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April 1, 2008

HAND DELIVERED

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08 APR -1 PM 3:21
COMMISSION CLERK

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

080000

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 2008 to December 2017 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,

Lee L. Willis

LLW/pp
Enclosures

CMP ______
COM ______
CTR ______
ECR ______
GCL 1
OPC ______
RCA ______
SCR ______
SGA ______
SEC ______
OTH 2

DOCUMENT NUMBER-DATE
02488 APR-1 08
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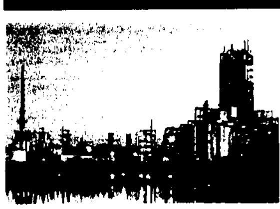
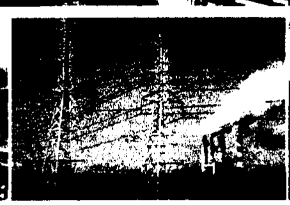
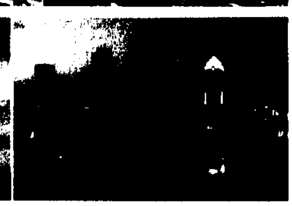
TECO
TAMPA ELECTRIC

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

January 2008 to December 2017

TAMPA ELECTRIC
H.L. Culbreath Bayside Power Station



Responsibly Serving Our Customers' Growing Needs

DOCUMENT NUMBER-DATE
02488 APR-1 8
FPSC-COMMISSION CLERK

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

January 2008 to December 2017

TAMPA ELECTRIC COMPANY

Tampa, Florida

April 1, 2008

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list of schedules and table

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glossary of terms

CODE IDENTIFICATION SHEET

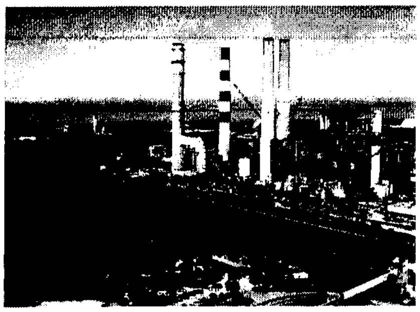
Unit Type:	CT	=	Combustion Turbine
	CC	=	Combined Cycle
	CG	=	Coal Gasifier
	D	=	Diesel
	FS	=	Fossil Steam
	GT	=	Gas Turbine
	HRSG	=	Heat Recovery Steam Generator
	IGCC	=	Integrated Gasification Combined Cycle
	ST	=	Steam Turbine
Unit Status:	OT	=	Other
	P	=	Planned
	R	=	Retired
	T	=	Regulatory Approval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

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.

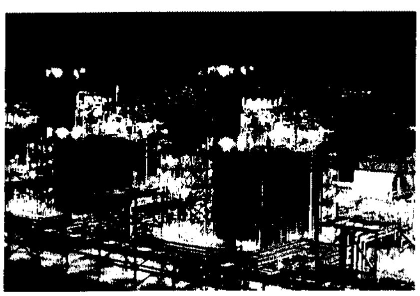
Description of Electric Generating Facilities

Big Bend Power Station



The station operates four (4) pulverized coal fired steam units equipped with desulfurization scrubbers, electrostatic precipitators and three (3) distillate fueled combustion turbines. The four (4) pulverized coal units are currently undergoing the addition of air pollution control systems called Selective Catalytic Reduction (SCR). This work is scheduled to be completed by 2010. Two of the units have been modified and the remaining two units will be modified by 2010.

H.L. Culbreath Bayside Power Station



The station operates two (2) natural gas fired combined cycle units. Bayside Unit 1 utilizes three (3) combustion turbines, three (3) heat recovery steam generators (HRSGs) and one (1) steam turbine. Bayside Unit 2 utilizes four (4) combustion turbines, four (4) HRSGs and one (1) steam turbine.

Polk Power Station

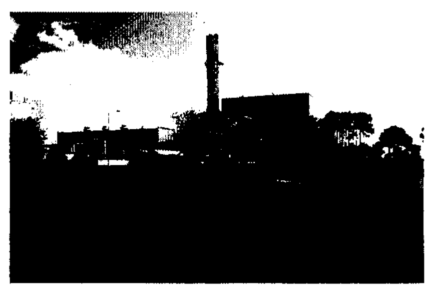
The station operates five (5) generating units. Polk Unit 1 is fired with synthetic gas produced from gasified coal and other carbonaceous fuels and is an integrated gasification combined cycle unit (IGCC). This technology integrates state-of-the-art environmental processes to create a clean fuel gas 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.

Other Facilities

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.

J.H. Phillips Power Station



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

Schedule 1

Existing Generating Facilities
As of December 31, 2007

(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									1,998,000	1,663	1,734
	1		ST	BIT	N	WA	N	0	10/70	Unknown	445,500	375	385
	2		ST	BIT	N	WA	N	0	04/73	Unknown	445,500	385	395
	3		ST	BIT	N	WA	N	0	05/76	Unknown	445,500	387	397
	4		ST	BIT	N	WA	N	0	02/85	Unknown	486,000	418	428
	CT 1		CT	DFO	N	WA	TK	0	02/69	05/09 *	18,000	10	11
	CT 2		CT	DFO	N	WA	TK	0	11/74	05/09 *	78,750	49	79
	CT 3		CT	DFO	N	WA	TK	0	11/74	05/09 *	78,750	39	39
Bayside		Hillsborough											
		Co. 4/30S/19E									2,014,160	1,628	1,837
	1		CC	NG	N	PL	N	0	4/03	Unknown	809,060	700	791
	2		CC	NG	N	PL	N	0	1/04	Unknown	1,205,100	928	1,046
Phillips		Highland Co.											
		12-055									38,430	34	36
	1		IC	DS	RFO	TK	N	0	06/83	Unknown	19,215	17	18
	2		IC	DS	RFO	TK	N	0	06/83	Unknown	19,215	17	18
Polk		Polk Co.											
		2,3/32S/23E									1,029,379	871	991
	1		IGCC	BIT	DFO	WA/TK	TK	0	09/96	Unknown	326,299	250	255
	2		GT	NG	DFO	PL	TK	0	07/00	Unknown	175,770 **	159	184
	3		GT	NG	DFO	PL	TK	0	5/02	Unknown	175,770 **	164	184
	4		GT	NG	N	PL	N	0	3/07	Unknown	175,770 **	149	184
	5		GT	NG	N	PL	N	0	4/07	Unknown	175,770 **	149	184
Partnership		Hillsborough											
		Co. W30/29/19									5,800	6	6
	1		IC	NG	N	PL	N	0	04/01	Unknown	2,900	3	3
	2		IC	NG	N	PL	N	0	04/01	Unknown	2,900	3	3
											TOTAL	4,202	4,604

Notes:

* Estimated retirement date

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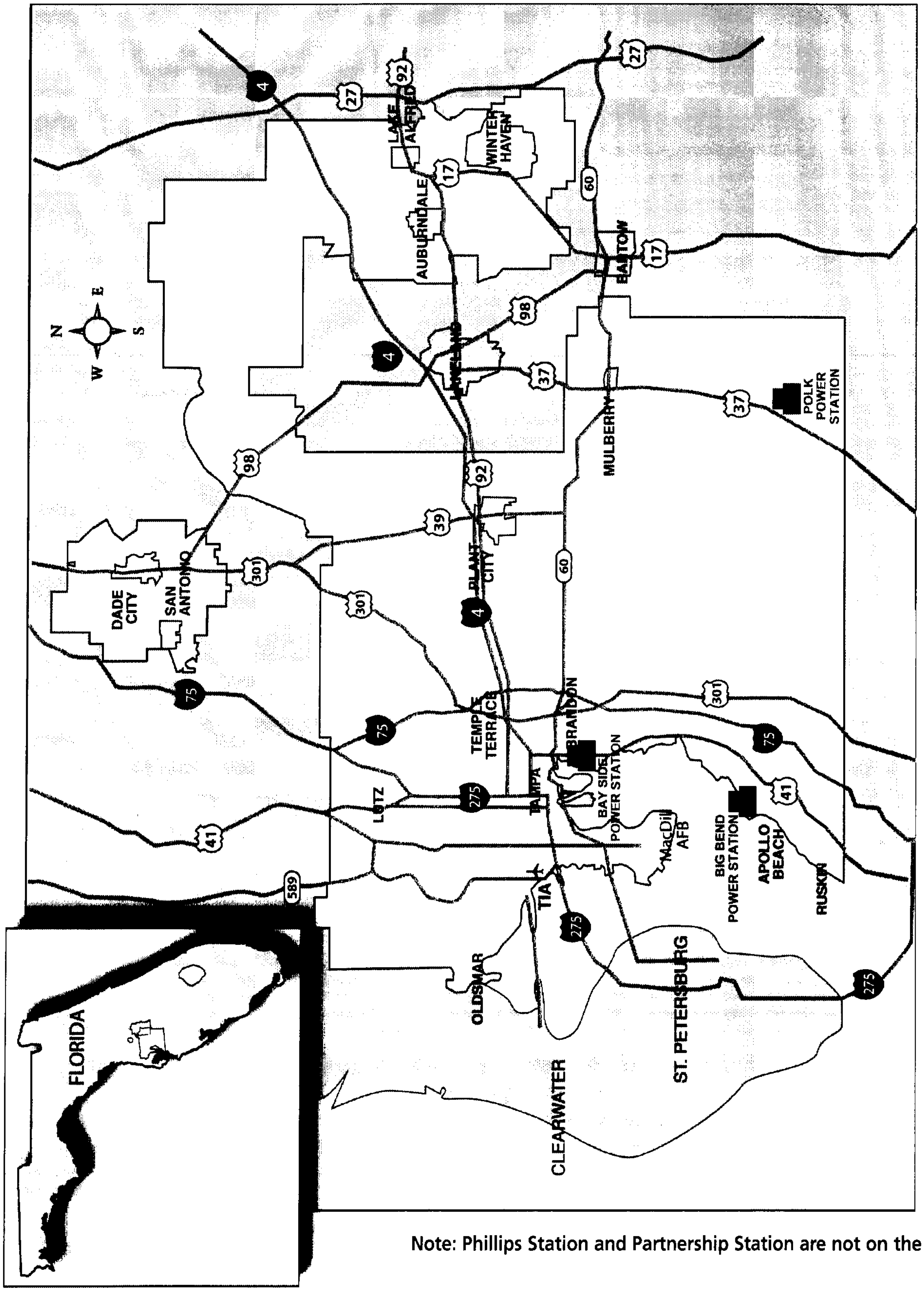
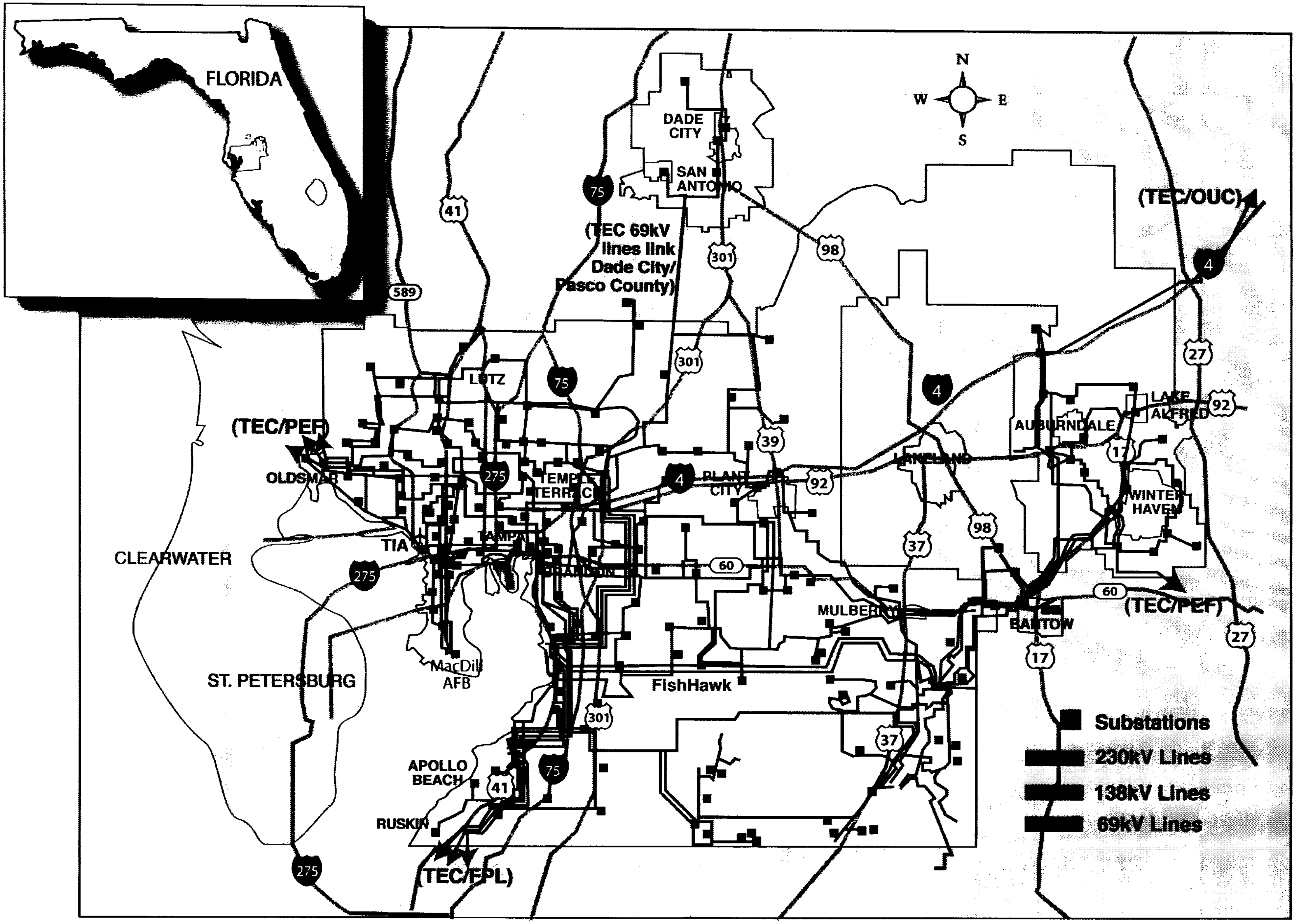
Tampa Electric Service Area & Generating Plant Map



Note: Phillips Station and Partnership Station are not on the diagrai

Tampa Electric Service Area Transmission Facility



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chapter II

Forecast of Electric Power, Demand and Energy Consumption

Schedule 2.1: History and Forecast of Energy Consumption and Number of Customers by Customer Class

Schedule 2.2: History and Forecast of Energy Consumption and Number of Customers by Customer Class

Schedule 2.3: History and Forecast of Energy Consumption and Number of Customers by Customer Class

Schedule 3.1: History and Forecast of Summer Peak Demand

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Schedule 5: History and Forecast of Fuel Requirements

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

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

Schedule 2.1

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

(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
1998	942,322	2.4	7,050	466,189	15,123	5,173	58,542	88,364
1999	962,153	2.4	6,967	477,533	14,590	5,337	60,089	88,818
2000	1,006,400	2.6	7,369	491,925	14,980	5,541	61,902	89,512
2001	1,030,900	2.6	7,594	505,964	15,009	5,685	63,316	89,788
2002	1,053,900	2.6	8,046	518,554	15,516	5,832	64,665	90,188
2003	1,084,198	2.5	8,265	531,257	15,557	5,843	66,041	88,475
2004	1,106,487	2.5	8,293	544,313	15,236	5,988	67,488	88,727
2005	1,127,449	2.5	8,558	558,601	15,320	6,233	69,027	90,298
2006	1,161,959	2.5	8,721	575,111	15,164	6,357	70,205	90,549
2007	1,192,861	2.5	8,871	586,776	15,119	6,542	70,891	92,276
2008	1,217,168	2.5	9,358	603,130	15,515	6,738	72,730	92,648
2009	1,244,429	2.5	9,630	617,613	15,593	6,936	74,254	93,412
2010	1,272,300	2.5	9,918	631,760	15,700	7,063	75,763	93,222
2011	1,295,870	2.5	10,196	646,226	15,777	7,226	77,283	93,495
2012	1,319,877	2.5	10,503	661,399	15,879	7,434	78,873	94,248
2013	1,344,329	2.5	10,777	677,052	15,917	7,658	80,525	95,102
2014	1,369,234	2.4	11,073	692,827	15,982	7,894	82,202	96,031
2015	1,394,600	2.4	11,394	708,889	16,074	8,066	83,920	96,112
2016	1,416,501	2.4	11,738	725,023	16,189	8,239	85,634	96,211
2017	1,438,746	2.4	12,065	741,579	16,270	8,418	87,390	96,323

December 31, 2007 Status

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

Schedule 2.2

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

(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
1998	2,520	682	3,695,015	0	54	1,231	16,028
1999	2,223	740	3,004,054	0	52	1,226	15,805
2000	2,390	776	3,079,897	0	53	1,285	16,638
2001	2,329	851	2,736,780	0	54	1,314	16,976
2002	2,612	948	2,755,274	0	55	1,380	17,925
2003	2,580	1,203	2,144,638	0	57	1,481	18,226
2004	2,556	1,299	1,967,667	0	58	1,542	18,437
2005	2,478	1,337	1,853,403	0	60	1,582	18,911
2006	2,279	1,485	1,534,680	0	61	1,607	19,025
2007	2,366	1,494	1,583,695	0	63	1,692	19,533
2008	2,497	1,507	1,656,404	0	67	1,690	20,350
2009	2,537	1,546	1,641,057	0	74	1,731	20,908
2010	2,576	1,591	1,619,521	0	80	1,759	21,396
2011	2,613	1,639	1,594,380	0	82	1,793	21,909
2012	2,646	1,687	1,568,424	0	83	1,834	22,500
2013	2,679	1,737	1,541,921	0	85	1,878	23,077
2014	2,714	1,792	1,514,395	0	87	1,924	23,692
2015	2,753	1,851	1,487,931	0	89	1,961	24,264
2016	2,796	1,914	1,461,137	0	91	2,000	24,863
2017	2,840	1,979	1,435,039	0	93	2,040	25,456

December 31, 2007 Status

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

Schedule 2.3

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

(1) Year	(2) Sales for * Resale GWh	(3) Utility Use ** & Losses GWh	(4) Net Energy *** for Load GWh	(5) Other **** Customers	(6) Total **** Customers
1998	431	783	17,242	4,839	530,252
1999	533	900	17,238	5,299	543,661
2000	763	972	18,373	5,497	560,100
2001	684	794	18,454	5,649	575,780
2002	502	935	19,362	6,032	590,199
2003	587	985	19,798	6,399	604,900
2004	589	945	19,971	6,435	619,535
2005	712	952	20,575	6,656	635,621
2006	700	1,000	20,725	6,905	653,706
2007	829	916	21,278	7,193	666,354
2008	652	1,046	22,048	7,338	684,704
2009	603	1,075	22,586	7,494	700,908
2010	602	1,100	23,099	7,646	716,759
2011	277	1,126	23,312	7,800	732,948
2012	217	1,156	23,873	7,960	749,920
2013	143	1,186	24,405	8,125	767,440
2014	87	1,218	24,996	8,291	785,111
2015	87	1,247	25,598	8,459	803,118
2016	87	1,277	26,228	8,628	821,198
2017	87	1,308	26,851	8,800	839,748

December 31, 2007 Status

* Includes sales to Progress Energy Florida, Wauchula, Ft. Meade, St. Cloud and Reedy Creek.
** Utility Use and Losses include accrued sales.
*** Net Energy for Load includes output to line including energy supplied by purchased cogeneration.
**** Average of end-of-month customers for the calendar year.

Schedule 3.1

History and Forecast of Summer Peak Demand
Base Case

(1) Year	(2) Total *	(3) Wholesale**	(4) Retail *	(5) Interruptible	(6) Residential Load Management	(7) Residential Conservation	(8) Comm./Ind. Load Management	(9) Comm./Ind. Conservation	(10) Net Firm Demand
1998	3,458	111	3,347	204	107	43	21	27	2,945
1999	3,648	190	3,458	193	98	48	19	31	3,069
2000	3,568	171	3,397	182	78	52	21	36	3,028
2001	3,730	178	3,552	181	90	55	21	40	3,165
2002	3,869	122	3,747	206	99	60	21	43	3,318 ***
2003	3,854	122	3,732	188	63	65	21	44	3,351
2004	3,974	120	3,854	177	95	70	20	47	3,445
2005	4,218	128	4,090	144	79	73	19	49	3,725
2006	4,265	128	4,137	146	77	77	18	50	3,769
2007	4,428	172	4,256	159	69	80	18	53	3,876
2008	4,530	186	4,344	159	63	82	23	53	3,963
2009	4,636	176	4,459	160	65	84	27	54	4,069
2010	4,755	176	4,579	160	68	86	31	55	4,179
2011	4,807	105	4,702	160	72	88	34	57	4,291
2012	4,942	105	4,836	159	76	90	39	58	4,415
2013	5,061	90	4,973	160	80	92	43	60	4,539
2014	5,192	76	5,115	160	84	93	47	61	4,670
2015	5,334	76	5,258	160	88	95	50	62	4,803
2016	5,480	76	5,404	159	93	96	50	63	4,942
2017	5,632	76	5,555	160	97	98	51	65	5,085

December 31, 2007 Status

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

Schedule 3.2

History and Forecast of Winter Peak Demand
Base Case

(1) Year	(2) Total *	(3) Wholesale **	(4) Retail *	(5) Interruptible	(6) Residential Load Management	(7) Residential Conservation	(8) Comm./Ind. Load Management	(9) Comm./Ind. Conservation	(10) Net Firm Demand
1997/98	3,231	99	3,132	210	160	370	21	39	2,332
1998/99	3,985	131	3,854	152	266	388	18	40	2,990
1999/00	4,019	125	3,894	212	209	402	19	43	3,009
2000/01	4,405	136	4,269	191	196	410	21	44	3,407
2001/02	4,217	127	4,090	168	176	419	22	46	3,259
2002/03	4,484	129	4,355	195	210	428	21	46	3,455
2003/04	3,949	120	3,829	254	136	437	18	48	2,936
2004/05	4,308	129	4,179	194	189	444	16	49	3,287
2005/06	4,404	171	4,233	51	144	447	18	50	3,523
2006/07	4,063	162	3,900	157	96	452	18	51	3,127
2007/08	5,156	191	4,964	172	135	457	20	50	4,130
2008/09	5,271	178	5,092	172	136	460	24	51	4,250
2009/10	5,401	178	5,222	172	138	464	27	51	4,370
2010/11	5,528	178	5,350	172	141	467	31	52	4,486
2011/12	5,592	107	5,485	172	145	470	35	53	4,610
2012/13	5,719	91	5,628	172	150	472	39	53	4,742
2013/14	5,851	76	5,774	172	155	475	43	54	4,876
2014/15	6,002	76	5,926	172	160	477	47	54	5,016
2015/16	6,153	76	6,077	172	165	479	47	54	5,159
2016/17	6,310	76	6,233	172	170	481	48	55	5,307

December 31, 2007 Status

* Includes cumulative conservation.
** Includes sales to Progress Energy Florida, Wauchula, Fort Meade, St. Cloud and Reedy Creek.
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) 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 %
1998	16,400	297	76	16,028	431	783	17,242	69.7
1999	16,212	315	92	15,805	533	900	17,238	55.1
2000	17,083	333	112	16,638	763	972	18,373	60.1
2001	17,444	346	122	16,976	684	794	18,454	53.3
2002	18,423	361	137	17,925	502	935	19,362	58.9
2003	18,756	378	152	18,226	587	985	19,799	60.4
2004	18,999	394	168	18,437	589	945	19,971	65.6
2005	19,491	404	176	18,911	712	952	20,575	57.3
2006	19,625	412	188	19,025	700	1000	20,725	57.2
2007	20,153	421	200	19,533	829	916	21,278	56.6
2008	20,976	427	199	20,350	652	1046	22,048	54.0
2009	21,546	434	204	20,908	603	1075	22,586	54.2
2010	22,047	441	210	21,396	602	1100	23,099	54.0
2011	22,572	448	215	21,909	277	1126	23,312	53.1
2012	23,175	454	221	22,500	217	1156	23,873	53.6
2013	23,764	460	227	23,077	143	1186	24,405	53.6
2014	24,390	467	231	23,692	87	1218	24,996	53.6
2015	24,972	473	235	24,264	87	1247	25,598	53.4
2016	25,582	479	239	24,863	87	1277	26,228	53.1
2017	26,184	485	243	25,456	87	1308	26,851	53.1

December 31, 2007 Status

- Includes sales to Progress Energy Florida, Wauchula, Ft. Meade, St. Cloud and Reedy Creek.

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

Schedule 4

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

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	2007 Actual		2008 Forecast		2009 Forecast	
Month	Peak Demand * MW	NEL ** GWh	Peak Demand * MW	NEL ** GWh	Peak Demand * MW	NEL ** GWh
January	3,424	1,562	4,648	1,672	4,760	1,718
February	3,560	1,461	3,819	1,480	3,911	1,514
March	3,130	1,557	3.599	1,609	3,690	1,652
April	3,407	1,584	3,554	1,640	3,646	1,683
May	3,646	1,838	4.061	1,987	4,163	2,038
June	3,968	1,960	4.262	2,063	4,368	2,114
July	4,157	2,111	4,399	2,204	4,507	2,257
August	4,295	2,255	4,388	2,231	4,497	2,283
September	4,000	1,995	4,230	2,017	4,337	2,062
October	3,933	1,929	3,945	1,875	4,048	1,918
November	3,111	1,478	3,570	1,586	3,663	1,624
December	3,028	1,548	3,814	1,683	3,910	1,724
TOTAL		21,277		22,048		22,586

December 31, 2007 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

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
				Actual	Actual										
	Fuel Requirements		Unit	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
(1)	Nuclear		Trillion BTU	0	0	0	0	0	0	0	0	0	0	0	0
(2)	Coal		1000 Ton	4,637	4,227	4,248	4,056	4,070	4,314	4,319	4,492	4,365	4,346	4,379	4,366
(3)	Residual	Total	1000 BBL	47	51	83	53	48	16	5	43	79	83	53	48
(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	47	51	83	53	48	16	5	43	79	83	53	48
(8)	Distillate	Total	1000 BBL	78	64	99	98	101	95	96	96	99	93	98	96
(9)		Steam	1000 BBL	0	0	0	0	0	0	0	0	0	0	0	0
(10)		CC	1000 BBL	71	58	89	92	95	90	93	95	95	89	95	95
(11)		CT	1000 BBL	7	6	10	6	6	5	3	1	4	4	3	1
(12)		Diesel	1000 BBL	0	0	0	0	0	0	0	0	0	0	0	0
(13)	Natural Gas	Total	1000 MCF	51,740	57,556	65,113	64,142	64,841	62,802	65,221	76,712	79,695	82,229	85,744	101,843
(14)		Steam	1000 MCF	0	0	0	0	0	0	0	0	0	0	0	0
(15)		CC	1000 MCF	49,823	54,249	62,201	61,745	60,919	58,291	60,812	73,750	76,068	76,740	77,808	97,047
(16)		CT	1000 MCF	1,917	3,307	2,912	2,397	3,922	4,511	4,409	2,962	3,627	5,489	7,936	4,796
(17)	Other (Specify)														
(18)	Petroleum Coke		1000 Ton	383	429	511	717	732	718	738	756	749	717	751	749

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

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

Schedule 6.1

History and Forecast of Net Energy for Load by Fuel Source in GWh

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
				Actual	Actual										
	Energy Sources		Unit	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
(1)	Annual Firm Interchange		GWh	369	383	920	1,536	1,521	1,578	1,467	1,129	1,133	1,175	1,201	199
(2)	Nuclear		GWh	0	0	0	0	0	0	0	0	0	0	0	0
(3)	Coal		GWh	9,906	8,990	9,286	8,929	8,937	9,517	9,465	9,869	9,568	9,529	9,605	9,574
(4)	Residual	Total	GWh	29	32	54	34	31	10	3	28	51	54	34	31
(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	29	32	54	34	31	10	3	28	51	54	34	31
(9)	Distillate	Total	GWh	45	36	54	53	55	51	52	53	54	51	54	53
(10)		Steam	GWh	0	0	0	0	0	0	0	0	0	0	0	0
(11)		CC	GWh	42	33	49	50	52	49	51	52	52	49	52	52
(12)		CT	GWh	2	3	5	3	3	2	1	1	2	2	2	1
(13)		Diesel	GWh	0	0	0	0	0	0	0	0	0	0	0	0
(14)	Natural Gas	Total	GWh	7,136	7,899	8,912	8,794	8,821	8,498	8,878	10,630	11,042	11,330	11,746	14,232
(15)		Steam	GWh	0	0	0	0	0	0	0	0	0	0	0	0
(16)		CC	GWh	6,971	7,612	8,665	8,591	8,473	8,100	8,465	10,352	10,701	10,797	10,956	13,758
(17)		CT	GWh	165	287	247	203	348	398	413	278	341	533	790	474
(18)	Other (Specify)														
(19)	Petroleum Coke Generation		GWh	1,011	1,201	1,351	1,901	1,942	1,909	1,957	2,005	1,986	1,901	1,992	1,986
(20)	Net Interchange		GWh	1,654	2,114	811	645	1,260	1,308	1,664	306	777	1,171	1,224	406
(21)	Purchased Energy from														
(22)	Non-Utility Generators		GWh	576	623	659	694	532	437	386	386	386	386	373	373
(23)	Net Energy for Load*		GWh	20,726	21,278	22,047	22,586	23,099	23,308	23,872	24,406	24,997	25,597	26,229	26,854

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

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

Schedule 6.2

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

(1)	(2)	(3)		(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
	Energy Sources			Unit	Actual 2006	Actual 2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
(1)	Annual Firm Interchange			%	1.8	1.8	4.2	6.8	6.6	6.8	6.1	4.6	4.5	4.6	4.6	0.7
(2)	Nuclear			%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(3)	Coal			%	47.8	42.3	42.1	39.5	38.7	40.8	39.6	40.4	38.3	37.2	36.6	35.7
(4)	Residual	Total		%	0.1	0.2	0.2	0.2	0.1	0.0	0.0	0.1	0.2	0.2	0.1	0.1
(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	0.2	0.2	0.2	0.1	0.0	0.0	0.1	0.2	0.2	0.1	0.1
(9)	Distillate	Total		%	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
(10)		Steam		%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(11)		CC		%	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
(12)		CT		%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(13)		Diesel		%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(14)	Natural Gas	Total		%	34.4	37.1	40.4	38.9	38.2	36.5	37.2	43.6	44.2	44.3	44.8	53.0
(15)		Steam		%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(16)		CC		%	33.6	35.8	39.3	38.0	36.7	34.8	35.5	42.4	42.8	42.2	41.8	51.2
(17)		CT		%	0.8	1.3	1.1	0.9	1.5	1.7	1.7	1.1	1.4	2.1	3.0	1.8
(18)	Other (Specify)															
(19)	Petroleum Coke Generation			%	4.9	5.6	6.1	8.4	8.4	8.2	8.2	8.2	7.9	7.4	7.6	7.4
(20)	Net Interchange			%	8.0	9.9	3.7	2.9	5.5	5.6	7.0	1.3	3.1	4.6	4.7	1.5
(21)	Purchased Energy from															
(22)	Non-Utility Generators			%	2.8	2.9	3.0	3.1	2.3	1.9	1.6	1.6	1.5	1.5	1.4	1.4
(23)	Net Energy for Load*			%	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0

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

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

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Tampa Electric Company Forecasting

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 2008-2017 forecasts. The data tables in Chapter II outline the expected customer, demand, and energy values for the 2008-2017 time period.

Retail Load

MetrixND, an advanced statistics program for analysis and forecasting, was used to develop the 2008-2017 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:

I. Economic Analysis;

II. Customer Multiregression Model;

III. Energy Multiregression Model;

IV. Peak Demand Multiregression Models;

V. Phosphate Demand and Energy Analysis;

VI. 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.

I. 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.

II. Customer Multiregression Model

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

1. ***Residential Customer Model:*** Customer projections are a function of Florida's population. Since a strong correlation exists between historical changes in service area customers and historical changes in Florida's population, Florida population estimates for 2008-2027 were used to forecast the future growth patterns in residential customers.
2. ***Commercial Customer Model:*** Total commercial customers include commercial customers plus temporary service customers (temporary poles on construction sites); therefore, two models are used to forecast total commercial customers:

a. The Commercial Customer Model is a function of residential customers. An increase in the number of households provides the need for additional services, restaurants, and retail establishments. The amount of residential activity also plays a part in the attractiveness of the Tampa Bay area as a place to relocate or start a new business.

b. Projections of employment in the construction sector are a good indicator of expected increases and decreases in local construction activity. Therefore, the Temporary Service Model projects the number of customers as a function of construction employment.

3. ***Industrial Customer Model (Non-Phosphate):*** Non-phosphate industrial customers include three rate classes that have been modeled individually: General Service, General Service Demand and General Service Large Demand.

   a. The General Service Customer Model is a function of Hillsborough County commercial employment.

   b. The General Service Demand Customer Model is a function of Hillsborough County commercial and industrial employment. Since the structure of our local industrial sector has been shifting from an energy-intense manufacturing sector to a non-energy intense manufacturing sector, the type of customers in this sector have qualities of both large scaled commercial customers and smaller scaled industrial customers.

   c. The General Service Large Demand Customer Model is based on Hillsborough County Industrial Employment.

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

5. ***Street & Highway Lighting Customer Model:*** As the number of commercial customers increases so does the need for infrastructure expansion, such as street and highway lighting. Therefore, the commercial customer forecast is the basis for the Street & Highway Lighting customer model.

III. Energy Multiregression Model

There are a total of eight energy models. All of these models represent average usage per customer (kWh/customer), except for th temporary services model which represents total kWh sales. The average usage models interact with the customer models to arrive a 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 i 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 thirc component is made up of weather variables, which serve to allocate the seasonal impacts of weather throughout the yea The SAE model framework begins by defining energy use fo an average customer in year (y) and month (m) as the sum c 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 weightec 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 energ use per household for each equipment type in the base year

Where:

$$HeatEquipIndex = \sum_{Tech} Weight \times \left(\frac{Saturation_y \; / \; Efficiency_y}{Saturation_{base\,y} \; / \; Efficiency_{base\,y}} \right)$$

$$CoolEquipIndex = \sum_{Tech} Weight \times \left(\frac{Saturation_y \; / \; Efficiency_y}{Saturation_{base\,y} \; / \; Efficiency_{base\,y}} \right)$$

$$OtherEquipIndex = \sum_{Tech} Weight \times \left(\frac{Saturation_y \; / \; Efficiency_y}{Saturation_{base\,y} \; / \; Efficiency_{base\,y}} \right)$$

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.

$$HeatUse_{y,m} = \left(\frac{Price_{y,m}}{Price_{base\,y,m}} \right)^{-.30} \times \left(\frac{HH\ Income_{y,m}}{HH\ Income_{base\,y,m}} \right)^{.30} \times \left(\frac{HH\ Size_{y,m}}{HH\ Size_{base\,y,m}} \right)^{.30} \times \left(\frac{HDD_{y,m}}{Normal\ HDD} \right)$$

$$CoolUse_{y,m} = \left(\frac{Price_{y,m}}{Price_{base\,y,m}} \right)^{-.30} \times \left(\frac{HH\ Income_{y,m}}{HH\ Income_{base\,y,m}} \right)^{.30} \times \left(\frac{HH\ Size_{y,m}}{HH\ Size_{base\,y,m}} \right)^{.30} \times \left(\frac{CDD_{y,m}}{Normal\ CDD} \right)$$

$$OtherUse_{y,m} = \left(\frac{Price_{y,m}}{Price_{base\,y,m}} \right)^{-.30} \times \left(\frac{HH\ Income_{y,m}}{HH\ Income_{base\,y,m}} \right)^{.30} \times \left(\frac{HH\ Size_{y,m}}{HH\ Size_{base\,y,m}} \right)^{.25} \times \left(\frac{Billing\ Days_{y,m}}{Billing\ Days_{base\,y,m}} \right)$$

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 drivers being the construction sector's productivity and heating and cooling degree-days.
3. ***Industrial Energy Model (Non-Phosphate):*** Non-phosphate 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 has two major components. Utilizing the SAE model framework, the first component, economic index variables, includes estimates for manufacturing output and the price of electricity in the industrial sector. The second component is a cooling degree-day variable. Unlike the previous models discussed, heating load does not impact the industrial sector.
   b. The General Service Demand Energy Model is modeled like the General Service Energy Model.
   c. The General Service Large Demand Customer Model is based on the industrial production manufacturing index variable and a cooling degree day variable.
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 & 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.

IV. Demand Multiregression Models

After the total retail energy sales forecast is complete, it is integrated into the peak demand model as an independent variable along with weather variables. The energy variable represents the long-term economic and appliance trend impacts. 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.

V. Phosphate Demand and Energy Analysis

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

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

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

VI. 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 these 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 anti-condensate equipment sensors for load control in commercial facilities.
20. Commercial Water Heating - Encourages the installation of high efficiency water heating systems.
21. Commercial Demand Response - A turn-key program to incent commercial/industrial customers to reduce their demand for electricity in response to market signals.

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 2007 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 sales contracts with the Cities of Wauchula, Fort Meade, St. Cloud, Progress Energy Florida and Reedy Creek Improvement District.

Since Tampa Electric's sales to Wauchula and Fort Meade will vary over time based on the strength of the local economies, a multiple regression approach has been utilized. Under this methodology, two equations have been developed for each municipality for: 1) An energy sales model based on Polk County real per-capita income and heating and cooling degree days; 2) Peak models for these two cities use 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 Electri

TABLE III-1

Comparison of Achieved MW and GWh Reductions With Florida Public Service Commission Goals

Residential

Year	Winter Peak MW Reduction: Total Achieved	Winter Peak MW Reduction: Commission Approved Goal	Winter Peak MW Reduction: % Variance	Summer Peak MW Reduction: Total Achieved	Summer Peak MW Reduction: Commission Approved Goal	Summer Peak MW Reduction: % Variance	GWh Energy Reduction: Total Achieved	GWh Energy Reduction: Commission Approved Goal	GWh Energy Reduction: % 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%

Commercial/Industrial

Year	Winter Peak MW Reduction: Total Achieved	Winter Peak MW Reduction: Commission Approved Goal	Winter Peak MW Reduction: % Variance	Summer Peak MW Reduction: Total Achieved	Summer Peak MW Reduction: Commission Approved Goal	Summer Peak MW Reduction: % Variance	GWh Energy Reduction: Total Achieved	GWh Energy Reduction: Commission Approved Goal	GWh Energy Reduction: % Variance
2005	3.4	1.0	340.0%	4.3	2.1	204.8%	7.9	6.7	117.9%
2006[(1)]	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	19.5	132.3%

Combined Total

Year	Winter Peak MW Reduction: Total Achieved	Winter Peak MW Reduction: Commission Approved Goal	Winter Peak MW Reduction: % Variance	Summer Peak MW Reduction: Total Achieved	Summer Peak MW Reduction: Commission Approved Goal	Summer Peak MW Reduction: % Variance	GWh Energy Reduction: Total Achieved	GWh Energy Reduction: Commission Approved Goal	GWh Energy Reduction: % Variance
2005	7.6	5.0	152.0%	7.1	4.5	157.8%	15.6	13.7	113.9%
2006[(1)]	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	42.0	120.0%

(1) Summer, winter peak MW and GWh energy reductions corrected from previous reports.

Base Case Forecast Assumptions

Retail Load

Numerous assumptions are inputs to the MetrixND models, of which the more significant ones are Population & Households, Commercial, Industrial & Governmental Employment, Commercial, Industrial & Governmental Output, Real Household Income, Price of Electricity, Appliance Efficiency Standards, and Weather.

1. Population and Households

The state population forecast is the starting point for developing the customer and energy projections. Both the University of Florida's Bureau of Economic and Business Research (BEBR) and Economy.com supply population projections for Hillsborough County and Florida. The population forecast is based upon the projections of BEBR in the short term and is a blend in the long term of BEBR and Economy.com. Over the next ten years (2008-2017) the average annual population growth rate in Hillsborough County and Florida is expected to be 1.9% and 2.1%, respectively. In addition, Economy.com provides household data as an input to the residential average use model.

2. Commercial, Industrial and Governmental Employment

Commercial and industrial employment assumptions are utilized in computing the number of customers in their respective sectors. It is imperative that employment growth be consistent with the expected population expansion and unemployment levels. Over the next ten years, employment is assumed to rise at a 2.7% 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 2008-2017, real household income for Hillsborough County is expected to increase at a 2.1% average annual rate.

5. Price of Electricity

Forecasts for the price of electricity by customer class are supplied by Tampa Electric's Regulatory 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. The high scenario represents more optimistic economic conditions in the areas of customers, employment, and income. The low band represents a less optimistic scenario in the same areas. Compared to the base case, the expected customer and 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 2008-2017, retail energy sales are projected to rise at a 2.5% annual rate. The major contributor to growth is the residential category, increasing at an annual rate of 2.9%.
2. Wholesale Energy
   Firm sales of wholesale energy to Progress Energy Florida, Wauchula, Ft. Meade, St. Cloud, and Reedy Creek are expected to range between 652 and 602 GWh per year for 2008 through 2010. Firm wholesale sales drop substantially in 2011 to 277 GWh as some of these contracts come to an end. The drop continues to a low of 87 GWh in 2014 and continues at that level into 2017 when all currently contracted firm wholesale sales end.

History and Forecast of Peak Loads

Historical and base scenario forecasts of peak loads for the summer and winter seasons are presented in Schedules 3.1 and 3.2, respectively. For the 2008-2017 period, Tampa Electric's base case retail firm peak demand for winter and summer are both expected to advance at annual rates of 2.8%.

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Forecast of Facilities Requirements

The proposed generating facility additions and changes shown in Schedule 8.2 integrate energy efficiency and conservation programs and generating resources to provide economical, reliable service to Tampa Electric's customers. Various energy resource plan alternatives, comprised of a mixture of generating technologies, purchased power, and cost-effective energy efficiency and conservation programs, are developed to determine this plan. These alternatives are combined with existing supply resources and analyzed to determine the energy resource option which best meets Tampa Electric's future system demand and energy requirements. A detailed discussion of Tampa Electric's integrated resource planning process is included in Chapter V.

The results of the integrated resource planning process provide Tampa Electric with a plan that is cost-effective while maintaining system reliability and environmental requirements while considering technology availability and lead times for construction. To meet the expected system demand and energy requirements over the next ten years peaking and base resources are needed. The peaking capacity need will be met by building combustion turbine additions in 2009, 2012, 2015 and 2016, and peaking power purchases. The base load capacity will be met by building one natural gas combined cycle (NGCC) unit planned for 2013, and a second natural gas combined cycle (NGCC) unit planned for 2017, or by purchase power agreements. The operating and cost parameters associated with the capacity additions resulting from the analysis are shown in Schedule 9.

As the construction start dates for each scheduled unit approaches, Tampa Electric will evaluate competitive purchased power agreements that may replace or delay the planned unit additions. The purchase power must have firm transmission service to support firm reserve margin criteria for reliability. Assumptions and information that impact the plan are discussed in the following sections and in Chapter V.

In the fall of 2006 Tampa Electric solicited offers for peaking generation as an alternative to scheduled units through a Request for Proposal (RFP). The overriding objective of this RFP was to solicit bids for competitive resources that provide Tampa Electric with reliable and cost-effective capacity alternatives to satisfy its projected capacity requirements. The RFP was open to products within the Florida Reliability Coordinating Council (FRCC) region of the North American Electric Reliability Council (NERC) as well as products originating outside of the FRCC given that the seller obtained the appropriate firm transmission service(s) to assure delivery. Tampa Electric requested proposals from all potential suppliers capable of satisfying the conditions of the RFP, including other electric utilities, power marketers, exempt wholesale generators, independent power producers, and qualifying facilities.

Through the RFP, Tampa Electric Company sought power supply proposals to meet its requirements for electric generating capacity and associated energy commencing on January 1, 2009, which would provide the best value to its customers based on cost, reliability, and flexibility. In the RFP, Tampa Electric solicited proposals for capacity and associated energy.

As a result of the peaking power RFP of 2006, Tampa Electric has entered into a firm purchase power agreement with Reliant Energy for a 158 MW year-round product that started in 2008 and will expire on May 31, 2012.

Additionally, Tampa Electric is currently negotiating purchase power agreements in the 2009 through 2016 time period.

Aero-derivative CT Technology

Tampa Electric's expansion plan includes the construction of five (5) aero-derivative combustion turbine assets (Aero CTS) in 2009 – totaling approximately 285 MW of summer capacity. These units will provide economic, black start and operating reserve requirement improvements:

- *Black Start capability.*
  The Aero CTs can be used to energize the Big Bend and Bayside Power Plants in the event of a plant, system or grid failure. Black Start is defined by the Florida Reliability Coordinating Council (FRCC) as a utility's ability to energize portions of a blacked out region utilizing resources independent of an energized interconnection. While Big Bend CT 1 is a black start asset, it will be retired with the in-service date of the new unit.

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

NGCC Technology

In October of 2007, Tampa Electric withdrew its petition for need for an integrated gasification combined cycle (IGCC) unit in 2013. This decision was largely based on the uncertainty related to carbon dioxide (CO_2) regulations and the potential for related project cost increases. Despite withdrawing the IGCC plant, the need for additional capacity in 2013 remains. Tampa Electric plans to meet this need in 2013 with a natural gas combined cycle (NGCC) unit. The NGCC unit has higher operating costs than the IGCC unit but lower construction costs while meeting current environmental emission requirements.

Cogeneration

Tampa Electric plans for 507 MW of cogeneration capacity operating in its service area in 2008. Self-service capacity of 260 MW is used by cogenerators to serve internal load requirements, 64 MW are purchased by Tampa Electric on a firm contract basis, and 29 MW are purchased on a non-firm, as-available basis. The remaining 154 MW of cogeneration capacity is expected to be sold to other utilities while Tampa Electric provides transmission service from its system to the Florida grid.

Fuel Requirements

A forecast of fuel requirements and energy sources is shown in Schedule 5, Schedule 6.1 and Schedule 6.2. Tampa Electric currently uses a generation portfolio consisting of coal and natural gas for its generating requirements. Tampa Electric has firm transportation contracts with the Florida Gas Transmission Company (FGT) and Gulfstream Natural Gas System LLC for delivery of natural gas to the Bayside and Polk Units. As shown in Schedule 6.2, in 2008 coal and pet coke will fuel 48% of net energy for load and natural gas will fuel 40%. Less than one percent of net energy for load will be fueled by oil at the Phillips plant and other combustion turbines. The remaining net energy for load is served by non-utility generators an(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 emission from the company's facilities began long before the agreements. Since 1998, Tampa Electric has reduced annual sulfur dioxides (SO_2) by 93%, nitrogen oxides (NO_x) by 60 percent, particulate matter (PN by 70% and mercury emissions by 70%.

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

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

The repowering of Gannon Station to H.L. Culbreath Bayside Power Station resulted in significant reduction in emissions of all pollutant types. Tampa Electric's decision to install additional NO_x emissions controls on all Big Bend Station Units by May of 2010 will result in reducing NO_x emissions by 90% compared to 1998 levels. Selective Catalytic Reduction (SCR) will be the control technology used to reduce Big Bend Station NO_x emissions. Tampa Electric completed installation of the SCR system on Big Bend Unit 4 and put it in-servic on June 1, 2007. Subsequently, the other units complete modifications in 2008, 2009 and 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 percent carbon dioxide (CO_2) reduction. With an actual reduction of more than 20 percent, the company far surpassed the CCX target.

As a result of all 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) Phase I requirements, the vacated Clean Air Mercury Rule (CAMR) Phase I requirements and be positioned for other potential future emission control requirements. No other utility in the state and few in the nation have made similar emissions reductions since 1998.

Interchange Sales and Purchases

Tampa Electric's long-term firm sale agreements include Progress Energy Florida for 71 MW and Reedy Creek Improvement District for 77 MW as well as the cities of Ft. Meade for 12 MW, St. Cloud for 15 MW and Wauchula for 15 MW.

Tampa Electric has a long-term purchased power contract for capacity and energy from the Hardee Power Station owned by Invenergy. The contract term is January 1, 1993 through December 31, 2012. The contract involves a shared-capacity agreement with Seminole Electric Cooperative (SEC), whereby Tampa Electric plans for the full net capability (353 MW winter and 287 MW summer) of the Hardee Power Station during those times when SEC plans for the Seminole Units 1 and 2 and the SEC Crystal River Unit 3 allocation to be available for operation, and reduced availability during times when Seminole Units 1 and 2 are derated or unavailable due to planned maintenance. Under the existing contract, Tampa Electric also has the right to purchase an additional 88 MW winter and 69 MW summer of firm non-shared capacity from the Hardee Power Station.

Tampa Electric also entered into a firm purchased power agreement with Progress Energy Florida for 100 MW from January 1, 2008 through March 31, 2008 and a second agreement for 25 MW from December 1, 2007 through December 31, 2008. Tampa Electric has an agreement with Calpine Energy Services for 170 MW from May 1, 2006 through April 30, 2011 and with Reliant Energy Service for 158 MW from January 1, 2008 to May 31, 2012. Additionally, Tampa Electric has an agreement for the purchase of 121 MW from Pasco Cogen for the period January 1, 2009 to December 31, 2018.

Tampa Electric has a need of approximately 136 MW winter and summer that begins in 2009. Likewise, as existing purchased power agreement end in 2011, Tampa Electric has an additional 170 MW winter and summer need – totaling 306 MW in 2011.

As discussed earlier in this section, Tampa Electric will seek to satisfy these capacity needs for the given years by contracting power from one or more entities. Inquiries have begun to locate potential sources of capacity. Tampa Electric will look to sign agreement(s) that provide cost-effective alternative(s) to satisfy the projected requirements.

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
2008	4,202	709	0	64	4,975	4,149	825	20%	0	825	20%
2009	4,225	941	0	64	5,230	4,245	984	23%	0	984	23%
2010	4,401	941	0	40	5,382	4,356	1,027	24%	0	1,027	24%
2011	4,406	941	0	32	5,379	4,396	983	22%	0	983	22%
2012	4,682	783	0	23	5,488	4,519	969	21%	0	969	21%
2013	5,242	427	0	23	5,692	4,628	1,064	23%	0	1,064	23%
2014	5,242	427	0	23	5,692	4,747	945	20%	0	945	20%
2015	5,412	427	0	23	5,862	4,880	982	20%	0	982	20%
2016	5,584	427	0	0	6,011	5,018	992	20%	0	992	20%
2017	6,139	121	0	0	6,260	5,162	1,098	21%	0	1,098	21%

NOTE:

1. Capacity import includes firm purchase power agreements (PPA) with Invenergy of 356 MW from 2006 through 2012, PPA with Progress Energy Florida of 25 MW from December 2007 through 2008, PPA with Calpine of 170 MW from May 2006 through April 2011, PPA with Reliant of 158 MW from 2008 through May 2012, and PPA with Pasco Cogen of 121 MW from 2009 through 2018.
2. Unspecified purchase power of approximately 136 MW is needed beginning in January 2009. A second unspecified purchase power of approximately 170 MW is needed beginning in the summer of 2011.
3. The QF column accounts for cogeneration that will be purchased under firm contracts and excludes non-firm purchases.
4. Column 2 Total Installed Capacity reflects changes identified in Schedule 8.1.

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
2007-08	4,604	894	0	64	5,562	4,321	1,240	29%	397	843	20%
2008-09	4,611	1,026	0	64	5,701	4,428	1,272	29%	400	872	20%
2009-10	4,797	1,026	0	64	5,887	4,548	1,339	29%	400	939	21%
2010-11	4,802	1,026	0	32	5,860	4,664	1,196	26%	0	1,196	26%
2011-12	4,802	1,026	0	23	5,851	4,717	1,134	24%	0	1,134	24%
2012-13	5,762	427	0	23	6,212	4,833	1,379	29%	0	1,379	29%
2013-14	5,762	427	0	23	6,212	4,953	1,259	25%	0	1,259	25%
2014-15	5,760	427	0	23	6,210	5,093	1,117	22%	0	1,117	22%
2015-16	5,952	427	0	0	6,379	5,236	1,143	22%	0	1,143	22%
2016-17	6,751	121	0	0	6,872	5,384	1,488	28%	0	1,488	28%

NOTE:

1. Capacity import includes firm purchase power agreements (PPA) with Invenergy of 441 MW from 2006 through 2012, PPA with Progress Energy Florida of 125 MW from December 2007 through March 2008, PPA with Calpine of 170 MW from May 2006 through April 2011, PPA with Reliant of 158 MW from 2008 through May 2012, and PPA with Pasco Cogen of 121 MW from 2009 through 2018.
2. Unspecified purchase power of approximately 136 MW is needed beginning in January 2009. A second unspecified purchase power of approximately 170 MW is needed beginning in the summer of 2011.
3. The QF column accounts for cogeneration that will be purchased under firm contracts and excludes non-firm purchases.
4. Column 2 Total Installed Capacity reflects changes identified in Schedule 8.1.

Schedule 8.1

Existing Generating Facility Changes

(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 Change		
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
2009														
Big Bend	1	Hillsborough	FS	BIT	N	WA	N	unknown	10/70	unknown	445,500	(5)	(5)	OT
Big Bend	2		FS	BIT	N	WA	N	unknown	04/73	unknown	445,500	5	5	OT
Big Bend	3		FS	BIT	N	WA	N	unknown	05/76	unknown	445,500	3	3	OT
Big Bend	4		FS	BIT	N	WA	N	unknown	02/85	unknown	486,000	4	4	OT
Big Bend	CT1		CT	DFO	N	WA	TK	unknown	02/69	05/09	18,000	(10)	0	R
Big Bend	CT2		CT	DFO	N	WA	TK	unknown	11/74	05/09	78,750	(49)	0	R
Big Bend	CT3		CT	DFO	N	WA	TK	unknown	11/74	05/09	78,750	(39)	0	R
										2009 Changes Total:		(91)	7	
2010														
Big Bend	1	Hillsborough	FS	BIT	N	WA	N	unknown	10/70	unknown	445,500	20	20	OT
Big Bend	2		FS	BIT	N	WA	N	unknown	04/73	unknown	445,500	(5)	(5)	OT
Big Bend	3		FS	BIT	N	WA	N	unknown	05/76	unknown	445,500	(5)	(5)	OT
Big Bend	4		FS	BIT	N	WA	N	unknown	02/85	unknown	486,000	(5)	(5)	OT
Big Bend	CT1		CT	DFO	N	WA	TK	unknown	02/69	05/09	18,000	0	(11)	R
Big Bend	CT2		CT	DFO	N	WA	TK	unknown	11/74	05/09	78,750	0	(79)	R
Big Bend	CT3		CT	DFO	N	WA	TK	unknown	11/74	05/09	78,750	0	(39)	R
										2010 Changes Total:		5	(124)	
2011														
Big Bend	1	Hillsborough	FS	BIT	N	WA	N	unknown	10/70	unknown	445,500	0	0	OT
Big Bend	2		FS	BIT	N	WA	N	unknown	04/73	unknown	445,500	(5)	(5)	OT
Big Bend	3		FS	BIT	N	WA	N	unknown	05/76	unknown	445,500	(5)	(5)	OT
Big Bend	4		FS	BIT	N	WA	N	unknown	02/85	unknown	486,000	15	15	OT
										2011 Changes Total:		5	5	
2013														
Big Bend	1	Hillsborough	FS	BIT	N	WA	N	unknown	10/70	unknown	445,500	(5)	(5)	OT
Big Bend	2		FS	BIT	N	WA	N	unknown	04/73	unknown	445,500	20	20	OT
Big Bend	3		FS	BIT	N	WA	N	unknown	05/76	unknown	445,500	(5)	(5)	OT
Big Bend	4		FS	BIT	N	WA	N	unknown	02/85	unknown	486,000	(5)	(5)	OT
										2013 Changes Total:		5	5	
2015														
Big Bend	1	Hillsborough	FS	BIT	N	WA	N	unknown	10/70	unknown	445,500	(8)	(8)	OT
Big Bend	2		FS	BIT	N	WA	N	unknown	04/73	unknown	445,500	(5)	(5)	OT
Big Bend	3		FS	BIT	N	WA	N	unknown	05/76	unknown	445,500	3	3	OT
Big Bend	4		FS	BIT	N	WA	N	unknown	02/85	unknown	486,000	8	8	OT
										2015 Changes Total:		(3)	(3)	

Schedule 8.2

Planned Generating Facility Additions

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
								Const.	Commercial	Expected	Gen. Max.	Net Capability		
Plant	Unit		Unit	Fuel		Fuel Trans.		Start	In-Service	Retirement	Nameplate	Summer	Winter	
Name	No.	Location	Type	Primary	Alternate	Primary	Alternate	Mo/Yr	Mo/Yr	Mo/Yr	kW	MW	MW	Status
Bayside	5	Bayside	GT	NG	N/A	PL	NA	8/08	5/09	unknown	unknown	57	62	P
Bayside	6	Bayside	GT	NG	N/A	PL	NA	8/08	5/09	unknown	unknown	57	62	P
Bayside	3	Bayside	GT	NG	N/A	PL	NA	8/08	10/09	unknown	unknown	57	62	P
Bayside	4	Bayside	GT	NG	N/A	PL	NA	8/08	10/09	unknown	unknown	57	62	P
Big Bend CT	4	Big Bend	GT	NG	DFO	PL	TK	8/08	10/09	unknown	unknown	57	62	P
Future CT	1	unknown	GT	NG	N/A	PL	N/A	1/11	5/12	unknown	unknown	46	58	P
Future CT	2	unknown	GT	NG	N/A	PL	N/A	1/11	5/12	unknown	unknown	46	58	P
Future CT	3	unknown	GT	NG	N/A	PL	N/A	1/11	5/12	unknown	unknown	46	58	P
Future CT	4	unknown	GT	NG	N/A	PL	N/A	1/11	5/12	unknown	unknown	46	58	P
Future CT	5	unknown	GT	NG	N/A	PL	N/A	1/11	5/12	unknown	unknown	46	58	P
Future CT	6	unknown	GT	NG	N/A	PL	N/A	1/11	5/12	unknown	unknown	46	58	P
Polk	6	Polk	CC	NG	N/A	PL	N/A	6/10	1/13	unknown	unknown	555	607	P
Future CT	7	unknown	GT	NG	N/A	PL	N/A	1/14	5/15	unknown	unknown	86	96	P
Future CT	8	unknown	GT	NG	N/A	PL	N/A	1/14	5/15	unknown	unknown	86	96	P
Future CT	9	unknown	GT	NG	N/A	PL	N/A	1/15	5/16	unknown	unknown	86	96	P
Future CT	10	unknown	GT	NG	N/A	PL	N/A	1/15	5/16	unknown	unknown	86	96	P
Future CC	1	unknown	CC	NG	N/A	PL	N/A	6/14	1/17	unknown	unknown	555	607	P

SCHEDULE 9
(Page 1 of 8)
STATUS REPORT AND SPECIFICATIONS OF PROPOSED GENERATING FACILITIES
UTILITY: TAMPA ELECTRIC COMPANY

(1)	PLANT NAME AND UNIT NUMBER	BAYSIDE 5 & 6
(2)	CAPACITY	
	A. SUMMER	57
	B. WINTER	62
(3)	TECHNOLOGY TYPE	COMBUSTION TURBINE
(4)	ANTICIPATED CONSTRUCTION TIMING	
	A. FIELD CONSTRUCTION START DATE	AUG 2008
	B. COMMERCIAL IN-SERVICE DATE	MAY 2009
(5)	FUEL	
	A. PRIMARY FUEL	NATURAL GAS
	B. ALTERNATE FUEL	N/A
(6)	AIR POLLUTION CONTROL STRATEGY	WET LOW EMISSION; CO OXIDATION
(7)	COOLING METHOD	N/A
(8)	TOTAL SITE AREA[1]	APPROXIMATELY 213 ACRES
(9)	CONSTRUCTION STATUS	PERMITTING
(10)	CERTIFICATION STATUS[2]	N/A
(11)	STATUS WITH FEDERAL AGENCIES	N/A
(12)	PROJECTED UNIT PERFORMANCE DATA	
	PLANNED OUTAGE FACTOR (POF)	2.6
	FORCED OUTAGE RATE (FOR)	1.0
	EQUIVALENT AVAILABILITY FACTOR (EAF)	95.4
	RESULTING CAPACITY FACTOR (2010)	7.2%
	AVERAGE NET OPERATING HEAT RATE (ANOHR)[3]	10,641 Btu/kWh
(13)	PROJECTED UNIT FINANCIAL DATA	
	BOOK LIFE (YEARS)	25
	TOTAL INSTALLED COST (IN-SERVICE YEAR $/kW)	818.56
	DIRECT CONSTRUCTION COST ($/kW)	775.08
	AFUDC AMOUNT ($/kW)	37.56
	ESCALATION ($/kW)	5.92
	FIXED O&M ($/kW – Yr)	20.53
	VARIABLE O&M ($/MWh)	3.72
	K FACTOR	1.6696

1 REPRESENTS TOTAL BAYSIDE SITE.
2 CERTIFICATION NOT REQUIRED.
3 BASED ON 2010 YEAR.

SCHEDULE 9
(Page 2 of 8)
STATUS REPORT AND SPECIFICATIONS OF PROPOSED GENERATING FACILITIES
UTILITY: TAMPA ELECTRIC COMPANY

((1)	PLANT NAME AND UNIT NUMBER	BAYSIDE 3 & 4
(2)	CAPACITY	
	A. SUMMER	57
	B. WINTER	62
(3)	TECHNOLOGY TYPE	COMBUSTION TURBINE
(4)	ANTICIPATED CONSTRUCTION TIMING	
	A. FIELD CONSTRUCTION START DATE	AUG 2008
	B. COMMERCIAL IN-SERVICE DATE	OCT 2009
(5)	FUEL	
	A. PRIMARY FUEL	NATURAL GAS
	B. ALTERNATE FUEL	N/A
(6)	AIR POLLUTION CONTROL STRATEGY	WET LOW EMISSION; CO OXIDATION
(7)	COOLING METHOD	N/A
(8)	TOTAL SITE AREA[1]	APPROXIMATELY 213 ACRES
(9)	CONSTRUCTION STATUS	PERMITTING
(10)	CERTIFICATION STATUS[2]	N/A
(11)	STATUS WITH FEDERAL AGENCIES	N/A
(12)	PROJECTED UNIT PERFORMANCE DATA	
	PLANNED OUTAGE FACTOR (POF)	2.6
	FORCED OUTAGE RATE (FOR)	1.0
	EQUIVALENT AVAILABILITY FACTOR (EAF)	95.4
	RESULTING CAPACITY FACTOR (2010)	7.2%
	AVERAGE NET OPERATING HEAT RATE (ANOHR)[3]	10,641 Btu/kWh
(13)	PROJECTED UNIT FINANCIAL DATA	
	BOOK LIFE (YEARS)	25
	TOTAL INSTALLED COST (IN-SERVICE YEAR $/kW)	767.95
	DIRECT CONSTRUCTION COST ($/kW)	715.07
	AFUDC AMOUNT ($/kW)	43.84
	ESCALATION ($/kW)	9.04
	FIXED O&M ($/kW – Yr)	20.53
	VARIABLE O&M ($/MWh)	3.72
	K FACTOR	1.6696

1 REPRESENTS TOTAL BAYSIDE SITE.
2 CERTIFICATION NOT REQUIRED.
3 BASED ON 2010 YEAR.

SCHEDULE 9
(Page 3 of 8)
STATUS REPORT AND SPECIFICATIONS OF PROPOSED GENERATING FACILITIES
UTILITY: TAMPA ELECTRIC COMPANY

(1)	PLANT NAME AND UNIT NUMBER	BIG BEND CT 4
(2)	CAPACITY	
	A. SUMMER	57
	B. WINTER	62
(3)	TECHNOLOGY TYPE	COMBUSTION TURBINE
(4)	ANTICIPATED CONSTRUCTION TIMING	
	A. FIELD CONSTRUCTION START DATE	AUG 2008
	B. COMMERCIAL IN-SERVICE DATE	OCT 2009
(5)	FUEL	
	A. PRIMARY FUEL	NATURAL GAS
	B. ALTERNATE FUEL	DISTILLATE OIL
(6)	AIR POLLUTION CONTROL STRATEGY	WET LOW EMISSION; CO OXIDATION
(7)	COOLING METHOD	N/A
(8)	TOTAL SITE AREA[1]	APPROXIMATELY 1492 ACRES
(9)	CONSTRUCTION STATUS	PERMITTING
(10)	CERTIFICATION STATUS[2]	N/A
(11)	STATUS WITH FEDERAL AGENCIES	N/A
(12)	PROJECTED UNIT PERFORMANCE DATA	
	PLANNED OUTAGE FACTOR (POF)	2.6
	FORCED OUTAGE RATE (FOR)	1.0
	EQUIVALENT AVAILABILITY FACTOR (EAF)	95.4
	RESULTING CAPACITY FACTOR (2010)	7.2%
	AVERAGE NET OPERATING HEAT RATE (ANOHR)[3]	10,641 Btu/kWh
(13)	PROJECTED UNIT FINANCIAL DATA	
	BOOK LIFE (YEARS)	25
	TOTAL INSTALLED COST (IN-SERVICE YEAR $/kW)	847.32
	DIRECT CONSTRUCTION COST ($/kW)	791.66
	AFUDC AMOUNT ($/kW)	44.24
	ESCALATION ($/kW)	11.42
	FIXED O&M ($/kW – Yr)	20.53
	VARIABLE O&M ($/MWh)	3.72
	K FACTOR	1.6696

1 REPRESENTS TOTAL BIG BEND SITE.
2 CERTIFICATION NOT REQUIRED.
3 BASED ON 2010 YEAR.

SCHEDULE 9
(Page 4 of 8)
STATUS REPORT AND SPECIFICATIONS OF PROPOSED GENERATING FACILITIES
UTILITY: TAMPA ELECTRIC COMPANY

(1)	PLANT NAME AND UNIT NUMBER	FUTURE CT 1, 2, 3, 4, 5 & 6
(2)	CAPACITY	
	A. SUMMER	46
	B. WINTER	58
(3)	TECHNOLOGY TYPE	COMBUSTION TURBINE
(4)	ANTICIPATED CONSTRUCTION TIMING	
	A. FIELD CONSTRUCTION START DATE	JAN 2011
	B. COMMERCIAL IN-SERVICE DATE	MAY 2012
(5)	FUEL	
	A. PRIMARY FUEL	NATURAL GAS
	B. ALTERNATE FUEL	N/A
(6)	AIR POLLUTION CONTROL STRATEGY	WET LOW EMISSION; CO OXIDATION
(7)	COOLING METHOD	N/A
(8)	TOTAL SITE AREA	UNDETERMINED
(9)	CONSTRUCTION STATUS	PROPOSED
(10)	CERTIFICATION STATUS	UNDETERMINED
(11)	STATUS WITH FEDERAL AGENCIES	N/A
(12)	PROJECTED UNIT PERFORMANCE DATA	
	PLANNED OUTAGE FACTOR (POF)	2.6
	FORCED OUTAGE RATE (FOR)	1.0
	EQUIVALENT AVAILABILITY FACTOR (EAF)	95.4
	RESULTING CAPACITY FACTOR (2012)	11.9%
	AVERAGE NET OPERATING HEAT RATE (ANOHR)[1]	10,213 Btu/kWh
(13)	PROJECTED UNIT FINANCIAL DATA	
	BOOK LIFE (YEARS)	25
	TOTAL INSTALLED COST (IN-SERVICE YEAR $/kW)	1,012.72
	DIRECT CONSTRUCTION COST ($/kW)	870.34
	AFUDC AMOUNT ($/kW)	87.55
	ESCALATION ($/kW)	54.83
	FIXED O&M ($/kW – Yr)	23.49
	VARIABLE O&M ($/MWh)	3.99
	K FACTOR	1.6696

1 BASED ON IN-SERVICE YEAR.

SCHEDULE 9
(Page 5 of 8)
STATUS REPORT AND SPECIFICATIONS OF PROPOSED GENERATING FACILITIES
UTILITY: TAMPA ELECTRIC COMPANY

(1)	PLANT NAME AND UNIT NUMBER	POLK 6
(2)	CAPACITY	
	A. SUMMER	555
	B. WINTER	607
(3)	TECHNOLOGY TYPE	COMBINED CYCLE
(4)	ANTICIPATED CONSTRUCTION TIMING	
	A. FIELD CONSTRUCTION START DATE	JUN 2010
	B. COMMERCIAL IN-SERVICE DATE	JAN 2013
(5)	FUEL	
	A. PRIMARY FUEL	NATURAL GAS
	B. ALTERNATE FUEL	N/A
(6)	AIR POLLUTION CONTROL STRATEGY	SCR, DLN BURNERS
(7)	COOLING METHOD	MECH. DRAFT TWR. & POND
(8)	TOTAL SITE AREA[1]	APPROXIMATELY 4,347 ACRES
(9)	CONSTRUCTION STATUS	PROPOSED
(10)	CERTIFICATION STATUS[2]	N/A
(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)	92.8
	RESULTING CAPACITY FACTOR (2013)	68.5%
	AVERAGE NET OPERATING HEAT RATE (ANOHR)[3]	7,128 Btu/kWh
(13)	PROJECTED UNIT FINANCIAL DATA	
	BOOK LIFE (YEARS)	25
	TOTAL INSTALLED COST (IN-SERVICE YEAR $/kW)	926.00
	DIRECT CONSTRUCTION COST ($/kW)	736.33
	AFUDC AMOUNT ($/kW)	153.29
	ESCALATION ($/kW)	36.38
	FIXED O&M ($/kW – Yr)	6.32
	VARIABLE O&M ($/MWh)	4.09
	K FACTOR	1.6696

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

SCHEDULE 9
(Page 6 of 8)
STATUS REPORT AND SPECIFICATIONS OF PROPOSED GENERATING FACILITIES
UTILITY: TAMPA ELECTRIC COMPANY

(1)	PLANT NAME AND UNIT NUMBER	FUTURE CT 7 & 8
(2)	CAPACITY	
	A. SUMMER	86
	B. WINTER	96
(3)	TECHNOLOGY TYPE	COMBUSTION TURBINE
(4)	ANTICIPATED CONSTRUCTION TIMING	
	A. FIELD CONSTRUCTION START DATE	JAN 2014
	B. COMMERCIAL IN-SERVICE DATE	MAY 2015
(5)	FUEL	
	A. PRIMARY FUEL	NATURAL GAS
	B. ALTERNATE FUEL	N/A
(6)	AIR POLLUTION CONTROL STRATEGY	UNDETERMINED
(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)	1.1
	FORCED OUTAGE RATE (FOR)	1.0
	EQUIVALENT AVAILABILITY FACTOR (EAF)	96.9
	RESULTING CAPACITY FACTOR (2015)	17.3%
	AVERAGE NET OPERATING HEAT RATE (ANOHR)[1]	9,600 Btu/kWh
(13)	PROJECTED UNIT FINANCIAL DATA	
	BOOK LIFE (YEARS)	25
	TOTAL INSTALLED COST (IN-SERVICE YEAR $/kW)	948.68
	DIRECT CONSTRUCTION COST ($/kW)	779.90
	AFUDC AMOUNT ($/kW)	49.58
	ESCALATION ($/kW)	119.20
	FIXED O&M ($/kW – Yr)	15.48
	VARIABLE O&M ($/MWh)	3.86
	K FACTOR	1.6696

1 BASED ON IN-SERVICE YEAR.

SCHEDULE 9
(Page 7 of 8)
STATUS REPORT AND SPECIFICATIONS OF PROPOSED GENERATING FACILITIES
UTILITY: TAMPA ELECTRIC COMPANY

(1)	PLANT NAME AND UNIT NUMBER	FUTURE CT 9 & 10
(2)	CAPACITY	
	A. SUMMER	86
	B. WINTER	96
(3)	TECHNOLOGY TYPE	COMBUSTION TURBINE
(4)	ANTICIPATED CONSTRUCTION TIMING	
	A. FIELD CONSTRUCTION START DATE	JAN 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	UNDETERMINED
(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)	1.1
	FORCED OUTAGE RATE (FOR)	1.0
	EQUIVALENT AVAILABILITY FACTOR (EAF)	96.9
	RESULTING CAPACITY FACTOR (2015)	16.5%
	AVERAGE NET OPERATING HEAT RATE (ANOHR)[1]	9,599 Btu/kWh
(13)	PROJECTED UNIT FINANCIAL DATA	
	BOOK LIFE (YEARS)	25
	TOTAL INSTALLED COST (IN-SERVICE YEAR $/kW)	970.49
	DIRECT CONSTRUCTION COST ($/kW)	779.90
	AFUDC AMOUNT ($/kW)	50.72
	ESCALATION ($/kW)	139.88
	FIXED O&M ($/kW – Yr)	16.20
	VARIABLE O&M ($/MWh)	3.95
	K FACTOR	1.6696

1 BASED ON IN-SERVICE YEAR.

SCHEDULE 9
(Page 8 of 8)
STATUS REPORT AND SPECIFICATIONS OF PROPOSED GENERATING FACILITIES
UTILITY: TAMPA ELECTRIC COMPANY

(1)	PLANT NAME AND UNIT NUMBER	FUTURE CC 1
(2)	CAPACITY	
	A. SUMMER	555
	B. WINTER	607
(3)	TECHNOLOGY TYPE	COMBINED CYCLE
(4)	ANTICIPATED CONSTRUCTION TIMING	
	A. FIELD CONSTRUCTION START DATE	JUL 2013
	B. COMMERCIAL IN-SERVICE DATE	JAN 2017
(5)	FUEL	
	A. PRIMARY FUEL	NATURAL GAS
	B. ALTERNATE FUEL	N/A
(6)	AIR POLLUTION CONTROL STRATEGY	SCR, DLN BURNERS
(7)	COOLING METHOD	UNDETERMINED
(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)	92.8
	RESULTING CAPACITY FACTOR (2017)	68.9%
	AVERAGE NET OPERATING HEAT RATE (ANOHR)[1]	7,100 Btu/kWh
(13)	PROJECTED UNIT FINANCIAL DATA	
	BOOK LIFE (YEARS)	25
	TOTAL INSTALLED COST (IN-SERVICE YEAR $/kW)	1,014.17
	DIRECT CONSTRUCTION COST ($/kW)	736.33
	AFUDC AMOUNT ($/kW)	167.89
	ESCALATION ($/kW)	109.95
	FIXED O&M ($/kW – Yr)	6.92
	VARIABLE O&M ($/MWh)	4.48
	K FACTOR	1.6696

1 BASED ON IN-SERVICE YEAR.

Schedule 10

Status Report and Specifications of Proposed Directly Associated Transmission Lines

Units	Point of Origin and Termination	Number of Circuits	Right-of-Way	Circuit Length	Voltage	Anticipated In-Service Date	Anticipated Capital Investment	Substations	Participation with Other Utilities
Bayside Units 5 and 6	Bayside to Gannon to Hookers Pt	1	Possible road ROW required	19 mi	69kV	Spring 2009	$9.0 million	New 230/69kV transformer at Gannon	None
Bayside Units 3 and 4	Gannon	1	No new ROW required	0.1 mi	138kV	Fall 2009	$0.5 million	No new substations	None
Big Bend CT 4	Big Bend	1	No new ROW required	0.1 mi	230kV	Fall 2009	$0.5 million	No new substations	None
Polk 6	Polk	3	No new ROW required	0.7 mi	230kV	Spring 2012	$10 million	No new substations	None
Polk 6	Polk to Pebbledale 1	1	No new ROW required	13.5 mi	230kV	Summer 2012	$5 million	No new substations	None
Polk 6	Polk to Pebbledale 2	1	No new ROW required	9.9 mi	230kV	Summer 2012	$6 million	No new substations	None
Polk 6	Polk to FishHawk	1	Possible road ROW required	28 mi	230kV	Winter 2012	$64 million	No new substations	None

Other Planning Assumptions and Inform

Transmission Constraints and Impacts

Based on a variety of assessments and sensitivity studies of the Tampa Electric transmission system using year 2007 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 to current operations, with objectives including meeting compliance requirements in the most cost-effective and reliable manner, maximizing operational flexibility and minimizing 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, 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 amount annual prices for those commodities varied during the preceding five years.

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 judgement, 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 set 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 conservation 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 efficienc and conservation analysis are considered for utility program adoptior Each adopted measure is quantified into annual kW/kWh savings an is reflected in the demand and energy forecast. Measures with the highest RIM values are generally adopted first. Tampa Electric evaluates energy efficiency and conservation measures using a spreadsheet that comports with Rule 25-17.008, F.A.C., and 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 sid analysis, which examines various supply side alternatives for meeting future capacity requirements.

Tampa Electric uses the PROVIEW module of STRATEGIST, a compute 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 specifie reliability criteria, and determines the schedule of additions that have the lowest revenue requirements. The model uses production costing analysis and incremental capital and O&M expenses to project the revenue requirements and rank each plan.

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

Strategic Concerns

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

The results of the Integrated Resource Planning process provide Tampa Electric with a plan that is cost-effective while maintaining flexibility and adaptability to a dynamic regulatory and competitive environment. The new capacity additions are shown in Schedule 8.2. To meet the expected system demand and energy requirements over the next ten years and cost-effectively maintain system reliability, Tampa Electric is planning the addition of combustion turbines, Polk Unit 6 NGCC, and economical market purchases. For the purposes of this study, Big Bend CT Units 1 through 3 are assumed to be retired in May 2009.

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

Generation and Transmission Reliability Criteria

Generation

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

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

Transmission

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

Tampa Electric follows FRCC planning criteria as contained in its Principles and Guides for Planning Reliable Bulk Electric Systems. The FRCC planning guide is based on NERC Planning Reliability Standards, which are used to measure system adequacy. In general the NERC standards state that the transmission system will remain stable, within the applicable thermal and voltage rating limits, without cascading outages, under normal, single and multiple contingency conditions.

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 loadflow 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 of 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 SYSTEMS CONDITIONS	MAXIMUM ACCEPTABLE LOADING LIMIT FOR TRANSFORMERS AND TRANSMISSION LINES
All elements in service	100%
Single Contingency (pre-switching)	115%
Single Contingency (post-switching)	100%
Bus Outages (pre-switching)	115%
Bus Outages (post-switching)	100%

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

Transmission System Voltage Limits

TRANSMISSION SYSTEMS CONDITIONS	INDUSTRIAL SUBSTATION BUSES AT POINT-OF-SERVICE	69 KV BUSES	138KV AND 230 KV BUSES
Single Contingency (pre-switching)	0.925 - 1.050 p.u.	0.925 - 1.050 p.u.	0.950 - 1.060 p.u.
Single Contingency (post-switching)	0.925 - 1.050 p.u.	0.925 - 1.050 p.u.	0.950 - 1.060 p.u.
Bus Outages	0.925 - 1.050 p.u.	0.925 - 1.050 p.u.	0.950 - 1.060 p.u.

Available Transmission Transfer Capability (ATC) Criteria

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

Transmission Planning Assessment Practices

Base Case Operating Conditions

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

Single Contingency Planning Criteria

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

Multiple Contingency Planning Criteria

Double contingencies involving two branches out of service simultaneously are analyzed at 100% of peak load level. The Tampa Electric Company transmission system is designed such that these double contingencies do not cause violation of NERC criteria.

Transmission Construction and Upgrade Plans

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

Supply Side Resources Procurement Process

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

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

Energy Efficiency and Conservation and Energy Savings Durability

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

1. periodic system load reduction analyses for residential load management (Prime Time) to confirm the accuracy of Tampa Electric's load reduction estimation formulas;
2. billing analysis of various program participants (Energy Planner), compared to control groups to minimize the impact of weather abnormalities;
3. periodic DOE2 modeling of various program participants such as the Residential and Commercial Building Envelope programs to evaluate savings achieved in residential programs involving building components; components;
4. end-use sampling of building segments to validate savings achieved in Conservation Value and Commercial Indoor Lighting programs; and
5. in commercial programs such as Standby Generator and Commercial Load Management and Commercial Demand Response, the reductions are verified through metering of loads under control to determine the demand and energy savings.

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

Tampa Electric's Renewable Energy Programs

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

Through December 2007, Tampa Electric's Renewable Energy Program has approximately 2,400 customers purchasing over 3,400 blocks of renewable energy each month. With the permanent program status effective January 2007, the company doubled the renewable energy block size from 100 to 200 kWh per month. Participation for 2007 alone increased the total number of participants in the program by over 66 percent in one year's time.

Tampa Electric is one of the few electric utilities in the state that uses renewable generation produced in the State of Florida. The company's renewable generation portfolio is a mix of various technologies and renewable fuel sources, including four company-owned photovoltaic (PV) arrays totaling 39.5 kW. The PV arrays are installed at the Museum of Science and Industry, Walker Middle and Middleton High schools and Tampa Electric's Manatee Viewing Center. In addition, the company purchases excess renewable energy from nine customers in Tampa Electric's service area who have PV interconnect agreements. Other types of renewable energy have included a 30 kW micro-turbine utilizing landfill gas. 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 2007, participating customers have utilized over 10.5 GWh of renewable energy since the program inception.

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

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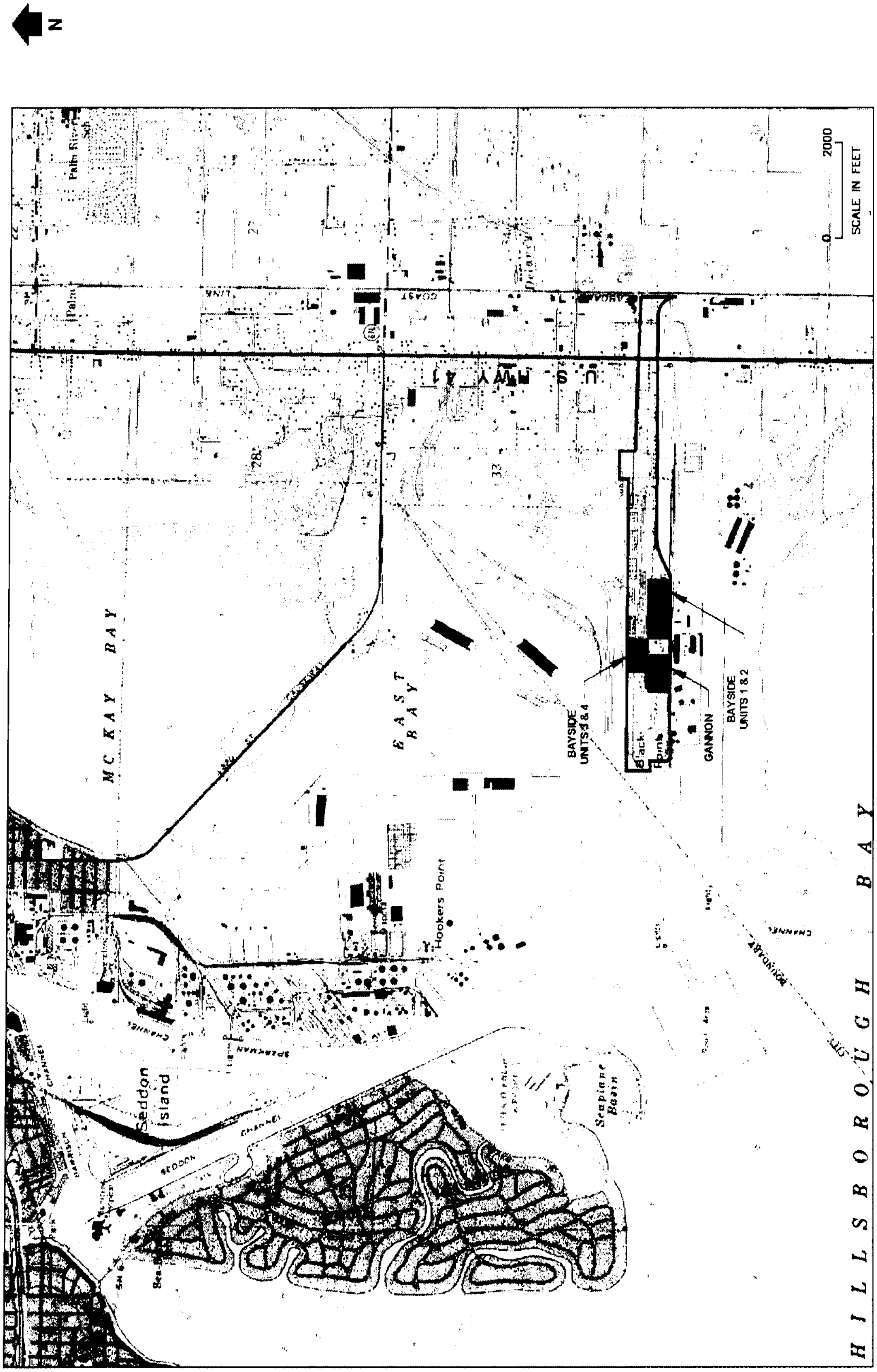
Environmental and Land Use Information

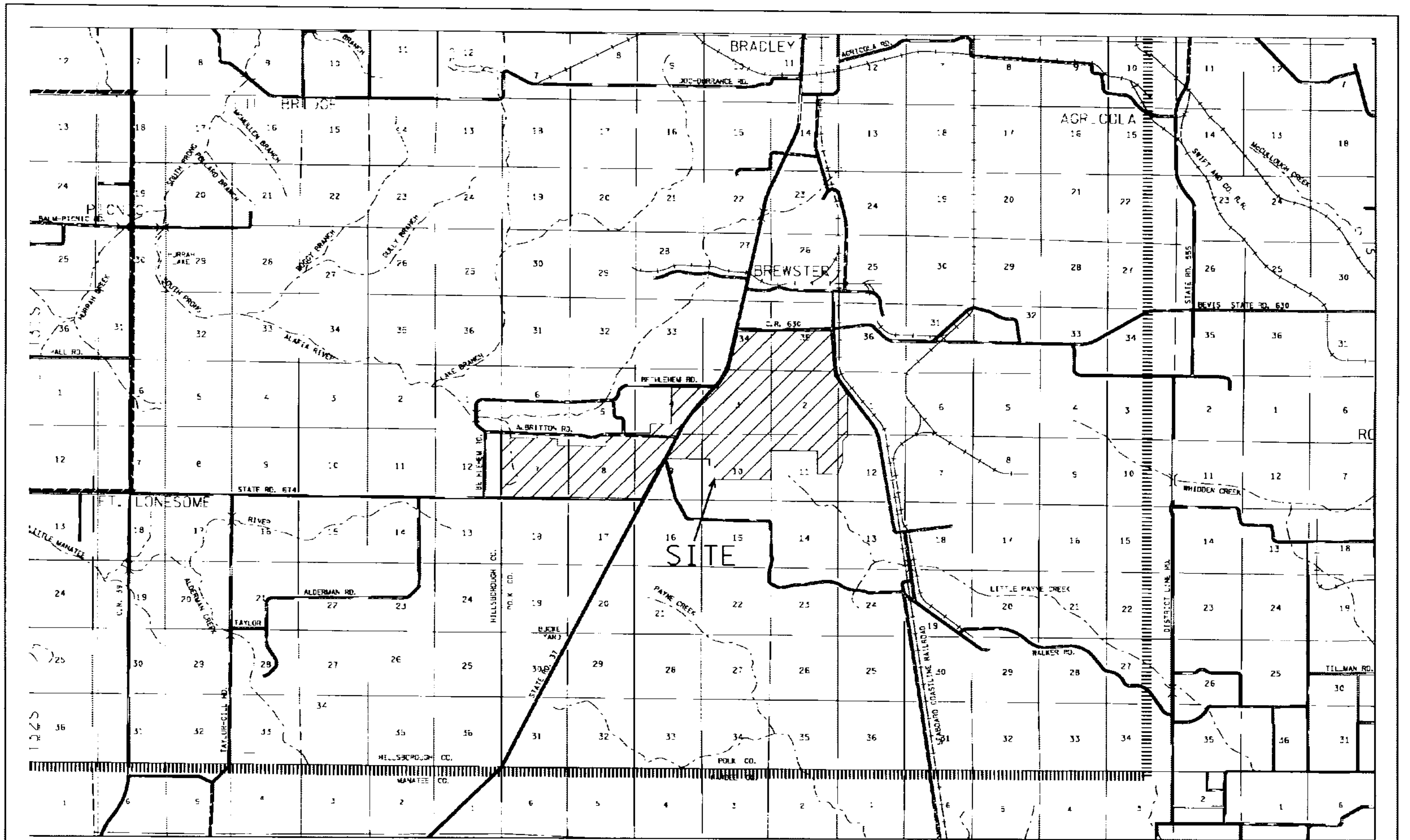
The future generating capacity additions identified in Chapter IV could occur at H.L. Culbreath Bayside Power Station, Polk Power Station, or Big Bend Power Station. The H.L. Culbreath Bayside Power Station site is located in Hillsborough County on Port Sutton Road (See Figure VI-1), Polk Power Station site is located in southwest Polk County close to the Hillsborough and Hardee County lines (See Figure VI-2) and Big Bend Power Station is located in Hillsborough County on Big Bend Road (See Figure VI-3). All facilities are currently permitted as existing power plant sites. Additional land use requirements and/or alternative site locations are not currently under consideration.

Figure VI-1



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

Figure VI-2



SITE LOCATION OF POLK POWER STATION

SOURCES: FDOT MAP, FLA, ECT

TAMPA ELECTRIC COMPANY

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

FILE NAME 403020.DGN
REVISION 3/9/2000 MMS

Figure VI-3

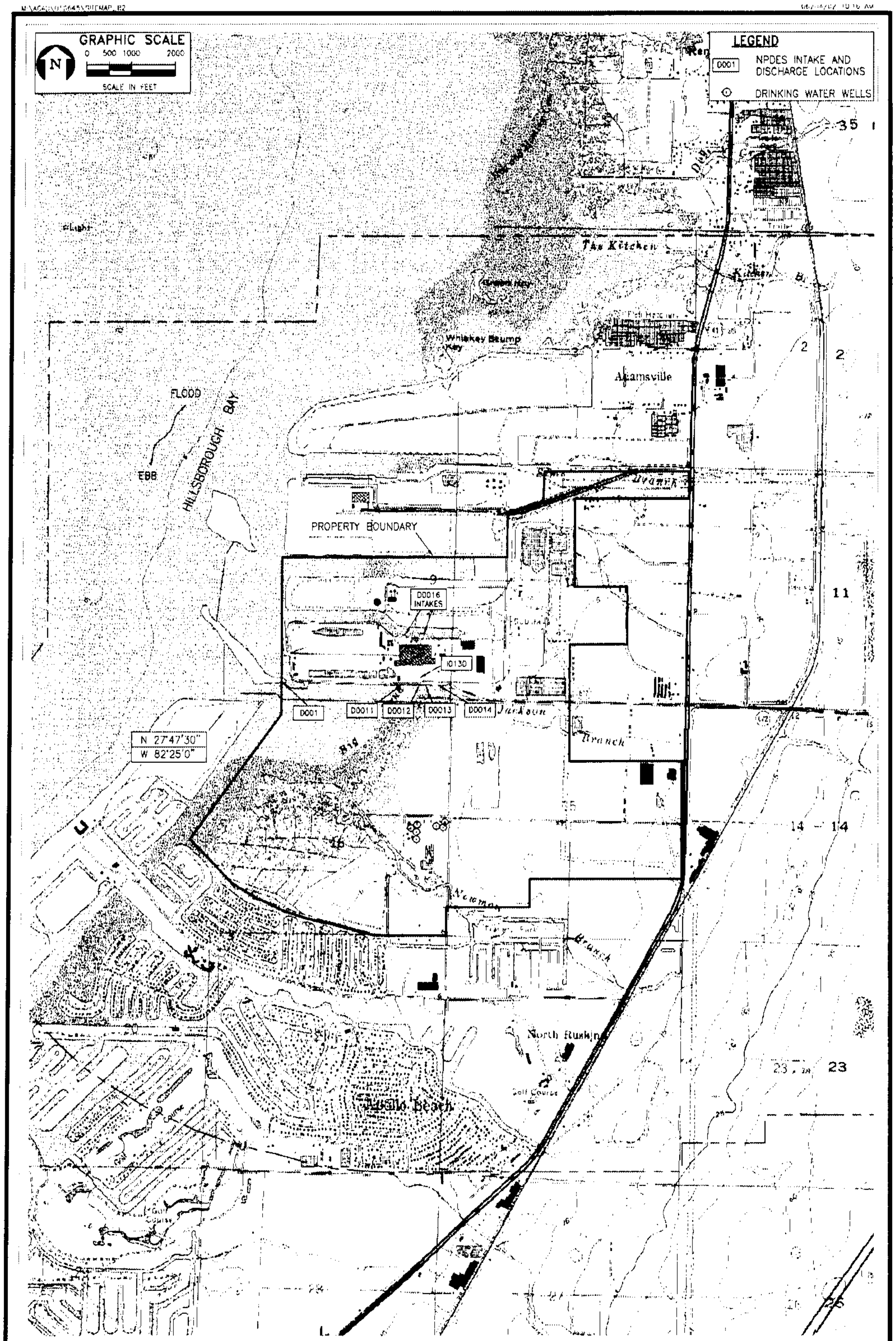


FIGURE XI .
SITE LOCATION MAP
TAMPA ELECTRIC COMPANY
BIG BEND STATION, TAMPA, FLORIDA
Source: USGS Quad : Gibsonton, FL, 1987; ECT, 2001.

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Environmental Consulting & Technology, Inc.