SACE 1st Response to Staff
020654

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April 1, 2014

VIA: ELECTRONIC FILING

Ms. Carlotta S. Stauffer
Commission Clerk
Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, FL 32399-0850

Re: Tampa Electric Company's 2014 Ten-Year Site Plan

Dear Ms. Stauffer:

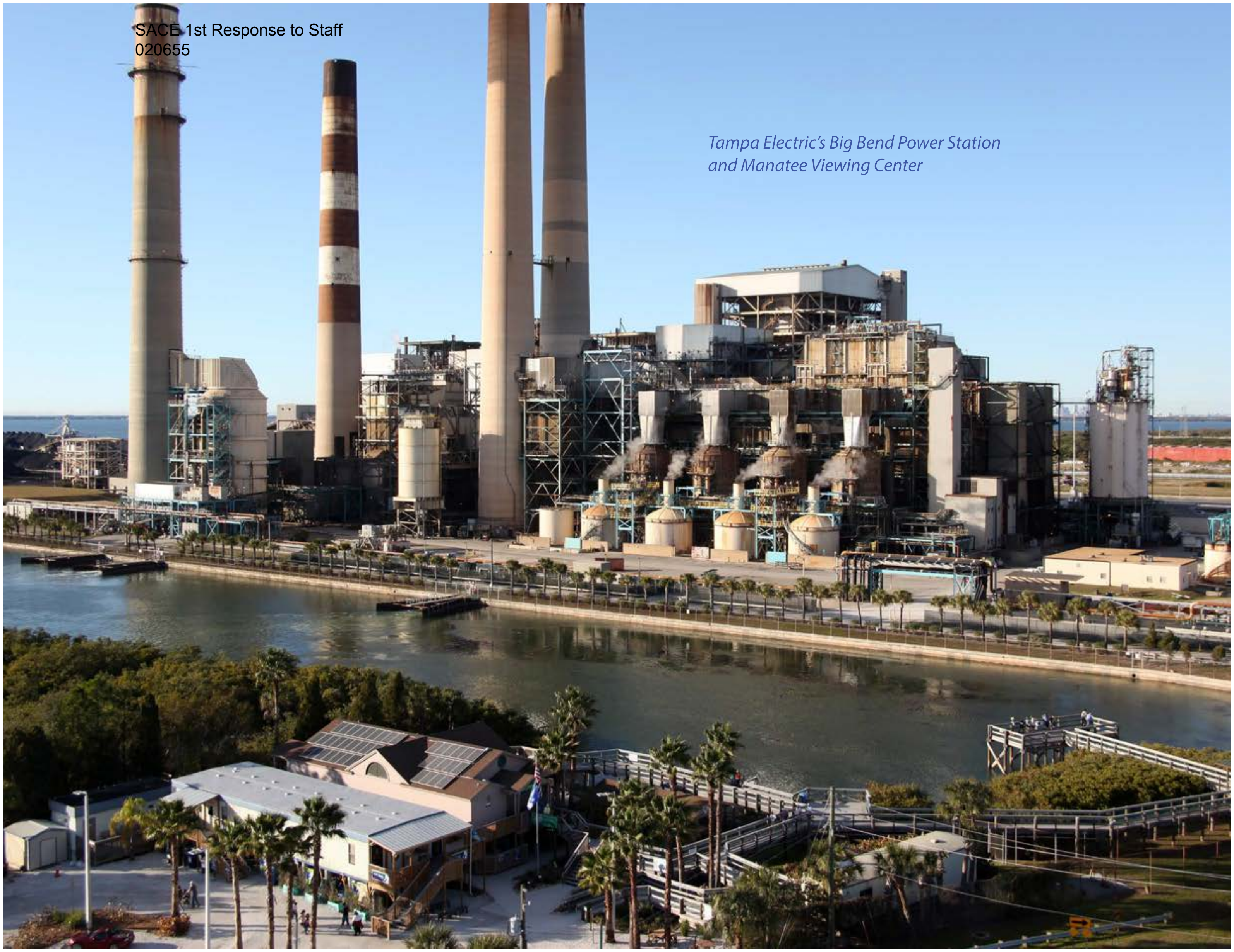
Attached for filing on behalf of Tampa Electric Company is the company's January 2014 to December 2023 Ten-Year Site Plan.

Thank you for your assistance in connection with this matter.

Sincerely,

James D. Beasley

JDB/pp
Attachment



Tampa Electric's Big Bend Power Station and Manatee Viewing Center

January 2014 to December 2023

Ten-Year Site Plan

For Electrical Generating Facilities and Associated Transmission Lines

TECO®

TAMPA ELECTRIC

Responsibly Serving Our Customers' Growing Needs

926.0031 CorpComm 3/13

SACE 1st Response to Staff
020656

Tampa Electric Company

Ten-Year Site Plan

for Electric Generating Facilities and Associated Transmission Lines
January 2014 – December 2023

Submitted to: Florida Public Service Commission
April 1, 2014

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GLOSSARY OF TERMS

CODE IDENTIFICATION SHEET

Unit Type:	CC	=	Combined Cycle
	D	=	Diesel
	FS	=	Fossil Steam
	GT	=	Gas 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
	U	=	Under Construction, less than or equal to 50% complete
	V	=	Under Construction, more than 50% complete
Fuel Type:	BIT	=	Bituminous Coal
	RFO	=	Heavy Oil (#6 Oil)
	DFO	=	Light Oil (#2 Oil)
	NG	=	Natural Gas
	PC	=	Petroleum Coke
	WH	=	Waste Heat
	BIO	=	Biomass
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
	SCR	=	Selective Catalytic Reduction
Transportation:	PL	=	Pipeline
	RR	=	Railroad
	TK	=	Truck
	WA	=	Water
Other:	NA	=	Not Applicable

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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. Unit 1 can also be fired with natural gas and units 2 and 3 can 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. The units were placed into long-term reserve standby in July of 2012.

Schedule 1

Existing Generating Facilities
As of December 31, 2013

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
								Alt	Commercial	Expected	Gen. Max.	Net Capability	
Plant	Unit		Unit	Fuel		Fuel Transport		Fuel	In-Service	Retirement	Nameplate	Summer	Winter
Name	No.	Location	Type	Pri	Alt	Pri	Alt	Days	Mo/Yr	Mo/Yr	kW	MW	MW
Big Bend		Hillsborough											
		Co. 14/31S/19E									1,892,485	1,598	1,633
	1		ST	BIT	NA	WA/RR	NA	NA	10/70	**	445,500	385	395
	2		ST	BIT	NA	WA/RR	NA	NA	04/73	**	445,500	385	395
	3		ST	BIT	NA	WA/RR	NA	NA	05/76	**	445,500	365	365
	4		ST	BIT	NA	WA/RR	NA	NA	02/85	**	486,000	407	417
	CT 4		GT	NG	DFO	PL	TK	*	08/09	**	69,985	56	61
Bayside		Hillsborough											
		Co. 4/30S/19E									2,294,100	1,854	2,083
	1		CC	NG	NA	PL	NA	NA	04/03	**	809,060	701	792
	2		CC	NG	NA	PL	NA	NA	01/04	**	1,205,100	929	1,047
	3		GT	NG	NA	PL	NA	NA	07/09	**	69,985	56	61
	4		GT	NG	NA	PL	NA	NA	07/09	**	69,985	56	61
	5		GT	NG	NA	PL	NA	NA	04/09	**	69,985	56	61
	6		GT	NG	NA	PL	NA	NA	04/09	**	69,985	56	61
Phillips		Highland Co.											
		12-055									38,430	36	36
	1		IC	RFO	DFO	TK	TK	NA	06/83	LTRS 09/09	19,215	18	18
	2		IC	RFO	DFO	TK	TK	NA	06/83	LTRS 09/09	19,215	18	18
Polk		Polk Co.											
		2,3/32S/23E									1,029,379	824	952
	1		IGCC	PC/BIT	NG	WA/TK	PL	*	09/96	**	326,299	220	220
	2		GT	NG	DFO	PL	TK	*	07/00	**	175,770	151	183
	3		GT	NG	DFO	PL	TK	*	05/02	**	175,770	151	183
	4		GT	NG	NA	PL	NA	NA	03/07	**	175,770	151	183
	5		GT	NG	NA	PL	NA	NA	04/07	**	175,770	151	183
Partnership		Hillsborough											
		Co. W30/29/19									5,800	6	6
	1		IC	NG	NA	PL	NA	NA	04/01	LTRS 07/12	2,900	3	3
	2		IC	NG	NA	PL	NA	NA	04/01	LTRS 07/12	2,900	3	3
											TOTAL	4,318	4,710

Notes:

* Limited by environmental permit

** Undetermined

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Figure I-1: Tampa Electric Service Area Map

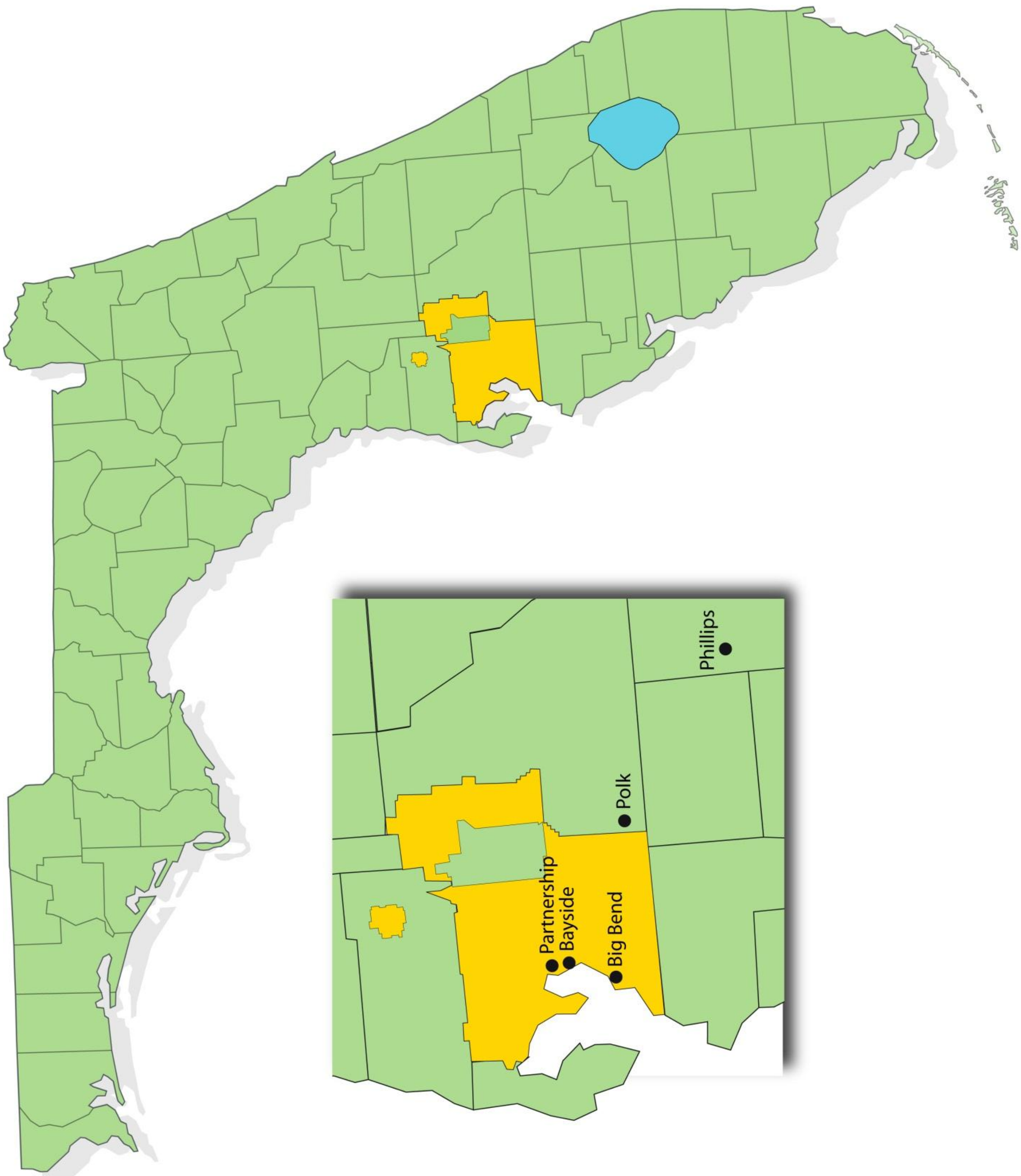
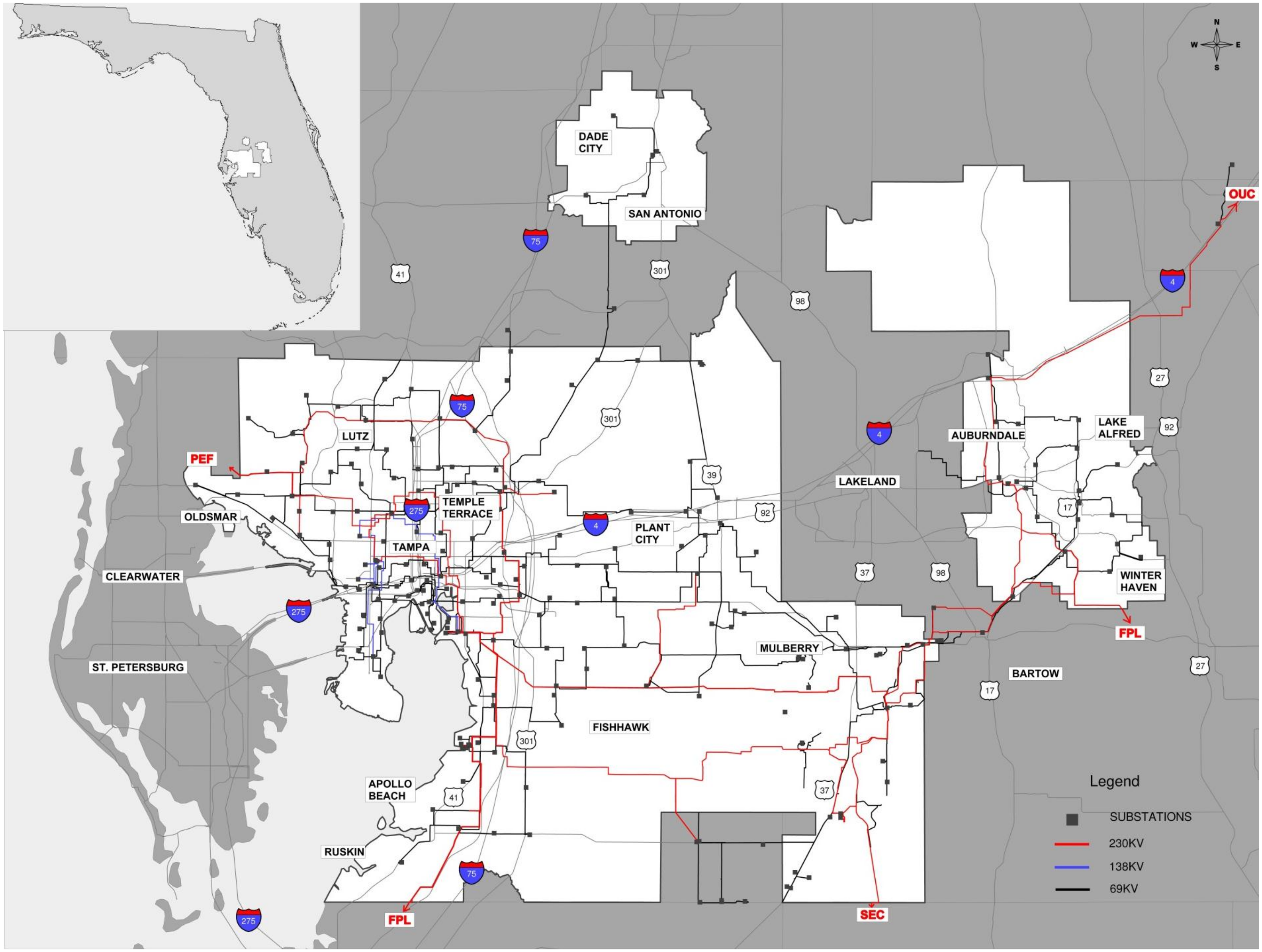


Figure I-2: Tampa Electric Service Area Transmission Facility



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Chapter II

FORECAST OF ELECTRIC POWER, DEMAND, AND ENERGY CONSUMPTION

Tables in Schedules 2 through 4 reflect three different levels of load forecasting: base case, high case, and low case. The expansion plan is developed using the base case load forecast and is reflected on 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)
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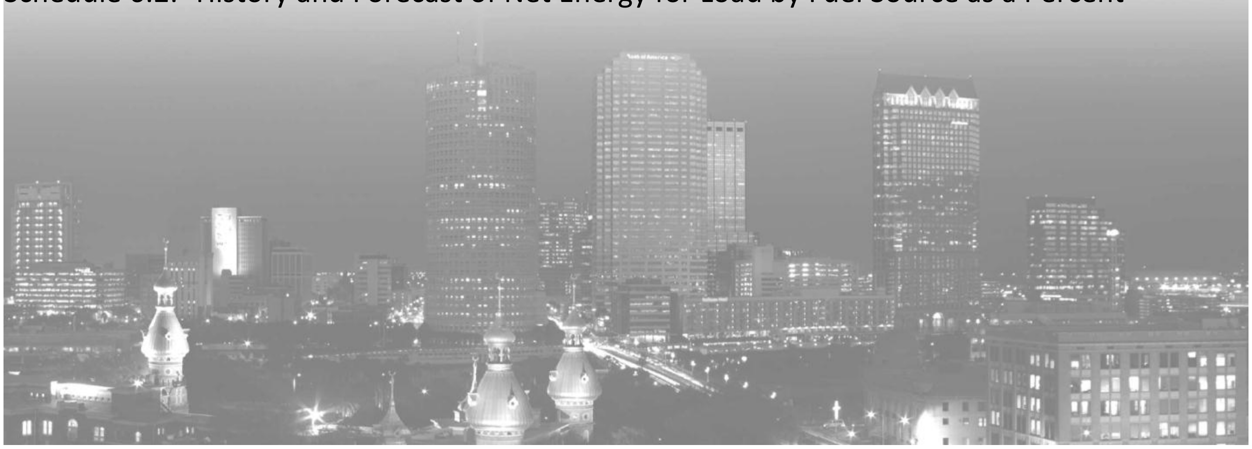

Schedule 2.1

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
2004	1,108,451	2.5	8,293	544,313	15,236	5,988	67,488	88,727
2005	1,138,786	2.5	8,562	558,728	15,324	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	1,238,951	2.6	8,718	595,914	14,630	6,207	70,522	88,009
2012	1,256,118	2.6	8,395	603,594	13,909	6,185	71,143	86,937
2013	1,276,410	2.6	8,470	613,206	13,812	6,090	71,966	84,619
2014	1,294,136	2.6	8,583	621,721	13,806	6,159	72,722	84,695
2015	1,313,809	2.6	8,644	630,869	13,701	6,228	73,713	84,494
2016	1,334,927	2.6	8,746	640,735	13,649	6,306	74,748	84,369
2017	1,356,205	2.6	8,865	650,702	13,624	6,398	75,734	84,484
2018	1,377,281	2.6	8,985	660,594	13,601	6,481	76,694	84,510
2019	1,398,097	2.6	9,107	670,381	13,585	6,569	77,650	84,601
2020	1,418,609	2.6	9,210	680,041	13,543	6,654	78,614	84,645
2021	1,438,761	2.5	9,326	689,544	13,525	6,729	79,573	84,560
2022	1,458,594	2.5	9,449	698,908	13,519	6,810	80,518	84,578
2023	1,478,099	2.5	9,577	708,128	13,525	6,888	81,451	84,569

Notes:

December 31, 2013 Status

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

Values shown may be affected due to rounding.

Schedule 2.1

**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
2014	1,300,518	2.6	8,642	624,773	13,833	6,181	72,970	84,703
2015	1,326,790	2.6	8,763	637,078	13,755	6,272	74,220	84,508
2016	1,354,751	2.6	8,927	650,217	13,729	6,374	75,523	84,394
2017	1,383,119	2.6	9,112	663,575	13,732	6,490	76,786	84,521
2018	1,411,529	2.6	9,300	676,975	13,738	6,599	78,034	84,560
2019	1,439,920	2.6	9,492	690,385	13,749	6,713	79,286	84,667
2020	1,468,882	2.6	9,667	703,782	13,736	6,825	80,557	84,724
2021	1,497,777	2.6	9,859	717,133	13,748	6,928	81,832	84,656
2022	1,526,542	2.6	10,060	730,457	13,772	7,038	83,102	84,692
2023	1,555,219	2.5	10,270	743,744	13,808	7,146	84,369	84,701

Notes:

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

Schedule 2.1

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
2014	1,287,754	2.6	8,525	618,668	13,779	6,138	72,474	84,687
2015	1,300,891	2.6	8,526	624,690	13,648	6,184	73,208	84,478
2016	1,315,297	2.6	8,567	631,346	13,569	6,240	73,981	84,342
2017	1,329,685	2.6	8,624	638,018	13,516	6,308	74,697	84,445
2018	1,343,701	2.5	8,679	644,533	13,465	6,367	75,381	84,458
2019	1,357,291	2.5	8,735	650,864	13,420	6,429	76,054	84,535
2020	1,370,418	2.5	8,771	656,991	13,350	6,488	76,728	84,562
2021	1,383,033	2.5	8,819	662,889	13,304	6,537	77,390	84,462
2022	1,395,183	2.5	8,871	668,579	13,269	6,591	78,035	84,461
2023	1,406,864	2.5	8,927	674,057	13,244	6,641	78,659	84,434

Notes:

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

Values shown may be affected due to rounding.

Schedule 2.2

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

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
	Industrial						
Year	GWh	Customers *	Average kWh Consumption Per Customer	Railroads and Railways GWh	Street & Highway Lighting GWh	Other Sales to Public Authorities GWh	Total Sales to Ultimate Consumers GWh
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	18,915
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	1,494	1,207,299	0	74	1,761	18,564
2012	2,001	1,537	1,302,171	0	75	1,756	18,412
2013	2,027	1,564	1,295,916	0	75	1,756	18,418
2014	1,756	1,571	1,117,720	0	79	1,775	18,352
2015	1,713	1,587	1,079,107	0	81	1,791	18,456
2016	1,691	1,602	1,055,424	0	82	1,813	18,638
2017	1,691	1,614	1,047,999	0	84	1,841	18,880
2018	1,690	1,623	1,041,325	0	86	1,866	19,109
2019	1,686	1,632	1,033,268	0	88	1,892	19,342
2020	1,682	1,641	1,025,124	0	89	1,918	19,553
2021	1,678	1,651	1,016,157	0	91	1,939	19,763
2022	1,672	1,660	1,007,496	0	93	1,963	19,987
2023	1,667	1,669	998,768	0	94	1,986	20,213

Notes:

December 31, 2013 Status

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

Values shown may be affected due to rounding.

Schedule 2.2

Forecast of Energy Consumption and Number of Customers by Customer Class High 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
2014	1,757	1,573	1,117,186	0	79	1,781	18,440
2015	1,715	1,592	1,077,465	0	81	1,803	18,634
2016	1,695	1,609	1,053,427	0	82	1,832	18,910
2017	1,697	1,624	1,044,961	0	84	1,867	19,250
2018	1,697	1,635	1,037,883	0	86	1,899	19,580
2019	1,694	1,647	1,028,804	0	88	1,932	19,919
2020	1,692	1,659	1,019,665	0	89	1,965	20,238
2021	1,688	1,672	1,009,739	0	91	1,994	20,560
2022	1,684	1,685	999,538	0	93	2,026	20,901
2023	1,680	1,697	989,888	0	94	2,057	21,247

Notes:

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

Schedule 2.2

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

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
	Industrial						
Year	GWh	Customers *	Average kWh Consumption Per Customer	Railroads and Railways GWh	Street & Highway Lighting GWh	Other Sales to Public Authorities GWh	Total Sales to Ultimate Consumers GWh
2014	1,755	1,569	1,118,256	0	79	1,769	18,265
2015	1,710	1,582	1,080,769	0	81	1,779	18,280
2016	1,687	1,595	1,057,466	0	82	1,795	18,370
2017	1,686	1,604	1,051,127	0	84	1,816	18,518
2018	1,683	1,610	1,045,552	0	86	1,835	18,649
2019	1,678	1,616	1,038,582	0	88	1,854	18,784
2020	1,673	1,623	1,030,877	0	89	1,872	18,893
2021	1,667	1,630	1,022,967	0	91	1,886	19,000
2022	1,661	1,636	1,015,363	0	93	1,902	19,118
2023	1,655	1,643	1,007,072	0	94	1,917	19,235

Notes:

* Average of end-of-month customers for the calendar year
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)	(2)	(3)	(4)	(5)	(6)
Year	Sales for * Resale GWh	Utility Use ** & Losses GWh	Net Energy *** for Load GWh	Other **** Customers	Total **** Customers
2004	589	945	19,971	6,435	619,535
2005	712	952	20,579	6,656	635,748
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	93	642	19,298	7,869	675,799
2012	69	839	19,320	7,962	684,236
2013	0	760	19,177	7,999	694,735
2014	0	953	19,305	8,070	704,084
2015	0	958	19,414	8,144	714,312
2016	0	967	19,606	8,223	725,307
2017	0	980	19,861	8,301	736,350
2018	0	992	20,101	8,380	747,291
2019	0	1,005	20,347	8,458	758,122
2020	0	1,016	20,568	8,535	768,831
2021	0	1,027	20,789	8,610	779,377
2022	0	1,039	21,025	8,684	789,771
2023	0	1,050	21,263	8,758	800,006

Notes:

December 31, 2013 Status

* Includes sales to Ft. Meade, Reedy Creek, Progress Energy Florida, Wauchula, St. Cloud and Florida Power & Light. Contract ended with Ft. Meade on 12/31/08, Reedy Creek on 12/31/10, Progress Energy Florida on 2/28/11, Wauchula on 9/31/11, St.Cloud on 12/31/2012 and Florida Power & Light on 12/31/12.

** 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.
Values shown may be affected due to rounding.

Schedule 2.3

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
2014	0	958	19,398	8,092	707,408
2015	0	967	19,601	8,189	721,079
2016	0	982	19,892	8,292	735,641
2017	0	999	20,249	8,396	750,381
2018	0	1,018	20,598	8,500	765,144
2019	0	1,034	20,953	8,605	779,923
2020	0	1,053	21,291	8,709	794,707
2021	0	1,068	21,628	8,812	809,449
2022	0	1,086	21,987	8,916	824,160
2023	0	1,104	22,351	9,019	838,829

Notes:

* 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.
Values shown may be affected due to rounding.

Schedule 2.3

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
2014	0	950	19,215	8,047	700,758
2015	0	947	19,227	8,098	707,578
2016	0	954	19,324	8,154	715,076
2017	0	961	19,479	8,208	722,527
2018	0	967	19,616	8,262	729,786
2019	0	976	19,760	8,315	736,849
2020	0	982	19,875	8,366	743,708
2021	0	987	19,987	8,414	750,323
2022	0	993	20,111	8,462	756,712
2023	0	1,000	20,235	8,508	762,867

Notes:

* 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.
Values shown may be affected due to rounding.

Schedule 3.1

History and Forecast of Summer Peak Demand - MW
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
2004	3,973	120	3,853	177	95	70	20	47	3,445
2005	4,218	128	4,090	144	79	73	19	49	3,725
2006	4,265	128	4,136	146	77	77	18	50	3,769
2007	4,428	172	4,256	159	69	80	18	53	3,876
2008	4,276	148	4,128	143	69	84	53	55	3,723
2009	4,316	136	4,180	120	54	90	58	59	3,799
2010	4,171	118	4,053	73	33	97	75	65	3,710
2011	4,130	28	4,102	109	48	103	75	68	3,699
2012	4,089	15	4,073	133	45	111	86	71	3,627
2013	4,072	0	4,072	131	39	122	89	77	3,614
2014	4,171	0	4,171	105	40	133	96	79	3,717
2015	4,216	0	4,216	102	38	145	98	84	3,748
2016	4,274	0	4,274	100	36	158	101	90	3,789
2017	4,339	0	4,339	100	34	170	103	96	3,836
2018	4,402	0	4,402	100	33	183	106	101	3,880
2019	4,466	0	4,466	100	31	196	108	106	3,925
2020	4,525	0	4,525	100	29	209	109	111	3,967
2021	4,585	0	4,585	100	28	222	111	115	4,010
2022	4,647	0	4,647	100	26	235	112	120	4,054
2023	4,708	0	4,708	101	24	248	113	125	4,097

Notes:

December 31, 2013 Status
2010 Net Firm Demand is not coincident with system peak.
Values shown may be affected due to rounding.
* Includes residential and commercial/industrial conservation
** Includes sales to Ft. Meade, Reedy Creek, Progress Energy Florida, Wauchula, St. Cloud and Florida Power & Light. Contract ended with Ft. Meade on 12/31/08, Reedy Creek on 12/31/10, Progress Energy Florida on 2/28/11, Wauchula on 9/31/11, St.Cloud on 12/31/2012 and Florida Power & Light on 12/31/12.
*** Includes Energy Planner program

Schedule 3.1

Forecast of Summer Peak Demand - MW
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
2014	4,190	0	4,190	105	40	133	96	79	3,736
2015	4,254	0	4,254	102	38	145	98	84	3,786
2016	4,333	0	4,333	100	36	158	101	90	3,848
2017	4,419	0	4,419	100	34	170	103	96	3,916
2018	4,504	0	4,504	100	33	183	106	101	3,982
2019	4,590	0	4,590	100	31	196	108	106	4,049
2020	4,672	0	4,672	100	29	209	109	111	4,114
2021	4,756	0	4,756	100	28	222	111	115	4,181
2022	4,843	0	4,843	100	26	235	112	120	4,250
2023	4,930	0	4,930	101	24	248	113	125	4,319

Notes:

Values shown may be affected due to rounding.

* Includes residential and commercial/industrial conservation

** Includes Energy Planner program

Schedule 3.1

Forecast of Summer Peak Demand - MW
Low Case

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
Year	Total *	Wholesale	Retail *	Interruptible	Residential Load Management	Residential ** Conservation	Comm./Ind. Load Management	Comm./Ind. Conservation	Net Firm Demand
2014	4,152	0	4,152	105	40	133	96	79	3,698
2015	4,177	0	4,177	102	38	145	98	84	3,709
2016	4,216	0	4,216	100	36	158	101	90	3,731
2017	4,261	0	4,261	100	34	170	103	96	3,758
2018	4,303	0	4,303	100	33	183	106	101	3,781
2019	4,345	0	4,345	100	31	196	108	106	3,804
2020	4,383	0	4,383	100	29	209	109	111	3,825
2021	4,421	0	4,421	100	28	222	111	115	3,846
2022	4,459	0	4,459	100	26	235	112	120	3,866
2023	4,497	0	4,497	101	24	248	113	125	3,886

Notes:

Values shown may be affected due to rounding.

* Includes residential and commercial/industrial conservation

** Includes Energy Planner program

Schedule 3.2

History and Forecast of Winter Peak Demand - MW
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
2003/04	3,949	120	3,829	254	136	437	18	48	2,936
2004/05	4,307	129	4,178	194	189	443	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	4,405	152	4,253	120	130	456	53	52	3,443
2008/09	4,696	67	4,629	181	105	462	75	52	3,754
2009/10	5,195	122	5,073	117	109	470	75	56	4,246
2010/11	4,695	120	4,575	140	88	480	75	58	3,735
2011/12	4,081	15	4,066	103	68	487	83	58	3,267
2012/13	3,764	0	3,764	130	65	501	90	61	2,918
2013/14	4,574	0	4,574	97	88	511	92	61	3,724
2014/15	4,625	0	4,625	93	83	525	95	63	3,766
2015/16	4,681	0	4,681	90	79	539	97	65	3,812
2016/17	4,747	0	4,747	92	75	553	99	68	3,861
2017/18	4,814	0	4,814	92	71	568	101	70	3,911
2018/19	4,880	0	4,880	92	68	582	103	73	3,962
2019/20	4,945	0	4,945	91	64	597	105	75	4,013
2020/21	5,008	0	5,008	92	60	611	106	77	4,061
2021/22	5,072	0	5,072	92	57	626	107	79	4,111
2022/23	5,135	0	5,135	92	53	640	108	82	4,159

Notes:

December 31, 2013 Status
2011/2012 Net Firm Demand is not coincident with system peak.
Values shown may be affected due to rounding.
* Includes residential and commercial/industrial conservation
** Includes sales to Ft. Meade, Reedy Creek, Progress Energy Florida, Wauchula, St. Cloud and Florida Power & Light. Contract ended with Ft. Meade on 12/31/08, Reedy Creek on 12/31/10, Progress Energy Florida on 2/28/11, Wauchula on 9/31/11, St.Cloud on 12/31/2012 and Florida Power & Light on 12/31/12.
*** Includes Energy Planner program

Schedule 3.2

Forecast of Winter Peak Demand - MW
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
2013/14	4,592	0	4,592	97	88	511	92	61	3,742
2014/15	4,664	0	4,664	93	83	525	95	63	3,805
2015/16	4,739	0	4,739	90	79	539	97	65	3,870
2016/17	4,827	0	4,827	92	75	553	99	68	3,941
2017/18	4,916	0	4,916	92	71	568	101	70	4,013
2018/19	5,004	0	5,004	92	68	582	103	73	4,086
2019/20	5,093	0	5,093	91	64	597	105	75	4,161
2020/21	5,180	0	5,180	92	60	611	106	77	4,233
2021/22	5,268	0	5,268	92	57	626	107	79	4,307
2022/23	5,358	0	5,358	92	53	640	108	82	4,382

Notes:

Values shown may be affected due to rounding.
* Includes residential and commercial/industrial conservation
** Includes Energy Planner program

Schedule 3.2

Forecast of Winter Peak Demand - MW
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
2013/14	4,555	0	4,555	97	88	511	92	61	3,705
2014/15	4,587	0	4,587	93	83	525	95	63	3,728
2015/16	4,623	0	4,623	90	79	539	97	65	3,754
2016/17	4,668	0	4,668	92	75	553	99	68	3,782
2017/18	4,715	0	4,715	92	71	568	101	70	3,812
2018/19	4,759	0	4,759	92	68	582	103	73	3,841
2019/20	4,803	0	4,803	91	64	597	105	75	3,871
2020/21	4,843	0	4,843	92	60	611	106	77	3,896
2021/22	4,883	0	4,883	92	57	626	107	79	3,922
2022/23	4,924	0	4,924	92	53	640	108	82	3,948

Notes:

Values shown may be affected due to rounding.

* Includes residential and commercial/industrial conservation

** Includes Energy Planner program

Schedule 3.3

History and Forecast of Annual Net Energy for Load - GWh
Base 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 %
2004	18,999	394	168	18,437	589	945	19,971	59.0
2005	19,495	404	176	18,915	712	952	20,579	57.4
2006	19,625	412	188	19,025	700	1,000	20,725	57.2
2007	20,153	421	200	19,533	829	916	21,278	56.6
2008	19,632	431	212	18,990	752	909	20,650	56.8
2009	19,449	444	231	18,774	191	978	19,943	54.4
2010	19,923	458	251	19,213	305	1,149	20,667	50.5
2011	19,296	474	259	18,564	93	642	19,298	53.0
2012	19,178	493	273	18,412	69	839	19,320	56.3
2013	19,225	513	294	18,418	0	760	19,177	56.5
2014	19,181	533	296	18,352	0	953	19,305	55.1
2015	19,326	554	315	18,456	0	958	19,414	54.9
2016	19,552	576	337	18,638	0	967	19,606	54.7
2017	19,839	600	359	18,880	0	980	19,861	54.9
2018	20,112	623	380	19,109	0	992	20,101	54.9
2019	20,389	648	398	19,342	0	1,005	20,347	55.0
2020	20,642	673	416	19,553	0	1,016	20,568	54.8
2021	20,894	697	434	19,763	0	1,027	20,789	54.9
2022	21,161	722	452	19,987	0	1,039	21,025	55.0
2023	21,429	747	470	20,213	0	1,050	21,263	55.0

Notes:

December 31, 2013 Status

Values shown may be affected due to rounding.

* Includes residential and commercial/industrial conservation

** Includes Energy Planner program

*** Includes sales to Ft. Meade, Reedy Creek, Progress Energy Florida, Wauchula, St. Cloud and Florida Power & Light. Contract ended with Ft. Meade on 12/31/08, Reedy Creek on 12/31/10, Progress Energy Florida on 2/28/11, Wauchula on 9/31/11, St.Cloud on 12/31/2012 and Florida Power & Light on 12/31/12.

**** Load Factor is the ratio of total system average load to peak.

Schedule 3.3

Forecast of Annual Net Energy for Load - GWh
High Case

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
Year	Total *	Residential ** Conservation	Comm./Ind. Conservation	Retail	Wholesale	Utility Use & Losses	Net Energy for Load	Load *** Factor %
2014	19,268	533	296	18,440	0	958	19,398	55.1
2015	19,503	554	315	18,634	0	967	19,601	54.9
2016	19,824	576	337	18,910	0	982	19,892	54.8
2017	20,209	600	359	19,250	0	999	20,249	55.0
2018	20,583	623	380	19,580	0	1,018	20,598	55.0
2019	20,966	648	398	19,919	0	1,034	20,953	55.0
2020	21,327	673	416	20,238	0	1,053	21,291	54.8
2021	21,692	697	434	20,560	0	1,068	21,628	55.0
2022	22,075	722	452	20,901	0	1,086	21,987	55.0
2023	22,464	747	470	21,247	0	1,104	22,351	55.0

Notes:

Values shown may be affected due to rounding.

* Includes residential and commercial/industrial conservation

** Includes Energy Planner program

*** Load Factor is the ratio of total system average load to peak.

Schedule 3.3

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 %
2014	19,093	533	296	18,265	0	950	19,215	55.1
2015	19,149	554	315	18,280	0	947	19,227	54.9
2016	19,284	576	337	18,370	0	954	19,324	54.7
2017	19,477	600	359	18,518	0	961	19,479	54.9
2018	19,652	623	380	18,649	0	967	19,616	54.9
2019	19,787	648	398	18,784	0	976	19,760	55.0
2020	19,940	673	416	18,893	0	982	19,875	54.8
2021	20,089	697	434	19,000	0	987	19,987	54.9
2022	20,250	722	452	19,118	0	993	20,111	54.9
2023	20,409	747	470	19,235	0	1,000	20,235	55.0

Notes:

Values shown may be affected due to rounding.

* Includes residential and commercial/industrial conservation

** Includes Energy Planner program

*** Load Factor is the ratio of total system average load to peak.

Schedule 4

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

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	2013 Actual		2014 Forecast		2015 Forecast	
	Peak Demand *	NEL	Peak Demand *	NEL	Peak Demand *	NEL
Month	**MW**	**GWh**	**MW**	**GWh**	**MW**	**GWh**
January	2,563	1,373	4,002	1,475	4,037	1,505
February	3,203	1,295	3,366	1,297	3,392	1,310
March	3,056	1,420	3,052	1,406	3,078	1,421
April	3,440	1,544	3,133	1,414	3,157	1,437
May	3,494	1,658	3,547	1,711	3,572	1,709
June	3,838	1,827	3,786	1,870	3,812	1,861
July	3,783	1,835	3,889	1,947	3,918	1,942
August	3,873	1,960	3,958	1,921	3,986	1,943
September	3,739	1,796	3,758	1,813	3,786	1,827
October	3,476	1,659	3,466	1,657	3,490	1,646
November	2,993	1,387	2,993	1,373	3,012	1,369
December	2,739	1,422	3,245	1,423	3,270	1,441
TOTAL		19,177		19,305		19,414

Notes:

December 31, 2013 Status

* Peak demand represents total retail and wholesale demand, excluding conservation impacts.

Values shown may be affected due to rounding.

Schedule 4

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

(1)	(2)	(3)	(4)	(5)
	2014 Forecast		2015 Forecast	
	Peak Demand *	NEL	Peak Demand *	NEL
Month	MW	GWh	MW	GWh
January	4,020	1,482	4,076	1,520
February	3,382	1,303	3,424	1,323
March	3,067	1,412	3,107	1,435
April	3,148	1,420	3,187	1,451
May	3,564	1,719	3,606	1,725
June	3,804	1,879	3,848	1,879
July	3,908	1,957	3,955	1,962
August	3,977	1,930	4,024	1,962
September	3,776	1,822	3,822	1,845
October	3,482	1,665	3,524	1,662
November	3,007	1,379	3,041	1,382
December	3,260	1,430	3,301	1,455
TOTAL		19,398		19,601

Notes:

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

Schedule 4

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

(1)	(2)	(3)	(4)	(5)
	2014 Forecast		2015 Forecast	
	Peak Demand *	NEL	Peak Demand *	NEL
Month	MW	GWh	MW	GWh
January	3,983	1,468	3,999	1,491
February	3,350	1,291	3,360	1,298
March	3,038	1,399	3,049	1,408
April	3,118	1,407	3,127	1,424
May	3,530	1,703	3,538	1,693
June	3,768	1,861	3,775	1,843
July	3,871	1,938	3,881	1,923
August	3,939	1,911	3,947	1,924
September	3,741	1,804	3,750	1,809
October	3,449	1,649	3,457	1,630
November	2,978	1,367	2,984	1,356
December	3,229	1,417	3,238	1,428
TOTAL		19,215		19,227

Notes:

* 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)
			Actual	Actual										
	Fuel Requirements	Unit	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
(1)	Nuclear	Trillion BTU	0	0	0	0	0	0	0	0	0	0	0	0
(2)	Coal	1000 Ton	4,325	4,283	4,568	4,551	4,643	4,666	4,556	4,627	4,652	4,638	4,626	4,646
(3)	Residual	1000 BBL	0	0	0	0	0	0	0	0	0	0	0	0
(4)	ST	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)	GT	1000 BBL	0	0	0	0	0	0	0	0	0	0	0	0
(7)	D	1000 BBL	0	0	0	0	0	0	0	0	0	0	0	0
(8)	Distillate	1000 BBL	37	14	0	0	0	0	0	0	0	0	0	0
(9)	ST	1000 BBL	0	0	0	0	0	0	0	0	0	0	0	0
(10)	CC	1000 BBL	36	14	0	0	0	0	0	0	0	0	0	0
(11)	GT	1000 BBL	1	0	0	0	0	0	0	0	0	0	0	0
(12)	D	1000 BBL	0	0	0	0	0	0	0	0	0	0	0	0
(13)	Natural Gas	1000 MCF	56,592	56,531	49,644	54,197	54,173	52,712	56,765	56,967	58,094	60,815	61,876	63,199
(14)	ST	1000 MCF	0	0	0	0	0	0	0	0	0	0	0	0
(15)	CC	1000 MCF	50,662	53,529	44,250	44,775	43,838	52,219	56,154	56,330	56,433	58,702	60,698	61,752
(16)	GT	1000 MCF	5,930	3,002	5,394	9,422	10,335	493	611	637	1,661	2,113	1,178	1,447
(17)	Other (Specify)													
(18)	PC	1000 Ton	347	419	482	455	488	486	456	486	488	455	486	486

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
Base Case Forecast Basis

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
	Energy Sources	Unit	Actual 2012	Actual 2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
(1)	Annual Firm Interchange	GWh	689	200	164	243	220	40	36	0	0	0	0	0
(2)	Nuclear	GWh	0	0	0	0	0	0	0	0	0	0	0	0
(3)	Coal	GWh	9,720	9,647	10,463	10,424	10,648	10,709	10,442	10,604	10,673	10,642	10,603	10,650
(4)	Residual	GWh	0	0	0	0	0	0	0	0	0	0	0	0
(5)	ST	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)	GT	GWh	0	0	0	0	0	0	0	0	0	0	0	0
(8)	D	GWh	0	0	0	0	0	0	0	0	0	0	0	0
(9)	Distillate	GWh	20	8	0	0	0	0	0	0	0	0	0	0
(10)	ST	GWh	0	0	0	0	0	0	0	0	0	0	0	0
(11)	CC	GWh	20	8	0	0	0	0	0	0	0	0	0	0
(12)	GT	GWh	0	0	0	0	0	0	0	0	0	0	0	0
(13)	D	GWh	0	0	0	0	0	0	0	0	0	0	0	0
(14)	Natural Gas	GWh	7,568	7,601	6,714	7,153	7,112	7,523	8,112	8,130	8,250	8,618	8,818	9,009
(15)	ST	GWh	0	0	0	0	0	0	0	0	0	0	0	0
(16)	CC	GWh	7,042	7,343	6,210	6,275	6,146	7,477	8,055	8,071	8,094	8,419	8,708	8,874
(17)	GT	GWh	526	258	504	878	966	46	57	59	156	199	110	135
(18)	Other (Specify)													
(19)	PC	GWh	971	1,174	1,374	1,298	1,389	1,385	1,300	1,386	1,390	1,298	1,386	1,386
(20)	Net Interchange	GWh	81	271	323	29	43	10	17	33	61	37	24	24
(21)	Purchased Energy from Non-Utility Generators	GWh	271	276	267	267	194	194	194	194	194	194	194	194
(22)	Net Energy for Load	GWh	19,320	19,177	19,305	19,414	19,606	19,861	20,101	20,347	20,568	20,789	21,025	21,263

Notes:

Line (21) includes energy purchased from Non-Renewable and Renewable resources.
Values shown may be affected due to rounding.

Schedule 6.2

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

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
	Energy Sources	**Unit**	**Actual 2012**	**Actual 2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**
(1)	Annual Firm Interchange	%	3.6	1.0	0.8	1.3	1.1	0.2	0.2	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	%	50.3	50.3	54.2	53.7	54.3	53.9	51.9	52.1	51.9	51.2	50.4	50.1
(4)	Residual	%	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)	ST	%	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)	GT	%	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)	D	%	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	%	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(10)	ST	%	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	%	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(12)	GT	%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(13)	D	%	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	%	39.2	39.6	34.8	36.8	36.3	37.9	40.4	40.0	40.1	41.5	41.9	42.4
(15)	ST	%	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	%	36.4	38.3	32.2	32.3	31.3	37.6	40.1	39.7	39.4	40.5	41.4	41.7
(17)	GT	%	2.7	1.3	2.6	4.5	4.9	0.2	0.3	0.3	0.8	1.0	0.5	0.6
(18)	Other (Specify)													
(19)	PC	%	5.0	6.1	7.1	6.7	7.1	7.0	6.5	6.8	6.8	6.2	6.6	6.5
(20)	Net Interchange	%	0.4	1.4	1.7	0.1	0.2	0.1	0.1	0.2	0.3	0.2	0.1	0.1
(21)	Purchased Energy from Non-Utility Generators	%	1.4	1.4	1.4	1.4	1.0	1.0	1.0	1.0	0.9	0.9	0.9	0.9
(22)	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

Notes:

Line (21) includes energy purchased from Non-Renewable and Renewable resources.
Values shown may be affected due to rounding.

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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 that 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 2014-2023 forecasts. The data tables in Chapter II outline the expected customer, demand, and energy values for the 2014-2023 time period.

<u>RETAIL LOAD</u>

MetrixND, an advanced statistics program for analysis and forecasting, was used to develop the 2014-2023 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 that 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. Interruptible Rate Class 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 effects of Tampa Electric's conservation, load management, and cogeneration programs are 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 Moody's Analytics 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 primary economic drivers in the customer forecast models are population estimates, service area households and employment growth. Below is a description of the models used for the five-customer classes.

1. *Residential Customer Model:* Customer projections are a function of regional population. Since a strong correlation exists between regional population and historical changes in service area customers, regional population estimates 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 <u>Commercial Customer Model</u> 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 <u>Temporary Service Model</u> 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 regional population. The need for public services will depend on the number of people in the region; therefore, consistent with the residential customer model, 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:

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

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

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

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.

$$\textbf{HeatUse}_{y,m} = \left(\frac{\text{Price}_{y,m}}{\text{Price}_{basey,m}}\right)^{-.10} \times \left(\frac{\text{HH Income}_{y,m}}{\text{HH Income}_{basey,m}}\right)^{.15} \times \left(\frac{\text{HH Size}_{y,m}}{\text{HH Size}_{basey,m}}\right)^{.20} \times \left(\frac{\text{HDD}_{y,m}}{\text{Normal HDD}}\right)$$

$$\textbf{CoolUse}_{y,m} = \left(\frac{\text{Price}_{y,m}}{\text{Price}_{basey,m}}\right)^{-.10} \times \left(\frac{\text{HH Income}_{y,m}}{\text{HH Income}_{basey,m}}\right)^{.15} \times \left(\frac{\text{HH Size}_{y,m}}{\text{HH Size}_{basey,m}}\right)^{.20} \times \left(\frac{\text{CDD}_{y,m}}{\text{Normal CDD}}\right)$$

$$\textbf{OtherUse}_{y,m} = \left(\frac{\text{Price}_{y,m}}{\text{Price}_{basey,m}}\right)^{-.10} \times \left(\frac{\text{HH Income}_{y,m}}{\text{HH Income}_{basey,m}}\right)^{.15} \times \left(\frac{\text{HH Size}_{y,m}}{\text{HH Size}_{basey,m}}\right)^{.20} \times \left(\frac{\text{Billing Days}_{y,m}}{\text{Billing Days}_{basey,m}}\right)$$

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):* Non-phosphate 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 seven 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 and day prior to 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. Interruptible Demand and Energy Analysis

Tampa Electric’s interruptible customers are relatively few in number, which has allowed the company’s Sales and Marketing Department to obtain detailed knowledge of industry developments including:

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

This department’s familiarity with industry dynamics and their close working relationship with phosphate and other company representatives were used to form the basis for a survey of the interruptible customers to determine their future energy and demand requirements. This survey is the foundation upon which the phosphate forecast and the commercial/industrial interruptible rate class forecasts are 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 28 programs:

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

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.

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.

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.

Commercial Lighting - Encourages investment in more efficient lighting technologies within existing commercial facilities.

Standby Generator - A program designed to utilize the emergency generation capacity of commercial/industrial facilities in order to reduce weather sensitive peak demand.

Conservation Value - Encourages investments in measures that are not sanctioned by other commercial programs.

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.

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.

Commercial Cooling - Encourages the installation of high efficiency direct expansion commercial and packaged terminal air conditioning cooling equipment.

Commercial Chillers - Encourages the installation of high efficiency chiller equipment.

Energy Plus Homes - Encourages the construction of residential dwellings at efficiency levels greater than current Florida building code baseline practices.

Low Income Weatherization - Provides for the installation of energy efficient measures for qualified low-income customers.

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.

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.

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.

Energy Efficient Motors - Encourages the installation of high-efficiency motors.

Commercial Lighting Occupancy Sensors – Encourages the installation of occupancy sensors for load control in commercial facilities.

Commercial Refrigeration (Anti-condensate) – A program to encourage the installation of anti-condensate equipment sensors for load control in commercial facilities.

Commercial Water Heating - Encourages the installation of high efficiency water heating systems.

<u>Commercial Demand Response</u> - A turn-key program to incent commercial/industrial customers to reduce their demand for electricity in response to market signals.

<u>Residential Electronically Commutated Motor -</u> 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.

<u>Residential HVAC Re-commissioning</u> - An incentive program designed to help residential customers ensure HVAC equipment is operating at optimal efficiency through maintenance and equipment tune-up.

<u>Energy Education Outreach</u> - 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.

<u>Commercial Electronically Commutated Motor</u> - 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.

<u>Commercial HVAC Re-commissioning</u> - An incentive program designed to help commercial customers ensure HVAC equipment is operating at optimal efficiency through maintenance and equipment tune-up.

<u>Cool Roof</u> - An incentive program designed to encourage commercial/industrial customers to install a cool roof system above conditioned spaces.

<u>Energy Recovery Ventilation</u> - An incentive program designed to help commercial/industrial customers reduce humidity and HVAC loads in buildings.

The programs listed above were developed to meet FPSC demand and energy goals established in Docket No. 080409-EG, approved on December 30, 2009. The 2013 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 FPSC 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.

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%
2012	32.4	25.1	129.1%	26.4	19.6	134.7%	57.5	41.5	138.6%
2013	45.7	36.6	124.9%	39.2	29.5	132.9%	83.9	62.1	135.1%

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[(1)]	6.6	0.9	733.3%	9.8	2.5	392.0%	16.4	6.5	252.3%
2011	18.4	2.0	920.0%	25.1	6.1	411.5%	49.4	17.1	288.9%
2012	22.0	3.4	647.1%	31.4	10.4	301.9%	59.9	32.5	184.3%
2013	28.8	4.7	612.8%	40.6	15.5	261.9%	83.1	48.7	170.6%

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	17.9	7.3	245.2%	17.9	7.1	252.1%	33.7	16.3	206.7%
2011	39.9	16.9	236.1%	41.8	17.3	241.6%	85.9	40.9	210.0%
2012	54.4	28.5	190.9%	57.8	30.0	192.7%	117.4	74.0	158.6%
2013	74.5	41.3	180.4%	79.8	45.0	177.3%	167.0	110.8	150.7%

Notes:

[(1)] 2010 Commercial/Industrial Reductions corrected in 2012

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 Moody's Analytics supply population projections for Hillsborough County and Florida comparisons. A blend of BEBR's population growth for Florida and Hillsborough County were used to project future growth patterns in residential customers for the period of 2014-2023. The average annual population growth rate is expected to be 1.5%. Moody's Analytics provides persons per household projections 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 (2014-2023), employment is assumed to rise at a 1.9% average annual rate within Hillsborough County. Moody's Analytics supplies employment projections for the non-residential models.

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. Output for the entire employment sector within Hillsborough County is assumed to rise at a 2.9% average annual rate from 2014-2023. Moody's Analytics supplies output projections.

4. Real Household Income

Moody's Analytics supplies the assumptions for Hillsborough County's real household income growth. During 2014-2023, real household income for Hillsborough County is expected to increase at a 2.1% 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 lighting and 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 help to lower electricity consumption. Although there is an increasing saturation trend of electronic equipment and appliances in households throughout the forecast period, it does not offset the efficiency gains from lighting and appliances.

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 2014-2023, retail energy sales are projected to rise at a 1.1% annual rate. The major contributors to growth include the residential and commercial categories, increasing at an annual rate of 1.2% and 1.3%, respectively.

2. Wholesale Energy

Tampa Electric does not currently have any contracts for firm wholesale sales.

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 period of 2014-2023, Tampa Electric's base retail firm peak demand is expected to increase in the summer at an average annual rate of 1.1% and at rate of 1.2% in the winter.

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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, both peaking and intermediate resources are needed. The peaking capacity need will be met by purchased 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 purchased power agreements.

Tampa Electric will compare viable purchased power options as an alternative and/or enhancement to planned unit additions. At a minimum, the purchased 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 2014 Tampa Electric plans for 362 MW of cogeneration capacity operating in its service area.

Table IV-1 2014 Cogeneration Capacity Forecast	Capacity (MW)
Self-service [1]	258
Firm to Tampa Electric	23
As-available to Tampa Electric	26
Export to other systems	55
Total	362

[1] Capacity and energy that cogenerators produce to serve their own internal load requirements

FIRM INTERCHANGE SALES AND PURCHASES

Currently, Tampa Electric has no long-term firm sales agreements. However, the company does have the following long-term firm purchased power contracts for capacity and energy:

- 117 MW from Calpine Energy Services through December 2016
- 160 MW (155 MW net to Tampa Electric) from Southern Power Company through December 2015
- 121 MW from Quantum Pasco Power through December 2018

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 mostly 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 units, and Polk units. As shown in Schedule 6.2, in 2014 coal and petcoke will fuel 61% of the net energy for load and natural gas will fuel 35%. The remaining net energy for load is served by firm, non-firm, and non-utility generator purchases. Some of 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 (NO_x) by 91%, particulate matter (PM) by 87% and mercury emissions by 90%. 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 flue gas desulfurization (scrubber) system in 1995
- Installation of a scrubber on Big Bend Units 1 and 2 in 1999
- Installation and operation of selective catalytic reduction systems (SCR), at Big Bend Station from 2007 to 2010
- Installation and operation of combustion tuning and optimization projects at Big Bend Station from 2000 to 2004
- 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

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.

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
2014	4,276	393	0	23	4,692	3,717	975	26%	151	824	22%
2015	4,276	393	0	23	4,692	3,748	944	25%	0	944	25%
2016	4,276	271	0	0	4,547	3,789	758	20%	0	758	20%
2017	4,735	121	0	0	4,856	3,836	1,020	27%	0	1,020	27%
2018	4,735	121	0	0	4,856	3,880	976	25%	0	976	25%
2019	4,735	0	0	0	4,735	3,925	810	21%	0	810	21%
2020	4,925	0	0	0	4,925	3,967	958	24%	0	958	24%
2021	4,925	0	0	0	4,925	4,010	915	23%	0	915	23%
2022	4,925	0	0	0	4,925	4,054	871	21%	0	871	21%
2023	4,925	0	0	0	4,925	4,097	828	20%	0	828	20%

Notes:

* Phillips Station and Partnership Station unit capabilities are not included in the Total Installed Capacity

** Includes firm purchase power agreements (PPA) with Southern Power Company of 155 MW through 2015, Calpine Energy Services of 117 MW through 2016, Quantum Pasco Power of 121 MW through 2018, and an unspecified 33 MW for the summer of 2016 that will be identified among multiple resources.

*** Accounts for Orange Cogen that will be purchased under firm contract 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
2013-14	4,668	393	0	23	5,084	3,724	1,360	37%	0	1,360	37%
2014-15	4,668	393	0	23	5,084	3,766	1,318	35%	0	1,318	35%
2015-16	4,668	238	0	0	4,906	3,812	1,094	29%	0	1,094	29%
2016-17	5,131	121	0	0	5,252	3,861	1,391	36%	0	1,391	36%
2017-18	5,131	121	0	0	5,252	3,911	1,341	34%	0	1,341	34%
2018-19	5,131	0	0	0	5,131	3,962	1,169	30%	0	1,169	30%
2019-20	5,131	0	0	0	5,131	4,013	1,118	28%	0	1,118	28%
2020-21	5,351	0	0	0	5,351	4,061	1,290	32%	0	1,290	32%
2021-22	5,351	0	0	0	5,351	4,111	1,240	30%	0	1,240	30%
2022-23	5,351	0	0	0	5,351	4,159	1,192	29%	0	1,192	29%

Notes:

* * Phillips Station and Partnership Station unit capabilities are not included in the Total Installed Capacity
* ** Includes firm purchase power agreements (PPA) with Southern Power Company of 155 MW through 2015, Calpine Energy Services of 117 MW through 2016, and Quantum Pasco Power of 121 MW through 2018.
* *** Accounts for Orange Cogen that will be purchased under firm contract 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)
								Const.	Commercial	Expected	Gen. Max.	Net Capability		
Plant	Unit		Unit	Fuel		Fuel Trans.		Start	In-Service	Retirement	Nameplate	Summer	Winter	
Name	No.	Location	Type	Primary	Alternate	Primary	Alternate	Mo/Yr	Mo/Yr	Mo/Yr	kW	MW	MW	Status
Polk 2 CC	2	Polk	CC	NG	LO	PL	TK	01/14	01/17	*	*	1,063 **	1,195 **	U
Future CT 1	1	*	GT	NG	NA	PL	NA	09/19	05/20	*	*	190	220	P

Notes:

* Undetermined

** Net capability values shown for the Polk 2 CC reflect the conversion of the existing Polk Units 2-5 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

(1)	Plant Name and Unit Number	Polk 2 CC
(2)	Net Capability	
	A. Summer	1,063 MW
	B. Winter	1,195 MW
(3)	Technology Type	Combined Cycle
(4)	Anticipated Construction Timing	
	A. Field Construction Start Date	Jan 2014
	B. Commercial In-Service Date	Jan 2017
(5)	Fuel	
	A. Primary Fuel	Natural Gas
	B. Alternate Fuel	Light Oil
(6)	Air Pollution Control Strategy	SCR, DLN Burners
(7)	Cooling Method	Cooling Reservoir
(8)	Total Site Area	Undetermined
(9)	Construction Status	In Progress
(10)	Certification Status	In Progress
(11)	Status with Federal Agencies	All Federal Permits Received
(12)	Projected Unit Performance Data	
	Planned Outage Factor (POF)	0.03
	Forced Outage Rate (FOF)	0.01
	Equivalent Availability Factor (EAF)	0.96
	Resulting Capacity Factor (2017)	46.2%
	Average Net Operating Heat Rate (ANOHR) [1]	7,049 Btu/kWh
(13)	Projected Unit Financial Data	
	Book Life (Years)	30
	Total Installed Cost (In-Service Year $/kW) [1]	436.59
	Direct Construction Cost ($/kW) [1]	355.17
	AFUDC* Amount ($/kW) [1]	58.65
	Escalation ($/kW) [1]	22.78
	Fixed O&M ($/kW – Yr) [1]	1.23
	Variable O&M ($/MWh) [1]	2.34
	K-Factor	1.5245

[1] Based On In-Service Year.

* Based On the Current AFUDC Rate Of 8.16%

Schedule 9
(Page 2 of 2)
Status Report and Specifications of Proposed Generating Facilities

(1)	Plant Name and Unit Number	Future CT 1
(2)	Net Capability	
	A. Summer	190 MW
	B. Winter	220 MW
(3)	Technology Type	Combustion Turbine
(4)	Anticipated Construction Timing	
	A. Field Construction Start Date	Sep 2019
	B. Commercial In-Service Date	May 2020
(5)	Fuel	
	A. Primary Fuel	Natural Gas
	B. Alternate Fuel	N/A
(6)	Air Pollution Control Strategy	Dry-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)	0.03
	Forced Outage Rate (FOF)	0.01
	Equivalent Availability Factor (EAF)	0.95
	Resulting Capacity Factor (2017)	2.4%
	Average Net Operating Heat Rate (ANOHR) [1]	10,434 Btu/kWh
(13)	Projected Unit Financial Data	
	Book Life (Years)	25
	Total Installed Cost (In-Service Year $/kW) [1]	747.38
	Direct Construction Cost ($/kW) [1]	511.24
	AFUDC* Amount ($/kW) [1]	69.41
	Escalation ($/kW) [1]	166.73
	Fixed O&M ($/kW – Yr) [1]	12.13
	Variable O&M ($/MWh) [1]	2.11
	K-Factor	1.4625

[1] Based On In-Service Year.
* Based On the Current AFUDC Rate Of 8.16%

Schedule 10

Status Report and Specifications of Proposed Directly Associated Transmission Lines

Units	Point of Origin and Termination	Number of Circuits	Right-of-Way (ROW)	Circuit Length	Voltage	Anticipated In-Service Date	Anticipated Capital Investment **	Substations	Participation with Other Utilities
Polk 2 CC	Polk-Aspen-FishHawk	5	ROW issues under-review	62.5 mi	230 kV	Jan. 2017	$151 million	Switching Station	None
Polk 2 CC	Davis Substation Switched Reactor	0	ROW issues under-review	0 mi	230 kV	Jan. 2017	$2 million	No New substations	None
Polk 2 CC	Polk Steam Turbine Interconnect & Upgrade	1	ROW issues under-review	0 mi	230 kV	Jan. 2017	$6 million	No New substations	None
Future CT 1	Unsited *	-	-	-	-	May 2020	-	-	-

Note:

* Specific information related to "Unsited" units unknown at this time.

** Cumulative capital investment at the in-service date

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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 2013 Florida Reliability Coordinating Council (FRCC) database 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.

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 a repetitive cycle.

The 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 rates are projected based on an average of three years of historical data and 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 are 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 the FPSC's prescribed cost-effectiveness methodology that complies with Rule 25-17.008, F.A.C.

Generating resources to be considered are determined through an alternative technology screening analysis that 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 that examines various supply-side alternatives for meeting future capacity requirements.

Tampa Electric uses a computer model developed by Ventyx, System Optimizer (SO), to evaluate supply-side resources. SO utilizes a mixed integer linear program (MILP) to develop an estimate of the timing and type of supply-side resources for capacity additions that would most economically meet the system demand and energy requirements. The MILP's objective function is to compare all feasible combinations of generating unit additions, satisfy the specified reliability criteria, and determine the schedule and addition with the lowest revenue requirement.

Detailed cost analyses for each of the top ranked resource plans are performed using the Planning & Risk (PaR) production cost model, also developed by Ventyx. 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 in 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.

RESULTS

The result of the integrated resource planning process provides 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 converting Polk units 2-5 to a natural gas combined cycle unit with the addition of a steam turbine that will go in-service in 2017. The company is also planning the addition of a simple cycle combustion turbine in 2020.

Tampa Electric will continue to assess competitive purchased power agreements that may replace or delay the scheduled new unit in 2020. Such alternatives would be considered if better suited to the overall objective of providing reliable power in the most cost effective manner.

GENERATION RELIABILITY CRITERIA

1. Generation

Tampa Electric currently uses two criteria to measure the reliability of its generating system. The company utilizes a minimum 20% reserve margin 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. 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 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 firm peak demand and interruptible and load management loads.

TRANSMISSION RELIABILITY CRITERIA

1. Transmission

The following criteria are used as guidelines for proposing transmission system expansion and/or improvement projects, however they are not absolute. These criteria are used to alert planners of potential transmission system capacity limitations. Engineering analysis is used in all stages of the planning process to weigh the impact of system deficiencies, the likelihood of the triggering contingency, and the viability of any operating options. Only by carefully researching each planning criteria violation can a final evaluation of available transmission capacity be made.

2. 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 function 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 planned and unplanned unit outages can result in a system dispatch that varies from a base plan (economic dispatch), bulk transmission planners also investigate several non-economic scenarios that may stress Tampa Electric's transmission system. These additional generation sensitivities are performed to ensure the integrity of the bulk electric system (BES) under maximized bulk power flows.

3. Transmission System Planning Loading Limits Criteria

Tampa Electric follows the FRCC planning criteria, as contained in the *FRCC Regional Transmission Planning Process.* 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 company-specific planning criteria for normal system operation and single-contingency operation.

The following table summarizes the thresholds, which alert planners to problematic transmission lines and transformers.

Table V-I
Transmission 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, these criteria can be approximated by the following table that provides transmission system voltage limits.

Table V-II
Transmission System Voltage Limits

Transmission System Conditions	Industrial Substation Buses at point-of-service	69 kV Buses	138 kV Buses	230 kV Buses
Single Contingency (pre-switching)	0.925 - 1.050 p.u.	0.925 - 1.050 p.u.	0.950 – 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 – 1.050 p.u.	0.950 - 1.060 p.u.
Bus Outages	0.925 - 1.050 p.u.	0.925 - 1.050 p.u.	0.950 – 1.050 p.u.	0.950 - 1.060 p.u.

4. Available Transmission Transfer Capability (ATC) Criteria

Tampa Electric adheres to the ATC calculation methodology described in the *Attachment C of Tampa Electric Company Open Access Transmission Tariff FERC Electric Tariff, Fourth Revised Volume No. 4* document, as well as the principles contained in the NERC Reliability Standards relating to ATC calculations. Members of the FRCC, including TEC, have formed the Florida Transmission Capability Determination Group in an effort to provide ATC values to the regional electric market that are transparent, coordinated, timely and accurate.

TRANSMISSION PLANNING ASSESSMENT PRACTICES

1. Base Case Operating Conditions

The Transmission Planning department ensures the Tampa Electric 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.

2. Single Contingency Planning Criteria

The Tampa Electric 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.

3. 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 transmission system is designed such that double contingencies do not cause violation of FRCC and NERC Reliability Standards criteria.

4. 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 BES 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.

5. 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 database 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, purchased 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.

6. 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;

5. Metering of loads under control to determine the demand and energy savings in commercial programs such as Standby Generator and Commercial Load Management and Commercial Demand Response

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.

7. 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 2013, Tampa Electric's Renewable Energy Program has over 2,100 customers purchasing almost 2,900 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 105 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. In September 2013, the capacity of the PV array at the Museum of Science and Industry was increased to 21.4 kW with a new set of more efficient PV panels. 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 biomass facilities in Florida. Through December 2013, participating customers have utilized over 62 GWh of renewable energy since the program inception.

In 2011, Tampa Electric also initiated a five-year renewable energy pilot that utilizes incentives to encourage the following installations:

- PV technologies on existing and new residential and commercial premises; solar water heating (SWH) technology on existing and new residential premises
- PV on emergency shelter schools coupled with an educational component for teachers and students
- SWH on low-income housing done in partnership with local non-profit building organizations

This pilot has an annual funding cap of $1.53 million. Through this initiative, Tampa Electric expects an additional 510 kW of customer owned PV to be installed and up to 150 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 its resource portfolio. For instance, renewable options for the future could be 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 customers and utility-scale PV is also being considered. As market conditions continue to change and technology improves in this sector, renewable alternatives, such as solar, become more cost-effective to customers. In fact, Tampa Electric has experienced a steady-significant increase in customer-owned PV systems and provides net metering to 425 customers having a total capacity of over 6.6 megawatts (MW) through December 2013.

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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.

Figure VI-1: Site Location of H.L. Culbreath Bayside Power Station

Figure VI-2: Site Location of Polk Power Station

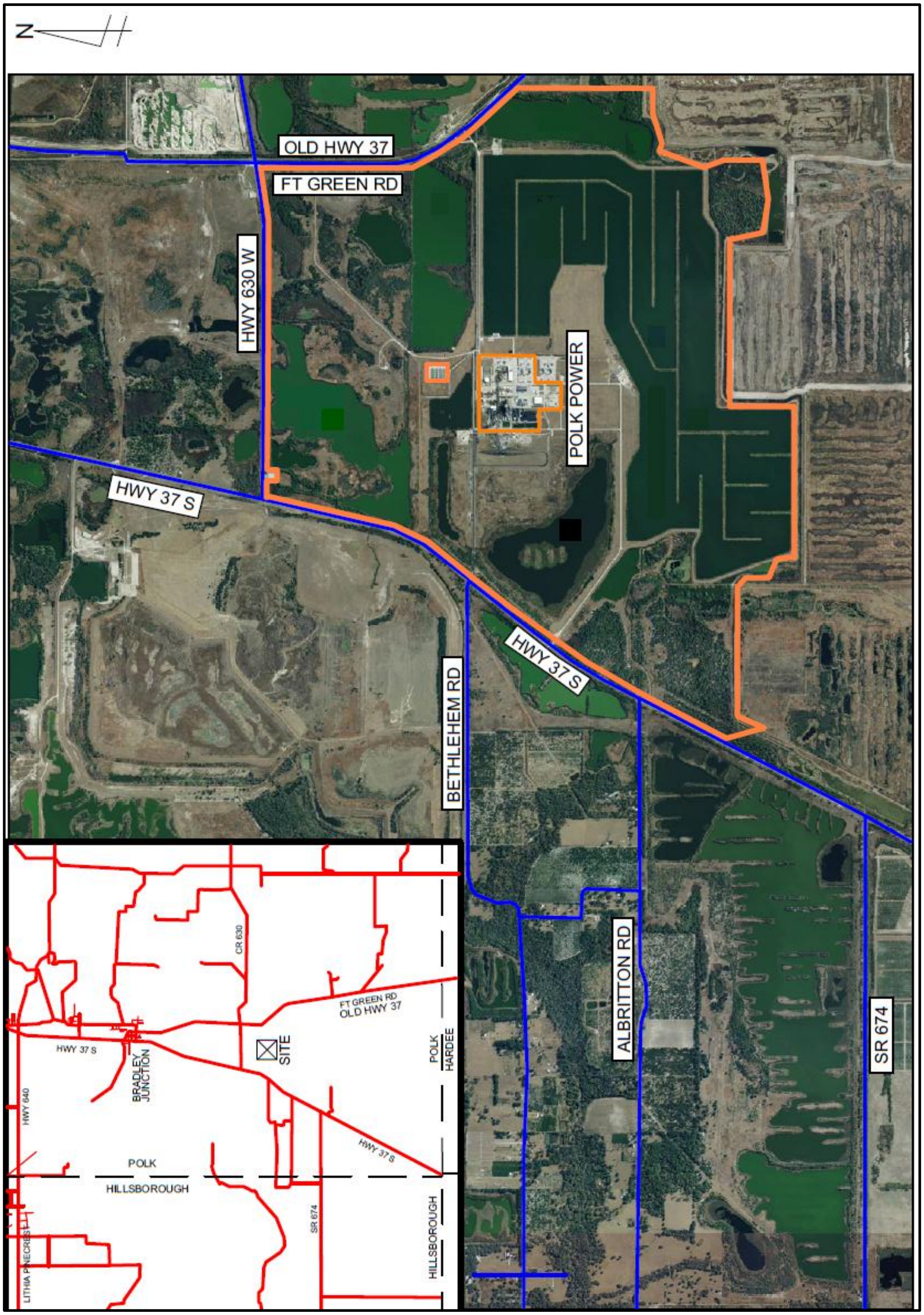

Figure VI-3: Site Location of Big Bend Power Station