SACE 1st Response to Staff
020114

AUSLEY & MCMULLEN

ATTORNEYS AND COUNSELORS AT LAW

123 SOUTH CALHOUN STREET
P.O. BOX 391 (ZIP 32302)
TALLAHASSEE, FLORIDA 32301
(850) 224-9115 FAX (850) 222-7560

RECEIVED-FPSC
12 APR -2 PM 2:01
COMMISSION
CLERK

April 2, 2012

HAND DELIVERED

Ms. Ann Cole, Director
Division of Commission Clerk
Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, FL 32399-0850

120000-OT

Re: Tampa Electric Company's Ten-Year Site Plan

Dear Ms. Cole:

Enclosed for filing on behalf of Tampa Electric Company are twenty-five (25) copies of the company's January 2012 to December 2021 Ten-Year Site Plan.

Please acknowledge receipt and filing of the above by stamping the duplicate copy of this letter and returning same to this writer.

Thank you for your assistance in connection with this matter.

Sincerely,

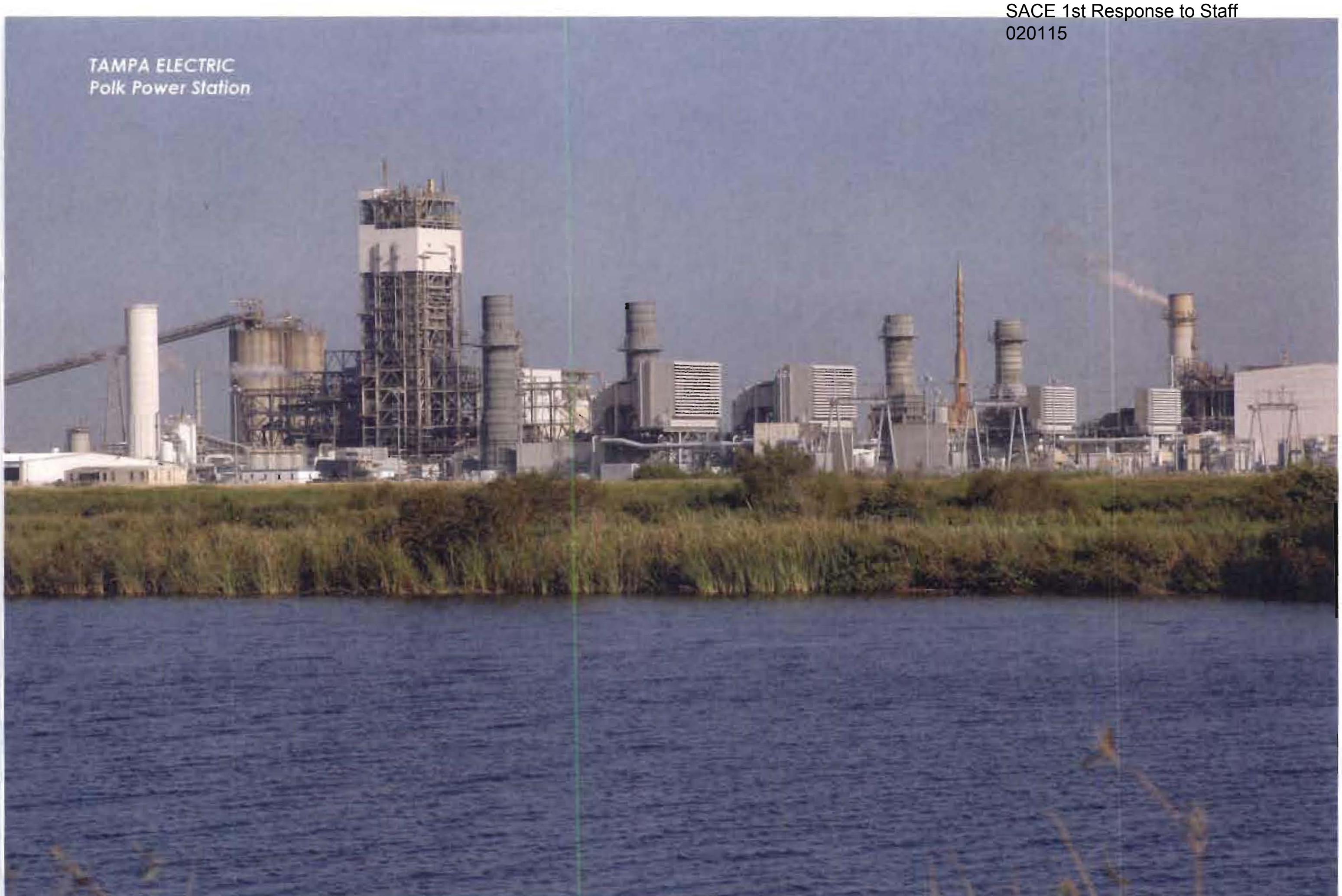
James D. Beasley

JDB/pp
Enclosures

COM ______
APA ______
ECR ______
GCL 2
RAD 22
SRC ______
ADM ______
OPC ______
CLK 1-original

DOCUMENT NUMBER-DATE
01955 APR-2 12
FPSC-COMMISSION CLERK

SACE 1st Response to Staff
020115



TECO
TAMPA ELECTRIC

Ten-Year Site Plan for Electrical Generating Facilities and Associated Transmission Lines

January 2012 to December 2021

DOCUMENT NUMBER-DATE

Responsibly Serving Our Customers' Growing Needs

FPSC-COMMISSION CLERK

926.0031 CorpComm 3/12

SACE 1st Response to Staff
020116

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

Table of Contents

List of Schedules & Tables

List of Schedules & Tables (continued)

List of Figures

THIS PAGE LEFT INTENTIONALLY BLANK

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

THIS PAGE LEFT INTENTIONALLY BLANK

Chapter I

DESCRIPTION OF EXISTING FACILITIES

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.

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

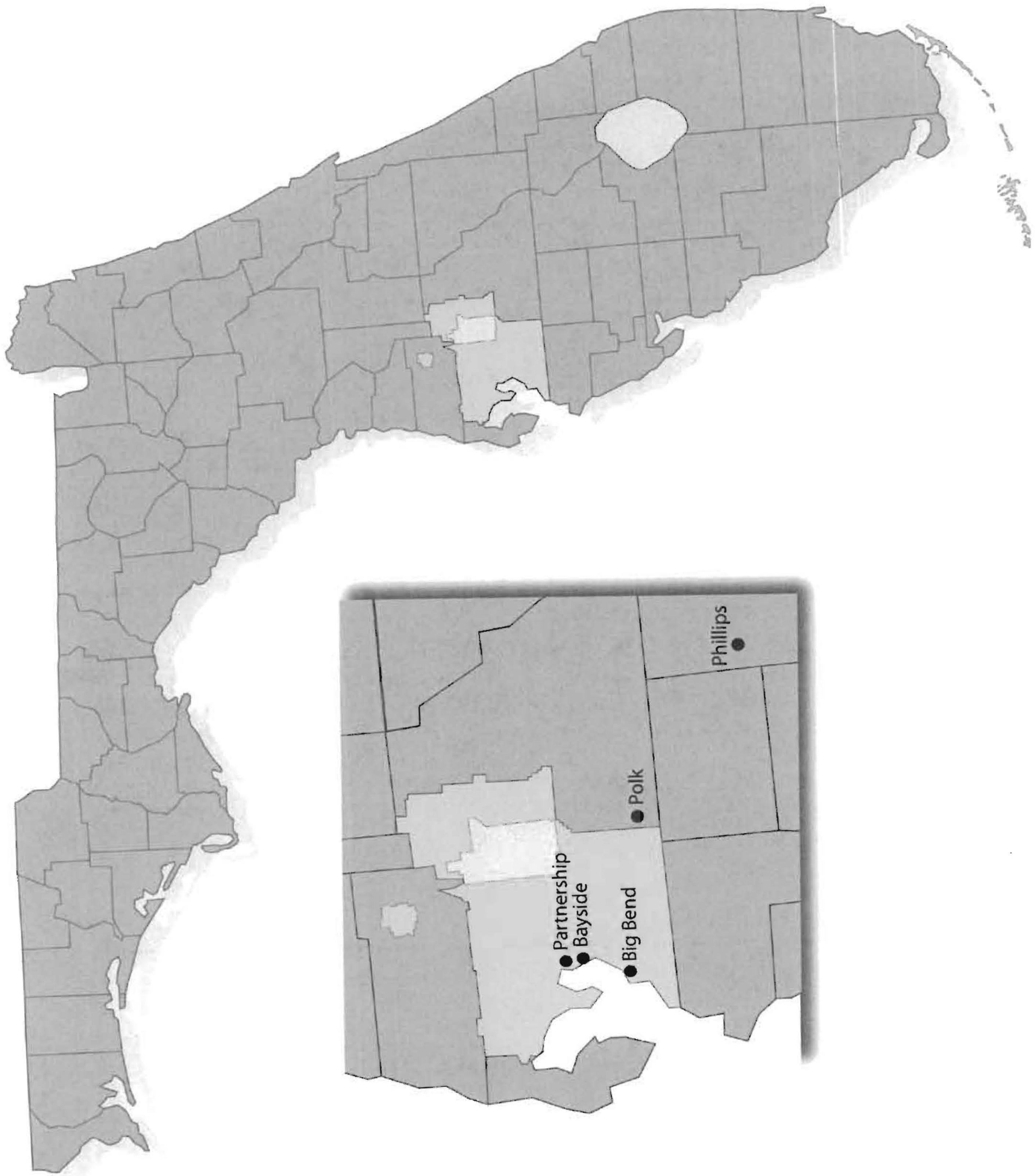
Notes:

[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.

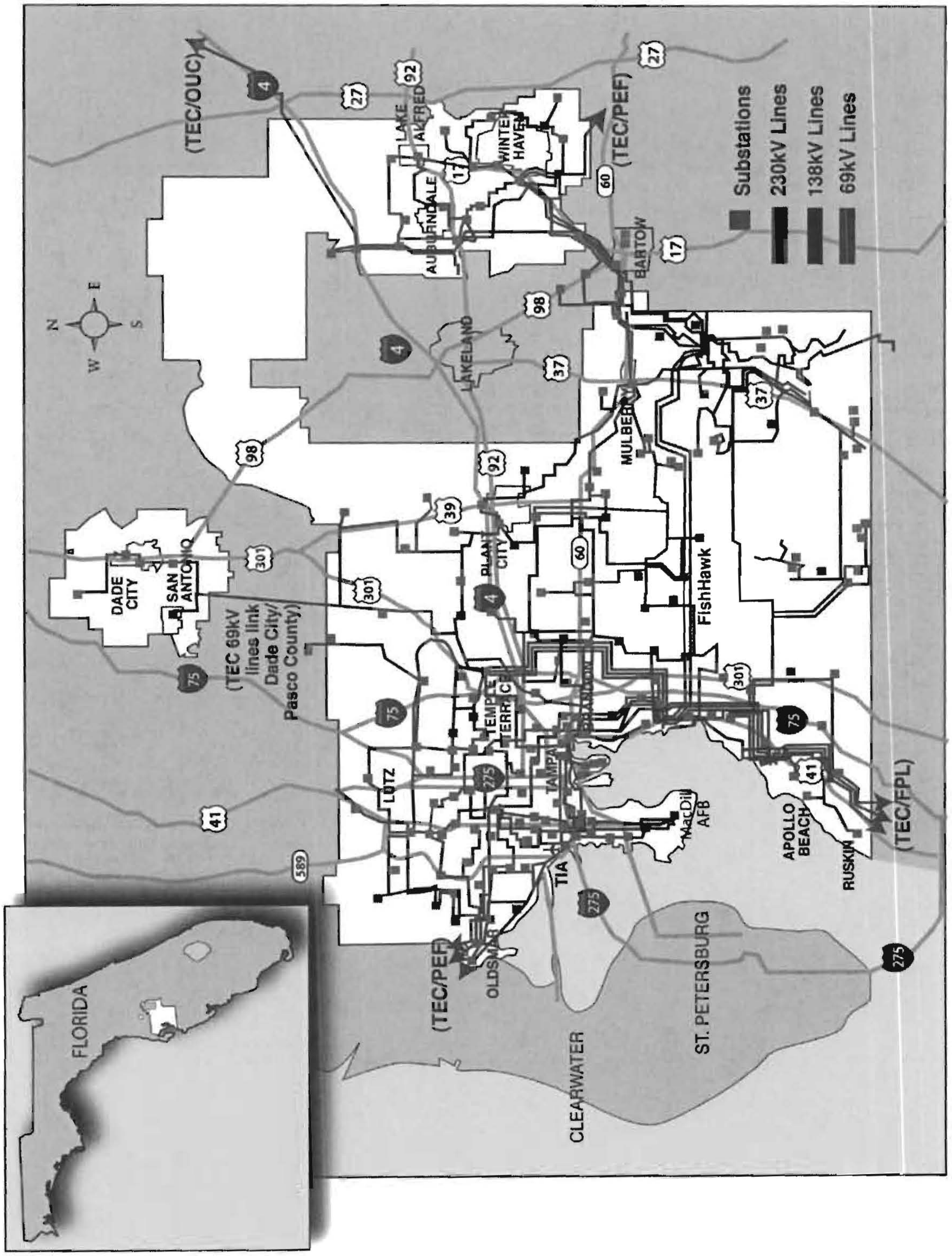
[2] Polk Units 2-5 turbine name plate ratings are based on 59 degrees Fahrenheit. The net capacity of these units vary with ambient air temperature.

THIS PAGE LEFT INTENTIONALLY BLANK

I.1 Tampa Electric Service Area Map



I.2 Tampa Electric Service Area Transmission Facility



THIS PAGE LEFT INTENTIONALLY BLANK

Chapter II

FORECAST OF ELECTRIC POWER, DEMAND, AND ENERGY CONSUMPTION

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

Schedule 6.1: History and Forecast of Net Energy for Load by Fuel Source in GWH

Schedule 6.2: History and Forecast of Net Energy for Load by Fuel Source as a Percent

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.

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				Street &	Other Sales	Total Sales
			Average KWH	Railroads	Highway	to Public	to Ultimate
			Consumption	and Railways	Lighting	Authorities	Consumers
Year	GWH	Customers*	Per Customer	GWH	GWH	GWH	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.

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				Street &	Other Sales	Total Sales
			Average KWH Consumption	Railroads and Railways	Highway Lighting	to Public Authorities	to Ultimate Consumers
Year	GWH	Customers*	Per Customer	GWH	GWH	GWH	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.

Schedule 2.3

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

(1) Year	(2) Sales for * Resale GWH	(3) Utility Use ** & Losses GWH	(4) Net Energy *** for Load GWH	(5) Other **** Customers	(6) 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) Year	(2) Sales for * Resale GWH	(3) Utility Use ** & Losses GWH	(4) Net Energy *** for Load GWH	(5) Other **** Customers	(6) 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.

Schedule 2.3

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

(1) Year	(2) Sales for * Resale GWH	(3) Utility Use ** & Losses GWH	(4) Net Energy *** for Load GWH	(5) Other **** Customers	(6) 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) Year	(2) Total *	(3) Wholesale**	(4) Retail *	(5) Interruptible	(6) Residential Load Management	(7) Residential Conservation	(8) Comm./Ind. Load Management	(9) Comm./Ind. Conservation	(10) 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.

Schedule 3.1

History and Forecast of Summer Peak Demand
Low Case

(1) Year	(2) Total *	(3) Wholesale**	(4) Retail *	(5) Interruptible	(6) Residential Load Management	(7) Residential Conservation	(8) Comm./Ind. Load Management	(9) Comm./Ind. Conservation	(10) 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.

Schedule 3.2

History and Forecast of Winter Peak Demand
Base Case

(1) Year	(2) Total *	(3) Wholesale **	(4) Retail *	(5) Interruptible	(6) Residential Load Management	(7) Residential Conservation	(8) Comm./Ind. Load Management	(9) Comm./Ind. Conservation	(10) 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.

Schedule 3.2

History and Forecast of Winter Peak Demand
High Case

(1) Year	(2) Total *	(3) Wholesale **	(4) Retail *	(5) Interruptible	(6) Residential Load Management	(7) Residential Conservation	(8) Comm./Ind. Load Management	(9) Comm./Ind. Conservation	(10) 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.

Schedule 3.2

History and Forecast of Winter Peak Demand
Low Case

(1) Year	(2) Total *	(3) Wholesale **	(4) Retail *	(5) Interruptible	(6) Residential Load Management	(7) Residential Conservation	(8) Comm./Ind. Load Management	(9) Comm./Ind. Conservation	(10) 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.

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.

Schedule 3.3

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

(1) Year	(2) Total	(3) Residential Conservation	(4) Comm./Ind. Conservation	(5) Retail	(6) Wholesale *	(7) Utility Use & Losses	(8) Net Energy for Load	(9) 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) Year	(2) Total	(3) Residential Conservation	(4) Comm./Ind. Conservation	(5) Retail	(6) Wholesale *	(7) Utility Use & Losses	(8) Net Energy for Load	(9) 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.

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.

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.

THIS PAGE LEFT INTENTIONALLY BLANK

Chapter III

TAMPA ELECTRIC COMPANY FORECASTING METHODOLOGY

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 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.

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

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.

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 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.

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.

THIS PAGE LEFT INTENTIONALLY BLANK

Chapter IV

FORECAST OF FACILITIES REQUIREMENTS

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.

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.

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)
	Total Installed Capacity	Firm Capacity Import	Firm Capacity Export	QF	Total Capacity Available	System Firm Summer 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
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)
	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.

Schedule 8.1

Planned and Prospective Generating Facility Additions

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
				Fuel		Fuel Trans.		Const.	Commercial	Expected	Gen. Max.	Net Capability		
Plant Name	Unit No.	Location	Unit Type	Primary	Alternate	Primary	Alternate	Start Mo/Yr	In-Service Mo/Yr	Retirement Mo/Yr	Nameplate kW	Summer MW	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.

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.**

THIS PAGE LEFT INTENTIONALLY BLANK

Chapter V

OTHER PLANNING ASSUMPTIONS AND INFORMATION

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.

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.

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.

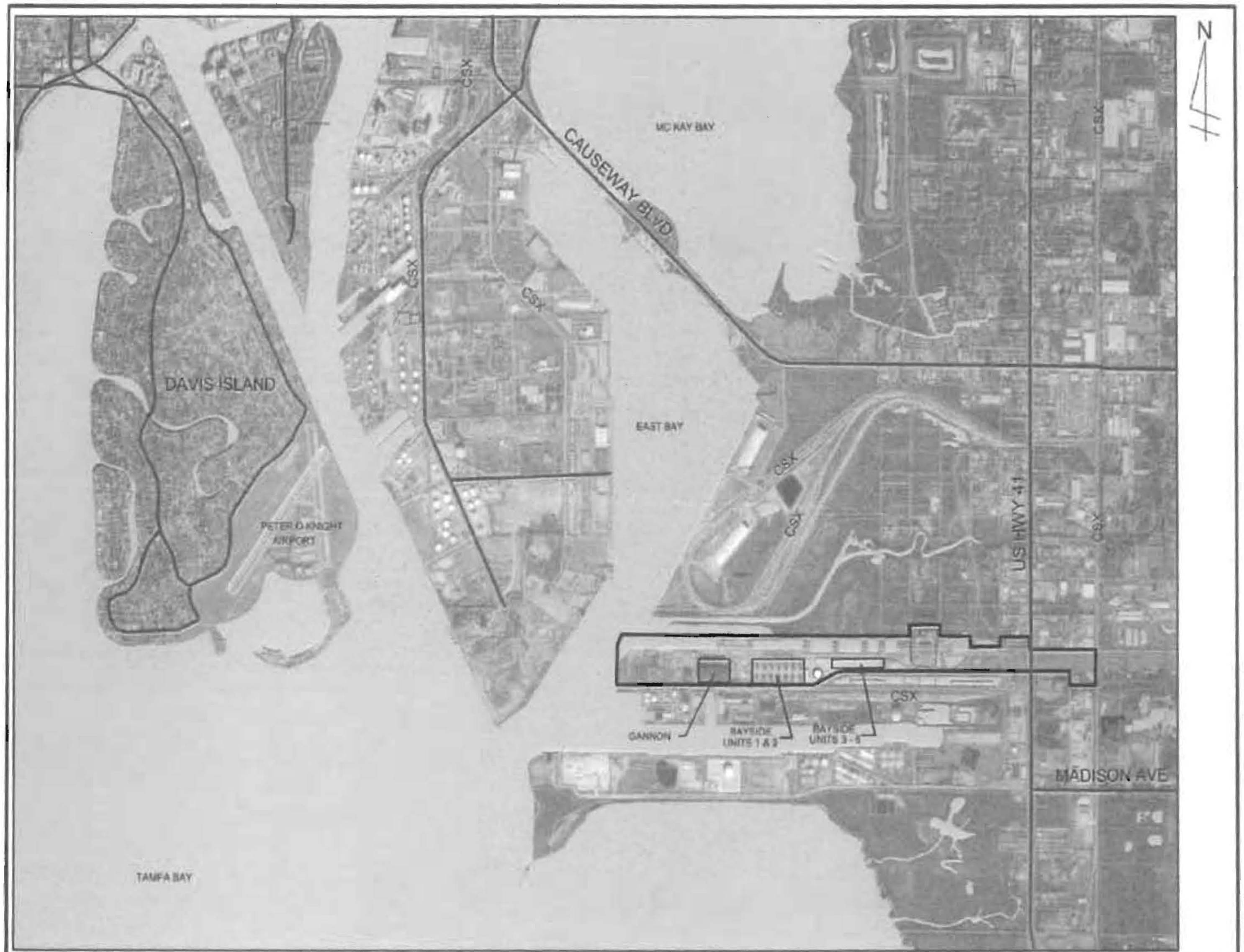
This pilot has annual funding capped at $1.53 million. Through this initiative Tampa Electric expects an additional 510 kW of customer owned PV to be installed along with 155 residential SWH systems to be added each year of the pilot.

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

ENVIRONMENTAL AND LAND USE INFORMATION

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.



TAMPA
ELECTRIC
A TECO ENERGY COMPANY

F.J. GANNON / BAYSIDE

GIS TECH: SEAN LOBUR DATE: 02 /04 / 2010

Figure VI-1

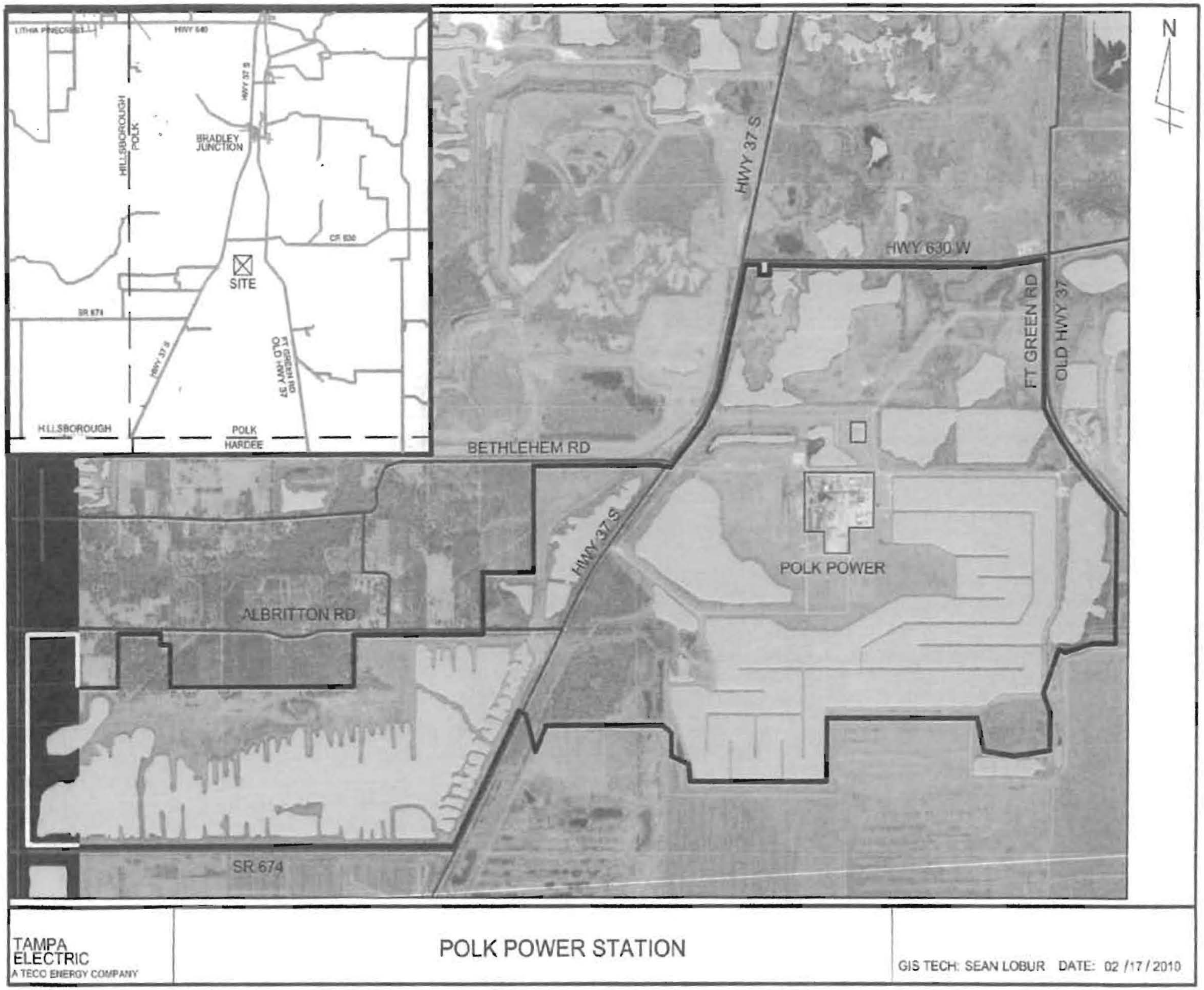
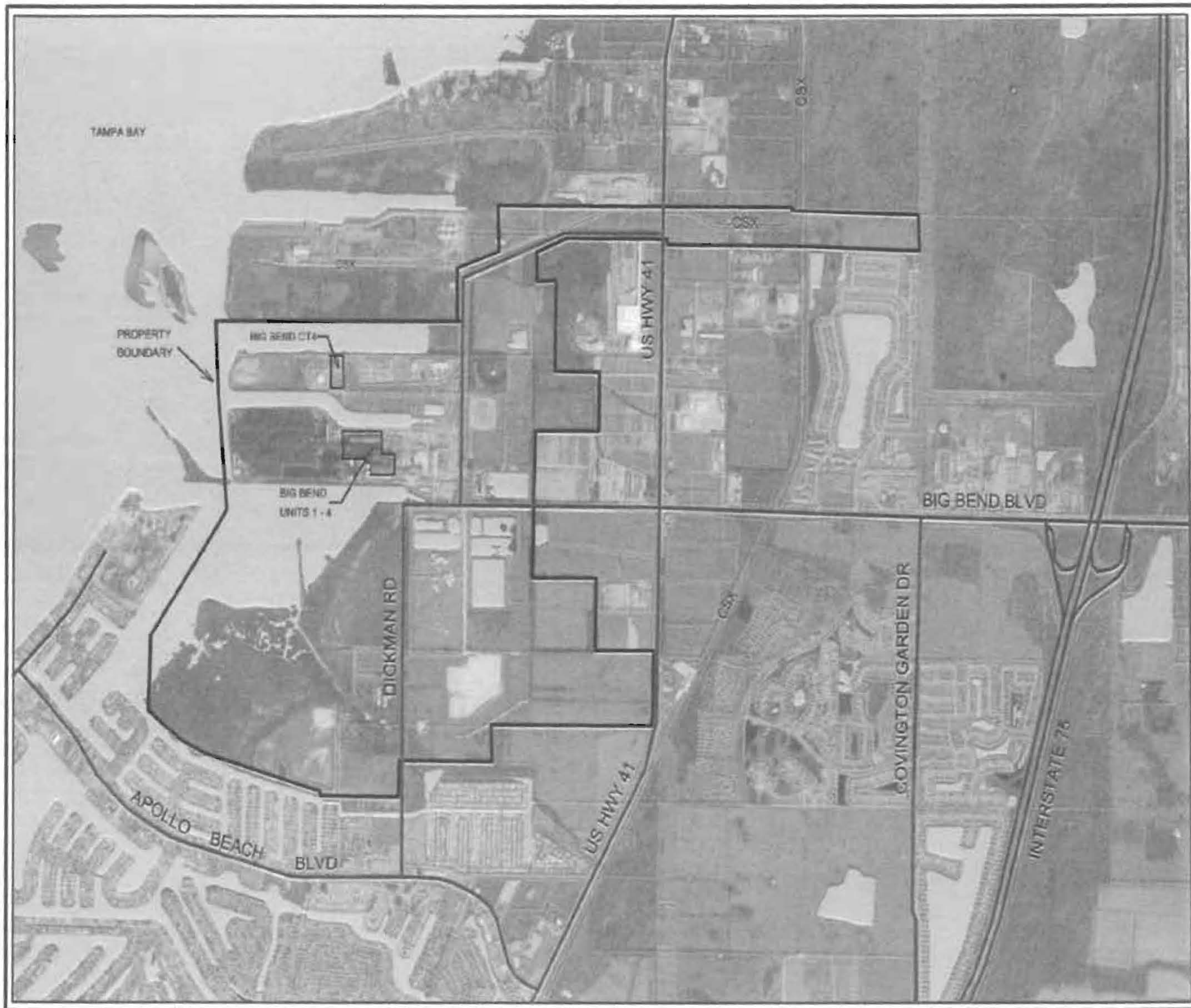

N
HWY 640
HWY 37 S
HILLSBOROUGH
POLK
BRADLEY JUNCTION
CR 630
SITE
SR 674
FT GREEN RD
OLD HWY 37
HILLSBOROUGH
POLK
HARDEE
HWY 37 S
HWY 630 W
FT GREEN RD
OLD HWY 37
BETHLEHEM RD
POLK POWER
ALBRITTON RD
SR 674
TAMPA ELECTRIC
A TECO ENERGY COMPANY
POLK POWER STATION
GIS TECH: SEAN LOBUR DATE: 02 /17 / 2010

Figure VI-2

Figure VI-3



TAMPA ELECTRIC A TECO ENERGY COMPANY	BIG BEND	GIS TECH: SEAN LOBUR DATE: 02 /04 / 2010