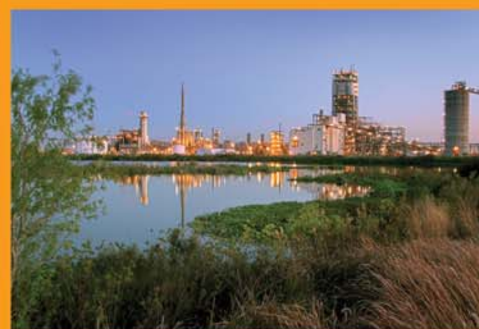
Ten-Year Site Plan for Electrical Generating Facilities and Associated Transmission Lines

January 2009 to December 2018

TECO
TAMPA ELECTRIC



TAMPA ELECTRIC H.L. Culbreath Bayside Power Station Pratt & Whitney Aero-derivative Expansion

REVISED APRIL 6, 2009

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

January 2009 to December 2018

TAMPA ELECTRIC COMPANY
Tampa, Florida

Revised April 6, 2009

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CHAPTER IV

List of Figures

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Glossary of Terms

CODE IDENTIFICATION SHEET

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

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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. In addition, the station will operate one (1) aero-derivative combustion turbine, scheduled for in-service in Fall 2009. The station's coal-fired units are currently undergoing the addition of air pollution control systems called Selective Catalytic Reduction (SCR). Three of the units have been modified and the remaining coal unit will be modified by 2010.

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 will operate four (4) aero-derivative combustion turbines, two (2) scheduled for in-service in Spring 2009 and the remaining two (2) in Fall 2009.

Polk Power Station

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

J.H. Phillips Power Station

The station is comprised of two (2) residual or distillate oil fired diesel engines.

Partnership Power Station

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

Schedule 1

Existing Generating Facilities
As of December 31, 2008

(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									**1,822,500**	**1,550**	**1,590**
	1		ST	BIT	N	WA	N	0	10/70	Unknown	445,500	379	389
	2		ST	BIT	N	WA	N	0	04/73	Unknown	445,500	373	383
	3		ST	BIT	N	WA	N	0	05/76	Unknown	445,500	381	391
	4		ST	BIT	N	WA	N	0	02/85	Unknown	486,000	417	427
Bayside		Hillsborough											
		Co. 4/30S/19E									**2,014,160**	**1,630**	**1,839**
	1		CC	NG	N	PL	N	0	4/03	Unknown	809,060	701	792
	2		CC	NG	N	PL	N	0	1/04	Unknown	1,205,100	929	1,047
Phillips		Highland Co.											
		12-055									**38,430**	**36**	**36**
	1		IC	HO	LO	TK	N	0	06/83	Unknown	19,215	18	18
	2		IC	HO	LO	TK	N	0	06/83	Unknown	19,215	18	18
Polk		Polk Co.											
		2,3/32S/23E									**1,029,379**	**839**	**972**
	1		IGCC	BIT	LO	WA/TK	TK	0	09/96	Unknown	326,299	235	240
	2		CT	NG	LO	PL	TK	0	07/00	Unknown	175,770 *	151	183
	3		CT	NG	LO	PL	TK	0	5/02	Unknown	175,770 *	151	183
	4		CT	NG	N	PL	N	0	3/07	Unknown	175,770 *	151	183
	5		CT	NG	N	PL	N	0	4/07	Unknown	175,770 *	151	183
Partnership		Hillsborough											
		Co. W30/29/19									**5,800**	**6**	**6**
	1		IC	NG	N	PL	N	0	04/01	Unknown	2,900	3	3
	2		IC	NG	N	PL	N	0	04/01	Unknown	2,900	3	3
											TOTAL	**4,061**	**4,443**

Notes:

* Polk Units 2-5 turbine name plate ratings are based on 59 deg F. The net capacity of these units vary with ambient air temperature.
Big Bend CT 1 retired 12/31/2008

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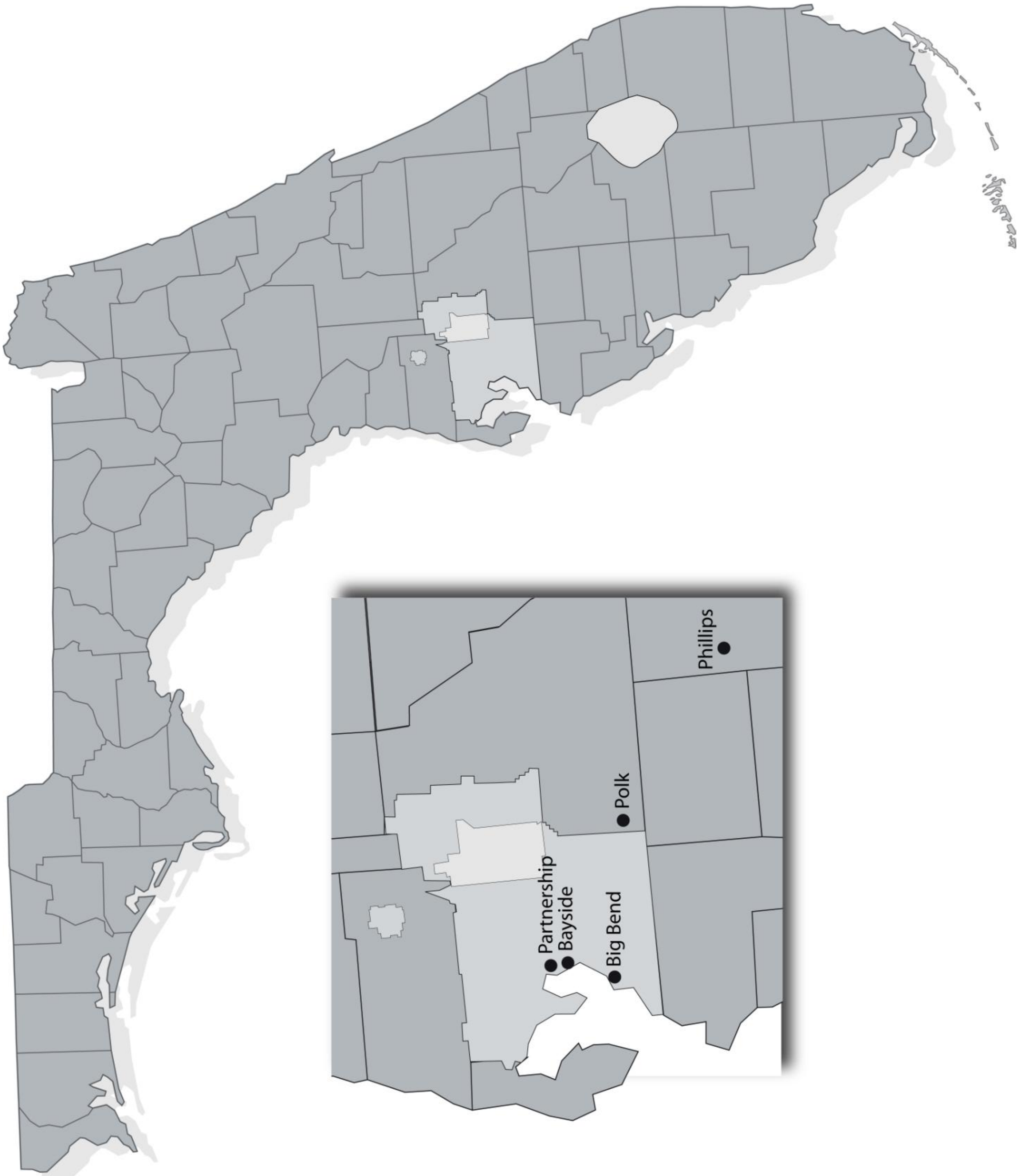
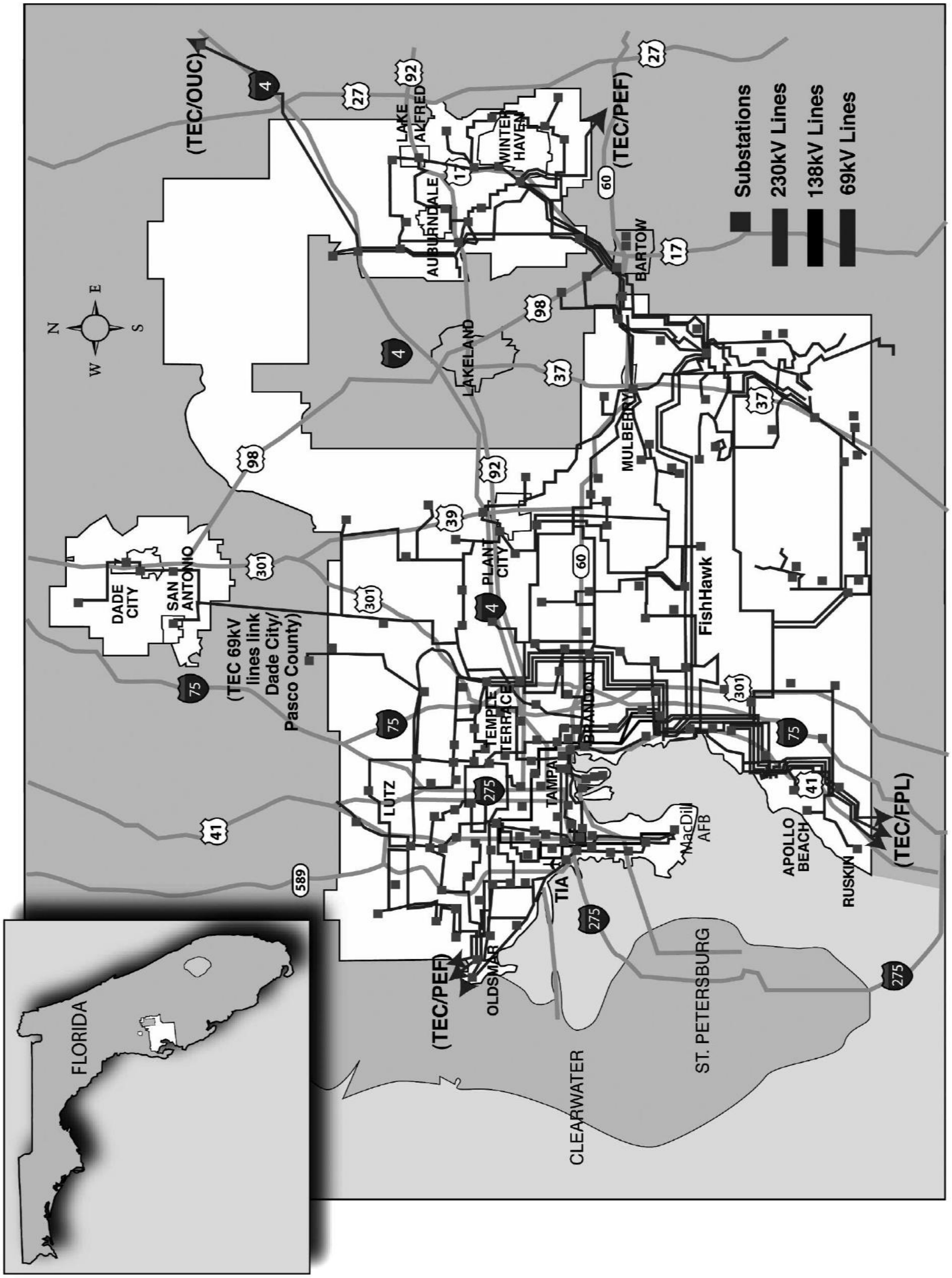
I.1 Tampa Electric Service Area Map



I.2 Tampa Electric Service Area Transmission Facility



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Chapter II

FORECAST OF ELECTRIC POWER, DEMAND, AND ENERGY CONSUMPTION

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

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

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

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

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

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

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

Schedule 2.1

History and Forecast of Energy Consumption and Number of Customers by Customer Class Base Case (1 of 3)

(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
1999	962,153	2.4	6,967	477,533	14,590	5,337	60,089	88,818
2000	1,006,400	2.6	7,369	491,925	14,980	5,541	61,902	89,512
2001	1,030,900	2.6	7,594	505,964	15,009	5,685	63,316	89,788
2002	1,053,900	2.6	8,046	518,554	15,516	5,832	64,665	90,188
2003	1,084,198	2.5	8,265	531,257	15,557	5,843	66,041	88,475
2004	1,106,487	2.5	8,293	544,313	15,236	5,988	67,488	88,727
2005	1,127,449	2.5	8,558	558,601	15,320	6,233	69,027	90,298
2006	1,161,959	2.5	8,721	575,111	15,164	6,357	70,205	90,549
2007	1,195,117	2.5	8,871	586,776	15,119	6,542	70,891	92,276
2008	1,209,625	2.5	8,546	587,602	14,545	6,399	70,770	90,415
2009	1,223,671	2.5	9,088	598,482	15,185	6,711	72,640	92,386
2010	1,239,675	2.5	9,276	609,633	15,216	6,845	74,097	92,382
2011	1,261,030	2.5	9,508	623,151	15,258	6,968	75,771	91,967
2012	1,283,060	2.5	9,737	637,608	15,271	7,124	77,394	92,053
2013	1,305,474	2.5	9,974	652,721	15,280	7,290	79,033	92,240
2014	1,328,280	2.5	10,225	668,445	15,297	7,457	80,729	92,370
2015	1,350,624	2.5	10,487	684,501	15,320	7,629	82,468	92,511
2016	1,370,881	2.5	10,755	700,613	15,351	7,804	84,219	92,665
2017	1,391,297	2.4	11,040	717,184	15,394	7,978	86,010	92,756
2018	1,412,016	2.4	11,339	734,158	15,445	8,159	87,835	92,895

December 31, 2008 Status

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

Schedule 2.1

History and Forecast of Energy Consumption and Number of Customers by Customer Class High Case (2 of 3)

(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
1999	962,153	2.4	6,967	477,533	14,590	5,337	60,089	88,818
2000	1,006,400	2.6	7,369	491,925	14,980	5,541	61,902	89,512
2001	1,030,900	2.6	7,594	505,964	15,009	5,685	63,316	89,788
2002	1,053,900	2.6	8,046	518,554	15,516	5,832	64,665	90,188
2003	1,084,198	2.5	8,265	531,257	15,557	5,843	66,041	88,475
2004	1,106,487	2.5	8,293	544,313	15,236	5,988	67,488	88,727
2005	1,127,449	2.5	8,558	558,601	15,320	6,233	69,027	90,298
2006	1,161,959	2.5	8,721	575,111	15,164	6,357	70,205	90,549
2007	1,195,117	2.5	8,871	586,776	15,119	6,542	70,891	92,276
2008	1,209,625	2.5	8,546	587,602	14,545	6,399	70,770	90,415
2009	1,256,324	2.5	9,163	602,376	15,212	6,731	72,843	92,403
2010	1,289,519	2.5	9,423	617,557	15,259	6,884	74,510	92,390
2011	1,320,062	2.5	9,730	635,288	15,316	7,027	76,406	91,969
2012	1,351,118	2.5	10,038	654,156	15,345	7,204	78,259	92,048
2013	1,382,904	2.5	10,357	673,887	15,369	7,391	80,140	92,226
2014	1,415,438	2.5	10,696	694,449	15,402	7,581	82,089	92,349
2015	1,447,733	2.5	11,049	715,565	15,441	7,777	84,094	92,482
2016	1,477,876	2.6	11,414	736,956	15,488	7,977	86,120	92,629
2017	1,508,474	2.6	11,801	759,046	15,547	8,177	88,201	92,713
2018	1,539,706	2.6	12,208	781,783	15,615	8,386	90,327	92,845

December 31, 2008 Status

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

Schedule 2.1

History and Forecast of Energy Consumption and Number of Customers by Customer Class Low Case (3 of 3)

(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
1999	962,153	2.4	6,967	477,533	14,590	5,337	60,089	88,818
2000	1,006,400	2.6	7,369	491,925	14,980	5,541	61,902	89,512
2001	1,030,900	2.6	7,594	505,964	15,009	5,685	63,316	89,788
2002	1,053,900	2.6	8,046	518,554	15,516	5,832	64,665	90,188
2003	1,084,198	2.5	8,265	531,257	15,557	5,843	66,041	88,475
2004	1,106,487	2.5	8,293	544,313	15,236	5,988	67,488	88,727
2005	1,127,449	2.5	8,558	558,601	15,320	6,233	69,027	90,298
2006	1,161,959	2.5	8,721	575,111	15,164	6,357	70,205	90,549
2007	1,195,117	2.5	8,871	586,776	15,119	6,542	70,891	92,276
2008	1,209,625	2.5	8,546	587,602	14,545	6,399	70,770	90,415
2009	1,244,096	2.5	9,012	594,589	15,157	6,691	72,437	92,369
2010	1,264,527	2.5	9,131	601,748	15,174	6,807	73,686	92,373
2011	1,281,833	2.5	9,289	611,133	15,200	6,911	75,143	91,964
2012	1,299,170	2.4	9,443	621,303	15,198	7,046	76,541	92,059
2013	1,316,743	2.4	9,600	631,966	15,191	7,191	77,947	92,253
2014	1,334,553	2.4	9,770	643,072	15,192	7,336	79,401	92,392
2015	1,351,657	2.4	9,945	654,339	15,199	7,486	80,890	92,541
2016	1,366,283	2.4	10,125	665,497	15,214	7,637	82,381	92,702
2017	1,380,908	2.3	10,317	676,933	15,240	7,786	83,904	92,801
2018	1,395,690	2.3	10,518	688,588	15,275	7,942	85,450	92,947

December 31, 2008 Status

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

Schedule 2.2

History and Forecast of Energy Consumption and Number of Customers by Customer Class Base Case (1 of 3)

(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
1999	2,223	740	3,004,054	0	52	1,226	15,805
2000	2,390	776	3,079,897	0	53	1,285	16,638
2001	2,329	851	2,736,780	0	54	1,314	16,976
2002	2,612	948	2,755,274	0	55	1,380	17,925
2003	2,580	1203	2,144,638	0	57	1,481	18,226
2004	2,556	1,299	1,967,667	0	58	1,542	18,437
2005	2,478	1,337	1,853,403	0	60	1,582	18,911
2006	2,279	1,485	1,534,680	0	61	1,607	19,025
2007	2,366	1,494	1,583,695	0	63	1,692	19,533
2008	2,205	1,421	1,551,724	0	64	1,776	18,990
2009	2,392	1,427	1,676,387	0	73	1,729	19,993
2010	2,401	1,447	1,659,279	0	80	1,756	20,358
2011	2,411	1,473	1,636,987	0	86	1,784	20,758
2012	2,419	1,492	1,621,474	0	87	1,811	21,179
2013	2,428	1,511	1,607,330	0	88	1,839	21,619
2014	2,438	1,531	1,592,420	0	89	1,869	22,078
2015	2,446	1,553	1,575,477	0	90	1,900	22,552
2016	2,457	1,577	1,558,295	0	91	1,932	23,040
2017	2,469	1,602	1,540,925	0	93	1,966	23,546
2018	2,480	1,627	1,524,227	0	94	2,003	24,075

December 31, 2008 Status

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

Schedule 2.2

History and Forecast of Energy Consumption and Number of Customers by Customer Class High Case (2 of 3)

(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
1999	2,223	740	3,004,054	0	52	1,226	15,805
2000	2,390	776	3,079,897	0	53	1,285	16,638
2001	2,329	851	2,736,780	0	54	1,314	16,976
2002	2,612	948	2,755,274	0	55	1,380	17,925
2003	2,580	1,203	2,144,638	0	57	1,481	18,226
2004	2,556	1,299	1,967,667	0	58	1,542	18,437
2005	2,478	1,337	1,853,403	0	60	1,582	18,911
2006	2,279	1,485	1,534,680	0	61	1,607	19,025
2007	2,366	1,494	1,583,695	0	63	1,692	19,533
2008	2,205	1,421	1,551,724	0	64	1,776	18,990
2009	2,393	1,431	1,672,013	0	73	1,737	20,096
2010	2,402	1,455	1,650,682	0	80	1,771	20,560
2011	2,413	1,486	1,624,256	0	86	1,806	21,063
2012	2,422	1,510	1,604,615	0	87	1,841	21,592
2013	2,432	1,533	1,586,391	0	88	1,877	22,146
2014	2,443	1,558	1,567,472	0	89	1,916	22,724
2015	2,452	1,586	1,546,619	0	90	1,956	23,324
2016	2,465	1,616	1,525,601	0	91	1,997	23,945
2017	2,477	1,647	1,504,479	0	93	2,041	24,590
2018	2,490	1,678	1,484,093	0	94	2,088	25,266

December 31, 2008 Status

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

Schedule 2.2

History and Forecast of Energy Consumption and Number of Customers by Customer Class Low Case (3 of 3)

(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
1999	2,223	740	3,004,054	0	52	1,226	15,805
2000	2,390	776	3,079,897	0	53	1,285	16,638
2001	2,329	851	2,736,780	0	54	1,314	16,976
2002	2,612	948	2,755,274	0	55	1,380	17,925
2003	2,580	1,203	2,144,638	0	57	1,481	18,226
2004	2,556	1,299	1,967,667	0	58	1,542	18,437
2005	2,478	1,337	1,853,403	0	60	1,582	18,911
2006	2,279	1,485	1,534,680	0	61	1,607	19,025
2007	2,366	1,494	1,583,695	0	63	1,692	19,533
2008	2,205	1,421	1,551,724	0	64	1,776	18,990
2009	2,391	1,423	1,680,785	0	73	1,722	19,890
2010	2,400	1,439	1,667,930	0	80	1,742	20,158
2011	2,409	1,460	1,649,814	0	86	1,762	20,457
2012	2,417	1,475	1,638,480	0	87	1,782	20,774
2013	2,425	1,489	1,628,481	0	88	1,802	21,105
2014	2,433	1,504	1,617,659	0	89	1,823	21,451
2015	2,440	1,521	1,604,714	0	90	1,845	21,807
2016	2,450	1,540	1,591,470	0	91	1,869	22,172
2017	2,460	1,559	1,577,973	0	93	1,894	22,550
2018	2,470	1,578	1,565,096	0	94	1,921	22,945

December 31, 2008 Status

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

Schedule 2.3

History and Forecast of Energy Consumption and Number of Customers by Customer Class Base Case (1 of 3)

(1) Year	(2) Sales for * Resale GWH	(3) Utility Use ** & Losses GWH	(4) Net Energy *** for Load GWH	(5) Other **** Customers	(6) Total **** Customers
1999	533	900	17,238	5,299	543,661
2000	763	972	18,373	5,497	560,100
2001	684	794	18,454	5,649	575,780
2002	502	935	19,362	6,032	590,199
2003	587	985	19,798	6,399	604,900
2004	589	945	19,971	6,435	619,535
2005	712	952	20,575	6,656	635,621
2006	700	1,000	20,725	6,905	653,706
2007	829	916	21,278	7,193	666,354
2008	752	909	20,650	7,473	667,266
2009	668	1,019	21,680	7,392	679,941
2010	668	1,038	22,064	7,499	692,676
2011	364	1,058	22,180	7,624	708,019
2012	313	1,079	22,571	7,757	724,251
2013	248	1,102	22,969	7,895	741,159
2014	180	1,125	23,382	8,038	758,742
2015	180	1,149	23,880	8,183	776,706
2016	180	1,173	24,393	8,330	794,739
2017	79	1,199	24,824	8,481	813,277
2018	0	1,226	25,301	8,634	832,254

December 31, 2008 Status

* Includes sales to FPC, Wauchula, Ft. Meade, St. Cloud and Reedy Creek. Contract ended with Ft. Meade on 12/31/08 and will end with Wauchula on 12/31/13.
** 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.

Schedule 2.3

History and Forecast of Energy Consumption and Number of Customers by Customer Class High Case (2 of 3)

(1)	(2)	(3)	(4)	(5)	(6)
Year	**Sales for * Resale GWH**	**Utility Use ** & Losses GWH**	**Net Energy *** for Load GWH**	**Other **** Customers**	**Total **** Customers**
1999	533	900	17,238	5,299	543,661
2000	763	972	18,373	5,497	560,100
2001	684	794	18,454	5,649	575,780
2002	502	935	19,362	6,032	590,199
2003	587	985	19,798	6,399	604,900
2004	589	945	19,971	6,435	619,535
2005	712	952	20,575	6,656	635,621
2006	700	1,000	20,725	6,905	653,706
2007	829	916	21,278	7,193	666,354
2008	752	909	20,650	7,473	667,266
2009	668	1,024	21,788	7,422	684,071
2010	668	1,048	22,276	7,559	701,082
2011	364	1,074	22,500	7,716	720,896
2012	313	1,100	23,005	7,882	741,807
2013	248	1,128	23,522	8,055	763,616
2014	180	1,158	24,061	8,235	786,332
2015	180	1,188	24,692	8,419	809,664
2016	180	1,219	25,344	8,606	833,299
2017	79	1,252	25,921	8,799	857,692
2018	0	1,287	26,552	8,996	882,785

December 31, 2008 Status

* Includes sales to FPC, Wauchula, Ft. Meade, St. Cloud and Reedy Creek. Contract ended with Ft. Meade on 12/31/08 and will end with Wauchula on 12/31/13.
** 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.

Schedule 2.3

History and Forecast of Energy Consumption and Number of Customers by Customer Class
Low Case (3 of 3)

(1) Year	(2) Sales for * Resale GWH	(3) Utility Use ** & Losses GWH	(4) Net Energy *** for Load GWH	(5) Other **** Customers	(6) Total **** Customers
1999	533	900	17,238	5,299	543,661
2000	763	972	18,373	5,497	560,100
2001	684	794	18,454	5,649	575,780
2002	502	935	19,362	6,032	590,199
2003	587	985	19,798	6,399	604,900
2004	589	945	19,971	6,435	619,535
2005	712	952	20,575	6,656	635,621
2006	700	1,000	20,725	6,905	653,706
2007	829	916	21,278	7,193	666,354
2008	752	909	20,650	7,473	667,266
2009	668	1,014	21,571	7,362	675,811
2010	668	1,028	21,854	7,439	684,311
2011	364	1,043	21,864	7,533	695,269
2012	313	1,058	22,146	7,633	706,951
2013	248	1,075	22,429	7,737	719,140
2014	180	1,093	22,723	7,845	731,822
2015	180	1,111	23,098	7,954	744,703
2016	180	1,129	23,482	8,063	757,480
2017	79	1,149	23,778	8,175	770,571
2018	0	1,169	24,114	8,288	783,905

December 31, 2008 Status

* Includes sales to FPC, Wauchula, Ft. Meade, St. Cloud and Reedy Creek. Contract ended with Ft. Meade on 12/31/08 and will end with Wauchula on 12/31/13.
** 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.

Schedule 3.1

History and Forecast of Summer Peak Demand
Base Case (1 of 3)

(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	
1999	3,648	190	3,458	193	98	48	19	31	3,069	
2000	3,568	171	3,397	182	78	52	21	36	3,028	
2001	3,730	178	3,552	181	90	55	21	40	3,165	
2002	3,869	122	3,747	206	99	60	21	43	3,318	***
2003	3,854	122	3,732	188	63	65	21	44	3,351	
2004	3,974	120	3,854	177	95	70	20	47	3,445	
2005	4,218	128	4,090	144	79	73	19	49	3,725	
2006	4,265	128	4,137	146	77	77	18	50	3,769	
2007	4,428	172	4,256	159	69	80	18	53	3,876	
2008	4,240	148	4,092	143	69	84	18	55	3,723	
2009	4,524	176	4,348	176	60	86	27	56	3,943	
2010	4,613	177	4,436	176	63	88	31	58	4,019	
2011	4,635	106	4,529	176	66	90	36	59	4,100	
2012	4,729	106	4,623	176	70	92	40	61	4,183	
2013	4,815	91	4,724	176	74	94	45	63	4,271	
2014	4,904	77	4,827	176	78	96	50	64	4,362	
2015	5,009	76	4,933	176	83	98	52	65	4,459	
2016	5,116	76	5,040	176	87	99	53	66	4,558	
2017	5,151	0	5,151	176	92	101	53	67	4,661	
2018	5,266	0	5,266	176	96	102	54	68	4,768	

December 31, 2008 Status

* Includes residential and commercial/industrial conservation.

** Includes sales to Progress Energy Florida, Wauchula, Ft. Meade, St. Cloud and Reedy Creek. Contract ended with Ft. Meade on 12/31/08 and will end with Wauchula on 12/31/13.

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

Note: Values shown may be affected due to rounding.

Schedule 3.1

History and Forecast of Summer Peak Demand
High Case (2 of 3)

(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**	
1999	3,648	190	3,458	193	98	48	19	31	3,069	
2000	3,568	171	3,397	182	78	52	21	36	3,028	
2001	3,730	178	3,552	181	90	55	21	40	3,165	
2002	3,869	122	3,747	206	99	60	21	43	3,318	***
2003	3,854	122	3,732	188	63	65	21	44	3,351	
2004	3,974	120	3,854	177	95	70	20	47	3,445	
2005	4,218	128	4,090	144	79	73	19	49	3,725	
2006	4,265	128	4,137	146	77	77	18	50	3,769	
2007	4,428	172	4,256	159	69	80	18	53	3,876	
2008	4,240	148	4,092	143	69	84	18	55	3,723	
2009	4,548	176	4,372	176	60	86	27	56	3,967	
2010	4,660	177	4,483	176	63	88	31	58	4,066	
2011	4,707	106	4,601	176	66	90	36	59	4,172	
2012	4,826	106	4,720	176	70	92	40	61	4,280	
2013	4,938	91	4,847	176	74	94	45	63	4,394	
2014	5,055	77	4,978	176	78	96	50	64	4,513	
2015	5,189	76	5,113	176	83	98	52	65	4,639	
2016	5,327	76	5,251	176	87	99	53	66	4,769	
2017	5,394	0	5,394	176	92	101	53	67	4,904	
2018	5,542	0	5,542	176	96	102	54	68	5,044	

December 31, 2008 Status

* Includes residential and commercial/industrial conservation.
** Includes sales to Progress Energy Florida, Wauchula, Ft. Meade, St. Cloud and Reedy Creek. Contract ended with Ft. Meade on 12/31/08 and will end with Wauchula on 12/31/13.
*** Net Firm Demand is not coincident with system peak.
Note: Values shown may be affected due to rounding.

Schedule 3.1

History and Forecast of Summer Peak Demand
Low Case (3 of 3)

(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
1999	3,648	190	3,458	193	98	48	19	31	3,069
2000	3,568	171	3,397	182	78	52	21	36	3,028
2001	3,730	178	3,552	181	90	55	21	40	3,165
2002	3,869	122	3,747	206	99	60	21	43	3,318 ***
2003	3,854	122	3,732	188	63	65	21	44	3,351
2004	3,974	120	3,854	177	95	70	20	47	3,445
2005	4,218	128	4,090	144	79	73	19	49	3,725
2006	4,265	128	4,137	146	77	77	18	50	3,769
2007	4,428	172	4,256	159	69	80	18	53	3,876
2008	4,240	148	4,092	143	69	84	18	55	3,723
2009	4,500	176	4,324	176	60	86	27	56	3,919
2010	4,566	177	4,389	176	63	88	31	58	3,972
2011	4,565	106	4,459	176	66	90	36	59	4,030
2012	4,634	106	4,528	176	70	92	40	61	4,088
2013	4,694	91	4,603	176	74	94	45	63	4,150
2014	4,757	77	4,680	176	78	96	50	64	4,215
2015	4,834	76	4,758	176	83	98	52	65	4,284
2016	4,913	76	4,837	176	87	99	53	66	4,355
2017	4,918	0	4,918	176	92	101	53	67	4,428
2018	5,002	0	5,002	176	96	102	54	68	4,504

December 31, 2008 Status

* Includes residential and commercial/industrial conservation.
** Includes sales to Progress Energy Florida, Wauchula, Ft. Meade, St. Cloud and Reedy Creek. Contract ended with Ft. Meade on 12/31/08 and will end with Wauchula on 12/31/13.
*** Net Firm Demand is not coincident with system peak.
Note: Values shown may be affected due to rounding.

Schedule 3.2

History and Forecast of Winter Peak Demand
Base Case (1 of 3)

(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
1998/99	3,985	131	3,854	152	266	388	18	40	2,990
1999/00	4,019	125	3,894	212	209	402	19	43	3,009
2000/01	4,405	136	4,269	191	196	410	21	44	3,407
2001/02	4,217	127	4,090	168	176	419	22	46	3,259
2002/03	4,484	129	4,355	195	210	428	21	46	3,455
2003/04	3,949	120	3,829	254	136	437	18	48	2,936
2004/05	4,308	129	4,179	194	189	444	16	49	3,287
2005/06	4,404	171	4,233	51	144	447	18	50	3,523
2006/07	4,063	162	3,900	157	96	452	18	51	3,127
2007/08	4,369	152	4,217	120	129	456	18	52	3,443
2008/09	5,037	179	4,857	173	125	459	27	53	4,020
2009/10	5,115	179	4,935	173	127	462	31	54	4,088
2010/11	5,208	178	5,029	173	130	465	35	55	4,171
2011/12	5,234	107	5,127	173	134	468	39	56	4,257
2012/13	5,321	93	5,228	173	139	470	44	57	4,345
2013/14	5,411	77	5,334	173	144	473	48	58	4,439
2014/15	5,519	76	5,443	173	149	475	52	58	4,536
2015/16	5,629	76	5,553	173	154	477	52	59	4,638
2016/17	5,743	76	5,667	173	159	479	52	59	4,744
2017/18	5,785	0	5,785	173	164	481	53	60	4,854

December 31, 2008 Status

* Includes residential and commercial/industrial conservation.
** Includes sales to Progress Energy Florida, Wauchula, Ft. Meade, St. Cloud and Reedy Creek. Contract ended with Ft. Meade on 12/31/08 and will end with Wauchula on 12/31/13.
Note: Values shown may be affected due to rounding.

Schedule 3.2

History and Forecast of Winter Peak Demand
High Case (2 of 3)

(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
1998/99	3,985	131	3,854	152	266	388	18	40	2,990
1999/00	4,019	125	3,894	212	209	402	19	43	3,009
2000/01	4,405	136	4,269	191	196	410	21	44	3,407
2001/02	4,217	127	4,090	168	176	419	22	46	3,259
2002/03	4,484	129	4,355	195	210	428	21	46	3,455
2003/04	3,949	120	3,829	254	136	437	18	48	2,936
2004/05	4,308	129	4,179	194	189	444	16	49	3,287
2005/06	4,404	171	4,233	51	144	447	18	50	3,523
2006/07	4,063	162	3,900	157	96	452	18	51	3,127
2007/08	4,369	152	4,217	120	129	456	18	52	3,443
2008/09	5,062	179	4,883	173	125	459	27	53	4,046
2009/10	5,164	179	4,985	173	127	462	31	54	4,138
2010/11	5,283	178	5,105	173	130	465	35	55	4,247
2011/12	5,335	107	5,228	173	134	468	39	56	4,358
2012/13	5,450	93	5,357	173	139	470	44	57	4,474
2013/14	5,568	77	5,491	173	144	473	48	58	4,596
2014/15	5,707	76	5,631	173	149	475	52	58	4,724
2015/16	5,848	76	5,772	173	154	477	52	59	4,857
2016/17	5,995	76	5,919	173	159	479	52	59	4,996
2017/18	6,072	0	6,072	173	164	481	53	60	5,141

December 31, 2008 Status

* Includes residential and commercial/industrial conservation.
** Includes sales to Progress Energy Florida, Wauchula, Ft. Meade, St. Cloud and Reedy Creek. Contract ended with Ft. Meade on 12/31/08 and will end with Wauchula on 12/31/13.
Note: Values shown may be affected due to rounding.

Schedule 3.2

History and Forecast of Winter Peak Demand
Low Case (3 of 3)

(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
1998/99	3,985	131	3,854	152	266	388	18	40	2,990
1999/00	4,019	125	3,894	212	209	402	19	43	3,009
2000/01	4,405	136	4,269	191	196	410	21	44	3,407
2001/02	4,217	127	4,090	168	176	419	22	46	3,259
2002/03	4,484	129	4,355	195	210	428	21	46	3,455
2003/04	3,949	120	3,829	254	136	437	18	48	2,936
2004/05	4,308	129	4,179	194	189	444	16	49	3,287
2005/06	4,404	171	4,233	51	144	447	18	50	3,523
2006/07	4,063	162	3,900	157	96	452	18	51	3,127
2007/08	4,369	152	4,217	120	129	456	18	52	3,443
2008/09	5,011	179	4,832	173	125	459	27	53	3,995
2009/10	5,064	179	4,885	173	127	462	31	54	4,038
2010/11	5,133	178	4,955	173	130	465	35	55	4,097
2011/12	5,134	107	5,027	173	134	468	39	56	4,157
2012/13	5,195	93	5,102	173	139	470	44	57	4,219
2013/14	5,257	77	5,180	173	144	473	48	58	4,285
2014/15	5,337	76	5,261	173	149	475	52	58	4,354
2015/16	5,418	76	5,342	173	154	477	52	59	4,427
2016/17	5,501	76	5,425	173	159	479	52	59	4,502
2017/18	5,511	0	5,511	173	164	481	53	60	4,580

December 31, 2008 Status

* Includes residential and commercial/industrial conservation.
** Includes sales to Progress Energy Florida, Wauchula, Ft. Meade, St. Cloud and Reedy Creek. Contract ended with Ft. Meade on 12/31/08 and will end with Wauchula on 12/31/13.
Note: Values shown may be affected due to rounding.

Schedule 3.3

History and Forecast of Annual Net Energy for Load - GWH
Base Case (1 of 3)

(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 %
1999	16,211	315	92	15,805	533	900	17,238	55.3
2000	17,083	333	112	16,638	763	972	18,373	60.1
2001	17,444	346	122	16,976	684	794	18,454	58.0
2002	18,423	361	137	17,925	502	935	19,362	58.9
2003	18,756	378	152	18,226	587	985	19,798	56.4
2004	18,999	394	168	18,437	589	945	19,972	58.9
2005	19,491	404	176	18,911	712	952	20,575	61.6
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	430	212	18,990	752	909	20,650	57.3
2009	20,646	437	216	19,993	668	1,019	21,680	54.7
2010	21,026	444	223	20,358	668	1,038	22,064	54.8
2011	21,440	452	230	20,758	364	1,058	22,180	54.0
2012	21,876	459	237	21,179	313	1,079	22,571	54.6
2013	22,329	466	243	21,619	248	1,102	22,969	54.7
2014	22,799	473	249	22,078	180	1,125	23,382	54.7
2015	23,285	480	253	22,552	180	1,149	23,880	54.7
2016	23,784	486	258	23,040	180	1,173	24,393	54.5
2017	24,300	492	262	23,546	79	1,199	24,824	54.4
2018	24,839	499	265	24,075	0	1,226	25,301	55.1

December 31, 2008 Status

* Includes sales to Progress Energy Florida, Wauchula, Ft. Meade, St. Cloud and Reedy Creek. Contract ended with Ft. Meade on 12/31/08 and will end with Wauchula on 12/31/13.
** Load Factor is the ratio of total system average load to peak demand.

Schedule 3.3

History and Forecast of Annual Net Energy for Load - GWH
High Case (2 of 3)

(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 %
1999	16,211	315	92	15,805	533	900	17,238	55.3
2000	17,083	333	112	16,638	763	972	18,373	60.1
2001	17,444	346	122	16,976	684	794	18,454	58.0
2002	18,423	361	137	17,925	502	935	19,362	58.9
2003	18,756	378	152	18,226	587	985	19,798	56.4
2004	18,999	394	168	18,437	589	945	19,972	58.9
2005	19,491	404	176	18,911	712	952	20,575	61.6
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	430	212	18,990	752	909	20,650	57.3
2009	20,749	437	216	20,096	668	1,024	21,788	56.9
2010	21,227	444	223	20,560	668	1,048	22,276	56.9
2011	21,745	452	230	21,063	364	1,074	22,500	56.0
2012	22,288	459	237	21,592	313	1,100	23,005	55.7
2013	22,855	466	243	22,146	248	1,128	23,522	55.6
2014	23,446	473	249	22,724	180	1,158	24,061	55.4
2015	24,057	480	253	23,324	180	1,188	24,692	55.3
2016	24,688	486	258	23,945	180	1,219	25,344	55.1
2017	25,344	492	262	24,590	79	1,252	25,921	55.0
2018	26,030	499	265	25,266	0	1,287	26,552	54.8

December 31, 2008 Status

* Includes sales to Progress Energy Florida, Wauchula, Ft. Meade, St. Cloud and Reedy Creek. Contract ended with Ft. Meade on 12/31/08 and will end with Wauchula on 12/31/13.
** Load Factor is the ratio of total system average load to peak demand.

Schedule 3.3

History and Forecast of Annual Net Energy for Load - GWH
Low Case (3 of 3)

(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 %
1999	16,211	315	92	15,805	533	900	17,238	55.3
2000	17,083	333	112	16,638	763	972	18,373	60.1
2001	17,444	346	122	16,976	684	794	18,454	58.0
2002	18,423	361	137	17,925	502	935	19,362	58.9
2003	18,756	378	152	18,226	587	985	19,798	56.4
2004	18,999	394	168	18,437	589	945	19,972	58.9
2005	19,491	404	176	18,911	712	952	20,575	61.6
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	430	212	18,990	752	909	20,650	57.3
2009	20,543	437	216	19,890	668	1,014	21,571	57.0
2010	20,826	444	223	20,158	668	1,028	21,854	57.1
2011	21,140	452	230	20,457	364	1,043	21,864	56.3
2012	21,470	459	237	20,774	313	1,058	22,146	56.0
2013	21,815	466	243	21,105	248	1,075	22,429	56.0
2014	22,173	473	249	21,451	180	1,093	22,723	55.8
2015	22,540	480	253	21,807	180	1,111	23,098	55.8
2016	22,916	486	258	22,172	180	1,129	23,482	55.6
2017	23,304	492	262	22,550	79	1,149	23,778	55.5
2018	23,709	499	265	22,945	0	1,169	24,114	55.4

December 31, 2008 Status

* Includes sales to Progress Energy Florida, Wauchula, Ft. Meade, St. Cloud and Reedy Creek. Contract ended with Ft. Meade on 12/31/08 and will end with Wauchula on 12/31/13.
** Load Factor is the ratio of total system average load to peak demand.

Schedule 4

Previous Year and 2-Year Forecast of Peak Demand and Net Energy for Load (NEL) by Month
Base Case (1 of 3)

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	2008 Actual		2009 Forecast		2010 Forecast	
Month	Peak Demand * MW	NEL ** GWH	Peak Demand * MW	NEL ** GWH	Peak Demand * MW	NEL ** GWH
January	3,862	1,573	4,524	1,648	4,598	1,668
February	3,136	1,446	3,794	1,468	3,859	1,490
March	2,971	1,515	3,443	1,591	3,505	1,624
April	3,325	1,604	3,601	1,627	3,667	1,660
May	3,823	1,928	4,003	1,943	4,077	1,973
June	4,101	1,964	4,238	2,016	4,319	2,058
July	4,052	1,960	4,382	2,157	4,467	2,193
August	4,063	2,024	4,356	2,184	4,442	2,235
September	3,946	1,969	4,170	2,001	4,252	2,046
October	3,565	1,719	3,888	1,848	3,965	1,881
November	3,119	1,461	3,409	1,539	3,476	1,569
December	3,313	1,488	3,636	1,658	3,705	1,667
TOTAL		20,651		21,680		22,064

December 31, 2008 Status

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

Schedule 4

Previous Year and 2-Year Forecast of Peak Demand and Net Energy for Load (NEL) by Month
High Case (2 of 3)

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	2008 Actual		2009 Forecast		2010 Forecast	
Month	**Peak Demand * MW**	**NEL ** GWH**	**Peak Demand * MW**	**NEL ** GWH**	**Peak Demand * MW**	**NEL ** GWH**
January	3,862	1,573	4,550	1,656	4,648	1,684
February	3,136	1,446	3,816	1,475	3,900	1,504
March	2,971	1,515	3,462	1,599	3,541	1,639
April	3,325	1,604	3,620	1,635	3,706	1,675
May	3,823	1,928	4,025	1,952	4,120	1,992
June	4,101	1,964	4,262	2,027	4,365	2,078
July	4,052	1,960	4,406	2,168	4,514	2,215
August	4,063	2,024	4,379	2,196	4,489	2,257
September	3,946	1,969	4,192	2,012	4,296	2,067
October	3,565	1,719	3,909	1,857	4,005	1,899
November	3,119	1,461	3,426	1,546	3,511	1,583
December	3,313	1,488	3,654	1,666	3,742	1,682
TOTAL		20,651		21,788		22,276

December 31, 2008 Status

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

Schedule 4

Previous Year and 2-Year Forecast of Peak Demand and Net Energy for Load (NEL) by Month
Low Case (3 of 3)

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	2008 Actual		2009 Forecast		2010 Forecast	
Month	Peak Demand * MW	NEL ** GWH	Peak Demand * MW	NEL ** GWH	Peak Demand * MW	NEL ** GWH
January	3,862	1,573	4,499	1,639	4,548	1,652
February	3,136	1,446	3,773	1,461	3,818	1,476
March	2,971	1,515	3,424	1,583	3,468	1,610
April	3,325	1,604	3,581	1,620	3,629	1,645
May	3,823	1,928	3,981	1,933	4,034	1,955
June	4,101	1,964	4,215	2,006	4,273	2,037
July	4,052	1,960	4,358	2,145	4,420	2,172
August	4,063	2,024	4,332	2,173	4,396	2,213
September	3,946	1,969	4,147	1,991	4,207	2,026
October	3,565	1,719	3,868	1,839	3,924	1,863
November	3,119	1,461	3,391	1,531	3,442	1,554
December	3,313	1,488	3,617	1,650	3,668	1,651
TOTAL		20,651		21,571		21,854

December 31, 2008 Status

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

Schedule 5

History and Forecast of Fuel Requirements
Low Case Forecast Basis

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
				Actual	Actual										
	Fuel Requirements		Unit	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
(1)	Nuclear		Trillion BTU	0	0	0	0	0	0	0	0	0	0	0	0
(2)	Coal		1000 Ton	4,227	4,233	4,144	4,319	4,643	4,670	4,747	4,682	4,654	4,668	4,714	4,679
(3)	Residual	Total	1000 BBL	51	32	5	2	1	1	0	0	0	0	0	0
(4)		Steam	1000 BBL	0	0	0	0	0	0	0	0	0	0	0	0
(5)		CC	1000 BBL	0	0	0	0	0	0	0	0	0	0	0	0
(6)		CT	1000 BBL	0	0	0	0	0	0	0	0	0	0	0	0
(7)		Diesel	(A) 1000 BBL	51	32	5	2	1	1	0	0	0	0	0	0
(8)	Distillate	Total	1000 BBL	64	58	89	97	98	95	100	100	96	99	100	95
(9)		Steam	1000 BBL	0	0	0	0	0	0	0	0	0	0	0	0
(10)		CC	1000 BBL	58	55	80	94	96	92	97	97	93	97	97	93
(11)		CT	1000 BBL	6	3	9	3	2	3	3	3	3	2	3	2
(12)		Diesel	1000 BBL	0	0	0	0	0	0	0	0	0	0	0	0
(13)	Natural Gas	Total	1000 MCF	57,556	54,383	69,626	66,026	61,748	62,937	64,241	67,237	70,687	73,556	75,078	77,456
(14)		Steam	1000 MCF	0	0	0	0	0	0	0	0	0	0	0	0
(15)		CC	1000 MCF	54,249	52,363	65,377	64,122	60,339	60,563	58,184	60,381	62,512	64,115	63,809	72,831
(16)		CT	1000 MCF	3,307	2,020	4,249	1,904	1,409	2,374	6,057	6,856	8,175	9,441	11,269	4,625
(17)	Other (Specify)														
(18)	Petroleum Coke		1000 Ton	429	388	461	548	570	553	581	581	556	581	580	558

(A) Data reported as diesel for Phillips Units 1 and 2.

Notes: Values shown may be affected due to rounding.
All values exclude ignition.
Polk 1 Unit changes from a 60/40 blend (petcoke/coal) to 80/20 blend in 2009.

Schedule 6.1

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

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
				Actual	Actual										
	Energy Sources		Unit	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
(1)	Annual Firm Interchange		GWh	383	1,375	889	398	363	382	175	190	211	220	258	148
(2)	Nuclear		GWh	0	0	0	0	0	0	0	0	0	0	0	0
(3)	Coal		GWh	8,990	9,105	9,110	9,470	10,192	10,258	10,425	10,265	10,226	10,261	10,336	10,259
(4)	Residual	Total	GWh	32	18	3	2	1	1	0	0	0	0	0	0
(5)		Steam	GWh	0	0	0	0	0	0	0	0	0	0	0	0
(6)		CC	GWh	0	0	0	0	0	0	0	0	0	0	0	0
(7)		CT	GWh	0	0	0	0	0	0	0	0	0	0	0	0
(8)		Diesel (A)	GWh	32	18	3	2	1	1	0	0	0	0	0	0
(9)	Distillate	Total	GWh	36	33	47	53	53	51	53	55	52	54	54	51
(10)		Steam	GWh	0	0	0	0	0	0	0	0	0	0	0	0
(11)		CC	GWh	33	32	43	51	52	50	52	53	50	53	52	50
(12)		CT	GWh	3	1	4	2	1	1	1	2	2	1	2	1
(13)		Diesel	GWh	0	0	0	0	0	0	0	0	0	0	0	0
(14)	Natural Gas	Total	GWh	7,899	7,536	9,509	9,129	8,551	8,671	8,663	9,048	9,484	9,838	9,969	10,791
(15)		Steam	GWh	0	0	0	0	0	0	0	0	0	0	0	0
(16)		CC	GWh	7,612	7,366	9,139	8,958	8,424	8,452	8,109	8,418	8,722	8,949	8,910	10,355
(17)		CT	GWh	287	170	370	171	127	219	554	630	762	889	1,059	436
(18)	Other (Specify)														
(19)	Petroleum Coke Generation		GWh	1,201	1,088	1,194	1,431	1,488	1,444	1,521	1,522	1,458	1,523	1,519	1,464
(20)	Net Interchange		GWh	2,114	824	(215)	480	406	635	763	814	838	833	887	649
(21)	Purchased Energy from														
(22)	Non-Utility Generators		GWh	623	676	1,035	893	809	704	829	829	829	753	753	753
(23)	Net Energy for Load		GWh	21,278	20,655	21,572	21,855	21,863	22,146	22,428	22,722	23,098	23,482	23,776	24,115

(A) Data reported as diesel for Phillips Units 1 and 2.
Notes: Values shown may be affected due to rounding.
Polk 1 Unit changes from a 60/40 blend (petcoke/coal) to 80/20 blend in 2009.

Schedule 6.2

History and Forecast of Net Energy for Load by Fuel Source as Percentage
Low Case Forecast Basis

(1)	(2)	(3)		(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
					Actual	Actual										
	Energy Sources			Unit	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
(1)	Annual Firm Interchange			%	1.8	6.7	4.1	1.8	1.7	1.7	0.8	0.8	0.9	0.9	1.1	0.6
(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			%	47.8	44.1	42.2	43.3	46.6	46.3	46.5	45.2	44.3	43.7	43.5	42.5
(4)	Residual	Total		%	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(5)		Steam		%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(6)		CC		%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(7)		CT		%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(8)		Diesel	(A)	%	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(9)	Distillate	Total		%	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
(10)		Steam		%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(11)		CC		%	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
(12)		CT		%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(13)		Diesel		%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(14)	Natural Gas	Total		%	34.4	36.5	44.1	41.8	39.1	39.2	38.6	39.8	41.1	41.9	41.9	44.7
(15)		Steam		%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(16)		CC		%	33.6	35.7	42.4	41.0	38.5	38.2	36.2	37.0	37.8	38.1	37.5	42.9
(17)		CT		%	0.8	0.8	1.7	0.8	0.6	1.0	2.5	2.8	3.3	3.8	4.5	1.8
(18)	Other (Specify)															
(19)	Petroleum Coke Generation			%	4.9	5.3	5.5	6.5	6.8	6.5	6.8	6.7	6.3	6.5	6.4	6.1
(20)	Net Interchange			%	8.0	4.0	(1.0)	2.2	1.9	2.9	3.4	3.6	3.6	3.5	3.7	2.7
(21)	Purchased Energy from															
(22)	Non-Utility Generators			%	2.8	3.3	4.8	4.1	3.7	3.2	3.7	3.6	3.6	3.2	3.2	3.1
(23)	Net Energy for Load			%	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0

(A) Data reported as diesel for Phillips Units 1 and 2.

Notes: Values shown may be affected due to rounding.
Polk 1 Unit changes from a 60/40 blend (petcoke/coal) to 80/20 blend in 2009.

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REVISED 04/06/09

Chapter III

TAMPA ELECTRIC COMPANY FORECASTING METHODOLOGY

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

This chapter is devoted to describing Tampa Electric's forecasting methods and the major assumptions utilized in developing the 2009-2018 forecasts. The data tables in Chapter II outline the expected customer, demand, and energy values for the 2009-2018 time period.

RETAIL LOAD

MetrixND, an advanced statistics program for analysis and forecasting, was used to develop the 2009-2018 Customer, Demand and Energy forecasts. This software allows a platform for the development of more dynamic and fully integrated models.

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

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

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

The MetrixND models are the company's most sophisticated and primary load forecasting models. The phosphate demand and energy is forecasted separately and then combined in the final forecast. Likewise, the effect of Tampa Electric's conservation, load management, and cogeneration programs is incorporated into the process by subtracting the expected reduction in demand and energy from the forecast.

1. Economic Analysis

The economic assumptions used in the forecast models are derived from forecasts from Economy.com and the University of Florida's Bureau of Economic and Business Research (BEBR).

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

2. Customer Multiregression Model

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

1. *Residential Customer Model:* Customer projections are a function of Florida's population. Since a strong correlation exists between historical changes in service area customers and historical changes in Florida's population, Florida population estimates for 2008-2018 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 three rate classes that have been modeled individually: General Service, General Service Demand and General Service Large Demand.
   a. The <u>General Service Customer Model</u> is a function of Hillsborough County commercial employment.
   b. The <u>General Service Demand Customer Model</u> is based on Hillsborough County commercial employment.
   c. The <u>General Service Large Demand Customer</u> Model is based on Hillsborough County industrial employment.

4. *Public Authority Customer Model:* Customer projections are a function of Florida's population. The need for public services will depend on the number of people in the region; therefore, consistent with the residential customer model, Florida's population projections are used to determine future growth in the public authorities sector.
5. *Street & Highway Lighting Customer Model:* As the number of commercial customers increases so does the need for infrastructure expansion, such as street and highway lighting. Therefore, the commercial customer forecast is the basis for the Street & Highway Lighting customer model.

3. Energy Multiregression Model

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

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

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

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

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

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

Next, the monthly usage multiplier or utilization variable (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.

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

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

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

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

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

   a. <u>Commercial Energy Model</u>: 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: The model is a subset of the total commercial sector and is a rather small percentage of the total commercial sector. Although small in nature, it is still a component that needs to be included. A simple regression model is used with the primary driver being temporary service customer growth.

3. *Industrial Energy Model (Non-Phosphate):* Nonphosphate industrial energy includes three rate classes that have been modeled individually: General Service, General Service Demand and General Service Large 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 has two major components. Utilizing the SAE model approach, the first component, economic index variables, includes estimates for manufacturing output and the price of electricity in the industrial sector. The second component is a cooling degree-day variable. Unlike the previous models discussed, heating load does not impact this sector.
   c. The General Service Large Demand Energy Model is based on the industrial production manufacturing index variable and the industrial price of electricity.

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

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

4. Peak Demand Multiregression Model

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

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

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

5. Phosphate Demand and Energy Analysis

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

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

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

6. Conservation, Load Management and Cogeneration Programs

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

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

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

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

2. Load Management - Residential, commercial and industrial programs reduce weather-sensitive heating, cooling and water heating through a radio signal control mechanism. However, the residential program is closed to new participation.

3. Energy Audits - The program is 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 for commercial/industrial customers.

4. Residential Building Envelope - An incentive program for existing residential structures which will help to supplement the cost of adding additional ceiling and wall insulation, window film and window upgrades.

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

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

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

8. Residential Duct Repair - An incentive program for existing homeowners which will help to supplement the cost of repairing leaky ductwork of central air-conditioning systems.

9. Cogeneration - A program whereby large industrial customers with waste heat or fuel resources may install electric generating equipment, meet their own electrical requirements and/or sell their surplus to the company.

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

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

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

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

14. Energy Planner - Reduces weather-sensitive loads through an innovative rate used to encourage residential customers to make behavioral or equipment usages changes by pre-programming HVAC, water heating and pool pumps.

15. Commercial Duct Repair - An incentive program for existing commercial customers which will help to supplement the cost of repairing leaky ductwork of central air-conditioning systems.

16. Commercial Building Envelope - An incentive program for existing commercial structures which will help to supplement the cost of adding additional ceiling and wall insulation and window film.

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

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

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

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

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

The programs listed above were developed to meet the FPSC demand and energy goals established in Docket No. 040033-EG, approved on August 9, 2004 and modified in Docket No. 070375-EG, approved on October 15, 2007. The 2005 through 2008 demand and energy savings achieved by conservation and load management programs are listed in Table III-1.

Tampa Electric developed a Monitoring and Evaluation (M&E) plan in response to requirements filed in Docket No. 941173-EG. The M&E plan was designed to effectively accomplish the required objective with prudent application of resources.

The M&E plan has as its focus two distinct areas: process evaluation and impact evaluation. Process evaluation examines how well a program has been implemented including the efficiency of delivery and customer satisfaction regarding the usefulness and quality of the services delivered. Impact evaluation is an evaluation of the change in demand and energy consumption achieved through program participation. The results of these evaluations give Tampa Electric insight into the direction that should be taken to refine delivery processes, program standards, and overall program cost-effectiveness.

WHOLESALE LOAD

Tampa Electric's firm long-term wholesale sales consist of contracts with Progress Energy Florida, Reedy Creek Improvement District and the Cities of Wauchula and St. Cloud.

Since Tampa Electric's sales to Wauchula will vary over time based on the strength of the local economies, a multiple regression approach similar to that used for forecasting Tampa Electric's retail load has been utilized. Under this methodology, two equations have been developed for the municipality for forecasting energy: 1) customer forecast; 2) average usage forecast. The peak model for this city uses sales forecast trend variables and heating and cooling degree variables as inputs.

For the remaining wholesale customers, future sales for a given year are based on the specific terms of their contracts with Tampa Electric.

TABLE III-1
Comparison of Achieved MW and GWH Reductions With Florida Public Service Commission Goals

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
2005	4.2	4.0	105.0%	2.8	2.4	116.7%	7.7	7.0	110.0%
2006	8.2	6.7	122.4%	6.1	4.4	138.6%	16.3	12.6	129.4%
2007	12.7	12.0	105.8%	9.8	8.5	115.3%	24.6	22.5	109.3%
2008	17.6	15.4	114.3%	13.9	10.7	129.9%	34.8	28.1	123.8%

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
2005	3.4	1.0	340.0%	4.3	2.1	204.8%	7.9	6.7	117.9%
2006	3.7	2.0	185.0%	5.4	4.4	122.7%	13.2	12.8	103.1%
2007	9.4	7.8	120.5%	13.4	10.5	127.6%	25.8	19.6	131.6%
2008	52.2	11.9	438.7%	58.3	15.3	381.0%	44.6	24.2	184.3%

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
2005	7.6	5.0	152.0%	7.1	4.5	157.8%	15.6	13.7	113.9%
2006	11.9	8.7	136.8%	11.5	8.8	130.7%	29.5	25.4	116.1%
2007	22.1	19.8	111.6%	23.2	19.0	122.1%	50.4	42.1	119.7%
2008	69.8	27.3	255.7%	72.2	26.0	277.7%	79.4	52.3	151.8%

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; and
7. Weather.

1. **Population and Households**

   The state population forecast is the starting point for developing the customer and energy projections. Both the University of Florida's Bureau of Economic and Business Research (BEBR) and Economy.com supply population projections for Hillsborough County and Florida. The population forecast is based upon the projections of BEBR in the short term and is a blend in the long term of BEBR and Economy.com. Over the next ten years (2009-2018) the average annual population growth rate in Hillsborough County and Florida is expected to be 1.8% and 2.0%, respectively. In addition, Economy.com provides household data as an input to the residential average use model.

2. **Commercial, Industrial and Governmental Employment**

   Commercial and industrial employment assumptions are utilized in computing the number of customers in their respective sectors. It is imperative that employment growth be consistent with the expected population expansion and unemployment levels. Over the next ten years, employment is assumed to rise at a 2.2% average annual rate. Economy.com supplies employment projections.

3. **Commercial, Industrial and Governmental Output**

   In addition to employment, output in terms of real gross domestic product by employment sector is utilized in computing energy in their respective sectors. Over the next ten years, output for the entire employment sector is assumed to rise at a 3.6% average annual rate. Economy.com supplies output projections.

4. **Real Household Income**

   Economy.com supplies the assumptions for Hillsborough County's real household income growth. During 2009-2018, real household income for Hillsborough County is expected to increase at a 1.5% average annual rate.

5. **Price of Electricity**
   Forecasts for the price of electricity by customer class are supplied by Tampa Electric's Regulatory Department.

6. **Appliance Efficiency Standards**
   Another factor influencing energy consumption is the movement toward more efficient appliances. The forces behind this development include market pressures for more energy-saving devices and the appliance efficiency standards enacted by the state and federal governments. Also influencing energy consumption is the saturation levels of appliances. The saturation trend for heating appliances is increasing through time; however, overall electricity consumption actually declines over time as less efficient heating technologies (room heating and furnaces) are replaced with more efficient technologies (heat pumps). Similarly, cooling equipment saturation will continue to increase, but be offset by heat pump and central air conditioning efficiency gains.

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

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

   In summary, despite the high saturation of electric appliances, increased appliance and equipment efficiencies will slow residential usage making them less sensitive to changes in temperature through time. However, economic conditions such as the decreasing real price of electricity and the increasing household income will mitigate any decline in consumption and actually increase overall energy consumption.

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 2009-2018, retail energy sales are projected to rise at a 2.1% annual rate. The major contributor to growth is the residential category, increasing at an annual rate of 2.5%.

2. Wholesale Energy

Wholesale energy sales to Progress Energy Florida, Wauchula, St. Cloud, and Reedy Creek are expected to be 668 GWH per year for 2009. In 2013, sales drop substantially to 248 GWH, decrease to 180 in 2014, and continue to decline to zero in 2018.

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 2009-2018 period, Tampa Electric's low retail firm peak demand are expected to advance in the winter at annual rates of 1.5% and in the summer at 1.6%.

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Chapter IV

FORECAST OF FACILITIES REQUIREMENTS

The proposed generating facility additions and changes shown in Schedule 8.2 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 plan that is cost-effective while maintaining system reliability and environmental requirements while considering technology availability and lead times for construction. To meet the expected system demand and energy requirements over the next ten years peaking and base resources are needed. The peaking capacity need will be met by building combustion turbine additions in 2009 and 2012 - 2017 along with peaking purchase power agreements. The base load capacity will be met by building one natural gas combined cycle (NGCC) unit planned for 2018 or by purchasing power agreements. The operating and cost parameters associated with the capacity additions resulting from the analysis are shown in Schedule 9.

As the construction start dates for each scheduled unit approaches, Tampa Electric will evaluate competitive purchased power agreements that may replace or delay the planned unit additions. The purchase power must have firm transmission service 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.

In 2007, Tampa Electric solicited offers for renewable generation through a Request for Proposal (RFP). The objective of this RFP was to identify existing and/or new, viable sources of renewable firm capacity and associated energy and/or non-firm energy to benefit Tampa Electric's customers. The desired result was to obtain a variety of supply-side resource proposals for renewable generation currently in commercial operation or with an expected in-service date prior to January 1, 2013 in anticipation of a state-wide Renewable Portfolio Standard requirement.

As a result of the Renewable Generation RFP of 2007, a solar energy contract was awarded to Energy 5.0, the successful bidder. Tampa Electric signed a contract to purchase solar power supplied by Energy 5.0's Florida Solar I facility, a proposed 25-megawatt (MW) solar photovoltaic (PV) electric generating station, for a 25-year period beginning in 2011. In addition, Tampa Electric filed a petition with the Florida Public Service Commission for approval to purchase the energy generated by the solar facility.

Over its 25-year proposed contract term, the project is expected to avoid the emission of up to 1.45 million tons of carbon dioxide when compared to a natural gas-fired peaking combustion turbine. The contract will also:

- Promote the state's goal of encouraging the production of renewable energy produced by renewable energy generating facilities in Florida.
- Reduce Florida's dependence on natural gas and fuel oil for electricity production.
- Provide the basis for significant new investment, economic development and job creation in Polk County and in the state.
- Reduce environmental impacts associated with electricity generation.
- Protect the company and its customers from technical and operational risks through its energy-only, fixed pricing.
- Provide fuel diversity benefits.

Energy 5.0, a Florida-based company with extensive experience and success in the development, financing and operation of renewable energy projects, will build the 25-MW facility on a proposed 200 to 400 acre site in Polk County. The facility will be one of the largest solar PV facilities in the nation.

The project will consist of silicon-based PV panels that generate electricity when exposed to sunlight. The 25-MW facility is expected to produce more than 48,000 MWh of electricity per year - enough output to serve the electric energy needs of more than 3,400 homes. The average home in Tampa Electric's service territory uses about 14,000 kWh per year.

AERO-DERIVATIVE CT TECHNOLOGY

Tampa Electric's expansion plan includes the construction of five (5) aero-derivative combustion turbine assets (Aero CTS) in 2009 – totaling approximately 280 MW of net summer capacity. These units will provide economic, black start and operating reserve requirement improvements:

- **Black Start Capability**

  The Aero CTs can be used to energize the Big Bend and Bayside Power Plants in the event of a plant, system or grid failure. Black Start is defined by the Florida Reliability Coordinating Council (FRCC) as a utility's ability to energize portions of a blacked out region utilizing resources independent of an energized interconnection.

- **State Operating Reserve Requirements**

  The Aero CTs offer a more economic option in meeting TEC operating reserve requirements than with spinning assets alone. Tampa Electric's current Operating Reserve requirement or "load responsibility" is approximately 88 MWs, and this requirement is expected to increase slightly by 2012. This is TEC's portion of the State's largest generating asset that must be "ready to deliver power promptly." Quick Start often refers to a generating unit's ability to achieve electrical synchronization with the grid and reach full load in less than 10 minutes.

COGENERATION

Tampa Electric plans for 520 MW of cogeneration capacity operating in its service area in 2009. Self-service capacity of 228 MW is used by cogenerators to serve internal load requirements, 65 MW are purchased by Tampa Electric on a firm contract basis, and 73 MW are purchased on a non-firm, as-available basis. The remaining 154 MW of cogeneration capacity is expected to be sold to other utilities while Tampa Electric provides transmission service from its system to the Florida grid.

FUEL REQUIREMENTS

A forecast of fuel requirements and energy sources is shown in Schedule 5, Schedule 6.1 and Schedule 6.2. Tampa Electric currently uses a generation portfolio consisting of coal and natural gas for its generating requirements. Tampa Electric has firm transportation contracts with the Florida Gas Transmission Company (FGT) and Gulfstream Natural Gas System LLC for delivery of natural gas to the Bayside and Polk Units. As shown in Schedule 6.2, in 2009 coal and petcoke will fuel 48% of net energy for load and natural gas will fuel 44%. Less than one (1) percent of net energy for load will be fueled by oil at the Phillips plant and other combustion turbines. The remaining net energy for load is served by non-utility generators and net interchange purchases.

ENVIRONMENTAL CONSIDERATIONS

An agreement between the Florida Department of Environmental Protection (DEP) and Tampa Electric produced a comprehensive emissions reduction plan delineated in a Consent Final Judgment (CFJ), which was finalized with the DEP on December 6, 1999. Approximately one year later, on February 29, 2000, Tampa Electric reached a similar agreement with the U.S. Environmental Protection Agency (EPA) in a Consent Decree (CD). Collectively, the CFJ and CD are referred to as the "Agreements". The efforts to reduce emissions from the company's facilities began long before the agreements. Since 1998, Tampa Electric has reduced annual sulfur dioxides (SO_2) by 94%, nitrogen oxides (NOx) by 73%, particulate matter (PM) by 73% and mercury emissions by 77%.

Reductions in SO_2 emissions were primarily accomplished through the installation of flue gas desulfurization (scrubber) systems on Big Bend Units 1 and 2 in 1999. Big Bend Unit 3 was integrated with Big Bend Unit 4's existing scrubber in 1995. Currently, the scrubbers at Big Bend station remove between 93% and 95% of the SO_2 emissions from the flue gas streams. In addition, reductions in NOx have been accomplished through installation and operation of selective catalytic reduction systems, combustion tuning and optimization projects at Big Bend Station and the repowering of Gannon Station to H.L. Culbreath Bayside Power Station which changed fuel from coal to natural gas.

Reductions in particulate matter were accomplished through scrubber optimization and the improvement of the Big Bend electrostatic precipitators which were in service for each unit at commercial operation. The precipitators, which remove more than 99.9% of the PM generated during the combustion process.

The repowering of Gannon Station to H.L. Culbreath Bayside Power Station resulted in significant reduction in emissions of all pollutant types. Tampa Electric's decision to complete installation of additional NOx emissions controls on all Big Bend Station Units by May of 2010 will result in reducing NOx emissions by 90% compared to 1998 levels. Selective Catalytic Reduction (SCR) is the primary control technology used to reduce Big Bend Station NOx emissions. Tampa Electric completed installation of the SCR system on Big Bend Unit 4 and put it in-service on June 1, 2007. Big Bend Unit 3 SCR was placed in service on June 1, 2008. Subsequently, Big Bend Units 2 and 1 will be installed in 2009 and 2010, respectively.

In January 2008, the Chicago Climate Exchange (CCX) applauded Tampa Electric for meeting the program's Phase I greenhouse gas commitment of a 4% carbon dioxide (CO2) reduction. With an actual reduction of more than 20%, the company far surpassed the CCX target.

As a result of its already completed emission reduction actions and upon completion of planned controls, Tampa Electric will have achieved emission reduction levels contained in the Clean Air Interstate Rule (CAIR) requirements, the vacated Clean Air Mercury Rule (CAMR) Phase I requirements and be well positioned for other potential future emission control requirements. No other utility in the state and few in the nation have made similar emissions reductions since 1998.

INTERCHANGE SALES AND PURCHASES

Tampa Electric's long-term firm sale agreements include Progress Energy Florida for 71 MW and Reedy Creek Improvement District for 77 MW as well as the cities of St. Cloud for 15 MW and Wauchula for 16 MW.

Tampa Electric has a long-term purchased power contract for capacity and energy from the Hardee Power Station owned by Invenergy. The contract term is January 1, 1993 through December 31, 2012. The contract involves a shared-capacity agreement with Seminole Electric Cooperative (SEC), whereby Tampa Electric plans for the full net capability (353 MW winter and 287 MW summer) of the Hardee Power Station during those times when SEC plans for the

Seminole Units 1 and 2 and the SEC Crystal River Unit 3 allocation to be available for operation, and reduced availability during times when Seminole Units 1 and 2 are derated or unavailable due to planned maintenance. Under the existing contract, Tampa Electric also has the right to purchase an additional 88 MW winter and 69 MW summer of firm non-shared capacity from the Hardee Power Station.

Tampa Electric also entered into a firm purchased power agreement with Progress Energy Florida for 100 MW from September 1, 2008 through September 30, 2009. Tampa Electric has an agreement with Calpine Energy Services for 170 MW from May 1, 2006 through April 30, 2011 and with Reliant Energy Service for 158 MW from January 1, 2008 to May 31, 2012. Additionally, Tampa Electric has an agreement for the purchase of 121 MW from Pasco Cogen for the period January 1, 2009 to December 31, 2018.

The wholesale power sales and purchases are included in Schedules 3.1, 3.2, 3.3, 4, 5, 6.1, 7.1, and 7.2.

Schedule 7.1

Forecast of Capacity, Demand, and Scheduled Maintenance at Time of Summer Peak

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
	Total Installed Capacity	Firm Capacity Import	Firm Capacity Export	QF	Total Capacity Available	System Firm Summer Peak Demand	Reserve Margin Before Maintenance		Scheduled Maintenance	Reserve Margin After Maintenance	
Year	MW	MW	MW	MW	MW	MW	MW	% of Peak	MW	MW	% of Peak
2009	4,172	905	0	65	5,142	4,095	1,047	26%	0	1,047	26%
2010	4,334	805	0	42	5,181	4,149	1,032	25%	0	1,032	25%
2011	4,334	635	0	42	5,011	4,136	875	21%	0	875	21%
2012	4,502	477	0	23	5,002	4,194	809	19%	0	809	19%
2013	4,949	121	0	23	5,093	4,240	853	20%	0	853	20%
2014	5,005	121	0	23	5,149	4,292	858	20%	0	858	20%
2015	5,117	121	0	23	5,261	4,360	901	21%	0	901	21%
2016	5,229	121	0	0	5,350	4,431	919	21%	0	919	21%
2017	5,229	121	0	0	5,350	4,428	922	21%	0	922	21%
2018	5,784	121	0	0	5,905	4,504	1,401	31%	0	1,401	31%

NOTE:

1. Capacity import includes firm purchase power agreements (PPA) with Invenergy of 356 MW from 2006 through 2012, PPA with Progress Energy Florida of 100 MW from September 2008 through September 2009, PPA with Calpine of 170 MW from May 2006 through April 2011, PPA with Reliant of 158 MW from 2008 through May 2012, and PPA with Pasco Cogen of 121 MW from 2009 through 2018.
2. The QF column accounts for cogeneration that will be purchased under firm contracts, and excludes non-firm purchases.

Schedule 7.2

Forecast of Capacity, Demand, and Scheduled Maintenance at Time of Winter Peak

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
	Total Installed Capacity	Firm Capacity Import	Firm Capacity Export	QF	Total Capacity Available	System Firm Winter Peak Demand	Reserve Margin Before Maintenance		Scheduled Maintenance	Reserve Margin After Maintenance	
Year	MW	MW	MW	MW	MW	MW	MW	% of Peak	MW	MW	% of Peak
2008-09	4,443	990	0	65	5,498	4,174	1,324	32%	383	941	23%
2009-10	4,737	890	0	65	5,692	4,217	1,476	35%	647	829	20%
2010-11	4,737	890	0	42	5,669	4,275	1,394	33%	0	1,394	33%
2011-12	4,737	720	0	23	5,480	4,264	1,216	29%	0	1,216	29%
2012-13	5,097	121	0	23	5,241	4,312	929	22%	0	929	22%
2013-14	5,451	121	0	23	5,595	4,362	1,234	28%	0	1,234	28%
2014-15	5,512	121	0	23	5,656	4,430	1,226	28%	0	1,226	28%
2015-16	5,634	121	0	0	5,755	4,503	1,252	28%	0	1,252	28%
2016-17	5,756	121	0	0	5,877	4,578	1,299	28%	0	1,299	28%
2017-18	5,756	121	0	0	5,877	4,580	1,297	28%	0	1,297	28%

NOTE:

1. Capacity import includes firm purchase power agreements (PPA) with Invenergy of 441 MW from 2006 through 2012, PPA with Progress Energy Florida of 100 MW from September 2008 through September 2009, PPA with Calpine of 170 MW from May 2006 through April 2011, PPA with Reliant of 158 MW from 2008 through May 2012, and PPA with Pasco Cogen of 121 MW from 2009 through 2018.
2. The QF column accounts for cogeneration that will be purchased under firm contracts, and excludes non-firm purchases.

Schedule 8

Planned and Prospective Generating Facility Additions

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
				Fuel		Fuel Trans.		Const.	Commercial	Expected	Gen. Max.	Net Capability		
Plant Name	Unit No.	Location	Unit Type	Primary	Alternate	Primary	Alternate	Start Mo/Yr	In-Service Mo/Yr	Retirement Mo/Yr	Nameplate kW	Summer MW	Winter MW	Status
Bayside CT	6	Hillsborough	CT	NG	N/A	PL	N/A	8/08	4/09	unknown	69,900	56	61	UC
Bayside CT	5	Hillsborough	CT	NG	N/A	PL	N/A	8/08	4/09	unknown	69,900	56	61	UC
Bayside CT	4	Hillsborough	CT	NG	N/A	PL	N/A	8/08	9/09	unknown	69,900	56	61	UC
Bayside CT	3	Hillsborough	CT	NG	N/A	PL	N/A	8/08	9/09	unknown	69,900	56	61	UC
Big Bend CT	4	Hillsborough	CT	NG	LO	PL	N/A	8/08	9/09	unknown	69,900	56	61	UC
Future CT	1	unknown	CT	NG	N/A	PL	N/A	9/11	5/12	unknown	unknown	56	61	P
Future CT	2	unknown	CT	NG	N/A	PL	N/A	9/11	5/12	unknown	unknown	56	61	P
Future CT	3	unknown	CT	NG	N/A	PL	N/A	9/11	5/12	unknown	unknown	56	61	P
Future CT	4	unknown	CT	NG	N/A	PL	N/A	5/12	1/13	unknown	unknown	149	177	P
Future CT	5	unknown	CT	NG	N/A	PL	N/A	9/12	5/13	unknown	unknown	149	177	P
Future CT	6	unknown	CT	NG	N/A	PL	N/A	9/12	5/13	unknown	unknown	149	177	P
Future CT	7	unknown	CT	NG	N/A	PL	N/A	9/13	5/14	unknown	unknown	56	61	P
Future CT	8	unknown	CT	NG	N/A	PL	N/A	9/14	5/15	unknown	unknown	56	61	P
Future CT	9	unknown	CT	NG	N/A	PL	N/A	9/14	5/15	unknown	unknown	56	61	P
Future CT	10	unknown	CT	NG	N/A	PL	N/A	9/15	5/16	unknown	unknown	56	61	P
Future CT	11	unknown	CT	NG	N/A	PL	N/A	9/15	5/16	unknown	unknown	56	61	P
Future CC	1	unknown	CC	NG	N/A	PL	N/A	1/14	5/18	unknown	unknown	555	607	P

SCHEDULE 9

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STATUS REPORT AND SPECIFICATIONS OF PROPOSED GENERATING FACILITIES
UTILITY: TAMPA ELECTRIC COMPANY

(1)	PLANT NAME AND UNIT NUMBER	BAYSIDE CT 6
(2)	CAPACITY	
	A. SUMMER	56
	B. WINTER	61
(3)	TECHNOLOGY TYPE	COMBUSTION TURBINE
(4)	ANTICIPATED CONSTRUCTION TIMING	
	A. FIELD CONSTRUCTION START DATE	AUG 2008
	B. COMMERCIAL IN-SERVICE DATE	APR 2009
(5)	FUEL	
	A. PRIMARY FUEL	NATURAL GAS
	B. ALTERNATE FUEL	N/A
(6)	AIR POLLUTION CONTROL STRATEGY	WET LOW EMISSION
(7)	COOLING METHOD	N/A
(8)	TOTAL SITE AREA [1]	APPROXIMATELY 213 ACRES
(9)	CONSTRUCTION STATUS	UNDER CONSTRUCTION
(10)	CERTIFICATION STATUS [2]	N/A.
(11)	STATUS WITH FEDERAL AGENCIES	N/A
(12)	PROJECTED UNIT PERFORMANCE DATA	
	PLANNED OUTAGE FACTOR (POF)	2.6
	FORCED OUTAGE RATE (FOR)	1.0
	EQUIVALENT AVAILABILITY FACTOR (EAF)	95.4
	RESULTING CAPACITY FACTOR (2009)	12.0%
	AVERAGE NET OPERATING HEAT RATE (ANOHR) [3]	10,620 Btu/kWh
(13)	PROJECTED UNIT FINANCIAL DATA	
	BOOK LIFE (YEARS)	25
	TOTAL INSTALLED COST (IN-SERVICE YEAR $/kW)	566.93
	DIRECT CONSTRUCTION COST ($/kW)	559.67
	AFUDC AMOUNT ($/kW)	7.26
	ESCALATION ($/kW)	
	FIXED O&M ($/kW – Yr)	20.00
	VARIABLE O&M ($/MWH)	3.72
	K FACTOR	1.5984

[1] REPRESENTS TOTAL BAYSIDE SITE.
[2] CERTIFICATION NOT REQUIRED.
[3] BASED ON IN-SERVICE YEAR.

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STATUS REPORT AND SPECIFICATIONS OF PROPOSED GENERATING FACILITIES
UTILITY: TAMPA ELECTRIC COMPANY

(1)	PLANT NAME AND UNIT NUMBER	BAYSIDE CT 5
(2)	CAPACITY	
	A. SUMMER	56
	B. WINTER	61
(3)	TECHNOLOGY TYPE	COMBUSTION TURBINE
(4)	ANTICIPATED CONSTRUCTION TIMING	
	A. FIELD CONSTRUCTION START DATE	AUG 2008
	B. COMMERCIAL IN-SERVICE DATE	APR 2009
(5)	FUEL	
	A. PRIMARY FUEL	NATURAL GAS
	B. ALTERNATE FUEL	N/A
(6)	AIR POLLUTION CONTROL STRATEGY	WET LOW EMISSION
(7)	COOLING METHOD	N/A
(8)	TOTAL SITE AREA [1]	APPROXIMATELY 213 ACRES
(9)	CONSTRUCTION STATUS	UNDER CONSTRUCTION
(10)	CERTIFICATION STATUS [2]	N/A
(11)	STATUS WITH FEDERAL AGENCIES	N/A
(12)	PROJECTED UNIT PERFORMANCE DATA	
	PLANNED OUTAGE FACTOR (POF)	2.6
	FORCED OUTAGE RATE (FOR)	1.0
	EQUIVALENT AVAILABILITY FACTOR (EAF)	95.4
	RESULTING CAPACITY FACTOR (2009)	12.0%
	AVERAGE NET OPERATING HEAT RATE (ANOHR) [3]	10,620 Btu/kWh
(13)	PROJECTED UNIT FINANCIAL DATA	
	BOOK LIFE (YEARS)	25
	TOTAL INSTALLED COST (IN-SERVICE YEAR $/kW)	566.93
	DIRECT CONSTRUCTION COST ($/kW)	559.67
	AFUDC AMOUNT ($/kW)	7.26
	ESCALATION ($/kW)	
	FIXED O&M ($/kW – Yr)	20.00
	VARIABLE O&M ($/MWH)	3.72
	K FACTOR	1.5984

[1] REPRESENTS TOTAL BAYSIDE SITE.
[2] CERTIFICATION NOT REQUIRED.
[3] BASED ON IN-SERVICE YEAR.

STATUS REPORT AND SPECIFICATIONS OF PROPOSED GENERATING FACILITIES
UTILITY: TAMPA ELECTRIC COMPANY

(1)	PLANT NAME AND UNIT NUMBER	BAYSIDE CT 4
(2)	CAPACITY	
	A. SUMMER	56
	B. WINTER	61
(3)	TECHNOLOGY TYPE	COMBUSTION TURBINE
(4)	ANTICIPATED CONSTRUCTION TIMING	
	A. FIELD CONSTRUCTION START DATE	AUG 2008
	B. COMMERCIAL IN-SERVICE DATE	SEP 2009
(5)	FUEL	
	A. PRIMARY FUEL	NATURAL GAS
	B. ALTERNATE FUEL	N/A
(6)	AIR POLLUTION CONTROL STRATEGY	WET LOW EMISSION
(7)	COOLING METHOD	N/A
(8)	TOTAL SITE AREA [1]	APPROXIMATELY 213 ACRES
(9)	CONSTRUCTION STATUS	UNDER CONSTRUCTION
(10)	CERTIFICATION STATUS [2]	N/A
(11)	STATUS WITH FEDERAL AGENCIES	N/A
(12)	PROJECTED UNIT PERFORMANCE DATA	
	PLANNED OUTAGE FACTOR (POF)	2.6
	FORCED OUTAGE RATE (FOR)	1.0
	EQUIVALENT AVAILABILITY FACTOR (EAF)	95.4
	RESULTING CAPACITY FACTOR (2009)	6.9%
	AVERAGE NET OPERATING HEAT RATE (ANOHR) [3]	10,598 Btu/kWh
(13)	PROJECTED UNIT FINANCIAL DATA	
	BOOK LIFE (YEARS)	25
	TOTAL INSTALLED COST (IN-SERVICE YEAR $/kW)	576.02
	DIRECT CONSTRUCTION COST ($/kW)	559.67
	AFUDC AMOUNT ($/kW)	16.34
	ESCALATION ($/kW)	
	FIXED O&M ($/kW – Yr)	20.00
	VARIABLE O&M ($/MWH)	3.72
	K FACTOR	1.5984

[1] REPRESENTS TOTAL BAYSIDE SITE.
[2] CERTIFICATION NOT REQUIRED.
[3] BASED ON IN-SERVICE YEAR.

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STATUS REPORT AND SPECIFICATIONS OF PROPOSED GENERATING FACILITIES
UTILITY: TAMPA ELECTRIC COMPANY

(1)	PLANT NAME AND UNIT NUMBER	BAYSIDE CT 3
(2)	CAPACITY	
	A. SUMMER	56
	B. WINTER	61
(3)	TECHNOLOGY TYPE	COMBUSTION TURBINE
(4)	ANTICIPATED CONSTRUCTION TIMING	
	A. FIELD CONSTRUCTION START DATE	AUG 2008
	B. COMMERCIAL IN-SERVICE DATE	SEP 2009
(5)	FUEL	
	A. PRIMARY FUEL	NATURAL GAS
	B. ALTERNATE FUEL	N/A
(6)	AIR POLLUTION CONTROL STRATEGY	WET LOW EMISSION
(7)	COOLING METHOD	N/A
(8)	TOTAL SITE AREA [1]	APPROXIMATELY 213 ACRES
(9)	CONSTRUCTION STATUS	UNDER CONSTRUCTION
(10)	CERTIFICATION STATUS [2]	N/A
(11)	STATUS WITH FEDERAL AGENCIES	N/A
(12)	PROJECTED UNIT PERFORMANCE DATA	
	PLANNED OUTAGE FACTOR (POF)	2.6
	FORCED OUTAGE RATE (FOR)	1.0
	EQUIVALENT AVAILABILITY FACTOR (EAF)	95.4
	RESULTING CAPACITY FACTOR (2009)	6.9%
	AVERAGE NET OPERATING HEAT RATE (ANOHR) [3]	10,598 Btu/kWh
(13)	PROJECTED UNIT FINANCIAL DATA	
	BOOK LIFE (YEARS)	25
	TOTAL INSTALLED COST (IN-SERVICE YEAR $/kW)	576.02
	DIRECT CONSTRUCTION COST ($/kW)	559.67
	AFUDC AMOUNT ($/kW)	16.34
	ESCALATION ($/kW)	
	FIXED O&M ($/kW – Yr)	20.00
	VARIABLE O&M ($/MWH)	3.72
	K FACTOR	1.5984

[1] REPRESENTS TOTAL BAYSIDE SITE.
[2] CERTIFICATION NOT REQUIRED.
[3] BASED ON IN-SERVICE YEAR.

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STATUS REPORT AND SPECIFICATIONS OF PROPOSED GENERATING FACILITIES
UTILITY: TAMPA ELECTRIC COMPANY

(1)	PLANT NAME AND UNIT NUMBER	BIG BEND CT 4
(2)	CAPACITY	
	A. SUMMER	56
	B. WINTER	61
(3)	TECHNOLOGY TYPE	COMBUSTION TURBINE
(4)	ANTICIPATED CONSTRUCTION TIMING	
	A. FIELD CONSTRUCTION START DATE	AUG 2008
	B. COMMERCIAL IN-SERVICE DATE	SEP 2009
(5)	FUEL	
	A. PRIMARY FUEL	NATURAL GAS
	B. ALTERNATE FUEL	DISTILLATE OIL
(6)	AIR POLLUTION CONTROL STRATEGY	WET LOW EMISSION
(7)	COOLING METHOD	N/A
(8)	TOTAL SITE AREA [1]	APPROXIMATELY 1500 ACRES
(9)	CONSTRUCTION STATUS	UNDER CONSTRUCTION
(10)	CERTIFICATION STATUS [2]	N/A
(11)	STATUS WITH FEDERAL AGENCIES	N/A
(12)	PROJECTED UNIT PERFORMANCE DATA	
	PLANNED OUTAGE FACTOR (POF)	2.6
	FORCED OUTAGE RATE (FOR)	1.0
	EQUIVALENT AVAILABILITY FACTOR (EAF)	95.4
	RESULTING CAPACITY FACTOR (2009)	6.9%
	AVERAGE NET OPERATING HEAT RATE (ANOHR) [3]	10,598 Btu/kWh
(13)	PROJECTED UNIT FINANCIAL DATA	
	BOOK LIFE (YEARS)	25
	TOTAL INSTALLED COST (IN-SERVICE YEAR $/kW)	576.02
	DIRECT CONSTRUCTION COST ($/kW)	559.67
	AFUDC AMOUNT ($/kW)	16.34
	ESCALATION ($/kW)	
	FIXED O&M ($/kW – Yr)	20.00
	VARIABLE O&M ($/MWH)	3.72
	K FACTOR	1.5984

[1] REPRESENTS TOTAL BIG BEND SITE.
[2] CERTIFICATION NOT REQUIRED.
[3] BASED ON IN-SERVICE YEAR.

SCHEDULE 9

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STATUS REPORT AND SPECIFICATIONS OF PROPOSED GENERATING FACILITIES
UTILITY: TAMPA ELECTRIC COMPANY

(1)	PLANT NAME AND UNIT NUMBER	FUTURE CT 1, 2 & 3
(2)	CAPACITY	
	A. SUMMER	56
	B. WINTER	61
(3)	TECHNOLOGY TYPE	COMBUSTION TURBINE
(4)	ANTICIPATED CONSTRUCTION TIMING	
	A. FIELD CONSTRUCTION START DATE	SEP 2011
	B. COMMERCIAL IN-SERVICE DATE	MAY 2012
(5)	FUEL	
	A. PRIMARY FUEL	NATURAL GAS
	B. ALTERNATE FUEL	N/A
(6)	AIR POLLUTION CONTROL STRATEGY	WET LOW EMISSION
(7)	COOLING METHOD	N/A
(8)	TOTAL SITE AREA	UNDETERMINED
(9)	CONSTRUCTION STATUS	PROPOSED
(10)	CERTIFICATION STATUS	UNDETERMINED
(11)	STATUS WITH FEDERAL AGENCIES	N/A
(12)	PROJECTED UNIT PERFORMANCE DATA	
	PLANNED OUTAGE FACTOR (POF)	2.6
	FORCED OUTAGE RATE (FOR)	1.0
	EQUIVALENT AVAILABILITY FACTOR (EAF)	95.4
	RESULTING CAPACITY FACTOR (2012)	4.2%
	AVERAGE NET OPERATING HEAT RATE (ANOHR) [1]	10,603 Btu/kWh
(13)	PROJECTED UNIT FINANCIAL DATA	
	BOOK LIFE (YEARS)	25
	TOTAL INSTALLED COST (IN-SERVICE YEAR $/kW)	623.95
	DIRECT CONSTRUCTION COST ($/kW)	559.67
	AFUDC AMOUNT ($/kW)	45.67
	ESCALATION ($/kW)	18.61
	FIXED O&M ($/kW – Yr)	21.35
	VARIABLE O&M ($/MWH)	3.97
	K FACTOR	1.5984

[1] BASED ON IN-SERVICE YEAR.

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STATUS REPORT AND SPECIFICATIONS OF PROPOSED GENERATING FACILITIES
UTILITY: TAMPA ELECTRIC COMPANY

(1)	PLANT NAME AND UNIT NUMBER	FUTURE CT 4
(2)	CAPACITY	
	A. SUMMER	149
	B. WINTER	177
(3)	TECHNOLOGY TYPE	COMBUSTION TURBINE
(4)	ANTICIPATED CONSTRUCTION TIMING	
	A. FIELD CONSTRUCTION START DATE	MAY 2012
	B. COMMERCIAL IN-SERVICE DATE	JAN 2013
(5)	FUEL	
	A. PRIMARY FUEL	NATURAL GAS
	B. ALTERNATE FUEL	N/A
(6)	AIR POLLUTION CONTROL STRATEGY	WET LOW EMISSION
(7)	COOLING METHOD	N/A
(8)	TOTAL SITE AREA	UNDETERMINED
(9)	CONSTRUCTION STATUS	PROPOSED
(10)	CERTIFICATION STATUS	UNDETERMINED
(11)	STATUS WITH FEDERAL AGENCIES	N/A
(12)	PROJECTED UNIT PERFORMANCE DATA	
	PLANNED OUTAGE FACTOR (POF)	2.6
	FORCED OUTAGE RATE (FOR)	2.0
	EQUIVALENT AVAILABILITY FACTOR (EAF)	94.4
	RESULTING CAPACITY FACTOR (2013)	6.3%
	AVERAGE NET OPERATING HEAT RATE (ANOHR) [1]	12,579 Btu/kWh
(13)	PROJECTED UNIT FINANCIAL DATA	
	BOOK LIFE (YEARS)	25
	TOTAL INSTALLED COST (IN-SERVICE YEAR $/kW)	742.27
	DIRECT CONSTRUCTION COST ($/kW)	651.47
	AFUDC AMOUNT ($/kW)	54.33
	ESCALATION ($/kW)	36.46
	FIXED O&M ($/kW – Yr)	8.09
	VARIABLE O&M ($/MWH)	17.79
	K FACTOR	1.5984

[1] BASED ON IN-SERVICE YEAR.

STATUS REPORT AND SPECIFICATIONS OF PROPOSED GENERATING FACILITIES
UTILITY: TAMPA ELECTRIC COMPANY

(1)	PLANT NAME AND UNIT NUMBER	FUTURE CT 5 & 6
(2)	CAPACITY	
	A. SUMMER	149
	B. WINTER	177
(3)	TECHNOLOGY TYPE	COMBUSTION TURBINE
(4)	ANTICIPATED CONSTRUCTION TIMING	
	A. FIELD CONSTRUCTION START DATE	SEP 2012
	B. COMMERCIAL IN-SERVICE DATE	MAY 2013
(5)	FUEL	
	A. PRIMARY FUEL	NATURAL GAS
	B. ALTERNATE FUEL	N/A
(6)	AIR POLLUTION CONTROL STRATEGY	WET LOW EMISSION
(7)	COOLING METHOD	N/A
(8)	TOTAL SITE AREA	UNDETERMINED
(9)	CONSTRUCTION STATUS	PROPOSED
(10)	CERTIFICATION STATUS	UNDETERMINED
(11)	STATUS WITH FEDERAL AGENCIES	N/A
(12)	PROJECTED UNIT PERFORMANCE DATA	
	PLANNED OUTAGE FACTOR (POF)	2.6
	FORCED OUTAGE RATE (FOR)	2.0
	EQUIVALENT AVAILABILITY FACTOR (EAF)	94.4
	RESULTING CAPACITY FACTOR (2013)	4.5%
	AVERAGE NET OPERATING HEAT RATE (ANOHR) [1]	12,928 Btu/kWh
(13)	PROJECTED UNIT FINANCIAL DATA	
	BOOK LIFE (YEARS)	25
	TOTAL INSTALLED COST (IN-SERVICE YEAR $/kW)	742.27
	DIRECT CONSTRUCTION COST ($/kW)	651.47
	AFUDC AMOUNT ($/kW)	54.33
	ESCALATION ($/kW)	36.46
	FIXED O&M ($/kW – Yr)	8.09
	VARIABLE O&M ($/MWH)	17.79
	K FACTOR	1.5984

[1] BASED ON IN-SERVICE YEAR.

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STATUS REPORT AND SPECIFICATIONS OF PROPOSED GENERATING FACILITIES
UTILITY: TAMPA ELECTRIC COMPANY

(1)	PLANT NAME AND UNIT NUMBER	FUTURE CT 7
(2)	CAPACITY	
	A. SUMMER	56
	B. WINTER	61
(3)	TECHNOLOGY TYPE	COMBUSTION TURBINE
(4)	ANTICIPATED CONSTRUCTION TIMING	
	A. FIELD CONSTRUCTION START DATE	SEP 2013
	B. COMMERCIAL IN-SERVICE DATE	MAY 2014
(5)	FUEL	
	A. PRIMARY FUEL	NATURAL GAS
	B. ALTERNATE FUEL	N/A
(6)	AIR POLLUTION CONTROL STRATEGY	WET LOW EMISSION
(7)	COOLING METHOD	N/A
(8)	TOTAL SITE AREA	UNDETERMINED
(9)	CONSTRUCTION STATUS	PROPOSED
(10)	CERTIFICATION STATUS	UNDETERMINED
(11)	STATUS WITH FEDERAL AGENCIES	N/A
(12)	PROJECTED UNIT PERFORMANCE DATA	
	PLANNED OUTAGE FACTOR (POF)	2.6
	FORCED OUTAGE RATE (FOR)	1.0
	EQUIVALENT AVAILABILITY FACTOR (EAF)	95.4
	RESULTING CAPACITY FACTOR (2014)	5.6%
	AVERAGE NET OPERATING HEAT RATE (ANOHR) [1]	10,658 Btu/kWh
(13)	PROJECTED UNIT FINANCIAL DATA	
	BOOK LIFE (YEARS)	25
	TOTAL INSTALLED COST (IN-SERVICE YEAR $/kW)	651.70
	DIRECT CONSTRUCTION COST ($/kW)	559.67
	AFUDC AMOUNT ($/kW)	47.70
	ESCALATION ($/kW)	44.33
	FIXED O&M ($/kW – Yr)	22.30
	VARIABLE O&M ($/MWH)	4.15
	K FACTOR	1.5984

[1] BASED ON IN-SERVICE YEAR.

SCHEDULE 9

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STATUS REPORT AND SPECIFICATIONS OF PROPOSED GENERATING FACILITIES
UTILITY: TAMPA ELECTRIC COMPANY

(1)	PLANT NAME AND UNIT NUMBER	FUTURE CT 8 & 9
(2)	CAPACITY	
	A. SUMMER	56
	B. WINTER	61
(3)	TECHNOLOGY TYPE	COMBUSTION TURBINE
(4)	ANTICIPATED CONSTRUCTION TIMING	
	A. FIELD CONSTRUCTION START DATE	SEP 2014
	B. COMMERCIAL IN-SERVICE DATE	MAY 2015
(5)	FUEL	
	A. PRIMARY FUEL	NATURAL GAS
	B. ALTERNATE FUEL	N/A
(6)	AIR POLLUTION CONTROL STRATEGY	WET LOW EMISSION
(7)	COOLING METHOD	N/A
(8)	TOTAL SITE AREA	UNDETERMINED
(9)	CONSTRUCTION STATUS	PROPOSED
(10)	CERTIFICATION STATUS	UNDETERMINED
(11)	STATUS WITH FEDERAL AGENCIES	N/A
(12)	PROJECTED UNIT PERFORMANCE DATA	
	PLANNED OUTAGE FACTOR (POF)	2.6
	FORCED OUTAGE RATE (FOR)	1.0
	EQUIVALENT AVAILABILITY FACTOR (EAF)	95.4
	RESULTING CAPACITY FACTOR (2015)	6.6%
	AVERAGE NET OPERATING HEAT RATE (ANOHR) [1]	10,649 Btu/kWh
(13)	PROJECTED UNIT FINANCIAL DATA	
	BOOK LIFE (YEARS)	25
	TOTAL INSTALLED COST (IN-SERVICE YEAR $/kW)	666.05
	DIRECT CONSTRUCTION COST ($/kW)	559.67
	AFUDC AMOUNT ($/kW)	48.75
	ESCALATION ($/kW)	57.62
	FIXED O&M ($/kW – Yr)	22.79
	VARIABLE O&M ($/MWH)	4.24
	K FACTOR	1.5984

[1] BASED ON IN-SERVICE YEAR.

SCHEDULE 9

STATUS REPORT AND SPECIFICATIONS OF PROPOSED GENERATING FACILITIES
UTILITY: TAMPA ELECTRIC COMPANY

(1)	PLANT NAME AND UNIT NUMBER	FUTURE CT 10 & 11
(2)	CAPACITY	
	A. SUMMER	56
	B. WINTER	61
(3)	TECHNOLOGY TYPE	COMBUSTION TURBINE
(4)	ANTICIPATED CONSTRUCTION TIMING	
	A. FIELD CONSTRUCTION START DATE	SEP 2015
	B. COMMERCIAL IN-SERVICE DATE	MAY 2016
(5)	FUEL	
	A. PRIMARY FUEL	NATURAL GAS
	B. ALTERNATE FUEL	N/A
(6)	AIR POLLUTION CONTROL STRATEGY	WET LOW EMISSION
(7)	COOLING METHOD	N/A
(8)	TOTAL SITE AREA	UNDETERMINED
(9)	CONSTRUCTION STATUS	PROPOSED
(10)	CERTIFICATION STATUS	UNDETERMINED
(11)	STATUS WITH FEDERAL AGENCIES	N/A
(12)	PROJECTED UNIT PERFORMANCE DATA	
	PLANNED OUTAGE FACTOR (POF)	2.6
	FORCED OUTAGE RATE (FOR)	1.0
	EQUIVALENT AVAILABILITY FACTOR (EAF)	95.4
	RESULTING CAPACITY FACTOR (2016)	7.7%
	AVERAGE NET OPERATING HEAT RATE (ANOHR) [1]	10,621 Btu/kWh
(13)	PROJECTED UNIT FINANCIAL DATA	
	BOOK LIFE (YEARS)	25
	TOTAL INSTALLED COST (IN-SERVICE YEAR $/kW)	680.69
	DIRECT CONSTRUCTION COST ($/kW)	559.67
	AFUDC AMOUNT ($/kW)	49.82
	ESCALATION ($/kW)	71.20
	FIXED O&M ($/kW – Yr)	23.29
	VARIABLE O&M ($/MWH)	4.34
	K FACTOR	1.5984

[1] BASED ON IN-SERVICE YEAR.

SCHEDULE 9

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STATUS REPORT AND SPECIFICATIONS OF PROPOSED GENERATING FACILITIES
UTILITY: TAMPA ELECTRIC COMPANY

(1)	PLANT NAME AND UNIT NUMBER	FUTURE CC 1
(2)	CAPACITY	
	A. SUMMER	555
	B. WINTER	607
(3)	TECHNOLOGY TYPE	COMBINED CYCLE
(4)	ANTICIPATED CONSTRUCTION TIMING	
	A. FIELD CONSTRUCTION START DATE	JAN 2014
	B. COMMERCIAL IN-SERVICE DATE	MAY 2018
(5)	FUEL	
	A. PRIMARY FUEL	NATURAL GAS
	B. ALTERNATE FUEL	N/A
(6)	AIR POLLUTION CONTROL STRATEGY	SCR, DLN BURNERS
(7)	COOLING METHOD	N/A
(8)	TOTAL SITE AREA	UNDETERMINED
(9)	CONSTRUCTION STATUS	PROPOSED
(10)	CERTIFICATION STATUS	UNDETERMINED
(11)	STATUS WITH FEDERAL AGENCIES	N/A
(12)	PROJECTED UNIT PERFORMANCE DATA	
	PLANNED OUTAGE FACTOR (POF)	3.8
	FORCED OUTAGE RATE (FOR)	3.0
	EQUIVALENT AVAILABILITY FACTOR (EAF)	93.2
	RESULTING CAPACITY FACTOR (2018)	88.4%
	AVERAGE NET OPERATING HEAT RATE (ANOHR) [1]	6,837 Btu/kWh
(13)	PROJECTED UNIT FINANCIAL DATA	
	BOOK LIFE (YEARS)	25
	TOTAL INSTALLED COST (IN-SERVICE YEAR $/kW)	1,528.71
	DIRECT CONSTRUCTION COST ($/kW)	1,158.85
	AFUDC AMOUNT ($/kW)	184.86
	ESCALATION ($/kW)	185.00
	FIXED O&M ($/kW – Yr)	6.70
	VARIABLE O&M ($/MWH)	4.66
	K FACTOR	1.6508

[1] BASED ON IN-SERVICE YEAR.

Schedule 10

Status Report and Specifications of Proposed Directly Associated Transmission Lines

Units	Point of Origin and Termination	Number of Circuits	Right-of-Way	Circuit Length	Voltage	Anticipated In-Service Date	Anticipated Capital Investment	Substations	Participation with Other Utilities
Bayside Units 3 and 4	Gannon	1	No new ROW required	0.1 mi	138kV	Spring 2009	$2.0 million	Upgrade Gannon 138kV ring-bus	None
Big Bend CT 4	Big Bend	1	No new ROW required	0.1 mi	230kV	Fall 2009	$0.7 million	No new substations	None
Future CT 1, 2, and 3	Big Bend	1	No new ROW required	0.1 mi	230kV	Summer 2012	$1.0 million	No new substations	None
Future CT 1, 2, and 3	Big Bend to SR60	1	No new ROW required	13.7 mi	230kV	Summer 2012	$9 million	Add 230kV ring-bus at SR60	None
Future CT 4, 5, and 6	Polk	2	No new ROW required	0.7 mi	230kV	Winter 2012/2013	$6 million	No new substations	None
Future CT 4, 5, and 6	Polk to Pebbledale - 1	1	No new ROW required	13.5 mi	230kV	Summer 2013	$2 million	No new substations	None
Future CT 4, 5, and 6	Polk to Pebbledale - 2	1	No new ROW required	9.9 mi	230kV	Summer 2013	$6 million	No new substations	None
Future CT 4, 5, and 6	Polk to FishHawk	1	ROW issues under-review	30.5 mi	230kV	Summer 2013	$74 million	No new substations	None
Future CC 1	Polk	1	No new ROW required	0.3 mi	230kV	Summer 2018	$1.5 million	No new substations	None
Future CC 1	Pebbledale to Willow Oak to Wheeler Road	1	ROW issues under-review	25.9 mi	230kV	Summer 2018	$60.8 million	New 230/69kV substation at Willow Oak	None

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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 2008 Florida Reliability Coordinating Council (FRCC) databank models, no transmission constraints that violate the criteria stated in the Generation and Transmission Reliability Criteria section of this document were identified in these studies.

EXPANSION PLAN ECONOMICS AND FUEL FORECAST

The overall economics and cost-effectiveness of the plan were analyzed using Tampa Electric’s Integrated Resource Planning process. As part of this process, Tampa Electric evaluated various planning and operating alternatives against expected operations, with the objective to: meet compliance requirements in the most cost-effective and reliable manner, maximize operational flexibility, and minimize total costs.

Early in the study process, many alternatives were screened on a qualitative and quantitative basis to determine those alternatives that were the most feasible overall. While 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.

Fuel commodity price forecasting for the base case is derived through analysis of historical and current prices combined with price forecasts obtained from various consultants and agencies. These sources include the New York Mercantile Exchange, Energy Information Administration, Hill & Associates (now part of Wood Mackenzie Energy Group), PIRA Energy Group, Coal Daily, Inside FERC and Platt’s Oilgram.

High and low fuel price projections represent alternative forecasts to the company’s base case outlook. The high and low price projections are defined by varying natural gas, coal and oil prices by the five year historical variation of those commodities’ annual prices.

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 weeks, and unplanned outage rates.

The unit performance projections are based on historical data trends, engineering judgment, time since last planned outage, and recent equipment performance. The first five years of planned outages are based on a forecasted outage schedule, and the planned outages for the balance of the years are based on an average of the first five years.

The five-year forecasted outage schedule is based on unit-specific maintenance needs, material lead-time, labor availability, and the need to supply our customers with power in the most economical manner. Unplanned outage rate projections are based on an average of three years of historical data adjusted, if necessary, to account for current unit conditions.

FINANCIAL ASSUMPTIONS

Tampa Electric makes numerous financial assumptions as part of the preparation for its Ten-Year Site Plan process. These assumptions are based on the current financial status of the company, the market for securities, and the best available forecast of future conditions. The primary financial assumptions include the FPSC-approved Allowance for Funds Used During Construction (AFUDC) rate, capitalization ratios, financing cost rates, tax rates, and FPSC-approved depreciation rates.

- Per the Florida Administrative Code, an amount for AFUDC is recorded by the company during the construction phase of each capital project. This rate is approved by the FPSC and represents the cost of money invested in the applicable project while it is under construction. This cost is capitalized, becomes part of the project investment, and is recovered over the life of the asset. The AFUDC rate assumed in the Ten-Year Site Plan represents the company's currently approved AFUDC rate.
- The capitalization ratios represent the percentages of incremental long-term capital that are expected to be issued to finance the capital projects identified in the Ten-Year Site Plan.
- The financing cost rates reflect the incremental cost of capital associated with each of the sources of long-term financing.
- Tax rates include federal income tax, state income tax, and miscellaneous taxes including property tax.
- Depreciation represents the annual cost to amortize the total original investment in a plant over its useful life less net salvage value. This provides for the recovery of plant investment. The assumed book life for each capital project within the Ten-Year Site Plan represents the average expected life for that type of investment.

INTEGRATED RESOURCE PLANNING PROCESS

Tampa Electric's Integrated Resource Planning process was designed to evaluate demand side and supply side resources on a fair and consistent basis to satisfy future energy requirements in a cost-effective and reliable manner, while considering the interests of utility customers and shareholders.

The process incorporates a reliability analysis to determine timing of future needs and an economic analysis to determine what resource alternatives best meet future system demand and energy requirements. Initially, a demand and energy forecast, which excludes incremental energy efficiency and conservation programs, is developed. Then a supply plan based on the system requirements, which excludes incremental energy efficiency and conservation, is developed. This interim supply plan becomes the basis for potential avoided unit(s) in a comprehensive cost-effective analysis of the energy efficiency and conservation programs. Once the cost-effective energy efficiency and conservation programs are determined, the system demand and energy requirements are revised to include the effects of these programs on reducing system peak and energy requirements. The process is repeated to incorporate the energy efficiency and conservation programs and supply side resources.

The cost-effectiveness of energy efficiency and demand response programs is based on the following standard Commission tests: the Rate Impact Measure (RIM), the Total Resource Cost (TRC), and the Participants Tests. Using the FPSC's standard cost-effectiveness methodology, each measure is evaluated based on different marketing and incentive assumptions. Utility plant avoidance assumptions for generation, transmission, and distribution are used in this analysis. All measures that pass the RIM, TRC, and Participants Tests in the energy efficiency and demand response analysis are considered for utility program adoption. Each adopted measure is quantified into annual kW/kWh savings and is reflected in the demand and energy forecast. Measures with the highest RIM values are generally adopted first. Tampa Electric evaluates energy efficiency and demand response measures using a spreadsheet that comports with Rule 25-17.008, F.A.C., the FPSC's prescribed cost-effectiveness methodology.

Generating resources to be considered are determined through an alternative technology screening analysis, which is designed to determine the economic viability of a wide range of generating technologies for the Tampa Electric service area.

The technologies that pass the screening are included in a supply side analysis, which examines various supply side alternatives for meeting future capacity requirements.

Tampa Electric uses the PROVIEW module of STRATEGIST, a computer model developed by New Energy Associates, to evaluate the supply side resources. PROVIEW uses a dynamic programming approach to develop an estimate of the timing and type of capacity additions which would most economically meet the system demand and energy requirements. Dynamic programming compares all feasible combinations of generating unit additions, which satisfy the specified reliability criteria, and determines the schedule of additions that have the lowest revenue requirements. The model uses production costing analysis and incremental capital and O&M expenses to project the revenue requirements and rank each plan.

A detailed cost analysis for each of the top ranked resource plans is performed using the Capital Expenditure and Recovery module and of STRATEGIST and the PROMOD economic dispatch model. The capital expenditures associated with each capacity addition are obtained based on the type of generating unit, fuel type, capital spending curve, and in-service year. The fixed charges resulting from the capital expenditures are expressed in present worth dollars for comparison. The fuel and the operating and maintenance costs associated with each scenario are projected based on economic dispatch of all the energy resources on our system. The projected operating expense, expressed in present worth dollars, is combined with the fixed charges to obtain the total present worth of revenue requirements for each alternative plan.

STRATEGIC CONCERNS

Strategic concerns affect the type, capacity, and/or timing of future generation resource requirements. Concerns such as competitive pressures, environmental legislation, and plan acceptance are not easily quantified. These strategic concerns are considered within the Integrated Resource Planning process to ensure that an economically viable expansion plan is selected which has the flexibility for the company to respond to future technological and economic changes. The resulting expansion plan may include self-build generation, market purchase options or other viable supply and demand-side alternatives.

The results of the Integrated Resource Planning process provide Tampa Electric with a plan that is cost-effective while maintaining flexibility and adaptability to a dynamic regulatory and competitive environment. The new capacity additions are shown in Schedule 8.2. To meet the expected system demand and energy requirements over the next ten years and cost-effectively maintain system reliability, Tampa Electric is planning the addition of combustion turbines and a combined cycle.

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

GENERATION AND TRANSMISSION RELIABILITY CRITERIA

Generation

Tampa Electric currently uses two criteria to measure the reliability of its generating system. The company utilizes a 20% reserve margin criteria with a minimum contribution of 7% supply side resources. Tampa Electric’s approach to calculating percent reserves are consistent with that outlined in the settlement agreement. The calculation of the minimum 20% reserve margin employs an industry accepted method of using total available generating and firm purchased power capacity (capacity less planned maintenance and contracted unit sales) and subtracting the annual firm peak load, then dividing by the firm peak load, and multiplying by 100%. Since the reserve margin calculation assumes no forced outages, Tampa Electric includes the purchased power contract with Invenergy for the Hardee Power Station in its available capacity.

Contractually, Hardee Power Station is planned to be available to Tampa Electric at the time of system peak. Also, the capacity dedicated to any firm unit or station power sales at the time of system peak is subtracted from Tampa Electric's available capacity.

Tampa Electric's summer supply-side reserve margin is calculated by dividing the difference of projected supply-side resources and projected total peak demand by the forecasted firm peak demand. The total peak demand includes the summer firm peak demand, and interruptible and load management loads.

Transmission

The following criteria are used as guidelines for proposing system expansion and/or improvement projects. A detailed engineering study must be performed prior to making a prudent decision to initiate a project.

Tampa Electric follows FRCC planning criteria as contained in its *Principles and Guides for Planning Reliable Bulk Electric Systems*. The FRCC planning guide is based on 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, Tampa Electric's specific criteria for normal system operation and single contingency operation are listed in the Generation and Transmission Reliability Criteria section of this document.

Generation Dispatch Modeled

The generation dispatched in the planning models is dictated on an economic basis and is calculated by the Economic Dispatch (ECDI) function of the PSS/E load flow software. The ECDI 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 unplanned and planned unit outages can result in a system dispatch that varies significantly from a base plan, bulk transmission planners also investigate several scenarios that may stress Tampa Electric's transmission system. These additional generation sensitivities are analyzed to ensure the integrity of the bulk transmission system under maximized bulk power flows.

Transmission System Planning Loading Limits Criteria

Tampa Electric follows the FRCC planning criteria as contained in the FRCC Standards Handbook and NERC Standards. In addition to FRCC criteria, Tampa Electric utilizes company-specific planning criteria.

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

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)	115%
Single Contingency (post-switching)	100%
Bus Outages (pre-switching)	115%
Bus Outages (post-switching)	100%

The transmission system is planned to allow voltage control on the 13.2 kV distribution buses between 1.023 and 1.043 per unit. For screening purposes, this criterion can be approximated by the following transmission system voltage limits.

Transmission System Voltage Limits

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

Available Transmission Transfer Capability (ATC) Criteria

Tampa Electric Company complies with the FRCC ATC calculation methodology as well as the principles contained in the NERC Standards relating to ATC.

TRANSMISSION PLANNING ASSESSMENT PRACTICES

Base Case Operating Conditions

The System Planning department ensures that the Tampa Electric Company transmission system can support peak and off-peak system load levels without violation of the loading and voltage criteria stated in the Generation and Transmission Reliability Criteria section of this document.

Single Contingency Planning Criteria

The Tampa Electric Company transmission system is designed such that any single branch (transmission line or autotransformer) can be removed from service up to the forecasted peak load level without any violations of the criteria stated in the Generation and Transmission Reliability Criteria section of this document.

Multiple Contingency Planning Criteria

Double contingencies (including FRCC studies of C2, C3, C3Gens, C3Lines, and C5 events) involving two branches or more out of service simultaneously are analyzed at a variety of load levels. The Tampa Electric Company transmission system is designed such that these double contingencies do not cause violation of NERC criteria.

Transmission Construction and Upgrade Plans

A detailed list of the construction projects can be found in Chapter IV, Schedule 10. This list represents the latest transmission expansion plan available. However, due to the timing of this document in relationship to the company's internal planning schedule, this plan may change in the near future.

Supply Side Resources Procurement Process

Tampa Electric will manage the procurement process in accordance with established policies and procedures. Prospective suppliers of supply side resources as well as suppliers of equipment and services will be identified using various data base resources and competitive bid evaluations, and will be used in developing award recommendations to management.

This process will allow for future supply side resources to be supplied from self-build, purchase power, or competitively bid third parties. Consistent with company practice, bidders will be encouraged to propose incentive arrangements that promote development and implementation of cost savings and process improvement recommendations.

Energy Efficiency and Conservation and Energy Savings Durability

Tampa Electric verifies the durability of energy savings from its conservation and load management programs by several methods. First, Tampa Electric has established a monitoring and evaluation process where historical analysis validates the energy savings. These include:

1. Periodic system load reduction analyses for residential load management (Prime Time) to confirm the accuracy of Tampa Electric's load reduction estimation formulas;

2. Billing analysis of various program participants (Energy Planner), compared to control groups to minimize the impact of weather abnormalities;

3. Periodic DOE2 modeling of various program participants such as the Residential and Commercial Building Envelope programs to evaluate savings achieved in residential programs involving building components; components;

4. End-use sampling of building segments to validate savings achieved in Conservation Value and Commercial Indoor Lighting programs; and

5. In commercial programs such as Standby Generator and Commercial Load Management and Commercial Demand Response, the reductions are verified through metering of loads under control to determine the demand and energy savings.

Second, the programs are designed to promote the use of high efficiency equipment having permanent installation characteristics. Specifically, those programs that promote the installation of energy efficient measures or equipment (heat pumps, hard-wired lighting fixtures, ceiling insulation, wall insulation, window replacements, air distribution system repairs, DX commercial cooling units, chiller replacements, water heating replacements and motor upgrades) have program standards that require the new equipment to be installed in a permanent manner thus insuring their durability.

Tampa Electric's Renewable Energy Programs

Tampa Electric has offered a pilot Renewable Energy Program for several years. Due to the success of the pilot, permanent program status was requested by the company and approved by the Commission in Docket No. 06078-EG, Order No. PSC-07-0052-CO-EG, issued January 19, 2007.

Through December 2008, Tampa Electric's Renewable Energy Program has almost 3,000 customers purchasing over 3,400 blocks of renewable energy each month. With the permanent program status effective January 2007, the company doubled the renewable energy block size from 100 to 200 kWh per month.

Tampa Electric is one of the few electric utilities in the state that uses renewable generation produced in the State of Florida. The company's renewable generation portfolio is a mix of various technologies and renewable fuel sources, including four company owned photovoltaic (PV) arrays totaling 39.5 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. Additional, the company is working with Tampa's Lowry Park Zoo to install 15 kW to further educate the public on the benefits of renewable energy. The company also purchases excess renewable energy from 37 customers in Tampa Electric's service area who have interconnect agreements for their renewable generating sources. Program growth has now reached a point where it has become necessary to supplement the company's renewable resources with incremental purchases from a biomass facility in south Florida. Through December 2008, participating customers have utilized over 20 GWH of renewable energy since the program inception.

Tampa Electric recognizes the need and value of renewable generation for the future, and to that end, the company continues to investigate and obtain the most cost-effective methods of system generation and available off-system incremental purchases.

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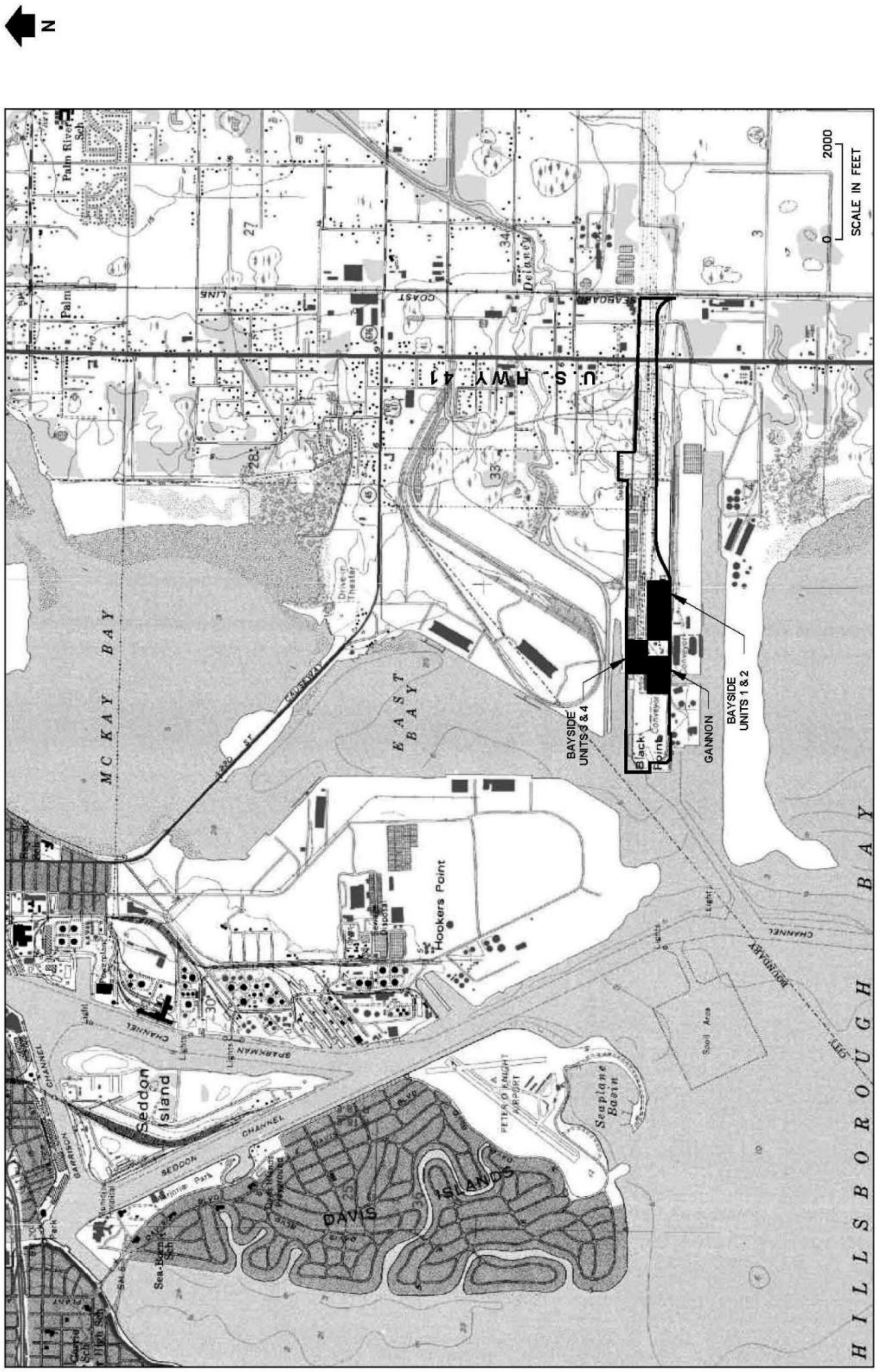
Chapter VI

ENVIRONMENTAL AND LAND USE INFORMATION

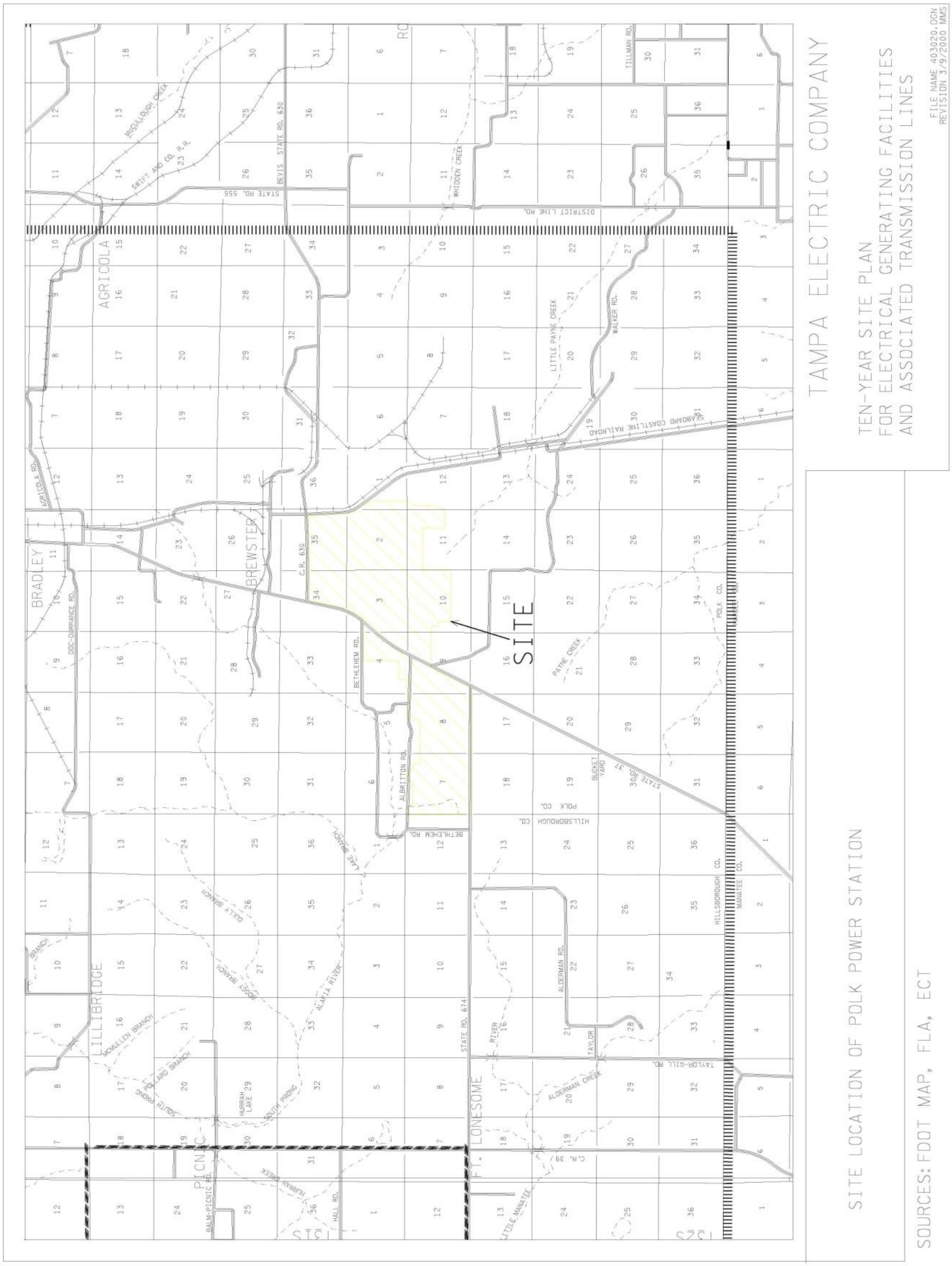
The future generating capacity additions identified in Chapter IV could occur at H.L. Culbreath Bayside Power Station, Polk Power Station, or Big Bend Power Station. The H.L. Culbreath Bayside Power Station site is located in Hillsborough County on Port Sutton Road (See Figure VI-1), Polk Power Station 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



F.J. GANNON / BAYSIDE LOCATION MAP
SOURCE: USGS QUAD, TAMPA, FL 1981

Figure VI-2



TAMPA ELECTRIC COMPANY
TEN-YEAR SITE PLAN
FOR ELECTRICAL GENERATING FACILITIES
AND ASSOCIATED TRANSMISSION LINES
FILE NAME 403020.DGN
REVISION 3/9/2000 MMS
SITE LOCATION OF POLK POWER STATION
SOURCES: FDOT MAP, FLA, ECT
SITE
AGRICOLA
BRADLEY
BREWSTER
LILLIBRIDGE
PICNIC
LONESOME
SEABOARD COASTLINE RAILROAD
DISTRICT LINE RD.
STATE RD. 555
STATE RD. 630
C.R. 630
STATE RD. 674
STATE RD. 37
BETHLEHEM RD.
ALBRITTON RD.
POLK CO.
HILLSBOROUGH CO.
MANATEE CO.

Figure VI-3

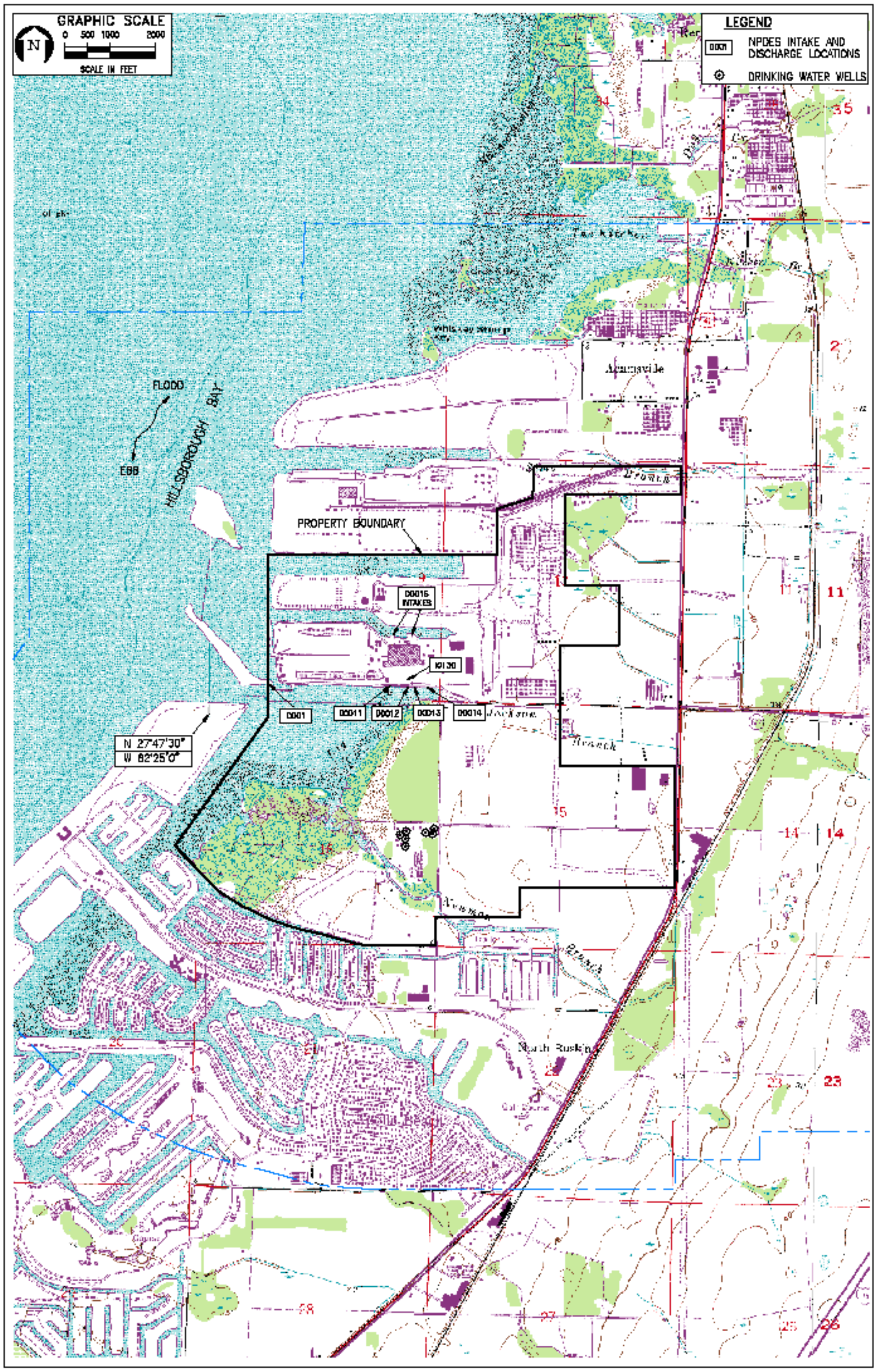


FIGURE XI.
SITE LOCATION MAP
TAMPA ELECTRIC COMPANY
BIG BEND STATION, TAMPA, FLORIDA
Source: USGS Quad : Gibsonton, FL, 1987; ECT, 2001.

ECT
Environmental Consulting & Technology, Inc.