ORIGINAL

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RECORDS AND REPORTING

August 19, 1998

HAND DELIVERED

Ms. Blanca S. Bayo, Director
Division of Records and Reporting
Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, FL 32399-0850

Re: Tampa Electric Company's Revised 1998 Ten Year Site Plan

Dear Ms. Bayo:

Enclosed for filing on behalf of Tampa Electric Company are twenty-five (25) copies of Tampa Electric Company's Revised 1998 Ten Year Site Plan. The original 1998 Plan was filed March 31, 1998. The Revised 1998 Ten Year Site Plan includes an amended expansion plan that identifies Tampa Electric's next unit to be a 180 megawatt simple cycle combustion turbine to be placed in service in January 2001.

The change in Tampa Electric's expansion plan is the result of information that was developed during the company's planning process for meeting the 1999 fuel adjustment filing date. The company finalized its 1999 demand and energy forecast and ten year resource plan on August 7, 1998. The Revised 1998 Ten Year Site Plan reflects the company's latest planning assumptions and forecasts. All tables have been updated with the most current data that Tampa Electric has available. Pages in the Ten Year Site Plan that have been revised are marked "Revision 8/98" on the lower right-hand corner of the page. Tampa Electric will utilize the Revised 1998 Ten Year Site Plan in its August 25, 1998 presentation to the Commission.

Please contact Mark Ward, Manager, Resource Planning (813 228-1542) if there are questions concerning the revised plan.

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

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Thank you for your assistance in connection with this matter.

Sincerely,

James D. Beasley

JDB/pp
Enclosure

cc: Michael Haff (w/enc.)

TECO

TAMPA ELECTRIC

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

JANUARY 1998 TO DECEMBER 2007

Revised August 1998

445.002 8/98

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

January 1998 to December 2007

TAMPA ELECTRIC COMPANY
Tampa, Florida

Revised August 1998

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CHAPTER IV

LIST OF FIGURES

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TAMPA ELECTRIC COMPANY
CODE IDENTIFICATION SHEET

Unit Type:	CT	=	Combustion Turbine
	CC	=	Combined Cycle
	CG	=	Coal Gasifier
	D	=	Diesel
	FS	=	Fossil Steam
	HRSG	=	Heat Recovery Steam Generator
	IGCC	=	Integrated Gasification Combined Cycle
	ST	=	Steam Turbine
Unit Status:	P	=	Planned
	T	=	Regulatory Approval Received
Fuel Type:	BIT	=	Bituminous Coal
	C	=	Coal
	PC	=	Petroleum Coke
	HO	=	Heavy Oil (#6 Oil)
	LO	=	Light Oil (#2 Oil)
	NG	=	Natural Gas
	WH	=	Waste Heat
Environmental:	CL	=	Closed Loop Water Cooled
	CLT	=	Cooling Tower
	EP	=	Electrostatic Precipitator
	FQ	=	Fuel Quality
	LS	=	Low Sulfur
	SC	=	Scrubber
	OLS	=	Open Loop Cooling Water System
	OTS	=	Once-Through System
	NO	=	Not Required
Transportation:	PL	=	Pipeline
	TK	=	Truck
	RR	=	Railroad
	WA	=	Water
Other:	N	=	None

CHAPTER I

DESCRIPTION OF EXISTING FACILITIES

Description of Electric Generating Facilities

Tampa Electric has six generating plants, consisting of fossil steam units, combustion turbine peaking units, diesel units, and an integrated gasification combined cycle unit. The six generating plants include Big Bend, Gannon, Hookers Point, Dinner Lake, Phillips, and Polk. Big Bend and Gannon consist of both steam-generating units and combustion turbine units.

Generation by coal continues to be the most economical fuel alternative for satisfying Tampa Electric's energy requirements. Tampa Electric has eleven coal-fired units. Ten of these units are fired with pulverized coal, while the Polk unit is fired with synthetic gas produced from gasified coal and other carbonaceous fuels. The Polk unit is an integrated gasification combined cycle unit (IGCC). This technology integrates state-of-the-art environmental processes for creating a clean fuel gas from a variety of feedstocks with the efficiency benefits of combined cycle generation equipment.

Generating units at Hookers Point and Phillips are residual oil fired units. Dinner Lake is fueled by natural gas and oil and is currently on long term reserve standby. The four combustion turbines at Big Bend and Gannon Stations use distillate oil as the primary fuel. Total net system generation in 1997 was 17,734 GWh.

Schedule 1

TABLE I-1
Existing Generating Facilities
August 1998 Status

(1) Plant Name	(2) Unit No.	(3) Location	(4) Unit Type	(5) Fuel Pri	(6) Fuel Alt	(7) Fuel Transport Pri	(8) Fuel Transport Alt	(9) Alt Fuel Days	(10) Commercial In-Service Mo/Yr	(11) Expected Retirement Mo/Yr	(12) Gen. Max. Nameplate KW	(13) Net Capability Summer MW	(14) Net Capability Winter MW
Big Bend		Hillsborough Co. 14/31S/19E									1,998,000	1,852	1,919
	1		FS	C	N	WA	N	0	10/70	Unknown	445,500	421	431
	2		FS	C	N	WA	N	0	4/73	"	445,500	416	426
	3		FS	C	N	WA	N	0	5/76	"	445,500	428	438
	4		FS	C	N	WA	N	0	2/85	"	486,000	442	447
	CT1		CT	LO	N	WA	TK	0	2/69	"	18,000	15	17
	CT2&3		CT	LO	N	WA	TK	0	11/74	"	157,500	130	160
Dinner Lake**		Highland Co. 12-055									12,650	11	11
	1		FS	NG	HO	PL	TK	2	12/66	Unknown	12,650	11	11
Gannon		Hillsborough Co. 4/30S/19E									1,319,880	1,150	1,197
	1		FS	C	N	WA	RR	0	9/57	Unknown	125,000	114	114
	2		FS	C	N	WA	RR	0	11/58	"	125,000	108	108
	3		FS	C	N	WA	RR	0	10/60	"	179,520	155	155
	4		FS	C	N	WA	RR	0	11/63	"	187,500	169	179
	5		FS	C	N	WA	RR	0	11/65	"	239,360	227	232
	6		FS	C	N	WA	RR	0	10/67	"	445,500	362	392
	CT1		CT	LO	N	WA	TK	0	3/69	"	18,000	15	17
Hookers Pt.		Hillsborough Co. 19/29S/19E									232,600	207	215
	1		FS	HO	N	WA	N	0	7/48	01/03*	33,000	32	34
	2		FS	HO	N	WA	N	0	6/50	01/03*	34,500	32	34
	3		FS	HO	N	WA	N	0	8/50	01/03*	34,500	32	34
	4		FS	HO	N	WA	N	0	10/53	01/03*	49,000	41	43
	5		FS	HO	N	WA	N	0	5/55	01/03*	81,600	70	70
Phillips		Highland Co. 12-055									42,030	37	37
	1		D	HO	N	TK	N	0	6/83	Unknown	19,215	17	17
	2		D	HO	N	TK	N	0	6/83	Unknown	19,215	17	17
	3 ***		HRSG	WH	N	N	N	0	6/83	Unknown	3,600	3	3
Polk		Polk Co. 2,3/32S/23E									326,299	250	250
	1		IGCC	C	LO	WA/TK	TK	0	9/96	Unknown	326,299	250	250
											TOTAL	3,507	3,629

* This is currently being reviewed by Tampa Electric Company

** Unit placed on long-term reserve standby 03/01/94

*** Unit on full forced outage with an undetermined return to service date

TABLE 1-2
Existing Generating Facilities/Land Use and Investment

Plant Name	Land Area		Plant Capital Investment ($000)			
	Total Acres	In Use Acres	Land	Structures & Improvements	Equipment	Total [1]
Hookers Point Station	25	25	$ 438	$ 7,867	$ 45,061	$ 53,366
Big Bend Station	1,124	1,124	5,147	157,914	852,843	1,015,904
Francis J. Gannon Station	213	213	1,556	60,942	389,843	452,341
Dinner Lake - Sebring	2	2	15	134	3,487	3,636
Phillips - Sebring	36	36	179	288	59,356	59,823
Combustion Turbine - Gannon	1	1	0	75	1,753	1,828
Combustion Turbines - Big Bend	75	75	834	1,516	21,138	23,488
Miscellaneous Production [2]	47	47	94	6,661	5,749	12,504
Polk Power Station	4,347	4,347	18,919	110,782	385,061	514,767
TOTALS			$27,182	$346,184	$1,764,291	$2,137,657

[1] Dollar values rounded to the nearest $1,000.

[2] Power Plant Services, Production Service Complex, Production Warehouse, Central Testing Lab, Production Training Facilities

TABLE I-3
Existing Generating Facilities/Environmental Considerations for Steam Generating Units

Cooling		Flue Gas Cleaning			
Plant Name	**Unit**	**Particulate**	**SO_x**	**NO_x**	**Type**
Francis J. Gannon	1	EP	LS	NR	OTS
	2	EP	LS	NR	OTS
	3	EP	LS	NR	OTS
	4	EP	LS	NR	OTS
	5	EP	LS	NR	OTS
	6	EP	LS	NR	OTS
	CT 1	NR	LS	NR	---
Hookers Point	1	NR	LS	NR	OTS
	2	NR	LS	NR	OTS
	3	NR	LS	NR	OTS
	4	NR	LS	NR	OTS
	5	NR	LS	NR	OTS
Big Bend	1	EP	(1)	NR	OTS
	2	EP	(1)	NR	OTS
	3	EP	SC	(2)	(4)
	4	EP	SC	(3)	(4)
	CT 1	NR	LS	NR	---
	CT 2	NR	LS	NR	---
	CT 3	NR	LS	NR	---
Dinner Lake	1	NR	FQ	NR	OTS
Phillips	1	NR	FQ	(2)	CLT
	2	NR	FQ	(2)	CLT
	HRSG 3	NA	NA	NA	NA
Polk	IGCC 1	NR	AGR	NI	OLS

CLT = Cooling Tower
CT = Combustion Turbine
EP = Electrostatic Precipitator
FQ = Fuel Quality
LS = Low Sulfur
SC = Scrubber
OTS = Once-Through System
HRSG = Heat Recovery Steam Generator

IGCC = Integrated Gasification Combined Cycle
AGR = Acid Gas Removal
NI = Nitrogen Injection
CR = Cooling Reservoir
OLS = Open Loop Cooling Water System
NA = Not Applicable
NR = Not Required

August 1998 Status.
Source: Tampa Electric Company

(1) Coal blending of units 1 and 2 will be replaced with a scrubber in 2000 to comply with Phase II of CAAA.
(2) NO_x controlled through unit operation.
(3) NO_x controlled through unit design and operation.
(4) OTS with fine mesh screens to minimize entrainment.

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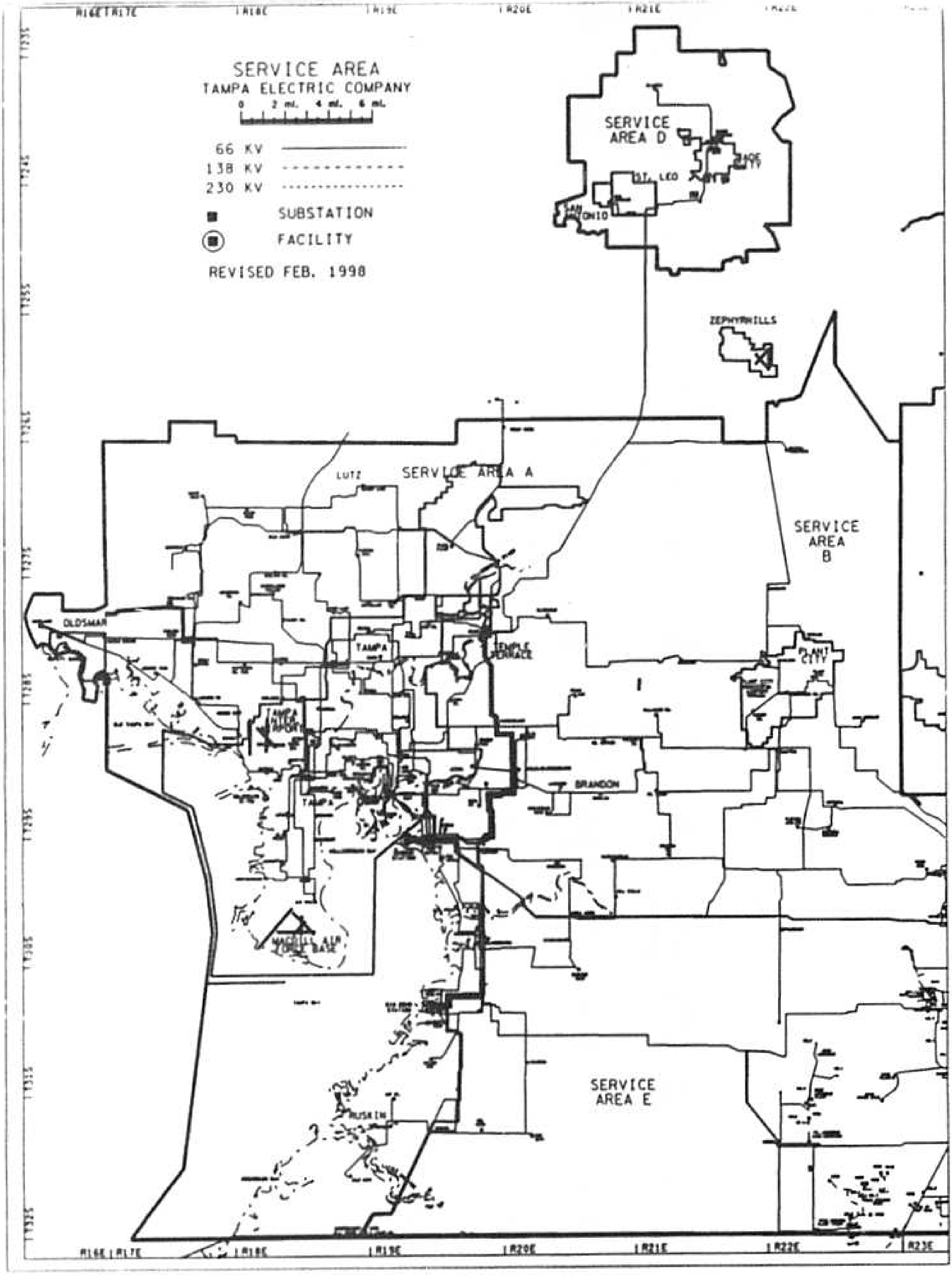

SERVICE AREA
TAMPA ELECTRIC COMPANY
0 2 mi. 4 mi. 6 mi.
66 KV
138 KV
230 KV
SUBSTATION
FACILITY
REVISED FEB. 1998
SERVICE AREA D
ST. LEO
ZEPHYRHILLS
LUTZ
SERVICE AREA A
SERVICE AREA B
OLDSMAR
TAMPA
TEMPLE TERRACE
PLANT CITY
BRANDON
SERVICE AREA E
RUSKIN
R16E R17E
R18E
R19E
R20E
R21E
R22E
R23E

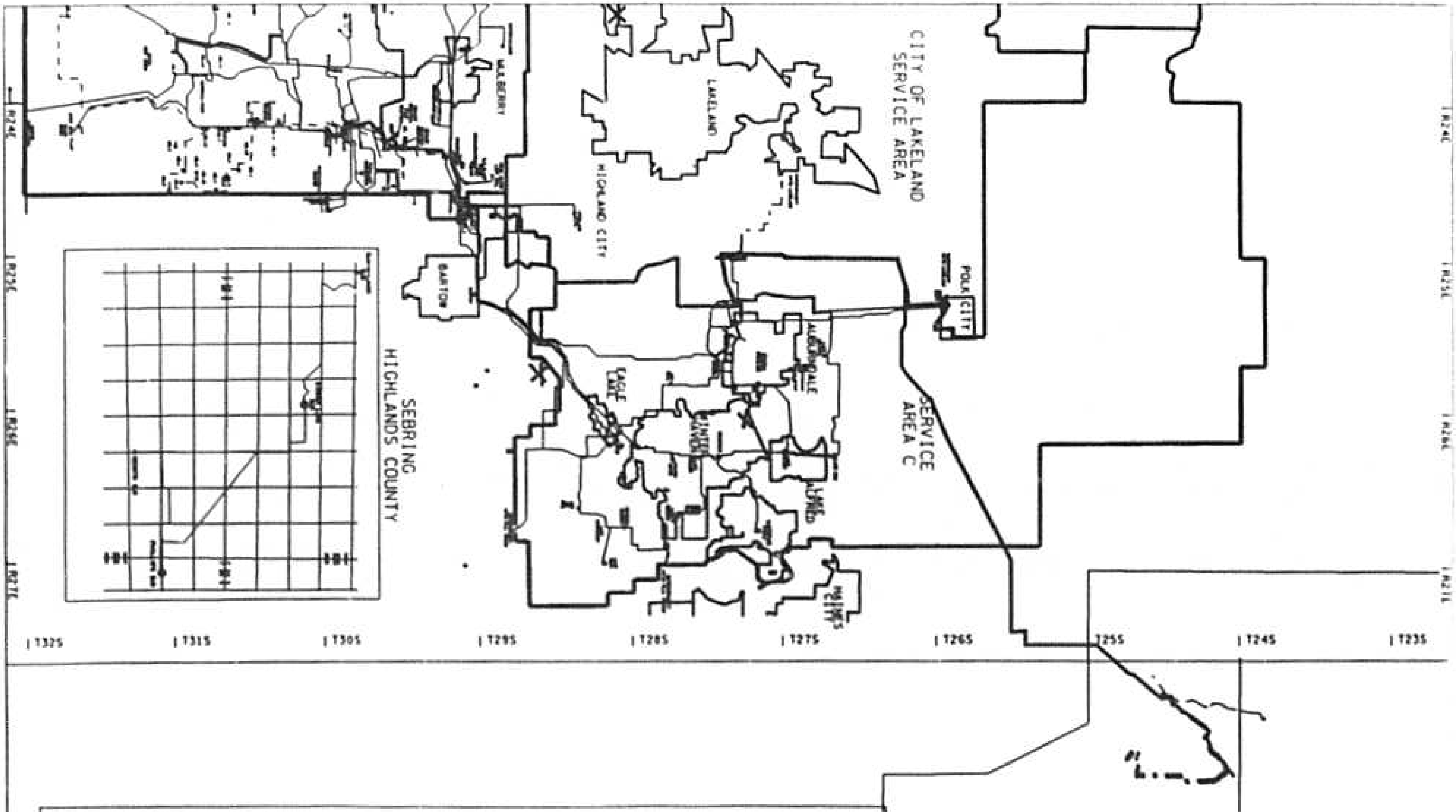


FIGURE I-1

TAMPA ELECTRIC RETAIL CUSTOMER SERVICE AREA

SOURCE: TAMPA ELECTRIC.

TAMPA ELECTRIC COMPANY

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

I-6

CHAPTER II

FORECAST OF ELECTRIC POWER, DEMAND, AND ENERGY CONSUMPTION

Schedule 2.1

TABLE II-1
History and Forecast of Energy Consumption and
Number of Customers by Customer Class
(Page 1 of 3)

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
	Rural and Residential					Commercial		
Year	Population**	Members Per Household	GWH	Average* No. of Customers	Average KWH Consumption Per Customer	GWH	Average* No. of Customers	Average KWH Consumption Per Customer
1988	809,468	2.5	4,967	383,717	12,944	3,814	48,713	78,295
1989	822,621	2.5	5,214	393,278	13,258	4,062	49,780	81,599
1990	834,054	2.5	5,412	401,172	13,490	4,231	50,287	84,137
1991	843,203	2.5	5,507	407,235	13,523	4,274	50,774	84,177
1992	853,990	2.5	5,560	412,970	13,463	4,333	51,727	83,767
1993	866,134	2.5	5,706	420,051	13,584	4,432	52,492	84,432
1994	879,069	2.5	5,947	427,594	13,908	4,583	53,482	85,692
1995	892,874	2.5	6,352	436,091	14,566	4,710	54,375	86,621
1996	910,855	2.5	6,607	445,664	14,825	4,815	55,479	86,790
1997	928,731	2.4	6,500	456,175	14,249	4,902	56,981	86,029
1998~	944,689	2.4	6,877	465,880	14,761	5,039	58,472	86,178
1999	964,345	2.4	7,067	475,958	14,848	5,272	59,564	88,510
2000	986,239	2.4	7,298	486,104	15,013	5,499	60,493	90,903
2001	1,006,167	2.4	7,487	496,132	15,091	5,720	61,594	92,866
2002	1,025,335	2.4	7,699	505,574	15,228	5,932	62,752	94,531
2003	1,042,326	2.4	7,945	514,538	15,441	6,112	63,875	95,687
2004	1,058,678	2.4	8,201	523,101	15,678	6,298	64,948	96,970
2005	1,073,895	2.4	8,478	531,290	15,957	6,483	65,975	98,264
2006	1,088,493	2.4	8,746	539,188	16,221	6,668	66,964	99,576
2007	1,102,801	2.4	8,973	546,990	16,404	6,844	67,955	100,714

August 1998 Status.

* Average of end-of-month customers for the calendar year.
** Hillsborough County population.
~ Includes actual data through June 1998.

Schedule 2.2

TABLE II-1
History and Forecast of Energy Consumption and
Number of Customers by Customer Class
(Page 2 of 3)

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
	Industrial						
Year	GWH	Average* No. of Customers	Average KWH Consumption Per Customer	Railroads and Railways GWH	Street & Highway Lighting GWH	Other Sales to Public Authorities GWH	Total Sales to Ultimate Consumers GWH
1988	2,749	561	4,900,178	0	40	856	12,426
1989	2,672	536	4,985,075	0	40	907	12,896
1990	2,818	518	5,440,154	0	41	934	13,436
1991	2,669	515	5,182,524	0	42	963	13,455
1992	2,625	509	5,157,171	0	43	991	13,552
1993	2,236	509	4,392,927	0	45	1,028	13,447
1994	2,278	511	4,457,926	0	46	1,078	13,932
1995	2,362	491	4,810,591	0	51	1,125	14,600
1996	2,305	504	4,573,413	0	53	1,150	14,929
1997	2,465	629	4,027,778	0	53	1,170	15,090
1998~	2,406	675	3,567,407	0	54	1,207	15,585
1999	2,416	692	3,491,329	0	57	1,248	16,060
2000	2,524	692	3,647,399	0	59	1,283	16,663
2001	2,522	692	3,644,509	0	61	1,318	17,108
2002	2,418	692	3,494,220	0	64	1,353	17,466
2003	2,432	692	3,514,451	0	66	1,388	17,943
2004	2,436	692	3,520,231	0	68	1,423	18,426
2005	2,446	692	3,534,682	0	70	1,458	18,935
2006	2,445	692	3,533,237	0	73	1,493	19,425
2007	2,436	692	3,520,231	0	75	1,528	19,856

August 1998 Status.

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

~ Includes actual data through June 1998.

Schedule 2.3

TABLE II-1
History and Forecast of Energy Consumption and
Number of Customers by Customer Class
(Page 3 of 3)

(1) Year	(2) Sales for Resale GWH	(3) Utility Use++ & Losses GWH	(4) Net Energy** for Load GWH	(5) Other* Customers (Average No.)	(6) Total* No. of Customers
1988	0	725	13,151	3,448	436,439
1989	0	809	13,704	3,563	447,157
1990	0	569	14,005	3,695	455,672
1991	129	695	14,279	3,736	462,260
1992	214	671	14,437	3,790	468,996
1993	246	807	14,500	3,958	477,010
1994	163	636	14,731	4,111	485,698
1995	212	870	15,682	4,241	495,198
1996	399	760	16,088	4,391	506,038
1997	507	731	16,328	4,583	518,368
1998~	412	825	16,822	4,678	529,704
1999	402	850	17,312	4,770	540,983
2000	324	882	17,869	4,865	552,154
2001	346	906	18,360	4,961	563,379
2002	349	924	18,739	5,055	574,073
2003	354	950	19,247	5,146	584,251
2004	362	974	19,762	5,233	593,974
2005	337	1,001	20,273	5,316	603,273
2006	338	1,028	20,791	5,396	612,240
2007	342	1,051	21,249	5,476	621,113

August 1998 Status.

* Average of end-of-month customers for the calendar year.
** Output to line including energy supplied by purchased cogeneration.
++ Utility Use and Losses include accrued sales.
~ Includes actual data through June 1998.

Schedule 3.1

TABLE II-2
History and Forecast of Summer Peak Demand
Base Case
(Page 1 of 3)

(1) Year	(2) Total+	(3) Wholesale++	(4) Retail+	(5) Interruptible	(6) Residential Load Management	(7) Residential Conservation	(8) Comm./Ind. Load Management #	(9) Comm./Ind. Conservation	(10) Net Firm Demand	
1988	2,501	0	2,501	221	75	18	1	7	2,179	
1989	2,583	0	2,583	315	71	19	2	9	2,233	*
1990	2,659	0	2,659	311	72	20	4	9	2,279	*
1991	2,750	39	2,711	265	71	23	1	10	2,341	
1992	2,856	50	2,806	294	77	25	3	10	2,401	*
1993	2,951	60	2,891	273	91	28	6	11	2,492	*
1994	2,865	69	2,796	200	97	31	8	11	2,451	*
1995	3,028	81	2,947	170	98	34	8	13	2,624	
1996	3,146	92	3,054	234	98	41	18	16	2,647	
1997	3,167	106	3,061	225	89	45	17	15	2,677	*
1998~	3,313	112	3,201	220	102	50	18	17	2,794	
1999	3,442	128	3,314	222	106	54	20	21	2,891	
2000	3,557	129	3,428	233	109	58	20	21	2,987	
2001	3,676	141	3,535	233	112	62	21	24	3,083	
2002	3,761	141	3,620	219	115	65	22	24	3,175	
2003	3,869	141	3,728	220	118	69	22	27	3,272	
2004	3,971	141	3,830	219	121	72	23	27	3,368	
2005	4,068	131	3,937	221	124	75	24	30	3,463	
2006	4,170	132	4,038	222	126	78	24	30	3,558	
2007	4,275	132	4,143	222	129	81	25	32	3,654	

August 1998 Status.

* Not coincident with system peak.
\+ Includes residential and commercial/industrial conservation.
++ Includes sales to FPC, Wauchula, Ft. Meade, St. Cloud and Reedy Creek.
\# Commercial/Industrial Load Management includes Standby Generator.
~ Includes actual data through June 1998.

Schedule 3.1

TABLE II-2
History and Forecast of Summer Peak Demand
High Case
(Page 2 of 3)

(1) Year	(2) Total+	(3) Wholesale++	(4) Retail+	(5) Interruptible	(6) Residential Load Management	(7) Residential Conservation	(8) Comm./Ind. Load Management #	(9) Comm./Ind. Conservation	(10) Net Firm Demand	
1988	2,501	0	2,501	221	75	18	1	7	2,179	
1989	2,583	0	2,583	315	71	19	2	9	2,233	*
1990	2,659	0	2,659	311	72	20	4	9	2,279	*
1991	2,750	39	2,711	265	71	23	1	10	2,341	
1992	2,856	50	2,806	294	77	25	3	10	2,401	*
1993	2,951	60	2,891	273	91	28	6	11	2,492	*
1994	2,865	69	2,796	200	97	31	8	11	2,451	*
1995	3,028	81	2,947	170	98	34	8	13	2,624	
1996	3,146	92	3,054	234	98	41	18	16	2,647	
1997	3,167	106	3,061	225	89	45	17	15	2,677	*
1998~	3,331	112	3,219	224	103	50	18	17	2,807	
1999	3,481	129	3,352	229	106	54	20	21	2,922	
2000	3,617	130	3,487	242	111	59	20	21	3,034	
2001	3,759	141	3,618	246	114	63	21	24	3,150	
2002	3,867	141	3,726	234	117	66	22	24	3,263	
2003	4,010	142	3,868	238	121	70	22	27	3,390	
2004	4,138	143	3,995	239	124	73	23	27	3,509	
2005	4,268	132	4,136	245	127	77	24	30	3,633	
2006	4,411	133	4,278	246	131	80	24	30	3,767	
2007	4,549	133	4,416	249	134	83	25	32	3,893	

August 1998 Status.

- * Not coincident with system peak.
- \+ Includes residential and commercial/industrial conservation.
- ++ Includes sales to FPC, Wauchula, Ft. Meade, St. Cloud and Reedy Creek.
- \# Commercial/Industrial Load Management includes Standby Generator.
- ~ Includes actual data through June 1998.

Schedule 3.1

TABLE II-2
History and Forecast of Summer Peak Demand
Low Case
(Page 3 of 3)

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	
Year	Total+	Wholesale++	Retail+	Interruptible	Residential Load Management	Residential Conservation	Comm./Ind. Load Management #	Comm./Ind. Conservation	Net Firm Demand	
1988	2,501	0	2,501	221	75	18	1	7	2,179	
1989	2,583	0	2,583	315	71	19	2	9	2,233	*
1990	2,659	0	2,659	311	72	20	4	9	2,279	*
1991	2,750	39	2,711	265	71	23	1	9	2,341	
1992	2,856	50	2,806	294	77	25	3	10	2,401	*
1993	2,951	60	2,891	273	91	28	6	11	2,492	*
1994	2,865	69	2,796	200	97	31	8	11	2,451	*
1995	3,028	81	2,947	170	98	34	8	13	2,624	
1996	3,146	92	3,054	234	98	41	18	16	2,647	
1997	3,167	106	3,061	225	89	45	17	15	2,677	*
1998~	3,293	112	3,181	218	102	50	18	17	2,776	
1999	3,398	128	3,270	214	105	54	20	21	2,856	
2000	3,501	128	3,373	223	108	58	20	21	2,943	
2001	3,591	139	3,452	220	110	61	21	24	3,016	
2002	3,647	140	3,507	202	113	64	22	24	3,082	
2003	3,737	141	3,596	200	116	68	22	27	3,163	
2004	3,804	141	3,663	199	118	71	23	27	3,225	
2005	3,874	130	3,744	199	120	73	24	30	3,298	
2006	3,943	130	3,813	197	122	76	24	30	3,364	
2007	4,016	130	3,886	195	124	79	25	32	3,431	

August 1998 Status.

- * Not coincident with system peak.
- \+ Includes residential and commercial/industrial conservation.
- ++ Includes sales to FPC, Wauchula, Ft. Meade, St. Cloud and Reedy Creek.
- # Commercial/Industrial Load Management includes Standby Generator.
- ~ Includes actual data through June 1998.

Schedule 3.2

TABLE II-3
History and Forecast of Winter Peak Demand
Base Case
(Page 1 of 3)

(1) Year	(2) Total+	(3) Wholesale++	(4) Retail+	(5) Interruptible	(6) Residential Load Management	(7) Residential Conservation =	(8) Comm./Ind. Load Management #	(9) Comm./Ind. Conservation	(10) Net Firm Demand
1988/89	2,769	0	2,769	242	127	168	1	17	2,270 *
1989/90	2,914	0	2,914	178	107	183	0	19	2,427
1990/91	2,638	0	2,638	227	139	196	0	20	2,056
1991/92	3,043	53	2,990	294	151	207	1	21	2,316
1992/93	3,130	63	3,067	281	168	221	4	23	2,370
1993/94	3,003	69	2,934	181	177	241	7	25	2,303
1994/95	3,539	74	3,465	240	227	270	8	25	2,695
1995/96	3,765	98	3,667	152	245	291	8	25	2,946
1996/97	3,577	109	3,468	228	153	325	18	25	2,719
1997/98	3,185	99	3,086	210	151	349	17	26	2,333
1998/99**	4,058	131	3,927	200	240	379	18	27	3,063
1999/00	4,208	131	4,077	212	247	409	19	28	3,162
2000/01	4,355	144	4,211	212	255	439	19	30	3,256
2001/02	4,481	144	4,337	199	262	469	20	31	3,356
2002/03	4,614	145	4,469	200	269	496	21	32	3,451
2003/04	4,743	145	4,598	199	276	522	21	33	3,547
2004/05	4,867	134	4,733	201	283	548	22	34	3,645
2005/06	4,997	136	4,861	201	289	573	22	35	3,741
2006/07	5,128	136	4,992	202	295	598	23	36	3,838
2007/08	5,236	136	5,100	183	300	622	23	37	3,935

August 1998 Status.

*	Not coincident with system peak.
+	Includes residential and commercial/industrial conservation.
++	Includes sales to FPC, Wauchula, Ft. Meade, St. Cloud and Reedy Creek.
#	Commercial/Industrial Load Management includes Standby Generator.
**	Forecasted Values: 1998/99 - 2007/08. Includes actual data through June 1998.
=	Residential conservation includes code changes.

Schedule 3.2

TABLE II-3
History and Forecast of Winter Peak Demand
High Case
(Page 2 of 3)

(1) Year	(2) Total+	(3) Wholesale++	(4) Retail+	(5) Interruptible	(6) Residential Load Management	(7) Residential Conservation =	(8) Comm./Ind. Load Management #	(9) Comm./Ind. Conservation	(10) Net Firm Demand
1988/89	2,769	0	2,769	242	127	168	1	17	2,270 *
1989/90	2,914	0	2,914	178	107	183	0	19	2,427
1990/91	2,638	0	2,638	227	139	196	0	20	2,056
1991/92	3,043	53	2,990	294	151	207	1	21	2,316
1992/93	3,130	63	3,067	281	168	221	4	23	2,370
1993/94	3,003	69	2,934	181	177	241	7	25	2,303
1994/95	3,539	74	3,465	240	227	270	8	25	2,695
1995/96	3,765	98	3,667	152	245	291	8	25	2,946
1996/97	3,577	109	3,468	228	153	325	18	25	2,719
1997/98	3,185	99	3,086	210	151	349	17	26	2,333
1998/99**	4,092	131	3,961	205	241	382	18	27	3,088
1999/00	4,270	132	4,138	221	250	414	19	28	3,206
2000/01	4,430	144	4,286	224	259	446	19	30	3,308
2001/02	4,580	145	4,435	212	267	478	20	31	3,427
2002/03	4,739	145	4,594	215	275	507	21	32	3,544
2003/04	4,910	146	4,764	218	284	536	21	33	3,672
2004/05	5,062	136	4,926	221	291	565	22	34	3,793
2005/06	5,227	136	5,091	223	299	593	22	35	3,919
2006/07	5,404	138	5,266	225	306	621	23	36	4,055
2007/08	5,558	138	5,420	205	314	648	23	37	4,193

August 1998 Status.

* Not coincident with system peak.
\+ Includes residential and commercial/industrial conservation.
++ Includes sales to FPC, Wauchula, Ft. Meade, St. Cloud and Reedy Creek.
\# Commercial/Industrial Load Management includes Standby Generator.
** Forecasted Values: 1998/99 - 2007/08.
Includes actual data through June 1998.
= Residential conservation includes code changes.

Schedule 3.2

TABLE II-3
History and Forecast of Winter Peak Demand
Low Case
(Page 3 of 3)

(1) Year	(2) Total+	(3) Wholesale++	(4) Retail+	(5) Interruptible	(6) Residential Load Management	(7) Residential Conservation =	(8) Comm./Ind. Load Management #	(9) Comm./Ind. Conservation	(10) Net Firm Demand
1988/89	2,769	0	2,769	242	127	168	1	17	2,270 *
1989/90	2,914	0	2,914	178	107	183	0	19	2,427
1990/91	2,638	0	2,638	227	139	196	0	20	2,056
1991/92	3,043	53	2,990	294	151	207	1	21	2,316
1992/93	3,130	63	3,067	281	168	221	4	23	2,370
1993/94	3,003	69	2,934	181	177	241	7	25	2,303
1994/95	3,539	74	3,465	240	227	270	8	25	2,695
1995/96	3,765	98	3,667	152	245	291	8	25	2,946
1996/97	3,577	109	3,468	228	153	325	18	25	2,719
1997/98	3,185	99	3,086	210	151	349	17	26	2,333
1998/99**	4,020	131	3,889	195	237	376	18	27	3,036
1999/00	4,147	131	4,016	203	244	405	19	28	3,117
2000/01	4,273	143	4,130	200	251	433	19	30	3,197
2001/02	4,372	143	4,229	185	257	460	20	31	3,276
2002/03	4,484	144	4,340	184	263	485	21	32	3,355
2003/04	4,585	144	4,441	181	269	509	21	33	3,428
2004/05	4,678	134	4,544	182	273	532	22	34	3,501
2005/06	4,779	134	4,645	180	279	554	22	35	3,575
2006/07	4,870	134	4,736	178	283	576	23	36	3,640
2007/08	4,964	134	4,830	162	288	597	23	37	3,723

August 1998 Status.

- * Not coincident with system peak.
- \+ Includes residential and commercial/industrial conservation.
- ++ Includes sales to FPC, Wauchula, Ft. Meade, St. Cloud and Reedy Creek.
- \# Commercial/Industrial Load Management includes Standby Generator.
- ** Forecasted Values: 1998/99 - 2007/08. Includes actual data through June 1998.
- = Residential conservation includes code changes.

Schedule 3.3

TABLE II-4
History and Forecast of Annual Net Energy for Load - GWH
Base Case
(Page 1 of 3)

(1) Year	(2) Total	(3) Residential Conservation =	(4) Comm./Ind. Conservation	(5) Retail	(6) Wholesale +	(7) Utility Use & Losses	(8) Net Energy for Load	(9) Load Factor % **
1988	12,529	91	12	12,426	0	725	13,151	57.1
1989	13,013	102	15	12,896	0	809	13,705	57.7
1990	13,565	108	21	13,436	0	569	14,005	60.8
1991	13,592	114	23	13,455	129	695	14,279	60.0
1992	13,697	120	25	13,552	214	671	14,437	58.3
1993	13,603	127	30	13,446	246	808	14,500	56.8
1994	14,103	138	33	13,932	163	636	14,731	59.6
1995	14,798	158	40	14,600	212	870	15,682	55.2
1996	15,167	189	49	14,929	399	760	16,088	53.1
1997	15,354	210	54	15,090	507	731	16,328	57.8
1998~	15,893	239	69	15,585	412	825	16,822	57.4
1999	16,413	269	84	16,060	402	850	17,312	54.1
2000	17,061	298	100	16,663	324	882	17,869	53.9
2001	17,550	327	115	17,108	346	906	18,360	53.9
2002	17,950	354	130	17,466	349	924	18,739	53.7
2003	18,465	380	142	17,943	354	950	19,247	53.8
2004	18,987	406	155	18,426	362	974	19,762	53.7
2005	19,534	432	167	18,935	337	1,001	20,273	54.0
2006	20,061	457	179	19,425	338	1,028	20,791	54.1
2007	20,528	481	191	19,856	342	1,051	21,249	54.0

August 1998 Status.

** Load Factor is the ratio of total system average load to peak demand.
+ Includes sales to FPC, Wauchula, Ft. Meade, St. Cloud and Reedy Creek.
= Residential conservation includes code changes.
~ Includes actual data through June 1998.

Schedule 3.3

TABLE II-4
History and Forecast of Annual Net Energy for Load - GWH
High Case
(Page 2 of 3)

(1) Year	(2) Total	(3) Residential Conservation =	(4) Comm./Ind. Conservation	(5) Retail	(6) Wholesale +	(7) Utility Use & Losses	(8) Net Energy for Load	(9) Load Factor % **
1988	12,529	91	12	12,426	0	725	13,151	57.1
1989	13,013	102	15	12,896	0	809	13,705	57.7
1990	13,565	108	21	13,436	0	560	14,005	60.8
1991	13,592	114	23	13,455	129	695	14,279	60.0
1992	13,697	120	25	13,552	214	671	14,437	58.3
1993	13,603	127	30	13,446	246	808	14,500	56.8
1994	14,103	138	33	13,932	163	636	14,731	59.6
1995	14,798	158	40	14,600	212	870	15,682	55.2
1996	15,167	189	49	14,929	399	760	16,088	53.1
1997	15,354	210	54	15,090	507	731	16,328	57.8
1998~	15,989	240	69	15,680	412	911	17,003	59.4
1999	16,615	271	84	16,260	403	945	17,608	54.6
2000	17,379	301	100	16,978	326	986	18,290	54.4
2001	17,973	331	115	17,527	349	1,018	18,894	54.5
2002	18,492	359	130	18,003	352	1,046	19,401	54.4
2003	19,147	387	142	18,618	359	1,082	20,059	54.5
2004	19,820	415	155	19,250	367	1,118	20,735	54.4
2005	20,516	442	167	19,907	344	1,156	21,407	54.8
2006	21,218	470	179	20,569	346	1,195	22,110	54.9
2007	21,863	496	191	21,176	350	1,230	22,756	54.7

August 1998 Status.

** Load Factor is the ratio of total system average load to peak demand.
+ Includes sales to FPC, Wauchula, Ft. Meade, St. Cloud and Reedy Creek.
= Residential conservation includes code changes.
~ Includes actual data through June 1998.

Schedule 3.3

TABLE II-4
History and Forecast of Annual Net Energy for Load - GWH
Low Case
(Page 3 of 3)

(1) Year	(2) Total	(3) Residential Conservation =	(4) Comm./Ind. Conservation	(5) Retail	(6) Wholesale +	(7) Utility Use & Losses	(8) Net Energy for Load	(9) Load Factor % **
1988	12,529	91	12	12,426	0	725	13,151	57.1
1989	13,013	102	15	12,896	0	809	13,705	57.7
1990	13,565	108	21	13,436	0	569	14,005	60.8
1991	13,592	114	23	13,455	129	695	14,279	60.0
1992	13,697	120	25	13,552	214	671	14,437	58.3
1993	13,603	127	30	13,446	246	808	14,500	56.8
1994	14,103	138	33	13,932	163	636	14,731	59.6
1995	14,798	158	40	14,600	212	870	15,682	55.2
1996	15,167	189	49	14,929	399	760	16,088	53.1
1997	15,354	210	54	15,090	507	731	16,328	57.8
1998~	15,793	238	69	15,486	412	900	16,798	57.4
1999	16,209	267	84	15,858	401	921	17,180	54.6
2000	16,744	295	100	16,349	321	950	17,620	54.4
2001	17,116	323	115	16,678	343	969	17,990	54.3
2002	17,404	349	130	16,925	345	983	18,253	54.1
2003	17,786	373	142	17,271	351	1,003	18,625	54.0
2004	18,169	398	155	17,616	357	1,023	18,996	53.9
2005	18,561	422	167	17,972	331	1,044	19,347	54.1
2006	18,960	445	179	18,336	331	1,065	19,732	54.1
2007	19,266	467	191	18,608	334	1,081	20,023	54.0

August 1998 Status.

** Load Factor is the ratio of total system average load to peak demand.
+ Includes sales to FPC, Wauchula, Ft. Meade, St. Cloud and Reedy Creek.
= Residential conservation includes code changes.
~ Includes actual data through June 1998.

Schedule 4

TABLE II-5
Previous Year and 2-Year Forecast of Peak Demand and Net Energy for Load by Month

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	1997 Actual		1998 Actual / Forecast ~		1999 Forecast	
Month	Peak Demand MW	NEL GWH	Peak Demand MW	NEL GWH	Peak Demand MW	NEL GWH
January	3,216	1,257	2,437	1,225	3,661	1,320
February	2,445	1,103	2,614	1,125	3,318	1,196
March	2,442	1,287	2,810	1,259	2,867	1,278
April	2,512	1,189	2,620	1,248	2,790	1,284
May	3,107	1,443	3,029	1,517	3,135	1,529
June	3,090	1,530	3,346	1,787	3,377	1,622
July	3,079	1,601	3,215	1,622	3,344	1,696
August	3,076	1,625	3,223	1,653	3,351	1,717
September	2,968	1,542	3,217	1,542	3,346	1,627
October	2,725	1,344	2,940	1,362	3,061	1,436
November	2,111	1,134	2,822	1,198	2,943	1,260
December	2,585	1,273	3,109	1,284	3,240	1,348
TOTAL		16,328		16,822		17,312

August 1998 Status.

~ Actual for January through June 1998. Forecast for July through December 1998.

Schedule 5

TABLE II-6
History and Forecast of Fuel Requirements

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
	Fuel Requirements		Units	Actual 1996	Actual 1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007
(1)	Nuclear		Trillion BTU	0	0	0	0	0	0	0	0	0	0	0	0
(2)	Coal*		1000 Ton	7,795	8,021	7,952	8,130	7,971	7,940	7,865	8,008	7,987	8,117	8,102	8,210
(3)	Residual	Total	1000 BBL	412	427	287	665	976	686	725	137	151	162	186	187
(4)		Steam	1000 BBL	333	345	245	588	862	587	621	0	0	0	0	0
(5)		CC	1000 BBL	79	82	41	77	114	99	104	137	151	162	186	187
(6)		CT	1000 BBL	0	0	0	0	0	0	0	0	0	0	0	0
(7)		Diesel	1000 BBL	0	0	0	0	0	0	0	0	0	0	0	0
(8)	Distillate	Total	1000 BBL	256	319	287	369	571	637	679	779	1,048	1,244	1,569	1,702
(9)		Steam	1000 BBL	0	0	0	0	0	0	0	0	0	0	0	0
(10)		CC	1000 BBL	210	250	208	229	245	246	245	245	245	244	244	244
(11)		CT	1000 BBL	46	70	79	140	326	392	434	534	804	1,000	1,325	1,457
(12)		Diesel	1000 BBL	0	0	0	0	0	0	0	0	0	0	0	0
(13)	Natural Gas	Total	1000 MCF	0	0	0	0	0	1,339	1,459	2,436	3,845	5,211	6,019	7,664
(14)		Steam	1000 MCF	0	0	0	0	0	0	0	0	0	0	0	0
(15)		CC	1000 MCF	0	0	0	0	0	0	0	0	0	0	0	0
(16)		CT	1000 MCF	0	0	0	0	0	1,339	1,459	2,436	3,845	5,211	6,019	7,664
(17)	Other (Specify)														
(18)	Petroleum Coke		1000 Ton	176	111	237	128	426	732	727	736	733	735	731	737

August, 1998 Status.

* Coal energy source includes an alternative fuel source consisting of a shredded tire/coal blend fuel for Gannon.

** Values shown may be affected by rounding.

*** All values exclude ignition.

Schedule 6.1

TABLE II-7
History and Forecast of Net Energy for Load by Fuel Source
(Page 1 of 2)

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
	Energy Sources		Units	Actual 1996	Actual 1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007
(1)	Annual Firm Interchange		GWh	5	(125)	(599)	74	(849)	(45)	337	473	552	635	733	737
(2)	Nuclear		GWh	0	0	0	0	0	0	0	0	0	0	0	0
(3)	Coal*		GWh	17,225	17,033	17,570	17,114	16,528	15,770	15,627	15,925	15,922	16,123	16,107	16,295
(4)	Residual	Total	GWh	182	188	124	282	415	297	313	92	101	108	124	125
(5)		Steam	GWh	129	136	96	231	339	231	244	0	0	0	0	0
(6)		CC	GWh	53	52	28	51	76	66	69	92	101	108	124	125
(7)		CT	GWh	0	0	0	0	0	0	0	0	0	0	0	0
(8)		Diesel	GWh	0	0	0	0	0	0	0	0	0	0	0	0
(9)	Distillate	Total	GWh	162	202	180	212	288	363	381	450	594	697	870	943
(10)		Steam	GWh	0	0	0	0	0	0	0	0	0	0	0	0
(11)		CC	GWh	146	178	153	164	175	175	175	175	175	175	175	175
(12)		CT	GWh	16	24	27	49	113	188	206	274	419	523	696	769
(13)		Diesel	GWh	0	0	0	0	0	0	0	0	0	0	0	0
(14)	Natural Gas	Total	GWh	0	0	0	0	0	113	123	208	343	477	549	709
(15)		Steam	GWh	0	0	0	0	0	0	0	0	0	0	0	0
(16)		CC	GWh	0	0	0	0	0	0	0	0	0	0	0	0
(17)		CT	GWh	0	0	0	0	0	113	123	208	343	477	549	709
(18)	Other (Specify)														
(19)	Petroleum Coke Generation		GWh	492	310	663	359	1,192	2,049	2,036	2,060	2,052	2,058	2,046	2,063
(20)	Net Interchange		GWh	(2,441)	(1,734)	(1,448)	(1,142)	(132)	(621)	(584)	(470)	(293)	(313)	(128)	(115)
(21)	Purchased Energy from Non-														
(22)	Utility Generators		GWh	464	453	444	415	427	432	505	509	491	491	491	491
(23)	Net Energy for Load		GWh	16,089	16,328	16,933	17,314	17,869	18,358	18,740	19,247	19,760	20,275	20,792	21,248

August, 1998 Status

* Coal energy source includes an alternative fuel source consisting of a shredded tire/coal blend fuel for Gannon.

** Values shown may be affected by rounding

Schedule 6.2

TABLE II-7
History and Forecast of Net Energy for Load by Fuel Source
(Page 2 of 2)

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
	Energy Sources		Units	Actual 1996	Actual 1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007
(1)	Annual Firm Interchange		%	0	(1)	(4)	0	(5)	(0)	2	2	3	3	4	3
(2)	Nuclear		%	0	0	0	0	0	0	0	0	0	0	0	0
(3)	Coal*		%	107	104	104	99	92	86	83	83	81	80	77	77
(4)	Residual	Total	%	1	1	1	2	2	2	2	0	1	1	1	1
(5)		Steam	%	1	1	1	1	2	1	1	0	0	0	0	0
(6)		CC	%	0	0	0	0	0	0	0	0	1	1	1	1
(7)		CT	%	0	0	0	0	0	0	0	0	0	0	0	0
(8)		Diesel	%	0	0	0	0	0	0	0	0	0	0	0	0
(9)	Distillate	Total	%	1	1	1	1	2	2	2	2	3	3	4	4
(10)		Steam	%	0	0	0	0	0	0	0	0	0	0	0	0
(11)		CC	%	1	1	1	1	1	1	1	1	1	1	1	1
(12)		CT	%	0	0	0	0	1	1	1	1	2	3	3	4
(13)		Diesel	%	0	0	0	0	0	0	0	0	0	0	0	0
(14)	Natural Gas	Total	%	0	0	0	0	0	1	1	1	2	2	3	3
(15)		Steam	%	0	0	0	0	0	0	0	0	0	0	0	0
(16)		CC	%	0	0	0	0	0	0	0	0	0	0	0	0
(17)		CT	%	0	0	0	0	0	1	1	1	2	2	3	3
(18)	Other (Specify)														
(19)	Petroleum Coke Generation		%	3	2	4	2	7	11	11	11	10	10	10	10
(20)	Net Interchange		%	(15)	(11)	(9)	(7)	(1)	(3)	(3)	(2)	(1)	(2)	(1)	(1)
(21)	Purchased Energy from Non-														
(22)	Utility Generators		%	3	3	3	2	2	2	3	3	2	2	2	2
(23)	Net Energy for Load		%	100	100	100	100	100	100	100	100	100	100	100	100

August, 1998 Status.

* Coal energy source includes an alternative fuel source consisting of a shredded tire/coal blend fuel for Gannon.
** Values shown may be affected by rounding

CHAPTER III

FORECAST OF ELECTRIC POWER DEMAND

Tampa Electric Company Forecasting Methodology

The Customer, Demand and Energy Forecast is the foundation from which the integrated resource plan is developed. Recognizing its importance, Tampa Electric Company employs state-of-the-art methodologies for carrying out this function. The primary objective in 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 Company's forecasting methods and the major assumptions utilized in developing the 1998-2007 forecast. The data tables in Chapter II outline the expected customer, demand, and energy values for the 1998-2007 time period.

Retail Load

The Tampa Electric Company retail demand and energy forecast is the result of five separate forecasting methods:

1. detailed end-use model (demand and energy);
2. multiregression model (demand and energy);
3. trend analysis (demand and energy);
4. phosphate analysis (demand and energy); and
5. conservation programs (demand and energy management).

The detailed end-use model, SHAPES, is the company's most sophisticated and primary forecasting model. As shown in Figure III-1, the first three forecasting methods are blended together to develop a demand and energy projection, excluding phosphate load. Phosphate demand and energy is forecasted separately and then combined in the final forecast. Likewise, the effect of Tampa Electric Company's conservation, load management, and cogeneration programs is incorporated into the process by subtracting their expected reduction in demand and energy from the forecast.

1. Detailed End-Use Model

The SHAPES model was developed jointly by Tampa Electric Company, Tech Resources (formerly part of the Battelle Memorial Institute), and New Energy Associates and is the foundation of the demand and energy forecasting process. SHAPES projects annual energy consumption for the service area and load profiles by end-use for typical and extreme (peak) days. The model has two major sections. The first section is the regional economic-demographic model, entitled REGIS, which generates population, households, income, and employment projections which are used in the second part of the model, called SHAPES.

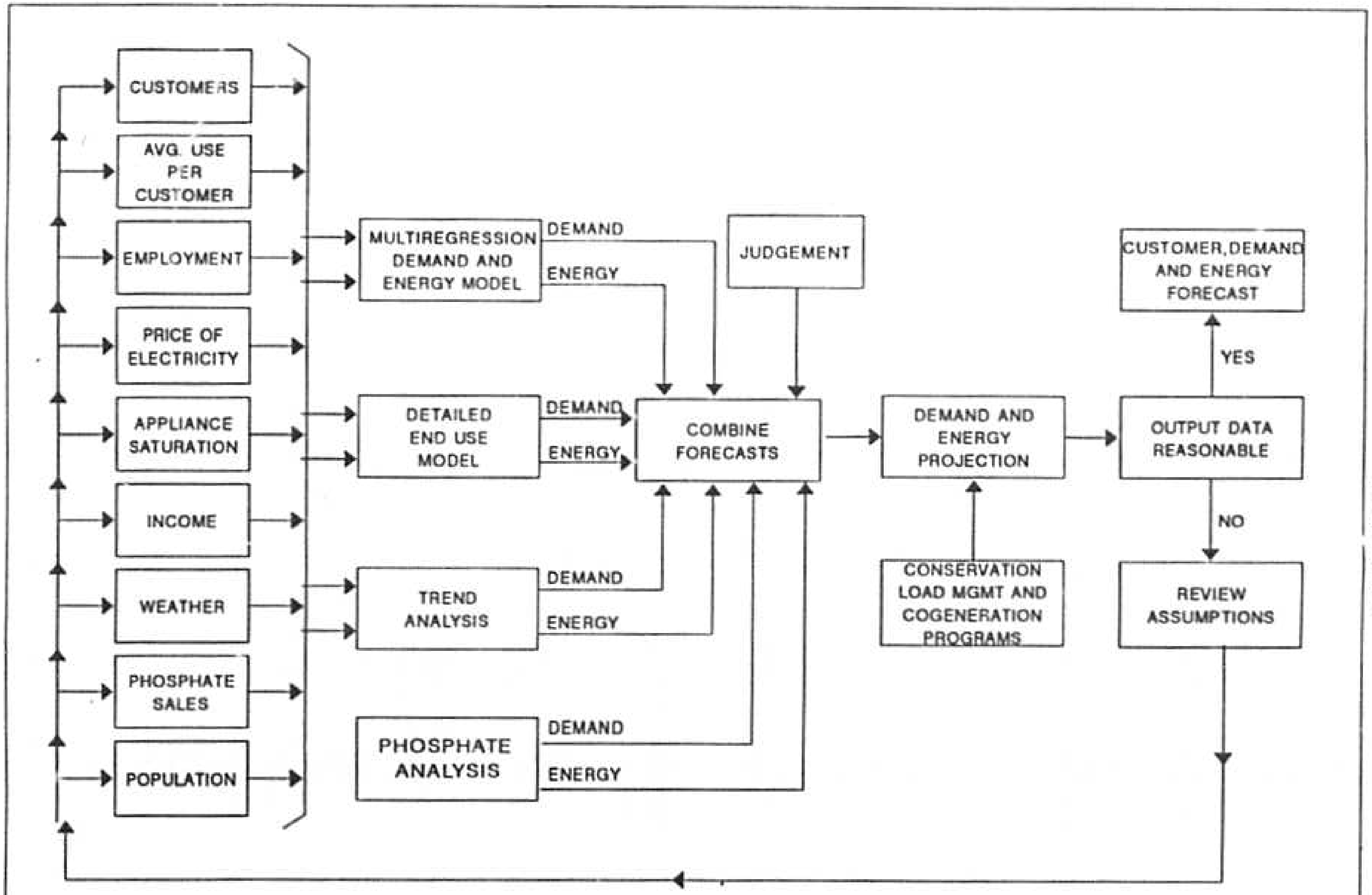


Figure III-1

TAMPA ELECTRIC COMPANY CUSTOMER, DEMAND AND ENERGY FORECAST PROCESS

SOURCE: TAMPA ELECTRIC COMPANY

As an option, the parameters furnished by REGIS may be replaced with other forecasts, such as the University of Florida's population projections. The SHAPES portion of the model consists of two parts: (1) a demand section, and (2) an energy section. The demand section calculates hourly demands including peak demands based on temperature profiles for normal and extreme conditions. The energy section forecasts residential energy use by appliance, commercial consumption by end-use and building type, and energy used in the industrial and miscellaneous sectors.

REGIS

Since electricity consumption, peak demand, and load shapes depend to a large extent on the nature and level of economic activity, the first step in system demand and energy requirements forecasting is to project the economic and population base of the service area. The economic-demographic model consists of approximately seventeen equations with four major components including migration and demographic, housing, labor, and income.

Population is developed through the migration/demographic component of the model which uses a cohort-survival approach as its foundation. More specifically, Hillsborough County population is partitioned into age groups and "aged" over time through the application of birth and death rates. Migration, the most significant component of population change in the service area, is calculated as a function of the relative economic opportunities in the local area and the general health of the overall economy. The population estimates are converted to residential customers by applying household formation rates to each age group. The housing sector determines the stock of housing that relates to the residential customer forecasts.

The labor market and income components are combined to determine service area employment and income. In the labor sector, employment for four manufacturing categories plus the commercial and governmental sectors is projected. Employment is then combined with the wage equation of the income sector to determine local earnings. Since earnings represent 70 to 75% of total personal income, this is an important input for deriving regional personal income.

SHAPES

The power model is comprised of four major sectors: (1) residential, (2) commercial, (3) industrial, and (4) miscellaneous (governmental, street lighting, and transmission and distribution line losses). This structure emphasizes the projection of hourly demand values by end-use based on month, day type, and temperature. Repeating these calculations for each hour of the day and for all consumption units yields the daily load curve of the system. The energy consumption for any period is calculated by summing demand in each hour in the period for all end-uses.

More specifically, the basic equation upon which the model is based is:

$$D_{ij} = \Sigma N_i * C_i * F_{ij}$$

where:

D_{ij} = Demand at hour j by end-use component i;

N_i = Number of use components of type i;

C_i = Connected load per use component i;

F_{ij} = Fraction of connected load of use component i which is operating at hour j.

In the residential sector, the energy consuming units are the major household appliances. A list of the seventeen appliances treated explicitly in the model is provided in Table III-1. The appliance stock in a given year is influenced by the number of households, the mix of dwelling unit types, and family income. The latter two variables are used to derive saturation levels for each appliance which combined with the number of households, results in the total number of units of a given appliance.

Looking at these two factors in more detail, data analysis indicates that saturation levels for certain appliances vary significantly according to housing type. To capture these differences, the occupied housing stock or number of households is partitioned into single family, multi-family, and mobile home categories. In addition, it was determined that certain appliance saturations are related to the individual household's income level. Those appliances having this characteristic included room air conditioners, electric clothes dryers, clothes washers, and dishwashers. Projections of housing mix and per capita income, therefore, were utilized in developing saturation rates for these appliance categories.

To capture the trend of including ranges, central air conditioning, electric water heating, electric space heating or electric heat pumps as standard items in new construction, penetration rates representing the percent of new housing with these features were used to project saturation levels for these appliances. Finally, certain appliances such as television sets and refrigerators have already achieved full saturation. Future saturation levels are similar to present rates except for quality shifts or intercategory adjustments from standard to frost free refrigerators and black and white to color television.

The second major factor in the demand estimation equation is the connected load of the appliance, which was developed from company and industry studies. The last factor in the equation is the use factor or the probability of the appliance operating at a given time.

TABLE III-1. Appliances Treated Explicitly In End-Use Model

Electric Range
Refrigerator - Frost Free
Refrigerator - Standard
Freezer - Frost Free
Freezer - Standard
Dishwasher
Clothes Washer
Electric Dryer
Electric Water Heater
Microwave Oven
TV-Color
TV-Black and White
Lighting
Room Air Conditioner
Central Air Conditioner
Electric Space Heating
Electric Heat Pump

SOURCE: Tampa Electric Company

In the model, appliances can be separated into two groups: temperature insensitive and temperature sensitive. Those appliances which are temperature insensitive have use factors which vary by day type, month, and hour. Thus, the usage of these appliances is characterized by 1,152 use factors (12 months x 24 hours x 4 day types). These four day types are Sunday, Monday, Tuesday-Friday, and Saturday. For temperature-sensitive appliances, which include air conditioners, electric space heaters, and electric heat pumps, the monthly use factors are replaced by a set of factors which vary with respect to time and temperature. Therefore, the energy consumption of these appliances is a function of temperature, time, and day type. These temperature-related use factors are combined with monthly temperature probability matrices to calculate energy requirements over that period.

The model is capable of developing a residential as well as a system demand profile for each hour of each day type for all twelve months. In order to calculate peak demand, a temperature profile representing the expected hottest or coldest day must be input into the model. An average day load profile for each month can also be developed by supplying an average temperature for every hour.

The commercial sector of the model forecasts energy and demand by building type by end-use. This sector estimates energy intensity by end-use for each building type in terms of kWh per square foot of floor space. The forecast of building type square footage can be developed within the model using the REGIS employment forecast by building type and estimates of projected floor space per employee.

In addition, end-use saturation rate estimates are developed from surveys of the service area's commercial customers by building type. The original survey of this sector was performed by Xenergy, Inc. during 1994 as part of commission-sanctioned research into the cost effectiveness of commercial DSM programs. In the future, Tampa Electric expects to survey its commercial customers regarding their end-use saturations by fuel type, building type, employment, square footage, and vintage age and demolition rate of the equipment stock on a semiannual basis.

From the calculation of energy, commercial demand is determined by allocating annual consumption to the hours of the day through use factors. However, the commercial sector contains both temperature-sensitive and insensitive end-uses. The temperature-sensitive use patterns are a function of temperature and time. Therefore, peak demand is calculated, as in the residential sector, by specifying extreme temperatures to represent severe weather conditions.

The nine end-uses and eleven building types that are included in Tampa Electric's commercial floorspace building type model are listed in Table III-2.

TABLE III-2. Commercial Floorspace Model End-Uses and Building Types

End-Uses:

Air Conditioning	Miscellaneous
Cooking	Refrigeration
Exterior Lighting	Ventilation
Heating	Water Heating
Interior Lighting	

Building Types:

Colleges	Offices
Groceries	Retail
Health Care	Restaurants
Hospitals	Schools
Lodging	Warehouses
Miscellaneous	

The industrial and miscellaneous sectors of the model are less detailed than the residential and commercial customer classes due to a lack of connected load data. The industrial class is disaggregated into four major groups representing different levels of energy intensiveness. These include Food Products (SIC 20); Tobacco, Printing, etc. (SIC 21, 23, 24, 25, 27, 37, 39); Fabricated Metals, etc. (SIC 26, 29, 30, 34, 35, 36, 38); and Basic Industries (SIC 32, 33). In each sector, annual energy consumption is computed by multiplying energy use per employee times projected employment. Monthly energy consumption is calculated by allocating the annual energy to the corresponding month using historic ratios of monthly-to-annual consumption. Once monthly energy is computed, it is further broken down by hour for each of the four day types. That is, a use factor is applied which denotes the fraction of each month's energy that is consumed in a given hour. These use factors were developed from hourly billing data available for major industrial customers in each of the four categories.

The miscellaneous sector includes street lighting, sales to public authorities, and transmission and distribution line losses. For street lighting and public authorities, sales are expressed as a function of the number of residential customers, and demand is calculated using an allocation method similar to the industrial and commercial sectors.

The model also allows for price elasticity adjustments which represent the change in electric consumption resulting from changes in the relative price of electricity. In order to capture the price effect, an adjustment factor is applied to the annual consumption. The adjustment factor for a given year is a time-dependent weighted average of short and long-run elasticity. The general mathematical form of the consumption adjustment equation is as follows:

$$C_n = C_0 * \text{(Price Elasticity Adjustment Factor)}$$

where:

C_n = Consumption at the price level in year n, adjusted for price changes in years 0 to n.

C_0 = Consumption at the base year price level, that is, assuming no price changes.

The Adjustment Factor is given by the following:

Price Elasticity Adjustment Factor

$$\left(\frac{P_1}{P_0}\right)^{E_n} \cdots \left(\frac{P_i}{P_{i-1}}\right)^{E_{n-i+1}} \cdots \left(\frac{P_n}{P_{n-1}}\right)^{E_1}$$

where:

P_i = Price of electricity in period i (i = 1 to n).

E_i = Price elasticity coefficient expressed as a time-dependent weighted average of the short and long-run elasticity coefficients (i = 1 to n)

This relationship can be expressed as follows:

$$E_i = E_S + W_i(E_L - E_S)$$

where:

E_S = Short-run elasticity

E_L = Long-run elasticity

W_i = Weighting factor, $0 \leq W_i \leq 1$; $W_1 = 0$, $W_i = 1$ for $i \geq 12$.

The above relationship warrants two important observations. First, the price elasticity adjustment factor that is applied to a given year incorporates the effects of price changes not only for the given year but also for previous years. Second, the elasticity coefficient that is applied to a given year's price change increases numerically over time, gradually rising from the short-term elasticity value to the long-term. Therefore, each price increase or decrease has a lasting effect on future consumption patterns.

In the residential sector, each of the specific appliances was assigned a short-run and long-run elasticity. This was accomplished by partitioning the major appliances into three groups whose change in consumption due to price changes was considered to be either low, medium, or high (Table III-3). In certain cases, these elasticities were assigned subjectively while in other cases they were based upon studies by National Economic Research Associates (NERA) and the Electric Power Research Institute (EPRI). In addition, the resulting coefficients have the mathematical property that their combined effect, which represents the average residential elasticity coefficient, closely approximates the results of NERA and EPRI research. Therefore, their cumulative effect is in accord with extensive statistical analysis. The elasticity factors used for the commercial and industrial categories were also developed from these studies.

TABLE III-3. Sensitivity of Consumption to Price

Appliances with Low Assumed Price Sensitivity:

Refrigerator	Frost Free Standard
Freezer	Frost Free Standard
TV	Color Black and White

Appliances with Medium Assumed Price Sensitivity:

Electric Range
Clothes Washer
Electric Water Heater
Microwave Oven
Lighting

Appliances with High Assumed Price Sensitivity:

Dishwasher
Electric Dryer
Room Air Conditioner
Central Air Conditioner
Electric Space Heating
Electric Heat Pump

SOURCE: Based on studies by National Economic Research Associates and the Electric Power Research Institute.

Another factor influencing residential energy consumption is the movement toward more energy-efficient appliances. The forces behind this development include market pressures for more energy-efficient technologies and the appliance efficiency standards enacted by the state and federal governments. The efficiency goals affect the usage associated with new additions to the appliance stock.

It should be noted that the base year appliance energy consumption is influenced by both price effects and efficiency improvements. Thus, while some appliances are assumed to be rather price insensitive, their individual consumption levels decrease due to efficiency improvements.

2. Multiregression Demand and Energy Model

The retail multiregression forecasting model is a nine-equation model with two major sections. The energy section forecasts energy sales by the six major customer categories. The demand section forecasts peak load other than phosphate for both summer and winter. The regression technique is a more sophisticated approach than trend analysis as it attempts to examine those factors which influence load.

The selection of appropriate variables to include in the multiregression model equations is an extensive process that begins with the identification of variables that affect demand and energy. Those variables which can not be reasonably quantified or forecast are dismissed from the process. Results from regressions using the remaining variables are evaluated to determine which variables perform best. As a result, the chosen equations are both statistically and theoretically appropriate.

The basic series that make up the regression method are supplied by Tampa Electric Company, the U.S. Bureau of Labor Statistics, the U.S. Bureau of Economic Analysis, the U.S. Geological Survey, the Federal Reserve Board, the National Oceanic and Atmospheric Administration, and the University of Florida's Bureau of Economic and Business Research. All projections of the independent variables in these equations are consistent with those used in the end-use model.

Demand Section

The demand section consists of three regression equations for load other than phosphate. One equation is for the base load which, by definition, is that load on the system that is independent of temperature. The remaining two equations describe the summer peak temperature-sensitive demand and the winter peak temperature-sensitive demand. From regression analysis, the following relationships have been determined.

Base Load = 70.159 + 4.3389 * # Residential Customers - 3707.9 * ¢/kWh (lagged 1 year)

(t = 35.8) (t = -3.7)

$\bar{R}$-Squared = .97 DW = 1.9

2.

Temperature Sensitive Demand (Summer) = (F° - 65) (20.718 + 0.1106 * # A/Cs - 244.53 * ¢/kWh (lagged 2 periods))

(t = 25.5) (t = -4.9)

$\bar{R}$-Squared = .91 DW = 1.9

3.

Temperature Sensitive Demand (Winter) = (65 - F°) (-0.9842 + 0.13284 * # Electric Heaters)

(t = 24.2)

$\bar{R}$-Squared = .89 DW = 1.4

The Variables are defined as follows:

Base Load	The temperature-insensitive component of demand (MW).
Temperature-Sensitive Demand	The load component (MW) which is affected by heating or air conditioning on the system.
# Residential Customers	The average number of residential customers (in thousands).
¢/kWh	Tampa Electric Company's average cost of electricity per kWh adjusted for inflation.
F° (Summer)	Average 24-hour temperature for the day of the system peak load.
F° (Winter)	Peak hour temperature at the time of the system peak load.
# A/Cs	Number of residential air conditioners (in thousands) calculated by multiplying residential customers by cooling saturation levels.
# Electric Heaters	Number of residential electric heaters (in thousands) calculated by multiplying residential customers by electric heating saturation levels.

Energy Section

The energy section of the retail multiregression model consists of six equations that estimate future energy by the major customer classes (residential, commercial, industrial other than phosphate, phosphate, sales to public authorities, and street and highway lighting.) These equations are listed below.

1.

Average Residential Usage = 6045.7 + 51.226 * Chg in Personal Inc. Per Capita (lagged 1 year) (t = 2.3) - 563.6 * ¢/kWh (lagged 1 year) (t = -8.9)
+ 1.06167 * Total Degree Days (t = 4.5) + 8362.9 * Htg/Cooling Saturation (t = 19.1)

$\bar{R}$-Squared = .94 DW = 1.7

2.

Commercial Energy Sales = -75.95 + 13.813 * Residential Customers (t = 23.2) - 583.0 * ¢/kWh (lagged 1 year) (t = -4.1)

$\bar{R}$-Squared = .99 DW = .94

3.

Other Industrial Energy Sales = 334.44 + 5.933 * Ind Prod Index (t = 7.7) - 88.7825 *Chg. in ¢/kWh (lagged 1 year) (t = -1.7)
- 138.1 * Trade Dummy Variable (t = -6.2)

$\bar{R}$-Squared = .70 DW = 1.7

4.

Phosphate Energy Sales = 1135.2 + 51.242 * U.S. Phosphate Mining (t = 10.3) - 331.39 * ¢/kWh (lagged 1 year) (t = -3.3)

$\bar{R}$-Squared = .84 DW = 1.0

5.

Sales to Public Authorities	= 530.50 + 2.4514 * Residential Customers - 251.11 * Chg in ¢/kWh		
		(t = 10.9)	(t = -4.4)
	$\bar{R}$-Squared = .98		DW = 1.1

6.

Street Lighting	= - 29.073 + 0.10370 * Population		
		(t = 34.8)	
	$\bar{R}$-Squared = .98		DW = .70

The Variables are defined as follows:

Population	Hillsborough County Population (in thousands).
Residential Customers	Service Area Residential Customers (in thousands).
Chg in Personal Inc. Per Capita	Percent change in real personal income per capita in Hillsborough County.
Htg/Cooling Saturation	Weighted average of heating and cooling saturation rates.
Total Degree Days	Sum of heating and cooling degree days (billing cycle adjusted).
Ind Prod Index	Industrial Production Index (1992 = 100).
U.S. Phosphate Mining	U.S. mining production (in millions of metric tons).
¢/kWh	Cost per kWh for a given customer class adjusted for inflation.
Chg in ¢/kWh	Percent change in cost per kWh for a given customer class adjusted for inflation.
Trade Dummy Variable	Dummy variable representing import substitution of local basic industries production.

5.

Sales to Public Authorities = 530.50 + 2.4514 * Residential Customers - 251.11 * Chg in ¢/kWh
(t = 10.9) (t = -4.4)

$\bar{R}$-Squared = .98 DW = 1.1

6.

Street Lighting = - 29.073 + 0.10370 * Population
(t = 34.8)

$\bar{R}$-Squared = .98 DW = .70

The Variables are defined as follows:

Population	Hillsborough County Population (in thousands).
Residential Customers	Service Area Residential Customers (in thousands).
Chg in Personal Inc. Per Capita	Percent change in real personal income per capita in Hillsborough County.
Htg/Cooling Saturation	Weighted average of heating and cooling saturation rates.
Total Degree Days	Sum of heating and cooling degree days (billing cycle adjusted).
Ind Prod Index	Industrial Production Index (1992 = 100).
U.S. Phosphate Mining	U.S. mining production (in millions of metric tons).
¢/kWh	Cost per kWh for a given customer class adjusted for inflation.
Chg in ¢/kWh	Percent change in cost per kWh for a given customer class adjusted for inflation.
Trade Dummy Variable	Dummy variable representing import substitution of local basic industries production.

3. Trend Analysis

The role of trend analysis in the Tampa Electric Company forecasting process has changed as the stability of fuel prices and supplies has decreased. The present economic and political environment throughout the world has contributed to changing energy consumption patterns resulting in a need for more sophisticated forecasting techniques. Trending provides a useful check for the more intricate methods used by the company in developing the Customer, Demand, and Energy Forecast.

The primary strength of trend analysis is simplicity. When applied to series with stable growth patterns, this method is easy to use and is readily understood by those outside the forecasting process. The need for historical data is minimal, compared to other methods, and the need for external forecasts is alleviated as time is the only predictive variable. However, weaknesses are also a function of this simplicity. The use of time as the only explanatory variable limits the ability of the process to reflect changing economic conditions. Given the limitations of this technique, it can still be used to identify time trends, and it provides a familiarity with the data that aids in evaluating forecasts from other methods.

Trend analysis is applied to several variables including:

1. population;
2. residential customers;
3. system peak demand;
4. residential energy sales;
5. commercial energy sales;
6. industrial energy sales;
7. street lighting energy sales;
8. sales to public authorities; and
9. average usage per customer.

The implementation of trend analysis involves establishing a mathematical relationship between the independent variable (time) and the dependent variable. A forecast can be constructed by entering a future year into the equation. Evaluating the data over different time periods allows one to identify changes in the trend over time. Once trend estimates for the various components are established, they can be combined to yield a total sales forecast.

4. Phosphate Demand and Energy Analysis

Because Tampa Electric Company's phosphate customers are relatively few in number, the Wholesale Marketing and Sales and Cogeneration Services Departments have 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;
6. knowledge of phosphate ore reserves; and
7. correlation between phosphate rock production and energy consumption.

These departments' familiarity with industry dynamics and their close working relationship with phosphate company representatives forms 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 the multiregression model's phosphate energy equation and discussions with industry experts.

5. Conservation, Load Management and Cogeneration Programs

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

1. to defer capital expansion, particularly production plant construction;
2. to reduce marginal fuel cost by managing energy usage during higher fuel cost periods;
3. to give customers some ability to control their energy usage and decrease their energy costs; and
4. to pursue the cost-effective accomplishment of ten-year demand and energy goals established by the Florida Public Service Commission (FPSC) for the residential and commercial/industrial sectors.

The company's current DSM plan contains a mix of proven, mature programs that focus on the market place demand for their specific offerings. Additionally, we have developed residential and commercial mail-in audits designed to more economically target customers who have the potential to benefit significantly from our energy management programs. The following is a list that briefly describes the company's programs:

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

2. Load Management - Reduces weather-sensitive heating, cooling, water heating, and pool pump loads through a radio signal control mechanism. In addition, a commercial/industrial program is in effect.

3. Energy Audits - The program is a "how to" information and analysis guide for customers. Six types of audits will be available in 1998 to Tampa Electric customers; three types are for residential class customers and three types for commercial/industrial customers.

4. Ceiling Insulation - An incentive program for existing residential structures which will help to supplement the cost of adding additional insulation.

5. Commercial Indoor 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 programs.

8. Duct Repair - An incentive program for existing homeowners which will help to supplement the cost of repairing leaky heating and cooling air ducts.

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

In addition, the Energy Answer Home and Street and Outdoor Lighting programs were completed in 1987 and 1990, respectively.

The 1997 demand and energy savings achieved by our conservation and load management programs are listed in Table III-4.

TABLE III-4
Comparison of Achieved MW and GWh Reductions With Florida Public Service Commission Goals

Residential

	Winter Peak MW Reduction			Summer Peak MW Reduction			GWh Energy Reduction		
Year	Total Achieved	Commission Approved Goal	% Goal	Total Achieved	Commission Approved Goal	% Goal	Total Achieved	Commission Approved Goal	% Goal
1995	24.0	36.0	66.7%	2.7	12.0	22.5%	12.2	21.0	58.1%
1996	56.7	72.0	78.8%	10.6	23.0	46.1%	28.3	41.0	69.0%
1997	79.2	107.0	74.0%	16.9	35.0	48.3%	43.6	60.0	72.7%

Commercial/Industrial

	Winter Peak MW Reduction			Summer Peak MW Reduction			GWh Energy Reduction		
Year	Total Achieved	Commission Approved Goal	% Goal	Total Achieved	Commission Approved Goal	% Goal	Total Achieved	Commission Approved Goal	% Goal
1995	5.1	2.0	255.0%	5.0	7.0	71.4%	11.7	29.0	40.3%
1996	13.1	5.0	262.0%	15.2	13.0	116.9%	27.4	59.0	46.4%
1997	14.4	7.0	205.7%	18.6	20.0	93.0%	42.0	90.0	46.7%

Combined Total

	Winter Peak MW Reduction			Summer Peak MW Reduction			GWh Energy Reduction		
Year	Total Achieved	Commission Approved Goal	% Goal	Total Achieved	Commission Approved Goal	% Goal	Total Achieved	Commission Approved Goal	% Goal
1995	29.1	38.0	76.6%	7.7	19.0	40.5%	23.9	50.0	47.8%
1996	69.8	77.0	90.6%	25.8	36.0	71.7%	55.7	100.0	55.7%
1997	93.6	114.0	82.1%	35.5	55.0	64.5%	85.6	150.0	57.1%

To support the demand and energy savings filed as part of its plan, Tampa Electric Company developed its 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. Generally speaking, 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 Company insight into the direction that should be taken to refine delivery processes, program standards, and overall program cost-effectiveness.

Wholesale Load

Tampa Electric's wholesale sales consist of sales contracts with the City of Wauchula, the City of Fort Meade, Florida Power Corp., the City of St. Cloud, and the Reedy Creek Improvement District.

Since Tampa Electric's sales to Wauchula and Fort Meade will vary over time based on the strength of their local economies, a multiple regression approach similar to that used for forecasting Tampa Electric's retail load has been utilized. Under this methodology, three equations have been developed for each municipality for forecasting energy and peak demand. These equations are shown on the following two pages.

WAUCHULA MULTIREGRESSION EQUATIONS

1.

Average Customer Usage = 3025.4 - 4.2441 * Change in ¢/kWh (t = - .98) + 0.05997 * Per Capita Income (t = 3.0) + 1.7935 * Cooling Degree Days (t = 19.6) + 2.5064 * Heating Degree Days (t = 7.0)

$\bar{R}$-Squared = .94 DW = 2.0

2.

Winter Peak Demand = - 11.427 + 0.00812 * Total Customers (t = 16.1) + 0.17877 * Heating Degree Days (t = 10.7)

$\bar{R}$-Squared = .90 DW = 1.8

3.

Summer Peak Demand = - 6.8121 + 0.0060109 * Total Customers (t = 11.4) + 0.20840 * Cooling Degree Days (t = 4.8) - 0.2670 * Change in ¢/kWh (lagged one month) (t = -1.4)

$\bar{R}$-Squared = .85 DW = 1.5

The Variables are defined as follows:

Change in ¢/kWh	Change in average cost per kWh adjusted for inflation.
Per Capita Income	Real per capita income (seasonally adjusted).
Total Customers	The average number of total customers.
Heating Degree Days	65 degrees less the average 24-hour temperature.
Cooling Degree Days	Average 24-hour temperature less 65 degrees.

FORT MEADE MULTIREGRESSION EQUATIONS

1.

Average Customer Usage = 1008.4 - 66.786 * ¢/kWh + 0.1100 * Change in Per Capita Income + 1.1327 * Cooling Degree Days + 1.5189 * Heating Degree Days

(t = -2.1) for ¢/kWh; (t = 2.1) for Change in Per Capita Income; (t = 12.5) for Cooling Degree Days; (t = 4.7) for Heating Degree Days

$\bar{R}$-Squared = .87 DW = 1.9

2.

Winter Peak Demand = - 11.523 + 0.0072114 * Total Customers + 0.14632 * Heating Degree Days

(t = 5.1) for Total Customers; (t = 4.7) for Heating Degree Days

$\bar{R}$-Squared = .79 DW = 1.6

3.

Summer Peak Demand = - 2.0035 + 0.0043383 * Total Customers + 0.10790 * Cooling Degree Days - 0.29532 * ¢/kWh

(t = 5.0) for Total Customers; (t = 2.6) for Cooling Degree Days; (t = -2.8) for ¢/kWh

$\bar{R}$-Squared = .87 DW = 1.7

The Variables are defined as follows:

¢/kWh	Average cost per kWh adjusted for inflation.
Change in Per Capita Income	Change in real per capita income (seasonally adjusted).
Total Customers	The average number of total customers.
Heating Degree Days	65 degrees less the average 24-hour temperature.
Cooling Degree Days	Average 24-hour temperature less 65 degrees.

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

Base Case Forecast Assumptions

Retail Load

1. Detailed End-Use Model

Numerous assumptions are inputs to the detailed end-use model of which the more significant ones are listed below.

1. Population and Residential Customers;
2. Commercial and Industrial Employment;
3. Per Capita Income;
4. Housing Mix;
5. Appliance Saturations;
6. Price Elasticity;
7. Price of Electricity;
8. Appliance Efficiency Standards; and
9. Weather.

Population/Residential Customers

The residential customer forecast is the starting point from which the demand and energy projections are developed. The most important factor in the customer forecast is the service area population estimate. The population estimate is based on Hillsborough County projections supplied by the University of Florida's Bureau of Economic and Business Research (BEBR), which are in the form of high, medium, and low forecasts. The REGIS model is utilized to determine where within the given range population growth is likely to be. For the 1997-2007 period, Hillsborough County population is expected to increase at a 1.7% average annual rate.

Household formation trends supplied by the U.S. Bureau of the Census are applied to the Hillsborough population projections to arrive at Hillsborough County households. Finally, service area household forecasts are determined by adjusting the Hillsborough County figures to reflect the relationship between service area and Hillsborough County residential customers. Since 1970, households in the service area have expanded at a faster rate than population due to a decline in household size. This decline in persons per household has been the result of lower birth rates, higher divorce rates, the postponement of marriage by young adults, and an aging overall population. During the next ten years (1998-2007), persons per household are expected to fall at an annual rate of 0.3 percent. Therefore, the household growth rate is expected to continue to exceed the population expansion rate in the service area over the next ten years.

Commercial and Industrial Employment

Commercial and industrial employment assumptions are utilized in computing energy and demand in their respective sectors. It is imperative that employment growth be consistent with the expected population expansion and unemployment levels. REGIS, which interrelates these important variables, ensures this consistency. In addition, forecasts from outside consulting firms also provide input into formulating these assumptions. For the 1997-2007 period, commercial employment is assumed to rise at a 2.3% average annual rate while industrial employment growth of 1.9% per year is expected.

Per Capita Income, Housing Mix, Appliance Saturations

The stock of appliances, which comprises the nucleus of SHAPES' residential sector, is determined by multiplying the number of households by the saturation rate for each appliance. The assumptions for real per capita income growth and housing mix are critical in computing these saturations since many of the appliances are influenced by income levels and the type of housing (single, multi-family, mobile home) in the service area. The housing mix and per capita income growth rates for the local area are based on forecasts from REGIS as well as from outside consulting services. For the 1997-2007 period, real per capita income is expected to increase at a 1.8% average annual rate.

Price Elasticity/Price of Electricity

Price elasticity measures the rate of change in the demand for a product, electricity in this case, that results from a change in its relative price. The expected elasticity effect can be quantified by multiplying this factor by the assumed change in the real price of electricity (See Page III-8). During the 1970s, price elasticity played a major role in slowing demand and energy growth due to the sharp increase in the price of electricity resulting from an explosion in fuel costs. Since 1981, an easing in fuel price pressures has been an important factor in keeping electricity cost changes below the general pace of inflation. Over the next decade, this pattern is expected to continue as the price of electricity should increase at a rate slower than other products and services.

Appliance Efficiency Standards

Another factor influencing residential 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. The efficiency goals affect the usage associated with new additions to the appliance stock.

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 ten 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 forty years plus the temperatures on peak days for the past fifteen to twenty years.

2. Multiregression Demand and Energy Model

The multiregression model utilizes assumptions which are common to SHAPES. These assumptions include future inputs for population, residential customers, income, saturation levels for air conditioners/heaters, and the price of electricity. In all cases where the multiregression and SHAPES models use common input variables, the assumptions for these inputs are the same and result in forecasts which are consistent and comparable.

Wholesale Load

Wauchula and Ft. Meade projections are developed from regression equations which, in turn, are driven by forecasts of customers, real per capita income, and the real price of electricity. For the 1998-2007 period, total customers are projected to expand at a 1.5% and 1.2% annual rate, respectively. Also, real per capita income for both cities is projected to grow annually at a pace of 1.2% and 1.3%, respectively.

High and Low Scenario Forecast Assumptions

Retail Load

The high and low peak demand and energy projections represent alternatives to the company's base case outlook. The high band represents a more optimistic economic scenario than the base case (most likely scenario) with greater expected growth in the areas of customers, employment, and income. The low band represents a less optimistic scenario than the base case with a slower pace of service area growth.

The assumptions related to the high, low, and base peak demand and energy cases are presented in Table III-5. For all other assumptions, including weather and price elasticity, the assumptions remain the same as in the base case scenario.

Wholesale Load

Likewise, high and low forecast scenarios are developed for wholesale customers Wauchula and Fort Meade. For these two municipalities, a percent change was applied to the wholesale base case to get the wholesale high and low forecast.

History and Forecast of Energy Use

A history and forecast of energy consumption by customer classification are shown in Table II-1 (Schedules 2.1 - 2.3) and Figure III-2.

Retail Energy

For 1997-2007, retail energy sales are projected to rise at a 2.8% annual rate. The major contributors to growth will continue to be the commercial, governmental, and residential categories. As a group, these three sectors will be increasing at a 3.3% annual rate.

In contrast, industrial sales are expected to decline over this period. Non-phosphate industrial consumption should register an annual gain over the coming years. However, this will be more than offset by a drop in phosphate sales due to an increase in self-service cogeneration and the southward migration of mining activity. This pattern reflects the changing American economy where the service sector is expanding at a rapid pace relative to manufacturing activity.

The combination of service area income growth and a declining real price of electricity has resulted in rising average residential usage in recent years. Over the 1998-2007 period, usage is anticipated to maintain this upward path based on expectations of continuing economic gains and a downward drift in the real price of electricity.

TABLE III-5. Economic Outlook Assumptions (1997-2007) For Retail Load Forecast

	Average Annual Growth Rate		
	BASE CASE	LOW GROWTH SCENARIO	HIGH GROWTH SCENARIO
Residential Customers	1.8%	1.4%	2.2%
Employment	1.6%	1.2%	2.0%
Real Per Capita Income	1.8%	1.3%	2.3%
Real Price of Electricity	-1.8%	-1.3%	-2.3%

Source: Tampa Electric Company

Wholesale Energy

Wholesale energy sales to FMPA, FPC, Wauchula, Ft. Meade, St. Cloud, and Reedy Creek of 412 GWh are expected in 1998, 402 GWh in 1999, and 324 GWh in 2000. Sales are expected to remain in the 330-370 GWh range for 2001-2007.

History and Forecast of Peak Loads

Historical and base, high, and low scenario forecasts of peak loads for the summer and winter seasons are presented in Tables II-2 and II-3 (Schedules 3.1 and 3.2), respectively. For the 1998-2007 period, Tampa Electric's base case retail firm peak demand for the winter and summer are expected to advance at annual rates of 2.8% and 3.0%, respectively. In addition, base, high, and low scenario forecasts of NEL are listed in Table II-4 (Schedule 3.3).

Monthly Forecast of Peak Loads for Years 1 and 2

A monthly forecast of retail peak loads (MW) and net energy for load (GWh) for years 1 and 2 of the forecast is provided in Table II-5 (Schedule 4) along with actual for 1997.

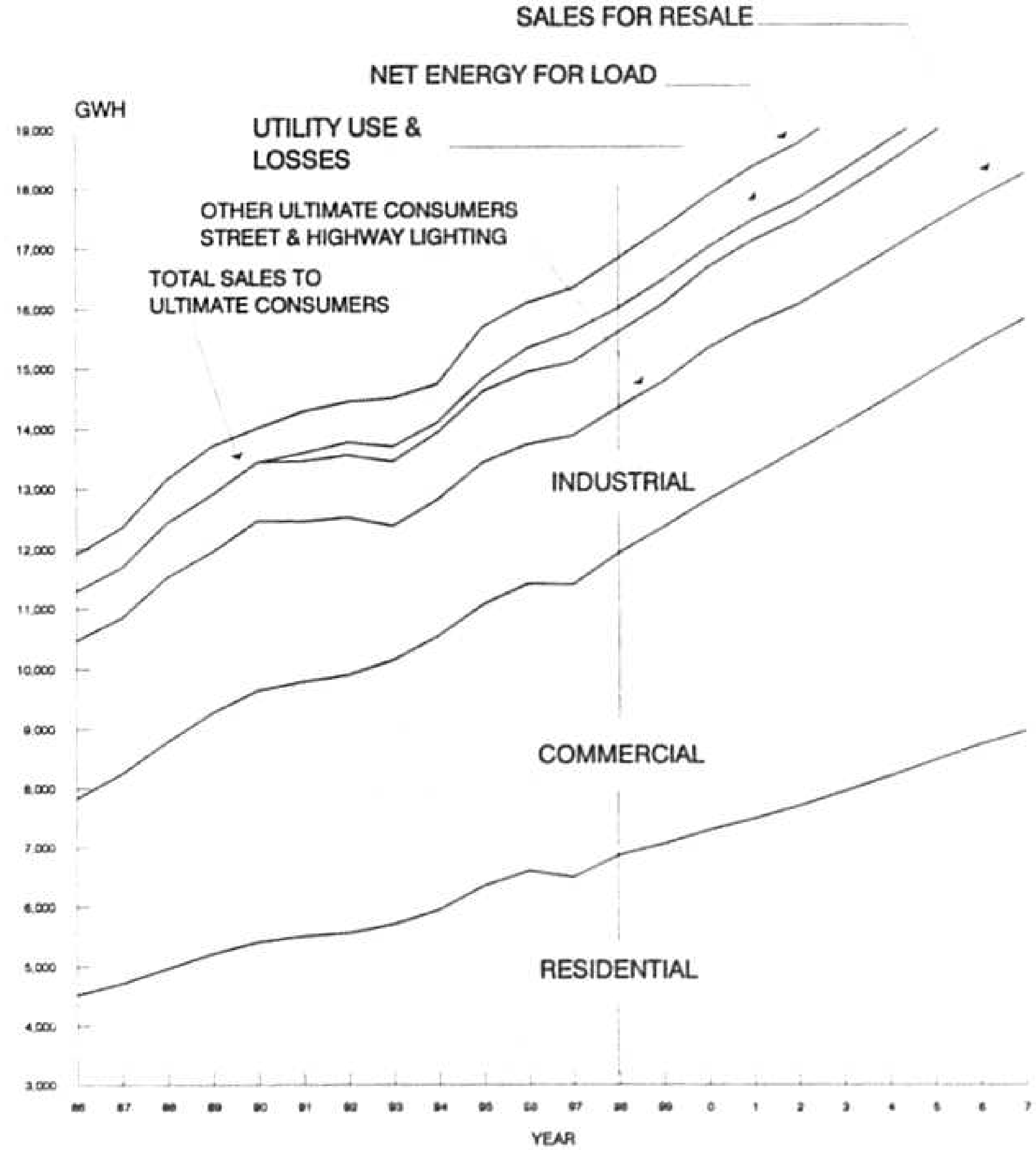


Figure III-2

HISTORY AND FORECAST OF ENERGY USE

SOURCE: TAMPA ELECTRIC COMPANY

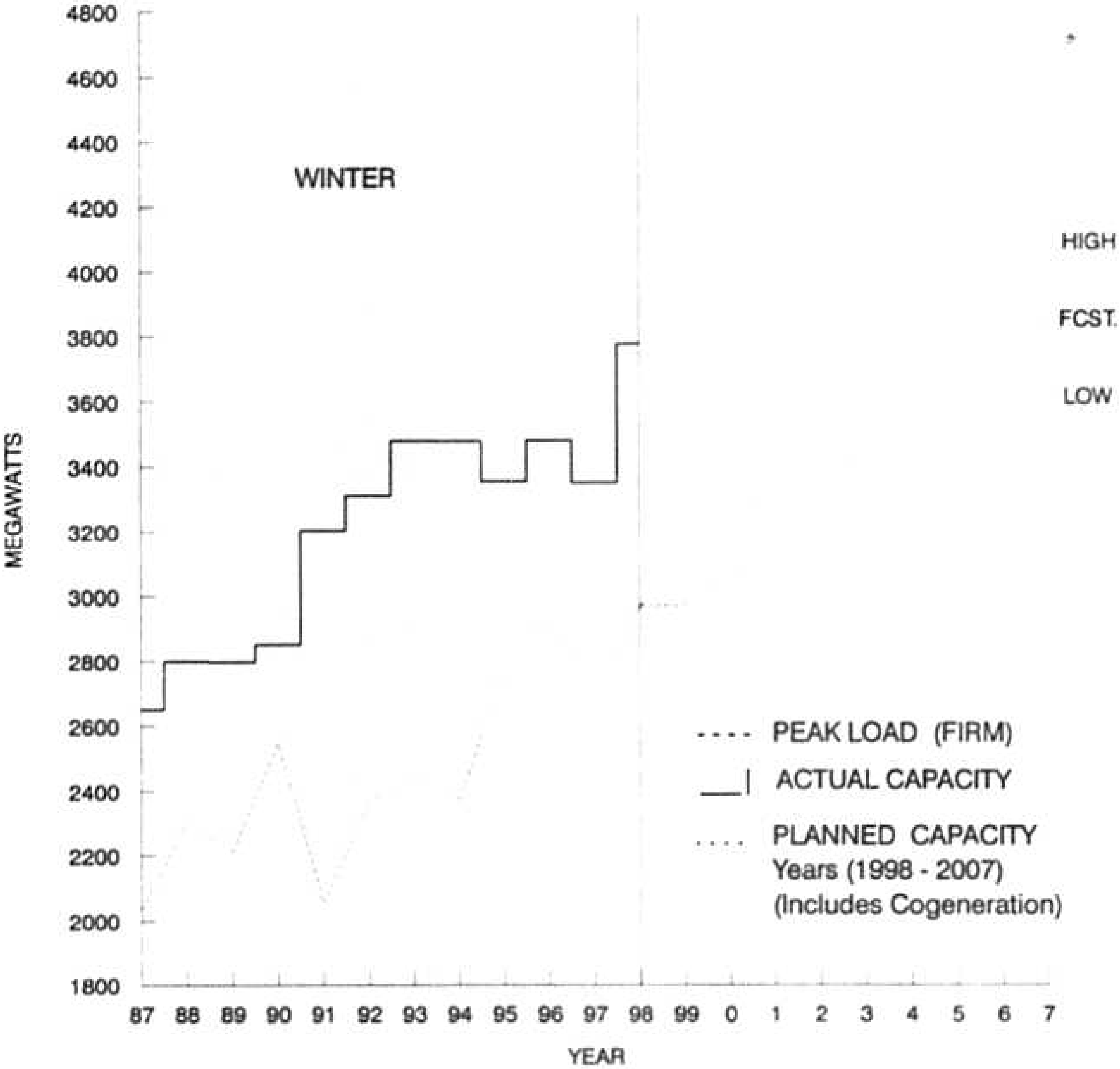
TAMPA ELECTRIC COMPANY

Ten-Year Site Plan

For Electrical Generating Facilities

And Associated Transmission Lines

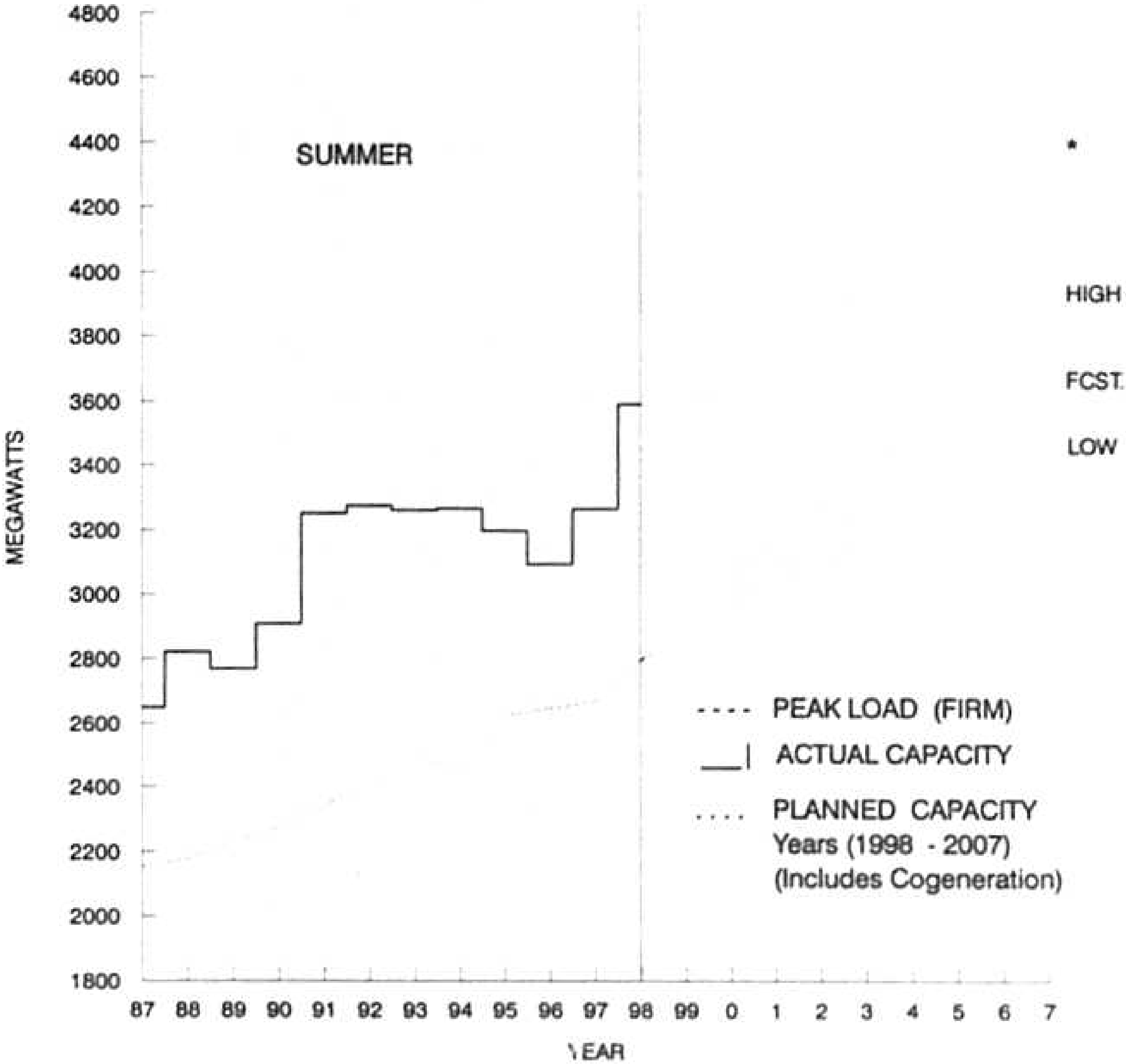
FIGURE III-3 HISTORY & FORECAST OF LOAD AND CAPACITY ADDITIONS
Page 1 of 2



* AGREES WITH SCHEDULE 7.2, COL. 6.

Ten-Year Site Plan
For Electrical Generating Facilities
And Associated Transmission Lines

FIGURE III-3 HISTORY & FORECAST OF LOAD AND CAPACITY ADDITIONS
Page 2 of 2



* AGREES WITH SCHEDULE 7.1, COL 6.

Ten-Year Site Plan
For Electrical Generating Facilities
And Associated Transmission Lines

CHAPTER IV

FORECAST OF FACILITIES REQUIREMENTS

The proposed generating facility additions and changes shown in Table IV-3 integrate demand side management programs and alternative generation technologies with traditional generating resources to provide economical, reliable service to Tampa Electric Company's customers. To achieve this objective, various energy resource plan alternatives comprised of a mixture of generating technologies, purchased power, and cost-effective demand side management programs are developed. These alternatives are analyzed with existing generating capabilities to develop a number of energy resource options which meet Tampa Electric's future system demand and energy requirements. A detailed discussion of Tampa Electric Company's integrated resource planning process is included in Chapter V.

The results of the analysis provide Tampa Electric Company with a plan that is cost-effective while maintaining system reliability and balancing other engineering, business, and industry issues. The new capacity additions are shown in Table IV-3. Additional capacity is first needed in 2001, based on an analysis of system reliability, the incorporation of the FPSC demand side management goals, projected system demand and energy requirements, purchase power, and the existing Tampa Electric generating system. To meet the expected system demand and energy requirements over the next ten years, combustion turbines are planned for service in 2001, 2003, 2004, 2005 and 2007. These dual-fuel combustion turbines will be fired by natural gas and distillate oil. For purposes of this study, Hookers Point Station is assumed to be retired in January 2003, and Tampa Electric's long-term purchase power contract with Hardee Power Partners Limited remains at 297 MW summer net capability and 360 MW winter net capability for the entire study period. Some of the assumptions and information that impact the plan are discussed below. Additional assumptions and information are discussed in Chapter V.

Cogeneration

Tampa Electric Company plans for 444 MW of cogeneration capacity operating in its service area in 1998. Self-service capacity of 236 MW (net) is used by cogenerators to serve internal load requirements, 62 MW are purchased by Tampa Electric on a firm contract basis, and 6 MW are purchased on a non-firm as-available basis. By 2007, the cogeneration capacity within our service area is expected to increase to 472 MW. This total will consist of 253 MW of self-service capacity, 62 MW of firm capacity purchases by Tampa Electric, and 7 MW of non-firm as-available purchases by Tampa Electric. During 1998, Tampa Electric has entered into transmission wheeling agreements with four of its cogeneration customers, supplying a total of 154 MW of firm contract capacity to two other utilities in the state. By 2007, this total is expected to decrease to 145 MW.

Interchange Sales and Purchases

Tampa Electric interchanges sales include Schedule D and Partial Requirements (PR) service agreements with several utilities and a Schedule G contract with Seminole Electric Cooperative, Inc. (SEC) for non-firm capacity and energy.

Tampa Electric has a long term purchase power contract for capacity and energy with Hardee Power Partners Limited (a TECO Power Services Corporation). The contract involves a shared-capacity agreement with SEC, whereby Tampa Electric plans for the full net capability of the Hardee Power Station during those times when SEC plans for the full availability of Seminole Units 1 and 2 and the SEC Crystal River Unit 3 allocation, and reduced availability during times when Seminole Units 1 and 2 are derated or unavailable due to planned maintenance. A firm capacity sale from Tampa Electric's Big Bend Station Unit No. 4 is made available, on a limited energy usage basis, to Hardee Power Partners Limited for resale to SEC.

In addition to the above sales and purchases, Tampa Electric also has Schedule J service agreements for the interchanges/sale of as-available power with/to thirteen utilities in Florida and Georgia.

Wholesale power sales and purchases are included in Tables II-2, II-3, II-4, II-5, II-6, II-7, IV-1, and IV-2.

Interchange Sales and Purchases

Tampa Electric interchanges sales include Schedule D and Partial Requirements (PR) service agreements with several utilities and a Schedule G contract with Seminole Electric Cooperative, Inc. (SEC) for non-firm capacity and energy.

Tampa Electric has a long term purchase power contract for capacity and energy with Hardee Power Partners Limited (a TECO Power Services Corporation). The contract involves a shared-capacity agreement with SEC, whereby Tampa Electric plans for the full net capability of the Hardee Power Station during those times when SEC plans for the full availability of Seminole Units 1 and 2 and the SEC Crystal River Unit 3 allocation, and reduced availability during times when Seminole Units 1 and 2 are derated or unavailable due to planned maintenance. A firm capacity sale from Tampa Electric's Big Bend Station Unit No. 4 is made available, on a limited energy usage basis, to Hardee Power Partners Limited for resale to SEC.

Tampa Electric will serve the FMPA purchase power agreement through 1999 with firm purchases from PECO and FPC. The remainder of the FMPA service agreement will be served by a combination of TEC resources and firm purchase power agreements.

In addition to the above sales and purchases, Tampa Electric also has Schedule J service agreements for the interchanges/sale of as-available power with/to thirteen utilities in Florida and Georgia.

Wholesale power sales and purchases are included in Tables II-2, II-3, II-4, II-5, II-6, II-7, IV-1, and IV-2.

Schedule 7.1

Table IV-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		Total Capacity Available	System Firm Summer Peak Demand	Reserve Margin Before Maintenance		Scheduled Maintenance	Reserve Margin After Maintenance	
Year	MW	MW	MW	QF MW	MW	MW	MW	% of Peak	MW	MW	% of Peak
1998	3,493 *	382	(347)	62	3,590	2,906	684	24%	123	561	19%
1999	3,433	402	(282)	62	3,615	3,019	596	20%	0	596	20%
2000	3,459	297	(297)	62	3,521	3,116	405	13%	0	405	13%
2001	3,614	297	(147)	62	3,826	3,224	602	19%	0	602	19%
2002	3,614	297	(147)	62	3,826	3,316	510	15%	0	510	15%
2003	3,565	297	0	62	3,924	3,413	511	15%	0	511	15%
2004	3,720	297	0	62	4,079	3,509	570	16%	0	570	16%
2005	3,875	297	0	62	4,234	3,594	640	18%	0	640	18%
2006	3,875	297	0	62	4,234	3,690	544	15%	0	544	15%
2007	4,030	297	0	62	4,389	3,786	603	16%	0	603	16%

August 1998 Status

NOTE: 1. Capacity import includes the Purchase Agreement with TECO Power Services (TPS) beginning in 1993. Availability of this capacity is subject to back-up requirements for Seminole Electric Cooperative.

2. Capacity export includes 145 MW of Big Bend 4 which will be sold to TECO Power Services, on a limited basis, for use by Seminole Electric Cooperative. Capacity export also includes a firm D transaction to New Smyrna Beach of 18 MW in 1998 and 19 MW in 1999 as well as a Schedule J transaction with New Smyrna Beach of 10 MW in 1998 and 1999 which is treated as firm for expansion planning purposes. Capacities shown in table include losses.

3. Tampa Electric plans to fulfill the firm D transactions to FMPA via firm power purchases in 1998-99 and from in-house generation thereafter.

4. The QF column accounts for cogeneration that will be purchased under firm contracts.

5. The 1998 system firm summer peak demand represents actual data.

* Does not include 11 MW from Dinner Lake unit which was placed on long-term reserve standby 03/01/94, [illegible] MW from Phillips HRSG which is on full forced outage with an undetermined return to service date.

** Values may be affected by rounding.

Schedule 7.2

Table IV-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
1997-98	3,615 *	360	(261)	62	3,776	2,432	1,344	55%	34	1,310	54%
1998-99	3,587	465	(265)	62	3,849	3,194	655	20%	34	621	19%
1999-00	3,592	360	(311)	62	3,703	3,293	410	12%	34	376	11%
2000-01	3,772	360	(297)	62	3,897	3,400	497	15%	34	463	14%
2001-02	3,772	360	(147)	62	4,047	3,500	547	16%	34	513	15%
2002-03	3,740	360	0	62	4,162	3,596	566	16%	0	566	16%
2003-04	3,920	360	0	62	4,342	3,692	650	18%	0	650	18%
2004-05	4,100	360	0	62	4,522	3,779	743	20%	0	743	20%
2005-06	4,100	360	0	62	4,522	3,877	645	17%	0	645	17%
2006-07	4,280	360	0	62	4,702	3,974	728	18%	0	728	18%

August 1998 Status

NOTE

1. Capacity import includes the Purchase Agreement with TECO Power Services (TPS) beginning in 1993. Availability of this capacity is subject to back-up requirements for Seminole Electric Cooperative.
2. Capacity export includes 145 MW of Big Bend 4 which will be sold to TECO Power Services, on a limited basis, for use by Seminole Electric Cooperative. Capacity export also includes firm transactions to Reedy Creek Improvement District of 15 MW and New Smyrna Beach of 12 MW in 1998, and firm transactions to New Smyrna Beach of 13 MW in 1999 and 14 MW in 2000. Capacities shown in table include losses.
3. Tampa Electric plans to fulfill the firm D transactions to FMPA via firm power purchases in 1998/99 and from in-house generation thereafter.
4. The QF column accounts for cogeneration that will be purchased under firm contracts.
5. The 1997/98 system firm winter peak demand represents actual data.

* Does not include 11 MW from Dinner Lake unit which was placed on long-term reserve standby 03/01/94, nor 3 MW from Phillips HRSG which is on full forced outage with an undetermined return to service date.

** Values may be affected by rounding

Schedule 8

Table IV-3
Planned and Prospective Generating Facility Additions

Plant Name	Unit No.	Location	Type	Fuel Primary	Fuel Alternate	Const. Start Mo/Yr	Commercial In-Service Mo/Yr	Expected Retirement Mo/Yr	Gen. Max. Nameplate kW	Net Capability Summer MW	Net Capability Winter MW	Fuel Trans. Primary	Fuel Trans. Alternate	Status
Polk	2	Polk Co.	CT	NG	LO	1/99	1/01	unknown	unknown	155	180	PL	TK	P
	3	Polk Co.	CT	NG	LO	1/01	1/03	unknown	unknown	155	180	PL	TK	P
	4	Polk Co.	CT	NG	LO	1/02	1/04	unknown	unknown	155	180	PL	TK	P
	5	Polk Co.	CT	NG	.O	1/03	1/05	unknown	unknown	155	180	PL	TK	P
	6	Polk Co.	CT	NG	LC	1/05	1/07	unknown	unknown	155	180	PL	TK	P

August 1998 Status

SCHEDULE 9

TABLE IV-4
(Page 1 of 5)

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

(1)	PLANT NAME AND UNIT NUMBER	POLK UNIT 2
(2)	CAPACITY	
	A. SUMMER	155
	B. WINTER	180
(3)	TECHNOLOGY TYPE	COMBUSTION TURBINE
(4)	ANTICIPATED CONSTRUCTION TIMING	
	A. FIELD CONSTRUCTION START-DATE	JAN 1999
	B. COMMERCIAL IN-SERVICE DATE	JAN 2001
(5)	FUEL	
	A. PRIMARY FUEL	NATURAL GAS
	B. ALTERNATE FUEL	DISTILLATE OIL
(6)	AIR POLLUTION CONTROL STRATEGY	N/A
(7)	COOLING METHOD	N/A
(8)	TOTAL SITE AREA [2]	APPROXIMATELY 4,347 ACRES
(9)	CONSTRUCTION STATUS	PROPOSED
(10)	CERTIFICATION STATUS	N/A
(11)	STATUS WITH FEDERAL AGENCIES	N/A
(12)	PROJECTED UNIT PERFORMANCE DATA	
	PLANNED OUTAGE FACTOR (POF)	1.7
	FORCED OUTAGE RATE (FOR)	3.4
	EQUIVALENT AVAILABILITY FACTOR (EAF)	95.0
	RESULTING CAPACITY FACTOR (%) [1]	17.3
	AVERAGE NET OPERATING HEAT RATE (ANOHR) [1]	11,122 Btu/kWh
(13)	PROJECTED UNIT FINANCIAL DATA	
	BOOK LIFE (YEARS)	30
	TOTAL INSTALLED COST (IN-SERVICE YEAR $/kW)	320.13
	DIRECT CONSTRUCTION COST ($/kW)	292.59
	AFUDC AMOUNT ($/kW)	24.31
	ESCALATION ($/kW)	3.23
	FIXED O&M (2001 $/kW-YR)	5.56
	VARIABLE O&M (2001 $/MWh)	2.72
	K-FACTOR [1]	1.590

[1] BASED ON IN-SERVICE YEAR.
[2] REPRESENTS TOTAL POLK SITE.

SCHEDULE 9

TABLE IV-4
(Page 2 of 5)
STATUS REPORT AND SPECIFICATIONS OF PROPOSED GENERATING FACILITIES
UTILITY: TAMPA ELECTRIC COMPANY

(1)	PLANT NAME AND UNIT NUMBER	POLK UNIT 3
(2)	CAPACITY	
	A. SUMMER	155
	B. WINTER	180
(3)	TECHNOLOGY TYPE	COMBUSTION TURBINE
(4)	ANTICIPATED CONSTRUCTION TIMING	
	A. FIELD CONSTRUCTION START DATE	JAN 2001
	B. COMMERCIAL IN-SERVICE DATE	JAN 2003
(5)	FUEL	
	A. PRIMARY FUEL	NATURAL GAS
	B. ALTERNATE FUEL	DISTILLATE OIL
(6)	AIR POLLUTION CONTROL STRATEGY	N/A
(7)	COOLING METHOD	N/A
(8)	TOTAL SITE AREA [2]	APPROXIMATELY 4,347 ACRES
(9)	CONSTRUCTION STATUS	PROPOSED
(10)	CERTIFICATION STATUS	N/A
(11)	STATUS WITH FEDERAL AGENCIES	N/A
(12)	PROJECTED UNIT PERFORMANCE DATA	
	PLANNED OUTAGE FACTOR (POF)	1.7
	FORCED OUTAGE RATE (FOR)	3.4
	EQUIVALENT AVAILABILITY FACTOR (EAF)	95.0
	RESULTING CAPACITY FACTOR (%) [1]	15.4
	AVERAGE NET OPERATING HEAT RATE (ANOHR) [1]	11,114 Btu/kWh
(13)	PROJECTED UNIT FINANCIAL DATA	
	BOOK LIFE (YEARS)	30
	TOTAL INSTALLED COST (IN-SERVICE YEAR $/kW)	335.68
	DIRECT CONSTRUCTION COST ($/kW)	292.59
	AFUDC AMOUNT ($/kW)	25.49
	ESCALATION ($/kW)	17.60
	FIXED O&M (2003 $/kW-YR)	5.86
	VARIABLE O&M (2003 $/MWh)	2.87
	K-FACTOR [1]	1.601

[1] BASED ON IN-SERVICE YEAR.
[2] REPRESENTS TOTAL POLK SITE.

SCHEDULE 9

TABLE IV-4
(Page 3 of 5)
STATUS REPORT AND SPECIFICATIONS OF PROPOSED GENERATING FACILITIES
UTILITY: TAMPA ELECTRIC COMPANY

(1)	PLANT NAME AND UNIT NUMBER	POLK UNIT 4
(2)	CAPACITY	
	A. SUMMER	155
	B. WINTER	180
(3)	TECHNOLOGY TYPE	COMBUSTION TURBINE
(4)	ANTICIPATED CONSTRUCTION TIMING	
	A. FIELD CONSTRUCTION START DATE	JAN 2002
	B. COMMERCIAL IN-SERVICE DATE	JAN 2004
(5)	FUEL	
	A. PRIMARY FUEL	NATURAL GAS
	B. ALTERNATE FUEL	DISTILLATE OIL
(6)	AIR POLLUTION CONTROL STRATEGY	N/A
(7)	COOLING METHOD	N/A
(8)	TOTAL SITE AREA [2]	APPROXIMATELY 4,347 ACRES
(9)	CONSTRUCTION STATUS	PROPOSED
(10)	CERTIFICATION STATUS	N/A
(11)	STATUS WITH FEDERAL AGENCIES	N/A
(12)	PROJECTED UNIT PERFORMANCE DATA	
	PLANNED OUTAGE FACTOR (POF)	1.7
	FORCED OUTAGE RATE (FOR)	3.4
	EQUIVALENT AVAILABILITY FACTOR (EAF)	95.0
	RESULTING CAPACITY FACTOR (%) [1]	17.1
	AVERAGE NET OPERATING HEAT RATE (ANOHR) [1]	11,094 Btu/kWh
(13)	PROJECTED UNIT FINANCIAL DATA	
	BOOK LIFE (YEARS)	30
	TOTAL INSTALLED COST (IN-SERVICE YEAR $/kW)	343.74
	DIRECT CONSTRUCTION COST ($/kW)	292.59
	AFUDC AMOUNT ($/kW)	26.10
	ESCALATION ($/kW)	25.04
	FIXED O&M (2004 $/kW-YR)	6.02
	VARIABLE O&M (2004 $/MWh)	2.95
	K-FACTOR [1]	1.607

[1] BASED ON IN-SERVICE YEAR.
[2] REPRESENTS TOTAL POLK SITE.

SCHEDULE 9

TABLE IV-4
(Page 4 of 5)
STATUS REPORT AND SPECIFICATIONS OF PROPOSED GENERATING FACILITIES
UTILITY: TAMPA ELECTRIC COMPANY

(1)	PLANT NAME AND UNIT NUMBER	POLK UNIT 5
(2)	CAPACITY	
	A. SUMMER	155
	B. WINTER	180
(3)	TECHNOLOGY TYPE	COMBUSTION TURBINE
(4)	ANTICIPATED CONSTRUCTION TIMING	
	A. FIELD CONSTRUCTION START DATE	JAN 2003
	B. COMMERCIAL IN-SERVICE DATE	JAN 2005
(5)	FUEL	
	A. PRIMARY FUEL	NATURAL GAS
	B. ALTERNATE FUEL	DISTILLATE OIL
(6)	AIR POLLUTION CONTROL STRATEGY	N/A
(7)	COOLING METHOD	N/A
(8)	TOTAL SITE AREA [2]	APPROXIMATELY 4,347 ACRES
(9)	CONSTRUCTION STATUS	PROPOSED
(10)	CERTIFICATION STATUS	N/A
(11)	STATUS WITH FEDERAL AGENCIES	N/A
(12)	PROJECTED UNIT PERFORMANCE DATA	
	PLANNED OUTAGE FACTOR (POF)	1.7
	FORCED OUTAGE RATE (FOR)	3.4
	EQUIVALENT AVAILABILITY FACTOR (EAF)	95.0
	RESULTING CAPACITY FACTOR (%) [1]	17.2
	AVERAGE NET OPERATING HEAT RATE (ANOHR) [1]	11,070 Btu/kWh
(13)	PROJECTED UNIT FINANCIAL DATA	
	BOOK LIFE (YEARS)	30
	TOTAL INSTALLED COST (IN-SERVICE YEAR $/kW)	351.99
	DIRECT CONSTRUCTION COST ($/kW)	292.59
	AFUDC AMOUNT ($/kW)	26.73
	ESCALATION ($/kW)	32.67
	FIXED O&M (2005 $/kW-YR)	6.18
	VARIABLE O&M (2005 $/MWh)	3.03
	K-FACTOR [1]	1.613

[1] BASED ON IN-SERVICE YEAR.
[2] REPRESENTS TOTAL POLK SITE.

SCHEDULE 9

TABLE IV-4
(Page 5 of 5)
STATUS REPORT AND SPECIFICATIONS OF PROPOSED GENERATING FACILITIES
UTILITY: TAMPA ELECTRIC COMPANY

(1)	PLANT NAME AND UNIT NUMBER	POLK UNIT 6
(2)	CAPACITY	
	A. SUMMER	155
	B. WINTER	180
(3)	TECHNOLOGY TYPE	COMBUSTION TURBINE
(4)	ANTICIPATED CONSTRUCTION TIMING	
	A. FIELD CONSTRUCTION START DATE	JAN 2005
	B. COMMERCIAL IN-SERVICE DATE	JAN 2007
(5)	FUEL	
	A. PRIMARY FUEL	NATURAL GAS
	B. ALTERNATE FUEL	DISTILLATE OIL
(6)	AIR POLLUTION CONTROL STRATEGY	N/A
(7)	COOLING METHOD	N/A
(8)	TOTAL SITE AREA [2]	APPROXIMATELY 4,347 ACRES
(9)	CONSTRUCTION STATUS	PROPOSED
(10)	CERTIFICATION STATUS	N/A
(11)	STATUS WITH FEDERAL AGENCIES	N/A
(12)	PROJECTED UNIT PERFORMANCE DATA	
	PLANNED OUTAGE FACTOR (POF)	1.7
	FORCED OUTAGE RATE (FOR)	3.4
	EQUIVALENT AVAILABILITY FACTOR (EAF)	95.0
	RESULTING CAPACITY FACTOR (%) [1]	20.6
	AVERAGE NET OPERATING HEAT RATE (ANOHR) [1]	11,004 Btu/kWh
(13)	PROJECTED UNIT FINANCIAL DATA	
	BOOK LIFE (YEARS)	30
	TOTAL INSTALLED COST (IN-SERVICE YEAR $/kW)	369.09
	DIRECT CONSTRUCTION COST ($/kW)	292.59
	AFUDC AMOUNT ($/kW)	28.03
	ESCALATION ($/kW)	48.47
	FIXED O&M (2007 $/kW-YR)	6.52
	VARIABLE O&M (2007 $/MWh)	3.19
	K-FACTOR [1]	1.626

[1] BASED ON IN-SERVICE YEAR.
[2] REPRESENTS TOTAL POLK SITE.

Schedule 10

Table IV-5
Status Report and Specifications of Proposed Directly Associated Transmission Lines

Point of Origin and Termination	Number of Lines	Right-of-Way	Line Length	Voltage	Anticipated Construction Timing (in service by)	Anticipated Capital Investment	Substations	Participation with Other Utilities
South Gibsonton - Gannon - 11th Ave	2	No new right of way is required	0.2 miles	230 kV	Fall 2000	$2 million	No new substations	None
Hardee - Polk	1	No new right of way is required	9.4 miles	230 kV	Fall 2000	$3 million	No new substations	Unknown at this time
S.R. 60 - Davis	2	No new right of way is required	0.7 miles	230 kV	Summer 2002	$12 million	Davis Substation	None
Polk - Mines	1	No new right of way is required	23.6 miles	230 kV	Fall 2002	$1 million	No new substations	None
Lithia - Wheeler	2	11 miles long and 100 feet wide	11.0 miles	230 kV	Summer 2003	$14 million	Lithia Switching Station	None
Polk - Lithia	2	28 miles long and 100 feet wide	28.0 miles	230 kV	Fall 2003	$21 million	No new substations	None
Wheeler - Davis - Chapman - DaleMabry	2	12 miles long and 100 feet wide	25.4 miles	230 kV	Fall 2004	$16 million	No new substations	None
Chapman - Dale Mabry - Florida Ave	2	No new right of way is required	1.5 miles	69 kV	Summer 2005	$3 million	No new substations	None
Gapway	2	No new right of way is required	0.2 miles	230 kV	Summer 2005	$4 million	No new substations	None
Chapman - Dale Mabry - Sheldon	2	No new right of way is required	9.0 miles	230 kV	Summer 2007	$6 million	No new substations	Unknown at this time
Barcola - Pebbledale	2	No new right of way is required	TEC 2.7 miles FPC 1.2 miles	230 kV	Unknown at this time	TEC $3 million	No new substations	Joint Project with FPC

CHAPTER V

OTHER PLANNING ASSUMPTIONS AND INFORMATION

Transmission Constraints and Impacts

Assessments of Tampa Electric transmission system performance are based upon planning studies completed in 1997 in support of Tampa Electric's transmission expansion plan. These studies are performed annually with the results of the study varying due to updates in load projections, planning criteria, and operating flexibility. Based on existing studies and Tampa Electric's current transmission construction program, Tampa Electric anticipates no transmission constraints on our system which violate the submitted performance criteria contained in the Generation and Transmission Reliability Criteria section of this document.

Expansion Plan Economics and Load Sensitivity

The overall economics and cost-effectiveness of the plan were analyzed as stated in Tampa Electric's Integrated Resource Planning process. This process is discussed in detail later in this chapter. Sensitivity analyses using high and low bands of the base case load forecast yielded generation expansion plans that were significantly different from the base case plan of one combustion turbine in each of the years 2001, 2003, 2004, 2005 and 2007. Optimization based on the low load forecast deferred the 2001 and 2004 combustion turbines one year and moved the 2005 and 2007 combustion turbines out of the ten-year planning window. The expansion plan based on the high load forecast adds two additional combustion turbines.

Fuel Forecast and Sensitivity

Product price for actual and forecast data for the purpose of deriving base, high, and low forecast pricing is done by careful analysis of actual price and current and previous forecasts obtained by various consultants and agencies. These sources include the Energy Information Administration, American Gas Association, Cambridge Energy Research Associates, Resource Data International, Coal Markets Weekly, Coal Daily, Energy Ventures Analysis, Inc., and coal, oil, natural gas, and propane pricing publications and periodicals which include: Coal Outlook, Inside FERC, Natural Gas Week, Platt's Oilgram, and the Oil and Gas Journal.

The high and low fuel price projections represent alternative forecasts to the company's base case outlook. The high price projection represents the effect of oil and natural gas prices escalating 10% above the base case on a monthly basis to the year 2000.

The low price scenario represents the effect of oil and natural gas prices escalating 10% below the product price of the base case on a monthly basis to the year 2000. Annual high and low

The low price scenario represents the effect of oil and natural gas prices escalating 10% below the product price of the base case on a monthly basis to the year 2000. Annual high and low case price projections after 2000 are based on the company's internal general approach using information provided by consultants combined with internal fuel markets analysis.

With a large percentage of fuel utilized by the company being coal, only base case forecasts are prepared for coal fuels. Base case analysis and forecasts include a large number of coal sources and diverse qualities. The individual price forecasts contained within the base forecast capture the market pressures and sensitivities that would otherwise be reflected in high and low case scenarios.

Expansion Plan Sensitivity Constant Fuel Differential

Even though Tampa Electric does not recognize, as a viable forecasting method, the arbitrary development of a fuel forecast by fixing the price differential between non-linked fuels, an expansion plan fuel sensitivity was performed by holding the differential between oil/gas and coal constant. The base case expansion plan did not change as a result of this change in the fuel price forecast. This result was expected because Tampa Electric Company's base case expansion plan consists of combustion turbines. These dual-fuel combustion turbines will be fired by natural gas and distillate oil. Because this sensitivity lowers Tampa Electric Company's natural gas and oil price forecasts and Tampa Electric Company's future resources are fired by natural gas and oil, it results in the same base case plan.

Generating Unit Performance Modeling

Tampa Electric Company models generating unit performance in the Generation and Fuel (GAF) module of PROSCREEN, a computer model developed by New Energy Associates. This module is a tool to evaluate long-range system operating costs associated with particular generation expansion plans. Generating units in the GAF 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 that are modeled are based on historical data trends, engineering judgement, time since last planned outage, and recent equipment performance. Specifically, unit capacity and heat rate projections are based on historical unit performance test values which are adjusted as needed for current unit conditions. Planned outage projections are modeled two ways. 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 outage schedule is based on unit-specific maintenance needs, material lead time, labor availability, budget constraints, 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 condition 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 over its useful life the total original investment in a plant item 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 Company'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. A flow diagram of the overall process is shown in Figure V-1.

The initial pass of 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. In this pass, a demand and energy forecast which excludes incremental DSM programs is developed. Then a supply plan based on the system requirements which excludes incremental DSM is developed. This interim supply plan becomes the basis for potential avoided unit(s) in a comprehensive cost-effective analysis of the DSM programs. Once the cost-effective DSM 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 DSM programs and supply side resources. The same planning and business assumptions are used to develop numerous combinations of DSM and supply side resources that account for variances in both timing and type of resources added to the Tampa Electric Company system.

The cost-effectiveness of DSM 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 Commission'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 DSM analysis are considered for utility program adoption. Each adopted measure is quantified into annual kW/kWh savings and is reflected in the demand and energy forecast. Measures with the highest RIM values are generally adopted first.

Tampa Electric Company evaluates DSM measures using a spreadsheet developed to meet the Commission'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 Company service area. Geographic viability, weather conditions, public acceptance, economics, lead-time, environmental acceptability, safety, and proven demonstration and commercialization are used as criteria to screen the generating technologies to a manageable number.

The technologies which pass the screening are included in a supply side analysis which examines various supply side alternatives for meeting future capacity requirements. These include modifying existing units by repowering or over-pressure operation and delayed retirements. Other supply resources such as constructing new unit additions, firm power purchases from other generating entities, joint ownership of generating capacity, and modifications of the transmission system to increase import capability are included in the analysis.

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

The results of the Integrated Resource Planning process provides Tampa Electric Company 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 Table IV-3. To meet the expected system demand and energy requirements over the next ten years and cost-effectively maintain system reliability, combustion turbines are planned for January of 2001, 2003, 2004, 2005 and 2007. These combustion turbines will be dual-fueled by natural gas and distillate oil. For the purposes of this study, Hookers Point Station is assumed to be retired in January of 2003, and Tampa Electric's long-term purchase power contract with Hardee Power Partners Limited remains at 297 MW summer net capability and 360 MW winter net capability for the entire study period.

TAMPA ELECTRIC COMPANY
INTEGRATED RESOURCE PLAN METHODOLOGY

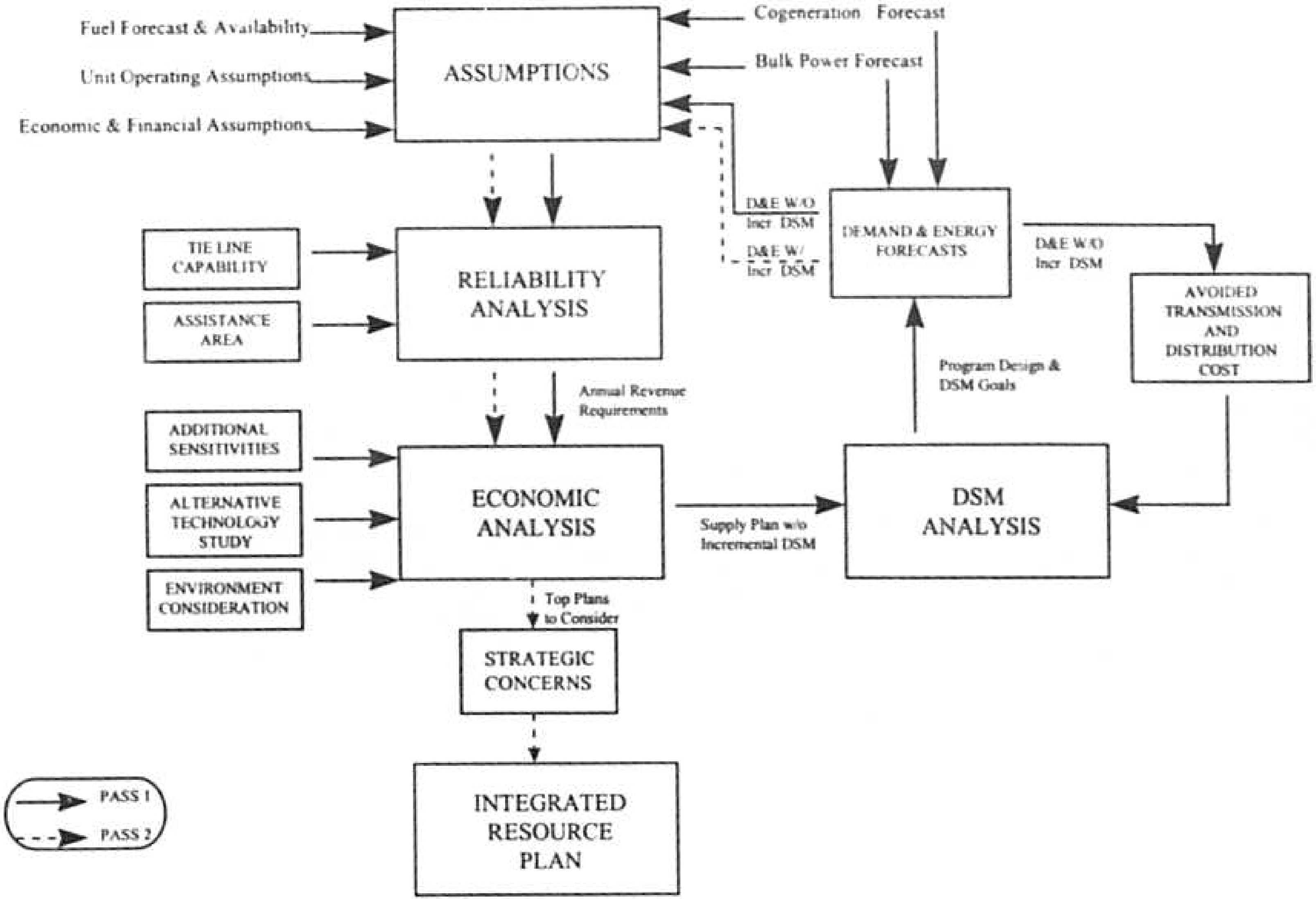


FIGURE V-1

Generation and Transmission Reliability Criteria

Generation

Tampa Electric Company uses the dual reliability criteria of 1% Expected Unserved Energy (%EUE) and a 15% minimum firm winter reserve margin for planning purposes.

Tampa Electric Company's approach to calculating percent reserves is consistent with the 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 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 percent Expected Unserved Energy (%EUE) criteria addresses annual reliability. Similar to calculating percent reserves, all firm unit and station power sales are accounted for in determining Tampa Electric's available capacity resources. The 1% EUE target was developed as an equivalent to the loss of Tampa Electric's largest unit (Big Bend Unit 4, 447 MW) for an entire year and maintaining firm reserves of approximately 15%. In calculating the EUE, the Hardee Power Station is considered to be available as a Tampa Electric capacity resource only after its availability is reduced for planned outages, forced outages, and projected Seminole Electric Cooperative (SEC) usage. SEC provides Tampa Electric with its projected usage of the Hardee Power Station capacity. Percent EUE is calculated by dividing Tampa Electric's projected annual non-firm purchases (excluding economy) by its Net Energy for Load and multiplying by 100%. Under these conditions, Tampa Electric will have adequate reserves or available emergency and/or contracted short-term firm capacity to mitigate expected unserved energy.

Transmission

The following criteria are used as guidelines by Tampa Electric Company Transmission Planners during planning studies. However, they are not absolute rules for system expansion; the criteria are used to alert planners of potential transmission system capacity limitations. Engineering analysis is used in all stages of the planning process to weigh the impact of system deficiencies, the likelihood of the triggering contingency, and the viability of any operating options. Only by carefully researching each planning criteria violation can a final evaluation of available transmission capacity be made.

Gene. ation 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 Florida Reliability Coordinating Council (FRCC).

Since 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 Criteria

Tampa Electric follows the FRCC planning criteria as contained in Section V of the FRCC System Planning Committee Handbook.

In addition to FRCC criteria, Tampa Electric utilizes company-specific planning criteria. Listed below are the guidelines which are used prior to contingency analysis to identify any inherent system flaws:

Transmission System Loading Limits	
Transmission System Conditions	Acceptable Loading Limit for Transformers and Transmission Lines
All facilities in service	100% or less

Transmission System Voltage Limits			
	Industrial Substation Buses at point-of-service	69 kV Buses	138 kV and 230 kV Buses
All facilities in service	0.950 - 1.050 pu	0.950 - 1.050 pu	0.950 - 1.050 pu

Single Contingency Planning Criteria

The following two tables summarize the thresholds which alert planners to problematic transmission line and transformer single contingency scenarios.

Transmission System Loading Limits	
Transmission System Conditions	Acceptable Loading Limit for Transmission Lines and Transformers
Single Contingency, pre-switching	115% or less
Single Contingency, after all switching	100% or less
Bus Outages, pre-switching	115% or less
Bus Outages, after all switching	100% or less

Transmission System Voltage Limits			
Transmission System Conditions	Industrial Substation Buses at point-of- service	69 kV Buses	138 kV and 230 kV Buses
Single Contingency, pre-switching	0.925 - 1.050 pu	0.950 - 1.050 pu	0.950 - 1.050 pu
Single Contingency, after all switching	0.950 - 1.050 pu	0.950 - 1.050 pu	0.950 - 1.050 pu
Bus Outages	0.925 - 1.050 pu	0.950 - 1.050 pu	0.950 - 1.050 pu

Available Transmission Transfer Capability (ATC) Criteria

Tampa Electric adheres to the FRCC ATC calculation methodology as well as the principles contained in the NERC ATC Definitions and Determinations document.

Transmission Planning Assessment Practices

Base Case Operating Conditions

Transmission planners ensure that Tampa Electric's transmission system can first and foremost support peak and off-peak system load with no facility overload, voltage violation, or imprudent operating modes. Therefore, the first step in assessing the health of the transmission system is to guarantee that all equipment is within specified continuous loading and voltage guidelines. Consult the previous section for more specific system parameters.

Single Contingency Planning Criteria

The objective of transmission planning is to design a system that can sustain the loss of any single circuit element without loading any transmission line or transformer beyond its rating or resulting in voltage levels that deviate outside of the bandwidths set forth in the Transmission System Planning Criteria section. In the course of single contingency analysis, single contingency fault events which result in the removal of multiple transmission system elements from service due to protection system response are modeled in the manner that the system would respond to the fault. Any verified criteria violation which cannot be mitigated with an appropriate operating measure is flagged as a limitation on transmission system capacity. Consult the Transmission System Planning Criteria section of this document for more specific system parameters.

Tampa Electric plans on any given piece of transmission system equipment being unavailable for service at some point in time. In addition to Tampa Electric equipment being out of service, Tampa Electric transmission planners plan the system to tolerate the loss of service of equipment outside of Tampa Electric's control area. This mainly consists of bulk transmission system equipment and generation units throughout the state.

Multiple Contingency Planning Criteria

Criteria for multiple contingency conditions are the same as single contingency criteria but are simulated at off-peak load levels. Appropriate double contingencies are investigated at 100% load level when warranted by area load factors. Multiple contingency conditions are also used to gauge the urgency of system deficiencies which are identified during single contingency analysis as cause for concern.

First Contingency Total Transfer Capability Considerations

Bulk transmission planners also use multiple generator/transmission equipment contingency criteria to ensure that Tampa Electric's transmission system import corridors are loaded within approved limits in the event of a Tampa Electric generation shortfall. To accomplish this, statewide dispatches are investigated which load each of Tampa Electric's tie lines to their First Contingency Total Transfer Capability.

Base case and contingency conditions are then imposed to locate any transmission or sub-transmission weaknesses which would require reinforcement under such a scenario. When necessary, bulk planners identify situations where FCTTC and/or internal system capacities should be increased to raise the capability of a transmission corridor.

FCTTC's which must be observed for Tampa Electric's multi-line corridors are listed below:

Tie line	FCTTC
Lake Tarpon-Sheldon 230 kV	1100 MVA
Big Bend-Florida Power & Light 230 kV	1500 MVA

DSM Energy Savings Durability

Tampa Electric Company identifies and verifies the durability of energy savings from our conservation and DSM programs by several methods. First, Tampa Electric Company has established a monitoring and evaluation (M&E) process where historical analysis identifies the energy savings. These include:

(1) end-use metering of a load survey sample to identify the savings achieved on air conditioning, heating, and water heating;

(2) bill analysis of program participants compared to control groups to minimize the impact of weather abnormalities; and

(3) in commercial programs such as Standby Generator and C/I Load Management, the reductions are verified through submetering of those loads under control to determine participant incentives relative to demand and energy savings.

Secondly, the programs are designed to promote the use of high-efficiency equipment having permanent installation characteristics. Where programs promote the installation of energy efficient measures or equipment (heat pumps, hard-wired lighting fixtures, ceiling insulation, air distribution system repairs), program standards require they be of a permanent nature. For example, our Commercial Indoor Lighting Program requires full-fixture replacement or hard-wiring of fixture replacements.

Supply Side Resources Procurement Process

Tampa Electric Company 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 a process improvement recommendations. The procurement process will also demonstrate continued positive efforts by Tampa Electric to include minority, small, and women-owned businesses. Goals will be established and tracked to measure opportunities and awards realized by these firms.

Transmission Construction and Upgrade Plans

Tampa Electric's planned generating units at the Polk Power Station changed the prevailing direction of power flow throughout the bulk 230kV system. Loads in the Eastern and Plant City Service Areas, which have traditionally been served by generation at Big Bend and Gannon, are now going to be served by new generation at Polk Power Station. This causes Big Bend and Gannon to redirect more power into the Central and Western Service Areas, resulting in numerous contingency overloads and low voltages. Thus, the first major transmission and substation construction projects are directed at improving the reliability and efficiency of the 230kV bulk system which transmits power north from Big Bend and Gannon. Later, as load growth continues and more generation is installed at Polk, additional transmission lines and substations must be built to deliver this new generation into the load centers in Eastern, Central and Western Service Areas.

By the Fall of 2000, Tampa Electric plans to upgrade and reconfigure several circuits at the Gannon 230kV Substation. In order to address transient and steady-state stability concerns at both Hardee and Polk Power Stations, a 2nd 9.4-mile Hardee-Polk 230kV circuit is planned for the Fall of 2000. A new 230/69kV Davis Substation and a new 230kV bus at S.R. 60 Substation are planned for the Summer of 2002, along with 0.7 miles of double-circuit 230kV line and the reconfiguration of several 230kV and 69kV circuits. The existing 23.6-mile Polk-Mines 230kV circuit is planned to be upgraded by the Fall of 2002. A new 230kV bus and 230/69kV transformer is planned at Wheeler Substation by the Summer of 2003, to be sourced by a new 11-mile double-circuit line from a new 230kV Lithia Switching Station. By the Fall of 2003, a new 28-mile double-circuit 230kV line is planned from Polk to Lithia, along with a 2nd 230/69kV transformer at Wheeler and two new 69kV circuits. By the Fall of 2004, a new 25.4-mile double-circuit 230kV line is planned to tie Wheeler to Davis, Chapman and Dale Mabry Substations. By the Summer of 2005, a 2nd 230/69kV transformer and 1.5 miles of double-circuit 69kV line is planned for Chapman, as well as a 230/69kV transformer at Gapway Substation. By the Summer of 2007, a new 9.0-mile double-circuit 230kV line is planned from Chapman and Dale Mabry to Sheldon. Also, the existing 3.9 mile 230kV interconnect circuit between Florida Power Corporation's Barcola Substation and Tampa Electric Company's Pebbledale Substation will need to be rebuilt as a double-circuit line. The timing for this joint project with FPC is yet to be determined, and is contingent on FPC's generation expansion plans at Hines Energy Complex.

Base case and contingency conditions are then imposed to locate any transmission or sub-transmission weaknesses which would require reinforcement under such a scenario. When necessary, bulk planners identify situations where FCTTC and/or internal system capacities should be increased to raise the capability of a transmission corridor.

FCTTC's which must be observed for Tampa Electric's multi-line corridors are listed below:

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(1) end-use metering of a load survey sample to identify the savings achieved on air conditioning, heating, and water heating;

(2) bill analysis of program participants compared to control groups to minimize the impact of weather abnormalities; and

(3) in commercial programs such as Standby Generator and C/I Load Management, the reductions are verified through submetering of those loads under control to determine participant incentives relative to demand and energy savings.

Secondly, the programs are designed to promote the use of high-efficiency equipment having permanent installation characteristics. Where programs promote the installation of energy efficient measures or equipment (heat pumps, hard-wired lighting fixtures, ceiling insulation, air distribution system repairs), program standards require they be of a permanent nature. For example, our Commercial Indoor Lighting Program requires full-fixture replacement or hard-wiring of fixture replacements.

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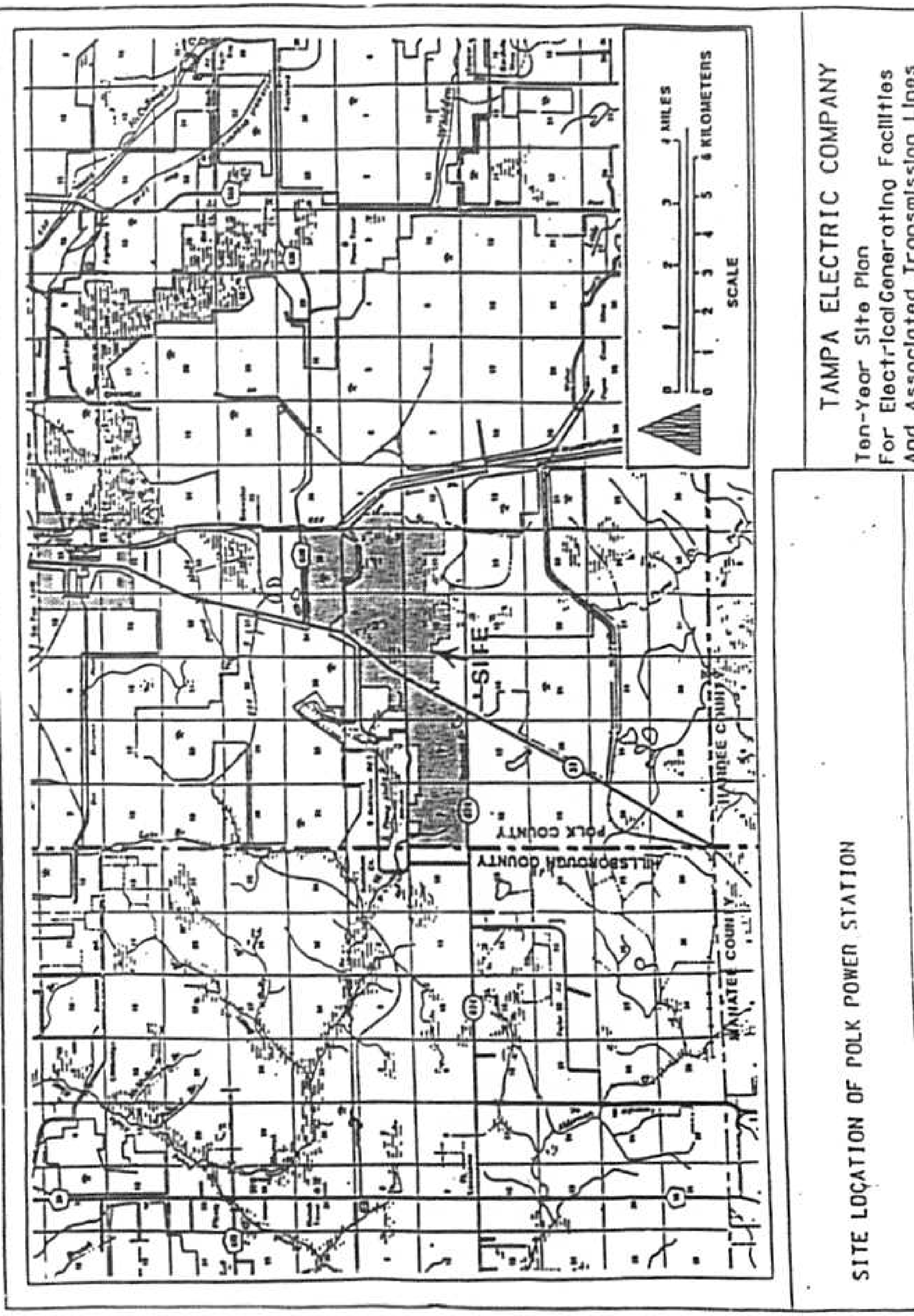
Tampa Electric Company will manage the procurement process in accordance with established policies and procedures. Prospective suppliers of supply side resources as well as suppliers of equipment and services will be identified using various data base resources and competitive bid evaluations, and will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

CHAPTER VI

ENVIRONMENTAL AND LAND USE INFORMATION

The future generating capacity additions identified in Chapter IV will occur at the existing Polk Power Plant facility. The Polk Power Plant site is located in southwest Polk County close to the Hillsborough and Hardee County lines (See Figure VI-1). This facility is an existing power plant site that has been permitted under the Florida Power Plant Siting Act. There are no new potential sites being considered for the 10-year horizon.

FIGURE VI-1



SITE LOCATION OF POLK POWER STATION

SOURCES: FDOT MAP, FLA. DCT.