SACE 1st Response to Staff
008136

AUSLEY & MCMULLEN

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COMMISSION CLERK

April 1, 2010

HAND DELIVERED

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

100000-OT

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

Dear Ms. Cole:

Enclosed for filing on behalf of Tampa Electric Company are twenty-five (25) copies of the company's January 2010 to December 2019 Ten-Year Site Plan.

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

Thank you for your assistance in connection with this matter.

Sincerely,

James D. Beasley

JDB/pp
Enclosures

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RAD 2D
SSC ___
ADM ___
OPC ___
CLK 2

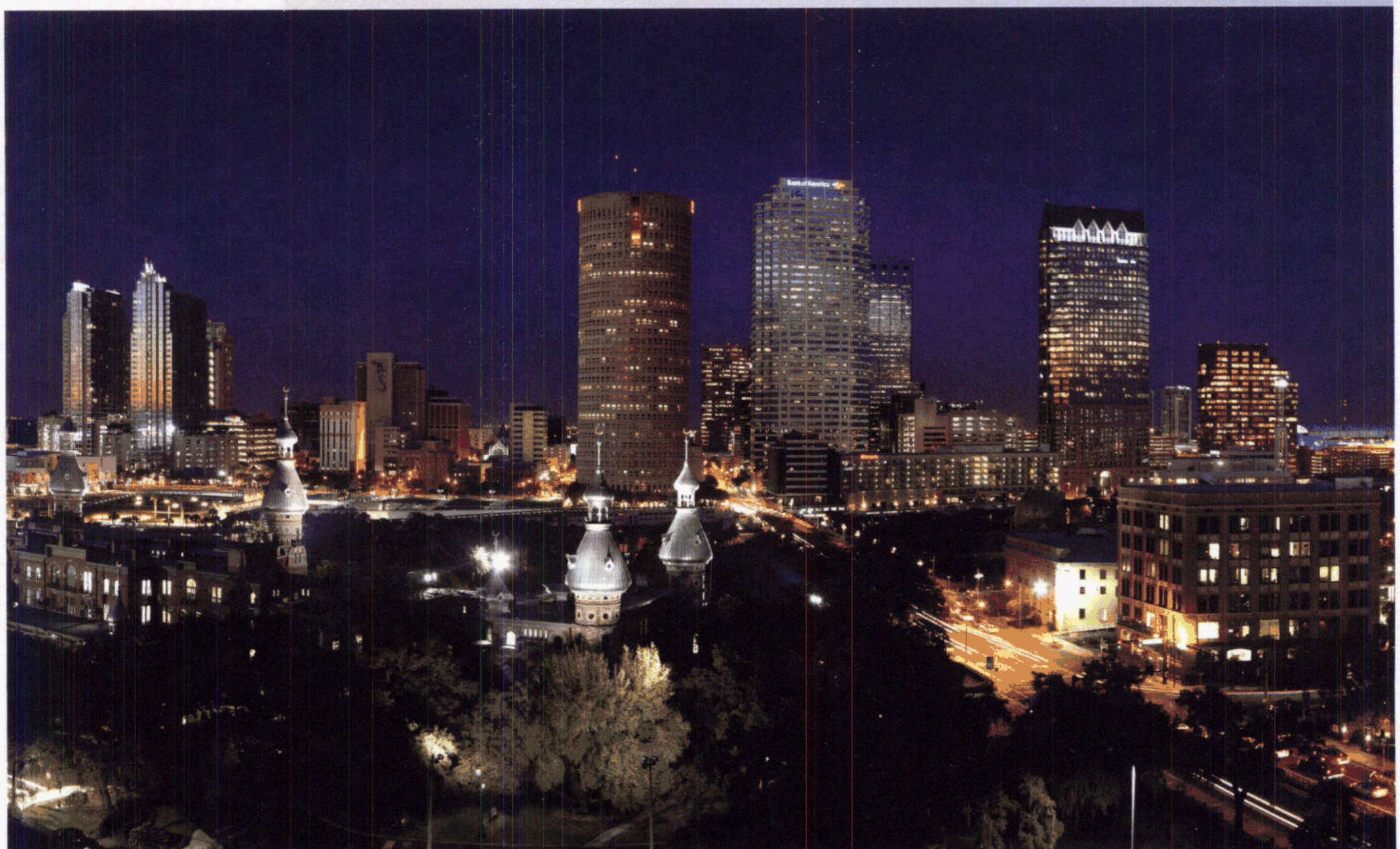
DOCUMENT NUMBER-DATE
02402 APR-1 ≗

SACE 1st Response to Staff
008137

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

January 2010 to December 2019

100000-OT



Responsibly Serving Our Customers' Growing Needs

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

January 2010 to December 2019

TAMPA ELECTRIC COMPANY
Tampa, Florida

April 1, 2010

Table of Contents

List of Schedules & Tables

List of Schedules & Tables (continued)

List of Figures

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Glossary of Terms

CODE IDENTIFICATION SHEET

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

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Chapter I

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 operates one (1) aero-derivative combustion turbine that entered into service in August 2009 and can be fired with natural gas or distilled oil. 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 Spring 2010.

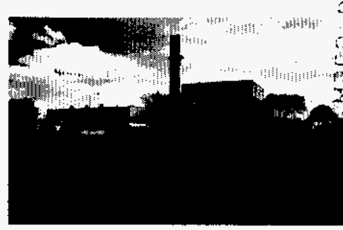
H.L. Culbreath Bayside Power Station

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 operates four (4) aero-derivative combustion turbines that were placed into service in 2009.

Polk Power Station

The station operates five (5) generating units. Polk Unit 1 is an integrated gasification combined cycle 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. The units were placed into long-term reserve standby in September 2009.

Partnership Power Station

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

Schedule 1

Existing Generating Facilities
As of December 31, 2009

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
								Alt	Commercial	Expected	Gen. Max.	Net Capability	
Plant	Unit		Unit	Fuel		Fuel Transport		Fuel	In-Service	Retirement	Nameplate	Summer	Winter
Name	No.	Location	Type	Pri	Alt	Pri	Alt	Days	Mo/Yr	Mo/Yr	KW	MW	MW
Big Bend		Hillsborough											
		Co. 14/31S/19E									1,892,485	1,633	1,663
	1		ST	BIT	N	WA/RR	N	0	10/70	Unknown	445,500	385	395
	2		ST	BIT	N	WA/RR	N	0	4/73	Unknown	445,500	385	395
	3		ST	BIT	N	WA/RR	N	0	5/76	Unknown	445,500	375	385
	4		ST	BIT	N	WA/RR	N	0	2/85	Unknown	486,000	432	427
	CT 4		GT	NG	LO	PL	TK	0	8/09	Unknown	69,985	56	61
Bayside		Hillsborough											
		Co. 4/30S/19E									2,294,100	1,854	2,083
	1		CC	NG	N	PL	N	0	4/03	Unknown	809,060	701	792
	2		CC	NG	N	PL	N	0	1/04	Unknown	1,205,100	929	1,047
	3		GT	NG	N	PL	N	0	7/09	Unknown	69,985	56	61
	4		GT	NG	N	PL	N	0	7/09	Unknown	69,985	56	61
	5		GT	NG	N	PL	N	0	4/09	Unknown	69,985	56	61
	6		GT	NG	N	PL	N	0	4/09	Unknown	69,985	56	61
Phillips		Highland Co.											
		12-055									38,430	36 [1]	36 [1]
	1		IC	HO	LO	TK	N	0	6/83	LTRS 9/09	19,215	18 [1]	18 [1]
	2		IC	HO	LO	TK	N	0	6/83	LTRS 9/09	19,215	18 [1]	18 [1]
Polk		Polk Co.											
		2,3/32S/23E									1,029,379	839	967
	1		IGCC	BIT	LO	WA/TK	TK	0	9/96	Unknown	326,299	235	235
	2		GT	NG	LO	PL	TK	0	7/00	Unknown	175,770 [2]	151	183
	3		GT	NG	LO	PL	TK	0	5/02	Unknown	175,770 [2]	151	183
	4		GT	NG	N	PL	N	0	3/07	Unknown	175,770 [2]	151	183
	5		GT	NG	N	PL	N	0	4/07	Unknown	175,770 [2]	151	183
Partnership		Hillsborough											
		Co. W30/29/19									5,800	6	6
	1		IC	NG	N	PL	N	0	4/01	Unknown	2,900	3	3
	2		IC	NG	N	PL	N	0	4/01	Unknown	2,900	3	3
											TOTAL	4,332	4,719

Notes:

[1] Phillips Units 1 & 2 were placed into long-term reserve standby (LTRS) on September 4, 2009, and net capacities are not included into the system total.

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

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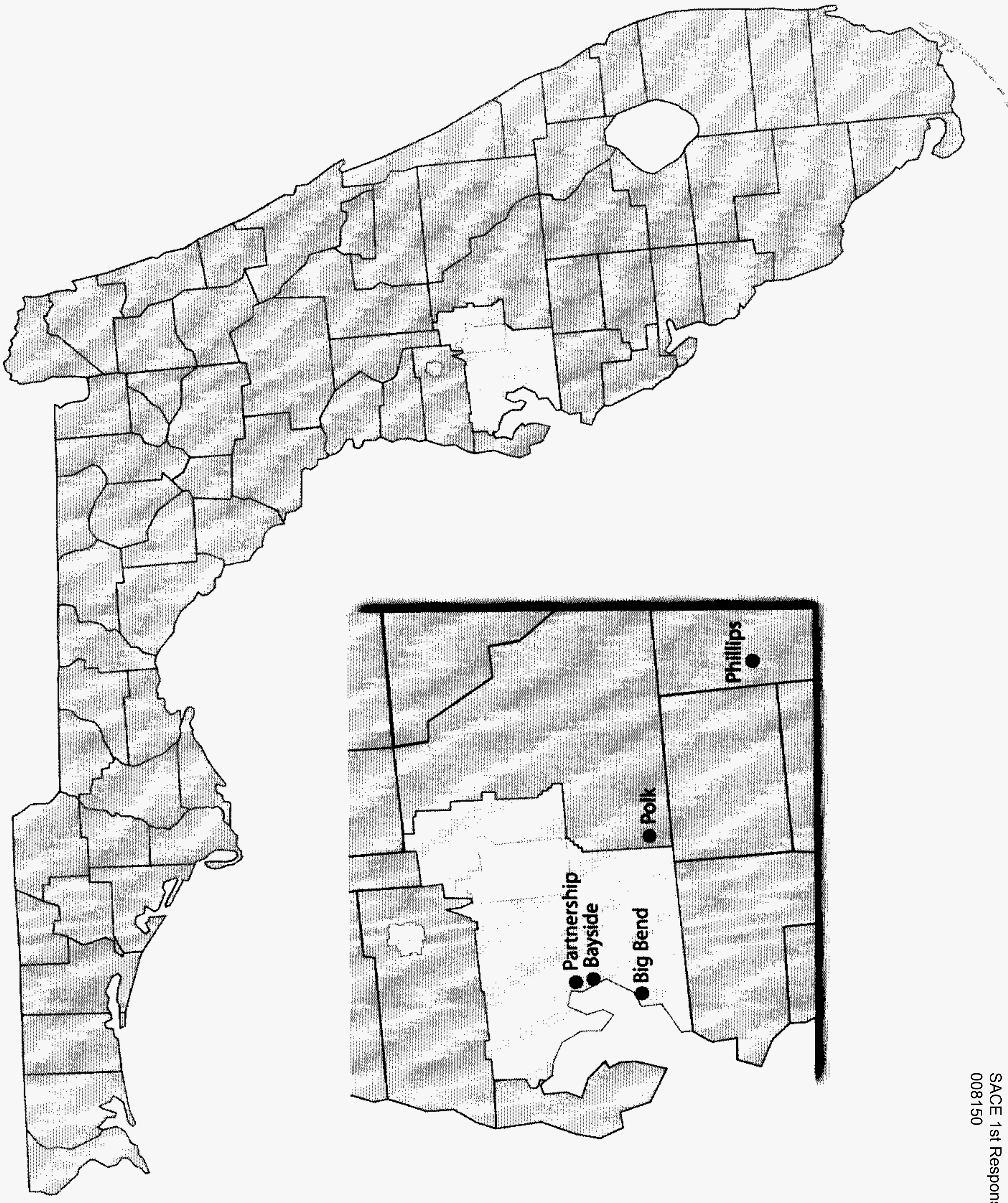
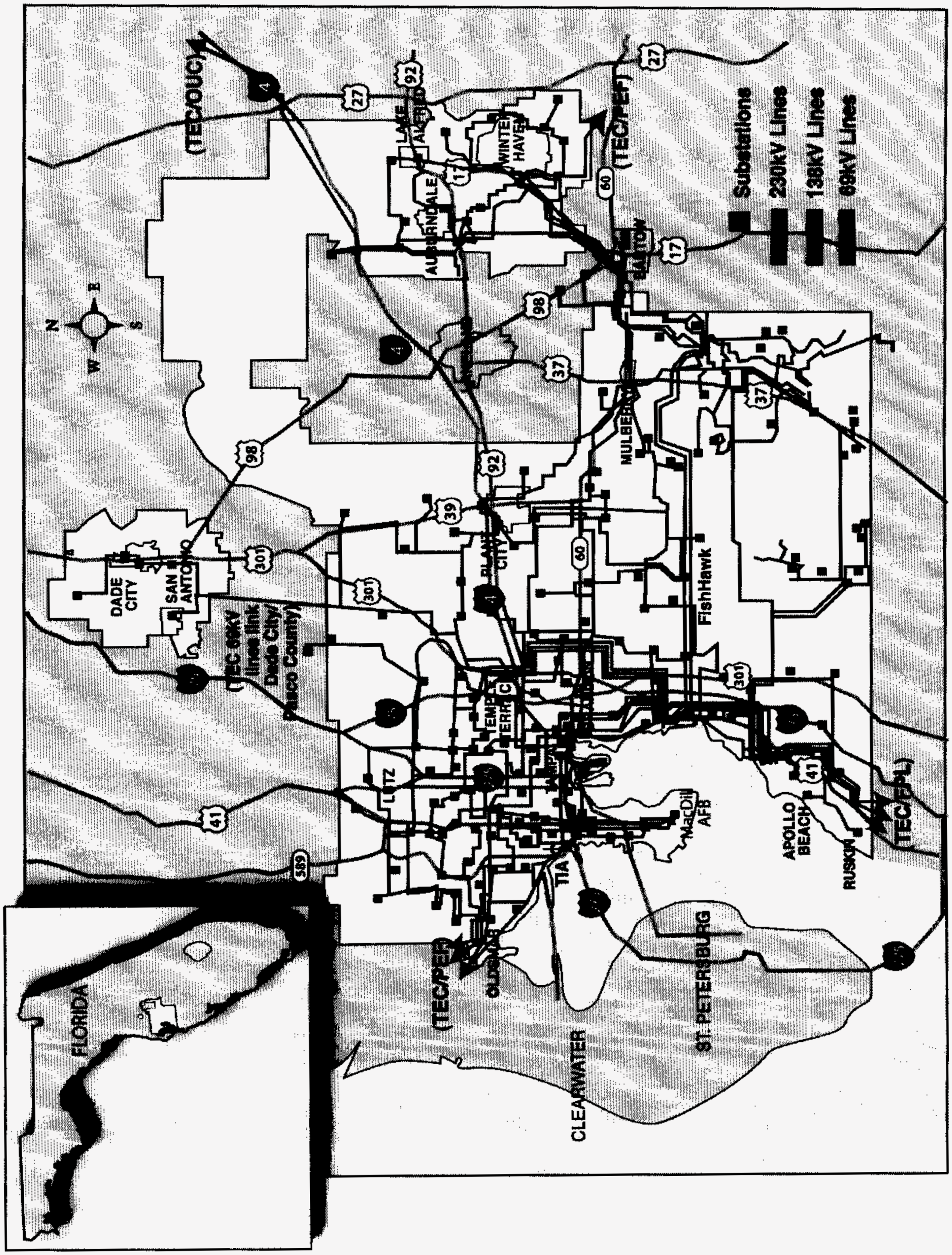
I.1 Tampa Electric Service Area Map



I.2 Tampa Electric Service Area Transmission Facility



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Chapter II

FORECAST OF ELECTRIC POWER, DEMAND, AND ENERGY CONSUMPTION

The Schedules 2 through 4 tables reflect three different levels of load forecasting: base case, high case and low case. The expansion plan is based on the 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)

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

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

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

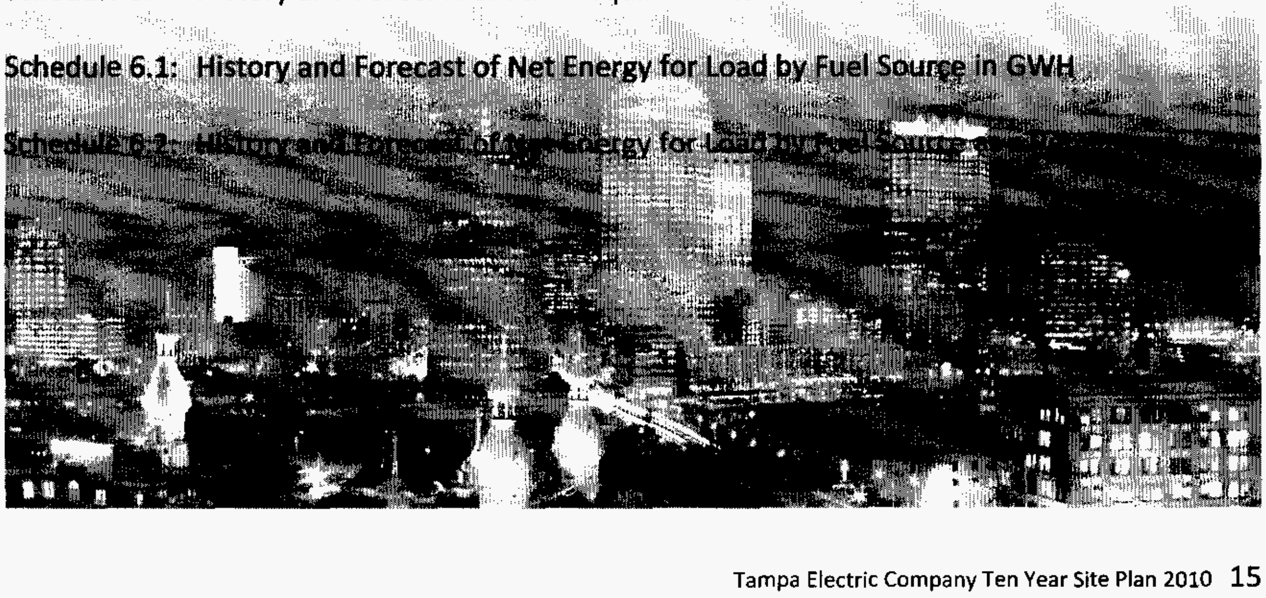
Schedule 3.3: History and Forecast of Annual Net Energy for Load (Base, High & Low)

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

Schedule 5: History and Forecast of Fuel Requirements

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

Schedule 6.2: History and Forecast of Net Energy for Load by Fuel Source [illegible]



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
2000	998,948	2.6	7,369	491,925	14,980	5,541	61,902	89,512
2001	1,027,283	2.6	7,594	505,964	15,009	5,685	63,316	89,788
2002	1,055,617	2.6	8,046	518,554	15,516	5,832	64,665	90,188
2003	1,079,587	2.5	8,265	531,257	15,557	5,843	66,041	88,475
2004	1,108,435	2.5	8,293	544,313	15,236	5,988	67,488	88,727
2005	1,131,546	2.5	8,558	558,601	15,320	6,233	69,027	90,298
2006	1,164,425	2.5	8,721	575,111	15,164	6,357	70,205	90,549
2007	1,192,861	2.5	8,871	586,776	15,119	6,542	70,891	92,276
2008	1,200,541	2.5	8,546	587,602	14,545	6,399	70,770	90,415
2009	1,196,892	2.5	8,666	587,396	14,754	6,274	70,182	89,395
2010	1,207,697	2.5	8,843	591,862	14,941	6,554	71,443	91,736
2011	1,218,526	2.5	9,012	597,638	15,079	6,665	72,823	91,526
2012	1,233,204	2.5	9,170	605,100	15,155	6,763	74,186	91,164
2013	1,250,755	2.5	9,328	613,853	15,195	6,850	75,488	90,745
2014	1,269,087	2.5	9,418	622,923	15,118	6,971	76,770	90,808
2015	1,287,553	2.5	9,487	632,020	15,011	7,115	78,056	91,146
2016	1,306,971	2.5	9,568	641,561	14,913	7,266	79,360	91,559
2017	1,326,743	2.5	9,692	651,262	14,881	7,420	80,675	91,971
2018	1,346,620	2.5	9,828	661,008	14,868	7,578	81,999	92,412
2019	1,366,536	2.5	9,982	670,769	14,882	7,736	83,339	92,822

December 31, 2009 Status

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

Note: Values shown may be affected due to rounding.

Schedule 2.1

History and Forecast of Energy Consumption and Number of Customers by Customer Class High Case (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
2000	998,948	2.6	7,369	491,925	14,980	5,541	61,902	89,512
2001	1,027,283	2.6	7,594	505,964	15,009	5,685	63,316	89,788
2002	1,055,617	2.6	8,046	518,554	15,516	5,832	64,665	90,188
2003	1,079,587	2.5	8,265	531,257	15,557	5,843	66,041	88,475
2004	1,108,435	2.5	8,293	544,313	15,236	5,988	67,488	88,727
2005	1,131,546	2.5	8,558	558,601	15,320	6,233	69,027	90,298
2006	1,164,425	2.5	8,721	575,111	15,164	6,357	70,205	90,549
2007	1,192,861	2.5	8,871	586,776	15,119	6,542	70,891	92,276
2008	1,200,541	2.5	8,546	587,602	14,545	6,399	70,770	90,415
2009	1,196,892	2.5	8,666	587,396	14,754	6,274	70,182	89,395
2010	1,219,769	2.6	8,927	596,330	14,970	6,578	71,729	91,708
2011	1,236,805	2.6	9,153	605,277	15,123	6,707	73,314	91,486
2012	1,257,888	2.6	9,366	615,681	15,213	6,821	74,869	91,112
2013	1,282,080	2.6	9,576	627,217	15,268	6,924	76,353	90,683
2014	1,307,281	2.6	9,718	639,158	15,205	7,061	77,825	90,733
2015	1,332,839	2.6	9,842	651,280	15,112	7,222	79,309	91,057
2016	1,359,604	2.6	9,977	663,878	15,028	7,391	80,814	91,455
2017	1,386,971	2.6	10,158	676,743	15,010	7,563	82,337	91,854
2018	1,414,685	2.6	10,355	689,788	15,012	7,740	83,878	92,280
2019	1,442,681	2.6	10,573	702,992	15,040	7,919	85,443	92,676

December 31, 2009 Status

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

Schedule 2.1

History and Forecast of Energy Consumption and Number of Customers by Customer Class Low Case (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
2000	998,948	2.6	7,369	491,925	14,980	5,541	61,902	89,512
2001	1,027,283	2.6	7,594	505,964	15,009	5,685	63,316	89,788
2002	1,055,617	2.6	8,046	518,554	15,516	5,832	64,665	90,188
2003	1,079,587	2.5	8,265	531,257	15,557	5,843	66,041	88,475
2004	1,108,435	2.5	8,293	544,313	15,236	5,988	67,488	88,727
2005	1,131,546	2.5	8,558	558,601	15,320	6,233	69,027	90,298
2006	1,164,425	2.5	8,721	575,111	15,164	6,357	70,205	90,549
2007	1,192,861	2.5	8,871	586,776	15,119	6,542	70,891	92,276
2008	1,200,541	2.5	8,546	587,602	14,545	6,399	70,770	90,415
2009	1,196,892	2.5	8,666	587,396	14,754	6,274	70,182	89,395
2010	1,195,684	2.5	8,763	587,664	14,911	6,531	71,172	91,764
2011	1,200,427	2.5	8,871	590,016	15,036	6,623	72,334	91,566
2012	1,208,885	2.5	8,970	594,172	15,097	6,703	73,484	91,214
2013	1,220,046	2.4	9,068	599,647	15,123	6,772	74,573	90,805
2014	1,231,827	2.4	9,100	605,423	15,031	6,874	75,643	90,879
2015	1,243,592	2.4	9,113	611,191	14,910	6,998	76,712	91,230
2016	1,256,129	2.4	9,135	617,338	14,798	7,130	77,797	91,655
2017	1,268,852	2.4	9,199	623,574	14,752	7,264	78,887	92,080
2018	1,281,517	2.3	9,273	629,783	14,725	7,401	79,983	92,534
2019	1,294,062	2.3	9,363	635,933	14,723	7,538	81,088	92,956

December 31, 2009 Status

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

Schedule 2.2

History and Forecast of Energy Consumption and Number of Customers by Customer Class Base Case (1 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
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	1,995	1,424	1,401,219	0	68	1,771	18,774
2010	1,939	1,398	1,387,127	0	64	1,775	19,174
2011	1,952	1,428	1,366,776	0	64	1,803	19,497
2012	1,973	1,474	1,338,585	0	65	1,832	19,802
2013	1,992	1,516	1,314,272	0	65	1,856	20,091
2014	2,006	1,539	1,303,186	0	66	1,876	20,337
2015	2,018	1,559	1,294,460	0	66	1,896	20,583
2016	2,031	1,581	1,284,400	0	67	1,919	20,850
2017	2,044	1,606	1,272,981	0	67	1,943	21,166
2018	2,057	1,630	1,261,809	0	68	1,970	21,501
2019	2,070	1,656	1,250,536	0	69	1,996	21,853

December 31, 2009 Status

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

Schedule 2.2

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

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
	Industrial				Street &	Other Sales	Total Sales
Year	GWH	Customers*	Average KWH Consumption Per Customer	Railroads and Railways GWH	Highway Lighting GWH	to Public Authorities GWH	to Ultimate Consumers GWH
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	1,995	1,424	1,401,219	0	68	1,771	18,774
2010	1,941	1,406	1,381,171	0	64	1,786	19,296
2011	1,956	1,442	1,356,435	0	64	1,821	19,702
2012	1,979	1,494	1,324,126	0	65	1,857	20,088
2013	2,000	1,543	1,295,874	0	65	1,889	20,454
2014	2,015	1,574	1,280,819	0	66	1,917	20,778
2015	2,030	1,601	1,268,185	0	66	1,945	21,105
2016	2,045	1,630	1,254,340	0	67	1,976	21,455
2017	2,060	1,662	1,239,263	0	67	2,009	21,858
2018	2,075	1,695	1,224,522	0	68	2,044	22,283
2019	2,091	1,728	1,209,780	0	69	2,081	22,732

December 31, 2009 Status

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

Schedule 2.2

History and Forecast of Energy Consumption and Number of Customers by Customer Class
Low Case (3 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
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	1,995	1,424	1,401,219	0	68	1,771	18,774
2010	1,936	1,389	1,393,408	0	64	1,764	19,058
2011	1,948	1,414	1,377,746	0	64	1,786	19,292
2012	1,967	1,452	1,353,979	0	65	1,807	19,511
2013	1,984	1,488	1,333,891	0	65	1,824	19,713
2014	1,996	1,504	1,327,043	0	66	1,837	19,873
2015	2,007	1,517	1,322,493	0	66	1,849	20,034
2016	2,018	1,533	1,316,500	0	67	1,864	20,214
2017	2,029	1,550	1,309,026	0	67	1,880	20,440
2018	2,040	1,567	1,301,718	0	68	1,898	20,681
2019	2,051	1,585	1,294,223	0	69	1,916	20,937

December 31, 2009 Status

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

Schedule 2.3

History and Forecast of Energy Consumption and Number of Customers by Customer Class Base Case (1 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
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	191	978	19,943	7,748	666,750
2010	516	997	20,688	7,707	672,409
2011	249	1,014	20,759	7,760	679,650
2012	209	1,030	21,041	7,832	688,592
2013	148	1,045	21,284	7,918	698,774
2014	75	1,058	21,470	8,007	709,239
2015	75	1,071	21,729	8,097	719,731
2016	75	1,085	22,011	8,191	730,693
2017	25	1,102	22,293	8,287	741,831
2018	0	1,120	22,621	8,384	753,022
2019	0	1,139	22,992	8,481	764,244

December 31, 2009 Status

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

Schedule 2.3

History and Forecast of Energy Consumption and Number of Customers by Customer Class High Case (2 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
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	191	978	19,943	7,748	666,750
2010	516	1,004	20,816	7,754	677,219
2011	249	1,024	20,976	7,837	687,870
2012	209	1,045	21,341	7,939	699,984
2013	148	1,064	21,666	8,056	713,170
2014	75	1,081	21,934	8,178	726,735
2015	75	1,098	22,279	8,302	740,492
2016	75	1,117	22,647	8,432	754,755
2017	25	1,138	23,021	8,565	769,307
2018	0	1,161	23,444	8,699	784,060
2019	0	1,184	23,916	8,834	798,997

December 31, 2009 Status

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

Schedule 2.3

History and Forecast of Energy Consumption and *Number of Customers by Customer Class* Low Case (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
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	191	978	19,943	7,748	666,750
2010	516	991	20,566	7,661	667,887
2011	249	1,003	20,544	7,685	671,449
2012	209	1,015	20,734	7,727	676,835
2013	148	1,026	20,887	7,782	683,489
2014	75	1,034	20,983	7,839	690,410
2015	75	1,043	21,152	7,897	697,318
2016	75	1,052	21,342	7,959	704,626
2017	25	1,064	21,529	8,021	712,033
2018	0	1,077	21,758	8,083	719,416
2019	0	1,091	22,027	8,145	726,750

December 31, 2009 Status

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

Schedule 3.1

History and Forecast of Summer Peak Demand
Base Case (1 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
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	4,310	136	4,174	120	56	89	51	59	3,799
2010	4,371	176	4,195	144	62	90	66	59	3,774
2011	4,344	105	4,239	144	66	92	67	61	3,809
2012	4,396	105	4,292	144	71	95	67	62	3,853
2013	4,441	89	4,352	145	75	97	68	63	3,904
2014	4,489	77	4,412	145	80	98	69	64	3,956
2015	4,545	77	4,468	146	84	100	69	65	4,004
2016	4,606	77	4,529	146	89	102	70	66	4,057
2017	4,593	0	4,593	146	93	103	70	67	4,113
2018	4,664	0	4,664	147	98	105	71	68	4,176
2019	4,735	0	4,735	147	102	106	71	69	4,239

December 31, 2009 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.
*** 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
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	4,310	136	4,174	120	56	89	51	59	3,799
2010	4,402	176	4,226	144	62	90	66	59	3,805
2011	4,395	105	4,290	144	66	92	67	61	3,860
2012	4,466	105	4,362	144	71	95	67	62	3,923
2013	4,523	89	4,434	145	75	97	68	63	3,986
2014	4,588	77	4,511	145	80	98	69	64	4,054
2015	4,662	77	4,585	146	84	100	69	65	4,121
2016	4,741	77	4,664	146	89	102	70	66	4,192
2017	4,747	0	4,747	146	93	103	70	67	4,267
2018	4,836	0	4,836	147	98	105	71	68	4,349
2019	4,930	0	4,930	147	102	106	71	69	4,434

December 31, 2009 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.

*** 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) 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	
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	4,310	136	4,174	120	56	89	51	59	3,799	
2010	4,347	176	4,171	144	62	90	66	59	3,750	
2011	4,298	105	4,193	144	66	92	67	61	3,763	
2012	4,329	105	4,225	144	71	95	67	62	3,786	
2013	4,360	89	4,271	145	75	97	68	63	3,823	
2014	4,388	77	4,311	145	80	98	69	64	3,855	
2015	4,425	77	4,348	146	84	100	69	65	3,884	
2016	4,467	77	4,390	146	89	102	70	66	3,918	
2017	4,434	0	4,434	146	93	103	70	67	3,954	
2018	4,484	0	4,484	147	98	105	71	68	3,996	
2019	4,533	0	4,533	147	102	106	71	69	4,038	

December 31, 2009 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.
*** 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)	(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
1999/00	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	4,687	67	4,620	181	120	461	52	52	3,754
2009/10	4,855	176	4,679	141	124	465	71	54	3,824
2010/11	4,891	176	4,714	141	129	468	71	55	3,850
2011/12	4,870	105	4,765	142	134	471	72	56	3,891
2012/13	4,912	89	4,822	142	139	474	72	56	3,939
2013/14	4,964	77	4,887	143	144	476	72	57	3,995
2014/15	5,022	77	4,945	143	149	479	73	58	4,044
2015/16	5,083	77	5,006	143	154	481	73	58	4,096
2016/17	5,146	77	5,069	144	160	483	74	58	4,151
2017/18	5,139	0	5,139	145	165	485	74	59	4,212
2018/19	5,212	0	5,212	145	170	487	74	59	4,277

December 31, 2009 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.

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)	(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*
1999/00	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	4,687	67	4,620	181	120	461	52	52	3,754
2009/10	4,878	176	4,702	141	124	465	71	54	3,848
2010/11	4,935	176	4,760	141	129	468	71	55	3,896
2011/12	4,935	105	4,831	142	134	471	72	56	3,957
2012/13	4,992	89	4,902	142	139	474	72	56	4,019
2013/14	5,062	77	4,985	143	144	476	72	57	4,093
2014/15	5,138	77	5,061	143	149	479	73	58	4,160
2015/16	5,217	77	5,140	143	154	481	73	58	4,230
2016/17	5,299	77	5,222	144	160	483	74	58	4,304
2017/18	5,313	0	5,313	145	165	485	74	59	4,386
2018/19	5,406	0	5,406	145	170	487	74	59	4,471

December 31, 2009 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.

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
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	4,687	67	4,620	181	120	461	52	52	3,754
2009/10	4,828	176	4,652	141	124	465	71	54	3,798
2010/11	4,841	176	4,666	141	129	468	71	55	3,802
2011/12	4,798	105	4,694	142	134	471	72	56	3,820
2012/13	4,825	89	4,735	142	139	474	72	56	3,852
2013/14	4,857	77	4,780	143	144	476	72	57	3,888
2014/15	4,896	77	4,819	143	149	479	73	58	3,918
2015/16	4,936	77	4,859	143	154	481	73	58	3,949
2016/17	4,979	77	4,902	144	160	483	74	58	3,984
2017/18	4,951	0	4,951	145	165	485	74	59	4,024
2018/19	5,002	0	5,002	145	170	487	74	59	4,067

December 31, 2009 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.

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 %
2000	17,082	333	112	16,638	763	972	18,373	58.5
2001	17,444	346	122	16,976	684	794	18,454	58.0
2002	18,423	361	137	17,925	502	935	19,362	58.7
2003	18,756	378	152	18,226	587	985	19,798	56.4
2004	18,999	394	168	18,437	589	945	19,971	65.6
2005	19,491	404	176	18,911	712	952	20,576	57.3
2006	19,625	412	188	19,025	700	1,000	20,725	60.6
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	19,449	443	231	18,774	191	978	19,943	54.7
2010	19,855	446	235	19,174	516	997	20,688	54.5
2011	20,192	452	244	19,497	249	1,014	20,759	54.3
2012	20,511	458	251	19,802	209	1,030	21,041	55.2
2013	20,811	463	257	20,091	148	1,045	21,284	55.5
2014	21,067	468	263	20,337	75	1,058	21,470	55.3
2015	21,322	472	267	20,583	75	1,071	21,729	55.3
2016	21,597	476	271	20,850	75	1,085	22,011	55.1
2017	21,921	480	274	21,166	25	1,102	22,293	55.3
2018	22,262	484	277	21,501	0	1,120	22,621	56.2
2019	22,621	488	280	21,853	0	1,139	22,992	56.3

December 31, 2009 Status

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

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

Note: Values shown may be affected due to rounding.

Schedule 3.3

History and Forecast of Annual Net Energy for Load - GWH
High Case (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 %
2000	17,082	333	112	16,638	763	972	18,373	58.5
2001	17,444	346	122	16,976	684	794	18,454	58.0
2002	18,423	361	137	17,925	502	935	19,362	58.7
2003	18,756	378	152	18,226	587	985	19,798	56.4
2004	18,999	394	168	18,437	589	945	19,971	65.6
2005	19,491	404	176	18,911	712	952	20,576	57.3
2006	19,625	412	188	19,025	700	1,000	20,725	60.6
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	19,449	443	231	18,774	191	978	19,943	54.7
2010	19,977	446	235	19,296	516	1,004	20,816	56.8
2011	20,398	452	244	19,702	249	1,024	20,976	56.5
2012	20,797	458	251	20,088	209	1,045	21,341	56.4
2013	21,174	463	257	20,454	148	1,064	21,666	56.6
2014	21,508	468	263	20,778	75	1,081	21,934	56.2
2015	21,844	472	267	21,105	75	1,098	22,279	56.2
2016	22,202	476	271	21,455	75	1,117	22,647	56.0
2017	22,612	480	274	21,858	25	1,138	23,021	56.1
2018	23,045	484	277	22,283	0	1,161	23,444	56.1
2019	23,500	488	280	22,732	0	1,184	23,916	56.2

December 31, 2009 Status

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

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

Note: Values shown may be affected due to rounding.

Schedule 3.3

History and Forecast of Annual Net Energy for Load - GWH
Low Case (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 %
2000	17,082	333	112	16,638	763	972	18,373	58.5
2001	17,444	346	122	16,976	684	794	18,454	58.0
2002	18,423	361	137	17,925	502	935	19,362	58.7
2003	18,756	378	152	18,226	587	985	19,798	56.4
2004	18,999	394	168	18,437	589	945	19,971	65.6
2005	19,491	404	176	18,911	712	952	20,576	57.3
2006	19,625	412	188	19,025	700	1,000	20,725	60.6
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	19,449	443	231	18,774	191	978	19,943	54.7
2010	19,739	446	235	19,058	516	991	20,566	56.8
2011	19,988	452	244	19,292	249	1,003	20,544	56.6
2012	20,220	458	251	19,511	209	1,015	20,734	56.6
2013	20,433	463	257	19,713	148	1,026	20,887	56.7
2014	20,603	468	263	19,873	75	1,034	20,983	56.4
2015	20,773	472	267	20,034	75	1,043	21,152	56.4
2016	20,961	476	271	20,214	75	1,052	21,342	56.2
2017	21,194	480	274	20,440	25	1,064	21,529	56.4
2018	21,442	484	277	20,681	0	1,077	21,758	56.4
2019	21,705	488	280	20,937	0	1,091	22,027	56.4

December 31, 2009 Status

* Includes sales to Progress Energy Florida, Wauchula, Ft. Meade, St. Cloud and Reedy Creek. Contract ended with Ft. Meade on 12/31/08.
** Load Factor is the ratio of total system average load to peak demand.
Note: 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
Base Case (1 of 3)

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	2009 Actual		2010 Forecast		2011 Forecast	
Month	Peak Demand * MW	NEL ** GWH	Peak Demand * MW	NEL ** GWH	Peak Demand * MW	NEL ** GWH
January	4,147	1,567	4,336	1,516	4,367	1,548
February	4,110	1,381	3,618	1,363	3,645	1,387
March	3,191	1,456	3,273	1,498	3,228	1,502
April	3,265	1,487	3,474	1,563	3,432	1,558
May	3,678	1,746	3,886	1,852	3,850	1,863
June	4,151	1,928	4,076	1,947	4,043	1,953
July	3,926	1,955	4,222	2,072	4,191	2,077
August	3,873	1,959	4,199	2,112	4,169	2,116
September	3,736	1,857	4,020	1,936	3,988	1,943
October	3,876	1,786	3,755	1,787	3,721	1,778
November	2,945	1,365	3,198	1,478	3,158	1,484
December	2,904	1,456	3,478	1,564	3,443	1,550
TOTAL		19,943		20,688		20,759

December 31, 2009 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)
	2009 Actual		2010 Forecast		2011 Forecast	
Month	Peak Demand * MW	NEL ** GWH	Peak Demand * MW	NEL ** GWH	Peak Demand * MW	NEL ** GWH
January	4,147	1,567	4,360	1,525	4,413	1,563
February	4,110	1,381	3,681	1,370	3,727	1,400
March	3,191	1,456	3,268	1,506	3,238	1,516
April	3,265	1,487	3,499	1,572	3,474	1,574
May	3,678	1,746	3,915	1,863	3,897	1,882
June	4,151	1,928	4,102	1,959	4,088	1,973
July	3,926	1,955	4,253	2,086	4,242	2,099
August	3,873	1,959	4,229	2,126	4,219	2,139
September	3,736	1,857	4,049	1,949	4,036	1,965
October	3,876	1,786	3,784	1,799	3,768	1,798
November	2,945	1,365	3,216	1,488	3,190	1,500
December	2,904	1,456	3,520	1,574	3,501	1,566
TOTAL		19,943		20,816		20,976

December 31, 2009 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)
	2009 Actual		2010 Forecast		2011 Forecast	
Month	Peak Demand * MW	NEL ** GWH	Peak Demand * MW	NEL ** GWH	Peak Demand * MW	NEL ** GWH
January	4,147	1,567	4,310	1,508	4,319	1,532
February	4,110	1,381	3,638	1,355	3,647	1,373
March	3,191	1,456	3,228	1,489	3,167	1,487
April	3,265	1,487	3,456	1,554	3,397	1,543
May	3,678	1,746	3,866	1,841	3,810	1,844
June	4,151	1,928	4,049	1,935	3,995	1,932
July	3,926	1,955	4,198	2,060	4,145	2,055
August	3,873	1,959	4,173	2,099	4,121	2,094
September	3,736	1,857	3,994	1,924	3,942	1,922
October	3,876	1,786	3,733	1,776	3,680	1,760
November	2,945	1,365	3,171	1,469	3,116	1,469
December	2,904	1,456	3,471	1,554	3,419	1,534
TOTAL		19,943		20,567		20,544

December 31, 2009 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	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
(1)	Nuclear		Trillion BTU	0	0	0	0	0	0	0	0	0	0	0	0
(2)	Coal		1000 Ton	4,233	3,818	4,450	4,667	4,800	4,967	5,132	5,160	5,157	5,114	5,153	5,140
(3)	Residual	Total	1000 BBL	32	40	0	0	0	0	0	0	0	0	0	0
(4)		Steam	1000 BBL	0	0	0	0	0	0	0	0	0	0	0	0
(5)		CC	1000 BBL	0	0	0	0	0	0	0	0	0	0	0	0
(6)		CT	1000 BBL	0	0	0	0	0	0	0	0	0	0	0	0
(7)		Diesel (A)	1000 BBL	32	40	0	0	0	0	0	0	0	0	0	0
(8)	Distillate	Total	1000 BBL	58	61	83	84	86	88	85	83	87	86	84	86
(9)		Steam	1000 BBL	0	0	0	0	0	0	0	0	0	0	0	0
(10)		CC	1000 BBL	55	47	81	81	82	84	84	82	85	84	82	86
(11)		CT	1000 BBL	3	14	2	3	4	4	1	1	2	2	2	0
(12)		Diesel	1000 BBL	0	0	0	0	0	0	0	0	0	0	0	0
(13)	Natural Gas	Total	1000 MCF	54,383	62,686	64,187	59,342	58,442	58,782	56,878	58,146	59,953	61,872	63,414	62,626
(14)		Steam	1000 MCF	0	0	0	0	0	0	0	0	0	0	0	0
(15)		CC	1000 MCF	52,363	59,134	60,766	55,379	55,266	53,760	53,063	53,710	54,508	55,442	57,637	61,726
(16)		CT	1000 MCF	2,020	3,552	3,421	3,963	3,176	5,022	3,815	4,436	5,445	6,430	5,777	900
(17)	Other (Specify)														
(18)	Petroleum Coke		1000 Ton	388	420	436	445	454	465	464	449	465	466	449	475

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

Schedule 6.1

History and Forecast of Net Energy for Load by Fuel Source in GWH
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	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
(1)	Annual Firm Interchange		GWh	1,375	704	385	425	354	143	139	134	151	184	158	0
(2)	Nuclear		GWh	0	0	0	0	0	0	0	0	0	0	0	0
(3)	Coal		GWh	9,105	8,442	9,555	10,017	10,322	10,693	11,003	11,071	11,068	10,993	11,050	11,057
(4)	Residual	Total	GWh	18	24	0	0	0	0	0	0	0	0	0	0
(5)		Steam	GWh	0	0	0	0	0	0	0	0	0	0	0	0
(6)		CC	GWh	0	0	0	0	0	0	0	0	0	0	0	0
(7)		CT	GWh	0	0	0	0	0	0	0	0	0	0	0	0
(8)		Diesel (A)	GWh	18	24	0	0	0	0	0	0	0	0	0	0
(9)	Distillate	Total	GWh	33	35	45	46	47	48	47	46	47	47	46	47
(10)		Steam	GWh	0	0	0	0	0	0	0	0	0	0	0	0
(11)		CC	GWh	32	28	44	44	45	46	46	45	46	46	45	47
(12)		CT	GWh	1	6	1	2	2	2	1	1	1	1	1	0
(13)		Diesel	GWh	0	0	0	0	0	0	0	0	0	0	0	0
(14)	Natural Gas	Total	GWh	7,536	8,659	8,761	8,047	7,961	7,911	7,702	7,851	8,055	8,280	8,525	8,869
(15)		Steam	GWh	0	0	0	0	0	0	0	0	0	0	0	0
(16)		CC	GWh	7,366	8,268	8,460	7,699	7,684	7,472	7,369	7,462	7,576	7,711	8,015	8,790
(17)		CT	GWh	170	391	301	348	277	439	333	389	479	569	510	79
(18)	Other (Specify)														
(19)	Petroleum Coke Generation		GWh	1,088	1,177	1,153	1,176	1,201	1,230	1,229	1,189	1,231	1,234	1,189	1,258
(20)	Net Interchange		GWh	824	227	300	207	208	221	221	221	221	221	221	228
(21)	Purchased Energy from														
(22)	Non-Utility Generators	(B)	GWh	676	675	366	627	641	640	641	642	571	570	570	570
(23)	Net Energy for Load		GWh	20,655	19,943	20,565	20,545	20,734	20,887	20,982	21,155	21,344	21,529	21,759	22,028

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

Schedule 6.2

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

(1)	(2)	(3)		(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
	Energy Sources			Unit	Actual 2008	Actual 2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
(1)	Annual Firm Interchange			%	6.7	3.5	1.9	2.1	1.7	0.7	0.7	0.6	0.7	0.9	0.7	0.0
(2)	Nuclear			%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(3)	Coal			%	44.1	42.3	46.5	48.8	49.8	51.2	52.4	52.3	51.9	51.1	50.8	50.2
(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	0.1	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		%	36.5	43.4	42.6	39.2	38.4	37.9	36.7	37.1	37.7	38.5	39.2	40.3
(15)		Steam		%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(16)		CC		%	35.7	41.5	41.1	37.5	37.1	35.8	35.1	35.3	35.5	35.8	36.8	39.9
(17)		CT		%	0.8	2.0	1.5	1.7	1.3	2.1	1.6	1.8	2.2	2.6	2.3	0.4
(18)	Other (Specify)															
(19)	Petroleum Coke Generation			%	5.3	5.9	5.6	5.7	5.8	5.9	5.9	5.6	5.8	5.7	5.5	5.7
(20)	Net Interchange			%	4.0	1.1	1.5	1.0	1.0	1.1	1.1	1.0	1.0	1.0	1.0	1.0
(21)	Purchased Energy from															
(22)	Non-Utility Generators		(B)	%	3.3	3.4	1.8	3.0	3.1	3.1	3.1	3.0	2.7	2.6	2.6	2.6
(23)	Net Energy for Load			%	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0

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

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Chapter III

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 2010-2019 forecasts. The data tables in Chapter II outline the expected customer, demand, and energy values for the 2010-2019 time period.

RETAIL LOAD

MetrixND, an advanced statistics program for analysis and forecasting, was used to develop the 2010-2019 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; and
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 Hillsborough County population estimates, service area households and Hillsborough County employment growth.

1. *Residential Customer Model:* Customer projections are a function of Hillsborough County's population. Since a strong correlation exists between historical changes in service area customers and historical changes in Hillsborough County, the County's population estimates for 2010-2019 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 General Service Large Demand Customer Model is based on the recent growth trend in the sector.

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

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

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

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

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.

$$\textbf{HeatUse}_{\mathbf{y,m}} =$$

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

$$\textbf{CoolUse}_{\mathbf{y,m}} =$$

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

$$\textbf{OtherUse}_{\mathbf{y,m}} =$$

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

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

b. Temporary Service Energy Model: 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 includes 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 recent trends in consumption in the sector.

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

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

The 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; and
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 2009 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%
2009	26.0	18.5	140.5%	20.4	12.7	160.6%	48.8	33.3	146.5%

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%
2009	55.9	16.0	349.4%	64.3	20.2	318.3%	70.7	29.3	241.3%

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%
2009	81.9	34.5	237.4%	84.7	32.9	257.4%	119.5	62.6	190.9%

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

Florida and Hillsborough County population forecasts are the starting point for developing the customer and energy projections. Both the University of Florida's Bureau of Economic and Business Research (BEBR) and Economy.com supply population projections for Hillsborough County and Florida. The population forecast is based upon 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 (2010-2019) the average annual population growth rate in Hillsborough County is expected to be 0.9%. 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 2.1% 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 2010-2019, real household income for Hillsborough County is expected to increase at a 1.9% 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 2010-2019, retail energy sales are projected to rise at a 1.0% annual rate. The major contributor to growth is the residential category, increasing at an annual rate of 0.7%.

2. WHOLESALE ENERGY

Wholesale energy sales to Progress Energy Florida, Wauchula, St. Cloud, and Reedy Creek are expected to be 516 GWH in 2010. In 2013, sales drop substantially to 148 GWH, decrease to 75 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 2010-2019 period, Tampa Electric's base retail firm peak demand is expected to advance in the winter and the summer at an average annual rate of 0.8%.

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Chapter IV

FORECAST OF FACILITIES REQUIREMENTS

The proposed generating facility additions and changes shown in Schedule 8.1 integrate energy efficiency and conservation programs and generating resources to provide economical, reliable service to Tampa Electric's customers. Various energy resource plan alternatives, comprised of a mixture of generating technologies, purchased power, and cost-effective energy efficiency and conservation programs, are developed to determine this plan. These alternatives are combined with existing supply resources and analyzed to determine the energy resource option which best meets Tampa Electric's future system demand and energy requirements. A detailed discussion of Tampa Electric's integrated resource planning process is included in Chapter V.

The results of the integrated resource planning process provide Tampa Electric with a 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 intermediate resources are needed. The peaking capacity need will be met by building combustion turbine additions in 2013 through 2016. The intermediate load capacity will be met by converting Polk Power Station's simple cycle combustion turbines (Polk Units 2 through 5) to a natural gas combined cycle (NGCC) unit in 2019 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.

AERO-DERIVATIVE CT TECHNOLOGY

Tampa Electric installed five (5) aero-derivative combustion turbine assets (Aero CTs) in 2009, totaling approximately 280 MW of net summer capacity. These units 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 86 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.

Economic Benefits

The Aero CTs also offer a more economic option in meeting TEC load requirements when additional generation is needed in small increments or for short run times. The Aero CTs can also provide fuel savings by displacing generation from less efficient units.

COGENERATION

Tampa Electric plans for 480 MW of cogeneration capacity operating in its service area in 2010. Self-service capacity of 246 MW is used by cogenerators to serve internal load requirements, 65 MW are purchased by Tampa Electric on a firm contract basis, and 22 MW are purchased on a non-firm, as-available basis. The remaining 153 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 Big Bend Aero, Bayside, and Polk Units. As shown in Schedule 6.2, in 2010 coal and petcoke will fuel 52% of net energy for load and natural gas will fuel 43%. Less than one (1) percent of net energy for load will be fueled by oil. The remaining net energy for load is served by non-utility generators and net interchange purchases.

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 (SO2) by 94%, nitrogen oxides (NOx) by 85%, particulate matter (PM) by 82% and mercury emissions by 76%.

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 90% 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 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. Big Bend Unit 2 SCR was placed in service on June 1, 2009. Big Bend Unit 1 SCR will be installed this year (2010).

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.

INTERCHANGE SALES AND PURCHASES

Tampa Electric's long-term firm sale agreements include Progress Energy Florida for 71 MW, Reedy Creek Improvement District for 77 MW, the City of St. Cloud for 15 MW, and the City of Wauchula for approximately 12 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 has long-term firm purchase power agreements from three other resources. Tampa Electric has an agreement with Calpine Energy Services to purchase 170 MW from May 1, 2006 through April 30, 2011. Tampa Electric also has an agreement with Reliant Energy Service to purchase 158 MW from January 1, 2008 to May 31, 2012. Lastly, 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
2010	4,307	805	0	42	5,154	3,925	1,229	31%	0	1,229	31%
2011	4,317	635	0	42	4,994	3,867	1,127	29%	0	1,127	29%
2012	4,317	477	0	23	4,817	3,890	927	24%	0	927	24%
2013	4,551	121	0	23	4,695	3,912	783	20%	0	783	20%
2014	4,607	121	0	23	4,751	3,932	819	21%	0	819	21%
2015	4,607	121	0	23	4,751	3,960	791	20%	0	791	20%
2016	4,663	121	0	0	4,784	3,994	790	20%	0	790	20%
2017	4,663	121	0	0	4,784	3,954	830	21%	0	830	21%
2018	4,663	121	0	0	4,784	3,996	788	20%	0	788	20%
2019	5,029	0	0	0	5,029	4,038	991	25%	0	991	25%

NOTE:

1. Capacity import includes firm purchase power agreements (PPA) with Invenergy of 356 MW through 2012, Calpine of 170 MW through April 2011, Reliant of 158 MW through May 2012, and Pasco Cogen of 121 MW 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
2009-10	4,684	890	0	65	5,639	3,973	1,666	42%	395	1,271	32%
2010-11	4,719	890	0	42	5,651	3,976	1,675	42%	0	1,675	42%
2011-12	4,719	720	0	23	5,462	3,924	1,538	39%	0	1,538	39%
2012-13	4,729	121	0	23	4,873	3,940	933	24%	0	933	24%
2013-14	4,973	121	0	23	5,117	3,964	1,153	29%	0	1,153	29%
2014-15	5,034	121	0	23	5,178	3,994	1,184	30%	0	1,184	30%
2015-16	5,034	121	0	0	5,155	4,025	1,130	28%	0	1,130	28%
2016-17	5,095	121	0	0	5,216	4,060	1,156	28%	0	1,156	28%
2017-18	5,095	121	0	0	5,216	4,024	1,192	30%	0	1,192	30%
2018-19	5,095	0	0	0	5,095	4,067	1,029	25%	0	1,029	25%

NOTE:

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

Schedule 8.1

Planned and Prospective Generating Facility Additions

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
				Fuel		Fuel Trans.		Const.	Commercial	Expected	Gen. Max.	Net Capability		
Plant Name	Unit No.	Location	Unit Type	Primary	Alternate	Primary	Alternate	Start Mo/Yr	In-Service Mo/Yr	Retirement Mo/Yr	Nameplate kW	Summer MW	Winter MW	Status
Future CT	1	unknown	GT	NG	N/A	PL	N/A	9/12	5/13	unknown	unknown	56	61	P
Future CT	2	unknown	GT	NG	N/A	PL	N/A	9/12	5/13	unknown	unknown	56	61	P
Future CT	3	unknown	GT	NG	N/A	PL	N/A	9/12	5/13	unknown	unknown	56	61	P
Future CT	4	unknown	GT	NG	N/A	PL	N/A	9/12	5/13	unknown	unknown	56	61	P
Future CT	5	unknown	GT	NG	N/A	PL	N/A	9/13	5/14	unknown	unknown	56	61	P
Future CT	6	unknown	GT	NG	N/A	PL	N/A	9/15	5/16	unknown	unknown	56	61	P
Polk 2 - 5 CC Conversion	1	Polk	CC	NG	N/A	PL	N/A	1/15	5/19	unknown	unknown	970	1063	P

Notes:
Net capability values shown for the Polk 2 - 5 CC Conversion reflect the conversion of Polk Units 2- 5 CTs to a natural gas CC unit in 2019 .

Schedule 8.2

Existing Generating Facility Changes

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
								Const.	Commercial	Expected	Gen. Max.	Net Capability Change		
Plant	Unit		Unit	Fuel		Fuel Trans.		Start	In-Service	Retirement	Nameplate	Summer	Winter	
Name	No.	Location	Type	Primary	Alternate	Primary	Alternate	Mo/Yr	Mo/Yr	Mo/Yr	kW	MW	MW	Status
2010														
Big Bend	1	Hillsborough	FS	BIT	N	WA/RR	N	unknown	10/70	unknown	445,500	0	0	OT
Big Bend	2	Hillsborough	FS	BIT	N	WA/RR	N	unknown	04/73	unknown	445,500	0	0	OT
Big Bend	3	Hillsborough	FS	BIT	N	WA/RR	N	unknown	05/76	unknown	445,500	(10)	(20)	OT
Big Bend	4	Hillsborough	FS	BIT	N	WA/RR	N	unknown	02/85	unknown	486,000	0	0	OT
Polk	1	Polk Co.	IGCC	BIT	DFO	WA/TK	TK	unknown	09/96	unknown	326,299	(15)	(15)	OT
											2010 Changes Total:	(25)	(35)	
2011														
Big Bend	1	Hillsborough	FS	BIT	N	WA/RR	N	unknown	10/70	unknown	445,500	0	0	OT
Big Bend	2	Hillsborough	FS	BIT	N	WA/RR	N	unknown	04/73	unknown	445,500	0	0	OT
Big Bend	3	Hillsborough	FS	BIT	N	WA/RR	N	unknown	05/76	unknown	445,500	10	20	OT
Big Bend	4	Hillsborough	FS	BIT	N	WA/RR	N	unknown	02/85	unknown	486,000	0	15	OT
Polk	1	Polk Co.	IGCC	BIT	DFO	WA/TK	TK	unknown	09/96	unknown	326,299	0	0	OT
											2011 Changes Total:	10	35	
2012														
Big Bend	1	Hillsborough	FS	BIT	N	WA/RR	N	unknown	10/70	unknown	445,500	0	0	OT
Big Bend	2	Hillsborough	FS	BIT	N	WA/RR	N	unknown	04/73	unknown	445,500	0	0	OT
Big Bend	3	Hillsborough	FS	BIT	N	WA/RR	N	unknown	05/76	unknown	445,500	0	0	OT
Big Bend	4	Hillsborough	FS	BIT	N	WA/RR	N	unknown	02/85	unknown	486,000	0	0	OT
Polk	1	Polk Co.	IGCC	BIT	DFO	WA/TK	TK	unknown	09/96	unknown	326,299	0	0	OT
											2012 Changes Total:	0	0	
2013														
Big Bend	1	Hillsborough	FS	BIT	N	WA/RR	N	unknown	10/70	unknown	445,500	0	0	OT
Big Bend	2	Hillsborough	FS	BIT	N	WA/RR	N	unknown	04/73	unknown	445,500	0	0	OT
Big Bend	3	Hillsborough	FS	BIT	N	WA/RR	N	unknown	05/76	unknown	445,500	10	10	OT
Big Bend	4	Hillsborough	FS	BIT	N	WA/RR	N	unknown	02/85	unknown	486,000	0	0	OT
Polk	1	Polk Co.	IGCC	BIT	DFO	WA/TK	TK	unknown	09/96	unknown	326,299	0	0	OT
											2013 Changes Total:	10	10	
2014														
Big Bend	1	Hillsborough	FS	BIT	N	WA/RR	N	unknown	10/70	unknown	445,500	0	0	OT
Big Bend	2	Hillsborough	FS	BIT	N	WA/RR	N	unknown	04/73	unknown	445,500	0	0	OT
Big Bend	3	Hillsborough	FS	BIT	N	WA/RR	N	unknown	05/76	unknown	445,500	0	0	OT
Big Bend	4	Hillsborough	FS	BIT	N	WA/RR	N	unknown	02/85	unknown	486,000	0	0	OT
Polk	1	Polk Co.	IGCC	BIT	DFO	WA/TK	TK	unknown	09/96	unknown	326,299	0	0	OT
											2014 Changes Total:	0	0	

SCHEDULE 9

(Page 1 of 4)

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

(1)	PLANT NAME AND UNIT NUMBER	FUTURE CT 1, 2, 3, & 4
(2)	CAPACITY	
	A. SUMMER	56
	B. WINTER	61
(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)	1.0
	EQUIVALENT AVAILABILITY FACTOR (EAF)	95.4
	RESULTING CAPACITY FACTOR (2013)	1.3%
	AVERAGE NET OPERATING HEAT RATE (ANOHR) [1]	11,496 Btu/kWh
(13)	PROJECTED UNIT FINANCIAL DATA	
	BOOK LIFE (YEARS)	25
	TOTAL INSTALLED COST (IN-SERVICE YEAR $/kW)	727.54
	DIRECT CONSTRUCTION COST ($/kW)	653.55
	AFUDC AMOUNT ($/kW)	53.26
	ESCALATION ($/kW)	20.73
	FIXED O&M ($/kW – Yr)	21.40
	VARIABLE O&M ($/MWH)	3.99
	K FACTOR	1.5975

[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 5
(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)	0.3%
	AVERAGE NET OPERATING HEAT RATE (ANOHR) [1]	11,500 Btu/kWh
(13)	PROJECTED UNIT FINANCIAL DATA	
	BOOK LIFE (YEARS)	25
	TOTAL INSTALLED COST (IN-SERVICE YEAR $/kW)	742.80
	DIRECT CONSTRUCTION COST ($/kW)	653.55
	AFUDC AMOUNT ($/kW)	54.38
	ESCALATION ($/kW)	34.88
	FIXED O&M ($/kW – Yr)	22.13
	VARIABLE O&M ($/MWH)	4.12
	K FACTOR	1.5975

[1] BASED ON IN-SERVICE YEAR.

SCHEDULE 9

(Page 3 of 4)

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

(1)	PLANT NAME AND UNIT NUMBER	FUTURE CT 6
(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)	0.4%
	AVERAGE NET OPERATING HEAT RATE (ANOHR) [1]	11,495 Btu/kWh
(13)	PROJECTED UNIT FINANCIAL DATA	
	BOOK LIFE (YEARS)	25
	TOTAL INSTALLED COST (IN-SERVICE YEAR $/kW)	774.34
	DIRECT CONSTRUCTION COST ($/kW)	653.55
	AFUDC AMOUNT ($/kW)	56.69
	ESCALATION ($/kW)	64.11
	FIXED O&M ($/kW – Yr)	22.51
	VARIABLE O&M ($/MWH)	4.19
	K FACTOR	1.5975

[1] BASED ON IN-SERVICE YEAR.

SCHEDULE 9

(Page 4 of 4)

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

(1)	PLANT NAME AND UNIT NUMBER	POLK 2-5 CC CONVERSION
(2)	CAPACITY	
	A. SUMMER	970
	B. WINTER	1063
(3)	TECHNOLOGY TYPE	COMBINED CYCLE
(4)	ANTICIPATED CONSTRUCTION TIMING	
	A. *FIELD CONSTRUCTION START DATE*	JAN 2016
	B. COMMERCIAL IN-SERVICE DATE	MAY 2019
(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)	93.1
	RESULTING CAPACITY FACTOR (2019)	43.8%
	AVERAGE NET OPERATING HEAT RATE (ANOHR) [1]	6,989 Btu/kWh
(13)	PROJECTED UNIT FINANCIAL DATA	
	BOOK LIFE (YEARS)	25
	TOTAL INSTALLED COST (IN-SERVICE YEAR $/kW)	706.74
	DIRECT CONSTRUCTION COST ($/kW)	539.31
	AFUDC AMOUNT ($/kW)	85.49
	ESCALATION ($/kW)	81.94
	FIXED O&M ($/kW – Yr)	8.80
	VARIABLE O&M ($/MWH)	3.36
	K FACTOR	1.6445

[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
Future CT 1, 2, and 3	Big Bend	1	No new ROW required	0.1 mi	230kV	Spring 2013	$1 million	No new substations	None
Future CT 4	Big Bend	2	No new ROW required	0.7 mi	230kV	Spring 2013	$4 million	No new substations	None
Future CT 5	Bayside	1	No new ROW required	0.7 mi	230kV	Spring 2014	$1 million	No new substations	None
Future CT 6	Bayside	1	No new ROW required	0.7 mi	230kV	Spring 2016	$1 million	No new substations	None
Polk 2 - 5 CC Conversion	Polk to Pebbledale - 1	1	No new ROW required	13.5 mi	230kV	Spring 2019	$6 million	No new substations	None
Polk 2 - 5 CC Conversion	Polk to Pebbledale - 2	1	No new ROW required	9.9 mi	230kV	Spring 2019	$10 million	No new substations	None
Polk 2 - 5 CC Conversion	Polk to Fishhawk	1	No new ROW required	30.5mi	230kV	Spring 2019	$80 million	No new substations	None
Polk 2 - 5 CC Conversion	Polk	1	No new ROW required	0.3 mi	230kV	Spring 2019	$4 million	No new substations	None
Polk 2 - 5 CC Conversion	Pebbledale to Willow Oak to Wheeler Road	1	ROW issues under-review	25.9 mi	230kV	Spring 2019	$75 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 2009 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. 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, Wood Mackenzie, 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 of STRATEGIST and the PLANNING & RISK (PAR) production cost model. PAR, a computer model developed by Ventyx, replaced PROMOD as Tampa Electric's production cost model in 2009. The capital expenditures associated with each capacity addition are obtained based on the type of generating unit, fuel type, capital spending curve, and in-service year. The fixed charges resulting from the capital expenditures are expressed in present worth dollars for comparison. The fuel and the operating and maintenance costs associated with each scenario are projected based on economic dispatch of all the energy resources on our system. The projected operating expense, expressed in present worth dollars, is combined with the fixed charges to obtain the total present worth of revenue requirements for each alternative plan.

STRATEGIC CONCERNS

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

The results of the Integrated Resource Planning process provide Tampa Electric with a plan that is cost-effective while maintaining flexibility and adaptability to a dynamic regulatory and competitive environment. The new capacity additions are shown in Schedule 8.1. To meet the expected system demand and energy requirements over the next ten years and cost-effectively maintain system reliability, Tampa Electric is planning the addition of combustion turbines and a conversion of Polk Units 2-5 to a natural gas 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 minimum 20% reserve margin criteria with a minimum contribution of 7% supply side resources. Tampa Electric's approach to calculating percent reserves are consistent with that outlined in the settlement agreement. The calculation of the minimum 20% reserve margin employs an industry accepted method of using total available generating and firm purchased power capacity (capacity less planned maintenance and contracted unit sales) and subtracting the annual firm peak load, then dividing by the firm peak load, and multiplying by 100%. Since the reserve margin calculation assumes no forced outages, Tampa Electric includes the purchased power contract with Invenergy for the Hardee Power Station in its available capacity. Contractually, Hardee Power Station is planned to be available to Tampa Electric at the time of system peak. Also, the capacity dedicated to any firm unit or station power sales at the time of system peak is subtracted from Tampa Electric's available capacity.

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

TRANSMISSION

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

TEC follows Florida Reliability Coordinating Council (FRCC) planning criteria as contained in the FRCC Regional Transmission Planning Process document. The FRCC planning guide is based on the North American Electric Reliability Council (NERC) Planning Reliability Standards, which are used to measure system adequacy. In general the NERC standards state that the transmission system will remain stable, within the applicable thermal and voltage rating limits, without cascading outages, under normal, single and multiple contingency conditions.

In addition to FRCC criteria, Tampa Electric utilizes specific criteria for normal system operation and single contingency operation 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)	120%
Single Contingency (post-switching)	100%
Bus Outages (pre-switching)	120%
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 adheres to the FRCC ATC calculation methodology described in the *FRCC ATC Calculation and Coordination Procedures* document, as well as the principles contained in the NERC Reliability Standards relating to ATC calculations.

TRANSMISSION PLANNING ASSESSMENT PRACTICES

BASE CASE OPERATING CONDITIONS

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

SINGLE CONTINGENCY PLANNING CRITERIA

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

MULTIPLE CONTINGENCY PLANNING CRITERIA

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

TRANSMISSION CONSTRUCTION AND UPGRADE PLANS

A 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 our 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;

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, Commercial Load Management, and Commercial Demand Response, the reductions are verified through metering of loads under control to determine the demand and energy savings.

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

TAMPA ELECTRIC'S RENEWABLE ENERGY PROGRAMS

Tampa Electric offered a pilot Renewable Energy Program for several years. Due to 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 2009, Tampa Electric's Renewable Energy Program has over 2,700 customers purchasing over 3,800 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 five company owned photovoltaic (PV) arrays totaling 54.5 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. The fifth system was recently installed at Tampa's Lowry Park Zoo to further educate the public on the benefits of renewable energy. An additional 10 kW PV array will be installed at the Florida Aquarium by the end of the first quarter, 2010. As with the systems at Lowery Park Zoo and MOSI, an interactive display will be built at the Aquarium to provide a hands on experience to engage visitors' interest in solar technology. 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 2009, participating customers have utilized over 30 GWH of renewable energy since the program inception.

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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), the Polk Power Station site is located in southwest Polk County close to the Hillsborough and Hardee County lines (See Figure VI-2) and the Big Bend Power Station site 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.

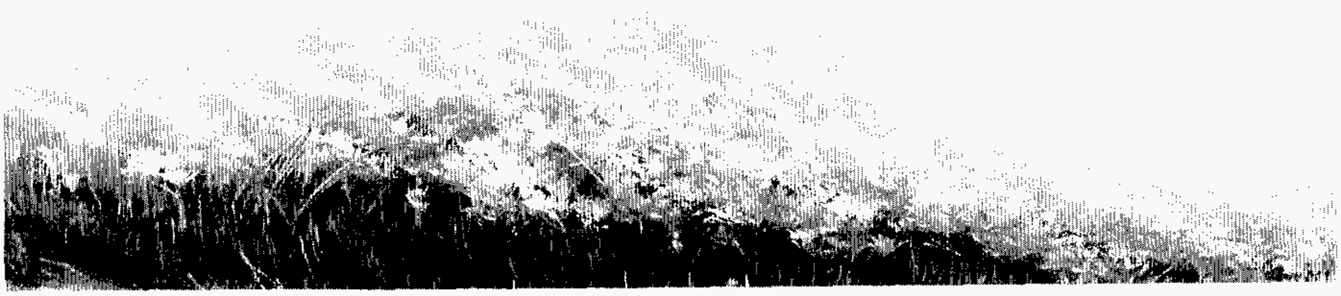


Figure VI-1

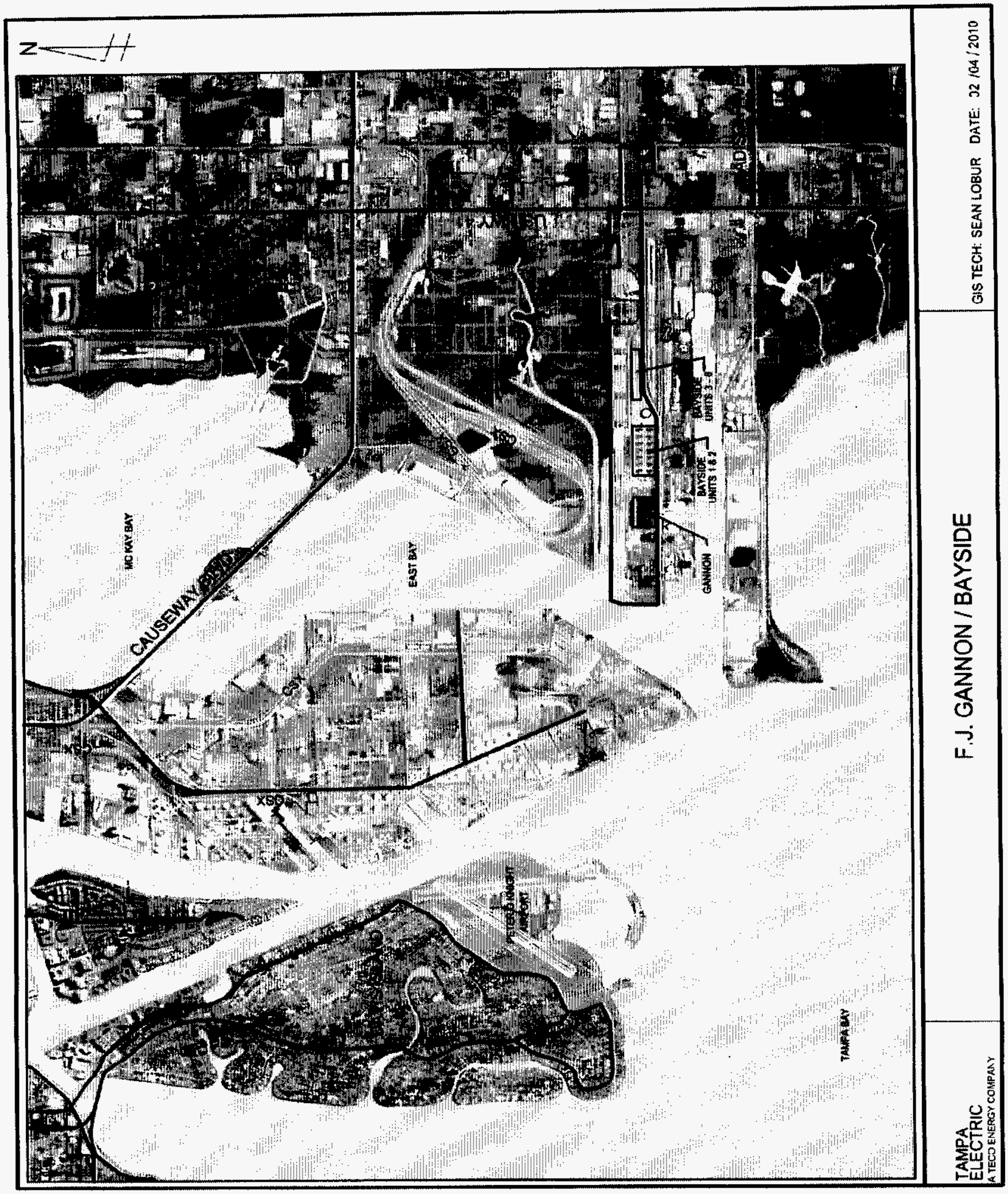

F.J. GANNON / BAYSIDE
GIS TECH: SEAN LOBUR
TAMPA ELECTRIC
A TECO ENERGY COMPANY
CAUSEWAY BLVD
MC KAY BAY
EAST BAY
TAMPA BAY
GANNON
BAYSIDE UNITS 1 & 2

Figure VI-2

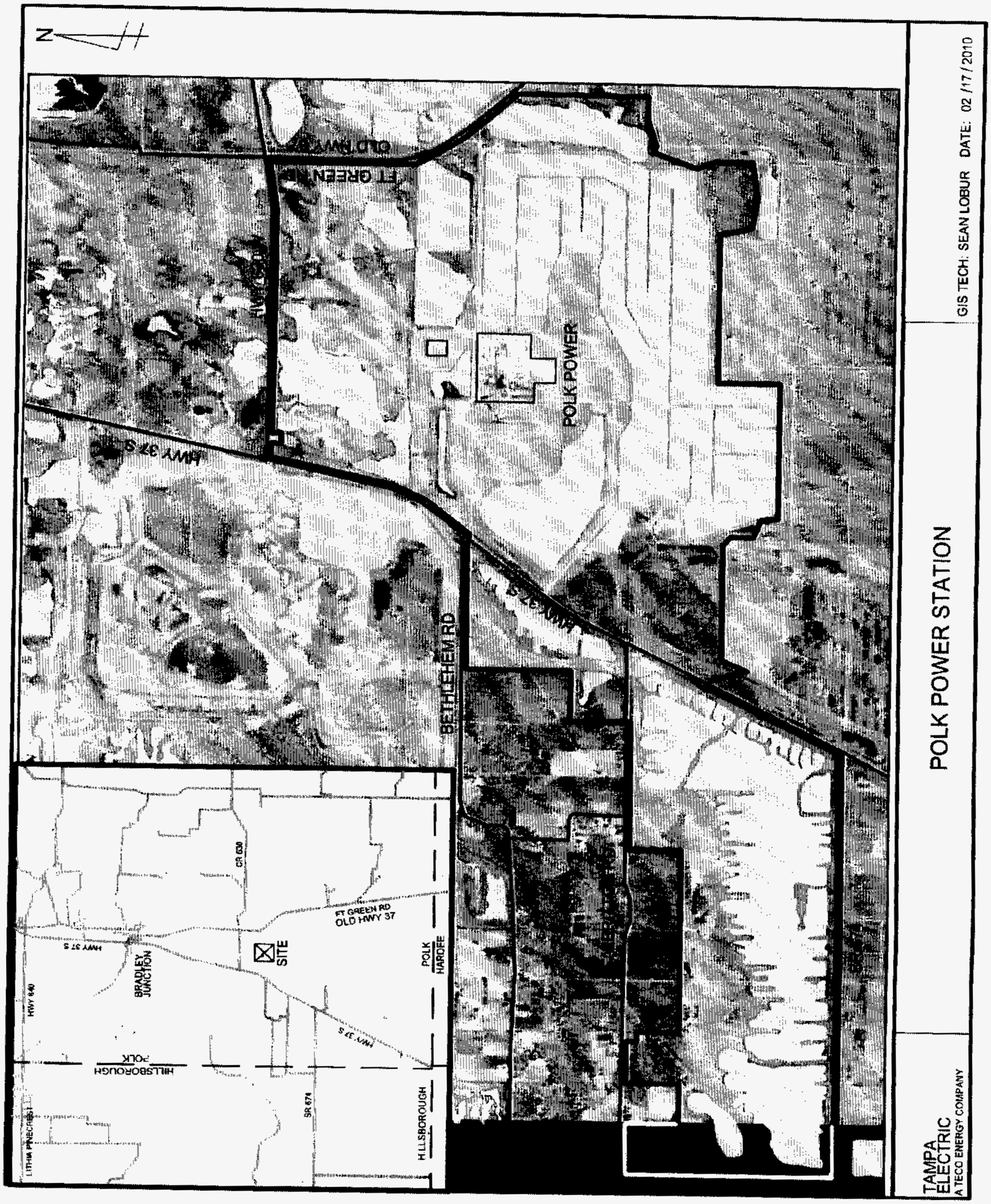
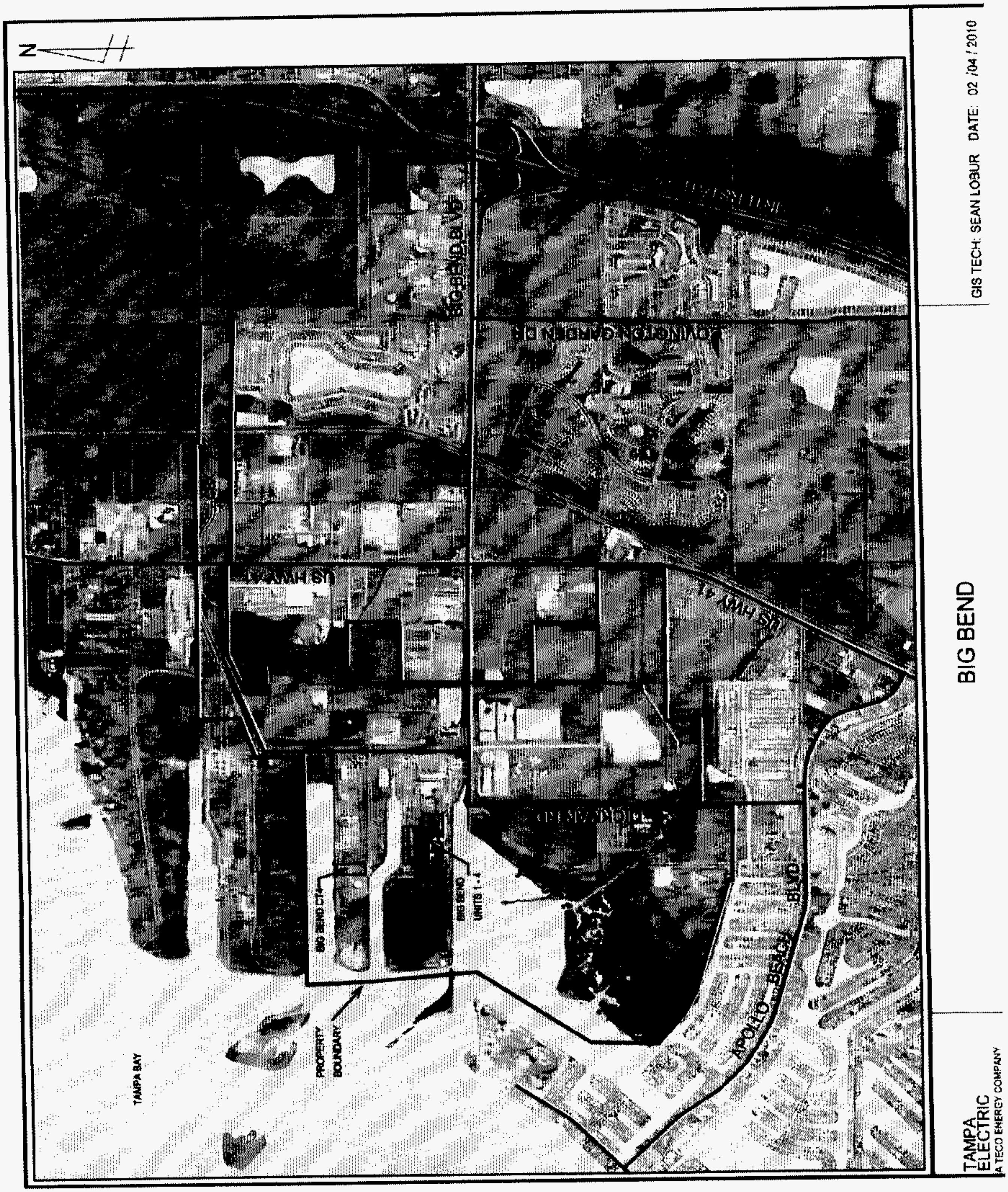

N
OLD HWY 37
FT GREEN RD
POLK POWER
HWY 37 S
BETHLEHEM RD
FT GREEN RD
OLD HWY 37
CR 630
SITE
BRADLEY JUNCTION
HWY 37 S
POLK
HARDEE
HWY 640
POLK
HILLSBOROUGH
LITHIA PINECREST
SR 674
HILLSBOROUGH
GIS TECH: SEAN LOBUR DATE: 02 / 17 / 2010
POLK POWER STATION
TAMPA ELECTRIC
A TECO ENERGY COMPANY

Figure VI-3


N
BIG BEND BLVD
COVINGTON GARDEN DR
US HWY 41
BIG BEND CT4
BIG BEND UNITS 1-4
PROPERTY BOUNDARY
TAMPA BAY
APOLLO BEACH BLVD
GIS TECH: SEAN LOBUR DATE: 02 /04 / 2010
BIG BEND
TAMPA ELECTRIC
A TECO ENERGY COMPANY