45	$2.45
2015	$5.67	$3.69	$26.62	$58.88	$2.56
2016	$5.95	$3.88	$27.96	$55.48	$2.41
2017	$6.23	$4.06	$29.25	$55.24	$2.40
2018	$6.51	$4.24	$30.58	$52.26	$2.27
2019	$6.79	$4.42	$31.88	$56.19	$2.44
2020	$7.07	$4.60	$33.17	$60.34	$2.62
2021	$7.34	$4.78	$34.48	$64.31	$2.80
2022	$7.63	$4.97	$35.83	$68.39	$2.97
2023	$7.80	$5.08	$36.62	$70.77	$3.08
2024	$7.97	$5.19	$37.42	$73.19	$3.18
2025	$8.14	$5.30	$38.22	$75.64	$3.29
2026	$8.31	$5.41	$39.04	$78.10	$3.40
2027	$8.49	$5.53	$39.86	$80.59	$3.50
2028	$8.67	$5.64	$40.70	$83.12	$3.61
2029	$8.85	$5.76	$41.55	$85.70	$3.73
2030	$9.03	$5.88	$42.41	$88.32	$3.84
2031	$9.22	$6.00	$43.29	$90.99	$3.96
2032	$9.41	$6.13	$44.19	$93.70	$4.07
2033	$9.61	$6.26	$45.10	$96.47	$4.19
2034	$9.80	$6.38	$46.03	$99.29	$4.32
2035	$10.01	$6.52	$46.98	$102.16	$4.44
2036	$10.21	$6.65	$47.95	$105.09	$4.57
2037	$10.42	$6.79	$48.93	$108.07	$4.70
2038	$10.64	$6.93	$49.94	$111.11	$4.83
2039	$10.85	$7.07	$50.96	$114.21	$4.97
2040	$11.08	$7.21	$52.00	$117.37	$5.10

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23. Please provide documents containing TECO's updated 30-year fuel price forecasts for the 2013 fuel and purchased power cost recovery clause projection filing, in hard copy and in Excel format as available, as referenced in witness Caldwell's direct testimony at Page 16, Lines 22-24.

A. Please see attached document.

Tampa Electric Fuel Price Forecasts
2012 - 2041

	Natural Gas	No. 2 Oil		Illinois Basin Coal	
Year	$/MMBtu	$/Gallon	$/MMBtu	$/ton	$/MMBtu
2012	$3.09	$3.00	$21.60	$42.21	$1.84
2013	$4.00	$2.85	$20.53	$45.00	$1.96
2014	$4.23	$2.79	$20.11	$47.09	$2.05
2015	$4.43	$2.73	$19.72	$48.05	$2.09
2016	$4.60	$2.82	$20.32	$46.32	$2.01
2017	$4.78	$2.92	$21.03	$47.76	$2.08
2018	$4.96	$2.99	$21.56	$48.39	$2.10
2019	$5.20	$3.07	$22.10	$48.75	$2.12
2020	$5.45	$3.16	$22.77	$50.26	$2.19
2021	$5.71	$3.24	$23.38	$50.93	$2.21
2022	$6.06	$3.33	$23.98	$51.93	$2.26
2023	$6.40	$3.41	$24.60	$54.07	$2.35
2024	$6.68	$3.50	$25.24	$55.73	$2.42
2025	$7.01	$3.61	$26.05	$57.95	$2.52
2026	$7.32	$3.72	$26.79	$60.18	$2.62
2027	$7.67	$3.81	$27.49	$62.44	$2.71
2028	$7.94	$3.92	$28.28	$64.63	$2.81
2029	$8.27	$4.05	$29.22	$67.15	$2.92
2030	$8.63	$4.18	$30.13	$69.65	$3.03
2031	$9.01	$4.37	$31.51	$72.52	$3.15
2032	$9.44	$4.53	$32.66	$75.44	$3.28
2033	$9.79	$4.57	$32.95	$77.90	$3.39
2034	$10.50	$4.72	$34.02	$81.99	$3.56
2035	$11.19	$4.89	$35.26	$86.27	$3.75
2036	$11.62	$5.06	$36.50	$89.91	$3.91
2037	$12.08	$5.24	$37.78	$93.70	$4.07
2038	$12.56	$5.42	$39.10	$97.65	$4.25
2039	$13.05	$5.61	$40.47	$101.77	$4.42
2040	$13.56	$5.81	$41.88	$106.06	$4.61
2041	$14.10	$6.01	$43.35	$110.53	$4.81

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24. Please provide a document containing TECO's high and low price forecasts of natural gas, distillate oil, residential oil, and coal as referenced in witness Caldwell's direct testimony at page 16.

A. Please see the attached document.

120234 Hearing Exhibits 00332

Tampa Electric Fuel Price Forecasts
2011 - 2040
Low Forecast

	Natural Gas	No. 2 Oil		Illinois Basin Coal	
Year	$/MMBtu	$/Gallon	$/MMBtu	$/ton	$/MMBtu
2012	$2.01	$1.95	$14.04	$43.79	$1.90
2013	$2.60	$1.85	$13.34	$51.07	$2.22
2014	$2.75	$1.81	$13.07	$44.46	$1.93
2015	$2.88	$1.78	$12.82	$45.16	$1.96
2016	$2.99	$1.83	$13.20	$47.11	$2.05
2017	$3.10	$1.90	$13.67	$44.39	$1.93
2018	$3.23	$1.94	$14.01	$44.19	$1.92
2019	$3.38	$1.99	$14.37	$41.81	$1.82
2020	$3.55	$2.05	$14.80	$45.40	$1.97
2021	$3.71	$2.11	$15.19	$49.19	$2.14
2022	$3.94	$2.16	$15.58	$52.81	$2.30
2023	$4.16	$2.22	$15.99	$56.54	$2.46
2024	$4.34	$2.28	$16.41	$58.71	$2.55
2025	$4.56	$2.35	$16.93	$60.92	$2.65
2026	$4.76	$2.41	$17.41	$63.15	$2.75
2027	$4.99	$2.48	$17.87	$65.40	$2.84
2028	$5.16	$2.55	$18.38	$67.67	$2.94
2029	$5.38	$2.63	$18.99	$69.98	$3.04
2030	$5.61	$2.72	$19.58	$72.33	$3.14
2031	$5.85	$2.84	$20.48	$74.72	$3.25
2032	$6.13	$2.94	$21.23	$77.16	$3.35
2033	$6.37	$2.97	$21.42	$79.64	$3.46
2034	$6.82	$3.07	$22.11	$82.17	$3.57
2035	$7.27	$3.18	$22.92	$84.74	$3.68
2036	$7.56	$3.29	$23.72	$87.36	$3.80
2037	$7.85	$3.41	$24.55	$90.03	$3.91
2038	$8.16	$3.52	$25.41	$92.76	$4.03
2039	$8.48	$3.65	$26.30	$95.53	$4.15
2040	$8.82	$3.78	$27.22	$98.36	$4.28
2041	$9.16	$3.91	$28.18	$101.24	$4.40

Tampa Electric Fuel Price Forecasts
2011 - 2040
High Forecast

	Natural Gas	No. 2 Oil		Illinois Basin Coal	
Year	$/MMBtu	$/Gallon	$/MMBtu	$/ton	$/MMBtu
2012	$4.17	$4.04	$29.16	$43.79	$1.90
2013	$5.40	$3.84	$27.72	$51.07	$2.22
2014	$5.71	$3.76	$27.14	$66.69	$2.90
2015	$5.98	$3.69	$26.62	$67.74	$2.95
2016	$6.21	$3.80	$27.43	$70.66	$3.07
2017	$6.45	$3.94	$28.39	$66.58	$2.89
2018	$6.70	$4.04	$29.10	$66.29	$2.88
2019	$7.02	$4.14	$29.84	$62.71	$2.73
2020	$7.36	$4.26	$30.74	$66.91	$2.91
2021	$7.71	$4.38	$31.56	$71.34	$3.10
2022	$8.19	$4.49	$32.37	$75.58	$3.29
2023	$8.64	$4.61	$33.21	$79.94	$3.48
2024	$9.02	$4.73	$34.08	$82.48	$3.59
2025	$9.47	$4.88	$35.17	$85.06	$3.70
2026	$9.89	$5.02	$36.16	$87.68	$3.81
2027	$10.36	$5.15	$37.12	$90.31	$3.93
2028	$10.72	$5.29	$38.18	$92.97	$4.04
2029	$11.17	$5.47	$39.44	$95.67	$4.16
2030	$11.65	$5.64	$40.67	$98.42	$4.28
2031	$12.16	$5.90	$42.53	$101.22	$4.40
2032	$12.74	$6.12	$44.09	$104.07	$4.52
2033	$13.22	$6.17	$44.48	$106.97	$4.65
2034	$14.17	$6.37	$45.93	$109.93	$4.78
2035	$15.10	$6.60	$47.61	$112.94	$4.91
2036	$15.69	$6.83	$49.27	$116.00	$5.04
2037	$16.31	$7.07	$51.00	$119.13	$5.18
2038	$16.95	$7.32	$52.78	$122.31	$5.32
2039	$17.62	$7.58	$54.63	$125.56	$5.46
2040	$18.31	$7.84	$56.54	$128.87	$5.60
2041	$19.03	$8.12	$58.52	$132.24	$5.75

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25. Please provide all documents TECO relied upon in the preparation of each high and low price forecast of natural gas, distillate oil, residual oil, and coal as referenced in witness Caldwell's direct testimony at page 16.

A. The enclosed CD contains all workpapers and source documents in Excel and Adobe PDF format used to support or develop Tampa Electric's 2013 fuel price forecasts. This electronic response contains both confidential and non-confidential documents. A redacted version of these documents are attached.

In addition, see Tampa Electric's response to Staff's Second Data Request, No. 20; file name: Confidential Workpapers/Confidential_2012 GFI NG Base Model Master.xlsx. as provided in on the enclosed CD.

Summary of Historic Fuel Price Variations
2005 - 2010

	Natural Gas $/mmBtu	No. 2 Oil $/gallon	Ill Basin Coal $/ton
2005	$ 8.62	$ 1.64	$ 36.99
2006	$ 7.23	$ 1.84	$ 38.31
2007	$ 6.86	$ 2.04	$ 33.75
2008	$ 9.03	$ 2.85	$ 64.41
2009	$ 3.99	$ 1.66	$ 46.65
2010	$ 4.39	$ 2.14	$ 44.30
Average 2005 - 2010	$ 6.69	$ 2.03	$ 44.07
High 2005 - 2010	$ 9.03	$ 2.85	$ 64.41
Low 2005 - 2010	$ 3.99	$ 1.64	$ 33.75
Range	$ 5.05	$ 1.22	$ 30.66
Half of Range	$ 2.52	$ 0.61	$ 15.33
Half of Range as % of Average	38%	30%	35%
Standard Deviation 2005 - 2010	$ 2.10	$ 0.45	$ 11.05
Standard Deviation as % of Average	31%	22%	25%
Recommended Sensitivity	35%	35%	20%

Natural Gas Prices		No. 2 Oil Prices		Illinois Basin Coal
Jan-02	$ 2.56	Jan-02	53.75	Jan-02
Feb-02	$ 2.01	Feb-02	54.47	Feb-02
Mar-02	$ 2.39	Mar-02	63.92	Mar-02
Apr-02	$ 3.47	Apr-02	66.94	Apr-02
May-02	$ 3.32	May-02	66.83	May-02
Jun-02	$ 3.42	Jun-02	65.01	Jun-02
Jul-02	$ 3.28	Jul-02	68.44	Jul-02
Aug-02	$ 2.98	Aug-02	71.44	Aug-02
Sep-02	$ 3.29	Sep-02	78.53	Sep-02
Oct-02	$ 3.69	Oct-02	77.70	Oct-02
Nov-02	$ 4.13	Nov-02	71.96	Nov-02
Dec-02	$ 4.26	Dec-02	82.51	Dec-02
Jan-03	$ 4.99	Jan-03	90.64	Jan-03
Feb-03	$ 5.66	Feb-03	107.42	Feb-03
Mar-03	$ 9.13	Mar-03	91.62	Mar-03
Apr-03	$ 5.15	Apr-03	74.69	Apr-03
May-03	$ 5.12	May-03	72.69	May-03
Jun-03	$ 5.95	Jun-03	76.17	Jun-03
Jul-03	$ 5.29	Jul-03	78.83	Jul-03
Aug-03	$ 4.69	Aug-03	82.37	Aug-03
Sep-03	$ 4.93	Sep-03	74.53	Sep-03
Oct-03	$ 4.43	Oct-03	82.53	Oct-03
Nov-03	$ 4.46	Nov-03	84.33	Nov-03
Dec-03	$ 4.68	Dec-03	90.11	Dec-03
Jan-04	$ 6.15	Jan-04	98.56	Jan-04
Feb-04	$ 5.78	Feb-04	91.28	Feb-04
Mar-04	$ 5.15	Mar-04	91.17	Mar-04
Apr-04	$ 5.37	Apr-04	92.19	Apr-04
May-04	$ 5.94	May-04	101.55	May-04
Jun-04	$ 6.68	Jun-04	99.89	Jun-04
Jul-04	$ 6.14	Jul-04	110.01	Jul-04
Aug-04	$ 6.05	Aug-04	118.24	Aug-04
Sep-04	$ 5.08	Sep-04	126.34	Sep-04
Oct-04	$ 5.72	Oct-04	149.03	Oct-04
Nov-04	$ 7.63	Nov-04	139.91	Nov-04
Dec-04	$ 7.98	Dec-04	129.88	Dec-04
Jan-05	$ 6.21	Jan-05	132.41	Jan-05
Feb-05	$ 6.29	Feb-05	133.96	Feb-05
Mar-05	$ 6.30	Mar-05	154.34	Mar-05
Apr-05	$ 7.32	Apr-05	151.54	Apr-05
May-05	$ 6.75	May-05	141.09	May-05
Jun-05	$ 6.12	Jun-05	162.01	Jun-05
Jul-05	$ 6.98	Jul-05	166.60	Jul-05

Natural Gas Prices		No. 2 Oil Prices		Illinois Basin Coal
Aug-05	$ 7.65	Aug-05	183.26	Aug-05
Sep-05	$ 10.85	Sep-05	200.02	Sep-05
Oct-05	$ 13.91	Oct-05	193.27	Oct-05
Nov-05	$ 13.83	Nov-05	172.85	Nov-05
Dec-05	$ 11.18	Dec-05	174.63	Dec-05
Jan-06	$ 11.43	Jan-06	178.71	Jan-06
Feb-06	$ 8.40	Feb-06	168.66	Feb-06
Mar-06	$ 7.11	Mar-06	177.92	Mar-06
Apr-06	$ 7.23	Apr-06	197.87	Apr-06
May-06	$ 7.20	May-06	198.60	May-06
Jun-06	$ 5.93	Jun-06	196.94	Jun-06
Jul-06	$ 5.89	Jul-06	199.51	Jul-06
Aug-06	$ 7.04	Aug-06	203.47	Aug-06
Sep-06	$ 6.82	Sep-06	175.42	Sep-06
Oct-06	$ 4.20	Oct-06	169.00	Oct-06
Nov-06	$ 7.15	Nov-06	169.89	Nov-06
Dec-06	$ 8.32	Dec-06	172.64	Dec-06
Jan-07	$ 5.84	Jan-07	154.67	Jan-07
Feb-07	$ 6.92	Feb-07	169.58	Feb-07
Mar-07	$ 7.55	Mar-07	174.15	Mar-07
Apr-07	$ 7.56	Apr-07	186.20	Apr-07
May-07	$ 7.51	May-07	188.03	May-07
Jun-07	$ 7.59	Jun-07	199.05	Jun-07
Jul-07	$ 6.93	Jul-07	207.90	Jul-07
Aug-07	$ 6.11	Aug-07	199.75	Aug-07
Sep-07	$ 5.43	Sep-07	219.88	Sep-07
Oct-07	$ 6.42	Oct-07	229.86	Oct-07
Nov-07	$ 7.27	Nov-07	260.05	Nov-07
Dec-07	$ 7.20	Dec-07	257.88	Dec-07
Jan-08	$ 7.17	Jan-08	256.13	Jan-08
Feb-08	$ 8.00	Feb-08	265.04	Feb-08
Mar-08	$ 8.93	Mar-08	300.98	Mar-08
Apr-08	$ 9.58	Apr-08	318.74	Apr-08
May-08	$ 11.28	May-08	361.63	May-08
Jun-08	$ 11.92	Jun-08	381.20	Jun-08
Jul-08	$ 13.11	Jul-08	378.16	Jul-08
Aug-08	$ 9.22	Aug-08	319.08	Aug-08
Sep-08	$ 8.39	Sep-08	293.18	Sep-08
Oct-08	$ 7.47	Oct-08	224.13	Oct-08
Nov-08	$ 6.47	Nov-08	185.13	Nov-08
Dec-08	$ 6.89	Dec-08	142.12	Dec-08
Jan-09	$ 6.14	Jan-09	146.55	Jan-09
Feb-09	$ 4.48	Feb-09	127.52	Feb-09
Mar-09	$ 4.06	Mar-09	129.24	Mar-09
Apr-09	$ 3.63	Apr-09	137.58	Apr-09
May-09	$ 3.32	May-09	150.28	May-09
Jun-09	$ 3.54	Jun-09	178.77	Jun-09

Natural Gas Prices				No. 2 Oil Prices				Illinois Basin Coal			
Jul-09	$	3.95		Jul-09		166.27		Jul-09			
Aug-09	$	3.38		Aug-09		188.50		Aug-09			
Sep-09	$	2.84		Sep-09		175.94		Sep-09			
Oct-09	$	3.73		Oct-09		195.52		Oct-09			
Nov-09	$	4.29		Nov-09		202.05		Nov-09			
Dec-09	$	4.49		Dec-09		199.77		Dec-09			
Jan-10	$	5.81		Jan-10		206.09		Jan-10			
Feb-10	$	5.27		Feb-10		198.72		Feb-10			
Mar-10	$	4.82		Mar-10		209.44		Mar-10			
Apr-10	$	3.84		Apr-10		223.04		Apr-10			
May-10	$	4.27		May-10		204.78		May-10			
Jun-10	$	4.16		Jun-10		204.67		Jun-10			
Jul-10	$	4.72		Jul-10		200.70		Jul-10			
Aug-10	$	4.77		Aug-10		205.40		Aug-10			
Sep-10	$	3.65		Sep-10		211.26		Sep-10			
Oct-10	$	3.84		Oct-10		226.06		Oct-10			
Nov-10	$	3.29		Nov-10		233.47		Nov-10			
Dec-10	$	4.27		Dec-10		248.69		Dec-10			
Jan-11	$	4.22		Jan-11		260.93		Jan-11			
Feb-11	$	4.32		Feb-11		277.72		Feb-11			
Mar-11	$	3.79		Mar-11		304.53		Mar-11			
Apr-11	$	4.24		Apr-11		320.62		Apr-11			
2002	$	3.23		**2002**	$	68.46		**2002**	$	24.52	
2003	$	5.37		**2003**	$	83.83		**2003**	$	34.10	
2004	$	6.14		**2004**	$	112.34		**2004**	$	36.99	
2005	$	8.62		**2005**	$	163.83		**2005**	$	38.31	
2006	$	7.23		**2006**	$	184.05		**2006**	$	33.75	
2007	$	6.86		**2007**	$	203.92		**2007**	$	64.41	
2008	$	9.03		**2008**	$	285.46		**2008**	$	46.65	
2009	$	3.99		**2009**	$	166.50		**2009**	$	44.30	
2010	$	4.39		**2010**	$	214.36		**2010**	$	49.68	
Average	$	6.10		**Average**	$	6.61		**Average**	$	6.61	
Std Dev	$	2.03	33%	**Std Dev**	$	1.93	29%	**Std Dev**	$	1.93	29%
Avg - 1STD	$	4.07		Avg - 1STD	$	4.68		Avg - 1STD	$	4.68	
Avg + 1STD	$	8.12		Avg + 1STD	$	8.54		Avg + 1STD	$	8.54	
Min	$	3.23	-47%	Min	$	68.46	936%	Min	$	24.52	271%
Max	$	9.03	48%	Max	$	285.46	4220%	Max	$	64.41	875%
Avg 2005 -	$	6.69		Avg 2005 -	$	203.02		Avg 2005 -	$	46.18	
STD 2005 -	$	2.10	31%	STD 2005 -	$	45.07	22%	STD 2005 -	$	10.63	23%
Min 2005 -	$	3.99	-40%	Min 2005 -	$	163.83	-19%	Min 2005 -	$	33.75	-27%
Max 2005 -	$	9.03	35%	Max 2005 -	$	285.46	41%	Max 2005 -	$	64.41	39%

TECO's Answer to Second Request for Production of Documents (No. 20) (CONFIDENTIAL – Work papers /Confidential_2012 GFI NG Base Model Master.xlsx, worksheet entitled "Inputs") of the Florida Public Service Commission

(Confidential FPSC Document No. 07212-12)

9

TECO's Answer to Third Request for Production of Documents (No. 26) of the Florida Public Service Commission

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 120234-EI EXHIBIT 9
PARTY Florida Public Service Commission Staff
DESCRIPTION TECO - Staff Exhibit #9
[Bates Nos. 00341-00344]

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition to determine need for) Polk 2-5 combined cycle conversion,) by Tampa Electric Company)	DOCKET NO. 120234-EI FILED: November 1, 2012

TAMPA ELECTRIC COMPANY'S

ANSWERS TO THIRD REQUEST FOR

PRODUCTION OF DOCUMENTS (NO. 26)

OF

FLORIDA PUBLIC SERVICE COMMISSION STAFF

Tampa Electric files this its Answers to Production of Documents (No. 26) propounded and served on October 12, 2012, by the Florida Public Service Commission Staff.

TAMPA ELECTRIC COMPANY
DOCKET NO. 120234-EI
INDEX TO STAFF'S THIRD REQUEST FOR
PRODUCTION OF DOCUMENTS (NO. 26)

Number	Subject	Bates Stamped Pages
26	Please provide the documents containing the development of the independent fuel price forecasts depicted in witness Caldwell's direct testimony, Exhibit JBC-1, Document 2, at Page 27.	1

TAMPA ELECTRIC COMPANY
DOCKET NO. 120234-EI
STAFF'S THIRD REQUEST FOR
PRODUCTION OF DOCUMENTS
DOCUMENT NO. 26
BATES STAMPED PAGE: 1
FILED: NOVEMBER 1, 2012

26. Please provide the documents containing the development of the independent fuel price forecasts depicted in witness Caldwell's direct testimony, Exhibit JBC-1, Document 2, at Page 27.

A. The documents containing the development of the independent fuel price forecasts depicted in witness Caldwell's direct testimony, Exhibit JBC-1, Document 2, at page 27, were previously provided as part of Tampa Electric's response to Staff's Second Request for Production of Documents, No. 20. The responsive files are listed below.

- CONFIDENTIAL-NAGS_LTV_Price_Outlook_Oct_2011.xls
- NON-CONFIDENTIAL _Source Docs/Non-confidential_Early 2012 NG Supply Disposition.pdf
- CONFIDENTIAL – Workpapers/CONFIDENTIAL_2012 GFI NG Base Model Master.xlsx

10

TECO's Answer to Fourth Request for Production of Documents (Nos. 27, 28 (redacted), 29 (*BSP 105-108*) of the Florida Public Service Commission

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 120234-EI EXHIBIT 10
PARTY Florida Public Service Commission Staff
DESCRIPTION TECO - Staff Exhibit #10 - Confidential
[Bates Nos. 00345-00355] & [Bates No. 00356]

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition to determine need for Polk 2-5 combined cycle conversion, by Tampa Electric Company	DOCKET NO. 120234-EI FILED: November 26, 2012

REDACTED

TAMPA ELECTRIC COMPANY'S

ANSWERS TO FOURTH REQUEST FOR

PRODUCTION OF DOCUMENTS (NO. 27-30)

OF

FLORIDA PUBLIC SERVICE COMMISSION STAFF

Tampa Electric files this its Answers to Production of Documents (No. 27-30) propounded and served on November 5, 2012, by the Florida Public Service Commission Staff.

TAMPA ELECTRIC COMPANY
DOCKET NO. 120234-EI
INDEX TO STAFF'S FOURTH REQUEST FOR PRODUCTION OF DOCUMENTS (NO. 27-30)

Number	Subject	Bates Stamped Pages
27	Please provide the Henry Hub natural gas price forecast TECO used to develop its natural gas price forecast, if not already reflected in Appendix H of the Need Study or elsewhere in its filings in this proceeding.	1
28	Please provide recent forecasts of the real price of natural gas prepared by the EIA or Wood MacKenzie which feature a growth rate for the years 2022 through 2040 which are approximately the same as the growth rate of the real price of natural gas (commodity) shown in TECO's response to Staff Interrogatory No. 50, Page 73B, for the same time period.	2-3
29	Please provide the independent fuel price forecasts TECO used to determine the reasonableness of its 2013 fuel price forecasts referenced on Page 17, lines 2-4 of witness Caldwell's direct testimony.	4-224
30	Please provide complete copies of all workpapers and source documents in hard copy and in Excel format as available, used to support and develop TECO's 2013 fuel price forecast as discussed in witness Caldwell's direct testimony, Page 17, lines 2-4.	225-360

TAMPA ELECTRIC COMPANY
DOCKET NO. 120234-EI
STAFF'S FOURTH REQUEST FOR
PRODUCTION OF DOCUMENTS
DOCUMENT NO. 27
BATES STAMPED PAGE: 1
FILED: NOVEMBER 26, 2012

27. Please provide the Henry Hub natural gas price forecast TECO used to develop its natural gas price forecast, if not already reflected in Appendix H of the Need Study or elsewhere in its filings in this proceeding.

A. The Henry Hub natural gas price forecast Tampa Electric used in its Need Study is shown in Exhibit JBC-1. The Henry Hub natural gas price forecast was also provided in Staff's Second Set of Interrogatories, No. 50, in the table under the column heading "Commodity". The natural gas commodity price is shown in nominal dollars in the first table and then in real dollars (2012$) in the second table.

While Appendix H includes the same price for the natural gas commodity as the Henry Hub; Appendix H also includes variable transportation costs to transport the commodity to a power plant.

120234 Hearing Exhibits 00348

REDACTED

TAMPA ELECTRIC COMPANY
DOCKET NO. 120234-EI
STAFF'S FOURTH REQUEST FOR
PRODUCTION OF DOCUMENTS
DOCUMENT NO. 28
BATES STAMPED PAGES: 2 - 3
FILED: NOVEMBER 26, 2012

28. Please provide recent forecasts of the real price of natural gas prepared by the EIA or Wood MacKenzie which feature a growth rate for the years 2022 through 2040 which are approximately the same as the growth rate of the real price of natural gas (commodity) shown in TECO's response to Staff Interrogatory No. 50, Page 73B, for the same time period.

A. The table below reflects the most recent Wood MacKenzie and EIA natural gas forecasts, as well as Tampa Electric's natural gas price forecast. The reflected prices are the commodity costs at the Henry Hub expressed in real dollars (using the basis year of the source). As can be seen by the Annual Average Growth Rate calculated at the bottom of each forecast, Tampa Electric's assumption of a constant price in real dollars is similar to the growth rate projected by Wood MacKenzie, but is less than the growth rate projected by the Energy Information Administration.

Natural Gas Price Forecasts at Henry Hub
(Real Dollars per Million Btu)

Year	Tampa Electric (2012$)	Wood MacKenzie (2011$)	Energy Information Administration (2010$)
2013	$5.05	[redacted]	$4.06
2014	$5.17		$4.17
2015	$5.31		$4.29
2016	$5.46		$4.26
2017	$5.60		$4.29
2018	$5.73		$4.34
2019	$5.85		$4.46
2020	$5.95		$4.58
2021	$6.05		$4.82
2022	$6.15		$5.11
2023	$6.15		$5.32
2024	$6.15		$5.46
2025	$6.15		$5.63
2026	$6.15		$5.77
2027	$6.15		$5.94
2028	$6.15		$6.03
2029	$6.15		$6.15
2030	$6.15		$6.29
2031	$6.15		$6.42

TAMPA ELECTRIC COMPANY
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Year	Tampa Electric (2012$)	Wood MacKenzie (2011$)	Energy Information Administration (2010$)
2032	$6.15		$6.58
2033	$6.15		$6.71
2034	$6.15		$7.06
2035	$6.15		$7.37
2036	$6.15		
2037	$6.15		
2038	$6.15		
2039	$6.15		
2040	$6.15		
AAGR 2023 - 2031	0.00%	0.43%	2.38%
AAGR 2023 - 2035	0.00%	NA	2.75%
AAGR 2023 - 2040	0.00%	NA	NA

Notes:
Tampa Electric natural gas price forecast is from summer 2011 prepared for 2012 Fuel Clause projection.
Wood MacKenzie natural gas price forecast is from the Natural Gas Service Long-term View issued April, 2012.
Energy Information Administration natural gas price forecast is from the 2012 Annual Energy Outlook released June, 2012.

TAMPA ELECTRIC COMPANY
DOCKET NO. 120234-EI
STAFF'S FOURTH REQUEST FOR
PRODUCTION OF DOCUMENTS
DOCUMENT NO. 29
BATES STAMPED PAGES: 4 - 224
FILED: NOVEMBER 26, 2012

29. Please provide the independent fuel price forecasts TECO used to determine the reasonableness of its 2013 fuel price forecasts referenced on Page 17, lines 2-4 of witness Caldwell's direct testimony.

A. Please see the attached document. Additionally, the enclosed CD contains, in Excel format, the confidential independent fuel price forecasts files listed below that were used to determine the reasonableness of Tampa Electric's 2013 fuel price forecasts. These documents are updated versions of the files that Tampa Electric previously provided as part of Staff's Second Request for Production of Documents, No. 20.

- NAGS_LTV_Price_Outlook_Spring_2012 inc Ill Basin coal.xls (CONFIDENTIAL)
- JDE_CM_201207.xls (CONFIDENTIAL).

ref2012.d020112c

133. Lower 48 Natural Gas Production and Wellhead Prices by Supply Region

Region	2009	2010	2011	2012	2013
Dry Production (trillion cubic feet) 1/					
Lower 48 Total	**20.21**	**21.22**	**22.62**	**23.34**	**22.46**
Lower 48 Onshore	**17.50**	**18.66**	**20.45**	**21.33**	**20.67**
Northeast	1.08	1.52	1.91	2.32	2.40
Gulf Coast	4.31	4.85	5.83	6.20	5.97
Midcontinent	3.24	3.43	3.53	3.42	3.21
Southwest	3.54	3.59	3.98	4.00	3.89
Rocky Mountain	5.11	5.06	4.93	5.13	4.96
West Coast	0.22	0.21	0.28	0.27	0.24
Lower 48 Offshore	**2.70**	**2.56**	**2.17**	**2.01**	**1.79**
Gulf	2.66	2.52	2.12	1.97	1.75
Shallow	1.21	0.94	1.08	0.87	0.71
Deep	1.45	1.58	1.04	1.10	1.04
Pacific	0.04	0.04	0.05	0.04	0.04
Atlantic	0.00	0.00	0.00	0.00	0.00
Prices					
(2010 dollars per million Btu)					
Henry Hub	4.00	4.39	3.94	3.58	4.06
Lower 48 Average	3.75	4.06	3.72	3.32	3.65
(2010 dollars per thousand cubic feet)					
Lower 48 Average	3.85	4.16	3.81	3.40	3.73
Lower 48 Onshore					
Northeast	4.22	4.59	4.38	3.91	3.95
Gulf Coast	3.87	4.18	3.55	3.20	3.80
Midcontinent	3.55	3.85	3.97	3.54	3.88
Southwest	3.90	4.21	3.72	3.34	3.69
Rocky Mountain	3.51	3.79	3.56	3.19	3.33
West Coast	4.01	4.33	3.72	3.52	3.94
Lower 48 Offshore					
Gulf	4.56	4.93	4.47	3.83	4.19
Pacific	4.19	4.52	5.04	4.29	3.93
Atlantic	3.92	4.25	4.27	3.40	3.60

1/ Marketed production (wet) minus extraction losses.
-- = Not applicable.
Note: Oil and Gas Supply Model regions are defined in Appendix F of the Annual Energy Outlook. Totals may not equal sum of components due to independent rounding.
Sources: 2009: U.S. Department of the Interior, Office of Natural Resources Revenue; and U.S. Energy Information Administration (EIA), Natural Gas Annual 2009, DOE/EIA-0131(2009) (Washington, DC, December 2010); EIA, U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves, DOE/EIA-0216(2009) (Washington, DC, November 2010); and EIA, Office of Energy Analysis (OEA). 2010: EIA, Natural Gas Monthly, DOE/EIA-0130(2011/07) (Washington, DC, July 2011) and EIA, OEA. Projections: EIA, AEO2012 National Energy Modeling System run ref2012.d020112c.

ref2012.d020112c
133. Lower 48 Natural Gas Production and W

Region	2014	2015	2016	2017	2018	2019	2020	2021
Dry Production (trillion cubic feet) 1/								
Lower 48 Total	**22.84**	**23.36**	**23.72**	**23.95**	**24.13**	**24.50**	**24.82**	**25.13**
Lower 48 Onshore	**21.08**	**21.48**	**21.62**	**21.79**	**22.01**	**22.30**	**22.48**	**22.75**
Northeast	2.59	2.78	2.96	3.16	3.33	3.48	3.62	3.77
Gulf Coast	5.96	5.98	5.92	5.87	5.86	5.92	5.96	6.03
Midcontinent	3.21	3.16	3.09	3.06	3.02	2.99	2.96	2.94
Southwest	3.98	4.06	4.07	4.10	4.15	4.19	4.20	4.19
Rocky Mountain	5.12	5.28	5.34	5.39	5.44	5.51	5.53	5.63
West Coast	0.23	0.22	0.24	0.22	0.21	0.21	0.20	0.20
Lower 48 Offshore	**1.76**	**1.88**	**2.10**	**2.16**	**2.12**	**2.20**	**2.34**	**2.38**
Gulf	1.72	1.85	2.06	2.12	2.09	2.17	2.31	2.35
Shallow	0.64	0.58	0.54	0.52	0.49	0.49	0.48	0.49
Deep	1.09	1.27	1.53	1.61	1.60	1.68	1.83	1.86
Pacific	0.04	0.03	0.03	0.03	0.03	0.03	0.03	0.03
Atlantic	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Prices								
(2010 dollars per million Btu)								
Henry Hub	4.17	4.29	4.26	4.29	4.34	4.46	4.58	4.82
Lower 48 Average	3.74	3.84	3.81	3.85	3.89	3.99	4.10	4.30
(2010 dollars per thousand cubic feet)								
Lower 48 Average	3.83	3.94	3.91	3.94	3.98	4.09	4.19	4.41
Lower 48 Onshore								
Northeast	4.05	4.16	4.10	4.10	4.19	4.32	4.44	4.65
Gulf Coast	3.95	4.04	3.97	4.00	3.97	4.06	4.21	4.37
Midcontinent	3.92	4.08	4.03	4.03	4.03	4.16	4.30	4.46
Southwest	3.76	3.93	3.92	3.87	3.92	4.06	4.20	4.42
Rocky Mountain	3.46	3.66	3.72	3.77	3.85	3.97	4.03	4.30
West Coast	4.06	4.09	4.21	4.22	4.33	4.50	4.44	4.70
Lower 48 Offshore								
Gulf	4.12	3.81	3.67	3.93	4.05	4.03	3.98	4.25
Pacific	3.88	4.21	4.49	4.49	4.41	4.63	4.62	4.90
Atlantic	3.75	4.02	3.94	3.68	3.84	4.00	4.15	4.36

1/ Marketed production (wet) minus extraction losses.
- - = Not applicable.
Note: Oil and Gas Supply Model regions are defined in Appendix F c
components due to independent rounding.
Sources: 2009: U.S. Department of the Interior, Office of Natural Re
Information Administration (EIA), Natural Gas Annual 2009, DOE/EIA-(
Natural Gas, and Natural Gas Liquids Reserves, DOE/EIA-0216(2009)
Energy Analysis (OEA). 2010: EIA, Natural Gas Monthly, DOE/EIA-01
and EIA, OEA. Projections: EIA, AEO2012 National Energy Modeling

ref2012.d020112c 133. Lower 48 Natural Gas Production and V	2022	2023	2024	2025	2026	2027	2028	2029
Region	2022	2023	2024	2025	2026	2027	2028	2029
Dry Production (trillion cubic feet) 1/								
Lower 48 Total	**25.40**	**25.66**	**25.86**	**26.02**	**26.18**	**26.29**	**26.41**	**26.55**
Lower 48 Onshore	**23.04**	**23.30**	**23.47**	**23.64**	**23.80**	**23.88**	**23.94**	**24.04**
Northeast	3.93	4.08	4.21	4.33	4.44	4.56	4.66	4.76
Gulf Coast	6.13	6.24	6.31	6.39	6.46	6.51	6.56	6.61
Midcontinent	2.90	2.87	2.85	2.83	2.81	2.79	2.76	2.73
Southwest	4.17	4.16	4.14	4.12	4.09	4.02	3.97	3.96
Rocky Mountain	5.72	5.76	5.78	5.79	5.81	5.83	5.81	5.81
West Coast	0.20	0.19	0.19	0.18	0.18	0.17	0.17	0.17
Lower 48 Offshore	**2.36**	**2.35**	**2.39**	**2.38**	**2.38**	**2.41**	**2.48**	**2.52**
Gulf	2.33	2.33	2.37	2.36	2.36	2.39	2.44	2.48
Shallow	0.49	0.49	0.49	0.50	0.50	0.51	0.52	0.52
Deep	1.84	1.84	1.88	1.86	1.85	1.88	1.93	1.96
Pacific	0.03	0.02	0.02	0.02	0.02	0.02	0.03	0.04
Atlantic	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Prices								
(2010 dollars per million Btu)								
Henry Hub	5.11	5.32	5.46	5.63	5.77	5.94	6.03	6.15
Lower 48 Average	4.55	4.73	4.85	5.00	5.12	5.26	5.34	5.44
(2010 dollars per thousand cubic feet)								
Lower 48 Average	4.66	4.85	4.97	5.12	5.24	5.39	5.47	5.57
Lower 48 Onshore								
Northeast	4.88	5.05	5.17	5.36	5.47	5.60	5.69	5.79
Gulf Coast	4.55	4.76	4.88	5.01	5.15	5.27	5.37	5.49
Midcontinent	4.71	4.85	4.99	5.12	5.23	5.35	5.45	5.56
Southwest	4.65	4.83	4.96	5.10	5.23	5.43	5.44	5.53
Rocky Mountain	4.60	4.83	4.96	5.09	5.23	5.40	5.48	5.56
West Coast	5.11	5.38	5.56	5.72	5.76	5.92	5.95	6.08
Lower 48 Offshore								
Gulf	4.63	4.73	4.79	5.03	5.12	5.21	5.27	5.40
Pacific	5.31	5.57	5.75	5.90	5.92	7.51	8.17	8.08
Atlantic	4.60	4.78	4.91	5.03	5.19	5.32	5.39	5.50

1/ Marketed production (wet) minus extraction losses.
- - = Not applicable.
Note: Oil and Gas Supply Model regions are defined in Appendix F c components due to independent rounding.
Sources: 2009: U.S. Department of the Interior, Office of Natural Re Information Administration (EIA), Natural Gas Annual 2009, DOE/EIA-(Natural Gas, and Natural Gas Liquids Reserves, DOE/EIA-0216(2009) Energy Analysis (OEA). 2010: EIA, Natural Gas Monthly, DOE/EIA-01 and EIA, OEA. Projections: EIA, AEO2012 National Energy Modeling

ref2012.d020112c 133. Lower 48 Natural Gas Production and W	2030	2031	2032	2033	2034	2035	
Region	2030	2031	2032	2033	2034	2035	2010-2035
Dry Production (trillion cubic feet) 1/							
Lower 48 Total	**26.69**	**26.80**	**27.04**	**27.22**	**27.45**	**27.70**	**1.1%**
Lower 48 Onshore	**24.11**	**24.20**	**24.35**	**24.42**	**24.67**	**24.97**	**1.2%**
Northeast	4.86	4.95	5.04	5.13	5.25	5.38	5.2%
Gulf Coast	6.61	6.65	6.71	6.72	6.79	6.89	1.4%
Midcontinent	2.70	2.67	2.65	2.63	2.63	2.63	-1.0%
Southwest	3.95	3.92	3.92	3.91	3.93	3.95	0.4%
Rocky Mountain	5.82	5.83	5.86	5.87	5.92	5.96	0.7%
West Coast	0.17	0.17	0.17	0.17	0.16	0.16	-1.0%
Lower 48 Offshore	**2.58**	**2.59**	**2.69**	**2.81**	**2.77**	**2.72**	**0.3%**
Gulf	2.51	2.52	2.56	2.68	2.62	2.56	0.1%
Shallow	0.53	0.52	0.51	0.50	0.50	0.49	-2.6%
Deep	1.98	2.00	2.05	2.18	2.12	2.07	1.1%
Pacific	0.07	0.08	0.13	0.13	0.15	0.16	5.9%
Atlantic	0.00	0.00	0.00	0.00	0.00	0.00	- -
Prices							
(2010 dollars per million Btu)							
Henry Hub	6.29	6.42	6.58	6.71	7.06	7.37	2.1%
Lower 48 Average	5.56	5.67	5.81	5.92	6.21	6.48	1.9%
(2010 dollars per thousand cubic feet)							
Lower 48 Average	5.69	5.81	5.95	6.06	6.36	6.64	1.9%
Lower 48 Onshore							
Northeast	5.93	6.09	6.23	6.35	6.62	6.85	1.6%
Gulf Coast	5.57	5.68	5.88	5.97	6.24	6.48	1.8%
Midcontinent	5.66	5.77	5.97	6.05	6.30	6.58	2.2%
Southwest	5.66	5.78	5.93	6.03	6.29	6.59	1.8%
Rocky Mountain	5.67	5.79	5.95	6.07	6.33	6.59	2.2%
West Coast	6.21	6.38	6.49	6.64	6.90	7.13	2.0%
Lower 48 Offshore							
Gulf	5.61	5.68	5.46	5.67	6.42	6.80	1.3%
Pacific	8.00	6.38	8.24	6.75	5.75	6.65	1.6%
Atlantic	5.59	5.70	5.87	6.00	6.26	6.54	1.7%

1/ Marketed production (wet) minus extraction losses.
- - = Not applicable.
Note: Oil and Gas Supply Model regions are defined in Appendix F c
components due to independent rounding.
Sources: 2009: U.S. Department of the Interior, Office of Natural Re
Information Administration (EIA), Natural Gas Annual 2009, DOE/EIA-(
Natural Gas, and Natural Gas Liquids Reserves, DOE/EIA-0216(2009)
Energy Analysis (OEA). 2010: EIA, Natural Gas Monthly, DOE/EIA-01
and EIA, OEA. Projections: EIA, AEO2012 National Energy Modeling

TECO's Answer to Fourth Request for Production of Documents (No. 28) of the Florida Public Service Commission

(Confidential FPSC Document No. 07840-12)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Tampa Electric Company's Petition to Determine Need for Polk 2-5 Combined Cycle Conversion.	DOCKET NO. 120234-EI
	FILED: SEPTEMBER 12, 2012

PETITION

Pursuant to Sections 366.04 and 403.519, Florida Statutes, and Rules 25-22.080, 15-22.081 and 28-106.201, Florida Administrative Code ("F.A.C."), Tampa Electric Company ("Tampa Electric" or "company") petitions the Florida Public Service Commission ("Commission") for an affirmative determination of need for the waste heat recovery conversion of its existing Polk combustion turbines ("CTs") 2 through 5 electrical power plant and associated facilities ("Project" or "Polk 2-5").

In support of this Petition, Tampa Electric States as follows:

1. The Petitioner's name and address are:

Tampa Electric Company
Post Office Box 111
Tampa, Florida 33601

2. The names and addresses of Tampa Electric's representatives to receive communications regarding this docket are:

James D. Beasley
jbeasley@ausley.com
J. Jeffry Wahlen
jwahlen@ausley.com
Ausley & McMullen
Post Office Box 391
Tallahassee, FL 32302
(850) 224-9115
(850) 222-7560 (fax)

Paula K. Brown
Manager Regulatory Coordination
pkbrown@tecoenergy.com
Tampa Electric Company
Post Office Box 111
Tampa, FL 33601
(813) 228-1444
(813) 228-1770 (fax)

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 120234-EI EXHIBIT 11
PARTY TAMPA ELECTRIC COMPANY (TECO) - (DIRECT)
DESCRIPTIO Petition

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3. Tampa Electric is a Commission regulated investor-owned utility with its principal offices located at 702 North Franklin Street, Tampa, Florida 33602. Tampa Electric is a utility as defined in Section 366.82(1), Florida Statutes, and is an applicant as defined in Section 403.503(4), for purposes of Section 403.519, Florida Statutes. Tampa Electric is the primarily affected utility within the meaning of Rule 25-22.081, F.A.C.

I. Introduction

4. Tampa Electric proposes to license, construct and operate Polk 2-5, a natural gas combined cycle ("NGCC") power plant at Polk Power Station, a 2,800-acre site located in Polk County, Florida, 40 miles southeast of Tampa. The site currently consists of Polk Unit 1, a 220 MW IGCC plant, and four CTs totaling a net 604 MW in the summer. Polk 2-5 is expected to generate a net 1,195 MW of electricity in winter and 1,063 MW in the summer. Polk 2-5 will result from the conversion of Tampa Electric's four existing CT generating units, Polk 2 through 5, at Polk Power Station into a modern NGCC generating facility, thereby making efficient and economic use of what is otherwise waste heat exhausted from the existing CTs. The energy from this waste heat is captured in four new heat recovery steam generators ("HRSGs"). The steam created in the HRSGs is directed to a single steam turbine generator. With additional supplemental firing of the HRSGs the single steam turbine will generate 459 MW of summer capacity and 463 MW of winter capacity. This generation will allow Tampa Electric to meet a projected need for additional generating resources that begins in 2017 and increases each year thereafter.

5. The Polk Power Station site was originally selected as the result of Tampa Electric's extensive Power Plant Site Selection Assessment Program, which set out in 1989 to

select the most suitable location for meeting the company's future power supply requirements. An integral part of the Polk site selection process was the formation and participation of a Siting Task Force composed of 17 private citizens from environmental groups, businesses and universities in Tampa Electric's service area and throughout Florida. The Polk site was developed to allow for generation expansion in the future.

6. Converting the existing CTs at Polk Power Station to a NGCC facility will enable Tampa Electric to meet its forthcoming electric generating needs through a project that will maximize generation efficiency and cost effectiveness and at the same time minimize impacts on the environment. Through the addition of HRSGs at Polk Power Station the company will be able to harness what otherwise is waste heat and use that essentially free energy source to meet its generating needs beginning in 2017. The addition of heat recovery will provide a 37 percent increase in the generating efficiency of the four CTs incorporated into Polk 2-5, thereby significantly reducing fuel costs. The inherent efficiencies associated with this opportunity will inure to the economic benefit of Tampa Electric's customers, and will do so in a manner that has improved environmental impacts.

7. The Polk 2-5 project, as the company's next unit addition, will provide significant savings to Tampa Electric's customers as compared to the other "self-build" options evaluated by the company. In addition, the project will provide savings over the most cost-effective alternative from among the various responses received in a request for proposal ("RFP") process conducted by the company in advance of filing this petition. Customers will save approximately $132.4 million in cumulative present worth revenue requirements ("CPWRR") in 2012 dollars over the most favorable proposal from the RFP responses the company received.

8. Polk 2-5 will also improve Tampa Electric's environmental profile. The improvement in power generating efficiency from waste heat as an energy source will result in a direct reduction in the emissions rate for all pollutants on a pounds per MW hour basis and reduce CO_2 emission rates by approximately 37 percent. Polk 2-5 will meet, if not exceed, all applicable local, state and federal environmental requirements. These benefits will be achieved using an existing permitted plant site and utilizing reclaimed water to provide the majority of the water needed for the expansion in lieu of further groundwater extraction.

9. Polk 2-5 is needed to provide sufficient generating capacity to maintain electric system reliability at a reasonable cost. As is later explained, that need cannot be satisfied by incremental demand side management ("DSM") measures, conservation or other non-generating alternatives.

10. The Polk 2-5 conversion creates additional dual fuel capacity and improves fuel diversity on Tampa Electric's system. Having dual fuel capability also increases power supply reliability through the added assurance of available fuel. This assurance is particularly valuable during times of potential natural gas disruptions such as those caused by hurricanes. A secondary fuel source also helps reduce the company's reliance on high cost market power during those disruptions, resulting in lower energy costs for customers.

11. Polk 2-5 is the most cost-effective alternative to meet the additional capacity needs of Tampa Electric's system.

12. Tampa Electric requests that the Commission, in its final Order granting a determination of need for Polk 2-5 and its associated facilities, find that the decision to construct the Project is prudent, based on the cost and performance estimates as well as the other relevant assumptions including all applicable statutory and Commission Rule criteria.

II. The Utility Primarily Affected (Rule 25-22.081(1)(a))

13. Tampa Electric is the utility primarily affected by the proposed Project. Tampa Electric is an investor-owned electric utility and the principal subsidiary of TECO Energy, Inc.

14. Tampa Electric is charged with serving its current customer base of over 680,000 customer accounts, as well as new customers that locate in its service territory of approximately 2,000 square miles covering Hillsborough and portions of Polk, Pinellas and Pasco Counties in Florida. The current population in the company's service area is approximately 1.25 million.

15. Tampa Electric is part of the nation's Eastern Interconnection Transmission Network. It has multiple points of interconnection with other utilities that enable power to be exchanged among them. The Tampa Electric bulk transmission system is comprised of 1,322 miles of transmission lines. Integration of the generation, transmission and distribution system is achieved through Tampa Electric's 219 substations.

16. The company has three primary generating stations that include steam, coal fueled and IGCC base load units, NGCC intermediate load units and natural gas and oil fired combustion turbine peaking load units. The total net system generating capacity in the winter of 2011 was 4,684 MW and on an energy basis generated 56 percent solid fuel, 43 percent natural gas and less than 1 percent oil.

17. Polk 2-5 helps contribute to the state's reserve margin criterion and helps alleviate the Florida Reliability Coordinating Council (FRCC) concern regarding the degree to which the peninsular Florida system is becoming increasingly dependent upon demand side management to meet its reserve margin criterion.

III. The Proposed Electrical Power Plant (Rule 25-22.081(1)(b))

18. The proposed Project consists of the construction and operation of Polk 2-5, a NGCC power plant at Polk Power Station, the site of Tampa Electric's existing IGCC facility. The company will utilize its experience with NGCC technology to convert the existing CT Units 2 through 5 at Polk Power Station into a NGCC facility.

19. Polk 2-5 will be a NGCC facility consisting of four CTs, four HRSGs with incremental supplemental firing and a single steam turbine arranged such that each of the four existing CTs will be coupled with a HRSG, with the output of the four HRSGs driving a single steam generator (referred to as a 4x4x1 configuration). The technology is a combination of a combustion turbine (Brayton) cycle and a traditional steam (Rankine) cycle technologies. The combination of these two technologies allows for thermal efficiency of almost 50 percent. This is a proven system for power generation and one with which Tampa Electric has significant experience designing, constructing and operating.

20. Capturing waste heat from the existing Polk CTs 2-5 will generate an incremental net 352 MW of electricity in winter at 32 degrees Fahrenheit and 339 MW in the summer at 92 degrees Fahrenheit. The HRSGs installed at Polk 2-5 will also utilize supplemental firing of natural gas, also known as duct burners, to generate additional steam and provide 120 MW (summer) and 111 MW (winter) of cost-effective peaking capacity that will offset the need for future peaking unit capacity.

21. The Project is being designed with the ability to incorporate approximately 30 MW of solar energy in the form of steam from solar thermal collectors located at the Polk Power Station site. The integration of steam produced via solar collectors into a combined cycle plant is known as a solar hybrid system as it uses the existing combined cycle steam turbine rather

than a separate turbine dedicated to solar use. This is more cost-effective than stand-alone solar and the HRSG supplemental firing creates a back-up and improves reliability.

22. The existing cooling reservoir at the Polk Power Station will be used for cooling the steam from the new steam turbine on Polk 2-5. Use of the existing cooling reservoir infrastructure reduces costs and will allow Polk 2-5 to operate with lower water consumption and lower parasitic load than if a stand-alone cooling tower were used for the steam turbine heat rejection system.

23. A new small cooling tower will be constructed to provide equipment for auxiliary cooling for Polk 2-5 as well as Polk Unit 1. This is needed to optimize the heat loading on the existing cooling reservoir and mitigate operational impacts that could occur due to increased water temperature in the cooling reservoir.

24. The Project is being designed to allow operation of each CT in either simple cycle or combined cycle mode. This will provide considerable operating flexibility and will allow the facility to serve both intermediate and peaking load requirements.

Fuel and Fuel Supply Considerations

25. Polk CTs 2 and 3 have dual fuel capability, meaning that they are able to utilize either natural gas or distillate oil. Polk CTs 4 and 5 will be permitted to have dual fuel capability. Dual fuel capability improves power supply reliability by significantly minimizing, if not eliminating, fuel supply risk.

26. The Project will utilize Tampa Electric's existing natural gas commodity portfolio, storage, pipeline capacity and infrastructure along with backup oil capability and storage. The use of these existing assets reduces costs and increases overall efficiency of fuel supply. Power generated using the waste heat from the existing CTs does not create additional fuel use.

Operation of the new combined cycle at times when the existing CTs would not otherwise be operating also reduces overall system fuel and purchased power costs due to the high efficiency of the new combined cycle unit.

27. Tampa Electric's portfolio of natural gas fuel supply assets and generation units combined with the company's experience and capability in managing its natural gas fuel supply will enhance the reliability and cost-effectiveness of the fuel supply for Polk 2-5.

28. Tampa Electric currently possesses both physical and contractual flexibility for gas delivery in its portfolio. This provides significant flexibility in procuring and allocating natural gas using both the Florida Gas Transmission ("FGT") pipeline system and Gulfstream Pipeline, LLC ("Gulfstream"). Polk Power Station is physically connected to the FGT system as a Primary Delivery Point. Tampa Electric's H. L. Culbreath Bayside Power Station can be supplied from either FGT or Gulfstream and Tampa Electric currently has multiple agreements with both FGT and Gulfstream.

29. Tampa Electric is sponsoring its fuel price forecasts in support of this Petition. Those forecasts are based on sound industry-respected publications, indices, forecasts and escalators. Tampa Electric will demonstrate that its fuel price forecasts are reasonable for planning purposes and for use as a basis for committing to proceed with Polk 2-5.

Fuel Diversity Considerations

30. The addition of Polk 2-5 will maintain Tampa Electric's already well-balanced fuel portfolio. The company will be adding one of the most efficient, economical, and environmental friendly energy sources to its existing well diversified fuel mix of solid fuel and natural gas.

Water Requirements of the Project

31. Polk 2-5's water requirements will be met primarily with reclaimed water from the City of Lakeland. This will minimize the use of ground water.

Transmission Integration and Interconnection Requirements

32. Associated facilities of the Project include new and upgraded transmission facilities with which Polk 2-5 will be interconnected and integrated into Tampa Electric's transmission system. These additions will increase the import and export capability of the Tampa Electric transmission system and provide more source options during planned and unplanned generation outages. Upgrades to the existing 230 KV facilities will also reduce exposure to multi-circuit structure outages, increasing the reliability of the transmission system. The addition of the new transmission facilities will also improve the reliability of the central Florida region for Tampa Electric customers and the entire Florida Reliability Coordinating Council ("FRCC") region.

Project Costs

33. The total in-service costs estimate for Polk 2-5 is $706.6 million, which includes overnight construction costs as well as escalation, transmission costs and AFUDC. 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.

34. Cost estimates are based on a preliminary design completed by the engineering firm of Black and Veatch, which has obtained multiple quotations from major equipment manufacturers and has validated current pricing for commodities and labor in the central Florida area.

35. Tampa Electric plans to competitively bid all the major equipment required for Polk 2-5. The company envisions using multiple prime contractors with contracts containing an appropriate mix of incentives and penalties to align the various contractors with the Project goals.

Environmental Attributes

36. From an environmental perspective, Polk 2-5 will utilize a proven technology that will not only meet, but will likely surpass all applicable environmental regulatory requirements. The selection of NGCC technology over other alternatives will minimize emissions while simultaneously providing cost-effective and reliable energy. By taking advantage of the waste heat from existing Polk CTs 2 through 5, the Project will provide additional generation with minimal additional fuel requirements, thereby reducing air emissions on a pounds per MWH basis. The Project will also take advantage of existing site infrastructure and reclaimed water resources, thereby greatly reducing the need for ground water consumption in the operation of the new facility.

IV. Need for Polk 2-5 (Rule 25-22.081(1)(c))

37. Tampa Electric's need for additional capacity is compelling. After taking into account existing power plant unit capacity, firm purchased power agreements ("PPAs"), and the most recent Ten Year Site Plan load forecast that considers DSM, conservation and renewable energy alternatives, Tampa Electric requires an addition of 294 MW of generating capacity to maintain Tampa Electric's system reliability requirements beginning in 2017. Without any additional capacity to maintain its 20 percent reserve margin reliability criterion, Tampa Electric's 2017 summer reserve margin is projected to decrease to 12.5 percent. Utilizing a

recently updated load, DSM and fuel forecast, and all of the aforementioned considerations, Tampa Electric still requires an additional 205 MW of generating capacity to maintain system reliability requirements beginning in 2017. Polk 2-5 is, therefore, needed to maintain the electric system reliability and integrity for Tampa Electric while addressing the need for reliability and fuel diversity in Florida.

38. Tampa Electric forecasts continued growth of customers in its service territory. The company's recently updated forecast projects approximately 60,000 new customers by 2017 and 103,000 new customers by 2021, with the total number of customers exceeding 735,000 by 2017 and 778,000 by 2021. Peak demand for the summer of 2012 is forecasted to be 3,993 MW, increasing to 4,331 MW in 2021, an average increase of 38 MW per year. Tampa Electric will need to invest in new infrastructure to keep pace with the increasing demand for adequate and reliable power to meet the needs of its growing customer base.

39. Tampa Electric meets its resource needs through generating units, purchased power and DSM. As stated earlier, Tampa Electric's generating resources are located at three primary sites distributed geographically throughout its service territory and as of summer 2012, they along with firm PPAs totaled approximately 4,909 MW (summer) of capacity.

40. Tampa Electric has PPAs with a variety of suppliers totaling 594 MW (summer) for 2012. Tampa Electric also has a contract to purchase firm cogeneration capacity totaling 23 MW in 2012.

41. Tampa Electric requires additional supply resources by 2017 to replace the purchased power contracts as all but one 121 MW contract expire prior to January 2017.

42. Tampa Electric determined in its 2012 integrated resource plan ("IRP") and communicated in its 2012 Ten Year Site Plan that it will need significant additional resources

starting in 2017 to meet its 20 percent reserve margin criterion approved by the Commission in Order No. PSC-99-2507-S-EU. To accomplish this, Tampa Electric will need a minimum of 294 MW of new supply from either power plant installation, purchased power or additional DSM to meet its 2017 reserve margin requirement.

43. New generating capacity, including the associated facilities described herein, built in Tampa Electric's service area is the most cost-effective option to maintain system reliability. After conducting a RFP and considering alternative technologies, Tampa Electric determined that the addition of Polk 2-5 into Tampa Electric's system is the best available option for meeting the company's system reliability needs.

44. Polk 2-5 will add highly efficient and cost-effective generation that, as a utility-owned plant, will be committed to Florida's retail customers and subject to Commission oversight. As shown in the accompanying Need Study, Polk 2-5 will produce adequate electric capacity, improve system efficiency, lower system environmental emissions and maintain system reliability all at a reasonable cost.

V. Tampa Electric's Analysis of Generating Alternatives (Rule 25-22.081(1)(d))

45. Tampa Electric considered a variety of generating options prior to identifying NGCC technology, in the form of Polk 2-5, as the best option for Tampa Electric and its customers. The company's screening process evaluated an array of natural gas, solid fuel and renewable technologies.

46. Strategic considerations in the company's analysis of generating alternatives included fuel price stability, fuel diversity, environmental impacts, technology viability,

construction lead times and site availability. The company's screening analysis narrowed the focus to NGCC or CT technologies for further analysis.

47. Tampa Electric considered simple cycle aero-derivative engines similar to Bayside Unit 3 and simple cycle CTs similar to the existing CTs at Polk Power Station. The company also considered a brownfield 2-on-1 combined cycle unit in addition to converting the existing four Polk CTs into a 4-on-1 combined cycle unit.

48. The company's screening analysis of the various alternatives compared the levelized annual cost of each technology at various capacity factors. Tampa Electric selected NGCC technology as a viable intermediate option and CT technology as a peaking option.

49. Tampa Electric's final integrated resource plan confirmed the need for additional firm purchases in each year from 2012 through 2017 and the addition of Polk 2-5 in 2017. The final plan also demonstrated a CPWRR savings of $65.4 million when Polk 2-5 was compared to the 2011 TYSP with updated fuel forecasts and updated demand and energy and DSM projections.

VI. RFP Process

50. In March 2012, Tampa Electric issued a request for proposal soliciting firm offers for cost-effective alternatives to Polk 2-5. From the initial drafting of the RFP document forward, this process was conducted under the guidance of a very reputable independent third party evaluator, Alan S. Taylor, President of Sedway Consulting, Inc., to keep the process as open and inviting to potential bidders as possible. The RFP process was extensively noticed with pre- and post-RFP release meetings, with website posting of questions from the potential and actual bidders and answers provided to all participants without disclosing the identity of the

participants posing the questions. Tampa Electric's RFP process was open to all potential providers of all or portions of the company's 2017 resource needs, including respondents submitting existing resources, proposing new construction, or offering PPAs.

51. There was robust participation in both the pre-release conference and the post-relief workshop with over 70 questions and answers posted to the company's website. Ultimately, Tampa Electric received four proposals, each of which was opened by the independent third party evaluator and accepted as a qualifying bid for further evaluation.

52. Sedway Consulting was involved in each step of the bid evaluation process including opening the sealed proposals received from each respondent. Sedway Consulting incorporated pricing and operational information from each proposal received into its own analytical model. After cross checking all key modeling assumptions for both the proposals and Tampa Electric's system Sedway Consulting performed and finalized their own initial, independent evaluation.

53. Sedway Consulting later met with Tampa Electric to discuss the evaluation results of the original proposals and agreed that all offers should be short listed. After clarification conference calls in which Sedway Consulting participated, the short listed respondents were provided an opportunity to provide best-and-final offers.

54. Using their own model, Sedway Consulting compared the economics of Tampa Electric's next planned generating unit, Polk 2-5, and each of the proposed resource options (both the original bids and the best-and-final offers). Sedway Consulting's evaluation revealed that Polk 2-5 was $148 million less expensive on a net present value basis than the next cost-effective

RFP compliant proposal.[1] Tampa Electric's internal analysis of the most cost-effective RFP compliant proposal indicated that Polk 2-5 was $132.4 million (NPV) less expensive.

55. After a thorough and detailed evaluation of the available alternatives, Sedway Consulting concluded that Tampa Electric's Polk 2-5 project is the most cost-effective resource for meeting the company's 2017 capacity needs and concurred with Tampa Electric's decision to move forward with that Project. Sedway Consulting's analysis concluded that the solicitation process yielded the best results for Tampa Electric's customers while treating respondents fairly.

VII. Tampa Electric Analysis of Non-Generating and "Self-Build" Generating Alternatives (Rule 25-22.081(1)(e))

56. Tampa Electric has long been a leader in offering its customers cost-effective DSM programs coupled with a comprehensive educational emphasis of the efficient use of energy. Those efforts began in the mid-1970's. Following the 1980 enactment of the Florida Energy Efficiency and Conservation Act, Tampa Electric has filed for and gained Commission approval of numerous DSM programs designed to promote new energy efficient technologies and to change customer behavioral patterns such that energy savings occur with minimal effect on customer comfort.

57. The company has experienced great success with its DSM initiatives. From the inception of its programs in 1980 through the end of 2011, Tampa Electric has achieved 719 MW on winter peak demand reduction, 306 MW of summer peak demand reduction and 770 GWH of annual energy savings. This amount of peak load reduction has eliminated the need for the equivalent of four 180 MW power plants of winter capacity.

[1] The respondent of this RFP compliant proposal also put forth two non-RFP compliant scenarios that Sedway Consulting examined and determined to be $131 million and $69 million (NPV) more expensive than Polk 2-5.

58. The company's DSM program results compare quite favorably to other utilities across the nation, with Tampa Electric's national average ranking for cumulative conservation at the 89th percentile and at the 85th percentile for load management achievement.

59. Tampa Electric reviewed the addition of other generating alternatives as well as potential demand-side programs in determining the most appropriate expansion plans.

60. Tampa Electric's existing DSM programs represent the company's most recently assessed, and most recently Commission approved, collection of available cost-effective DSM alternatives. Tampa Electric included all of these DSM programs in its preliminary demand and energy forecast which effectively reduced system peaks and energy requirements. Since the projected results of those recently approved programs were factored into the assessment for this determination of need, there are no additional cost-effective DSM alternatives or viable renewable options that would defer the need for additional generating capacity in 2017.

61. Similarly, all anticipated cost-effective generating capacity that will be available from renewable resources and qualifying facilities through 2017 has been reflected in Tampa Electric's resource plan. In the future non-firm renewable resources that could cost-effectively provide energy to Tampa Electric would complement the benefits Tampa Electric's customers will receive from Polk 2-5.

62. Taking these benefits into consideration, the interests of Tampa Electric's customers are best served by placing Polk 2-5 in commercial operation in January 2017.

VIII. Adverse Consequences of Delay (Rule 25-22.081(f))

63. In the event Polk 2-5 is delayed by one year or longer, project costs would likely increase and customers would lose the fuel savings benefits for 2017 through the duration of the

delay. In addition to typical factors such as inflation and project management expenses, there is a risk of higher than normal cost increases due to equipment demand. For the past several years there has been somewhat of a lull in generating unit additions due to the broad economic downturn and reduction in energy use. As the economy picks up and energy use increases, it is likely that most utilities will choose gas fired combined cycle technology. The potential rapid increase in demand and the focus on one generating technology by the industry could create a sharp increase in prices for combined cycle equipment and skilled construction labor.

64. The potential for an equipment demand spike would translate to significantly higher costs for customers. Under a scenario where such demand spikes materialize, the result would be higher costs for customers of $100 million on a cumulative present worth revenue requirement basis.

65. In the event of the denial of Tampa Electric's application for a determination of need for Polk 2-5, the company most likely would construct a simple cycle peaking unit in 2017. This would result in higher costs for customers compared to the costs of the proposed Project. Tampa Electric's customers would be denied the efficiencies and economies associated with utilizing waste heat to generate incremental capacity and the environmental attributes associated with Polk 2-5 would not be realized.

IX. Need Study and Prefiled Testimony

66. Tampa Electric submits in support of this Petition and incorporates herein by reference its detailed Need Study and appendices that develop more fully the information required by Rule 25-22.081, Florida Administrative Code. Tampa Electric is also submitting the

testimony of eight witnesses supporting Tampa Electric's request that the Commission grant an affirmative finding of need for Polk 2-5 and its associated facilities.

X. Disputed Issues of Material Fact

67. Tampa Electric presently is unaware of any disputed issues of material fact affecting this proceeding. Tampa Electric will demonstrate during the course of the proceeding that approving a determination of need for Polk 2-5 beginning in 2017 will best serve Tampa Electric's customers by meeting their growing electric supply needs while at the same time providing substantial economic benefits as well as substantial environmental benefits through the efficient use of currently available waste heat as an energy source, an existing generation station site and other existing committed resources. Tampa Electric will demonstrate that there are no reasonably available renewable resources, DSM or other non-generation alternative that would significantly mitigate the need for Polk 2-5.

CONCLUSION

68. Tampa Electric's proposed Polk 2-5 Project is a highly efficient, cost-effective and reliable choice to meet the growing electric needs of Tampa Electric's customers in a very environmentally friendly way. The construction and operation of Polk 2-5 offers Tampa Electric and its customers a number of significant advantages over any other alternative. The Project will deliver major cost savings for the benefit of Tampa Electric's customers, will enable Tampa Electric to reliably meet the electric power needs of its growing customer base and provide Tampa Electric customers and, indeed, all Floridians with key environmental benefits through reduced emissions. Polk 2-5 is consistent with the Peninsular Florida capacity needs and reduces

the dependency on DSM programs to meet reserve criterion. All of this will be achieved using as a base for the Project existing generation plant on an already permitted power plant site.

69. Based upon all of these considerations and the greater level of detail provided in the prepared direct testimony and exhibits of Tampa Electric's witnesses and the need study submitted with this Petition, Tampa Electric respectfully requests that the Commission grant the company an affirmative determination of need for Polk 2-5 and its associated facilities beginning in 2017. Upon approval of this Project Tampa Electric will periodically report to the Commission updated information on the budgeted and actual costs of the Project, compared to the estimated total in-service costs presented in this Petition.

WHEREFORE, Tampa Electric respectfully requests that the Commission grant an affirmative determination of need for Polk 2-5 and its associated facilities beginning in 2017. In so doing, the Commission should:

(a) find that Polk 2-5 is needed to maintain electric system reliability and integrity and to provide adequate electricity at reasonable cost, taking into account the need for fuel diversity and supply reliability;

(b) find that Polk 2-5 is the most cost-effective option for providing efficient fuel diverse generation capacity needed to meet the needs of Tampa Electric's customers beginning in 2017;

(c) find that there is no reasonably available DSM, renewable or other non-generation alternative that would mitigate the need for Polk 2-5;

(d) find that the decision to construct Polk 2-5 is reasonable and prudent, based on the estimated installed costs as well as the other relevant assumptions;

(e) affirm that after Polk 2-5 is placed in service, all prudently incurred non-fuel costs of the Project shall be recoverable through base rates.

Respectfully submitted this 12th day of September 2012.

JAMES D. BEASLEY
J. JEFFRY WAHLEN
Ausley & McMullen
Post Office Box 391
Tallahassee, Florida 32302
(850) 224-9115

ATTORNEYS FOR TAMPA ELECTRIC COMPANY

TAMPA ELECTRIC

Tampa Electric Company's Determination of Need for Electrical Power: Polk 2-5 Combined Cycle Conversion

Filed: September 12, 2012

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I. EXECUTIVE SUMMARY

Tampa Electric Company ("Tampa Electric" or "company") has determined through its integrated resource planning ("IRP") process a need for the Polk 2-5 combined cycle project ("Polk 2-5"), with a targeted commercial operation date of January 2017. The existing Polk 2 through 5 combustion turbines ("CTs") will be converted to a natural gas combined cycle ("NGCC") facility located at Polk Power Station by integrating a new steam turbine with an additional capacity of 459 MW summer and 463 MW winter. This incremental capacity is derived from waste heat from the four existing combustion turbines of 339 MW summer and 352 MW winter, as well as 120 MW summer and 111 MW winter from supplemental natural gas duct-firing in the four Heat Recovery Steam Generators ("HRSGs").

Prospectively, Tampa Electric's firm load is expected to grow approximately 1.2 percent annually winter (1.0 percent summer) or 40-45 MW of firm demand per year. Tampa Electric will continue to meet capacity requirements with the most economical combination of demand-side management ("DSM"), conservation, renewable energy, purchased power, and generating capacity additions. In addition to normal load growth, Tampa Electric requires additional supply resources by 2017 to replace the purchased power contracts of 183 MW expiring on December 31, 2015, 117 MW expiring on December 31, 2016, and an additional 121 MW expiring on December 31, 2018.

Tampa Electric's IRP process incorporated an on-going evaluation of demand and supply resources and conservation measures to maintain system reliability. By 2017, Tampa Electric's DSM programs will have produced summer and winter customer demand and energy reductions of 376.4 MW and 752.1 MW, respectively and energy conservation of 1,000.7 GWH. The reliability analysis determined that Tampa Electric will have capacity needs by 2017 of 294 MW. In

order to develop the optimum expansion plan, the company researched current technologies for feasible options. The resulting list of supply resources was screened for technical feasibility, reliability and relative economics. The initial screening resulted in the narrowing of technology alternatives to simple-cycle natural gas and NGCC 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 NGCC technology is the best option to meet the 2017 need, and conversion of the four existing combustion turbines at Polk Power Station to an NGCC is the most cost-effective alternative.

Once this need was identified, Tampa Electric solicited market alternatives to its next planned generating unit as directed by the resource bid rule. The company issued a Request For Proposals ("RFP"), and considered price and non-price attributes, operational performance, dispatchability, reliability, and environmental compliance, and other issues. After carefully considering and integrating Tampa Electric's DSM load reduction and energy conservation programs and other supply resources, Polk 2-5 was selected as the most cost-effective, reliable means of serving Tampa Electric's customers for the following reasons:

1. It is the most cost-effective next addition to the Tampa Electric system, when compared with all of the "self-build" alternatives.
2. It is the most cost-effective alternative, and the project results in a savings of $117.9 million Cumulative Present Worth Revenue Requirements ("CPWRR") compared to the next best proposal in the RFP process.

3. It achieves significant energy efficiency savings by capturing the waste heat from four existing combustion turbines to generate up to 352 MW of net electrical output with no additional fuel input.
4. It provides up to 120 MW of additional low cost peaking capacity from supplemental natural gas duct-firing in the four HRSGs. This supplemental firing eliminates the need for future higher-cost simple cycle CT peaking units.
5. The retention of simple cycle operating capability of the four existing combustion turbines provides operating flexibility and improves system reliability.
6. It achieves dramatic reduction in emission rates from new environmental control equipment and efficiency improvements. The resulting NO_x emission rate is reduced by 86 percent, while the CO_2 emission rate is reduced 37 percent.
7. It conserves fresh water resources by using waste water from the City of Lakeland, and reduces nitrogen loading to Tampa Bay.
8. It enables the potential integration of solar thermal renewable capacity and energy in the future.
9. The existing Polk Power Station site and supporting infrastructure for natural gas is uniquely compatible with Polk 2-5.
10. The transmission upgrade portion of the project will provide much needed infrastructure to reduce transmission congestion, improve grid reliability and reduce losses.

In summary, the selection of Polk 2-5 was supported by subsequent economic analyses of viable supply alternatives, demonstrating that Polk 2-5 is the most cost-effective option compared to other technologies and available supply capacity from the Florida market. After consideration of all existing, new and modified DSM programs and renewable energy initiatives, the construction of Polk 2-5 with a January 2017 in-service date should not be deferred. A two-year

deferral of the recommended plan could increase costs to customers by $100 million. Tampa Electric also determined that fuel diversity is a key objective and the addition of natural gas combined cycle technology in 2017 still maintains a prudent balance in Tampa Electric's capacity and energy mix. Finally, when considering the viability of uncommitted resources, the risk of emerging environmental regulations, and the uncertainty of voluntary DSM programs, Polk 2-5 is needed as a firm resource within the FRCC region.

Polk 2-5 is the best of the "self-build" alternatives and provides significant savings of $117.9 million to Tampa Electric's customers when compared to the second most cost-effective alternative in the RFP while providing additional benefits in the areas of reliability, fuel diversity, environmental impacts, and generating system efficiency. The results of these scenarios reinforce Tampa Electric's selection of Polk 2-5 as the best alternative for Tampa Electric and its customers.

II. INTRODUCTION AND IRP PROCESS OVERVIEW

A. Introduction

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 2-5 NGCC rated at 459 MW summer and 463 MW winter net incremental capacity once the integration with the four existing simple cycle combustion turbines is completed by 2017. 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, the need to determine whether the proposed plant is the most cost-effective alternative available, and the need to determine whether renewable energy sources and technologies, as well as conservation measures, are utilized to the extent reasonably available." This information supports Tampa Electric's selection of Polk 2-5 as the most cost-effective, reliable, and fuel diverse option to meet its supply resource need in 2017.

The Need Study is composed of twelve major sections. Section I is an "Executive Summary" of Tampa Electric's overall IRP process and the results. Section II "Introduction and IRP Process Overview" 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 "Need for Capacity in 2017" discusses the calculation of Tampa Electric's 2017 need including the impact of DSM load reduction and energy conservation programs. Section V describes the screening of potential supply technologies and results

and Section VI includes the detailed economic analysis where the supply 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 2-5. Section VII describes sensitivity cases and results related to fuel pricing, demand and energy, and construction costs. Section VIII describes the RFP process and results. Section IX describes Polk 2-5 in detail including design, permitting, location, cost and schedule, Section X examines the results with updated assumtions, and Section XI describes the adverse consequences if Polk 2-5 is not approved or is delayed. Finally, Section XII 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 2-5, is a planning process that determines the timing, type, and amount of additional demand reduction, energy conservation and supply resources required to maintain system reliability in a cost-effective manner. The process considers the existing customer demand and energy mix, expected growth and changes in the customer demand and energy requirements, existing and future DSM and energy conservation programs, existing Tampa Electric generating units and purchased power, future traditional and renewable supply resources, existing and future bulk transmission system for Tampa Electric and the Florida grid, and potential renewable energy resources appropriate for the Florida energy market. The process used to develop the Polk 2-5 Need Study was conducted as an integral component of Tampa Electric's ongoing IRP process. The primary steps in the process include:

1. Identify additional DSM load reduction alternatives and cost-effective energy conservation alternatives to reduce demand and energy requirements utilizing avoided costs from an initial resource plan;

2. Forecast demand and energy including the impact of existing and potential demand alternatives;
3. Identify the amount and timing of Tampa Electric's incremental resource needs to maintain system reliability criteria;
4. Identify the types of technologies that have the greatest potential for meeting the required resource need and perform an initial economic screen.
5. Conduct detailed economic analysis and consider non-economic factors to decide on the best supply alternatives;
6. Conduct sensitivity analyses to evaluate the impact of potential load forecast and economic variations;
7. Conduct an RFP process and/or business plan development as required based on the recommended resource plan.
8. Incorporate any updated assumptions and confirm the recommended resource plan.
9. Based on the recommended resource plan, determine the avoided costs for deferral of supply resources and implement additional cost-effective DSM resources in the next business planning cycle.

III. BACKGROUND AND ASSUMPTIONS

A. Description of Tampa Electric's System

Tampa Electric, an investor-owned electric utility, is the largest subsidiary of TECO Energy. 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 served approximately 676,000 customers in 2011. Tampa Electric has three large generating stations and one peaking station that include fossil steam units, combined cycle units, combustion turbine peaking units, aero-derivative engine units, diesel engine units and an integrated coal gasification combined cycle unit.

Big Bend Power Station: The station contains four pulverized coal-fired steam units equipped with additional environmental controls including selective catalytic reduction, de-sulfurization scrubbers, and electrostatic precipitators. Big Bend Power Station also contains one dual fuel (natural gas or oil), quick-start (full load in less than 15 minutes) aero-derivative peaking unit that could provide black-start capability for the station and the system.

H. L. Culbreath Bayside Power Station: The station contains two natural gas-fired combined cycle units and four quick-start aero-derivative peaking units with black-start capability. Bayside Unit 1 utilizes three combustion turbines, three HRSGs and one steam turbine. Bayside Unit 2 utilizes four combustion turbines, four HRSGs and one steam turbine. Bayside Units 3 through 6 are natural gas-fired aero-derivative peaking units that are quick-start and provides black-start capability for the station and the system.

Polk Power Station: Polk Power Station includes one base load and four peak load generating units. Polk Unit 1 is a dual fuel integrated gasification combined cycle ("IGCC") unit primarily fired with synthesis gas produced from a blend of low-sulfur coal and petroleum coke ("petcoke"). Distillate oil is a secondary fuel which is used for both start-up and shut-down of the power block, and can be used to operate the combined cycle at times when the gasification system is unavailable. Polk Units 2 through 5 are simple cycle combustion turbines primarily fired by natural gas, and Units 2 and 3 are capable of firing distillate oil as a secondary fuel.

J. H. Phillips Sebring Power Station: Phillips Sebring Power Station includes two diesel oil-fired peaking units located in Sebring, Florida.

These two units were placed on long-term reserve stand-by ("LTRS") status on September 4, 2009 due to the relative higher cost of heavy oil compared to natural gas and coal. These units will remain on LTRS until the operating costs are competitive with other supply resources. These units also have the potential to utilize liquid biofuels and operate as a renewable energy resource in the future.

Other Facilities: Tampa Electric owns two 3 MW diesel engines converted to use natural gas located at the City of Tampa's McKay Bay Refuse to Energy Facility.

The following table lists Tampa Electric's generating assets as of January 1, 2012.

Table 1: Tampa Electric System Installed Capacity

Plant Name	Number of Units	Summer Net MW	Winter Net MW
Big Bend Power Station	5	1608	1643
Bayside Power Station	6	1854	2083
Polk Power Station	5	824	952
Phillips Sebring Power Station[1]	2	36	36
Other Facilities	2	6	6
TOTAL	**20**	**4,292**	**4,684**

1. Transmission and Distribution

Tampa Electric's transmission and distribution system is comprised of 219 substations, 1,322 miles of transmission and 10,998 miles of distribution lines. Tampa Electric's transmission system is interconnected to the Florida

[1] Phillips Sebring Power Station was placed on long-term standby on September 4, 2009 and net capacities are not included in the system total.

transmission grid through ties with Lakeland Electric, Florida Power & Light, Orlando Utilities Commission, Seminole Electric Cooperative, and Progress Energy Florida.

2. Firm Purchased Power Capacity

Tampa Electric currently has a number of firm purchased power agreements ("PPA") with cogeneration facilities, other investor-owned utilities and merchant power providers. Listed below are long term purchase power contracts for capacity and energy ordered by expiration date:

- 441 MW winter and 356 MW summer from the Hardee Power Station through December 2012.
- 23 MW Non-Utility Generator Orange Cogen through December 2015.
- 160 MW from Southern Power from January 2013 through December 2015. Tampa Electric has an option to extend.
- 117 MW from Auburndale Peaking Energy Center through December 2016.
- 121 MW from the Pasco Cogen facility through December 2018.

Tampa Electric expects 499 MW of cogeneration capacity in its service area in 2012. Self-service capacity of 268 MW is used by cogenerators to serve internal load requirements, 23 MW are purchased by Tampa Electric on a firm contract basis, and 19 MW are purchased on a non-firm, as-available basis. The remaining 189 MW of cogeneration capacity is exported out of Tampa Electric's system.

3. Demand-Side Management

DSM is the planning, development, implementation, monitoring and evaluation of energy 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 the 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 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.

Through 2011, Tampa Electric's successful DSM initiatives have achieved 719 MW of winter peak demand reduction, 306 MW of summer peak demand

reduction and 770 GWH of annual energy savings. Peak load reduction has eliminated the need for the equivalent of four 180 MW power plants.

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 last decade, Tampa Electric ranked as high as the 89th percentile for cumulative conservation and the 85th percentile for load management achievements. Also, of the eight regional entities of NERC, the FRCC ranks third in terms of DSM as a percentage of regional peak.

4. Renewable Energy

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 the company will demonstrate sound environmental stewardship. Tampa Electric has actively evaluated various renewable energy developers over the years, and continues to investigate ways to structure agreements with consideration of the FPSC avoided cost standard.

Tampa Electric's renewable Standard Offer Contract ("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 is continuously available; 3) there is no subscription limit; 4) the renewable generator can select the term of the contract; and 5) flexibility on capacity and energy payments to the customer.

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

The energy and capacity mix for Tampa Electric's generation can significantly affect the cost of electricity. Too much reliance on fuel types with volatile fuel prices can result in significant volatility in the ultimate cost of electricity. Tampa Electric's fuel type mix to meet system demand and energy requirements for 2011 actuals and projections for 2017 are shown below.

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

Total System	2011 Actual	2017 Forecast
Solid Fuel	56%	59%
Natural Gas	43%	39%
Oil / Other	1%	2%
System Net Energy for Load (GWH)	19,325	20,772

Table 3: Tampa Electric's Capacity Mix by Fuel Type

Total System	2011 Actual	2017 Forecast
Solid Fuel	36.1%	36.3%
Natural Gas	63.9%	63.7%
Oil / Other	0%	0%
System Capacity (MW)	4,909	4,856

B. Assumptions

Demand and Energy Forecasts - 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 (Moody's Analytics) and the University of Florida's Bureau of Economic and Business Research ("BEBR"). Numerous assumptions entered into the MetrixND models, an advanced statistics program for analysis and forecasting, of which the more significant ones are listed below.

Population and Households

The 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 2021, the average annual population growth rate for Hillsborough County is expected to be 1.4 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 projected to rise at a 2.3 percent average annual rate and industrial employment is projected to decline slowly at an annual rate of -1.2 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 0.7 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 3.4 percent average annual rate.

Real Household Income

Economy.com supplies the assumptions for Hillsborough County's real household income growth. During 2012-2021, real household income for Hillsborough County is expected to increase at a 2.9 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.

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 heat pump and 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 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.

High and Low Economic Sensitivities

The base case sensitivity is tested for sensitivity to varying economic conditions and customer growth rates. The high and low peak demand and energy sensitivities represent alternatives to the company's base case outlook. Compared to the base case, the expected economic growth rates are 0.5 percent higher in the high sensitivity and 0.5 percent lower in the low sensitivity. High and Low firm peak demands are shown in Appendix F.

2. Forecast Methodology

MetrixND was used to develop customer, demand and energy forecasts. The software provides a platform for the development of 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 a seven-equation model. The equations forecast the number of customers by seven major categories.

Residential Customer Model

Customer projections are a function of Hillsborough County's population. Since a strong correlation exists between historical changes in customers and historical changes in the county's population, Hillsborough County population estimates for 2012-2021 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 customers as a function of construction

employment.

Industrial General Service Customer Model

Industrial customers include two rate classes that have been modeled individually: General Service ("GS") and General Service Demand ("GSD"). 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 recent growth trends in the sector.

Public Authority Customer Model

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

Street & Highway Lighting Customer Model

Recent growth trends in this sector are the basis for the street & highway lighting customer model.

3. Energy Forecast Models

There are a total of seven 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 driver being temporary service customer growth.

Industrial-GS Energy Model

Industrial energy forecasts include two rate classes that have been modeled individually: GS and GSD. The Industrial-GS energy model utilizes the same SAE model framework as the commercial energy model. The weather component is consistent with the residential and commercial models.

Industrial-GSD Energy Model

The GSD model is based on industrial employment, the price of electricity in the industrial sector, cooling degree-days and the number of days billed. Unlike the previous models discussed, heating load does not impact this sector.

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 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 capacity and energy Tampa Electric provides to these customers.

Wholesale Load

Tampa Electric's long-term firm sales are served through contracts with the City of St. Cloud. Future sales for a given year are based on the specific terms of their contracts with Tampa Electric. The City of St. Cloud contract will expire December 31, 2012.

5. Demand and Energy Forecasts

The analysis that resulted in the selection of Polk 2-5 incorporated the June 2011 base demand and energy forecast. In June 2012, an updated demand and energy forecast was completed.

Customer Forecasts

Based on the Demand and Energy forecast, Tampa Electric is projecting an annual average increase of 9,597 new customers over the next ten years from 2012-2021. This average annual increase of 1.3 percent is slightly lower than the average annual growth rate of 1.5 percent during the past ten years from 2002-2011. The number of retail customers by customer class are shown in Appendix C.

Retail Energy Sales Forecasts

The primary driver behind the increase in the energy sales forecast is the average annual increase in customers of 1.3 percent. In addition, average per-customer consumption is expected to decrease at an average annual rate of 0.5 percent. Combining the growth in customers and decline in per-customer consumption, retail energy sales are expected to increase at an average annual rate of 0.8 percent. Excluding the phosphate sector, which has recently been declining, retail energy sales are expected to increase at an average annual rate of 1.0 percent. The amount of retail energy sales by customer class are shown in Appendix D.

Retail Peak Demand Forecasts

Summer and winter retail peak usage per-customer is projected to decrease at an average annual rate of 0.4 percent, which is consistent with historical growth rates as well as per-customer energy consumption. The increase in customers and the decrease in per-customer demand results in an average annual growth rate of 1.0 percent for the winter peak and a 0.9 percent growth rate for the summer peak. Total peak demand for the summer 2012 is forecasted to be 3,993 MW and increase to 4,331 MW in 2021, an average increase of 38 MW per year. The 2012 winter peak was forecasted to be 4,081 MW and increase to 4,453 MW in 2021, an average increase of 41 MW per year. Winter and summer total and firm peak demands are shown in Appendix E. High and low winter and

summer firm peak demands are calculated for high and low economic sensitivities and are shown in Appendix F.

June 2012 Customer, Demand and Energy Update

An updated forecast of customers, demand and energy was completed in June of 2012 as part of Tampa Electric's annual planning process. The most current forecast of customers is higher than the forecast presented in the Need Determination Study. However, the current energy sales and peak demand forecasts are lower than the forecasts presented in the Need Study. The primary factor that is driving the changes in the load forecasts is the slower than expected economic recovery and continued reduction in per-customer consumption. The updated retail peak demands are shown in Appendix G.

C. Fuel Forecast

Annual fuel price forecasts developed for the 2012 Fuel and Purchased Power Cost Recovery Clause projection filing and the 2012 Ten Year Site Plan filing were used to analyze supply alternatives for the 2017 need. The coal and natural gas forecasts are provided in Appendix H. These fuel price forecasts were utilized in the detailed economic analysis. Tampa Electric also prepared low and high price forecasts for the sensitivity analyses which are provided in Appendix I and Appendix J, respectively.

Tampa Electric developed a 30-year fuel price forecast utilizing published market pricing indexes and long-term forecasts from independent energy consultants. Refinements were made to the market indexes or consultant prices to align the forecasts to Tampa Electric's physical quality requirements and/or receipt location. 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. **Natural Gas**

   The foundation for the natural gas price forecast is the 10-year New York Mercantile Exchange ("NYMEX") natural gas futures monthly contract closing prices for the five consecutive business days between July 5, 2011 and July 11, 2011. Since the NYMEX natural gas futures contract is based on physical delivery of natural gas to the Henry Hub in southern Louisiana, Tampa Electric adds a "basis" cost to account for the company receiving its natural gas delivered into FGT Zone 3 instead of into the Henry Hub. This establishes the first 10 years of the forecast. The remaining twenty years of the natural gas forecast are derived by escalating the prior year's price by the projected annual escalation of the Consumer Price Index Less Energy.

2. **Solid Fuels**

   The foundation of the coal price forecast is a combination of various published index prices for like-quality coal for the first two to four years. The publications include Coal Daily and ICAP, an online energy broker and information service. For the subsequent years through 2018, a weighted average price is developed using Argus Coal Daily and index prices, along with the coal prices from an independent, published forecast from Wood Mackenzie Energy Consultants ("Wood Mac"). The company utilizes a weighted average method where Tampa Electric's final coal forecast blends the published market indices with the Wood Mac forecast. The market indices are a high percentage of the blend in the near term and Wood Mac is a low percent. Over time the market indices percentage decreases until the Wood Mac forecast is 100

percent of the forecasted price. Beyond 2018 the coal commodity price is escalated annually consistent with the escalation of the other commodities.

3. Transportation

Tampa Electric has bi-modal transportation to receive fuel for the five solid fuel units, and convey coal to Big Bend Power Station and utilize trucking to deliver blended low sulfur coal and petcoke to the Polk Power Station. Tampa Electric can receive its entire coal supply from either water transportation or rail transportation. These bi-modal transportation services provide reliability and cost-effectiveness.

For natural gas transportation, Tampa Electric has long-term firm pipeline capacity reserved on the FGTpipeline and the Gulfstream Pipeline Company, LLC ("Gulfstream") pipeline. Both the Bayside Power Station and the Polk Power Station are listed as Primary Delivery Points on the FGT Firm Service Agreement which allows for flexible and reliable delivery of natural gas to either station using the same agreement. Also, Bayside Power Station and Big Bend Power Station are connected to both FGT and Gulfstream. Thus, depending on conditions, Tampa Electric can deliver natural gas via different pipelines to different plants.

4. Fuel Price Forecasts

The fuel commodity prices used for the Need Determination Analysis are shown in the following table:

Tampa Electric Fuel Prices Forecast 2013 - 2040			
Year	Natural Gas $/MMBtu	No. 2 Oil $/Gallon	Illinois Basin Coal $/ton
2013	$5.12	$3.33	$55.57
2014	$5.39	$3.51	$56.45
2015	$5.67	$3.69	$58.88
2016	$5.95	$3.88	$55.48
2017	$6.23	$4.06	$55.24
2018	$6.51	$4.24	$52.26
2019	$6.79	$4.42	$55.94
2020	$7.07	$4.60	$59.64
2021	$7.34	$4.78	$63.20
2022	$7.63	$4.97	$66.81
2023	$7.80	$5.08	$69.16
2024	$7.97	$5.19	$71.55
2025	$8.14	$5.30	$73.96
2026	$8.31	$5.41	$76.40
2027	$8.49	$5.53	$78.85
2028	$8.67	$5.64	$81.35
2029	$8.85	$5.76	$83.89
2030	$9.03	$5.88	$86.48
2031	$9.22	$6.00	$89.11
2032	$9.41	$6.13	$91.79
2033	$9.61	$6.26	$94.52
2034	$9.80	$6.38	$97.31
2035	$10.01	$6.52	$100.14
2036	$10.21	$6.65	$103.03
2037	$10.42	$6.79	$105.97
2038	$10.64	$6.93	$108.97
2039	$10.85	$7.07	$112.03
2040	$11.08	$7.21	$115.15

Figure 1: Fuel Forecast for Final Analysis

D. Environmental

Environmental requirements considered in Tampa Electric's analysis of supply 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 2-5 environmental permitting requirements discussed in Section XI.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 future water restrictions in the Southwest Florida Water Management District ("SWFWMD") Southern Water Use Caution Area ("SWUCA"), Mercury Air Toxic and Standards ("MACT"), Clean Air Interstate Rule ("CAIR"), Green House Gas New Source Performance Standards ("GHGNSPS"), New Source Performance Standards ("NSPS"), and 316 (b).

E. General Financial Assumptions

In addition to the fuel, load, environmental and other assumptions described, Tampa Electric utilized certain financial assumptions to conduct its detailed economic analysis. Major financial assumptions used in the Ten Year Site Plan ("TYSP") analysis include:

- Discount rate of 7.95 percent;
- Tax rate of 38.575 percent;
- Property tax of 1.27 percent;
- Escalation rate for capital expenditures of 3.0 percent;
- Escalation rate for fixed and variable O&M of 2.4 percent; and
- AFUDC rate of 8.16 percent.

F. Technology Assumptions

1. Demand Side Programs

Tampa Electric's current DSM plan consists of 30 comprehensive residential, commercial, and industrial 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. Appendix A and Appendix B contain a listing of Tampa Electric's current residential and commercial DSM programs, respectively.

2. Supply Technologies

Solid Fuel Technologies

In the screening process, Tampa Electric considered all feasible technologies including IGCC, super-critical pulverized coal ("SCPC"), and circulating fluidized bed combustion ("CFB"). These technologies were evaluated as base load power derived from a blend of bituminous coal that meets current emission standards and limits. Solid fuel technologies typically are characterized as higher construction cost with traditionally lower operating costs when compared to natural gas technologies. The current and near term projections of natural gas prices have reduced operating costs of natural gas technologies compared to solid fuel technologies.

Natural Gas Technologies

Tampa Electric considered a number of natural gas technologies including simple cycle combustion turbine and combined cycle alternatives. The simple cycle combustion turbines ranged from GE 7FA type units to more modern GE LMS100 type units. The combined cycle units considered included 2x1 GE 7FA type units, 2x1 M501G units and the Polk Power Station repower

project involving four HRSGs and a single steam turbine or four HRSGs and two steam turbines.

In comparison to other generating technologies, NGCC technologies are typically characterized by relatively lower 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 than combined cycle technologies 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

Renewable technologies tend to have lower or no fuel costs but have significant fixed costs. In addition, technologies such as geothermal and hydroelectric have limited practical application in Florida. Similarly, wind and solar have limited and unpredictable operating hours due to the intermittent nature of their energy source. In the absence of stored energy capability, intermittent renewables are best considered as energy resources and not as firm capacity for planning purposes. However, some renewable energy such as biomass can be considered as a firm resource if sufficient biomass material is stored and available.

IV. NEED FOR CAPACITY IN 2017

A. Reliability Assessment

Tampa Electric utilizes a twenty percent firm reserve margin reliability criteria above the system firm peak, as required by the Florida Public Service Commission ("Commission" or "FPSC") in Order No. PSC-99-2507-S-EU issued on December 22, 1999, and a minimum seven percent supply reserve margin.

The firm reserve margin consists of both supply and non-firm demand resources to maintain an allowance for unexpected variances in system demand, generating unit availability, and purchased power availability and deliverability. The minimum supply reserve margin criterion maintains an important qualitative component of firm reserves for reliability purposes to minimize the impact of the loss of a supply resource at the time of peak. If the firm reserve margin consisted of only non-firm demand reserves (whereby total firm supply equals total load), then the frequency of use of demand resources in a given year would increase significantly. The firm system peak is determined by including all firm wholesale agreements and excluding non-firm customer demand from the total system demand. Non-firm demand includes all interruptible service customers and customer load reduction programs. Customers who continue to participate in these voluntary programs help defer the need for additional supply resources by reducing firm peak demands. These customers may request to become a firm customer or be excluded from a DSM program with appropriate notification.

Utilizing the June 2011 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.

1. Demand-Side Management

Tampa Electric conducted an extensive evaluation of all conservation measures reasonably available. The company's current 2010-2019 DSM goals were established utilizing a comprehensive set of DSM measures. Through the company's efforts, these goals are being exceeded. Tampa Electric has identified all reasonably achievable DSM demand and energy reductions in its Need Study. There are no DSM alternatives that will cost-effectively defer the need for additional generating capacity in 2017.

B. Tampa Electric's Reliability Assessment Results

The results of the 2012 TYSP final reliability assessment indicate that Tampa Electric will have a summer 2017 need of 294 MW. Table 3 identifies the firm peak demand of 3,940 MW in the summer of 2017 and illustrates the addition of the 20 percent reserve margin requirement to the firm peak to determine the total firm capacity requirement. Tampa Electric's 2017 summer total firm capacity requirement is 4,728 MW. Tampa Electric's net available firm capacity is subtracted from the total firm capacity requirement to determine the summer 2017 incremental capacity need of 294 MW. Details for each year are shown in Appendix K.

Table 4: 2017 Firm Peak Requirements

	Summer 2017 (MW)
Forecasted Firm Retail	3,940
Forecasted Firm Wholesale	0
Total Firm Peak Demand	3,940
Total Firm Capacity Required for 20% Reserve Margin	4,728
Net Available Firm Capacity	4,433
Incremental Capacity Needed[1]	**294**

The reliability analysis was based on existing generating unit operating data and projected system firm peak and energy requirements which were developed in summer 2011. This data supported the development of Tampa Electric's 2012 TYSP filed with the Commission in April 2012. This analysis indicated incremental supply resources are needed in 2017 to meet the 20 percent reserve margin criteria and 7 percent minimum supply criteria. Without additional firm supply resources the summer firm reserve margin is 12.5 percent and the supply component would fall to 6.8 percent in summer 2017.

C. FRCC Reliability Assessment Results

Tampa Electric specific data in conjunction with similar information from other Florida electric utilities is included in the aggregate 2012 FRCC Load and Resource Plan. The FRCC shows that the existing planned demand and supply resource additions by Florida utilities will meet the minimum reliability of 15 percent through 2021, as shown in Appendix M. However, the initial reliability assessment should remove all planned and proposed unit additions and review potential modifications to existing generating capacity.

[1] May not add due to rounding

In addition, the FRCC has analyzed the increasing dependency on DSM programs to provide these reserves. During the 2012 FRCC TYSP workshop on August 13, 2012, it was reported that of the eight NERC reliability regions, the FRCC is among the highest in DSM as a percentage of regional peak. This increased dependency on DSM programs combined with the uncertainty of planned yet uncommitted supply additions as well as existing resources at risk of retirement due to emerging environmental regulations or other factors raise questions regarding future reserve margin calculations. If future additions do not materialize and some existing resources in the region are retired in response to costly mandatory retrofits, the FRCC reserve margin could drop below the minimum required from 2016 through 2019. This sensitivity analysis is reflected in Appendix N. When considering the viability of uncommitted resources, the risk of emerging environmental regulations, and the uncertainty of voluntary DSM programs, firm resources are needed within the FRCC region toward the end of the decade.

V. SCREENING OF POTENTIAL TECHNOLOGIES

Electric utilities have a wide range of potential supply technologies which may be considered for future load requirements. Tampa Electric conducted an initial screening of potential supply technologies (including solid fuel, natural gas fired and renewable resources), based on economic viability and qualitative factors such as technical feasibility, commercial availability, construction timing, and environmental impacts and permitting.

Tampa Electric's supply 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 on the most viable options. Then Tampa Electric conducted a detailed analysis to

determine the selection of the most cost-effective option. 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 by means of 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.

A. Qualitative Screening

Traditional technologies and renewable technologies including wind, solar and biomass were included in the initial screening. Tampa Electric has experience utilizing a diverse range of fuels, including, coal, oil, gas, and biomass, and is always searching for the best option with which to reliably meet our customer need for power.

Renewable technologies, such as wind and solar were looked at as one option to meet our 2017 need. However, the siting difficulty along with inability to meet the requirement for firm capacity eliminated these as viable options for Tampa Electric. It is important to note that Tampa Electric currently employs use of solar power at a number of sites in our service territory and that we continue to evaluate opportunities and proposals on renewable technologies as they fit into our portfolio, while also continuing to maintain our system reliability.

Biomass was also considered as an option. 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 exotherrnic processes. Tampa Electric also encourages additional renewable energy through its renewable standard offer contract approved by the Commission.

Other technologies such as ocean thermal and tidal are not considered commercially available, and there are no significant geothermal sources in Florida. Finally, there are no fuel cells of sufficient size commercially available to offset the 2017 need.

Qualitatively, solid fuel based units were also considered. Siting for solid fuel based units require more than five years to permit and construct. A solid fuel unit would not be able to be in service by the company's target date in 2017, and could possibly put the reliability of Tampa Electric's system in jeopardy of not meeting customer needs.

B. Quantitative Screening

As part of the initial screening process, Tampa Electric performed a more detailed economic evaluation of the viable technologies available. In this step of Tampa Electric's analysis, the levelized annual cost of each 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.

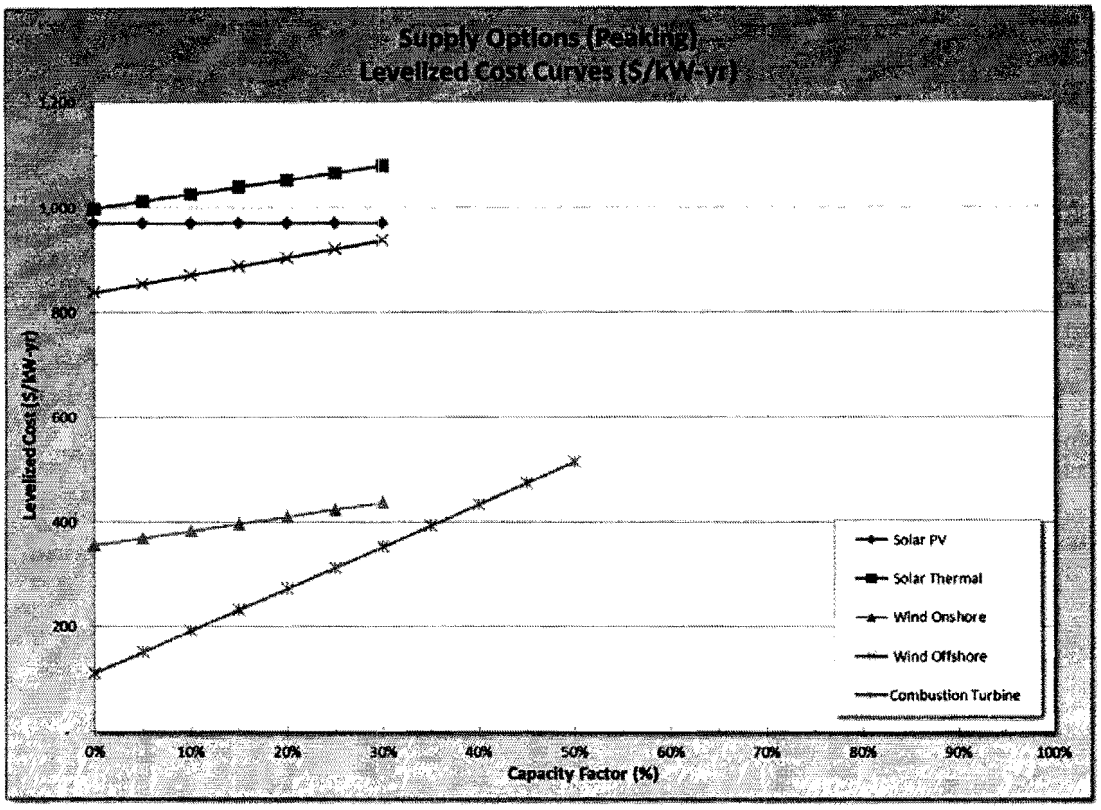


Figure 2: Peaking Technology Screening Curve

Figure 2 shows the low capacity factor technology screen curves. The high cost shown in the curves above further solidifies that wind and solar are not viable options to meet our need in 2017.

In an effort to continue to screen potential technologies and consider a wide range of fuels and capacity factors, Figure 3 includes more traditional technologies over the full range of capacity factors.

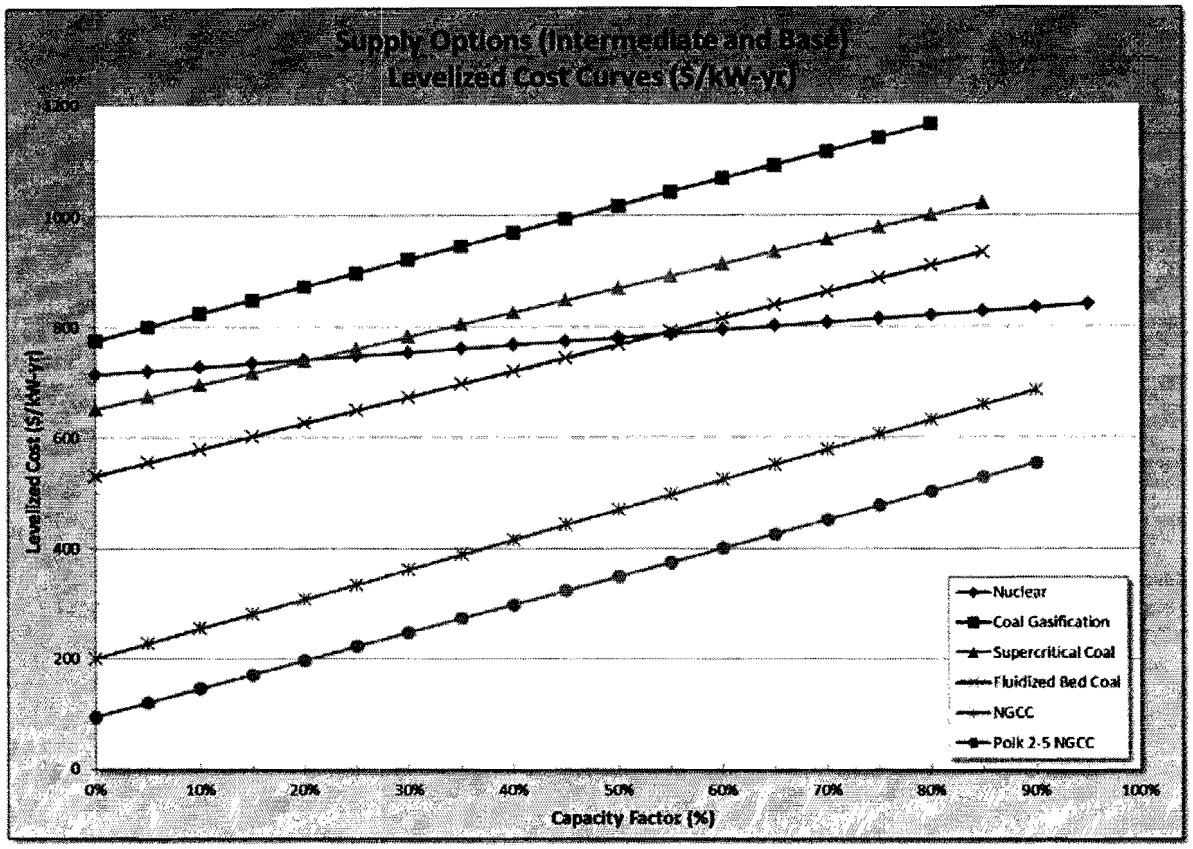


Figure 3: Intermediate and Base Screening Curve

As a result of the screening analysis, Tampa Electric concluded that simple cycle gas-fired CTs and NGCC were the most viable technologies for further consideration of the company's 2017 intermediate need. Because the cost of Aero type CTs and 7FA type CTs are similar on a $/kW-year basis, Tampa Electric determined that due to our experience and our need for power in excess of 60 MWs in 2017, CTs and an NGCC unit were the two alternatives to further consider.

VI. DETAILED ECONOMIC ANALYSIS

A. Description of Analysis

Tampa Electric next conducted detailed economic analysis of the leading supply alternatives. 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.

There were numerous resource plans that included various in-service dates and various combinations of simple cycle combustion turbines, combined cycle units and the Polk 2-5 conversion. The results of the detailed production costing analyses were combined with the capital revenue requirements to produce results on a CPWRR basis. However, the top eight (lowest cost) plans and fifteen out of the top twenty plans selected the Polk 2-5 conversion in 2017.

Two higher cost plans shown in Table 5 are compared to the Polk 2-5 expansion plan. Alternative 1 is a plan that excludes the Polk 2-5 NGCC conversion and adds only simple cycle natural gas combustion turbines to maintain system reliability. Alternative 2 is a plan that delays the in-service date of the Polk 2-5 NGCC conversion until 2025 and adds simple cycle natural gas combustion turbines to maintain system reliability.

Table 5: Detailed Economic Analysis Resource Plan

Resource Plans

Polk 2-5

Year	Portfolio Additions
2012	Peaker PPA 117 MW
2013	Peaker PPA 117 MW Peaker PPA 160 MW
2014	Peaker PPA 117 MW Peaker PPA 160 MW
2015	Peaker PPA 117 MW Peaker PPA 160 MW
2016	Peaker PPA 117 MW Peaker PPA 160 MW
2017	(1) Polk 2-5 NGCC 463/459 MW
2018	
2019	(1) 7FA CT 177/149 MW
2020	
2021	
2022	(1) 7FA CT 177/149 MW
2023	
2024	
2025	(1) 7FA CT 177/149 MW
2026	
2027	-
2028	-
2029	(1) 7FA CT 177/149 MW
2030	-
2031	-
2032	-

Alternative 1

Year	Portfolio Additions
2012	Peaker PPA 117 MW
2013	Peaker PPA 117 MW Peaker PPA 160 MW
2014	Peaker PPA 117 MW Peaker PPA 160 MW
2015	Peaker PPA 117 MW Peaker PPA 160 MW
2016	Peaker PPA 117 MW Peaker PPA 160 MW
2017	(2) 7FA CT 354/298 MW
2018	(1) 7FA CT 177/149 MW
2019	(1) 7FA CT 177/149 MW
2020	
2021	
2022	(1) 7FA CT 177/149 MW
2023	
2024	
2025	(1) 7FA CT 177/149 MW
2026	
2027	-
2028	-
2029	(1) 7FA CT 177/149 MW
2030	-
2031	-
2032	-

Alternative 2

Year	Portfolio Additions
2012	Peaker PPA 117 MW
2013	Peaker PPA 117 MW Peaker PPA 160 MW
2014	Peaker PPA 117 MW Peaker PPA 160 MW
2015	Peaker PPA 117 MW Peaker PPA 160 MW
2016	Peaker PPA 117 MW Peaker PPA 160 MW
2017	(2) 7FA CT 354/298 MW
2018	(1) 7FA CT 177/149 MW
2019	(1) 7FA CT 177/149 MW
2020	
2021	
2022	(1) 7FA CT 177/149 MW
2023	
2024	
2025	(1) Polk 2-5 NGCC 463/459 MW
2026	
2027	-
2028	-
2029	-
2030	-
2031	-
2032	-

B. Economic Analysis Results

The results of the Tampa Electric's analysis are illustrated in the Table 6. Polk 2-5 provides a CPWRR savings of $284 million and $231 million when compared to the Alternative 1 plan that did not include the Polk 2-5 conversion and the Alternative 2 plan that delayed the Polk 2-5 conversion from 2017 to 2025.

Table 6: Results of Final Economic Analysis

Total System Costs (2012 $ million)

	Polk 2-5 Conversion	Alternative 1	Alternative 2
CPWRR	18,232	18,516	18,463
Delta		284	231

1. Tampa Electric Selected Alternative

Tampa Electric selected NGCC technology as the best supply alternative to meet its 2017 need based on the results of the levelized cost analysis, detailed economic analysis and consideration of qualitative factors. Important qualitative factors were considered in the selection of NGCC technology including efficiency, dual fuel capability, transmission reliability and voltage support, dispatchability, low environmental emissions, and renewable integration. The levelized cost analysis and initial screening confirmed that the Polk 2-5 conversion was lower cost compared to a stand-alone NGCC. As a result of the lower cost associated with the Polk 2-5 Conversion as well as the factors listed above, the Polk 2-5 Conversion in 2017 was deemed the most cost-effective, reliable, dispatchable, and environmentally beneficial option. The reliability analysis of this recommended expansion plan is reflected in Appendix L.

2. Qualitative Factors and Benefits of the Selected Alternative

The selection of Polk 2-5 provides a number of qualitative benefits to Tampa Electric's customers. The use of natural gas for Polk 2-5 will ensure a diverse energy mix for Tampa Electric and its customers. The existing Polk 2 and 3 CTs have existing dual-fuel capability, thus further improving reliability to our customers. In addition, the resulting availability of these units is expected to be upwards of 96 percent.

Polk 2-5 will be connected directly to Tampa Electric's transmission network. This will provide higher reliability of delivery and the most ancillary benefits to the company's system. The conversion of our existing units also provides additional power with no added fuel consumption (and thereby no increase in emissions) by capturing waste heat from existing CTs which lowers emissions rates. In addition, after the Polk 2-5 conversion to NGCC, the HRSGs are designed to allow the existing combustion turbines to operate independently in simple cycle mode in the event the steam turbine is unavailable, providing significant system reliability and operating flexibility. The conversion also provides the capability for future integration of renewable energy options.

From a qualitative perspective, Polk 2-5 NGCC was favored due to its overall reliability, system emissions rate, and dispatchability.

3. Consistency with Florida Needs

Polk 2-5 does not significantly increase Tampa Electric's reliance on natural gas on a capacity and energy basis and is therefore consistent with state policy actions that encourage fuel diversity. The Polk 2-5 conversion significantly improves the efficiency of the four existing combustion turbines units and the Tampa Electric system overall by lowering the heat rate and dispatching ahead of other less efficient units. It should also be noted that load management and interruptible customer DSM programs are voluntary, so customers have a choice to withdraw from programs at any time with proper notification.

Tampa Electric's need for additional natural gas-fired combined cycle capacity in January 2017 is consistent with the peninsular Florida capacity needs in this same period, as identified by the FRCC and reported in the FRCC 2012 Regional Load and Resource Plan. The FRCC 2012 plan uses Tampa Electric specific data in conjunction with similar information from other

Florida electric utilities. In addition, there are concerns regarding continued operation of existing solid fuel assets due to emerging environmental regulations. If future additions do not materialize and some existing resources in the region are retired in response to costly mandatory retrofits, the FRCC reserve margin could drop below the minimum required from 2016 through 2019.

VII. SENSITIVITY ANALYSIS

A. Approach

As the final step in our process to select the most cost-effective resource addition as the basis for soliciting requests for power proposals, the company conducted sensitivity analyses comparing uncertainty factors of capital costs, fuel prices, and load growth. To evaluate the sensitivities of these factors, high and low price forecasts were established for capital construction costs and fuel price variations, and in addition, high and low load forecasts were also evaluated for Polk 2-5 and the two selected alternatives.

B. Results of Sensitivity

The results of the capital costs, fuel, and load sensitivities are presented in CPWRR for the Polk 2-5 conversion case in 2017 and the alternative plans described above.

1. Capital Cost Sensitivity

Recognizing that the estimated in-service costs for the Polk 2-5 Conversion are based on preliminary estimates, capital cost sensitivities were analyzed. The high and low cases were established utilizing higher and lower in-service cost for each of the technologies. The results of the capital cost sensitivity analysis are provided in table below:

Table 7: CPWRR Based on Capital Cost Sensitivities ($ million)

	Polk 2-5 Conversion	Alternative 1	Alternative 2
Low Capital Cost	17,951	18,417	18,229
Delta		466	278
High Capital Cost	18,135	18,592	18,425
Delta		457	290

2. Fuel Price Sensitivity

To evaluate fuel price fluctuations, Tampa Electric prepared high and low price forecasts for coal, natural gas and oil. Appendices G and H include the low and high fuel forecasts, respectively. The high case for natural gas and oil is 35 percent higher than the base case and the low case is 35 percent lower than the base case. Solid fuel commodity pricing is 20 percent higher and lower than the base case, respectively. The results of the fuel sensitivity analysis are provided below:

Table 8: CPWRR Based on Fuel Pricing Sensitivities (2012 $ million)

	Polk 2-5 Conversion	Alternative 1	Alternative 2
Low Fuel Cost	15,550	15,656	15,716
Delta		106	166
High Fuel Cost	21,972	22,454	22,274
Delta		482	302

3. Load Sensitivity

The base case load sensitivity is tested for sensitivity to varying economic conditions and customer growth rates. The high and low peak demand and energy sensitivities represent alternatives to the company's base case outlook. Compared to the base case, the expected economic growth rates

are 0.5 percent higher in the high sensitivity and 0.5 percent lower in the low sensitivity. The results of the load sensitivity analysis are provided in the following table:

Table 9: CPWRR Based on Load Sensitivities ($ million)

	Polk 2-5 Conversion	Peaking Only	CC Alt
Low Load Cost	16,857	17,141	17,169
Delta		284	312
High Load Cost	19,792	20,357	19,867
Delta		565	76

These sensitivities demonstrated that Polk 2-5 in 2017 was still the most cost-effective alternative for Tampa Electric's customers.

VIII. RFP for Capacity as per Bid Rule

On March 23, 2012, Tampa Electric issued an RFP to solicit competitive offers to satisfy the company's projected capacity and energy requirements for comparison to Tampa Electric's Polk 2-5. In accordance with the Chapter 25.22.082 Selection of Generating Capacity ("Bid Rule") of the Florida Administrative Code, the RFP provided a detailed description of the Polk 2-5 site, fuel types and costs, estimated costs of the proposed project, and other major financial assumptions. The RFP also detailed the minimum requirements, including but not limited to a minimum 10-year term for purchase power agreements, a maximum of 500 MW and minimum of 50 MW of capacity, and the requirement for firm capacity and energy. The RFP also described the company's objective to maintain a balanced generation mix, while also inviting proposals from renewable generating facilities.

To further ensure the proposals were evaluated on an even and fair basis, Tampa Electric retained the services of Sedway Consulting, Inc. (Sedway Consulting) as an independent evaluator to assist with the development of the RFP and evaluation of the responses. Alan S. Taylor, President of Sedway Consulting, was the primary independent evaluation consultant for the solicitation and has provided testimony in this filing.

On March 16, 2012, the company notified the market of the company's intent to issue an RFP by publishing notices in the Wall Street Journal, the Tampa Tribune, and energy industry publications. An informational meeting was held at Tampa Electric's headquarters on March 21, 2012, prior to the release of the RFP to educate potential bidders on the RFP process and how they could obtain a copy of the RFP. A second meeting was held after the issuance of the RFP, on April 4, 2012, to provide a more in-depth review of the RFP, the Polk 2-5 project, and to answer any questions. Tampa Electric also established a web site that granted access to the RFP documents and allowed potential bidders to submit questions. Both the questions and answers were posted on a "FAQ" page for all to view.

A. Initial Screening

On May 22, 2012, the published due date for proposals, Sedway Consulting facilitated the receipt and opening of all proposals delivered to the company's corporate headquarters. Tampa Electric received a total of four proposals from three bidders, and the table below summarizes these four proposals:

Table 10: RFP Summary of Proposals

Proposal	Type & Term	Technology
A	PPA	Existing CC
B	Sale of Facility	Existing CTs
C	PPA	New CT
D	PPA	New CT

Following the initial screening process described in Section III A.1. of the RFP document, Sedway Consulting, along with Tampa Electric personnel reviewed the proposals to ensure they met the general and specific minimum requirements set forth in the RFP. Tampa Electric, along with Sedway Consulting, contacted bidders whenever there was any missing data, or a need to clarify submitted data.

B. Economic Evaluation of Individual Proposals/Bids

Tampa Electric began the economic evaluation of the above four proposals to determine the relative economic impact on Tampa Electric's system over the study period. The initial rankings of the bid proposals, based on levelized cost curves at the expected capacity factor, indicated A as the most cost effective bid. Bid proposals C and D were initially the least economic for several reasons. Both C and D proposals had higher capacity payments (on a $/kW-month basis) and less efficient heat rates compared to bid proposal A.

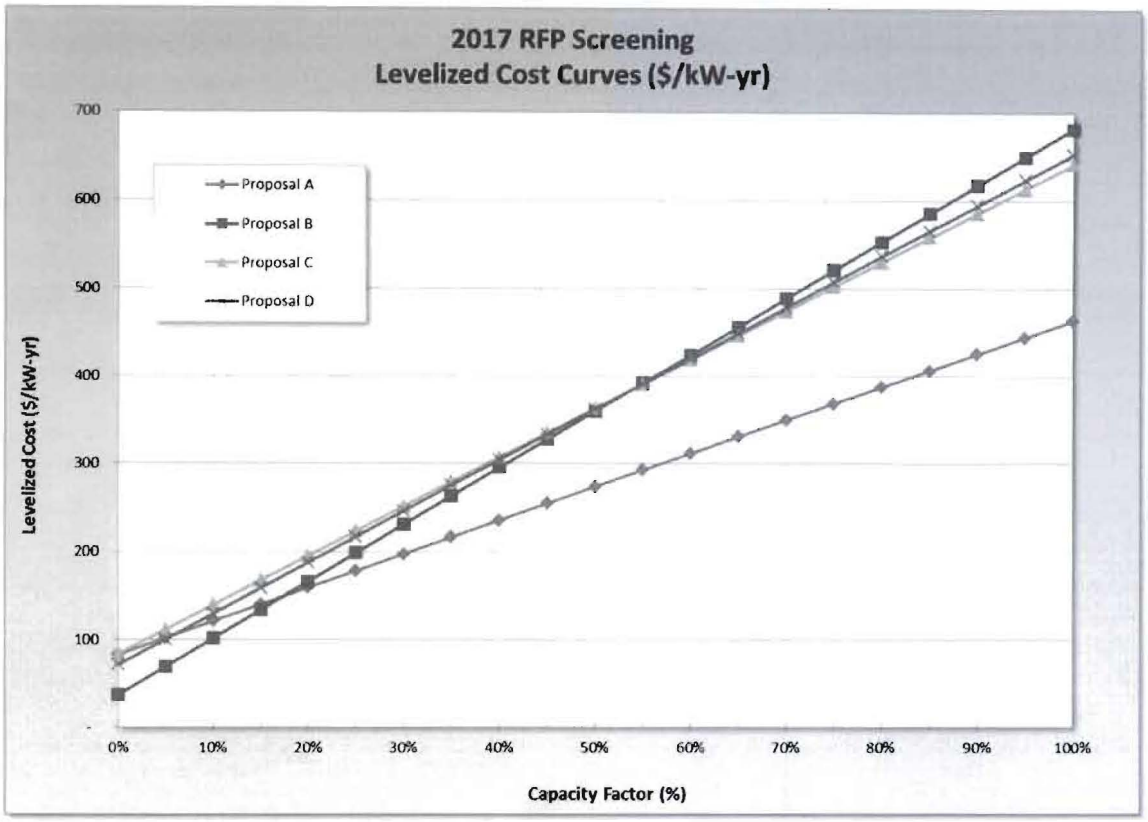


Figure 4: RFP – Initial Screening of Proposals

C. Present Value Economic Screen

Using preliminary system cost assumptions, all four bid proposals were passed to the present value economic ccreen evaluation process where each was evaluated using the CPWRR. This phase of the analysis took into account fixed and variable costs of production for the bid proposals as well as Tampa Electric system impacts. Neither proposal C or D met the 294 MW need in 2017 without the need to add peaking CTs in the 2017 time period.

D. Final Evaluation of Total System Costs

Tampa Electric short-listed all proposals and invited the bidders to submit their best and final offers to the company no later than July 13, 2012. Only proposals

B, C, and D submitted modifications to their initial offers. Tampa Electric used the information provided in the best and final offers, as well as transmission integration cost estimates, net equity adjustment for purchase obligations, and fuel infrastructure costs to determine the final total system cost for each proposal.

Table 11: Resource Plans of RFP Portfolios

Year	Polk 2-5	Proposal A	Proposal B	Proposal C	Proposal D
2012					
2013			Proposal B		
2014					
2015					
2016					
2017	Polk 2-5	Proposal A		Proposal C 7FA CT	Proposal D 7FA CT
2018			Polk 2-5		
2019	7FA CT	7FA CT		(2) 7FA CTs	(2) 7FA CTs
2020					
2021					
2022	7FA CT	7FA CT			
2023				Polk 2-5	Polk 2-5
2024					
2025	7FA CT	7FA CT			
2026			7FA CT		
2027		Polk 2-5			
2028					
2029	7FA CT	7FA CT	7FA CT	7FA CT	
2030					
2031					
2032					7FA CT

Analyzing the above resource plans with the revised data provided by the bidders, yielded the following results:

Table 12: RFP CPWRR Results in 2012 ($ million)

	CPWRR ($ million)				
	Polk 2-5	Proposal A	Proposal B	Proposal C	Proposal D
Capital	$1,575.2	$1,253.3	$1,400.1	$1,430.9	$1,416.6
O&M	$1,099.7	$1,064.6	$1,068.4	$1,111.2	$1,109.2
Fuel & Purchased Power	$15,566.1	$16,143.0	$15,890.3	$15,909.9	$15,954.9
Total	$18,241.0	$18,460.9	$18,358.9	$18,452.0	$18,480.8
Delta		$219.9	$117.9	$210.9	$239.7

As seen above, Polk 2-5 is the lowest cost option against all proposals. Proposal B, which Tampa electric evaluated as the next best option shows a $117.9 million CPWRR additional cost to Polk 2-5.

E. Non-Economic Evaluation

Tampa Electric understands that while the cost-effectiveness of its selection is important, there are many other qualitative impacts that must be considered. Therefore, thirteen unique, non-economic qualitative factors were developed and evaluated across Polk 2-5 and the proposals.. After review of all of these factors, Polk 2-5 was favored due to its overall reliability, emission rate, and dispatchability. The factors considered and a summary of how each proposal was judged is shown in Appendix P.

F. Final Selection

The results of the RFP analysis indicate that Polk 2-5 is the most economic plan to meet the 2017 capacity needs by $117.9 million CPWRR compared to the next best proposal. Based on these economic results, and consideration of the non-economic impacts relative to the other proposals and technologies considered,

Polk 2-5 was selected as the best solution for Tampa Electric's customers in meeting its 2017 need.

IX. TAMPA ELECTRIC'S PROPOSED UNIT

A. Overview

The existing Polk 2 through 5 combustion turbines will be converted to a NGCC facility located at Polk Power Station by integrating a new steam turbine with an additional capacity of 459 MW summer and 463 MW winter, incrementally with a planned in-service date of January 2017. This incremental capacity is derived from waste heat from the four existing combustion turbines of 339 MW summer and 352 MW winter, as well as 120 MW summer and 111 MW winter from supplemental natural gas duct-firing in the four HRSGs. This supplemental firing eliminates the need for two future aero-derivative peaking units due to the expiration of a 121 MW PPA on December 31, 2018. In addition, after the Polk 2-5 conversion to NGCC, the HRSGs are designed to allow the existing combustion turbines to operate independently in simple cycle mode in the event the steam turbine is unavailable, providing significant system reliability and operating flexibility. The NGCC configuration also enables the potential integration of solar thermal renewable capacity and energy in the future.

The total in-service cost of the project (including transmission, but without AFUDC) is expected to be $610.4 million. This includes the direct overnight engineering and procurement costs for the project of $424.4 million. It also includes transmission costs, owner's costs, allowance for indeterminates and escalation.

B. Description

Tampa Electric plans to make use of its experience with NGCC technology to construct Polk 2-5 at Polk Power Station. Polk Power 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. The primary fuel for Polk 2-5 will be natural gas and two of the four units will utilize distillate oil for backup.

Polk 2-5 is expected to generate a net 1,195 MW of electricity in winter at 32 degrees Fahrenheit and 1,063 MW in the summer at 92 degrees Fahrenheit. The average annual net heat rate, higher heating value is expected to be about 7,062 Btu/kWh.

The existing units 2-5 are General Electric 7FA combustion turbines installed in a simple cycle configuration. Units 2 and 3 have the ability to use distillate oil for backup and units 4 and 5 are natural gas only. Simple cycle units have a relatively low capital cost and are able to dispatch rapidly to meet peaking needs, but a significant amount of energy is lost in the exhaust.

After conversion, with no additional fuel consumption, Polk 2-5 will generate an incremental net electrical output of 352 MW in the winter at 32 degrees Fahrenheit and 339 MW in the summer at 92 degrees Fahrenheit. In addition, Polk 2-5 will utilize supplemental firing, also known as duct burners, to provide up to 120 MW of additional cost effective peaking capacity that will offset the need for future peaking unit construction.

1. Location

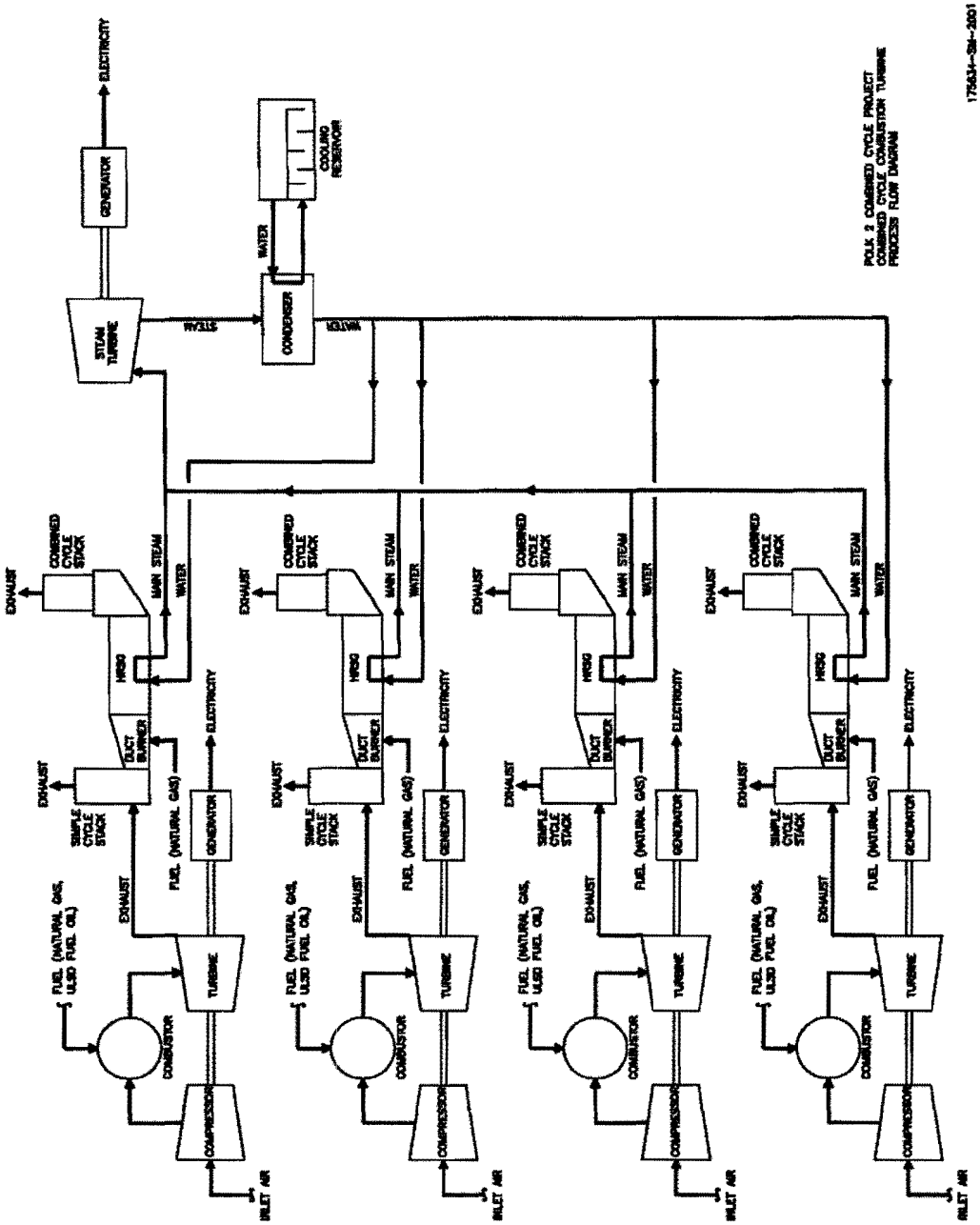
By co-locating Polk 2-5 at Polk Power Station, there are numerous benefits including but not limited to:

- An existing site that has already been developed with future expansion in mind.
- An existing 750 acre cooling reservoir that has adequate capacity to handle a large portion of the cooling needs for Polk 2-5.
- Existing natural gas pipeline infrastructure that already serves the existing units 2-5 and has adequate capacity to serve the incremental need for the supplemental firing system.
- The existing on-site substation can be readily expanded to accommodate the new steam turbine generator interconnection.
- The site has an existing administration building, control room, warehouse, maintenance shop and other facilities that are capable of serving the new unit.
- An existing operations staff experienced in operating this type of generation equipment with minimal training.

2. Design

Tampa Electric is currently in the preliminary engineering stage of design for Polk 2-5. 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 7 below.

Figure 5: Polk 2-5 Overall Process



3. Systems

a. Natural Gas Delivery

Natural gas will be delivered via an existing FGT pipeline already on the Polk site. The pipeline already serves the existing units 2-5 and has adequate capacity to serve the incremental needs of the supplemental firing system. In addition, the Gulfstream Natural Gas Company's pipeline is close to the Polk site and could be extended in the future for added natural gas delivery diversity.

b. Water Use

The primary consumption of water will be for makeup to the cooling reservoir and cooling tower to replace water lost by evaporation. To a much lesser extent, water will also be used to provide demineralized water for makeup to the HRSGs. The majority of the makeup water needs will be from reclaimed water from the City of Lakeland. In addition, by using the existing cooling reservoir to the maximum extent possible, water use from evaporative losses will be reduced relative to using a cooling tower.

c. Heat Recovery Steam Generators (HRSGs)

Polk 2-5 will utilize triple pressure HRSGs with reheat. This design is the standard for domestic combined cycles and is a very proven and reliable technology. In addition, the HRSGs for Polk 2-5 will include diverter dampers and supplemental firing capability. The diverter dampers provide increased reliability by allowing the combustion turbine to remain in operation in the event the associated HRSG or steam turbine is unavailable. The diverter dampers will also allow Polk 2-5 to retain the current rapid response capability if needed for peaking

service. The supplemental firing system will add up to 120 MW (30 MW per HRSG) of relatively low cost and high efficiency peaking capacity when compared to simple cycle combustion turbines.

d. Steam Turbine Generator ("STG")

Polk 2-5 will utilize a modern STG which will be designed with the flexibility to allow cycling, intermediate or base load operation depending on the system's needs and economics. The expected Equivalent Availability Factor for Polk 2-5 is 96.1 percent.

C. Environmental

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 2-5, coordinated through the FDEP and involving all state and regional agencies with environmental responsibility and those potentially affected by Polk 2-5.

Polk 2-5 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 2-5 will be located at the existing site of Polk Unit 1, minimal impacts to wetlands will

occur. Appendix R contains a detailed list of environmental permitting activities that are currently in process by Tampa Electric for Polk 2-5.

Under the federally authorized PSD program, Polk 2-5 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 2-5 site was selected at a location that provides the needed infrastructure and minimizes environmental impacts. The Polk Power Station site includes sufficient land area, which has been previously certified to minimize any additional environmental impacts. Water use will be minimized by utilizing reclaimed water for the makeup to the cooling reservoir. Lakeland's Water Treatment Facility currently discharges its reclaimed water into the Alafia River which ends up in Tampa Bay. Polk is taking this water from Lakeland and treating it removing any nutrients before discharging into Little Pane Creek which aids in improving the water quality in Tampa Bay. Using the treated water will minimize additional consumptive use withdrawals to the greatest extent possible and will assist in accelerating the removal of nutrients from Tampa Bay.

Air emissions from Polk Power Station will be minimized by use of Selective Catalytic Reduction ("SCRs") equipment in each HRSG to reduce nitrogen oxide emissions. The SCRs in combination with cycle efficiency improvements will provide an 86 percent reduction in the NO_x emission rate.

D. Transmission Facilities

Polk 2-5 will require the construction of transmission infrastructure as shown in Appendix S. The infrastructure/facilities required are described below:

1. Two new 230 kV transmission lines, three new 230 kV circuit breakers and

a generator step-up transformer are required at Polk to interconnect the Polk 2-5 to the transmission system.

2. A new 230 kV transmission switching station (Aspen Substation) west of Mines Substation.
3. The following new 230 kV transmission lines:
   - Polk Substation to Mines Substation
   - Mines Substation to Aspen Substation
   - Two lines from Aspen Substation to FishHawk Substation
4. Upgrade segments of existing 230 kV transmission lines to create a 230 kV transmission line from Polk Power Substation to Aspen Substation.
5. Interconnect and rerate existing 230 kV transmission line from Big Bend Power Station Substation to Mines Substation into Aspen Substation.
6. Upgrade 16-230 kV circuit breakers at Polk Power Substation, Pebbledale Substation, Mines Substation and Big Bend Power Station Substation.
7. Reroute and upgrade the first Polk Power Substation to Pebbledale Substation 230 kV transmission line.
8. Rerate the second Polk Power Substation to Pebbledale Substation 230 kV transmission line.
9. Install a switched reactor at Davis Substation.
10. Upgrade the bus for the State Road 60 North 230/69 kV Transformer.
11. Upgrade the bus and low side circuit breaker for the Dale Mabry West 230/69 kV Transformer.

The total project costs are approximately $147.2 million. The Polk interconnection/integration work would begin in January 2013 and would be completed by November 2016. The Polk Power Substation to Aspen Substation to FishHawk Substation transmission line construction must begin by October 2014 in order to make an in-service date of November 2016. The remainder of the work will be completed prior to November 2016. This ensures that all

transmission facilities are in-service prior to any testing of Polk 2-5 and its equipment prior to its commercial date.

Polk 2-5 will be interconnected with Tampa Electric with 4 transmission lines to the existing Polk Power Substation. The Polk Power Substation is currently 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. With the new construction, a 230 kV line will be added to the Aspen Substation, eventually running to the FishHawk Substation.

FRCC Transmission Working Group and Stability Working Group have evaluated the proposed interconnection and integration of the Polk 2-5 project and determined it is reliable and does not adversely impact the transmission system in the FRCC region.

E. Cost

The overnight construction cost for Polk 2-5 is $424.4 million. The estimate represents the following pricing components: engineering, equipment procurement, direct and indirect construction, commissioning and owner's costs in 2012 dollars. This estimate was developed by Black & Veatch and reflects current equipment and labor pricing. This project estimate does not include related transmission upgrades or AFUDC. Owner's costs include project development costs such as environmental permitting, project management, operation support and training, legal and other professional services costs. Tampa Electric estimated the owner's costs for Polk 2-5 based on its experience developing and constructing generating units in Florida.

The total in-service cost estimate for Polk 2-5 is $610.4 million, which includes the aforementioned overnight construction costs as well as transmission costs and escalation.

F. Schedule

Conceptual design began in late 2011, and the preliminary engineering package development began in February 2012 and was completed in May 2012. The Site Certification Application will be filed with the FDEP in September 2012. The detailed design and procurement will begin January 2013. Detailed design and procurement activities are expected to continue through November 2014. Construction activities are expected to begin in the first quarter 2014 with general site work. Commissioning of the equipment is expected to begin in February 2016 and the unit is expected to begin commercial operation in January 2017.

The preliminary project schedule is shown in Appendix Q.

X. JUNE 2012 ASSUMPTIONS UPDATE

During the course of this RFP, Tampa Electric, as part of its annual IRP process, developed an updated customer demand & energy forecast, as well as a new fuel pricing forecast. In order to assess the effects of these new forecasts and to ensure it would not alter the selection of the most economical option, another economic evaluation of Polk 2-5 and the most competitive proposal from the RFP process and Alternative 2 was completed utilizing these new forecasts. The results of this analysis is shown in the table below. Even considering newer forecast data developed as part of the on-going IRP process, Tampa Electric determined Polk 2-5 is still the most cost effective alternative compared to the lowest RFP bid proposal.

Table 13: Economic Evaluation with Consideration of June 2012 Updated Assumptions

CPWRR ($ million)			
	Polk 2-5	Alternative 2	Proposal B
Capital	$1,557.2	$1,520.4	$1,357.5
O&M	$845.2	$897.5	$815.0
Fuel & Purchased Power	$13,631.7	$13,882.9	$13,602.5
Total	$16,034.1	$16,300.8	$16,109.6
Delta		$266.7	$75.4

As can be seen in the table, Polk 2-5 is still the best option compared to Alternative 2 and Proposal B, which are $266.7 million and $75.4 million more costly with the latest demand and energy and fuel cost forecasts considered.

XI. Adverse Consequences If Polk 2-5 Is Delayed Or Denied

In the event that Polk 2-5 is delayed by two years, project costs would increase, and customer fuel savings for 2017 and 2018 would not be realized. Tampa Electric would construct simple cycle peaking units in 2017 to cover the reserve margin requirement in 2017 and 2018. System energy requirements would be served by peaking capacity resulting in higher fuel costs. This would result in higher costs for customers of $65.4 million on a CPWRR basis. Witness Hornick described the potential for an equipment demand spike scenario if there is a delay. If an equipment demand spike scenario materializes, this could result in higher costs for customers of $100.0 million on a CPWRR basis.

If Tampa Electric's proposed Polk 2-5 is denied, Tampa Electric would not be able to satisfy its minimum 20 percent Reserve Margin and minimum 7 percent supply planning criteria by the summer of 2017 in the most reliable and cost-effective manner. This would expose Tampa Electric's customers to a greater

risk of interruption of service in the event of unanticipated forced outages or other contingencies for which Tampa Electric maintains reserves. Even without an interruption in service, without Polk 2-5 the company's customers would be subject to higher fuel costs as the company would have to rely on less efficient simple cycle generation to meet its need.

XII. CONCLUSION

Tampa Electric, through its IRP process, incorporated an on-going evaluation of demand and supply resources and conservation measures to maintain system reliability. The reliability analysis determined that Tampa Electric will have capacity needs by 2017 of 294 MW in order to meet the Commission-approved 20 percent reserve margin criteria. Despite Tampa Electric's utilization of all cost-effective 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 alternatives, including natural gas-fired and solid fuel-fired. After an initial screening process of a variety of viable technologies and fuels, a detailed economic analysis demonstrated that Polk 2-5 is the most cost-effective means of meeting Tampa Electric's 2017 need compared to other technologies and available supply capacity from the Florida market. Tampa Electric's analysis demonstrated Polk 2-5 provides $284 million in savings compared to peaking technology and $231 million in savings compared to peaking then NGCC technology.

After consideration of all existing, new and modified DSM programs and renewable energy initiatives, the construction of Polk 2-5 with a January 2017 in-service date should not be deferred. A two-year deferral of the recommended plan could increase costs to customer by $100 million. Tampa Electric also determined that fuel diversity is a key objective and the addition of natural gas

combined cycle technology in 2017 still maintains a prudent balance in Tampa Electric's capacity and energy mix.

In conclusion, Polk 2-5 provides significant savings of $117.9 million to Tampa Electric's customers when compared to the next higher cost alternative while providing additional benefits in the areas of reliability, fuel diversity, environmental impacts, and generating system efficiency. All these reasons reinforce Tampa Electric's selection of Polk 2-5 as the best alternative for Tampa Electric and its customers.

XIII. APPENDICES

Appendix A: Residential DSM Programs

Appendix B: Commercial/Industrial DSM Programs

Appendix C: Retail Customers by Customer Class

Appendix D: Retail Energy Sales by Customer Class

Appendix E: Retail Peak Demand Forecast

Appendix F: High and Low Retail Peak Demand Used in Sensitivity

Appendix G: June 2012 Update Used in Sensitivity

Appendix H: Fuel Forecast

Appendix I: Low Fuel Forecast Used in Sensitivity Analysis

Appendix J: High Fuel Forecast Used in Sensitivity Analysis

Appendix K: Tampa Electric Reliability Analysis

Appendix L: Tampa Final Electric Reliability Analysis

Appendix M: FRCC Reliability Analysis

Appendix N: FRCC Reliability Sensitivity Analysis

Appendix O: Technology Assumptions

Appendix P: RFP Qualitative Factors

Appendix Q: Polk 2-5 Preliminary Project Schedule

Appendix R: Polk 2-5 Environmental Permit Requirements

Appendix S: Transmission Interconnection and Integration Diagrams

Appendix A: Residential DSM Programs

Residential Programs	Measures	Brief Description
Walk-Through Audit	Customer is given eight CFLs	Free audit conducted on-site by trained analyst
On-Line Audit	Customer is given eight CFLs	Free on-line audit available at customer's convenience
Paid Audit	Customer is given eight CFLs	Paid computer assisted audit conducted on-site by trained analyst
Telephone Audit	Customer is given eight CFLs	Free audit conducted by telephone; uses on-line audit tool for evaluation
Heating & Cooling	High-efficiency heat pumps or high-efficiency cooling with natural gas heating	Incentives are $400 for heat pumps replacing strip heat; $275 for heat pumps replacing strip heat; $275 for straight cool with gas heat
Duct Repair	Duct repair	Customer cost to participate is $50 for repairs and sealing of ductwork.
Residential Building Envelope Improvement	Ceiling insulation	Incentive up to $350
	Wall Insulation	Incentive of $0.31 per sq. ft.
	Window Replacement	Incentive of $2.65 per sq. ft.
	Window Film	Incentive of $2.00 per sq. ft.
New Construction Program	Duct Sealing With Mastic	Incentive of $100
	High-efficiency heat pumps or high-efficiency cooling with natural gas heating	Incentive of $275 per unit
	Ceiling insulation	Incentive of $150
	Window upgrades	Incentive of $400
	Water heating	Incentive of $150
	HERs certification	Incentive of $100
Energy Planner	Price responsive load management	Uses programmable thermostat in conjunction with time-of-use pricing tiers to reduce weather sensitive peak loads.
Electronically Commutated Motors	Air hander fan motor upgrade	Incentive of $135
HVAC Re-commissioning	HVAC equipment tune-up and maintenance	Incentive of $75
Energy Education Outreach	CFLs, low-flow items and filter whistles	Program is designed to establish opportunities for energy-efficiency related discussions in an organized setting
Weatherization and Agency Outreach	**Weatherization** - Installation of the following applicable measures: eight CFLs, water heater wrap, water temp cards, low-flow showerheads, wall plate thermometer, refrigeration coil brush, weather-stripping and caulking, R-13 ceiling insulation and duct repair	Low income weatherization through either direct customer request or by the utilization of census data
	Agency Outreach - Customer is given four CFLs, water temp card, low-flow aerators and change air filter whistles	The delivery of energy efficiency kits to educate agency clients on practices that help reduce energy consumption
Prime Time	Direct load control of HVAC equipment, water heating and pool pumps.	This program has been closed to new customers since 2005

Appendix B: Commercial/Industrial DSM Programs

Commercial Programs	Measures	Brief Description
Free Audit	Customer is given eight CFLs	Free audit conducted on-site by trained analyst
Paid Audit	Customer is given eight CFLs	Paid audit conducted by analyst; includes specific data collection
Duct Repair	Duct repair	Incentive of $300
Building Envelope Improvement	Ceiling insulation	Incentive of $0.25 per sq. ft.
	Roof insulation	Incentive of $0.15 per sq. ft.
	Wall insulation	Incentive of $0.40 per sq. ft.
	Window film	Incentive of $1.25 per sq. ft.
Energy Efficient Motors	Motor upgrades	Incentive of $6.00 per HP
Commercial Cooling	High-efficiency cooling equipment	Incentives are $50 per ton for DX units and $37.50 per ton for PTAC units
Chillers	High-efficiency chilled water HVAC	Incentive of $175 per kW reduction
Lighting	High-efficiency lighting in conditioned or unconditioned space	Incentive of $175 per kW reduction
	High-efficiency exit signs	Incentive of $25 per sign
Occupancy Sensors	Installation of occupancy sensors for lighting	Incentive of $25 per sensor
Standby Generator	Load reduction through emergency generation	Incentive of $4.00 per kW reduction
Refrigeration (anti-condensate controls)	Installation of anti-condensate heat controls	Incentive of $0.65 per linear ft.
Water Heating	Water heating upgrades	Incentive of $0.0116 per btu
Conservation Value	Customer specific measures with reductions greater than 5 kW	Incentive of $175 per kW reduction
Commercial Load Management	Direct load control of HVAC equipment, water heating	Incentive for cyclic control (summer only) $3.00 per kW; Incentive for extended control (summer and winter) $3.50 per kW
Demand Response	Price responsive load management	Turn-key program providing price incentives for demand reduction
Industrial Load Management	Load reduction for facilities 500 kW and greater	Approved annual incentive per FPSC cost-effectiveness methodology
Electronically Commutated Motors	Air hander fan and refrigeration motors upgrade	Incentives range from $125 to $180 per HP
HVAC Re-commissioning	HVAC equipment tune-up and maintenance	Incentive of $25 per ton
Cool Roof	Roof systems to reduce cooling demand	Incentive of $0.60 per sq. ft.
Energy Recovery Ventilation	HVAC ventilation systems to reduce cooling demand	Incentives range from $1.32 to $2.26 per cfm of system

Appendix C: Retail Customers by Customer Class

	Residential	Commercial	Industrial	Phosphate	Public Authorities	Street&Hwy Lighting	Total Retail Sales
2002	518,554	64,665	904	44	5,812	220	590,199
2003	531,257	66,041	1,159	44	6,188	211	604,900
2004	544,313	67,488	1,260	39	6,226	209	619,535
2005	558,601	69,027	1,300	37	6,447	209	635,621
2006	575,111	70,205	1,448	37	6,706	199	653,706
2007	586,776	70,891	1,458	36	6,992	201	666,354
2008	587,602	70,770	1,385	36	7,271	202	667,266
2009	587,396	70,182	1,392	32	7,521	227	666,750
2010	591,554	70,176	1,405	29	7,607	220	670,991
2011	595,914	70,522	1,465	28	7,666	203	675,798
2012	599,454	71,418	1,464	32	7,746	201	680,315
2013	606,320	72,252	1,475	32	7,802	202	688,083
2014	614,152	73,176	1,486	32	7,863	204	696,913
2015	622,637	74,183	1,494	32	7,929	206	706,481
2016	632,012	75,278	1,501	32	8,002	208	717,033
2017	641,161	76,346	1,508	32	8,073	210	727,330
2018	650,099	77,398	1,516	32	8,141	213	737,399
2019	659,014	78,447	1,523	32	8,210	215	747,441
2020	667,793	79,491	1,531	32	8,278	217	757,342
2021	676,073	80,484	1,539	32	8,342	220	766,690
Average Annual Growth Rates							
2002-2011	1.6%	1.0%	5.5%	-4.8%	3.1%	-0.9%	1.5%
2012-2021	1.3%	1.3%	0.6%	0.0%	0.8%	1.0%	1.3%
Average Absolute Growth							
2002-2011	8,596	651	62	-2	206	-2	9,511
2012-2021	8,513	1,007	8	0	66	2	9,597

Appendix D: Retail Energy Sales by Customer Class

Tampa Electric Company
Retail Energy Sales
(GWH)

	Residential	Commercial	Industrial	Phosphate	Public Authorities	Street&Hwy Lighting	Total Retail Sales
2002	8,046	5,832	1,234	1,378	1,380	55	17,925
2003	8,265	5,843	1,303	1,277	1,481	57	18,225
2004	8,293	5,988	1,327	1,229	1,542	58	18,437
2005	8,558	6,234	1,329	1,149	1,582	60	18,912
2006	8,721	6,357	1,343	936	1,607	61	19,025
2007	8,871	6,542	1,316	1,050	1,692	63	19,533
2008	8,546	6,399	1,236	969	1,776	64	18,990
2009	8,666	6,274	1,088	906	1,771	68	18,774
2010	9,185	6,221	1,058	952	1,724	73	19,213
2011	8,718	6,207	1,072	731	1,761	74	18,564
2012	8,904	6,346	1,121	777	1,822	74	19,044
2013	9,003	6,412	1,131	706	1,833	74	19,158
2014	9,095	6,484	1,135	568	1,844	75	19,201
2015	9,174	6,557	1,133	530	1,856	76	19,326
2016	9,272	6,640	1,128	540	1,871	77	19,528
2017	9,376	6,727	1,122	529	1,887	77	19,719
2018	9,486	6,814	1,117	529	1,903	78	19,927
2019	9,600	6,901	1,112	529	1,919	79	20,141
2020	9,716	6,985	1,107	529	1,935	80	20,352
2021	9,826	7,063	1,102	529	1,949	81	20,550
Average Annual Growth Rates							
2002-2011	0.9%	0.7%	-1.5%	-6.8%	2.7%	3.3%	0.4%
2012-2021	1.1%	1.2%	-0.2%	-4.2%	0.8%	1.0%	0.8%
Average Absolute Growth							
2002-2011	75	42	-18	-72	42	2	71
2012-2021	102	80	-2	-28	14	1	167

Appendix E: Retail Peak Demand Forecast

Tampa Electric Company
Total Retail Peak Demand
(MW)

	Winter	Summer
2002	3612	3634
2003	3881	3623
2004	3344	3737
2005	3686	3968
2006	3736	4010
2007	3398	4123
2008	3709	3952
2009	4080	4015
2010	4512	3917
2011	4037	3976
2012	4081	3993
2013	4112	4023
2014	4141	4049
2015	4180	4082
2016	4224	4125
2017	4269	4165
2018	4315	4207
2019	4361	4250
2020	4408	4292
2021	4453	4331

Average Annual Growth Rates

2002-2011	1.2%	1.0%
2012-2021	1.0%	0.9%

Average Absolute Growth

2002-2011	47	38
2012-2021	41	38

Tampa Electric Company
Firm Retail Peak Demand
(MW)

	Winter	Summer
2002	3259	3318
2003	3455	3351
2004	2936	3445
2005	3287	3725
2006	3523	3769
2007	3127	3876
2008	3443	3723
2009	3754	3799
2010	4246	3710
2011	3735	3699
2012	3777	3748
2013	3819	3784
2014	3864	3823
2015	3910	3859
2016	3955	3900
2017	4003	3940
2018	4050	3980
2019	4097	4022
2020	4146	4064
2021	4194	4103

Average Annual Growth Rates

2002-2011	1.5%	1.2%
2012-2021	1.2%	1.0%

Average Absolute Growth

2002-2011	53	42
2012-2021	46	39

Appendix F: High and Low Retail Peak Demand Used in Sensitivity

High Load Scenario

Tampa Electric Company
Firm Retail Peak Demand
(MW)

	Winter	Summer
2002	3259	3318
2003	3455	3351
2004	2936	3445
2005	3287	3725
2006	3523	3769
2007	3127	3876
2008	3443	3723
2009	3754	3799
2010	4246	3710
2011	3735	3699
2012	3802	3778
2013	3868	3836
2014	3936	3897
2015	4003	3955
2016	4072	4017
2017	4142	4080
2018	4212	4144
2019	4284	4209
2020	4358	4276
2021	4431	4341

Average Annual Growth Rates

2002-2011	1.5%	1.2%
2012-2021	1.7%	1.6%

Average Absolute Growth

2002-2011	53	42
2012-2021	70	63

Low Load Scenario

Tampa Electric Company
Firm Retail Peak Demand
(MW)

	Winter	Summer
2002	3259	3318
2003	3455	3351
2004	2936	3445
2005	3287	3725
2006	3523	3769
2007	3127	3876
2008	3443	3723
2009	3754	3799
2010	4246	3710
2011	3725	3699
2012	3758	3725
2013	3779	3740
2014	3802	3758
2015	3825	3773
2016	3849	3791
2017	3874	3810
2018	3898	3827
2019	3922	3847
2020	3947	3866
2021	3972	3882

Average Annual Growth Rates

2002-2011	1.5%	1.2%
2012-2021	0.6%	0.5%

Average Absolute Growth

2002-2011	52	42
2012-2021	24	17

Appendix G: June 2012 Update Used in Sensitivity

Tampa Electric Company
Total Retail Peak Demand
(MW)

	Winter	Summer
2002	3612	3634
2003	3881	3623
2004	3344	3737
2005	3686	3968
2006	3736	4010
2007	3398	4123
2008	3709	3952
2009	4080	4015
2010	4512	3917
2011	4037	3931
2012	3523	3916
2013	3970	3893
2014	3999	3928
2015	4043	3969
2016	4095	4017
2017	4147	4065
2018	4200	4112
2019	4251	4159
2020	4301	4203
2021	4349	4244

Average Annual Growth Rates

2002-2011	1.2%	0.9%
2012-2021	1.1%	0.9%

Average Absolute Growth

2002-2011	47	33
2012-2021	47	36

Tampa Electric Company
Firm Retail Peak Demand
(MW)

	Winter	Summer
2002	3259	3318
2003	3455	3351
2004	2936	3445
2005	3287	3725
2006	3523	3769
2007	3127	3876
2008	3443	3723
2009	3754	3799
2010	4246	3710
2011	3725	3699
2012	3237	3677
2013	3699	3667
2014	3731	3701
2015	3778	3741
2016	3832	3788
2017	3887	3835
2018	3941	3881
2019	3993	3927
2020	4045	3971
2021	4095	4012

Average Annual Growth Rates

2002-2011	1.5%	1.2%
2012-2021	1.3%	1.0%

Average Absolute Growth

2002-2011	52	42
2012-2021	50	37

Appendix H: Fuel Forecast

Tampa Electric has forecasted the commodity price of fuels through 2041. Natural gas is forecasted for the Henry Hub.

Nominal $/MMBtu for Fuel

	No. 2 Oil	NG	Coal
2012	$25.68	$4.92	$2.22
2013	$26.88	$5.30	$2.42
2014	$27.98	$5.58	$2.45
2015	$29.44	$5.86	$2.56
2016	$30.84	$6.12	$2.41
2017	$32.06	$6.39	$2.40
2018	$33.34	$6.67	$2.27
2019	$34.63	$6.93	$2.43
2020	$35.98	$7.19	$2.59
2021	$37.39	$7.44	$2.75
2022	$38.89	$7.70	$2.90
2023	$39.75	$7.87	$3.01
2024	$40.61	$8.04	$3.11
2025	$41.49	$8.21	$3.22
2026	$42.37	$8.39	$3.32
2027	$43.27	$8.56	$3.43
2028	$44.17	$8.74	$3.54
2029	$45.09	$8.93	$3.65
2030	$46.03	$9.11	$3.76
2031	$46.99	$9.30	$3.87
2032	$47.96	$9.49	$3.99
2033	$48.96	$9.69	$4.11
2034	$49.97	$9.89	$4.23
2035	$50.99	$10.09	$4.35
2036	$52.04	$10.30	$4.48
2037	$53.11	$10.51	$4.61
2038	$54.20	$10.72	$4.74
2039	$55.31	$10.94	$4.87
2040	$56.44	$11.16	$5.01

Appendix I: Low Fuel Forecast Used in Sensitivity Analysis

Tampa Electric has forecasted the commodity price of fuels through 2041. Natural gas is forecasted for the Henry Hub.

Nominal $/MMBtu for Fuel

	No. 2 Oil	NG	Coal
2012	$14.52	$3.09	$2.22
2013	$15.63	$3.33	$1.93
2014	$16.46	$3.51	$1.96
2015	$17.30	$3.69	$2.05
2016	$18.17	$3.87	$1.93
2017	$19.01	$4.05	$1.92
2018	$19.88	$4.23	$1.82
2019	$20.72	$4.41	$1.97
2020	$21.56	$4.59	$2.14
2021	$22.42	$4.77	$2.30
2022	$23.29	$4.96	$2.46
2023	$23.80	$5.07	$2.55
2024	$24.32	$5.18	$2.65
2025	$24.85	$5.29	$2.75
2026	$25.38	$5.40	$2.84
2027	$25.91	$5.52	$2.94
2028	$26.45	$5.63	$3.04
2029	$27.00	$5.75	$3.14
2030	$27.57	$5.87	$3.25
2031	$28.14	$5.99	$3.35
2032	$28.72	$6.12	$3.46
2033	$29.32	$6.24	$3.57
2034	$29.92	$6.37	$3.68
2035	$30.54	$6.50	$3.80
2036	$31.17	$6.64	$3.91
2037	$31.81	$6.77	$4.03
2038	$32.46	$6.91	$4.15
2039	$33.12	$7.05	$4.28
2040	$33.80	$7.20	$4.40

Appendix J: High Fuel Forecast Used in Sensitivity Analysis

Tampa Electric has forecasted the commodity price of fuels through 2041. Natural gas is forecasted for the Henry Hub.

Nominal $/MMBtu for Fuel

	No. 2 Oil	NG	Coal
2012	$30.15	$6.42	$2.22
2013	$32.46	$6.91	$2.90
2014	$34.18	$7.28	$2.95
2015	$35.93	$7.65	$3.07
2016	$37.74	$8.04	$2.89
2017	$39.49	$8.41	$2.88
2018	$41.28	$8.79	$2.73
2019	$43.04	$9.17	$2.91
2020	$44.79	$9.54	$3.10
2021	$46.55	$9.92	$3.29
2022	$48.37	$10.30	$3.48
2023	$49.43	$10.53	$3.59
2024	$50.51	$10.76	$3.70
2025	$51.60	$10.99	$3.81
2026	$52.70	$11.23	$3.93
2027	$53.81	$11.46	$4.04
2028	$54.94	$11.70	$4.16
2029	$56.09	$11.95	$4.28
2030	$57.25	$12.19	$4.40
2031	$58.44	$12.45	$4.52
2032	$59.66	$12.71	$4.65
2033	$60.89	$12.97	$4.78
2034	$62.15	$13.24	$4.91
2035	$63.43	$13.51	$5.04
2036	$64.73	$13.79	$5.18
2037	$66.06	$14.07	$5.32
2038	$67.41	$14.36	$5.46
2039	$68.79	$14.65	$5.60
2040	$70.20	$14.95	$5.75

Appendix K: Tampa Electric Reliability Analysis

Forecast of Capacity and Demand at Time of Summer Peak

Year	Total Installed Capacity MW	Net Firm Capacity Purchases MW	Total Capacity Available MW	System Firm Peak Demand MW	System Total Peak Demand MW	Firm Reserve Margin w/o Planned Additions MW	Firm Reserve Margin w/o Planned Additions % of Peak	Firm Reserve Margin w/o Planned Additions Shortfall for 20% MW	Supply-Side Reserve Margin w/o Planned Additions MW	Supply-Side Reserve Margin w/o Planned Additions % of Peak	Supply-Side Reserve Margin w/o Planned Additions Shortfall for 7% MW
2012	4,292	617	4,909	3,763	4,008	1,146	30.5%	N/A	901	23.9%	N/A
2013	4,312	421	4,733	3,784	4,023	949	25.1%	N/A	710	18.8%	N/A
2014	4,312	421	4,733	3,823	4,049	910	23.8%	N/A	684	17.9%	N/A
2015	4,312	421	4,733	3,859	4,082	874	22.7%	N/A	651	16.9%	N/A
2016	4,312	398	4,710	3,900	4,125	810	20.8%	N/A	585	15.0%	N/A
2017	4,312	121	4,433	3,940	4,165	493	12.5%	294	268	6.8%	8
2018	4,312	121	4,433	3,980	4,207	453	11.4%	343	226	5.7%	53
2019	4,312	0	4,312	4,022	4,250	290	7.2%	515	62	1.5%	220
2020	4,312	0	4,312	4,064	4,292	248	6.1%	565	20	0.5%	264
2021	4,312	0	4,312	4,103	4,331	209	5.1%	612	(19)	-0.5%	306

Forecast of Capacity and Demand at Time of Summer Peak

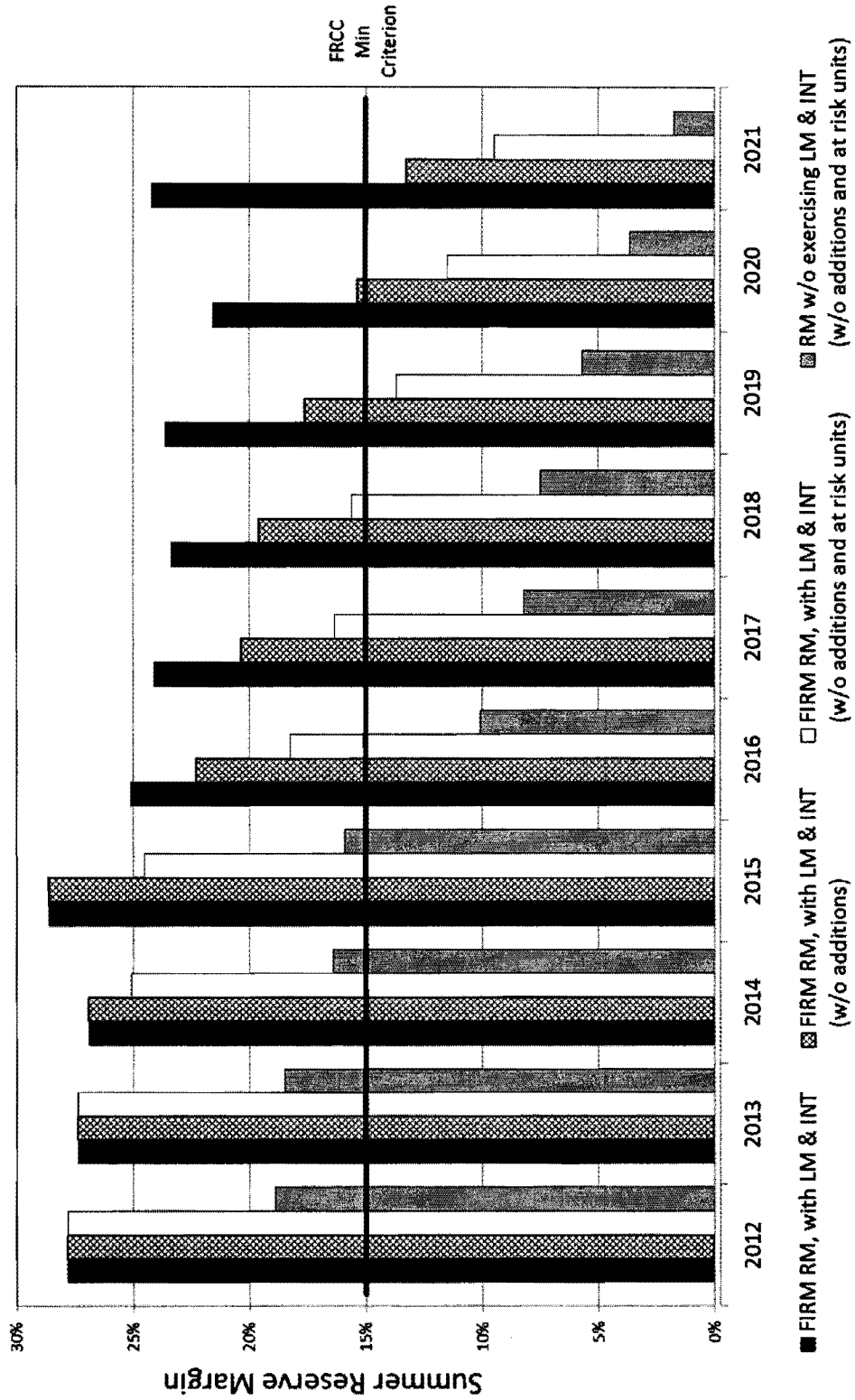
Year	Total Installed Capacity MW	Net Firm Capacity Purchases MW	Total Capacity Available MW	System Firm Peak Demand MW	System Total Peak Demand MW	Reserve Margin MW	Reserve Margin % of Peak	Reserve Margin Shortfall for 20% MW	Supply-Side Reserve Margin MW	Supply-Side Reserve Margin % of Peak	Supply-Side Reserve Margin Shortfall for 7% MW
2012	4,292	617	4,909	3,763	4,008	1,146	30.5%	N/A	901	23.9%	N/A
2013	4,312	421	4,733	3,784	4,023	949	25.1%	N/A	710	18.8%	N/A
2014	4,312	421	4,733	3,823	4,049	910	23.8%	N/A	684	17.9%	N/A
2015	4,312	421	4,733	3,859	4,082	874	22.7%	N/A	651	16.9%	N/A
2016	4,312	398	4,710	3,900	4,125	810	20.8%	N/A	585	15.0%	N/A
2017	4,771	121	4,892	3,940	4,165	952	24.2%	N/A	727	18.5%	N/A
2018	4,771	121	4,892	3,980	4,207	912	22.9%	N/A	685	17.2%	N/A
2019	4,920	0	4,920	4,022	4,250	898	22.3%	N/A	670	16.7%	N/A
2020	4,920	0	4,920	4,064	4,292	856	21.1%	N/A	628	15.5%	N/A
2021	4,920	0	4,920	4,103	4,331	817	19.9%	4	589	14.4%	N/A

Appendix M: FRCC Reliability Analysis

Forecast of Capacity and Demand at Time of Summer Peak with Planned Additions

Year	Total Installed Capacity MW	Net Firm Capacity Purchases MW	Total Capacity Available MW	System Firm Peak Demand MW	System Total Peak Demand MW	Firm Reserve Margin With Excercising Load Mgmt & Int. MW	Firm Reserve Margin With Excercising Load Mgmt & Int. % of Peak	Reserve Margin w/o Excercising Load Mgmt & Int. MW	Reserve Margin w/o Excercising Load Mgmt & Int. % of Peak
2012	47,747	6,486	54,233	42,430	45,613	11,803	27.8%	8,620	18.9%
2013	48,506	6,316	54,822	43,041	46,270	11,781	27.4%	8,552	18.5%
2014	49,730	5,613	55,343	43,618	46,857	11,725	26.9%	8,486	18.1%
2015	51,567	5,614	57,181	44,459	47,758	12,722	28.6%	9,423	19.7%
2016	52,118	4,473	56,591	45,242	48,594	11,349	25.1%	7,997	16.5%
2017	52,553	4,296	56,849	45,802	49,244	11,047	24.1%	7,605	15.4%
2018	52,539	4,382	56,921	46,152	49,643	10,769	23.3%	7,278	14.7%
2019	53,585	4,263	57,848	46,803	50,356	11,045	23.6%	7,492	14.9%
2020	53,667	4,180	57,847	47,581	51,191	10,266	21.6%	6,656	13.0%
2021	55,968	3,973	59,941	48,273	51,933	11,668	24.2%	8,008	15.4%

Appendix N: FRCC Reliability Sensitivity Analysis



Appendix O: Technology Assumptions

Screening Data

NAME	Solar PV	Solar Thermal	Wind Onshore	Wind Offshore	Aero CT	7FA CT
CAPACITY (MW)	10	100	50	300	61	177
BASE YEAR CAPITAL COST ($000)	62,200	668,200	119,177	1,620,000	40,624	119,498
BASE YEAR CAPITAL RATE ($/kW)	6,220	6,682	2,384	5,400	666	675
BASE YEAR FIXED O&M ($000/Year)	311	0	0	6,900	1,265	1,359
BASE YEAR FIXED O&M ($/kW-yr)	31.09	0.00	0.00	23.00	20.73	7.68
USE FIXED O&M STREAM BELOW? (Y/N) [If No, rate will be escalated on next page]	N	N	N	N	N	N
BASE YEAR VARIABLE O&M ($/MWh)	0.00	23.32	23.63	29.02	3.87	3.87
USE VARIABLE O&M STREAM BELOW? (Y/N) [If No, rate will be escalated on next page]	N	N	N	N	N	N
BASE YEAR FUEL RATE ($/MWH)	-	-	-	-	-	-
USE FUEL STREAM BELOW? (Y/N) [If No, rate will be escalated on next page]	Y	Y	Y	Y	Y	Y
K-FACTOR	1.5937	1.5937	1.5937	1.5937	1.5937	1.5937
REMAINING LIFE (Years)	25	25	25	25	25	25
Levlized Fixed Charge Rate (FCR)	0.1382	0.1382	0.1382	0.1382	0.1382	0.1382

NAME	Nuclear	IGCC	CFB	SCPC	NGCC	Biomass
CAPACITY (MW)	1,140	623	295	785	530	35
BASE YEAR CAPITAL COST ($000)	5,799,264	3,055,080	1,185,554	2,593,916	680,470	173,195
BASE YEAR CAPITAL RATE ($/kW)	5,087	4,904	4,019	3,304	1,283	4,948
BASE YEAR FIXED O&M ($000/Year)	15,358	20,198	11,411	21,907	3,333	3,990
BASE YEAR FIXED O&M ($/kW-yr)	13.47	32.42	38.68	27.91	6.28	114.00
USE FIXED O&M STREAM BELOW? (Y/N) [If No, rate will be escalated on next page]	N	N	N	N	N	N
BASE YEAR VARIABLE O&M ($/MWh)	3.86	6.63	1.97	1.55	4.27	15.65
USE VARIABLE O&M STREAM BELOW? (Y/N) [If No, rate will be escalated on next page]	N	N	N	N	N	N
BASE YEAR FUEL RATE ($/MWH)	-	-	-	-	-	-
USE FUEL STREAM BELOW? (Y/N) [If No, rate will be escalated on next page]	Y	Y	Y	Y	Y	Y
K-FACTOR	1.6301	1.5937	1.5937	1.5937	1.5937	1.5937
REMAINING LIFE (Years)	40	25	25	25	25	25
Levlized Fixed Charge Rate (FCR)	0.1265	0.1382	0.1382	0.1382	0.1382	0.1382

Appendix P: RFP Qualitative Factors

	PK 2-5	Proposal A	Proposal B	Proposal C	Proposal D
Technology Type	Combined Cycle	Combined Cycle	Peakers	Peaker	Peaker
Transmission Reliability, Voltage Support, Reserves	High High	High High	Medium Low	Medium Low	Medium Low
Water Availability	Municipal Source	Municipal Source	Limited, water use caution area	Unknown	Unknown
Dual Fuel Capability	2 CTs - Yes, 2 CTs - Capable	No	2 CTs - Yes	1 CT - Yes	1 CT - Yes
Project Execution	Low risk	Existing Unit	Existing Unit	Low risk	Low risk
Project Operation	TEC	Owner	ST – contractors LT – TEC employees	Contractor	Contractor
Project Maintenance	CSA	Self-managed, as needed	CSA and CT spares modeled	Self-managed, as needed	Self-managed, as needed
Project Security	Investment Grade	Low – offered lien or step in rights	Investment Grade	Investment Grade	Investment Grade
Environmental Emission Rates	Lower	Lower	Higher	Higher	Higher
Renewable Option	30 MW Solar	None	None	None	None
Simple Cycle Capability	Yes	No	Yes	Yes	Yes
Job Creation and Tax Base	Construction labor	No: existing unit	No: existing unit TEC may increase O&M	Construction, O&M labor	Construction, O&M labor

Appendix Q: Polk 2-5 Preliminary Project Schedule

POLK 2-5 COMBINED CYCLE PROJECT MAJOR MILESTONE SCHEDULE	
Award Contract for Steam Turbine Generator Supply	January 4, 2013
Award Contract for Heat Recovery Steam Generator Supply	April 12, 2013
Award Contract for Preliminary Construction	November 22, 2013
Receive Permits and Modified Site Certification	January 31, 2014
Begin Construction (Plant and Transmission)	February 3, 2014
Award Contract for Construction	March 21, 2014
Begin Tie-in Outages on Existing Units	September 1, 2014
Begin Combined Cycle Startup and Testing	May 2, 2016
Transmission System Upgrades Complete	November 4, 2016
Commercial Operation	January 2, 2017

Appendix R: Polk 2-5 Environmental Permit Requirements

Permit	Review/ Approval Agencies	Status/Comments
• Florida Electrical Power Plant Siting Act (PPSA)	FDEP/Affected Agencies/Siting Board	
○ PSD air construction permit	FDEP	
○ NPDES industrial wastewater treatment permit	FDEP	
• Ground water discharge permit	FDEP	
• Consumptive water use permit	SWFWMD	
○ Section 404 dredge-and-fill permit	USACE/ FDEP	
○ Section 10 permit	USACE	
○ Endangered/threatened species review	USFWS/ FFWCC	
• Section 401 water quality certification	FDEP	
• Environmental resource permit/storm water management	FDEP	
• Water well construction permit	FDEP	
• Non-transient, non-community water system permit	FDEP	
• Domestic septic system permit	Polk County	
• NPDES storm water permit NOI associated with industrial activity	FDEP	
• Solid waste management facilities permit	FDEP	
Determination of need	FPSC	
○ NPDES general permit NOI for storm water for construction sites	EPA	
✦ Phase II Title IV acid rain permit	FDEP/EPA	

Permit	Review/ Approval Agencies	Status/Comments
✦ Title V air emissions operation permit	FDEP	
• Construction dewatering permit	SWFWMD	
✦ Hazardous waste generator registration	EPA/ FDEP	
Notice of construction in navigable aerospace	FAA	
✦ Aboveground storage tank (AST) registration	FDEP	
✦ Spill prevention, control, and countermeasure plan	EPA	
✦ Facility response plan	EPA/FDEP	
• 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.
- o 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.

REDACTED

Appendix S: Transmission Interconnection and Integration Diagrams

The content of pages 84-85 has been redacted and filed separately with a request for confidential classification.

The content of pages 84-85 has been redacted and filed separately with a request for confidential classification.

REDACTED

The content of pages 84-85 has been redacted and filed separately with a request for confidential classification.

TAMPA ELECTRIC COMPANY
DOCKET NO. 12____-EI
WITNESS: HORNICK

EXHIBIT

OF

MARK J. HORNICK

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 120234-EI EXHIBIT 12
PARTY TAMPA ELECTRIC COMPANY (TECO) - (DIRECT)
DESCRIPTION Mark J. Hornick (MJH-1)

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TAMPA ELECTRIC COMPANY
DOCKET NO. 12_____-EI
EXHIBIT NO. ___ (MJH-1)
DOCUMENT NO. 1
FILED: 09/12/2012

DOCUMENT NO. 1

POLK SITE AERIAL PHOTOGRAPH

TAMPA ELECTRIC COMPANY
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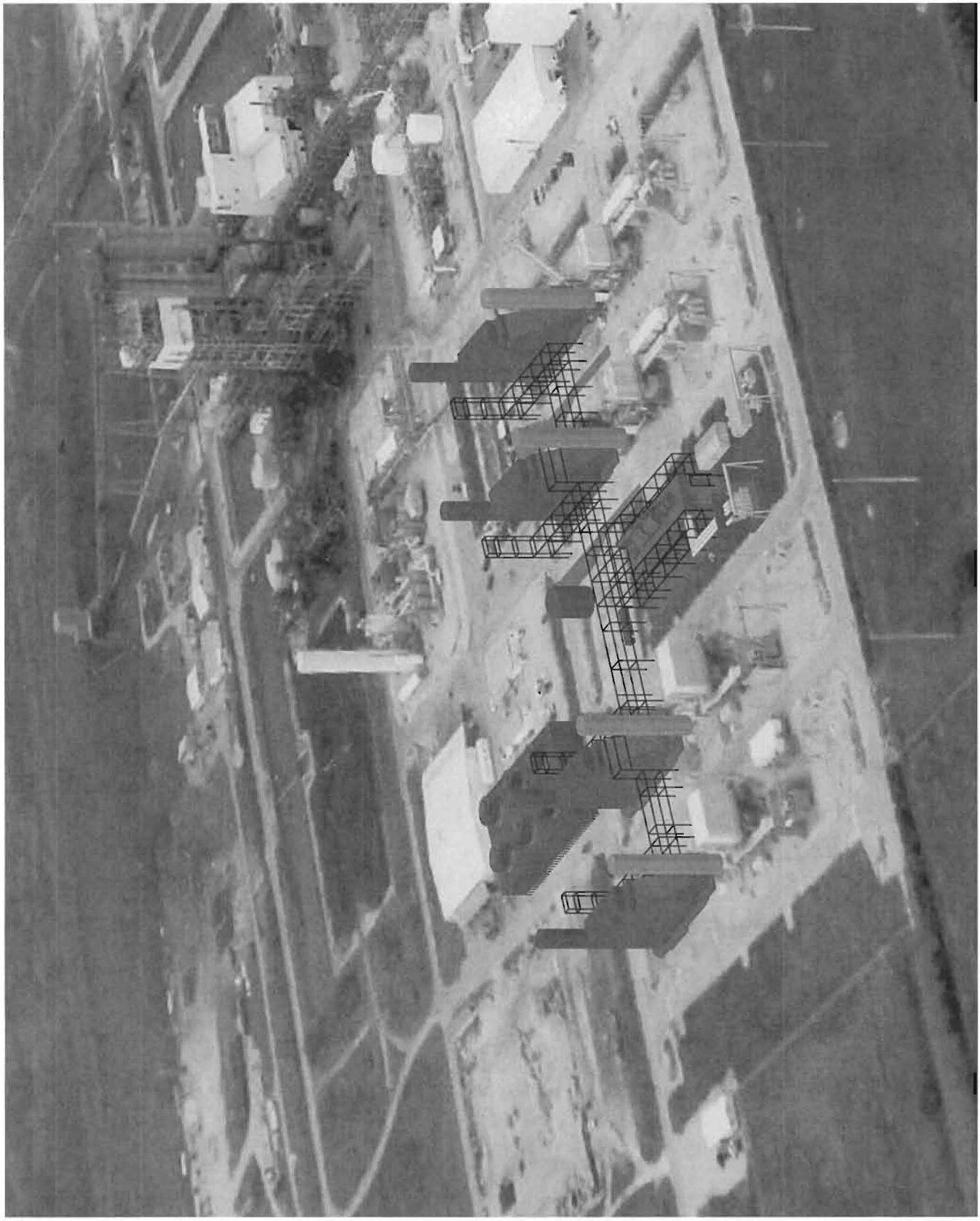
EXHIBIT NO. ____ (MJH-1)
DOCUMENT NO. 1
FILED: 09/12/2012

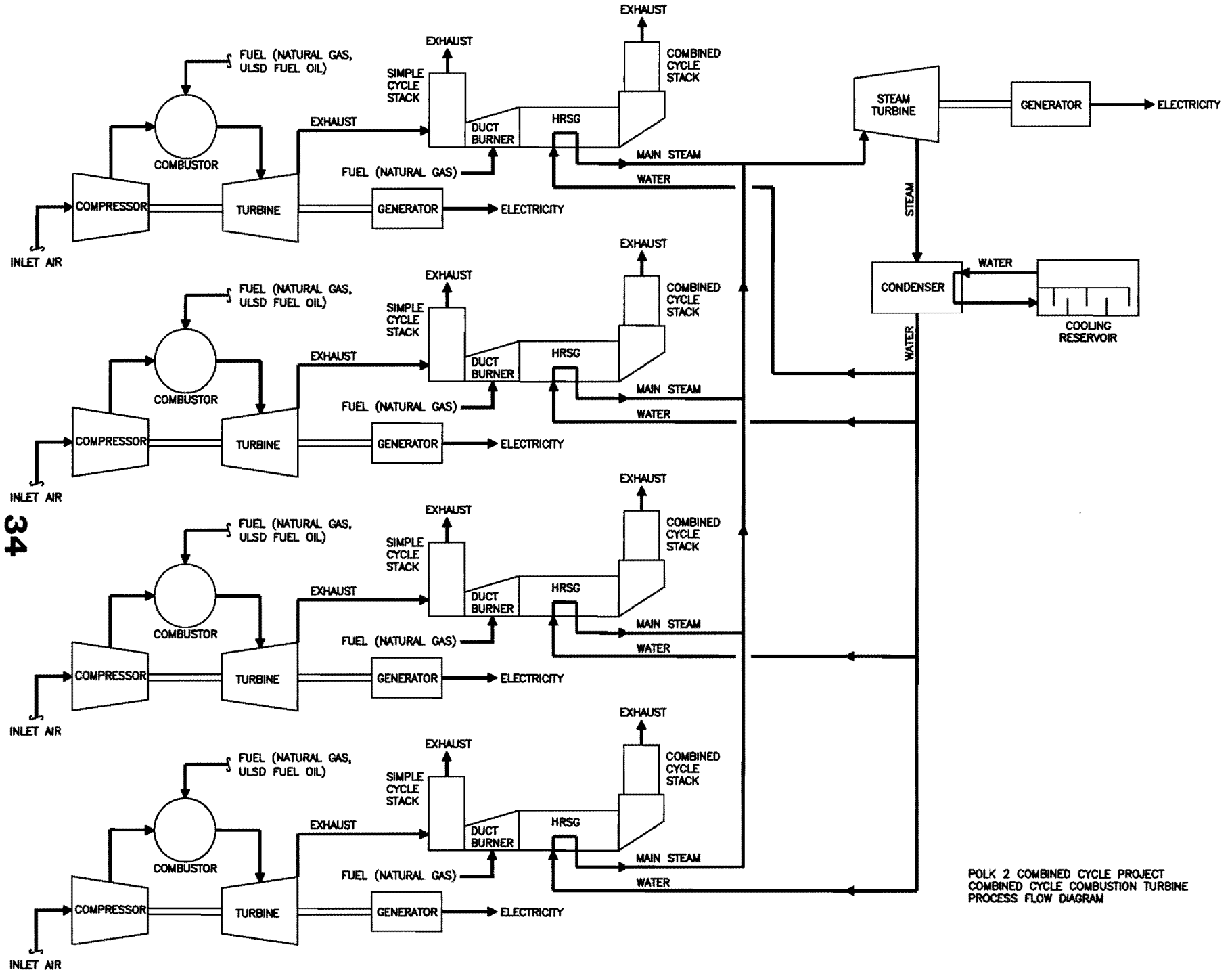


TAMPA ELECTRIC COMPANY
DOCKET NO. 12_____-EI
EXHIBIT NO. ___ (MJH-1)
DOCUMENT NO. 2
FILED: 09/12/2012

DOCUMENT NO. 2

PROCESS DIAGRAM - 4 X 1 COMBINED CYCLE

CONFIGURATION



POLK 2 COMBINED CYCLE PROJECT
COMBINED CYCLE COMBUSTION TURBINE
PROCESS FLOW DIAGRAM

175634-SM-2001

34

TAMPA ELECTRIC COMPANY
DOCKET NO. 12____-EI
EXHIBIT NO. ____ (MJH-1)
DOCUMENT NO. 2
FILED: 09/12/2012

TAMPA ELECTRIC COMPANY
DOCKET NO. 12_____-EI
EXHIBIT NO. ___ (MJH-1)
DOCUMENT NO. 3
FILED: 09/12/2012

DOCUMENT NO. 3

PROJECT SCHEDULE

POLK 2-5 COMBINED CYCLE PROJECT
MAJOR MILESTONE SCHEDULE

Award Contract for Steam Turbine Generator Supply	January 4, 2013
Award Contract for Heat Recovery Steam Generator Supply	April 12, 2013
Award Contract for Preliminary Construction	November 22, 2013
Receive Permits and Modified Site Certification	January 31, 2014
Begin Construction (Plant and Transmission)	February 3, 2014
Award Contract for Construction	March 21, 2014
Begin Tie-in Outages on Existing Units	September 1, 2014
Begin Combined Cycle Startup and Testing	May 2, 2016
Transmission System Upgrades Complete	November 4, 2016
Commercial Operation	January 2, 2017

TAMPA ELECTRIC COMPANY
DOCKET NO. 12_____-EI
EXHIBIT NO. ___ (MJH-1)
DOCUMENT NO. 4
FILED: 09/12/2012

DOCUMENT NO. 4

COST ESTIMATE

POLK 2-5 CONVERSION PROJECT PROJECT COST ESTIMATE	($000)
Direct Construction Costs	352,610
Indirect Construction Costs	71,813
Total Generating Plant Cost	424,422
Transmission Upgrade Cost	147,193
Escalation	38,825
Total Project Before AFUDC	610,440
AFUDC	96,179
Total Expected Project Cost	706,619

TAMPA ELECTRIC COMPANY
DOCKET NO. 12____-EI
WITNESS: CIFUENTES

EXHIBIT

OF

LORRAINE L. CIFUENTES

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 120234-EI EXHIBIT 13
PARTY TAMPA ELECTRIC COMPANY (TECO) - (DIRECT)
DESCRIPTION Lorraine L. Cifuentes (LLC-1)

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ECONOMIC ASSUMPTIONS

	Population (Millions)	Residential Price of Electricity ($/MWH)	Real Household Income	Persons Per Household	Per Capita Commercial Real Gross Output (Millions)	Per Capita Government Real Gross Output (Millions)	Construction Employment (Thousands)	Commercial Employment (Thousands)	Industrial Employment (Thousands)
2002	1,060	$64.75	$82,367	2.6	647.5	74.7	35.3	453.6	34.0
2003	1,086	$65.00	$84,255	2.6	653.4	75.7	37.0	448.7	31.7
2004	1,113	$65.95	$86,610	2.6	668.4	77.4	41.0	465.5	32.7
2005	1,139	$65.66	$88,639	2.6	704.9	72.1	45.5	480.8	33.5
2006	1,170	$66.43	$91,584	2.6	714.4	71.9	47.2	490.6	33.8
2007	1,194	$70.16	$91,789	2.6	709.6	76.0	44.9	500.6	32.1
2008	1,200	$69.38	$90,562	2.6	680.0	76.9	39.2	479.9	29.5
2009	1,199	$71.91	$89,183	2.6	666.9	90.2	30.6	453.3	25.7
2010	1,203	$71.55	$88,502	2.6	685.8	77.4	27.0	452.0	24.2
2011	1,211	$66.85	$91,166	2.6	715.0	77.1	29.0	456.7	24.5
2012	1,221	$64.68	$95,661	2.56	748.1	77.7	34.0	472.0	25.2
2013	1,235	$63.21	$99,245	2.56	777.9	77.4	35.5	486.7	25.4
2014	1,252	$61.40	$101,779	2.56	797.8	76.3	36.4	502.0	25.3
2015	1,269	$60.49	$104,180	2.56	814.5	75.6	37.4	514.1	25.1
2016	1,288	$59.65	$106,693	2.56	830.9	75.7	38.1	523.8	24.6
2017	1,307	$58.81	$109,611	2.56	850.9	76.3	38.7	534.0	24.2
2018	1,325	$57.99	$112,938	2.56	871.9	77.1	39.4	544.5	23.8
2019	1,344	$57.19	$116,465	2.56	892.5	78.0	40.3	555.2	23.5
2020	1,361	$56.43	$120,064	2.56	911.8	78.8	41.3	566.1	23.1
2021	1,378	$55.71	$123,867	2.56	929.8	79.7	42.4	576.9	22.7
Average Annual Growth Rates									
2002-2011	1.5%	0.4%	1.1%	0.0%	1.1%	0.4%	-2.2%	0.1%	-3.6%
2012-2021	1.4%	-1.6%	2.9%	0.0%	2.4%	0.3%	2.5%	2.3%	-1.2%
Average Absolute Growth									
2002-2011	17	$0.23	$978	0.00	7.5	0.3	(0.7)	0.3	(1.1)
2012-2021	18	($1.00)	$3,134	0.00	20.2	0.2	0.9	11.7	(0.3)

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BILLING CYCLE DEGREE DAYS

Tampa Electric Company
Billing Cycle Based Degree Days

	Heating Degree Days	Cooling Degree Days
1992	540	3,302
1993	441	3,453
1994	430	3,762
1995	547	3,689
1996	792	3,479
1997	343	3,754
1998	406	4,011
1999	342	3,719
2000	417	3,689
2001	572	3,613
2002	447	3,982
2003	605	3,736
2004	547	3,490
2005	534	3,469
2006	499	3,513
2007	381	3,849
2008	420	3,523
2009	457	3,823
2010	1000	3,642
2011	575	3,844
2012	494	3,661
2013	492	3,665
2014	492	3,665
2015	492	3,665
2016	492	3,665
2017	492	3,665
2018	492	3,665
2019	492	3,665
2020	492	3,665
2021	492	3,665

Average Annual Degree Days		
1992-2011	515	3,667
2012-2021	494	3,661

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CUSTOMER FORECAST

Tampa Electric Company Customer Forecast	
	Number of Customers
2002	590,199
2003	604,900
2004	619,535
2005	635,621
2006	653,706
2007	666,354
2008	667,266
2009	666,750
2010	670,991
2011	675,799
2012	680,316
2013	688,083
2014	696,913
2015	706,481
2016	717,032
2017	727,330
2018	737,398
2019	747,441
2020	757,343
2021	766,690

Average Annual Growth Rates	
2002-2011	1.5%
2012-2021	1.3%

Average Absolute Growth	
2002-2011	9,511
2012-2021	9,597

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PER-CUSTOMER ENERGY CONSUMPTION

(KWH/CUSTOMER)

Tampa Electric Company Per Customer Energy Consumption (kWh/Customer)		
	Total Retail	Total Excluding Phosphate
2002	30,371	28,039
2003	30,131	28,021
2004	29,759	27,777
2005	29,752	27,954
2006	29,103	27,673
2007	29,313	27,739
2008	28,459	27,008
2009	28,158	26,800
2010	28,634	27,216
2011	27,469	26,388
2012	27,993	26,853
2013	27,843	26,818
2014	27,551	26,737
2015	27,355	26,606
2016	27,234	26,482
2017	27,111	26,385
2018	27,023	26,307
2019	26,946	26,239
2020	26,873	26,175
2021	26,804	26,115

Average Annual Growth Rates		
2002-2011	-1.1%	-0.7%
2012-2021	-0.5%	-0.3%

Average Absolute Growth		
2002-2011	-322	-183
2012-2021	-132	-82

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RETAIL ENERGY SALES

(GWH)

Tampa Electric Company
Retail Energy Sales
(GWH)

	Total Retail	Total Excluding Phosphate
2002	17,925	16,547
2003	18,226	16,948
2004	18,437	17,208
2005	18,911	17,767
2006	19,025	18,089
2007	19,533	18,483
2008	18,990	18,020
2009	18,774	17,868
2010	19,213	18,261
2011	18,564	17,832
2012	19,044	18,268
2013	19,158	18,452
2014	19,201	18,633
2015	19,326	18,796
2016	19,528	18,988
2017	19,719	19,190
2018	19,927	19,398
2019	20,141	19,612
2020	20,352	19,823
2021	20,550	20,021

Average Annual Growth Rates		
2002-2011	0.4%	0.8%
2012-2021	0.8%	1.0%

Average Absolute Growth		
2002-2011	71	143
2012-2021	167	195

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PER-CUSTOMER PEAK DEMAND

(kW/Customer)

Tampa Electric Company Per Customer Peak Demand (kW/Customer)		
	Winter	Summer
2002	6.12	6.16
2003	6.42	5.99
2004	5.40	6.03
2005	5.80	6.24
2006	5.72	6.13
2007	5.10	6.19
2008	5.56	5.92
2009	6.12	6.02
2010	6.72	5.84
2011	5.97	5.88
2012	6.00	5.87
2013	5.98	5.85
2014	5.94	5.81
2015	5.92	5.78
2016	5.89	5.75
2017	5.87	5.73
2018	5.85	5.71
2019	5.83	5.69
2020	5.82	5.67
2021	5.81	5.65

Average Annual Growth Rates		
2002-2011	-0.3%	-0.5%
2012-2021	-0.4%	-0.4%

Average Absolute Growth		
2002-2011	-0.02	-0.03
2012-2021	-0.02	-0.02

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PEAK DEMAND

(MW)

Tampa Electric Company Peak Demand (MW)		
	Winter	Summer
2002	3612	3634
2003	3881	3623
2004	3344	3737
2005	3686	3968
2006	3736	4010
2007	3398	4123
2008	3709	3952
2009	4080	4015
2010	4512	3917
2011	4037	3976
2012	4081	3993
2013	4112	4023
2014	4141	4049
2015	4180	4082
2016	4224	4125
2017	4269	4165
2018	4315	4207
2019	4361	4250
2020	4408	4292
2021	4453	4331

Average Annual Growth Rates		
2002-2011	1.2%	1.0%
2012-2021	1.0%	0.9%

Average Absolute Growth		
2002-2011	47	38
2012-2021	41	38

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FIRM PEAK DEMAND

(MW)

Tampa Electric Company Firm Peak Demand (MW)		
	Winter	Summer
2002	3259	3318
2003	3455	3351
2004	2936	3445
2005	3287	3725
2006	3523	3769
2007	3127	3876
2008	3443	3723
2009	3754	3799
2010	4246	3710
2011	3735	3699
2012	3777	3748
2013	3819	3784
2014	3864	3823
2015	3910	3859
2016	3955	3900
2017	4003	3940
2018	4050	3980
2019	4097	4022
2020	4146	4064
2021	4194	4103

Average Annual Growth Rates		
2002-2011	1.5%	1.2%
2012-2021	1.2%	1.0%

Average Absolute Growth		
2002-2011	53	42
2012-2021	46	39

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FIRM PEAK LOAD FACTOR

(%)

Tampa Electric Company
Firm Peak Load Factor
(%)

	Winter	Summer
2002	62.8%	61.7%
2003	60.2%	62.1%
2004	71.5%	60.9%
2005	65.7%	57.9%
2006	61.6%	57.6%
2007	71.3%	57.5%
2008	62.8%	58.1%
2009	57.1%	56.4%
2010	51.7%	59.1%
2011	56.7%	57.3%
2012	57.4%	57.9%
2013	57.3%	57.8%
2014	56.7%	57.3%
2015	56.4%	57.2%
2016	56.2%	57.0%
2017	56.2%	57.1%
2018	56.2%	57.2%
2019	56.1%	57.2%
2020	55.9%	57.0%
2021	55.9%	57.2%

Average Annual Growth Rates		
2002-2011	-1.1%	-0.8%
2012-2021	-0.3%	-0.1%

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JUNE 2012 UPDATE
FIRM PEAK DEMAND
(MW)

Tampa Electric Company
June 2012 Update
Firm Peak Demand
(MW)

	Winter	Summer
2002	3259	3318
2003	3455	3351
2004	2936	3445
2005	3287	3725
2006	3523	3769
2007	3127	3876
2008	3443	3723
2009	3754	3799
2010	4246	3710
2011	3725	3699
2012	3237	3677
2013	3699	3667
2014	3731	3701
2015	3778	3741
2016	3832	3788
2017	3887	3835
2018	3941	3881
2019	3993	3927
2020	4045	3971
2021	4095	4012

Average Annual Growth Rates		
2002-2011	1.5%	1.2%
2012-2021	1.3%	1.0%

Average Absolute Growth		
2002-2011	52	42
2012-2021	50	37

TAMPA ELECTRIC COMPAN
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WITNESS: BRYANT

EXHIBIT

OF

HOWARD T. BRYANT

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 120234-EI EXHIBIT 14
PARTY TAMPA ELECTRIC COMPANY (TECO) - (DIRECT)
DESCRIPTION Howard T. Bryant - (HTB-1)

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TAMPA ELECTRIC DSM PROGRAMS

Tampa Electric DSM Programs

Residential
Energy Audits:
Walk-Through
Computer Assisted
Phone
Paid
Building Envelope:
Ceiling Insulation
Wall Insulation
Window Replacement
Window film
Energy Planner
Duct Repair
New Construction
Heating and Cooling
Low Income Weatherization/Agency Outreach
Public Education Outreach
HVAC Maintenance
Electronically Commutated Motors (HVAC)
Prime Time

Commercial/Industrial
Energy Audits:
Free
Paid
Cool Roof
Energy Recovery Ventilation
Chiller Replacement
Lighting:
Indoor
Outdoor
Exit Signs
Air Conditioning Replacement
Duct Repair
Building Envelope:
Ceiling Insulation
Roof Insulation
Wall Insulation
Window Film
Energy Efficient Motors
Lighting Occupancy Sensors
Refrigeration (Anti-Condensate)
Water Heating
Conservation Value
Industrial Load Management
Standby Generator
Demand Response
Cogeneration
HVAC Maintenance
Electronically Commutated Motors (HVAC, Refrigeration)
Commercial Load Management
Renewable Energy
Renewable Energy Subscription
Solar PV Incentives
Solar Water Heating Incentives
Solar for Schools
Low-Income Solar Water Heating

DOCUMENT NO. 2

TAMPA ELECTRIC DSM GOALS

(2010 - 2019)

Tampa Electric DSM Goals
2010-2019

Residential

Year	Tampa Electric Projected Summer Demand Savings (MW) Incr.	Tampa Electric Projected Summer Demand Savings (MW) Cum.	Commission Approved Summer Goal (MW) Incr.	Commission Approved Summer Goal (MW) Cum.	Tampa Electric Projected Winter Demand Savings (MW) Incr.	Tampa Electric Projected Winter Demand Savings (MW) Cum.	Commission Approved Winter Goal (MW) Incr.	Commission Approved Winter Goal (MW) Cum.	Tampa Electric Projected Annual Energy Savings (GWH) Incr.	Tampa Electric Projected Annual Energy Savings (GWH) Cum.	Commission Approved Annual Energy Goal (GWH) Incr.	Commission Approved Annual Energy Goal (GWH) Cum.
2010	7.0	7.0	4.6	4.6	9.2	9.2	6.4	6.4	14.9	14.9	9.8	9.8
2011	8.8	15.9	6.6	11.2	11.1	20.3	8.5	14.9	19.9	34.8	14	23.8
2012	10.0	25.9	8.4	19.6	12.3	32.6	10.2	25.1	23.1	57.9	17.7	41.5
2013	11.5	37.4	9.9	29.5	13.8	46.4	11.5	36.6	20.6	78.5	20.6	62.1
2014	12.7	50.1	10.8	40.3	15.1	61.5	12.2	48.8	22.6	101.1	22.6	84.7
2015	13.3	63.5	10.9	51.2	16.0	77.6	11.6	60.4	23.0	124.1	23.0	107.7
2016	12.7	76.2	9.8	61.0	15.4	92.9	10.1	70.5	21.5	145.6	21.3	129.0
2017	11.7	87.9	9.0	70.0	14.1	107.0	8.8	79.3	20.2	165.7	19.4	148.4
2018	11.4	99.3	8.3	78.3	13.6	120.6	8.0	87.3	19.8	185.5	18.3	166.7
2019	11.0	110.3	7.8	86.1	12.9	133.6	7.4	94.7	19.2	204.7	17.3	184.0

Commercial / Industrial

Year	Tampa Electric Projected Summer Demand Savings (MW) Incr.	Tampa Electric Projected Summer Demand Savings (MW) Cum.	Commission Approved Summer Goal (MW) Incr.	Commission Approved Summer Goal (MW) Cum.	Tampa Electric Projected Winter Demand Savings (MW) Incr.	Tampa Electric Projected Winter Demand Savings (MW) Cum.	Commission Approved Winter Goal (MW) Incr.	Commission Approved Winter Goal (MW) Cum.	Tampa Electric Projected Annual Energy Savings (GWH) Incr.	Tampa Electric Projected Annual Energy Savings (GWH) Cum.	Commission Approved Annual Energy Goal (GWH) Incr.	Commission Approved Annual Energy Goal (GWH) Cum.
2010	3.7	3.7	2.5	2.5	2.1	2.1	0.9	0.9	12.2	12.2	6.5	6.5
2011	4.9	8.6	3.6	6.1	2.5	4.6	1.1	2.0	17.3	29.5	10.6	17.1
2012	5.7	14.3	4.3	10.4	3.0	7.6	1.4	3.4	18.4	48.0	15.4	32.5
2013	6.0	20.3	5.1	15.5	3.2	10.7	1.3	4.7	19.2	67.1	16.2	48.7
2014	6.8	27.0	5.4	20.9	3.7	14.4	1.5	6.2	20.4	87.5	19.5	68.2
2015	7.1	34.1	6.0	26.9	4.0	18.4	1.7	7.9	21.6	109.1	20.9	89.1
2016	7.4	41.5	6.2	33.1	4.1	22.5	1.6	9.5	22.7	131.8	21.6	110.7
2017	8.2	49.7	6.3	39.4	4.6	27.1	1.6	11.1	22.9	154.7	21.8	132.5
2018	7.6	57.2	6.4	45.8	4.2	31.2	1.7	12.8	22.1	176.8	22.1	154.6
2019	7.0	64.2	6.3	52.1	3.7	34.9	1.7	14.5	21.7	198.5	21.7	176.3

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Tampa Electric

2010-2019 DSM Goals Accomplishments

Tampa Electric Incremental 2010-2019 DSM Goals Accomplishments

Total Residential and Commercial/Industrial

	Winter Peak MW Reduction			Summer Peak MW Reduction			GWh Energy Reduction		
		Commission			Commission			Commission	
Year	Total Achieved	Approved Goal	% Variance	Total Achieved	Approved Goal	% Variance	Total Achieved	Approved Goal	% Variance
2010	18.5	7.3	253.4%	19.2	7.1	270.4%	35.6	16.3	218.4%
2011	22.0	9.6	229.2%	23.9	10.2	234.3%	52.2	24.6	212.2%

Residential

	Winter Peak MW Reduction			Summer Peak MW Reduction			GWh Energy Reduction		
		Commission			Commission			Commission	
Year	Total Achieved	Approved Goal	% Variance	Total Achieved	Approved Goal	% Variance	Total Achieved	Approved Goal	% Variance
2010	11.3	6.4	176.6%	8.1	4.6	176.1%	17.3	9.8	176.5%
2011	10.2	8.5	120.0%	8.6	6.6	130.3%	19.2	14.0	137.1%

Commercial/Industrial

	Winter Peak MW Reduction			Summer Peak MW Reduction			GWh Energy Reduction		
		Commission			Commission			Commission	
Year	Total Achieved	Approved Goal	% Variance	Total Achieved	Approved Goal	% Variance	Total Achieved	Approved Goal	% Variance
2010	7.2	0.9	800.0%	11.1	2.5	444.0%	18.3	6.5	281.5%
2011	11.8	1.1	1072.7%	15.3	3.6	425.0%	33.0	10.6	311.3%

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Tampa Electric Cumulative 2010-2019 DSM Goals Accomplishments

Total Residential and Commercial/Industrial

	Winter Peak MW Reduction			Summer Peak MW Reduction			GWh Energy Reduction		
		Commission			Commission			Commission	
Year	Total Achieved	Approved Goal	% Variance	Total Achieved	Approved Goal	% Variance	Total Achieved	Approved Goal	% Variance
2010	18.5	7.3	253.4%	19.2	7.1	270.4%	35.6	16.3	218.4%
2011	40.5	16.9	239.6%	43.1	17.3	249.1%	87.8	40.9	214.7%

Residential

	Winter Peak MW Reduction			Summer Peak MW Reduction			GWh Energy Reduction		
		Commission			Commission			Commission	
Year	Total Achieved	Approved Goal	% Variance	Total Achieved	Approved Goal	% Variance	Total Achieved	Approved Goal	% Variance
2010	11.3	6.4	176.6%	8.1	4.6	176.1%	17.3	9.8	176.5%
2011	21.5	14.9	144.3%	16.7	11.2	149.1%	36.5	23.8	153.4%

Commercial/Industrial

	Winter Peak MW Reduction			Summer Peak MW Reduction			GWh Energy Reduction		
		Commission			Commission			Commission	
Year	Total Achieved	Approved Goal	% Variance	Total Achieved	Approved Goal	% Variance	Total Achieved	Approved Goal	% Variance
2010	7.2	0.9	800.0%	11.1	2.5	444.0%	18.3	6.5	281.5%
2011	19.0	2.0	950.0%	26.4	6.1	432.8%	51.3	17.1	300.0%

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WITNESS: CALDWELL

EXHIBIT

OF

J. BRENT CALDWELL

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 120234-EI EXHIBIT 15
PARTY TAMPA ELECTRIC COMPANY (TECO) - (DIRECT)
DESCRIPTION J. Brent Caldwell (JBC-1)

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DOCUMENT NO. 1

FUEL PRICE FORECAST

TAMPA ELECTRIC COMPANY
DOCKET NO. 12_____-EI
EXHIBIT NO. ___ (JBC-1)
DOCUMENT NO. 1
FILED: 09/12/2012

Table of Forecasted Fuel Prices

Tampa Electric Fuel Prices Forecast
2013 - 2040

Year	Natural Gas $/MMBtu	No. 2 Oil $/Gallon	Illinois Basin Coal $/ton
2013	$5.12	$3.33	$55.57
2014	$5.39	$3.51	$56.45
2015	$5.67	$3.69	$58.88
2016	$5.95	$3.88	$55.48
2017	$6.23	$4.06	$55.24
2018	$6.51	$4.24	$52.26
2019	$6.79	$4.42	$55.94
2020	$7.07	$4.60	$59.64
2021	$7.34	$4.78	$63.20
2022	$7.63	$4.97	$66.81
2023	$7.80	$5.08	$69.16
2024	$7.97	$5.19	$71.55
2025	$8.14	$5.30	$73.96
2026	$8.31	$5.41	$76.40
2027	$8.49	$5.53	$78.85
2028	$8.67	$5.64	$81.35
2029	$8.85	$5.76	$83.89
2030	$9.03	$5.88	$86.48
2031	$9.22	$6.00	$89.11
2032	$9.41	$6.13	$91.79
2033	$9.61	$6.26	$94.52
2034	$9.80	$6.38	$97.31
2035	$10.01	$6.52	$100.14
2036	$10.21	$6.65	$103.03
2037	$10.42	$6.79	$105.97
2038	$10.64	$6.93	$108.97
2039	$10.85	$7.07	$112.03
2040	$11.08	$7.21	$115.15

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DOCUMENT NO. 2

FUEL PRICE FORECAST RANGE

COMPARED TO INDEPENDENT FORECASTS

TAMPA ELECTRIC COMPANY
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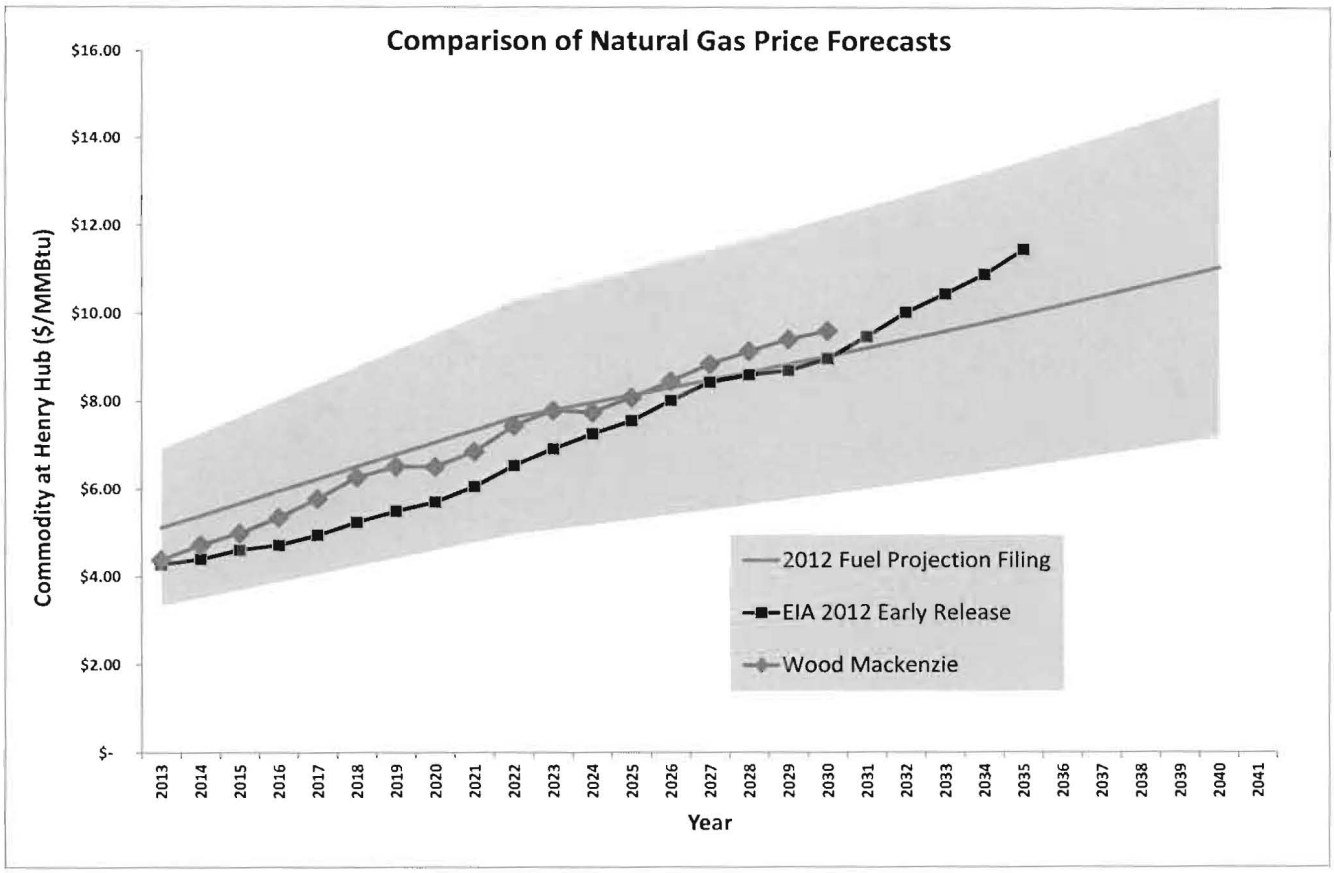
Graph of Natural Gas Price Forecast with Range and Compared to Independent Forecasts



TAMPA ELECTRIC COMPANY
DOCKET NO. 12____-EI
WITNESS: YOUNG

EXHIBIT

OF

S. BETH YOUNG

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 120234-EI EXHIBIT 16
PARTY TAMPA ELECTRIC COMPANY (TECO) - (DIRECT)
DESCRIPTION S. Beth Young (SBY-1)

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POLK 2-5 CC INTERCONNECTION DIAGRAM

TAMPA ELECTRIC COMPANY
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DOCUMENT NO. 2

POLK 2-5 INTEGRATION DIAGRAM

REDACTED

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DOCUMENT NO. 3
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DOCUMENT NO. 3

SUMMARY OF REQUIRED FACILITIES, RATINGS AND COST

Summary of Required Facilities, Ratings and Cost

Circuit #	Point of Origin and Termination	Project Description	Revised Rating (MVA)	Anticipated Capital Investment ($ million)
230007	Big Bend to Aspen 230 kV	This circuit will be rerated to a rating of 729.4 MVA.	729.4	$125
230401	Polk to Aspen 230 kV	The existing circuits from Polk to Mines East and from Mines West to Big Bend will be disconnected from Mines substation and tied together to create the modified circuit 230401. This circuit will be rerated to a rating of 729.4 MVA.	729.4	
230402	Mines West to Aspen 230 kV	This is a new consctruction of approximately 15 miles circuit with a rating of 1,118.6 MVA.	1,118.6	
230426	Aspen to FishHawk 230 kV	This is a new consctruction of approximately 6 miles of two circuits with a rating of 1,195.1 MVA.	1,195.1	
230427	Aspen to FishHawk 230 kV	This is a new consctruction of approximately 6 miles of two circuits with a rating of 1,195.1 MVA.	1,195.1	
230606	Polk to Pebbledale Ckt 1 230 kV	This circuit will be rerouted for approximately 9.8 miles to eliminate a double circuit line with the existing Polk to Mines East line with a rerate of 729.4 MVA.	729.4	
230635	Polk to Mines East 230 kV	This is a new consctruction of approximately 12 miles circuit with a rating of 1,118.6 MVA.	1,118.6	
-	Aspen Switching Station	This is a new contruction of the Aspen 230 kV Switching Station along the existing circuits between Mines West and Big Bend.	-	$8
-	Davis Substation Switched Reactor	A new switchable series reactor will be installed on the Davis to Chapman circuit (230601).	-	$2
-	FishHawk 230 kV Substation Upgrade	The FishHawk 230 kV Substation will be upgraded as a result of the addional capacity.	-	$1
-	Mines 230 kV Substation Upgrade	The Mines 230 kV Substation will be upgraded as a result of the addional capacity.	-	$2
-	Polk Steam Turbine Interconnect & Upgrade	The Polk 2-5 Steam Turbine will be interconnected to the existing station and required upgrades.	-	$5

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TAMPA ELECTRIC COMPANY
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FRCC LETTER CONFIRMING THE RELIABILITY OF THE INTERCONNECTION AND INTEGRATION PLAN

TAMPA ELECTRIC COMPANY
DOCKET NO. 12_____-EI
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DOCUMENT NO. 4
FILED: 09/12/2012

FLORIDA RELIABILITY COORDINATING COUNCIL, INC.
1408 N. WESTSHORE BLVD., SUITE 1002
TAMPA, FLORIDA 33607-4512
PHONE 813.289.5644 • FAX 813.289.5646
WWW.FRCC.COM

June 7, 2012

Beth Young
Director of Energy Control Center
Tampa Electric
P.O. Box 111
Tampa, Fl 33601-0111

Re: FRCC Review of the Polk Power Station Combined Cycle Conversion interconnection

Dear Beth,

Florida Reliability Coordinating Council's (FRCC) Transmission Working Group (TWG) and Stability Working Group (SWG) have evaluated the proposed interconnection and integration of the Polk Power Station Units 2-5 Combined Cycle Conversion Project (PK CC Conv Project) to interconnect to the Tampa Electric (TEC) transmission system. Based upon the information provided by TEC to the FRCC, the TWG has determined that the proposed interconnection and integration of the PK CC Conv Project with the identified projects, protection upgrades and remedies, is reliable and does not adversely impact the transmission system within the FRCC Region.

The PK CC Conv Project will encompass converting the existing Polk Power Station simple cycle combustion turbines (Polk Units 2-5) into a natural gas fired, four-on-one, combined cycle unit with the addition of a new steam turbine. The new steam turbine will result in an incremental 500 MW net increase (summer and winter) to the existing capacity of the four simple cycle combustion turbines located in Polk County, Florida. The proposed total capability of the PK CC Conv Project will have a summer net output of 1,195 MW and a winter net output of 1,232 MW. The scheduled in-service date is January 1, 2017.

The TWG reviewed the results of the steady state single and multiple contingency analyses. The results did not identify any contingency event that caused limitations in the FRCC Region with PK CC Conv Project facility at maximum queued output. In addition to the steady state analysis, the SWG reviewed the dynamic simulations showing a stable response at peak load and light load levels for normally cleared and delayed cleared three-phase faults in the vicinity of PK CC Conv Project. The results indicate that there are no grid stability concerns with the addition of the PK CC Conv Project.

A review of the short circuit analysis has shown that there are no short circuit concerns with the addition of the PK CC Conv Project.

Based upon the above review and analysis conducted by the TWG, the FRCC Planning Committee has determined that the proposed interconnection and integration of the PK CC Conv Project to interconnect to the TEC system, does not adversely impact the reliability of FRCC transmission system.

Sincerely,

Vicente Ordax

Vicente Ordax, Jr., P.E.
Manager of Planning

TAMPA ELECTRIC COMPANY
DOCKET NO. 12____-EI
FILED: 09/12/2012

EXHIBIT

OF

R. JAMES ROCHA

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 120234-EI EXHIBIT 17
PARTY TAMPA ELECTRIC COMPANY (TECO) - (DIRECT)
DESCRIPTION R. James Rocha (RJR-1)

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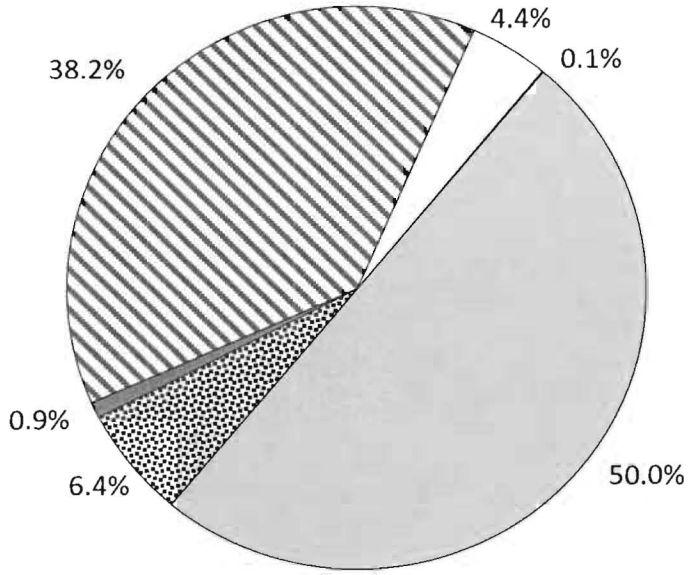
DOCUMENT NO. 1

ENERGY MIX BY FUEL TYPE

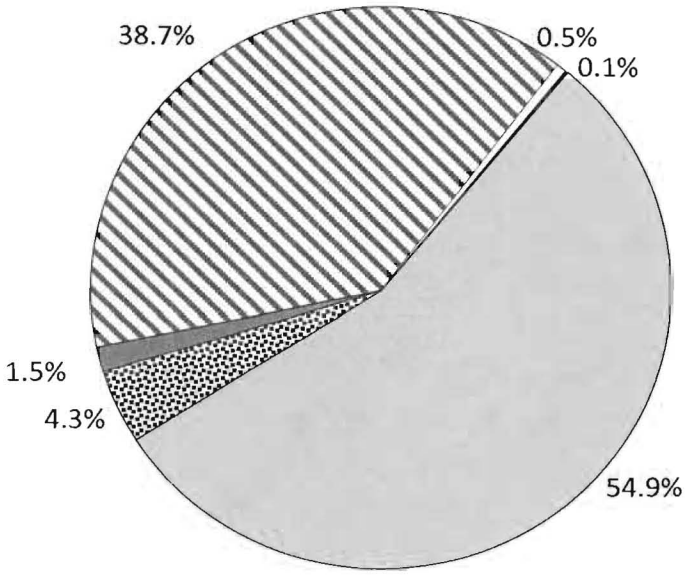
Energy Mix By Fuel Type

2011 Actual Energy Percentage By Fuel Type
Total Energy - 19,325 GWh



□ Coal ▨ Petcoke ■ Net Interchange ▨ Gas - TEC Owned □ Gas - Purchased ■ Oil

2017 Projected Energy Percentage By Fuel Type
Total Energy - 20,773 GWh



□ Coal ▨ Petcoke ■ Net Interchange ▨ Gas - TEC Owned □ Gas - Purchased ■ Oil

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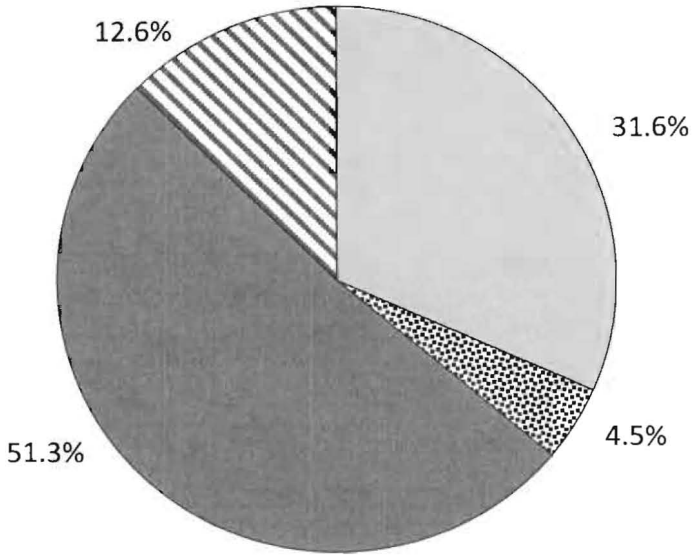
CAPACITY MIX BY FUEL TYPE

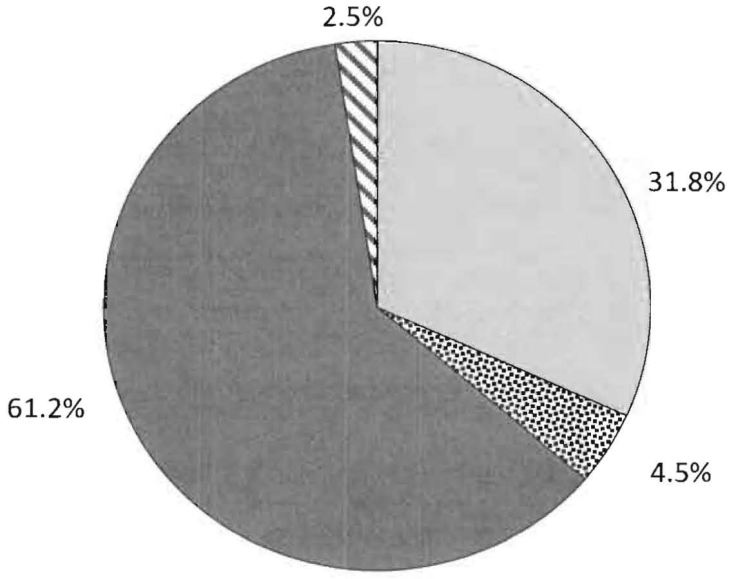
Capacity Mix By Fuel Type

2011 Actual Capacity Percentage By Fuel Type
Total Capacity - 4,909 MW



☐ Coal ▩ Petcoke ■ Gas - TEC Owned ▨ Gas - Purchased

2017 Projected Capacity Percentage By Fuel Type
Total Capacity - 4,856 MW



☐ Coal ▩ Petcoke ■ Gas - TEC Owned ▨ Gas - Purchased

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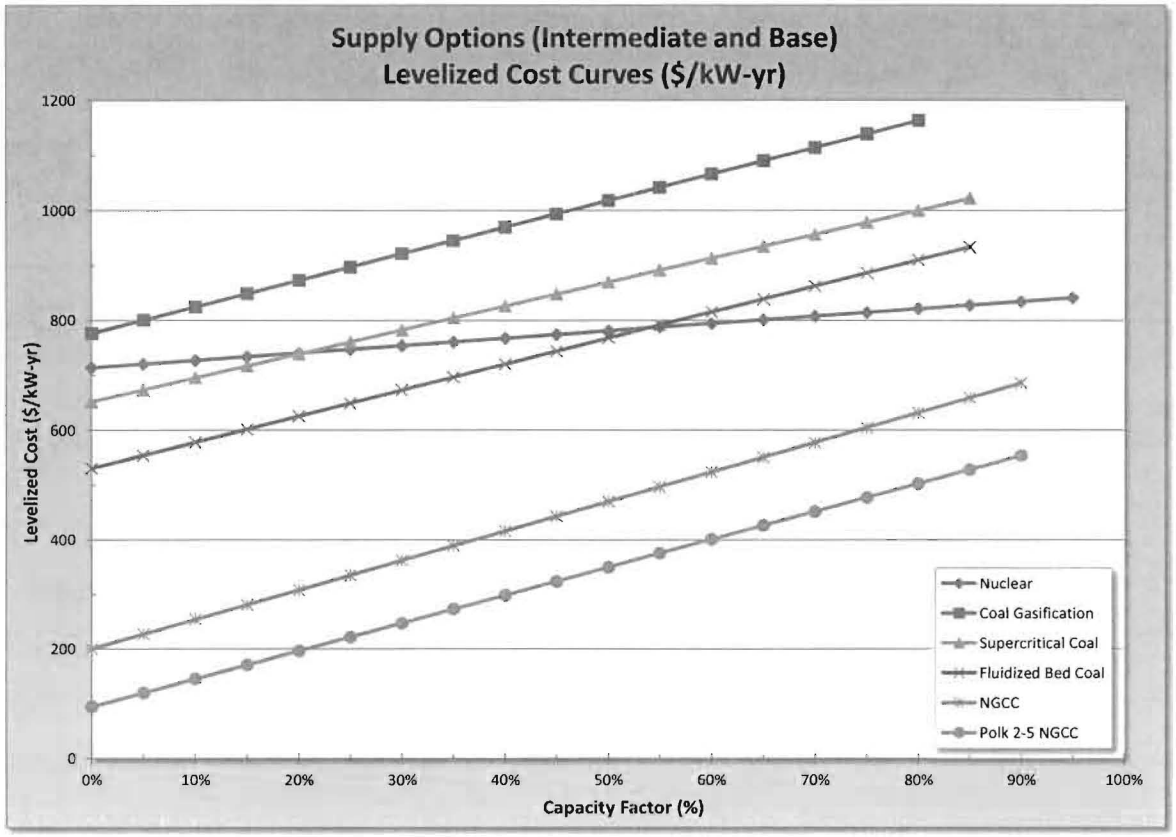
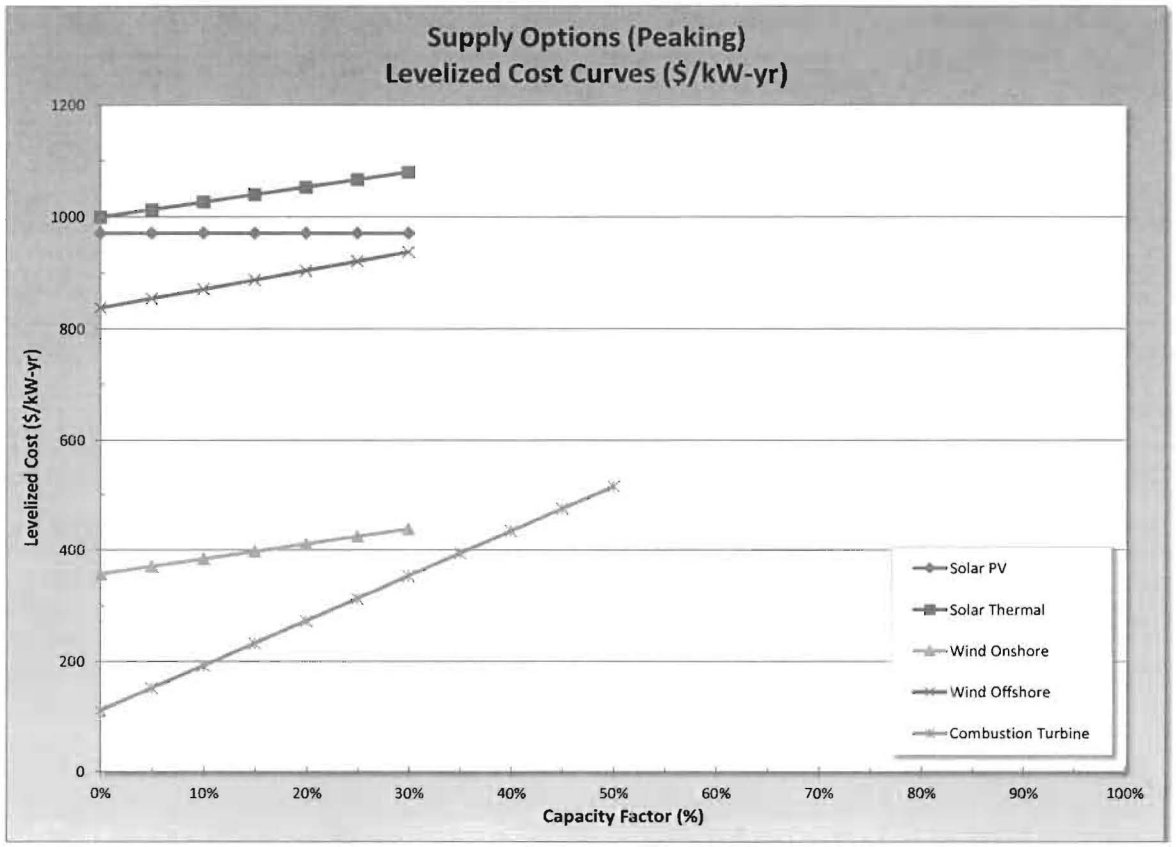
LEVELIZED COST SCREENING CURVES

Levelized Cost Screening Curves





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TAMPA ELECTRIC RELIABILITY ANALYSIS

Tampa Electric Reliability Analysis

Forecast of Capacity and Demand at Time of Summer Peak

Year	Total Installed Capacity MW	Net Firm Capacity Purchases MW	Total Capacity Available MW	System Firm Peak Demand MW	System Total Peak Demand MW	Firm Reserve Margin w/o Planned Additions MW	Firm Reserve Margin w/o Planned Additions % of Peak	Firm Reserve Margin w/o Planned Additions Shortfall for 20% MW	Supply-Side Reserve Margin w/o Planned Additions MW	Supply-Side Reserve Margin w/o Planned Additions % of Peak	Supply-Side Reserve Margin w/o Planned Additions Shortfall for 7% MW
2012	4,292	617	4,909	3,763	4,008	1,146	30.5%	N/A	901	23.9%	N/A
2013	4,312	421	4,733	3,784	4,023	949	25.1%	N/A	710	18.8%	N/A
2014	4,312	421	4,733	3,823	4,049	910	23.8%	N/A	684	17.9%	N/A
2015	4,312	421	4,733	3,859	4,082	874	22.7%	N/A	651	16.9%	N/A
2016	4,312	398	4,710	3,900	4,125	810	20.8%	N/A	585	15.0%	N/A
2017	4,312	121	4,433	3,940	4,165	493	12.5%	294	268	6.8%	8
2018	4,312	121	4,433	3,980	4,207	453	11.4%	343	226	5.7%	53
2019	4,312	0	4,312	4,022	4,250	290	7.2%	515	62	1.5%	220
2020	4,312	0	4,312	4,064	4,292	248	6.1%	565	20	0.5%	264
2021	4,312	0	4,312	4,103	4,331	209	5.1%	612	(19)	-0.5%	306

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DOCUMENT NO. 5

FRCC RELIABILITY ANALYSIS

FRCC Reliability Analysis

Forecast of Capacity and Demand at Time of Summer Peak with Planned Additions

Year	Total Installed Capacity MW	Net Firm Capacity Purchases MW	Total Capacity Available MW	System Firm Peak Demand MW	System Total Peak Demand MW	Firm Reserve Margin With Excercising Load Mgmt & Int. MW	Firm Reserve Margin With Excercising Load Mgmt & Int. % of Peak	Reserve Margin w/o Excercising Load Mgmt & Int. MW	Reserve Margin w/o Excercising Load Mgmt & Int. % of Peak
2012	47,747	6,486	54,233	42,430	45,613	11,803	27.8%	8,620	18.9%
2013	48,506	6,316	54,822	43,041	46,270	11,781	27.4%	8,552	18.5%
2014	49,730	5,613	55,343	43,618	46,857	11,725	26.9%	8,486	18.1%
2015	51,567	5,614	57,181	44,459	47,758	12,722	28.6%	9,423	19.7%
2016	52,118	4,473	56,591	45,242	48,594	11,349	25.1%	7,997	16.5%
2017	52,553	4,296	56,849	45,802	49,244	11,047	24.1%	7,605	15.4%
2018	52,539	4,382	56,921	46,152	49,643	10,769	23.3%	7,278	14.7%
2019	53,585	4,263	57,848	46,803	50,356	11,045	23.6%	7,492	14.9%
2020	53,667	4,180	57,847	47,581	51,191	10,266	21.6%	6,656	13.0%
2021	55,968	3,973	59,941	48,273	51,933	11,668	24.2%	8,008	15.4%

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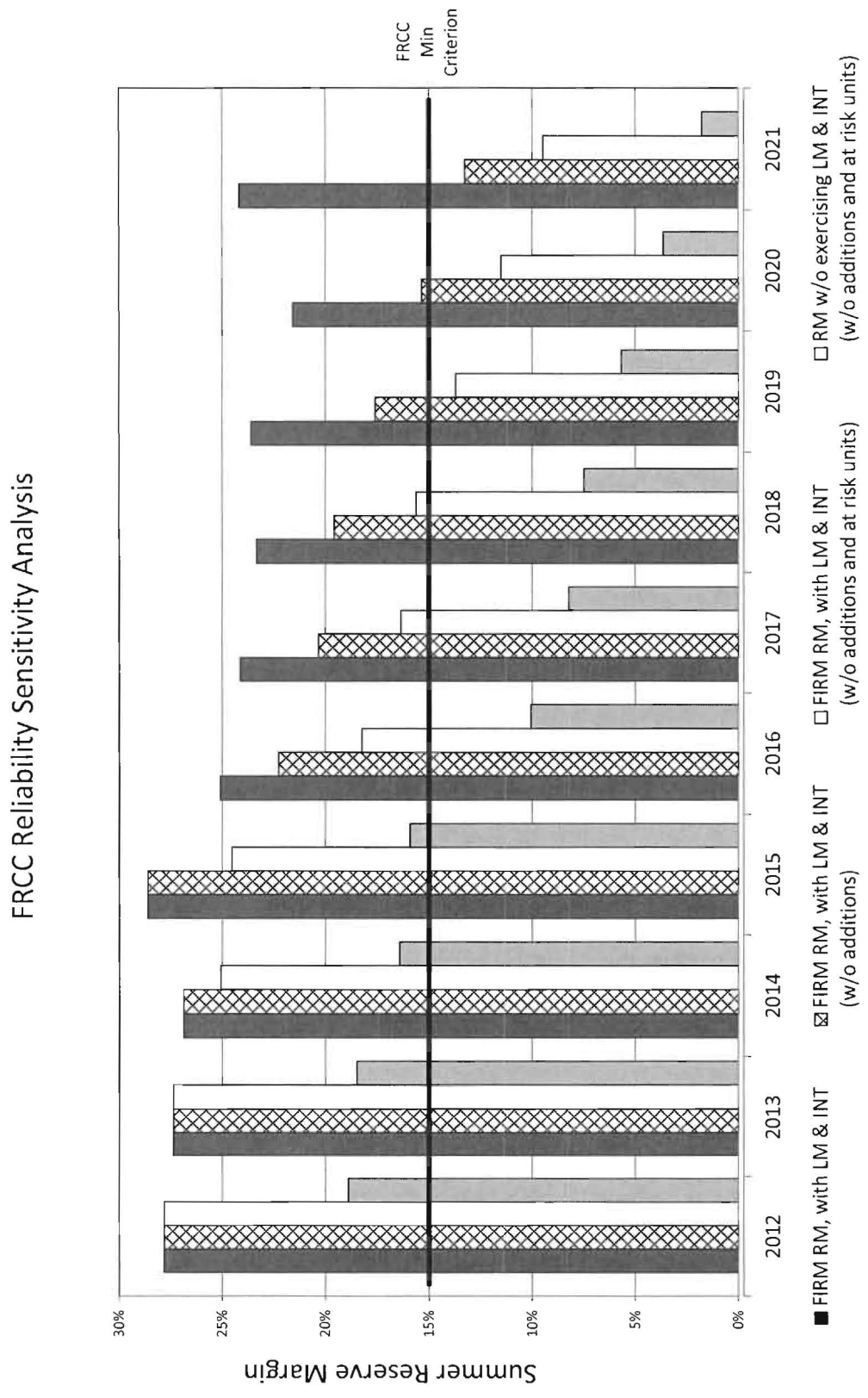
FRCC RELIABILITY SENSITIVITY ANALYSIS


FRCC Reliability Sensitivity Analysis
FRCC Min Criterion
Summer Reserve Margin
30%
25%
20%
15%
10%
5%
0%
2012
2013
2014
2015
2016
2017
2018
2019
2020
2021
■ FIRM RM, with LM & INT
☒ FIRM RM, with LM & INT (w/o additions)
☐ FIRM RM, with LM & INT (w/o additions and at risk units)
☐ RM w/o exercising LM & INT (w/o additions and at risk units)

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DOCUMENT NO. 7

PRELIMINARY RESOURCE PLANS & ANALYSIS

Preliminary Resource Plans & Analysis

Resource Plans

2019 Polk 2-5

Year	Portfolio Additions
2012	Peaker PPA 117 MW
2013	Peaker PPA 117 MW Peaker PPA 160 MW
2014	Peaker PPA 117 MW Peaker PPA 160 MW
2015	Peaker PPA 117 MW Peaker PPA 160 MW
2016	Peaker PPA 117 MW Peaker PPA 160 MW
2017	(2) 7FA CT 354/298 MW
2018	(1) 7FA CT 177/149 MW
2019	(1) Polk 2-5 NGCC 463/459 MW
2020	
2021	

2017 Polk 2-5

Year	Portfolio Additions
2012	Peaker PPA 117 MW
2013	Peaker PPA 117 MW Peaker PPA 160 MW
2014	Peaker PPA 117 MW Peaker PPA 160 MW
2015	Peaker PPA 117 MW Peaker PPA 160 MW
2016	Peaker PPA 117 MW Peaker PPA 160 MW
2017	(1) Polk 2-5 NGCC 463/459 MW
2018	
2019	(1) 7FA CT 177/149 MW
2020	
2021	

CPWRR ($M)

	2019 Polk 2-5	2017 Polk 2-5
Capital	$1,584.2	$1,566.4
O&M	$1,113.6	$1,099.7
Fuel & Purchased Power	$15,599.8	$15,566.1
Total	$18,300.3	$18,232.2
Delta		$65.4

TAMPA ELECTRIC COMPANY
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DOCUMENT NO. 8

IRP RESOURCE PLANS & ANALYSIS

IRP Resource Plans & Analysis

Resource Plans

Polk 2-5

Year	Portfolio Additions
2012	Peaker PPA 117 MW
2013	Peaker PPA 117 MW Peaker PPA 160 MW
2014	Peaker PPA 117 MW Peaker PPA 160 MW
2015	Peaker PPA 117 MW Peaker PPA 160 MW
2016	Peaker PPA 117 MW Peaker PPA 160 MW
2017	(1) Polk 2-5 NGCC 463/459 MW
2018	
2019	(1) 7FA CT 177/149 MW
2020	
2021	
2022	(1) 7FA CT 177/149 MW
2023	
2024	
2025	(1) 7FA CT 177/149 MW
2026	
2027	_
2028	_
2029	(1) 7FA CT 177/149 MW
2030	_
2031	_
2032	_

Alternative 1

Year	Portfolio Additions
2012	Peaker PPA 117 MW
2013	Peaker PPA 117 MW Peaker PPA 160 MW
2014	Peaker PPA 117 MW Peaker PPA 160 MW
2015	Peaker PPA 117 MW Peaker PPA 160 MW
2016	Peaker PPA 117 MW Peaker PPA 160 MW
2017	(2) 7FA CT 354/298 MW
2018	(1) 7FA CT 177/149 MW
2019	(1) 7FA CT 177/149 MW
2020	
2021	
2022	(1) 7FA CT 177/149 MW
2023	
2024	
2025	(1) 7FA CT 177/149 MW
2026	
2027	_
2028	_
2029	(1) 7FA CT 177/149 MW
2030	_
2031	_
2032	_

Alternative 2

Year	Portfolio Additions
2012	Peaker PPA 117 MW
2013	Peaker PPA 117 MW Peaker PPA 160 MW
2014	Peaker PPA 117 MW Peaker PPA 160 MW
2015	Peaker PPA 117 MW Peaker PPA 160 MW
2016	Peaker PPA 117 MW Peaker PPA 160 MW
2017	(2) 7FA CT 354/298 MW
2018	(1) 7FA CT 177/149 MW
2019	(1) 7FA CT 177/149 MW
2020	
2021	
2022	(1) 7FA CT 177/149 MW
2023	
2024	
2025	(1) Polk 2-5 NGCC 463/459 MW
2026	
2027	_
2028	_
2029	_
2030	_
2031	_
2032	_

CPWRR ($M)

	Polk 2-5	Alternative 1	Alternative 2
Capital	$1,566.4	$1,281.1	$1,576.9
O&M	$1,099.7	$1,172.5	$1,139.5
Fuel & Purchased Power	$15,566.1	$16,062.6	$15,746.9
Total	$18,232.2	$18,516.2	$18,463.3
Delta		$284.0	$231.1

TAMPA ELECTRIC COMPANY
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FILED: 09/12/2012

DOCUMENT NO. 9

IRP SENSITIVITY ANALYSIS

IRP Sensitivity Analysis

CPWRR ($M)

		Polk 2-5	Alternative 1	Alternative 2
Capital Costs Sensitivities:				
Low		$17,950.5	$18,416.9	$18,228.9
	Delta		$466.4	$278.4
High		$18,135.3	$18,592.1	$18,425.2
	Delta		$456.8	$289.9
Customer Demand Sensitivities				
Low		$16,857.1	$17,141.0	$17,168.7
	Delta		$283.9	$311.6
High		$19,791.6	$20,356.6	$19,867.2
	Delta		$565.0	$75.6
Fuel Costs Sensitivities				
Low		$15,549.6	$15,655.8	$15,715.5
	Delta		$106.2	$165.8
High		$21,971.5	$22,453.5	$22,273.5
	Delta		$482.1	$302.1

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DOCUMENT NO. 10

RFP SUMMARY OF PROPOSALS

REDACTED

RFP Summary of Proposals

	PK 2-5	Proposal A	Proposal B	Proposal C	Proposal D
Company	TEC				
Type	Intermediate	Intermediate PPA	Sale of peaking facility	Peaking PPA	Peaking PPA
Technology	4x1 CC Conversion	2x1 CC	(2) 7FA CTs	New Build 7FA.05 CT	New Build 7FA.05 CT
Plant Name	Polk Power Station				
Capacity (MW)	459(S)/463(W)				
Start Year	2017	2017	2013	2017	2017
Term (years)	N/A	10	N/A	10	15
HR (Btu/kWh)	7,062				

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DOCUMENT NO. 11

RFP RESOURCE PLANS & ANALYSIS

RFP Resource Plans & Analysis

Resource Plans

Year	Polk 2-5	Proposal A	Proposal B	Proposal C	Proposal D
2012					
2013			Proposal B		
2014					
2015					
2016					
2017	(1) Polk 2-5 NGCC 463/459 MW	Proposal A		Proposal C (1) 7FA CT 177/149 MW	Proposal D (1) 7FA CT 177/149 MW
2018			(1) Polk 2-5 NGCC 463/459 MW		
2019	(1) 7FA CT 177/149 MW	(1) 7FA CT 177/149 MW		(2) 7FA CT 354/298 MW	(2) 7FA CT 354/298 MW
2020					
2021					
2022	(1) 7FA CT 177/149 MW	(1) 7FA CT 177/149 MW			
2023				(1) Polk 2-5 NGCC 463/459 MW	(1) Polk 2-5 NGCC 463/459 MW
2024					
2025	(1) 7FA CT 177/149 MW	(1) 7FA CT 177/149 MW			
2026			(1) 7FA CT 177/149 MW		
2027		(1) Polk 2-5 NGCC 463/459 MW			
2028					
2029	(1) 7FA CT 177/149 MW	(1) 7FA CT 177/149 MW	(1) 7FA CT 177/149 MW	(1) 7FA CT 177/149 MW	
2030					
2031					
2032					(1) 7FA CT 177/149 MW

CPWRR ($ million)

	Polk 2-5	Proposal A	Proposal B	Proposal C	Proposal D
Capital	$1,575.2	$1,253.3	$1,400.1	$1,430.9	$1,416.6
O&M	$1,099.7	$1,064.6	$1,068.4	$1,111.2	$1,109.2
Fuel & Purchased Power	$15,566.1	$16,143.0	$15,890.3	$15,909.9	$15,954.9
Total	$18,241.0	$18,460.9	$18,358.9	$18,452.0	$18,480.8
Delta		$219.9	$117.9	$210.9	$239.7

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DOCUMENT NO.12

RFP QUALITATIVE FACTORS

RFP Qualitative Factors

	PK 2-5	Proposal A	Proposal B	Proposal C	Proposal D
Technology Type	Combined Cycle	Combined Cycle	Peakers	Peaker	Peaker
Transmission Reliability, Voltage Support, Reserves	High High	High High	Medium Low	Medium Low	Medium Low
Water Availability	Municipal Source	Municipal Source	Limited, water use caution area	Unknown	Unknown
Dual Fuel Capability	2 CTs - Yes, 2 CTs - Capable	No	2 CTs - Yes	1 CT - Yes	1 CT - Yes
Project Execution	Low risk	Existing Unit	Existing Unit	Low risk	Low risk
Project Operation	TEC	Owner	ST – contractors LT – TEC employees	Contractor	Contractor
Project Maintenance	CSA	Self-managed, as needed	CSA and CT spares modeled	Self-managed, as needed	Self-managed, as needed
Project Security	Investment Grade	Low – offered lien or step in rights	Investment Grade	Investment Grade	Investment Grade
Environmental Emission Rates	Lower	Lower	Higher	Higher	Higher
Renewable Option	30 MW Solar	None	None	None	None
Simple Cycle Capability	Yes	No	Yes	Yes	Yes
Job Creation and Tax Base	Construction labor	No: existing unit	No: existing unit TEC may increase O&M	Construction, O&M labor	Construction, O&M labor

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DOCUMENT NO. 13

JUNE 2012 ASSUMPTIONS UPDATE

TAMPA ELECTRIC COMPANY
DOCKET NO. 12_____-EI
EXHIBIT NO. ____ (RJR-1)
DOCUMENT NO. 13
FILED: 09/12/2012
REVISED: 10/12/2012
REVISED:11/27/2012

June 2012 Assumptions Update

Resource Plans

Polk 2-5

Year	Portfolio Additions
2012	
2013	
2014	
2015	
2016	
2017	(1) Polk 2-5 NGCC 463/459 MW
2018	
2019	
2020	(1) 7FA CT 177/149 MW
2021	
2022	
2023	(1) 7FA CT 177/149 MW
2024	
2025	
2026	(1) 7FA CT 177/149 MW
2027	
2028	
2029	(1) 7FA CT 177/149 MW
2030	
2031	
2032	

Alternative 2

Year	Portfolio Additions
2012	
2013	
2014	
2015	
2016	
2017	(2) 7FA CT 354/298 MW
2018	
2019	(1) 7FA CT 177/149 MW
2020	(1) 7FA CT 177/149 MW
2021	
2022	
2023	(1) 7FA CT 177/149 MW
2024	
2025	
2026	(1) Polk 2-5 NGCC 463/459 MW
2027	
2028	
2029	
2030	
2031	
2032	

Proposal B

Year	Portfolio Additions
2012	
2013	Proposal B
2014	
2015	
2016	
2017	
2018	
2019	(1) Polk 2-5 NGCC 463/459 MW
2020	
2021	
2022	
2023	
2024	
2025	
2026	
2027	(1) 7FA CT 177/149 MW
2028	
2029	(1) 7FA CT 177/149 MW
2030	
2031	
2032	

CPWRR ($ million)

	Polk 2-5	Alternative 2	Proposal B
Capital	$1,557.2	$1,520.4	$1,357.5
O&M	$845.2	$897.5	$815.0
Fuel & Purchased Power	$13,631.7	$13,882.9	$13,937.1
Total	$16,034.1	$16,300.8	$16,109.6
Delta		$266.7	$75.4

DOCKET NO. 12____-EI
WITNESS: TAYLOR

EXHIBIT

OF

ALAN S. TAYLOR

ON BEHALF OF TAMPA ELECTRIC COMPANY

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 120234-EI EXHIBIT 18
PARTY TAMPA ELECTRIC COMPANY (TECO) - (DIRECT)
DESCRIPTION Alan S. Taylor (AST-1)

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DOCUMENT NO. 1

RESUME OF ALAN S. TAYLOR

RESUME OF ALAN S. TAYLOR

AREAS OF QUALIFICATION

Independent evaluation services for competitive bidding resource selection, integrated resource planning, market analysis, risk assessment, and strategic planning

EMPLOYMENT HISTORY

- President, Sedway Consulting, Inc., Boulder, CO, 2001-present
- Senior Member of PA Consulting, Inc., Boulder, CO, 2001
- Vice President, Global Energy Business Sector, PHB Hagler Bailly, Inc., Boulder, CO, 2000
- From Senior Associate to Principal, Utility Services Group, Hagler Bailly Consulting, Inc., Boulder, CO, 1991-1999
- Senior Consultant, Energy Management Associates, Atlanta, GA, 1983-1988
- Internships at: Pacific Gas & Electric Company, San Francisco, CA (1990)
  Lawrence Berkeley National Laboratory, Berkeley, CA (1989-1991)
  MIT Resource Extraction Laboratory, Cambridge, MA (1982)
  Baltimore Gas and Electric Company, Baltimore, MD (1980)

EDUCATION

- Walter A. Haas School of Business, University of California at Berkeley, MBA, Valedictorian, Corporate Finance, 1991
- Massachusetts Institute of Technology, BS, Energy Engineering, 1983

PROFESSIONAL EXPERIENCE

- Developed and/or reviewed dozens of requests for proposals for utility resource solicitations.
- Conducted numerous competitive bidding project evaluations for conventional generating resources, renewable facilities, and off-system power purchases; analyzed thousands of power supply proposals.
- Assisted in or monitored contract negotiations with hundreds of shortlisted bidders in utility resource solicitations.
- Testified on utility competitive bidding solicitation results, affiliate transactions, cost recovery procedures, rate case calculations, and incentive ratemaking proposals.
- Managed the development of market price forecasts of North American and European electricity markets under deregulation.
- Performed financial modeling of electric utility bankruptcy workout plans.
- Trained and assisted many of the nation's largest electric and gas utilities in their use of operational and strategic planning computer models.

SELECTED PROJECTS

2006- **California Solicitations for Conventional and Renewable Resources**
2012 Client: Southern California Edison

Currently serving or has served as the Independent Evaluator (IE) in 18 solicitations for power or gas supplies in southern California – one for over 2,500 MW of new conventional resources, four for renewable energy purchases to help Southern California Edison meet its state Renewables Portfolio Standard (RPS) requirements, five for near-term capacity resources, four for reverse energy auctions of the dispatch rights to facilities under new power purchase agreements, and four for gas financial hedging products. Mr. Taylor managed or is managing a Sedway Consulting team to perform a parallel evaluation of all proposals, monitor communications and negotiations with power suppliers, and support the review of the final selected proposals by the Procurement Review Group – a collection of non-market-participant stakeholders and regulators who are/were provided confidential access to the evaluation results at intermediate stages. He has filed IE reports and sponsored testimony before the California Public Utilities Commission concerning the results of most of these solicitations.

2011 **Minnesota Solicitation for Wind Resources**
Client: Minnesota Power

Provided independent evaluation services in a solicitation for 100 MW of wind generation in Minnesota. Proposals competed with a utility proposal to develop its own wind farm. Mr. Taylor assisted with the development of the RFP and performed a parallel economic evaluation of the utility's facility and all competing proposals.

2005- **California Solicitations for Conventional and Renewable Resources**
2010 Client: Pacific Gas & Electric

Served as the Independent Evaluator in four solicitations for new power supplies in northern California – one for 2,200 MW of new conventional resources, another for up to 1,200 MW of new generating resources from any source, and two others for between 1,400 and 2,800 GWh/year of renewable energy purchases. Mr. Taylor managed a Sedway Consulting team to perform a parallel evaluation of all proposals, monitor communications and negotiations with power suppliers, and support the review of the final selected proposals by the Procurement Review Group – a collection of non-market-participant stakeholders and regulators who were provided confidential access to the evaluation results at intermediate stages. He has filed IE reports and sponsored testimony before the California Public Utilities Commission concerning the results of most of these solicitations.

2007- **Florida Solicitation for New Resources**
2008 Client: Florida Power & Light

Provided independent evaluation services in Florida Power & Light's solicitation for 1,250 MW of new power supplies for 2011. Mr. Taylor performed a parallel economic evaluation to that which was undertaken by the utility. His work efforts allowed all proposal parameters to be cross-checked and corrected where necessary. He sponsored testimony before the Florida Public Service Commission concerning the results of the solicitation evaluation.

2007- **Avoided Cost Analysis for Interruptible Loads**
2008 Client: Public Service Company of Colorado

Provided an independent assessment of Public Service Company of Colorado's peaking resource avoided costs for use in the utility's development of customer credits for its interruptible service tariff.

2007- **Florida Solicitations for New Resources**
2008 Client: Tampa Electric Company

Provided independent evaluation services in two separate Tampa Electric Company solicitations for 600 MW of new power supplies for 2013, as a market test for the utility's proposals to develop initially an integrated gasification combined cycle (IGCC) facility and later a gas-fired combined cycle facility.

2004- **Regulatory Support of Commission Staff**
2005 Client: Utah Division of Public Utilities

Assisted staff for the Utah Division of Public Utilities in the division's efforts to analyze PacifiCorp's 2005 rate case. Mr. Taylor reviewed production cost modeling results and forecasts of system-wide fuel and purchase power costs.

2004- **Minnesota Solicitation for New Resources**
2005 Client: Minnesota Power

Provided independent evaluation services in a solicitation for 200 MW of firm power supplies. Mr. Taylor reviewed all proposals and performed a parallel economic evaluation among proposed turnkey facilities and power purchases.

2004 **Canadian Solicitations for Conventional and Renewable Resources**
Client: Ontario Energy Ministry

Participated in a broader consulting team and provided assistance in the development of RFPs for 2,500 MW of conventional resources and 300 MW of renewable resources. New long-term sources of power were sought to replace regional coal-fired generation.

2003- **Florida Solicitation for New Resources**
2004 Client: Florida Power & Light

Provided independent evaluation services in Florida Power & Light's solicitation for 1,100 MW of new power supplies for 2007. Mr. Taylor performed a parallel economic evaluation of all proposals and reviewed, cross-checked, and corrected (where necessary) the utility's analyses. He sponsored testimony before the Florida Public Service Commission concerning the results of the solicitation evaluation.

2002- **Minnesota Solicitation for New Resources**
2003 Client: Northern States Power

Assisted in the evaluation of a large number of multi-option proposals for new power supplies in the 2005-2009 time frame. Mr. Taylor was the independent evaluator in two separate solicitations. He managed a team of individuals in the evaluation of responses for both Requests for Proposals (RFPs). In the first solicitation, contingent proposals were received that could serve as replacement contracts for 1,100 MW of nuclear capacity if NSP were forced to decommission its Prairie Island power plant in 2007. In the second solicitation, NSP sought approximately 1,000 MW of new supplies to supplement its existing supply portfolio. The evaluation included the review of over a dozen proposed wind projects.

2002 **Florida Revisions to Bidding Rule**
Client: Consortium of utilities

Provided the Florida Public Service Commission with recommendations concerning appropriate revisions to the state's bidding rule. Mr. Taylor participated in public workshops to provide the benefits of his extensive experience in performing competitive bidding solicitations and to convey what changes should or should not be made to Florida's existing bid rule to ensure the selection of the best resources for the state's electricity customers.

2002 **Arizona Testimony Concerning Competitive Bidding Solicitations**
Client: Harquahala Generating Company, LLC

Filed testimony before the Arizona Corporation Commission in the Generic Proceedings Concerning Electric Restructuring Issues and Associated Proceedings. Mr. Taylor's testimony provided the Commission with information about competitive bidding processes that he had seen

work in other states. Also, his testimony addressed various concerns that were raised by Arizona Public Service as to the feasibility of implementing competitive bidding in Arizona.

2002 **Florida Solicitation for New Resources**
Client: Florida Power & Light

Provided independent evaluation services in Florida Power & Light's solicitation for 1,750 MW of new power supplies in the 2005-2006 time frame. Mr. Taylor performed a parallel economic evaluation to that which was undertaken by the utility. His work efforts allowed all proposal parameters to be cross-checked and corrected where necessary. Also, he provided suggestions on resource optimization modeling approaches that ensured the most comprehensive examination of thousands of potential combinations of proposals.

2001 **Wisconsin Testimony Concerning Competitive Bidding Solicitations**
Client: MidWest Independent Power Suppliers

Provided testimony in a proceeding before the Wisconsin Public Service Commission on behalf of a consortium of independent power producers. Mr. Taylor testified on the benefits and timing of a competitive bidding solicitation that Wisconsin Electric Power Company (WEPCO) should be ordered to conduct prior to the utility's development of $2.8 billion in self-build generation facilities (embodied in a WEPCO proposal called Power the Future – 2). Without the benefits of a competitive solicitation, there would be no defensible means of ensuring that the utility's customers were being offered the best, most cost-effective resources.

2001 **Negotiation of Full-Requirements Purchase Contract**
Client: Georgia cooperative utility

Assisted in negotiation of a $2 billion power purchase contract. Mr. Taylor worked with a team of legal experts and other consultants to assist the client in negotiating a 15-year full-requirements contract with a large, national power supplier. Detailed modeling simulations were performed to compare the complex transaction to the utility's own self-build alternatives. Mr. Taylor helped investigate and negotiate detailed provisions in the power supply contract concerning ancillary services and other operational parameters.

2001 **Evaluation of Resource Proposals**
Client: North Carolina municipal utility

Reviewed responses to a utility resource solicitation and assisted the client in developing a short list of the best bidders. Mr. Taylor reviewed the results of the client's economic analysis of the proposals and provided insights on various nonprice factors related to each of the top-ranked proposals. Mr. Taylor helped the client in structuring and strategizing for the negotiation process.

2000- **Solicitation for New Resources**
2001 Client: Public Service of Colorado

Assisted in the evaluation of a large number of multi-option proposals for new power supplies in the 2002-2005 time frame. Mr. Taylor managed a team of a dozen individuals who performed economic and nonprice evaluations of conventional and renewable proposals. Mr. Taylor developed recommendations for a short list of the best resources and managed a supplemental evaluation of second-tier bidders when the client's capacity needs subsequently increased. Ultimately, over $2 billion of contracts were negotiated for over 1,700 MW of new power supplies under terms of up to 10 years. Mr. Taylor testified before the Colorado Public Utilities Commission on the processes and results of both the primary and supplemental evaluations.

1999- **Solicitation for New Resources**
2000 Client: MidAmerican Energy

Reviewed MidAmerican's solicitation for new power supplies for the 2000-2005 resource planning period. Mr. Taylor managed a team of individuals who performed an independent parallel evaluation of MidAmerican's analysis of responses to the utility's request for proposals (RFP). Mr. Taylor reviewed MidAmerican's evaluation and negotiation process and testified to the fairness and appropriateness of MidAmerican's actions. He filed testimony before the utility regulatory commissions in Iowa, Illinois, and South Dakota.

2000 **Electricity Market Assessments**
Client: various American and European clients

Helped develop electricity market prices for regional electricity markets in North America (California, New England, Arizona/New Mexico, Louisiana) and Europe (Austria, Belgium, France, Germany, and the Netherlands). Mr. Taylor worked with project teams in the U.S. and Europe to develop simulation models and databases to forecast energy and capacity prices in the deregulating power markets.

1999 **Evaluation of New Resources**
Client: Florida Power Corporation

Helped prepare the FPC's RFP for long-term supply-side resources and assisted in the independent evaluation of responses. Mr. Taylor oversaw the review of FPC's computer simulations (in PROVIEW and PROSYM) of the proposals that were received. The project team also evaluated the proposals by using a response surface model to approximate the results that might be produced in the more detailed simulations. Mr. Taylor testified before the Florida Public Service Commission concerning his assessment of FPC's solicitation and the results of the analysis.

1998 **Evaluation of New Resources**
Client: Public Service of Colorado

Assisted the evaluation of proposals for PSCo's near-term 1999 resource additions and managed the complete third party evaluation of proposals for resources in the 2000-2007 time frame. Such resources included third-party facilities and power purchases, as well as company-sponsored interruptible tariffs. Mr. Taylor assisted with the development of the request for proposals and oversaw the evaluation of all responses. He and his team monitored subsequent negotiations with shortlisted bidders. Mr. Taylor testified before the Colorado Public Utilities Commission on the fairness of the solicitation and the results of the evaluation.

1997- **Evaluation/Negotiation of Transmission Interconnection Solicitation**
1999 Client: New Century Energies

Managed a solicitation for participation in a major transmission project interconnecting Southwestern Public Service (a Texas member of the Southwest Power Pool) and Public Service of Colorado (a member of the Western Systems Coordinating Council). As the first major inter-reliability-council transmission project in the era of open access, FERC required that SPS and PSCo solicit third-party interest in participation. This project required the development of an RFP and evaluation of responses for both equity participation and long-term transmission service for over 21 alternative high-voltage AC/DC/AC transmission projects. The evaluation focused on the costs and intangible risks of different transmission alternatives relative to the benefits and savings associated with increased economy interchange, avoided future generating capacity, and reductions in single-system spinning reserve and reliability requirements.

1996- **Evaluation/Negotiation of All-Source Solicitation**
1997 Client: Southwestern Public Service

Managed the evaluation of a broad array of responses to an all-source solicitation that was issued by Southwestern Public Service (SPS). Resources in the areas of conventional supply-side generation, renewable resources, off-system transactions, DSM, and interruptible loads were proposed. The evaluation entailed scoring the proposals for a variety of price and nonprice attributes. Mr. Taylor assisted Southwestern in its negotiations with the bidders and performed the detailed evaluation of the best and final offers.

1996- **Risk Assessment for 1,000-MW Solicitation**
1997 Client: Seminole Electric Cooperative

Managed the review and assessment of risks associated with responses to a 1,000-MW solicitation that was issued by Seminole Electric Cooperative. The evaluation entailed reviewing selected proposals' financial feasibility, performance guarantees, fuel supply plans, O&M plans, project siting, dispatching flexibility, and bidder qualifications.

1997 **Analysis/Testimony Concerning Louisville Gas & Electric's Fuel Adjustment Clause**
Client: Kentucky Industrial Utility Customers

Performed a detailed examination of Louisville Gas & Electric's (LG&E) fuel adjustment clause and identified misallocated costs in the areas of transmission line losses and purchased power fuel costs. Mr. Taylor also critiqued LG&E's rate adjustment methodology and recommended closer scrutiny of costs associated with jurisdictional and non-jurisdictional sales. Mr. Taylor testified before the Kentucky Public Service Commission and presented the findings of his analysis.

1995 **Development of All-Source Solicitation RFPs**
Client: Southwestern Public Service

Managed the development of five RFPs that solicited resources in the areas of conventional supply-side generation, renewable resources, off-system transactions, DSM, and interruptible loads. The RFPs were issued by SPS as part of an all-source solicitation to identify resources that may be competitive with two generation facilities that SPS intended to develop.

1994 **Development of Competitive Bidding RFP**
Client: Empire District Electric Company

Based on knowledge gained from the review of dozens of other utility RFPs, developed a combined-cycle resource RFP for Empire District Electric Company. The project team was responsible for the RFP's entire development, including the development of scoring provisions for price and nonprice project attributes.

1993 **Selection of Developer for 25 MW Wind Facility**
Client: Northern States Power

Evaluated ten bids that were received by NSP in a solicitation for the development of a 25 MW wind facility in Minnesota. The proposals were scored and ranked through a point-based evaluation system that was developed prior to the solicitation. The scoring involved an assessment of operational and financial feasibility, power purchase pricing terms, construction schedules, and community acceptance issues.

1993 **Competitive Bidding Design**
Client: Northern States Power

Assisted NSP in the utility's effort to design a generic competitive bidding RFP that could be issued for a variety of generation resources. Two dozen RFPs from other utilities were reviewed to determine the appropriate weights and mechanisms that should be used to score various project attributes.

1993 **Evaluation of 500 MW Supply-Side Solicitation**
Client: San Diego Gas & Electric

Assisted in the evaluation of 15 bids that were received from a 500 MW solicitation for power by SDG&E. The utility wanted to determine whether or not there were less expensive alternatives to the implementation of its plan to repower one of its own units. The 15 projects represented over 4,000 MW. The bids were evaluated using extensive production costing modeling, in which over 1,000 model runs were performed to evaluate each bid under a variety of scenarios.

DOCUMENT NO. 2

SEDWAY CONSULTING'S

INDEPENDENT EVALUATION REPORT

Sedway Consulting, Inc.

INDEPENDENT EVALUATION REPORT FOR TAMPA ELECTRIC COMPANY'S 2012 POWER SUPPLY SOLICITATION

Submitted by:

Alan S. Taylor
Sedway Consulting, Inc.
Boulder, Colorado

September 10, 2012

REDACTED

Introduction and Background

On March 23, 2012, Tampa Electric Company (Tampa Electric) issued a Request for Proposals (RFP) for capacity and energy to satisfy the utility's projected incremental resource need for 2017. In April, 2012, Tampa Electric released its 2012 Ten-Year Site Plan with three load forecasts (a low-load scenario, a base case, and a high-load scenario) that translated into the cumulative 2017-2019 capacity needs depicted in Table A-1.

Table A-1
Tampa Electric Cumulative Capacity Needs
(All Values in MWs)

Year	Low Load Forecast	Base Case Forecast	High Load Forecast
2017	139	295	463
2018	159	343	540
2019	304	515	739

Tampa Electric's RFP indicated that power supply proposals would be competing against a utility self-build option – namely, a conversion of four existing simple-cycle combustion turbines (CTs) at Tampa Electric's Polk power plant[1] into a 4-on-1 combined-cycle (CC) facility. The addition of the CC steam cycle is projected to provide Tampa Electric with incremental summer capacity of 459 MW by January, 2017; this conversion project was referred to as the Next Planned Generating Unit (NPGU).

Sedway Consulting, Inc. (Sedway Consulting) was retained to provide independent evaluation services to Tampa Electric and provide a parallel economic evaluation of responses to the RFP. This independent evaluation report documents Sedway Consulting's evaluation process and presents the results of Sedway Consulting's economic analysis. It describes Sedway Consulting's proprietary Response Surface Model (RSM) which was used to conduct the parallel economic evaluation, fundamental assumptions that were applied, and additional economic factors that affected the final cost of each resource.

Receipt of Proposals

On May 22, 2012, Tampa Electric received five proposals from four power suppliers. One proposal – from [redacted] – was a follow-up offer regarding a biomass retrofit project of some of TECO's existing Bayside units. Because the proposal involved a developer's use of a Tampa Electric-owned power plant, it did not comply with the RFP. Indeed, the bidder confirmed that the proposal was never meant to be considered as part of the 2012 RFP and was merely a continuation of negotiations that had been underway with Tampa Electric for several years. Thus, the [redacted] proposal was set aside, and four

[1] Specifically Polk Units 2-5.

remaining proposals that involved three power projects from three bidders were ultimately compared with Tampa Electric's NPGU. All of these projects were natural gas-fired technologies. The four proposals/three projects entailed the following:

1. [redacted] a [redacted] power purchase agreement (PPA) for capacity and energy deliveries commencing January 1, 2017 [redacted] Hereafter, this proposal will be referred to as Proposal A in the unredacted portions of this report.

2. [redacted] a sale [redacted] proposed that the asset sale and transfer conclude on June 1, 2013. Hereafter, this proposal will be referred to as Proposal B in the unredacted portions of this report.

3. [redacted] PPA for capacity and energy deliveries commencing January 1, 2017 [redacted] The bidder provided alternative proposals for two PPAs of different durations – one of approximately [redacted] with an expiration date of [redacted] and a second of approximately [redacted] with an expiration date of [redacted].[2] Hereafter, these two proposals will be referred to as Proposal C (for the shorter PPA) and Proposal D (for the longer PPA) in the unredacted portions of this report.

Table A-2 depicts key information for Tampa Electric's NPGU and each of the proposals. Specifically, the table includes each resource's summer capacity, type (combined cycle or combustion turbine), the year that the PPA or asset transaction is expected to commence deliveries, the PPA term (or economic life in the case of asset transaction), levelized capacity price or capital-related revenue requirement (over the PPA term or asset life), full load heat rate, and variable operation and maintenance (O&M) charge.

Table A-2
Summary of Tampa Electric's NPGU and Initial Proposals

Resource	Sum. Cap. (MW)	Type	Start Year	Term/ Econ. Life (yrs)	Cap. Price ($/kW-mo)	Full Load Heat Rate (Btu/kWh)	Var. O&M ($/MWh)
Proposal A	[redacted]		2017	[redacted]			
Proposal B			2013				
Proposal C			2017				
Proposal D			2017				
Polk NPGU	459	CC	2017	30	16.94	7,062	2.98

[2] For ease of reference, these PPA alternatives will simply be referred to as [redacted]-year and [redacted]-year proposals in the remainder of this report.

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Sedway Consulting's
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It is important to note that the statistics for Tampa Electric's NPGU in Table A-2 are based on the conversion project's *incremental* capacity. On a total capacity basis, the project will entail adding 459 MW of summer capacity to four existing CTs that have a combined summer capacity of 604 MW. Thus, the complete combined cycle plant will have a summer capacity of 1,063 MW. The levelized capacity price includes all capital costs (for generation and transmission investments) and fixed O&M costs and is converted into an equivalent levelized capacity price by dividing these costs by the incremental 459 MW. The Proposal B levelized capacity price also includes an estimate for fixed O&M costs. Unlike the NPGU, none of the bid information in Table A-2 includes transmission costs or firm gas transportation costs – all of which were calculated as described later in this report and subsequently added to the bid costs. In some cases (specifically, Proposal B), such additional costs amounted to more than $[redacted]/kW-month in levelized terms.

[redacted]

Although Sedway Consulting's (and Tampa Electric's) base case evaluation results of the initial proposals yielded total costs that were higher than the costs of Tampa Electric's NPGU, the results were deemed to be close enough[3] to warrant shortlisting all four proposals on June 22, 2012. Conference calls were scheduled with each of the bidders on July 2-3, 2012 to allow for further clarification of each bid. Sedway Consulting monitored all of those conference calls. Each bidder was offered the opportunity to provide a best-and-final offer by July 13, 2012.

[redacted]

[3] Also, sufficient uncertainty existed in key evaluation areas to warrant further review of each bid.

[redacted] All subsequent information and results in this report pertain to the best-and-final offers.

Evaluation Process

Through its review of the proposals that Sedway Consulting retrieved at the bid opening (and the subsequent submission of best-and-final offers), Sedway Consulting extracted the following economic information for each proposal:

- Capacity (winter and summer; base and duct-fired, where applicable)
- Commencement and expiration dates of contract
- Capacity pricing (or asset sales price, if applicable)
- Fixed operation and maintenance (O&M) charges (where applicable)
- Firm fuel transportation assumptions
- Fuel pricing or indexing
- Heat rate (base and duct-fired, where applicable)
- Variable O&M pricing
- Start-up costs and fuel requirements
- Expected forced outage and planned outage hours
- Tampa Electric and third-party transmission costs.

The same or analogous information was received for Tampa Electric's NPGU.

The remainder of this report section addresses the following topics:

- a description of the RSM,
- the use of a "filler" resource in evaluating proposed transactions that expired before the end of the study period, and
- the process of developing final cost estimates for all resources.

RSM Evaluation Process

The economic information for all outside proposals and Tampa Electric's NPGU was input into Sedway Consulting's RSM – a power supply evaluation tool that was calibrated to approximate the impact of each proposal on Tampa Electric's system production costs. The RSM calculated each option's annual fixed costs and variable dispatch costs, estimated the production cost impacts of each option, and accounted for capacity replacement costs for all proposed contracts that expired before the end of the study period. In addition, Sedway Consulting's analysis accounted for the different sizes of resources by calculating additional costs or benefits associated with meeting Tampa

Electric's resource needs from 2017-2019. For those resources and scenarios where a resource would not fully meet Tampa Electric's resource needs through 2019, a per-MW cost of a new generic CT was added to the resource's costs to cover the deficiency. In instances where a resource provided more than the required capacity, a credit was calculated – thereby recognizing the value of surplus capacity in deferring the need for Tampa Electric to develop or procure future generating capacity in 2019 and beyond.

An option's net cost was a combination of fixed and variable cost factors. On the fixed side, the RSM calculated annual fixed costs associated with capacity payments (or generation and transmission revenue requirements), fixed O&M costs, incremental capital charges, and firm gas transportation costs. These annual total fixed costs were discounted to mid-2012 dollars.

On the variable cost side, the RSM first developed a variable dispatch charge (in $/MWh) for each option for each month. This charge was calculated by multiplying the option's heat rate by the specified monthly fuel index price and adding the variable O&M charge.

The RSM then estimated Tampa Electric's system production costs for each month and each option by interpolating between production costs estimates that were extracted from a set of Planning and Risk runs. These runs were performed at the start of the project and were used to calibrate the RSM by varying the monthly variable dispatch charge for a proxy proposal and recording the resulting Tampa Electric system production cost.

For the same capacity as the proposal under consideration, the RSM also estimated Tampa Electric's system production costs for a natural-gas-fired reference unit that had a high variable dispatch charge based on a heat rate of 25,000 Btu/kWh. Thus, for each option, the RSM yielded estimates of the annual production cost savings that Tampa Electric would be projected to experience if the utility selected the resource option, relative to acquiring the same sized transaction but at the high reference resource dispatch rate. The lower an option's variable dispatch charge, the greater the production cost savings.

Filler Resource

As was mentioned earlier, the RSM accounted for the costs of replacing capacity for all proposed contracts that expired before the end of the study period (2046). This was done by "filling in" for the lost capacity at the end of each proposal's term of service. This allowed for a side-by-side comparison of the value of proposals that had varying contract durations. Also, the RSM had been calibrated with Planning and Risk runs that assumed that a proxy proposed resource would provide its capacity for the entire duration of the study period. Thus, it was necessary to continue a proposal's capacity throughout the entire period so as to maintain consistent and sufficient reserve margins. In effect, by supplementing each short-term proposal with a filler resource for the later years, the RSM was simulating what Tampa Electric would have to do when a proposed transaction expired – acquire or develop an amount of replacement capacity equal to that expired resource.

As the basis for cost assumptions for the filler resource, Sedway Consulting (and Tampa Electric) used the Polk NPGU CC resource. The same $/kW fixed cost assumptions (e.g., capital-related revenue requirements, fixed O&M costs) and variable cost assumptions (e.g., heat rates, variable O&M costs, fuel supply issues) were used, although all capital-related costs were escalated by 3%/year and variable O&M costs were escalated by 2.4%/year to account for later in-service dates than the NPGU's 2017 expected commercial operation date. The only difference involved a methodological variation, whereby the RSM scaled the replacement capacity to exactly equal the size of the expiring proposal resource. Thus, all PPA proposals enjoyed the benefit of being replaced at the end of their terms with a resource that exhibited the operating efficiencies and economy-of-scale benefits of the NPGU combined-cycle plant. In other words, if a 200 MW proposal ended in 2027, the RSM assumed that a 200 MW combined-cycle facility replaced it in 2028; however, the construction costs for the replacement facility were not those that would typically be associated with a 200 MW combined-cycle plant, but rather, they were a prorated portion of the construction costs of the larger NPGU combined-cycle facility.

As noted above, depending on the "in-service date" for the filler resource, the filler's capital costs were escalated from a 2012 base-year value by 3%/year. This escalation assumption represented Tampa Electric's estimate of how construction costs were likely to increase for its generation alternatives. Sedway Consulting decided to use this escalation value to trend the filler's annual capacity charges over time. Thus, instead of using Tampa Electric's declining revenue requirements profile for the recovery of capacity costs, Sedway Consulting used an escalating pattern that yielded the same long-term present value of revenue requirements. A traditional revenue requirements profile results in the highest capital charges in a project's early years. Thereafter, the capital-related charges decline. This is the opposite from what is usually seen in most power purchase proposals in power supply solicitations. Most power purchase proposals tend to have flat or escalating capacity charges, presumably reflecting expectations that general inflation will increase the costs of constructing new facilities in the future. Sedway Consulting therefore restructured the filler's profile of capacity costs to match what is generally seen in the marketplace. This meant that the filler's first year's capacity costs were the lowest, with each year thereafter escalating at 3%. Figure A-1 displays the escalating capacity price profile used by Sedway Consulting as well as the traditional declining revenue requirements profile. Both profiles have the same present value.

Over the full 30 years, the restructuring of the filler's capacity costs made no difference to the present value of the facility's revenue requirements. However, in the evaluation of outside proposals that did not extend through 2046 (the end of the study period), it provided the most favorable basis for such proposals' evaluation. In effect, it assumed that, following the expiration of an outside proposal's term, Tampa Electric would procure replacement power supplies at a trended price based its NPGU. In reality, if the NPGU was determined to be most cost-effective at this future decision point, the declining revenue requirements profile would present the actual annual costs that Tampa Electric's customers would likely pay.

Figure A-1
Comparison of Capacity Price Profiles

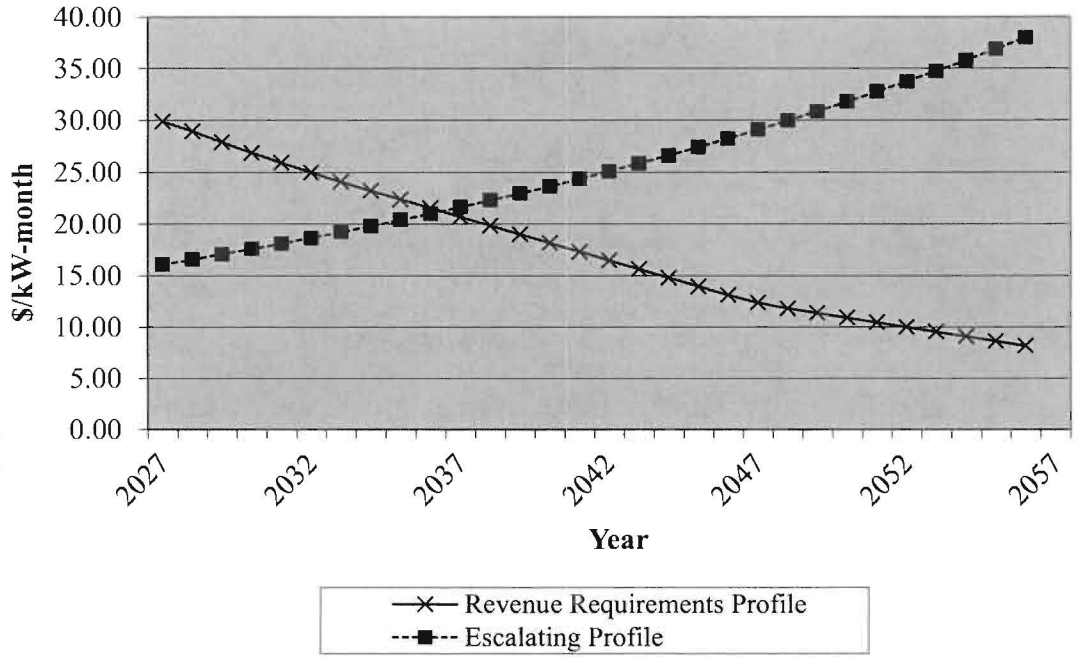
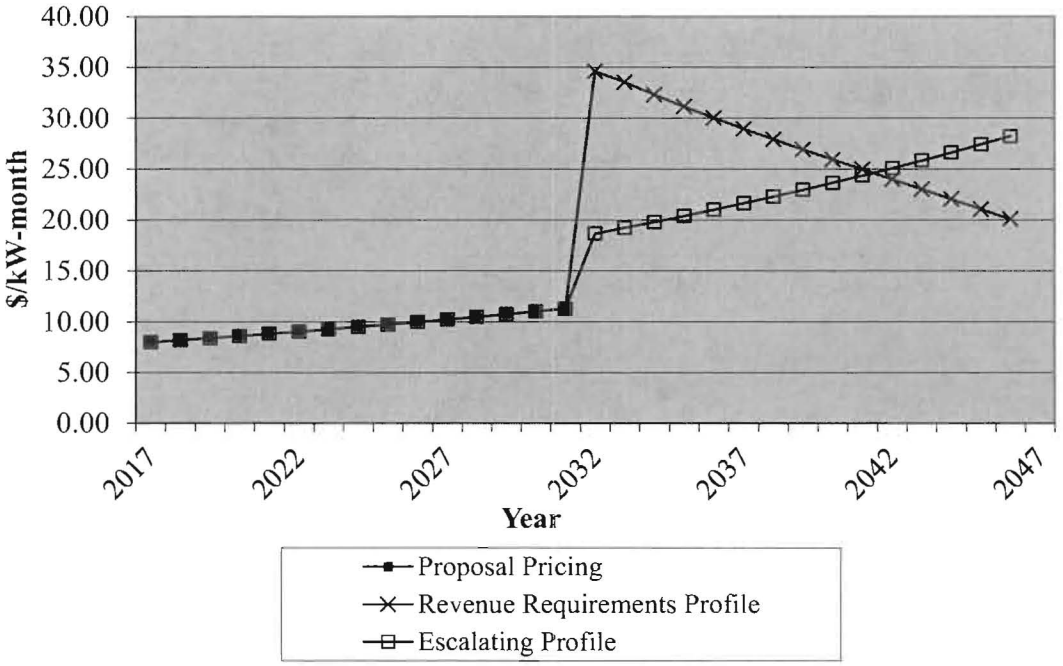


Figure A-2 depicts a comparison of the two approaches for replacing a hypothetical 15-year proposed power supply contract. The proposed contract is assumed to have a capacity charge that begins at $8/kW-month and escalates at 2.5%/year.

Relative to the declining revenue requirements methodology, the escalating filler capacity price methodology favors the 10-year proposed power supply because it defers the most expensive years of capacity costs until beyond the end of the study period. Thus, the present value of total study-period capacity costs (i.e., power supply proposal plus filler resource) is lower under the escalating filler methodology than under the declining revenue requirements methodology. Ultimately, the use of different filler methodologies by Sedway Consulting and Tampa Electric provided added value in looking at the evaluation results from two different perspectives and ensuring that the conclusions were supported from either perspective. However, because Sedway Consulting and Tampa Electric used these different methodologies, the total net present value differences depicted in the final results were understandably different.

Figure A-2
Comparison of Filler Capacity Price Methodologies



Proposal Cost Computation

Most of the input assumptions for the proposals and Tampa Electric's NPGU were directly input into the RSM in a straightforward fashion. There were some key additional external cost estimates that were developed outside of the proposal and input into the RSM or calculated within the model. They entailed the following:

- Firm gas transportation
- Tampa Electric transmission costs
- Third-party transmission costs
- Net equity adjustment
- Surplus/deficient capacity valuation.

Firm gas transportation. Tampa Electric's RFP required that bidders of gas-fired projects ensure that firm gas transportation would be available for their facilities. In the RFP bid forms/spreadsheets, bidders were asked to provide information that would allow Tampa Electric to estimate the expected annual firm gas transportation charges for each project. Sedway Consulting reviewed Tampa Electric's calculations – which included two different estimates for each project. Sedway Consulting used the lower estimate for each project. In the case of the Proposal A, the bidder had provided its own estimate (which Sedway Consulting used) that was essentially identical to the value developed by Tampa Electric. Table A-3 shows the annual firm gas transportation charges that were assigned to each resource/proposal, as well as the net present value impact on each proposal's economic evaluation.

Table A-3
Firm Gas Transportation Cost Assumptions and NPV Impact

Resource/Proposal	Annual Charges ($M/year)	NPV Impact ($M)
Proposal A	13.7	68
Proposal B	17.4	196
Proposal C	10.6	54
Proposal D	10.6	68
Polk NPGU	0	0

Tampa Electric's Polk NPGU was assumed to have no incremental firm gas transportation charges associated with it. Sedway Consulting had several discussions with Tampa Electric regarding this assumption. Tampa Electric explained that existing firm gas transportation contracts were already in place to provide a firm gas supply to the existing Polk 2-5 CTs. During full load operations of the base combined-cycle capacity of the new project, the gas consumption would not increase because the new project would simply be using the waste heat from the CTs for the incremental generation. During hours when the 120 MW of duct-firing is called on, however, gas consumption would increase. Tampa Electric maintained that it might supplement its firm gas supply with interruptible gas (i.e., higher-commodity-priced gas that did not have firm gas reservation charges associated with it). Sedway Consulting reviewed Tampa Electric's modeling results that indicated that the NPGU could be expected to consume an annual average of 6% of its gas supply in the form of interruptible gas. Sedway Consulting incorporated the annual percentage assumptions into its modeling of the NPGU, thereby increasing the effective commodity price of gas for the NPGU. All of the proposals were modeled as consuming fully firm gas (at a lower commodity price).

Tampa Electric transmission costs. With addition of new generation to a utility system, portions of the utility's transmission grid may need to be reinforced. This can entail the construction of new circuits or the reconductoring and upgrading of existing transmission lines. For proposals that were outside of Tampa Electric's transmission system, bidders were responsible for including the costs of such network upgrades to the

other transmission provider's system in their bid pricing. However, with regard to Tampa Electric's transmission system, any proposal for generation supplies – whether located within or outside of Tampa Electric's system – might trigger the need for Tampa Electric network upgrades. Estimates of such investments were calculated by Tampa Electric's transmission department and were not verifiable by Sedway Consulting. Table A-4 provides those estimates, as well as the net present value impact on each proposal's economic evaluation.

Table A-4
Tampa Electric Network Upgrade Assumptions and NPV Impact

Resource/Proposal	Network Upgrades ($M)	NPV Impact ($M)
Proposal A	100	62
Proposal B	17	23
Proposal C	1	1
Proposal D	1	1
Polk NPGU	147	N/A[1]

[1]Included in base revenue requirements for NPGU.

Sedway Consulting and Tampa Electric had several discussions particularly about the Proposal A transmission cost estimate. Given that [redacted], Sedway Consulting thought that it would likely have no network upgrades. However, Tampa Electric's transmission department maintains that [redacted], thereby necessitating Tampa Electric transmission system reinforcements.

Sedway Consulting employed a different methodology for developing the cost impacts of network upgrades than Tampa Electric. Sedway Consulting calculated levelized annual transmission revenue requirements[4] for the applicable investment and applied those annual costs only during the term of the PPA (or economic life of the asset in the case of owned generation options). Tampa Electric developed revenue requirements from the transmission investment estimates and applied them for all years of the study period for all bids. Neither approach is right or wrong. Sedway Consulting's approach simply assumes that a transaction's transmission investments may benefit Tampa Electric's customers after the expiration of the current PPA or be associated with other power purchase transactions in the future and thus only attributes annual transmission charges to the current PPA during the years that the PPA is active. Tampa Electric's approach assumes that no future benefits will exist and the full study period revenue requirements of the transmission investment must be associated with the PPA regardless of the PPA's duration. The only proposal where this resulted in any significant net present value difference was the [redacted]. Tampa Electric's approach yielded an NPV

[4] Assuming a 30-year asset life.

cost impact for this project of $130 million, approximately $68 million more than Sedway Consulting's approach.

Third-party transmission costs. As noted above, bidders were required to include network upgrade investments on other transmission owners' systems in their bid pricing. In addition, bidders had to identify in their proposals any firm transmission wheeling charges (e.g., for point-to-point transmission service) that would be incurred and passed on to Tampa Electric. Table A-5 depicts the assumptions that were provided by the bidders and verified by the evaluation team. Wheeling charges were assumed to remain flat over the duration of the transaction – likely a conservative assumption.

Table A-5
Transmission Wheeling Cost Assumptions and NPV Impact

Resource/Proposal	Annual Wheeling Charges ($M/year)	NPV Impact ($M)
Proposal A	0	0
Proposal B	6.8	77
Proposal C	5.3	27
Proposal D	5.3	34
Polk NPGU	0	0

Net Equity Adjustment. Rating agencies view some portion of a utility's capacity payment obligations to a power provider as the equivalent of debt on the utility's balance sheet. If a utility does not rebalance its capital structure by issuing stock, this debt equivalent can negatively impact a utility's financial ratios and cause rating agencies to downgrade their opinion of the utility's creditworthiness. This can increase the utility's cost of borrowing.

Sedway Consulting estimated for each PPA proposal (i.e., Proposals A, C and D) the costs for Tampa Electric to rebalance its capital structure if it were to enter into the PPA. This estimate was referred to as an "equity adjustment" because it reflected the present value of the incremental cost of the additional equity that Tampa Electric would need to raise to preserve the integrity of its balance sheet. The net present value of the equity adjustment for the Proposal A was in the range of $16-$17 million; it was $8 million and $13 million for Proposal C and Proposal D, respectively.

Surplus/Deficient Capacity Valuation. In Sedway Consulting's analysis, projects were evaluated on a stand-alone basis rather than in the context of a 30-year generation expansion plan, as was the case with Tampa Electric's detailed model. Sedway Consulting therefore accounted for the different capacity of each resource by recognizing to what extent it either exceeded or failed to meet Tampa Electric's capacity need in 2017-2019 and valuing the surplus or deficient capacity based on Tampa Electric's generic Frame 7FA CT costs. Specifically, if a resource provided more than Tampa Electric's cumulative capacity need in 2017-2019, then the resource was deemed to

provide surplus capacity. This capacity had value because it would reduce Tampa Electric's capacity needs in 2019 and beyond and reduce the need in future power supply solicitations.[5] Using the costs and expected energy benefits of a generic Frame 7FA CT, Sedway Consulting derived a 2017 value of $8.90/kW-month, escalating thereafter at 3% per year. This stream represented trended values for the net cost of the surplus/deficient capacity.

The same arithmetic applied to those resources that were too small to meet Tampa Electric's 2017-2019 capacity needs, although in the other direction. In those cases, the deficient capacity in each year (2017-2019 and beyond) was assigned a cost that was based on the same trended net cost of Tampa Electric's generic Frame 7FA CT. In essence, such offers were being packaged with a CT to create a compliant portfolio, much the same way that Tampa Electric's generation expansion plan model did.

The inclusion of a surplus/deficient capacity benefit/cost in the RSM results placed those results on a more comparable footing with the Tampa Electric detailed production costing and generation expansion results. While no explicit surplus/deficient capacity benefit/cost was calculated to supplement the model results in Tampa Electric's analysis, this cost or benefit was captured in the long-range expansion plans that were developed around each resource.

RSM Evaluation Results

As noted in the Introduction and Background section and Table A-1 of this report, Tampa Electric's 2012 Ten-Year Site Plan included three load forecasts (a low-load scenario, a base case, and a high-load scenario). Sedway Consulting and Tampa Electric decided to conduct the evaluation of all resources under each of those load forecasts. In addition, each load scenario would be coupled with a fuel price scenario. Thus, the base load scenario would be run with the base fuel price forecast, and the high and low load forecasts would be paired with fuel prices that were approximately 35% higher or lower, respectively, than the base forecast. All such assumption details were anchored before proposals were received.

Under all scenarios, Sedway Consulting found that Tampa Electric's NPGU was the least-cost option. Table A-6 depicts the cost differences that Sedway Consulting's analysis determined for each proposal under each of the three fuel price/load scenarios.

[5] Sedway Consulting assumed that little opportunity for short-term capacity sales in the Tampa Electric area would exist in 2017 and 2018 and therefore assigned no surplus capacity value in those years; surplus capacity was only valued for 2019 and beyond.

Table A-6
Cost Differences Relative to Tampa Electric's NPGU
($M, NPV_{2012})

Proposal	Low Case	Base Case	High Case
Proposal A [redacted]	62	148	242
Proposal A [redacted]	52	131	210
Proposal A [redacted]	15	69	120
Proposal B	291	592	947
Proposal C	240	508	802
Proposal D	260	553	876

On a net present value basis, the NPGU was found to be $69 million less expensive than the lowest-cost proposal under base case assumptions. However, it is important to note that this cost differential was associated with Proposal A's [redacted]. It is Sedway Consulting's understanding that Tampa Electric did not initially evaluate this or the [redacted] offer because they were not compliant with the RFP [redacted]. Sedway Consulting's results for the [redacted] offer are fairly close to Tampa Electric's results, after accounting for the transmission revenue requirement methodology differences described above.

Sedway Consulting's evaluation of all of the Proposal A offers is predicated on the assumption that Tampa Electric's Polk NPGU could be deferred until the end of the PPAs ([redacted]). However, at that time, the existing Polk 2-5 CTs will be approaching an age where it may not make economic sense to invest in their conversion. Sedway Consulting followed the same process with Proposal C and Proposal D (replacing them with Tampa Electric's NPGU at the expiration of the PPAs in [redacted] and [redacted]) and thus the same or stronger caveat applies. Proposal B did not entail an expiration of the resources (i.e., the resources were assumed to continue operating through the end of the study period, 2046) and therefore they were never "replaced" with the NPGU. This is consistent with Sedway Consulting's stand-alone bid evaluation process. However, in reviewing the details behind Tampa Electric's results, Sedway Consulting noted that Tampa Electric optimized the bid-specific generation expansion plans. This optimization resulted in the NPGU resource being included in the bid plans, commencing operations in 2018 in the Proposal B base case analysis and 2023 in the Proposal C and Proposal D base case analyses. Tampa Electric's NPGU is a very cost-effective resource; its expected system production cost savings more than offset the project's investment costs in Sedway Consulting's base and high gas price results. Thus, its inclusion in the Proposal B analysis and its earlier inclusion in the Proposal C and Proposal D analyses significantly improved the economics of those resources' analyses. In essence, Tampa Electric's Proposal B base case evaluation is largely an analysis of a one-year deferral of the NPGU. Sedway Consulting's analysis was based more on a stand-alone bid evaluation process.

Conclusions

Sedway Consulting performed an independent evaluation of Tampa Electric's Polk NPGU relative to the responses to Tampa Electric's 2012 resource RFP and concluded that the NPGU represents the lowest-cost resource for meeting Tampa Electric's 2017 resource need. The NPGU was found to be $69 million on a cumulative present value of revenue requirements basis (CPVRR) less expensive than the next cheapest option under base case assumptions.

EXHIBIT NO. 19

DOCKET NO: 120234-EI

WITNESS:

PARTY:

DESCRIPTION: Notice of Hearing & Affidavit of Publication The Ledger, Lakeland, Polk County, Florida.

DOCUMENTS:

PROFFERED BY: TECO

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 120234-EI EXHIBIT 19
PARTY TAMPA ELECTRIC COMPANY (TECO) - (DIRECT)
DESCRIPTION TECO - Notice of Hearing & Affidavit of Publication
The Ledger, Lakeland, Polk County, Florida

AFFIDAVIT OF PUBLICATION
THE LEDGER
Lakeland, Polk County, Florida

STATE OF FLORIDA)
COUNTY OF POLK)

Before the undersigned authority personally appeared Carl Holweg, who on oath says that he is an Sales Executive at The Ledger a daily newspaper published at Lakeland in Polk County, Florida; that the attached copy of advertisement, being a

NOTICE OF HEARING

In the matter of **TAMPA ELECTRIC**

Concerning **PETITION TO DETERMINE NEED FOR POLK 2-5**

in said newspaper in the issues of **11-21; 2012**

Affiant further says that said The Ledger is a newspaper published at Lakeland, in said Polk County, Florida, and that the said newspaper has heretofore been continuously published in said Polk County, Florida, daily, and has been entered as second class matter at the post office in Lakeland, in said Polk County, Florida, for a period of one year next preceding the first publication of the attached copy of advertisement; and affiant further says that he has neither paid nor promised any person, firm or corporation any discount, rebate, commission or refund for the purpose of securing this advertisement for publication in the said newspaper.

Signed.....
Carl Holweg
Sales Executive
Who is personally known to me.

Sworn to and subscribed before me this 21ST day of NOVEMBER A.D. 2012

Patricia Ann Rouse
Notary Public

(SEAL)

PATRICIA ANN ROUSE
MY COMMISSION EXPIRES
October 17, 2016
#EE 220383
Bonded thru
Notary Public Underwriters
NOTARY PUBLIC, STATE OF FLORIDA

My Commission Expires - October 17, 2016

LEGAL ADVERTISEMENT

Notice of Hearing

Tampa Electric Company announces a public meeting to which all persons are invited.

DATE AND TIME: Hearing- Wednesday, Dec. 12, 2012, at 9:30 am.

PLACE: Room 148, Betty Easley Conference Center, 4075 Esplanade Way, Tallahassee, Fla.

GENERAL SUBJECT MATTER TO BE CONSIDERED:
Docket Number 12023 Petition to determine Need for Polk 2-5 Combined Cycle Conversion, by Tampa Electric Company.

GENERAL SUBJECT MATTER TO BE CONSIDERED AT THE HEARING:
The purpose of this hearing is for the Florida Public Service Commission to take final action to determine the need, pursuant to Section 403.519, Florida Statutes (F.S.) for Combined Cycle Conversion of Polk 2-5, by Tampa Electric Company and to consider any motions or other matters that may be pending at the time of the hearing. The Commission may rule on any such motions from the bench or may take the matters under advisement. This proceeding shall: (1) allow Tampa Electric to present evidence and testimony in support of their petition for a determination of need for the proposed Polk 2-5 Combined Cycle Conversion; (2) permit any intervenors to present testimony and exhibits concerning this matter; (3) permit members of the public who are not parties to the need determination proceeding the opportunity to present testimony concerning this matter; and (4) allow for such other purposes as the Commission may deem appropriate.

PUBLIC TESTIMONY: Any member of the public who wishes to offer testimony should be present at the beginning of the hearing on Dec. 12, 2012. By providing public testimony, a person does not become a party to the proceeding. To become an official party of record, you must file a Petition for Intervention at least five days before the final hearing, pursuant to the requirements contained in Rule 25-22.039, Florida Administrative Code (F.A.C.). All witnesses shall be subject to cross-examination at the conclusion of their testimony.

The hearing will be governed by the provisions of Chapter 120, F.S.; Section 403.519, F.S.; and Chapters 25-22 and 28-106, F.A.C. Only issues relating to the need for the Polk 2-5 Combined Cycle Conversion by Tampa Electric will be heard at the hearing. Separate public hearings may be held before the Division of Administrative Hearings to consider environmental and other impacts of the proposed power plants, as required by the "Power Plant Siting Act," Sections 403.501 – 403.519, F.S.

TECO
TAMPA ELECTRIC

EXHIBIT NO. 20

DOCKET NO: 120234-EI

WITNESS:

PARTY:

DESCRIPTION: Tampa Electric Company's 2017 Power Generation Request for Proposals, dated March 23, 2012.

DOCUMENTS:

PROFFERED BY: TECO

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 120234-EI EXHIBIT 20
PARTY TAMPA ELECTRIC COMPANY (TECO) - (DIRECT)
DESCRIPTION TECO's 2017 Power Generation Request for Proposals, dated March 23, 2012.

Tampa Electric Company's

2017 Power Generation Request for Proposals

March 23, 2012

Tampa Electric Company 2017 Power Generation RFP

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Tampa Electric Company 2017 Power Generation RFP

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Tampa Electric Company 2017 Power Generation RFP

Section I – RFP Overview

A. Introduction and Objective

This section provides an overview of the information contained in this Request for Proposals ("RFP") and includes a schedule of critical dates for Respondents. Much of the detailed RFP information is included in the Appendices of this document. Potential Respondents are urged to carefully read this entire document.

The objective of this Tampa Electric Company ("TEC" or the "company") RFP is to solicit competitive offers to satisfy the company's projected capacity and energy requirements for comparison to TEC's Planned Generating Unit ("PGU"). When the RFP process is completed, the company will select the most beneficial option for its general body of customers that will result in the addition of sufficient capacity to meet the forecasted need. Such capacity may be obtained through power purchase agreement(s) ("PPA") and/or a TEC self-build unit.

The RFP will enable TEC to select generating resources that offer the maximum value, based on cost and non-cost attributes, for the ultimate benefit of TEC's customers.

TEC prefers proposals that supply the needed firm capacity and associated energy from generating resources located within the Florida Reliability Coordinating Corporation ("FRCC") region of the North American Electric Reliability Council ("NERC"). All proposals, regardless of origin, must include the appropriate firm transmission service(s) and ancillary services (e.g, scheduling and voltage control) to assure that capacity and associated energy can be delivered to TEC's transmission system and can be designated as a TEC network resource.

TEC prefers alternatives that provide the best value to its customers based on factors such as life cycle cost effectiveness, reliability, environmental considerations, and risk. TEC reserves the right to select a proposal, or proposals, that provide the best value, but which may not necessarily provide the lowest cost. TEC also reserves the right, in its sole discretion, to cancel, modify or withdraw this RFP, to reject any, and all responses, and to terminate negotiations at any time during this RFP process.

TEC invites proposals from all credit worthy suppliers that are capable of satisfying the conditions of this RFP, including but not limited to other electric utilities, power marketers, exempt wholesale generators, independent power producers, renewable energy facilities, and Qualifying Facilities ("Respondents").

The RFP process attempts to give all potential Respondents—even those considering new construction—adequate lead-time to develop those projects on a schedule that would allow such projects to be proposed, evaluated and, if selected, constructed and placed into operation in the required time period.

B. Regulatory Background

TEC has a need for additional capacity commencing in 2017 and has determined that the most cost-effective TEC self-build option would require a Determination of Need. TEC recognizes that proposals submitted as alternatives to the company's self-build option may or may not require a Determination of Need.

C. Critical Dates in the RFP Process

The solicitation schedule for this RFP includes the following critical dates:

RFP Schedule*

Event	Date	Comments
RFP Pre-Release Meeting/Teleconference	March 21, 2012	Participant information posted on Web site.
Release RFP Solicitation	March 23, 2012	RFP available on Web site.
RFP Bid Workshop	April 4, 2012	Hosted by TEC in Tampa, FL Additional details to be posted on Web site.
Proposal Due Date	May 22, 2012	Proposals must be received by 12:00 Noon ET.
Bidder's Notice in Major Publications	June 1, 2012	Required of each Respondent as needed. See Section II. D.2.
Short List Notification	June 22, 2012	All Respondents will be notified of the status of their proposal. The Respondents selected for the Short List will be advised to provide their Best and Final Offers.

RFP Schedule*

Event	Date	Comments
Commence Preliminary Negotiations with Short List Respondents	June 22, 2012	
Best and Final Offers Due	July 13, 2012	
Select Final Proposal(s) and Begin Final Negotiations	July 27, 2012	

* TEC reserves the right to revise this schedule as necessary. Depending on the number and nature of proposals received, TEC may shorten or extend this RFP Schedule. For information about this RFP, including any schedule changes, Respondents are urged to monitor www.tampaelectric.com/2017powerrfp.

D. TEC Contact Person

All inquiries or contact about this RFP, including questions or clarification, requests for additional information, and submission of proposals, should be emailed or submitted in writing and directed to the TEC Contact Person listed below:

Benjamin F. Smith II
Manager, Energy Products & Structures
Fuels Management Department
Tampa Electric Company
702 North Franklin Street
Tampa, Florida 33602
Telephone number: (813) 228-1373
Fax number: (813) 228-4922
E-mail address: bfsmith@tecoenergy.com

Proposals must be received by **12:00 Noon Eastern Time ("ET") on May 22, 2012 (Proposal Due Date).** Respondents must send proposals via physical delivery. **Proposals submitted by electronic mail will not be considered.**
The company has established a website on which it will provide information regarding the RFP. The web site is www.tampaelectric.com/2017powerrfp. The

web site contains the RFP schedule, a copy of the RFP, contact information and provides the ability for Respondents to submit questions. Questions and answers will be posted to the web site for the benefit of all potential Respondents. The web site will also contain any future updates/changes about the RFP. Potential Respondents are urged to closely monitor this website.

E. Limitations on the Function and Effect of this RFP

In order to protect the interests of customers, TEC retains the right during the process to select a proposal or combination of proposals that is not the lowest-priced proposal or combination, waive a non-compliance in any proposal, reject any and all proposals, modify or cancel the RFP, refine the cost and/or performance assumptions of TEC's PGU and refine TEC's projected need for resource additions. In the event that TEC materially modifies the cost, performance, and/or resource need assumptions of TEC's PGU, those Respondents that have viable and competitive proposals under evaluation at that time will be given the opportunity to refine their proposals in those aspects that are affected by TEC's modifications.

This RFP is not an offer to enter into a contract. It is a solicitation of exclusive firm offers of fixed duration from Respondents. Nothing in this RFP, or any communication associated with this RFP, shall be taken as constituting an offer or representation between TEC and any other party. Neither issuance of this RFP, nor the entry of TEC into negotiations with any Respondent, will be deemed to create any commitment or obligation on the part of TEC to enter into a binding agreement with any Respondent. Those who submit proposals do so without recourse against TEC, its division, any of its affiliates, or its parent company, for either rejection of their proposal(s) or for failure to execute a purchase agreement for any reason.

F. TEC's Next Planned Generating Unit ("NPGU")

TEC desires to add reliable, efficient and environmentally sensitive generating capacity to its system. TEC has experience with a broad range of generating technologies and fuel sources. The company's internal analysis indicates that conversion of the existing Polk Units 2-5 simple cycle combustion turbines into a combined cycle unit will provide the most prudent and cost effective self-build alternative for adding needed generating capacity on its system. This facility will capture waste heat from existing assets, lower TEC's system heat rate, lower its environmental emissions rate, improve transmission system reliability, and minimize ground water withdrawal through use of reclaimed water. Through the RFP process,

Tampa Electric Company 2017 Power Generation RFP

TEC will consider proposals that offer superior benefits to its customers from the standpoint of cost effectiveness, reliability, environmental considerations, risk and other relevant considerations

Tampa Electric's most recent Ten Year Site Plan is attached as Appendix A. However, the NPGU listed in Appendix A is superseded by the company's updated plan to convert its existing Polk CTs 2 through 5 to a combined cycle generating facility with an in-service date of January 2017 to serve the company's forecasted needs beginning in 2017. The updated plan will be included in the company's 2012 Ten Year Site Plan expected to be published on April 1, 2012. All further references in this RFP to Tampa Electric's NPGU relate to TEC's updated NPGU (the conversion of Polk CTs 2 through 5 to a combined cycle generating facility with an in-service date of January 2017).

A technical description of Tampa Electric's NPGU on which this RFP is based is contained in Section IV of this RFP

Tampa Electric Company 2017 Power Generation RFP

Section II – RFP Information and Requirements

A. Issues Influencing System Cost and Reliability

1. Geographic Location

The ability of a generator to deliver power in, or near, the load center lowers the cost of delivering that power and provides operational flexibility for the system. Additionally, exposure to hurricane related outages can be mitigated if generating units are located away from coastal areas. Thus, a well-situated generating unit contributes to the long-term reliability and stability of the power grid. Therefore, TEC prefers proposals that address such operational and geographical considerations.

2. Firm Capacity and Associated Firm Energy

TEC seeks proposals that would allow TEC to meet its firm capacity and associated firm energy requirement in future years. Therefore, TEC requires Respondents to offer the commitment of firm capacity and, preferably, associated firm energy ("RFP Product"). With the exception of fuel requirements for certain renewable energy types, TEC considers "firm capacity and associated firm energy" to mean a product that meets all the following criteria:

a. **grants TEC full access when needed to all electric energy and capacity on a first call basis and priority second to no other entity, as if TEC owned the generating capacity on its own system**
b. **is delivered to TEC transmission interface via firm transmission service and is designated as a network resource**
c. **provides full fuel services, including procurement**
d. **possesses primary firm transportation for fuel supply [in quantities not less than the proposed product's maximum hourly capability]**

This RFP is limited to a maximum total capacity of 500 MW. In the case of renewable facilities, such as solar or wind, "Associated Firm Energy" will be relative to the times sunlight or wind is available. Thus, energy will be delivered to TEC as it is produced. Likewise, criteria (c) and (d) do not apply, as there are no "fuel transportation" and "fuel services" for sunlight and wind. Nonetheless, criteria (a) and (b) apply as stated above. For clarity, criteria (a) through (d) apply to other renewable facilities, such as biomass, that require fuel procurement and/or transportation services.

purchase of energy and capacity from renewable generators at full avoided cost. As it looks toward the future, TEC believes the economics as well as the technical viability of dispatchable, renewable energy generating resources continue to improve, and it prefers proposals that include or allow for renewable energy integration.

B. Respondent Obligations

1. Regulatory Support and Compliance

Each Respondent agrees by the act of submitting a proposal in response to this RFP to file, as needed, with TEC as co-applicant, an application for Determination of Need and to fully support, as requested by TEC, any TEC regulatory proceeding(s) related to firm capacity purchases and/or sale of an existing power plant(s) emanating from this solicitation. At all times, the Respondent shall be solely responsible for its expenses and legal fees associated with its participation in regulatory activities.

Furthermore, each Respondent agrees to acquire and maintain compliance with all necessary licenses, permits, and other regulatory approvals (including environmental) that will be required by current or future federal, state, or other local government laws, regulations, or ordinances to successfully implement the proposal. TEC will be a co-applicant in any necessary Determination of Need filing and the Site Certification Application for the power plant and associated facilities, as appropriate, whether or not the selected proposal requires new power plant construction falling under the Florida Electrical Power Plant Siting Act ("PPSA"), Florida Statutes *Section 403.501etseq*. TEC will cooperate with any selected Respondent(s) to provide information or such other assistance as may reasonably be necessary for the Respondent(s) to satisfy licensing and regulatory requirements. The selected Respondent(s) shall fully support all of TEC's regulatory requirements associated with this potential capacity and energy arrangement. A proposal that requires new power plant construction falling under the PPSA must include a permitting and construction schedule that allows the new plant to be in commercial operation by 2017. The NPGU is planned for January 2017. The Respondent's Capacity Delivery Date ("CDD") is the date on which the proposed facility, system sale or existing facility begins delivering the RFP Product hereunder. See Appendix C that requests, in part, the Respondent's permitting and construction schedule information.

2. Development Activities

The Respondent is completely responsible for the selection, acquisition, and development of the plant site and other land or infrastructure that is needed for new generating units. **TEC's power plant sites are not available for site development by Respondents.** The Respondent is also completely responsible for securing, locating, or guaranteeing any emissions allowances, credits, or offsetswhich may be required by the Clean Air Act Amendments, Clean Air Interstate Rule, Cross-State Air Pollution Rule (CSAPR)or other federal, state, or local requirements to allow the construction and operation of the proposed facility. Respondents whose proposals offer the sale of an existing power plant(s) must secure the emission allowances, credits, or approvals necessary to operate the facility and comply with associated regulations until ownership of the facility and the emission allowances, credits, or approvals are transferred to TEC.

3. Project Execution

Each Respondent assumes full responsibility for ensuring that the implementation of any and all parts of the proposal are carried out in full compliance with laws, regulations, ordinances, licenses, permits, and other regulatory approvals, including environmental that affect the proposal. TEC shall not bear any economic or operational risk associated with any changes, modifications, or additions to such laws, regulations, ordinances, licenses, permits, and other regulatory approvals, except in accordance with any provision that may be included within the PPA or except in the case of proposals offering the sale of an existing power plant(s) to the extent the contract for conveyance expressly places such risk(s) on TEC upon transfer of ownership of the facility.

4. Project Funding, Costs and Engineering

Respondent assumes full responsibility for all financing activities related to the project and for engineering, design, procurement and construction of all aspects of the facility. These include, but are not limited to, the power block, environmental control systems, fuel delivery systems and transmission system interconnections and integration, etc. All costs associated with the design, construction, operation, and maintenance of the transmission interconnection facilities (including but not limited to generator step-up transformers and high-voltage breakers) associated with the delivery of the RFP Product to TEC will be the responsibility of the Respondent.

5. Interconnection and Transmission Service

The Respondent must secure, with the appropriate transmission service provider(s), all needed transmission facilities and arrangements required to interconnect the proposed generating resource(s) to the transmission service provider's transmission system. The Respondent must secure, with the appropriate third-party transmission service provider(s), all needed firm, long-term transmission service(s) to deliver the capacity and energy to the TEC transmission system for the entire term of the proposal. Likewise, the Respondent must secure, with the appropriate transmission service provider(s), all needed firm, long ancillary services—"ancillary services" include, but are not limited to, scheduling, voltage control, and generator imbalance service. Respondent acknowledges that TEC must be able to request and obtain firm, network transmission service(s) and network resource designation(s) from TEC's transmission function for all proposed power supply resource(s) and that Respondent is responsible for network service integration costs on the Tampa Electric system.

6. Natural Gas Pipeline Interconnections, Laterals, and Firm Fuel Transportation

   The Respondent shall obtain all necessary fuel arrangements to ensure fuel can be delivered on a firm basis year round to allow TEC use of the RFP Product during any hour (i.e., as a minimum, must cover max-hour burn).

7. Environmental Credits and Allowances

   The Respondent is responsible for acquiring any environmental credits and allowances necessary for TEC to fully utilize the RFP Product through the service term identified in a definitive agreement.

8. Cost Reimbursement

   Respondent must identify and include, through its pricing, reimbursement of any costs (e.g., electric transmission, gas transportation, environmental allowances) the Respondent incurs.

C. General Instructions for Respondent

1. Proposal Confidentiality

   TEC will take reasonable precautions and use reasonable efforts to protect proprietary and confidential information contained in a proposal, provided that such information is clearly identified by the Respondent as Proprietary and Confidential on the page(s) on which the information appears.

To clearly identify confidential information, the Respondent must (1) stamp each such page with "Confidential Information" and (2) highlight/shade the confidential information on the pages stamped "Confidential Information." **A blanket statement that an entire page or proposal is proprietary and confidential will not be considered identification.**

Notwithstanding the foregoing, TEC shall disclose Confidential Information in the event that it determines, at its sole discretion, that disclosure is necessary in order to comply with any applicable law, order, regulation, ruling, subpoena, stock exchange rule or order of the Florida Public Service Commission ("FPSC"), or other governmental authority or tribunal with competent jurisdiction. Such disclosure may include, but is not limited to, production of Confidential Information to the FPSC and to parties in legal and regulatory proceedings conducted to consider and approve any project selected pursuant to this RFP.

In the event that TEC is requested or required to disclose any Confidential Information, TEC will provide prior notice to the entity whose Confidential Information has been requested so that such entity may, if it chooses, seek an appropriate protective order subject to protections available under the Florida Statutes, Florida Administrative Code and Florida Rules of Civil Procedure.

With respect to any disclosure made by TEC pursuant to the foregoing paragraphs, TEC will furnish only that portion of the Confidential Information that TEC determines at its sole discretion to be consistent with the scope of the subpoena, demand, or request and will seek reasonable assurances that confidential treatment will be accorded such Confidential Information.

TEC shall not be liable to any Respondent for any costs, expenses, damages, claims or claims of damages arising from the disclosure by TEC of any confidential information pursuant to this RFP.

2. Respondent Exceptions

TEC will consider proposals that contain exceptions to the general terms and conditions of the RFP; however, no **exceptions to the General Minimum Requirements of Proposals/Bids (Section II.D.) or Specific Minimum Requirements of Proposals/Bids (Section II.E.) will be accepted.** If a Respondent identifies exceptions, the exceptions must be explained in writing as part of the proposal using the attached forms. See Appendix C. For each material exception, the Respondent must fully explain in writing the condition,

requirement, or facet of the RFP to which the Respondent takes exception and provide the replacement language proposed and the resulting product pricing associated with TEC's rejection of said exception.

Inclusion of exception information with a proposal will be used to compare proposals to one another and will facilitate negotiations by allowing TEC to evaluate the specific core issues of the exceptions, rather than addressing generic or conceptual comments. TEC reserves the right to request additional information from a Respondent concerning impact on the proposal of TEC's contemplated rejection of a particular exception.

If a Respondent fails to state exceptions and does not pose alternative language to the material terms set forth in the RFP, TEC shall assume that a Respondent has no specific objection to such terms and conditions.

3. Respondent Questions and Communication

Respondents are to follow all instructions contained in this RFP and provide all information requested in the RFP and on the forms presented and discussed in Appendix C of this document. Respondents shall provide supporting documentation, and answer any follow-up questions from TEC, as requested.

Respondents are encouraged to contact the Contact Person designated by TEC with questions to ensure complete and accurate proposals. Following the RFP release date, questions will be recorded and must be submitted on a website, www.tampaelectric.com/2017powerrfp. TEC will post the questions and answers on the website for the benefit of all Respondents.

D. General Minimum Requirements of Proposals/Bids

1. Minimum Requirements

All proposals must satisfy each of the General Minimum Requirements listed below and the Specific Minimum Requirements (Section II. E.) of this RFP. Failure of a proposal to satisfy one or more General or Specific Minimum Requirements will be grounds for determining a proposal ineligible. However, TEC reserves the right to waive non-compliant terms of proposals with the Minimum Requirements.

At a minimum, all Respondents acknowledge and agree to abide by the following General Minimum Requirements:

a. Respondent must document ownership or contractual rights to the unit, plant or system capacity.

b. If the Respondent is an entity proposing a capacity sale from existing resources, the Respondent must provide sufficient documentation to demonstrate that, over the term of service, the source utility or entity will have sufficient capacity to sell to TEC as well as to serve its own load and other commitments, if applicable.

c. The proposal must be an RFP Product as defined in Section II.A.3 of this RFP.

d. All proposals must remain in effect until the purchase is finalized pending all necessary Respondent and TEC transmission service requests.

e. All generating units providing the proposed capacity must be in commercial operation prior to the commencement date of the proposed term of service.

f. Respondent acknowledges that all proposed power supply resource(s) located outside TEC's transmission system must be delivered directly to TEC's transmission system utilizing firm, third-party transmission services(s) and that Respondent is responsible for securing said transmission services.

g. Respondent acknowledges that TEC must be able to request and obtain firm, network transmission and network resource designation(s) from TEC's transmission function for all proposed power supply resource(s) and that Respondent is responsible for network service integration costs on the Tampa Electric system.

h. Respondent shall be financially responsible over the term of the contract for securing the needed transmission ancillary services to deliver the capacity and energy to the TEC transmission system.

i. Respondent shall be financially responsible over the term of the contract for fuel imbalances it causes.

2. Proposal Submission Requirements

All proposals and variations to proposals must be received by May 22, 2012 at 12:00 Noon (ET) ("the Proposal Due Date and Time"). Respondents must submit an electronic copy of the completed forms on a flash drive by the Proposal Due Date and Time. For forms requiring a signature, Respondent must submit both the unsigned form and a scan (or digital copy) of the signed version. Proposals must be physically received by the Proposed Due Date and Time. **Proposals**

submitted by electronic mail will not be considered. The RFP Evaluation Fees must accompany the proposal(s) and any variations. Any proposals or variations to proposals received after the Proposal Due Date and Time will not be evaluated and will be returned to the Respondent.

Forms: All required forms and the information requested on these forms must be submitted. TEC may choose to contact a Respondent to request that omitted or incomplete information be provided, but is under no obligation to do so. Incomplete form submittal or any attempt by a Respondent to disclaim generally the terms and conditions of this RFP without stating specific exceptions and alternative language will be grounds for determining a proposal to be incomplete, and therefore ineligible. All forms are in Microsoft Word and Excel format, and Respondents shall carefully review each form and input alpha and numeric characters in the appropriate cells, as forms will be a source of modeling data. For example, if a form requests megawatts and has a "MW" heading, TEC expects a Respondent with 100 megawatts to only input "100" in that cell—not "100 **MW**".

Proposed PPA: A draft agreement is provided in Appendix B. Respondents must provide any exceptions to the proposed PPA. Although not listed in the RFP forms, prior to entering into any definitive agreement, TEC will require Respondents to complete the **Form of Guaranty** and **Form of Letter of Credit** contained within the proposed PPA appendices. Thus, Respondents should price proposals accordingly.

Publication Notice: Respondents must publish a notice in a newspaper of general circulation in each county in which the participant proposes to build an electrical power plant. The notice shall be at least one quarter of a page and shall be published no later than 10 days after the Proposal Due Date. The notice shall state that the participant has submitted a proposal to build an electrical power plant, and shall include the name and address of the participant submitting the proposal, the name and address of the public utility that solicited the proposals, and a general description of the proposed power plant and its location. A copy of the notice, including an affidavit confirming publication, must be submitted to TEC within ten (10) days of publication.

3. Term of the Proposal(s)

The RFP Product offered in a proposal must commence within the time frame identified in the RFP. The acceptable term lengths for proposals are established recognizing factors that are specific to the source of the proposals.

a. The minimum term length of any proposal type is ten(10) years; and
b. The maximum term length of any proposal type is twenty-five (25) years.

4. Firm Nature of Proposal(s)

a. Proposals must offer a year-round RFP Product;
b. Proposals, including system sales, must be fully dispatchable under the operational control of TEC, subject only to physical restrictions, such as the operating capabilities of the facility, environmental permit limits, and an approved maintenance schedule. Operational control is to include placing the resource on automatic generation control (AGC) or, for system sales, a form of control that simulates AGC;
c. Except as may be allowed in connection with system sales meeting the qualifying requirements of subsection D.7. (Identifiable Capacity Resource), proposals must be supported by identifiable units and must dedicate the offered output of the unit(s), including any ancillary service(s) products and RECs, if applicable;
d. The delivery of the RFP Product must commence within the required time frame of the RFP and remain throughout the term of the proposed offer;
e. Respondent must secure any applicable firm third party transmission, firm transmission ancillary services, and firm, delivered fuel supply arrangements for the duration of the term. If the proposal's term extends beyond the period that applicable firm services for transmission and/or fuel are available, Respondent will be responsible (and present a reasonably justifiable plan) for procuring such services on a schedule such these firm services are in place for the entire term; and
f. Respondent must obtain firm network transmission and network resource designation(s) from TEC's transmission function.

5. Permit and Authorization Feasibility

The Respondent must demonstrate that there are no significant barriers to obtaining the necessary regulatory and governmental permits and authorizations to execute, implement or operate the proposed project on a schedule that meets the CDD. All proposed projects will be subject to the approval of the appropriate regulatory authorities.

6. Binding Nature of Proposal(s)

Proposals must be certified by an authorized Officer of the proposing entity. Proposal(s) must remain as valid and binding offers for one-hundred eighty (180) days from the submittal date and cannot be modified, except to be withdrawn in full, modified in response to a modification (as described in Section I. E.), or in response to a request for a Best and Final Offer ("BAFO") from TEC. Clarifications requested by TEC are not considered modifications. Bids must be binding.

If a proposal is selected for the Short List, the selected Respondent will be asked to provide a BAFO. Such BAFO must be valid and binding for one-hundred eighty (180) days from the date of Short List notification.

7. Identifiable Capacity Resource

The RFP Product must be from specific power plants that are clearly identified in the proposal. An exception to this requirement will be made for system sales from electric systems that are accountable to the FPSC or similar public authority, have direct control of generation and transmission assets and are members in good standing of the FRCC or all other applicable NERC reliability coordinating council(s); unless the proposed product is from only a portion of the Respondents system resources, in which case the specific resources must be identified. System sales must include a clear explanation of how the capacity is to be obtained and delivered. Proposals for system sales must include the fuel mix of the units that will serve those sales. The proposal must also explain how commitment of such system capacity to TEC will affect the Respondent's ability to meet the FPSC reserve margin requirements (or the requirements of other state agencies as appropriate).

8. Site Development

For newly built generation, the Respondent shall be responsible for the location, development and permitting of the Respondent's site for the proposed facility. TEC's power plant sites are not available for site development by Respondents.

9. Minimum Operating Characteristics

The facility must be able to achieve and sustain generation at the proposed capacity, heat rate, and operating functions (e.g., AGC) while maintaining compliance with all permits and authorizations.

10. Regulatory Modifications

Respondent must agree that should TEC, at any time during the term of a contract between TEC and the Respondent entered into as a result of this RFP, fail to obtain or is denied the authorization of the FPSC, or the authorization of any other legislative, administrative, judicial or regulatory body which now has, or in the future may have, jurisdiction over TEC's rates and charges, to recover from its customers through the utility's capacity, fuel and purchased power cost recovery clauses absent evidence of fraud, perjury or intentional withholding of key information sufficient to disturb the finality of the approval under governing law all of the payments required to be made to the Respondent, who then will be the Seller, under the terms of such a contract or any subsequent amendment hereto, TEC may, at its sole option, adjust the payments made under such contract to the amount(s) which TEC is authorized to recover from its customers. In the event that TEC so adjusts the payments to which the Respondent, who then will be the Seller, is entitled under such a contract, then the Respondent, who then will be the Seller, may, at its sole option, terminate such a contract upon one hundred eighty (180) days notice to TEC. If such determination of disallowance is ultimately reversed and such payments previously disallowed are found to be recoverable, TEC shall pay all withheld payments. The Respondent, who then will be the Seller, acknowledges that any amounts initially received by TEC from its customers, but for which recovery is subsequently disallowed and charged back to TEC, may be offset or credited, against subsequent payments to be made by TEC to the Respondent, who then will be the Seller, under such a contract. If, at any time, TEC receives notice that the FPSC or any other legislative, administrative, judicial or regulatory body seeks or will seek to prevent full recovery by TEC from its customers of all payments required to be made under the terms of such a contract or any subsequent amendments to such a contract, then TEC shall, within thirty (30) days of such action, give notice thereof to the Respondent, who then will be the Seller. TEC shall use reasonable efforts to defend and uphold the validity of such a contract and its right to recover from its customers all payments required to be made by TEC, and will cooperate in any effort by the Respondent, who t hen will be the Seller, to intervene in any proceeding challenging, or to otherwise defend, the validity of such a contract and the right of TEC to recover from its customers all payments to be made by it.

11. Regulatory Approvals

A definitive agreement is conditional upon the approval and acceptable purchased power treatment by the FPSC, the Federal Energy Regulatory Commission or any other applicable legislative, administrative, judicial or

regulatory body that has jurisdiction. If a power purchase agreement results from this RFP process, such agreement shall not become effective until: (1) the FPSC acknowledges that the purchase described in the power purchase agreement is applicable to TEC's commitment to maintain the required installed reserve margin; (2) the FPSC authorizes TECO to collect all payments to be made for such a purchase through the appropriate cost recovery clause; and (3) the Parties shall have delivered collateral that meets the requirements of the Construction and Performance Security section of this RFP. If the conditions precedent and approvals described in items 1 through 3 above are not achieved and obtained by July 1, 2013, each Party has the right, but not the obligation, to immediately terminate the power purchase agreement upon written notice to the other Party.

12. FIN 46(R) Compliance

Certain accounting rules now in effect, or as they might be amended or interpreted in the future, may require that the financial statements of a Seller be consolidated into the financial statements of TEC. Respondents must submit an analysis, with supporting information as required in Appendix C, evaluating whether or not TEC would be required to consolidate the financial statements of the Seller under the provisions of Financial Accounting Standards Board Interpretation No. 46, (FIN 46(R) revised December 2003). A Respondent who enters into a contract with TEC under this RFP must agree to comply with FIN 46(R) and to cooperate with TEC so it can comply with FIN 46(R).

13. Environmental Credits, Allowances, and Increased Generation Costs

Although the Respondent is responsible for acquiring any environmental credits and allowances necessary for TEC to fully utilize the RFP Product through the service term, TEC also acknowledges that unforeseen changes in rules and laws may occur. Respondents must clearly identify any aspect of their proposal that would change because of a change in rule, law, or industry landscape (e.g., implementation of an RTO/ISO) and quantify the change to the proposed pricing.

E. Specific Minimum Requirements of Proposals/Bids

1. Resource Block Size (MW) and RFP Capacity Range

The minimum resource block size that TEC will consider in a proposal is fifty megawatts (50 MW). Exceptions to this minimum requirement will be made for proposals based on Qualifying Facilities or renewable energy facilities, which

may be as small as twenty-five megawatts (25 MW). The maximum block size in a proposal that TEC will consider is 500 MW.

2. Financial Viability and Security Requirements

   a. For proposals supported by newly built generation (e.g., greenfield, brownfield, turnkey), Respondent agrees to provide Security as specifically defined in the Construction and Performance Security section of this RFP.
   b. For proposals supported by newly built generation, Respondent must demonstrate debt and equity financing by the earlier of thirty (30) days following the signing of a definitive agreement or December 31, 2012.
   c. For proposals supported by existing facilities, Respondent must agree to provide the Security as specifically defined in the Construction and Performance Security section of this RFP.
   d. Respondent agrees to provide Security by the earlier of fifteen (15) days following the signing of a definitive agreement or December 31, 2012.
   e. Respondent must certify that there are no pending legal or civil actions that would affect the ability of the Respondent and/or its guarantor to maintain the criteria identified in this RFP.
   f. Respondent must demonstrate credit support that is satisfactory to TEC by the earlier of fifteen (15) days following the signing of a definitive agreement or December 31, 2012.

3. Proposal/Bid Pricing and Fuel Requirements

   The pricing proposed by a Respondent must identify all applicable costs and expenses TEC will be expected to pay if the proposal is selected. These costs and expenses include, but are not limited to, capital, fixed O&M, standard and major maintenance, contractual service agreements (CSAs), variable O&M, start charges, start-up fuel, transmission costs (including interconnection), natural gas transportation (including pipeline construction), and environmental costs. Any costs and/or expenses not clearly identified within a proposal may be grounds for TEC deeming the proposal invalid. This includes without limitation:

   a. Prices for RFP Products, including proposals for the actual sale of a new or an existing power plant, must be provided on the pricing forms in Appendix C.
   b. The proposal must clearly state whether pricing is guaranteed or, if not guaranteed, how the pricing changes throughout the proposed term.
   c. All proposals, except those offering a guaranteed energy price, must state a heat rate. This includes system sales—system sales must be at a heat rate (i.e., not simply a statement of "actual cost").

d. The costs of all equipment, development, design, construction, commissioning and all costs of meeting and maintaining compliance with environmental regulations that are in effect as of the CDD, or are known as of the CDD to be in effect.
e. The proposal must specify the availability of firm fuel and the availability of firm transportation for such fuel and the transportation provider(s). The proposal must specify if backup fuel is available and describe the logistics requirements for use of backup fuel, if applicable. If the backup fuel is natural gas, the proposal must specify the availability of firm fuel and the availability of firm transportation for such fuel and the transportation provider(s), the pipeline receipt points and any fuel nomination requirements. Respondent is financially responsible for any fuel imbalance it causes.
f. Proposals must specify the firm gas transportation receipt and delivery points under contract (or planned to be contracted) to support the proposed RFP Product.
g. All required capital and O&M costs that would be incurred to transport fuel from the Fuel Delivery Point to the facility burner-tip for all proposals. This requirement applies to PPAs and asset sales.
h. All costs for the required amount of firm transmission meeting the requirements as described in this RFP. This includes transmission interconnection, integration and/or upgrade costs. The Respondent must also provide evidence of feasibility documenting arrangements that support the aforementioned costs.
i. The proposal must clearly state the percent availability guarantee for energy delivery and any associated details (e.g., seasonality).

4. Proposal/Bid Transmission Requirements

All power proposed to be supplied in response to this RFP is to be delivered directly to TEC's transmission system using firm transmission service. Proposals should include the costs of third-party transmission service(s), ancillary services, and losses to effect delivery of all power to TEC's transmission system. Proposals must also include any costs associated with designating the resource as a network resource for Tampa Electric load , including the cost of integration on the Tampa Electric system.

Proposals/bids must include any supplemental, applicable publicly-available transmission data that should be considered in TEC's evaluation of the bid including available transmission capability, the results of transmission studies or independent transmission analyses.

If a proposal/bid is expected to utilize existing transmission capability, the proposal must contain all the background information concerning such transmission capability. See Appendix C for the appropriate forms.

a. For proposals with generation located outside of the TEC system, TEC will not accept any proposal that requires TEC to secure firm transmission service and any associated rights, as this shall be a responsibility of the Respondent. Proposed prices must include all costs of delivering capacity and energy from the Respondent's facility to the TEC system delivery point.
b. For proposals with generation located inside the TEC system (directly connecting to the TEC transmission system), TEC will coordinate and cooperate with the generation owner, if selected, to obtain the required TEC interconnection and integration/transmission service needed for the transaction, including any associated rights and the reactive capability of the resource.
c. Transmission interconnection costs to connect the proposed units to the TEC system, or a third party system and the system integration and/or upgrade costs to deliver the energy to the TEC system receipt point and designate the resource as a network resource are the financial responsibility of the Respondent. If Respondent expects TEC to reimburse such costs, the costs must be included in the proposal price and separately identified in Appendix C.
d. The costs of energy and capacity losses within TEC's system for each proposal will be developed by TEC during the economic analysis of candidate portfolios and should not be included in the proposal price.
e. Respondent is financially responsible for transmission ancillary services.
f. If selected for the short list, Respondent, at its own expense, must submit for all necessary firm transmission service requests at that time and submit a copy of the results to TEC upon receipt. Respondent agrees to carry the transmission request process through the engineering construction estimate phase, if required to confirm service to TEC.

5. Minimum Experience of Respondent

Any Respondent whose proposal is supported by new construction must have successfully executed the development, permitting, design, procurement, construction, and commissioning of a project similar to that proposed. The operating entity of a proposed facility must have over five years of demonstrated experience in the successful and reliable operation of facilities employing the technology similar to that proposed. The success and reliability of operations

may be demonstrated through operational records as requested in Appendix C. In addition, the Respondent must provide the key milestone data required in Form 8.

Tampa Electric Company 2017 Power Generation RFP

Section III – Evaluation Process

A. Evaluation Process

The objective of the RFP is to solicit proposals that allow TEC to assess the best generating alternatives that cost-effectively meet its capacity requirement. It is anticipated that TEC will receive a variety of proposals that may vary in length of term, capacity, source, price, fuel and other pertinent characteristics. In addition to the variations that may be presented within individual proposals, there may be a need to combine multiple proposals to develop portfolios that meet the capacity requirements. TEC will employ an evaluation methodology that will anticipate responses that offer a wide range of individual characteristics and can evaluate the costs and benefits offered by combining various proposals into unique portfolios of generating alternatives. Therefore, eligible proposals that pass initial screening and individual economic ranking, but do not individually meet the capacity requirement for a given year, will be evaluated in portfolios that match them with other resources to meet the capacity need and the sequence of annual need identified in this solicitation. Ultimately, TEC will identify the best portfolio that cost-effectively meets the RFP capacity requirement. TEC's evaluation methodology, including a detailed description of the criteria to be used to evaluate price and non-price attributes, is described in the following paragraphs:

1. Initial Screening

   An independent third party evaluator will review proposals for compliance with the General and Specific Minimum Requirements set forth in this RFP. Those proposals determined to be sufficient will advance in the evaluation. Proposals determined to be insufficient will not be evaluated further.

2. Economic Evaluation of Individual Proposals/Bids

   Proposals determined to be eligible will first be ranked by their individual economic impact on the TEC system over the length of the study period. If there are a large number of eligible proposals and a significant difference in economic impact on the TEC system is noted, this analysis may be used to eliminate a portion of the lowest ranked proposals from further evaluation. Smaller bids may be combined with others to reach the needed level of capacity.

3. Present Value Economic Screen of Proposals/Bids

In the event that some of the proposals need to be combined with other proposals to present portfolios that fully meet the RFP capacity needs. TEC will, therefore conduct a portfolio analysis. Load growth will be modeled using TEC's Load Forecast and additional generation will be added to complete the generation plan maintaining the required reserve margin into the future. An estimated system economic cost (presented as the Cumulative Present Value of Revenue Requirements - CPVRR) for each portfolio and associated generation plan will be developed during the portfolio analysis step. This estimated cost will provide a basis for further screening of noncompetitive proposals, if necessary.

4. Final Evaluation of Total System Costs

The top ranking proposals or portfolios emerging from the creation and screening step will undergo a detailed economic evaluation, including estimates developed for system costs specific to each proposal or portfolio and associated generation plan.

The system costs include variable and fixed costs of production for all units, transmission-related costs, delivered fuel related costs and a net equity adjustment for purchase obligations (as described by Standard and Poors). The transmission-related costs include transmission interconnection costs, transmission integration costs, TEC transmission reactive requirements and the costs of system energy and capacity losses. The fuel-related costs include all infrastructure upgrades and firm fuel transportation costs necessary to deliver the fuel requirements of the proposal or portfolio. The fixed and variable costs developed for each specific proposal or portfolio and associated generation plan will be combined to represent the full economic evaluation. The results will be compared to the results of other proposal or portfolio and generation plan options.

5. Non-Economic Evaluation

In addition to the economic evaluation, the proposals or portfolios will be evaluated for non-economic factors. In the non-economic evaluation, the proposals will be evaluated individually and in the context of the other proposals in the portfolio as to the environmental considerations, water supply, technical and financial viability, operational attributes, renewable energy integration potential, and project execution. Other non-economic factors include transmission system benefits, dual fuel capability, dispatchability and commitment benefits. The objective of the evaluation is to develop an

understanding of the proposal and identify areas that may warrant further review.

The result of the non-economic evaluation will be a summary report on the risk areas that may be used in conjunction with the results of the economic evaluation to select Finalists.

6. Best and Final Offer Evaluation

TEC will apply the process above to develop a Short List of proposals that will be the Finalists. TEC will request from each Finalist a BAFO, if and only after preliminary negotiations have yielded a consensus on basic terms and conditions between TEC and such Finalist. Each Finalist will provide such information as TEC requires in order to assess such Finalist's ability to meet contract requirements. TEC will evaluate these BAFOs to develop the final economic and non-economic results.

7. Final Selection

The economic and non-economic factors will be presented to a TEC Management Review Team. The Management Review Team will then make a selection based on sound business practices and the best interests of TEC customers.

B. Other Respondent Information

1. RFP Evaluation Fees(s)

In order for a proposal to be evaluated, the complete proposal accompanied by a certified, non-refundable check of $10,000 made payable to "Tampa Electric Company" must be delivered to the RFP Contact Person designated by TEC on or before 12:00 Noon (ET) on May 22, 2012. If more than one proposal is submitted by a specific Respondent, then a separate, certified, non-refundable $10,000 check made payable to "Tampa Electric Company" must accompany each proposal. One proposal consists of a specific combination of a site, technology, fuel source, total capacity level, CDD, term (e.g., 10 years) and pricing submittal. A Respondent may submit variations of CDD, term and/or price related to a specific proposal at a fee of $5,000 per variation. A single variation is defined as a change in either CDD, term, price, or combination of the three. A change in any other category (e.g., site or technology) constitutes a separate proposal. There are no limitations to the number of variations

submitted, as long as each additional variation is accompanied by a $5,000 fee. Also, variations must be submitted with their own set of forms. Changes in site, technology, fuel source, or, capacity level will constitute a separate proposal and require a full evaluation fee. The RFP base evaluation fee and the incremental variation fee are based on the costs expected to be incurred to evaluate the type of proposals solicited in the RFP.

2. Power Purchase Agreement

For each selected power purchase proposal, TEC expects to enter into a pay-for-performance type power purchase agreement. Such power purchase agreement shall be established as a dedicated, stand-alone contract. Refer to Appendix B for proposed PPA. Respondents must specify any exceptions to this proposed contract in their response to this RFP.

3. Construction and Performance Security Requirements

Tampa Electric will require that the successful Respondent post a Security. For new construction, "Security" means both a construction and performance security. In the case of existing resources, "Security" means a performance security. Security must be in the form of (1) a Letter of Credit for the benefit of TEC in the form attached to the PPA and from an issuer reasonable acceptable to TEC, or (2) Cash in U.S. Dollars deposited with TEC with interest to be paid monthly at the Federal Funds rate for assurance that the capacity and energy delivery obligations will be met over the full term of the PPA. TEC, at its sole discretion, will allow a portion of Security to be in the form of a guaranty. The amount of the Security will be equal to TEC's market exposure, in dollars, if the Respondent defaults under the PPA.

a. TEC's Market Exposure

If the successful Respondent were to default on capacity and energy delivery obligations under the PPA, TEC would need to consider the purchase of replacement capacity and energy from the wholesale electric power market or construction of substitute generation facilities to meet its needs. It is difficult to estimate the exact impact of such event; however, TEC has made a conservative estimate of the damage at $139,000,000.

b. Credit Limit

A Credit Limit will be calculated for each Short List Respondent, or Guarantor (an entity which guarantees the obligations of a Respondent) utilizing a credit scoring model. The credit scoring methodology utilized for evaluating a Respondent or its Guarantor at TEC places a heavy emphasis on financial performance. The credit score is comprised of ten qualitative and quantitative factors. The Credit Limit may be adjusted based upon Seller's, or its Guarantor's, most current financial statements, changes in Seller's, or its Guarantor's, bond rating, or other factors or events determined to be significant in TEC's reasonable sole discretion.

To qualify for a Credit Limit, Respondent or its Guarantor must have no history of bankruptcy and must also demonstrate that it has a senior unsecured bond rating (excluding any third party support) of at least Baa3 from Moody's Investors Service ("Moody's") and BBB- from Standard and Poor's ("S&P").

If the specified bond rating is not available and the Credit Limit has been based upon a Guarantor's credit worthiness, a guaranty for the benefit of TEC will be executed in the form attached to the PPA.

The Seller may replace the Security held by TEC with another form of acceptable Security in an equivalent amount. Once TEC determines that the replacement Security is acceptable, the Seller shall deliver or issue, or cause to be delivered or issued, the replacement Security. Upon receipt of such replacement Security, TEC shall promptly return or release, or cause the return or release of the Security being replaced.

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Section IV – Detailed Technical Description of TEC's NPGU

A. Detailed Technical Description of TEC's NPGU

The following data represents the preliminary cost and performance estimates for Tampa Electric Company's NPGU and are provided for informational purposes only. These estimates have not been refined by detailed engineering or equipment proposals and contain contingencies and assumptions as appropriate.

a. Conversion of four existing simple cycle combustion turbines to a combined cycle generating unit to be located at TEC's existing Polk Power Station site in Polk County, FL.
b. Planned incremental capacity: 463 MW (Winter), 459 MW (Summer).
c. Commercial operation of the facility is proposed to be January 2017.
d. The primary fuel is natural gas. Distillate fuel oil will be used as a backup fuel for at least 50% of the unit(s) need.
e. The estimated total direct cost is $424.4 million (2012$), excluding AFUDC. This estimate does not include transmission interconnection or required system upgrade costs.
f. The estimated annual levelized revenue requirement is $89.0 million over 30 years (2012$)
g. The estimated annual value of deferral of this unit is $74.12 /kW-yr (2012$), which includes generation and transmission construction costs.
h. The estimated annual fixed O&M is $ 2.85/kW-yr (2012$). The estimated variable O&M is $2.09 /MWh (2012$).
i. The estimated commodity fuel cost is included in the subsequent table.
j. The following are estimates for:
    1. Planned Outage Rate 3.2%
    2. Forced Outage Rate 0.7%
    3. Minimum load 90 MW (simple cycle)
    4. Ramp Rate 32 MW/min
    5. Net Heat Rate 7,000 Btu/kWh
k. The estimated transmission interconnection and system upgrade costs are $147.2 million (2012$) excluding AFUDC.
l. Modification of the existing site certification as well as amendment to related environmental permits will be required for this unit. It is TEC's plan to comply with all environmental standards of Local, Regional, State and Federal Governments.

m. The major financial assumptions in the development of these numbers were:

1.	Construction escalation:	3.0%
2.	O&M escalation:	2.4%
3.	Fuel escalation:	Varies by year
4.	Capital Structure:	46.04% Debt @ 6.66% 53.96% Equity @ 11.25%
5.	ATWACC:	7.95%

B. Fuel Price Forecast

Tampa Electric has forecasted the commodity price of fuels through 2041.

Natural gas is forecasted for the Henry Hub.

	Nominal $/MMBtu for Fuel	
	No. 2 Oil	NG
2012	$22.33	$4.76
2013	$24.04	$5.12
2014	$25.32	$5.39
2015	$26.62	$5.67
2016	$27.96	$5.95
2017	$29.25	$6.23
2018	$30.58	$6.51
2019	$31.88	$6.79
2020	$33.17	$7.07
2021	$34.48	$7.34
2022	$35.83	$7.63
2023	$36.62	$7.80
2024	$37.42	$7.97
2025	$38.22	$8.14
2026	$39.04	$8.31
2027	$39.86	$8.49
2028	$40.70	$8.67
2029	$41.55	$8.85
2030	$42.41	$9.03
2031	$43.29	$9.22
2032	$44.19	$9.41
2033	$45.10	$9.61
2034	$46.03	$9.80
2035	$46.98	$10.01
2036	$47.95	$10.21
2037	$48.93	$10.42
2038	$49.94	$10.64
2039	$50.96	$10.85
2040	$52.00	$11.08
2041	$53.04	$11.30

C. Actions to Comply With Environmental 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.
○ PSD air construction permit	FDEP/EPA	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). GHG PSD permitting may be processed by EPA if FDEP does not seek delegacy.
○ 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.
○ 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.

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Permit	Review/ Approval Agencies	Status/Comments
○ 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.
○ Endangered/threatened species review	USFWS/ FFWCC	Will be reviewed and approved as part of the supplemental site certification application and Section 404 processes.
• 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

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Permit	Review/ Approval Agencies	Status/Comments
✦ 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.
✦ 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. GHG permitting may be processed by EPA.
• 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.
- o Reviewed concurrently with the PPSA process with separate permit issued 30 to 45days 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.

EXHIBIT NO. 21

DOCKET NO: 120234-EI – Polk Conversion Project Need Determination

WITNESS: Hornick/Rocha

PARTY: TAMPA ELECTRIC COMPANY

DESCRIPTION: CROSS-EXAMINATION EXHIBIT

DOCUMENT: Excerpt from Tampa Electric's 2011 FERC Form 1

PROFFERED BY: DeSoto Generating Company

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 120234-EI EXHIBIT 21
PARTY DeSoto Generating Company
DESCRIPTION Hornick/Rocha - Excerpt from Tampa Electric's 2011 FERC Form 1

THIS FILING IS	
Item 1: ☐ An Initial (Original) Submission	OR ☒ Resubmission No. ____

Form 1 Approved
OMB No.1902-0021
(Expires 12/31/2014)
Form 1-F Approved
OMB No.1902-0029
(Expires 12/31/2014)
Form 3-Q Approved
OMB No.1902-0205
(Expires 05/31/2014)

FERC FINANCIAL REPORT
FERC FORM No. 1: Annual Report of Major Electric Utilities, Licensees and Others and Supplemental Form 3-Q: Quarterly Financial Report

These reports are mandatory under the Federal Power Act, Sections 3, 4(a), 304 and 309, and 18 CFR 141.1 and 141.400. Failure to report may result in criminal fines, civil penalties and other sanctions as provided by law. The Federal Energy Regulatory Commission does not consider these reports to be of confidential nature

Exact Legal Name of Respondent (Company)	Year/Period of Report
Tampa Electric Company	End of 2011/Q4

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Tampa Electric Company	(1) ☐ An Original (2) ☒ A Resubmission	12/06/2012	End of 2011/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants)

1. Report data for plant in Service only. 2. Large plants are steam plants with installed capacity (name plate rating) of 25,000 Kw or more. Report in this page gas-turbine and internal combustion plants of 10,000 Kw or more, and nuclear plants. 3. Indicate by a footnote any plant leased or operated as a joint facility. 4. If net peak demand for 60 minutes is not available, give data which is available, specifying period. 5. If any employees attend more than one plant, report on line 11 the approximate average number of employees assignable to each plant. 6. If gas is used and purchased on a therm basis report the Btu content or the gas and the quantity of fuel burned converted to Mct. 7. Quantities of fuel burned (Line 38) and average cost per unit of fuel burned (Line 41) must be consistent with charges to expense accounts 501 and 547 (Line 42) as show on Line 20. 8. If more than one fuel is burned in a plant furnish only the composite heat rate for all fuels burned.

Line No.	Item (a)	Plant Name: *Big Bend 1 - 4* (b)			Plant Name: *Big Bend CT 4* (c)		
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear	STEAM			JET ENGINE		
2	Type of Constr (Conventional, Outdoor, Boiler, etc)	OUTDOOR BOILER			FULL OUTDOOR		
3	Year Originally Constructed	1970			2009		
4	Year Last Unit was Installed	1985			2009		
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	1822.50			69.99		
6	Net Peak Demand on Plant - MW (60 minutes)	1693			63		
7	Plant Hours Connected to Load	6935			219		
8	Net Continuous Plant Capability (Megawatts)	0			0		
9	When Not Limited by Condenser Water	1582			61		
10	When Limited by Condenser Water	1552			56		
11	Average Number of Employees	385			0		
12	Net Generation, Exclusive of Plant Use - KWh	9418308000			7682000		
13	Cost of Plant: Land and Land Rights	5981510			0		
14	Structures and Improvements	398836674			3299244		
15	Equipment Costs	1498807618			36704033		
16	Asset Retirement Costs	0			0		
17	Total Cost	1903625802			40003277		
18	Cost per KW of Installed Capacity (line 17/5) Including	1044.5135			571.5570		
19	Production Expenses: Oper, Supv, & Engr	5390364			0		
20	Fuel	325431350			767288		
21	Coolants and Water (Nuclear Plants Only)	0			0		
22	Steam Expenses	23047857			0		
23	Steam From Other Sources	0			0		
24	Steam Transferred (Cr)	0			0		
25	Electric Expenses	2718654			0		
26	Misc Steam (or Nuclear) Power Expenses	7060758			0		
27	Rents	0			0		
28	Allowances	-1229			0		
29	Maintenance Supervision and Engineering	337169			0		
30	Maintenance of Structures	5402054			30774		
31	Maintenance of Boiler (or reactor) Plant	35349444			0		
32	Maintenance of Electric Plant	5303768			68682		
33	Maintenance of Misc Steam (or Nuclear) Plant	1295770			0		
34	Total Production Expenses	411335959			866744		
35	Expenses per Net KWh	0.0437			0.1128		
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)			Coal		Oil	Natural Gas
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)			Coal-TON		Oil-BBL	Gas-MCF
38	Quantity (Units) of Fuel Burned	0	0	4151622	0	99	107225
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	0	0	11809	0	128417	1014009
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	0.000	0.000	76.749	0.000	128.720	6.442
41	Average Cost of Fuel per Unit Burned	0.000	0.000	78.387	0.000	753.422	6.458
42	Average Cost of Fuel Burned per Million BTU	0.000	0.000	3.319	0.000	139.690	6.368
43	Average Cost of Fuel Burned per KWh Net Gen	0.000	0.000	3.455	0.000	102.548	9.100
44	Average BTU per KWh Net Generation	0.000	0.000	10.411	0.000	7.341	14.289

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Tampa Electric Company	(1) ☐ An Original (2) ☒ A Resubmission	12/06/2012	End of 2011/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

1. Report data for plant in Service only. 2. Large plants are steam plants with installed capacity (name plate rating) of 25,000 Kw or more. Report in this page gas-turbine and internal combustion plants of 10,000 Kw or more, and nuclear plants. 3. Indicate by a footnote any plant leased or operated as a joint facility. 4. If net peak demand for 60 minutes is not available, give data which is available, specifying period. 5. If any employees attend more than one plant, report on line 11 the approximate average number of employees assignable to each plant. 6. If gas is used and purchased on a therm basis report the Btu content or the gas and the quantity of fuel burned converted to Mct. 7. Quantities of fuel burned (Line 38) and average cost per unit of fuel burned (Line 41) must be consistent with charges to expense accounts 501 and 547 (Line 42) as show on Line 20. 8. If more than one fuel is burned in a plant furnish only the composite heat rate for all fuels burned.

Line No.	Item (a)	Plant Name: *Polk Units 2 & 3* (b)			Plant Name: *Polk Units 4 & 5* (c)		
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear	COMBUSTION TURBINE			COMBUSTION TURBINE		
2	Type of Constr (Conventional, Outdoor, Boiler, etc)	FULL OUTDOOR BOILER			FULL OUTDOOR BOILER		
3	Year Originally Constructed	2000			2007		
4	Year Last Unit was Installed	2002			2007		
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	351.54			351.54		
6	Net Peak Demand on Plant - MW (60 minutes)	301			310		
7	Plant Hours Connected to Load	802			1469		
8	Net Continuous Plant Capability (Megawatts)	0			0		
9	When Not Limited by Condenser Water	366			366		
10	When Limited by Condenser Water	302			302		
11	Average Number of Employees	0			0		
12	Net Generation, Exclusive of Plant Use - KWh	163044000			305328000		
13	Cost of Plant: Land and Land Rights	0			0		
14	Structures and Improvements	12486163			11177737		
15	Equipment Costs	99066254			57620784		
16	Asset Retirement Costs	0			0		
17	Total Cost	111552417			68798521		
18	Cost per KW of Installed Capacity (line 17/5) Including	317.3250			195.7061		
19	Production Expenses: Oper, Supv, & Engr	0			0		
20	Fuel	11560921			19993235		
21	Coolants and Water (Nuclear Plants Only)	0			0		
22	Steam Expenses	0			0		
23	Steam From Other Sources	0			0		
24	Steam Transferred (Cr)	0			0		
25	Electric Expenses	0			0		
26	Misc Steam (or Nuclear) Power Expenses	0			0		
27	Rents	0			0		
28	Allowances	0			0		
29	Maintenance Supervision and Engineering	0			0		
30	Maintenance of Structures	0			0		
31	Maintenance of Boiler (or reactor) Plant	0			0		
32	Maintenance of Electric Plant	258199			226528		
33	Maintenance of Misc Steam (or Nuclear) Plant	0			0		
34	Total Production Expenses	11819120			20219763		
35	Expenses per Net KWh	0.0725			0.0662		
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)			Natural Gas			Natural Gas
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)			Gas-MCF			Gas-MCF
38	Quantity (Units) of Fuel Burned	0	0	1897221	0	0	3330448
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	0	0	1013956	0	0	1013999
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	0.000	0.000	6.036	0.000	0.000	6.003
41	Average Cost of Fuel per Unit Burned	0.000	0.000	6.094	0.000	0.000	6.003
42	Average Cost of Fuel Burned per Million BTU	0.000	0.000	6.010	0.000	0.000	5.920
43	Average Cost of Fuel Burned per KWh Net Gen	0.000	0.000	7.091	0.000	0.000	6.548
44	Average BTU per KWh Net Generation	0.000	0.000	11.799	0.000	0.000	11.060

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Tampa Electric Company	(1) ☐ An Original (2) ☒ A Resubmission	12/06/2012	End of 2011/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

1. Report data for plant in Service only. 2. Large plants are steam plants with installed capacity (name plate rating) of 25,000 Kw or more. Report in this page gas-turbine and internal combustion plants of 10,000 Kw or more, and nuclear plants. 3. Indicate by a footnote any plant leased or operated as a joint facility. 4. If net peak demand for 60 minutes is not available, give data which is available, specifying period. 5. If any employees attend more than one plant, report on line 11 the approximate average number of employees assignable to each plant. 6. If gas is used and purchased on a therm basis report the Btu content or the gas and the quantity of fuel burned converted to Mct. 7. Quantities of fuel burned (Line 38) and average cost per unit of fuel burned (Line 41) must be consistent with charges to expense accounts 501 and 547 (Line 42) as show on Line 20. 8. If more than one fuel is burned in a plant furnish only the composite heat rate for all fuels burned.

Line No.	Item (a)	Plant Name: (b)	Plant Name: (c)
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear		
2	Type of Constr (Conventional, Outdoor, Boiler, etc)		
3	Year Originally Constructed		
4	Year Last Unit was Installed		
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	0.00	0.00
6	Net Peak Demand on Plant - MW (60 minutes)	0	0
7	Plant Hours Connected to Load	0	0
8	Net Continuous Plant Capability (Megawatts)	0	0
9	When Not Limited by Condenser Water	0	0
10	When Limited by Condenser Water	0	0
11	Average Number of Employees	0	0
12	Net Generation, Exclusive of Plant Use - KWh	0	0
13	Cost of Plant: Land and Land Rights	0	0
14	Structures and Improvements	0	0
15	Equipment Costs	0	0
16	Asset Retirement Costs	0	0
17	Total Cost	0	0
18	Cost per KW of Installed Capacity (line 17/5) Including	0	0
19	Production Expenses: Oper, Supv, & Engr	0	0
20	Fuel	0	0
21	Coolants and Water (Nuclear Plants Only)	0	0
22	Steam Expenses	0	0
23	Steam From Other Sources	0	0
24	Steam Transferred (Cr)	0	0
25	Electric Expenses	0	0
26	Misc Steam (or Nuclear) Power Expenses	0	0
27	Rents	0	0
28	Allowances	0	0
29	Maintenance Supervision and Engineering	0	0
30	Maintenance of Structures	0	0
31	Maintenance of Boiler (or reactor) Plant	0	0
32	Maintenance of Electric Plant	0	0
33	Maintenance of Misc Steam (or Nuclear) Plant	0	0
34	Total Production Expenses	0	0
35	Expenses per Net KWh	0.0000	0.0000
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)		
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)		
38	Quantity (Units) of Fuel Burned	0 0 0	0 0 0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	0 0 0	0 0 0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	0.000 0.000 0.000	0.000 0.000 0.000
41	Average Cost of Fuel per Unit Burned	0.000 0.000 0.000	0.000 0.000 0.000
42	Average Cost of Fuel Burned per Million BTU	0.000 0.000 0.000	0.000 0.000 0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.000 0.000 0.000	0.000 0.000 0.000
44	Average BTU per KWh Net Generation	0.000 0.000 0.000	0.000 0.000 0.000

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Tampa Electric Company	(1) ☐ An Original (2) ☒ A Resubmission	12/06/2012	End of 2011/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants)*(Continued)*

9. Items under Cost of Plant are based on U. S. of A. Accounts. Production expenses do not include Purchased Power, System Control and Load Dispatching, and Other Expenses Classified as Other Power Supply Expenses. 10. For IC and GT plants, report Operating Expenses, Account Nos. 547 and 549 on Line 25 "Electric Expenses," and Maintenance Account Nos. 553 and 554 on Line 32, "Maintenance of Electric Plant." Indicate plants designed for peak load service. Designate automatically operated plants. 11. For a plant equipped with combinations of fossil fuel steam, nuclear steam, hydro, internal combustion or gas-turbine equipment, report each as a separate plant. However, if a gas-turbine unit functions in a combined cycle operation with a conventional steam unit, include the gas-turbine with the steam plant. 12. If a nuclear power generating plant, briefly explain by footnote (a) accounting method for cost of power generated including any excess costs attributed to research and development; (b) types of cost units used for the various components of fuel cost; and (c) any other informative data concerning plant type fuel used, fuel enrichment type and quantity for the report period and other physical and operating characteristics of plant.

Plant Name: *Bayside Units 1 & 2* (d)	Plant Name: *Bayside Units 3 - 6* (e)	Plant Name: *Polk Unit 1* (f)	Line No.
COMBINED CYCLE	JET ENGINE	IGCC	1
OUTDOOR REPOWER	FULL OUTDOOR	FULL OUTDOOR BOILER	2
2003	2009	1996	3
2004	2009	1996	4
2014.16	279.94	326.30	5
1699	210	313	6
6827	955	5337	7
0	0	0	8
1839	244	220	9
1630	224	220	10
64	0	76	11
6860004000	55885000	1483473000	12
1592891	0	18197341	13
117874961	3742018	113431936	14
808045448	115946146	435162601	15
0	0	0	16
927513300	119688164	566791878	17
460.4963	427.5493	1737.0269	18
2604865	0	1072065	19
312557195	4103961	68488303	20
0	0	0	21
0	0	0	22
0	0	0	23
0	0	0	24
7152895	89246	8739644	25
11581	0	0	26
0	0	0	27
0	0	-143	28
0	0	839696	29
84284	0	6456721	30
0	0	0	31
8861320	499454	2414513	32
0	0	0	33
331272140	4692661	88010799	34
0.0483	0.0840	0.0593	35

		Natural Gas			Natural Gas		Coal	Oil	36
		Gas-MCF			Gas-MCF		Coal-TON	Oil-BBL	37
0	0	49541972	0	0	638095	0	548556	27374	38
0	0	1014089	0	0	1014035	0	13644	126539	39
0.000	0.000	6.301	0.000	0.000	6.432	0.000	125.688	127.323	40
0.000	0.000	6.309	0.000	0.000	6.432	0.000	119.343	110.406	41
0.000	0.000	6.221	0.000	0.000	6.343	0.000	4.373	20.774	42
0.000	0.000	4.556	0.000	0.000	7.344	0.000	4.453	22.637	43
0.000	0.000	7.324	0.000	0.000	11.578	0.000	10.183	10.897	44

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Tampa Electric Company	(1) ☐ An Original (2) ☒ A Resubmission	12/06/2012	End of 2011/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

9. Items under Cost of Plant are based on U. S. of A. Accounts. Production expenses do not include Purchased Power, System Control and Load Dispatching, and Other Expenses Classified as Other Power Supply Expenses. 10. For IC and GT plants, report Operating Expenses, Account Nos. 547 and 549 on Line 25 "Electric Expenses," and Maintenance Account Nos. 553 and 554 on Line 32, "Maintenance of Electric Plant." Indicate plants designed for peak load service. Designate automatically operated plants. 11. For a plant equipped with combinations of fossil fuel steam, nuclear steam, hydro, internal combustion or gas-turbine equipment, report each as a separate plant. However, if a gas-turbine unit functions in a combined cycle operation with a conventional steam unit, include the gas-turbine with the steam plant. 12. If a nuclear power generating plant, briefly explain by footnote (a) accounting method for cost of power generated including any excess costs attributed to research and development; (b) types of cost units used for the various components of fuel cost; and (c) any other informative data concerning plant type fuel used, fuel enrichment type and quantity for the report period and other physical and operating characteristics of plant.

Plant Name: *Phillips* (d)	Plant Name: (e)	Plant Name: (f)	Line No.
INT.COMBUSTINE			1
CONVENTIONAL			2
1983			3
1983			4
38.43	0.00	0.00	5
0	0	0	6
0	0	0	7
0	0	0	8
0	0	0	9
0	0	0	10
0	0	0	11
0	0	0	12
179223	0	0	13
9481580	0	0	14
50847155	0	0	15
0	0	0	16
60507958	0	0	17
1574.4980	0	0	18
208	0	0	19
2642	0	0	20
0	0	0	21
0	0	0	22
0	0	0	23
0	0	0	24
9111	0	0	25
0	0	0	26
0	0	0	27
0	0	0	28
0	0	0	29
3167	0	0	30
0	0	0	31
116217	0	0	32
0	0	0	33
131345	0	0	34
0.0000	0.0000	0.0000	35

									36
									37
0	0	0	0	0	0	0	0	0	38
0	0	0	0	0	0	0	0	0	39
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	40
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	41
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	42
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	43
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	44

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Tampa Electric Company	(1) ☐ An Original (2) ☒ A Resubmission	12/06/2012	End of 2011/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants)*(Continued)*

9. Items under Cost of Plant are based on U. S. of A. Accounts. Production expenses do not include Purchased Power, System Control and Load Dispatching, and Other Expenses Classified as Other Power Supply Expenses. 10. For IC and GT plants, report Operating Expenses, Account Nos. 547 and 549 on Line 25 "Electric Expenses," and Maintenance Account Nos. 553 and 554 on Line 32, "Maintenance of Electric Plant." Indicate plants designed for peak load service. Designate automatically operated plants. 11. For a plant equipped with combinations of fossil fuel steam, nuclear steam, hydro, internal combustion or gas-turbine equipment, report each as a separate plant. However, if a gas-turbine unit functions in a combined cycle operation with a conventional steam unit, include the gas-turbine with the steam plant. 12. If a nuclear power generating plant, briefly explain by footnote (a) accounting method for cost of power generated including any excess costs attributed to research and development; (b) types of cost units used for the various components of fuel cost; and (c) any other informative data concerning plant type fuel used, fuel enrichment type and quantity for the report period and other physical and operating characteristics of plant.

Plant Name: (d)	Plant Name: (e)	Plant Name: (f)	Line No.
			1
			2
			3
			4
0.00	0.00	0.00	5
0	0	0	6
0	0	0	7
0	0	0	8
0	0	0	9
0	0	0	10
0	0	0	11
0	0	0	12
0	0	0	13
0	0	0	14
0	0	0	15
0	0	0	16
0	0	0	17
0	0	0	18
0	0	0	19
0	0	0	20
0	0	0	21
0	0	0	22
0	0	0	23
0	0	0	24
0	0	0	25
0	0	0	26
0	0	0	27
0	0	0	28
0	0	0	29
0	0	0	30
0	0	0	31
0	0	0	32
0	0	0	33
0	0	0	34
0.0000	0.0000	0.0000	35
			36
			37
0	0	0	38
0	0	0	39
0.000	0.000	0.000	40
0.000	0.000	0.000	41
0.000	0.000	0.000	42
0.000	0.000	0.000	43
0.000	0.000	0.000	44

FOOTNOTE DATA

Schedule Page: 402.1 Line No.: 1 Column: d

Phillips Station has been on long-term reserve standby since September 4, 2009.

EXHIBIT NO. 22

DOCKET NO: 120234-EI – Polk Conversion Project Need Determination

WITNESS: Hornick/Rocha

PARTY: TAMPA ELECTRIC COMPANY

DESCRIPTION: CROSS-EXAMINATION EXHIBIT

DOCUMENT: Tampa Electric Discount Rate Calculation and Escalation Rates – Staff's POD No. 19, BSP 971, 972, 975

PROFFERED BY: DeSoto Generating Company

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 120234-EI EXHIBIT 22
PARTY DeSoto Generating Company
DESCRIPTION Hornick/Rocha - Tampa Electric Discount Rate Calculation and Escalation Rates – Staff's POD No. 19, BSP 971, 972, 975

TAMPA ELECTRIC COMPANY
DOCKET NO. 120234-EI
STAFF'S SECOND REQUEST FOR
PRODUCTION OF DOCUMENTS
DOCUMENT NO. 19
BATES STAMPED PAGES: 971 - 981
FILED: OCTOBER 23, 2012

19. Regarding the economic parameters in the application, please provide complete copies of all source documents, reports, etc., that support the selection of the capital structure, the assumed escalation rates, the assumed financing rates, the capital structure ratios, the AFUDC rate, and the assumed present worth discount rates.

A. Please see attached documents.

TECO TAMPA ELECTRIC

MEMORANDUM

FROM: Chrys Remmers

DATE: September 30, 2011

SUBJECT: Financial Assumptions for Economic Evaluations and Planning Studies

This memo contains two sets of financial assumptions for engineering economy studies and for the calculation of avoided costs.

1) The first set of costs are for discretionary capital projects and contain a hurtle rate. These assumptions are to be used for internal economic evaluations. The capital structure and incremental costs of capital are:

	Rate	Weight
Debt	6.66%	46.04%
Common Equity	12.25%	53.96%
		100.00%

After tax discount rate for present worth calculations: 8.49%

2) The second set of financial assumptions is to be used for external studies where the costs are to reflect TEC's projected actual costs. The capital structure and incremental costs of capital are:

	Rate	Weight
Debt	6.66%	46.04%
Common Equity	11.25%	53.96%
		100.00%

After tax discount rate for present worth calculations: 7.95%

Common analysis assumptions include:

Property Tax Rate	
Hillsborough	2.00%
Polk	1.60%
Property Insurance Rate	0.15% / $100 of value
Income Tax Rate	38.575%

These are general assumptions to use in project evaluations. Please contact me if you have questions regarding specific assumptions for your project analysis.

TAMPA ELECTRIC

MEMORANDUM

FROM: Samantha Superville, Load Research & Forecasting

DATE: June 28, 2011

SUBJECT: Escalation Rates

Please use the following escalation rates for this year's budget process.

Consumer Price Index (CPI): Moderate inflation in 2011
The consumer price index in April was up 3.2% from April 2010. Inflation has moderated in recent months primarily due to a slowdown in food and energy price increases. Moody's Economy.com and over 50 economists participating in the Wall Street Journal's forecasting survey (April 2011) predict an inflation rate just under 3.0 percent for 2011. The annual inflation rate for 2012 is projected to be 2.1 percent. Consumer price inflation over the next decade will remain in the 2.0 percent range annually, averaging 2.4 percent each year from 2014 and beyond.

According to the Federal Reserve's FOMC (Federal Open Market Committee), longer-term inflation stayed within the range that has prevailed over the past several years. The Committee said it anticipates long-run inflation to remain stable.

TAMPA ELECTRIC COMPANY
ESCALATION RATES [3]
(Annual Percent Change)

Year	Production HWI (1)	Non-Production CPI (2)
2009	6.0%	-0.4%
2010	5.6%	1.6%
2011	3.6%	2.8%
2012	5.2%	2.1%
2013	2.5%	2.9%
2014 - 2018	2.1%	2.4%

(1) Handy Whitman Index – South Atlantic Region; June 2011 delivery
(2) Consumer Price Index – All Urban Consumers, All Items, NSA; April 2011 delivery
(3) Forecast and commentary provided by Economy.com

Handy-Whitman Index (HWI): Production Inflation Moderating Long-Term
Currently, the inflation rate for electric utility construction costs is 3.6 percent, 2 percentage points lower than in 2010. Production inflation rates are projected to be 5.2 percent in 2012 and drop to the 2 percent range from 2013 and beyond (2.5% in 2013, 2.1% in 2014+).

There was a drop in the 1st Quarter 2011 actual values which drove the forecast down for that year. The rest of the forecast is driven by the cost of industrial goods, specifically machinery and equipment.

cc: TJ Szelistowski, Lori Cifuentes, Stacy Hallman

EXHIBIT NO. 23

DOCKET NO: 120234-EI – Polk Conversion Project Need Determination

WITNESS: Hornick/Rocha/Taylor

PARTY: TAMPA ELECTRIC COMPANY

DESCRIPTION: CROSS-EXAMINATION EXHIBIT

DOCUMENT: Tampa Electric COG-2 Tariff Sheets 8.406-8.424, Effective June 19, 2012

PROFFERED BY: DeSoto Generating Company

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 120234-EI EXHIBIT 23
PARTY DeSoto Generating Company
DESCRIPTION Hornick/Rocha - Tampa Electric COG-2 Tariff Sheets 8. 406-8.424, Effective June 19, 2012

TAMPA ELECTRIC

FOURTH REVISED SHEET NO. 8.406
CANCELS THIRD REVISED SHEET NO. 8.406

RATE SCHEDULE COG-2
APPENDIX C

2019 COMBUSTION TURBINE

This Designated Avoided Unit is a 177 MW (winter rating) natural gas-fired combustion turbine with a May 1,2019, in-service date.

MINIMUM PERFORMANCE STANDARDS

In order to receive a Monthly Capacity Payment, all Contracted Capacity and Associated Energy provided by CEPs shall meet or exceed the following MPS on a monthly basis. The MPS are based on the anticipated peak and off-peak dispatchability, unit availability, and operating factor of the Designated Avoided Unit over the term of this Standard Offer Contract. The CEP's proposed generating facility ("the Facility") as defined in the Standard Offer Contract will be evaluated against the anticipated performance of a combustion turbine, starting with the first Monthly Period following the date selected in Paragraph 6.b.ii of the Company's Standard Offer Contract.

1. **Dispatch Requirements:** The CEP shall provide peaking capacity to the Company on a firm commitment, first-call, on-call, as-needed basis. In order to receive a Contracted Capacity Payment for each calendar month that the Facility is to be dispatched, the CEP must meet or exceed both the minimum Monthly Availability and Monthly Capacity Factor requirements.

2. **Dispatch Procedure:** Commencing on the calendar day prior to the Facility In-Service Date or the Extended Facility In-Service Date, as applicable, and continuing each calendar day thereafter during the Term, by 7:00 A.M. EPT, the CEP shall electronically transmit a schedule ("Available Schedule") of the hour-by-hour amounts of Contracted Capacity expected to be available from the Facility the next day ("Committed Capacity"). Commencing on the calendar day prior to the Facility In-Service Date or the Extended Facility In-Service Date, as applicable, and continuing each calendar day thereafter during the Term, by 3:00 P.M. EPT, the Company shall electronically transmit the hour-by-hour amounts of Contracted Capacity that the Company desires the CEP to dispatch from the Facility the next day based on the Available Schedule supplied at 7:00 A.M. EPT by the CEP ("Dispatch Schedule"). The CEP's Available Schedule and the Company's Dispatch

Continued to Sheet No. 8.408

Schedule for Fridays will include Saturday, Sunday, and Monday schedules. The CEP's Available Schedule and the Company's Dispatch Schedule during holiday periods will be similarly adjusted. The CEP shall control and operate the Facility in accordance with the Company's Dispatch Schedule. From time to time (i.e. during emergency conditions), the Company may be required to adjust the Dispatch Schedule or ignore scheduled levels altogether, however, each Party shall make reasonable efforts to minimize departures from the Dispatch Schedule.

3. **Automatic Generation Control:** At the Company's discretion, the CEP will operate the Facility with Automatic Generation Control (AGC) equipment, speed governors, and voltage regulators in-service, except at such times when operational constraints of the equipment prevent AGC operation.

4. **Start-up Time:** Upon notification by the Company, the CEP's Facility shall provide its capacity within 15 minutes from a cold-start condition to maximum capacity.

5. **Minimum Run Time:** Minimum run time for the CEP's unit shall be 1 hour.

BASIS FOR MONTHLY CAPACITY PAYMENT CALCULATION:

1. **Monthly Availability Factor:** The Monthly Availability Factor of the CEP's generating facility will be calculated by averaging the Hourly Availability Factors for each hour of the Monthly Period. The Hourly Availability Factor may not exceed 100% and shall be defined as the hourly Committed Capacity expressed as a percentage of Contracted Capacity to the nearest whole percentile. The CEP is required to achieve a minimum Monthly Availability Factor of 90% in order to meet the MPS and be eligible to receive a Monthly Capacity Payment. Periods of Annual Planned Maintenance will be excluded from the calculation of the Monthly Availability Factor. For purposes of calculating the Monthly Availability Factor, the CEP's Committed Capacity may not exceed its Contracted Capacity.

2. **Monthly Capacity Factor:** In addition to the MPS for Monthly Availability, the CEP shall provide capacity into the Company's electric grid in order to meet or exceed a Monthly Capacity Factor of 80%. The Monthly Capacity Factor for the period April 1st through October 31st shall be defined as the sum of 80% of the Monthly Average On-peak Operating Factor plus 20% of the Monthly Average Off-peak Operating Factor. The Monthly Capacity Factor for the period November 1st through March 31st shall be defined as the sum of 90% of the Monthly Average On-peak Operating Factor plus 10% of the Monthly Average Off-peak Operating Factor.

   a. **Operating Factor:** The CEP shall endeavor to provide capacity in the amount dispatched by the Company. The Company may at times request capacity in an amount that exceeds the Committed Capacity as declared by CEP the previous day.

      However, the Operating Factor may not exceed 100% and shall be defined as the actual energy received during each hour that the CEP unit is dispatched by the Company divided by the lesser of the CEP's Committed Capacity or the capacity requested by the Company for that hour, expressed to the nearest whole percentile.

   b. **Monthly Average On-peak Operating Factor:** The monthly average of the Operating Factor for all hours the CEP unit has been dispatched during On-peak Hours will be termed the Monthly Average On-peak Operating Factor.

   c. **Monthly Average Off-peak Operating Factor:** The monthly average of the Operating Factor for all hours the CEP unit has been dispatched during Off-peak Hours will be termed the Monthly Average Off-peak Operating Factor.

3. **Off-Peak and On-Peak Hours:** Those weekday hours occurring April 1 through October 31, from 12:00 noon to 9:00 p.m. and November 1 through March 31, from 6:00 a.m. to 10:00 a.m. and from 6:00 p.m. to 10:00 p.m. All other weekday hours and weekends shall be deemed Off-peak Hours including the following holidays: New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day, and Christmas Day. The Company shall have the right to change such On-peak Hours by providing written notice to CEP a minimum of 90 calendar days prior to such change.

4. **Annual Scheduled Maintenance:** Each year the CEP shall prepare, coordinate, and provide by April 1st all planned maintenance with the Company. The Company will review and approve annual/major scheduled maintenance by July 1st for the balance of the current year and following calendar year. A maximum of 4 days (72 hours) each year for annual maintenance and a total of 12 weeks (2,016 hours) every fifteenth year for major maintenance will be allowed. Scheduled maintenance shall not be planned during December through February without prior written consent from the Company. At the option of the CEP and by written notification to the Company, scheduled outage time may be utilized during any other months to improve the CEP's Availability and Capacity Factors and such scheduled outage hours will be disregarded from the Monthly Availability Factor and Capacity Factor calculations. However, once allowable maintenance hours have been utilized, all other hours during the year will be considered in Availability and Capacity Factor calculations.

5. **Monthly Capacity Payment**: Starting with the CEP's Commercial In-Service Date, for months when the CEP unit has been dispatched (provided that CEP has achieved at least a 90% Monthly Availability Factor), the Monthly Capacity Payment for each Monthly Period shall be calculated according to the following:

   a. In the event that the Monthly Capacity Factor is less than 80%, no Monthly Capacity Payment shall be paid to the CEP. That is:

   $$MCP = \$0$$

   b. In the event that the Monthly Capacity Factor is greater than or equal to 80% but less than 90%, the Monthly Capacity Payment shall be calculated from the following formula:

   $$MCP = [(BCC) \times (.02 \times (CF - 45))] \times CC$$

c. In the event that the Monthly Capacity Factor is greater than or equal to 90%, the Monthly Capacity Payment shall be calculated from the following formula:

MCP= (BCC) x CC

Where:

MCP = Monthly Capacity Payment in dollars.
BCC = Base Capacity Credit in $/KW-Month *(as exemplified by the Payment Schedules included in this Appendix for the minimum contract term under Capacity Payment Options 1, 2, 3 and 4.)*
CC = Contracted Capacity in KW
CF = Monthly Capacity Factor; or

During April 1 - October 31:

= 80% x Monthly Average On-peak Operating Factor +
20% x Monthly Average Off-peak Operating Factor

During November 1 - March 31:

= 90% x Monthly Average On-peak Operating Factor +
10% x Monthly Average Off-peak Operating Factor

6. **Non-Dispatch Condition:** The CEP may be entitled to a Monthly Capacity Payment (BCC x CC) even if the CEP's unit was not dispatched by the Company during a Monthly Period. In this instance however, in order to cover the Company's operating reserve criteria, the CEP unit must have achieved a minimum Monthly Availability Factor of 90% for the Monthly Period to be eligible to receive a Monthly Capacity Payment.

In the event the CEP unit is dispatched during one but not the other (On-peak vs. Off- peak) period during the month, the CEP's Monthly Average Operating Factor for the "non-dispatched" period will be set equal to the Monthly Average Operating Factor achieved during the "dispatched" period, for the purpose of calculating the Monthly Capacity Factor, as defined in Paragraph 2 above.

The CEP may be entitled to a Monthly Capacity Payment when the CEP's unit is out of service during the month for allowable scheduled maintenance in accordance with the Paragraph 4 above.

TAMPA ELECTRIC

FIFTH REVISED SHEET NO. 8.422
CANCELS FOURTH REVISED SHEET NO. 8.422

Continued from Sheet No. 8.418

PARAMETERS FOR AVOIDED CAPACITY COSTS

Beginning with the in-service date (5/12019) of the Company's Designated Avoided Unit, a 177 MW (Winter Rating) natural gas-fired Combustion Turbine, for a 1 year deferral:

			VALUE
VAC_m	=	Company's monthly value of avoided capacity, $/kW/month, for each month of year n	8.12
K	=	present value of carrying charges for one dollar of investment over L years with carrying charges computed using average annual rate base and assumed to be paid at the middle of each year and present value to the middle of the first year	1.4763
I_n	=	total direct and indirect cost, in mid-year $/kW including AFUDC but excluding CWIP, of the Designated Avoided Unit(s) with an in-service date of year n, including all identifiable and quantifiable costs relating to the construction of the Designated Avoided Unit that would have been paid had the Designated Avoided Unit(s) been constructed	878.11
O_n	=	total fixed operation and maintenance expense for the year n, in mid-year $/kW/year, of the Designated Avoided Unit(s);	9.67
i_p	=	annual escalation rate associated with the plant cost of the Designated Avoided Unit(s)	3.0%
i_o	=	annual escalation rate associated with the operation and maintenance expense of the Designated Avoided Unit(s);	2.4%
r	=	discount rate, defined as the Company's incremental after tax cost of capital;	7.95%

Continued to Sheet No. 4.424

TAMPA ELECTRIC

FIFTH REVISED SHEET NO. 8.424
CANCELS FOURTH REVISED SHEET NO. 8.424

Continue from Sheet No. 8.122

L	=	expected life of the Designated Avoided Unit(s); and	25
n	=	year for which the Designated Avoided Unit is deferred starting with its original anticipated in-service date and ending with the termination of the contract for the purchase of firm capacity and energy.	2019
A_m	=	monthly early capacity payments to be made to the CEP for each month of the contract year n, in $/kW/month, if payments start in2012;	3.25
m	=	Earliest year in which early capacity payments to the CEP may begin;	2012*
F	=	the cumulative present value, in the year contractual payments will begin, of the avoided capital cost component of capacity payments over the term of the contract which would have been made had capacity payments commenced with the anticipated in-service date of the Designated Avoided Unit(s);	411.58*
t	=	the term, in years, of the contract for the purchase of firm capacity if early capacity payments commence in year m;	17*

** Actual values will be determined based on the capacity payment start date and contract term selected by the CEP.*

Continued to Sheet No. 8.426

EXHIBIT NO. 24

DOCKET NO: 120234-EI – Polk Conversion Project Need Determination

WITNESS: Hornick

PARTY: TAMPA ELECTRIC COMPANY

DESCRIPTION: CROSS-EXAMINATION EXHIBIT

DOCUMENT: Excerpt from FPL 2012 Ten Year Site Plan,
Future Combined Cycle Costs,
Canaveral, Riviera, and Port Everglades Projects

PROFFERED BY: DeSoto Generating Company

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 120234-EI EXHIBIT 24
PARTY DeSoto Generating Company
DESCRIPTION Hornick - Excerpt from FPL, 2012 Ten Year Site Plan Future Combined Cycle Costs

Ten Year Power Plant Site Plan
2012 – 2021

FPL

DOCUMENT NUMBER-DATE
01983 APR-2 12
FPSC-COMMISSION CLERK

Schedule 9

Status Report and Specifications of Proposed Generating Facilities

(1) **Plant Name and Unit Number:** Cape Canaveral Next Generation Clean Energy Center

(2) **Capacity**
- a. Summer 1,210 MW
- b. Winter 1,355 MW

(3) **Technology Type:** Combined Cycle

(4) **Anticipated Construction Timing**
- a. Field construction start-date: 2011
- b. Commercial In-service date: 2013

(5) **Fuel**
- a. Primary Fuel: Natural Gas
- b. Alternate Fuel: Ultra-low sulfur distillate

(6) **Air Pollution and Control Strategy:** Dry Low NO_x Burners, SCR, Natural Gas, 0.0015% S. Distillate and Water Injection on Distillate

(7) **Cooling Method:** Once-through cooling water

(8) **Total Site Area:** 43 Acres

(9) **Construction Status:** U (Under construction, less than or equal to 50% complete)

(10) **Certification Status:** Permitted

(11) **Status with Federal Agencies:** Permitted

(12) **Projected Unit Performance Data:**

Planned Outage Factor (POF):	2.4%
Forced Outage Factor (FOF):	1.1%
Equivalent Availability Factor (EAF):	96.5%
Resulting Capacity Factor (%):	Approx. 90 % (First Full Year Base Operation)
Average Net Operating Heat Rate (ANOHR):	6,484 Btu/kWh
Base Operation 75F,100%	

(13) **Projected Unit Financial Data *,****

Book Life (Years):	30 years
Total Installed Cost (2013 $/kW):	921
Direct Construction Cost ($/kW):	
AFUDC Amount ($/kW):	98
Escalation ($/kW):	
Fixed O&M ($/kW-Yr): (2013 $)	13.29
Variable O&M ($/MWH): (2013 $)	0.16
K Factor:	1.484

* $/kW values are based on Summer capacity.
** Fixed O&M cost includes capital replacement.

NOTE: Total installed cost includes gas expansion, transmission interconnection and integration, escalation, and AFUDC. Demolition costs of existing plant are not included.

Schedule 9

Status Report and Specifications of Proposed Generating Facilities

(1) **Plant Name and Unit Number:** Riviera Beach Next Generation Clean Energy Center

(2) **Capacity**
- a. Summer 1,212 MW
- b. Winter 1,344 MW

(3) **Technology Type:** Combined Cycle

(4) **Anticipated Construction Timing**
- a. Field construction start-date: 2012
- b. Commercial In-service date: 2014

(5) **Fuel**
- a. Primary Fuel: Natural Gas
- b. Alternate Fuel: Ultra-low sulfur distillate

(6) **Air Pollution and Control Strategy:** Dry Low No_x Burners, SCR, Natural Gas, 0.0015% S. Distillate and Water Injection on Distillate

(7) **Cooling Method:** Once-through cooling water

(8) **Total Site Area:** 33 Acres

(9) **Construction Status:** U (Under construction, less than or equal to 50% complete)

(10) **Certification Status:** Permitted

(11) **Status with Federal Agencies:** Permitted

(12) **Projected Unit Performance Data:**

Planned Outage Factor (POF):	2.4%
Forced Outage Factor (FOF):	1.1%
Equivalent Availability Factor (EAF):	96.5%
Resulting Capacity Factor (%):	Approx. 90% (First Full Year Base Operation)
Average Net Operating Heat Rate (ANOHR):	6,480 Btu/kWh
Base Operation 75F,100%	

(13) **Projected Unit Financial Data *,****

Book Life (Years):	30 years
Total Installed Cost (2014 $/kW):	1,053
Direct Construction Cost ($/kW):	
AFUDC Amount ($/kW):	121
Escalation ($/kW):	
Fixed O&M ($/kW-Yr): (2014 $)	13.67
Variable O&M ($/MWH): (2014 $)	0.13
K Factor:	1.509

* $/kW values are based on Summer capacity.
** Fixed O&M cost includes capital replacement.

NOTE: Total installed cost includes gas expansion, transmission interconnection and integration, escalation, and AFUDC.Demolition costs of existing plant are not included.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1) **Plant Name and Unit Number:** Port Everglades Next Generation Clean Energy Center

(2) **Capacity**
a. Summer 1,277 MW
b. Winter 1,429 MW

(3) **Technology Type:** Combined Cycle

(4) **Anticipated Construction Timing**
a. Field construction start-date: 2014
b. Commercial In-service date: 2016

(5) **Fuel**
a. Primary Fuel: Natural Gas
b. Alternate Fuel: Ultra-low sulfur distillate

(6) **Air Pollution and Control Strategy:** Dry Low NO_x Burners, SCR, Natural Gas, 0.0015% S. Distillate and Water Injection on Distillate

(7) **Cooling Method:** Once-through cooling water

(8) **Total Site Area:** Existing Site Acres

(9) **Construction Status:** P (Planned Unit)

(10) **Certification Status:** ---

(11) **Status with Federal Agencies:** ---

(12) **Projected Unit Performance Data:**

Planned Outage Factor (POF):	3.5%	
Forced Outage Factor (FOF):	1.1%	
Equivalent Availability Factor (EAF):	95.4%	
Resulting Capacity Factor (%):	Approx. 90%	(First Full Year Base Operation)
Average Net Operating Heat Rate (ANOHR):	6,330	Btu/kWh
Base Operation 75F,100%		

(13) **Projected Unit Financial Data *,****

Book Life (Years):	30 years
Total Installed Cost (2016 $/kW):	928
Direct Construction Cost ($/kW):	
AFUDC Amount ($/kW):	87
Escalation ($/kW):	
Fixed O&M ($/kW-Yr): (2016 $)	30.00
Variable O&M ($/MWH): (2016 $)	0.10
K Factor:	1.51

* $/kW values are based on Summer capacity.
** Fixed O&M cost includes capital replacement.

NOTE: Total installed cost includes gas expansion, transmission interconnection and integration, escalation, and AFUDC. Demolition costs of existing plant are not included.

EXHIBIT NO. 25

DOCKET NO: 120234-EI – Polk Conversion Project Need Determination

WITNESS: Hornick/Rocha

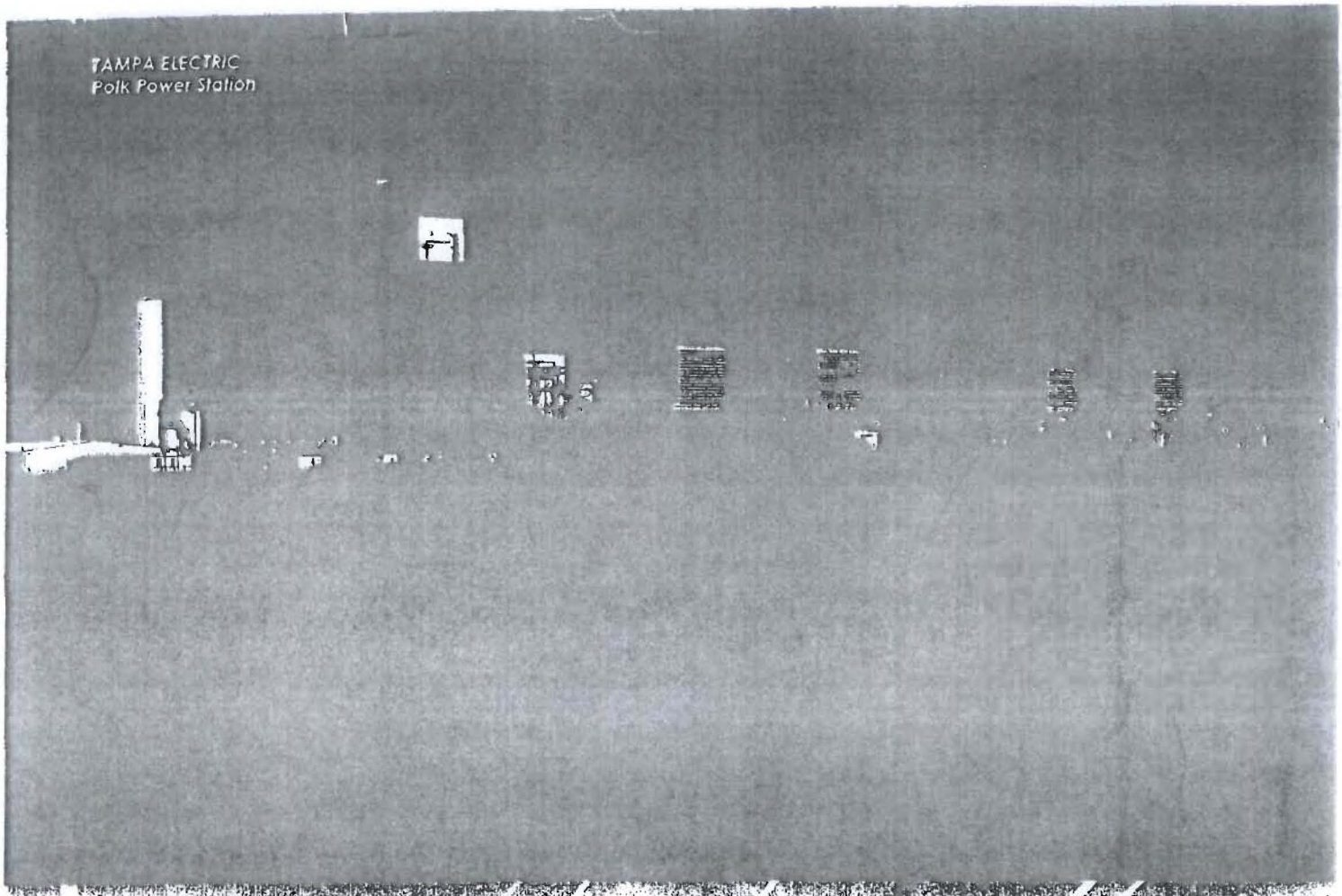
PARTY: TAMPA ELECTRIC COMPANY

DESCRIPTION: CROSS-EXAMINATION EXHIBIT

DOCUMENT: Excerpts from Tampa Electric's 2012 Ten-Year Site Plan

PROFFERED BY: DeSoto Generating Company

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 120234-EI EXHIBIT 25
PARTY DeSoto Generating Company
DESCRIPTION Hornick/Rocha - Excerpt from Tampa Electric 2012 Ten-Year Site Plan



TECO
TAMPA ELECTRIC

Ten-Year Site Plan for Electrical Generating Facilities and Associated Transmission Lines

January 2012 to December 2021

DOCUMENT NUMBER-DATE
01530 APR 02
FPSC-COMMISSION CLERK

Responsibly Serving Our Customers' Growing Needs

TEN-YEAR SITE PLAN FOR ELECTRICAL GENERATING FACILITIES AND ASSOCIATED TRANSMISSION LINES

January 2012 to December 2021

TAMPA ELECTRIC COMPANY
Tampa, Florida

April 1, 2012

DOCUMENT NUMBER-DATE
01955 APR-2 2
FPSC-COMMISSION CLERK

Schedule 5

History and Forecast of Fuel Requirements
Base Case Forecast Basis

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
	Fuel Requirements		Unit	Actual 2010	Actual 2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
(1)	Nuclear		Trillion BTU	0	0	0	0	0	0	0	0	0	0	0	0
(2)	Coal		1000 Ton	4,025	4,261	4,717	4,589	4,630	4,640	4,799	4,903	4,900	4,910	4,941	4,902
(3)	Residual	Total	1000 BBL	0	0	0	0	0	0	0	0	0	0	0	0
(4)		Steam	1000 BBL	0	0	0	0	0	0	0	0	0	0	0	0
(5)		CC	1000 BBL	0	0	0	0	0	0	0	0	0	0	0	0
(6)		CT	1000 BBL	0	0	0	0	0	0	0	0	0	0	0	0
(7)		Diesel	(A) 1000 BBL	0	0	0	0	0	0	0	0	0	0	0	0
(8)	Distillate	Total	1000 BBL	82	26	49	56	57	55	57	55	52	55	55	53
(9)		Steam	1000 BBL	0	0	0	0	0	0	0	0	0	0	0	0
(10)		CC	1000 BBL	59	26	49	55	55	52	55	55	52	55	55	52
(11)		CT	1000 BBL	23	0	0	1	2	3	2	0	0	0	0	1
(12)		Diesel	1000 BBL	0	0	0	0	0	0	0	0	0	0	0	0
(13)	Natural Gas	Total	1000 MCF	61,924	55,515	54,996	59,448	59,058	60,136	58,898	56,272	58,246	59,352	60,408	63,044
(14)		Steam	1000 MCF	0	0	0	0	0	0	0	0	0	0	0	0
(15)		CC	1000 MCF	57,625	49,542	52,952	56,489	55,650	56,142	54,778	56,259	58,094	59,225	60,099	62,459
(16)		CT	1000 MCF	4,299	5,973	2,044	2,959	3,408	3,995	4,120	13	152	127	309	585
(17)	Other (Specify)														
(18)	Petroleum Coke		1000 Ton	481	439	297	324	325	310	323	325	309	325	327	311

(A) Data reported as diesel for Phillips Units 1 and 2.
Notes: Values shown may be affected due to rounding.
All values exclude ignition.

Schedule 6.1

History and Forecast of Net Energy for Load by Fuel Source in GWH
Base Case Forecast Basis

(1)	(2)	(3)		(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
	Energy Sources			Unit	Actual 2010	Actual 2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
(1)	Annual Firm Interchange			GWh	864	461	334	99	120	147	212	2	5	0	0	0
(2)	Nuclear			GWh	0	0	0	0	0	0	0	0	0	0	0	0
(3)	Coal			GWh	9,267	9,657	10,933	10,647	10,745	10,761	11,119	11,397	11,386	11,401	11,460	11,396
(4)	Residual	Total		GWh	0	0	0	0	0	0	0	0	0	0	0	0
(5)		Steam		GWh	0	0	0	0	0	0	0	0	0	0	0	0
(6)		CC		GWh	0	0	0	0	0	0	0	0	0	0	0	0
(7)		CT		GWh	0	0	0	0	0	0	0	0	0	0	0	0
(8)		Diesel	(A)	GWh	0	0	0	0	0	0	0	0	0	0	0	0
(9)	Distillate	Total		GWh	49	13	28	32	32	31	32	31	30	31	31	30
(10)		Steam		GWh	0	0	0	0	0	0	0	0	0	0	0	0
(11)		CC		GWh	38	13	28	31	31	30	31	31	30	31	31	30
(12)		CT		GWh	12	0	0	1	1	1	1	0	0	0	0	0
(13)		Diesel		GWh	0	0	0	0	0	0	0	0	0	0	0	0
(14)	Natural Gas	Total		GWh	8,375	7,392	7,456	8,014	7,942	8,075	7,904	8,033	8,304	8,477	8,630	8,949
(15)		Steam		GWh	0	0	0	0	0	0	0	0	0	0	0	0
(16)		CC		GWh	8,004	6,860	7,275	7,754	7,642	7,723	7,540	8,032	8,290	8,466	8,603	8,897
(17)		CT		GWh	371	532	181	260	300	352	364	1	14	11	27	52
(18)	Other (Specify)															
(19)	Petroleum Coke Generation			GWh	1,346	1,231	812	888	895	854	884	883	848	894	899	854
(20)	Net Interchange			GWh	235	177	292	307	308	307	309	305	305	303	308	309
(21)	Purchased Energy from															
(22)	Non-Utility Generators		(B)	GWh	530	393	225	194	184	183	112	111	111	111	112	111
(23)	Net Energy for Load			GWh	20,667	19,325	20,080	20,180	20,226	20,358	20,571	20,772	20,991	21,217	21,439	21,649

(A) Data reported as diesel for Phillips Units 1 and 2.

(B) Line (22) includes energy purchased from Non-Renewable and Renewable resources.

Notes: Values shown may be affected due to rounding.

successful completion of the program's Phase II greenhouse gas commitment of a 6% carbon dioxide (CO2) reduction. With an actual reduction of more than 13% in 2010, the company far surpassed the CCX target.

Through a proactive approach, Tampa Electric has achieved significant levels of emission reduction. However, the company recognizes that environmental regulations continue to change. As these regulations evolve, they will impact both cost and operations.

INTERCHANGE SALES AND PURCHASES

Tampa Electric has the following long-term firm sale agreements:

- 15 MW to the City of St. Cloud through December 2012
- 75 MW winter and 125 MW summer to Florida Power & Light through December 2012

Tampa Electric has the following long-term purchase power contracts for capacity and energy:

- 441 MW winter and 356 MW summer from the Hardee Power Station through December 2012
- 117 MW from Calpine Energy Services for the period November 2011 through December 2016
- 158 MW from RRI Energy (previously Reliant Energy Services) through May 2012
- 160 MW from Southern Power Company for the period January 2013 through December 2015 (Tampa Electric has an option to extend this agreement and will compare it to the unspecified purchase power of 160 MW noted in Schedules 7.1 and 7.2 for the period January 2016 through December 2016)
- 121 MW from Pasco Cogen for the period January 2009 through December 2018

The wholesale power sales and purchases are included in Schedules 3.1, 3.2, 3.3, 4, 5, 6.1, 7.1, and 7.2.

Schedule 7.1

Forecast of Capacity, Demand, and Scheduled Maintenance at Time of Summer Peak

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
Year	Total Installed Capacity MW	Firm Capacity Import MW	Firm Capacity Export MW	QF MW	Total Capacity Available MW	System Firm Summer Peak Demand MW	Reserve Margin Before Maintenance MW	Reserve Margin Before Maintenance % of Peak	Scheduled Maintenance MW	Reserve Margin After Maintenance MW	Reserve Margin After Maintenance % of Peak
2012	4,292	594	0	23	4,909	3,890	1,019	26%	0	1,019	26%
2013	4,312	398	0	23	4,733	3,784	949	25%	0	949	25%
2014	4,312	398	0	23	4,733	3,823	910	24%	0	910	24%
2015	4,312	398	0	23	4,733	3,859	874	23%	0	874	23%
2016	4,312	398	0	0	4,710	3,900	810	21%	0	810	21%
2017	4,771	121	0	0	4,892	3,940	952	24%	0	952	24%
2018	4,771	121	0	0	4,892	3,980	912	23%	0	912	23%
2019	4,920	0	0	0	4,920	4,022	898	22%	0	898	22%
2020	4,920	0	0	0	4,920	4,064	856	21%	0	856	21%
2021	4,920	0	0	0	4,920	4,103	817	20%	0	817	20%

NOTE:
1. Capacity import includes firm purchase power agreements (PPA) with Invenergy of 356 MW through 2012, Calpine of 117 MW through 2016, Reliant of 158 MW through May 2012, Southern of 160 MW through 2015, STC of 15 MW through 2012, Pasco Cogen of 121 MW through 2018, and an unspecified 160 MW in 2016.
2. The QF column accounts for cogeneration that will be purchased under firm contracts, and excludes non-firm purchases.

Schedule 7.2

Forecast of Capacity, Demand, and Scheduled Maintenance at Time of Winter Peak

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
Year	Total Installed Capacity MW	Firm Capacity Import MW	Firm Capacity Export MW	QF MW	Total Capacity Available MW	System Firm Winter Peak Demand MW	Reserve Margin Before Maintenance MW	Reserve Margin Before Maintenance % of Peak	Scheduled Maintenance MW	Reserve Margin After Maintenance MW	Reserve Margin After Maintenance % of Peak
2011-12	4,684	837	0	23	5,544	3,868	1,676	43%	0	1,676	43%
2012-13	4,684	398	0	23	5,105	3,819	1,286	34%	0	1,286	34%
2013-14	4,714	398	0	23	5,135	3,864	1,271	33%	0	1,271	33%
2014-15	4,714	398	0	23	5,135	3,910	1,225	31%	0	1,225	31%
2015-16	4,714	398	0	0	5,112	3,955	1,157	29%	0	1,157	29%
2016-17	5,177	121	0	0	5,298	4,003	1,295	32%	0	1,295	32%
2017-18	5,177	121	0	0	5,298	4,050	1,248	31%	0	1,248	31%
2018-19	5,177	0	0	0	5,177	4,097	1,080	26%	0	1,080	26%
2019-20	5,354	0	0	0	5,354	4,146	1,208	29%	0	1,208	29%
2020-21	5,354	0	0	0	5,354	4,194	1,160	28%	0	1,160	28%

NOTE:
1. Capacity import includes firm purchase power agreements (PPA) with Invenergy of 356 MW through 2012, Calpine of 117 MW through 2016, Reliant of 158 MW through May 2012, Southern of 160 MW through 2015, STC of 15 MW through 2012, Pasco Cogen of 121 MW through 2018, and an unspecified 160 MW in 2016.
2. The QF column accounts for cogeneration that will be purchased under firm contracts, and excludes non-firm purchases.

Schedule 8.1

Planned and Prospective Generating Facility Additions

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
Plant Name	Unit No.	Location	Unit Type	Fuel Primary	Fuel Alternate	Fuel Trans. Primary	Fuel Trans. Alternate	Const. Start Mo/Yr	Commercial In-Service Mo/Yr	Expected Retirement Mo/Yr	Gen. Max. Nameplate kW	Net Capability Summer MW	Net Capability Winter MW	Status
Polk 2-5 CC	1	Polk	CC	NG	N/A	PL	N/A	10/14	1/17	unknown	unknown	1063*	1195*	P
Future CT	1	unknown	CT	NG	N/A	PL	N/A	9/18	5/19	unknown	unknown	149	177	P

Notes:

* Net capability values shown for the Polk 2-5 CC reflect the conversion of Polk Units 2-5 CTs to a natural gas CC unit in 2017. Incremental capacity gain from the conversion is 459 MW summer and 463 MW winter.

SCHEDULE 9
(Page 1 of 2)
STATUS REPORT AND SPECIFICATIONS OF PROPOSED GENERATING FACILITIES
UTILITY: TAMPA ELECTRIC COMPANY

(1)	PLANT NAME AND UNIT NUMBER	POLK 2-5 CC CONVERSION
(2)	CAPACITY	
	A. SUMMER	1063
	B. WINTER	1195
(3)	TECHNOLOGY TYPE	COMBINED CYCLE
(4)	ANTICIPATED CONSTRUCTION TIMING	
	A. FIELD CONSTRUCTION START DATE	OCT 2014
	B. COMMERCIAL IN-SERVICE DATE	JAN 2017
(5)	FUEL	
	A. PRIMARY FUEL	NATURAL GAS
	B. ALTERNATE FUEL	DISTILLATE OIL
(6)	AIR POLLUTION CONTROL STRATEGY	SCR, DLN BURNERS
(7)	COOLING METHOD	N/A
(8)	TOTAL SITE AREA	UNDETERMINED
(9)	CONSTRUCTION STATUS	PROPOSED
(10)	CERTIFICATION STATUS	UNDETERMINED
(11)	STATUS WITH FEDERAL AGENCIES	N/A
(12)	PROJECTED UNIT PERFORMANCE DATA	
	PLANNED OUTAGE FACTOR (POF)	3.2
	FORCED OUTAGE RATE (FOR)	0.7
	EQUIVALENT AVAILABILITY FACTOR (EAF)	96.1
	RESULTING CAPACITY FACTOR (2017)	48.2%
	AVERAGE NET OPERATING HEAT RATE (ANOHR) [1]	7,012 Btu/kWh
(13)	PROJECTED UNIT FINANCIAL DATA	
	BOOK LIFE (YEARS)	30
	TOTAL INSTALLED COST (IN-SERVICE YEAR $/kW)	448.01
	DIRECT CONSTRUCTION COST ($/kW)	355.17
	AFUDC AMOUNT ($/kW)	61.34
	ESCALATION ($/kW)	31.51
	FIXED O&M ($/kW – Yr)	1.27
	VARIABLE O&M ($/MWH)	2.43
	K FACTOR	1.5383

[1] BASED ON IN-SERVICE YEAR.

SCHEDULE 9
(Page 2 of 2)
STATUS REPORT AND SPECIFICATIONS OF PROPOSED GENERATING FACILITIES
UTILITY: TAMPA ELECTRIC COMPANY

(1)	PLANT NAME AND UNIT NUMBER	FUTURE CT 1
(2)	CAPACITY	
	A. SUMMER	149
	B. WINTER	177
(3)	TECHNOLOGY TYPE	COMBUSTION TURBINE
(4)	ANTICIPATED CONSTRUCTION TIMING	
	A. FIELD CONSTRUCTION START DATE	SEP 2018
	B. COMMERCIAL IN-SERVICE DATE	MAY 2019
(5)	FUEL	
	A. PRIMARY FUEL	NATURAL GAS
	B. ALTERNATE FUEL	N/A
(6)	AIR POLLUTION CONTROL STRATEGY	WET LOW EMISSION
(7)	COOLING METHOD	N/A
(8)	TOTAL SITE AREA	UNDETERMINED
(9)	CONSTRUCTION STATUS	PROPOSED
(10)	CERTIFICATION STATUS	UNDETERMINED
(11)	STATUS WITH FEDERAL AGENCIES	N/A
(12)	PROJECTED UNIT PERFORMANCE DATA	
	PLANNED OUTAGE FACTOR (POF)	2.6
	FORCED OUTAGE RATE (FOR)	1.0
	EQUIVALENT AVAILABILITY FACTOR (EAF)	95.4
	RESULTING CAPACITY FACTOR (2019)	0.3%
	AVERAGE NET OPERATING HEAT RATE (ANOHR) [1]	11,983 Btu/kWh
(13)	PROJECTED UNIT FINANCIAL DATA	
	BOOK LIFE (YEARS)	25
	TOTAL INSTALLED COST (IN-SERVICE YEAR $/kW)	878.11
	DIRECT CONSTRUCTION COST ($/kW)	689.31
	AFUDC AMOUNT ($/kW)	67.03
	ESCALATION ($/kW)	121.77
	FIXED O&M ($/kW – Yr)	9.67
	VARIABLE O&M ($/MWH)	4.87
	K FACTOR	1.4763

[1] BASED ON IN-SERVICE YEAR.

EXHIBIT NO. 26

DOCKET NO: 120234-EI – Polk Conversion Project Need Determination

WITNESS: Caldwell

PARTY: TAMPA ELECTRIC COMPANY

DESCRIPTION: CROSS-EXAMINATION EXHIBIT

DOCUMENT: Tampa Electric's Responses to Staff's POD Requests 22, 23, and 24

PROFFERED BY: DeSoto Generating Company

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 120234-EI EXHIBIT 26
PARTY DeSoto Generating Company
DESCRIPTION Caldwell - Tampa Electric's Responses to Staff's' POD Requests 22, 23, and 24

TAMPA ELECTRIC COMPANY
DOCKET NO. 120234-EI
STAFF'S SECOND REQUEST FOR
PRODUCTION OF DOCUMENTS
DOCUMENT NO. 22
BATES STAMPED PAGES: 984 - 985
FILED: OCTOBER 23, 2012

22. Witness Caldwell stated that TECO's fuel price forecast used in the Polk 2-5 economic analyses was the same official long-term forecast prepared in the summer of 2011. Please provide documents containing the full 30-year fuel price forecast TECO prepared in the summer of 2011, inclusive of the years 2011 through 2040.

A. Tampa Electric prepared a 30-year outlook in the summer of 2011 for the 2012 Fuel and Purchase Power Recovery Clause projection. Please see attached document.

Tampa Electric Fuel Price Forecasts
2011 - 2040

	Natural Gas	No. 2 Oil		Illinois Basin Coal	
Year	$/MMBtu	$/Gallon	$/MMBtu	$/ton	$/MMBtu
2011	$4.30	$3.01	$21.69	$43.79	$1.90
2012	$4.76	$3.10	$22.33	$51.07	$2.22
2013	$5.12	$3.33	$24.04	$55.57	$2.42
2014	$5.39	$3.51	$25.32	$56.45	$2.45
2015	$5.67	$3.69	$26.62	$58.88	$2.56
2016	$5.95	$3.88	$27.96	$55.48	$2.41
2017	$6.23	$4.06	$29.25	$55.24	$2.40
2018	$6.51	$4.24	$30.58	$52.26	$2.27
2019	$6.79	$4.42	$31.88	$56.19	$2.44
2020	$7.07	$4.60	$33.17	$60.34	$2.62
2021	$7.34	$4.78	$34.48	$64.31	$2.80
2022	$7.63	$4.97	$35.83	$68.39	$2.97
2023	$7.80	$5.08	$36.62	$70.77	$3.08
2024	$7.97	$5.19	$37.42	$73.19	$3.18
2025	$8.14	$5.30	$38.22	$75.64	$3.29
2026	$8.31	$5.41	$39.04	$78.10	$3.40
2027	$8.49	$5.53	$39.86	$80.59	$3.50
2028	$8.67	$5.64	$40.70	$83.12	$3.61
2029	$8.85	$5.76	$41.55	$85.70	$3.73
2030	$9.03	$5.88	$42.41	$88.32	$3.84
2031	$9.22	$6.00	$43.29	$90.99	$3.96
2032	$9.41	$6.13	$44.19	$93.70	$4.07
2033	$9.61	$6.26	$45.10	$96.47	$4.19
2034	$9.80	$6.38	$46.03	$99.29	$4.32
2035	$10.01	$6.52	$46.98	$102.16	$4.44
2036	$10.21	$6.65	$47.95	$105.09	$4.57
2037	$10.42	$6.79	$48.93	$108.07	$4.70
2038	$10.64	$6.93	$49.94	$111.11	$4.83
2039	$10.85	$7.07	$50.96	$114.21	$4.97
2040	$11.08	$7.21	$52.00	$117.37	$5.10

TAMPA ELECTRIC COMPANY
DOCKET NO. 120234-EI
STAFF'S SECOND REQUEST FOR
PRODUCTION OF DOCUMENTS
DOCUMENT NO. 23
BATES STAMPED PAGES: 986 - 987
FILED: OCTOBER 23, 2012

23. Please provide documents containing TECO's updated 30-year fuel price forecasts for the 2013 fuel and purchased power cost recovery clause projection filing, in hard copy and in Excel format as available, as referenced in witness Caldwell's direct testimony at Page 16, Lines 22-24.

A. Please see attached document.

Tampa Electric Fuel Price Forecasts
2012 - 2041

	Natural Gas	No. 2 Oil		Illinois Basin Coal	
Year	$/MMBtu	$/Gallon	$/MMBtu	$/ton	$/MMBtu
2012	$3.09	$3.00	$21.60	$42.21	$1.84
2013	$4.00	$2.85	$20.53	$45.00	$1.96
2014	$4.23	$2.79	$20.11	$47.09	$2.05
2015	$4.43	$2.73	$19.72	$48.05	$2.09
2016	$4.60	$2.82	$20.32	$46.32	$2.01
2017	$4.78	$2.92	$21.03	$47.76	$2.08
2018	$4.96	$2.99	$21.56	$48.39	$2.10
2019	$5.20	$3.07	$22.10	$48.75	$2.12
2020	$5.45	$3.16	$22.77	$50.26	$2.19
2021	$5.71	$3.24	$23.38	$50.93	$2.21
2022	$6.06	$3.33	$23.98	$51.93	$2.26
2023	$6.40	$3.41	$24.60	$54.07	$2.35
2024	$6.68	$3.50	$25.24	$55.73	$2.42
2025	$7.01	$3.61	$26.05	$57.95	$2.52
2026	$7.32	$3.72	$26.79	$60.18	$2.62
2027	$7.67	$3.81	$27.49	$62.44	$2.71
2028	$7.94	$3.92	$28.28	$64.63	$2.81
2029	$8.27	$4.05	$29.22	$67.15	$2.92
2030	$8.63	$4.18	$30.13	$69.65	$3.03
2031	$9.01	$4.37	$31.51	$72.52	$3.15
2032	$9.44	$4.53	$32.66	$75.44	$3.28
2033	$9.79	$4.57	$32.95	$77.90	$3.39
2034	$10.50	$4.72	$34.02	$81.99	$3.56
2035	$11.19	$4.89	$35.26	$86.27	$3.75
2036	$11.62	$5.06	$36.50	$89.91	$3.91
2037	$12.08	$5.24	$37.78	$93.70	$4.07
2038	$12.56	$5.42	$39.10	$97.65	$4.25
2039	$13.05	$5.61	$40.47	$101.77	$4.42
2040	$13.56	$5.81	$41.88	$106.06	$4.61
2041	$14.10	$6.01	$43.35	$110.53	$4.81

TAMPA ELECTRIC COMPANY
DOCKET NO. 120234-EI
STAFF'S SECOND REQUEST FOR
PRODUCTION OF DOCUMENTS
DOCUMENT NO. 24
BATES STAMPED PAGES: 988 - 990
FILED: OCTOBER 23, 2012

24. Please provide a document containing TECO's high and low price forecasts of natural gas, distillate oil, residential oil, and coal as referenced in witness Caldwell's direct testimony at page 16.

A. Please see the attached document.

Tampa Electric Fuel Price Forecasts
2011 - 2040
Low Forecast

	Natural Gas	No. 2 Oil		Illinois Basin Coal	
Year	$/MMBtu	$/Gallon	$/MMBtu	$/ton	$/MMBtu
2012	$2.01	$1.95	$14.04	$43.79	$1.90
2013	$2.60	$1.85	$13.34	$51.07	$2.22
2014	$2.75	$1.81	$13.07	$44.46	$1.93
2015	$2.88	$1.78	$12.82	$45.16	$1.96
2016	$2.99	$1.83	$13.20	$47.11	$2.05
2017	$3.10	$1.90	$13.67	$44.39	$1.93
2018	$3.23	$1.94	$14.01	$44.19	$1.92
2019	$3.38	$1.99	$14.37	$41.81	$1.82
2020	$3.55	$2.05	$14.80	$45.40	$1.97
2021	$3.71	$2.11	$15.19	$49.19	$2.14
2022	$3.94	$2.16	$15.58	$52.81	$2.30
2023	$4.16	$2.22	$15.99	$56.54	$2.46
2024	$4.34	$2.28	$16.41	$58.71	$2.55
2025	$4.56	$2.35	$16.93	$60.92	$2.65
2026	$4.76	$2.41	$17.41	$63.15	$2.75
2027	$4.99	$2.48	$17.87	$65.40	$2.84
2028	$5.16	$2.55	$18.38	$67.67	$2.94
2029	$5.38	$2.63	$18.99	$69.98	$3.04
2030	$5.61	$2.72	$19.58	$72.33	$3.14
2031	$5.85	$2.84	$20.48	$74.72	$3.25
2032	$6.13	$2.94	$21.23	$77.16	$3.35
2033	$6.37	$2.97	$21.42	$79.64	$3.46
2034	$6.82	$3.07	$22.11	$82.17	$3.57
2035	$7.27	$3.18	$22.92	$84.74	$3.68
2036	$7.56	$3.29	$23.72	$87.36	$3.80
2037	$7.85	$3.41	$24.55	$90.03	$3.91
2038	$8.16	$3.52	$25.41	$92.76	$4.03
2039	$8.48	$3.65	$26.30	$95.53	$4.15
2040	$8.82	$3.78	$27.22	$98.36	$4.28
2041	$9.16	$3.91	$28.18	$101.24	$4.40

Tampa Electric Fuel Price Forecasts
2011 - 2040
High Forecast

	Natural Gas	No. 2 Oil		Illinois Basin Coal	
Year	$/MMBtu	$/Gallon	$/MMBtu	$/ton	$/MMBtu
2012	$4.17	$4.04	$29.16	$43.79	$1.90
2013	$5.40	$3.84	$27.72	$51.07	$2.22
2014	$5.71	$3.76	$27.14	$66.69	$2.90
2015	$5.98	$3.69	$26.62	$67.74	$2.95
2016	$6.21	$3.80	$27.43	$70.66	$3.07
2017	$6.45	$3.94	$28.39	$66.58	$2.89
2018	$6.70	$4.04	$29.10	$66.29	$2.88
2019	$7.02	$4.14	$29.84	$62.71	$2.73
2020	$7.36	$4.26	$30.74	$66.91	$2.91
2021	$7.71	$4.38	$31.56	$71.34	$3.10
2022	$8.19	$4.49	$32.37	$75.58	$3.29
2023	$8.64	$4.61	$33.21	$79.94	$3.48
2024	$9.02	$4.73	$34.08	$82.48	$3.59
2025	$9.47	$4.88	$35.17	$85.06	$3.70
2026	$9.89	$5.02	$36.16	$87.68	$3.81
2027	$10.36	$5.15	$37.12	$90.31	$3.93
2028	$10.72	$5.29	$38.18	$92.97	$4.04
2029	$11.17	$5.47	$39.44	$95.67	$4.16
2030	$11.65	$5.64	$40.67	$98.42	$4.28
2031	$12.16	$5.90	$42.53	$101.22	$4.40
2032	$12.74	$6.12	$44.09	$104.07	$4.52
2033	$13.22	$6.17	$44.48	$106.97	$4.65
2034	$14.17	$6.37	$45.93	$109.93	$4.78
2035	$15.10	$6.60	$47.61	$112.94	$4.91
2036	$15.69	$6.83	$49.27	$116.00	$5.04
2037	$16.31	$7.07	$51.00	$119.13	$5.18
2038	$16.95	$7.32	$52.78	$122.31	$5.32
2039	$17.62	$7.58	$54.63	$125.56	$5.46
2040	$18.31	$7.84	$56.54	$128.87	$5.60
2041	$19.03	$8.12	$58.52	$132.24	$5.75

EXHIBIT NO. 27

DOCKET NO: 120234-EI – Polk Conversion Project Need Determination

WITNESS: Caldwell

PARTY: TAMPA ELECTRIC COMPANY

DESCRIPTION: CROSS-EXAMINATION EXHIBIT

DOCUMENT: 12/6/2012 Download of 2013-2025 NYMEX Henry Hub Natural Gas Prices

PROFFERED BY: DeSoto Generating Company

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 120234-EI EXHIBIT 27
PARTY DeSoto Generating Company
DESCRIPTION Caldwell - 12/6/12 NYMEX Gas Price

Trade Date 12/6/2012
Source: NYMEX

Year	Heating Oil ~ No 2 Fuel Oil ($/MMBTu)	Henry Hub Natural Gas ($/MMBTu)
2013	$ 21.74	$ 3.80
2014	$ 21.21	$ 4.15
2015	$ 20.74	$ 4.31
2016	$ 20.49	$ 4.46
2017	$ 20.50	$ 4.64
2018	N/A	$ 4.85
2019	N/A	$ 5.09
2020	N/A	$ 5.36
2021	N/A	$ 5.66
2022	N/A	$ 5.99
2023	N/A	$ 6.33
2024	N/A	$ 6.70
2025	N/A	$ 7.07

EXHIBIT NO. 28

DOCKET NO: 120234-EI – Polk Conversion Project Need Determination

WITNESS: Caldwell

PARTY: TAMPA ELECTRIC COMPANY

DESCRIPTION: CROSS-EXAMINATION EXHIBIT

DOCUMENT: Table A3, Energy Prices by Sector and Source,
U.S. Energy Information Administration,
Annual Energy Outlook 2013

PROFFERED BY: DeSoto Generating Company

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 120234-EI EXHIBIT 28
PARTY Future Combined Cycke Costs,
DESCRIPTION Caldwell - Table A3, Energy Prices by Sector and Source, U.S. Energy Information Administration, Annual Energy Outlook 2013

Table A3. Energy prices by sector and source
(2011 dollars per million Btu, unless otherwise noted)

Sector and source	Reference case							Annual growth 2011-2040 (percent)
	2010	2011	2020	2025	2030	2035	2040	
Residential								
Propane	27.61	25.06	23.41	24.77	25.73	26.70	27.99	0.4%
Distillate fuel oil	21.77	26.38	26.91	29.08	31.26	33.71	36.54	1.1%
Natural gas	11.36	10.80	11.78	12.67	13.37	14.60	16.36	1.4%
Electricity	34.52	34.34	33.62	33.96	34.56	35.42	37.10	0.3%
Commercial								
Propane	24.10	22.10	20.04	21.74	22.97	24.23	25.94	0.6%
Distillate fuel oil	21.35	25.87	24.26	26.51	28.51	30.91	33.74	0.9%
Residual fuel oil	11.39	19.17	14.82	16.60	18.77	20.89	23.41	0.7%
Natural gas	9.40	8.84	9.47	10.19	10.70	11.68	13.21	1.4%
Electricity	30.49	29.98	28.57	28.49	28.65	29.66	31.75	0.2%
Industrial[1]								
Propane	23.73	22.54	20.51	22.33	23.64	24.97	26.78	0.6%
Distillate fuel oil	21.87	26.50	24.67	27.02	28.91	31.31	34.16	0.9%
Residual fuel oil	11.30	18.86	17.19	18.96	21.09	23.25	25.78	1.1%
Natural gas[2]	5.48	4.89	5.53	6.15	6.56	7.45	8.88	2.1%
Metallurgical coal	5.96	7.01	8.75	9.36	10.09	10.69	11.11	1.6%
Other industrial coal	2.77	3.43	3.44	3.56	3.71	3.88	4.06	0.6%
Coal to liquids	--	--	--	2.30	2.55	2.76	2.95	--
Electricity	20.26	19.98	18.72	19.18	19.73	20.80	22.74	0.4%
Transportation								
Propane[3]	27.52	26.06	24.48	25.83	26.80	27.77	29.07	0.4%
E85[4]	25.56	25.30	29.64	27.27	26.94	29.19	30.58	0.7%
Motor gasoline[5]	23.18	28.70	27.84	29.26	30.73	32.99	36.18	0.8%
Jet fuel[6]	16.57	22.49	21.50	23.73	26.03	28.52	31.07	1.1%
Diesel fuel (distillate fuel oil)[7]	22.38	26.15	26.61	28.98	30.81	33.19	36.05	1.1%
Residual fuel oil	10.62	17.83	14.91	16.58	18.34	20.25	22.45	0.8%
Natural gas[8]	16.51	16.14	16.87	17.97	18.90	19.86	21.20	0.9%
Electricity	33.91	32.77	29.60	30.40	31.53	32.84	35.07	0.2%
Electric power[9]								
Distillate fuel oil	19.22	23.30	22.45	24.61	26.80	29.23	32.03	1.1%
Residual fuel oil	12.11	15.97	24.94	27.29	29.36	31.85	34.54	2.7%
Natural gas	5.26	4.77	4.90	5.58	6.05	6.98	8.38	2.0%
Steam coal	2.30	2.38	2.52	2.69	2.87	3.03	3.20	1.0%
Average price to all users[10]								
Propane	16.23	17.13	13.69	16.07	18.14	20.43	23.79	1.1%
E85[4]	25.56	25.30	29.64	27.27	26.94	29.19	30.58	0.7%
Motor gasoline[5]	23.06	28.47	27.84	29.26	30.72	32.99	36.17	0.8%
Jet fuel	16.57	22.49	21.50	23.73	26.03	28.52	31.07	1.1%
Distillate fuel oil	22.17	26.18	26.25	28.62	30.48	32.88	35.73	1.1%
Residual fuel oil	11.06	17.65	15.97	17.72	19.59	21.61	23.95	1.1%
Natural gas	7.27	6.68	7.07	7.76	8.27	9.31	10.94	1.7%
Metallurgical coal	5.96	7.01	8.75	9.36	10.09	10.69	11.11	1.6%
Other coal	2.33	2.45	2.57	2.74	2.92	3.08	3.25	1.0%
Coal to liquids	--	--	--	2.30	2.55	2.76	2.95	--
Electricity	29.40	29.03	27.50	27.79	28.41	29.55	31.58	0.3%
Non-renewable energy expenditures by sector (billion 2011 dollars)								
Residential	253.56	248.08	243.44	256.13	271.05	290.43	319.63	0.9%
Commercial	182.47	179.97	181.68	192.15	203.80	221.86	249.60	1.1%
Industrial	210.38	225.18	259.03	283.62	294.99	316.87	353.70	1.6%
Transportation	584.31	718.25	694.73	722.24	749.40	808.74	900.68	0.8%
Total non-renewable expenditures	1,230.73	1,371.48	1,378.87	1,454.13	1,519.24	1,637.91	1,823.61	1.0%
Transportation renewable expenditures	0.16	1.24	2.44	3.92	4.39	4.43	5.05	5.0%
Total expenditures	**1,230.88**	**1,372.71**	**1,381.31**	**1,458.06**	**1,523.63**	**1,642.34**	**1,828.66**	**1.0%**

Table A3. Energy prices by sector and source (continued)
(nominal dollars per million Btu, unless otherwise noted)

Sector and source	Reference case							Annual growth 2011-2040 (percent)
	2010	2011	2020	2025	2030	2035	2040	
Residential								
Propane	27.04	25.06	27.00	31.21	35.51	40.35	46.20	2.1%
Distillate fuel oil	21.31	26.38	31.03	36.64	43.14	50.93	60.31	2.9%
Natural gas	11.12	10.80	13.58	15.97	18.45	22.06	27.01	3.2%
Electricity	33.80	34.34	38.76	42.80	47.69	53.52	61.23	2.0%
Commercial								
Propane	23.60	22.10	23.11	27.39	31.70	36.62	42.82	2.3%
Distillate fuel oil	20.91	25.87	27.97	33.41	39.34	46.71	55.68	2.7%
Residual fuel oil	11.15	19.17	17.09	20.92	25.90	31.56	38.64	2.4%
Natural gas	9.20	8.84	10.92	12.85	14.76	17.65	21.81	3.2%
Electricity	29.86	29.98	32.94	35.90	39.54	44.82	52.40	1.9%
Industrial[1]								
Propane	23.23	22.54	23.65	28.14	32.62	37.74	44.20	2.3%
Distillate fuel oil	21.42	26.50	28.45	34.05	39.89	47.31	56.39	2.6%
Residual fuel oil	11.06	18.86	19.82	23.89	29.10	35.13	42.55	2.8%
Natural gas[2]	5.37	4.89	6.38	7.75	9.05	11.25	14.66	3.9%
Metallurgical coal	5.84	7.01	10.09	11.79	13.92	16.15	18.34	3.4%
Other industrial coal	2.71	3.43	3.97	4.48	5.12	5.86	6.70	2.3%
Coal to liquids	--	--	--	2.90	3.52	4.17	4.87	--
Electricity	19.84	19.98	21.59	24.17	27.22	31.42	37.54	2.2%
Transportation								
Propane[3]	26.95	26.06	28.22	32.56	36.98	41.97	47.97	2.1%
E85[4]	25.03	25.30	34.18	34.37	37.18	44.10	50.46	2.4%
Motor gasoline[5]	22.70	28.70	32.10	36.88	42.41	49.85	59.72	2.6%
Jet fuel[6]	16.22	22.49	24.79	29.90	35.92	43.09	51.27	2.9%
Diesel fuel (distillate fuel oil)[7]	21.91	26.15	30.68	36.52	42.52	50.16	59.50	2.9%
Residual fuel oil	10.40	17.83	17.19	20.89	25.31	30.60	37.06	2.6%
Natural gas[8]	16.17	16.14	19.46	22.65	26.08	30.01	34.98	2.7%
Electricity	33.20	32.77	34.13	38.31	43.51	49.63	57.88	2.0%
Electric power[9]								
Distillate fuel oil	18.82	23.30	25.89	31.02	36.98	44.17	52.87	2.9%
Residual fuel oil	11.86	15.97	28.76	34.39	40.52	48.13	57.01	4.5%
Natural gas	5.15	4.77	5.65	7.03	8.35	10.55	13.83	3.7%
Steam coal	2.25	2.38	2.90	3.39	3.96	4.58	5.28	2.8%

Table A3. Energy prices by sector and source (continued)
(nominal dollars per million Btu, unless otherwise noted)

Sector and source	Reference case							Annual growth 2011-2040 (percent)
	2010	2011	2020	2025	2030	2035	2040	
Average price to all users[10]								
Propane	15.89	17.13	15.78	20.26	25.03	30.86	39.26	2.9%
E85[4]	25.03	25.30	34.18	34.37	37.18	44.10	50.46	2.4%
Motor gasoline[5]	22.58	28.47	32.10	36.87	42.40	49.84	59.70	2.6%
Jet fuel	16.22	22.49	24.79	29.90	35.92	43.09	51.27	2.9%
Distillate fuel oil	21.71	26.18	30.27	36.06	42.07	49.68	58.97	2.8%
Residual fuel oil	10.83	17.65	18.41	22.33	27.03	32.66	39.53	2.8%
Natural gas	7.12	6.68	8.16	9.78	11.41	14.06	18.06	3.5%
Metallurgical coal	5.84	7.01	10.09	11.79	13.92	16.15	18.34	3.4%
Other coal	2.28	2.45	2.97	3.46	4.03	4.65	5.37	2.7%
Coal to liquids	- -	- -	- -	2.90	3.52	4.17	4.87	- -
Electricity	28.79	29.03	31.71	35.02	39.20	44.65	52.12	2.0%
Non-renewable energy expenditures by sector (billion nominal dollars)								
Residential	248.27	248.08	280.71	322.77	374.04	438.86	527.54	2.6%
Commercial	178.66	179.97	209.48	242.14	281.23	335.25	411.95	2.9%
Industrial	205.99	225.18	298.68	357.41	407.07	478.81	583.76	3.3%
Transportation	572.11	718.25	801.07	910.16	1,034.13	1,222.05	1,486.52	2.5%
Total non-renewable expenditures	1,205.03	1,371.48	1,589.94	1,832.48	2,096.47	2,474.97	3,009.77	2.7%
Transportation renewable expenditures	0.15	1.24	2.81	4.95	6.06	6.70	8.33	6.8%
Total expenditures	**1,205.18**	**1,372.71**	**1,592.75**	**1,837.43**	**2,102.52**	**2,481.67**	**3,018.11**	**2.8%**

[1]Includes energy for combined heat and power plants that have a non-regulatory status, and small on-site generating systems.
[2]Excludes use for lease and plant fuel.
[3]Includes Federal and State taxes while excluding county and local taxes.
[4]E85 refers to a blend of 85 percent ethanol (renewable) and 15 percent motor gasoline (nonrenewable). To address cold starting issues, the percentage of ethanol varies seasonally. The annual average ethanol content of 74 percent is used for this forecast.
[5]Sales weighted-average price for all grades. Includes Federal, State and local taxes.
[6]Kerosene-type jet fuel. Includes Federal and State taxes while excluding county and local taxes.
[7]Diesel fuel for on-road use. Includes Federal and State taxes while excluding county and local taxes.
[8]Natural gas used as a vehicle fuel. Includes estimated motor vehicle fuel taxes and estimated dispensing costs or charges.
[9]Includes electricity-only and combined heat and power plants that have a regulatory status.
[10]Weighted averages of end-use fuel prices are derived from the prices shown in each sector and the corresponding sectoral consumption.
Btu = British thermal unit.
- - = Not applicable.
Note: Data for 2010 and 2011 are model results and may differ slightly from official EIA data reports.
Sources: 2010 and 2011 prices for motor gasoline, distillate fuel oil, and jet fuel are based on prices in the U.S. Energy Information Administration (EIA), *Petroleum Marketing Monthly*, DOE/EIA-0380(2012/08) (Washington, DC, August 2012). 2010 residential, commercial, and industrial natural gas delivered prices: EIA, *Natural Gas Annual 2010*, DOE/EIA-0131(2010) (Washington, DC, December 2011). 2011 residential, commercial, and industrial natural gas delivered prices: EIA, *Natural Gas Monthly*, DOE/EIA-0130(2012/07) (Washington, DC, July 2012). 2010 transportation sector natural gas delivered prices are based on: EIA, *Natural Gas Annual 2010*, DOE/EIA-0131(2010) (Washington, DC, December 2011) and estimated State taxes, Federal taxes, and dispensing costs or charges. 2011 transportation sector natural gas delivered prices are model results. 2010 and 2011 electric power sector distillate and residual fuel oil prices: EIA, *Monthly Energy Review*, DOE/EIA-0035(2012/09) (Washington, DC, September 2012). 2010 and 2011 electric power sector natural gas prices: EIA, *Electric Power Monthly*, DOE/EIA-0226, April 2011 and April 2012, Table 4.2, and EIA, *State Energy Data Report 2010*, DOE/EIA-0214(2010) (Washington, DC, June 2012). 2010 and 2011 coal prices based on: EIA, *Quarterly Coal Report, October-December 2011*, DOE/EIA-0121(2011/4Q) (Washington, DC, March 2012) and EIA, AEO2013 National Energy Modeling System run REF2013.D102312A. 2010 and 2011 electricity prices: EIA, *Annual Energy Review 2011*, DOE/EIA-0384(2011) (Washington, DC, September 2012). 2010 and 2011 E85 prices derived from monthly prices in the Clean Cities Alternative Fuel Price Report.
Projections: EIA, AEO2013 National Energy Modeling System run REF2013.D102312A.

EXHIBIT NO. 29

DOCKET NO: 120234-EI – Polk Conversion Project Need Determination

WITNESS: Rocha

PARTY: TAMPA ELECTRIC COMPANY

DESCRIPTION: CROSS-EXAMINATION EXHIBIT

DOCUMENT: TECO Need Study, Table 13 and
TECO's Answers to Staff's Int. No. 38,
Original (10/23/2012) and Revised (11/27/2012)

PROFFERED BY: DeSoto Generating Company

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 120234-EI EXHIBIT 29
PARTY DeSoto Generating Company
DESCRIPTION Rocha - TECO Need Study, Table 13 and TECO's Answers to Staff's Int. No. 38, (10/23/2012) and Revised (11/27/2012)

Table 13: Economic Evaluation with Consideration of June 2012 Updated Assumptions

	CPWRR ($ million)		
	Polk 2-5	Alternative 2	Proposal B
Capital	$1,557.2	$1,520.4	$1,357.5
O&M	$845.2	$897.5	$815.1
Fuel & Purchased Power	$13,631.7	$13,882.9	$13,623.5
Total	$16,034.1	$16,300.8	$16,131.5
Delta		$266.7	$97.4

As can be seen in the table, Polk 2-5 is still the best option compared to Alternative 2 and Proposal B, which are $266.7 million and $97.4 million more costly with the latest demand and energy and fuel cost forecasts considered.

XI. Adverse Consequences If Polk 2-5 Is Delayed Or Denied

In the event that Polk 2-5 is delayed by two years, project costs would increase, and customer fuel savings for 2017 and 2018 would not be realized. Tampa Electric would construct simple cycle peaking units in 2017 to cover the reserve margin requirement in 2017 and 2018. System energy requirements would be served by peaking capacity resulting in higher fuel costs. This would result in higher costs for customers of $65.4 million on a CPWRR basis. Witness Hornick described the potential for an equipment demand spike scenario if there is a delay. If an equipment demand spike scenario materializes, this could result in higher costs for customers of $100.0 million on a CPWRR basis.

If Tampa Electric's proposed Polk 2-5 is denied, Tampa Electric would not be able to satisfy its minimum 20 percent Reserve Margin and minimum 7 percent supply planning criteria by the summer of 2017 in the most reliable and cost-effective manner. This would expose Tampa Electric's customers to a greater

38. Referencing Table 13, under the column labeled "Proposal B", of the Determination of Need Study, the total value does not appear to be consistent with the summation of its components (Capital, O&M, Fuel, and Purchased Power). Please reconcile this difference.

a. If the total value is incorrect and it should be equal to the summation of the components in that column, how would this impact the conclusion of TECO's economic evaluation?

A. For Proposal B, the line item labeled, "Fuel & Purchased Power" is incorrect. The correct CPWRR should be $13,958.9 MM versus the $13,623.5 MM that is shown. The error was due to an incorrect link to a cell that was in the source spreadsheet. However, the total CPWRR was correctly linked for Proposal B of $16,131.5 MM, as well as the $97.4 MM cost delta between Proposal B and Polk 2-5.

Please note that this error also exists in Exhibit 1, Document 13 of witness Rocha's testimony.

a. The total value is correct; therefore it would not impact the conclusion of Tampa Electric's economic evaluation.

38. Referencing Table 13, under the column labeled "Proposal B", of the Determination of Need Study, the total value does not appear to be consistent with the summation of its components (Capital, O&M, Fuel, and Purchased Power). Please reconcile this difference.

a. If the total value is incorrect and it should be equal to the summation of the components in that column, how would this impact the conclusion of TECO's economic evaluation?

A. For Proposal B, the line item labeled, "Fuel & Purchased Power" was incorrect, due to an incorrect link to a cell that was in the source spreadsheet.

Please note that this error also existed in Exhibit 1, Document 13 of witness Rocha's testimony.

Subsequent to the change identified above, while preparing the response to Staff's 4th set of interrogatories question 75, the company discovered an inadvertent input error in the model that impacts the fuel and purchased power estimated costs of only Proposal B. As such, the original calculated fuel and purchased power costs should have been $13,602.5 million resulting in a total CPWRR of $16,109.6 million and a delta of $75.4 million.

a. The total value has been corrected and does not impact the conclusion of Tampa Electric's economic evaluation.